ACER

European Union Agency for the Cooperation of Energy Regulators

Demand response and other distributed energy resources: what barriers are holding them back?

2023 Market Monitoring Report

19 December 2023

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EXECUTIVE SUMMARY AND MAIN RECOMMENDATIONS

1 This ACER report highlights the key potential of consumers as providers of much-needed flexibility in the European Union (EU) power system. It identifies key barriers to the participation of distributed energy resources (i.e., demand response, energy storage, and distributed generation) in the wholesale electricity markets and system operation services in the EU-27 Member States plus Norway[1] in 2022, and it presents key findings and specific recommendations per country.

Distributed energy resources include:

- ***Demand response***
- ***New energy storage solutions***
- ***Distributed generation***

Flexibility is the ability of energy resources and consumers to change or adjust their consumption or production in response to price signals or to provide services to system operators

2 The recent energy crisis carries important lessons with implications for energy decision makers at the EU and national level. First, Member States benefit massively from Europe's highly integrated electricity market both in times of crisis and beyond. Second, shifting and reducing electricity demand plays a crucial role when electricity supply is scarce or at risk. Adding to this context, Europe's ambition to be a carbon neutral continent by 2050, and the need to fully utilise the available flexibility in the system becomes obvious. Flexibility refers to the ability of energy resources and consumers to change or adjust their consumption or production in response to price signals or to help system operators solve imbalances or network congestions. An increasing need for flexibility in the EU power system is a key opportunity for consumers to be part of the energy transition.

3 During the recent energy crisis, Europe's highly integrated power market helped Member States mitigate energy price shocks and enhance security of supply. Integrated and well-interconnected electricity markets provide huge benefits in terms of enhanced resilience, trade, and dampening price volatility compared to Member States operating in isolation. An integrated EU power market requires maximising the interconnection levels: Member States must increase the electricity capacity available for trade with their neighbours to further improve both short-term and long-term market functioning, and to speed up the needed investments into energy infrastructure.

4 Energy systems need to deal with the huge increase in fluctuation of electricity supply driven by the exponential growth expected in solar and wind electricity generation in the coming years. Flexibility in the EU power system needs to almost double by 2030 compared to today to keep up with the growth of variable renewable electricity sources. As shown in ACER-EEA's 2023 report entitled Flexibility solutions to support a decarbonised and secure EU electricity system, Member States should exploit collaboration synergies to unlock flexibility and enhance energy security while contributing to long-term climate neutrality. Key necessary improvements include better cross-border planning and forecasting, enhanced use of interconnectors, as well as financial incentives and reliable information for electricity consumers to adapt demand when needed.

Flexibility in the EU power system needs to almost double by 2030

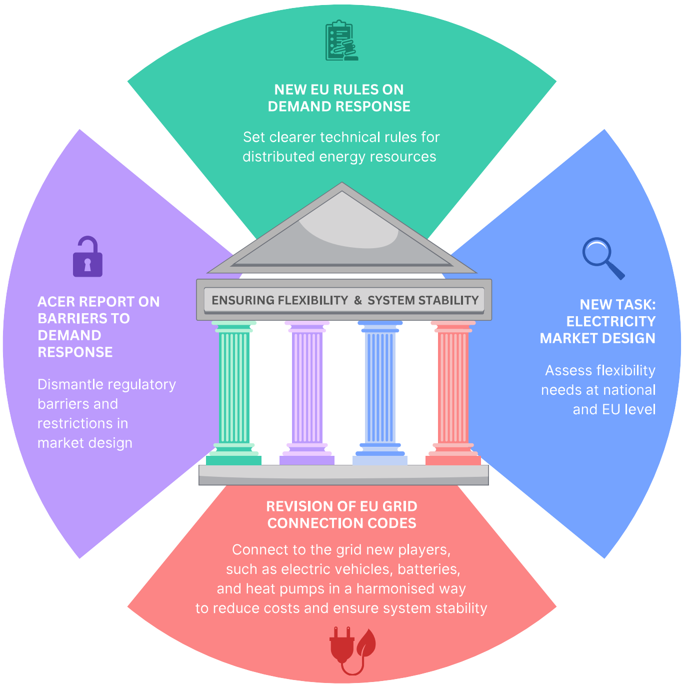
This report focuses on demand response, energy storage, and distributed generation as key flexibility solutions

5 Several of ACER's market monitoring reports published this year underline the importance of the EU's integrated energy markets and further challenges ahead[2]. This report focuses on demand response, energy storage, and distributed generation as key flexibility solutions. It points out the barriers to these distributed energy resources in each EU-27 Member State and Norway. It includes specific recommendations on how countries can tackle such barriers and enable consumers to play their part in the transition to clean energy.

1 The term 'Member States' is used throughout this report to cover the EU-27 Member States and Norway.

2 For the reports ACER has published in 2023 and in previous years, see the ACER market monitoring page.

Figure 1: Ongoing efforts to ensure flexibility and stability in the EU power system – 2023



Source: ACER.

6 The above visualisation represents the many ongoing efforts to bring the EU into a situation where all the available flexibility in the power system can be used successfully. The revision of the existing grid connection network codes should result in a harmonised approach to connect new users such as electric vehicles, storage, and heat pumps to the grid, providing economies of scale and supporting a massive uptake of emerging technologies while ensuring system stability. The new rules on demand response should set clearer technical rules to allow all distributed energy resources to effectively participate in the electricity markets and help system operators solve imbalances or network congestions. The upcoming reform of the electricity market design is expected to introduce flexibility needs assessments in a forward-looking way. Such assessments will inform targets to increase flexibility of distributed energy resources. However, more efforts are needed. This report shows how Member States must also dismantle the existing regulatory barriers and restrictions in the design of their electricity markets and system operation services as soon as possible. Each and every effort is crucial to ensure a strong foundation to ensure flexibility and stability in the EU power system.

The challenge - targeting the many barriers to demand response often hiding in plain sight

Individually, each separate barrier might seem small in isolation. However, the sum of many small obstacles adds up to serious barriers impacting the overall market

7 Multiple barriers to demand response persist (e.g., difficulties to access markets, lack of national rules, retail prices not reflecting system needs, etc.). Individually, each separate barrier might seem small in isolation. However, the sum of many small obstacles adds up to serious barriers impacting the overall market. Hence, dismantling the many barriers to demand response and other distributed energy resources requires a significant effort.

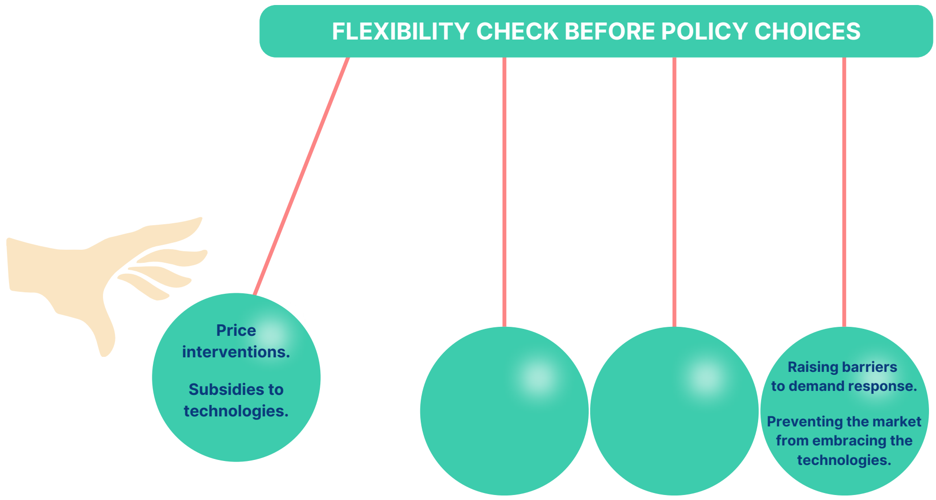
Policy choices involve tough trade-offs; demand response risks ending up their victim

8 Barriers to demand response are important for policymakers to consider when setting and reviewing policy goals. Policies involve trade-offs, sometimes between providing a short-term relief and hindering demand response over the long term. This can be the case when a Member State decreases the wholesale or retail electricity price. Whilst seeking to cushion consumers from higher prices in the short term, intervening can have unintended consequences such as removing the price signal to reduce or shift electricity demand; at times a necessary means to tackle scarce supply. It can also delay investments that allow consumers (households or non-households) to actively invest or participate in demand response programmes, mitigating higher prices. The impact of certain interventions therefore needs to be carefully considered since they can raise new barriers for distributed energy resources.

Market interventions (e.g., decreasing retail electricity prices or subsidising some technologies) can raise barriers or prevent distributed energy resources finding their way to the market

9 The same happens when Member States subsidise certain technologies to trigger investments, before removing the barriers that were preventing such technologies from finding their way to the market in the first place. Such barriers should usefully be targeted ahead of any additional intervention, thus avoiding 'addressing symptoms before the cause'. Identifying and considering barriers to uptake of distributed energy resources is therefore crucial in national policymaking.

Figure 2: Some policy choices that can raise barriers to demand response or prevent distributed energy resources finding their way to the market



Source: ACER.

Very high and very low prices each signal opportunities

10 Very high and very low (or even negative) wholesale electricity prices send important signals. They tell generators where to invest and when to generate. They signal to traders where to trade. They nudge consumers on whether and when to consume (e.g., to charge their electric vehicle).

11 Negative wholesale prices are becoming more prevalent, indicating a need to enhance overall system responsiveness, or put more simply, make sure assets in the system respond to what the system needs. Such system responsiveness can be increased in different ways, namely through investment and deployment of new assets and through making decisions on how to operate the system. Investment and deployment of new assets needs to be made based on realistic targets, risk allocation, system planning and how to factor in signals that show more appropriate locations for new generation compared to others (e.g., grid connection charges). Operational decisions may be influenced by support schemes in place or whether cost-reflective grid charging is prevalent or not (e.g., through injection charges).

12 Most importantly, a certain amount of price volatility and thus also at times negative wholesale prices send clear signals to activate demand response. Dampening such signals for other policy objectives can of course be legitimate but may come at a price in terms of future-proofing the system towards a more dynamic, responsive, and renewables-ready pathway.

What are the main barriers to the uptake of demand response, energy storage, and distributed generation?

The potential for demand response, energy storage, and distributed generation remains largely untapped

13 This report examines why the potential flexibility in demand response, energy storage, and distributed generation remains largely untapped. It monitors the following barriers in the EU-27 Member States and Norway:

- Lack of a proper legal framework to allow distributed energy resources to access electricity markets and provide services to system operators;
- Unavailability or lack of incentives (e.g., some price signal or reward) to provide flexibility;
- Restrictive requirements to providing balancing and congestion management services or to participating in capacity mechanisms and interruptibility schemes;
- Limited competitive pressure in the retail market;
- Public interventions in the retail electricity prices;
- Other frequent barriers in the electricity sector also impacting distributed energy resources such as insufficient electricity capacity being made available by Member States for trading with their neighbours, bidding zones not reflecting structural congestions, limited competitive pressure and/or liquidity in wholesale electricity markets or certain administrative and financial requirements.

14 Table 1 shows the persistence of the different barriers across Europe.

Every Member State has barriers that prevent consumers from adapting their electricity consumption

Table 1: Overview of barriers to distributed energy resources and other new entrants and small actors per Member State

Barrier	AT	BE	BG	CY	CZ	DE	DK	EE	ES	FI	FR	GR	HR	HU	IE	IT	LT	LU	LV	MT	NL	NO	PL	PT	RO	SE	SI	SK
Lack of a proper legal framework to allow market access	Not (too) restrictive	Not (too) restrictive	N/A	Low	Low	Low	Not (too) restrictive	Not (too) restrictive	Not (too) restrictive	Low	Not (too) restrictive	Not (too) restrictive	Not (too) restrictive	Not (too) restrictive	Not (too) restrictive	Not (too) restrictive	Not (too) restrictive	Moderate	Not (too) restrictive	Not (too) restrictive	Low	Not (too) restrictive	Low	Not (too) restrictive	Not (too) restrictive	Not (too) restrictive	Not (too) restrictive	Not (too) restrictive
Unavailability or lack of incentives to provide flexibility	Low	Low	N/A	Moderate	Moderate	Low	N/A	Not (too) restrictive	Not (too) restrictive	Low	Not (too) restrictive	Low	Low	Low	N/A	Not (too) restrictive	Low	Low	Not (too) restrictive	Low	Not (too) restrictive	Low	Moderate	Not (too) restrictive	Low	Low	Not (too) restrictive	Moderate
Restrictive requirements to providing balancing services	Not (too) restrictive	Not (too) restrictive	N/A	NAP	Not (too) restrictive	Not (too) restrictive	Not (too) restrictive	Not (too) restrictive	Low	Not (too) restrictive	Not (too) restrictive	Not (too) restrictive	Moderate	Not (too) restrictive	N/A	Low	Not (too) restrictive	Not (too) restrictive	Not (too) restrictive	NAP	Not (too) restrictive	Not (too) restrictive	Low	Low	Not (too) restrictive	Not (too) restrictive	Not (too) restrictive	Not (too) restrictive
Restrictive requirements to providing congestion management	High	Not (too) restrictive	N/A	N/A	High	Moderate	High	NAP	Not (too) restrictive	Not (too) restrictive	Not (too) restrictive	Low	Not (too) restrictive	Not (too) restrictive	High	Not (too) restrictive	NAP	NAP	High	Moderate	Moderate	Not (too) restrictive	Moderate	Not (too) restrictive	Low	Not (too) restrictive	High	High
Restrictive requirements to participating in capacity mechanisms	NAP	Low	NAP	NAP	NAP	Moderate	NAP	NAP	NAP	Low	Not (too) restrictive	NAP	NAP	NAP	Low	Not (too) restrictive	NAP	NAP	NAP	NAP	NAP	NAP	Low	NAP	NAP	Not (too) restrictive	NAP	NAP
Restrictive requirements to participating in interruptibility schemes	NAP	NAP	NAP	NAP	NAP	Moderate	NAP	NAP	NAP	NAP	Moderate	NAP	NAP	NAP	NAP	Not (too) restrictive	NAP	NAP	NAP	NAP	NAP	NAP	Low	NAP	NAP	NAP	NAP	NAP
Limited competitive pressure in the retail market	Not (too) restrictive	Not (too) restrictive	Low	Moderate	Not (too) restrictive	N/A	N/A	Not (too) restrictive	Not (too) restrictive	Not (too) restrictive	Low	Moderate	Moderate	Moderate	Low	Not (too) restrictive	Low	Low	Not (too) restrictive	High	Low	Not (too) restrictive	Low	Moderate	Not (too) restrictive	Not (too) restrictive	Not (too) restrictive	Low
Retail price interventions	Not (too) restrictive	N/A	Low	High	Not (too) restrictive	Not (too) restrictive	NAP	NAP	Not (too) restrictive	NAP	Low	High	N/A	Moderate	NAP	Not (too) restrictive	Low	N/A	NAP	High	High	Not (too) restrictive	High	N/A	NAP	NAP	NAP	High

High Moderate Low Not (too) restrictive N/A NAP

Source: ACER calculation.
Notes:
(1) The intensity of each barrier is measured using a total normalised indicator ranging from 0 to 1 and qualified as "High" or highly restrictive (if it is below or equal to 0.2), "Moderate" (from 0.2 up to 0.4), "Low" (from 0.4 to 0.6), and "Not (too) restrictive" if the indicator is above 0.6. "Not (too) restrictive" does not necessarily indicate the absence of the barrier; but overall, the indicators assessed in this report do not show a high level of restrictions.
(2) For more information on the methodology for assessing barrier scores, please refer to Annex I.
(3) N/A (not available) refers to Member States where it was not possible to assess barriers due to insufficient data being provided.
(4) NAP (not applicable) refers to Member States where barriers are not applicable, e.g., Member States where no capacity market was operational in 2022, where there was no public price intervention in retail price settings or where there was no liquid wholesale electricity market in 2022 (i.e., Cyprus and Malta).

A proper legal framework is a pre-condition to unlock demand

Multiple Member States lack a proper legal foundation to unlock the flexibility potential of distributed energy resources

15 Multiple Member States lack a proper legal foundation to unlock the flexibility potential of distributed energy resources. New flexibility actors can only gain access to all electricity markets and system operation services if all roles and responsibilities are clearly defined. Lack of such legal framework results in missing foundation for active demand response.

No one offers flexibility when there are no technical possibilities or incentives to do so

16 Consumers need smart meters that provide time-sensitive information. Half of the Member States had a very limited rollout of smart meters in 2022, which acts as a barrier to demand response. Consumers also need retail electricity contracts that provide incentives to become active and engage in demand response (e.g., through time-of-use price signals). Finally, consumers need to be informed on how they can benefit from joining demand response programmes.

Consumers need smart meters, retail electricity contracts that provide incentives and information on the benefits of providing demand response

Distributed energy resources should be able to participate in balancing services, congestion management services, and capacity mechanisms

Distributed energy resources need to have a market opportunity to solve imbalances, network congestions or adequacy resource issues

17 The participation of distributed energy resources in balancing services, congestion management services or capacity mechanisms is still too limited.

18 In most Member States balancing products have some limiting design features for distributed energy resources. In addition, a few Member States do not procure all their balancing services through a market-based method.

19 Rather than to solve network congestions by re-dispatching conventional power plants, curtailing renewable generation or through network expansion and reinforcement, Member States and regulators should assess possibilities of having market-based congestion management services where distributed energy resources can effectively play a role. Especially at the distribution level, so-called 'local flexibility markets' are still in an infancy stage.

20 All capacity mechanisms in operation in 2022 had some constraining or unachievable requirements for most distributed energy resources.

Retail markets need to be fully open to competition

21 Some large retail markets in terms of number of consumers still show high concentration levels. With a low competitive pressure, incumbents may hold a dominant position that may limit new entrants' ability to compete on a level playing field and to offer innovative products allowing consumers provide demand response and benefit from potential costs savings.

Some retail price interventions dampen the price signal effect

22 During 2022 at least thirteen Member States had in place some kind of public intervention in the price setting that predates the energy crisis. Consequently, a high share of consumers in these Member States have a regulated price that usually does not send them proper price signals to potentially provide demand response.

23 In response to the energy crisis, many Member States also introduced temporary retail price interventions as emergency measures to quickly halt the increase in retail prices. As shown in ACER's 2023 Market Monitoring Report on emergency measures in electricity markets, these emergency retail price interventions may have also limited incentives for demand response (note that this particular report does not assess the scope of these measures).

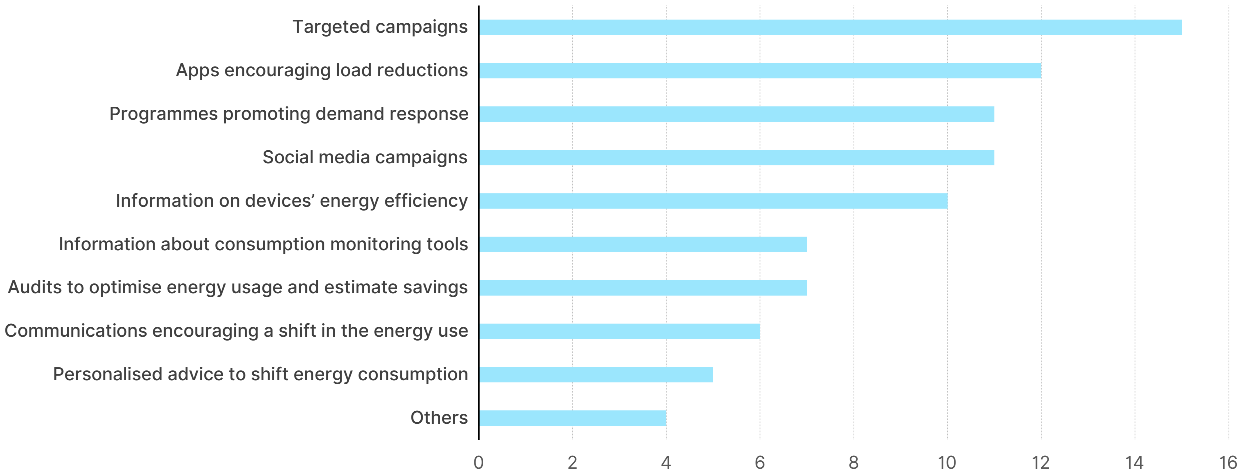
The situation has slightly improved since 2020

24 Since the previous assessment in ACER's 2020 Market Monitoring Report - Electricity Wholesale Market Volume, some progress has been made. Some examples are as follows:

- The regulatory framework for customers and aggregators is now more clearly defined in Member States such as Belgium, Croatia, and Latvia.
- Some Member States such as Austria, Germany, and the Czech Republic have relaxed some requirements in their balancing products.
- Some capacity mechanisms are now more inclusive. For example, the Finnish strategic reserve introduced in 2022 is now open to energy storage units, allows aggregation, and requires a lower minimum bid size.

25 In addition, in 2022 multiple Member States implemented measures such as communication campaigns, training or apps to improve consumer awareness and engagement to provide demand response.

Figure 3: Number of Member States implementing measures to improve consumers awareness on demand response – 2022



Source: ACER based on NRA data.

ACER recommendations:

26 In Chapter 12 ACER's recommendations are targeted at individual Member States, where specific barriers were identified. If implemented, these recommendations will help consumers play an active role in reducing their bills and supporting EU climate goals through demand response.

27 In short, ACER's suite of recommendations, including the authorities which in particular they target[3], can be grouped and summarised as follows:

Speed up removing persistent barriers to electricity consumers providing demand response (Member States and NRAs)

- Business and technological innovation as well as the evolution of the electricity market are fast. By contrast, national regulatory changes to dismantle barriers to new entrants and small actors are often too slow. Given the rapid evolution of the electricity market and prevailing business and technological innovation, national authorities must evolve their approaches at a comparable pace. Investments require regulatory clarity and predictability, and while a few years may seem short to a public authority, it may prove to be a proverbial lifetime for a new entrant with a sound business model but only a few years of initial capital.

Have suitable rules in place (Member States, TSOs, and DSOs)

- Member States should enable consumers to reduce their bills and support decarbonisation efforts through demand response by providing the right rules that
    - define a proper national legal framework for new entrants in line with the Electricity Directive,
    - define at least one aggregation model for each wholesale electricity market and system operation service,
    - allow access to final customer data while ensuring data protection and security.
- Member States, TSOs, and DSOs need to ensure that all eligible parties can access the wholesale electricity markets and system operation services, individually or aggregated, in line with the Electricity Regulation.

Provide aligned incentives by (Member States)

- speeding up the roll out of smart meters,
- raising consumer awareness, mobilising flexibility, and sharing good practices.

Ensure open access and participation in balancing services, distributed energy resources included, by (Member States, NRAs, and TSOs)

- adapting the rules for balancing services in ways to become more accessible for distributed energy sources,
- having rules in place to procure all balancing services through market-based mechanisms.

Ensure open access and participation in congestion management services, distributed energy resources included, by (Member States, NRAs, TSOs, and DSOs)

- ensuring that the reasons for not using market-based re-dispatching do not contravene the exceptions allowed in the Clean Energy Package and defining an iterative national reassessment process to review the exceptions from using market-based re-dispatching.

3 In brackets after the recommendation or in the text when certain parts of the recommendation are differentiated.

Ensure open participation in capacity markets, distributed energy resources included, by (Member States, NRAs, and TSOs)

- removing or relaxing the requirements that exclude some distributed energy resources from participation in capacity markets, where possible,

- preferably integrating services related to interruptibility schemes within the existing wholesale electricity markets and system operation services.

Facilitate new entrants' access to retail markets (Member States)

Be targeted, tailored, and temporary with any electricity price interventions (Member States)

- ensuring an appropiate trade-off between providing short-term relief from high prices and hindering demand response over the long term.

Have accurate, complete, and consistent data for a good assessment of the barriers to demand response and other distributed energy resources (TSOs, DSOs, and NRAs)

TSOs, DSOs, and NRAs need sufficiently granular data on the following:

- any data that identifies potential barriers for distributed energy sources and new actors to participate in the market integration,

- network conditions, individual network users subject to the rollout of fit-for-time-of-use meters and network use by individual network users,

- level of penetration of all types of new actors and distributed energy resources in all wholesale electricity markets and system operation services,

- level of penetration of all types of retail electricity contracts, including those with time-of-use signals.

1. Introduction

1.1. Why the need to remove barriers to demand response? Lessons from the energy crisis

28 The energy crisis, mostly driven by the Russian invasion of Ukraine, carries two main lessons with regard to the further development of integrated electricity markets in the European Union (EU). First, that integrated markets provide huge benefits in terms of enhanced resilience, trade and volatility-dampening compared to Member States operating in isolation. Second, that demand reductions play a crucial role when supply is scarce, restricted or under threat.

29 Both lessons carry strong implications for decision-makers going forward. The former (i.e., the role of the EU's integrated energy markets) requires doubling down on efforts to enhance interconnection levels. This implies maximising the available cross-zonal capacity for trade[4], to further improve both short-term and long-term market functioning and to speed up the needed investments in energy infrastructure. The latter lesson (i.e., adjusting demand to fit with changed supply patterns) encompasses many dimensions, with a key one being the need to increase the overall responsiveness of the energy system. Indeed, those systems need to deal with the huge increases in fluctuating electricity supply driven by the exponential growth expected in solar and wind electricity generation over the coming years. This report, the last in ACER's market monitoring series this year, is dedicated to this latter challenge. More specifically, it tackles the barriers to demand response and other new entrants and small actors.

30 The challenge is not a minor one. Rather than saving energy volumes per se, the demand response challenge is about shifting energy across time and use cases. Yet it suffers from the same affliction as energy efficiency: the need for coordination of otherwise fragmented efforts. Indeed, successful demand response involves the efforts of many, as opposed to one centralised action. Barriers that impede such a demand response are usually hiding in plain sight: they might lack a sense of urgency since they seem less important when seen in isolation. However, the sum of many small obstacles does add up to serious barriers.

31 The energy crisis resulted in soaring electricity prices and the call for demand response in the form of general load reduction and peak shaving, hence reducing peak electricity demand. The Council Regulation 2022/1854 of 6 October 2022 on an emergency intervention to address high energy prices even adopted a mandatory reduction of peak demand by 5%.

32 Such events stress the importance of reducing the existing barriers to distributed energy resources, including demand response, distributed generation, and energy storage to ensure security of supply, and to dampen prices. While Member States reported fulfilment of these load reduction targets, some of the emergency measures introduced had adverse effects on efficient price formation, such as interventions on wholesale or retail prices, possibly limiting the incentive for demand response[5]. This exemplifies the trade-offs policymakers need to make: part of the short-term solution to soaring prices could well develop into a barrier to tackle price spikes in the long run.

33 Considering these price trends and events, monitoring barriers to distributed energy resources and other new entrants and smaller actors becomes even more important. Consequently, ACER has widened the scope of monitoring these barriers as outlined in Chapter 2.

4 See ACER's 2023 Market Monitoring Report on cross-zonal capacities and the 70% margin available for cross-zonal trade (MACZT).

5 See ACER's 2023 Market Monitoring Report on emergency measures in electricity markets.

1.2. Why the need to remove barriers to demand response? How demand response can help the energy transition

34 The EU is committed to reducing greenhouse gas emissions to limit the climate change. To decarbonise the electricity sector, fossil fuel-based power plants need to be phased out and most Member States have set ambitious goals regarding the integration of renewable energy sources (RES) such as solar and wind to replace them.

35 The Fit-for-55 package published in 2022 includes the target for the share of RES in the EU energy mix, which is set to 42.5% by 2030 representing a nearly two-fold increase from 2021[6]. Today renewables contribute around 20% of the total EU energy mix. Within the electricity sector already one third is generated by renewable technologies[7]. To fulfil the targets set out in the RePowerEU scenario, the share of renewables in electricity generation is forecasted to reach around 69% by 2030[8]. This high penetration of renewables leads to changes to system design and operation. In particular, it leads to additional needs to balance the electricity demand and supply both in time and in space and solve increasing network congestions, ensuring security of supply[9].

36 To keep up with the growth of variable renewable electricity sources, flexibility in the EU power system needs to almost double by 2030 compared to today. As shown in ACER-EEAACER-EEA's 2023 report entitled Flexibility solutions to support a decarbonised and secure EU electricity system, Member States should exploit collaboration synergies to unlock flexibility and enhance energy security while contributing to long-term climate neutrality. Key necessary improvements include better cross-border planning and forecasting, enhanced use of interconnectors as well as financial incentives and reliable information for electricity consumers to adapt demand when needed.

37 With the current penetration of renewables in the electricity system, there is already an increase in price volatility as shown in Figure 4 and an increasing occurrence of negative prices as shown in Figure 5. Both underscore the market signalling the high value of flexibility, which is currently not fully tapped into. Negative prices usually occur at times of high generation from renewables in combination with low demand. They indicate, among other aspects, that some generation units are not sufficiently flexible due to lacking incentives to respond, the demand side is not adequately price-responsive or there is not enough storage to conduct energy arbitrage.

38 More specifically, the annual volatility of day-ahead prices has increased in all bidding zones in the period of 2019-2022 as shown in Figure 4. The only exception is found in Spain and Portugal where volatility dropped in 2022, which is mainly explained by the introduction of the 'Iberian exception', i.e., setting a price cap on gas used for electricity production in June 2022.

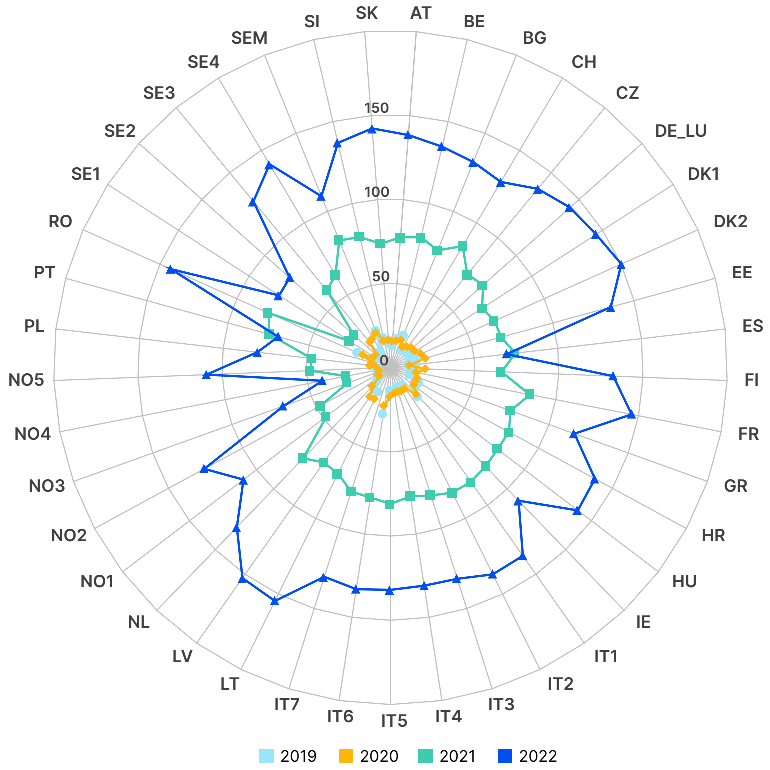
6 A detailed presentation of the Fit-for-55 package is available at: https://www.consilium.europa.eu/en/infographics/fit-for-55-how-the-eu-plans-to-boost-renewable-energy/.

7 ACER calculation based on ENTSO-E TP data.

8 More information can be found in the Commission Staff Working Document accompanying the REPowerEU plan from the European Commission.

9 Security of Supply refers to a continuous supply of electricity to all consumers now and in the future, considering both sufficient energy availability as well as the operational security of the grid. Further analysis can be found in ACER's 2023 report on Security of EU electricity supply.

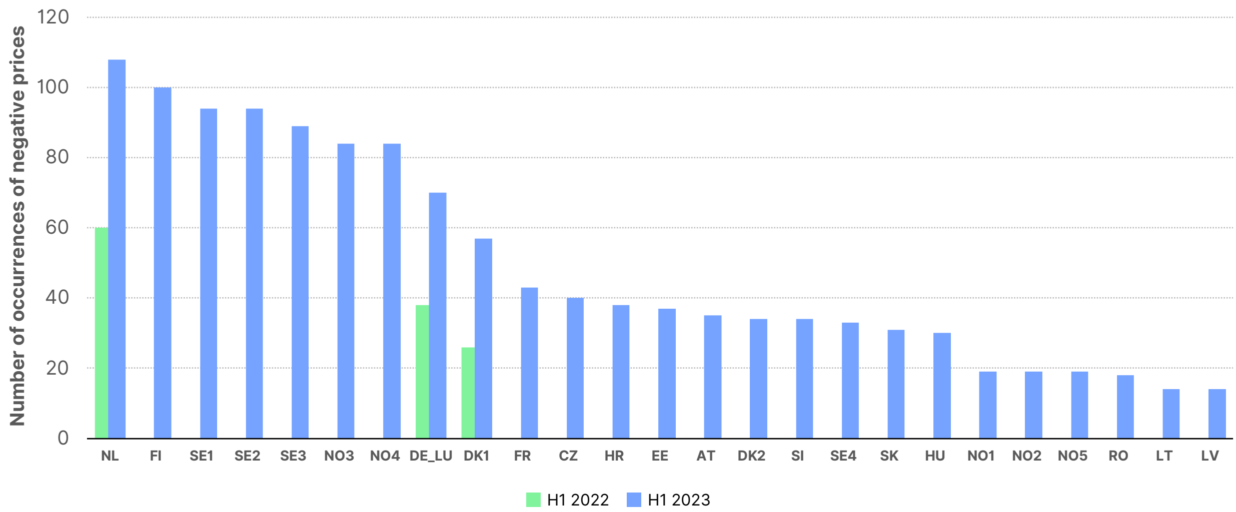
Figure 4: Annual volatility of day-ahead prices per bidding zone – 2019-2022



Source: ACER calculation based on ENTSO-E TP data.
Notes: (1) The figure shows the annual volatility calculated as the standard deviation of all hourly day-ahead prices. (2) The internal Italian bidding zones are presented as follows: IT1 (Italy North), IT2 (Italy Centre North), IT3 (Italy Centre South), IT4 (Italy South), IT5 (Italy Sardinia), IT6 (Italy Sicily), and IT7 (Italia Calabria).

39 As shown in Figure 5, the number of hours in which electricity prices dropped below zero has increased sharply in most EU bidding zones in the first half of 2023 compared to the same period in 2022.

Figure 5: Number of occurrences of negative prices in some bidding zones – first half 2023 vs. first half 2022



Source: ACER calculation based on ENTSO-E TP data.
Notes: (1) One occurrence corresponds to one hour during which the day-ahead prices are negative. (2) The bidding zones without values in the first half of 2022 did not have any negative price occurrence during that period.

40 Very high and very low wholesale prices, especially negative prices, send important signals. They tell generators where to invest and when to generate. They signal to traders where to trade. They nudge consumers on whether and when to consume. Consistently low or high prices call for attention and require system responsiveness that addresses the vast increase in intermittent generation towards 2030, the commensurate need for much more flexibility in the system and the role distributed energy sources will play in this situation. Such system responsiveness can be obtained in different ways, namely through investment and deployment of new assets and through making decisions on how to operate the system. Investment and deployment of new assets needs to be made based on realistic targets, risk allocation, system planning and how to factor in signals that show more appropriate locations for new generation compared to others (e.g., grid connection charges). Operational decisions may be influenced by support schemes in place or whether cost-reflective grid charging is prevalent or not (e.g., through injection charges).

41 Most importantly, a certain amount of price volatility and thus also at times negative wholesale prices send clear signals to activate demand response. The current report delves into the barriers such demand response is facing. Before considering any intervention, it is important to first verify all barriers for proper market operation have been taken down first.

1.3. Structure of this report

42 Chapter 1 introduces the main reasons to remove barriers to distributed energy resources and other new entrants and small actors. Chapter 2 clarifies the scope of this report and briefly presents the methodology used to score the different indicators and barriers. Chapters 3 to 9 monitor each barrier in 2022 across the EU-27 Member States and Norway. Chapter 10 briefly describes other barriers in the electricity sector that also impact entry and participation of distributed energy resources. Chapter 11 looks in detail to what extent some design features of the network tariffs can serve as potential 'facilitators' or 'barriers' to demand response. Finally, Chapter 12 presents key findings and specific recommendations per Member State.

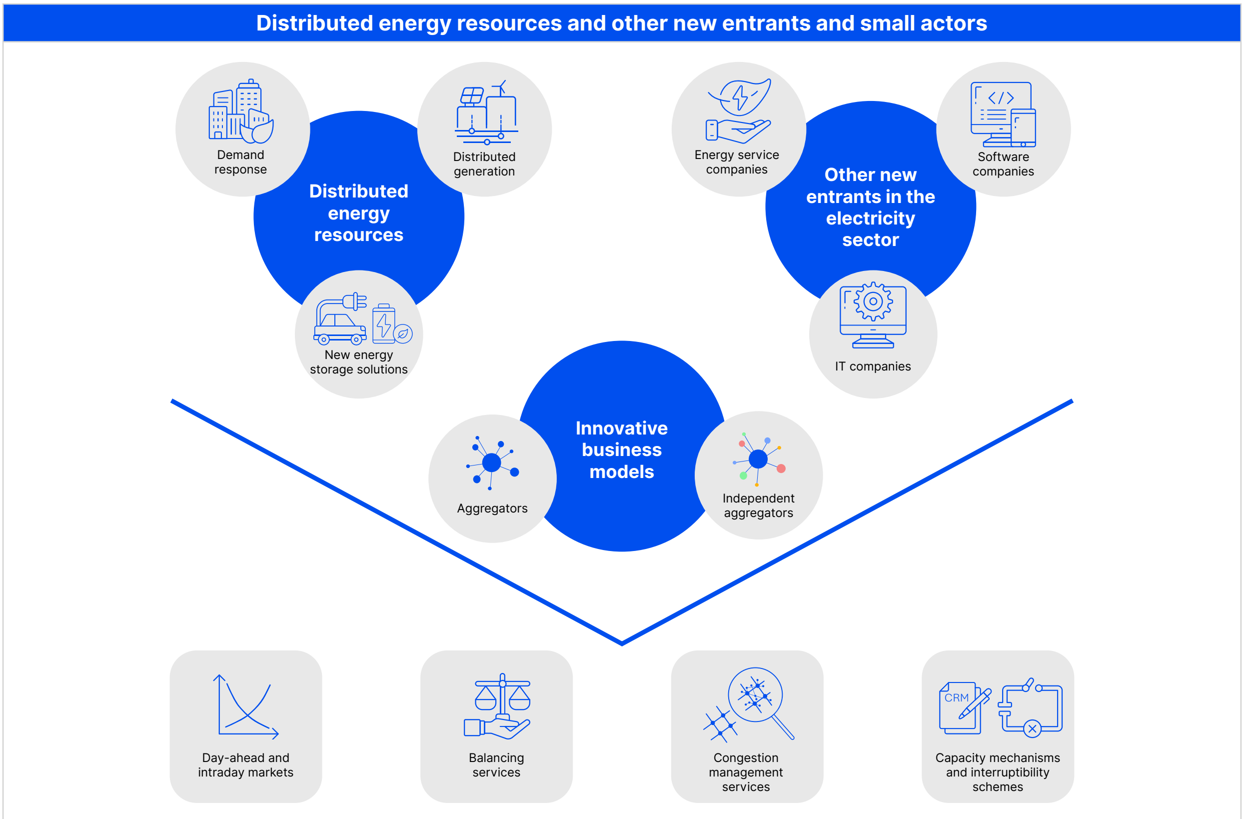
43 ACER would like to express its gratitude for the large volume of data provided by all national regulatory authorities (NRAs) since the indicators assessed in this report are highly dependent on NRA input.

2. Scope and methodology

44 The [ACER Regulation][10] requires ACER to monitor the regulatory barriers to new entrants and smaller actors in wholesale electricity markets. To fulfil this task, ACER commissioned a methodological study in 2020 to identify barriers and indicators to assess the performance of the Member States in terms of ease of market entry and the participation of new entrants and small actors[11], and carried out a first analysis of the barriers across the Member States in 2020[12].

45 The current report has a wider scope including new barriers and assessing more restrictions in comparison with the 2020 monitoring exercise. It illustrates the status of the barriers in the EU-27 Member States and Norway[13] in 2022. It describes other relevant barriers in the electricity sector that also undermine the ability of new entrants and smaller actors to enter and participate in wholesale electricity markets. Figure 6 shows the scope of the current report.

Figure 6: Scope of the report



Barriers
Lack of a proper legal framework to allow market access
Unavailability or lack of incentives to provide flexibility
Restrictive requirements to providing balancing services
Restrictive requirements to providing congestion management
Restrictive requirements to participating in capacity mechanisms and interruptibility schemes
Limited competitive pressure in the retail market
Retail price interventions

Source: ACER.

10 Article 15 of the Regulation (EU) 2019/942 of the European Parliament and of the Council of 5 June 2019 establishing a European Union Agency for the Cooperation of Energy Regulators (recast) (hereafter ACER Regulation).

11 DNV's 2021 study on a methodology for benchmarking the performance of the EU Member States in terms of efficient price formation and easy market entry and participation for new entrants and small actors.

12 For more information, please refer to Chapter 7 of the ACER's 2020 Market Monitoring Report - Electricity Wholesale Market Volume.

13 In this report, EU-27 refers to the 27 Member States after Brexit, i.e., after the United Kingdom left the EU on 31 January 2020. ACER did not have access to UK-related data; therefore, the United Kingdom is excluded from the scope of this report. Although an EEA Joint Committee Decision to incorporate the Clean Energy Package into the EEA Agreement is still pending, Norway enforces most of the EU energy legislation, including legislation on the internal energy market, thus it is included in the scope of this report. Switzerland is not included since the national regulatory authority was not able to provide data. For the sake of simplicity, the term 'Member States' is used throughout this report to cover the EU-27 Member States and Norway.

46 This report monitors the barriers to the following categories of new entrants and small actors:

- Distributed energy resources (DER) understood as small-scale energy resources without economies of scale that generate, store or manage energy and that are usually situated near sites of electricity use. These resources can be used by new actors such as active customers[14] or energy communities[15]. They include the following:

    - Demand response: The change of electricity load by final customers from their normal or current consumption patterns in response to market signals, including in response to time-variable electricity prices or incentive payments (i.e., implicit demand response), or in response to the acceptance of the final customer's bid to sell demand reduction or increase at a price in an organised market, whether alone or through aggregation (i.e., explicit demand response)[16]. All the relevant types of final customers providing demand response are in the scope of this report. In some chapters or sections, demand response is split into commercial or industrial consumers, energy communities and residential consumers.

    - Distributed generation: Generating installations connected to the distribution system[17].

    - Energy storage: New 'behind-the-meter' and in-front-of-the-meter energy storage solutions, including battery energy storage systems, electric vehicles (EVs) with bidirectional charging capabilities, etc. and excluding hydro and pumped-hydro storage.

- Innovative business models that combine multiple distributed energy resources, such as market participants engaged in aggregation[18] (also referred to as aggregators) including independent aggregators[19].

- New technologies or market players active on or with experience in other markets (such as energy efficiency services, IT or software development) aiming to enter in the wholesale electricity markets.

47 In principle all energy resources, including generation and storage resources, and all consumers or demand resources can provide flexibility. This report refers to flexibility as the ability of energy resources and consumers to change or adjust their injection or withdrawal to/from to the electricity system in response to prices (if active on day-ahead and intraday markets) or to provide services to system operators (SOs), i.e., balancing services for Transmission System Operators (TSOs) and congestion management or voltage control to TSOs and Distribution System Operators (DSOs). The scope of this report focuses on barriers to new entrants and small actors to offer such an ability, individually or through aggregation, from the day-ahead timeframe up to real time. More specifically, this report monitors barriers to access and participate in day-ahead and intraday electricity markets and system operation services (SO services). The latter includes market-based procurement of balancing and congestion management services and where applicable, local markets (also commonly referred to as local flexibility markets or local markets for SO services) to solve network congestions[20].

48 This report considers that any discriminatory, arbitrary or avoidable requirement imposed on these new entrants and small actors[21] that is not equally applied to actors already active on wholesale electricity markets or providing services to system operators can be considered as a potential barrier.

14 Active customer means a final customer (or a group of jointly acting final customers) who consumes or stores electricity generated within its premises located within confined boundaries or, where permitted by a Member State, within other premises, or who sells self-generated electricity or participates in flexibility or energy efficiency schemes, provided that those activities do not constitute its primary commercial or professional activity as set out in Article 2(8) of the 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 and amending Directive 2012/27/EU (recast) (hereafter Electricity Directive).

15 Energy communities refer to citizen energy communities as defined in Article 2(11) of the Electricity Directive and renewable energy communities as defined in Article 2(16) of the Renewable Energy Directive.

16 Article 2(20) of the Electricity Directive.

17 Article 2(32) of the Electricity Directive.

18 Aggregation means a function performed by a natural or legal person who combines multiple customer loads or generated electricity for sale, purchase or auction in any electricity market as set out in Article 2(18) of the Electricity Directive.

19 Independent aggregator means a market participant engaged in aggregation who is not affiliated to the customer's supplier as set out in Article 2(19) of the Electricity Directive.

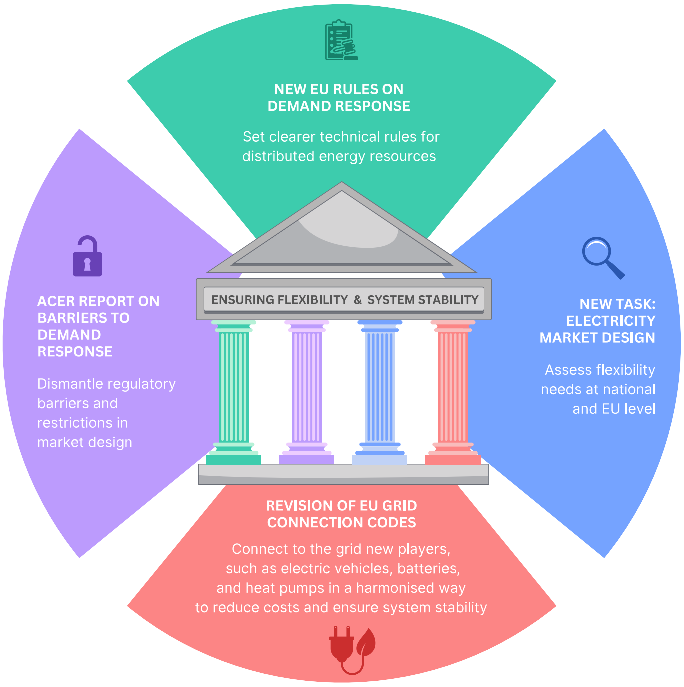
20 Local markets are commonly known as market-based procurement of congestion management or voltage control from decentralised resources by system operators although they can also offer access to wholesale and balancing markets.

21 Discriminatory requirements refer to those that lead to additional costs on an unequal treatment compared to incumbent market participants, arbitrary requirements mean those that are imposed without a valid justification according to the market needs and avoidable requirements refer to those that can be prevented by the competent authorities. For more information, please refer to DNV's 2021 study on a methodology for benchmarking the performance of the EU Member States in terms of efficient price formation and easy market entry and participation for new entrants and small actors.

49 More specifically, this report focuses on two types of barriers: (i) regulatory barriers mainly related to the lack of implementation of some provisions of the Clean Energy Package and some EU Guidelines that are crucial to bringing more flexibility from distributed energy resources into the wholesale electricity markets and SO services; and (ii) barriers related to the market design and structure. Financial, economic, technical, and behavioural barriers to new entrants and small actors are out of the scope of this study.

50 Figure 7 shows the many ongoing efforts to bring the EU into a situation where all the available flexibility in the power system can be used successfully. This report shows how Member States must dismantle the existing regulatory barriers and restrictions in the design of their electricity markets and system operation services as soon as possible. However, more efforts are needed. Firstly, the revision of the existing grid connection network codes should result in a harmonised approach to connect new users such as electric vehicles, storage and heat pumps to the grid providing economies of scale and supporting mass-uptake of emerging technologies while ensuring system stability. Secondly, the new rules on demand response[22] should set clearer technical rules to allow all distributed resources to effectively participate in the electricity markets and help system operators solve imbalances or network congestions. These new rules are expected to further define and clarify the current regulatory framework of some issues addressed in this report such as requirements for market access (including the specification of aggregation models), prequalification processes, data exchange and system operators' coordination and congestion management services. Lastly, the upcoming reform of the electricity market design is expected to introduce flexibility needs assessments in a forward-looking way. Each and every effort is crucial to ensure a strong foundation to ensure flexibility and stability in the EU power system.

Figure 7: Ongoing efforts to ensure flexibility and stability in the EU power system – 2023



Source: ACER.

51 This report uses a methodology to measure the intensity of each barrier and allow for a general comparison across the Member States. An overview of all barriers in 2022 across the Member States is shown in Table 1 of the Executive Summary. Each barrier is assessed based on a set of quantitative and qualitative indicators, which are described in the different sections of this report. The methodology to estimate the intensity of each barrier as well as the underlying indicators used to measure each barrier and the scoring system is described in Annex I and Table 28. It is important to note that some chapters of this report describe some requirements or design features that may become restrictive. However, they are not included in the scoring system to calculate the intensity of the barrier since proper indicator(s) were not found to ensure comparability across the Member States.

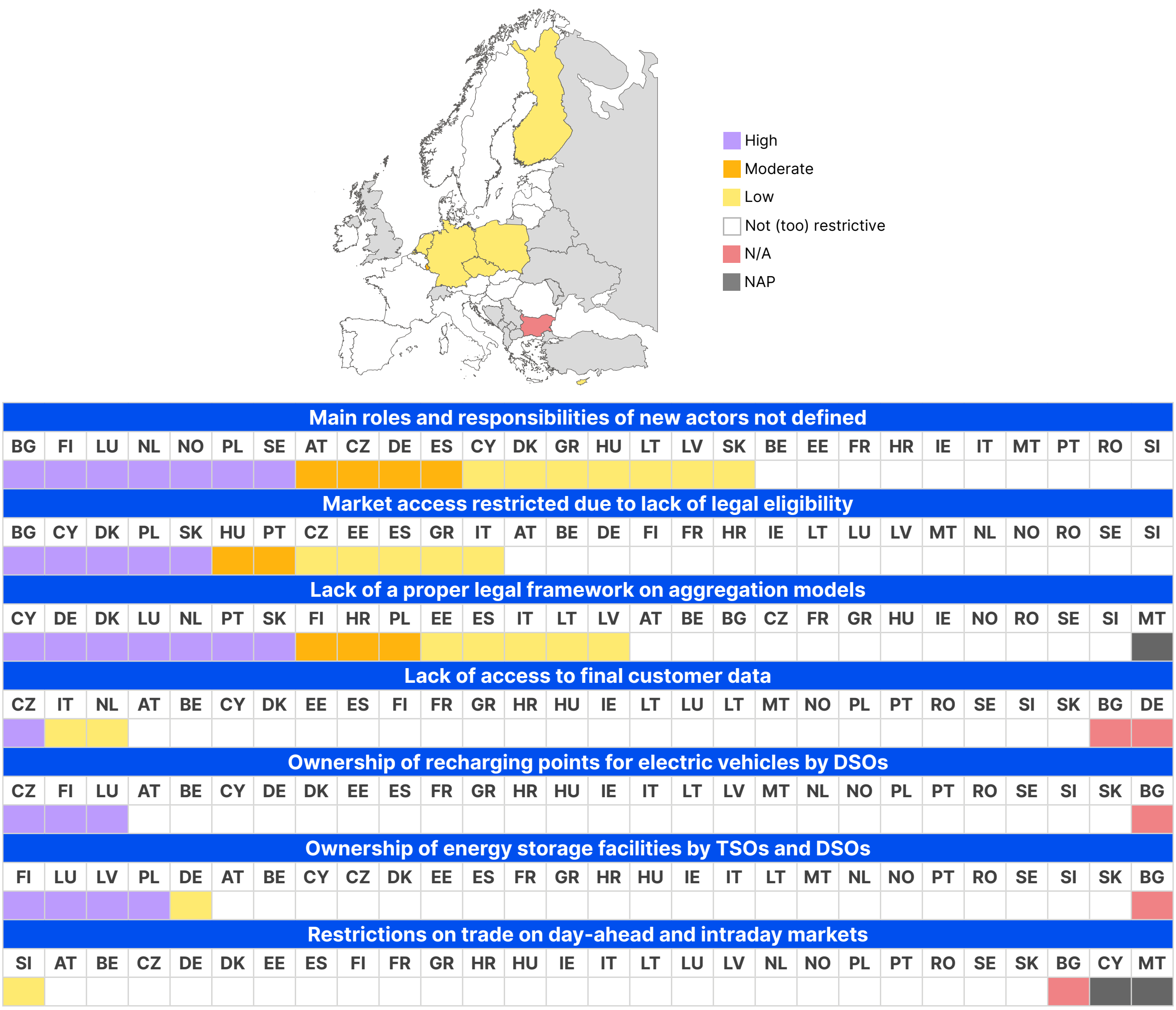
22 On 9 March 2023 the European Commission requested EU DSO Entity and ENTSO-E to submit within 12 months a draft of new rules to further support the development of demand response, including rules on aggregation, energy storage, and demand curtailment in line with ACER Framework Guideline on Demand Response.

3. Lack of a proper legal framework to allow market access

Multiple Member States have not yet defined the main roles and responsibilities of some new actors or have not fully opened their wholesale electricity markets and SO services to all types of distributed energy resources, individually or aggregated. Almost half of the Member States also lack at least one aggregation model in all electricity markets and market-based congestion management services, where applicable.

A few Member States still miss a legal framework on the ownership of storage facilities and recharging points for electric vehicles by system operators or to ensure new actors can access data in a non-discriminatory manner and simultaneously compared to other market participants.

Figure 8: Lack of a proper legal framework to allow market access. Overview of the barrier (top) and underlying indicators (bottom) per Member State – 2022



Source: ACER.

Notes: (1) The figure above and at the beginning of subsequent chapters shows an overview of the intensity of the barrier in 2022 across the Member States (top) and the normalised indicators to measure the barrier (bottom). The intensity of the barrier and indicators ranges from 0 (lowest performance) to 1 (highest performance). They are qualified as "High" or highly restrictive (normalised value below or equal to 0.2), "Moderate" (from 0.2 up to 0.4), "Low" (from 0.4 to 0.6) and "Not (too) restrictive" if it is above 0.6. For more information on the methodology for assessing the scores per barrier (top) and indicator (bottom), please refer to Annex I. (2) ACER was not able to calculate the barrier score for Bulgaria since at least half of the indicators were missing.

52 This chapter presents how some national legal frameworks may limit market access to distributed energy resources, individually or aggregated. It covers general aspects such as the definition of roles and responsibilities, the lack of legal eligibility to access all electricity wholesale markets and SO services or the implementation of aggregation models. It also focuses on more specific restrictions related to data access, ownership of recharging points for electric vehicles, and storage facilities by system operators and trading on day-ahead and intraday markets.

3.1. Main roles and responsibilities of new actors not defined

53 The Electricity Directive[23] requires Member States to develop an appropriate regulatory framework for active customers, market participants engaged in aggregation, and citizen energy communities (CECs) to effectively enable the active participation of demand response.

54 The main roles and responsibilities of these new actors should have been transposed into national legislation by 31 December 2020. However, as shown in Table 2, their implementation was still work in progress in multiple Member States as of 31 December 2022. It should be noted that a full implementation of the main roles and responsibilities in the primary national legislation does not necessarily ensure an appropriate regulatory framework for these actors. A secondary legislation defining more detailed duties, rules, and procedures is also needed to ensure that these new actors can perform their activities in an efficient, non-discriminatory, and transparent manner.

55 In 2022, nine Member States still had not included a legal definition in their national rules to ensure final customers are entitled to act as active customers. Five out of these nine Member States had not defined any responsibilities of these actors.

56 Defining the role of aggregation is crucial to activate distributed energy resources, especially demand response from household customers. In 2022, nine Member States still lagged in defining the role and the main responsibilities of aggregators and independent aggregators. Six Member States had not even defined the function of 'aggregation'. At the same time, ten Member States had not fully recognised independent aggregators as market participants.

57 Some provisions are crucial to ensure independent aggregators can access electricity markets, including their interaction with final customers in a non-discriminatory manner compared to other market participants as follows:

- Protecting customers who have a contract with independent aggregators from undue payments, penalties or other undue contractual restrictions as well as discriminatory technical and administrative requirements, procedures or charges by the supplier. This is crucial to ensure final customers are free to conclude a contract with an independent aggregation. Twelve Member States still do not fully ensure this protection.

- Requiring prior consent by suppliers before concluding an aggregation contract can greatly hinder attracting customers by independent aggregators. The national rules in ten Member States still have not eliminated the possibility for suppliers to discriminate against customers that have a contract with an aggregator. A conflict resolution mechanism between market participants engaged in aggregation and other market participants, including responsibility for imbalances, is also lacking in nine Member States

58 In 2022 seven Member States still did not have a legal definition of citizen energy community[24]. Some Member States have granted public funds to promote these energy communities, therefore setting a definition is essential to ensure these funds do not end up with the wrong actors. No Member State has fully defined the main roles and responsibilities for the citizen energy communities except for Malta and Portugal. In many Member States their existing national rules ensure some responsibilities (e.g., financial responsibility for imbalances caused in the electricity system). Nevertheless, most still have not defined a specific regulatory framework for these actors.

23 Articles 13, 15, 16, and 17 of the Electricity Directive.

24 In Poland, the amendment to the Energy Law introducing the definition of citizen energy community entered into force in September 2023.

Table 2: Definition of the main roles and responsibilities for active customers, market participants engaged in aggregation and citizen energy communities in the national rules per Member State – 31 December 2022

	Main roles and responsibilities	AT	BE	BG	CY	CZ	DE	DK	EE	ES	FI	FR	GR	HR	HU	IE	IT	LT	LU	LV	MT	NL	NO	PL	PT	RO	SE	SI	SK
Active customers	Active customer legally defined	NI	I	I	I	NI	N/A	I	I	I	NI	I	I	I	I	I	I	I	NI	I	I	NI	NI	NI	NI	I	NI	I	I
Active customers	Entitled to operate directly or aggregation	I	I	I	I	NI	N/A	I	I	I	NI	I	I	I	I	I	I	I	NI	I	I	NI	NI	NI	I	I	NI	I	I
Active customers	Entitled to sell self-generated electricity, including through PPAs	I	I	I	I	I	N/A	I	I	I	NI	I	I	I	I	I	I	I	NI	I	I	I	NI	NI	I	I	NI	I	NI
Active customers	Entitled to participate in flexibility and energy efficiency schemes	I	I	I	I	NI	N/A	I	I	I	NI	I	I	I	I	I	I	I	NI	I	I	NI	NI	NI	I	I	NI	I	NI
Active customers	Financially responsible for its imbalances	I	I	I	I	I	N/A	I	I	I	NI	I	I	I	I	I	I	I	NI	I	I	NI	NI	NI	I	I	NI	I	NI
Aggregators and independent aggregators	Aggregation legally defined	NI	I	N/A	I	NI	I	I	I	I	NI	I	I	I	I	I	I	I	I	I	I	NI	NI	NI	I	I	I	I	I
Aggregators and independent aggregators	Independent aggregator legally defined	NI	I	N/A	I	NI	I	I	NI	NI	NI	I	I	I	I	I	I	I	NI	I	I	NI	NI	NI	I	I	NI	I	I
Aggregators and independent aggregators	Right to enter DA markets without prior consent of other market participants	NI	I	N/A	NAP	NI	N/A	I	I	NI	NI	I	I	I	I	I	I	NI	NI	I	NAP	NI	NI	NI	I	I	NI	I	NI
Aggregators and independent aggregators	Right to enter ID markets without prior consent of other market participants	NI	I	N/A	NAP	NI	N/A	I	I	NI	NI	I	I	I	I	I	I	NI	NI	I	NAP	NI	NI	NI	I	I	NI	I	NI
Aggregators and independent aggregators	Right to enter balancing markets without consent of other market participants	NI	I	I	NAP	NI	N/A	I	I	NI	NI	I	I	NAP	I	I	I	NI	NI	I	NAP	NI	NI	NI	I	I	NI	I	NI
Aggregators and independent aggregators	Right to enter capacity markets without prior consent of other market participants	NAP	I	NAP	NAP	NAP	NAP	I	NAP	NI	NI	I	NAP	NAP	NAP	I	I	NAP	NI	NAP	NAP	NAP	NAP	NI	NAP	NAP	NI	NAP	NAP
Aggregators and independent aggregators	Roles and responsibilities clearly assigned to all electricity undertakings and customers	NI	I	I	I	NI	I	I	I	NI	NI	I	I	I	I	I	I	I	NI	I	I	I	NI	NI	I	I	NI	I	I
Aggregators and independent aggregators	Exchange of data between market participants engaged in aggregation and other electricity undertakings while ensuring easy access to data on equal and non-discriminatory terms and full protection of commercially sensitive information an customers' personal data	NI	I	N/A	I	NI	N/A	I	I	NI	NI	I	I	I	N/A	I	I	I	NI	I	I	NI	NI	NI	I	I	NI	I	I
Aggregators and independent aggregators	Conflict resolution mechanism between market participants engaged in aggregation and other market participants, including responsibility for imbalances	I	I	N/A	I	NI	N/A	I	I	NI	NI	I	NI	I	N/A	I	I	I	NI	I	I	NI	NI	NI	I	I	NI	I	I
Aggregators and independent aggregators	Customers with independent aggregators protected from undue payments, penalties or other undue contractual restrictions by their suppliers	NI	I	N/A	I	NI	I	I	NI	NI	NI	I	I	I	N/A	I	I	I	NI	I	I	NI	NI	NI	I	I	NI	I	I
Aggregators and independent aggregators	Final customer entitled to conclude an aggregation contract without the consent of its electricity undertakings	NI	I	N/A	I	NI	N/A	I	I	NI	NI	I	I	I	N/A	I	I	NI	NI	I	I	NI	NI	NI	I	I	NI	I	I
Aggregators and independent aggregators	Customer not subject to discriminatory technical and administrative requirements, procedures or charges by their supplier or on the basis of whether they have a contract with a market participant engaged in aggregation	NI	I	N/A	I	NI	N/A	I	I	NI	N/A	I	I	I	I	I	I	NI	NI	I	I	NI	NI	NI	I	I	NI	I	NI
Citizen energy communities	CEC legally defined	I	I	N/A	I	I	N/A	I	I	I	NI	I	NI	I	I	I	I	I	NI	I	I	NI	NI	NI	I	I	NI	I	I
Citizen energy communities	Participation open and voluntary	I	I	N/A	I	I	N/A	I	I	NI	NI	I	NI	I	I	I	I	I	NI	I	I	NI	NI	NI	I	I	NI	I	I
Citizen energy communities	CEC members or shareholders are protected from losing rights and obligations as household customers or active customers	I	I	N/A	I	I	N/A	I	I	NI	NI	I	NI	I	N/A	I	I	I	NI	I	I	NI	NI	NI	I	I	NI	I	I
Citizen energy communities	Open to cross-border participation	N/A	NI	N/A	I	NI	N/A	I	I	NI	NI	NI	NI	NI	NI	I	NI	NI	NI	NI	I	NI	NI	NI	I	NI	NI	NI	NI
Citizen energy communities	Financially responsible for its imbalances	I	I	N/A	I	NI	N/A	I	I	NI	NI	I	NI	I	I	I	I	I	NI	NI	I	NI	NI	NI	I	I	NI	I	NI
Citizen energy communities	Treated like an active customer regarding consumption of self-generated electricity	NI	I	N/A	I	I	N/A	I	I	NI	NI	I	NI	I	I	I	I	I	NI	I	I	NI	NI	I	I	I	NI	I	I
Citizen energy communities	Competent national regulatory authority has developed a CBA to set network charges, tariffs and levies where electricity is shared	N/A	I	N/A	NI	I	N/A	I	NI	NI	NI	NI	NI	NI	N/A	NI	I	NI	NI	NI	I	NI	NI	NI	I	NI	NI	I	NI
Citizen energy communities	Entitled to share self-generated electricity within the community	I	I	N/A	I	I	N/A	I	I	NI	NI	I	NI	I	I	I	I	I	NI	NI	I	I	NI	NI	I	I	NI	I	NI
Citizen energy communities	Right to manage distribution networks in their area of operation	N/A	NI	N/A	I	I	N/A	NI	I	NI	NI	NI	NI	NI	I	NI	I	NI	NI	NI	I	NI	NI	NI	I	I	NI	NI	NI

Implemented in national rules (I) | Not implemented in national rules (NI) | N/A | NAP

Source: ACER based on NRA data.
Notes: (1) Limited information for Bulgaria and Germany. (2) Austria has not defined active customer in their national legislation because customers can act in the spirit of an active customer, i.e., they can operate generation and storage units, participate in energy communities, etc. Austria aims to make progress defining the main roles and responsibilities for some new actors in the new Federal Electricity Act 2023. (3) Czech Republic plans to define aggregation and independent aggregation in the so-called LEX RESS III amendment to their Energy Act that is expected to come into force in 2024. (4) Luxembourg has defined the main roles and responsibilities for new actors in line with the Electricity Directive in June 2023. (5) Poland introduced a legal framework for active customers, aggregation, and citizen energy communities in September 2023.

Box 1: Do Member States monitor the number and level of activity of new entrants?

Monitoring the number and level of activity of all market participants, including new actors, is essential for several reasons as follows:

- To assess their evolution and how changes and improvements in the regulatory framework or market conditions and products impact their activity.
- To identify areas that should be prioritised to ensure new actors can access and participate in all electricity markets and SO services and provide flexibility in a non-discriminatory, transparent and efficient manner.
- To ensure transparency and that no one is left in the dark, which also leads to better accountability.
- To ensure that all energy resources are used efficiently.

Table 3 reveals that a limited number of Member States periodically monitor the number and level of activity of some new entrants such as active customers, aggregators (including independent aggregators), and citizen energy communities. In some cases, this is because the Member States have not yet recognised their role as market participants and/or have not defined their main responsibilities (see Table 2) while in other cases, the Member States do have a national legal framework but have not kicked off any monitoring exercises. For example, Belgium, Denmark, Spain, Greece, Croatia, Ireland, Italy, and Slovakia have primary rules for active customers but still do not monitor neither their number nor their level of activity.

Currently there is a lack of harmonisation of the indicators used to monitor these new entrants, which makes comparison analysis across the Member States significantly complicated. ACER invites Member States to count the new actors as Balance Responsible Parties[25] (BRPs) since this shows with how many actors the full injection and withdrawal on the system is covered. ACER also invites the NRAs to share experience to find a proper method to measure their level of activity.

Table 3: Monitoring number and level of activity of active customers, aggregators, and citizen energy communities per Member State – 2022

Monitoring	AT	BE	BG	CY	CZ	DE	DK	EE	ES	FI	FR	GR	HR	HU	IE	IT	LT	LU	LV	MT	NL	NO	PL	PT	RO	SE	SI	SK
Active customers	None	None	N/A	Both, periodically	None	None	None	Number, periodically	None	None	None	None	None	Both, periodically	None	None	Both, periodically	None	Both, periodically	Both, periodically	None	None	None	Both, periodically	N/A	None	Both, periodically	None
Aggregators	Number, periodically	None	N/A	Both, periodically	None	None	None	None	None	None	Number, periodically	Both, periodically	Both, periodically	Number, periodically	Both, periodically	Number, periodically	Both, periodically	None	Both, periodically	Both, not periodically	None	None	None	Both, periodically	N/A	None	Both, periodically	Number, periodically
Citizen energy communities	Number, periodically	Number, not periodically	N/A	Both, periodically	None	None	None	Both, not periodically	None	None	None	Number, periodically	Both, periodically	None	None	None	Both, periodically	Number, periodically	Number, not periodically	Both, not periodically	None	None	None	N/A	N/A	None	Both, periodically	Number, periodically

- Both, periodically: My country monitors periodically both the number and the level of activity
- Number, periodically: My country monitors periodically the number only
- Both, not periodically: My country monitors both the number and the level of activity but not periodically
- Number, not periodically: My country monitors the number only but not periodically
- None: My country monitors none of them
- N/A: N/A

Source: ACER based on NRA data.
Notes: (1) The table shows the number and level of activity according to the criteria chosen in each Member State. (2) In Hungary the number of registered aggregators includes trades, virtual power plants (VPPs) and independent aggregators.

25 A balance responsible party means a market participant or its chosen representative responsible for its imbalances as set out in Article 2(7) of the Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing (hereafter Electricity Balancing Regulation).

3.2. Market access restricted due to lack of legal eligibility

59 The Member States must ensure non-discriminatory access to all market participants, individually or through aggregation, including for electricity generated from variable renewable energy sources, demand response and energy storage in all wholesale electricity markets[26]. When TSOs re-dispatch resources using a market-based mechanism or DSOs procure congestion management services in their areas, such procurement procedures must also be open to all generation technologies, energy storage and demand response in accordance with a non-discriminatory procedure[27].

60 To ensure non-discriminatory access, the national rules should legally allow all energy resources to become eligible parties, i.e., market participants. This legal eligibility does not refer to whether the resources meet the technical or financial requirements to participate in wholesale electricity markets and SO services or whether they currently participate.

61 Most distributed energy resources are not expected to directly participate. They would rather offer their flexibility through market participants engaged in aggregation, hence the importance of allowing these new actors to become market participants. Even though some electricity markets and SO services allow aggregation of resources as shown in the sections below, it should be pointed out that in some Member States this aggregation is only allowed under specific conditions, e.g., only some types of energy resources can be aggregated under the same group to provide balancing services (more information in Section 5.2.1).

3.2.1. Legal eligibility to participate in day-ahead and intraday markets

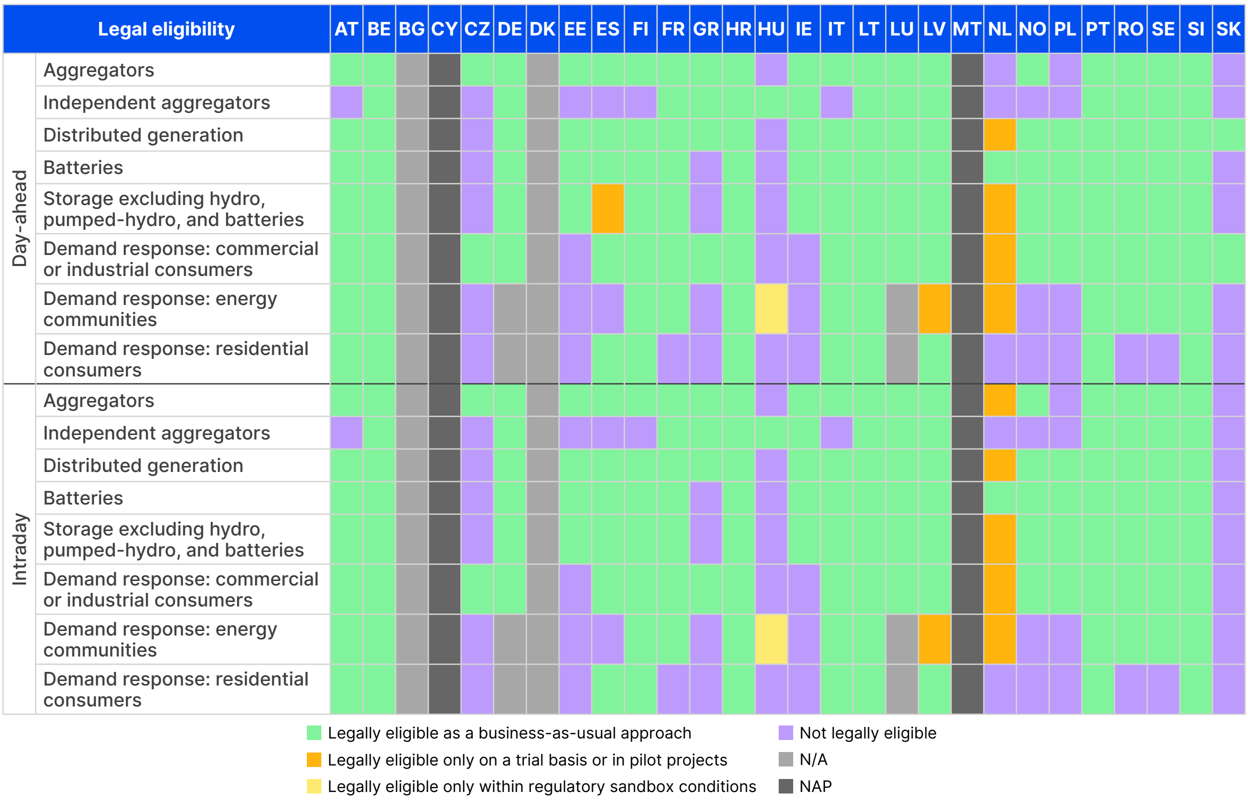
62 Table 4 shows the legal eligibility of new actors and distributed energy resources to access day-ahead and intraday markets in 2022. Based on the information reported, only Belgium, Croatia, Lithuania, Portugal, and Slovenia have fully opened these markets to all actors and distributed energy resources. The most restrictive day-ahead and intraday markets in terms of legal eligibility are found in the Czech Republic, Hungary, and Slovakia.

63 Aggregators are still deprived from access in four Member States (of which the Netherlands is in testing phase), while independent aggregators do not have access in ten Member States.

26 Article 6 and 7 of the Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (recast) (hereafter Electricity Regulation).

27 Article 13 of the Electricity Regulation and Article 32 of the Electricity Directive.

Table 4: Legal eligibility of different distributed energy resources and new actors to access day-ahead and intraday markets per Member State – 31 December 2022



Source: ACER based on NRA data.
Notes: (1) No information for Bulgaria and Denmark. (2) Not applicable to Cyprus and Malta since they do not have a liquid wholesale electricity market. (3) Luxembourg is integrated within the load frequency control (LFC) perimeter of Amprion in the DE-LU bidding zone, hence German provisions apply.

3.2.2. Legal eligibility to provide balancing services

64 Table 5 shows the legal eligibility of new actors and distributed energy resources in different balancing products across the Member States in 2022. Based on the information reported, only Germany, Estonia, the Netherlands, Romania, and Slovenia have fully opened all their balancing services to all types of new actors and distributed energy resources.

65 The most restrictive balancing services are found in Denmark (their automatically activated balancing energy for Frequency Restoration Reserves (aFRR) and manually activated balancing energy for Frequency Restoration Reserves (mFRR) are fully closed to aggregation and to all distributed energy resources), Poland (no distributed energy resource nor type of aggregation is legally allowed in any balancing market), Portugal (same as Poland although the activation of balancing energy for mFRR and Replacement Reserves (RR) is open to aggregators and industrial consumers, the latter on a trial basis for mFRR), and Slovakia (only batteries and commercial or industrial consumers are legally eligible in all balancing services).

66 In 2022 the balancing services were closed to varying degrees to aggregators in six Member States: all balancing services are fully closed in Poland and Slovakia[28] and partially closed in Denmark, Italy (still testing), Lithuania, and Portugal. They were also closed to independent aggregators in eleven Member States: fully closed in Spain, Italy (still testing), Latvia, Norway, Poland, Portugal, Sweden, and Slovakia and partially closed in the Czech Republic, Denmark, and Lithuania.

28 Slovakia has an ongoing process in 2023 to open balancing services to aggregators.

Table 5: Legal eligibility of different distributed energy resources and new actors to access balancing products per Member State – 31 December 2022

Legal eligibility			AT	BE	BG	CZ	DE	DK	EE	ES	FI	FR	GR	HR	HU	IT	LT	LV	NL	NO	PL	PT	RO	SE	SI	SK
FCR	Balancing capacity	Aggregators																								
FCR	Balancing capacity	Independent aggregators																								
FCR	Balancing capacity	Distributed generation																								
FCR	Balancing capacity	Batteries																								
FCR	Balancing capacity	Storage excluding hydro, pumped-hydro, and batteries																								
FCR	Balancing capacity	Demand response: commercial or industrial consumers																								
FCR	Balancing capacity	Demand response: energy communities																								
FCR	Balancing capacity	Demand response: residential consumers																								
aFRR	Balancing capacity	Aggregators																								
aFRR	Balancing capacity	Independent aggregators																								
aFRR	Balancing capacity	Distributed generation																								
aFRR	Balancing capacity	Batteries																								
aFRR	Balancing capacity	Storage excluding hydro, pumped-hydro, and batteries																								
aFRR	Balancing capacity	Demand response: commercial or industrial consumers																								
aFRR	Balancing capacity	Demand response: energy communities																								
aFRR	Balancing capacity	Demand response: residential consumers																								
aFRR	Balancing energy	Aggregators																								
aFRR	Balancing energy	Independent aggregators																								
aFRR	Balancing energy	Distributed generation																								
aFRR	Balancing energy	Batteries																								
aFRR	Balancing energy	Storage excluding hydro, pumped-hydro, and batteries																								
aFRR	Balancing energy	Demand response: commercial or industrial consumers																								
aFRR	Balancing energy	Demand response: energy communities																								
aFRR	Balancing energy	Demand response: residential consumers																								
mFRR	Balancing capacity	Aggregators																								
mFRR	Balancing capacity	Independent aggregators																								
mFRR	Balancing capacity	Distributed generation																								
mFRR	Balancing capacity	Batteries																								
mFRR	Balancing capacity	Storage excluding hydro, pumped-hydro, and batteries																								
mFRR	Balancing capacity	Demand response: commercial or industrial consumers																								
mFRR	Balancing capacity	Demand response: energy communities																								
mFRR	Balancing capacity	Demand response: residential consumers																								
mFRR	Balancing energy	Aggregators																								
mFRR	Balancing energy	Independent aggregators																								
mFRR	Balancing energy	Distributed generation																								
mFRR	Balancing energy	Batteries																								
mFRR	Balancing energy	Storage excluding hydro, pumped-hydro, and batteries																								
mFRR	Balancing energy	Demand response: commercial or industrial consumers																								
mFRR	Balancing energy	Demand response: energy communities																								
mFRR	Balancing energy	Demand response: residential consumers																								

		Legal eligibility	AT	BE	BG	CZ	DE	DK	EE	ES	FI	FR	GR	HR	HU	IT	LT	LV	NL	NO	PL	PT	RO	SE	SI	SK
RR	Balancing capacity	Aggregators	NAP	NAP	NAP	NAP	NAP	NAP	NAP	NAP	NAP	Eligible	NAP	NAP	NAP	NAP	Not eligible	NAP	NAP	NAP	NAP	Not eligible	Eligible	NAP	NAP	NAP
		Independent aggregators	NAP	NAP	NAP	NAP	NAP	NAP	NAP	NAP	NAP	Eligible	NAP	NAP	NAP	NAP	Not eligible	NAP	NAP	NAP	NAP	Not eligible	Eligible	NAP	NAP	NAP
		Distributed generation	NAP	NAP	NAP	NAP	NAP	NAP	NAP	NAP	NAP	Eligible	NAP	NAP	NAP	NAP	Eligible	NAP	NAP	NAP	NAP	Not eligible	Eligible	NAP	NAP	NAP
		Batteries	NAP	NAP	NAP	NAP	NAP	NAP	NAP	NAP	NAP	Eligible	NAP	NAP	NAP	NAP	Not eligible	NAP	NAP	NAP	NAP	Not eligible	Eligible	NAP	NAP	NAP
		Storage excluding hydro, pumped-hydro, and batteries	NAP	NAP	NAP	NAP	NAP	NAP	NAP	NAP	NAP	Not eligible	NAP	NAP	NAP	NAP	Not eligible	NAP	NAP	NAP	NAP	Not eligible	Eligible	NAP	NAP	NAP
		Demand response: commercial or industrial consumers	NAP	NAP	NAP	NAP	NAP	NAP	NAP	NAP	NAP	Eligible	NAP	NAP	NAP	NAP	Not eligible	NAP	NAP	NAP	NAP	Not eligible	Eligible	NAP	NAP	NAP
		Demand response: energy communities	NAP	NAP	NAP	NAP	NAP	NAP	NAP	NAP	NAP	Not eligible	NAP	NAP	NAP	NAP	Not eligible	NAP	NAP	NAP	NAP	Not eligible	Eligible	NAP	NAP	NAP
		Demand response: residential consumers	NAP	NAP	NAP	NAP	NAP	NAP	NAP	NAP	NAP	Eligible	NAP	NAP	NAP	NAP	Not eligible	NAP	NAP	NAP	NAP	Not eligible	Eligible	NAP	NAP	NAP
	Balancing energy	Aggregators	NAP	NAP	NAP	Eligible	NAP	NAP	NAP	Eligible	NAP	Eligible	NAP	NAP	NAP	Trial	NAP	NAP	NAP	NAP	Not eligible	Eligible	Eligible	NAP	Eligible	NAP
		Independent aggregators	NAP	NAP	NAP	Not eligible	NAP	NAP	NAP	Not eligible	NAP	Eligible	NAP	NAP	NAP	Trial	NAP	NAP	NAP	NAP	Not eligible	Not eligible	Eligible	NAP	Eligible	NAP
		Distributed generation	NAP	NAP	NAP	Eligible	NAP	NAP	NAP	Eligible	NAP	Eligible	NAP	NAP	NAP	Trial	NAP	NAP	NAP	NAP	Not eligible	Not eligible	Eligible	NAP	Eligible	NAP
		Batteries	NAP	NAP	NAP	Eligible	NAP	NAP	NAP	Eligible	NAP	Eligible	NAP	NAP	NAP	Not eligible	NAP	NAP	NAP	NAP	Not eligible	Not eligible	Eligible	NAP	Eligible	NAP
		Storage excluding hydro, pumped-hydro, and batteries	NAP	NAP	NAP	Eligible	NAP	NAP	NAP	Eligible	NAP	Not eligible	NAP	NAP	NAP	Not eligible	NAP	NAP	NAP	NAP	Not eligible	Not eligible	Eligible	NAP	Eligible	NAP
		Demand response: commercial or industrial consumers	NAP	NAP	NAP	Eligible	NAP	NAP	NAP	Eligible	NAP	Eligible	NAP	NAP	NAP	Trial	NAP	NAP	NAP	NAP	Not eligible	Eligible	Eligible	NAP	Eligible	NAP
		Demand response: energy communities	NAP	NAP	NAP	Not eligible	NAP	NAP	NAP	Eligible	NAP	Not eligible	NAP	NAP	NAP	Not eligible	NAP	NAP	NAP	NAP	Not eligible	Not eligible	Eligible	NAP	Eligible	NAP
		Demand response: residential consumers	NAP	NAP	NAP	Not eligible	NAP	NAP	NAP	Eligible	NAP	Eligible	NAP	NAP	NAP	Trial	NAP	NAP	NAP	NAP	Not eligible	Not eligible	Eligible	NAP	Eligible	NAP

Legally eligible as a business-as-usual approach
Legally eligible only on a trial basis or in pilot projects
Not legally eligible
N/A
NAP

Source: ACER based on NRA data.
Notes: (1) The table refers to legal eligibility to access local, specific or standard balancing products. (2) Not applicable to Cyprus and Malta since they do not have a liquid wholesale electricity market. (3) The table does not show Ireland since there is no clear translation of the EU balancing services to the IE-SEM due to the way that central dispatch has been implemented in Ireland. Nevertheless, all generators, battery energy storage systems, and demand-side units with capacity greater than 5 MW are mandated to make their capacity available to the TSO for balancing services and congestion management. (4) Luxembourg is integrated within the LFC perimeter of Amprion in the DE-LU bidding zone, hence German provisions apply. (5) In 2022 all distributed energy resources in Italy excluding energy communities, batteries, and other new storage solutions (e.g., compressed air energy, flywheels, hydrogen, etc.) were legally eligible to provide balancing energy in the framework of the national pilot projects 'Regolazione Secondaria' and 'UVAM'; however, they were not converted to the EU balancing energy platforms. This is expected to change from January 2025 when all types of distributed energy resources will be eligible to participate according to the regular regulatory framework. Since 2023, all energy storage solutions have become legally eligible to provide balancing energy individually.

3.2.3. Legal eligibility to provide congestion management services for TSOs and DSOs

67 Table 6 shows the legal eligibility of new actors and distributed energy resources to provide congestion management services for TSOs and DSOs in 2022.

68 In the nineteen Member States where TSOs use some market-based or non-market-based mechanism for re-dispatching to tackle congestions in their transmission grid (more information in Chapter 6), only Belgium, Germany, France, Croatia, and the Netherlands have fully opened this service to all new actors and distributed energy resources.

69 Based on the information reported, the most restrictive TSOs re-dispatching services are found in Greece, Poland, and Portugal where no distributed energy resource, individually or aggregated, is legally allowed to participate (in Portugal only industrial and commercial consumers were piloted in 2022). Re-dispatching is unavailable to aggregators in at least Greece, Italy (only allowed on a trial basis), Poland, and Portugal and to independent aggregators in at least eleven Member States, including Austria, the Czech Republic, Spain, Finland, Greece, Hungary, Italy (only allowed on a trial basis), Norway, Poland, Portugal, and Sweden.

70 In the thirteen Member States where DSOs implement some kind of congestion management measure, i.e., market-based[29] or non-market-based re-dispatching (also referred to as local markets), non-firm connection agreements or interruptible tariffs (more information in Chapter 6), only Belgium, Germany, France, Malta, the Netherlands, Sweden and Slovenia have fully opened this service to all new actors and distributed energy resources.

29 In a market-based setting, the DSO could negotiate bilaterally or participate in an organised marketplace with network users offering their flexibility, or interact with service providers acting on their behalf, defining and trading desired products. For more information, please refer to CEER's 2020 Paper on DSO Procedures of Procurement of Flexibility.

Table 6: Legal eligibility of different distributed energy resources and new actors to provide congestion management services for TSOs and DSOs per Member State – 31 December 2022

	Legal eligibility	AT	BE	BG	CY	CZ	DE	DK	EE	ES	FI	FR	GR	HR	HU	IE	IT	LT	LU	LV	MT	NL	NO	PL	PT	RO	SE	SI	SK
TSO Congestion Management	Aggregators	BAU	BAU	N/A	N/A	BAU	BAU	NAP	NAP	BAU	BAU	BAU	Not eligible	BAU	BAU	BAU	Trial/pilot	NAP	NAP	NAP	NAP	BAU	BAU	Not eligible	Not eligible	BAU	BAU	NAP	N/A
TSO Congestion Management	Independent aggregators	Not eligible	BAU	N/A	N/A	Not eligible	BAU	NAP	NAP	Not eligible	Not eligible	BAU	Not eligible	BAU	Not eligible	BAU	Trial/pilot	NAP	NAP	NAP	NAP	BAU	Not eligible	Not eligible	Not eligible	BAU	Not eligible	NAP	N/A
TSO Congestion Management	Distributed generation	BAU	BAU	N/A	N/A	BAU	BAU	NAP	NAP	BAU	BAU	BAU	Not eligible	BAU	Not eligible	BAU	Trial/pilot	NAP	NAP	NAP	NAP	BAU	BAU	Not eligible	Not eligible	BAU	BAU	NAP	N/A
TSO Congestion Management	Batteries	BAU	BAU	N/A	N/A	BAU	BAU	NAP	NAP	BAU	BAU	BAU	Not eligible	BAU	Not eligible	BAU	Not eligible	NAP	NAP	NAP	NAP	BAU	BAU	Not eligible	Not eligible	BAU	BAU	NAP	N/A
TSO Congestion Management	Storage excluding hydro, pumped-hydro, and batteries	BAU	BAU	N/A	N/A	BAU	BAU	NAP	NAP	BAU	BAU	BAU	Not eligible	BAU	Not eligible	BAU	BAU	NAP	NAP	NAP	NAP	BAU	BAU	Not eligible	Not eligible	BAU	BAU	NAP	N/A
TSO Congestion Management	Demand response: commercial or industrial consumers	BAU	BAU	N/A	N/A	BAU	BAU	NAP	NAP	Not eligible	BAU	BAU	Not eligible	BAU	Trial/pilot	Not eligible	Trial/pilot	NAP	NAP	NAP	NAP	BAU	BAU	Not eligible	Trial/pilot	BAU	BAU	NAP	N/A
TSO Congestion Management	Demand response: energy communities	BAU	BAU	N/A	N/A	Not eligible	BAU	NAP	NAP	Not eligible	Not eligible	BAU	Not eligible	BAU	Trial/pilot	Not eligible	Trial/pilot	NAP	NAP	NAP	NAP	BAU	Not eligible	Not eligible	Not eligible	Not eligible	BAU	NAP	N/A
TSO Congestion Management	Demand response: residential consumers	BAU	BAU	N/A	N/A	BAU	BAU	NAP	NAP	Not eligible	Not eligible	BAU	Not eligible	BAU	Not eligible	Not eligible	Trial/pilot	NAP	NAP	NAP	NAP	BAU	Not eligible	Not eligible	Not eligible	Not eligible	BAU	NAP	N/A
DSO Congestion Management	Aggregators	NAP	BAU	NAP	NAP	N/A	BAU	N/A	NAP	N/A	NAP	BAU	NAP	NAP	Not eligible	NAP	NAP	NAP	NAP	NAP	BAU	BAU	Trial/pilot	NAP	N/A	Not eligible	BAU	BAU	NAP
DSO Congestion Management	Independent aggregators	NAP	BAU	NAP	NAP	Not eligible	BAU	N/A	NAP	N/A	NAP	BAU	NAP	NAP	Not eligible	NAP	NAP	NAP	NAP	NAP	BAU	BAU	Trial/pilot	NAP	N/A	Not eligible	Trial/pilot	BAU	NAP
DSO Congestion Management	Distributed generation	NAP	BAU	NAP	NAP	BAU	BAU	N/A	NAP	N/A	NAP	BAU	NAP	NAP	Not eligible	NAP	NAP	NAP	NAP	NAP	BAU	BAU	Trial/pilot	NAP	N/A	Not eligible	BAU	BAU	NAP
DSO Congestion Management	Batteries	NAP	BAU	NAP	NAP	BAU	BAU	N/A	NAP	N/A	NAP	BAU	NAP	NAP	Not eligible	NAP	NAP	NAP	NAP	NAP	BAU	BAU	Trial/pilot	NAP	N/A	Not eligible	BAU	BAU	NAP
DSO Congestion Management	Storage excluding hydro, pumped-hydro, and batteries	NAP	BAU	NAP	NAP	BAU	BAU	N/A	NAP	N/A	NAP	BAU	NAP	NAP	Not eligible	NAP	NAP	NAP	NAP	NAP	BAU	BAU	Trial/pilot	NAP	N/A	Not eligible	BAU	BAU	NAP
DSO Congestion Management	Demand response: commercial or industrial consumers	NAP	BAU	NAP	NAP	BAU	BAU	N/A	NAP	N/A	NAP	BAU	NAP	NAP	Not eligible	NAP	NAP	NAP	NAP	NAP	BAU	BAU	Trial/pilot	NAP	N/A	Not eligible	BAU	BAU	NAP
DSO Congestion Management	Demand response: energy communities	NAP	BAU	NAP	NAP	Not eligible	BAU	N/A	NAP	N/A	NAP	BAU	NAP	NAP	Trial/pilot	NAP	NAP	NAP	NAP	NAP	BAU	BAU	Trial/pilot	NAP	N/A	Not eligible	BAU	BAU	NAP
DSO Congestion Management	Demand response: residential consumers	NAP	BAU	NAP	NAP	BAU	BAU	N/A	NAP	N/A	NAP	BAU	NAP	NAP	Not eligible	NAP	NAP	NAP	NAP	NAP	BAU	BAU	Trial/pilot	NAP	N/A	Not eligible	BAU	BAU	NAP

Legally eligible as a business-as-usual approach
Legally eligible only on a trial basis or in pilot projects
Not legally eligible
N/A (Legal eligibility not available but congestion management services in place)
NAP

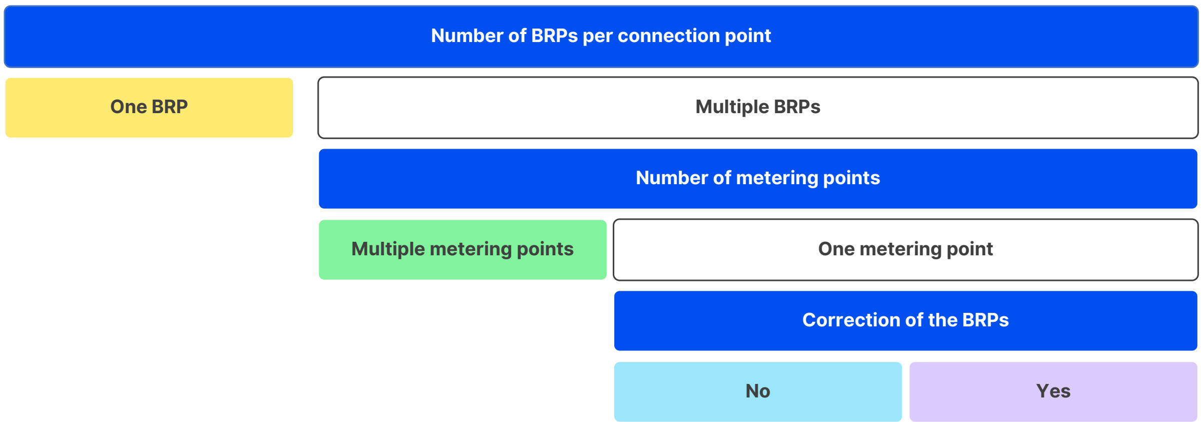
Source: ACER based on NRA data.
Notes: (1) No information for Bulgaria, Cyprus, Denmark, Portugal, and Slovakia. (2) NAP (Not applicable) refers to cases where the TSO/DSO does not use a market-based or non-market-based congestion management measures, i.e., when there are no congestions at transmission/distribution level or when the DSOs do not perform a congestion management measure other than requesting the TSO to solve the congestion or network reinforcement and expansion. (3) In Germany all types of actors are obliged to provide congestion management for the TSOs and DSOs if needed. (4) In Ireland all generators, battery energy storage systems, and demand-side units with capacity greater than 5 MW are mandated to make their capacity available to the TSO for balancing services and congestion management. (5) In Norway, DSOs use non-market-based re-dispatching but they are testing market-based re-dispatching in pilot projects and within regulatory sandboxes where all resources and actors are eligible parties. (6) In Slovenia the DSOs do not take any congestion management measure however their national rules allow all types of resources and market participants to provide DSOs with congestion management services. (7) Since 2023 all energy storage solutions in Italy have become legally eligible to provide congestion management services to the TSO.

3.3. Lack of a proper legal framework on aggregation models

71 Member States must allow and foster participation of demand response through aggregation in all electricity markets and ensure that SOs, when procuring SO services, treat market participants engaged in aggregation in a non-discriminatory manner[30]. Market participants may engage in aggregation following different models with respect to their relationship with the customer's supplier and their balance responsibility, i.e., aggregation models. For the aggregation model(s) chosen for each electricity market and SO service, Member States must also ensure that their national regulatory framework defines at least the elements included in the Electricity Directive, including non-discriminatory and transparent rules clearly assigning roles and responsibilities to all electricity undertakings and customers and non-discriminatory and transparent rules and procedures for the exchange of data, among others[31].

72 Figure 9 shows a general categorisation of the aggregation models with three levels: one or multiple BRPs per connection point, one or multiple metering points if there are multiple BRPs per connection point and whether there is any correction in the volumes attributed to the BRPs in the context of the imbalance settlement[32] (i.e., correction in the allocated volumes, final position or imbalance adjustment) if there is a single metering point. With this classification, all aggregation models are split into four categories, illustrated with the four pastel colours.

Figure 9: General categorisation of aggregation models



Source: ACER .

73 Based on this general categorisation, Table 7 shows an overview of the aggregation models implemented in each Member State in 2022: each type of aggregation model and its maturity level (left) and whether it is only applicable to a specific customer segment (right). Some conclusions can be drawn regarding the types of aggregation models in place:

- All Member States implement or plan to implement the same type of aggregation model across all their electricity markets and SO services except for Austria, Estonia, Finland, Norway, and Sweden.
- Per category, the aggregation models with a single BRP per connection point show the highest level of implementation across the EU (implemented as a business-as-usual approach or on a trial stage or in a pilot project in eleven Member States) and across the electricity markets and SO services. On top of this model, Austria, Estonia, Norway, and Sweden also plan or are already piloting aggregation models with multiple BRPs per connection point.
- Eight Member States only have some aggregation models with multiple BRPs per connection point up and running. For the time being, the Member States do not show a preference for any particular model with multiple BRPs per connection point.

30 Article 17 and 32(1) of the Electricity Directive.

31 Article 17 of the Electricity Directive.

32 As defined in Article 2(9) of the Electricity Balancing Regulation. This correction does not refer to the financial compensation that Member States may require to pay from electricity undertakings or participating final customers to other market participants or to the market participants' BRPs, if those are directly affected by demand response activation (Article 17(4) of the Electricity Directive).

Table 7: Aggregation models per Member State and per electricity market and SO service according to a general categorisation – 2022

	Type of aggregation model								Customer segment							
	DA and ID	CRMs	FCR	aFRR	mFRR	RR	TSO re-dispatching	DSO congestion management	DA and ID	CRMs	FCR	aFRR	mFRR	RR	TSO re-dispatching	DSO congestion management
AT	BaU		BaU	BaU	BaU		BaU	Non-market based								
	P			BaU	BaU		P	P								
BE	BaU	BaU	BaU	BaU	BaU		Non-market based	Non-market based								
	BaU	BaU	BaU	BaU	BaU											
BG			BaU	BaU	BaU	BaU	N/A								N/A	
CY							N/A								N/A	
CZ	BaU		BaU	BaU	BaU	BaU	Non-market based	Non-market based								
							P									
DE							Non-market based	Non-market based								
DK	N/A		N/A	N/A	N/A		No congestion	Non-market based	N/A		N/A	N/A	N/A			
EE	P				BaU		No congestion	No congestion								
					P											
ES	P		Non-market based	BaU	BaU	BaU	P		N/A						N/A	
FI		TorP	BaU	P	TorP			No congestion		N/A						
			BaU													
FR	BaU	BaU	BaU	BaU	BaU	BaU	P	P								
	BaU	BaU	BaU	BaU	BaU	BaU	P	P								
GR	P		BaU	BaU	BaU		BaU									
HR	BaU		Non-market based				Non-market based	No congestion								
HU	BaU		BaU	BaU	Bau		Non-market based	Non-market based								
IE	BaU	BaU					BaU									
IT		BaU	Non-market based	TorP	TorP	TorP	TorP	No congestion								
			P													
LT					BaU		No congestion	No congestion								
LU							No congestion	No congestion								
LV	P				BaU		No congestion		N/A							
MT								Non-market based								
NL	P		P	P	P		P	P								
	P		P	P	P		P	P								
NO	BaU			Bau	BaU		BaU	Non-market based	N/A			N/A	N/A		N/A	
								TorP								N/A
	BaU			BaU	BaU		BaU	TorP	N/A			N/A	N/A		N/A	N/A
								TorP								N/A
PL	BaU	BaU	P	P		P	N/A								N/A	
PT			Non-market based					Non-market based								
RO	BaU		Non-market based	BaU	BaU	BaU	BaU	BaU								
SE	BaU		BaU	BaU	BaU		BaU	TorP								
	BaU		BaU	BaU	BaU		BaU	TorP								
	P		P	P	P		P	TorP								
			P	P	P		P	P								
SI	BaU		BaU	BaU	BaU	BaU	No congestion	TorP			N/A					
SK							Non-market based									

Type of aggregation model
- 1 BRP/connection point + 1 metering point
- Multiple BRPs/connection point + Multiple metering points
- Multiple BRPs/connection point + 1 metering point + No correction of the BRPs
- Multiple BRPs/connection point + 1 metering point + Correction of the BRPs
- N/A (Not available: there is an aggregation model in place but the NRA does not have any information)
- NAP (Not applicable: the market/SO service is not in operation or the SO service is non-market-based)
- No aggregation model implemented as BaU or TorP

Customer segment
- Applicable to all customers
- Only applicable to customers connected to LV level
- Only applicable to customers connected to MV and HV level

Maturity level
- BaU: implemented as a business as usual approach
- TorP: implemented on a trial stage or in a pilot project
- P: under discussion/planning
- N/A: NRA does not have information on the maturity level or on the customer segment

Source: ACER based on NRA data.
Notes: (1) Please note that the aggregation models usually differ across the markets and SO services even though this overview shows similar categorisations. (2) In the second aggregation model in Belgium, even though there are multiple BRPs per connection point, the BSP is only responsible for balancing. It is not responsible for the supply of the connection point. (3) In Germany aggregation usually takes place in an integrated way (i.e., within the supplier's balancing group) however the NRA has no overview of the types of aggregation models in place. (4) Estonia plans to change the current BaU aggregation model for mFRR with a new aggregation model with multiple BRPs per connection point. (5) In France there are two aggregation models (one applicable to customers connected to low voltage and another one applicable to medium and high voltage customers) for all electricity markets. The model applicable to low voltage levels is still not up and running for aFRR but it is expected to enter into operation at the end of 2023. Both models are legally possible for any SO service. (6) In Greece all the aggregation models are only applicable to aggregations with only loads or with only renewable energy sources in its portfolio. (7) Due to the way that central dispatch has been implemented in Ireland, there is no clear translation of EU balancing services to the IE-SEM, therefore there is no information on the aggregation models for balancing services. (8) In 2023 Portugal has conducted a public consultation on the legal framework for aggregation before setting national rules. (9) In Slovakia secondary legislation to define the aggregation models is under preparation. (10) In Lithuania the aggregation model for mFRR is applicable to all types of consumers, although in practice only consumers connected to medium and high voltage level use this aggregation model.

74 The following aspects can be considered as an entry barrier for market participants engaged in aggregation and for the distributed energy resources:

- Lack of at least one aggregation model implemented as a business-as-usual approach, on a trial stage or in a pilot project in each electricity market and market-based SO services in each Member State.
- Missing aggregation models for some customer segments.
- Lack of monitoring by Member States of the aggregation models up and running. Without monitoring, Member States cannot ensure the fulfillment of all requirements of the Electricity Directive and that all market participants engaged in aggregation are really allowed to participate in all electricity markets and market-based SO services on equal and non-discriminatory terms.

75 Table 7 shows that at least thirteen Member States (Estonia, Spain, Finland, France, Greece, Croatia, Luxembourg, Latvia, the Netherlands, Norway, Poland, Portugal, and Slovakia) lack an aggregation model up and running, on a trial stage or in a pilot project in at least one of their electricity markets or market-based SO services in operation. Even though Belgium, the Czech Republic, Greece, Hungary, and Ireland, have some aggregation models implemented as a business-as-usual approach, they are not applicable to customers connected to low voltage levels. In addition, NRAs in ten Member States (Bulgaria, Cyprus, Germany, Denmark, Finland, Croatia, Italy, Lithuania, Poland, and Sweden) lack information about all types of aggregation models currently implemented at national level.

3.4. Lack of access to final customer data

76 The Electricity Directive[33] sets that Member States must specify the rules on the access to data of the final customer by eligible parties. Such data should include metering and consumption data as well as data required for customer switching, demand response and other services (e.g., self-consumption or electromobility). Regardless of the data management model applied, Member States must ensure efficient and secure data access and exchange, data protection and data security as well as provide access to the data of the final customer to any eligible party. Member States must also ensure that the relevant procedures for obtaining access to data are publicly available and that no additional cost is allowed to be charged to final customers for access to their data or for a request to make their data available.

77 As shown in Table 8, in 2022 most Member States had ensured all these requirements in their national rules except for the Czech Republic, Italy, the Netherlands, and Sweden. Nevertheless, Swedish national rules ensure no additional costs to final customers for accessing their data since 1 June 2023 while the new Energy Act in the Netherlands is expected to further define the rules on access to final customer data.

33 Article 23 of the Electricity Directive.

Table 8: Restrictions to access final customer data per Member State – 2022

Data management	AT	BE	BG	CY	CZ	DE	DK	EE	ES	FI	FR	GR	HR	HU	IE	IT	LT	LU	LV	MT	NL	NO	PL	PT	RO	SE	SI	SK
Specify rules on access to data of final customer	Implemented	Implemented	N/A	Implemented	Not implemented	N/A	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Not implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented
Relevant procedures for obtaining data access publicly available	Implemented	Implemented	N/A	Implemented	Not implemented	N/A	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Not implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented
No additional costs to customer to access their data	Implemented	Implemented	N/A	Implemented	Not implemented	N/A	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Not implemented	Implemented	Implemented	Implemented	Implemented	Not implemented	Implemented	Implemented

Implemented in national rules Not implemented in national rules N/A

Source: ACER based on NRA data.
Notes: (1) No information for Bulgaria and Germany. (2) Cyprus has defined the requirements in its national rules; however, the Regulatory Decision has not been implemented yet. The NRA is going to publish a tender for the provision of consultancy services for the determination of the rules, including the definition of the eligible parties.

78 The Electricity Directive[34] also sets that the eligible parties must have the requested data at their disposal in a non-discriminatory manner and simultaneously.

79 As shown in Table 9, in 2022 some Member States did not recognise aggregators, independent aggregators or energy service companies as eligible parties to access final customers data based on their consent.

Table 9: Eligible parties to access data of final customers per Member State – 2022

Eligible parties	AT	BE	BG	CY	CZ	DE	DK	EE	ES	FI	FR	GR	HR	HU	IE	IT	LT	LU	LV	MT	NL	NO	PL	PT	RO	SE	SI	SK
Suppliers	Eligible	Eligible	N/A	Non-eligible	Eligible	N/A	Eligible	Eligible	Eligible	Eligible	Eligible	Eligible	Eligible	Eligible	Non-eligible	Eligible	Eligible	N/A	Eligible	Eligible	Eligible	Eligible	Eligible	Eligible	Eligible	Eligible	Eligible	Eligible
Aggregators	Eligible	Eligible	N/A	Non-eligible	Eligible	N/A	Eligible	Eligible	Eligible	Eligible	Eligible	Eligible	Eligible	Eligible	Non-eligible	Non-eligible	Eligible	N/A	Eligible	Non-eligible	Eligible	Eligible	Non-eligible	Eligible	Eligible	Eligible	Eligible	Non-eligible
Independent aggregators	Eligible	Eligible	N/A	Non-eligible	Non-eligible	N/A	Eligible	Eligible	Non-eligible	Eligible	Eligible	Eligible	Eligible	Eligible	Non-eligible	Non-eligible	Eligible	N/A	Eligible	Non-eligible	Eligible	Eligible	Non-eligible	Eligible	Eligible	Eligible	Eligible	Non-eligible
Energy service companies	Eligible	Eligible	N/A	Non-eligible	Non-eligible	N/A	Eligible	Eligible	Non-eligible	Eligible	Eligible	Eligible	Non-eligible	Eligible	Non-eligible	Non-eligible	Eligible	N/A	Eligible	Non-eligible	Eligible	Eligible	N/A	Non-eligible	Non-eligible	Eligible	Eligible	Non-eligible

Eligible party in national rules Non-eligible party in national rules N/A

Source: ACER based on NRA data.
Notes: (1) No information for Bulgaria, Germany, and Luxembourg. (2) The Cypriot NRA is going to publish a tender for the provision of consultancy services for the determination of the rules, including the definition of the eligible parties. (3) The Irish NRA is currently developing the Smart Meter Data Access Code which will specify the rights of access to data of final customers. (4) By law, in Malta there is only one electricity supplier, that is also the DSO, thus it has direct access to all final consumers' data.

80 In most Member States each supplier is only allowed to access data of the final customers with whom they have concluded an electricity supply contract. Accessing data of non-customers is fully restricted without their prior authorisation. Such a restriction applies even in Member States that have set up or plan to set up a Central Data Platform (e.g., Estonia, Luxembourg or Slovenia); however, there are some exceptions where suppliers have access to partial data of non-customers. For example, in Spain suppliers have access to technical data of all connection points, including monthly energy consumption via a Central Data Platform named "SIPS"[35]. For confidentiality reasons, they are not allowed to access their commercial or personal data. With the current national legal framework, only market participants licensed as suppliers are allowed to access this data platform. Third parties such as independent aggregators or energy service companies are required to get a prior final customer' authorisation before accessing their data. However, when they obtain such an authorisation, they are not allowed to access this Central Data Platform, but must access the data through the DSO website of each individual final customer[36].

81 To ensure that all eligible parties have the requested data at their disposal in a non-discriminatory manner and simultaneously in line with the Electricity Directive, ACER considers that all those eligible should be given access (i) to the same type and amount of data of non-customers, and (ii) through the same data platforms or tools to avoid creating undue administrative barriers between suppliers and new actors. Having access to final customer data subject to its consent is a crucial enabler to allow new actors such as aggregators, independent aggregators or energy service companies offering their services to final customers and promoting explicit demand response or energy efficient measures.

34 Article 23(2) of the Electricity Directive.

35 For more information on SIPS (Sistema de Información de Puntos de Suministro), please refer to: https://www.cnmc.es/ambitos-de-actuacion/energia/sips.

36 As a private initiative, the Spanish DSOs have created the data platform 'DATADIS'. It enables each final customer to easily access its electricity consumption data and give authorisations to third parties to access their data including historical aggregate data series.

82 In June 2023 the European Commission adopted a new implementing act to improve access to metering and consumption data[37]. The requirements and procedures implemented under this secondary legislation will ensure that data on metering and consumption in all EU Member States use one common reference model that should be in force from 5 January 2025. To facilitate the interoperability of energy consumer data, in compliance with Article 24 of the Electricity Directive, the European Commission will adopt additional implementing acts including data required for demand response and other services.

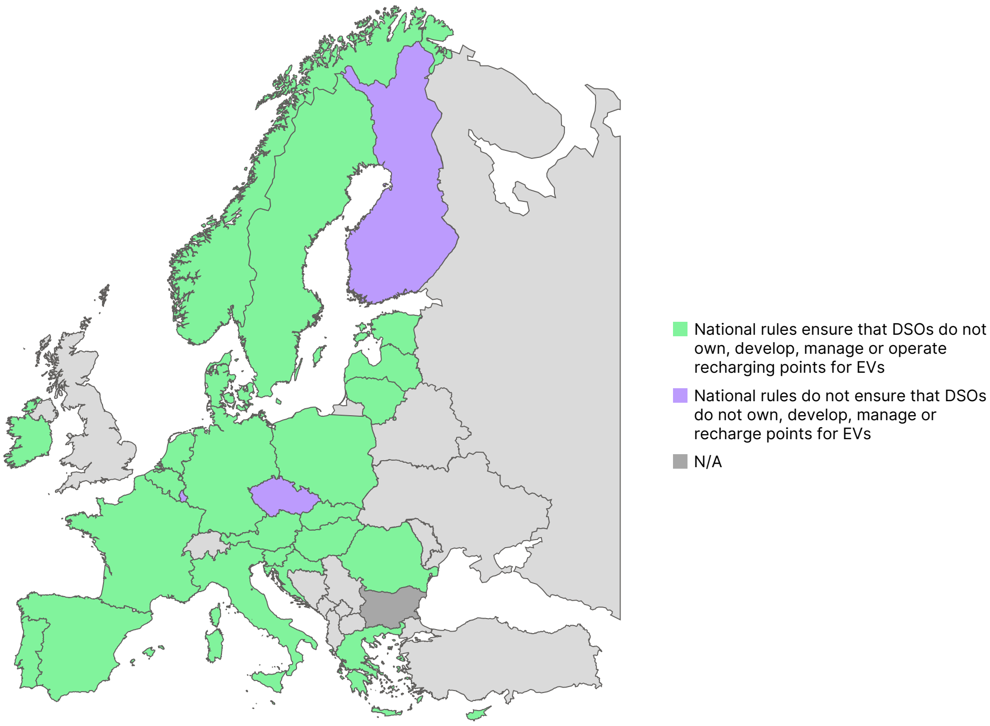
3.5. Ownership of recharging points for electric vehicles and storage facilities by system operators

83 DSOs should act as neutral market facilitators and should not own, develop, manage or operate storage facilities nor EV charging facilities, unless they are used to ensure network security and reliability or unless no other market participant, including demand response, can ensure the provision of such services. A national derogation can only be granted if a market-based process did not identify any company willing to provide the same service. If granted, the NRA must revise the decision every few years to ensure that SOs do not hinder market competition from emerging market participants in the energy system[38]. The same applies to TSOs with storage facilities[39].

Recharging points for electric vehicles

84 As shown in Figure 10, in 2022 most Member States had included in their national rules some provisions to ensure that DSOs do not own, develop, manage or operate recharging points for electric vehicles (except where DSOs own private recharging points solely for their own use), with the exception of the Czech Republic, Finland, and Luxembourg. In 2023 Finland and Luxembourg have formally transposed this requirement. In 2022 no Member State had granted a derogation to DSOs to own, develop, manage or operate recharging points for electric vehicles.

Figure 10: Ownership of recharging points for electric vehicles by DSOs per Member State – 2022



Source: ACER based on NRA data.
Note: (1) No information for Bulgaria.

37 Commission Implementing Regulation (EU) of 6 June 2023 on interoperability requirements and non-discriminatory and transparent procedures for access to metering and consumption data.

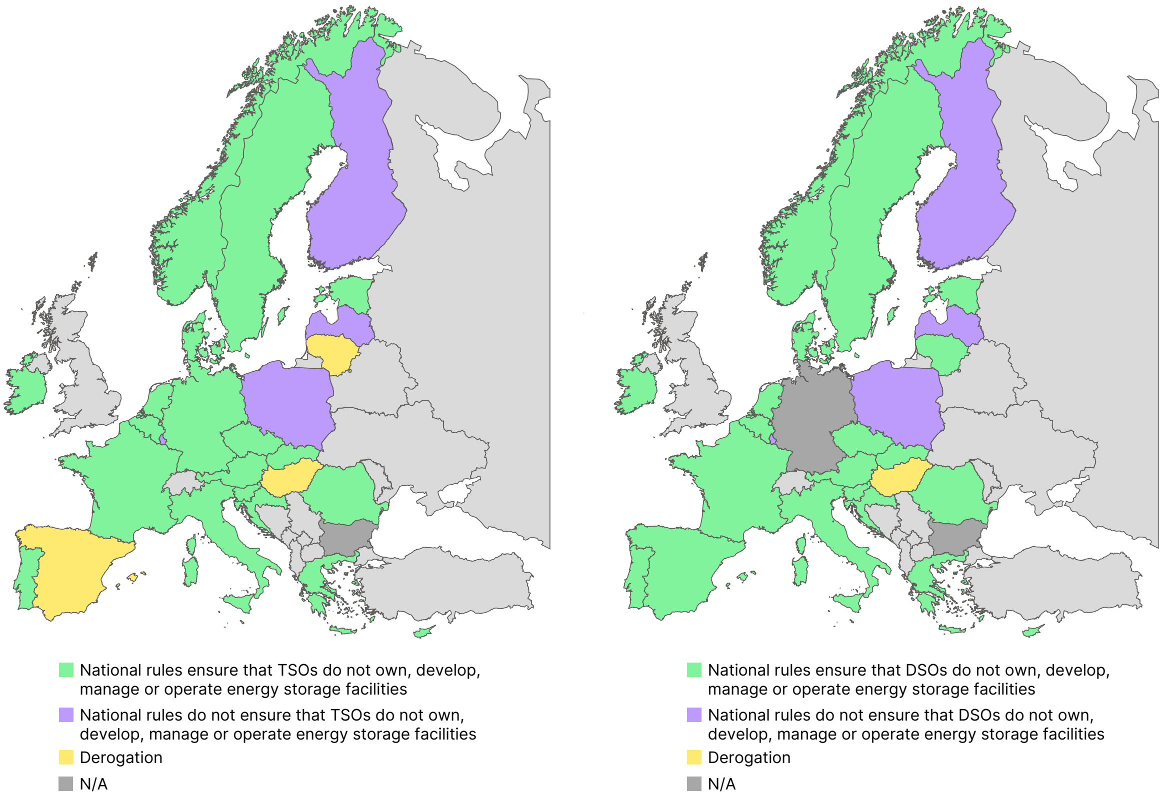
38 Articles 33 and 36 of the Electricity Directive.

39 Article 54 of the Electricity Directive.

Storage facilities

85 As depicted in Figure 11, in 2022 most Member States had included in their national rules some provisions to ensure that TSOs and DSOs do not own, develop, manage nor operate energy storage facilities except for Finland, Luxembourg, Latvia, and Poland. In 2023 these four Member States have formally transposed this requirement.

Figure 11: Ownership of storage facilities by TSOs (left) and DSOs (right) per Member State – 2022



Source: ACER based on NRA data.
Note: (1) No information for Bulgaria on the ownership of storage facilities by TSOs and DSOs and for Germany on the ownership of storage facilities by DSOs.

86 Spain, Hungary, and Lithuania have granted some derogations to allow their TSO to own, develop, manage and/or operate some energy storage facilities.

- Spain has granted a derogation to pumped-hydro storage facilities located on non-mainland territories as long as their main aim is to ensure security of supply and renewable energy integration. So far, this derogation only applies to a pumped-hydro storage facility in the Grand Canary Island, yet to be commissioned.
- Hungary and Lithuania have granted derogations to energy storage facilities that are considered fully integrated network components, therefore no tendering procedure was needed before granting the derogations. In Hungary the derogation applies to one planned energy storage facility while in Lithuania it applies to a single 1 MW battery storage facility installed at a TSO transformer station to participate in reserve and innovative projects and provide non-frequency ancillary services.

87 In February 2023 Germany also approved the request from TenneT TSO GmbH to own, develop, manage, and operate a battery storage facility. BNetzA (the German NRA) approved the request according to the conditions set out in Article 54(2)(a)-(c) of the Electricity Directive. Before granting the approval there was a tender, but no party offered bids at a reasonable cost[40]. The TSO is not allowed to use the battery storage facility for balancing or interfere with the balancing market.

40 For more information on the tender please refer to: https://www.bundesnetzagentur.de/DE/Fachthemen/ElektrizitaetundGas/Entflechtung/start.html.

88 Only Hungary has granted derogations to allow some DSOs to own, develop, manage and/or operate multiple energy storage facilities which are considered fully integrated network components.

89 Some Member States including Denmark, Greece, Sweden, and Slovakia, confirm that their current national rules still do not fully define the procedure to grant derogations to TSOs and DSOs to own, develop, manage or operate energy storage facilities and to DSOs to own, develop, manage or operate recharging points for electric vehicles.

3.6. Restrictions on trade on day-ahead and intraday markets

90 A low time granularity and a large minimum product size in the day-ahead and intraday markets can hinder an effective participation of distributed energy resources in these markets.

91 The Electricity Regulation[41] sets that Nominated Electricity Market Operators (NEMOs) must provide products for trading in day-ahead and intraday markets sufficiently small, with minimum bid sizes of 500 kW or less, to allow for the effective participation of demand response, energy storage and small-scale renewables, including direct participation by customers. Table 10 shows that in 2022 Hungary, the Netherlands, Poland, and Slovenia[42] still had a minimum bid size higher than 500 kW in their day-ahead and intraday markets.

92 Market participants should also be able to trade energy as close as possible to real time on the day-ahead and intraday markets. The Electricity Regulation sets that NEMOs must provide market participants with the opportunity to trade in time intervals which are at least as short as the imbalance settlement period (ISP)[43] for both day-ahead and intraday markets[44]. The ISP should be 15 minutes in all scheduling areas unless the regulatory authority has granted a derogation or an exemption[45]. As shown in Table 10, in 2022 the imbalance settlement period was longer than 15 minutes in half of the Member States, reaching 1 hour in most cases. In all these Member States the regulatory authority granted a derogation until 31 December 2024, except for Poland where the derogation was applicable until 31 December 2021 which means it is not in line with the Electricity Regulation.

93 In all Member States NEMOs provide market participants with the opportunity to trade in the same time intervals as the ISP with seven exceptions. In day-ahead markets, some NEMOs cannot offer 15 minutes until SDAC algorithm implements 15 minutes MTUs by 2025. Some NEMOs (e.g., Austria, Germany or the Netherlands) hold national auctions outside the SDAC which offer 15 minutes products. In all Member States but in Greece and Latvia, intraday products with the MTU as short as the ISP are available in the SIDC.

41 Article 8(3) of the Electricity Regulation.

42 In Slovenia intraday trading takes place on the Slovenian intraday continuous market and the Complementary Regional Intraday Auctions (CRIDA) separately. The CRIDA market aims to couple the Italian and Slovenian intraday local auctions. The minimum bid size of the Slovenian intraday continuous market is 1 MW while the minimum bid size in the CRIDA market is 0.1 MW.

43 The imbalance settlement period means the time unit for which balance responsible parties' imbalance is calculated as set out in Article 2(10) of the Electricity Balancing Regulation.

44 Article 8(2) of the Electricity Regulation.

45 The regulatory authorities are allowed to grant a derogation or an exemption from an ISP of 15 minutes only until 31 December 2024. From 1 January 2025, the ISP shall not exceed 30 minutes where an exemption has been granted by all the regulatory authorities within a synchronous area.

Table 10: Restrictions in the product size and the time granularity in day-ahead and intraday markets – 2022

Day-ahead and intraday	AT	BE	BG	CZ	DE	DK	EE	ES	FI	FR	GR	HR	HU	IE	IT	LT	LV	NL	NO	PL	PT	RO	SE	SI	SK
Smallest minimum bid size in day-ahead market (MW)	≤ 0.5	≤ 0.5		≤ 0.5	≤ 0.5	≤ 0.5	≤ 0.5	≤ 0.5	≤ 0.5	≤ 0.5	≤ 0.5	≤ 0.5	1 < x ≤ 5	≤ 0.5	No min	≤ 0.5	≤ 0.5	1 < x ≤ 5	≤ 0.5	0.5 < x ≤ 1	≤ 0.5	≤ 0.5	No min	0.5 < x ≤ 1	≤ 0.5
Smallest minimum bid size in intraday market (MW)	≤ 0.5	≤ 0.5		≤ 0.5	≤ 0.5	≤ 0.5	≤ 0.5	≤ 0.5	≤ 0.5	≤ 0.5	≤ 0.5	≤ 0.5	1 < x ≤ 5	≤ 0.5	No min	≤ 0.5	≤ 0.5	1 < x ≤ 5	≤ 0.5	0.5 < x ≤ 1	≤ 0.5	≤ 0.5	No min		≤ 0.5
Imbalance settlement period (ISP) (min)	15	15		60	15	60	60	60	60	30	15	60	15	30	60	60	15	15	60	60	60	15	60	15	15
If ISP not 15 min, derogation granted until 31 December 2024				YES		YES	YES	YES	YES	YES		YES		YES	YES	YES			YES	NO	YES		YES		
In the day-ahead market, NEMOs provide market participants with the opportunity to trade in time intervals which are at least as short as the ISP	YES	NO		YES	YES	YES	YES	YES	YES	NO	NO	YES	YES	NO	YES	YES	NO	YES	YES	YES	YES	NO	YES	NO	YES
In the intraday market, NEMOs provide market participants with the opportunity to trade in time intervals which are at least as short as the ISP	YES	YES		YES	YES	YES	YES	YES	YES	YES	NO	YES	YES	YES	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES

Not restrictive
Potentially restrictive
N/A
NAP (Not applicable, the Member State has not granted any derogation)

Source: ACER based on NRA data.
Notes: (1) No information for Bulgaria. (2) Not applicable to Cyprus and Malta since they do not have a liquid wholesale electricity market. (3) Luxembourg is integrated within the LFC perimeter of Amprion in the DE-LU bidding zone, hence German provisions apply.

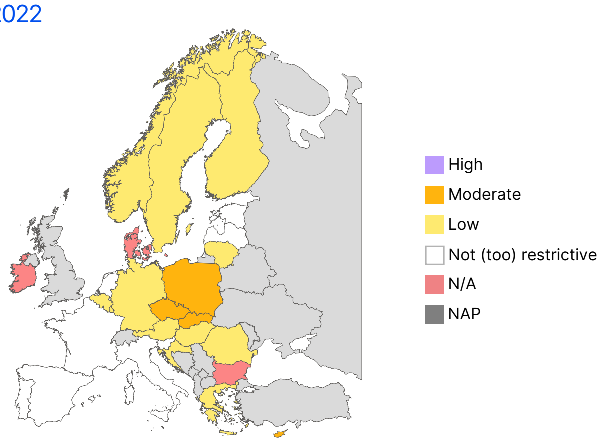
4. Unavailability or lack of incentives to provide flexibility

The lack of smart metering devices restrict access to price signals in nearly half of the Member States. There is limited information on the value propositions enabled in smart meters installed, thus many consumers likely do not take full advantage of these devices.

Some Member States with time-differentiated network tariffs estimate a limited level of penetration. Eight Member States do not apply this type of tariffs although some have a high smart meter roll-out or have not properly assessed the implementation of network tariffs with time differentiation.

There is marginal information on the level of penetration of retail electricity contracts with time differentiation across Member States. In some national frameworks, suppliers are allowed to offer fixed electricity price contracts where both the energy component and the network tariff component is bundled into a fixed sum, in which case no time-of-use signals are provided to these customers, regardless of whether time-differentiated network tariffs were set.

Figure 12: Unavailability or lack of incentives to provide flexibility. Overview of the barrier (top) and underlying indicators (bottom) per Member State – 2022



Low roll-out of smart meters

BG	CY	CZ	DE	GR	HU	LT	PL	RO	SK	BE	HR	IE	AT	DK	EE	ES	FI	FR	IT	LU	LV	MT	NL	NO	PT	SE	SI

Lack of a proper legal framework on minimum functionalities of smart meters

CZ	SK	AT	BE	CY	DE	EE	ES	FI	FR	GR	HR	HU	IT	LT	LU	LV	MT	NL	NO	PL	PT	RO	SE	SI	BG	DK	IE

Low number of value propositions enabled by the smart meters installed

BE	BG	CY	GR	MT	PT	RO	SK	AT	EE	ES	IT	LU	LV	SI	FR	LT	NO	CZ	DE	DK	FI	HR	HU	IE	NL	PL	SE

Low share of energy component in the retail electricity prices

DE	HU	AT	BE	BG	DK	EE	ES	FI	FR	HR	IE	LT	LU	PT	SE	SI	SK	CY	CZ	GR	IT	LV	MT	NL	NO	RO	PL

Limited availability of Time-of-Use network tariffs

BG	CY	CZ	DE	GR	HR	LT	LU	LV	MT	NL	RO	SK	BE	FR	PL	SI	AT	ES	HU	IT	NO	PT	DK	EE	FI	IE	SE

Limited availability of retail electricity contracts with time differentiation

CY	CZ	ES	FI	GR	HU	IT	LT	LU	LV	MT	NO	SE	BE	FR	SI	PT	AT	BG	DE	DK	EE	HR	IE	NL	PL	RO	SK

Lack of a proper legal framework on dynamic electricity price contracts

FI	LU	PL	SE	NO	BE	CY	CZ	DE	EE	ES	FR	GR	HR	HU	IT	LT	LV	MT	NL	PT	RO	SI	SK	AT	BG	DK	IE

Lack of measures to mobilise flexibility

AT	DK	EE	IE	IT	NL	NO	PL	RO	SK	DE	ES	FI	FR	LT	MT	PT	SE	BE	LU	LV	SI	BG	CY	CZ	GR	HR	HU

Source: ACER.
Notes: (1) ACER was not able to calculate the barrier score for Bulgaria, Denmark, and Ireland since at least half of the indicators were missing. (2) In the indicator "Limited availability of retail electricity contracts with time differentiation", some Member States are shown as "high barrier" or "NA" because no information on the share of retail electricity contracts with different time differentiations was available; however, some have a certain level of penetration of dynamic electricity price contracts. For more information, please refer to Section 4.2.3. (3) For more information on the methodology for assessing the scores per barrier (top) and indicator (bottom), please refer to Annex I.

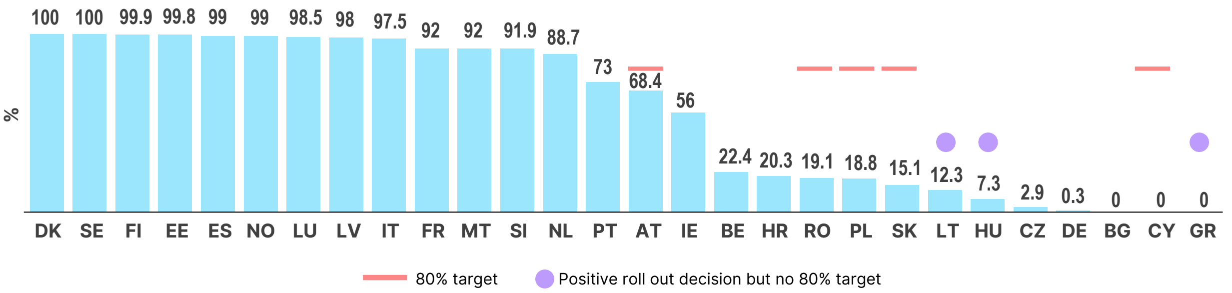
94 This chapter aims to assess to what extent some consumers still do not have the technical possibility to provide demand response due to the lack of smart metering devices. It also shows how consumers may not receive sufficient incentives due to the lack of price signals in their retail price contracts or the absence of national measures to mobilise their flexibility.

4.1. Lack of smart meters with proper functionalities

95 To conclude retail electricity contracts with some kind of time-differentiation, including dynamic electricity price contracts[46], and participate in all forms of demand response, consumers need to be equipped with smart metering devices. While Member States are not required to roll out smart meters to 80% of consumers until 2024[47], the lack of these devices limits consumers' ability to react to and therefore potentially benefit from market price signals.

96 As shown in Figure 13, only thirteen Member States reached a significant level of smart metering deployment in 2022 (i.e., a roll-out rate of at least 80%). Ten still have a roll-out rate below 20%, with some being practically at 0%. In addition, some Member States have experienced delays in their plans to develop smart meters. Austria and Slovakia had legal plans to reach the 80% target by 2020 and 2021, respectively. Romania, Poland, and Cyprus have an 80% target beyond 2024. Hungary, Lithuania or Greece have not set the 80% target in their national rules yet despite a positive roll-out decision. Since July 2024 Czech Republic plans to develop smart meters for customers with annual electricity consumption greater than 6 MWh.

Figure 13: Roll out rate of smart meters per Member State – 2022 (%)



Source: ACER based on NRA data.
Note: (1) Data for the Czech Republic, Croatia, Germany, and Poland is updated compared to ACER's 2023 Market Monitoring Report on Energy Retail and Consumer Protection.

97 Equipping consumers with smart meters does not assure these devices to be interoperable and for them to have the necessary functionalities for consumers to benefit from all their potential. To that extent, Member States must define some minimum requirements for smart meters in their national legislation in line with the Electricity Directive[48]. Table 11 shows that in 2022 most Member States had set out in their national rules that smart meters (i) must be interoperable with both the consumer energy management systems and the smart grids, (ii) must accurately measure actual electricity consumption, (iii) must provide validated historical consumption and non-validated near-real time consumption to final customers at no additional cost, (iv) must account for electricity fed into the grid by active customers and make this data available to them or to a third party at no additional cost, and (v) must enable final customers to be metered and settled at the same time resolution as the imbalance settlement period set at the national level. However, five Member States still have not set all these minimum functionalities in their national rules despite two (the Netherlands and Sweden) having a high penetration of smart meters as shown in Figure 13.

46 A retail electricity contract with time differentiation means an electricity supply contract between a supplier and a final customer that reflects a price variation in different time periods, i.e., different prices per hour, per day/night, per peak period/non-peak period, per business days/weekend, etc. For example, the dynamic electricity price contract means an electricity supply contract between a supplier and a final customer that reflects the price variation on the spot markets, including in the day-ahead and intraday markets, at intervals at least equal to the market settlement frequency as set out in Article 2(15) of the Electricity Directive.

47 As outlined in Annex II of the Electricity Directive, where the deployment of smart metering systems is assessed positively by a Member State, at least 80% of final customers shall be equipped with smart meters either within seven years of the date of the positive assessment or by 2024 for those Member States that have initiated the systematic deployment of smart metering systems before 4 July 2019.

48 Articles 19 and 20 of the Electricity Directive.

Table 11: Definition of the minimum functionalities of small meters in the national rules per Member State – 31 December 2022

Functionalities	AT	BE	BG	CY	CZ	DE	DK	EE	ES	FI	FR	GR	HR	HU	IE	IT	LT	LU	LV	MT	NL	NO	PL	PT	RO	SE	SI	SK
Smart meters need to be interoperable with both consumer energy management systems and with smart grids	Implemented	Implemented	N/A	Implemented	Not implemented	Not implemented	N/A	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	N/A	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Not implemented
Smart meters must measure actual electricity consumption and provide information on actual time of use	Implemented	Implemented	N/A	Implemented	Implemented	Implemented	N/A	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	N/A	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented
Validated historical consumption easily and securely available and visualised to final customers upon request and at no cost	Implemented	Implemented	N/A	Implemented	Implemented	Implemented	N/A	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	N/A	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented
Non-validated near real-time consumption data easily and securely available to final customers at no additional cost	Implemented	Implemented	N/A	Implemented	Implemented	Implemented	N/A	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	N/A	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented
Active customers' meters can account for electricity fed into the grid from active customers' meters	Implemented	Implemented	N/A	Implemented	Not implemented	Implemented	N/A	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	N/A	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Not implemented
Data on the electricity fed into the grid and the electricity consumption available to final customers upon request in an easily understandable format allowing them to compare offers	Implemented	Implemented	N/A	Implemented	Not implemented	Implemented	N/A	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	N/A	Implemented	Implemented	Implemented	Implemented	Implemented	Not implemented	Implemented	Implemented	Implemented	Implemented	Not implemented	Implemented	Not implemented
Retrieving metering data by final customers or transmit them to another party at no additional cost	Implemented	Implemented	N/A	Implemented	Not implemented	Implemented	N/A	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	N/A	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Not implemented	Implemented	Not implemented
Smart meters enable final customers to be metered and settled at the same time resolution as the ISP	Implemented	Implemented	N/A	Implemented	Not implemented	Not implemented	N/A	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	N/A	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented	Implemented

Implemented in national rules · Not implemented in national rules · N/A

Source: ACER based on NRA data.
Note: (1) No information for Bulgaria, Denmark, and Ireland.

98 To maximise the direct benefits of smart meters for final customers, they should enable some value propositions. Table 12 shows the share of smart meters installed in 2022 in each Member State that enabled different value propositions classified as follows[49]:

- Standard value propositions that mainly allow consumers to better understand, control and reduce their energy consumption.
- Advanced value propositions that require further developments in technologies (e.g., data analytics) and proper regulatory and market contexts (e.g., set-up of flexibility market; penetration of electric vehicles, etc.) and mainly allow consumers to reduce their electricity bill.

99 Some main conclusions can be drawn as follows:

- There is still limited information on the real functionalities allowed by the smart metering devices installed across the Member States. Nevertheless, based on some NRAs estimates, overall they enable more standard than advanced value propositions although there are many differences across the Member States.
- The most common value propositions enabled by smart metering devices installed are the energy consumption in real-time and an overview of the historical consumption.
- In the thirteen Member States with the highest smart metering roll-out rate deployment in 2022 (i.e., a roll-out rate of at least 80%), the NRAs from Denmark, Finland, the Netherlands, and Sweden have no information on the type of value propositions enabled by the smart meters installed. Therefore, no conclusion can be drawn on whether their consumers benefit from the full potential of these devices.

49 The value propositions are based on ASSET's 2018 study on Consumer Satisfaction KPIs for the roll-out of Smart Metering in the EU Member States.

Table 12: Value propositions enabled by the smart meters installed per Member State – 2022 (% ranges)

	STANDARD VALUE PROPOSITIONS									ADVANCED VALUE PROPOSITIONS					
	Leverage smart meters data	Bill forecasting	Real-time consumption display	Real-time cost display	Unusual usage alert	Historical consumption overview	Real-time carbon impact	Pre-payment capacity	Day-ahead prices	Ability to valorise the provision of explicit demand response to the power markets	Fuel poverty detection	Energy sharing	Integrate prosumers in the market	Facilitate smart charging of EVs at home	Facilitate smart charging of batteries
AT	100%		100%			100%						100%			
BE			0% - 20%									0% - 20%			
BG	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
CY	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
CZ															
DE															
DK															
EE	100%	100%	100%			100%	100%		100%						
ES	0%	0%	100%	0%	0%	100%	0%		100%	100%	0%	100%	0%	0%	0%
FI															
FR	80% - 100%	80% - 100%	80% - 100%	0% - 20%	0% - 20%	80% - 100%	0% - 20%	0%	0%	80% - 100%		80% 100%		100%	100%
GR	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
HR															
HU															
IE															
IT	0%	0%	80% - 100%	0%	80% - 100%	100%	0%	80% - 100%	0%	0%	0%	0%	0%	0%	0%
LT	100%	0%	100%	0%	0%	100%	0%	0%	100%	100%	0%	0%	100%	100%	100%
LU	0%	0%	100%	0%	0%	100%	0%	0%	0%	100%	0%	100%	0%	100%	100%
LV	60% - 80%	0% - 20%	100%	60% - 80%	0% - 20%	100%	20% - 40%	20% - 40%	0% - 20%	0%	0%	0%	0%	0% - 20%	0% - 20%
MT	0%	0%	100%		0%	0%	0%	0%			0%	0%			
NL															
NO	100%	100%	100%	100%	0%	100%	0%	0%	100%	0%	0%	100%	100%	100%	100%
PL															
PT	0%	0%	60% - 80%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
RO		100%	100%		0%	100%	0%	0%							
SE															
SI	60% - 80%	60% - 80%	80% - 100%	0%	0%	60% - 80%	0%	0%	0%	0%- 20%	0%	0%	0%	40% - 60%	40% - 60%
SK	100%	20% - 40%	60% - 80%												

0% | 20% - 40% | 60% - 80% | 100%
0% - 20% | 40% - 60% | 80% - 100% | N/A

Source: ACER based on NRA data.

Notes: (1) The value propositions have been selected based on the ASSET's 2018 study on Consumer Satisfaction KPIs for the roll-out of Smart Metering in the EU Member States. (2) No information for the Czech Republic, Germany, Denmark, Finland, Croatia, Hungary, Ireland, the Netherlands, Poland, and Sweden.

Box 2: Is the consumption data available to final customers too late to provide demand response?

Figure 14 shows that in all Member States but Latvia the smart metering systems installed meter and settle consumptions at the same time resolution as the imbalance settlement period set in the national market or even at a shorter time resolution. When it comes to the frequency at which the consumption data is available to customers, it is usually the next day, although in some Member States it depends on the type of consumer, the option chosen by the consumer or whether the consumer has some additional equipment connected to the smart meter.

To trigger demand response based on the system needs, the consumption data should be available to consumers close to real time or at least at intervals matching the national imbalance settlement period. This would allow consumers to take informed decisions on their potential demand response.

Figure 14: Frequency at which consumption data is metered and settled by smart meters compared to the imbalance settlement period per Member State and frequency at which the consumption data is available to final customers – 2022

	ISP	Frequency at which consumption data is metered and settled	Frequency at which consumption data is available to final customers with smart meters
AT	15 min	15 min	It depends on the settings of the smart meter: • Default setting: one consumption value per day • Opt-in setting: 15-minute-values • Opt-out setting: one value per year Customers are free to opt-in or opt-out.
BE	15 min	N/A	Yearly, monthly or daily
BG	N/A	N/A	N/A
CY	NAP	N/A	N/A
CZ	1 hour	1 hour	N/A
DE	15 min	15 min	Yearly, monthly or daily
DK	1 hour	15 min	N/A
EE	1 hour	1 hour	Day+1
ES	1 hour	1 hour	Day+1
FI	1 hour	1 hour	Day+1
FR	30 min	30 min	Day+1 for households; Day+1 or Day+3 for non-households
GR	15 min	N/A	N/A
HR	1 hour	1 hour	N/A
HU	15 min	15 min	Monthly (Near real time data possible through a P1 port)
IE	30 min	30 min	N/A
IT	1 hour	15 min	Day+1
LT	1 hour	15 min	Day+1
LU	15 min	15 min	Day+1
LV	15 min	1 hour	N/A
MT	NAP	1 hour	Approximately Day+2
NL	15 min	15 min for households; N/A for non-households	N/A
NO	1 hour	1 hour	Day+1
PL	1 hour	15 min	Day+1
PT	1 hour	15 min	Day+1
RO	15 min	15 min	Day+1
SE	1 hour	1 hour	Day+1
SI	15 min	15 min	Day+1 on national hub; Near real time on I1 port; Every 15 min only for non-household consumers > 43 kW
SK	15 min	15 min	At least Day+1

Source: ACER based on NRA data.
Notes: (1) In Austria and Norway power usage can be reported with a frequency between 2.5 and 10 seconds when additional equipment is connected to the smart meter. (2) In Sweden smart meters must meter and settle consumption data every 15 min from 1 January 2025. (3) In Poland smart meters must collect data in 15-minute periods from 2022, but settlement in 15-minute periods will only be possible after the introduction of a central information exchange system from 1 July 2025. Currently, consumption data is provided to only some customers on the next day depending on the DSO system. After the introduction of the central information exchange system, 15-minute data will be made available to all final customers equipped with smart meters on the following day (Day+1). They will also be given access to unverified real-time consumption data.

4.2. Absence of price signals

100 As shown in the introduction of this report, an increase of volatility and negative prices in the spot markets send signals of the need for flexible resources in the power system. However, end-users may not receive these price signals. One of the main barriers for consumers to provide demand response or for other distributed energy resources to offer flexibility in different electricity markets is the lack of proper price signals reflecting the value and cost of electricity or transportation and distribution in different time periods. This section shows some aspects that may explain the absence of price signals for consumers.

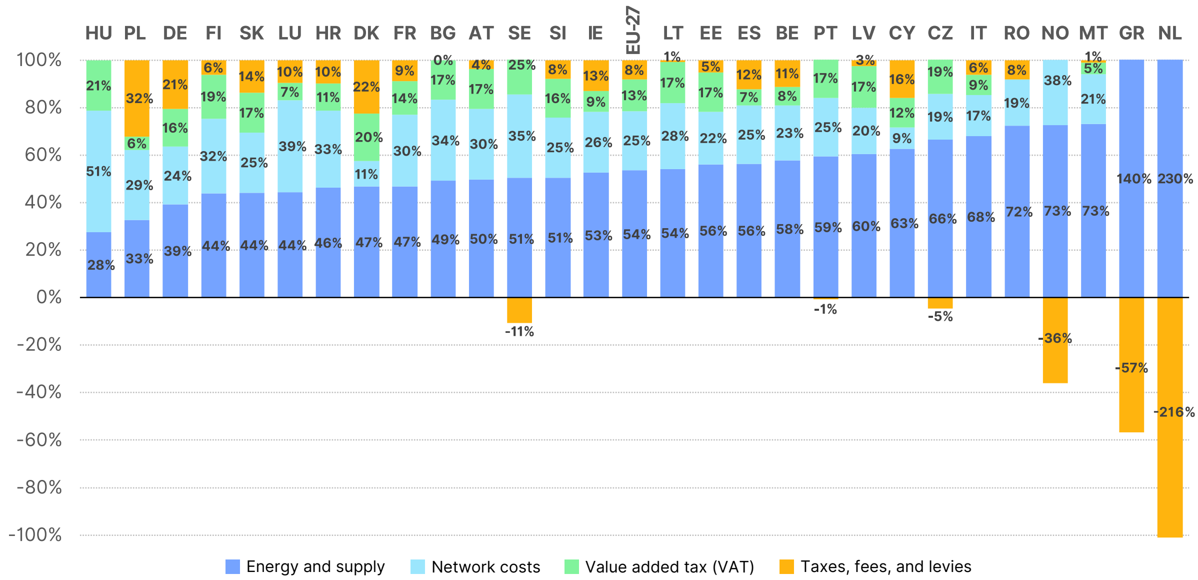
101 It should be noted that price signals may not be appropriate to all types of consumers and in all situations. Member States must ensure consumer protection with a reasonable exposure to price signals, especially in energy crisis as experienced during the COVID-19 pandemic and the Russian invasion of Ukraine. Therefore, consumers must always be informed about benefits and potential risks of price signals in their retail electricity contracts, must always be given the right to choose, and must be protected if they are in vulnerable situations.

4.2.1. Low energy component

102 A low share of the energy component in the final electricity bill or a low correlation between the energy consumption and the network charges does not give end users price signals nor incentives to enhance their flexibility potential and it blurs the benefits of dynamic or time-differentiated retail electricity contracts.

103 Figure 15 shows how the composition of the final electricity bill for household consumers varies greatly across the Member States. Even though in 2022 the energy component on average increased significantly in the EU in response to the increase in the wholesale energy prices[50], it represented on average less than 50% of the electricity bill in ten Member States.

Figure 15: Breakdown of electricity bill for households per Member State – 2022 (%)



Source: ACER based on Eurostat data (nrg_pc_204_c) (June 2023).
Notes: (1) The breakdown is calculated for Eurostat Band-DC. (2) Some countries implemented negative taxes in 2022 and all percentages are not visible in the figure. In Norway the VAT represented 26% of the electricity bill. In Greece and the Netherlands the network costs and VAT represented 11% and 6% and 76% and 10%, respectively.

50 For more information on the electricity bill breakdown, please refer to Section 3.2.3 of ACER's 2023 Market Monitoring Report on Energy Retail and Consumer Protection volume.

4.2.2. Absence of time-differentiated network tariffs

104 Time-differentiated or Time-of-Use (ToU) network tariffs can also be a useful tool for reducing network peak-load, which is the main driver for network investments, thereby promoting network efficiency. They can also help reduce network congestions by giving economic signals to network users to reduce network utilisation (e.g., lowering withdrawal by consumers or injection by generators) in some periods in the day, week or year when network capacity is closer to the technical limits and increase during times without stress on the network. The Electricity Regulation[51] encourages Member States not only to develop smart metering systems, but where such systems are implemented, to also introduce ToU network tariffs to reflect the use of the network, in a transparent, cost-efficient, and foreseeable manner for the final customer.

105 ACER acknowledges that not all end users may be capable to react to such signals to the same extent. Moreover, efficiency and effectiveness of the time signals can vary depending on various factors, including network conditions, price difference between time periods, share of network charges[52] within the final electricity bill, etc. Nevertheless, depending on how strong the cost signals are and to what extent the users are capable to react to such signals, Time-of-Use network charges can encourage efficient use of flexibility solutions, e.g., incentivising consumers to invest in generation and/or storage assets to become active customers or to provide implicit demand response.

106 Typically, ToU network tariffs vary within day by defining (blocks of) hours during which a higher or lower unit price is charged for using the network. It is also common to distinguish weekend days (and sometimes holidays) from business days, with a lower tariff applying to all hours of non-business days. Further variation can also be introduced through a seasonal element that makes unit charges vary with the months.

107 As shown in ACER's 2023 report on electricity transmission and distribution tariff methodologies in Europe, in 2022 eight Member States did not apply any type of time differentiation in any of their network tariffs (Bulgaria, Cyprus, Germany, Hungary, Italy, Luxembourg, and Romania) or only for a fraction of network users (the Netherlands)[53]. The remaining Member States (i.e., vast majority) embedded a certain time-differentiation in at least one of the network tariff components. Regardless of whether the ToU network tariffs are implemented or not, the suppliers may offer time-differentiated retail electricity contracts to their customers.

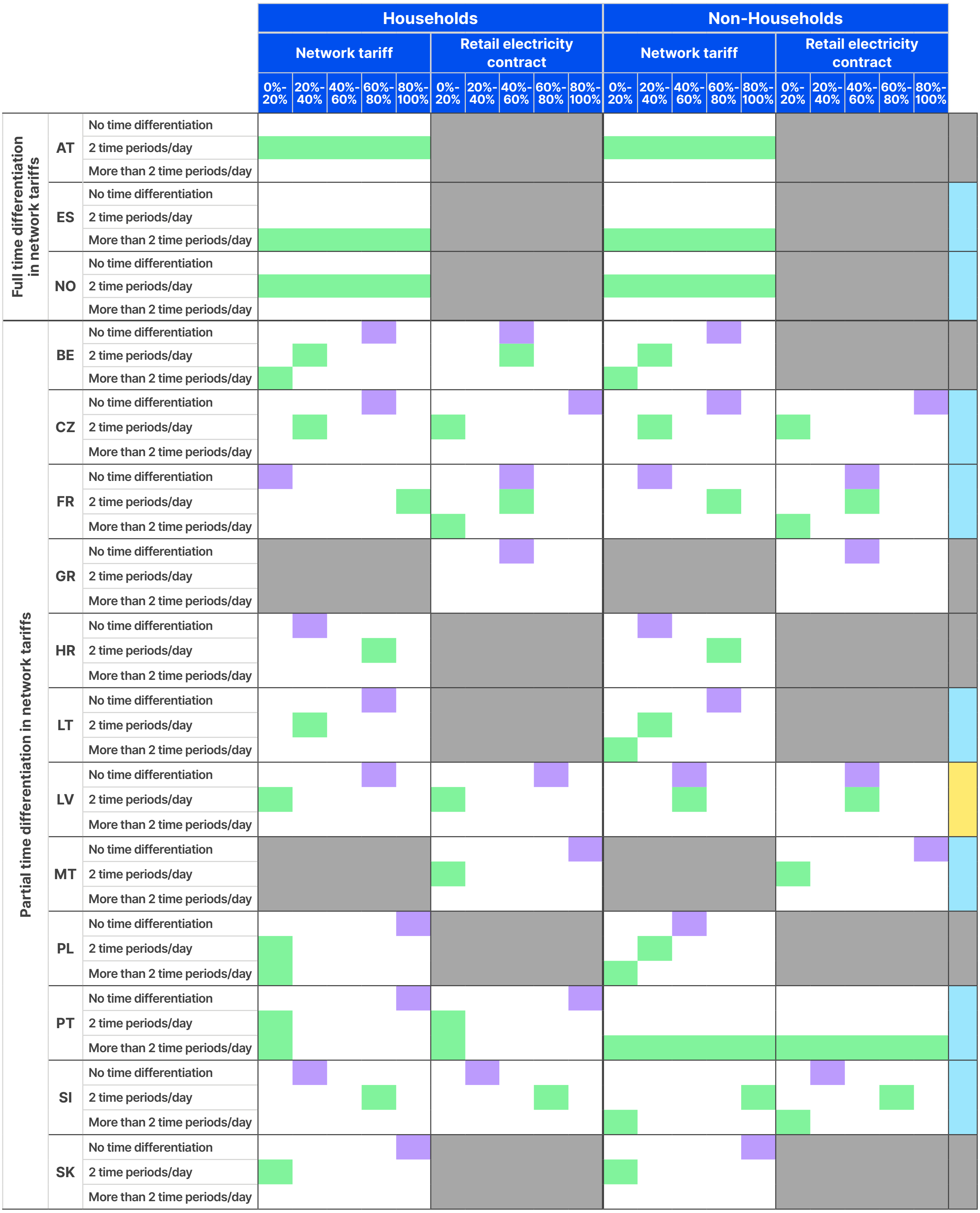
108 Figure 16 shows an estimation of the level of penetration of network tariffs and retail electricity contracts with time differentiation per day across the Member States for household and non-household customers in 2022. It also shows whether suppliers are allowed to offer fixed electricity price contracts to customers with ToU network tariffs.

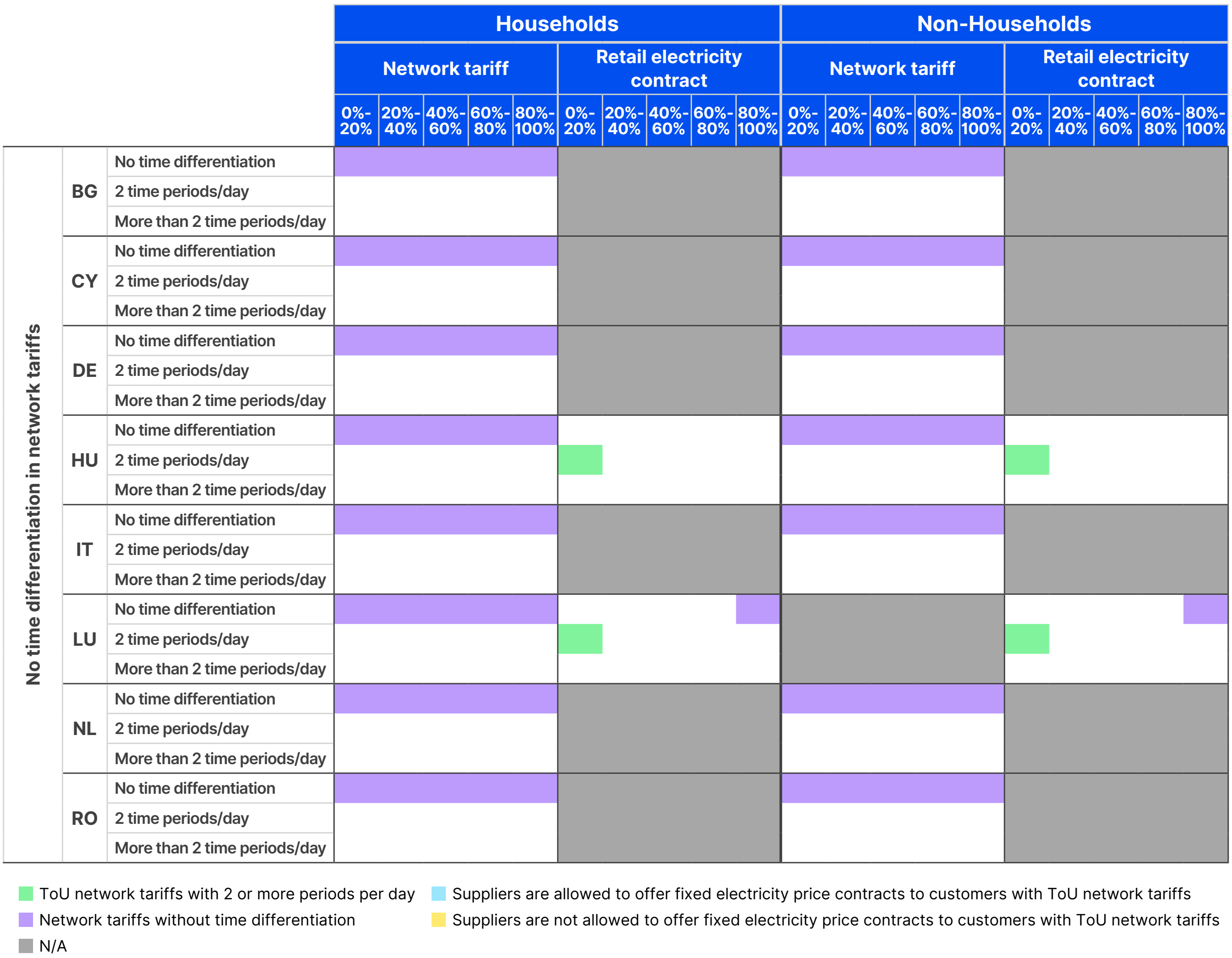
51 Article 18(7) of the Electricity Regulation.

52 In line with ACER's 2023 report on electricity transmission and distribution tariff methodologies in Europe, "network charges" include all charges paid to the TSO and DSO, including charges for use of the network, connection charges, and charges for individual (specific) services provided by the TSO or DSO at the request of the network user. Within the charges for use of the network, ACER differentiates further between the transmission and distribution tariffs for building, upgrading, and maintaining infrastructure and the transmission and distribution tariffs for losses, from other charges, such as charges for system services, charges for metering and charges which are paid for withdrawing and/or for injecting reactive power outside the allowed limits (i.e., reactive energy charges).

53 In ACER's 2023 report on electricity transmission and distribution tariff methodologies in Europe, Greece is considered as a country that applies ToU network tariff as the capacity charge is based on network use during predefined peak periods that vary by season/month, as such the tariff can provide time-of-use signals. In general Malta has a bundled electricity tariff, which covers energy, supply, and distribution costs. ToU bundled tariffs are available for two types of customers: non-residential customers with a consumption >5,000 MWh or 5,500 MVAh and customers consuming electricity to charge their EVs.

Figure 16: Estimated level of penetration of network tariffs and retail electricity contracts with time differentiation per day per type of customer and per Member State – 2022 (% ranges)





Source: ACER based on NRA data.
Notes: (1) No data for Denmark, Estonia, Finland, Ireland, and Sweden. (2) The Netherlands is shown under "no time differentiation in network tariffs" since their time differentiation applies to a very small fraction of network users.

109 Based on data provided by 23 NRAs, fifteen Member States apply time-of-use network tariffs with different periods per day while eight have a non-existent (or only a very small fraction of) penetration of this type of tariffs. In 2022 all customers had ToU network tariffs with two time periods per day in Austria and Norway or more time periods per day in Spain. The remaining Member States showed a partial penetration of this type of ToU network tariffs ranging from less than 20% of households (Latvia, Poland, Portugal, and Slovakia) to more than 80% of households (France) and to values between 20%-80% of households. All these Member States show similar levels of penetration for non-households except for France, Lithuania, Latvia, Poland, Portugal, and Slovenia.

110 As expected, most Member States without time-differentiation in network tariffs also have a marginal or zero roll-out rate of smart meters. However, Italy, Luxembourg, and the Netherlands do not apply ToU network tariffs (Italy has phased them out) despite their high penetration of smart meters (see Figure 13). Out of the eight Member States that do not apply ToU network tariffs, only two (Hungary and Italy) have carried out a pilot study and/or impact assessment study regarding the introduction or phase out of ToU network tariffs.

111 NRAs provide different reasons for not implementing ToU network tariffs:

- there were doubts concerning the willingness of network users to react to time-of-use in the network tariff (Italy and the Netherlands);
- the complexity of implementing time-of-use network tariffs may not outweigh the benefits (Italy and the Netherlands);
- technical reasons such as a low penetration of smart meters (or other capable meters able to record time-of-use, e.g., different time bands) (Romania);
- The German NRA notes that it did not have legal competency on the network tariffs up to now while the Bulgarian NRA did not give any reason for not implementing ToU network tariffs;
- Bulgaria, Cyprus, and Hungary did not provide any explanation. However, the lack of ToU network tariffs may be explained by the lack (or marginal penetration) of smart meters in these Member States.

4.2.3. Absence of retail electricity contracts with time-differentiation

112 Time-differentiated retail electricity contracts can provide price signals to final customers regarding the cost of production depending on the time of consumption. The effectiveness of those signals may depend on the share of the energy component in the bill and/or the difference between the applied periods. At a certain point in time, the price signals coming from the energy price and from the network tariffs may strengthen each other or they may be conflicting with each other. In some national frameworks, suppliers may be allowed to offer fixed electricity price contracts to (some of) their customers, where both the energy component and the network tariff component is bundled into a fixed sum, in which case no time-of-use signals are provided to these customers, regardless of whether Time-of-Use network tariffs were set or not.

113 As shown in Figure 16, most NRAs do not monitor the level of penetration of retail price contracts with time-differentiation, including dynamic electricity price contracts[54] for household and non-household consumers. This lack of information precludes assessing whether final customers indeed receive the price signal of the cost of electricity or transportation and distribution in different time periods in the Member States implementing ToU network tariffs.

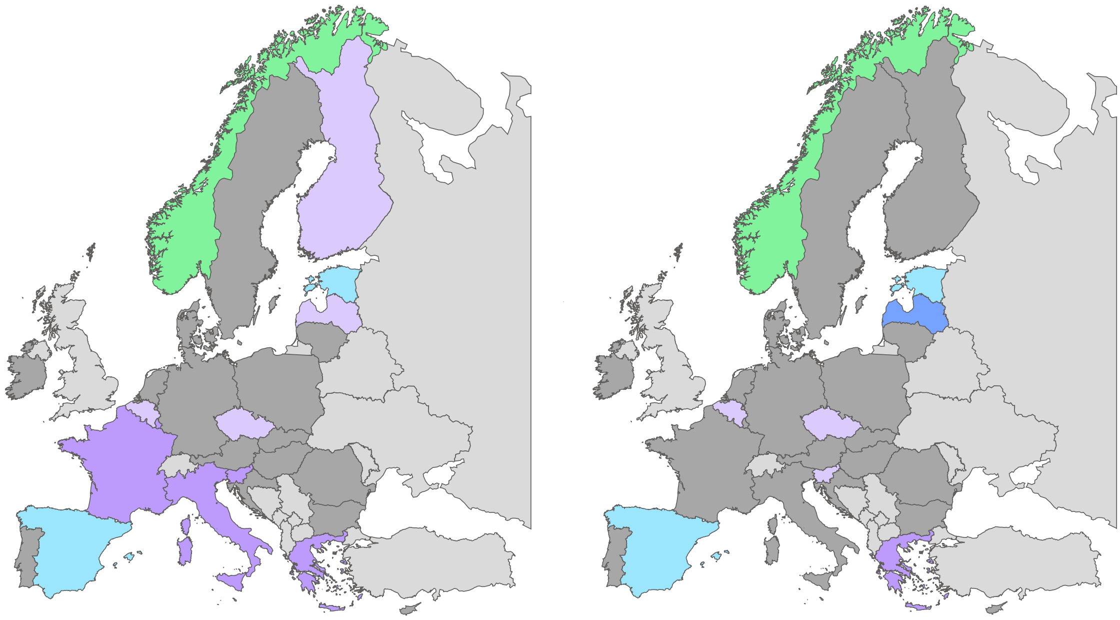
114 Ten NRAs provide estimates of the level of penetration of retail electricity contracts with time-differentiation as follows (see Figure 16):

- With a partial penetration of ToU network tariffs, the Czech Republic, Latvia, Malta, and Portugal report retail electricity contracts with time-differentiation for less than 20% of households. These contracts are estimated to range between 20%-80% of households in Belgium, France, and Slovenia. Similar figures are estimated for non-households except for Portugal (100% of non-households have retail electricity contracts with time differentiation) and Latvia (between 40%-60% of non-households).
- Hungary and Luxembourg estimate that less than 20% of their households and non-households may also have retail electricity contracts with time-differentiation although these Member States do not apply ToU network tariffs.

115 Figure 17 shows an estimation of the level of penetration of dynamic electricity price contracts across the Member States for household and non-household customers in 2022. The highest levels of penetration are estimated in Norway followed by Estonia, Spain, and Latvia (for non-households).

54 See footnote 45.

Figure 17: Estimated level of penetration of dynamic electricity price contracts for households (left) and non-households (right) per Member State – 2022 (% ranges)



Source: ACER based on NRA data.
Notes: (1) No information for Austria, Bulgaria, Cyprus, Germany, Denmark, Croatia, Hungary, Ireland, Lithuania, Luxembourg, Malta, the Netherlands, Poland, Portugal, Romania, Sweden, and Slovakia. Limited information for Finland, France, and Italy.

116 The Electricity Directive[55] sets some requirements to ensure that final customers equipped with a smart meter are entitled to conclude dynamic electricity price contracts as follows: (i) to enable final customers with a smart meter installed to conclude a dynamic electricity price contract with at least one supplier and with every supplier that has more than 200,000 final customers, (ii) to ensure final customers to be fully informed by the suppliers of the opportunities, costs and risks of such electricity price contracts, (iii) to ensure NRAs monitor the market developments of these contracts, assess potential risks and deal with abusive practices and (iv) to require suppliers to obtain each final customer's consent before that customer is switched to a dynamic electricity price contract. As shown in Table 13, in 2022 at least ten Member States had not fully defined these requirements in their national regulatory framework. Even though most Member States have defined the need to monitor market developments of dynamic electricity price contracts, as shown above, in practice most NRAs still do not monitor the level of penetration of retail electricity prices with time-differentiation.

Table 13: Legal restrictions to implement dynamic electricity price contracts per Member State – 2022

Dynamic electricity price contracts	AT	BE	BG	CY	CZ	DE	DK	EE	ES	FI	FR	GR	HR	HU	IE	IT	LT	LU	LV	MT	NL	NO	PL	PT	RO	SE	SI	SK
Final customers with smart meters can request to conclude a dynamic electricity price contract with at least one supplier and with every supplier with more than 200,000 customers	N/A	Implemented	N/A	Implemented	Implemented	Implemented	N/A	Implemented	Not implemented	Not implemented	Implemented	Implemented	Implemented	Implemented	N/A	Implemented	Implemented	Not implemented	Implemented	Implemented	Not implemented	Not implemented	Not implemented	Implemented	Implemented	Not implemented	Implemented	Implemented
Final customers are fully informed about opportunities, costs, and risks of dynamic electricity price contracts	N/A	Implemented	N/A	Implemented	Implemented	Implemented	N/A	Implemented	Implemented	Not implemented	Implemented	Implemented	Implemented	Implemented	N/A	Implemented	Implemented	Not implemented	Implemented	Implemented	Implemented	Not implemented	Not implemented	Implemented	Implemented	Not implemented	Implemented	Implemented
NRA monitors market developments of dynamic electricity price contracts, risks, and abusive practices	N/A	Implemented	N/A	Implemented	Not implemented	Implemented	N/A	Implemented	Implemented	Not implemented	Implemented	Implemented	Implemented	Implemented	N/A	Implemented	Implemented	Not implemented	Implemented	Implemented	Implemented	Implemented	Not implemented	Not implemented	Not implemented	Not implemented	Implemented	Implemented
Suppliers must obtain final customer consent before switching to dynamic electricity price contract	N/A	Implemented	N/A	Implemented	Implemented	Implemented	N/A	Implemented	Implemented	Not implemented	Implemented	Implemented	Implemented	Implemented	N/A	Implemented	Implemented	Not implemented	Implemented	Implemented	Implemented	Implemented	Not implemented	Implemented	Implemented	Implemented	Implemented	Implemented

Implemented in national rules | Not implemented in national rules | N/A

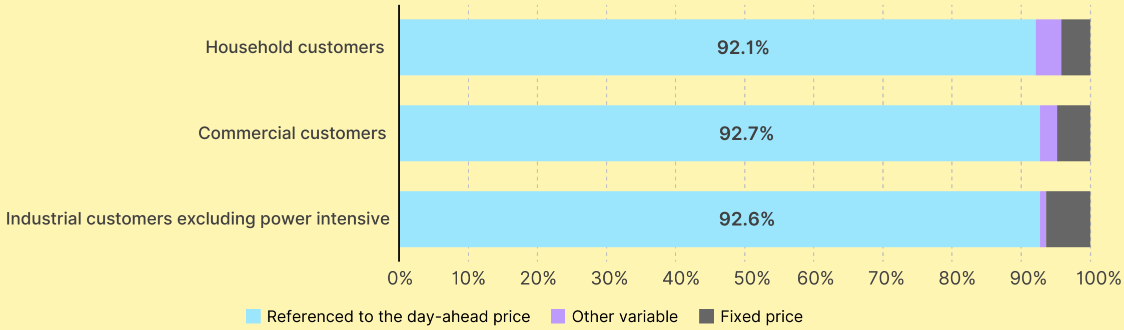
Source: ACER based on NRA data.
Notes: (1) No information for Austria, Bulgaria, Denmark, and Ireland. (2) Luxembourg and Poland defined the requirements on dynamic electricity price contracts into the national legal framework in June and September 2023, respectively.

55 Article 11 of the Electricity Directive.

Box 3: How Norwegian customers are exposed to price signals

In Norway, a country with a high share of electric vehicles and heat pumps, more than 90% of customers have chosen to be exposed to price signals with dynamic electricity price contracts (Figure 18). Customers are metered at an hourly resolution and are directly exposed to the day-ahead prices which enables implicit demand response and can be supported by (out of market) automation.

Figure 18: Level of penetration of different types of retail electricity contracts per type of final customer in Norway – Q2 2023 (%)



Source: Statistics Norway.

4.3. Lack of national measures to mobilise flexibility

117 Final customers may not be aware or receive enough incentives to provide demand response despite having a smart metering system and a retail electricity contract with proper price signals. Therefore, communication is key to raise awareness in demand response. Even though implementing a higher number or more diverse measures does not necessarily lead to more awareness, ACER considers that the lack of national measures to inform consumers on how they could participate in all forms of demand response could be seen as a barrier for market entry and participation of distributed energy resources and other new actors.

118 Table 14 shows some national measures implemented or planned in 2022 to improve consumer awareness and engagement to provide demand response through awareness campaigns, training, apps, tools, etc., including links to the specific measures. Some main conclusions can be drawn as follows:

- Most Member States adopted some kind of measure to promote demand response in 2022 although ACER does not have information for Bulgaria, Cyprus, the Czech Republic, Greece, Croatia, and Hungary. Some measures may have been implemented to address the high prices due to the energy crisis and to meet the demand reduction targets set out by the Council Regulation 2022/1854 of 6 October 2022 on an emergency intervention to address high energy prices[56].

- Communication campaigns with direct and targeted advice to specific types of consumers, at individual level or through direct training were the most common measures in fifteen Member States, followed by TSO or DSO apps or tools to encourage load reduction at peak times (twelve Member States) and communication programmes to encourage overall implicit demand response (eleven Member States). Ten Member States have also provided some consumers with information about the relative power intensity of different devices and have offered practical information on lower power substitutes and more energy efficient means of using devices and eleven Member States have launched broad social media campaigns.

- In terms of type of measures, Latvia and Slovenia implemented the broader range of measures to promote demand response. At the other end, we find Austria, Denmark, Italy, Norway, Romania, and the Netherlands with one national measure.

56 According to the Council Regulation 2022/1854, Member States had an obligation of at least a 5% reduction in gross electricity consumption during selected peak price hours and had to seek to implement measures to lower overall electricity consumption by at least 10% until 31 March 2023.

119 Some Member States may have tools to be successful, but it seems more efforts are still needed. For example, France and Slovenia have a significant level of smart metering deployment (higher than 80% in 2022 as shown in Figure 13), a national legal framework on dynamic electricity price contracts as required in the Electricity Directive (see Table 13), and have implemented diverse national measures to improve consumer awareness on demand response. However, the NRAs estimate a marginal share of consumers have electricity price contracts with time differentiation (Figure 16) or dynamic electricity price contracts (Figure 17). ACER invites Member States in such a situation to investigate what is preventing consumers to conclude dynamic electricity price contracts and provide demand response.

Table 14: National measures to improve consumers awareness and engagement to provide demand response – 2022

National measures	AT	BE	DE	DK	EE	ES	FI	FR	IE	IT	LT
Communication programmes to encourage **overall implicit demand response**				Energy savings	Kodused energiasäästu võimalused	Comparador de ofertas de energía					Energy saving plan Energy saving race
Communication campaigns with **direct and targeted** advice to a specific type of consumers, at individual level or through direct training	Mission 11	Nieuwe nettarieven	Energie sparen			Plan + seguridad para tu energía (+SE)	Down a degree		Reduce your use		Energijos tiekimo rinkos
TSO or DSO apps or tools to encourage load reduction at peak times for some consumers		Mijn Fluvius Simulator new network tariffs	StromGedacht		Elering e-services	redOS	Fingrid's Tuntihinta	ecowatt	Beat the peak	Eco-clock	
Messages, emails and reminders to consumers broadly about ways to shift their energy consumption away from peak times											
Messages, emails and reminders to a targeted type of consumers based on their lifestyle, demographic and household/commercial/ industrial information with insights and tips about ways to shift their energy consumption away from peak times											
Targeted free (or more accessible) **energy audits** to determine what can be done to optimise energy use and provide an estimate of the level of savings possible for some consumers		Energie- en klimaatbeleid voor ondernemingen	Energieberatung der Verbraucherzentrale								
Equipping some consumers with information about the relative **power intensity of different devices** and offering practical information on **lower power substitutes and more energy efficient means of using devices**			Wen füttern Sie mit durch?				Energy labelling				
Provide **equipment or information about available equipment** that some consumers can connect into the plugs to either **monitor consumption or programme with times to connect/disconnect**		Slim Besparen	Messeinrichtungen								
Broad **social media campaigns**		Nieuwe nettarieven									
Others						Bono social eléctrico					

National measures	LU	LV	MT	NL	NO	PL	PT	RO	SE	SI	SK
Communication programmes to encourage **overall implicit demand response**	Zesumme spueren – Zesummenhalen	Public Utilities Commission	Energy & water saving tips Household Visits Awareness in Micro SMEs			Edukacja-Ekologiczna/ Oszczedzamy-energie			Efterfråge-flexibilitet Varje kilowat-timme räknas Husguiden	Elektro Ljubljana Z-manj-do-več Zlata ura	Poďme šetriť spolu!
Communication campaigns with **direct and targeted** advice to a specific type of consumers, at individual level or through direct training	Klima-Agence	Nordic and Baltic Sea Winter Power Balance	WE MAKE	Zet ook de knop om			Campaign in schools Save: to compete			Use Smart	SIEA
TSO or DSO apps or tools to encourage load reduction at peak times for some consumers	Stroum Monitor				The power situation					Izračunaj prihranke	
Messages, emails and reminders to consumers broadly about ways to shift their energy consumption away from peak times											
Messages, emails and reminders to a targeted type of consumers based on their lifestyle, demographic and household/commercial/ industrial information with insights and tips about ways to shift their energy consumption away from peak times											
Targeted free (or more accessible) **energy audits** to determine what can be done to optimise energy use and provide an estimate of the level of savings possible for some consumers		elektrum	Energy Audits for SMEs						Energi- och klimatrådgivare	EKO sklad	
Equipping some consumers with information about the relative **power intensity of different devices** and offering practical information on **lower power substitutes and more energy efficient means of using devices**		elektrum								Izračunaj prihranke	
Provide **equipment or information about available equipment** that some consumers can connect into the plugs to either **monitor consumption or programme with times to connect/disconnect**	smarty+									Pametna vtičnica	
Broad **social media campaigns**			Innaqqsu l-ħela tal-enerġija House Visits							Z manj do več	
Others		Elektro-enerģijas birža							Flytta din elanvändning Elavtal Elnätsföretagens effekttariffer	Energy poverty	

Ongoing   Planned   Not considered nor planned   N/A

Source: ACER based on NRA data complemented with the European Smart Grids Task Force Expert Group 3 "Paper on electricity demand reduction: Measures to mobilise consumers' flexibility this winter and beyond", November 2022.
Note: (1) No information for Bulgaria, Cyprus, the Czech Republic, Greece, Croatia, and Hungary. (2) Member States do not have any legal obligation to implement the national measures shown in this table and NRAs do not have any legal obligation either to monitor their implementation, which may lead to incomplete information for this indicator in some Member States.

Box 4: Some national measures to mobilise end-users flexibility

The following briefly describes some national measures identified in Table 14 to mobilise end-users flexibility. For more information on the different national measures, please click on the hyperlinks in Table 14.

In Belgium, the independent Flemish Regulator of the Electricity and Gas Market, VREG, launched a communication campaign on the reformed electricity network tariffs for households and small businesses. This reform included a capacity tariff, incentivising overall implicit demand response of consumers and informing on the advantages of the reform[1]. Based on the capacity tariff and the average electricity prices of September 2023, about 14% of the electricity bill of an average household depends on consumers' peak power. The new tariff thus serves as a strong incentive for spreading electricity consumption[2]. VREG also informs about dynamic price contracts through the price comparator V-test.

The Flemish grid operator, Fluvius provides smart meters and information about available equipment that some consumers can use to either monitor consumption or programme with times to connect/disconnect. The smart meters introduced by Fluvius offer consumers a range of new features that extend beyond traditional metering, supported by a dedicated platform, My Fluvius. The app can be connected to installed smart meters to inform consumers about individual consumption patterns and further providing advice for energy peak spreading. Of the installed smart meters, around 500,000 families actively utilize their energy consumption data through the My Fluvius application. This platform provides users with real-time electricity consumption data at a 15-minute interval and hourly data for gas consumption. The number of My Fluvius users has more than doubled in the past year, indicating a growing interest and engagement in understanding and managing energy consumption.

ENGIE Belgium also developed an app that allows consumers to actively manage their energy usage. It features tracking electricity and gas consumption, monitoring associated costs, registering and managing green energy installations, and applying for energy premiums.

In Germany, the government promotes free online energy-saving counselling[3]. With a broad reach spanning approximately 900 locations in Germany, around 700 dedicated consultants also offer on-site energy efficiency inspections, providing practical advice tailored to individual households.

The outcomes of this initiative are substantial. According to the Verbraucherzentrale, in 2022 alone, more than 280,000 energy-saving counselling sessions were conducted, resulting in savings of over 6,680 GWh of energy and a reduction of more than 3.4 million tonnes of CO_2 emissions. 95% of recipients express satisfaction and subsequently recommend the counselling, which underscores the value of the initiative. Equally noteworthy is that approximately 80% of recipients take tangible actions based on the provided advice, showcasing a high level of consumer engagement and a willingness to implement energy-efficient practices in their daily lives.

Beat the Peak is an Irish DSO (ESB Networks) initiative to help customers regardless of their supplier take control of their electricity use and reduce electricity demand at peak times. It comprises of four parts: (a) domestic, (b) commercial pledged, (c) commercial active, and (d) conservation voltage reduction. It was implemented as a pilot for the winter 2022/2023.

- Beat the Peak – Domestic started with a cross media channel campaign to encourage customers to sign up to the pilot. Customers received weekly texts and emails with insights and tips targeted at individual customers based on lifestyle, demographic, and household information. These texts and emails aimed at getting people to ask themselves "is this a good time?" before they used electricity for dishwashing or clothes washing, informing them if it was a windy day or equipping them with information about the relative power intensity of different household devices and offering practical information on lower power substitutes and more energy efficient means of using devices. If consumers signed up to peak events they were also prompted to act during amber alerts. The pilot also tested customers reaction to reward. Some groups were given no reward, others got a 30 EUR voucher before taking any action, others after their participation, still other groups were told a charitable donation was made on their behalf. In addition, ESB Networks requested feedback from customers with a view to implementation on a larger scale next winter.

- In Beat the Peak – Commercial pledged aimed at circa 30 businesses. When a company signed up, they received content and materials to share with their staff. Companies then made "pledges" and ESB Networks provided information material on changes different types of organisations can take to move demand away from peak times. The customers then put in place their "Pledges". ESB Networks communicated with these customers in the event of an amber alert, and it also provided a platform to promote the actions taken by the organizations to support the national effort.

- Beat the Peak – Commercial active aimed at circa 50 businesses who were allowed to participate through aggregators. Since this scheme was financially incentivized, there were some eligibility criteria. When customers received a confirmation from ESB that they were eligible to participate, they could sign up via an aggregator. The customers were baselined on winter 2019 and winter 2021. In case of an amber alert, ESB Networks notified the aggregator who then notified the individual customers to reduce demand. For settlement, ESB Networks measured performance relative to baseline demand and provided to aggregators (who provided to customers) performance statements and payments.

ESB Networks intends to apply the learnings, scale up the scheme and run these initiatives again across winters 2023/2024 and 2024/2025. It expects the contribution to peak reduction to reach 25 MW, 17 MW, and 28 MW in winter 2024/2025 in the domestic, commercial pledged and commercial active initiatives respectively.

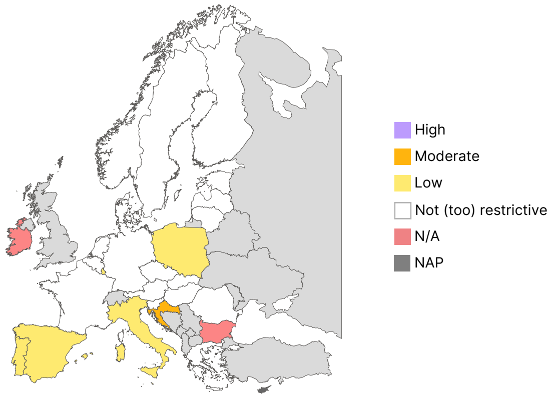
Sources: (1) Communication campaign by VREG: https://www.vreg.be/nl/communicatiecampagnes. (2) Electricity bill composition: https://www.vreg.be/nl/wat-zijn-de-nieuwe-nettarieven-en-hoe-worden-ze-berekend. (3) Verbraucherzentrale Energieberatung: https://verbraucherzentrale-energieberatung.de/beratung/online/.

5. Restrictive requirements to providing balancing services

A few Member States do not procure some balancing services using a market-based method. When market-based, the duration of the prequalification processes (especially when required after changes in the reserve providing groups) and the lack of regulated deadlines may be restrictive in some Member States. Some limitations to prequalify reserve providing groups aggregating different technologies may also hinder access of distributed energy resources to balancing services.

Some features of the local or specific balancing products are still far from the EU target model, e.g., protracted validity periods of balancing energy bids in many Member States or still large minimum bid sizes in some cases. Multiple Member States still procure balancing capacity more than one day before its provision with contracting periods being much longer than one day.

Figure 19: Restrictive requirements to providing balancing services. Overview of the barrier (top) and underlying indicators (bottom) per Member State – 2022



Non-market based balancing products

ES	FR	HR	IT	PT	RO	AT	BE	CZ	DE	DK	EE	FI	GR	HU	LT	LU	LV	NL	NO	PL	SE	SI	SK	BG	IE	CY	MT

Restrictions in the prequalification of reserve providing groups

NO	PL	PT	ES	GR	IT	RO	AT	BE	BG	CZ	DE	DK	EE	FI	FR	HR	HU	LT	LU	LV	NL	SE	SI	SK	IE	CY	MT

Large minimum eligible capacity

ES	PT	RO	FI	HU	IT	SE	SI	AT	BE	BG	CZ	DE	DK	EE	FR	GR	LU	LV	NL	NO	PL	SK	HR	IE	LT	CY	MT

Protracted minimum delivery period

PL	DK	SE	BG	AT	BE	CZ	DE	EE	ES	FI	FR	GR	HU	IT	LU	LV	NO	PT	RO	SI	SK	HR	IE	LT	NL	CY	MT

Unregulated duration or long prequalification process

CZ	FR	GR	IT	LT	PT	SI	AT	BE	BG	DE	DK	EE	ES	HU	LU	LV	NL	PL	RO	SE	SK	FI	HR	IE	NO	CY	MT

Large minimum bid size

DK	ES	FR	GR	HU	IT	NL	RO	AT	BE	BG	CZ	DE	EE	FI	LT	LU	LV	NO	PL	PT	SE	SI	SK	HR	IE	CY	MT

Long validity period of balancing energy bids

DK	FI	NO	SE	SK	EE	HR	HU	IT	LT	LV	PL	PT	ES	AT	BE	CZ	DE	FR	GR	LU	NL	RO	SI	BG	IE	CY	MT

Long procurement lead time

EE	HR	SK	CZ	LT	LV	SI	DK	FR	HU	NO	AT	BE	BG	DE	ES	FI	GR	LU	NL	PL	PT	RO	SE	IE	CY	IT	MT

Long balancing capacity contracts

EE	LV	HR	PL	PT	DK	ES	SI	AT	BE	CZ	DE	FI	FR	GR	HU	LT	LU	NL	NO	RO	SE	SK	BG	IE	CY	IT	MT

Symmetric balancing capacity products

PL	DK	ES	FR	PT	RO	AT	BE	CZ	DE	FI	GR	HR	HU	LT	LU	LV	NL	NP	SE	SI	SK	BG	IE	CY	EE	IT	MT

Restrictions in the price settlement rule of balancing energy

FR	DK	HR	HU	NO	SK	AT	BE	CZ	DE	EE	ES	FI	GR	IT	LT	LU	LV	NL	PL	RO	SE	SI	SK	BG	IE	CY	MT

Non-contracted balancing energy bids not allowed

HR	PT	SK	ES	DK	FI	GR	NO	PL	SE	AT	BE	CZ	DE	EE	FR	HU	IT	LT	LU	LV	NL	RO	SI	BG	IE	CY	MT

Balancing energy gate closure time before intraday cross-zonal gate closure time

EE	FI	SE	AT	BE	CZ	DE	DK	ES	FR	GR	HU	IT	LT	LU	LV	NL	NO	PL	PT	RO	SI	SK	BG	HR	IE	CY	MT

Source: ACER.

Notes: (1) ACER was not able to calculate the barrier score for Bulgaria and Ireland since at least half of the indicators were missing. (2) The barrier and the underlying indicators are not applicable to Cyprus and Malta since they do not have a liquid wholesale electricity market. (3) For more information on the methodology for assessing the scores per barrier (top) and indicator (bottom), please refer to Annex I.

120 The Electricity Regulation and the Electricity Balancing Regulation lay down rules for the integration of the balancing energy markets in Europe with the purpose of (i) ensuring effective and greater competition and non-discrimination between market participants as well as (ii) efficient price signals through balancing services defined and procured in a transparent, technologically neutral, and market-based manner. A European-wide coupling of national balancing markets means the deployment of standard balancing energy products, harmonised balancing energy gate closure times, a common merit order list, a central activation optimization function, merit order activation, and a harmonised pricing of balancing energy, among others. However, in 2022 only a limited number of Member States had joined the EU balancing energy platforms[57]. Therefore, until all TSOs procure their balancing energy needs via the EU balancing platforms, it is important to monitor their adherence to the European target model. This includes monitoring some features of the prequalification process, the product design, and the market structure to procure local balancing products[58] and specific balancing products that may hinder the participation of distributed energy resources and other new actors.

121 This chapter aims (i) to identify non-market-based balancing services, (ii) to monitor to what extent some features of the prequalification process, product design, and structure of the balancing markets are still not in line with the European target model, and (iii) to show the capacity prequalified of distributed energy resources and new actors and its level of participation in the different balancing services in 2022.

5.1. Non-market based balancing services

122 Non-market based balancing services are de facto closed to all distributed energy resources and all new actors (e.g., independent aggregators or energy communities aiming to provide balancing services). The Electricity Balancing Regulation aims at ensuring that the procurement of balancing services (i.e., both balancing energy and balancing capacity)[59] is fair, objective, transparent and market-based, avoids undue barriers to entry for new entrants, and fosters the liquidity of balancing markets while preventing undue distortions within the internal market in electricity[60].

123 Table 15 shows the Member States with non-market-based procurement of balancing capacity and/or non-market-based activation of balancing energy in 2022, therefore not in line with the Electricity Balancing Regulation. France and Croatia procure balancing capacity for aFRR with a non-market-based method while Portugal applies the same approach for mFRR and RR. The procurement of balancing energy for aFRR is done using a non-market-based mechanism in Spain, France, Croatia, and Portugal while Croatia also applies the same approach for balancing energy for mFRR. Since November 2023, France plans to start activating energy for aFRR using a market-based approach with a merit order list with a remuneration at the marginal price. Portugal also intends to change the type of procurement of capacity for mFRR and RR in 2024.

124 In Spain, Croatia, Italy, Portugal, and Romania, a certain group of generation units are obliged to provide FCR (Frequency Containment Reserves). In Member States where this obligation cannot be transferred to other power plants or with requirements to keep high margins, the overall system operation becomes less efficient. Each generation unit cannot run at maximum power because they need to keep a certain margin and automatically respond to frequency variations. On the contrary, if the TSO procured FCR provision, all inframarginal generation units would always run at maximum power and the TSO would ensure running the unit that can provide FCR more efficiently. Only Romania plans to start procuring capacity for FCR based on a tender from April 2024.

125 In addition, when generation units provide FCR in Spain, Croatia, and Romania, they do not receive any remuneration, which represents an entry barrier for distributed energy resources which have no incentive to provide this balancing service.

57 The aFRR platform (PICASSO) and the mFRR platform (MARI) were brought successfully into operation on 1 June 2022 and 5 October 2022 respectively, while the RR platform (TERRE) has been operational since January 2020. The Czech TSO accessed PICASSO on the day of the go-live while the Austrian and German TSOs successfully accessed and exchanged via the platform on 22 June 2022. The last accession was the Italian TSO on 19 July 2023. In MARI only the Czech and German TSOs have connected their respective national markets since the day of the go-live. The Austrian TSO joined MARI on 20 June 2023. TERRE has six countries connected, including the Czech Republic, France, Italy, Spain, Switzerland, and Portugal.

58 Local balancing energy products refer to balancing energy products procured nationally by the TSO before joining the respective EU balancing energy platform.

59 Article 2(3) of the Electricity Balancing Regulation.

60 Article 3(1) of the Electricity Balancing Regulation read together with Article 32(2)(c) and Title V, Chapter 2 of the Electricity Balancing Regulation.

Table 15: Non-market-based balancing products – 2022

ES	FR	HR	IT	PT	RO
FCR Mandatory provision for all generation units and not remunerated.	**aFRR** Non-market-based procurement of balancing capacity and balancing energy. RTE procures aFRR capacity based on a regulated method with a regulated price (20.5 EUR/MW/h). The aFRR energy activated is remunerated at the day-ahead price.	**FCR** Mandatory provision for all generation units and not remunerated.	**FCR** Mandatory provision for conventional generation units and CHP equal or above 10MVA. BSPs with units equipped with suitable meters can apply to get remuneration for the energy delivered. The price is related to the day-ahead price and the delta between average aFRR price and day-ahead price. If not equipped with suitable meters, the FCR provision is accounted in the imbalances.	**FCR** Mandatory provision for all generation units connected to the transmission grid. It is remunerated at a fixed price set out in PPAs signed between the TSO and the generation units.	**FCR** Mandatory provision for all generation units and not remunerated.
aFRR Non-market-based procurement of balancing energy. BSPs provide aFRR energy according to the aFRR capacity allocated. The price for the aFRR energy activated is set at 15-minutes intervals based on the non-activated mFRR bids in the same quarter hour.		**aFRR** Non-market-based procurement of balancing energy and balancing capacity at a regulated price.		**aFRR** Non-market-based procurement of balancing energy. The power plants with aFRR capacity allocated receive setpoints with a pro-rata scheme. They are remunerated according to the marginal price of "Reserva de Regulação" (a specific mFRR product).	
		mFRR Non-market-based procurement of balancing energy at a regulated price.		**mFRR** Non-market-based procurement of balancing capacity. The power plants have to offer for mFRR the non-contracted capacity in other markets. This mFRR capacity is not remunerated. Only the energy activated from mFRR is remunerated according to market-based rules.	
				RR Non-market-based procurement of balancing capacity. The power plants have to offer for RR the non-contracted capacity in other markets. This RR capacity is not remunerated. Only the energy activated from RR via TERRE is remunerated.	

Source: ACER based on NRA data.
Notes: (1) No information for Bulgaria. (2) Not applicable to Cyprus and Malta since they do not have a liquid wholesale electricity market. The table does not show Ireland since there is no clear translation of the EU balancing services to the IE-SEM due to the way that central dispatch has been implemented in Ireland. (4) In Croatia mFRR is divided in two types: mFRR for security reasons (for the case of outage of the largest power plant, only upward) and mFRR for balancing purposes (upward and downward). Both the procurement of balancing capacity and the activation of balancing energy for mFRR for security reasons are market-based with a price cap. However, mFRR for balancing purposes is non-market based and the price is regulated.

5.2. Restrictions in market-based balancing services

126 As shown in Section 3.2.2. in 2022 only five Member States (Germany, Estonia, the Netherlands, Romania, and Slovenia) had fully opened up all their balancing markets allowing any type of distributed energy resources, individually or aggregated, being eligible to participate. This section aims to assess (i) how some design features of the prequalification processes may restrict access to some resources or actors despite being legally eligible parties, and (ii) to what extent some product requirements and features of the market structure of balancing products are misaligned with the European target model thus representing an obstacle for the participation of distributed energy resources.

5.2.1. Constraints in the prequalification process

127 The prequalification process to provide balancing services consists of verifying the compliance of the assets of the Balancing Service Provider (BSP)[61] to the technical requirements set out by the TSO[62] and, where applicable, verifying that the service delivery can be technically supported by the connecting and intermediate grids.

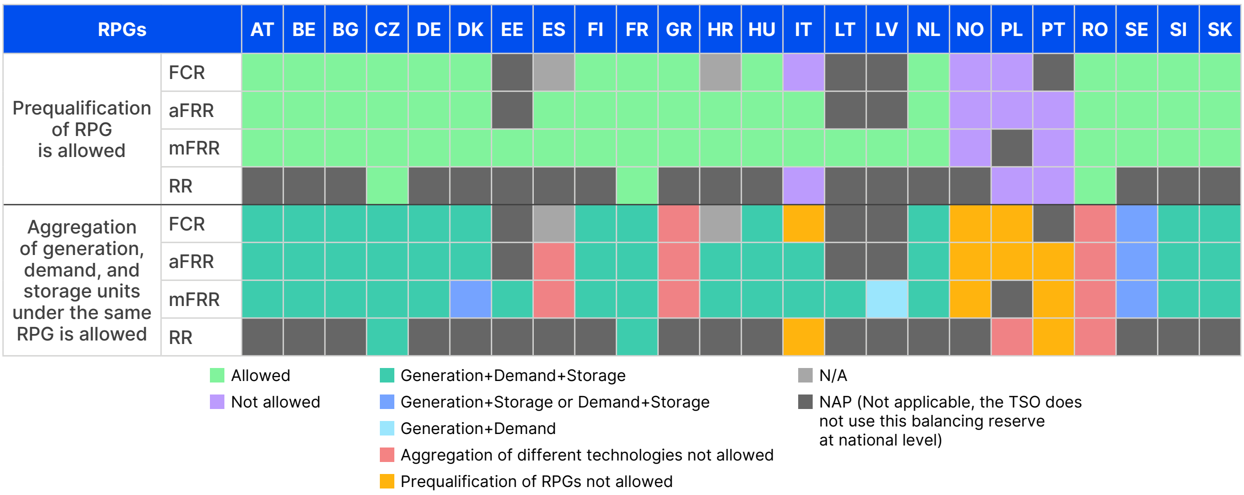
61 A balancing service provider means a market participant with reserve-providing units or reserve-providing groups able to provide balancing services to TSOs as set out in Article 2(6) of the Electricity Balancing Regulation.

62 On some occasions, some TSOs require potential BSPs to pass an activation test as part of the product prequalification. In this activation test, the TSO sends an activation signal to the BSP's assets during normal operating conditions to ensure that in case of need (and favourable market clearing) the resources can be activated, their capabilities meet the product requirements, and the relevant data can be exchanged. Testing IT and communication requirements are out of the scope of the activation test.

Restrictions in the prequalification of reserve providing groups

128 To allow distributed energy resources accessing balancing services regardless of their size, TSOs need to have a prequalification process not only for reserve providing units (RPUs) but also for reserve providing groups (RPGs or pools)[63]. Moreover, BSPs should be allowed to aggregate all types of units, including generation, demand, and energy storage units in the same reserve providing group. This way market participants engaged in aggregation (including independent aggregators) will be able to manage their portfolio in an effective manner always finding the best combination of resources to provide the balancing service.

Table 16: Types of reserve providing groups allowed to be prequalified under the business-as-usual approach per Member State – 2022



Source: ACER based on NRA data.
Notes: (1) Not applicable to Cyprus and Malta since they do not have a liquid wholesale electricity market. (2) The table does not show Ireland since there is no clear translation of the EU balancing services to the IE-SEM due to the way that central dispatch has been implemented in Ireland. (3) In Luxembourg Creos Luxembourg S.A. has a service-level agreement with Amprion GmbH which operates the common LFC area between Creos and Amprion. No unit connected to Creos can participate in the prequalification for aFRR or mFRR in the German market although they can participate in the prequalification for FCR. These units must sign a contract with Amprion and need to fulfil the prequalification process requirements as defined and approved for Germany. As of 31 December 2022, there was no application from these potential units connected to Creos. (4) Belgium has two types of Technical Units: DPsu (units > 25 MW with obligation to provide schedules to Elia) and DPpg (units < 25 MW with possibility of not providing schedules). Aggregation under RPGs is only allowed for Dppg and for DPsu, the latter under the condition to be part of the same technical facility.

129 As shown in Table 16, in 2022 most Member States allowed prequalifying RPGs under the business-as-usual approach, however some still have restrictions to aggregate different types of technologies in the same RPG as follows:

- Denmark and Sweden allow aggregating either generation and energy storage units or demand and energy storage units in the same group but generation and demand units cannot be aggregated in the same RPG.
- In Latvia a RPG is allowed to aggregate only generation and demand units but energy storage units are not allowed to aggregate with generation nor demand units in the same group.
- Spain[64], Greece, Poland (only for RR), and Romania do not allow combining generation, demand, and energy storage units in the same RPG. In Spain the combination of generation and energy storage units is only allowed for pumped-hydro storage and other hydro power plants.

63 According to ACER's interpretation, it follows from the Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation (hereafter System Operation Regulation), in particular Articles 3(9), 154, 155, 158, 159, 161, and 162 thereof, that a reserve provider can be supplying from one or more units (RPU), one or more groups (RPG) or from both RPU(s) and RPG(s), and that the TSOs' RPU/RPG prequalification process needs to cover all these options. As set out in Article 3(11) and 3(12) of the System Operation Regulation, a reserve providing group means an aggregation of power generating modules, demand units and/or reserve providing units connected to more than one connection point fulfilling the requirements to provide FCR, FRR or RR. A reserve providing unit means a single or an aggregation of power generating modules and/or demand units connected to a common connection point fulfilling the requirements to provide FCR, FRR or RR.

64 In Spain the combination of generation and storage units in the same RPG is only allowed for pumped-hydro storage together with other hydro power plants. At the time of writing this report, batteries cannot aggregate with generation or demand units, but the Spain is working on a regulatory framework for hybrid utilities.

130 Italy (only FCR and RR), Norway, Poland (only FCR and aFRR), and Portugal still do not allow prequalifying RPGs. Nevertheless, in Italy the TSO allows prequalifying RPGs aggregating power generation modules, demand units and/or energy storage units from multiple connection points with a power capacity lower than 10 MW for aFRR under the pilot project 'Regolazione Secondaria' and for mFRR and RR under the pilot project 'UVAM' (Unità Virtuali Abilitate Miste)[65]. In Norway, even though there is no formal prequalification of RPGs, the TSO usually gathers RPUs in 'station groups' to streamline the prequalification process, especially when units are small. These station groups can aggregate generation and energy storage units or demand and energy storage units.

Large minimum eligible capacity

131 Balancing markets, including prequalification processes, must be organised in such a way as to ensure non-discriminatory access to all market participants, individually or through aggregation, including for electricity generated from variable renewable energy sources, demand response, and energy storage, as set out in the Electricity Regulation[66]. When the minimum eligible capacity is too large or aggregation of units is not allowed, accessing to balancing markets is de facto closed to the smaller distributed energy resources.

132 As shown in Table 17, the minimum eligible capacity in 2022 was less than or equal to 1 MW for most balancing products in most Member States although there were still larger values as follows:

- The minimum eligible capacity is higher than 10 MW in Spain (aFRR), Portugal (aFRR), and Romania (FCR and aFRR). As an example, Spain procures aFRR through D-1 auctions open to demand and generation resources from 1 MW of capacity. However, the resources must belong to the same regulated zone with a minimum portfolio size of 200 MW without the possibility of aggregating demand and generation in the same reserve providing group as shown in Table 16. This requirement excludes the participation of distributed energy resources.

- In Sweden the minimum eligible capacity reaches 10 MW for mFRR.

133 The balancing markets in five Member States have minimum eligible capacities higher than 1 MW and up to 5 MW: Bulgaria (RR), Denmark, Finland, and Portugal (all for mFRR), and Hungary (aFRR and mFRR). These thresholds become more restrictive in Denmark and Portugal where no aggregation is allowed to provide mFRR (Table 5).

134 Even though Poland and Slovakia require a 1 MW of minimum eligible capacity, it may also become restrictive to smaller units since aggregation is not allowed, same as Denmark and Portugal (Table 5).

65 ARERA (the Italian NRA) has recently approved a new regulatory framework to allow the prequalification tested in these pilot projects as the business-as-usual approach from 2025. For more information on the pilot project 'Regolazione Secondaria', please refer to: https://www.terna.it/it/sistema-elettrico/progetti-pilota-delibera-arera-300-2017-reel/progetto-pilota-regolazione-secondaria. For more information on the pilot project 'UVAM', please refer to: https://www.terna.it/it/sistema-elettrico/progetti-pilota-delibera-arera-300-2017-reel/progetto-pilota-uvam.

66 Article 6(1)(c) of the Electricity Regulation.

Table 17: Some prequalification requirements to provide balancing services per Member State. Alignment with the European target model – 31 December 2022

Prequalification requirements		AT	BE	BG	CZ	DE	DK	EE	ES	FI	FR	GR	HR	HU	IT	LT	LV	NL	NO	PL	PT	RO	SE	SI	SK
Minimum eligible capacity (MW)	FCR	1	1	1	1	1	1			< 1	1	1		1				1	no min	1		>10	1	1	1
	aFRR	1	1	1	1	1	1		>10	1	1	1		1 < x ≤ 5	1			1	no min	1	>10	>10	1	1	1
	mFRR	1	1	1	1	1	1 < x ≤ 5	1	1	1 < x ≤ 5	1	1		1 < x ≤ 5	1		1	1	no min		1 < x ≤ 5	1	5 < x ≤ 10	1	1
	RR			1 < x ≤ 5	1						1				1					1	1	1			
Minimum duration of the delivery period (min)	mFRR	1	15	15	15	0	60	1	15	15	5	15		15	60		1		30		15	5	60	0	15
	RR				15				15		15				15					> 240	30	15		15	

Aligned with the European target model
Misaligned with the European target model
N/A
NAP (Not applicable, the TSO does not use this balancing reserve at national level)

Source: ACER based on NRA data.
Notes: (1) Not applicable to Cyprus and Malta since they do not have a liquid wholesale electricity market. (2) The table does not show Ireland since there is no clear translation of the EU balancing services to the IE-SEM due to the way that central dispatch has been implemented in Ireland. (3) In Luxembourg Creos Luxembourg S.A. has a service-level agreement with Amprion GmbH which operates the common LFC area between Creos and Amprion. No unit connected to Creos can participate in the prequalification for aFRR or mFRR in the German market although they can participate in the prequalification for FCR. These units must sign a contract with Amprion and need to fulfil the prequalification process requirements as defined and approved for Germany. As of 31 December 2022, there was no application from these potential units connected to Creos.

Protracted minimum delivery period

135 During the delivery period the BSP delivers the full requested change of power in-feed to or withdrawal from the connected TSO system for mFRR and RR[67]. TSOs prequalify BSPs for a minimum and a maximum delivery period[68]. Both can range from 0 minutes (i.e., the TSO only requires BSPs to ramp up and down) to more than 4 hours. The European target model sets a minimum delivery period of 15 minutes for standard mFRR balancing products[69] and assumes an exchange profile between TSOs with a 15-minute delivery period: 5 minutes for ramp-up, 5 minutes full delivery, and 5 minutes for ramp down. The duration of the delivery period for standard RR balancing products can be 15, 30 or 60 minutes[70]. Overlong delivery periods may represent a direct barrier for some distributed energy resources. As an example, a minimum delivery period of 4 hours can limit the participation of demand response since most residential and tertiary consumers are only able to activate their flexibility during 1 or 2 hours a day at most.

136 As shown in Table 17, in 2022 the TSOs in six Member States required BSPs to deliver the maximum power for more than 15 minutes for mFRR or RR: 30 minutes in Norway and Portugal for mFRR and RR respectively, 1 hour in Denmark, Italy, and Sweden for mFRR, reaching more than 4 hours in Poland for RR.

Unregulated duration or long prequalification process

137 When the duration of the prequalification process, including the intermediate steps, is not regulated, it may create legal uncertainty for the BSPs since they do not have certainty on when they will be able to effectively start providing balancing services with the corresponding RPUs or RPGs. It may also impact their business case losing some customers if eventually the process becomes much longer than estimated. The latter is especially true for BSPs aiming to prequalify RPGs with multiple units (e.g.,

67 This design parameter is not applicable to aFRR and FCR since the TSO procures continuous products.

68 During the prequalification process, a BSP is required to deliver during a minimum period after which it should be able to gradually reduce the delivery of balancing energy, and during a maximum period during which the BSP should be able to deliver the required energy without interruption.

69 ACER Decision No 03/2020 on the Implementation framework for mFRR Platform – Annex I.

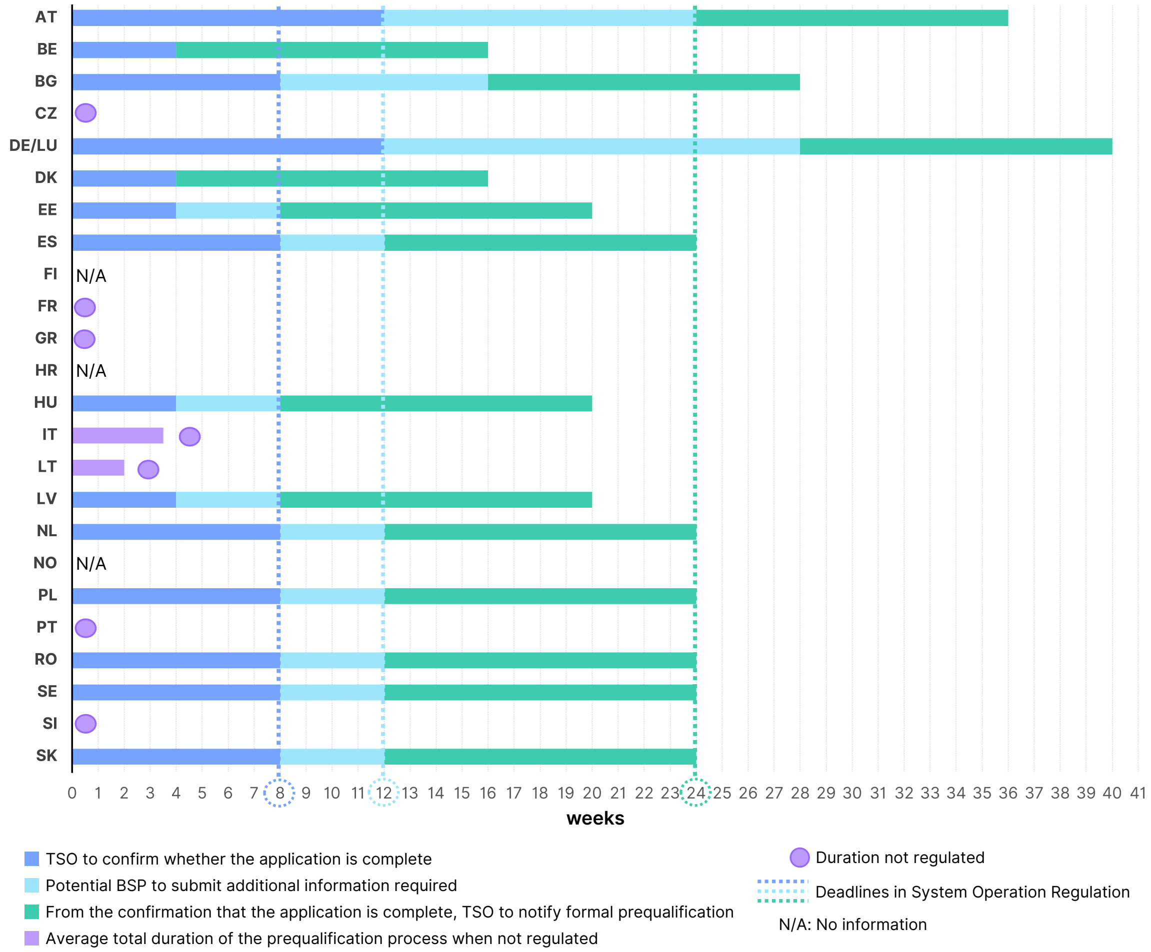
70 Approval by relevant regulatory authorities on the proposal of all TSOs performing the reserve replacement process for the implementation framework for the exchange of balancing energy from RRs in accordance with Article 19 of Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing.
ENTSO-E: The proposal of all TSOs performing the reserve replacement process for the implementation framework for the exchange of balancing energy from Replacement Reserves in accordance with Article 19 of Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing.

aggregators-BSPs of demand response units) since some final customers may not be willing to wait for prorated periods of time to offer their flexibility. Moreover, the lack of regulated deadlines does not create a level-playing field for all BSPs since some may prequalify their RPUs or RPGs very quickly while it may take a much longer time for others.

138 The System Operation Regulation sets out some deadlines in the prequalification process defined by TSOs[71]. Within 8 weeks from receipt of the application of the potential BSP provider, the reserve connecting TSO must confirm whether the application is complete. If incomplete, the potential BSP provider must submit the additional required information within 4 weeks from receipt of the request for additional information. Finally, within 3 months from confirmation that the application is complete, the reserve connecting TSO must decide whether the potential reserve providing units or groups meet the criteria for a prequalification.

139 Figure 20 shows the deadlines of the above-mentioned intermediate steps defined by each Member State for the first-time prequalification of potential reserve providing units or groups. In 2022 seven Member States still had not regulated the maximum duration of the prequalification process and its intermediate steps in line with the System Balancing Regulation. In Belgium the maximum duration is regulated except for the deadline for potential BSPs to submit additional information if required. In Austria, Bulgaria, and Germany/Luxembourg, the total maximum duration of the process supersedes the 24 weeks set out in the System Operation Regulation.

Figure 20: Maximum duration of the first-time prequalification process for balancing services per Member State – 2022



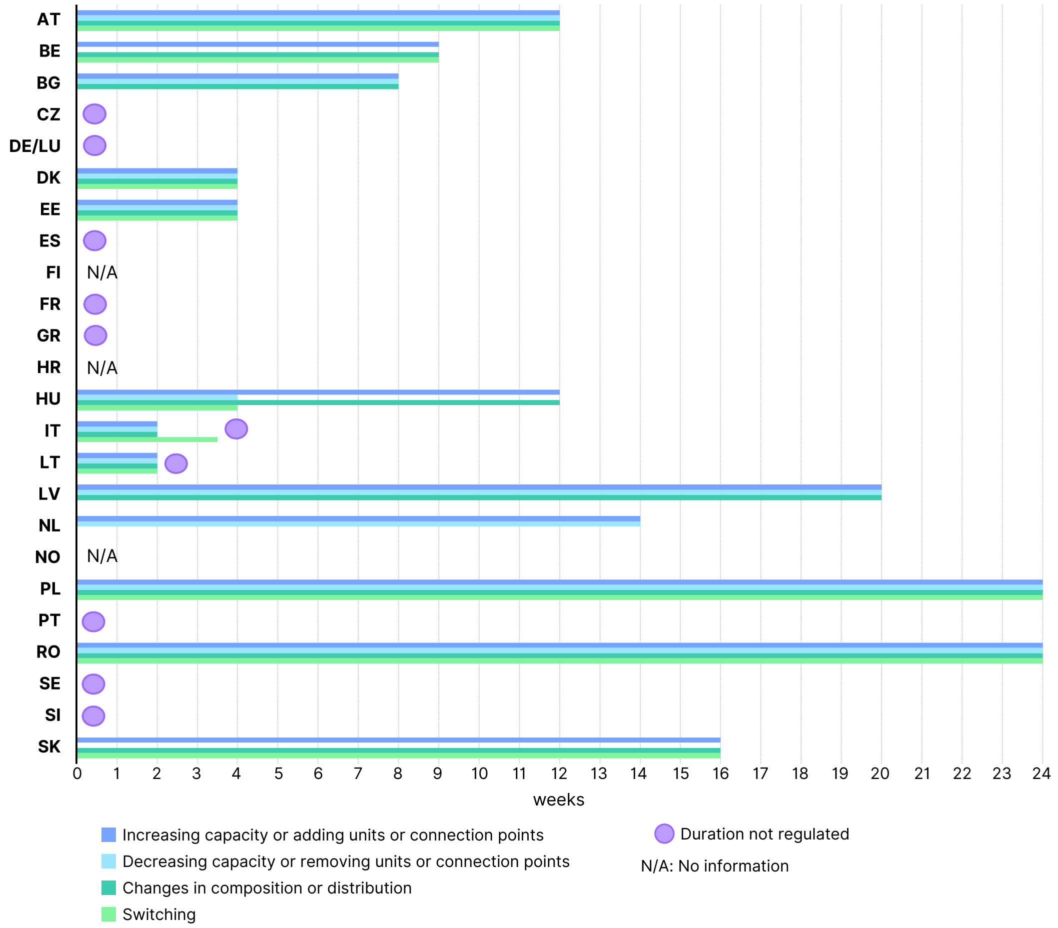
Source: ACER based on NRA data.
Notes: (1) Finland, Croatia, and Norway did not provide information on whether the duration of the prequalification process is regulated or its maximum duration. (2) Not applicable to Cyprus and Malta since they do not have a liquid wholesale electricity market. (3) The table does not show Ireland since there is no clear translation of the EU balancing services to the IE-SEM due to the way that central dispatch has been implemented in Ireland. (4) In Belgium there is no deadline in the national rules for potential BSPs to submit additional information when required by the TSO. (5) The Danish NRA does not have information on the deadline in the national rules for potential BSPs to submit additional information when required by the TSO. (6) The duration of the prequalification process in Luxembourg is aligned with Germany for FCR. No unit connected to Creos can participate in the prequalification for aFRR or mFRR in the German market although they can participate in the prequalification for FCR. These units must sign a contract with Amprion and need to fulfil the prequalification process requirements as defined and approved for Germany. As of 31 December 2022, there was no application from these potential units connected to Creos.

71 Article 155(3)-(4), Article 159(3)-(4), and Article 162(3)-(4) of the System Operation Regulation.

140 The System Operation Regulation does not specify whether the maximum durations are also applicable when TSOs require to pass a re-prequalification process after changes in the prequalified reserve providing units and groups. In a context where changes in units and groups will happen with increasing frequency (e.g., aggregator-BSPs may often need to switch consumers between different portfolios or add new units into their RPGs), a short re-prequalification process, if needed, helps distributed energy resources effectively enter balancing markets.

141 Figure 21 shows the maximum duration of the re-prequalification process defined by each Member State after making different types of changes in the prequalified reserve providing units or groups. Eleven Member States do not regulate the maximum duration of the re-prequalification process. In the Member States where the duration is regulated, it ranges from four weeks in Denmark and Estonia to 24 weeks in Poland and Romania. In most Member States the maximum duration does not depend on the type of change, with some exceptions in Austria, Germany/Luxembourg, Hungary, and the Netherlands.

Figure 21: Maximum duration of the prequalification process for balancing services after changes in the prequalified reserve providing units or groups per Member State – 2022



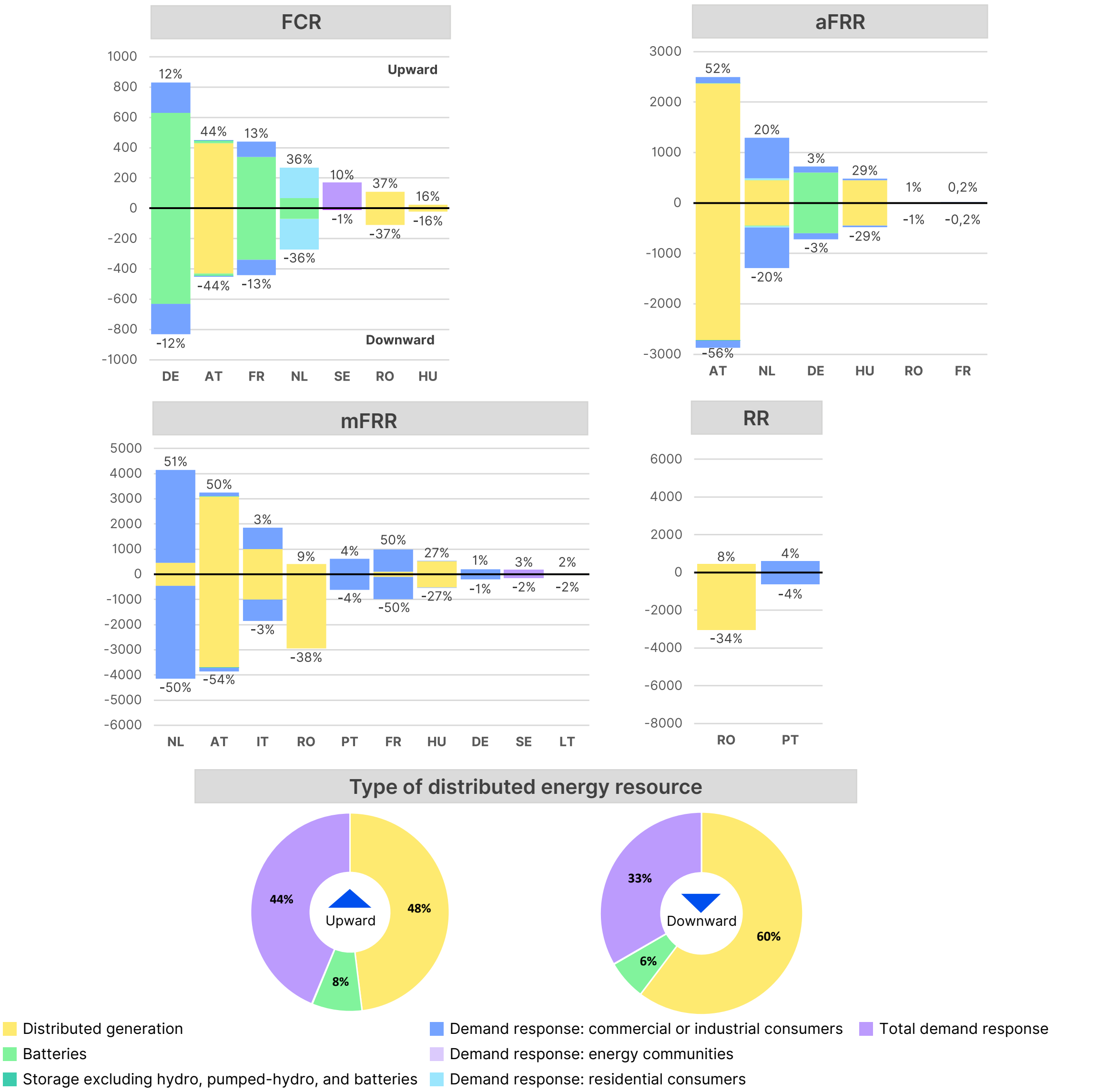
Source: ACER based on NRA data.
Notes: (1) Changes in the composition of a prequalified RPG always imply removing some connection points or some units connected to the connection points within the RPG while others are added but keeping the same prequalified reserve capacity/volume. Changes in the distribution of a prequalified RPG refer to changes in the location of the connection points or the units connected to connection points within the RPG while keeping the same connection points and units (i.e., no changes in their prequalified reserve capacity/volume nor their features). (2) Finland, Croatia, and Norway did not provide information on whether the duration of the re-prequalification process is regulated or its maximum duration. (3) Not applicable to Cyprus and Malta since they do not have a liquid wholesale electricity market. (4) The table does not show Ireland since there is no clear translation of the EU balancing services to the IE-SEM due to the way that central dispatch has been implemented in Ireland. (5) In Austria the maximum duration of the re-prequalification is 12 weeks although it is typically 3 weeks for add-ons and 2 weeks for removals. (6) In Germany the re-prequalification for switching usually takes longer than re-prequalification for other types of changes. (7) In Hungary the maximum duration after switching is 4 weeks after verification of data connection. (8) In the Netherlands the maximum duration for re-prequalification after changes in existing prequalified units is 14 weeks. It becomes 20 weeks for testing when adding new units. After removals, there is no re-prequalification if the removed units were considered as separate RPUs. Otherwise, the maximum duration extends to 20 weeks. (9) The duration of the prequalification process in Luxembourg is aligned with Germany for FCR. No unit connected to Creos can participate in the prequalification for aFRR or mFRR in the German market although they can participate in the prequalification for FCR. These units must sign a contract with Amprion and need to fulfil the prequalification process requirements as defined and approved for Germany. As of 31 December 2022, there was no application from these potential units connected to Creos.

Distributed energy resources prequalified for balancing services

142 In 2022, sixteen Member States had some distributed energy resources prequalified to provide balancing services[72]. On the contrary, all capacity prequalified in Estonia, Greece, Croatia, Latvia, and Poland corresponded to generation units connected to the transmission network.

143 Figure 22 shows the capacity of distributed energy resources prequalified per balancing product and per Member State in 2022 and the share of this capacity over the total capacity prequalified as well as the distribution of the distributed energy resource prequalified at EU level. For more information on the types of distributed energy resources prequalified in all Member States, please see Table 29 in Annex II.

Figure 22: Capacity prequalified (upward/downward) of distributed energy resources per balancing product and per Member State – 2022 (MW and %)



Source: ACER based on NRA data.
Notes: (1) The figure refers to the capacity prequalified as of 31 December 2022 for local, specific, and standard balancing products. (2) The bar charts show the share of distributed energy resources prequalified over the total capacity prequalified per Member State for each corresponding balancing product. The pie charts show the share of each type of distributed energy resource over the total capacity prequalified of distributed energy resources at the EU level. (3) No information for Denmark, Finland, and Slovakia. Data for Germany and France is not complete. In Belgium, Bulgaria, the Czech Republic, Spain, Norway, and Slovenia there was some capacity of distributed energy resources prequalified in 2022, but the data is not available. For more information on the amount of capacity prequalified for the different types of distributed energy resources per Member State, please refer to Table 29 in Annex II. (4) Not applicable to Cyprus and Malta since they do not have a liquid wholesale electricity market. (5) The figure does not show Ireland since there is no clear translation of the EU balancing services to the IE-SEM due to the way that central dispatch has been implemented in Ireland. (6) In Austria approximately 83%, 75% and 70% of the capacity of distributed generation prequalified for FCR, aFRR and mFRR respectively, corresponds to hydro-power plants connected to the distribution grid. In Romania most prequalified distributed generation also corresponds hydro-power plants connected to the distribution grid. (7) Luxembourg is integrated within the LFC perimeter of Amprion in the DE-LU bidding zone, hence German provisions apply. (8) In Italy the prequalified capacity of distributed generation also includes units smaller than 10 MVA, connected to the transmission network and participating through the pilot projects 'Regolazione Secondaria' and 'UVAM'. See footnote 64.

72 Belgium, Bulgaria, the Czech Republic, Spain, Norway, and Slovenia had some capacity of distributed energy resources prequalified in 2022, but the data is not available.

144 Some main conclusions can be drawn from Figure 22 as follows:

- Most capacity of distributed energy resources prequalified at the EU level corresponds to distributed generation, followed by demand response units and batteries. As expected, there is relatively more downward capacity from distributed generation and more upward capacity from demand response. Indeed, it is easier for distributed generation such as renewable energy sources to offer negative balancing energy lowering or curtailing their production, and for demand response to offer positive balancing energy reducing their consumption. Overall, most distributed energy resources are prequalified for mFRR, followed by aFRR.

- In absolute terms, Germany, Austria, the Netherlands, and Romania show the highest total capacity of distributed energy resources prequalified for FCR, aFRR, mFRR and RR, respectively. In relative terms, Austria stands out since around 50% of its total capacity prequalified for aFRR and mFRR corresponds to distributed energy resources, mainly distributed generation. This figure reaches around 45% for FCR. Nevertheless, it is closely followed by the Netherlands and France where around 50% of the capacity prequalified for mFRR corresponds to distributed energy resources, mainly commercial and industrial consumers.

- The type of resources prequalified is very diverse across the Member States. In absolute terms, the main resources prequalified are distributed generation mainly in Austria for all balancing services and in Romania for FCR, mFRR, and RR. In both Member States, this distribution generation consists of hydro-power plants connected to the distribution grid. Distributed generation is followed by commercial and industrial consumers (in most Member States but especially in the Netherlands for aFRR and mFRR) and batteries (mainly for FCR and aFRR with Germany leading followed by France, and the Netherlands). Residential consumers still have a very marginal role being mainly prequalified in the Netherlands for FCR. There is no capacity prequalified of energy communities.

5.2.2. Product design and market structure not aligned with the EU target model

145 This section shows to what extent certain design features of some balancing products and their market structure are misaligned with the European target model and how such a misalignment may hinder participation of distributed energy resources.

Large minimum bid size

146 The European target model sets out that the minimum quantity of the energy bid volume offered and the bid granularity[73] for standard balancing products shall be 1 MW for all reserve types[74], which facilitates entry of small distributed flexible resources. Some balancing markets with larger minimum bid size allow bidding with a pool of assets (i.e., reserve providing groups), thus reducing the entry barrier.

147 As shown in Table 18, the minimum bid size in 2022 was less or equal to 1 MW for most balancing products in most Member States although there were still larger values as follows:

- The minimum size reached 20 MW for mFRR capacity in the Netherlands. Nevertheless, in April 2023 it was reduced up to 1 MW.

- 10 MW were found in four Member States: France (for mFRR and RR), Romania (for aFRR)[75], Sweden (for mFRR energy), and market participants located in the Norwegian bidding zones NO2, NO4, and NO5 (for mFRR energy). In France the minimum bid size is expected to become 1 MW for mFRR and RR since April 2024.

- The balancing markets had minimum bid sizes larger than 1 MW up to 5 MW in seven Member States as follows: Greece (all products), Denmark and Hungary (all products except for FCR), Bulgaria (RR energy), Finland (mFRR), the Netherlands (aFRR energy), and market participants located in the NO1 and NO3 bidding zones (mFRR energy).

73 The lowest possible increment for offers above the minimum bid size.

74 This requirement already applies to the PICASSO, MARI, and TERRE platforms for exchanging balancing energy for aFRR, mFRR, and RR respectively. If there is a derogation, the requirement will be binding from July 2024. More information in ACER Decision No 02/2020 on the Implementation framework for aFRR Platform – Annex I and ACER Decision No 03/2020 on the Implementation framework for mFRR Platform – Annex I.

75 In Romania where the activation of aFRR is pro-rata, the minimum regulating band was 10 MW, i.e., a symmetrical reserve +/- 5 MW (up and down).

148 Some balancing markets have 1 MW of minimum bid size but with some limitations on these bids. For example, in the Netherlands market participants are allowed to offer bids of 4 MW for aFRR capacity without limitation but they are not allowed to submit an unlimited amount of 1 MW bids. TenneT expects to remove this restriction in 2024.

Table 18: Some product requirements and features of balancing products per Member State. Alignment with the European target model – 31 December 2022

Product requirements and features		AT	BE	BG	CZ	DE	DK	EE	ES
MINIMUM BID SIZE (MW)	FCR_Capacity	≤ 1	≤ 1	≤ 1	≤ 1	≤ 1	≤ 1		
	aFRR_Capacity	≤ 1	≤ 1	≤ 1	≤ 1	≤ 1	1 < x ≤ 5		≤ 1
	aFRR_Energy	≤ 1	≤ 1	≤ 1	≤ 1	≤ 1	1 < x ≤ 5		
	mFRR_Capacity	≤ 1	≤ 1	≤ 1	≤ 1	≤ 1	1 < x ≤ 5		
	mFRR_Energy	≤ 1	≤ 1	≤ 1	≤ 1	≤ 1	1 < x ≤ 5	≤ 1	≤ 1
	RR_Capacity								
	RR_Energy			1 < x ≤ 5	≤ 1				≤ 1
VALIDITY PERIOD OF BALANCING ENERGY BIDS (min)	aFRR_Energy	15	15		15	15			
	mFRR_Energy	60	15		60	15	60	60	60
	RR_Energy				15				15
PROCUREMENT LEAD TIME (%)	Within the same delivery day	0	0	0	0	0	0	0	0
	Daily ahead	100	100	100	35	100	58	0	100
	Weekly ahead	0	0	0	0	0	15	0	0
	Monthly ahead	0	0	0	1	0	27	0	0
	Yearly ahead	0	0	0	64	0	0	0	0
	Other	0	0	0	0	0	0	0	0
LENGTH OF BALANCING CAPACITY CONTRACTS	FCR_Capacity	Hour(s)	Hour(s)		Hour(s)	Hour(s)	Hour(s)		Year(s)
	aFRR_Capacity	Hour(s)	Day(s)		Hour(s)	Hour(s)	Month(s)		Hour(s)
	mFRR_Capacity	Hour(s)	Hour(s)		Hour(s)	Hour(s)	Month(s)	Year(s)	Day(s)
	RR_Capacity								
SYMMETRY IN BALANCING CAPACITY CONTRACTS	aFRR_Capacity	Asymmetrical	Asymmetrical		Asymmetrical	Asymmetrical	Symmetrical		Asymmetrical
	mFRR_Capacity	Asymmetrical	Asymmetrical		Asymmetrical	Asymmetrical	Asymmetrical		
PRICE SETTLEMENT RULE OF BALANCING ENERGY	aFRR_Energy	Marginal pricing	Pay as bid		Marginal pricing	Marginal pricing	Regulated price		Hybrid
	mFRR_Energy	Pay as bid	Marginal pricing		Pay as bid	Marginal pricing	Marginal pricing	Hybrid	Marginal pricing
	RR_Energy				Marginal pricing				Marginal pricing
NON-CONTRACTED BALANCING ENERGY BIDS	aFRR_Energy	YES	YES		YES	YES	NO		NO
	mFRR_Energy	YES	YES		YES	YES	YES	YES	YES
	RR_Energy				YES				

Product requirements and features		FI	FR	GR	HR	HU	IT	LT	LV
MINIMUM BID SIZE (MW)	FCR_Capacity	≤ 1	≤ 1	1 < x ≤ 5		≤ 1			
	aFRR_Capacity	≤ 1	≤ 1	1 < x ≤ 5		1 < x ≤ 5			
	aFRR_Energy	≤ 1	≤ 1	1 < x ≤ 5		1 < x ≤ 5	≤ 1		
	mFRR_Capacity	1 < x ≤ 5	5 < x ≤ 10	1 < x ≤ 5		1 < x ≤ 5		≤ 1	
	mFRR_Energy	1 < x ≤ 5	5 < x ≤ 10	1 < x ≤ 5		1 < x ≤ 5	≤ 1	≤ 1	≤ 1
	RR_Capacity		5 < x ≤ 10						
	RR_Energy		5 < x ≤ 10				≤ 1		
VALIDITY PERIOD OF BALANCING ENERGY BIDS (min)	aFRR_Energy		30	15	60	60	60		
	mFRR_Energy	60	30	15	60	60	60	60	60
	RR_Energy		30				60		
PROCUREMENT LEAD TIME (%)	Within the same delivery day	100	0	0	0	0		0	0
	Daily ahead	0	76	100	0	30		42	42
	Weekly ahead	0	0	0	13	3		0	0
	Monthly ahead	0	0	0	0	67		0	0
	Yearly ahead	0	24	0	87	0		58	58
	Other	0	0	0	0	0		0	0
LENGTH OF BALANCING CAPACITY CONTRACTS	FCR_Capacity	Hour(s)	Hour(s)	Hour(s)		Hour(s)			
	aFRR_Capacity	Hour(s)	Hour(s)	Hour(s)	Year(s)	Hour(s)			
	mFRR_Capacity	Hour(s)	Day(s)	Hour(s)	Day(s)	Hour(s)		Hour(s)	Year(s)
	RR_Capacity		Day(s)						
SYMMETRY IN BALANCING CAPACITY CONTRACTS	aFRR_Capacity	Asymmetrical	Symmetrical	Asymmetrical	Asymmetrical	Asymmetrical			
	mFRR_Capacity	Asymmetrical	Asymmetrical	Asymmetrical	Asymmetrical	Asymmetrical		Asymmetrical	Asymmetrical
PRICE SETTLEMENT RULE OF BALANCING ENERGY	aFRR_Energy	Marginal pricing	Regulated price	Hybrid	Pay as bid	Pay as bid	Pay as bid		
	mFRR_Energy	Marginal pricing	Pay as bid	Marginal pricing	Pay as bid	Pay as bid	Pay as bid	Hybrid	Marginal pricing
	RR_Energy		Pay as bid				Marginal pricing		
NON-CONTRACTED BALANCING ENERGY BIDS	aFRR_Energy	NO	YES	NO	NO	YES	YES		
	mFRR_Energy	YES	YES	YES	NO	YES	YES	YES	YES
	RR_Energy		YES				YES		

Product requirements and features		NL	NO	PL	PT	RO	SE	SI	SK
MINIMUM BID SIZE (MW)	FCR_Capacity	≤ 1	≤ 1	≤ 1			≤ 1	≤ 1	No min
	aFRR_Capacity	≤ 1	≤ 1	≤ 1	≤ 1	5 < x ≤ 10	≤ 1	≤ 1	No min
	aFRR_Energy	1 < x ≤ 5	≤ 1	≤ 1	≤ 1	5 < x ≤ 10	≤ 1	≤ 1	No min
	mFRR_Capacity	> 10	≤ 1		No min	≤ 1		≤ 1	No min
	mFRR_Energy		5 < x ≤ 10		≤ 1	≤ 1	5 < x ≤ 10	≤ 1	No min
	RR_Capacity			≤ 1		≤ 1			
	RR_Energy			≤ 1	≤ 1	≤ 1		≤ 1	
VALIDITY PERIOD OF BALANCING ENERGY BIDS (min)	aFRR_Energy	15		60		15		15	
	mFRR_Energy		60		60	15	60	15	60
	RR_Energy			60	60	15		15	
PROCUREMENT LEAD TIME (%)	Within the same delivery day	0	0	0	0	0	0	0	0
	Daily ahead	100	46	100	100	100	95	39	2
	Weekly ahead	0	25	0	0	0	5	0	0
	Monthly ahead	0	0	0	0	0	0	2	0
	Yearly ahead	0	28	0	0	0	0	0	98
	Other	0	0	0	0	0	0	41	0
LENGTH OF BALANCING CAPACITY CONTRACTS	FCR_Capacity	Hour(s)	Hour(s)			Hour(s)	Hour(s)	Hour(s)	Hour(s)
	aFRR_Capacity	Day(s)	Hour(s)		Hour(s)	Hour(s)	Hour(s)	Month(s)	Hour(s)
	mFRR_Capacity	Day(s)	Week(s)			Hour(s)		Year(s)	Hour(s)
	RR_Capacity			Hour(s)		Hour(s)			
SYMMETRY IN BALANCING CAPACITY CONTRACTS	aFRR_Capacity	Asymmetrical	Asymmetrical	Symmetrical	Asymmetrical	Symmetrical	Asymmetrical	Asymmetrical	Asymmetrical
	mFRR_Capacity	Asymmetrical	Asymmetrical			Asymmetrical		Asymmetrical	Asymmetrical
PRICE SETTLEMENT RULE OF BALANCING ENERGY	aFRR_Energy	Marginal pricing	Regulated price	Marginal pricing	Marginal pricing	Marginal pricing	Marginal pricing	Marginal pricing	Pay as bid
	mFRR_Energy		Marginal pricing		Marginal pricing	Marginal pricing	Marginal pricing	Marginal pricing	Pay as bid
	RR_Energy			Marginal pricing	Marginal pricing	Marginal pricing		Pay as bid	
NON-CONTRACTED BALANCING ENERGY BIDS	aFRR_Energy	YES	NO	NO	NO	YES	NO	YES	NO
	mFRR_Energy		YES		NO	YES	YES	YES	NO
	RR_Energy			YES	NO	YES		YES	

Aligned with the European target model
Misaligned with the European target model
N/A
NAP (Not applicable, the TSO does not use this balancing reserve at national level)

Source: ACER based on NRA data.
Notes: (1) Not applicable to Cyprus and Malta since they do not have a liquid wholesale electricity market. (2) The figure does not show Ireland since there is no clear translation of the EU balancing services to the IE-SEM due to the way that central dispatch has been implemented in Ireland. (3) Luxembourg is integrated within the LFC perimeter of Amprion in the DE-LU bidding zone, hence German provisions apply. (4) For aFRR, mFRR and RR, the minimum eligible capacity, the minimum bid size, the validity period of the balancing energy bids, and the price settlement rule of balancing energy correspond to the following products:
(i) standard products if the Member State has started procuring balancing energy on the corresponding EU balancing platform and it does not procure any specific product (i.e., Austria, the Czech Republic, and Germany for aFRR after joining PICASSO, Germany for mFRR after joining MARI, and Spain and Portugal for RR after joining TERRE).
(ii) specific products if the Member State has started procuring balancing energy on the corresponding EU balancing platform but it also procures a specific product (i.e., the Czech Republic for mFRR after joining MARI, and the Czech Republic, France, and Italy for RR after joining TERRE); and
(iii) local products if the Member State has not joined the corresponding EU balancing platform (the remaining Member States and balancing products). (5) In Spain, Croatia, Italy, Portugal, and Romania, the minimum bid size for FCR is not shown because the provision of this balancing service is not market-based but mandatory for some generation units. (6) Lithuanian TSO has stopped using RR since 2023. (7) The procurement lead time in Denmark is shown as the average between values for DK1 and DK2. (8) In Slovenia the TSO procures aFRR balancing capacity at monthly and daily auctions through monthly and daily contracts and mFRR balancing capacity at yearly and daily auctions through multi-year and daily contracts.

Long validity period of balancing energy bids

149 The validity period of the balancing energy bids is the minimum resolution for which the product is required to bid into the market. It can range from 15 minutes up to four hours (or blocks). Overlong balancing energy products prevent participation of demand response and storage, leading to higher balancing energy prices with lower price fluctuation. The Electricity Balancing Regulation[76] sets out that the imbalance settlement period should be harmonised to 15 minutes. The validity period should also comply with this resolution. Having the same length allows similar incentives for BSPs and BRPs. Balancing energy products should also comply with this resolution.

150 As shown in Table 18, in 2022 the validity period of the balancing energy bids was higher than 15 minutes in most jurisdictions. Most Member States still procure 1-hour products except for France with 30-minute products. The validity period is only 15 minutes in the Member States who joined the EU balancing energy platforms and do not procure specific balancing products anymore (i.e., Austria, the Czech Republic, and Germany for aFRR after joining PICASSO, Germany for mFRR after joining MARI, and Spain and Portugal in TERRE) and in the local balancing products procured in Belgium (aFRR and mFRR), the Czech Republic (RR), Greece (aFRR and mFRR), the Netherlands (aFRR), Romania (aFRR, mFRR and RR), and Slovenia (aFRR, mFRR and RR).

76 Article 53 of the Electricity Balancing Regulation.

Long procurement lead time and long balancing capacity contracts

151 The procurement lead-time[77] and the duration of the balancing capacity contracts[78] must be no longer than one day after 1 January 2020 pursuant to the Electricity Regulation unless a derogation applies[79]. Longer procurement lead times and balancing capacity contracts may limit the participation of distributed energy resources in balancing capacity markets, since they have more difficulties than large conventional power plants to commit long time ahead of delivery and for long delivery periods.

152 In 2022 ten Member States did not procure all balancing capacity day-ahead of delivery as shown in Table 18. Out of those ten, Czech Republic, Croatia Hungary, Lithuania, Norway, Slovenia, and Slovakia procured more than 50% of their balancing capacity long before day-ahead[80].

153 In 2022, the length of the balancing capacity contracts had a duration of at least one year in Spain for FCR, Croatia for aFRR, and Estonia, Latvia, and Slovenia for mFRR. It reached one or more months in Denmark (aFRR, mFRR) and Slovenia (aFRR) and one or more weeks in Norway (mFRR). In Estonia, Latvia, and Croatia no balancing capacity was procured with a duration of one day.

Symmetric balancing capacity products

154 The procurement of upward and downward FRR capacity must be carried out separately (i.e., without a requirement to be symmetrically offered or provided) pursuant to the Electricity Regulation[81]. Symmetric FRR capacity products hinder the participation of variable renewable energy resources, demand response and energy storage since it is easier for renewables to offer downward regulation (i.e., negative balancing energy) curtailing their production and for demand response to offer upward regulation (i.e., positive balancing energy) consuming less energy while energy storage can have technical constraints to provide symmetrical load variations. In addition, symmetric products can decrease the portfolio of aggregators since some consumers can or may be willing to offer flexibility only in one direction.

155 In 2022, all Member States allowed asymmetric mFRR capacity products (Table 18). However, aFRR capacity products were still required to be symmetric in Denmark, France, Poland, and Romania.

Restrictions in the price settlement rule of balancing energy

156 The price settlement of balancing energy products must be based on marginal pricing (pay-as-cleared) pursuant to the Electricity Regulation[82]. Marginal pricing makes it easier for new entrants to offer balancing energy bids since they do not have to guess the ‘right’ bid to offer and they are only concerned about their own marginal (including opportunity) cost.

157 As shown in Table 18, in 2022, pay-as-bid was the pricing method for some local products in nine Member States (Austria, Belgium, the Czech Republic, France, Croatia, Hungary, Italy, Slovenia, and Slovakia). In Denmark, France, and Norway, BSPs still receive a regulated price for the energy activated from aFRR.

Non-contracted balancing energy bids not allowed

158 BRPs must have the right to submit non-contracted balancing energy bids (also known as ‘free’ balancing energy bids) pursuant to the Electricity Balancing Regulation[83]. This type of bids refers to the possibility of offering balancing energy bids on a voluntary basis without the need for a previous contract for balancing capacity. This promotes competition and participation of new entrants in the balancing energy markets.

77 Time-lag between the balancing capacity auction (gate closure of the balancing capacity market) and the start of the contract period in which the balancing capacity must be offered as balancing energy in the real-time market.

78 When the balancing capacity offered by a BSP is accepted, the BSP is obliged to offer a certain volume of balancing energy during a certain period.

79 Article 6(9) of the Electricity Regulation.

80 For more information on procurement lead times, please refer to ACER’s 2023 Market Monitoring Report on progress of EU electricity wholesale market integration.

81 Article 6(9) of the Electricity Regulation.

82 Article 6(4) of the Electricity Regulation.

83 Article 16(5) of the Electricity Balancing Regulation.

159 In 2022, almost half of Member States still did not allow free bids in many balancing services but mainly for aFRR (Table 18). More specifically, Croatia, Portugal, and Slovakia did not allow free bids for any balancing product while Denmark, Spain, Finland, Greece, Norway, Poland, and Sweden did not allow free bids for aFRR only.

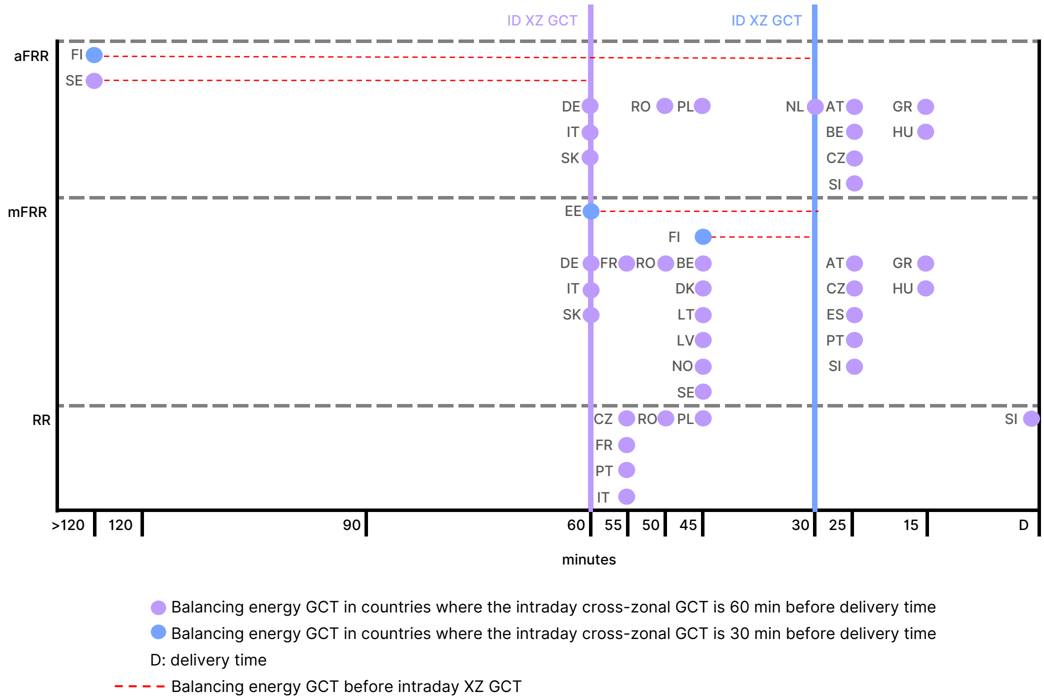
Balancing energy gate closure times before intraday cross-zonal gate closure time

160 The balancing energy gate closure time must take place after the intraday cross-zonal gate closure time for all balancing energy bids to maximise opportunities for market participants to balance themselves as closely as possible to real time pursuant to the Electricity Regulation[84]. This is particularly relevant for distributed energy resources, especially for distributed renewable generation due to its high variability and uncertainty.

161 The gate closure time for the pan-European intraday market is 60 minutes before delivery time except for the EE-FI border with 30 minutes before delivery time[85]. Figure 23 shows the gate closure time of each balancing energy market in Europe compared to the intraday cross-zonal gate closure time in 2022.

162 In Finland, Sweden, and Estonia the gate closure time of some balancing energy markets still takes place before the intraday cross-zonal gate closure time while in Germany, Italy, and Slovakia both gate closure times overlap.

Figure 23: Gate closure time of balancing energy markets per Member State compared to the intraday cross-zonal gate closure time – 2022 (minutes before delivery time)



Source: ACER based on NRA data.
Notes: (1) Not applicable to Cyprus and Malta since they do not have a liquid wholesale electricity market. (2) The figure does not show Ireland since there is no clear translation of the EU balancing services to the IE-SEM due to the way that central dispatch has been implemented in Ireland. (3) Luxembourg is integrated within the LFC perimeter of Amprion in the DE-LU bidding zone, hence German provisions apply.

Participation of distributed energy resources in balancing services

163 Table 19 shows an estimation of the balancing capacity procured and the balancing energy activated from distributed energy resources per Member State in 2022.

84 Article 6(4) of the Electricity Regulation.
85 ACER Decision No 04/2018 on the Intraday Cross-Zonal Gate Opening and Gate Closure Times.

Table 19: Estimated balancing capacity procured and balancing energy activated from distributed energy resources per balancing product and per Member State – 2022 (% ranges)

Balancing capacity procured and balancing energy activated (%)			AT	BE	BG	CZ	DE	DK	EE	ES	FI	FR	GR	HR	HU	IT	LT	LV	NL	NO	PL	PT	RO	SE	SI	SK
FCR	BALANCING CAPACITY	Distributed generation		0	0							0	0		>20						0	0	0		0	
FCR	BALANCING CAPACITY	Storage excluding hydro and pumped-hydro storage		>20	0							>20	0		0						0	0	0		0	
FCR	BALANCING CAPACITY	Demand response		1-5	0					0		>20	0		0						0	0	0		0	
FCR	BALANCING CAPACITY	Total of distributed energy resources		>20	0							>20	0		>20						0	0	0		0	
aFRR	BALANCING CAPACITY	Distributed generation		5-10	0							0	0	0	>20						0	0	0		0	
aFRR	BALANCING CAPACITY	Storage excluding hydro and pumped-hydro storage		10-20	0							0	0	0	0					0	0	0	0		0	
aFRR	BALANCING CAPACITY	Demand response		0	0					0		0	0		1-5					0	0	0	0	0	0	
aFRR	BALANCING CAPACITY	Total of distributed energy resources		>20	0							0	0		>20						0	0	0		0	
aFRR	BALANCING ENERGY	Distributed generation		5-10	0							0	0	0	10-20	0					0	0	0		0	
aFRR	BALANCING ENERGY	Storage excluding hydro and pumped-hydro storage		10-20	0							0	0	0	0	0					0	0	0		0-1	
aFRR	BALANCING ENERGY	Demand response		0	0					0		0	0		0-1	0					0	0	0	0	0	
aFRR	BALANCING ENERGY	Total of distributed energy resources		>20	0							0	0		10-20	0					0	0	0		0	
mFRR	BALANCING CAPACITY	Distributed generation		5-10	0							10-20	0	0	5-10		0					0	5-10		>20	
mFRR	BALANCING CAPACITY	Storage excluding hydro and pumped-hydro storage		5-10	0							0	0	0	0		0					0	0		0	
mFRR	BALANCING CAPACITY	Demand response		5-10	0							>20	0		0-1		0					>20	0		0	
mFRR	BALANCING CAPACITY	Total of distributed energy resources		5-10	0							>20	0		5-10		0					0	0		>20	
mFRR	BALANCING ENERGY	Distributed generation		0-1	0				0			0-1	0	0	10-20	0-1		0				0	1-5		>20	
mFRR	BALANCING ENERGY	Storage excluding hydro and pumped-hydro storage		0-1	0				0			0	0	0	0	10-20	0	0				0	0		0	
mFRR	BALANCING ENERGY	Demand response		0	0				0	0		0-1	0		0-1		0	0				1-5	0		0	
mFRR	BALANCING ENERGY	Total of distributed energy resources		0-1	0				0			1-5	0		10-20	10-20		0				0	0		>20	
RR	BALANCING CAPACITY	Distributed generation										1-5										0	0			
RR	BALANCING CAPACITY	Storage excluding hydro and pumped-hydro storage										0										0	0			
RR	BALANCING CAPACITY	Demand response										1-5										0	0			
RR	BALANCING CAPACITY	Total of distributed energy resources										1-5										0	0			
RR	BALANCING ENERGY	Distributed generation				0						0-1				0					0	0	0			
RR	BALANCING ENERGY	Storage excluding hydro and pumped-hydro storage				0						0				0					0	0	0			
RR	BALANCING ENERGY	Demand response				0				0		0-1				0					0	0	0			
RR	BALANCING ENERGY	Total of distributed energy resources				0						1-5				0					0	0	0			

- More than 20% of total balancing capacity or total balancing energy
- Between 10%-20% of total balancing capacity or total balancing energy
- Between 5%-10% of total balancing capacity or total balancing energy
- Between 1%-5% of total balancing capacity or total balancing energy
- Between 0%-1% of total balancing capacity or total balancing energy
- No balancing capacity procured or no balancing energy activated
- N/A
- NAP (Not applicable: balancing reserve not used by the TSO)

Source: ACER based on NRA and TSO data.
Notes: (1) Demand response aggregates residential, commercial, industrial consumers and energy communities. (2) No information for Austria, the Czech Republic, Germany, Denmark, Finland, the Netherlands, and Slovakia. Limited information for Spain, Croatia, Norway, and Sweden. (3) Not applicable to Cyprus and Malta since they do not have a liquid wholesale electricity market. (4) The figure does not show Ireland since there is no clear translation of the EU balancing services to the IE-SEM due to the way that central dispatch has been implemented in Ireland. (5) Luxembourg is integrated within the LFC perimeter of Amprion in the DE-LU bidding zone, hence German provisions apply. (6) In Slovenia RR balancing energy is shown as NAP since the TSO does not prequalify balancing energy products for RR. (7) In Italy the TSO activates RR through the TERRE platform; however, the distributed energy resources that participate through the pilot project 'UVAM' are not converted into the RR standard product.

164 Some main conclusions can be drawn as follows:

- Overall, there is very limited information on the actual participation of distributed energy resources in balancing services since most Member States have self-dispatch portfolio-based systems[86]. Only some TSOs and NRAs are able to provide rough estimations or accurate figures when there is no participation. More specifically, in eleven Member States the TSOs cannot provide either actual or estimated data on the balancing capacity procured and balancing energy activated from distributed energy resources. Nevertheless, seven out of these eleven Member States can estimate some participation in 2022 since some distributed energy resources were prequalified (see Figure 22 and Table 29 in Annex II for more information).

- When estimations are available, the participation of distributed energy resources in balancing services is still very marginal compared to conventional generation technologies. In 2022, a higher participation is estimated in Belgium (in all balancing products but mainly in FCR and aFRR), France (mainly in FCR and capacity for mFRR), Hungary (similar levels in all balancing products), and Slovenia (mainly in mFRR). These Member States are followed by Italy, Portugal, and Romania with a more residual participation of some types of distributed energy resources in some balancing products.

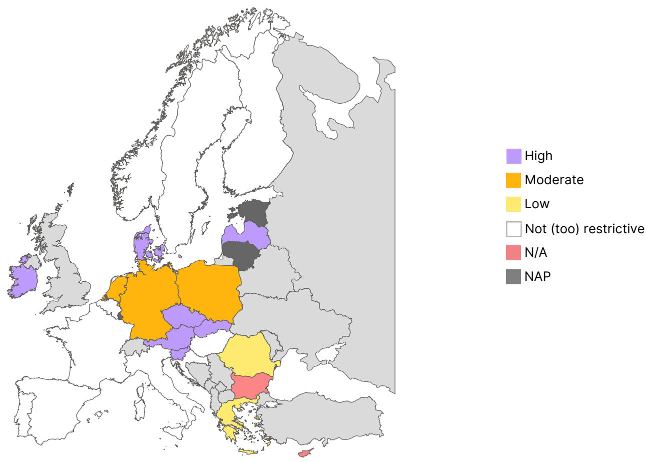
86 Fifteen countries (Austria, Belgium, Bulgaria, Germany/Luxembourg, Denmark, Estonia, Finland, Croatia, Lithuania, Latvia, the Netherlands, Sweden, Slovenia, and Slovakia) have self-dispatch portfolio-based systems while seven (the Czech Republic, Spain, France, Hungary, Norway, Portugal, and Romania) have self-dispatch portfolio-based systems and four (Greece, Ireland, Italy, and Poland) a central dispatch-based system.

6. Restrictive requirements to providing congestion management services

Congestion management measures are usually performed using non-market-based procedures, especially at distribution level. In the Member States where TSOs do not use market-based re-dispatching it is usually justified by the exemptions allowed in the Clean Energy Package. However, when it comes to the DSO level, there is lack of information on the reasons for not implementing market-based re-dispatching.

A very limited number of Member States have an iterative national reassessment process with a transparent decision-making process to review whether the exceptions from using market-based re-dispatching have become inapplicable. This complicates setting up local markets for congestion management.

Figure 24: Restrictive requirements to providing congestion management services. Overview of the barrier (top) and underlying indicators (bottom) per Member State – 2022



Non-market based TSO(s) congestion management: Unjustified or lack of reassessment																											
AT	SK	CZ	DE	HU	IE	NL	PL	BE	ES	FI	FR	GR	HR	IT	NO	PT	RO	SE	BG	CY	DK	EE	LT	LU	LV	MT	SI

Non-market based DSO(s) congestion management: Unjustified or lack of reassessment																											
AT	BG	CY	CZ	DK	GR	IE	LV	RO	SI	SK	DE	MT	NL	NO	PL	PT	SE	BE	ES	FR	HU	EE	FI	HR	IT	LT	LU

Source: ACER.
Notes: (1) ACER was not able to calculate the barrier score for Bulgaria and Cyprus since half of the indicators were missing. (2) For more information on the methodology for assessing the scores per barrier (top) and indicator (bottom), please refer to Annex I.

165 This chapter shows the type of congestion management services and the procurement method used by TSOs and DSOs in 2022. When market-based congestion management services are not implemented, it identifies (i) whether the reasons are in line with the Clean Energy Package and (ii) whether the Member States have defined an iterative national reassessment process to review whether the exceptions from using market-based re-dispatching have become inapplicable.

166 With the pace of the energy transition increasing, SOs have been encountering an increasing number of capacity bottlenecks caused by network congestions at both transmission and distribution level. For example, the total cost of remedial actions taken by TSOs in 2022 totalled 5.2 billion EUR representing almost a 50% increase compared to 2021, mainly triggered by the increased use of remedial actions[87].

167 Network congestions will become especially relevant at the distribution level as more and more new production and decentralised energy sources are being connected and with the expected rise of active customers engaging in demand response and electromobility.

87 For more information on the use of remedial actions across the EU, please refer to ACER's 2023 Market Monitoring Report on progress of EU electricity wholesale market integration.

168 To tackle network congestions, SOs can implement different solutions as follows: network reinforcement and expansion, a redefinition of bidding zones[88], re-dispatching (including curtailment)[89], countertrading[90], non-firm connection agreements[91] or interruptible tariffs[92], among others. Grid investments will continue to be necessary to facilitate the transition to a more decentralised and greener power system. However, it cannot be the only measure to solve congestions due to its long lead time and high costs. It is therefore necessary to put in place quicker and more cost-efficient congestion management solutions.

169 Re-dispatching is the main measure to solve network congestions. There are basically two different options[93]:

- Non-market based re-dispatching, also named cost-based mechanisms for re-dispatch, cost-based re-dispatching, regulatory obligation or administrative re-dispatch; or

- Market based re-dispatching, also referred to as market-based mechanisms for re-dispatching, competitive procurement or local flexibility markets for re-dispatching.

170 Local markets for re-dispatching are expected to be one of the main drivers for unlocking the flexibility potential, especially at distribution level. They can be applicable to multiple congestion areas and to a wide range of network users and can provide information on the activated volumes, thus potentially lowering the overall cost of solving network congestions and facilitating comparison with other congestion management options such as network reinforcement and expansion. In addition, they can interact with other wholesale markets, thus maximising the value for the service providers.

171 To ensure SOs can solve their congestions in the most cost-efficient way and to allow for the entire potential of flexible resources to be available for re-dispatching at transmission and distribution level, it is in the spirit of the Clean Energy Package to set market-based re-dispatching when it states that "the resources that are re-dispatched shall be selected from among generating facilities, energy storage or demand response using market-based mechanisms and shall be financially compensated"[94]. However, the Clean Energy Package also allows the use of non-market re-dispatching where "*(a) no market-based alternative is available; (b) all available market-based resources have been used; (c) the number of available power generating, energy storage or demand response facilities is too low to ensure effective competition in the area where suitable facilities for the provision of the service are located; or (d) the current grid situation leads to congestion in such a regular and predictable way that market-based re-dispatching would lead to regular strategic bidding which would increase the level of internal congestion and the Member State concerned either has adopted an action plan to address this congestion or ensures that minimum available capacity for cross-zonal trade is in accordance with Article 16(8)6*"[95].

172 The Clean Energy Package reinforces the promotion of market-based procurement of congestion management services by DSOs when it states that "Member States shall provide the necessary regulatory framework to allow and provide incentives to distribution system operators to procure flexibility services, including congestion management in their areas" and "Distribution system operators shall procure such services in accordance with transparent, non-discriminatory and market-based procedures" although it also includes possible exceptions from the use of market-based congestion management when "the regulatory authorities have established that the procurement of such services

88 Bidding zones should be defined to ensure efficient congestion management and overall market efficiency, according to CACM Regulation. In addition, bidding zone borders shall be based on long-term, structural congestions in the transmission network, in line with the Electricity Regulation. The definition of adequate bidding zones is a decision that affects the TSOs' congestions.

89 Re-dispatching means a measure, including curtailment, that is activated by one or more transmission system operators or distribution system operators by altering the generation, load pattern or both, to change physical flows in the electricity system and relieve a physical congestion or otherwise ensure system security (Article 2(26) of the Electricity Regulation). Re-dispatch products can be activated after closure of the day-ahead market.

90 Countertrading means a cross-zonal exchange initiated by system operators between two bidding zones to relieve physical congestion (Article 2(27) of the Electricity Regulation).

91 Connection contract that contains restrictions that limit the network user from being able to export their full capacity under certain conditions. The non-firm period can either be temporary (staged contract) or permanent.

92 Temporary load reduction in exchange for reduced network charges.

93 For more information, please refer to CEER's 2021 report on Re-dispatching Arrangements in Europe against the Background of the Clean Energy Package Requirements.

94 Article 13(2) of the Electricity Regulation.

95 Article 13(3) of the Electricity Regulation.

is not economically efficient or that such procurement would lead to severe market distortions or to higher congestion"[96].

173 The following aspects can be considered an entry barrier for demand response and other new entrants and small actors:

- Not foreseeing market-based congestion management services at transmission or distribution level for any reason other than the exceptions foreseen in the Clean Energy Package.
- Lack of a transparent national process to assess whether market-based re-dispatching can be used. The Clean Energy Package sets no requirement regarding the level of transparency with respect to the decision-making process to set market-based or non-market-based re-dispatching. It only requires regulatory authorities to establish when the procurement of flexibility services by DSOs, including congestion management, cannot be based on a market-based procedure.
- Lack of an iterative process to review whether the exceptions from the use of market-based re-dispatching have become inapplicable. In a context with increasing network congestions and more and more resources and actors willing to provide flexibility, some market conditions, such as predictability of network congestions or lack of competition may become inapplicable.

TSOs congestion management

174 Figure 25 shows the congestion management measure implemented by TSOs as a business-as-usual approach to solve network congestions after day-ahead and intraday market coupling in 2022. Six Member States only use market-based re-dispatching while six only use a non-market-based method for re-dispatching. Three Member States use a combination of both procurement approaches. In Greece, Ireland, Italy, and Poland, the TSO solves network congestions within the integrated scheduling process in their central dispatch model. Greece, Italy, and Poland base their re-dispatching action on the BSP bid price in the context of the integrated scheduling process. The Polish TSO occasionally re-dispatches specific resources through a cost-based procurement when a congestion can only be solved by such resources, and they cannot be activated from the balancing market within the integrated scheduling process.

175 In the eleven Member States where the TSOs use some non-market-based approach to re-dispatch resources, Table 20 shows whether the reasons are in line with the four exceptions foreseen in the Clean Energy Package, i.e., no market-based alternative is available, all available market-based resources have been used, lack of competition or predictability of network congestions. The table also shows whether these Member States have defined an iterative national reassessment process to review whether the exceptions from the use of market-based re-dispatching have become inapplicable.

176 TSOs use non-market-based re-dispatching in all Member States in line with at least one of the four exceptions allowed by the Clean Energy Package, except for Belgium[97] and Slovakia[98].

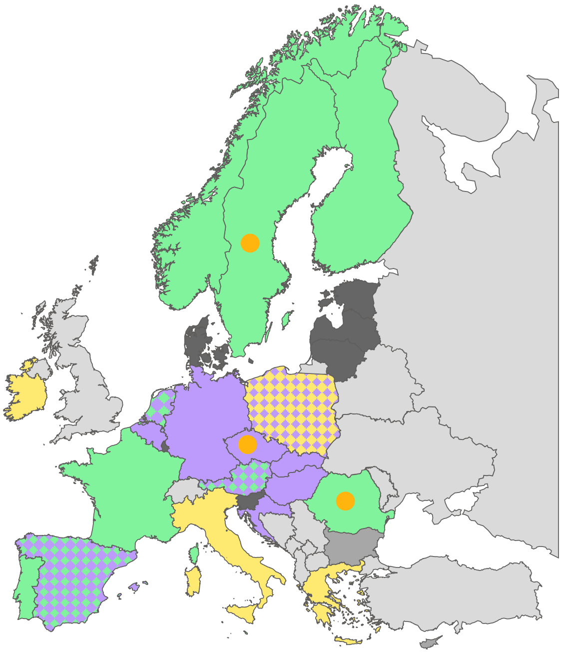
177 Only five Member States performed a national assessment to set non-market-based re-dispatching. Most Member States have not defined an iterative national reassessment process with a transparent decision-making process to review whether the exceptions from using market-based re-dispatching have become inapplicable.

96 Article 32(1) of the Electricity Directive.

97 Belgium expects to regulate the procurement process for re-dispatching in 2023.

98 In Slovakia the TSO uses non-market-based re-dispatching for non-frequency ancillary services in general.

Figure 25: Congestion management at transmission level per type of procurement and per Member State – 2022



Source: ACER based on NRA data.
Notes: (1) In Austria, Portugal, and Romania the TSOs set up tenders for re-dispatching while in France, Spain, Finland, Norway, and Sweden the TSOs have a continuous market. In the Netherlands both types of markets are in place. (2) In Austria the TSO uses cost-based re-dispatching with large power plants. To ensure there are always sufficient resources available for re-dispatching, network reserves are contracted through a competitive process which is opened to all types of resources, including aggregated distributed energy resources. (3) In Belgium there is no procurement, i.e., the BSPs submit the volumes after closure of the EU intraday market. The TSO activates the volumes respecting the techno-economic merit order and considering the impact of the activation on the congestion. (4) In the Netherlands new rules for congestion management entered into force in November 2022. The TSO and DSOs share access to two market-based products: the re-dispatch and the dispatch limitation product. Both can be contracted long-term. The TSO and DSOs also use non-market re-dispatching for supply when all available market-based resources have been used (i.e., after all bids for market-based re-dispatching have been activated). (5) In Norway and Romania, the TSOs activate mFRR energy bids outside the merit order list for congestion management purposes, i.e., these bids do not set the marginal price. If the bids activated for congestion management purposes are within the merit order, BSPs receive the marginal price. (6) In Spain the non-market-based congestion management only applies to those congestions solved right after the closure of the day-ahead market when the TSO solves the congestions through a partial rejection of the day-ahead schedule. Afterwards, in real time, the procurement is market-based.

Table 20: Reasons for establishing non-market-based re-dispatching at transmission level and implementation status of an iterative national reassessment process – 2022

	TSO congestion management measure per procurement method		Reason(s) for not using market-based re-dispatching	National assessment to set non-market-based congestion management	National reassessment process	Iterative national reassessment process
AT	BAU	BAU	N/A	N/A	No	No
BE	BAU		E	2021	2023	Every 2 years
CZ	BAU		A	2021	No	No
DE	BAU		D	N/A	No	No
ES	BAU	BAU	C	2004	2022	No
HR	BAU		A	2021	Yes	Every year
HU	BAU		D	N/A	No	No
IE	BAU		D (A, B, and C to some extent)	2018	No	No
NL	BAU	BAU	B	N/A	No	No
PL	BAU	BAU	A	N/A	No	No
SK	BAU		E	N/A	No	No

TSO congestion management measure per procurement method
- Market based re-dispatching
- Non-market-based re-dispatching
- Integrated scheduling process
- N/A

National reassessment process
- Reassessment defined
- No reassessment defined

Iterative national reassessment process
- Frequency of the reassessment defined
- No frequency of the reassessment defined

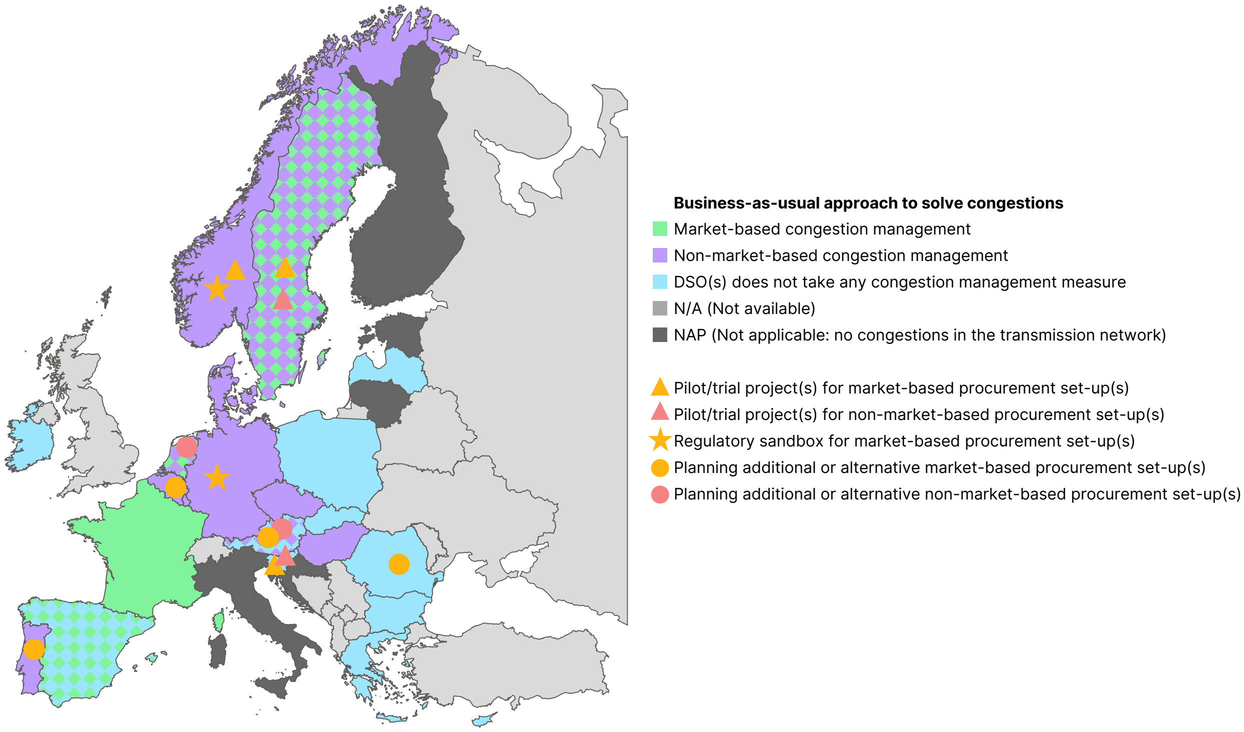
Reason(s)
- A) No market-based alternative is available
- B) All available market-based resources have been used
- C) The number of available power generating, energy storage or demand response facilities is too low to ensure effective competition
- D) The current grid situation leads to congestion in such a regular and predictable way that market-based re-dispatching would lead to regular strategic bidding which would increase the level of internal congestion
- E) Other

Source: ACER based on NRA data.
Notes: (1) To address the current grid situation in Germany and Hungary where congestions have become regular and predictable, both countries have adopted action plans for grid reinforcement when congestions are structural. (2) In Poland the assessment to use the market-based or the non-market-based procurement approach is done by the TSO whenever it needs to solve network constraints. Firstly, the TSO checks whether the market resources can be used to solve network constraint, if not, it applies non-market-based re-dispatching.

DSOs congestion management

178 Figure 26 shows the congestion management measure(s) implemented by DSOs as a business-as-usual approach in 2022. Market-based re-dispatching (i.e., local flexibility markets for re-dispatching at distribution level) is only implemented in four Member States (France, the Netherlands, Spain, and Sweden) while DSOs in eleven Member States use some kind of non-market-based measure to solve congestions (i.e., non-market-based re-dispatching, non-firm connection agreements or interruptible tariffs). In the remaining Member States the DSOs do not perform a congestion management measure other than requesting the TSO to solve the congestion or network reinforcement and expansion.

Figure 26: Congestion management at distribution level per type of procurement and per Member State – 2022



Source: ACER based on NRA data.
Notes: (1) 'Market-based congestion management' refers to local markets where the DSO uses re-dispatching to solve network congestions. 'Non-market-based congestion management' can include non-market-based re-dispatching, non-firm connection agreements or interruptible tariffs depending on the country. 'DSOs do not take any congestion management measure' means that they do not take any measure other than requesting the TSO to solve the congestion or network reinforcement and expansion. (2) In Austria non-firm connection agreements are concluded bilaterally, without a legal basis. Interruptible tariffs are widespread but usually not designed to be used for congestion management by DSO. (3) In Hungary DSOs use non-firm connection agreements. Non-market-based re-dispatching is legally possible by DSOs have not used it yet. (4) In the Netherlands new rules for congestion management entered into force in November 2022. The TSO and DSOs share access to two market-based products: the re-dispatch and the dispatch limitation product. Both can be contracted long-term. The TSO and DSOs also use non-market re-dispatch for supply when all available market-based resources have been used (i.e., after all bids for market-based re-dispatching have been activated). (5) In Spain DSOs do not procure congestion management in a local market but may require the TSO to use market-based re-dispatching on assets connected to the distribution grid. (6) In Sweden some DSOs take non-market-based congestion management measures such as non-firm connection agreements. As shown in Box 5 below, in some pilot projects some DSOs procure congestion management services in local flexibility markets although for some this measure has become their business-as-usual approach to solve congestions in their distribution networks. (7) In the Czech Republic DSOs use non-market-based re-dispatching; however, the current legal framework allows DSOs to set interruptible tariffs and limit grid connection contracts without compensation.

Box 5: Some initiatives to implement additional or alternative DSOs congestion management services

Figure 26 identifies some Member States with ongoing pilot projects, regulatory sandboxes or plans to test market-based re-dispatching or other non-market-based congestion management measures by DSOs.

Pilot projects and regulatory sandboxes

Norway and Sweden have multiple ongoing pilot projects on local markets to test market-based re-dispatching. They use NODES as market platform, including Norflex, Smart Senja, Powerconsumer and PowerShare in Norway and Jämtland, Effekthandel Väst, and sthlmflex in Sweden.

Sweden is also piloting local markets for congestion management in the Stockholm area, Hässleholm, and Southern Scania with the SWITCH flexibility platform.

In Slovenia there is a regulatory sandbox to test market-congestion management services by DSOs that is widely used. Some ongoing projects are STREAM (Streaming flexibility to the power system), DN-FLEX (Local flexibility market), iFLEX (Intelligent Assistants for Flexibility Management), DUSE (Dynamic management of solar power plants (SPP) to increase the share of connected SPP to the low voltage (LV) network), SENERGY NETS (Increase the Synergy among different ENERGY NETworkS) and EV4EU (Electric Vehicles Management for carbon neutrality in Europe). The pilot project OneNet (One Network for Europe), INTERRFACE (TSO-DSO-Consumer INTERRFACE aRchitecture to provide innovative grid services for an efficient power system) and X-FLEX (Integrated energy solutions and new market mechanisms for an eXtended FLEXibility of the European grid) have recently closed. In addition, Slovenia has also launched a pilot project (Flexibility as a new tool for issuing approvals for time-limited increase in connection capacity) for non-firm connection agreements.

In 2023 Portugal launched the pilot project FIRMe (Integrated Flexibility in Market Regime) to test market-based re-dispatching.

Germany also implemented a regulatory sandbox to test market-based re-dispatching that ended in June 2022. The DSOs who participated in the SINTEG (Smart Energy Showcases – Digital Agenda for the Energy Transition) were able to apply market-based re-dispatching.

Other initiatives

In Austria market-based re-dispatching is under discussion and there are plans to implement non-firm connection agreements and non-firm/interruptible tariffs power. With these tariffs, DSO would request temporary load reduction in return for a reduced network tariff.

The introduction of market-based re-dispatching is under discussion in Belgium (only for the Flemish region) and Romania.

The Netherlands plans to allow non-firm connection agreements in 2023.

179 Regarding the Member States where DSOs do not use market-based re-dispatching, Table 21 shows whether the reasons are in line with the four exceptions allowed in the Clean Energy Package. It also shows whether these Member States have defined an iterative national reassessment process to review whether the exceptions from the use of market-based re-dispatching have become inapplicable.

180 Only around half of NRAs have shared the reason(s) for not using market-based re-dispatching for DSOs. All are in line with the exceptions foreseen in the Clean Energy Package, except for Slovakia. Most point out that DSOs do not use market-based re-dispatching because no market-based option (i.e., no local market) is available. Only four Member States performed a national assessment to set a non-market-based congestion management measure. Most Member States have not defined an iterative national reassessment process with a transparent decision-making process to review whether the exceptions from using market-based re-dispatching have become inapplicable.

Table 21: Reasons for establishing non-market-based congestion management at distribution level and implementation status of an iterative national reassessment process – 2022

		DSO congestion management measure per procurement method		Reason(s) for not using market-based re-dispatching	National assessment to set non-market-based congestion management	National reassessment process	Iterative national reassessment process
AT		BAU	BAU	N/A	N/A	No	No
BE	Walloon	BAU		A	2014	Yes	No
	Flemish	BAU		A	2021	No	No
	Brussels capital	BAU		A	N/A	Yes	Every 2 years
BG		BAU		N/A	N/A	No	No
CY		BAU		N/A	N/A	No	No
CZ		BAU		N/A	N/A	No	No
DE		BAU		D	N/A	No	No
DK		BAU		N/A	N/A	No	No
ES		BAU	BAU	C	2004	2022	No
GR		BAU		N/A	N/A	No	No
HU		BAU		A	2021	Yes	Every year
IE		BAU		N/A	N/A	No	No
LV		BAU		N/A	N/A	No	No
MT		BAU		C	N/A	No	No
NL		BAU	BAU	B	N/A	No	No
NO		BAU		C (A and D to some extent)	N/A	No	No
PL		BAU		A	N/A	No	No
PT		BAU		A	N/A	No	No
RO		BAU		N/A	N/A	No	No
SE		BAU	BAU	A	N/A	No	No
SI		BAU		N/A	N/A	No	No
SK		BAU		E	N/A	No	No

DSO congestion management measure per procurement method
- Market-based congestion management
- Non-market-based congestion management
- DSO(s) does not take any congestion management measure
- N/A

National reassessment process
- Reassessment defined
- No reassessment defined

Iterative national reassessment process
- Frequency of the reassessment defined
- No frequency of the reassessment defined

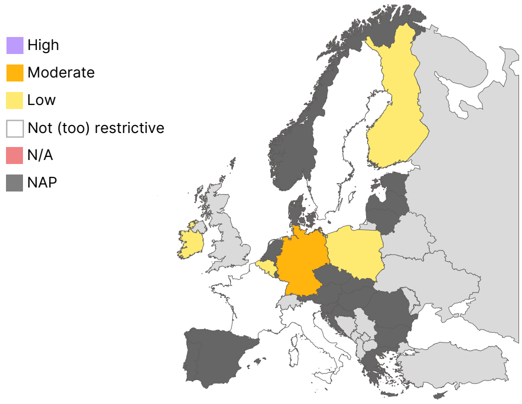
Reason(s)
- A) No market-based alternative is available
- B) All available market-based resources have been used
- C) The number of available power generating, energy storage or demand response facilities is too low to ensure effective competition
- D) The current grid situation leads to congestion in such a regular and predictable way that market-based re-dispatching would lead to regular strategic bidding which would increase the level of internal congestion
- E) Other

Source: ACER based on NRA data.
Notes: (1) In Slovenia there is no national reassessment process since market-based congestion management is currently the preferred option and a local market operated by the DSO is under development. A non-market-based approach is also expected to be available with the new tariff setting methodology starting on March 2024. (2) In the Netherlands, non-market re-dispatching is considered business-as-usual and an integral part of the market-based approach to congestion management, therefore they do not see a need to define an iterative national reassessment process.

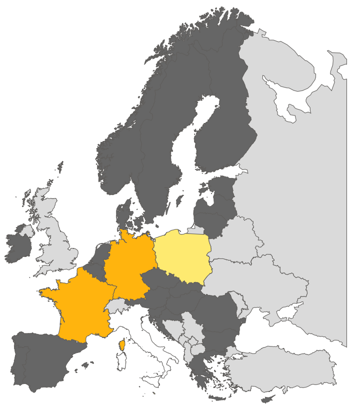
7. Restrictive requirements to participating in capacity mechanisms and interruptibility schemes

Most capacity mechanisms in operation in 2022 had some limiting requirements mainly in the product design. Overall, the requirements assessed are found more restrictive in some Member States than others. Actual participation of distributed energy resources in capacity mechanisms suggests there might be other requirements and design features, out of scope for this exercise, that explain the limited participation of distributed energy resources in some capacity mechanisms. The design of interruptibility schemes is targeted for industrial loads only. Most limiting requirements are in the French and German scheme, the latter being terminated in July 2022, although it may be renewed.

Figure 27: Restrictive requirements to participating in capacity mechanisms (top) and interruptibility schemes (bottom). Overview of the barrier (left) and underlying indicators (right) per Member State – 2022



Restrictions in the eligibility process							
DE	BE	FI	FR	IE	IT	PL	SE
Restrictions in the product design							
BE	DE	IE	FI	IT	PL	FR	SE
Restrictions in the allocation process							
DE	IE	SE	BE	FI	FR	IT	PL



Restrictions in the eligibility process			
FR	DE	IT	PL
Restrictions in the product design			
DE	FR	IT	PL
Restrictions in the allocation process			
FR	DE	PL	IT

Source: ACER.
Notes: (1) ACER was not able to calculate the barrier score for Bulgaria and Cyprus since half of the indicators were missing. (2) The barrier is not applicable in Member States without a capacity mechanism or an interruptibility scheme in operation in 2022. (3) For more information on the methodology for assessing the scores per barrier (left) and indicator (right), please refer to Annex I.

181 Comparing requirements between resource adequacy mechanisms can be challenging due to different designs used in each country. Nevertheless, this chapter aims to identify some requirements and design features of capacity mechanisms and interruptibility schemes in operation in 2022 that may restrict access to and participation of distributed energy resources. It also shows the capacity contracted from these resources in the last auctions.

7.1. Design features of capacity mechanisms discouraging participation of distributed energy resources

182 The Electricity Regulation[99] sets out that capacity mechanisms (i) must be based on a transparent, non-discriminatory, and competitive process, (ii) must provide incentives for capacity providers to be available at times of expected system stress, and (iii) must be open to the participation of all resources that can provide the required technical performance, including energy storage and demand-side management.

183 This section aims to assess to what extent some requirements for the eligibility of capacity providers, design features of the capacity products, and requirements in the capacity allocation process may hinder participation of distributed energy resources. It covers the eight capacity mechanisms that were operational in 2022, i.e., the strategic reserves in Finland, Germany, and Sweden[100] and the market-wide capacity mechanisms in Belgium, France, Ireland (IE-SEM), Italy, and Poland[101]. Table 22 presents the results of the analysis.

Table 22: Potential restrictive requirements for distributed energy resources in capacity mechanisms – 2022

		BE (MWCB)	DE (SR)	FI (SR)	FR (MWDCO)	IE-SEM (MWCB)	IT (MWCB)	PL (MWCB)	SE (SR)
Eligibility process	DSR is eligible	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
	Intermittent RES are eligible	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
	Storage other than hydro and pumped-hydro storage are eligible	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
	Units connected to all voltage levels are eligible	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes
	Minimum eligible capacity	1 MW	5 MW	1 MW	0.1 MW	10 MW	0 MW	2 MW (up to 50 MW)	5 MW
	Aggregation allowed to reach minimum eligible capacity	Generation and load	Only load	Generation and load	Generation and load	Generation and load	Generation and load	Generation and load	Generation and load
	Maximum CO_2 emission limits	Yes	No	Yes	Yes	Yes	Yes	Yes	No
Product design	Multi-year capacity contracts	Yes (3, 8 or 15 years)	Yes (2 years)	No (1 year)	Yes (7 years in long-term tenders; 1 up to 10 years for DSR tenders)	Yes (up to 10 years)	Yes (1 year by default for all technologies; only new generators may apply for 15-year capacity contracts, which are not available for DSR, RES and storage)	Yes (up to 17 years)	Yes (4 years)
	Multi-year capacity contracts with same provisions for DSR, intermittent RES, and storage as for thermal power plants	Yes	Yes	NAP	Yes	Yes	No (different availability requirements per technology)	Yes	No
	Time-limited availability period during the contract duration	No	No	No	Yes	No	Peak hours (only non-dispatchable resources)	Peak hours	Yes
	Share targeted for DSR in T-1 auctions	No	No	No	No (Specific DSR tender)	No	No	No	Yes
Allocation process	Minimum bid size	1 MW	5 MW	1 MW	0.1 MW	Up to five quantity-price blocks with no minimum quantity size	1 MW	0.001 MW	5 MW
	Minimum lead time between capacity contracting and capacity delivery	1 year (complementary to the main tender T-4)	1 year (complementary to the main tender T-2)	Only 1 year	1 year in DSR tender (Other tenders T-4, T-3, T-2, T+1, T+3)	1 year (complementary to tenders T-4, T-3, T-2)	1 year (complementary to the main tenders T-4, T-3, T-2)	1 year (complementary to the main tender T-5)	Only 1 year

More restrictive for some distributed energy resources   Less restrictive for some distributed energy resources

Source: ACER based on NRA data and Commission Decisions SA.48648 (BE), SA.45852 (DE), SA. 55604 (FI), SA.39621 (FR), SA.44465 (IE-SEM), SA.53821 (IT), and SA.46100 (PL).
Notes: (1) The categorisation of the schemes is based on the taxonomy of the European Commission's sector inquiry, available at: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A52016SC0385&qid=1659684217752. Abbreviations refer to market-wide central buyer (MWCB), strategic reserve (SR), and market-wide decentralised capacity obligations (MW-DCO). (2) The Swedish strategic reserve has not been approved by the European Commission under State Aid legislation. (3) In Belgium the default duration of a capacity contract is 1 year; however, some projects may ask for a longer contract duration (3, 8 or 15 years) if they exceed certain investment thresholds. (4) In France the duration of capacity contracts is 7 years for the capacities selected through the long-term tenders and from 1 year up to 10 years for demand-capacities selected through the annual tender for demand response. Multi-year contracts in the tenders for demand response were introduced in 2022.

99 Article 22 of the Electricity Regulation.

100 For completeness, the Swedish strategic reserve is included in the analysis although it is currently frozen. The last auction was held in 2019. Currently its reserve capacity consists of only a single oil-fired power plant.

101 For more information on the status, costs and technologies remunerated by these capacity mechanisms, please refer to ACER's 2023 report on Security of EU electricity supply.

184 In theory all capacity mechanisms are designed to be technology-neutral (i.e., all types of technologies are legally eligible to participate); however, some eligibility requirements exclude smaller units. For example, the German strategic reserve has a restriction regarding connection requirements: the units must be directly connected to the maximum voltage level of the transmission system and via not more than two voltage transformations. In practice, this condition restricts entry of distributed energy resources connected to lower voltage levels.

185 The minimum eligible capacity for participation, the minimum bid size and restrictions to aggregation can also constitute barriers in capacity mechanisms. In particular, the minimum capacity that must be offered in the auctions reaches the highest values in the Irish mechanism with 10 MW, followed by the German and Swedish strategic reserves with 5 MW. The German mechanism only allows for aggregation of demand response units in minimum bid groups of at least 1 MW. Energy storage and renewable units smaller than 5 MW cannot effectively participate. In the Polish mechanism, the minimum bid size is 1 kW; however, the minimum capacity required for participation is 2 MW.

186 The lack of CO_2 emissions limits may implicitly favour allocating capacity to conventional high-carbon power plants. All capacity mechanisms in operation in 2022 included CO_2 emissions limits in line with the Electricity Regulation[102] except for the German and Swedish strategic reserves[103]. In addition to the CO_2 emissions limits, Belgium and Poland have included auction winner selection rules that promote the procurement of low carbon capacity. In both mechanisms if bids with equal prices are submitted, the bid with the lowest CO_2 emissions is favoured. Additionally, the Belgian mechanism requires any thermal capacity awarded with long-term contracts to develop a plan to become carbon-neutral by 2050 with monitoring steps in 2035 and 2045. In the Polish mechanism, new low-carbon units may apply for an extension by two years of their capacity agreements[104].

187 The new Finnish strategic reserve introduced in 2022 is more inclusive of distributed energy resources than the former scheme with respect to the eligibility process: the new mechanism is open to energy storage, the minimum eligible capacity and the minimum bid size have been significantly lowered from 10 MW to 1 MW, and aggregation is now allowed for both generation and demand units.

188 Some product design features and requirements in the allocation process may also hinder participation of demand response, energy storage, and renewable energy sources as shown in Table 22. Even though long-term contracts could be suitable for some distributed energy resources by providing more certainty for the future, in general multi-year contracts may create a bias in favour of investing in conventional high-carbon technologies as stressed in ACER's 2023 report on Security of EU electricity supply[105]. All market-wide capacity mechanisms in operation in 2022 had multi-year capacity contracts, reaching periods of up to 17 years in Poland, 15 years in Belgium and Italy and 10 years in Ireland. However, the French and the Italian mechanisms have different durations for some distributed energy resources as follows: (i) in France, the demand response units selected through the specific tenders can have contracts ranging from 1 year up to 10 years since 2022; (ii) in Italy the duration is 1 year for all technologies, only new generation units may apply for 15 years capacity contracts. In the strategic reserves, capacity contracts reach 4 years in Sweden and 2 years in Germany. Only the Finnish strategic reserve has 1-year contracts. It should be noted that the Polish mechanism allows for multi-year capacity contracts in the main auction although contract duration differs based on the unit type: new generation units may apply for 5-year and 15-year contracts[106] while modernised generation units and demand response units are only eligible for 5-year contracts.

189 In principle capacity contracts should be set with the same provisions for all types of capacity providers to ensure a level-playing field. All capacity mechanisms in 2022 had the same conditions except those in Sweden and Italy.

102 Article 22(4) of the Electricity Regulation.

103 Germany is going to set CO_2 emissions limits in line with the Electricity Regulation in the auction taking place in December 2023. More information on the participation requirements for the procurement of capacity reserve for the bidding date of 1 December 2023 is available at: https://www.bundesnetzagentur.de/DE/Fachthemen/ElektrizitaetundGas/Versorgungssicherheit/KapRes/start.html.

104 The 5-year and 15-year capacity contracts can be extended by 2 years if the capacity providers meet a 450 kg CO_2/MWh emission performance standard and with regards to CHP units, at least 50% of the heat production is dedicated to district heating.

105 For more information, please refer to the Executive Summary and Section 4.1.3 of ACER's 2023 report on Security of EU electricity supply.

106 See footnote 103.

190 A limited availability period for the duration of the contract may facilitate participation of distributed energy resources that may struggle to be available and provide capacity over long periods. Only two capacity mechanisms have a limited availability period:

- In the French mechanism, the capacity availability obligation is limited to between 10 and 25 delivery days in November-December and January-March and 10 hours (from 7 a.m. to 3 p.m. and from 6 p.m. to 8 p.m.) per delivery day. The TSO notifies the specific delivery days in D-1 before 10:30 a.m.

- In Sweden the strategic reserve is only active during the winter period (i.e., between 16 November and 15 March); however, the reserve capacity must be available 95% of the time during this period.

191 Belgium, Finland, Germany, Ireland, Italy, and Poland do not have a time-limited availability period, i.e., capacity resources must remain available all year round. However, the Italian mechanism also has different availability requirements per technology: dispatchable resources must always be available except during maintenance periods, while non-dispatchable resources such as wind and solar must be available only during peak hours announced by the TSO in advance. Similarly, in the Polish mechanism capacity providers are obliged to remain ready to supply the contracted electricity power during the delivery period and to deliver the specified amount of power within the recall period, which could be announced by the TSO only at specific hours (between 7 a.m. and 10 p.m. on business days).

192 Long lead times between the conclusion of the capacity contract and the start of the delivery obligation for the successful bidders may also hinder participation of distributed energy resources, especially some demand response units that may not be able to commit for too long in advance of the delivery period[107]. All capacity mechanisms hold auctions one year before delivery although in Belgium, Germany, Ireland, Italy, and Poland these T-1 auctions are complementary to the main auctions with longer lead-times. It should be noted that the French and the Swedish mechanisms reserve some capacity targeted to demand response units. More specifically, France is the only Member State with specific T-1 auctions dedicated to demand response[108] while the Swedish strategic reserve is the only mechanism that reserves at least 25% of auctioned capacity for demand response units exclusively. However, the last auction was held in spring 2019 before the implementation of the Electricity Regulation and the current reserve capacity consists of a single oil-fired generation plant only.

193 Beyond the design features shown in Table 22, some Member States have relaxed some requirements of their capacity mechanisms thus facilitating participation of demand response or other distributed energy resources as follows:

- In France generation capacities can ask for a certification from four years before delivery up to three years before delivery for existing generation capacities or up to 2 months before delivery for planned generation capacity. The latter also applies to demand response units. This is convenient for aggregators of demand response units that might not have certainty over their portfolios some years in advance if they wish to participate in the T-4, T-3, and T-2 auctions.

- In Belgium the individual assets must be grouped into capacity market units (i.e., bid blocks) of at least 1 MW of de-rated capacity. Each capacity market unit can be comprised of a single or multiple delivery points. The mechanism allows prequalifying capacity market units for those assets that are not yet deployed or are in planning stages if associated with delivery points prior to the delivery period. In addition, the mechanism limits excessive profits with payback obligation if market prices exceed a strike price.

107 In practice, there is evidence that at least some demand response and energy storage units participate in some auctions with lead times longer than 1 year.

108 Once demand response capacities are selected through the T-1 auctions, they are allowed to participate in all regular auctions of the capacity mechanism. For more information, please refer to: https://competition-cases.ec.europa.eu/cases/SA.48490.

Capacity contracted of distributed energy resources in capacity mechanisms

194 Figure 28 shows the contracted capacity of demand response, intermittent RES, and energy storage (excluding hydro and pumped-hydro storage) for all capacity mechanisms in operation in 2022 as GW of de-rated capacity, and as a share of the total volume contracted. It should be noted that in Finland the results correspond to the previous strategic reserve that was in operation from 2007 to 2021[109].

Figure 28: Contracted capacity of demand response, intermittent RES, and energy storage in capacity mechanisms since 2019 per Member State (GW and %)

Source: ACER based on NRA data.
Notes: (1) The charts only show delivery years for which the main auctions of capacity mechanisms have already taken place. The charts therefore do not depict capacity with multi-year contracts that include delivery in years after the delivery year of the last main auction. (2) The share of demand response, intermittent RES, and storage (other than hydro and pumped-hydro storage) is calculated as the sum of capacity procured from these technologies for a delivery year over the total capacity procured for the same delivery year. The share may still change in Member States where some capacity is procured in additional auctions (for example, T-1 auctions are expected to take place in capacity mechanisms of Ireland and Poland). (3) In Belgium's market-wide capacity mechanism (approved in 2021) only one main auction has so far procured capacity (i.e., the auction held in 2021 for delivery in 2025/2026 that is shown as 2025 on the chart). The main auction held in 2022 for the delivery in 2026/2027 did not procure any capacity. (4) In Finland the results correspond to the previous strategic reserve that was in operation from 2007 to 2021. (5) In France the results correspond to the annual auctions dedicated to demand response that were approved in 2018 until 2023. In the long-term auctions, only conventional generation plants were awarded.

109 For more information on the characteristics of the previous strategic reserve in Finland, please refer to Table 7 of ACER's 2021 report on Security of EU electricity supply.

195 Overall, the participation of distributed energy resources remains limited compared to traditional thermal generation technologies although it has been steadily increasing over time in some capacity mechanisms (France, Ireland, Italy, and Poland). In the most recent auctions, the pace of growth has increased particularly for storage capacity.

196 Some conclusions can be drawn per Member State when assessing the capacity contracted (Figure 28) together with some requirements that may be more and less restrictive for distributed energy resources as explained above:

- In terms of total capacity contracted, the participation of distributed energy resources in the French mechanism stands out due to the unique annual auctions in Europe dedicated to demand response. It remains relatively stable (total capacity contracted ranged from 3.05 GW in 2020 to 3.1 GW in 2023) while the capacity contracted of intermittent RES and storage is increasing at a slow but steady pace.

- The German strategic reserve is at the other end of the spectrum with no participation of distributed flexibility resources. This may be explained by the lack of CO_2 emissions limits in the auctions up to delivery period of 2023/2024, by potentially restricting the participation of small units connected to lower voltage levels and by setting a minimum bid size of 5 MW as explained above. These design features strongly favour conventional power plants.

- Only 44 MW of demand-side units were contracted in the previous Finnish strategic reserve in the period of 2019-2022 since energy storage was not legally eligible and aggregation of units was not allowed to reach the 10 MW of minimum capacity to offer in the auctions. Since the eligibility process of the Finnish strategic reserve introduced in 2022 is more inclusive, it would be reasonable to expect greater participation of distributed energy resources; however, a single fossil-fuel power plant participated in the first auction for delivery in winter 2022/2023. In the end, this auction awarded no capacity.

- The Swedish strategic reserve only contracted demand-side capacity in the last auction held in spring 2019 where at least 25% of the auctioned capacity targeted demand response units. No auction has been arranged since then thus the current reserve capacity only consists of a single oil-fired generation plant.

- In Belgium demand response and storage capacity received just over 0.3 GW (or around 7.4%) of awarded capacity contracts in the first T-4 auction of the new capacity mechanism (it took place in 2021 for delivery in 2025/26)[110]. It is reasonable to expect greater participation of demand response units in the auction that will be held one year before delivery, much better suited for the characteristics of these technologies. The lack of participation of intermittent RES may be explained by the fact that the eligibility criteria do not allow resources to receive remuneration through other support schemes during the delivery period of the capacity mechanism (if subsidies end before the delivery year, participation is allowed).

- In the Italian mechanism, no demand-side capacity has been contracted so far. The auctions held in 2019 and 2022 resulted in limited capacity of intermittent renewable energy sources and storage units contracted. Some factors may explain the lack of attractiveness of the Italian mechanism as follows: (i) the UVAM project for the provision of ancillary services is more profitable and the participation in both programmes is not compatible; (ii) demand-side resources are remunerated based on their availability to reduce the load in specified critical hours and their participation is rewarded in the form of partial exemption from capacity mechanism fees[111] that customers should otherwise pay to the TSO in their electricity bills, instead of direct capacity payments which are only granted to generation technologies[112].

- Ireland and Poland show a rapidly increasing pace of capacity contracted from distributed energy resources: it has tripled in the Polish capacity mechanism from around 0.5 GW for delivery year of 2021 to more than 1.5 GW for delivery year of 2027 while it has almost doubled in the Irish capacity

110 A second auction was held in 2022 for delivery in 2026/2027 but it awarded no capacity. More information available at: https://www.elia.be/en/electricity-market-and-system/adequacy/capacity-remuneration-mechanism.

111 Partial exemption from the costs associated to the financing of the capacity mechanism.

112 ARERA (the Italian NRA) has assessed the implicit remuneration for demand response units and it considers that it is similar to the direct payment granted to generation technologies.

mechanism from 0.45 GW to almost 0.9 GW. The higher increase from the delivery year of 2025 could be partly explained by the exclusion of most polluting conventional generation units from the capacity mechanisms due to CO_2 emission restrictions set out in Article 22(4)(b) of the Electricity Regulation[113].

7.2. Interruptibility schemes only open to large industrial loads

197 Interruptibility schemes normally refer to national programmes dedicated to demand response, organised by TSOs for temporary load interruption or reduction. According to the European Commission's 2022 Guidelines on State aid for climate, environmental protection and energy 2022, interruptibility schemes aim to ensure a stable frequency in the electricity system or address short-term security of supply problems.

198 These schemes have traditionally contributed to the development of a certain level of demand response at earlier stages. They typically pool large industrial consumers from energy intensive industries with processes that can be suspended for a limited amount of time. As a result, some design features may hinder the participation of smaller demand-side capacity.

199 As shown in ACER's 2023 report on Security of EU electricity supply, only four interruptibility schemes were operational in 2022 in Germany, France, Italy, and Poland. The German scheme was terminated in July 2022 although it could be potentially renewed. Table 23 shows some requirements and features of interruptibility schemes that may become restrictive for the participation of smaller loads.

Table 23: Potential restrictive requirements for smaller loads in interruptibility schemes – 2022

		DE	FR	IT	PL
Eligibility process	All loads/sectors eligible to participate	No	Yes	Yes	N/A
	Units connected to all voltage levels eligible	No	No	Yes	Yes
	Minimum eligible capacity	5 MW	25 MW	0 MW	1 MW (up to 10 MW)
	Aggregation of individual loads allowed	Yes	No	Yes	Yes
Product design	Multi-year capacity agreements	No	No	Yes	Yes
	Time-limited delivery period during the contract period	No	Yes	No	No
Allocation process	Minimum bid size	5 MW	25 MW	1 MW	1 MW (up to 10 MW)
	Minimum lead time between capacity contracting and capacity delivery	≤ 1 year	≤ 1 year	≤ 1 year	> 3 years

More restrictive for smaller loads | Less restrictive for smaller loads | N/A

Source: ACER based on NRA data.
Notes: (1) The French interruptibility scheme has never been approved by the European Commission under State Aid regulation. (2) The German interruptibility scheme called "AbLaV" was terminated in July 2022 although a renewal is under consideration.

200 The German interruptible scheme "AbLaV" was specifically designed for industrial loads. Even though aggregation of individual loads was allowed, it did not allow the participation of units connected to the low voltage level (similarly as in their strategic reserve) and it required a minimum eligible capacity for participation of 5 MW. The interruptibility scheme in France is only open to capacity units connected to the transmission network that are above 25 MW, with no possibility of aggregation. Nevertheless, in 2023 the minimum eligible capacity and the minimum bid size are expected to be reduced to up to 10 MW and as required by CRE, the French TSO and DSOs are carrying out a study to define the conditions to open the scheme to loads connected to the distribution network and aggregated resources in 2024.

201 On the contrary, the Italian and Polish interruptible schemes are open to small assets and aggregators although assets contracted in the capacity market in Poland are excluded from the participation in the interruptibility scheme.

113 From 1 July 2025 at the latest, generation capacity that started commercial production before 4 July 2019 and that emits more than 550 g of CO_2 of fossil fuel origin per kWh of electricity and more than 350 kg of CO_2 of fossil fuel origin on average per year per installed kWe shall not be committed or receive payments or commitments for future payments under a capacity mechanism.

202 The lack of multi-year capacity agreements in the German and French schemes may also make them less appealing for some types of loads. A minimum lead-time of more than 3 years between the capacity contracting and the capacity delivery in the Polish scheme may also become restrictive for some loads that may not be able to commit so long in advance of the delivery period.

Box 6: New ancillary service-related schemes targeted to demand response: are they limited to industrial loads like most interruptibility schemes or are they also open to smaller loads?
Case study: Active Demand-Side-Response Service "SRAD" in Spain

In the last years Member States have gradually phased out interruptibility schemes. Some TSOs have started to introduce demand response schemes to provide balancing services or to ensure resource adequacy. Such schemes can be found in Poland, Portugal, and Spain. Germany may also replace its interruptibility scheme "AbLaV" with "SeaL", an ancillary service for instantaneous load reduction.

It is ACER's view that the development of such schemes may hold early lessons in terms of auction design and participation criteria relevant for efficient delivery of the services sought to be delivered.

Spain's approval of the so-called SRAD (Servicio de Respuesta Activa de la Demanda or Active Demand-Side-Response Service) in September 2022 as an extraordinary measure is a case in point. It anticipated potential frequency deviations in a context of supply stresses arising from the energy crisis and drought events that could reduce hydroelectric capacity. As explained below, its initial design had some constraints although it is expected to include some improvements after one year in operation based on lessons learnt.

More specifically, SRAD was projected as a specific balancing product to ensure continuity of supply in exceptional situations when there is a lack of balancing energy that can be activated from mFRR or RR. It targets demand response capacity which is obliged to provide balancing services in pre-defined periods in around 30% of the hours of the year. More specifically, bidders awarded must reduce their demand after a request, with at least a 15-minute notice for a maximum period of 3 hours per day.

A single auction took place to cover the period from 1 November 2022 until 31 October 2023. Out of the 2,700 MW initially required by the Spanish TSO, only 699 MW were offered by sixteen service providers and 497 MW were eventually contracted. The auction set an availability payment of 69.97 EUR/MWh (almost 190,000 EUR/MW) and an activation payment that is calculated based on the mFRR or RR price for the hour when the service is requested.

The large discrepancy between the required and contracted capacity may be explained by some constraints in the design of this scheme as follows:

- The minimum bid size was 1 MW. Aggregation was allowed but each delivery point within the reserve providing group was required to have a minimum capacity of 1 MW, which excluded from participation to residential consumers and most commercial consumers. The contracted capacity was exclusively for industrial loads.

- Independent aggregators were not allowed to participate since Spain has not defined their roles and responsibilities yet and they are not legally recognised as eligible parties to participate in any electricity market. Thus, the BSP of each consumer participating in the auction was required to be its supplier. This could be seen as a restriction to both the BSP-supplier and the load unit-consumer. The BSP cannot participate with any load unit unless it first becomes its supplier. The consumer would be obliged to directly participate in the scheme if its supplier is not willing to act as its BSP.

- Switching or adding consumers within a reserve providing group was not allowed. Consequently, after being awarded, a consumer aggregated under a reserve providing group would not be able to switch its supplier. This may restrict the right of consumers to freely choose their suppliers. Moreover, if the consumer terminates the contract with its supplier (i.e., its BSP-aggregator in SRAD) for any reason, the aggregator is not allowed to add another replacing consumer. As a result, the "lost load" must be covered by the remaining consumers of the reserve providing group. This leads to a higher risk for these consumers to be penalised and potentially disqualified in case of non-delivery.

- The load units participating in SRAD are not allowed to provide other balancing services.
- SRAD was projected as a specific balancing product although its approval procedure was not in line with the Electricity Balancing Regulation.

During the delivery period from November 2022 to October 2023, the TSO activated SRAD once in September 2023 (497 MW; 1,424.7 MWh; 133.19 EUR/MWh).

The Spanish TSO and NRA launched a public consultation in April and July 2023 respectively, aiming to improve the design of SRAD. In October 2023 CNMC (the Spanish NRA) published the design of the new mechanism with some improvements, such as allowing switching of suppliers for consumers joining SRAD, adding new criteria to improve competition in future tenders, increasing transparency in tenders and activations, and optimising processes as well as information exchange. On 4 December 2023, the Spanish TSO held a second auction to cover the period from 1 January until 31 December 2024. Out of the 1,812 MW initially required, only 953 MW were offered by nineteen service providers and 609 MW were eventually contracted. The auction set an availability payment of 40.82 EUR/MWh.

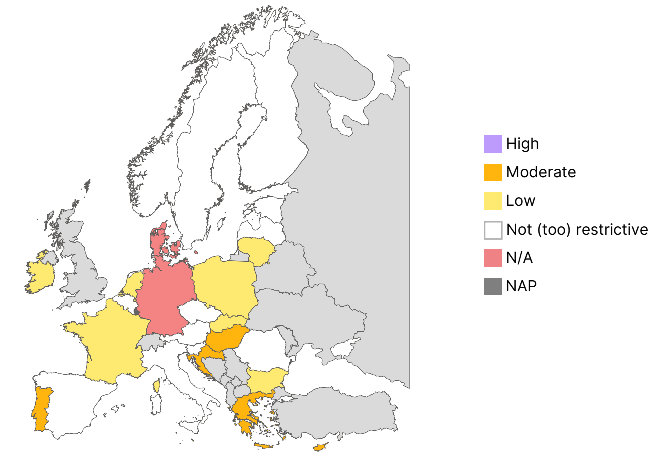
When introducing new ancillary service-related schemes targeted to demand response is justified, ACER recommends Member States to carefully review their requirements and design features to ensure they do not restrict participation of smaller interruptible loads or new actors capable of fulfilling the required technical performance. ACER also reminds Member States to follow the approval procedures envisaged by the EU legislation.

Notes:
SRAD was approved in the Royal Decree-Law 17/2022, available at: https://www.boe.es/buscar/act.php?id=BOE-A-2022-15354.
Information prior to the first auction of SRAD, available at: https://api.esios.ree.es/documents/669/download?locale=es.
CNMC Decision on the new operating procedure of SRAD, available at: https://www.boe.es/eli/es/res/2023/10/19/(5).
Information prior to the second auction of SRAD, available at: https://api.esios.ree.es/documents/1344/download?locale=es.
Results of the second auction of SRAD, available at: https://api.esios.ree.es/documents/1538/download?locale=es.

8. Limited competitive pressure in the retail market

There is still room to improve competitive pressure in multiple retail markets due to high market concentration levels. Some Member States also show a low entry/exit activity although that is partly explained by the energy crisis.

Figure 29: Limited competitive pressure in the retail market. Overview of the barrier (top) and underlying indicators (bottom) per Member State – 2022



High Herfindahl-Hirschman Index in the household market

CY	HR	MT	LT	LU	EE	FR	GR	HU	PT	AT	BE	BG	CZ	ES	FI	IE	IT	NL	NO	PL	RO	SE	SI	SL	DE	DK	LV

High market share of the three largest suppliers in the retail market by volume

CY	HR	LT	LU	LV	MT	BE	FR	GR	IE	PT	EE	ES	HU	NL	PL	SK	AT	BG	FI	IT	NO	RO	SE	SI	CZ	DE	DK

Low number of suppliers for households with market shares higher than 5%

BG	CY	EE	ES	FR	GR	HR	HU	IT	LT	LU	MT	PT	CZ	IE	NO	PL	RO	SE	SK	AT	BE	FI	NL	SI	DE	DK	LV

Low entry/exit activity in the retail market

FR	GR	MT	SE	BE	FI	HU	IE	NL	PL	PT	RO	AT	DE	HR	CY	CZ	DK	EE	ES	IT	LT	LU	LV	NO	SI	SK	BG

Low correlation coeficient between the energy component of retail prices for households and the wholesale prices

HU	PT	BG	AT	BE	CZ	DE	DK	EE	ES	FI	FR	GR	HR	IE	IT	LT	LU	LV	NL	NO	PL	RO	SE	SI	SK	CY	MT

Source: ACER.
Notes: (1) ACER was not able to calculate the barrier score for Germany and Denmark since half of the indicators were missing. (2) The number of suppliers for households with market shares higher than 5% is a complementary indicator to the Herfindahl-Hirschman Index and the market share of the three largest suppliers in the retail market. It contains information on the tail of the distribution of suppliers and aims to identify a potential limitation of competition although it must be read carefully since it does not provide information on the amount of suppliers with a low market share. (3) For more information on the methodology for assessing the scores per barrier (top) and indicator (bottom), please refer to Annex I.

203 The ease with which a new entrant (e.g., an independent aggregator or a new market player with experience in other markets) can enter the electricity market is highly dependent on a well-functioning and effective competition in the retail market. With a low competitive pressure, incumbents may hold a dominant position that may limit new entrants' ability to compete on a level playing field and to offer innovative and flexibility products allowing end users benefit from potential costs savings.

204 This chapter assesses how competitive pressure in some retail markets may be lower because of a combination of factors, including (i) a relatively high market concentration, (ii) a low entry-exit activity of suppliers and (iii) a low correlation between the energy component of retail prices and wholesale prices, which may hinder market entry for new entrants.

205 The Herfindahl-Hirschman Index (HHI) is a commonly used indicator to measure the degree of market concentration. A HHI above 2,000 is a sign of a highly concentrated market. In general, a high number of suppliers and low market concentration are indicators of a competitive market structure. With low market concentration (i.e., a lower HHI score), the ability of any market player to exploit market power to the detriment of energy consumers is reduced and consumers can benefit from competition and innovative services offered by some new entrants, such as explicit demand response. Thus, a higher HHI indicates a high entry barrier, and that more competition is possible in the market. Since the HHI merely points out the structural dominance of the market, it is complemented with other metrics to assess market concentration. Concentration ratio 3 (CR3) is a traditional structural measure of market concentration based on market shares. In this report, we measure the total market share of the three largest suppliers per Member State by volume in the whole retail market[114]. Markets with a CR3 between 70 and 100% are considered highly concentrated, ranging from oligopolies to monopolies. It is important to note that smaller Member States may have a relatively small market, with limited suppliers and hence high CR3 levels. Finally, a low number of suppliers with market shares higher than 5% by metering points may also indicate high concentration levels in the retail market.

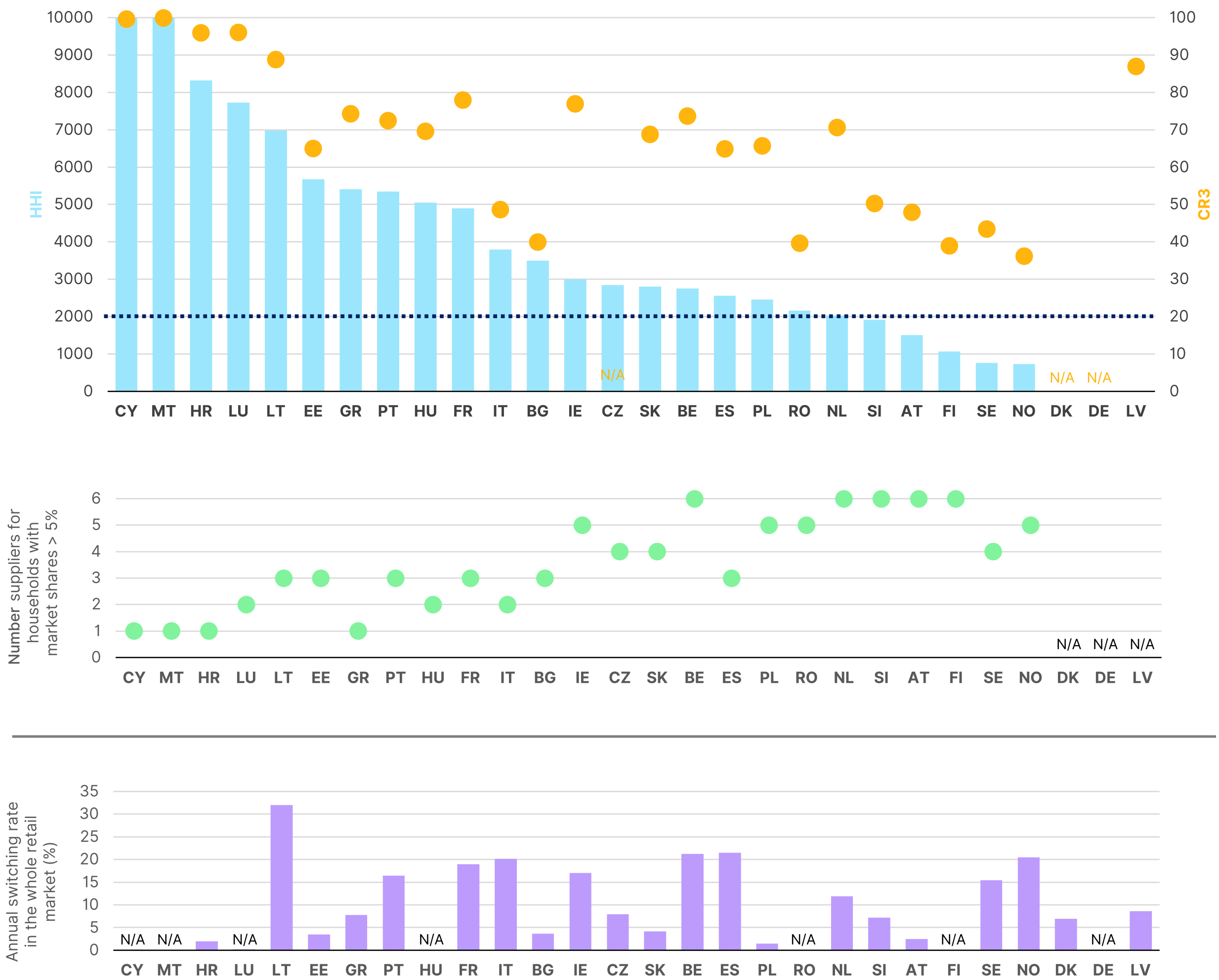
206 Figure 30 shows these three market concentration metrics per Member State in 2022. Twenty Member States reported high HHI levels in 2022 (HHI>2000). The Member States with HHI higher than 7000 (Cyprus, Malta, Croatia, and Luxembourg) also recorded the highest CR3 ratios and a very limited number of suppliers with market shares higher than 5%. These high concentration levels can be justified in all Member States due to their small size, except for Croatia. In HHI ranging from 5000 to 7000, there are some Member States with big retail markets in terms of number of metering points but still high concentration levels: Lithuania, Greece, Portugal, Hungary, and France.

207 Figure 30 also shows the switching rate in the whole retail market per Member State in 2022. Switching rates vary significantly among Member States. Remarkably, some of the Member States with lower switching rates also have retail markets highly concentrated (e.g., Croatia, Estonia, Greece, and Bulgaria). Low switching rates represent a poor appetite by customers to change to better energy offers and to offer their flexibility to the electricity markets. This can represent a barrier for suppliers to offer demand response services and an entry barrier for new business models to enter the electricity market[115].

114 Annex of ACER's 2023 Market Monitoring Report on Energy Retail and Consumer Protection shows concentration ratio 3 based on the total number of metering points.

115 For more information on switching rates, please refer to Chapter 6 of ACER's 2023 Market Monitoring Report on Energy Retail and Consumer Protection.

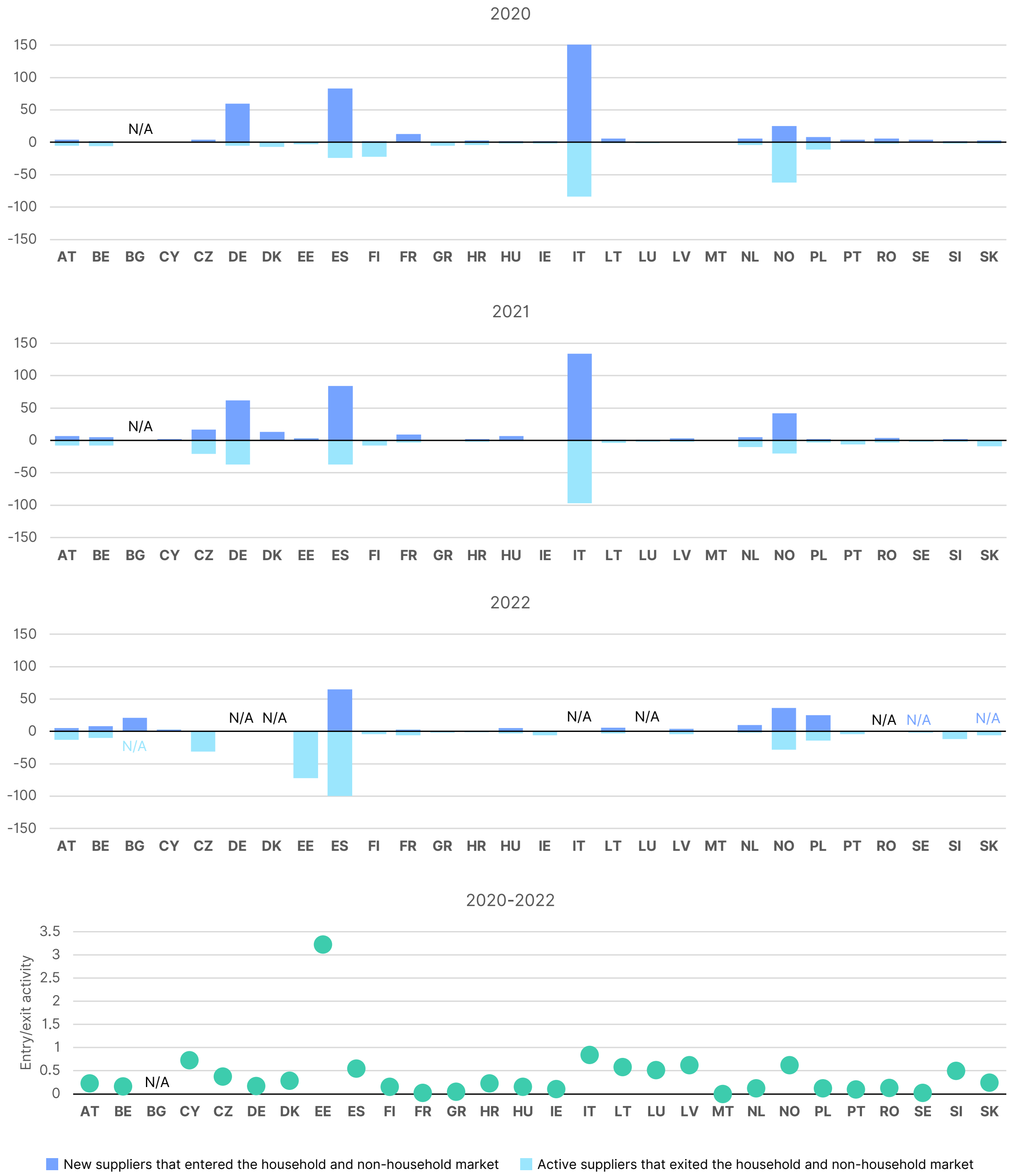
Figure 30: Market concentration metrics in comparison with the annual switching rate in the whole retail market per Member State – 2022



Source: ACER based on CEER data.
Notes: (1) The figure shows the HHI in the household market and market share of the three largest suppliers in the retail market per volume (top), the number of suppliers for households with market shares higher than 5% by metering points (middle) and the annual switching rate in the whole retail market (bottom) per Member State in 2022. (2) No information for Denmark and Germany. No information on HHI and the number of suppliers with market shares higher than 5% for Latvia. No information on CR3 for the Czech Republic.

208 While market concentration metrics are structural indicators, the entry/exit activity in the retail market helps us understand whether it is static or dynamic. A static retail market (i.e., low entry/exit activity) can indicate a lower ability for new entrants to access the market and compete with existing suppliers. For example, in a static retail market, independent aggregators may face more difficulties to start their business and offer innovative solutions to customers. Figure 31 shows the number of suppliers that entered and exited the retail market in 2020-2022 as well as the entry/exit activity calculated as the average number of entries and exits over the period of 2020-2022 normalised with the national electricity demand.

Figure 31: Number of suppliers that entered and exited the retail market and average entry/exit activity per Member State – 2020-2022



Source: ACER based on CEER data.
Note: (1) It is not possible to calculate the average entry/exit activity for Bulgaria due to lack of data. The average entry/exit activity for Germany, Denmark, Italy, Luxembourg, and Romania is only calculated for the period of 2020-2021 due to lack of 2022 data.

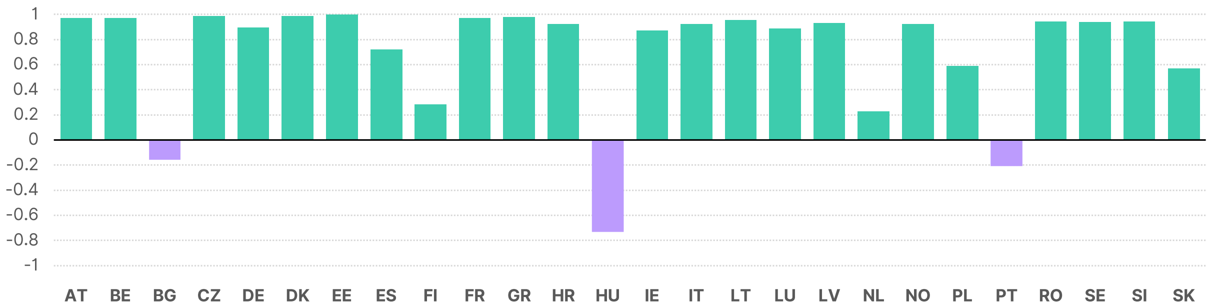
209 The number of suppliers entering and exiting the retail market varies greatly across the Member States. In Italy, Spain, Germany, and Norway the number of suppliers entering and exiting was relatively high in the period of 2020-2022 compared to other Member States. The German retail market is not highly dynamic when comparing entry/exit activity with the national demand.

210 The more static retail markets with a lower average entry/exit activity are found in Malta, Sweden, France, Greece, Portugal, Ireland, the Netherlands, Poland, and Romania.

211 It is important to note that the energy crisis created a higher risk environment which increased the number of suppliers exiting the retail energy market in 2021 and 2022 (from 254 exits in EU28 in 2020 to 286 and 323 exits in 2021 and 2022 respectively) and slowed down the entry activity in 2022 (from 405 in 2021 to only 191 in 2022)[116].

212 Another indication of the level of competition in retail markets is the correlation between the energy component in retail prices and the wholesale prices[117]. A stronger correlation can usually be expected in markets characterised by a more robust competition. However, the opposite is not always true since a high correlation may also be the result of price intervention linking the retail prices to the wholesale prices by law. Most Member States show a high correlation over the period of 2013-2022 except for Bulgaria, Hungary, and Portugal (Figure 32). In 2022 negative mark-ups were more common across the EU, as shown in ACER's 2023 Market Monitoring Report on Energy Retail and Consumer Protection. They were not unexpected given the significant increase in wholesale electricity prices combined with the hedging strategies of suppliers which will have shielded energy consumers to some extent. Also, the support measures implemented by some Member States that have, in many cases, bridged the difference between the wholesale and retail prices, helped both consumers and energy suppliers, while possibly leading to negative mark-ups[118].

Figure 32: Correlation coefficient between the energy component of retail prices and the wholesale prices for household customers – 2013-2022



Source: ACER calculation based on Eurostat (July 2023), NRAs, European power exchanges data, Eurostat Comext, and ICIS Heren.

116 For more information on suppliers exits due to financial issues, please refer to Chapter 5 of ACER's 2023 Market Monitoring Report on Energy Retail and Consumer Protection.

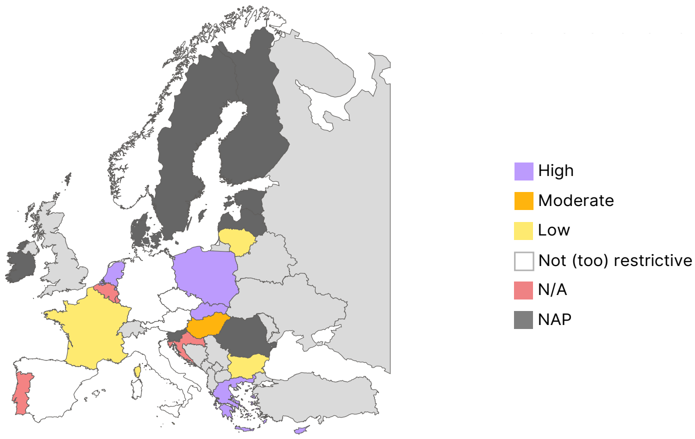
117 This correlation is calculated for the period of 2013-2022 based on Eurostat data and ACER database on retail offers and other relevant data. The methodology is further described in Annex 6 of the ACER's 2015 Market Monitoring Report.

118 For more information on the mark-ups per Member State, please refer to Annex 7.7 of ACER's 2023 Market Monitoring Report on Energy Retail and Consumer Protection.

9. Retail price interventions

Overall, price interventions apply to a wide spread of consumers. In most Member States they are not targeted to vulnerable consumers; however, when targeted, they also apply to a huge segment of consumers who are not deemed vulnerable.

Figure 33: Retail price interventions. Overview of the barrier (top) and underlying indicators (bottom) per Member State – 2022



MEMBER STATES WITH PUBLIC INTERVENTIONS IN THE PRICE SETTING FOR HOUSEHOLDS												
BG	CY	ES	FR	GR	HU	IT	LT	MT	NL	PL	PT	SK

High share of household consumers benefiting from public intervention(s) in the price setting															
BG	CY	GR	HU	MT	NL	PL	SK	FR	LT	ES	IT	BE	HR	LU	PT

High share of non-vulnerable consumers benefiting from public intervention(s) in the price setting															
ES	GR	HU	NL	FR	BE	BG	CY	HR	IT	LT	LU	MT	PL	PT	SK

MEMBER STATES WITH PUBLIC INTERVENTIONS IN THE PRICE SETTING FOR NON-HOUSEHOLDS							
CY	FR	GR	HU	LT	MT	NL	PT

High share of consumption of non-household consumers benefiting from public intervention(s) in the price setting																	
CY	GR	MT	NL	FR	HU	AT	BE	CZ	DE	HR	IT	LT	LU	NL	PL	PT	SK

Source: ACER.
Notes: (1) This overview only refers to retail price interventions implemented as a business-as-usual approach, excluding those introduced as emergency measures in response to the energy crisis. (2) ACER was not able to calculate the barrier score for Bulgaria, Croatia, Luxembourg, and Portugal since half of the indicators were missing. (3) The barrier is shown as NAP (not applicable) for Member States that confirmed not to have public price information for both households and non-households. (4) For more information on the methodology for assessing the scores per barrier (top) and indicator (bottom), please refer to Annex I.

213 This chapter aims to assess the level of penetration of retail price interventions applied by Member States in 2022, excluding those introduced in response to the energy crisis. More specifically, it seeks to identify if the size of the regulated customer segment is too large, reaching a high share of consumers that are not deemed vulnerable, since this may limit the amount of consumers that may receive incentives to provide demand response.

214 The Electricity Directive[119] states that Member States shall ensure the protection of energy poor and vulnerable household customers by social policy or by means other than public interventions in the price setting[120] for the supply of electricity. Nevertheless, such public interventions may be applied if limited in time and proportionate with regards to their beneficiaries, among other compliance criteria. In

119 Article 5 of the Electricity Directive.

120 Public price intervention means that at least the price of the energy component of the energy customer's bill is subject to regulation or controlled/ intervened by a public authority like a government, NRA, etc.

addition, Member States may apply public interventions in the price setting to household customers and to microenterprises during a transition period to establish effective competition for electricity supply contracts between suppliers, and to achieve fully effective market-based retail pricing of electricity. Nevertheless, such public interventions must be set at a price that is above cost and at a level where effective price competition can occur and must minimise the negative impact on the wholesale electricity market, among other compliance criteria.

215 In October 2022, in response to the high energy prices because of the aftermath of the restrictions of COVID-19 pandemic and greatly encouraged by Russia's invasion of Ukraine, the Council of the European Union adopted Council Regulation 1854/2022[121] which established an emergency intervention to mitigate the effects of high energy prices through exceptional, targeted and time-limited measures. This regulation expanded the scope of the public price interventions allowing Member States to temporarily extend public intervention in price setting for the supply of electricity to small and medium-sized enterprises (SME) under specific conditions (Article 12)[122] and to set retail electricity prices below cost temporarily and exceptionally for both households and SMEs (Article 13)[123]. These temporary interventions are allowed until 31 December 2023.

216 In a context of unusual high energy prices, policymakers certainly face a tough dilemma: on one the one hand, how to protect end users from undesirable economic consequences while on the other hand, how to preserve the role and benefits of the price signals to promote demand response. Public interventions in retail prices may have significant downsides for demand response, energy efficiency and competition in retail markets. Public price interventions may create a legal framework that systematically eliminates price signals from the functioning of the market, thus discouraging the provision of explicit demand response and hindering competition in retail markets. This is particularly true when price interventions consisting of regulated prices are set below costs (i.e., without taking into consideration wholesale market prices and/or other supply costs). Nevertheless, artificially low regulated prices (even without pushing them below costs but with a very squeezed margin) also limit market entry and innovation, prompt consumers to disengage from the switching process or providing demand response and consequently hinder competition in retail markets. In addition, they may increase investor uncertainty and impact the long-term security of supply. Other price interventions, including regulated prices set above costs, can act as a pricing focal point which competing suppliers are able to cluster around and – at least in markets featuring strong consumer inertia – can also considerably dilute competition. Hence, in general, the larger the size of the regulated customer segment, the stronger the impact on competition in retail markets and the less consumers receive incentives to provide demand response.

217 In 2022 at least thirteen Member States had some kind of public intervention in the price setting that predated the energy crisis for either household, non-household consumers or both (left map in Figure 34). At least seventeen Member States also introduced different types of temporary public price interventions in response to the energy crisis, such as price caps, frozen electricity prices or reimbursements and discounts[124] (right map in Figure 34). Most Member States intend to abolish these measures but there could be extensions beyond the end of 2023 in at least four Member States. Such extensions may have potential downsides in the promotion of demand response if not carefully assessed.

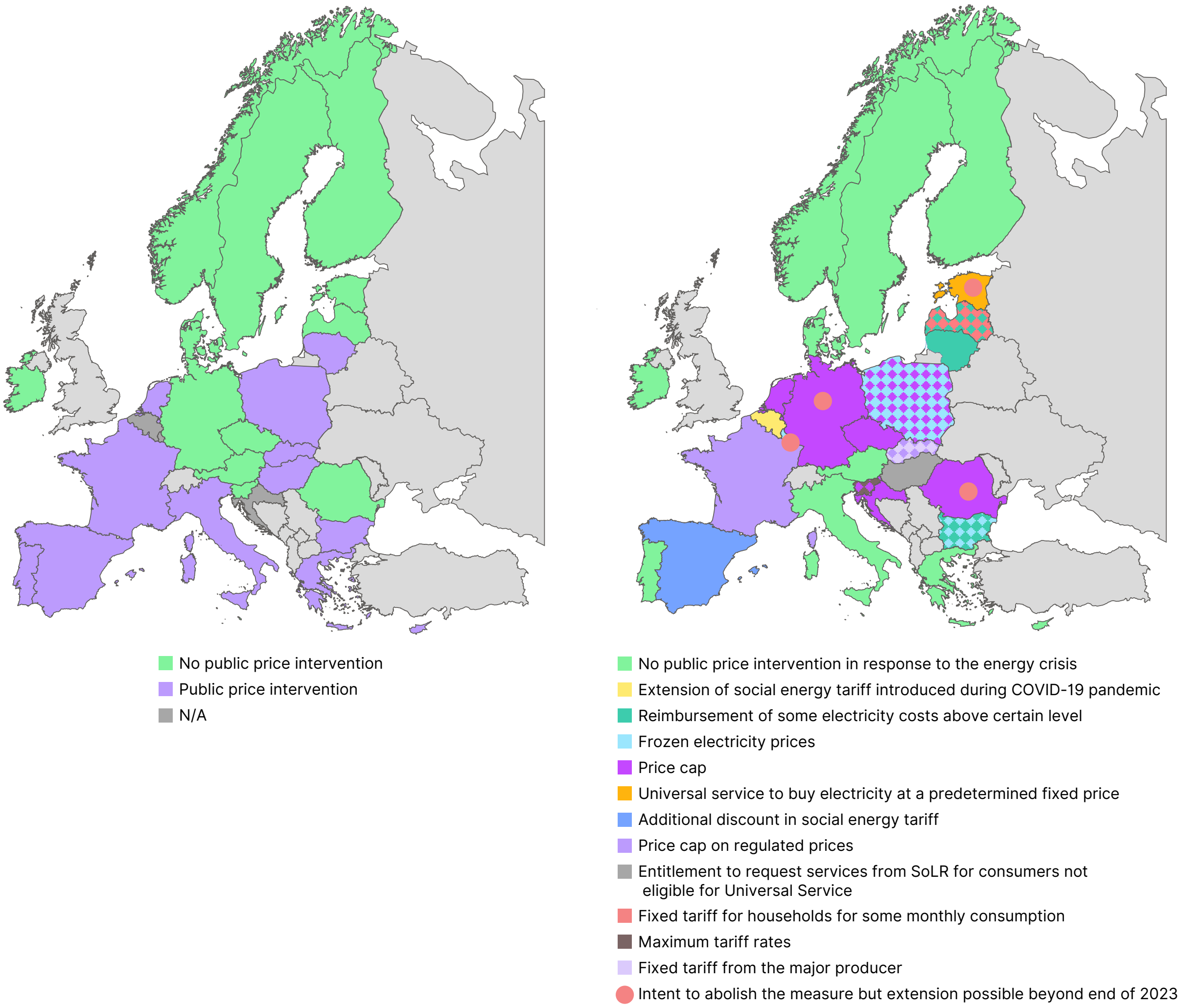
121 Council Regulation (EU) 2022/1854 of 6 October 2022 on an emergency intervention to address high energy prices.

122 This temporary extension to small and medium-sized enterprises is limited to 80% of the beneficiary's highest annual consumption over the last 5 years.

123 To set electricity prices below cost temporarily and exceptionally, the measure must cover a limited amount of consumption, there cannot be any discrimination between suppliers, suppliers must be compensated for supplying below cost and all suppliers must be eligible to provide offers at the regulated price on the same basis.

124 For more information about the types of public price interventions in response to the energy crisis in each Member State, please refer to Section 3.2.5 of ACER's 2023 Market Monitoring Report on Energy Retail and Consumer Protection.

Figure 34: Public price interventions (left) and temporary public price interventions in response to the energy crisis (right) per Member State – 2022



Source: ACER based on NRA data and ACER Dashboard on emergency measures implemented by the European Member States and Norway in 2022 in response to the energy crisis.
Note: (1) No data on public price interventions (left) for Belgium, Croatia, Luxembourg, and Portugal.

218 Figure 35 shows the level of penetration of the public price interventions that predated the energy crisis in the thirteen Member States in 2022 (left map in Figure 34). As shown, price interventions are widespread which may eliminate price signals from the market, thus discouraging the provision of demand response.

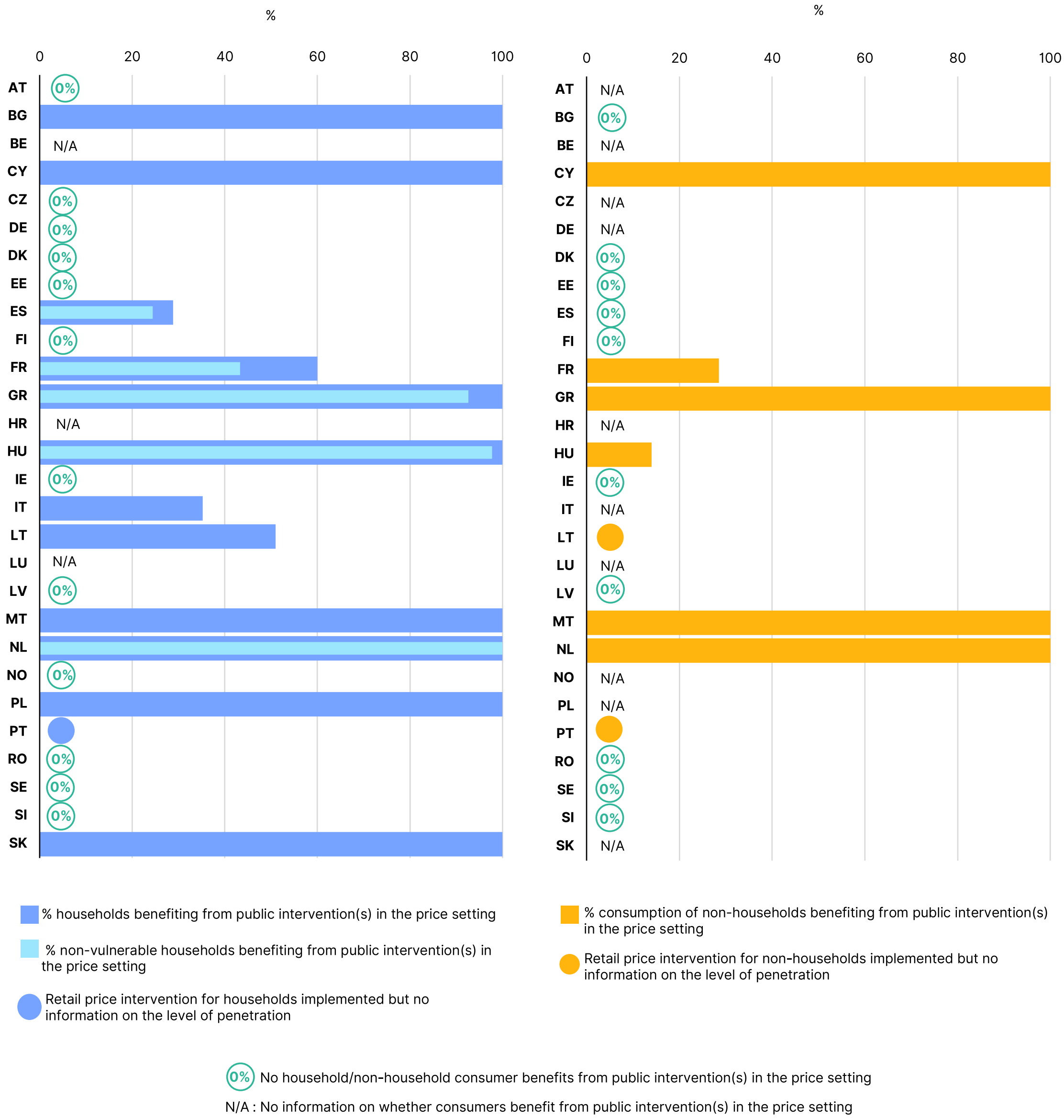
219 In the household market, all Member States had some type of public price intervention consisting of regulated prices, except for the Netherlands. In some cases, they consisted of fixed regulated prices[125].

- The level of penetration of public price interventions is very broad: most Member States implement price interventions to 100% of their households, except for Spain, France, Italy, and Lithuania.
- Price interventions targeted vulnerable consumers in only four Member States (Spain, France, Greece, and Hungary). However, in practice the main beneficiaries of price interventions in all Member States are households who are not deemed vulnerable consumers.

220 In the non-household market, at least eight Member States had some kind of price intervention implemented in 2022, always consisting of regulated prices, except for the Netherlands. Similar to households, most Member States implement price interventions to 100% of their non-households, except for France (small businesses representing 28.5% of non-households) and Hungary (microenterprises representing 14%).

125 For additional information about the types of price interventions in each Member States, please refer to Section 3.2.5 of ACER's 2023 Market Monitoring Report on Energy Retail and Consumer Protection.

Figure 35: Share of households and households not deemed vulnerable consumers with public interventions in their price setting (left) and share of non-households with public interventions in their price setting (right) – 2022



Source: ACER based on CEER data.
Note: (1) The figure represents the level of penetration of the public price interventions predating the energy crisis, i.e., excluding temporary interventions introduced by some Member States in response to the energy crisis.

221 As mentioned above, the Electricity Directive requires public interventions be set at a price above cost. NRAs reported that their price interventions are in line with this requirement except for Hungary.

222 Even though there are plans to phase out price intervention in Italy (2024), Portugal (only to remove the transitional tariffs applicable to household consumers from 2025), and Lithuania (2026) there is no concrete intention to remove price regulation in the other Member States[126].

126 It should be noted that the provisions of Article 5 of the Electricity Directive are not fully applicable to Malta due to its derogation from Article 4.

10. Frequent barriers in the electricity sector also impacting demand response and other new entrants and small actors

223 This chapter briefly explains how some relevant barriers to market integration and additional regulatory obstacles may negatively impact the entry and participation of distributed energy resources and other new actors in electricity wholesale markets and SO services.

Insufficient cross-zonal transmission capacity

224 Insufficient cross-zonal transmission capacity is one of the main barriers to the integration of electricity markets in the EU. A larger amount of cross-zonal capacity available for trade increases cross-border competition, allows for closer integration of renewable energy sources and other new entrants and provides a key source of flexibility to the market.

225 According to the Electricity Regulation[127], TSOs may not limit interconnection capacity to solve congestion or manage flows resulting from transactions inside their own bidding zone. This ensures the non-discrimination of cross-zonal trades over domestic ones, and it is a cornerstone of the EU electricity internal market. TSOs are considered compliant with this provision as long as they make available for cross-zonal trade at least 70% of the physical capacity respecting operational security limits.

226 As illustrated in ACER's 2023 Market Monitoring Report on cross-zonal capacities and the 70% margin available for cross-zonal trade (MACZT), the progress in the implementation of such requirement is not straightforward. The EU as a whole is currently not there yet, mainly due to the existence of derogations to the requirements and multi-year action plans for their achievement in several Member States. In addition, reductions of capacity below the minimum requirements happen often, and can have a significant impact to efficient price formation.

Bidding zones not reflecting structural congestions

227 A bidding zone is the largest geographical area within which market participants can exchange energy without capacity allocation. Currently, bidding zones in Europe are mostly defined by national borders. However, the existing European electricity target model requires defining bidding zones based on network congestions. This hinders the efficient operation and planning of the EU electricity network and the provision of effective price signals for generation, demand response, and transmission infrastructure.

228 The Electricity Regulation[128] stipulates that the configuration of bidding zones in the EU must be designed in such a way as to maximise economic efficiency and to maximise cross-zonal trading opportunities, while maintaining security of supply. To ensure a configuration of bidding zones in line with the above principles, a bidding zone review is to be carried out, with the aim to identify all structural congestions and include an analysis of different bidding zone configurations. Better defined bidding zone configurations can bring several benefits, including increased opportunities for cross-zonal trade, more efficient network investments and cost-efficient integration of new technologies.

229 A pan-European bidding zone review is currently ongoing, triggered by Article 14(5) of the Electricity Regulation. With ACER Decision No 11/2022 on the alternative bidding zones configurations, based on the assessment of the amount of loop and internal flows and the level of price dispersion throughout the EU, ACER proposed to study alternative bidding zone configurations for five Member States as follows:

- In Continental Europe, alternative configurations are proposed for Germany (four alternatives), France (one), Italy (one), and the Netherlands (one);
- In the Nordic area, four alternative configurations are proposed for Sweden.

127 Article 16(8) of the Electricity Regulation.

128 Article 14(1) of the Electricity Regulation.

230 Following ACER's Decision, TSOs have 12 months to conduct the bidding zone review and provide a recommendation on whether to keep or amend the existing bidding zones[129]. Member States will then decide whether to change the bidding zones accordingly.

Limited competitive pressure and/or liquidity in wholesale electricity markets

231 In electricity markets with low liquidity, market participants face difficulties and high costs to find counterparts, which may result in an inefficient price formation. An electricity market can be considered liquid if a significant number of market participants can sell and buy products in large quantities, quickly, without significantly affecting prices, and without incurring significant transaction costs. In terms of economic value for market participants, the forward, day-ahead, and intraday timeframes are the most important. As illustrated in ACER's 2023 Market Monitoring Report on progress of EU electricity wholesale market integration, forward markets in Europe show limited liquidity with local variations. Liquidity further decreased in 2022, partly due to increased collateral requirements, resulting in lower trading rates. Ongoing discussions between ACER and NRAs influenced by ACER's policy paper of February 2023 on further development of the EU electricity forward market, and the role of long-term transmission rights therein is expected to lead to further integration of the forward market. Day-ahead and intraday liquidity remained stable in 2022.

Complex, lengthy, and discriminatory administrative and financial requirements

232 The electricity sector demands a high standard of performance from the market participants in producing, selling, consuming or investing in electricity-related activities. To address the substantial technical and economic risks inherent in the sector, different administrative and financial requirements are generally imposed. When appropriately implemented, these requirements ensure an open and accessible market for new entrants and smaller actors. However, if such requirements extend beyond what is strictly necessary, they can become unjust or inefficient constraints, hindering investments, impeding access to the network or restricting entry and participation in wholesale electricity markets or SO services.

233 Financial obligations, such as the requirements for BRPs or other market participants, to furnish collaterals to entities like TSOs, DSOs, NEMOs, as well as market platforms or clearinghouses, may be necessary for participation but can inefficiently raise the market entrance barrier when the requirements are too strict. Complex and lengthy administrative procedures to acquire necessary licenses and approvals can similarly impede easy entry and participation in electricity markets. Furthermore, exit conditions can also pose challenges, especially for new entrants and small actors.

Lack of incentives to consider non-wire alternatives

234 The types of regulations that TSOs and DSOs are subject to may influence their choice between the use of traditional solutions (i.e., network expansion or reinforcement) or the use of non-wire alternatives (i.e., market-based re-dispatching, non-firm connection agreements or interruptible tariffs, dynamic line rating, among others) or a combination thereof. As shown in Chapter 6, non-wire alternatives are more common at transmission level (mainly though re-dispatching), but they are still a niche practice at distribution level. In many Member States, DSOs tackle congestions through traditional solutions or with TSO assistance.

235 In this context, TSO and DSO revenue models should incorporate the value of non-wire alternatives, promote and facilitate innovation in the operation and planning of networks and incentivise TSOs or DSOs for more cost-efficient operation and planning of the grid. The Electricity Directive[130] highlights the importance of the development of an adequate regulatory framework to allow and provide incentives to DSOs to procure flexibility services, including congestion management in their areas, to improve efficiencies in the operation and development of the distribution system.

236 In ACER's report on investment evaluation, risk assessment and regulatory incentives for energy network projects published in June 2023, ACER also highlights that CAPEX bias is currently a prominent issue and regulatory measures like total cost approach and benefit-based or performance based incentives have a potential to address it.

129 More information on the status of the study being carried out by TSOs may be found on ENTSO-E's website, available at: https://www.entsoe.eu/network_codes/bzr/.

130 Article 32 of the Electricity Directive.

Scope for improving transparency, cost-reflectivity, and non-discrimination in network tariffs

237 Network tariffs are designed with the primary goal of recovering costs incurred by transmission or distribution system operators, seeking a balance among tariff-setting principles like transparency, predictability, cost reflectivity, recovery, and non-discrimination. Despite these intentions, network tariffs can become a barrier to efficient price formation when they lead to inefficient behaviour among users. This inefficiency may result from insufficient transparency and stakeholder involvement during the establishment of network methodology and tariffs, non-cost-reflective network tariffs, and unequal treatment of similar user groups without proper justification.

238 Enhancing transparency is crucial for the effectiveness of network tariffs. Transparency should extend into two layers: firstly, during the method-setting phase, primarily accomplished through consultations; and secondly, by ensuring the public availability of pertinent tariff-related information for network users and stakeholders. This includes details on costs and other inputs, methodology, and resulting charges. To prevent non-cost-reflective network tariffs, there should be restrictions on incorporating non-network-related charges within these tariffs, as explained in Chapter 11.

11. Focal topic: Network tariffs as both potential 'facilitators' and 'barriers' to active customers and providing demand response

239 Electricity transmission and distribution networks represent the backbone of the national and European energy systems and play a key role in the energy transition. Network tariffs have the core objective of recovering the costs incurred by transmission and distribution system operators. In line with the Electricity Directive[131], NRAs must fix or approve transmission or distribution tariffs or their methodologies.

240 Tariff methodologies must neutrally support overall system efficiency over the long run through price signals to network users. Since charges related to transmission and distribution networks can constitute a considerable cost to the network users, the way how tariffs are set up can provide additional incentives (additional to those given by energy pricing) to the network users to adapt their behaviour. The effectiveness of such signals depends on factors such as the type of network user and the share of network costs on the final bill.

241 Member States must ensure that network users are subject to cost-reflective, transparent, and non-discriminatory network charges[132] that account separately for the electricity fed into the grid and the electricity consumed from the grid[133]. Moreover, their network charges should not discriminate either positively or negatively against energy storage or aggregation and should not create disincentives for self-generation, self-consumption or for participation in demand response[134].

242 Technological developments, including digitalisation, distributed energy resources (generation and storage assets) or automation further empower final customers (by providing them with more possibilities) to react to cost signals (via demand response) and thus increase power system efficiency. Network charges can have a large impact on final customers' decisions whether to become active customers, by consuming or storing self-generated electricity and/or injecting it into the grid.

243 Network charges can incentivise self-generation and/or 'behind-the-meter' energy storage, for example when investments in such technologies result in lower individual capacity need (and the user is charged based on contracted or measured capacity) and increase of network users' ability to react to cost signals e.g., shifting load from periods of system peaks to periods with lower network utilisation.

244 To fit their purpose, network tariffs must be technology-neutral and must not discriminate among network users.

245 Using network tariffs to support unrelated energy policy goals, such as promoting a particular generation technology, without a corresponding beneficial network impact, would be distortive to overall network efficiency and unsustainable over the long term.

246 Exemptions, discounts and/or other differentiations in network tariffs, if provided to a portion of network users irrespective to their cost impacts on the network, can be a barrier to demand response and active customers by distorting or mitigating cost signals coming from other network tariff design elements. Certainly, such differentiations should not be applied to facilitate demand response where they are not cost reflective and lead to inefficiency in the development and operation of the power system.

247 Similarly, (non-VAT) taxes, levies, surcharges, and fees should not be levied on network users, where they are unrelated to network use. These costs often constitute a significant part of the electricity bill so they can distort cost signals to network users or have a diminishing impact on those cost signals, potentially leading to suboptimal decisions on investments, production and/or consumption. For example, an energy tax levied on consumption may incentivise load curtailment, but disincentivise increasing demand at a time of excessive production, while this may be efficient from the system point of view.

131 Article 59(1) of the Electricity Directive.

132 See footnote 51.

133 Article 15(2)(3) of the Electricity Directive.

134 Article 18(1) of the Electricity Regulation.

248 In the following sections, the following network tariff design elements for active customers and/or consumers providing demand response, will be scrutinised:

- Differentiation in network charges for active and non-active customers
- Incentivising 'behind-the-meter' energy storage and explicit demand response via network charges
- Differentiation in taxes and levies for active customers and non-active customers
- Exemptions, discounts, and other differentiations in network tariffs for specific consumers
- Network tariff basis to activate end users' flexibility

11.1. Differentiation in network charges for active and non-active customers

249 Network charges for each type of network user must reflect the costs caused by their network connection and use. While non-active customers only withdraw from the grid, active customers may also inject. Setting the very same network charges for active and non-active customers cannot be cost-reflective and non-discriminatory if the costs caused by them are remarkably different. The same is true when setting different network charges while the cost impact of the active and non-active customers is about the same, thus any differentiation must be justified based on network-related reasons.

250 ACER considers that Member States should conduct a study, pilot project and/or impact assessment to determine whether a differentiation in network charges for active customers is required based on their cost impact to ensure their cost-reflectiveness and non-discrimination and not to create disincentives for self-generation or self-consumption. Such assessments require sufficiently granular data collection on network development and system operation to identify the most appropriate cost drivers to the different cost categories arising from the network use.

251 Table 24 shows Member States with differentiation in network charges for active and non-active customers and whether this differentiation is based on a study, pilot project and/or impact assessment.

Table 24: Differentiation in network charges for active and non-active customers per Member State – 2022

	AT	BE	BG	CY	CZ	DE	DK	EE	ES	FI	FR	GR	HR	HU
Same connection charge for active and non-active customers	Same	Same	Same	Same	Same	Same	N/A	Different	Same	N/A	Same	Same	Same	Same
Same withdrawal charge for active and non-active customers	Same	Same	Same	Same	N/A	Same	N/A	Same	Same	N/A	Different	Same	Same	Same
Same injection charge for active and non-active customers	N/A	Different	Same	NAP	NAP	NAP	N/A	Same	NAP	N/A	NAP	NAP	NAP	NAP
Decision on whether there is a differentiation in network charges for active customers is based on a study, pilot project and/or impact assessment	N/A	No	No	N/A	No	No	N/A	No	No	No	Yes	No	No	No

	IE	IT	LT	LU	LV	MT	NL	NO	PL	PT	RO	SE	SI	SK
Same connection charge for active and non-active customers	Same	Same	Same	Same	Same	Different	Same	Same	N/A	Same	Same	Same	Same	Same
Same withdrawal charge for active and non-active customers	Same	Same	Same	Different	Same	Same	Same	Same	N/A	Same	Same	Same	Same	Same
Same injection charge for active and non-active customers	NAP	NAP	NAP	NAP	Same	NAP	NAP	Different	N/A	NAP	Same	Different	NAP	Different
Decision on whether there is a differentiation in network charges for active customers is based on a study, pilot project and/or impact assessment	No	No	No	No	Yes	No	No	Yes	N/A	Yes	No	Yes	Yes	No

Same for active and non-active customers
Different for active and non-active customers
Yes, decision based on a study, pilot project and/or impact assessment
No, decision not based on a study, pilot project and/or impact assessment
N/A
NAP (The network charge is not applicable for non-active customers)

Source: ACER based on NRA data.
Notes: (1) In Belgium the injection charge in distribution applies only in the regions of Flanders and Wallonia but not in the region of Brussels. (2) Romania only applies injection charges to generators connected to the transmission grid with an installed capacity higher than 5 MW. (3) In France (for distribution), Malta (there is only a distribution network) and the Netherlands, the injection charge is only a small lump sum fee, for the metering, administrative and/or management costs, which recovers a fraction of the TSO or DSO costs. Therefore, it is considered not applicable.

252 Most Member States apply the same network charges (i.e., same values, same tariff-basis, same variation of the charge per voltage level, time-of-use and/or location) for active and non-active customers with eight exceptions:

- Estonia and Malta apply different connection charges for network related reasons:
    - In Estonia the setting of the connection charge (basis) is different for active customers who sell their self-generated electricity. They must cover the costs related to the reinforcement of the grid.
    - In Malta the network charges cover different cost categories. Up to 60A, active customers are charged a lump sum charge to cover metering and administrative costs that non-active customers do not have. Over 60A, the charges for connections extended from an existing substation are based on the actual cost and capacity.
- France and Luxembourg apply different withdrawal charges for network and non-network- related reasons respectively:
    - France applies different withdrawal charges only for active customers with collective self-consumption.
    - In Luxembourg the amount of withdrawal considered for the calculation of the charge is different for some active customers. Renewable energy communities benefit from an exemption under certain conditions related to localisation and proximity.
- Belgium, Norway, Sweden, and Slovakia apply different injection charges for network-related reasons:
    - In Belgium for energy communities, different grid fees apply to the quantities of shared electricity depending on the configuration and connection of its members (e.g., in distribution, some transmission tariffs do not apply).
    - In Norway the active customers with self-generation, less than 100 kW injection capacity and no licenced facility behind the connection point are exempt from paying the fixed component of the injection charge.
    - In Sweden active customers are exempted from paying for the injection charge.
    - In Slovakia network users who both inject into and withdraw from the grid pay costs for the access to the grid either based on the injection capacity or based on the withdrawal capacity, depending on which one is higher.

253 In each of these eight Member States, at least some active customers enjoy a form of preferential treatment in their network charges compared to other customers. In this regard, based on NRAs input, ACER cannot identify any instance where network charges may create undue disincentives for self-generation or self-consumption (vs. non-active customers) although this does not mean their network tariffs do incentivise active customers.

254 Only six Member States have conducted a study, pilot project and/or impact assessment before setting the network charges for active customers: France, Norway, and Sweden concluded that there must be a differentiation from non-active customers. Latvia, Poland, and Slovenia concluded that active and non-active customers must have the same network charges. In these Member States, the NRAs explained that the choice of the network charges for active customers was for network-related reasons except for Sweden where the exemption aimed to incentivise distributed generation. Belgium and Slovakia have not conducted any study, pilot project or impact assessment before setting the network charges for active customers. Consequently, NRAs may have insufficient information to judge the cost reflectivity and non-discrimination of these charges.

11.2. Incentivising ‘behind-the-meter’ energy storage and explicit demand response via network charges

255 Network tariffs must be technology-neutral. If two network users’ cost impact on the network is exactly the same, their charges should not be different just because different assets caused that impact. While network tariffs may be tempting to be used to support energy policy goals, such as promoting new

technologies, different network tariffs must also be justified by network purposes (and the corresponding costs of the network use).

256 As shown in Table 25, no Member State applies a network charge for stored electricity remaining within the premises of the active customer (i.e., self-generated and self-consumed electricity). Furthermore, no Member State applies any differentiation in network charges for active customers owning energy storage 'behind-the-meter'. Thus, in no Member State do active customers have any tariff-related disadvantage for having and using energy storage installed 'behind-the-meter'. ACER welcomes this finding, as network charges should not depend (per se) on the type of assets installed behind the meter.

Table 25: Network charges for active customers with energy storage 'behind-the-meter' or providing explicit demand response services to system operators per Member State – 2022

	AT	BE	BG	CY	CZ	DE	DK	EE	ES	FI	FR	GR	HR	HU	IE	IT	LT	LU	LV	MT	NL	NO	PL	PT	RO	SE	SI	SK
Network charge for stored electricity remaining withing premises		No			No	No		No	No		No	No	No	No	No	No	No	No	No	No	No	No		No	No	No	No	No
Tariff differentiation for active customers owning energy storage behind the meter		No				No		No	No		No	No	No	No	No	No	No	No	No	No	No	No		No	No	No	No	No
Tariff differentiation for active customers providing explicit demand response services to system operators		No			No	No		No	No		No	No	No	No	No	No	No	No	No	No	No	No		Yes	No	No	Yes	Yes

Not restrictive N/A

Source: ACER based on NRA data.
Notes: (1) In 2023 Germany is conducting a public consultation to allow DSOs to reduce load from interruptible devices at low voltage level, such as heat pumps or electric vehicles in exchange for a reduction in their network tariffs. (2) Slovenia has a new methodology for network charges that will be applicable from 1 March 2024 onwards. The new methodology aims to provide a level playing field for active customers, energy storage and distributed generation by exempting explicit flexibility provision for system services from additional network charges. Besides, the new methodology also covers network charging for energy community members who will be entitled to recover the network cost according to the extent of network in use as stated in the national legislation in "Electricity Supply Act" and "Act on the Promotion of the Use of Renewable Energy Sources".

257 Cost-reflective network charges can provide important incentives to network users to provide demand response. In this respect, reduced charges could apply when the power system benefits (i.e., a cost reduction) from demand response. The effectiveness of the demand response depends on several factors, including technical conditions (e.g., automation) or the strength of the cost signal In order to ensure an efficient demand response from the system point of view, it is similarly important that the network tariffs properly reflect the cost impact of the participation in the demand response even if it leads to an overall increase in costs (e.g., when the reduction in curtailment costs would not fully offset the corresponding network reinforcement costs) and an increase of the network charges. Otherwise, the network charges would provide distorted incentives, thus reducing overall system efficiency.

258 When demand response does not impact the network costs, but the network charges do increase when providing demand response, they distort incentives for demand response as they do not accurately reflect the impact of demand response on the grid costs. Similar distortion happens, when demand response reduces the network costs, but the network charges remain the same.

259 Table 25 also reveals that most Member States do not apply any kind of differentiation in network charges for active customers providing explicit demand response services to system operators, such as balancing services or congestion management compared to those who do not provide such services. This lack of differentiation is not because active customers still would not be legally eligible to provide these services. Indeed, as shown in Table 5 and Table 6, at least some types of active customers (i.e., residential, commercial or industrial consumers, and energy communities) are allowed to participate in some balancing or congestion management services in all these Member States.

260 Three Member States apply some differentiation in network charges for active customers providing these SO services, in all instances, to incentivise active customers to provide explicit demand response, as follows:

- In Slovenia an exemption applies in the time intervals when active customers provide SO services. More specifically, if active customers increase withdrawal from the network in time intervals of service provision, reduced peak load charges apply to the extent of the activated power needed for provision of the service. In the new network charges methodology that will be applied starting with March 2024, the storage that provides explicit demand response services to TSO or DSO will be exempted from paying the excessive capacity charge and energy withdrawal charge up to the activated quantities needed for provision of the service in time intervals of the service provision. This assures level playing field among storage (directly connected to the grid), generators, and active customers when they participate in the markets. The need for such level playing field derives from the fact that when providing system services (e.g., downward regulation) generators only lower their generation (i.e., no network charges apply), whereas storage units need to withdraw energy from the grid. Thus, when active customers provide explicit demand response services to SOs, they are also exempted from paying the excess capacity network charge (i.e. the capacity charge exceeding the contracted capacity) and energy network charge in time intervals of the service provision in the amount of activated energy.

- In Slovakia active customers providing ancillary services are exempt from paying for the connection charge if they fulfil a monthly obligation to certify their facility for the purpose of providing ancillary services.

- In Portugal the energy activated from active customers for balancing services is exempted from access tariffs, having equal conditions as generators.

261 Even though ACER did not identify any instances where providing explicit demand response would have resulted in a disadvantage, ACER considers that the design of network tariffs may still create disincentives to provide demand response, e.g., via net metering and/or by lack of rewarding (via network tariffs) beneficial system impacts (where they exist).

262 Finally, ACER notes that the incentives provided by network tariff differentiations to promote explicit demand response can also be achieved with other network tariff design tools, such as time-of-use signals to promote implicit demand response (see Section 4.2.2). In some cases, they may be alternatives or complement or each other.

11.3. Differentiation in taxes and levies between active and non-active customers

263 Taxes, levies, surcharges, and fees often constitute a significant part of the electricity bill (see Figure 15 for more information). They are typically set by the governments to serve different policy purposes (e.g., social, climate or energy) and they may differentiate between particular network user groups. Since these costs are unrelated to the use of the network, they cannot be allocated to network users in a cost-reflective manner. Therefore, they can distort or diminish cost signals coming from network tariffs, potentially leading to suboptimal investment or operational decisions. For example, an energy tax levied on consumption may incentivise load curtailment but disincentivise increasing demand at a time of excessive production, while this may be more efficient from the system point of view.

Table 26: Differentiation in taxes and levies per Member State – 2022

AT	BE	BG	CY	CZ	DE	DK	EE	ES	FI	FR	GR	HR	HU	IE	IT	LT	LU	LV	MT	NL	NO	PL	PT	RO	SE	SI	SK
Same	Same	N/A	N/A	Same	Same	N/A	Same	Same	N/A	Different	Same	Same	Same	Same	Same	Same	Different	Different	Same	Same	Different	N/A	Different	Same	Different	Same	Same

Same taxes, levies, surcharges, fees, etc. for active and non-active customers
Different taxes, levies, surcharges, fees, etc. for active and non-active customers
N/A

Source: ACER based on NRA data.

264 Table 26 shows whether there is any differentiation in taxes, levies, surcharges, and fees between active and non-active customers. Six Member States reported some differentiation relating to active customers as follows:

- France applies different taxes on self-generated electricity injected to the network.

- In Luxembourg energy sharing within energy communities is exempted from some taxes and levies up to certain thresholds.

- In Portugal the self-generated energy consumed behind the meter is exempted from levies and taxes.
- In Norway active customers with less than 100 kW injection and no licenced facility behind the connection point do not pay taxes on the self-generated electricity consumed behind the meter.
- In Sweden active customers are exempted from paying the taxes on the self-generated electricity consumed behind the meter.
- Latvia has not provided any information.

265 ACER notes that the above differentiations in taxes, levies, surcharges, and fees generally incentivise network users to become "active customers" by providing more favourable conditions for self-generation, self-consumption, and energy sharing. While differentiation is in no Member State at explicit disadvantage of "active customers", as mentioned above, this does not mean that these unrelated costs do not create disincentives for them in providing explicit services to the system operators, especially when the taxes are linked to amount of withdrawal or injection.

266 ACER acknowledges that tax exemptions or reductions may play an important role in supporting active customers and reaching the set energy policy goals. However, they can interfere with cost signals coming from network charges, resulting in non-cost-reflective and discriminatory network charges[135]. In this regard, ACER recalls that according to Article 18(1) of the Electricity Regulation network charges must not include unrelated costs supporting unrelated policy objectives.

11.4. Exemptions, discounts, and other differentiations in network tariffs for specific consumers

267 Some Member States apply exemptions, discounts and/or other differentiations in network tariffs for some consumers (e.g., some network tariffs or tariff elements are set on a different basis). In some instances, these exemptions, discounts and/or other differentiations have been justified by cost impacts (including consideration of the trade-off between simplicity and cost-reflectivity) while in other instances no justification has been provided by the NRAs and sometimes they appear to be motivated by non-network related policy reasons.

268 Exemptions, discounts and/or other differentiations in network tariffs, if provided to a portion of the consumers irrespective to their cost impacts on the network, can be a barrier to demand response by distorting or mitigating cost signals coming from other network tariff design elements. Certainly, such exemptions, discounts and/or other differentiations may be designed exactly with the purpose to facilitate demand response, but without the correct cost signals, they will also lead to inefficiency in the development and operation of the power system.

269 Moreover, the exemptions, discounts, and other tariff differentiations, if not designed in a cost-reflective manner, may be particularly detrimental to large consumers who in general may be more interested and capable to react to cost signals and the network impact resulting from changes in their behaviour would be more significant.

270 In this section the exemptions, discounts and/or other differentiations in network tariffs for specific consumers compared to other consumers are under scrutiny. This assessment excludes (i) differences between consumers and other groups of network users, such as energy storage facilities or other network users who are both injecting into or withdrawing from the grid, (ii) a comparison within energy storage facilitates or within other network users, which are both injecting into and withdrawing from the grid, and (iii) connection charges and differences due to network charge variations because of cost cascading across voltage levels.

271 Regarding consumers, ACER reports on exemptions, discounts and/or other network tariffs differentiations in 21 Member States as shown in Table 27.

135 More information on the cost recovery of unrelated policy costs (e.g., non-VAT taxes, levies, renewables support schemes, etc.) via network charges in Member States can be found in Table 45 and Table 46 of ACER's 2023 report on electricity transmission and distribution tariff methodologies in Europe.

Table 27: Exemptions, discounts and/or other differentiations in network tariffs for specific consumers per Member State – 2022

AT	BE	BG	CY	CZ	DE	DK	EE	ES	FI	FR	GR	HR	HU	IE	IT	LT	LU	LV	MT	NL	NO	PL	PT	RO	SE	SI	SK
■	■				■					■	■			■	■	■				■							■
				■				■		■	■								■								
■	■	■		■	■		■	■	■		■		■	■	■		■		■				■		■	■	■

Explicit discounts and exemptions for some consumers (row 1)
Different time-of-use signals for some consumers (row 2)
Different tariff basis for some consumers (row 3)

Source: ACER based on NRA data.
Note: (1) For more information on the exemptions, discounts, and differentiations, please refer to ACER's 2023 report on electricity transmission and distribution tariff methodologies in Europe.

272 Explicit discounts and exemptions for some consumers (i.e., network users only withdrawing from the electricity grid):

- **Austria**: No grid charges for withdrawal for power-to-gas plants with power capacity equal to or higher than 1 MW for 15 years after commissioning.
- **Belgium** (Flanders region): 'Exclusive night' energy-based distribution network tariff (D-tariff) for consumers with accumulation heating.
- **France**: Some of the largest industrial consumers are partially exempted from paying the transmission network tariff (T-tariff).
- **Germany**: A discount on the T-tariff is granted to consumers whose individual peak load predictably differs in a considerable manner from the annual peak load of the grid as well as to large consumers who consume for 7.000 h/year at one connection point and whose annual consumption at this connection point crosses 10 GWh.
- **Greece**: Agricultural users are fully exempted from T-tariffs. They are also exempted from the capacity and energy charge of D-tariffs but not from the small fixed charge of the D-tariff related to metering, billing and customer service costs.
- **Ireland**: Both consumers connected to the transmission grid and consumers connected to the distribution grid with a Minimum Import Capacity (MIC) ≥0.5 MW pay different power-based charge compared to distribution-connected consumers with MIC <0.5 MW.
- **Italy**: High voltage (HV) and extra-high voltage (EHV) consumers pay a T-tariff with a power-based component and an energy-based component. The power-based component of the T-tariff is the same for all consumers, while EHV consumers have a discount on the energy-based component. Medium voltage (MV) and low voltage (LV) consumers pay an energy-based T-tariff.
- **Lithuania**: Consumers whose permitted capacity is less than 30 kW are partially exempted from paying T-tariffs.
- **The Netherlands**: The large industrial EHV and HV consumers receive a partial tariff exemption if they meet certain criteria (consumption level and profile).
- **Slovakia**: Some of the largest industrial consumers are partially exempted if they meet high network capacity utilisation criteria (T-tariff reduction).

273 Different time-of-use signals for some consumers:

- **The Czech Republic**: The charging points for electric vehicles benefit from a peak/off-peak withdrawal charge where the charge is significantly lower in the off-peak period (from 10 p.m. till 6 a.m.) than during the peak period.
- **France**: Time-of-use tariffs embedded both in power and energy-based component for MV consumers; time-of-use tariffs embedded only in the energy-based component for LV consumers.

- **Greece**: Night time consumption of LV consumers (where separately measured) was partially exempted from paying T-tariffs until September 2022 and D-tariffs until May 2023. No explicit exemption for night time consumption is foreseen afterwards.
- **Malta**: There are specific off-peak tariffs for charging points for electric vehicles.
- **Spain**: For household consumers the time-of-use D-tariff periods are different (2 periods are considered for power-based component and 3 periods are considered for energy-based components while 6 periods are considered for non-household consumers).

274 Different tariff basis for some consumers may constitute an implicit discount:

- **Austria**: Network tariffs of all network users are composed of a power-based component and an energy-based component. For larger LV customers and all customers at higher network levels, the power-based component is calculated from metered data (measured monthly 15-minute-peaks). For most LV customers (especially households), the power-based component is a lump sum charge, and thus not based on measured peaks.
- **Belgium** (Brussels region): LV consumers pay an energy-based D-tariff and a yearly lump sum fee based on the connection capacity (i.e. less than or equal to 13 kVA vs. greater than 13 kVA). HV consumers with peak measurement pay an energy-based charge and a power-based charge based on their actual monthly peak capacity (maximum of the last 12 months) during peak period (business days from 7 a.m. to 10 p.m.)
- **Bulgaria**: Some network users have energy-based D-tariffs only, while other network users have a mix of energy- and power-based D-tariffs.
- **The Czech Republic**: Both MV and HV consumers have the option to have a mix of energy- and power-based charges or an energy-based tariff only. However, only a fraction of the eligible network users decide to use the latter option. LV consumers have a mix of energy- and power-based charges without any other option.
- **Germany**: The weight of T-tariff components depends on the user's peak load that occurs simultaneously with the annual peak load of the network. For users exceeding 2500 hours of consumption, the capacity-based term is higher than the energy-based term. The opposite is true for consumers under the 2500-hour threshold. In addition, for LV consumers (without the meter which measures withdrawal capacity power), the D-tariff has an energy-based and optionally a lump sum components, for non-LV consumers and for LV consumers (with power metering) the D-tariff has an energy-based and power-based components. The weight of components depends on the individual peak load occurring simultaneously with the annual peak load. For users exceeding 2500 hours of consumption, the power-based term is higher than the energy-based term and viceversa.
- **Greece**: HV/MV customers pay fully capacity-based T-tariffs while LV customer pay mostly energy-based T-tariffs. For MV consumers the D-tariff has a power-based charge, which is based on the actual power at specified periods. For LV consumers the D-tariff has a power-based charge, which is based on contracted or rated power.
- **Estonia**: All consumers can choose different D-tariff options (i.e., only energy-based, mix of energy-based and power-based or mix of energy-based, power-based and lump sum). Households have an additional D-tariff option (i.e., mix of energy-based and lump sum). MV consumers pay lower energy-based D-tariffs, but higher capacity and lump sum D-tariffs than LV consumers.
- **Finland**: For households and other small consumers, the D-tariff has an energy-based and a lump-sum component (the latter may depend on the size of the main fuse). For industrial consumers, the D-tariff has a lump sum and a capacity-based component. Industrial consumers also pay for reactive power withdrawal.
- **Hungary**: For LV consumers of up to 3×80A connection capacity, the D-tariff has an energy-based and a lump sum component. For other consumers, the D-tariff has an energy-based, power-based, and lump sum component.

- **Ireland**: For some consumers the D-tariff is only energy-based, for other consumers the D-tariff is energy-based and lump sum and yet for some other consumers the D-tariff is energy-based, power-based, and lump sum.

- **Italy**: D-tariff for public lighting and public EV charging points has only an energy-based component while for other consumers it has a power-based and a lump sum component.

- **Luxembourg**: For LV consumers the D-tariff has an energy-based component and a fixed monthly fee while for non-LV consumers the D-tariff has an energy-based, a power-based component, and a separate monthly fee for metering.

- **Malta**: For consumers of up to 60A per phase the D-tariff has an energy-based component and a fixed annual component. For consumers exceeding 60A per phase, the D-tariff has an energy-based component, a fixed annual component and a capacity-based component (kW or kVA). In addition, time-differentiated energy-based tariff is only available to consumers exceeding 5GWh withdrawal per year.

- **Portugal**: The criteria for the power-based D-tariff is contracted power and peak-power, except for small consumers connected to the LV grid (denominated as Normal Low Voltage, with power levels ≤ 41.4 kVA), where peak-power is not applied. For EV recharging stations the network tariff is only energy-based while for other consumers the network tariff is mainly power-based.

- **Slovakia**: A separate tariff has been introduced for dedicated EV recharging points, reflecting their specific network capacity utilization.

- **Slovenia**: For LV consumers of up to 43 kW, the D-tariff has a power-based component based, using as a basis the rated power according to the size of fuse. For the rest of consumers, the D-tariff has a power-based component on the basis of the actual monthly peak power at a specified time. For MV and HV consumers, the D-tariff is based on the actual monthly peak power at specified system peak periods.

- **Spain**: For EV recharging stations the energy component of the network tariff can be optionally chosen to be higher compared to other network consumers.

- **Sweden**: For household consumers the D-tariff often has a fixed component (based on fuse size) and an energy-based component. For other LV consumers, the D-tariff often has an energy-based, a power-based, and a fixed charge.

275 ACER finds that most differentiation applied among consumers concerns network tariff drivers. ACER notes that these differentiations, while often not explained, could be linked to different capabilities of the consumers' meter or due to reasonable trade-offs between simplicity and cost reflectivity. However, in other instances the exemptions aim to support specific network users, such as electric vehicle charging.

276 Similarly, it may be reasonable that certain network users face no or different time-of-use signals, as their capability to react to such signals may be different, along with the impact of their load variation on the network.

277 Finally, in a few instances ACER also finds that some explicit discounts are granted to specific network users (e.g., large consumers in Germany, France, the Netherlands, and Slovakia) but the network-related reasons for these discounts are not straightforward.

11.5. Network tariff basis to activate end users' flexibility

278 Different system operator costs show correlation with different cost drivers. Some costs, such as infrastructure costs, show a strong correlation with capacity usage, while other costs, such as network losses, may significantly depend on the energy volume withdrawn from the grid. To provide appropriate cost signals to the network users and incentivise demand response, the recovery of costs via network tariffs should reflect the corresponding cost drivers.

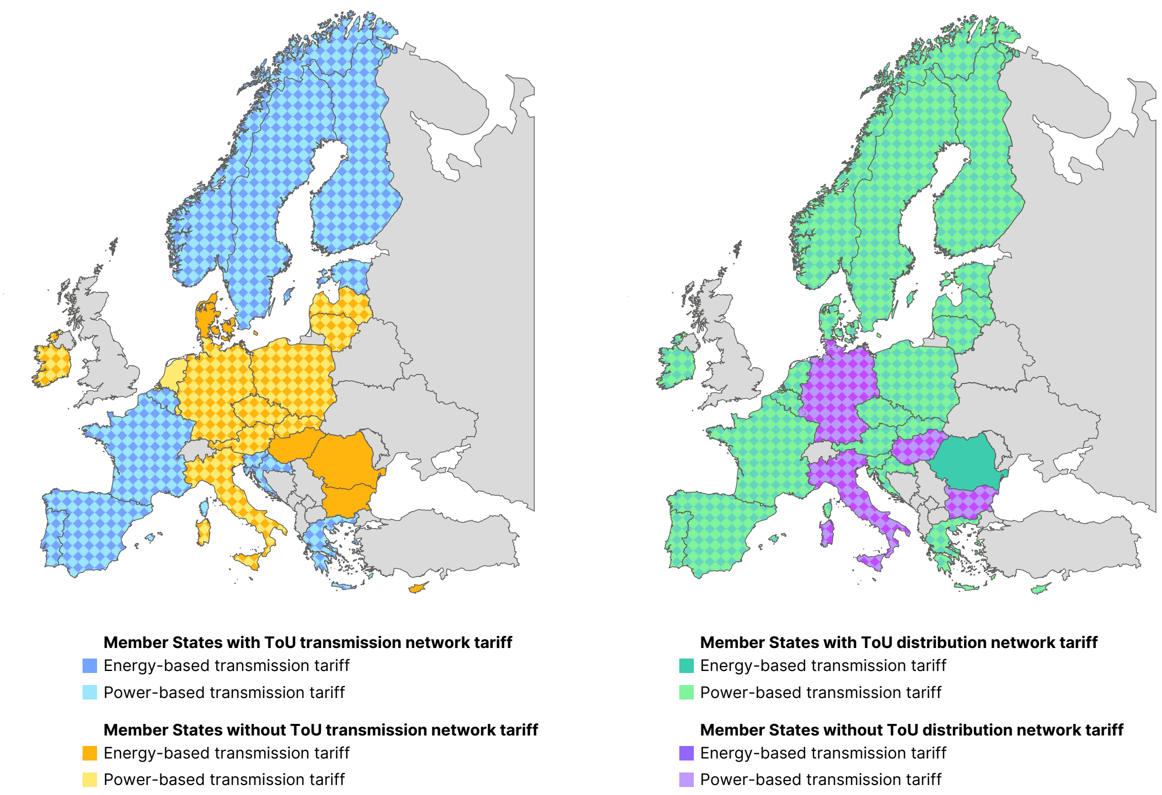
279 The bulk of network costs (recovered via network tariffs) are typically related to building, upgrading, and

maintaining transmission and distribution infrastructure[136], which supports a wide application of power-based network tariffs. Conceptually, time-differentiated network tariffs with sufficient granularity may achieve similar cost reflectivity as contracted capacity or peak-based tariffs.

280 As shown in ACER's 2023 report on electricity transmission and distribution tariff methodologies in Europe, in most Member States transmission and distribution tariffs for withdrawal have a combined tariff basis (i.e., an energy-based component and a power-based or lump sum component). Figure 36 shows that among the Member States without ToU network tariffs, there are six applying only an energy-based component in their transmission tariff and one Member State applying a combination of a power-based component and a lump sum component. For distribution tariffs, two Member States apply only energy-based charges. None of the Member States assessed apply only a power-based or only a lump sum transmission or distribution tariff for withdrawal.

281 Five Member States (Bulgaria, Cyprus, Denmark, Hungary, and Romania) apply only energy-based transmission and/or distribution tariffs without time-differentiation. ACER considers that in case of congested networks the tariff design (per se) of these Member States does not provide appropriate cost signals regarding the cost of network use.

Figure 36: Transmission tariff structure (left) and distribution tariff structure (right) per Member State – 2022



Source: ACER based on NRA data.
Note: (1) For more information on tariff structures, please refer to ACER's 2023 report on electricity transmission and distribution tariff methodologies in Europe.

282 In addition, in some Member States the network users who are both injecting into the grid and withdrawing from the grid are subject to energy-based network charges which are set based on net withdrawal/net metering (i.e., gross withdrawal minus injection). Such network charges are not cost-reflective as they imply that the power system storage capacity is available for free, the cost impacts of injection and withdrawal are assumed to null each other, and they shift costs to those network users who only inject into or only withdraw from the grid. Net metering also reduces consumers' time-value sensitivity to volatile energy prices and hence undermines efforts to enhance flexibility and to develop a wider demand response.

136 For more information, please refer to ENTSO-E's 2020 Overview of Transmission Tariffs in Europe, available at: https://eepublicdownloads.entsoe.eu/clean-documents/mc-documents/I_entso-e_TTO-Report_2020_03.pdf

283 In 2022 there were seven Member States where some network users were charged with a network tariff (or tariff component) based on the net energy withdrawal in their distribution and/or transmission network tariff as follows:

- Household consumers in Croatia, active customers under 100 kW injection in Norway, active customers under 50 kW injection in Hungary, and active customers with renewable energy sources in Luxembourg.
- Active customers in Belgium pay transmission tariffs according to net metering.
- Active customers in Poland and active customers with connection capacity equal to or lower than 43 kW in Slovenia have net metering on both distribution and transmission network tariffs.

12. Conclusions and summary list of recommendations to Member States

284 This chapter presents key findings per barrier monitored in 2022 and ACER's summary list of recommendations to overcome each obstacle identified.

285 The identified barriers and recommendations to remove them are important to consider when addressing certain policy goals. Some market interventions could indeed constitute trade-offs between a short-term relief and an added barrier to a long-term solution. This is the case, for example, when market interventions unilaterally lower electricity price, thereby reducing the incentive to actively invest or participate in demand response. Other market interventions bear the risk of being considered before having exploited all available market opportunities. This is the case, for example, when subsidies to certain technologies are used to trigger investments, before having removed the barriers that were preventing such technologies from finding their ways to the market. Knowing and considering the barriers to demand response and other distributed energy resources is therefore important in future policy-making for integrated electricity markets.

286 Some recommendations are addressed to all Member States. Others are targeted to specific Member States where the barrier was identified, where there is room for improvement even though the overall barrier was not found restrictive and/or where no relevant information was provided. These specific recommendations include a table to highlight the Member States where they are applicable.

287 Whilst this report provides specific recommendations for mitigating the barriers identified across the Member States, it is important to acknowledge that certain barriers may need more tailored and country-specific solutions to effectively overcome them. Some barriers may exhibit significant variations from country to country and not all of them are universally present; some are indeed unique to specific Member States. Moreover, even when certain barriers are prevalent in numerous Member States, their precise characteristics and severity are typically contingent on the specific contextual factors within each country. Furthermore, a barrier that exists in multiple Member States may only be substantial in a select few, i.e., it may be critical for unlocking distributed energy resources and innovative players in some markets, but for some players, such barriers may have little effect.

12.1. Lack of a proper legal framework to allow market access

288 Progress in setting a legal framework for new entrants is uneven. Many Member States have not defined yet the main roles and responsibilities of active customers, aggregators, including independent aggregators, and citizen energy communities in line with the Electricity Directive. For example, in 2022 the role of independent aggregators as market participants was not recognised in eleven Member States.

ACER recommendation

289 ACER urges Member States to define a proper national legal framework for all new entrants in line with the Electricity Directive. It reminds the deadline for transposition was 1 January 2020.

AT	BE	BG	CY	CZ	DE	DK	EE	ES	FI	FR	GR	HR	HU	IE	IT	LT	LU	LV	MT	NL	NO	PL	PT	RO	SE	SI	SK
■		■		■	■		■	■	■		■	■	■			■	■	■		■	■	■			■		■

290 Most Member States have not fully opened all their electricity markets and system operation services (i.e., balancing and congestion management services) to all types of distributed energy resources. Consequently, they cannot ensure non-discriminatory access to distributed energy resources, individually or through aggregation, as required by the European legislation.

ACER recommendation

291 National rules should legally allow all energy resources to become eligible parties in all electricity markets, balancing and congestion management services.

AT	BE	BG	CY	CZ	DE	DK	EE	ES	FI	FR	GR	HR	HU	IE	IT	LT	LU	LV	MT	NL	NO	PL	PT	RO	SE	SI	SK
■		■	■	■		■	■	■	■		■		■	■	■	■		■	■	■	■	■	■		■		■

292 Almost half of Member States lack at least one aggregation model up and running or at a trial or pilot stage in some electricity markets or system operation service in operation. In some Member States, the aggregation models may still not be implemented as a business-as-usual approach to customers connected to some voltage levels.

ACER recommendation

293 To ensure participation of distributed energy resources through aggregation in all electricity markets, balancing and congestion services, the national rules should define at least one aggregation model applicable to all types of distributed energy resources for each market and SO service in line with the requirements of the Electricity Directive.

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294 Some Member States do ensure that new entrants such as aggregators, independent aggregators or energy service companies can access data of final customers in a level playing field compared to suppliers.

ACER recommendation

295 To ensure new actors can offer innovative services and promote demand response, the national rules should recognise them as eligible parties to access final customer data.

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296 In addition, ACER considers that new actors should get access to data of non-customers in a level playing field compared to suppliers while the Member States ensure data protection and security. To ensure they all have access to data in a non-discriminatory manner and simultaneously, all Member States should give access to the same type and amount of data and through the same data platform or tool.

297 In 2022 a limited number of Member States still did not ensure in their national rules that DSOs do not own, develop, manage or operate recharging points for electric vehicles and that TSOs and DSOs do not own, develop, manage or operate storage facilities.

298 In some Member States a low time granularity or a big product size in their day-ahead and intraday markets may also restrict an effective participation of distributed energy resources.

12.2. Unavailability or lack of incentives to provide flexibility

299 In nearly half of the Member States, consumers do not have the technical possibility to access price signals due to the lack of smart meters. Without smart metering devices, consumers cannot access accurate and real-time information, which makes demand response impossible at times when it is more beneficial to the energy system. More specifically, ten Member States still have a roll-out rate of below 20%, with some being practically at 0%. In addition, some Member States have experienced delays in their plans to develop smart meters: Austria, Slovakia, Romania, Poland, and Cyprus have legal plans to reach an 80% target, but they are still far from this target while Hungary, Lithuania, and Greece have not set an 80% target yet despite a positive roll-out decision.

300 To maximise the direct benefits of smart meters for final customers, they should enable some value propositions such as display of real-time consumption and cost, bill forecasting or a valorisation of the provision of explicit demand response, among others. NRAs have limited information about the value propositions enabled in the smart meters installed.

ACER recommendation

301 ACER recommends accelerating the penetration of smart meters in the Member States with legal plans to reach the 80% target in place but still far from this target and in the Member States that have not set the 80% target in their national rules yet, despite a positive roll-out decision.

302 ACER also invites Member States with low penetration levels of smart meters but no legal plans nor target to accelerate the development of these devices.

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303 In 2022 eight Member States did not apply network tariffs with time-differentiation. Some have a high penetration of smart meters. ACER notes that some Member States have not carried out any pilot study or impact assessment regarding the implementation time-differentiated network tariffs. ACER considers that the use of time signals can be a useful tool for reducing network peak-load, thereby promoting network efficiency, while it can also provide incentives for consumers to invest in generation/storage assets and/or to engage in demand response.

ACER recommendation

304 With regard to network tariffs with time-differentiation, ACER reiterates the recommendations made in ACER's 2023 report on electricity transmission and distribution tariff methodologies in Europe.

305 Where time-differentiated network tariffs are introduced, the NRA should regularly evaluate their impacts and their appropriateness. NRAs should obtain sufficiently granular temporal data on network conditions, on individual network users subject to the rollout of fit-for-time-of-use meters, and on the network use by individual network users.

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Note: The list above includes the Member States that apply network tariffs with time-differentiation in transmission and/or in distribution and did not carry out any pilot or impact assessment study (beyond a consultation) nor an evaluation study according to the ACER's 2023 report on electricity transmission and distribution tariff methodologies in Europe.

306 Where time-differentiated network tariffs are introduced, the network tariff structures and the signals should be mandatory for all network users, without a possibility to opt-out from them. Optionality may be temporarily reasonable when transitioning to a new time-of-use schedule to limit tariff impacts on network users.

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Note: The list above includes the Member States that apply network tariffs with time-differentiation in transmission and/or in distribution and some network users can optionally chose to time-of-use network tariffs.

307 Where no time-of-use signals apply in transmission and/or distribution network tariffs, NRAs should investigate the need to introduce such signals from a cost-efficiency and/or network congestion point of view. Such studies should aim to identify which elements affect the effectiveness and efficiency of time-of-use signals to justify a decision to apply such signals or not in each context.

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Note: The list above only includes Member States where no time-of-use signals are applied neither to transmission nor to distribution or no up-to-date relevant information was provided (in dark blue) and where time-of-use signals apply to distribution only and no studies were carried out about the use of those signals (in light blue).

308 Where fit-for-time-of-use meters are largely missing, as a temporary solution, NRAs may design network tariffs by determining for different user profiles their contribution to the system peak.

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Note: The list above only includes the Member States where the share of the distribution connected network users with meters capable of measuring withdrawal from the grid for different time-of-use is below 50%, or where no relevant information was provided.

309 Only a limited number of NRAs can provide estimates on the level of penetration of retail electricity contracts with time differentiation, including dynamic electricity price contracts. This hinders assessment of whether consumers receive proper price signals.

ACER recommendation

310 ACER reiterates the recommendations made in ACER's 2023 Market Monitoring Report on Energy Retail and Consumer Protection. All NRAs should track and monitor the level of penetration of all types of retail electricity contracts.

311 Most Member States have recently adopted some kind of national measure to improve consumers' awareness and engagement to provide demand response through awareness campaigns, training, apps, tools, etc. However, there is limited information on the outcomes of these measures and whether they have successfully mobilised flexibility.

ACER recommendation

312 National authorities need to do even more to inform consumers on the benefits and potential risks of providing demand response. Therefore, ACER recommends all Member States to strengthen national measures to raise consumer awareness and mobilise flexibility and to share good practices that can be followed.

12.3. Restrictive requirements to providing balancing services

313 TSOs do not procure some balancing services using a market-based mechanism in a limited number of Member States. More specifically, Spain, France, Croatia, and Portugal procure some FRR and RR services using a non-market-based method with a regulated price or without remuneration.

314 FCR provision in Spain, Croatia, Italy, Portugal, and Romania is mandatory for some generation units and without remuneration in Spain, Croatia, and Romania. When this obligation is applicable to certain generation units the overall operation of the power system became less efficient and blocks a potential value stream for distributed energy resources and new actors.

ACER recommendation

315 To be in line with the Electricity Balancing Regulation, ACER urges TSOs not doing so yet, to procure Frequency Restoration Reserves and Replacement Reserve services using a market-based mechanism.

316 ACER encourages Member States where a mandatory provision for Frequency Containment Reserve applies to some generation to abolish this requirement and to open this balancing service to all resources by applying a market-based procurement method.

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317 Some prequalification processes for balancing services may hinder access to distributed energy resources and new actors. A small number of Member States still limit prequalification of reserve providing groups or aggregation of different types of technologies into the same group.

318 Some prequalification processes may drag out for too long. Nearly half of Member States do not regulate the maximum duration of the re-prequalification process after changes in the prequalified units and groups. As a result, the duration can range from 2 weeks to even 24 weeks in Member States like Poland and Romania.

319 Requirements to prequalify big capacities and deliver the maximum power for very long periods may also become restrictive in a small number of Member States.

ACER recommendation

320 When a prequalification process is technically justified, ACER recommends TSOs to define a formal process to prequalify reserve providing groups and to allow aggregating all types of technologies under the same group so that BSPs can combine their portfolios to optimise their service provision.

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321 ACER urges TSOs to regulate the duration of the process, including the intermediate steps in line with the System Operation Regulation. When passing a re-prequalification after changes in the reserve providing group is justified, ACER also invites TSOs to regulate and curtail the duration of this process as much as possible. In a context where changes in units and groups will happen with increasing frequency, a short re-prequalification process, if such a process is justified, can help distributed energy resources effectively enter balancing markets.

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322 The EU balancing platforms are a crucial move to ensure distributed energy resources can effectively provide balancing services, individually or aggregated, in a non-discriminatory manner. In 2022 the number of Member States with standard balancing products was still too limited. As a result, some features of the local or specific balancing products are not in line with the EU target model, which may hinder the participation of distributed energy resources. These restricting features include long validity periods of balancing energy bids in many Member States or still large minimum bid sizes, among others. In addition, multiple Member States still procure balancing capacity more than one day before its provision, with contracting periods much longer than one day, which is not in line with the Electricity Regulation.

ACER recommendation

323 ACER recommends Member States to implement the requirements of the Electricity Regulation and the Electricity Balancing Regulation for balancing services provision and not to delay accession to the EU balancing platforms.

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324 The participation of distributed energy resources in balancing services is limited. Most capacity prequalified consists of distributed generation (Austria and Romania being the frontrunners although most distributed generation consists of hydro-power plants connected to the distribution network), followed by demand response units, mainly commercial and industrial loads (the Netherlands), and batteries (Germany, France, and the Netherlands). There is very limited information on the balancing capacity procured and activated from these resources, mainly explained by data availability issues in portfolio-based systems.

12.4. Restrictive requirements to providing congestion management services

325 Local markets for congestion management services for TSOs and DSOs are still in their infancy, especially at distribution level despite potentially being one of the main drivers for unlocking the flexibility potential of distributed energy resources. Moreover, it is in the spirit of the Clean Energy Package to set market-based re-dispatching (i.e., local markets for congestion management) with only four exceptions: no market-based alternative is available, all available market-based resources have been used, lack of competition or predictability of network congestions (Article 13 of the Electricity Regulation).

326 At transmission level, TSOs use non-market procurement for re-dispatching in eleven Member States. Their reasons for not implementing a market-based procurement method are found to be in line with the exceptions allowed by the Clean Energy Package, except in Belgium and Slovakia.

327 At distribution level, DSOs use market-based re-dispatching to solve network congestions in only four Member States. In the remaining Member States the DSOs use some kind of non-market-based measure (i.e., non-market-based re-dispatching, non-firm connection agreements or interruptible tariffs) or do not take any congestion management measure (i.e., the TSOs solve the congestion or DSOs make some kind of network reinforcement and expansion). In most cases, NRAs cannot guarantee whether the reasons for not implementing a market-based re-dispatching are in line with the exceptions allowed by the Clean Energy Package.

ACER recommendation

328 ACER urges Member States to ensure that the reasons for not using market-based re-dispatching at transmission or distribution level do not contravene the exceptions allowed in the Clean Energy Package.

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Note: The list above includes the Member States where TSOs do not use market-based re-dispatching and/or DSOs do not use market-based congestion management measures and the reasons are not in line with the four exceptions foreseen in the Clean Energy Package or there is no information on the reasons (see Table 20 and Table 22 respectively).

329 ACER also reminds all Member States to urgently define a regulatory framework to allow and provide incentives to DSOs to procure congestion management in their areas and to ensure they can procure such services from distributed energy resources pursuant to Article 32(1) of the Electricity Directive.

330 A very limited number of Member States have an iterative national reassessment process along with a transparent decision-making procedure in place to review whether the exceptions from using market-based re-dispatching are no longer applicable. This makes it difficult to set up local markets for congestion management.

ACER recommendation

331 Most Member States should define an iterative national reassessment process with a transparent decision-making procedure as soon as possible. ACER reminds Member States that in a context with increasing network congestions and more and more distributed energy resources and new actors willing to provide flexibility, some market conditions such as predictability of network congestions or lack of competition may become inapplicable. As a result, the lack of market-based re-dispatching may not be sufficiently justified.

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*Note: * In Belgium, this recommendation only applies to the Walloon and Flemish regions for DSOs congestion management.*

12.5. Restrictive requirements to participating in capacity mechanisms and interruptibility schemes

332 Most capacity mechanisms in operation in 2022 had some constraining or unachievable requirement mainly in the product design for most distributed energy resources.

333 The participation of distributed energy resources remains limited although steadily increasing over time in France, Ireland, Italy, and Poland.

ACER recommendation

334 Less restrictive requirements allow for more competition which may potentially reduce the costs of these mechanisms for consumers. To ensure capacity mechanisms are effectively available to all resources with non-discriminatory design features and processes:

- ACER recommends removing the requirements that directly exclude some distributed energy resources, such as restrictions to aggregation or to units connected to lower voltage levels.
- ACER invites all Member States with capacity mechanisms to relax those requirements that can facilitate participation of distributed energy resources capable of fulfilling the required technical performance without jeopardizing the quality of the service delivery.

335 All interruptibility schemes in operation in 2022 had some limiting requirements for smaller demand response units, which are especially restrictive in the German and French schemes. As a new trend some TSOs have started to introduce ancillary service-related schemes targeted to demand response to provide balancing services or to ensure resource adequacy. Like interruptibility schemes, the design of these demand response schemes may also limit participation of smaller load units such as residential or some commercial consumers.

ACER recommendation

336 Interruptibility schemes or new ancillary service-related schemes targeted to demand response may weaken the competitive and direct participation of demand response units into capacity mechanisms, balancing markets or network reserves by establishing a separate specific demand response product for the provision of these services. To ensure a level-playing field among all technologies and actors, and to maximise competition and avoid market fragmentation, ACER recommends the services related to interruptibility or demand response schemes to preferably be integrated within the existing wholesale electricity markets and SO services. Dedicated mechanisms for demand response should only be left to cases where no parallel procurement channels exist, or when there is a need to kick-start the development of demand response.

337 When the introduction of an interruptibility or a new ancillary service-related scheme targeted to demand response is justified, ACER recommends all Member States to carefully review the requirements and design features of these schemes to ensure they do not restrict participation of smaller interruptible loads or new actors capable of fulfilling the required technical performance. ACER also reminds the Member States to follow the approval procedures envisaged by the EU legislation.

12.6. Limited competitive pressure in the retail market

338 There is still room to improve competition in some retail markets with a view of facilitating the entry of new actors that can effectively unlock flexibility from distributed energy resources.

339 Multiple Member States show high market concentration ratios, only explained by their small size in limited cases.

340 Entry-exit activity varies greatly across the Member States, although the more static markets are found in Malta, Sweden, France, Greece, Portugal, Ireland, the Netherlands, Poland, and Romania. Nevertheless,

the energy crisis created a higher-risk environment which increased the number of suppliers exiting the retail energy market in 2021 and 2022 and slowed down the entry activity in 2022.

ACER recommendation

341 ACER invites all Member States to remove the barriers and restrictions assessed in this study to facilitate entry of new actors (aggregators, active customers, energy communities, etc.) and new business models (local markets, peer-to-peer trading, etc.). To prevent suppliers and other new actors from exiting the market due to undue barriers, ACER also invites all Member States to take measures such as increasing opportunities for innovative models, facilitate switching, among others.

12.7. Retail price interventions

342 In 2022 at least thirteen Member States had some kind of public intervention in the price setting implemented as a business-as-usual approach which predated the energy crisis. All consisted of regulated prices, usually fixed prices, except for the Netherlands.

343 These price interventions are only targeted to vulnerable consumers in limited cases but when this happens, the main beneficiaries are consumers who are not deemed vulnerable. Consequently, a high share of household or non-household consumers in these Member States have a regulated price that usually does not send them any price signal to potentially provide demand response.

344 In response to the energy crisis many Member States also introduced temporary retail price interventions to quickly halt the increase in retail prices. As shown in ACER's 2023 Market Monitoring Report on emergency measures in electricity markets, these emergency retail price interventions may have also limited incentives for demand response although their scope is not assessed in this report.

ACER recommendation

345 Retail price interventions, including regulated prices, are not a barrier when targeted and aimed at those most in need. However, in some markets price intervention essentially kills the business case for new actors aiming at unlocking flexibility from distributed energy resources. ACER therefore recommends Member States to ensure these interventions are targeted and aimed at those most in need. Member States should adopt detailed definitions and criteria for vulnerable consumers in line with the Electricity Directive.

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346 With regard to retail price interventions, ACER reiterates other recommendations made in ACER's 2023 Market Monitoring Report on Energy Retail and Consumer Protection.

12.8. Focal topic: Network tariffs as both potential 'facilitators' and 'barriers' to active customers and providing demand response

Differentiation in network charges for active and non-active customers

347 Six Member States have conducted a study, pilot project and/or impact assessment before setting the network charges for active customers: three concluded that there must be a differentiation from non-active customers, while three concluded otherwise. The NRAs of the remaining Member States have not conducted such studies, which would be required to have sufficient information to judge the cost reflectivity and non-discrimination of the currently applied network charges for active customers.

ACER recommendation

348 Member States should conduct a study, pilot project and/or impact assessment to determine whether the network charges for active customers must have some differentiation compared to non-active customers to ensure they are cost-reflective and non-discriminatory.

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Incentivising ‘behind-the-meter’ energy storage and explicit demand response via network charges

349 Most Member States do not apply any kind of differentiation in network charges for active customers providing explicit demand response services to system operators, except for three Member States. ACER underlines that non-differentiated network tariffs may discriminate positively or negatively among network users if they do not reflect the corresponding costs by their network use. Therefore, any differentiation or non-differentiation between network users regarding the network tariffs should be justified by their corresponding network impact.

ACER recommendation

350 Member States should apply differentiated network tariffs for active customers providing explicit demand response as long as they reflect the different network costs triggered by their network use and they are not discriminatory vis-à-vis other network users.

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Note: The list above includes all the Member States without differentiation in network charges for active customers providing explicit demand response services to system operators. It does not mean that a differentiation is required in each of these Member States.

Differentiation in taxes and levies between active and non-active customers

351 Taxes, levies, surcharges, and fees, serving unrelated policy purposes, show no correlation with the costs of using the network, as such they can either distort the cost signals to network users or have a diminishing impact on them. Five Member States reported some differentiation of taxation for active customers, providing more favourable conditions for self-generation, self-consumption, and energy sharing.

Exemptions, discounts, and other differentiations in network tariffs for specific consumers

352 Multiple Member States apply exemptions, discounts and/or other differentiations in the network tariffs for specific consumers. They may be barrier to demand response by distorting or mitigating cost signals coming from other network tariff design elements or could otherwise lead to inefficiency in the development and operation of the power system. In some instances, these exemptions, discounts and/or other differentiations have been justified by cost impacts, but often no justification is provided.

353 In addition, several Member States apply some differentiation between different groups of consumers, most of them concern network tariff drivers. ACER considers that these differentiations may be linked to different features of the consumers’ meter, reasonable trade-offs between simplicity and cost reflectivity. However, in other instances for these discounts there appears to be no network-related or other justified reason.

ACER recommendation

354 Member States should apply exemptions, discounts or other differentiations in network tariffs for specific consumers only when duly justified. In a context of increasing network congestion and flexibility needs, NRAs should periodically assess the need and adequacy of any network tariff differentiation, taking into account the overall network impacts, not to provide disincentives for efficient network use.

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Note: The list above includes only the Member States with some exemptions, discounts, and other differentiations in network tariffs for specific consumers.

Network tariff basis to activate end user' flexibility

355 In most Member States the withdrawal charges have a combined tariff basis, others apply a single tariff basis with or without time-differentiation; however, five Member States (Bulgaria, Cyprus, Denmark, Hungary, and Romania) apply only energy-based transmission and/or distribution tariffs without time-differentiation. ACER considers that in case of congested networks applying only energy-based tariffs without time-differentiation are unlikely to provide appropriate cost signals regarding the cost of the network use.

ACER recommendation

356 As described in ACER's 2023 report on electricity transmission and distribution tariff methodologies in Europe, ACER considers appropriate a gradual move to increasingly power-based network tariffs to recover those costs which show correlation with contracted or peak capacity. In particular ACER recommends against using flat-rate energy-based charges (EUR/MWh), i.e., which do include any time element which corresponds to the peak network usage, to recover infrastructure costs from network users.

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Note: The list above only includes the Member States with only energy-based network charges without any time differentiation either in transmission or in distribution or where no relevant information was provided.

357 In 2022 there were eight Member States where some network users were charged (at least partially) with an energy-based (transmission and/or distribution) charge based on net withdrawal from the grid. ACER considers that applying network charges based on the net energy withdrawal (i.e., gross withdrawal minus injection) is not cost-reflective as it implies that the power system storage capacity is available for free and the sum of the marginal costs of the injection and withdrawal is zero. Net metering also reduces consumers' time-value sensitivity regarding the cost of the use of the network and hence undermines efforts to enhance flexibility and to develop a wider demand response.

ACER recommendation

358 ACER recommends avoiding net-metering where volumetric/energy network charges apply. Moreover, to be in line with Article 15(2) of the Electricity Directive, ACER reminds Member States that net metering (with an exception)[137] shall not apply to active customers after 31 December 2023.

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Note: The list above includes the Member States where some of the network users pay the transmission and/or distribution tariff based on net energy withdrawal.

137 On the basis of Article 15(4) of the Electricity Directive, Member States that have existing net metering scheme (i.e., in place prior to entry into force of the Electricity Directive of 4 July 2019) may continue to conclude net-metering contracts with self-consumers, which can run for a fixed or indefinite time, until 31 December 2023 but they shall not grant new rights under such schemes after 31 December 2023. In any event, customers subject to existing schemes shall have the possibility at any time to opt for a new scheme that accounts separately for the electricity fed into the grid and the electricity consumed from the grid as the basis for calculating network charges.

12.9. Other conclusions and recommendations

359 ACER stresses that data quality matters when performing monitoring. The current report shows incomplete assessments in several of its analyses, tables, and figures[138]. ACER recommends NRAs to obtain sufficiently granular data on the following:

- any missing data that identifies potential barriers to distributed energy resources to participate in the market integration
- network conditions, on individual network users subject to the rollout of fit-for-time-of-use meters and on the network use by individual network users
- the level of penetration of all types of new actors and distributed energy resources in all electricity markets and balancing and congestion management services
- the level of penetration of all types of retail electricity contracts, including those with time-of-use signals

360 ACER also reminds NRAs that sufficient completeness and timely delivery of the necessary data is a precondition for effective monitoring.

138 This is indicated as 'N/A' (not available) in the tables and figures.

Annex I: Methodology for assessing the scores per indicator and barrier

361 As described in the methodological study[139], the construction of the scores follows a stepwise approach, as follows:

- **STEP 1**: Starting from raw data, the relevant indicators for each barrier are calculated as explained in Table 28. The table also describes how missing data are processed to derive a value for the indicator, or otherwise to consider the indicator as N/A (not available).

- **STEP 2**: To ensure comparability across Member States, each indicator is normalised onto a common scale ranging from 0 (worst performance) to 1 (best performance).

- **STEP 3**: A score is then calculated for each barrier as the weighted average of the values resulting from step 2. By default, all indicators are assumed to have the same weight. When at least half of the indicators of a barrier are missing, the barrier score is considered N/A (not available). If the number of indicators per barrier is uneven, the barrier score is considered N/A when at least half plus one are missing.

139 DNV's 2021 study on a methodology for benchmarking the performance of the EU Member States in terms of efficient price formation and easy market entry and participation for new entrants and small actors.

Table 28: Overview of the indicators used to measure each barrier – 2022

Barrier	Indicator	Ranges and thresholds	Method to treat missing data (please see the note below)	Data sources	Comparison with ACER 2020 Market Monitoring Report
Lack of a proper legal framework to allow market access	**Main roles and responsibilities not defined** Composite indicator based on closed-ended questions describing whether the national rules define the main roles and responsibilities for active customers, market participants engaged in aggregation, independent aggregators and citizen energy communities as set out in Articles 13, 15, 16 and 17 of the Electricity Directive. Some questions refer to the Focal topic 'Network tariffs as both potential 'facilitators' and 'barriers' to active customers and providing demand response' in Chapter 11 of this report. A scoring system allocates 1 point when the roles or responsibility is defined in the national rules and 0 points otherwise.	From 0 to 46 (best score when the national rules define all the main roles and responsibilities).	Method 1	ACER calculation based on NRA data	**Scope extended**
	Market access restricted due to lack of legal eligibility Composite indicator based on closed-ended questions assessing whether different types of new entrants and small actors (e.g., distributed generation, batteries, residential consumers, energy communities, independent aggregators, etc.) are legally eligible to participate in different market timeframes and services procured by SOs (i.e., day-ahead and intraday markets, balancing markets, TSO re-dispatching, and DSO congestion management services). This indicator does not refer to whether each new entrant and small actor meets the technical requirements to participate but whether the national rules do not allow them to become market participants. A scoring system allocates 3 points when the actor is legally eligible to participate as a business-as-usual approach, 2 points when legally eligible only on a trial basis or in a pilot project, 1 point when legally eligible only within regulatory sandbox conditions, and 0 points when not legally eligible. The final score is weighted as follows: 1/3 for day-ahead and intraday markets, 1/3 for balancing markets and 1/3 for TSO re-dispatching and DSO congestion management services.	From 0 to 100 (maximum score if all types of new entrants and small actors are legally eligible to participate in all market timeframes and all services procured by SOs). If a market or SO service is not in operation in a Member State, the final score is resized to ensure comparability among the Member States.	Method 1	ACER calculation based on NRA data	**Scope extended**
	Lack of a proper legal framework on aggregation models Composite indicator assessing if there is at least one aggregation model implemented in each energy market, capacity market and SO service. Per market and SO service, a scoring system allocates 2 points when there is at least one aggregation model implemented as a business-as-usual approach (i.e., "up and running"), 1 point when the aggregation model(s) is used on a trial basis or is being tested in a pilot project, and 0 points when there is no aggregation model up and running neither on a trial basis nor in a pilot project.	From 0 to 16 (best score if there is at least one aggregation model up and running in all markets and SO service). If a market or SO service is not in operation in a Member State, the final score is resized to ensure comparability among the Member States.	Method 1	ACER calculation based on NRA data	**New indicator**

Barrier	Indicator	Ranges and thresholds	Method to treat missing data (please see the note below)	Data sources	Comparison with ACER 2020 Market Monitoring Report
Lack of a proper legal framework to allow market access	**Lack of access to final customer data** Composite indicator based on closed-ended questions describing whether the national rules define requirements and procedures on access to data of final customers by eligible parties as set out in Article 23 of the Electricity Directive. A scoring system allocates 1 point when the requirement or procedure is defined in the national rules and when actors other than suppliers are eligible parties to assess the data of final customers. It allocates 0 points otherwise.	From 0 to 4 (best score when the national rules define all the requirements on data access).	Method 1	ACER calculation based on NRA data	New indicator
	Ownership of recharging points for electric vehicles by DSOs Composite indicator based on closed-ended questions assessing: (i) if DSOs are not allowed to own, develop, manage or operate recharging points for electric vehicles, or (ii) if Member States have granted a derogation in line with the requirements set out in Article 33 of the Electricity Directive. A scoring system allocates 1 point when DSOs are not allowed to own, develop, manage or operate recharging points for electric vehicles or when the Member State has granted a derogation meeting each requirement set out in Article 33 of the Electricity Directive. It allocates 0 points otherwise.	From 0 to 7 (best score if national rules stipulate that DSOs are not allowed to own, develop, manage or operate recharging points for electric vehicles, or if Member States have granted a derogation in line with the Electricity Directive).	Method 1	ACER calculation based on NRA data	New indicator
	Ownership of energy storage facilities by TSOs and DSOs Composite indicator based on closed-ended questions assessing: (i) if TSOs and DSOs are not allowed to own, develop, manage or operate energy storage facilities, or (ii) if Member States have granted a derogation in line with the requirement set out in Articles 36 and 54 of the Electricity Directive. A scoring system allocates 1 point when SOs are not allowed to own, develop, manage or operate energy storage facilities, or when the Member State has granted a derogation meeting each requirement set out in Articles 36 and 54 of the Electricity Directive. It allocates 0 points otherwise.	From 0 to 12 (best score if national rules stipulate that TSOs and DSOs are not allowed to own, develop, manage or operate energy storage facilities, or if Member States have granted a derogation in line with the Electricity Directive).	Method 1	ACER calculation based on NRA data	New indicator
	Restrictions on trade on day-ahead and intraday markets Composite indicator based on closed-ended questions assessing whether there are restrictions in the product size and the time granularity in day-ahead and intraday markets based on the requirements set out in Article 8 of the Electricity Directive. A scoring system allocates the best score when the minimum bid size of day-ahead and intraday is lower than or equal to 500 kW, the imbalance settlement period is 15 minutes, and market participants are allowed to trade in time intervals which are at least as short as the imbalance settlement period. It allocates the worst score when the minimum bid size is higher than 10 MW, the imbalance settlement period is 1 hour, and market participants are not allowed to trade in time intervals which are at least as short as the imbalance settlement period.	From 0 to 14 (best score). If there is no day-ahead nor intraday market in operation in a Member State, the final score is resized to ensure comparability among the Member States.	Method 1	ACER calculation based on NRA data	New indicator

Barrier	Indicator	Ranges and thresholds	Method to treat missing data (please see the note below)	Data sources	Comparison with ACER 2020 Market Monitoring Report
Unavailability or lack of incentive by end-users to provide flexibility	Share of final household consumers (metering points) with **smart meters**	From 0% to 100% (best score).	Method 2	CEER data	No difference
	Lack of a proper legal framework on interoperability and functionalities of smart meters Composite indicator based on closed-ended questions assessing whether the national rules define that smart metering devices should have the main functionalities set out in Articles 19 and 20 of the Electricity Directive. A scoring system allocates 1 point per functionality defined in the national rules and 0 points otherwise.	From 0 to 8 (best score if the national rules ensure smart meters to have all the main functionalities).	Method 1	ACER calculation based on NRA data	**New indicator**
	Low number of value propositions enabled by the smart meters installed Composite indicator assessing the share of smart meters installed that enable different value propositions such as comparison of energy consumption with peer consumers, bill forecasting, real-time consumption and cost, etc. Per value proposition, a scoring system allocates from 6 points (if 100% of the smart meters installed enable the value proposition) to 0 points (if none of the small meters installed enable the value proposition).	From 0 to 90 (best score if 100% of the smart meters installed enable all the value propositions).	Method 1	ACER calculation based on NRA data	**New indicator**
	Level of dispersion of day-ahead prices in 2022 calculated as the difference between P95 and P5	From the lowest to the highest level of dispersion (best score) in 2022.	Method 2	ACER calculation based on ENTSO-E data	Discarded A low level of dispersion cannot be considered as a barrier.
	Share of the **energy component** in the electricity bill	From 0% to 100% (best score).	Method 2	CEER data	No difference

Barrier	Indicator	Ranges and thresholds	Method to treat missing data (please see the note below)	Data sources	Comparison with ACER 2020 Market Monitoring Report
Unavailability or lack of incentive by end-users to provide flexibility	**Limited availability of Time-of-Use network tariffs** Composite indicator to measure the availability of ToU network tariffs, including the type of granularity of time signals (i.e., time periods) and the share of household and non-household consumers benefiting from different ToU network tariffs. The indicator is split into time differentiation per day and other time differentiation (e.g., weekly, monthly, seasonal, etc.). The final score is calculated according to the following formula: $Score = \sum_{k} \sum_{i=1}^{2} Weight_i * \% \ users_i$ k = type of consumer; i = type of network tariffs; Weight = weight of each type of network tariff. It is equal to 0 for network tariffs without time differentiation, 1 for network tariffs with 2 time periods and 2 for network tariffs with more than 2 time periods. A Member State gets the best score if all household and non-household consumers have ToU network tariffs with more than 2 time periods in either energy or capacity charge or in both. If no consumer has ToU network tariffs but the NRA carried out a pilot study, impact assessment study and/or consultation before deciding not to implement ToU network tariffs, the Member State also gets the best score.	From 0 to 48 (best score).	Method 1	ACER calculation based on NRA data	**New indicator**
	Lack of a proper legal framework on dynamic electricity price contracts Composite indicator based on closed-ended questions assessing whether the national rules stipulate that final customers who have a smart meter installed are entitled to conclude dynamic electricity price contracts based on the requirements set out in Article 11 of the Electricity Directive. A scoring system allocates 1 point when the requirement is defined in the national rules. It allocates 0 points otherwise.	From 0 to 4 (best score when the national rules define all the requirements on dynamic electricity price contracts).	Method 1	ACER calculation based on NRA data	**New indicator**

Barrier	Indicator	Ranges and thresholds	Method to treat missing data (please see the note below)	Data sources	Comparison with ACER 2020 Market Monitoring Report
Unavailability or lack of incentive by end-users to provide flexibility	**Limited availability of retail electricity contracts with time differentiation** Composite indicator to measure the availability of time-differentiated electricity price contracts, including the type of granularity of time signals (i.e., time periods) and the share of household and non-household consumers benefiting from different types of time-differentiated electricity price contracts. The indicator is split into time differentiation per day and other time differentiation (e.g., weekly, monthly, seasonal, etc.). The final score is calculated according to the following formula: $Score = \sum_{k} \sum_{i=1}^{2} Weight_i * \%\ users_i$ k = type of consumer; i = type of electricity price contract with time differentiation; Weight = weight of each type of electricity price contract. It is equal to 0 for electricity price contracts without time differentiation, 1 for electricity price contracts with 2 time periods, and 2 for electricity price contracts with more than 2 time periods. A Member State gets the best score if all household and non-household consumers have electricity price contracts with more than 2 time periods in either energy or capacity component or in both. In addition, the Member State gets 1 point if suppliers are not allowed to offer fixed electricity price contracts to consumers with ToU network tariffs and 0 points otherwise.	From 0 to 49 (best score).	Method 1	ACER calculation based on NRA data	New indicator
	Lack of measures to mobilise end-user's flexibility Composite indicator based on closed-ended questions assessing whether the Member State has taken or planned actions to improve consumer-awareness and engagement in implicit demand response through training, awareness campaigns and tools or incentives for technology. Per measure, a scoring system allocates 1 point if the measure is ongoing, 0.5 points if it is planned, and 0 points if it has not been considered nor planned.	From 0 to 10 (best score if all the national measures proposed were implemented in 2022).	Method 1	ACER calculation based on NRA and EC data	New indicator
Restrictive requirements to provide balancing services	**Non-market based balancing products** Composite indicator assessing if the procurement of FCR, aFRR, mFRR, and RR capacity as well as the activation of aFRR, mFRR, and RR energy is done using on a market-based mechanism in line with Article 2(3) and Article 3(1) read together with Article 32(2) and Title V, Chapter 2 of the Electricity Balancing Regulation. A scoring system allocates 0 points if the procurement of at least one balancing capacity product or the activation of at least one balancing energy product is non-market based and 1 point otherwise.	From 0 to 1 (best score if the procurement and activation of all balancing products is done using a market-based mechanism).	Method 1	ACER calculation based on NRA data	New indicator

Barrier	Indicator	Ranges and thresholds	Method to treat missing data (please see the note below)	Data sources	Comparison with ACER 2020 Market Monitoring Report
Restrictive requirements to provide balancing services	**Restrictions in the prequalification of reserve providing groups** Composite indicator assessing if the TSO(s) allows prequalifying reserve providing groups aggregating generation, demand, and energy storage units under the same group. Per balancing reserve, a scoring system allocates 1 point if the prequalification of RPGs is allowed. It also allocates 1 point if aggregation of all generation, demand, and storage units is allowed or 0.5 points if other type of aggregation is allowed. It allocates 0 points otherwise.	From 0 to 8 (best score if the TSO(s) allows prequalifying reserve providing groups aggregating generation, demand, and storage units under the same group for all balancing reserves). If a Member State does not use any of the four balancing reserves, the final score is resized to ensure comparability among the Member States.	Method 1	ACER calculation based on NRA data	**New indicator**
	Large minimum eligible capacity Composite indicator assessing the minimum capacity required in the prequalification process for all balancing capacity and balancing energy reserves. Per balancing reserve, a scoring system allocates 4 points if there is no minimum capacity required, 3 points if lower or equal to 1 MW, 2 points if higher than 1 MW or lower or equal to 5 MW, 1 point if higher than 5 MW or equal or lower to 10 MW and 0 points if higher than 10 MW.	From 0 to 16 (best score if no minimum capacity is required to be eligible for all balancing reserves). If a Member State does not use any of the four balancing reserves, the final score is resized to ensure comparability among the Member States.	Method 1	ACER calculation based on ENTSO-E data	No difference
	Protracted minimum delivery period Composite indicator assessing the minimum duration of the delivery period requested by TSOs in the prequalification for mFRR and RR. Per balancing reserve, a scoring system allocates from 3 points if the minimum delivery period required is lower or equal to 15 minutes to 0 points if it is equal to or higher than 240 minutes.	From 0 to 6 (best score if the minimum delivery period required is lower or equal to 15 minutes). If a Member State does not use any of the four balancing reserves, the final score is resized to ensure comparability among the Member States.	Method 1	ACER calculation based on NRA data	No difference in scoring. **Difference in scope since the maximum duration of the delivery period is not assessed.**

Barrier	Indicator	Ranges and thresholds	Method to treat missing data (please see the note below)	Data sources	Comparison with ACER 2020 Market Monitoring Report
Restrictive requirements to provide balancing services	**Unregulated duration or long prequalification process** Composite indicator assessing (i) whether the maximum duration of the prequalification process is regulated and (ii) whether the deadlines of the intermediate steps are in line with Articles 155(3)-(4), 159(3)-(4), and 162(3)-(4) of the System Operation Regulation. These intermediate steps with deadlines are as follows: TSO to confirm whether the application is complete, potential BSP to submit the additional required information by the TSO if the formal application is incomplete, and the TSO to confirm whether the RPG has been formally prequalified after confirming that the application was complete. Per balancing reserve, a scoring system allocates 1 point if the maximum duration of the prequalification process is regulated and if the deadlines of the intermediate steps are equal to or lower than the time periods set out in the System Operation Regulation.	From 0 to 16 (best score if the maximum duration of the prequalification process is regulated and if the deadlines of the intermediate steps are in line with the System Operation Regulation for all balancing reserves). If a Member State does not use any of the four balancing reserves, the final score is resized to ensure comparability among the Member States.	Method 1	ACER calculation based on NRA data	New indicator
	Large minimum bid size Composite indicator assessing the minimum bid size for all balancing capacity and balancing energy reserves. Per balancing reserve, a scoring system allocates 4 points if there is no minimum bid size, 3 points if lower or equal to 1 MW, 2 points if higher than 1 MW or lower or equal to 5 MW, 1 point if higher than 5 MW or equal or lower to 10 MW and 0 points if higher than 10 MW.	From 0 to 28 (best score if no minimum bid size is required for all balancing reserves). If a Member State does not use any of the four balancing reserves, the final score is resized to ensure comparability among the Member States.	Method 1	ACER calculation based on ENTSO-E data	No difference
	Long validity period of balancing energy bids Composite indicator assessing the validity period of the balancing energy bids for aFRR, mFRR and RR. Per balancing product, a scoring system allocates 3 points for 15-minute products, 2 points for 30-minute products, 1 point for 1-hour products, and 0 points for 4 hour-products.	From 0 to 9 (best score if the validity period is 15 min for all three balancing reserves). If a Member State does not use any of the three balancing reserves, the final score is resized to ensure comparability among the Member States.	Method 1	ACER calculation based on ENTSO-E data	No difference

Barrier	Indicator	Ranges and thresholds	Method to treat missing data (please see the note below)	Data sources	Comparison with ACER 2020 Market Monitoring Report
Restrictive requirements to provide balancing services	**Long procurement lead time** Composite indicator assessing whether the lead time for the procurement of balancing capacity for all balancing reserves is equal to or shorter than one day, as set out in Article 6(9) of the Electricity Regulation. This lead time refers to the time lag between the balancing capacity auction (gate closure of the balancing capacity market) and the start of the contract period in which the balancing capacity must be offered as balancing energy in the real-time market. It is calculated in three steps: (i) first the share of volume procured for each lead time range (i.e., within the same delivery day, daily ahead, weekly ahead, monthly ahead, yearly ahead or other) is calculated; (ii) then the shares are multiplied by a weight ranging from 4 points when the procurement is within the delivery day to 0 points when the procurement is yearly ahead, and finally (iii) the scores are aggregated.	From 0 to 4 (best score if 100% of balancing capacity in all balancing reserves is procured within the same day of delivery).	Method 2	ACER calculation based on NRA data	No difference
	Long balancing capacity contracts Composite indicator assessing whether the length of the balancing capacity contracts for all balancing reserves is equal to or shorter than one day as set out in Article 6(9) of the Electricity Regulation. A scoring system allocates 4 points if the length is hour(s), 3 points if day(s), 2 points if week(s), 1 point if month(s), and 0 points if year(s).	From 0 to 16 (best score if the length of the balancing capacity contracts is hour(s) for all balancing reserves). If a Member State does not use any of the four balancing reserves, the final score is resized to ensure comparability among the Member States.	Method 1	ACER calculation based on ENTSO-E data	No difference
	Symmetric balancing capacity products Composite indicator assessing whether the TSOs procure upward and downward aFRR and mFRR capacity separately (i.e., asymmetrical balancing capacity products) in line with Article 6(9) of the Electricity Regulation. Per balancing reserve, a scoring system allocates 1 point if asymmetrical and 0 points if symmetrical.	From 0 to 2 (best score if the TSO(s) procures upward and downward aFRR and mFRR capacity separately). If a Member State does not use any of the two balancing reserves, the final score is resized to ensure comparability among the Member States.	Method 1	ACER calculation based on ENTSO-E data	No difference

Barrier	Indicator	Ranges and thresholds	Method to treat missing data (please see the note below)	Data sources	Comparison with ACER 2020 Market Monitoring Report
Restrictive requirements to provide balancing services	**Restrictions in the price settlement rule of balancing energy** Composite indicator assessing whether the price settlement rule when activating aFRR, mFRR, and RR energy is based on marginal pricing (pay-as-cleared) in line with Article 6(4) of the Electricity Regulation. A scoring system allocates 2 points if marginal pricing, 1 point if pay as bid, 0.5 points if hybrid price settlement rule and 0 points if regulated price.	From 0 to 6 (best score if marginal pricing is the price settlement rule for all balancing reserves). If a Member State does not use any of the four balancing reserves, the final score is resized to ensure comparability among the Member States.	Method 1	ACER calculation based on ENTSO-E data	No difference
	Non-contracted balancing energy bids not allowed Composite indicator assessing the possibility to offer non-contracted balancing energy bids, also known as free bids, for aFRR, mFRR, and RR in line with Article 16(5) of the Electricity Balancing Regulation. Per balancing reserve, a scoring system allocates 1 point if free bids are allowed and 0 points if not allowed.	From 0 to 3 (best score if free bids are allowed for all balancing reserves). If a Member State does not use any of the three balancing reserves, the final score is resized to ensure comparability among the Member States.	Method 1	ACER calculation based on ENTSO-E data	No difference
	Balancing energy Gate Closure Time before intraday cross-zonal Gate Closure Time Indicator assessing whether balancing energy GCT takes place after the intraday cross zonal GCT for all balancing energy markets (i.e., aFRR, mFRR, and RR) in line with Article 6(4) of the Electricity Regulation.	From 0 to 1 (best score if balancing energy GCT of all balancing energy markets takes place after the intraday cross zonal GCT).	Method 1	ACER calculation based on ENTSO-E and NRA data	**New indicator**

Barrier	Indicator	Ranges and thresholds	Method to treat missing data (please see the note below)	Data sources	Comparison with ACER 2020 Market Monitoring Report
Restrictive requirements to provide congestion management	**Non-market based TSO congestion management: Unjustified or lack of reassessment** Composite indicator based on closed-ended questions to assess: (i) if the reasons to set non-market based mechanisms for re-dispatching are in line with Article 13 of the Electricity Regulation, (ii) if the Member State has set a transparent national process to assess whether market-based re-dispatching can be used by the TSO(s), and (iii) if this national process is iterative. A scoring system allocates the best score if the TSO uses a market-based mechanism for re-dispatching or if the mechanism is non-market based according to the criteria set out in Article 13 of the Electricity Regulation and a Member State has set out a transparent iterative national process to assess whether market-based re-dispatching can be used. The score is NAP (not applicable) if the TSO only uses market-based re-dispatching (i.e., it does not use any non-market-based mechanism for re-dispatching) and if the NRA points out that there are no congestions in the transmission grid.	From 0 to 3 (best score if the reasons to set non-market based re-dispatching are in line with the Electricity Regulation, if a Member State has a national process to assess whether market-based re-dispatching can be used by the TSO(s), and if this national process is iterative).	Method 1	ACER calculation based on NRA data	New indicator
	Non-market based DSO congestion management: Unjustified or lack of reassessment Composite indicator based on closed-ended questions to assess: (i) if the reasons to set non-market based mechanisms for congestion management are in line with Article 13 of the Electricity Regulation, (ii) if the Member State has set a transparent national process to assess whether market-based re-dispatching can be used by DSO(s), and (iii) if this national process is iterative. A scoring system allocates the best score if the DSO(s) use a market-based mechanism for re-dispatching or if the mechanism is non-market based according to the criteria set out in Article 13 of the Electricity Regulation and a Member State has set out a transparent iterative national process to assess whether market-based re-dispatching can be used. The score is NAP (not applicable) if the DSO(s) only use market-based re-dispatching (i.e., it does not use any non-market-based mechanism for re-dispatching) and if the NRA points out that there are no congestions in the distribution grid.	From 0 to 3 (best score if the reasons to set non-market based re-dispatching are in line with the Electricity Regulation, if a Member State has a national process to assess whether market-based re-dispatching can be used by the TSO(s), and if this national process is iterative).	Method 1	ACER calculation based on NRA data	New indicator

Barrier	Indicator	Ranges and thresholds	Method to treat missing data (please see the note below)	Data sources	Comparison with ACER 2020 Market Monitoring Report
Restrictive requirements to participate in capacity mechanisms and interruptibility schemes	**Restrictions in the eligibility process of capacity mechanisms** Composite indicator based on closed-ended questions to assess: (i) whether all distributed energy resources and all units connected to all voltage levels are legally eligible as capacity providers, (ii) the minimum eligible capacity, (iii) whether aggregation is allowed, and (iv) whether the capacity mechanism requires potential capacity providers to meet the maximum CO_2 emission limits set out in Article 22 of the Electricity Regulation. A scoring system allocates the best score if all types of capacity resources and all voltage levels are legally eligible to participate, there is no minimum eligible capacity, aggregation is allowed and the capacity mechanism sets maximum CO_2 emission limits. It allocates the worst score if no distributed energy resource or resources connected to some voltage level are not legally eligible to be capacity providers, the minimum eligible capacity is higher than 10 MW, aggregation is not allowed, and the capacity mechanism does not have any maximum CO_2 emission limits.	From 0 to 14 (best score).	Method 1	ACER calculation based on NRA data	**Scope extended**
	Restrictions in the product design of capacity mechanisms Composite indicator based on closed-ended questions to assess: (i) whether there are multi-year agreements and whether they are available for distributed resources with similar provisions as for conventional generation technologies, and (ii) whether there is a time-limited availability period. A scoring system allocates the best score if there are no multi-year agreements or if there are such agreements with similar provisions for distributed energy resources and conventional generation technologies, and if there is a time-limited availability period. It allocates the worst score if there are multi-year agreements with different provisions for distributed energy resources and conventional generation technologies and if there is no time-limited availability period set.	From 0 to 8 (best score).	Method 1	ACER calculation based on NRA data	**Reduced scope** **Setting a share of capacity targeted for demand response in T-1 auctions is not included in the scoring. It is considered an enabler.**
	Restrictions in the allocation process of capacity mechanisms Composite indicator based on closed-ended questions to assess: (i) the minimum bid size, and (ii) the lead-time between the conclusion of the allocation process and the start of the delivery obligation. A scoring system allocates the best score if there is no minimum bid size and the lead time is shorter or equal to 1 year. It allocates the worst score if the minimum bid size is higher than 10 MW and the lead time is longer than 3 years.	From 0 to 7 (best score).	Method 1	ACER calculation based on NRA data	No difference

Barrier	Indicator	Ranges and thresholds	Method to treat missing data (please see the note below)	Data sources	Comparison with ACER 2020 Market Monitoring Report
Restrictive requirements to participate in capacity mechanisms and interruptibility schemes	**Restrictions in the eligibility process of interruptibility schemes** Composite indicator based on closed-ended questions to assess: (i) whether all types of loads and sectors connected to all voltage levels are legally eligible as interruptible loads, (ii) the minimum eligible capacity, and (iii) whether aggregation is allowed. A scoring system allocates the best score if all types of loads and sectors connected to all voltage levels are legally eligible to participate, there is no minimum eligible capacity, and aggregation is allowed. It allocates the worst score if some types of loads or sectors and units connected to some voltage levels are not legally eligible, the minimum eligible capacity is higher than 10 MW, and aggregation is not allowed.	From 0 to 8 (best score).	Method 1	ACER calculation based on NRA data	**Scope extended**
	Restrictions in the product design of interruptibility schemes Composite indicator based on closed-ended questions to assess: (i) whether there are multi-year agreements, and (ii) whether there is a time-limited availability period. A scoring system allocates the best score if there are no multi-year agreements available, and if there is a time-limited availability period. It allocates the worst score otherwise.	From 0 to 2 (best score).	Method 1	ACER calculation based on NRA data	**New indicator**
	Restrictions in the allocation process of interruptibility schemes Composite indicator based on closed-ended questions to assess: (i) the minimum bid size, and (ii) the lead-time between the conclusion of the allocation process and the start of the delivery obligation. A scoring system allocates the best score if there is no minimum bid size and the lead time is shorter or equal to 1 year. It allocates the worst score if the minimum bid size is higher than 10 MW and the lead time is longer than 3 years.	From 0 to 7 (best score).	Method 1	ACER calculation based on NRA data	**New indicator**
Limited competitive pressure in the retail market	**Herfindahl-Hirschman Index (HHI)** for the household market based on metering points	From the lowest HHI in 2022 (best score) to the highest HHI in 2022.	Method 2	CEER data	**New indicator**
	Concentration ratio 3 (CR3) Market share of the three largest suppliers in the whole retail market by volume.	From 30% (best score) to 100%. When CR3 is equal and below 30%, a Member State receives the best score.	Method 2	CEER data	No difference
	Number of suppliers for households with **market shares higher than 5% by metering points**	From 0 to 10 (best score when there are more than 10 suppliers with a market share higher than 5% of metering points).	Method 2	CEER data	No difference

Barrier	Indicator	Ranges and thresholds	Method to treat missing data (please see the note below)	Data sources	Comparison with ACER 2020 Market Monitoring Report
Limited **competitive pressure** in the **retail market**	**Entry/exit activity** Average number of entries and exits in the retail market for households and non-households over the period of 2020-2022, normalised with the national electricity demand.	From 0 to the average value in the Member States in the period of 2020-2022 (best score).	Method 2	ACER calculation based on CEER data	**Best score is changed from the maximum value in the period of 2020-2022 to the average value in Member States due to outliers in 2022.**
	Correlation coefficient between the energy component of retail prices and wholesale prices for household consumers in the period of 2013-2022 The methodology is described in Annex 6 of the ACER's 2015 Market Monitoring Report.	From -1 to 1 (best score when there is a perfect positive correlation).	Method 2	ACER calculation based on Eurostat data and ACER database on retail offers and other relevant data.	No difference
Retail price interventions	Share of **household consumers subject to public intervention(s)** in the price setting	From 0% (best score) to 100%.	Method 2	CEER data	No difference
	Share of **consumption of household consumers in the country benefiting from the public intervention** in the price setting	From 0% (best score) to 100%.	Method 2	CEER data	Discarded. Data not collected by CEER
	Share of **non-vulnerable consumers subject to public intervention(s)** in the price setting	From 0% (best score) to 100%.	Method 2	CEER data	No difference
	Share of **consumption of non-household consumers subject to public intervention(s)** in the price setting	From 0% (best score) to 100%.	Method 2	CEER data	No difference

Source: ACER based on DNV's 2021 study on a methodology for benchmarking the performance of the EU Member States in terms of efficient price formation and easy market entry and participation for new entrants and small actors.
Note: (1) Methods applied to deal with missing information: Method 1: When some underlying raw data are missing or a question is not answered, it is considered that the missing information corresponds to the lowest possible performance. Method 2: When some underlying raw data are missing or a question is not answered, the missing information is considered as not available (N/A).

Annex II: Additional figures and tables

Table 29: Capacity prequalified of distributed energy resources per balancing product and per Member State – 2022 (MW and %)

Product		AT	BE	BG	CZ	DE	DK	EE	ES	FI	FR	GR	HR	HU	IT	LT	LV	NL	NO	PL	PT	RO	SE	SI	SK
FCR	Total number of BSPs	8	3	4	11	30					12	5		18						10		94		2	
FCR	Total capacity prequalified (MW)	1032			372	6950					3400	958.8		144				759		1257		300	FCR-N: 1910 FCR-D: (+)1690 (-)1100	75	
FCR	Distributed generation	42%	PQ		PQ	PQ					0%	0%		16%				0%		0%		37%		0%	
FCR	Batteries	2%	PQ	0%	PQ	9%					10%	0%		0%				<9%		0%		0%		0%	
FCR	Storage excluding hydro, pumped-hydro and batteries	0.1%		0%	0%	PQ					0%	0%		0%						0%		0%		PQ	
FCR	Total demand response:	0.5%			0%	2.9%					2.9%	0%								0%		0%	FCR-N: 0% FCR-D: (+)10% (-)<0.9%	0%	
FCR	Commercial or industrial consumers	0.5%	PQ	PQ	0%	2.9%					2.9%	0%		0%				0%		0%		0%		0%	
FCR	Energy communities	0%		PQ	0%	0%					0%	0%								0%		0%		0%	
FCR	Residential consumers	0%	PQ	0%	0%	0%					0%	0%						<26%		0%		0%		0%	
aFRR	Total number of BSPs	15	7	4	18	33			16		8	6	1	20	19				7	10	4	5		2	
aFRR	Total capacity prequalified (MW)	(+)4779 (-)5148				23400			46921.8		6020	3730		1641	6100			6422	785	1341	4008	960	(+)1850 (-)1900	(+)115 (-)114	
aFRR	Distributed generation	(+)49% (-)53%	PQ		PQ	PQ			PQ		0%	0%	0%	27%	0%			<7%	PQ	0%	0%	1%		PQ	
aFRR	Batteries	(+)0.15% (-)0.14%	PQ	0%	0%	3%			0%		0%	0%	0%	0%	0%			<0.16%	0%	0%	0%	0%		PQ	
aFRR	Storage excluding hydro, pumped-hydro and batteries	(+)0.13% (-)0.12%		0%	0%	PQ			PQ		0%	0%	0%	0%	0%				0%	0%	0%	0%		PQ	
aFRR	Total demand response:	(+)2.62% (-)2.72%				0.5%			0%			0%	0%						0%	0%	0%	0%	0%	PQ	
aFRR	Commercial or industrial consumers	(+)2.6% (-)2.7%	PQ	PQ	PQ	0.5%			0%		0.2%	0%	0%	1.8%	0%			<12%	0%	0%	0%	0%	0%	PQ	
aFRR	Energy communities	0%		PQ	0%	0%			0%		0%	0%	0%						0%	0%	0%	0%	0%	0%	
aFRR	Residential consumers	(+)0.02% (-)0.02%	0%	0%	0%	0%			0%		0%	0%	0%		0%			<0.47%	0%	0%	0%	0%	0%	PQ	
mFRR	Total number of BSPs	14	7	9	31	34		4	31		8	6	9	47	49	5	1				24	87		5	
mFRR	Total capacity prequalified (MW)	(+)6470 (-)7072				32290		103	74014.2		1960	5424.7		1962	61650	1373		(+)8113 (-)8283			15915	(+)4417 (-)7737	(+)6760 (-)7210	(+)326 (-)156	
mFRR	Distributed generation	(+)48% (-)52%	PQ		PQ	PQ		0%	PQ		5%	0%	0%	27%	1.6%	2.1%	0%	(+)<6% (-)<5%			0%	(+)9% (-)38%		PQ	
mFRR	Batteries	(+)0.11% (-)0.1%	PQ	0%	0%	0%		0%	0%		0%	0%	0%	0%	0%	0%	0%	0%			0%	0%		PQ	
mFRR	Storage excluding hydro, pumped-hydro and batteries	(+)0.17% (-)0.14%		0%	0%	PQ		0%	PQ		0%	0%	0%	0%	0%	0%	0%	0%			0%	0%		PQ	
mFRR	Total demand response:	(+)2.2% (-)2.03%				0.6%		0%	0%			0%				0%	0%				4%	0%	(+)2.8% (-)2.2%	PQ	
mFRR	Commercial or industrial consumers	(+)2.18% (-)2.02%	PQ	PQ	PQ	0.6%		0%	0%		45%	0%		0,5%	1.4%	0%	0%	(+)<46% (-)<45%			4%	0%		PQ	
mFRR	Energy communities	0%		PQ	0%	0%		0%	0%		0%	0%	0%			0%	0%				0%	0%		0%	
mFRR	Residential consumers	(+)0.02% (-)0.01%	0%	0%	0%	0%		0%	0%		0%	0%			0.02%	0%	0%	0%			0%	0%		PQ	
RR	Total number of BSPs				3				31						27						24	94			
RR	Total capacity prequalified (MW)								74067.7						53600						15915	(+)5530 (-)8943			
RR	Distributed generation				PQ				PQ		PQ					PQ					0%	(+)8% (-)34%			
RR	Batteries				0%				0%		0%				0%	0%					0%	0%			
RR	Storage excluding hydro, pumped-hydro and batteries				0%						0%				0%	0%					0%	0%			
RR	Total demand response:				0%				0%												4%	0%			
RR	Commercial or industrial consumers				0%				0%		PQ					0%					4%	0%			
RR	Energy communities				0%				0%		0%					0%					0%	0%			
RR	Residential consumers				0%				0%		0%					0%					0%	0%			

Some capacity prequalified
No capacity prequalified
NAP (Not applicable: balancing reserve not used by the TSO)
NAP (Not applicable, obligatory service for some units and/or no prequalification process)
N/A (Not available)
PQ: there is some capacity prequalified but the NRA does not have this information

Source: ACER based on NRA data.
Notes: (1) The table refers to the capacity prequalified as of 31 December 2022 for local, standard, and specific balancing products. The shares are calculated over the total capacity prequalified for the corresponding balancing product. Distributed generation means generating installations connected to the distribution system as defined in the Electricity Directive. Energy communities include citizen energy communities and renewable energy communities as defined in the Electricity Directive and the Renewable Energy Directive. (2) No information for Denmark, Finland, and Slovakia. (3) Not applicable to Cyprus and Malta since they do not have a liquid wholesale electricity market. (4) The figure does not show Ireland since there is no clear translation of the EU balancing services to the IE-SEM due to the way that central dispatch has been implemented in Ireland. (5) Luxembourg is integrated within the LFC perimeter of Amprion in the DE-LU bidding zone, hence German provisions apply. (6) In Spain, Croatia, Italy, Portugal, and Romania the provision of FCR is mandatory for some generation units connected to the transmission grid. (7) In Hungary battery energy storage systems, residential consumers, and energy communities can only participate in the different balancing reserves through a registered aggregator which currently includes traders, VPPs, and independent aggregators. (8) In Italy the data on distributed generation, energy storage, and demand response refer to the RPGs participating in the UVAM pilot project which allows the aggregation of power generation modules, demand units and/or storage units from multiple connection points. (9) In the Netherlands the total capacity prequalified only refers to RPGs excluding the existing small-scale assets that, once offered on wholesale markets via aggregation, could add several GW of balancing capacity in the upcoming years. Thus, the shares shown in the table correspond to the maximum shares

Annex III: List of acronyms

Acronym	Meaning
ACER	European Union Agency for the Cooperation of Energy Regulators
aFRR	Automatically activated Frequency Restoration Reserve
BRP	Balance Responsible Party
BSP	Balancing Service Provider
CBA	Cost-Benefit Analysis
CEC	Citizen Energy Community
CEER	Council of European Energy Regulators
CHP	Combined Heat and Power
CRIDA	Complementary Regional Intraday Auctions
DSO	Distribution System Operator
D-tariff	Distribution network tariff
EC	European Commission
EHV	Extra High Voltage
ENTSO-E	European Network of Transmission System Operators for Electricity
ENTSO-E TP	ENTSO-E Transparency Platform
EU	European Union
EV	Electric Vehicle
FCR	Frequency Containment Reserves
GCT	Gate Closure Time
HHI	Herfindahl-Hirschman Index
HV	High Voltage
IE-SEM	Irish Single Electricity Market
ISP	Imbalance Settlement Period
IT	Information Technology
LFC	Load Frequency Control
MARI	Manually Activated Reserves Initiative
mFRR	Manually activated Frequency Restoration Reserve
MIC	Minimum Import Capacity
MMR	Market Monitoring Report
MS	Member State
N/A	Not Available
NAP	Not Applicable
NEMO	Nominated Electricity Market Operator
NRA	National Regulatory Authority
PICASSO	Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation
PV	Solar Photovoltaic

Acronym	Meaning
RES	Renewable Energy Sources
RPG	Reserve Providing Group
RPU	Reserve Providing Unit
RR	Replacement Reserve
SIPS	Sistema de Información de Puntos de Suministro
SME	Small and Medium-sized Enterprises
SO	System Operator
TERRE	Trans European Replacement Reserves Exchange
TSO	Transmission System Operator
T-tariff	Transmission network tariff
VAT	Value-Added Tax
VPP	Virtual Power Plants

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