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THE EU CLEAN ENERGY PACKAGE

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ABSTRACT

The EU Clean Energy Package, proposed by the European Commission in November 2016, includes eight legislative texts on the electricity market and consumers, Energy Efficiency and Energy Efficiency of buildings, Renewables & bioenergy sustainability as well as governance of the Energy Union. They were all published in the Official Journal of the European Union by June 2019. In this report, we will focus on two of the eight legislative texts; the Directive on common rules for the internal market in electricity (e-Directive) and the Regulation on the internal market for electricity (e-Regulation). We will assess their impact on the European internal electricity market rules compared to the framework established by the Third Energy Package, including the first generation of network codes. In the different topics, we present the final versions of the CEP provisions and highlight the main differences compared to initial proposals of the Commission.

The structure of this report follows the structure of the Clean Energy Package online course. The first section on Electricity Markets is 'Ensuring the internal market level playing field.' The second section on Electricity Grids is 'Adapting to the decentralization of the power system.' The third, on the New Deal, is 'Empowering customers and citizens.'

Keywords: European regulation, public interventions in electricity prices, network tariffs, capacity mechanisms, network codes, bidding zones, interconnectors capacity, EV charging infrastructure, electricity storage, DSO planning, DSO active network management, procurement of flexibility services, TSO-DSO coordination, EU DSO entity, active customers, smart metering, dynamic pricing, aggregators, citizens energy communities

Note: This report is an updated version of 'Meeus and Nouicer, 2018'. The EU Clean Energy Package. FSR Technical report. July 2018. ''

This version of the report includes the provisions from the final text of the electricity Directive and Regulation of the Clean Energy Package. It updates the previous version that was based on the Commission and Council positions.

Content

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Abbreviations

ACER: Agency for Cooperation of Energy Regulators, also called the agency

Art: Article

BEUC: The European Consumer Organisation

BRP: Balance responsible party

BSP: Balance service provider

BZ : Bidding zone

CA: Capacity auction

CACM: Regulation establishing a guideline on capacity allocation and congestion management

CBA: cost-benefit analysis

CCP: Critical peak pricing

CEC: Citizens Energy Community

CEDEC: The European Federation of Local Energy Companies

CEP: Clean Energy Package

CEER: Council of European Energy Regulators

CHP: Combined Heat and Power

CM: Capacity mechanism

CO: Capacity obligation

CO2: Carbon dioxide

CRM: Capacity remuneration mechanism

CP: Capacity Payments

DCC: Regulation establishing a network code on demand connection

DEP: Data Exchange Platform

DER: Distributed Energy Resources

DNDP: Distribution network development plan

DP: Dynamic pricing

DR: Demand Response

DSO: Distribution System Operator

EB GL: Regulation establishing a guideline on electricity balancing

EC: European Commission

EDSO for Smart Grids: Distribution System Operators' Association for Smart Grids

FBCC: Flow-based capacity calculation

EIF: Entry into force

ENTSO-E: European Network of Transmission System Operators for Electricity

EENS: Expected energy not served

EFET: European Federation of Energy Traders

EP: European Parliament

EPOV : European Energy Poverty Observatory

EPS : Emission Performance Standard

E-Directive: The Directive on common rules for the internal market in electricity (final text)

E-Regulation: The electricity Regulation on the internal market for electricity (final text)

EU: European Union

EURELECTRIC: The Union of the Electricity Industry

Europex: Association of European Energy Exchanges

EV: Electric vehicle

FCA: Regulation establishing a guideline on forward capacity allocation

FSR: Florence School of Regulation

GB: Great Britain

Gr: Gram

HVDC NC: Regulation establishing a network code on requirements for grid connection of high voltage direct current systems and direct current-connected power park modules

IEM: Internal Energy Market

kW: Kilowatt

kWh: Kilowatt hour

LEC: Local energy community

LOLE: Loss of load expectation

LOLP: Loss of load probability

MMR: Market Monitoring Report

MS: Member State

MW: Megawatt

MWh: Megawatt-hour

NC: Network code

NC ER: Regulation establishing a network code on electricity emergency and restoration

NIS Directive: The Directive on security of network and information systems (NIS Directive)

NRA: National Regulatory Authority

NTC: Net transfer capacity

Ofgem: Office of Gas and Electricity Markets (UK)

OJ: Official Journal of the European Union

RE: Renewable energy

REScoop: European federation of renewable energy cooperatives

RES-E: Electricity from Renewable Energy Sources

RfG NC: Regulation establishing a network code on requirements for grid connection of generators

RO: Reliability options

ROC: Regional Operation Centre

RSC: Regional Security Coordinators

RSCI: Regional Security Coordination Initiatives

SEDC: Smart Energy Demand Coalition

SO: System operation

SO GL: Regulation establishing a guideline on electricity transmission system operation

SoS: Security of supply

SR: Strategic reserve

T&L: taxes and levies

TFEU: Treaty on the Functioning of the European Union

ToU: Time of Use

TSO: transmission system operator

UK: United Kingdom

VAT: Value-Added Tax

VOLL: Value of Lost Load

Acknowledgments

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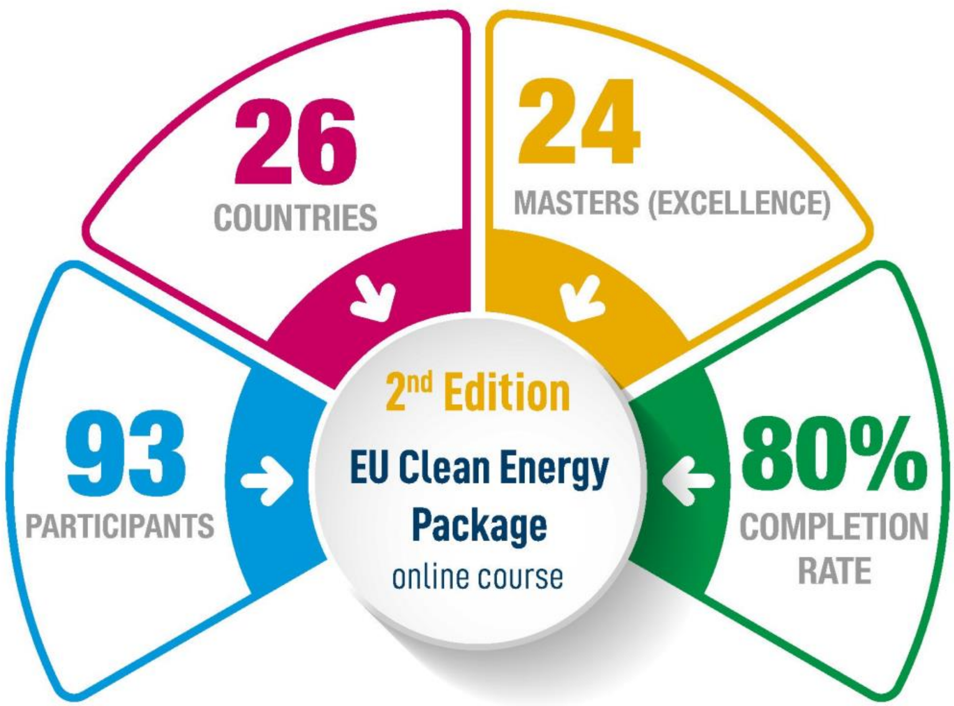

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Disclaimer: The authors are responsible for any errors or omissions. The underlined text in this report, reflects the authors' selected important points.

Introduction

The adoption process of the Clean Energy Package (CEP), composed of four Directives and four Regulations, was completed in June 2019 after the publication of the last legislative texts in the Official Journal (OJ)[1]. The CEP was proposed by the European Commission (EC) in November 2016. The European Council published its agreed negotiating position on these proposals in December 2017[2] for the 'trialogue' negotiations that continued until the end of 2018. The CEP Regulations entry into force (EIF) was on the twentieth day following their publication in the OJ, corresponding to the 4th of July 2019. The date of application for the Regulation on the internal market for electricity (e-Regulation) is the 1st of January 2020. The provisions of Directive on common rules for the internal market in electricity (e-Directive), representing substantive amendments with regard to Directive 2009/72/EC, will have to be transposed into national law within 18 months from the Directive's publication.

The Commission shall review the e-Directive implementation and the e-Regulation by 31 December 2025 and 31 December 2030, respectively. It shall submit a report, regarding the e-Directive and e-Regulation to the European Parliament and the Council, accompanied by a legislative proposal where appropriate. The Commission's review of the e-Directive shall assess, in particular, whether customers, especially energy poor or vulnerable ones, are adequately protected.

This report focuses on two of the eight legislative texts; the e-Directive and the e-Regulation. We will assess their impact on the European internal electricity market rules compared to the framework established by the Third Energy Package, including the first generation of network codes. In the different topics, we present the final versions of the CEP provisions and highlight the main differences compared to initial proposals of the Commission.

The structure of this text follows the structure of the online course. The first section on Electricity Markets is 'Ensuring the internal market level playing field.' The second section on Electricity Grids is 'Adapting to the decentralization of the power system.' The third, on the New Deal, is 'Empowering customers and citizens.'

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[1] The Directive text can be found at: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=uriserv:OJ.L_.2019.158.01.0125.01.ENG&toc=OJ:L:2019:158:TOC
The Regulation text can be found at: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=uriserv:OJ.L_.2019.158.01.0054.01.ENG&toc=OJ:L:2019:158:TOC

[2] The document can be found at: http://www.consilium.europa.eu/en/documents-publications/public-register/

1. Ensuring the internal market level playing field

In this section, we first set the scene by introducing the different components of the typical electricity bill. We then focus on three key measures in the CEP to ensure the level playing field in the internal electricity market, i.e., the phasing out of public intervention in setting electricity prices, the methodologies for network tariffs, and the limitation of the use of capacity mechanisms. We conclude the section by highlighting the interlinkage of the CEP with the network codes (NC) on topics related to the internal electricity market such as balancing responsibilities and system operation regional governance, as well as bidding zones and the calculation of interconnectors' capacity. We also refer to the second generation of network codes that are included in the CEP.

1.1. Setting the scene: the different components of the electricity bill

End-user electricity prices consist of the sum of three main components: the energy component, network charges, and taxes and levies[3] (T&L). The European average in 2017 of the energy component (contestable charges), is about 35% of the total bill for households. Non-contestable charges (i.e., network charges, T&L, and possible other charges) constitute the remaining 65% of the consumers' bill. Note that for countries with a high share of renewable energy sources (RES) like Germany or Denmark[4], the T&L, which also include RES contributions, constitute the main part of the electricity bill. Figure 1 gives an overview of the composition of end-user electricity prices across EU capital cities.

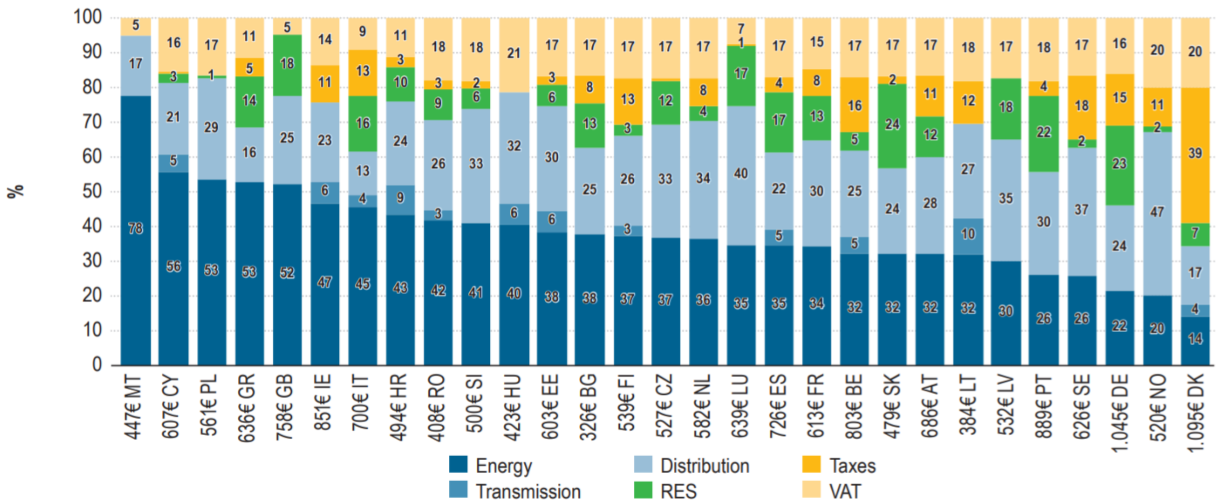

Figure 1: End-user electricity prices breakdown of incumbents' standard offers for households in EU capital cities – November–December 2017 (%), source: (ACER and CEER, 2018a)

Electricity prices differ significantly across MSs for several non-market reasons. For households, they increased by 25.9% compared to 2008 (ACER and CEER, 2018a). This increase is due to significant rises in non-contestable charges (network charges and T&L) in absolute terms (EC, 2016a). However, the shares of network charges (%) in the electricity bill, as shown in Figure 2**,** have remained almost unchanged (ACER and CEER, 2018a). Germany, with 30.5 € cents/kWh, has the highest household electricity prices. This represents more than three times the household prices in Bulgaria (9.7 € cents/kWh). For the industrial

[3] Please take into account that RES subsidies are considered in this text as T&L. Indeed, RES are not a necessary cost for grids, however, they bring significant positive externalities for the environment and promote energy transition.

[4] In the case of Denmark, even though the share of renewable energies is expected to increase, this part of the bill will decline in the coming years, because costs for renewable energies are going to be gradually moved from the electricity bill to the national budget (Blomgren-Hansen and Rye-Andersen, 2017).

sector, this difference is even more important with 24.0 € cents/ kWh) in Denmark and 4.3 € cents/kWh in Luxembourg (ACER and CEER, 2018a).

The energy component is determined by two main factors: wholesale prices and costs associated with the retail activity. There are three main drivers for wholesale electricity prices: fuel shares in the electricity generation mix, commodity prices, and market features (i.e., the degree of competition, access to resources, and regional market integration). Retail costs include supply operating costs (i.e., billing and marketing) and a profit margin for providing retail services[5]. The energy component share declined from 41% to 35% in EU capital cities between 2012 and 2017. This decline over the past years reflects a better functioning of the internal electricity market as well as the decrease in wholesale electricity prices.

The network component, including subcomponents of transmission and distribution, represented 27% of the EU electricity bill for households in EU capital cities in 2017 (weighted average). Distribution charges represent the largest part of network charges in a consumer bill. They ranged from 13% to 47% in 2017 households' electricity bill in EU capital cities, while for the transmission network charges, these percentages were between approximately 0% and 10%.

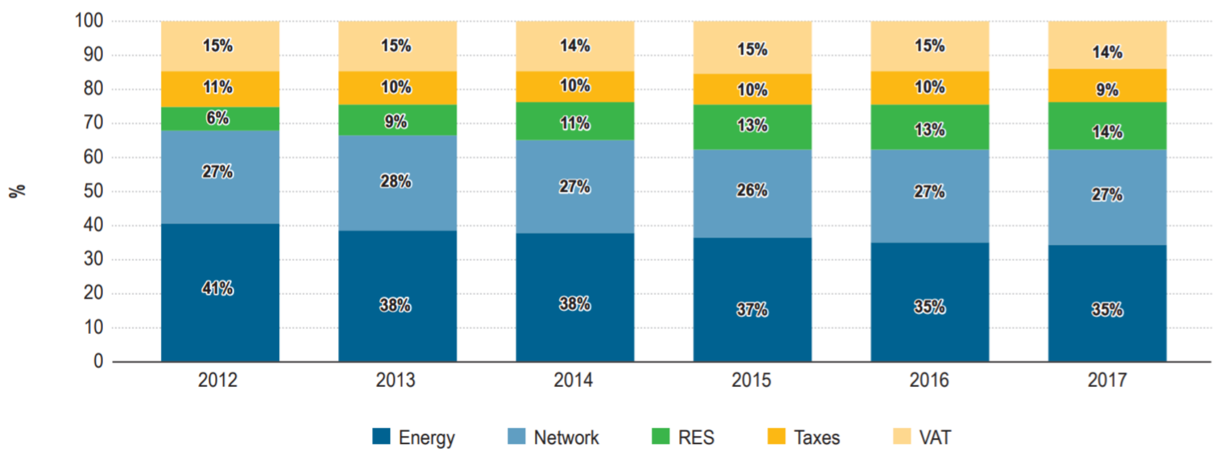

Figure 2: Weighted average breakdown of end-user electricity price components in EU capital cities – 2012–2017 (%), source: (ACER and CEER, 2018a)

The T&L component share of the electricity bill has increased[6] for electricity since 2012. This is mainly due to the cost of support mechanisms for electricity from renewable energy sources (RES-E) and cogeneration or combined heat and power (CHP) across Europe[7]. The applied value-added taxes (VAT) on household electricity prices are percentages of these prices. Therefore, its nominal effect increased with the increase of total prices. Some MSs additionally raised the VAT rate. Tax rates vary in general for consumers across MSs depending on factors such as consumption and grid connection.

1.2. Limiting public interventions in electricity market prices

In this part, we begin by providing an overview of the current practices for electricity price regulation in Europe. Then we present measures included in the CEP to limit public interventions in the electricity price setting, as well as the transitional measures aiming at ensuring customer protection during the transition to market-based retail prices.

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[5] Note that in some reports the energy component does not include the retail costs. This would mean that the electricity bill would contain four components (CRU, 2017).

[6] Also its absolute value increased as the end-users' electricity prices have risen since then.

[7] In some countries (Italy, for example) RES levy is paid through a specific fee added to the electricity bill. Levies to remunerate RES are usually not included in the network component but rather in the T&L one to allow a comparison between different MSs.

1.2.1 Current practices

In Europe, the majority of MSs have opted for retail liberalization with the phasing out of regulated electricity market prices. **Art 21** of the European Directive 2003/54/EC already required that non-household electricity consumers should be able to freely choose their supplier from 1 July 2004 and for household electricity consumers starting from 1 July 2007[8]. Today, around 40% of Member states still have regulated end-user electricity prices, as presented in Figure 3[9]. Countries in Eastern Europe, as well as France, Spain, and Portugal still have public interventions in setting electricity prices, either for the entire retail segment or only for the household segment.

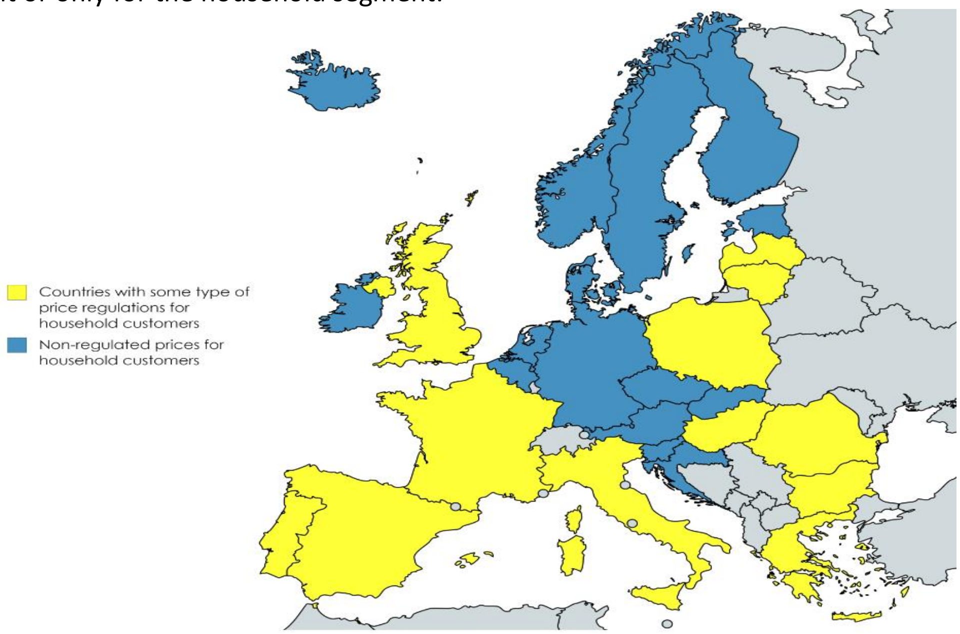

Figure 3: Application of regulated prices for households as of June 2019, source: based on (CEER, 2017a)

MSs have adopted varying approaches for retail competition following the European Directive 2009/72/EC. **Art 3(3)** of European Directive 2009/72/EC states that '*Member States shall ensure that all household customers, and (…) small enterprises, (…), enjoy universal service, that is, the right to be supplied with electricity of a specified quality within their territory at reasonable, easily and clearly comparable and transparent prices'.* The Directive adds in **art 3(14)** that '*the interests of the Community include, inter alia, competition with regard to eligible customers*'. Besides, the Directive foresees the possibility to introduce a 'supplier of last resort'[10] to ensure the provision of a universal service of electricity connection and supply. This Directive was interpreted differently by MSs, and thus varying approaches have been adopted by MSs for introducing retail competition leading to significant variation in the degree of market liberalisation between them.

The European Commission framework strategy encourages MSs to establish a roadmap for the phasing out of public interventions in electricity prices where such intervention still exists (EC, 2015a). The phasing-out of regulated prices should be pursued with a mechanism to protect vulnerable consumers. According to the Commission framework strategy, this may be provided through the general welfare system. It adds

[8] These provisions were kept by the electricity Directive 2009/72/EC of the Third Energy Package.

[9] Please note that this figure indicates the countries that still offer regulated electricity prices regardless of their shares compared to competitive retail offers. For instance, in Portugal, 80% of electricity customers were under a liberalised tariff regime in January 2018 (Baratti, 2018). Italy will phase electricity price regulation (called "maggior tutela") by July 1st, 2020 (Stagnaro et al., 2018).

[10] **Art 3** of the Directive 2009/72/EC states that *'to ensure the provision of universal service, Member States may appoint a supplier of last resort'.*

that if it is provided through the energy market, then it could be implemented through schemes such as a solidarity tariff or as a discount on energy bills, moving away from the tradition of regulated prices.

1.2.2. Measures for limiting public intervention in electricity market prices

The CEP and more specifically the e-Directive *'aims to ensure affordable, transparent energy prices and costs for consumers, a high degree of security of supply and a smooth transition towards a sustainable low-carbon energy system.'* The e-Directive allows MSs, by way of derogation, to temporarily regulate prices to protect energy-poor or vulnerable households. It sets specific conditions for interventions in the electricity price setting, to be only applied as public service obligations and subject to specific conditions. These public interventions should not sidestep open market principles.

Recital 22 of the e-Directive, on public authorities' price regulation, highlights the distorting effect of public interventions on price regulation. It states that '*Member States should maintain wide discretion to impose public service obligations on electricity undertakings*[11] *in pursuing objectives of general economic interest. (…) Nevertheless, public service obligations in the form of price setting for the supply of electricity constitute a fundamentally distortive measure that often leads to the accumulation of tariff deficits, the limitation of consumer choice, (…).*' MSs are invited to apply other policy tools, such as targeted social policy measures, to guarantee citizens affordability of electricity supply. It adds that *'a fully liberalised, well-functioning retail electricity market would stimulate price and non-price competition among existing suppliers and provide incentives to new market entrants, thereby improving consumer choice and satisfaction.'*

MSs shall adopt appropriate measures to promote effective competition among electricity suppliers, which shall be able to set the electricity supply prices freely, according to **Art 5(1)** of the e-Directive. **Art 5(2)** adds that MSs shall ensure the protection of energy-poor or vulnerable household customers, defined in **art 28** and **art 29**, through social policy or other means than public interventions in price setting. These principles were included in the first draft of the e-Directive and approved in the final version. Transitional measures for applying market-based supply prices and derogations to apply public intervention in price setting are possible for MSs. These measures changed from the first Commission proposal to different extents. We present them in the following subsection.

Art 9 of the e-Directive introduces public service obligations. In price setting, they can occur in situations; first, when the electricity prices rise higher than normal due to constrained supply. Second, in case of a market failure where NRAs and competition authorities' interventions were ineffective.

1.2.3. Transitional measures for limiting public intervention in electricity market prices

The measures for limiting public intervention include two main derogations. The first one concerns the application of these interventions for vulnerable consumers and households in a situation of energy poverty. The second one is to ensure the transition towards retail market competition where MSs applying public interventions in price-setting shall report on the necessity of these interventions and the progress made towards market-based prices.

By 1 January 2022 and 1 January 2025, MSs shall submit reports to the Commission on the implementation of market-based prices and the necessity of public interventions. Following this, by the end of 2025, the Commission shall submit a report to the European Parliament and the Council on the implementation of market-based retail pricing. This can be together with or followed by a legislative proposal that may

[11] **Art 2(57)** of the e-Directive defines an 'electricity undertaking' as *'a natural or legal person who carries out at least one of the following functions: generation, transmission, distribution, aggregation, demand response, energy storage, supply or purchase of electricity, and who is responsible for the commercial, technical or maintenance tasks related to those functions, but does not include final customers.'*

include a roadmap for removing regulated prices with an end-date to them. In the remainder of this section, we discuss the two derogations under which MSs may apply public interventions in electricity prices.

Derogation 1: Protective measures for energy-poor and vulnerable customers:

Regarding energy poverty, the e-Directive indicates, in **recital 58**, that *'Member States should take the necessary measures to protect vulnerable and energy poor customers in the context of the internal market in electricity.'* Indeed, confirming the need for a common EU-wide effort to face energy poverty, the Commission launched, in December 2016, the European Energy Poverty Observatory (EPOV) to provide support for MSs. It is a 40-month research project aiming to improve the state of the art on energy poverty detection and the measures to tackle it. For more information, see Bouzarovski (2018).

The **recital (4)** of the e-Directive emphasizes the protection of vulnerable consumers and states that the Energy Union Framework Strategy *'sets out the vision of an Energy Union with citizens at its core, where citizens take ownership of the energy transition, (…) and where vulnerable consumers are protected'*. MSs should identify through accurate measures, according to **recital (59)**, vulnerable consumers and put measures in place that give them adequate attention. **Art 5 (2)** of the e-Directive adds that '*Member States shall ensure the protection of energy poor or vulnerable household customers pursuant to Articles 28 and 29 by social policy*[12] *or by other means than public interventions in the price setting for the supply of electricity.'*

The conditions for MSs' derogation to apply public intervention in electricity price to protect energy poor or vulnerable household customers are stated in **art 5(4)** and **art5(5).** These conditions changed from the first Commission proposal to the final e-Directive text. In the first draft, the Commission proposed that public interventions in price setting for energy-poor or vulnerable household customers may continue to be applied by MSs up to five years from the entry into force of the e-Directive. This option allows for transitional price regulation for vulnerable consumers. After the five years, MSs may still apply these interventions for vulnerable household customers for reasons of extreme urgency.

The final text removed the five-year period. **Art 5(4)**, sets the conditions for MSs applying these interventions in the electricity price setting. Public interventions shall:

'(a) pursue a general economic interest and not go beyond what is necessary to achieve that general economic interest;
(b) be clearly defined, transparent, non-discriminatory and verifiable;
(c) guarantee equal access for Union electricity undertakings to customers;
(d) be limited in time and proportionate as regards their beneficiaries;
(e) not result in additional costs for market participants in a discriminatory way.'

The application of these public interventions by a MS shall comply with **art 3(3)d** of the Governance Regulation for the assessment the number of households in energy poverty and **art 24** of the same Regulation on the integrated reporting on energy poverty. This should be done '*regardless of whether the Member State concerned has a significant number of households in energy poverty'* (**art 5(5)** of the e-Directive).
In addition to that, MSs are obliged to monitor the number of households in energy poverty to provide targeted support. According to **art 29**, '*Member States shall establish and publish a set of criteria, which may include low income, high expenditure of disposable income on energy and poor energy efficiency.'* In addition, guidance on the definition of *'significant number of households in energy poverty'* should be provided by the Commission in the context of this **art 29** on energy poverty and **art 5(5)** on public

[12] Social policy was added in the final text of the e-Directive

interventions in price setting. This should be done *'starting from the premise that any proportion of households in energy poverty can be considered to be significant.'*

Derogation 2: Public intervention and market monitoring for a transition period to establish retail competition

The second derogation stated in **art 5(6)**, aims to make it possible for MSs to apply public interventions in electricity price setting for a transitional period in order to establish effective retail competition. In addition to the compliance criteria set out in **art 5(4)** and presented under the previous derogation**,** further criteria for the application of the second derogation are set out in **art 5(7)**. Indeed, for the purpose of a transition period, public interventions shall:

'(a) be accompanied by a set of measures to achieve effective competition and a methodology for assessing progress with regard to those measures;
(b) be set using a methodology that ensures non-discriminatory treatment of suppliers;
(c) be set at a price that is above cost, at a level where effective price competition can occur;
(d) be designed to minimise any negative impact on the wholesale electricity market;
(e) ensure that all beneficiaries of such public interventions have the possibility to choose competitive market offers and are directly informed at least every quarter of the availability of offers and savings in the competitive market, in particular of dynamic electricity price contracts, and shall ensure that they are provided with assistance to switch to a market-based offer;
(f) ensure that, pursuant to Articles 19 and 21, all beneficiaries of such public interventions are entitled to, and are offered to, have smart meters installed at no extra upfront cost to the customer, are directly informed of the possibility of installing smart meters and are provided with necessary assistance;
(g) not lead to direct cross-subsidisation between customers supplied at free market prices and those supplied at regulated supply prices.'

At the same time, MSs have also monitoring obligations on retail market competition. **Art 12** of the e-Directive, promoting retail competition, states that MSs shall ensure that *'switching supplier or market participant engaged in aggregation shall be carried out within the shortest possible time.'* Also, MSs shall provide that the switching should happen within a maximum of three weeks from the date of the request. Additionally, MSs shall ensure that *'at least household customers, microenterprises and small enterprises*[13] *are not charged any switching-related fees.*' The final version of the e-Directive added that '*by no later than 2026, the technical process of switching supplier shall take no longer than 24 hours and shall be possible on any working day.'*

Nevertheless, contract termination fees, charged to customers willingly terminating fixed-term supply contracts before their maturity, can be allowed by way of derogation. These fees have to be clearly communicated to the customer before they sign the contract, as emphasized in the **art 12(3)** of the e-Directive. They shall be proportional to the direct economic loss of the contract termination for the supplier or the aggregator and shall not exceed it. NRAs, or any other competent authority, shall monitor the permissibility of these fees.

On retail offer comparison tools, **art 14** of the e-Directive states that *'Member States shall ensure that at least household customers, and microenterprises*[14] *with an expected yearly consumption of below 100,000 kWh have access, free of charge, to <u>at least one tool comparing the offers of suppliers</u>*. The article also mentions the different criteria that have to be met by these tools such as their independence from market

[13] A microenterprise, according to **art 2(6)** of the e-Directive, means *'an enterprise which employs fewer than 10 persons and whose annual turnover and/or annual balance sheet total does not exceed EUR 2 million.'*
[14] Same replacement here as in the previous footnote

participants, the disclosure of the tool owner as well as setting out, and disclosing, comparison criteria. Comparison tools should also use plain and unambiguous language, be accessible for persons with disabilities, and be accurate. MSs shall ensure that there is at least one tool that covers the whole of the market as they predominantly benefit consumers and especially the active ones who compare offers and/or switch regularly between suppliers. Finally, these tools should provide *'an effective procedure to report incorrect information on published offers'* and perform offers' comparisons while limiting the requested personal data to the strictly necessary for the comparison.

Customers should be informed about the availability of such tools. These tools may be operated by any entity, including private companies and public authorities or bodies**.** A competent authority shall be appointed by MSs to be responsible for issuing a trust mark to comparison tools that meet the criteria stated above.[15] CEER (2016) public consultation paper presents, for instance, guidelines of good practice on comparison tools.

Moreover, **art 59** of the e-Directive on 'Duties and powers of the regulatory authority' adds in paragraph (1)(o) that NRAs have <u>to monitor</u> *'the level and effectiveness of market opening and competition at wholesale and retail levels, including on electricity exchanges, prices for household customers including prepayment systems, the impact of dynamic electricity price contracts and of the use of smart metering systems, switching rates, disconnection rates, (…).'* They should also monitor the interrelation between household and wholesale electricity prices as well as the evolution of grid tariffs and levies. Any complaints by household customers and any distortion or restriction of competition shall be brought to the relevant competition authorities.

Highlights

Main measures

- Public interventions in end-user electricity prices shall be gradually removed.

- NRAs are required to enhance retail markets competition, to ensure efficient competition and to guarantee consumer protection.

- MSs are required to define and publish a set of criteria for measuring energy poverty and to ensure that the customers who are vulnerable or in energy poverty are protected.

- By 1 January 2022 and 1 January 2025, MSs shall submit reports to the Commission on the implementation of market-based prices and the necessity of public interventions.

- By 31 December 2025, the Commission shall submit a report on the implementation of market-based retail pricing. This can be together with or followed by a legislative proposal which may include an end date for regulated prices.

Transitional measures

- A derogation for using public intervention to protect vulnerable household customers.

- A derogation for using public intervention as a transitional measure towards establishing retail competition together with parallel provisions for retail market monitoring.

[15] The trust mark replaces the certificate introduced in the Commission proposal. The final text of the Directive includes a derogation for MSs not to issue a trust mark for comparison tools fulfilling the mentioned criteria in **art 14(6)**.

1.3. Methodologies for network tariffs

In this part, we first present the current practices for network tariffs across Europe. Then, we describe the CEP measures regarding the network tariffs design and methodologies.

1.3.1. Current practices

Transmission tariffs design across Europe

In Europe, there are different systems of electricity transmission pricing and associated tariff structures. Transmission access is generally charged via capacity component (€/kW) and/or energy volumetric component (€/kWh). Transmission tariffs can be applied to electricity generators and consumers, or in some cases only to the consumers. Figure 4 shows the differences across Europe based on ENTSO-E data.

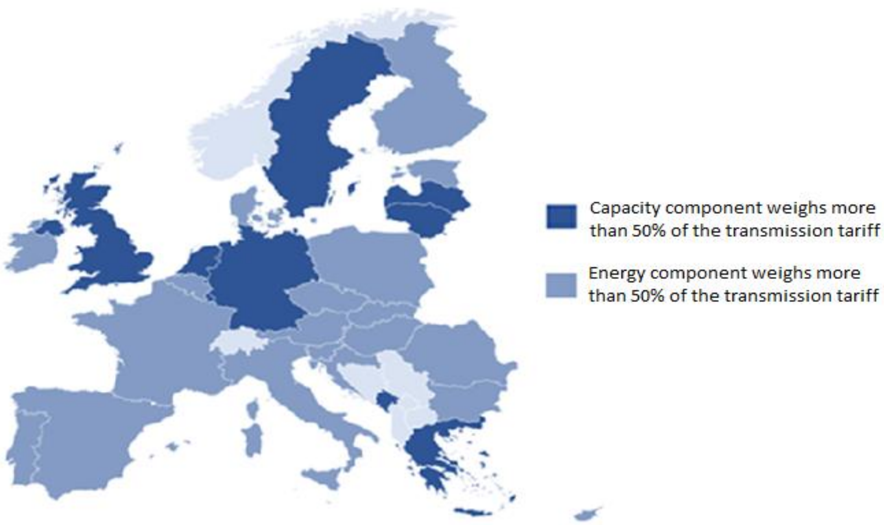

Figure 4: Status quo on energy and capacity transmission tariffs components among MSs, based on (ENTSO-E, 2017a)

The current situation is the result of nationally established transmission tariff policies and different national contexts. Some MSs (i.e., Germany, the UK, and Sweden) have implemented a capacity-based tariff whereas some other MSs (i.e., France, Spain and Italy) have implemented an energy-based tariff. In some tariff designs, system ancillary service costs and network losses costs can be charged through transmission tariffs (partially or totally) (such as Austria and France (ENTSO-E, 2017a)), rather than through market mechanisms (such as Spain and Portugal). Another difference between TSO charges in the EU is the share between generation (G-charge) and load (L-Charge) network charges as well as the seasonal and locational differentiation. This implies a certain complexity at the EU level. The Regulation EC 838/2010 (EC, 2010), is the last published legislative document relevant to the regulation of the network tariffs.

Part B of this Regulation sets guidelines for a common regulatory approach to transmission charging, such as annual average transmission charges paid by producers (G-charges) and their ranges. These ranges differ by category of MSs. Four categories of MSs are distinguished. The first includes producers from all MSs, except for Denmark, Sweden, Finland, Romania, Ireland, Great Britain and Northern Ireland, which pay a G-charge in the range of 0 to 0,5 EUR/MWh. The second category is for producers from Denmark, Sweden and Finland, where the G-charges shall be within a range of 0 to 1,2 EUR/MWh. The third category is for producers from Ireland, Great Britain and Northern Ireland where the G-charges shall be within a range of 0 to 2,5 EUR/MWh and the fourth category is for producers from Romania where the G-charges shall be within 0 and 2,0 EUR/MWh.

These ranges aim to ensure that the benefits of harmonisation are realized and to prevent the variations in G-charges from undermining the internal market, according to **recital (10)** of the Regulation EC

838/2010. The different ranges by MSs can be explained by the different tariffs methodologies and policies within the EU (ENTSO-E, 2017a).

Distribution tariffs design across Europe

The methodologies and structures for distribution tariffs are also different across Europe. As with transmission tariffs, the shares of energy/capacity components for distribution tariffs, shown in Figure 5, vary significantly across EU countries. Most European DSOs' revenue is currently based on volumetric tariffs, i.e., 69% of the revenue for households, 54% for small industrial consumers and 58% for large industrial consumers. For more details, please refer to (EC, 2015b).

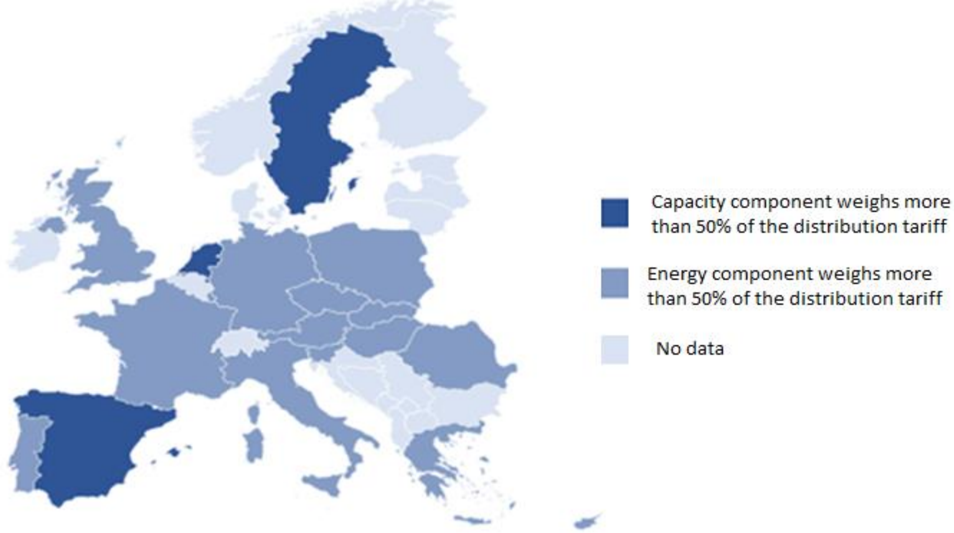

Figure 5: Status quo on energy and capacity distribution tariffs components among MSs for households, based on (EC, 2016b)

Interesting cases are the Netherlands and Great Britain (GB). In the Netherlands, the distribution tariff has been based on the physical capacity of the household connection since 2009, and there is no energy component in the tariff. In GB, part of the network charges paid is intended to reflect the consumers' contribution to the system peak. For more information per country, please consult CEER (2017b) guidelines of good practice for electricity distribution network tariffs.

1.3.2. Principles for network tariffs design in the CEP

The CEP brings new measures for network tariffs methodologies. **Art 18** of the e-Regulation states that network tariffs shall be cost-reflective[16] and send appropriate signals on the short and long term. This shall support overall system efficiency and guide efficient investments. Also, network tariffs shall not discriminate against distributed energy resources and aggregation either positively or negatively. Non-distortive and cost-reflective tariffs design facilitate innovation and ease unlocking flexibility potential in electricity systems. **Art 18(1)** adds that network charges shall not include unrelated costs supporting unrelated policy objectives, such as T&L, as this would distort production, consumption, and investment decisions.

Distribution tariffs, in particular, shall be cost-reflective regarding the use of the distribution network by grid-connected users, including active customers **art 18(7)**. The article adds that they '*may contain network connection capacity elements and may be differentiated based on system users' consumption or generation profiles*.' In case a MS has undertaken smart metering system roll-out, the NRA shall consider

[16] A cost reflective tariff, according to SCHITTEKATTE et al. (2019), implies that the cost a consumer creates on the electricity network should be reflected by the network tariff. It aims to lead to an overall lowest final cost for serving electricity to different system customers. Ideally, the tariff level for different user groups should reflect over time how their usages affect the costs of the network.

time differentiated network tariffs '*when fixing or approving transmission and distribution tariffs or their methodologies.'* This should be in line with **art 59** of the e-Directive. Then, where appropriate, time differentiated network tariffs may be introduced.

Regarding system operation, distribution tariff methodologies shall provide incentives to DSOs for the most cost-efficient operation and development of their networks, including through the procurement of services. NRAs shall, therefore, according to **art 16(8)** recognize the relevant costs that result from the procurement of innovative services and include them in distribution tariffs. NRAs may also introduce '*performance targets in order to provide incentives to distribution system operators to increase efficiencies in their networks, including through energy efficiency, flexibility and the development of smart grids and intelligent metering systems.'*

In order to mitigate the risk of internal electricity market fragmentation, ACER shall provide a best practice report[17] on transmission and distribution tariff methodologies within <u>three months after the entry into force of the Regulation</u> as stated in **art 16(9).** *'That best practice report shall address at least:*

'(a) the ratio of tariffs applied to producers and tariffs applied to final customers;
(b) the costs to be recovered by tariffs;
(c) time-differentiated network tariffs;
(d) locational signals; (e) the relationship between transmission tariffs and distribution tariffs;
(f) methods to ensure transparency in the setting and structure of tariffs;
(g) groups of network users subject to tariffs including, where applicable, the characteristics of those groups, forms of consumption, and any tariff exemptions;
(h) losses in high, medium and low-voltage grids.'

ACER shall update its report at least once every two years and should leave sufficient room for MSs to take into account national specificities. NRAs shall duly take into consideration this report when approving, determining network tariffs, or their methodologies, or both.

Regarding the harmonization of network tariffs, it should be noted that the Commission proposed in the e-Regulation proposal version that this area should be handled through network codes as indicated in **art 55(1)(k**) of the Commission proposal. It added the harmonization of distribution tariffs in the areas to be covered by network codes in addition to transmission tariffs. Following the 'trilogue' negotiations, the final text of the e-Regulation has removed the addition of the harmonization of distribution tariffs from the network codes focus areas. It has also removed the harmonization of transmission tariffs, which has been first introduced in **art 8** of the Regulation (EC) No 714/2009 of the Third Energy Package, among the focus areas of network codes. However, it has not been developed into a tariff network code[18].

Highlights

- Network tariffs shall give appropriate incentives to TSOs and DSOs to foster market integration and security of supply (SoS) as well as to increase efficiencies and support investment and R&D.
- ACER shall provide a best practice report transmission and distribution tariff methodologies.
- NRAs shall take into consideration ACER's best practice report when approving or determining transmission and distribution tariffs or their methodologies.

[17]The best practice report replaced the recommendation on the progressive convergence of transmission and distribution tariff methodologies, to be addressed by ACER to NRAs, included in the Commission proposal.

[18]There are tariff network codes only for the gas sector. For the electricity, the developed network codes are on market, grid and connection.

1.4. Limiting the use of capacity mechanisms

Security of supply, resource adequacy, and capacity mechanism are three related topics in electricity systems. Security of supply is a key pillar of the European Electricity Policy as stated in **art 194(1)** of the Treaty on the Functioning of the European Union ('TFEU'). It is indispensable in modern societies that are increasingly relying on electricity both for households and industries segments. Resource adequacy needs, therefore, to be suitably assessed to ensure that there are sufficient generation and flexibility for a reliable electricity supply at all times. In case of adequacy concerns, MSs may anticipate this inadequacy in generation capacity and introduce capacity mechanisms at the national level, supporting generation capacity investment and ensuring system adequacy. However, when capacity mechanisms are uncoordinated and imperfectly designed, they may risk affecting cross-border trade and distort investment signals, creating market entry-barriers for alternative providers. The CEP prioritizes the adoption of market reforms to address resource adequacy. MSs may apply capacity mechanism, as a last resort, to eliminate residual adequacy concerns.

In this section, we discuss the current implementation practices on capacity mechanisms (CMs), also called capacity remuneration mechanisms (CRMs) in Europe. The CEP includes measures to limit their use, the discrimination against emerging business, their impact on climate goals, and the related cross-border concerns.

1.4.1. Fundamentals of Capacity Mechanisms

Capacity mechanisms are defined in **art2(22)** of the e-Regulation as *'temporary measure to ensure the achievement of the necessary level of resource adequacy by remunerating resources for their availability, excluding measures relating to ancillary services or congestion management.'*

Capacity mechanisms can be classified as 'volume-based mechanisms' and 'price based mechanisms'. In Figure 6, below, we illustrate the classification of CMs according to their characteristics.

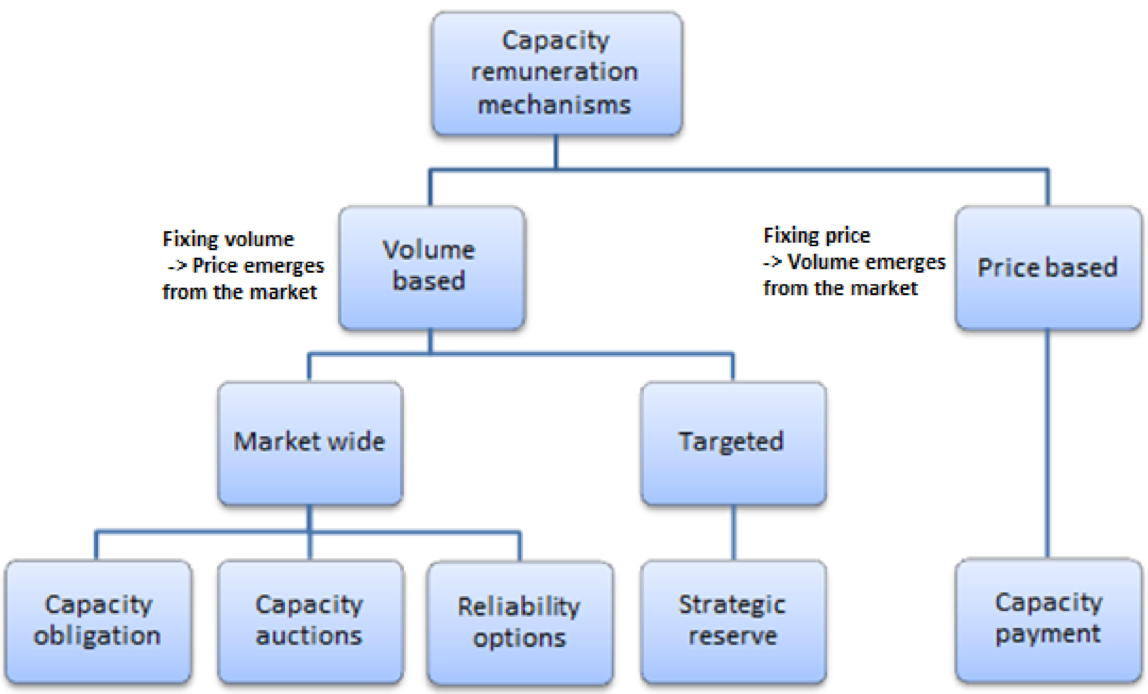

Figure 6: Taxonomy of capacity mechanisms, source: based on (EP, 2017)

In the volume-based mechanisms, the total amount of capacity required is determined in advance by policymakers or by a designated entity, i.e., a TSO or a NRA. A market-based process is then used to establish the price to be paid. Volume-based mechanisms may also be divided into two subcategories. The first is ‘Market-wide mechanisms’ which provide support to all market participants that are required to meet the reliability standard, and they, in principle, reward all capacity providers. The second subcategory is ‘targeted mechanisms’ which reward only specific plants or technologies, i.e., they provide support only to the extra capacity required in addition to that provided by the market without the subsidies (Hancher et al., 2015).

In the price-based mechanisms, a price is administratively set by policymakers at a level calculated to achieve investment in the amount of capacity required. The investors decide how much volume of capacity they are willing to invest for the given price. The box below describes the different capacity mechanisms[19] used in Europe (EP, 2017).

Box: Description of the different capacity mechanisms

Capacity obligation (CO): Also called capacity requirement, is an obligation on suppliers or large consumers to contract with generators for a certain level of capacity. This capacity is determined by TSO/regulator and related to their self-assessed future consumption or supply (e.g. three years ahead), plus a reserve margin. If not enough capacity is contracted, the supplier or the consumer will pay a buy-out price/fine. The price for capacity is determined in a decentralised way, through the contracts; this model could also include a market of exchangeable obligations (secondary market).

Capacity auction (CA): The capacity volume to be auctioned is decided centrally (by the TSO or regulator) a few years in advance. The price is determined by auction and is paid to all resources (existing and new) clearing the auction. Capacity providers bid to receive a payment that reflects the cost of building new capacity. The new capacity participates in the energy-only market.

Reliability options (RO): RO is based on a forward auction (e.g. three years ahead). A capacity provider enters into an option contract with a counterparty (a TSO or a large consumer or supplier). The contract offers the counterparty the option to procure electricity at a predetermined strike price. The capacity provider must be available to the system operator for dispatch above the strike price.

Strategic reserve (SR): A central agency (transmission system operator or government agency) decides upon the amount of capacity needed to make up any shortfall in the market few years in advance. The level of payment of the contracted capacity (strategic reserve) is set through a competitive tendering process. The contracted power plants cannot participate in the electricity market and are only activated in case of extreme conditions.

Capacity Payments (CP): CP is a price-based mechanism. It pays a fixed amount (set by the regulator) for available capacity to all generators. The plants receiving capacity payments continue to participate in the energy-only market. The payment could be given also when the plant does not run, but certain availability criteria have to be met.

1.4.2. Current implementation practices in capacity mechanisms

In recent years, different EU Member States have implemented varying CM designs (see Figure 7). The most common CMs are strategic reserves (EC, 2016c). They are used, for example, in Belgium, Germany, Poland, Sweden, and Finland. In Germany, the strategic reserve mechanism requires network operators to procure and hold 2GW of capacity outside the market, starting in winter 2018/2019 and

[19] For more details on the different uses of capacity mechanisms, please see (ACER, 2013), (Hancher et al., 2015) and (EC, 2016d)

lasting initially for two years (BMWi, 2018). In Italy, a reliability option scheme is planned with a first delivery in 2020. Capacity procurment will be through competitive tenders for reliability option contract.

Recent Developments:
In February 2018, capacity mechanisms in six member states, namely Belgium, France, Germany, Greece, Italy, and Poland, received EU State aid approval (EC, 2018).The Commission found that these measures will contribute towards ensuring security of supply while preserving competition in the single market. The approved mechanisms are the following: strategic reserves, in Belgium and Germany, two market-wide capacity mechanisms in Italy and Poland, as well as a demand response[20] (DR) tender in France and an interruptibility scheme in Greece[21].

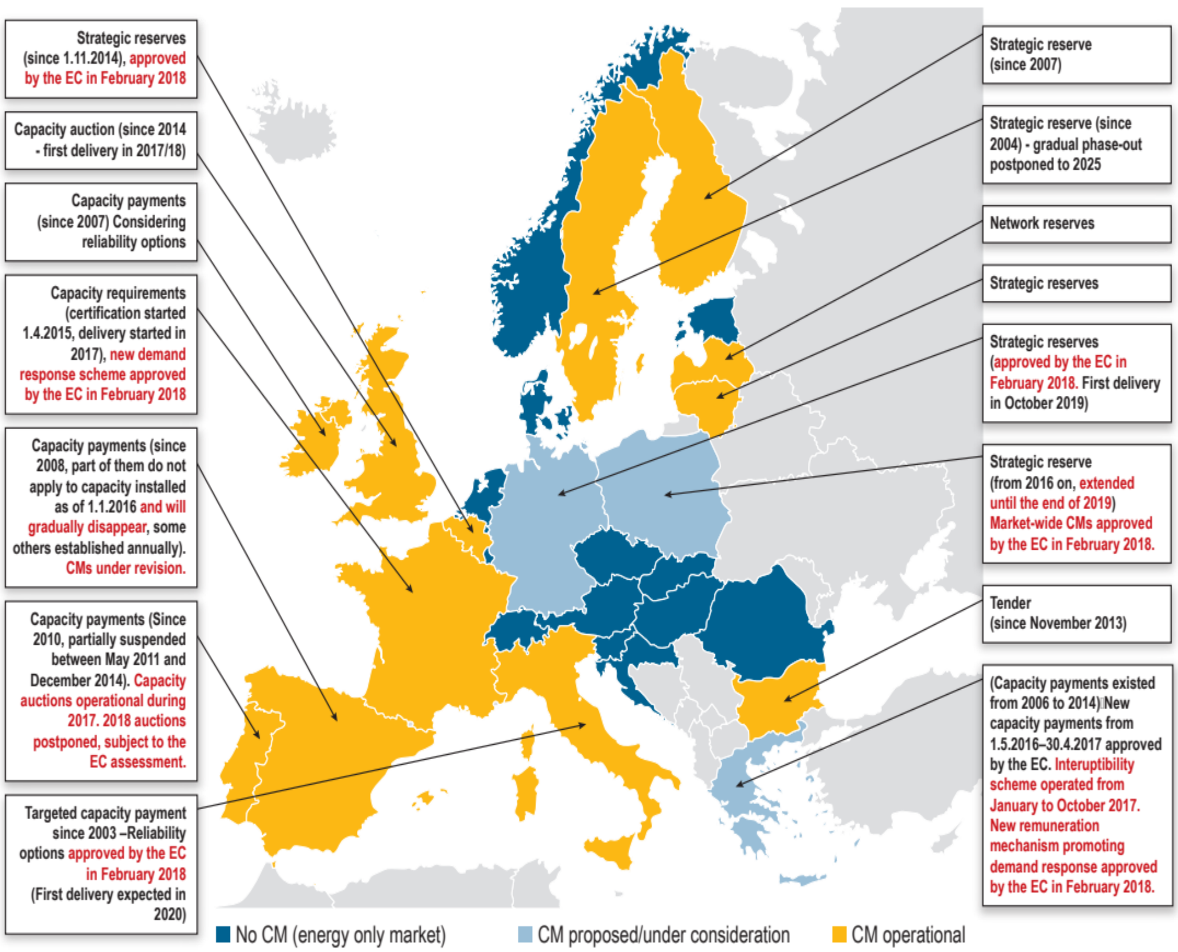

Figure 7: CMs implementation in Europe, source: (ACER and CEER, 2018b)

[20] DR operators can choose either between a certification of DR as capacity or a reduction of consumption as supplier obligation.

[21] 'Interruptibility schemes' are mechanisms '*in which industrial customers are asked by the network operator to reduce their demand in scarcity situations, are also considered a form of "reserve", as they provide capacity that is only activated when a supply shortfall occurs',* (EC, 2016c).

1.4.3. Current practices in adequacy assessments

According to the sector inquiry report (EC, 2016d), many MSs have not applied sufficiently rigorous assessment methodologies to establish appropriate levels of SoS before applying a CM. As can be observed in Table 1, the methods of assessing resource adequacy vary widely among MSs[22] and there is no common approach between MSs. This makes a comparison between the assessment results quite difficult. The sector inquiry report adds that '*many resource adequacy assessments take a purely national perspective and may substantially differ depending on the underlying assumptions made and the extent to which foreign capacities as well as demand side flexibility are taken into account.*'

Adequacy assessments can follow two approaches: a deterministic approach and a probabilistic one. The deterministic approach compares the sum of all generation capacities with the peak demand for a single one-off moment. It assesses the generation adequacy level via the capacity margin, which is the relation between peak demand and the reliably available supply, as a percentage[23]. This approach, however, does not give a reliable picture of the adequacy situation due to the increase in renewable energies in electricity systems. The Probabilistic approach, in turn, considers variations in demand over the years. Generation adequacy can be measured through the calculation of the loss of load probability (LOLP), '*which quantifies the probability of a given level of unmet demand over a certain period of time*.' In many cases LOLP is expressed as a loss of load expectation (LOLE) representing the number of hours per annum in which, over the long-term, the supply is statistically expected not to meet demand (EC, 2016d). Both LOLP and LOLE, however, do not measure the shortfall in the capacity that arises when there are disconnections and neither LOLP/LOLE nor capacity margins can measure the unmet demand. This would require a measurement of expected energy not served (EENS), which represents the amount of electricity demand (in MWh) that is expected not to be met by generation for a given year. Note that to obtain the economic value of adequacy, it is necessary to quantify the Value of Lost Load (VOLL). As the name suggests, VOLL measures the damage suffered by consumers when the supply is curtailed[24]. It is crucial to implement a cost-effective adequacy level.

Compared to the deterministic approach, the Probabilistic approach considers a wide range of variables and assesses their behavior under different scenarios. The probabilistic approach is gradually replacing the deterministic one in some MSs as electricity systems are becoming more complex.

Table 1: Probabilistic Vs Deterministic approaches to adequacy assessments, source: (EC, 2016d)

Adequacy Assessments							
Country	Y/N	Who?	What?	Country	Y/N	Who?	What?
Belgium	Y	TSO	Probabilistic assessment based on LOLE	Italy	Y	TSO	EENS, LOLE, LOLP and Capacity Margin are calculated
Denmark	Y	TSO	EENS, LOLE and LOLP	Poland	Y	TSO	Capacity Margin
France	Y	TSO	LOLE	Portugal	Y	TSO + Gov	Load Supply Index (supply/demand per hour)
Germany	Y	TSOs + NRA	Calculation of EENS, LOLE, LOLP and Capacity Margin	Spain	Y	TSO	Capacity Margin
Ireland	Y	TSOs + NRA	Probabilistic assessment based primarily on LOLE	Sweden	Y	TSO	EENS, LOLE and LOLP are measured

22 There were eleven markets under this assessment: Belgium, Croatia, Denmark, France, Germany, Ireland, Italy, Poland, Portugal, Spain and Sweden (EC, 2016d).

23 For instance, a system with 11 GW of installed capacity and 10 GW of peak demand has a 10% capacity margin. In two of the eleven Member States, only this relatively simple capacity margin is calculated.

24 VOLL calculation is quite complex. It is normally based on surveys and includes several factors such as types of customers, duration of interruption, frequency and occurrence time.

Reliability Standards

The level of capacity needed to ensure SoS, is expressed by the reliability standards. There are different metrics used across MSs to set reliability standards depending on the adopted adequacy assessment approach. Each one of them represents a way of measuring SoS based on consumers' willingness to pay.

Table 2, based on replies to the sector inquiry, shows the MSs practices in setting a reliability standard. It can be observed that currently there are some MSs that do not measure this level, and others that have not even defined a reliability standard when introducing capacity mechanism.

Table 2: MSs practice in setting a reliability standard, source: (EC, 2016d)

Legal Reliability Standard or Target?							
Country	Y/N	Which?	Link with VOLL?	Country	Y/N	Which?	Link with VOLL?
Belgium	Y	LOLE (average) < 3h LOLE (extreme 95%) < 20h	N	Italy	N	In the future: LOLP	Possible future regime: curve linked to VOLL of 3000,-
Denmark	N	Non-legislative target for TSO to ensure max. 5 min. of disconnections per consumer/year (LOLE < 0.25).	N	Poland	Y	Reserve capacity levels	N
France	Y	3 hrs LOLE	Yes, 20.000,-	Portugal	Y	Reserve Margin and LOLE 8hrs	N
Germany	N	n.a.	N	Spain	Y	Capacity margin of 10%	N
Ireland	Y	LOLE < 8h	Y, 10.898,-	Sweden	N	Reserves to meet N-1 is target for TSO	N

1.4.4. Limiting the introduction of capacity mechanisms

The e-Regulation includes measures to limit the implementation of capacity mechanisms, considering the views of the sector inquiry report (EC, 2016d). Adequacy concerns need to be identified, against reliability standards, by the European and/or the national resource adequacy assessment[25] as a binding measure. Then, MSs, with adequacy concerns, shall publish, first, an implementation plan for adopting measures eliminating the identified regulatory distortions and/or market failures. CMs may be implemented as a last resort to eliminate residual adequacy concerns. They should be temporary and should not create undue market distortions **art 22(1)**. In this subsection, we will present the different provisions of the e-Regulation for resource adequacy assessment, reliability standards, implementation plans and the principles for applying capacity mechanisms. The new rules for capacity mechanisms, as stated in **art 22(5)**, will not prejudice to commitments or contracts concluded before 31 December 2019.

European resource adequacy assessment

The European resource adequacy assessment is the first step in a significantly important procedure that may potentially lead to the implementation of a CM. According to **art 23** of the e-Regulation, it *'shall identify resource adequacy concerns by assessing the overall adequacy of the electricity system to supply current and projected demands for electricity at Union level, at the level of the Member States, and at the level of individual bidding zones, where relevant.'* It shall cover each year within a ten-year period, starting from the date of the assessment. The assessment shall be conducted every year by ENTSO-E based on

[25] The complementing national resource adequacy assessment were added in the final e-Regulation text and did not exist in the first Commission proposal.

data provided by national TSOs. Generators and other market participants, in their turn, shall provide TSOs with data about the expected utilization of the generation resources. By 5 January 2020, ENTSO-E shall submit to the Electricity Coordination Group and ACER a draft methodology for the European resource adequacy assessment. The methodology shall be transparent and ensure that the assessment is carried out on each respective bidding zone level and based on appropriate central reference scenarios of projected demand and supply. In addition to applying a single modelling tool, the assessment shall contain separate scenarios reflecting generation adequacy concerns that the capacity mechanisms are designed to address. Also, according to **art 23(5)**, the assessment shall apply at least the "expected energy not served" (EENS) and the "loss of load expectation" (LOLE) indicators. By 5 January 2020, ENTSO-E shall submit to ACER a draft methodology for calculating the VOLL, the cost of new entry for generation, or demand response, and the reliability standard referred to in **art 25**, integrating, therefore, existing work on VOLL and other indicators.

A complementing national resource adequacy assessment

MSs may complement the European resource adequacy assessment with national resource adequacy assessments. This additional assessment was not included in the Commission proposal for e-Regulation and was brought by the Council negotiating position. National adequacy assessments shall have a regional scope, and their methodology shall be similar to the European one described in **art 23(4).** They shall contain the reference central scenarios of projected demand and supply similarly to the European assessment. In addition, they may provide additional sensitivities through considering particularities of national power demand and supply and use complementary tools as well as more consistent and recent data than the European one.

When there is a divergence[26] between the national and the European resource adequacy assessment with regard to the same bidding zone, the national assessment shall include the reasons for the divergence, *'including details of the sensitivities used and the underlying assumptions'*. MSs shall publish that assessment and submit it to ACER. Within two months from report submission, ACER shall provide an opinion on whether the discrepancies are justified. Then ACER opinion shall be taken duly into account by the body governing the national assessment and where necessary it shall amend the final assessment. However, they if the governing body decides not to consider ACER opinion fully, it shall publish its detailed reasoning in a report.

Reliability standards

The e-Regulation also proposes the development of EU-wide methodologies for calculating coherent reliability standards, representing the basis for capacity mechanism implementation decisions. **Art 25** of the e-Regulation states that *'a reliability standard shall indicate the necessary level of security of supply of the Member State in a transparent manner.'* For cross-border bidding zones, the relevant authorities shall jointly establish reliability standards. Reliability standards shall be set by a MS or a competent authority designated by the MS based on the methodology referred to in **art 23(6)**. This article states that *'by 5 January 2020, the ENTSO for Electricity shall submit to ACER a draft methodology for calculating:*

(a) the value of lost load;
(b) the cost of new entry for generation, or demand response; and
(c) the reliability standard referred to in Article 25.'

Art 25(3) adds that reliability standard, expressed as EENS and LOLE, *'shall be calculated using at least the value of lost load and the cost of new entry over a given timeframe.'* Also, *'when applying capacity mechanisms, the parameters determining the amount of capacity procured in the capacity mechanism*

[26] A divergence means that the national resource adequacy assessment identifies a concern with regard to a bidding zone and the European resource adequacy assessment has not identified a concern.

shall be approved by the Member State or by a competent authority designated by the Member State, on the basis of a proposal of the regulatory authority,' (**art 25(4)**).

An implementation plan for market reforms before capacity mechanisms

The EC (2016d) sector inquiry states that MSs are required to put in place measures to address the regulatory distortions causing the identified resource adequacy concerns, such as market reforms. The sector inquiry report highlighted four market reforms that can address the security of supply concern and may even remove the need for capacity mechanisms. MSs that have introduced capacity mechanisms should also make appropriate efforts to integrate market reforms, as they are not substitutable by capacity mechanisms. The market reforms are with regard to the removal of prices caps and regulated electricity prices, the participation of demand response, the de-lineation of bidding zones, and the balancing market reform.

To address the identified regulatory distortions at the level of MS, **art 20(3)** of the e-Regulation requires in turn from MSs to '*publish an implementation plan with a timeline for adopting measures to eliminate any identified regulatory distortions or market failures as a part of the State aid process.'* In addition, when addressing these regulatory distortions and market failures, MSs shall take into account the principles regarding the operation of electricity markets stated in **art 3** of the e-Regulation. The **art 20(3)** adds that MSs shall also consider:

'(a) removing regulatory distortions;

(b) removing price caps in accordance with Article 10;

(c) introducing a shortage pricing function for balancing energy as referred to in Article 44(3) of Regulation (EU) 2017/2195;

(d) increasing interconnection and internal grid capacity with a view to reaching at least their interconnection targets as referred in point (d)(1) of Article 4 of Regulation (EU) 2018/1999;

(e) enabling self-generation, energy storage, demand side measures and energy efficiency by adopting measures to eliminate any identified regulatory distortions;

(f) ensuring cost-efficient and market-based procurement of balancing and ancillary services;

(g) removing regulated prices where required by Article 5 of Directive (EU) 2019/944.'

MSs shall submit the developed implementation plans to the Commission for review and opinion. They shall monitor their application and publish an annual report on the results to be also submitted to the Commission. Figure 8, at the end of this subsection, explains the CEP e-Regulation process to address adequacy concerns in MSs. A more detailed explanation of the impact of these market reforms can be found in EC (2016b) and EC (2016d).

General principles for capacity mechanisms

When a MS decides to implement a CM following the resource adequacy assessment and the implementation plan for market reforms. The MS should study its cross-border effects, assess strategic reserves first then the other types of CMs.

When a MS is already applying a CM, the mechanism shall be reviewed. The MS shall not also conclude new contracts if both the European and the national resource adequacy assessment have not provided so pursuant to **art 21(6),** *'or in the absence of a national resource adequacy assessment, the European resource adequacy assessment have not identified a resource adequacy concern or the implementation plan as referred to in Article 20(3) has not received an opinion by the Commission as referred to in Article 20(5).*' Capacity mechanisms shall be temporary, and MSs shall include a provision allowing for an efficient administrative phase-out of the CMs in case no new contracts are concluded for a CM following **art 21(6)** during three consecutive years.

In addition, according to **art 21(8)**, capacity mechanisms '*shall be approved by the Commission for no longer than 10 years.'* Then, they shall be phased out, or the amount of the committed capacities shall be reduced based on the implementation plan pursuant to **art 20(3)** aiming to eliminate any identified regulatory distortions. Also, MSs shall continue the application of the implementation plan after the introduction of the capacity mechanism.

Limiting cross-border concerns

Cross-border participation in capacity mechanisms is not very common between MSs. Some of them do not even take into account the contribution of imports when assessing their resource adequacy, thus leading to a collection of national overcapacities (EC, 2016d). Nevertheless, this situation is changing. For instance, France and Ireland are developing plans to allow cross-border participation in their capacity mechanisms, (RTE, (2019); EC, (2016d)).

The EC (2016b) impact assessment highlights the necessity of taking into account cross-border participation in CMs to ensure efficient signals and avoid internal market failure such as distorting cross-border trade, leading to suboptimal investments and creating shifts of generation capacity towards the country with a capacity mechanism.

The e-Regulation sets cross-border participation rules in capacity mechanisms. **Art 26** of the e-Regulation states that '*mechanisms other than strategic reserves and where technically feasible, strategic reserves, shall be open to direct cross-border participation of capacity providers located in another Member State (…).*' Indeed, CMs must be open to explicit cross-border participation to limit distortions to cross-border trade and competition as well as providing incentives for interconnection investment to ensure the EU security of electricity supply at least costs.

When implementing a capacity mechanism, a study on cross-border effect shall be undertaken by the MS implementing it through consulting at least its electrically connected neighbouring MSs and the stakeholders of those MSs (**art 21(2)**). In addition, '*national regulatory authorities shall ensure that cross-border participation in capacity mechanisms is organised in an effective and non-discriminatory manner. (…)*' (**art 26 (13)**).

Regional coordination centres (RCCs)[27], national TSOs, the ENTSO-E, NRAs and ACER are involved in the development of technical parameters for the participation of foreign capacities as well as the operational rules for their participation. For instance, according to **art 21(6)** of the e-Regulation, the maximum entry capacity available for the participation of foreign capacity shall be calculated annually by TSOs, based on the recommendation of the RCC. The calculation, required for each bidding zone border, should take into account '*the expected availability of interconnection and the likely concurrence of system stress between the system where the mechanism is applied and the system in which the foreign capacity is located.*'

The methodology for calculating the maximum entry capacity for cross-border participation shall be developed by ENTSO-E and submitted to ACER by 5 July 2020. Also, ENTSO-E shall submit a methodology for sharing the revenues arising through the allocation of eligible capacity providers in case of cross border participation pursuant to **art 26(11)(b)** and **art 26(9)**. ENTSO-E shall also develop and submit to ACER the common rules for the carrying out of availability checks by TSOs, where the foreign capacity is located, as well as the common rules for determining when a non-availability payment is due. Also, the terms of the operation of the registry of eligible capacity providers for a CM and the common rules for identifying

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[27] The creation of new Regional Coordination Centres (RCCs) builds on the framework established by the Regional Security Coordinators in the CEP. This aims to ensure a more coordinated regional approach to transmission system operations. For more information, please see 1.5.2.

capacity eligible to participate in the capacity mechanism shall be developed by ENTSO-E and submitted to ACER by the same time, as stated in **art 26(11)**.

Specific design principles for strategic reserves

Strategic reserves, described in 1.4.1, are widely used across MSs such as in Belgium, Germany, Poland, and Sweden. They are, according to EC (2016d), the most appropriate response to temporary adequacy concerns since they operate only outside the market and only in rare cases when markets can no longer clear. When they are designed not to promote new generation and when the reserve is kept as small as possible, distortions can be kept at a minimum.

The final text of the e-Regulation includes specific design principles for strategic reserves. They shall be assessed first by MSs when introducing capacity mechanisms. A specific paragraph was added regarding strategic reserves compared to the Commission proposal for the e-Regulation. Strategic reserves shall only be dispatched in case TSOs are likely to exhaust their balancing resources. The strategic reserve's output after the dispatch shall be attributed to BRPs through the imbalance settlement mechanism**. Art 22(2)** states the following requirement that the design of strategic reserves shall meet:

(a) where a capacity mechanism has been designed as a strategic reserve, the resources thereof are to be dispatched only if the transmission system operators are likely to exhaust their balancing resources to establish an equilibrium between demand and supply;
(b) during imbalance settlement periods where resources in the strategic reserve are dispatched, imbalances in the market are to be settled at least at the value of lost load or at a higher value than the intraday technical price limit as referred in Article 10(1), whichever is higher;
(c) the output of the strategic reserve following dispatch is to be attributed to balance responsible parties through the imbalance settlement mechanism;
(d) the resources taking part in the strategic reserve are not to receive remuneration from the wholesale electricity markets or from the balancing markets;
(e) the resources in the strategic reserve are to be held outside the market for at least the duration of the contractual period.

Further design principles for other capacity mechanisms

For CMs other than strategic reserves, the e-Regulation adds further specifications on the design principles with regard to the availability payment and capacity obligation. **Art 22(3)** of the e-Regulation states that CMs, other than strategic reserves, shall:

(a) be constructed so as to ensure that the price paid for availability automatically tends to zero when the level of capacity supplied is expected to be adequate to meet the level of capacity demanded;
(b) remunerate the participating resources only for their availability and ensure that the remuneration does not affect decisions of the capacity provider on whether or not to generate;
(c) ensure that capacity obligations are transferable between eligible capacity providers.

Figure 8, in the next page, summarizes the different steps prior to the introduction of a capacity mechanism by a MS following the CEP provisions.

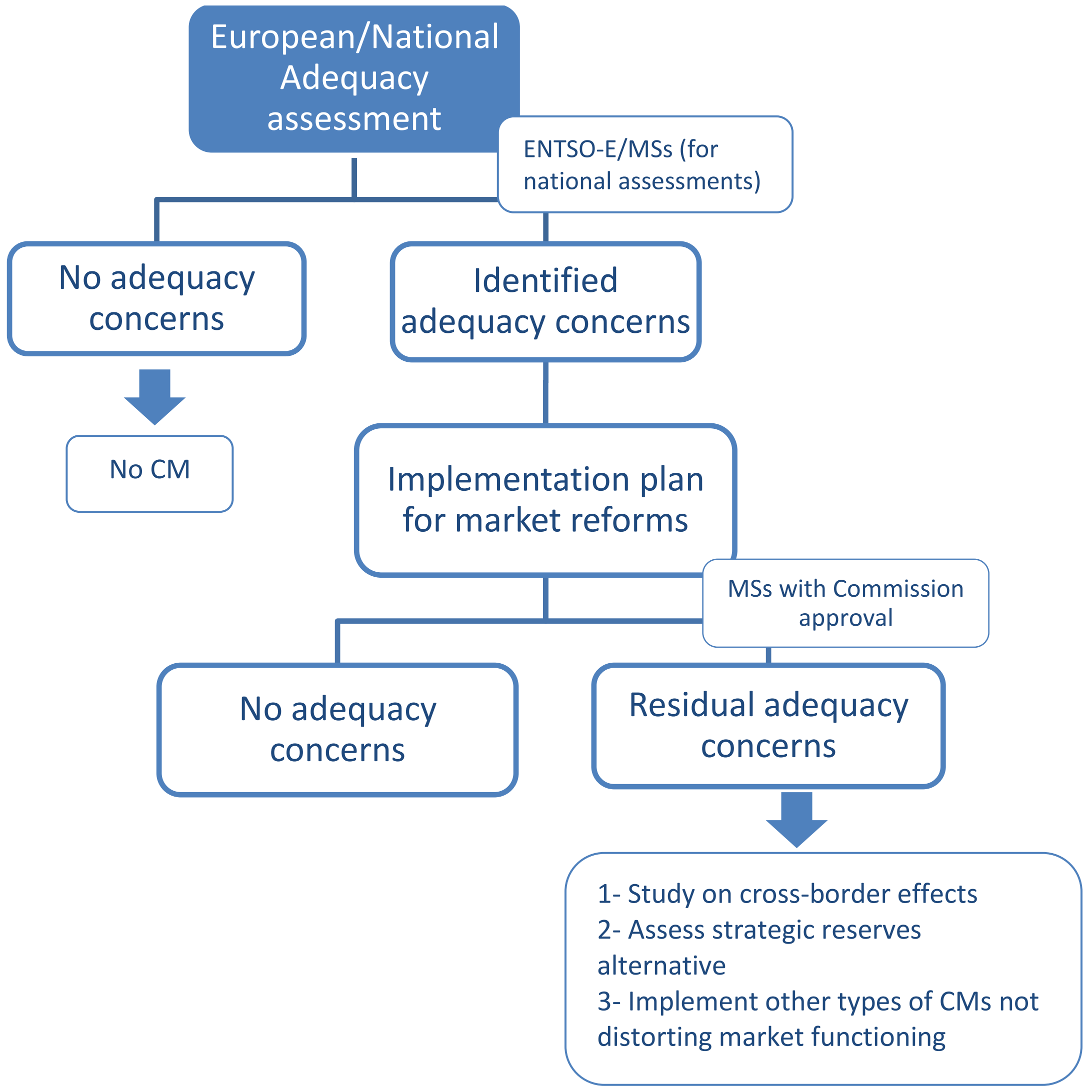

Figure 8: New framework for Capacity Mechanisms implementation, source: own illustration

1.4.5. Limiting discrimination between existing versus alternative resources

Demand response providers still face important barriers for participating in capacity mechanisms across Europe. The report of the sector inquiry on capacity mechanisms concluded that capacity mechanisms should be open to all types of potential capacity providers, except for the mechanisms specific for demand response given their particular ability to address market failures, and strategic reserves since they are not designed to promote new generation capacity[28](EC, 2016d).

In the first place, the European resource adequacy assessment should appropriately take account of *'the contribution of all resources including existing and future possibilities for generation, energy storage, sectoral integration, demand response, and import and export and their contribution to flexible system operation.'* It shall also ensure that *'the national characteristics of generation, demand flexibility and energy storage, the availability of primary resources and the level of interconnection are properly taken into consideration,'* (**art 23(5)(m)** of the e-Regulation).

[28]According to the same report, '*market distortions can be kept at a minimum if the reserve is kept as small as possible*'. Strategic reserve is designed not to promote new generation capacity.

Regarding the participation of alternative resources in capacity mechanisms, the first Commission proposal for e-Regulation did not specify precise rules for this. However, the final text brings more provisions for alternative resources participation, inter alia, for the participation of storage, energy efficiency, and demand response. They are stated, first, among the measures to be considered for eliminating regulatory distortions creating adequacy concerns. Then, for the design principles, in **art 22(1)(h),** indicating that any capacity mechanism shall *'be open to participation of all resources that are capable of providing the required technical performance, including energy storage and demand side management'.*

1.4.6. Limiting the impacts on climate goals

The e-Regulation sets emission limits for MSs willing to subsidize polluting generation units. Indeed a capacity mechanism shall prevent the most polluting coal power plants in Europe from receiving state aid and shall aim to help the EU to reach its climate targets. A grandfathering clause was introduced in **art 22(5)**, for capacity mechanisms contracts that were concluded before 31 December 2019. This grandfathering clause aims to protect investment security, according to Council (2018).

Art 22(4) of the e-Regulation introduces the Emission Performance Standard (EPS) to which capacity mechanisms shall comply:

- *'(a) from 4 July 2019 at the latest, generation capacity that started commercial production on or after that date and that emits more than 550 g of CO2 of fossil fuel origin per kWh of electricity shall not be committed or to receive payments or commitments for future payments under a capacity mechanism;*
- *(b) 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 CO2 of fossil fuel origin per kWh of electricity and more than 350 kg CO2 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.'*

These emissions limits *'shall be calculated on the basis of the design efficiency of the generation unit meaning the net efficiency at nominal capacity under the relevant standards provided for by the International Organization for Standardization.'* Regarding the calculation of the EPS values, ACER shall publish an opinion providing technical guidance related to their calculation by 5 January 2020. Figure 9 gives an overview about the new emission requirements to participate in capacity mechanism.

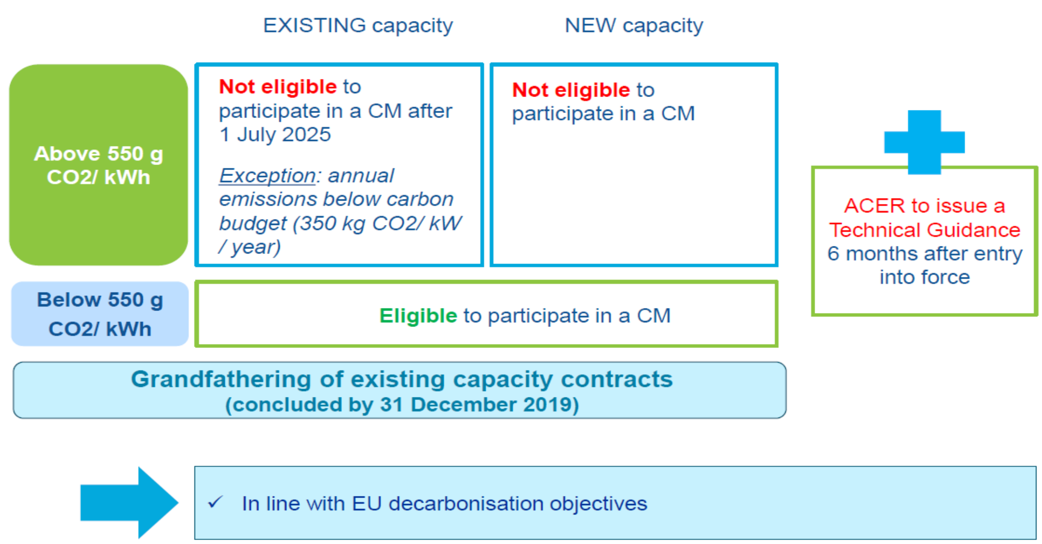

Figure 9: Emission limit (550 g CO2/ kWh) in CMs (Article 22), source : (EC, 2019a)

Emissions threshold throughout the 'trialogue' negotiations

These emissions' thresholds have changed compared to the first draft of the commission for the e-Regulation. The Commission introduced in the draft only a 550gr CO2/kWh without differentiation for new and existing generation units. In addition, it did not include the clause excluding contracts approved before 31 December 2019.

The Council negotiating position included a 550 gr CO2/kWh of energy **or** a 700 kg CO2 on average per year per installed kW threshold for new and existing generation. Existing generation should not receive payments as of 31 December 2030. This could be seen as a stricter provision as it provides two independent metrics. European countries that are heavily dependent on fossil fuels were concerned about the EPS provisions (EURACTIV, 2018).

The Parliament proposed a different limit for strategic reserves, a system widely used in Europe. It has also privileged this mechanism over other mechanisms when a country decides to introduce one. The final text is a compromise between the different positions.

This emission limitation will impact the participation of coal-fired and lignite power plants as well as oil-based plants and gas peaking plants in CMs as they emit, in most cases, more than the stated threshold of 550 gr CO2/KWh (IEA, 2013). The second metric, expressed in kg CO2 on average per year per installed KWe, based on yearly emissions, targets highly emitting plants that are dispatched occasionally (a few hours per year).

Highlights

- A European resource adequacy assessment is introduced. It may be complemented by national resource adequacy assessments performed by the MS.
- Common methodologies for reliability standards shall be developed.
- In case of adequacy concerns, an implementation plan to eliminate identified regulatory distortions before implementing CMs shall be developed.
- MSs shall assess first the potential of strategic reserves to address adequacy concerns before the other types of CMs. Specific design principles for strategic reserves are introduced.
- CMs can be introduced, as a last resort, for possible residual concerns.
- The participating of the most polluting units is limited by introducing an emission threshold of 550gr CO2/kWh for new generating units as of 4 July 2019.
- For existing generation units, they are not eligible to participate in CM if they emit more than 550gr CO2/kWh and more than 350 kg CO2 on average per year per installed KWe as of 1 July 2025.
- CMs shall be open to direct cross-border participation of capacity providers.
- TSOs shall annually calculate this maximum entry capacity available for cross-border participation, based on RCCs recommendation.
- MSs applying CMs on 4 July 2019 shall adapt their mechanisms to comply with the described provisions, without prejudice to commitments or contracts concluded by 31 December 2019.

1.5. Interlinkage with Network codes

In what follows, we discuss the interlinkages between topics that are covered in the first generation of network codes and that are also addressed in the CEP, i.e. balancing responsibilities, the regional governance of system operation, bidding zones, and the calculation of interconnection capacities.

The first generation of network codes includes:

- The market codes:
  - Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a **guideline on capacity allocation and congestion management (CACM)**
  - Commission Regulation (EU) 2016/1719 26 September 2016 establishing a **guideline on forward capacity allocation (FCA)**
  - Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a **guideline on electricity balancing (EB GL)**
- The connection codes:
  - Commission Regulation (EU) 2016/631 of 14 April 2016 establishing a **network code on requirements for grid connection of generators (RfG NC)**
  - Commission Regulation (EU) 2016/1388 of 17 August 2016 establishing **a network code on demand connection (DCC)**
  - Commission Regulation (EU) 2016/1447 of 26 August 2016 establishing **a network code on requirements for grid connection of high voltage direct current systems and direct current-connected power park modules (HVDC NC)**
- The operation codes:
  - Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a **guideline on electricity transmission system operation (SO GL)**
  - Commission Regulation (EU) 2017/2196 of 24 November 2017 establishing a **network code on electricity emergency and restoration (ER)**

For a more complete introduction to the first generation of network codes, see Schittekatte et al., (2019).

1.5.1. Balancing responsibilities

Balancing in network codes

The Balancing Guideline (EB GL) has been adopted as a Commission Regulation and entered into force in 18 December 2017. Balancing responsibilities are not explicitly mentioned in the electricity network codes. However, the EB GL **art 18(1)** states that no later than six months after its entry into force and for all scheduling areas of a MS, a national proposal regarding the terms and conditions for BSPs and BRPs should be submitted by the TSOs of this MS. This proposal, which is currently under development in the different MSs, shall contain the <u>definition of balance responsibility for each</u> (Schittekatte et al., 2019). **Art 18(4d**) of the EB GL adds that terms and conditions for BRPs shall *'require that each balancing energy bid from a balancing service provider is assigned to one or more balance responsible parties to enable the calculation of an imbalance adjustment pursuant to Article 49.'*

The different terms & conditions as well as methodologies of the EB GL are currently in the development or approval process (ACER, 2019a). ACER's first monitoring report on the implementation of EB GL is expected to be issued in 2020 (ACER, 2019b).

CEP measures on balancing responsibilities

Art 2 of the e-Regulation defines a BRP as *'a market participant or its chosen representative responsible for its imbalances in the electricity market.'* The balance responsibility is passed on to the BRP before the actual delivery. A BRP can represent one or more electricity generators, suppliers and/or large consumers.

On balancing responsibility, **art 4** of the e-Regulation indicates in the first paragraph that *'all market participants shall be responsible for the imbalances they cause in the system.'* Thus, market participants shall either be BRPs or delegate contractually their responsibility to a BRP. The article adds that each BRP shall be financially responsible for its imbalance, strive to be balanced, and aim to keep the power system balanced.

Derogations from balance responsibilities

MSs may provide derogations from balance responsibility only for projects the following characteristics, **art 4(2)** of the regulation:

'(a) demonstration projects for innovative technologies, subject to approval by the regulatory authority, provided that those derogations are limited to the time and extent necessary for achieving the demonstration purposes;

(b) power-generating facilities using renewable energy sources with an installed electricity capacity of less than 400 kW;

(c) installations benefitting from support approved by the Commission under Union State aid rules pursuant to Articles 107, 108 and 109 TFEU, and commissioned before 4 July 2019.'

When such derogations are given, MSs *'shall ensure that the financial responsibility for imbalances is fulfilled by another market participant.'* From 1 January 2026, point (b) of **art 4(2)** shall apply only '*to generating installations using renewable energy sources with an installed electricity capacity of less than 200 kW'* (**art 4(3)**).

1.5.2. System operation regional governance

RSCs in network codes

The system operation guideline (SO GL) introduced the establishment of Regional Security Coordinators (RSCs). RSCs are owned or controlled by TSOs and perform tasks related to TSO regional coordination. The SO GL states that each control area shall be covered by at least one RSC. A control area is defined as a coherent part of the interconnected system, operated by a single system operator. RSCs combine the tasks outlined in the SO GL and the capacity calculation stated in the CACM. Regional cooperation in SO allows TSOs to have a regional vision on threats to SO coming from regional power flows. The TSOs remain in charge of security of supply and consequently of the final operational decision-making. RSCs are intended to provide five core services. They are presented in Figure 10.

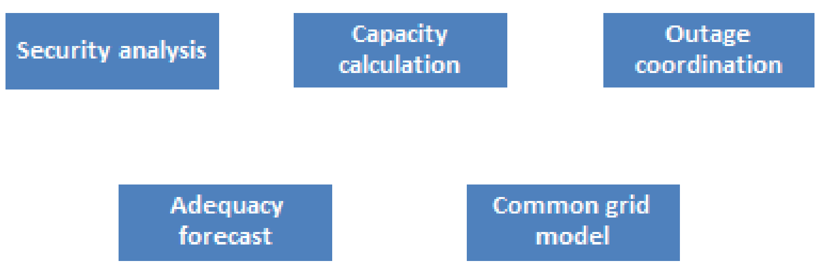

Figure 10: Services provided by RSCs to TSOs, source: (ENTSO-E, 2016)

The implementation of Regional Coordination Centres (RCCs)

Originally introduced as Regional Operational Centres (ROC) in the Commission proposal, these bodies will finally be called Regional Coordination Centres (RCCs), which is the version chosen by the Parliament. Two proposals, introduced by the e-Regulation, shall be made regarding the implementation of RCCs. The first by ENTSO-E to ACER for their geographical scope, called System Operation Region (SOR), and the second by TSOs to their NRAs for RCCs' establishment which includes an implementation plan. The RCCs will have to be set up by 1 July 2022 replacing the regional security coordinators (RSCs). This date is sooner than what the Council proposed[29].

[29] The Council proposed a RCCs start date of January 2025.

In the first proposal, ENTSO-E shall submit to ACER, by six months from the entry into force of the e-Regulation, a proposal on SORs, the geographical scope of RCCs, *'specifying which transmission system operators, bidding zones, bidding zone borders, capacity calculation regions and outage coordination regions are covered by each of the system operation regions.'* It shall consider the grid topology, inter alia, the degree of interconnection and the interdependency of the power system in terms of flows. The size of the SOR shall cover at least one capacity calculation region (**art 36(1)**). This aims to set effective RCCs contribution to the coordination of the operations of TSOs over regions, as well as increasing system security and market efficiency. TSOs of a SOR shall participate in the RCC of that region. In cases where the control area of a TSO is part of different synchronous areas, the TSO may be exceptionally coordinated by two RCCs. To better understand the new geographical scope of RCCs, Figure 11 shows a map of the CCRs as of the 1st of January 2019 on the left and of RSCs on the right.

ACER shall either approve ENTSO-E proposal defining the SORs or propose amendments within three months of its reception. In the case of amendments, ACER shall consult ENTSO-E before adopting them. ACER shall, afterward, publish the proposal on its website.

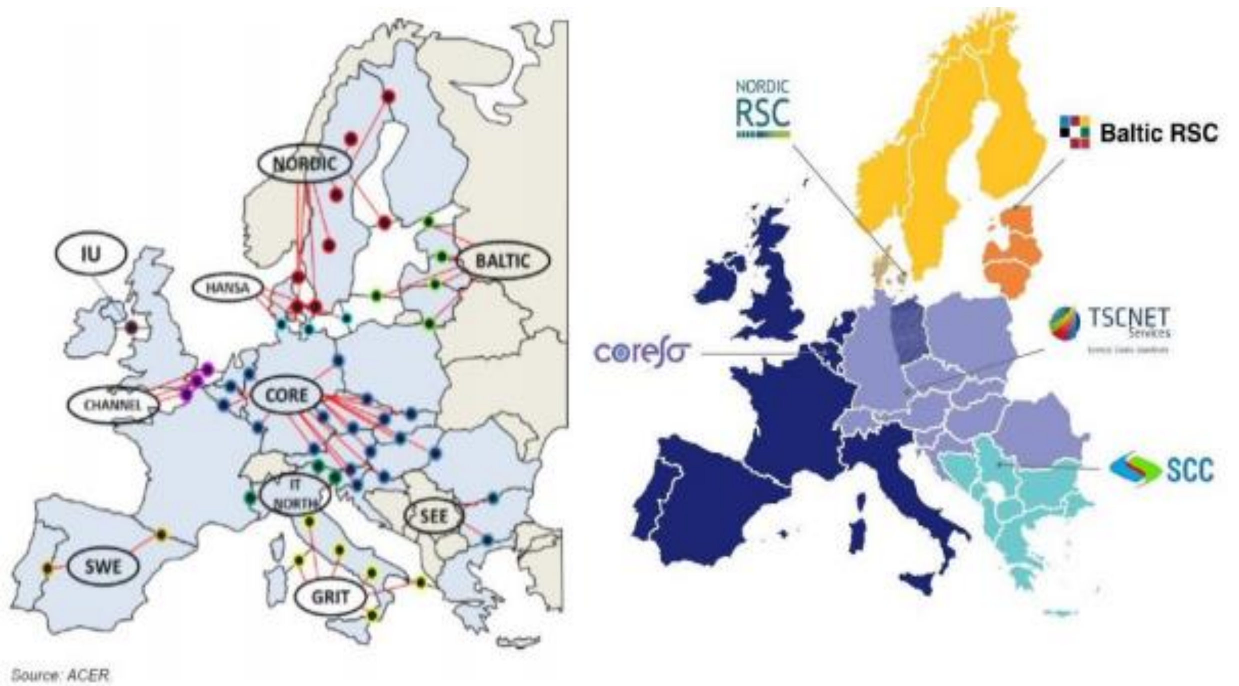

Figure 11: Left – The Capacity Calculation Regions (CCRs), status as on the 1st of January 2019 (ACER, 2019c) Right – Map of the Regional Security Coordinators in Europe as established by the end of 2016 (ENTSO-E, 2019)

In the second proposal, according to **art 35(1)**, all TSOs of a SOR, which is the region to be covered by a RCC, shall submit, within twelve months after entry into force of the Regulation, a proposal for the establishment of RCCs to their respective NRAs. NRAs of the system operation region shall review the proposal and approve it. The different elements that shall be at least included in the proposal are set out in **art 35(1)**. Among them, we find the location of the RCC (the MS of the RCC prospective seat), the participating TSOs, arrangements regarding the RCC organization, finance, operations, and liability as well as the RCC implementation plan for the entry into operation. RCCs shall replace RSCs established pursuant to the SO GL after the NRAs' approval of the TSOs' proposal according to **art 35(2)** of the e-Regulation.

Tasks of Regional Coordination Centres (RCCs)

RCCs tasks complement the RSCIs[30] voluntary TSOs' approach and the RSCs established in the SO GL of the Network Codes as shown in Figure 12. They were set to perform regionalisation tasks where it brings benefit for the system and market operation, compared to actions performed at national level. ENTSO-E role regarding RCCs is to ensure that their activities are coordinated across the regions' boundaries. RCCs' tasks do not include the real-time operation of the electricity system, which remains a task of national TSOs. In contrast to the e-Regulation proposal of the Commission, ROCs' ''binding decisions" were replaced by RCCs' "coordinated actions".

The full list of tasks that shall be carried out by RCCs is available in **art 34** and with more details ANNEX I of the e-Regulation. Some tasks shall be performed and others may be performed subject to the request of TSOs or the delegation from ENTSO-E. They shall also perform coordinated security analysis and create common grid models, in accordance with the methodologies developed following the SO GL.

Note also that the Emergency and Restoration Network Code (ER NC) states that RSCs, which will be replaced by RCCs, shall be consulted to assess the consistency of a TSO system defence and restoration plan measures within its synchronous area and in the plans of neighbouring TSOs belonging to another synchronous area (ER NC, Art. 6(1)). In the e-Regulation, more clear roles for RCCs regarding the support for TSOs' defence and restoration plans with regard to the consistency assessment and the coordination and optimisation of regional restoration.

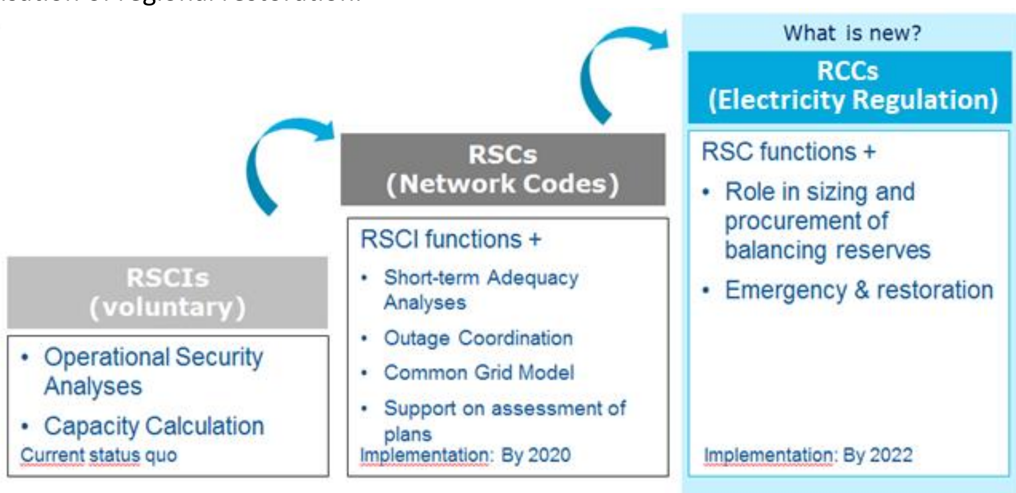

Figure 12: Sequence of ROCs functions, adapted from: EC (2017b)

To fulfill these tasks, RCCs shall be entrusted with the necessary powers to coordinate the actions of the TSOs in the system operation region for certain functions, and with an enhanced advisory role for the remaining tasks. The e-Regulation adds that their resources should not go beyond what is necessary to perform their tasks.

1.5.3. Bidding zones and capacity calculation between zones

Bidding zones in Europe

Europe is divided into different bidding zones, as shown in Figure 13. Currently, their configurations are mainly defined by national borders (e.g., France or Spain). Other bidding zones can be within the same

[30] The Regional Security Coordination Initiatives (RSCIs) were launched voluntarily by TSOs since 2009. They aim to improve TSOs cooperation by covering a greater part of the European interconnected networks. CORESO and TSC are the pioneers in this respect in continental Europe (ENTSO-E, 2015).

countries (Italy or Sweden) or grouping more than one country (Germany and Luxembourg). Austria was part of this bidding zone together with Germany and Luxembourg until its split in October 2018.

Within a bidding zone, wholesale electricity prices are the same per market time unit. Market participants who wish to trade electricity in another bidding zone have to consider bidding zone interconnection constraints. As long as electricity can flow freely through the interconnector (no congestion), there will be a single price across the markets. However, when the cross-zonal interconnector is congested between bidding zones, prices can diverge between those zones. The markets of the two bidding zones are in this case split. The price differential between the two interconnected bidding zones, in case of congestion, multiplied by the capacity of the line is called the congestion rent, and this is a revenue for the TSOs owning the interconnection[31].

Regarding congestion income, **art 19(2)** states that *'the following objectives shall have priority with the respect to the allocation of any revenues resulting from the allocation of cross-zonal capacity:*

'(a) guaranteeing the actual availability of the allocated capacity including firmness compensation; or

(b) maintaining or increasing cross-zonal capacities through optimisation of the usage of existing interconnectors by means of coordinated remedial actions, where applicable, or covering costs resulting from network investments that are relevant to reduce interconnector congestion.'

When these objectives are fulfilled, the revenues may be used as income to be taken into account by NRAs when approving network tariffs calculation methodology or fixing network tariffs, or both. Then the residual revenues shall be placed on a separate internal account line until such a time as it can be spent for the same objectives.

Regarding the use of revenues with respect to these objectives, a methodology shall be proposed by the TSOs after consulting NRAs and relevant stakeholders and after approval by ACER. The TSOs shall submit the proposed methodology to ACER by 5 July 2020. ACER shall decide then on the proposed methodology within six months of receiving it. It may request from TSOs to amend or update the methodology and decide on it within six months from the submission.

In addition, **art 19(5)** states that TSOs shall clearly establish beforehand how any congestion income will be used. They shall also report on the actual use of that income. In addition, *'by 1 March each year, the regulatory authorities shall inform ACER and shall publish a report setting out:*

(a) the amount of revenue collected for the 12-month period ending on 31 December of the previous year;

(b) how that revenue was used pursuant to paragraph 2, including the specific projects the income has been used for, and the amount placed on a separate account line;

(c) the amount that was used when calculating network tariffs; and

(d) verification that the amount referred to in point (c) complies with this Regulation and the methodology developed pursuant to paragraphs 3 and 4.'

Art 19(5) adds that in the case of some of the congestion revenues being used when calculating network tariffs, the NRAs report shall set out how the TSOs fulfilled the stated objectives regarding congestion income set out in **art 19(2)**.

[31] For example, imagine that during a certain hour the interconnectors between two bidding zones are congested. The price in one bidding zone equals 30 €/MWh and 40 €/MWh in the other. The interconnection capacity between the two bidding zones is 500 MW. This means that the congestion rent for this hour is 5,000 €.

Figure 13: New bidding zones configuration in Europe as of May 2019, source: own illustration

A review process, to be taken by TSOs, has been formalized in legislation as part of the CACM Guideline on the existing and possible alternative configurations. It aims to ensure the alignment between the market and the physical characteristics of the electricity grid, thereby increasing trades. It also reduces the need for costly remedial actions[32] and enhances the security of supply (SoS) by ensuring that electricity flows where it is most needed. The review can be launched by ACER, NRA(s), TSO(s) or MSs. It consists of two steps stated in **art 32** of the CACM; first participating TSOs *'shall develop the methodology and assumptions that will be used in the review process and propose alternative bidding zone configurations for the assessment'* and submit it to NRAs. Second, participating TSOs shall *'assess and compare the current bidding zone configuration and each alternative bidding zone configuration'*, hold a consultation and a workshop regarding the alternative bidding zone configuration and submit a joint proposal to maintain or amend the bidding zone configuration to participating MSs within 15 months of the decision to start the review. MSs shall reach an agreement within six months.

In November 2017, ENTSO-E developed the first edition of the bidding zone review (ENTSO-E, 2017b). The review was based on three categories of criteria: network security, market efficiency and stability and robustness of bidding zones, as prescribed in the CACM. The participating TSOs recommended maintaining the current bidding zone delimitation. This was quite a lengthy process. Early studies began in 2012, where ACER invited ENTSO-E to initiate a pilot project on bidding zone configuration assessment and review. ENTSO-E published a technical report in January 2014, followed by the ACER Market Report in March 2014. Based on those early findings, in the spring of 2015 ENTSO-E began its investigation on the technical and

[32] Remedial action according to **art 2(13)** of CACM Regulation as *"any measure applied by a TSO or several TSOs, manually or automatically, in order to maintain operational security."* They may include re-dispatching, countertrading, Demand Side Response, increase/decrease energy storage, topology changes in the network.

economic efficiency of the current European bidding zones, including the possibility of splitting the German-Austrian bidding zone (Rossetto, 2017).

CEP measures on bidding zones

A bidding zone review aims to address long-term structural congestion. The process of bidding zone configuration has experienced several proposals and positions from the different EU institutions. The Commission proposed in its draft e-Regulation that more powers would be given to EU institutions to decide on bidding zone configuration following the bidding zone review. The Commission was given the task of adopting a decision whether to amend or maintain the bidding zone configuration. The Council position for the e-Regulation had foreseen more national decision-making powers for the bidding zones review. In the Council position, ACER was also tasked to decide on the methodology of the review if the relevant NRAs do not come to a unanimous decision within three months, (**art 13(3)** of the Council position). The bidding zone review shall be submitted in a joint proposal by the participating TSOs to the relevant Member States or designated NRAs. The final text of the e-Regulation highlights the importance of addressing structural congestion, defined in **art 2(2)e** as a '*congestion in the transmission system that is capable of being unambiguously defined, is predictable, is geographically stable over time, and frequently reoccurs under normal electricity system conditions.'*

Bidding zone configuration shall reflect long-term structural congestions in the transmission grid. MSs can choose between a bidding zone reconfiguration or measures such as grid reinforcement and grid optimization. According to **art 14(1),** '*bidding zones shall not contain such structural congestions unless they have no impact on neighbouring bidding zones, or, as a temporary exemption, their impact on neighbouring bidding zones is mitigated through the use of remedial actions and those structural congestions do not lead to reductions of cross-zonal trading capacity in accordance with the requirements of Article 16*[33]*.'*

Two main measures are stated in **art 14** of the e-Regulation related to bidding zones. The first one is on the identification of structural congestions and the second one on bidding zone review.

The identification of long term structural congestions can be done via three means; ENTSO-E's report on structural congestion (**art 14(2)**), TSOs assessments or the bidding zone review itself (**art 14(7))**. When structural congestion is identified, the MS in cooperation with its TSOs shall decide, within six months of receipt of the report, *'either to establish national or multinational action plans pursuant to Article 15, or to review and amend its bidding zone configuration'* (**art 14(7)**). These Action Plans shall contain network investments to be achieved by the end of 2025. They shall also include a concrete timetable for adopting measures reducing the identified structural congestions within four years of the adoption of the MS decision of **art 14(7)**. The Commission and ACER shall be notified immediately by those decisions. In the case of a structural congestion having been identified but no action plan having been defined within 6 months, the relevant TSOs shall, *'within 12 months of identification of such structural congestion, assess whether the available cross-border capacity has reached the minimum capacities provided for in Article 16(8) during the previous 12 months and shall submit an assessment report to the relevant regulatory authorities and to ACER.'* If the minimum level of interconnector capacity is not reached, the decision-making process of **art 15(5)**, regarding MSs unanimous decision and the Commission last resort decision after consulting ACER and the relevant stakeholders, applies.

Regarding the bidding zones review, **art 14(3)** states that the review *'shall identify all structural congestions and shall include an analysis of different configurations of bidding zones in a coordinated manner with the involvement of affected stakeholders from all relevant Member States (…).'* This shall follow the CACM Regulation that provides a framework for bidding zones reconfiguration (art 32-34). **Art 14(5)** adds that *'by 5 October 2019 all relevant transmission system operators shall submit a proposal for*

[33] **Art 16** on General principles of capacity allocation and congestion management

the methodology and assumptions that are to be used in the bidding zone review process and for the alternative bidding zone configurations to be considered to the relevant regulatory authorities for approval.' This time limit was not included in the CACM process. Then, NRAs *'shall take a unanimous decision on the proposal within 3 months of submission of the proposal.'* If NRAs fail to reach a unanimous decision on the proposal within the 3 months, then ACER shall decide, within an additional 3 months, on the methodology and assumptions of the bidding zone review process, as well as the alternative bidding zone configurations to be considered.

CEP measures for interconnector capacity calculation

The rules on capacity allocation, as stated in the e-Regulation, require the allocation of maximum capacity to market participants on the bidding zone border. According to **art 16(4)**, *'the maximum level of capacity of the interconnections and the transmission networks affected by cross-border capacity shall be made available to market participants complying with the safety standards of secure network operation.'* It adds that '*counter-trading and redispatch, including cross-border redispatch, shall be used to maximise available capacities to reach the minimum capacity provided for in paragraph 8. A coordinated and non-discriminatory process for cross-border remedial actions shall be applied to enable such maximisation, following the implementation of a redispatching and counter-trading cost-sharing methodology.'*

Art 16(8) of the e-Regulation introduces the minimum levels of available capacity for cross-zonal trade to be reached. These minimum levels were not included in the Commission proposal of the e-Regulation but were introduced in the Council position.

TSOs, according to **art 16(8)**, shall not limit the volume of interconnection capacity to be made available to market participants in order to solve congestion inside their bidding zone or as a means of managing flows from transaction internal to bidding zones[34]. The minimum levels of available capacity for cross-zonal trade, also called minRAM, to be complied with are:

'(a) for borders using a coordinated net transmission capacity *approach, the minimum capacity shall be 70 % of the transmission capacity respecting operational security limits after deduction of contingencies, as determined in accordance with the capacity allocation and congestion management guideline adopted on the basis of Article 18(5) of Regulation (EC) No 714/2009;*

(b) for borders using a flow-based approach, the minimum capacity shall be a margin set in the capacity calculation process as available for flows induced by cross-zonal exchange. The margin shall be 70 % of the capacity respecting operational security limits of internal and cross-zonal critical network elements, taking into account contingencies, as determined in accordance with the capacity allocation and congestion management guideline adopted on the basis of Article 18(5) of Regulation (EC) No 714/2009.'

The article adds that *'the total amount of 30 % can be used for the reliability margins, loop flows and internal flows on each critical network element.'* Moreover, note that ACER (2019c) decision on the CORE[35] Capacity Calculation Methodology, which already considers the recast e-Regulation, states that *'independently from the minRAM trajectory and from transit flows, at least 20% Fmax shall remain available for trade within Core.'*

Note that the 70% minimum capacity available for trade applies in general from January 2020. However, for the purpose of implementing **art 14(7)**, on action plans adoption decisions, and **art 15(2)**, on the linear trajectory achievement, the minimum applies from EIF which is July 2019. Figure 14 explains the changes in cross-zonal and also internal capacity for Critical Network Elements and Contingencies (CNECs).

[34] Flows over a bidding zone caused by having the origin and destination within one zone.

[35] Core is a Capacity Calculation Region (CCR), which comprises Austria, Belgium, Croatia, the Czech Republic, France, Germany, Hungary, Luxembourg, the Netherlands, Poland, Romania, Slovakia and Slovenia. See Figure 11 for its representation.

The 'starting point' shall be calculated pursuant to **art 15(2)** for each Critical Network Element (CNE), or border and see how does it compare to 70%. A CNE, according to ENTSO-E (2017c) is *'a network element either within a bidding zone or between bidding zones monitored during the CCC[36] process'*. It can be an overhead line, underground cable or transformer that is significantly impacted by cross-border exchange. The CNEC (Critical Network Element and Contingencies) is a *'CNE limiting the amount of power that can be exchanged, potentially associated to a contingency.'* Internal CNECs can be included based on efficiency considerations and may impact cross-border CNEC. Note that, according to ACER (2019c), '*internal CNECs are allowed only for a transition period (2 years). After the transition period, internal CNECs are allowed only if other alternatives are less efficient.'*

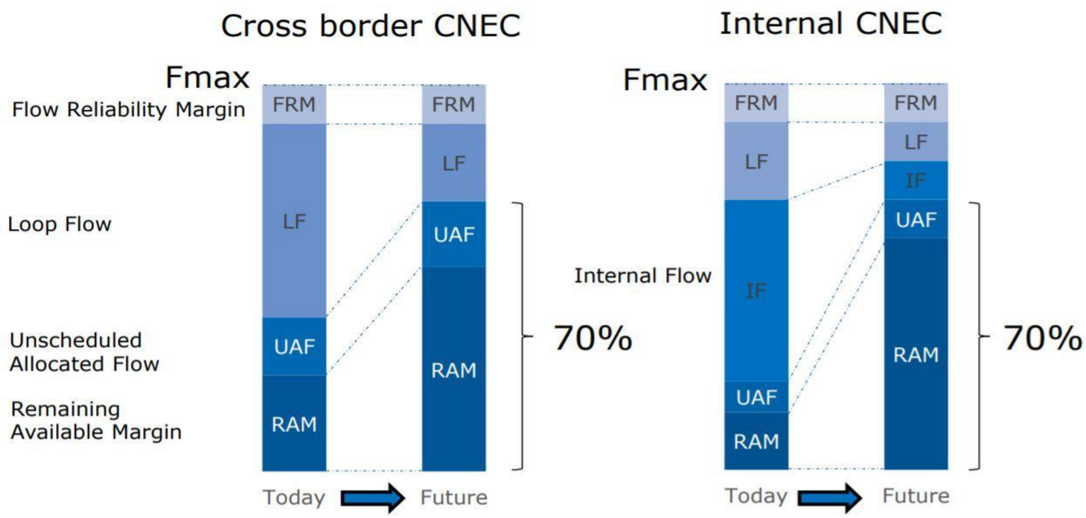

Figure 14: Breakdown of the transmission capacity, source: (ACER, 2019d)

-The way the **flow reliability margin (FRM)** is described in detail in the Capacity Calculation Methodology (ENTSO-E, 2018a). The FRM shall cover the following uncertainties:

- *'Core external transactions (out of Core CCR control: both between Core CCR and other CCRs as well as among TSOs outside the Core CCR);*
- *Generation pattern including specific wind and solar generation forecast;*
- *Generation shift key;*
- *Load forecast;*
- *Topology forecast;*
- *Unintentional flow deviation due to the operation of frequency containment reserves;*
- *Flow-based capacity calculation assumptions including linearity and modelling of external (non-Core) TSOs' areas.'*

The **unscheduled allocated flows (UAF) or transit flows** are flows due of exchanges outside of Core CCR. They are calculated, according to ACER (2018) as the difference between 'scheduled flows' (known as schedules, SCHs), representing administrative (calculated) flows resulting from capacity allocation and 'actual flows' coming from capacity allocation (allocated flows, AFs).

Two derogations from the 70% threshold are possible;

A. Derogation related to RCCs conclusion on available remedial actions

The first derogation, stated in **art 16(9)**, is related to the calculation of the threshold and where RCCs conclude that all available remedial actions in the CCR or between CCRs are not sufficient to reach the

[36] Coordinated Capacity Calculation

70% threshold while respecting operational security limits. Then, RCCs may as a measure of last resort*,* *'set out coordinated actions reducing the cross-zonal capacities accordingly.'* TSOs *'may deviate from coordinated actions in respect of coordinated capacity calculation and coordinated security analysis only in accordance with Article 42(2)'*

By 3 months after the entry into operation of the RCCs and every three months thereafter, the RCCs shall report to the relevant NRAs and ACER on reductions of the capacity or any deviations from the coordinated actions. They *'shall assess the incidences and make recommendations, if necessary, on how to avoid such deviations in the future.'* If ACER concludes that the prerequisites for a deviation were not fulfilled or are of a structural nature, it shall *'shall submit an opinion to the relevant regulatory authorities and to the Commission. The competent regulatory authorities shall take appropriate action against transmission system operators or regional coordination centres pursuant to Article 59 or 62 of Directive (EU) 2019/944 if the prerequisites for a deviation pursuant to this paragraph were not fulfilled.'*

B. Derogation upon TSOs request for maintaining the system operational security

The second derogation may be granted by relevant NRAs upon request by TSOs of a CCR according to **art 16(9)**. It shall have foreseeable reasons where it is necessary for maintaining the system operational security. It shall be limited to one year at a time, or up to a maximum two years with a significantly decreasing level of the derogation after the first year. Art 16(9) adds that *'the extent of such derogations shall be strictly limited to what is necessary to maintain operational security and they shall avoid discrimination between internal and cross-zonal exchanges.'*

The NRA has to consult the relevant other NRAs of an affected CCR before granting this derogation. If one of them disagrees, ACER shall decide on the derogation according to **art 6(10)(b)** of the ACER Regulation (EU) 2019/942 giving ACER the right and competency to adopt individual decisions on regulatory issues having effects on cross-border trade. Note that *'where a derogation is granted, the relevant transmission system operators shall develop and publish a methodology and projects that shall provide a long-term solution to the issue that the derogation seeks to address. The derogation shall expire when the time limit for the derogation is reached or when the solution is applied, whichever is earlier.'*

Highlights

- All market participants shall aim for system balance and shall be financially responsible for imbalances they cause in the system. Derogations are possible for projects with certain characteristics.

- RCCs will have to enter into operation by July 2022. They gradually build on RSCs and aim to strength regional cooperation between TSOs through providing coordinated actions and recommendations.

-RCCs complement TSOs roles to ensure secure and reliable operation of the interconnected transmission system.

- MSs can choose between an Action Plan with network investments until 2025, or a bidding zone reconfiguration to address structural congestion. The Commission may intervene in the decision making process, as a measure of last resort, if no agreement between MSs.

- Maximisation of trade across borders. A threshold of 70% for minimum available capacity for cross-zonal trade that TSOs have to comply with. Derogations are possible, at the request of the TSOs in a CCR.

- The e-Regulation applies in general from Jan 2020. However, for the purpose of implementing art 14(7) on action plans establishment and art 15(2) on cross-zonal trade capacity increase, art 16, including the 70% minimum cross-border transmission capacity threshold, applies from the EIF (4 July 2019).

2. Adapting to the decentralisation of the power system

In this section, we set the scene by introducing the DSO landscape in Europe. We then focus on key measures included in the CEP to adapt the DSOs' roles and responsibilities to the ongoing decentralisation of the power system. This includes increased expectations in their traditional roles of network planning and network management. It also covers the limitations that have been introduced for DSO ownership of EV charging infrastructures, storage facilities, and for data management by DSOs. To conclude, we discuss the establishment of an EU DSO entity, and the interlinkages between DSO topics and network codes.

2.1. Setting the scene: The DSO landscape

There are around 2,600 DSOs (Figure 15) that own and operate around 10 million km of power lines in Europe. They employ around 240,000 people and service 260 million customers. About 90 % of these customers are residential and small businesses (Meeus and Glachant, 2018).

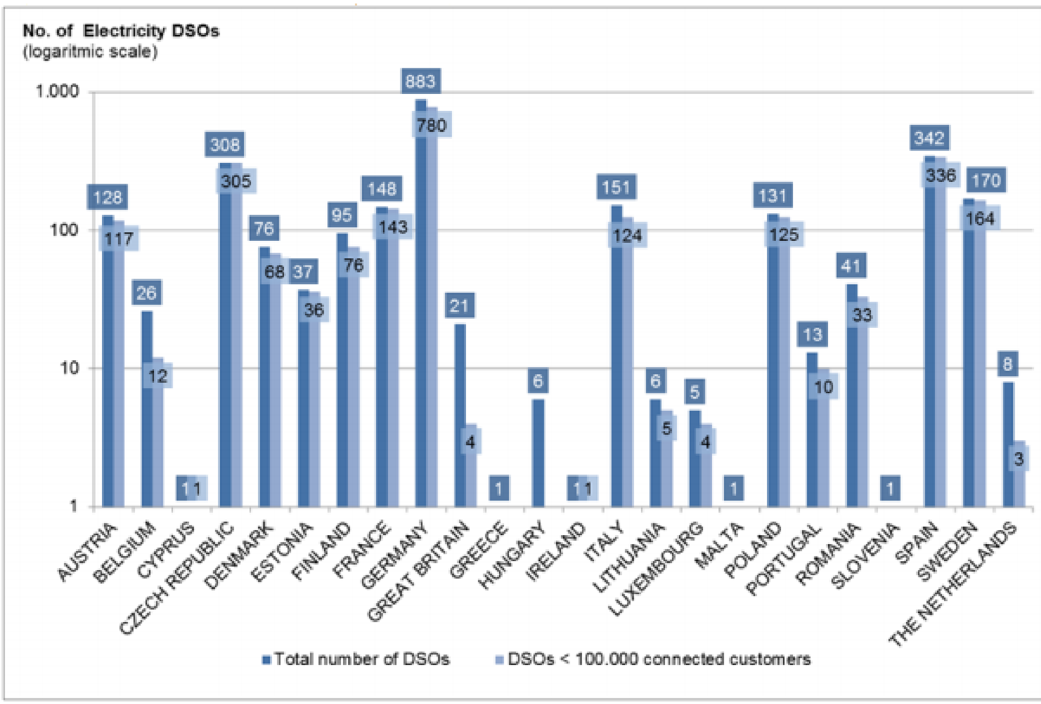

Figure 15: Number of electricity DSOs per Member State, source: (EC, 2016b)

Despite the large number of DSOs in Europe, the distribution industry is rather concentrated. In countries such as Ireland and Slovenia there is only one DSO. In France (148 DSOs) and Italy (151 DSOs), there is one dominant DSO and many small players sharing small market shares. In other MSs we find a significantly lower concentration. For instance, in Austria (128 DSOs), Belgium (26 DSOs), Sweden (170 DSOs), and Germany (883 DSOs) where the three largest DSOs represent less than half of the industry (Meeus and Glachant, 2018). Today, according to data from EC (2016b), only 13% of the European DSOs have more than 100,000 connected customers.

DSOs are represented in five different industry associations based in Brussels: EURELECTRIC, GEODE, CEDEC, EDSO for Smart Grids and REScoop. The larger DSOs in Europe work together within the association EDSO for smart grids. This association has about 30 members that represent more than 70 % of the industry. EURELECTRIC gathers electricity industry companies (generators and retailers, most of them are not ownership-unbundled). CEDEC and GEODE represent smaller 'local' and 'regional' energy distributors. REScoop is the federation of energy cooperatives that undertake distribution activities in some cases.

2.2. Current practices

According to CEER (2015), DSOs activities can be separated into three categories. This categorization regards the nature and the different businesses at the distribution network:

- Core activities, such as planning, developing, operating and maintaining the network, connecting users to the grid, managing technical data and managing network losses;
- Prohibited activities such as electricity generation;
- Non-core activities or grey areas where there are concerns about DSOs activities, such as infrastructure for EVs, flexibility services such as the ownership of flexibility assets, managing metering data for customers.

Their logical framework for categorizing DSOs activities is described in Figure 16.

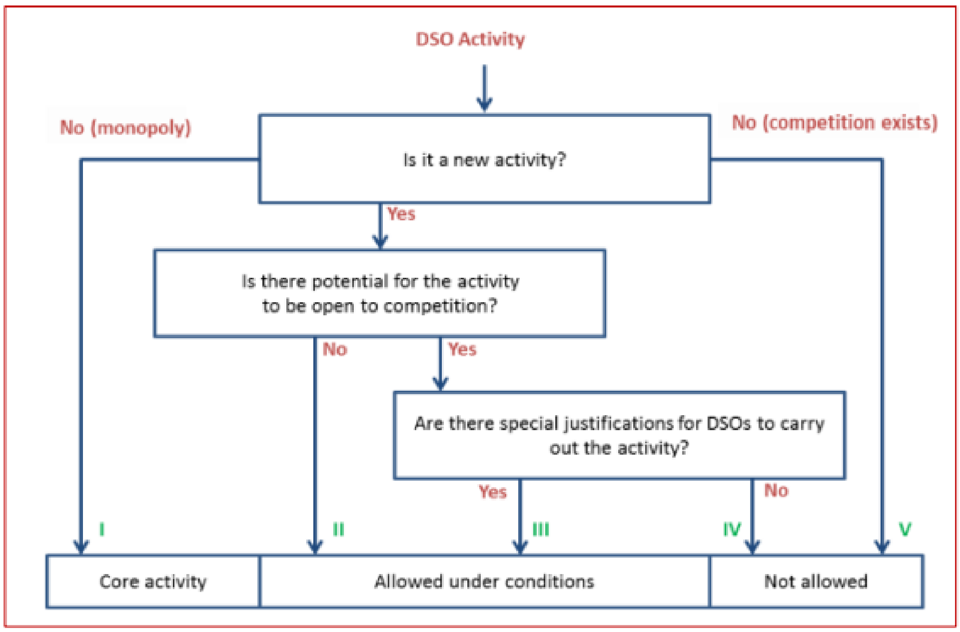

Figure 16: Logical Framework for DSO Activities, source: (CEER, 2014)

For the grey areas, there is no single model defining how they should be regulated. The DSO involvement in areas such as the ownership of storage and EV charging infrastructure is allowed in some MSs under certain conditions. In such cases, the aim is to help the development of this sector on a provisional mandate until the market evolves into actual competition.

2.2.1. Traditional Roles

In what follows, we discuss the traditional DSO roles in network planning and network management.

Network planning

The EC (2015b) study on tariff design for distribution systems presents the main features of the DSOs network development process. It considers whether the distribution network development plan is published in different MSs and whether the investments are subject to approval by the NRAs or the government.

Across Europe, only DSOs in Italy, Portugal, Hungary, the Netherlands, Poland, UK, and Germany (for network assets at high voltage distribution level) publish distribution network development plans. In six MSs (Spain, Greece, Poland Portugal, Romania, and Slovenia) distribution network development plans are approved by regulators. In France, Germany, and Lithuania, the regulator approves only selected investments. Figure 17 gives an overview of the situation in various MSs.

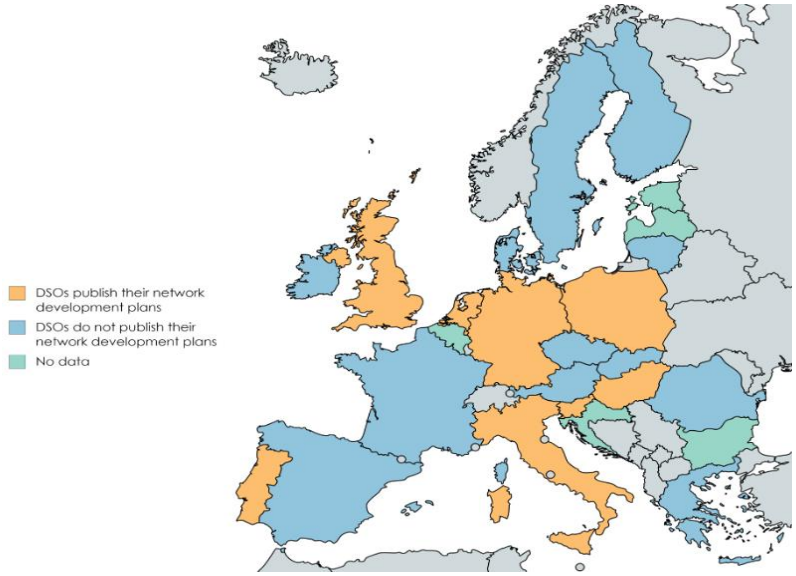

Figure 17: Published distribution network development plans (DNDP), based on: (EC, 2015b)

The Commission report adds that the decision-making process of distribution network development appears less structured and transparent than for transmission network development in most MSs. However, the importance of the process has increased with the recent trends in the sector. Distribution and transmission system operators may need to take a coordinated approach to network planning and development with transparent data exchange processes for an increased overall efficiency and quality of the electricity network. For instance, planned reinforcements on the transmission network may offset the need for reinforcements of the distribution system.

Some countries allow planning flexibility options for DSOs in order to optimize their network planning. Indeed, in Germany, the amendment of the Energy Act in 2016 allows DSOs to consider curtailment in the planning of distribution grid expansion. The government allows TSOs and DSO to curtail a maximum of 3% of onshore wind and PV in their network development plans. This aims to avoid high grid investments. In Figure 18 from the BMWi (2014) study, we can see that a 3% curtailment, in the EEG scenario, can bring up to 40% of saving in investment expansion. This rule is, however, optional and DSOs can choose not to consider it in their planning (Furusawa et al., 2019).

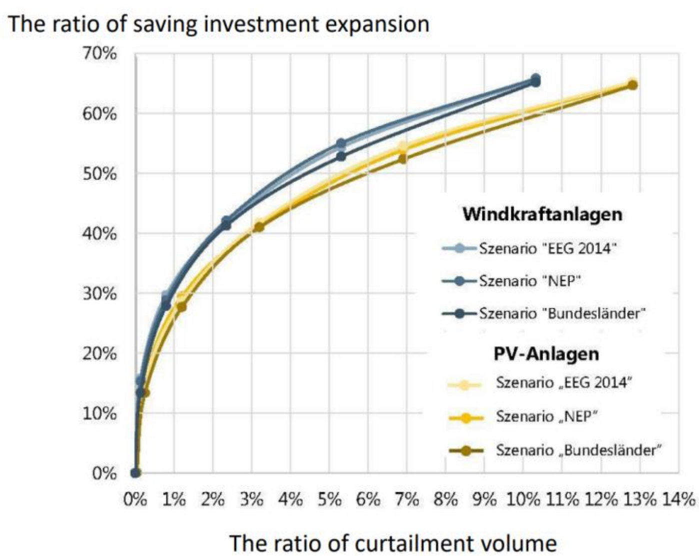

Figure 18: The saving network expansion by the curtailment of RES energy, source: (BMWi, 2014)

Network management

Today, some DSOs have already started to consider procuring flexibility services to re-dispatch the system at the level of distribution grids. However, in most countries, there are no rules in place that allow DSOs to do that. According to the EvolvDSO[37] project survey, in countries like France, Ireland, Italy, or Portugal, DSOs are not able to contract flexibility for congestion management, except possibly for pilot projects. Discussions on the topic are ongoing in these countries. In others, like Belgium and Germany[38], DSOs can obtain system flexibility services via connection and distribution access contracts. These contracts provide a reduced network fee in exchange of the unit control by the DSO. CEDEC et al. (2019) TSO–DSO report focusing on TSO–DSO coordination in congestion management and balancing presents different market models for flexibility procurement. It aims to provide, based on discussion with the main stakeholders, sharing TSOs and DSOs needs, a framework that could be used for assessment at the EU level, leaving freedom for MSs to choose the model to implement. Three main options for models were derived depending on the links between congestion management and balancing. The first one is where TSO and DSO have separated congestion management markets. This requires coordination between market processes. The second is with combined TSO and DSO congestion management, with separated balancing. This model gathers TSOs and DSOs needs, which may overlap. The third model is with combined balancing and congestion management for all system operators together. The different market models need appropriate governance with clear processes to manage interactions.

The implementation of these different market models can take place through different platforms options. The CEDEC et al. (2019) report also presents different platforms options that can be used according to the market model chosen as both issues are linked. A digital platform is defined, in CEDEC et al., (2019), as a *'(distributed) software functionality, needed by actors to perform their tasks, corresponding to their roles and responsibilities, which as part of an ecosystem interacts with other relevant actors in the energy system.'* Four platforms options are presented. In the first option DSOs and TSOs interact with flexibility service providers via their own separately developed platforms. In the second option, DSOs interact with flexibility providers directly in the market or via congestion management market platforms, and the TSO uses the balancing platform also for congestion management. In the third option, DSOs and TSOs use a combined platform for congestion management, where TSO–DSO coordination might take place through algorithms to avoid conflicts and double-activation of flexibility). TSOs continue to operate their separate platform for balancing. In the fourth option, DSOs and TSOs interact with flexibility providers through a joint platform market trading platforms for DSOs and TSOs congestion management as well as TSOs balancing.

In Europe, there are currently DSOs, TSOs, and other market actors that have started to develop platforms for procuring and trading flexibility services. Figure 19, in the next page, presents a mapping of the main flexibility pilot projects in Europe. Among these pilot projects, there are pilot demonstrators (e.g., SmartNet and INTERRFACE) that are elaborated in the framework of R&D projects to test new functionalities. Others are pilots for commercial projects aiming for a wider scale implementation. Schittekatte and Meeus (2019) have studied four pioneering projects; Piclo Flex, Enera, GOPACS, and NODES, implementing flexibility markets and analysed the projects over a six-question framework that covers, for instance, their integration in electricity market sequence and the existence of TSO-DSO cooperation for the organisation of the flexibility market.

[37] EvolvDSO ('Development of methodologies and tools for new and evolving DSO roles for efficient DERs integration in distribution networks') is an FP7 collaborative project funded by the European Commission.

[38] This is particularly relevant for DSOs in Germany where the distribution grid can be up to 110 kV and therefore hosts large amounts of DG.

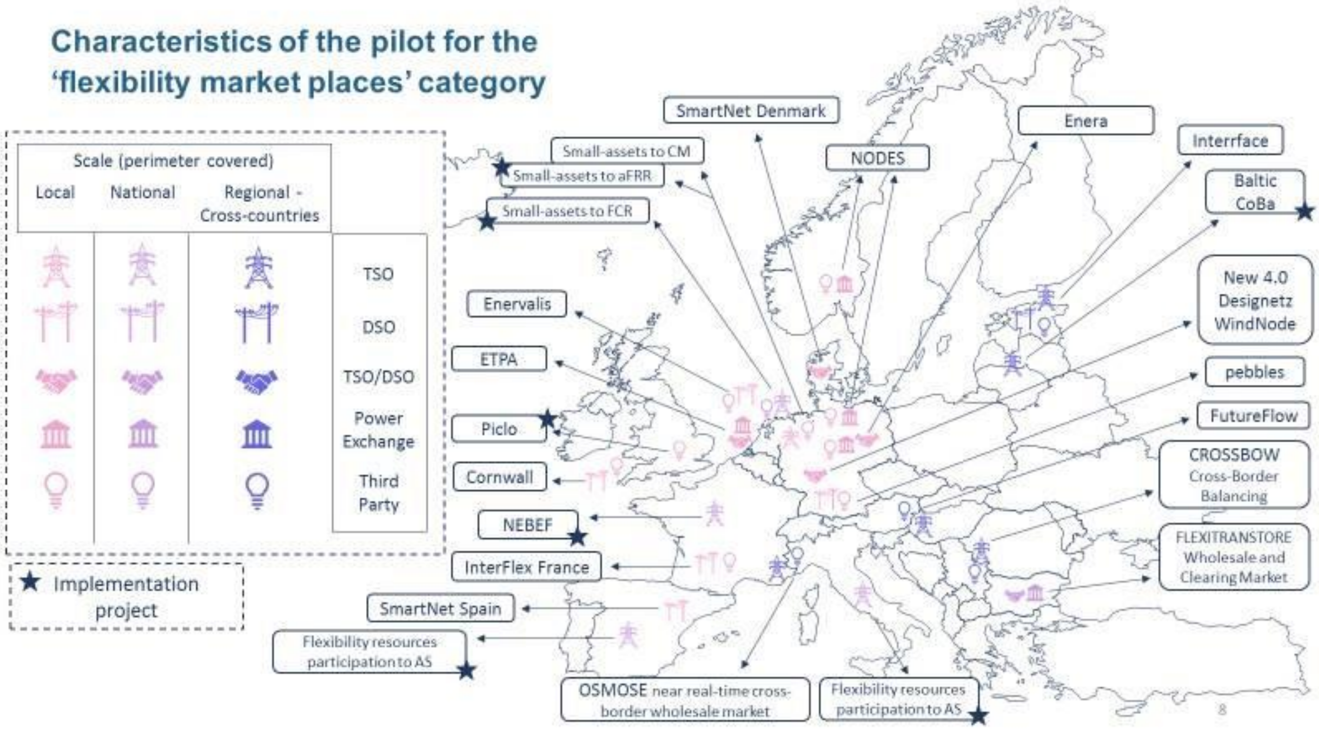

Figure 19: Flexibility pilot projects in EU, source: (ENTSO-E, 2018b)

2.2.2. Emerging Roles

Storage facilities

Electricity storage is one way of providing flexibility to the system. It can be defined as any device that can store electrical energy and make it available when required. Several types of storage technologies have been proposed, tested, and are currently being implemented. Storage systems can be chemical, electrochemical, electrical, mechanical, and thermal. Currently, pumped hydro, which is classified as mechanical storage, accounts for most of the storage capacity. This can be considered as a traditional storage technology as it has been around for a long time.

However, due to rapid innovation, large-scale batteries (also referred to as electrochemical storage devices) are recently becoming economically viable (Obi et al., 2017). Batteries have some unique characteristics that set them apart from traditional storage resources. These devices are modular and can be installed quickly, and they are not constrained by location. Not only can batteries be installed at any location, but they can also be cost-effectively moved to other locations when required. This makes them an invaluable resource for providing location-specific services such as voltage control for distribution grids.

Before the adoption of the e-Directive of the EU Clean Energy Package, there was no common EU regulatory framework incorporating storage in distribution grids. In the UK, DSOs that have invested in batteries have been exempted from acquiring generation license for capacities below 50 MW and possibly up to 100 MW in individual cases. In Spain, the DSO and the TSO could own batteries and have also been exempted from acquiring authorization if the generation output is less than 50MW.[39] Several other regulators across the EU have approved battery pilots in motivated cases, such as in Germany and Italy (Meeus and Bhagwat, 2018).

[39] Ley 24/2013, de 26 de diciembre, del Sector Eléctrico.

EV charging infrastructure

According to Meeus and Schittekatte (2018), 70,000 public charging points were in place in Europe by the end of 2016, representing one public charging point for every nine EVs. 27% of them are installed in the Netherlands. 90% of the public charging points in the EU are normal charging points (AC, <22 kW), meaning that full charging times is a matter of hours. The remaining 10% are considered fast (AC, >22 kW or DC, >25 kW) where the charging time is lower than an hour.[40] Also, there were 390,000 private charging points in Europe in 2016, bringing the total charging points to 460,000. During the year (2015-2016), the amount of public charging stations installed had a higher increase than the number of EVs sold (71% versus 53%).

Several actors may play a role in the provision of EV charging infrastructures, such as DSOs, suppliers, or third parties who can use the charging points to sell electricity. DSOs' involvement in EV charging is different across MS as there was no common EU regulatory framework before the adoption of the EU Clean Energy Package. In the Spanish model, most DSOs deployed the charging infrastructure while the commercial operation is open to retailers. In Ireland, the DSO is involved, but the assets have not yet been included in the regulated asset base. Costs have been recovered via the distribution tariffs but are kept in a separate company and account. In the Czech Republic EV public charging infrastructure is built, owned and managed through competitive tenders mostly pushed by the three biggest energy utilities while DSOs are only in charge of the connection (EDSO, 2018).

Data management

Data management comprises *'the processes by which data is sourced, validated, stored, protected and processed and by which it can be accessed by suppliers or customers',* according to the EC impact assessment (EC, 2016b).

Data access and management is a key enabler for the operation of electricity markets. There are currently different data management models across EU MS, as presented in CEER (2016b); decentralised, partially centralized or fully centralised. The categories of data management models are described as follows:

- A fully centralized model comprises a centralization of all key aspects related to data management. A typical centralized model is a data hub, where all data is retrieved, validated, stored, protected, processed, distributed and accessed. In this model DSOs, market actors and all consumers relate to the data hub. The party responsible for a Data Exchange Platform (DEP) should be full neutral in order to avoid any discrimination in data access and delivery.
- A partially centralized model involves centralization of one or a few of the key aspects of data management, typically distribution and access to data. It is rather a communication hub that provides a common access point to data stored in several databases, at DSOs or metering points.
- A decentralized model, or DSO model, typically means that all the key aspects of data management are decentralized, meaning that they are the responsibility of the DSO. A typical decentralized model would be a standardized message exchange system or another cruder way of connecting market actors with DSOs.

[40] As a reference, it would take approximately 30 minutes for an 80 % charge or 120 km of extra range with a 60 kW DC charger on a Nissan Leaf.

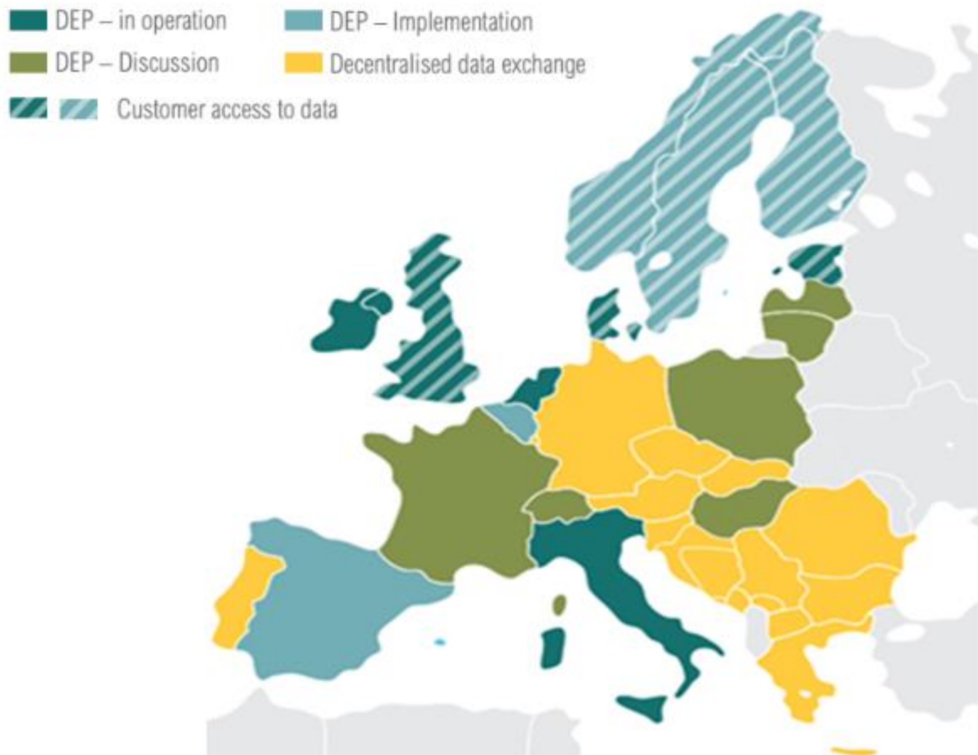

Figure 20: Responsible parties for access to metering data, source: (THEMA, 2017)

Figure 20 gives an overview of the state of play of data management models in Europe. Italy and Ireland currently operate each a DEP. The Netherlands has a partially centralized model, with centralized communications with multiple databases and is considered as a DEP. Denmark, Estonia and the UK have just recently implemented a central DEP. Other MSs, such as Sweden and Finland, are either in the discussion or the implementation process of DEPs. Germany, which has a combination of models, is considered as a decentralized data exchange (DSO) model in the figure. In fact, a metering point operator, which can be a DSO, is responsible for third-party access to metering data in Germany. Portugal and Austria are also using decentralised data exchange, also called the DSO model.

2.3. Increased expectations for DSOs in their traditional roles

In this subsection, we will present two new responsibilities that the CEP assigns to the DSOs. First, we present the measures for DSOs in network planning and then the incentives for flexibility procurement.

2.3.1. Measures for DSOs network planning

On the introduction of distribution network planning, the newly added **recital (62)** of the e-Directive states that '*(..) Member States should also introduce network development plans for distribution systems in order to support the integration of installations generating electricity from renewable energy sources, facilitate the development of energy storage facilities and the electrification of the transport sector, and provide to system users adequate information regarding the anticipated expansions or upgrades of the network, as currently such procedures do not exist in the majority of Member States.'*

The e-Directive requires that DSOs prepare and implement multi-annual development plans and coordinate with TSOs on such multi-annual development plans. It adds in **art 32(3)** that *'the development of a distribution system shall be based on a transparent network development plan that the distribution system operator <u>shall publish at least every two years</u> and shall submit to the regulatory authority.'* Moreover *'the network development plan shall provide transparency on the medium and long-term* *flexibility services needed, and shall set out the planned investments for the next five-to-ten years, with particular emphasis on the main distribution infrastructure which is required in order to connect new generation capacity and new loads, including recharging points for electric vehicles.'* The development plan *'shall also include the use of demand response, energy efficiency, energy storage facilities or other resources that the distribution system operator is to use as an alternative to system expansion.'*

During the network development plan elaboration, DSOs shall consult all relevant system users and the relevant TSOs. They shall publish the results of the consultation process together with the network development plan and submit both to the relevant NRA.[41] The NRA may request amendments to the plan.

Regarding renewable energy sources or high-efficiency cogeneration integration, **art 13(5)(a)** of the e-Regulation states that a limited redispatching can be taken into account by DSOs and TSOs in their network planning where proven in a transparent way to be economically efficient. It *'shall not exceed 5 % of the annual generated electricity in installations which use renewable energy sources and which are directly connected to their respective grid (…).'* MSs, where electricity from RES or high-efficiency cogeneration represents more than 50 % of the annual gross final electricity consumption, can exceed this threshold according the same article.

Art 57(1) of the e-Regulation adds that in order to ensure a cost-efficient, secure and reliable development and operation of the network, DSOs and TSOs *'shall cooperate with each other in planning and operating their networks.'* They shall, in particular, *'exchange all necessary information and data regarding, the performance of generation assets and demand side response, the daily operation of their networks and the long-term planning of network investments, with the view to ensure the cost-efficient, secure and reliable development and operation of their networks.'*

A derogation from the development and publication of distribution network plans may be granted for DSOs serving less than 100,000 connected consumers, or serving small isolated systems, according to **art 32(5)** of the e-Directive.

Highlights

- DSOs are required to prepare and implement multi-annual development plans and coordinate with TSOs and other relevant stakeholders on their development.
- DSOs shall publish the network development plan and submit it to the NRA at least every two years.

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- DSOs should undertake a public consultation on the proposed investment in the network plans. NRAs may require amendments.
- The network development plan shall provide transparency on the medium and long-term flexibility services needed and contain the planned investments for the next five to ten years.
- DSOs (and TSOs) can integrate up to 5% of curtailment in their distribution planning, with derogation for MSs with high share or RES and cogeneration integration in their annual gross final electricity consumption (50%).
- For DSOs serving less than 100,000 connected consumers, or serving small isolated systems, MSs may decide not to apply these obligations.

[41] In the Commission draft of the e-Directive, it was the NRAs that were in charge of the consultation process and the publication of the network development plans.

2.3.2. Measure to incentivize DSOs to procure flexibility services

The CEP aims to define the conditions under which DSOs may acquire flexibility services[42] without distorting the markets for such services. It includes clear provisions that will enable DSOs to manage local grid issues and enhance the security of supply (SoS) through flexibility procurement.

DSOs flexibility services procurement process

Regarding the regulatory framework for the procurement of flexibility by distribution system operators, **art 32(1)** of the e-Directive requires MSs to define the exact regulatory framework, including incentives for DSOs and adequate remuneration. 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, in order to improve efficiencies in the operation and development of the distribution system.'*

This procurement shall be transparent, non-discriminatory, and <u>market-based.</u> In this context, market-based flexibility procurement refers to a process whereby flexibility is obtained and priced through a (separate) market mechanism from all stakeholders that are a source of flexibility, benefit from it, or have a controlling role, i.e., consumers, producers, BRP, system operators and regulators. In addition, the non-discriminatory aspect refers to the '*participation of all market participants, including market participants offering energy from renewable sources, market participants engaged in demand response, operators of energy storage facilities and market participants engaged in aggregation,'* as stated in **art 32(2)**.

In addition, <u>DSOs</u>, subject to NRA approval <u>or the NRA itself</u>, shall define *'the specifications for the flexibility services procured and, where appropriate, <u>standardised market products</u> for such services at least at national level.'* This shall be done in a transparent and participatory process, including all relevant system users and the TSO.

DSOs shall receive an adequate remuneration for the procurement of flexibility service so that they recover *'at least their reasonable corresponding costs, including the necessary information and communication technology expenses and infrastructure costs.'*

A <u>derogation</u> could be given by NRAs if they establish that this kind of procurement is not economically efficient or if it may cause severe market distortions or higher congestions. Note that on the application of flexibility service procurement to smaller DSOs, no clear derogation was introduced. However, there is a nuance. **Art 32(5)** gives the possibility to MSs to not apply the obligation of developing and publishing network plans only for small DSOs. So, in theory, this is not directly related to flexibility procurement incentives introduced in **art 32(2)**, even though that DSO plans shall include the use of DERs as an alternative to system expansion.

Coordination with TSOs in the procurement of flexibility services

Using system flexibility services will require extensive cooperation and clear boundaries between TSOs and DSOs. This aims to ensure an efficient data exchange on the activated flexibility resources and to avoid a double activation from a DSO and a TSO of the same flexibility source. According to **art 32(2)** of the e-Directive, 'd*istribution system operators shall exchange all necessary information and shall coordinate with transmission system operators in order to ensure the optimal utilisation of resources, to ensure the secure and efficient operation of the system and to facilitate market development.'*

[42] Regarding the DSO role in balancing the system, the CEP has not foreseen the procurement of frequency ancillary services (Frequency Containment Reserves (FCR), Frequency Restoration Reserves (FRR) and Replacement Reserves (RR)) by DSOs. The flexibility services, that DSOs may procure, have been limited to non-frequency ones and congestion management services.

In addition, for the access to flexibility resources, **art 57(2)** of the e-Regulation states that *'distribution system operators and transmission system operators shall cooperate with each other in order to achieve coordinated access to resources such as distributed generation, energy storage or demand response that may support particular needs of both the distribution system operators and the transmission system operators.'* Figure 21 shows the new one-system approach for flexibility provision.

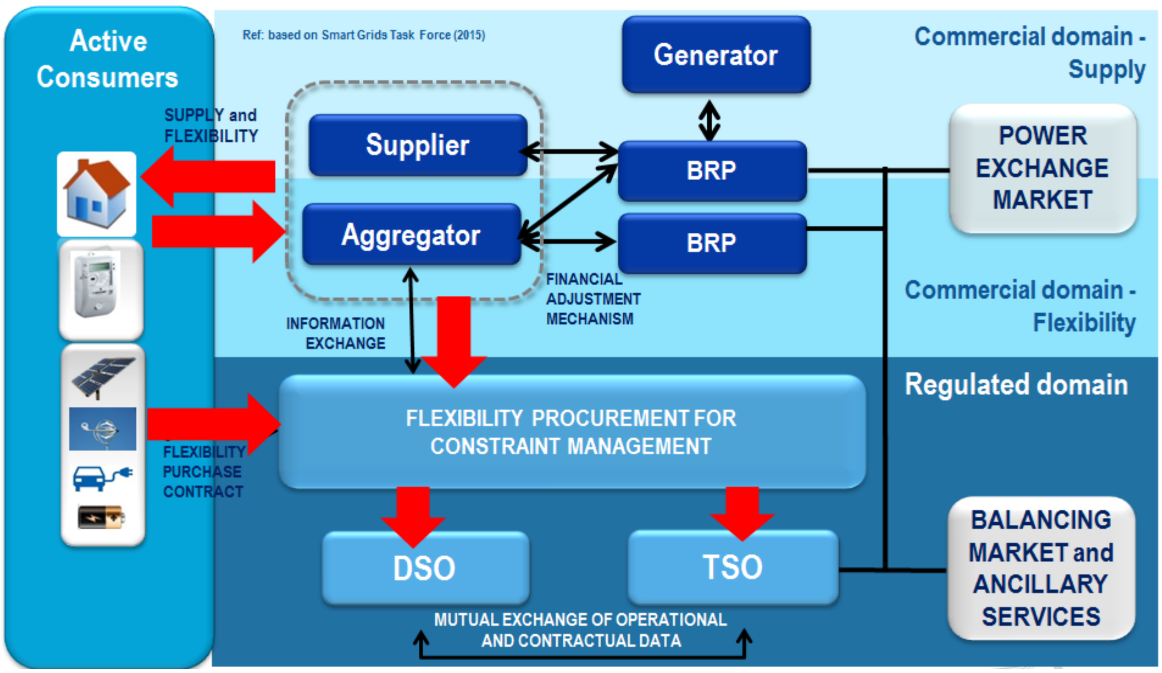

Figure 21: A one-system approach for flexibility procurement, source: (EC, 2017a)

Highlights

- DSOs shall include flexibility services in network planning, as an alternative to traditional grid investment.
- MSs shall provide the necessary regulatory framework to allow and to incentivise DSOs to procure flexibility services.
- DSOs subject to NRA approval, or the NRA itself, shall define the specifications for the flexibility services and where appropriate standardized products.
- The procurement of flexibility services shall be transparent, non-discriminatory and market-based, unless the NRA grants a derogation. At the same time, it shall ensure TSO/DSO coordination.
- DSOs shall receive an adequate remuneration for the procurement of flexibility services so that they recover at least the corresponding reasonable costs.
- A derogation could be given by NRAs, from market-based flexibility services procurement, if they establish that it is not economically efficient or if it may cause severe market distortions or higher congestions.

2.4. Limiting the role of DSOs in emerging businesses

EV charging and storage facilities are emerging businesses in the electricity sector. The CEP aims to establish a regulatory framework for limiting the DSOs' roles in these businesses when their involvement is not necessary.

2.4.1. Limiting DSOs' ownership of EV charging facilities

DSOs, according to **recital 40** of the e-Directive, have to integrate electric vehicles into their system in a cost-efficient manner, and to create favourable conditions for electric vehicles through the different market rules set out in the e-Directive. For instance, the distribution network development plans, submitted at least every two years to NRAs, shall include the planned investments for the next five to ten years covering, inter alia, re-charging points for electric vehicles.

MSs are in charge of providing the necessary regulatory framework facilitating the connection of public and private EV charging facilities to the distribution networks. According to **art 33(1)** of the e-Directive, each MS shall ensure that DSOs *'cooperate on a non-discriminatory basis with any undertaking that owns, develops, operates or manages recharging points for electric vehicles, including with regard to connection to the grid.'* In addition, DSOs *'shall not own, develop, manage or operate recharging points for electric vehicles, except where distribution system operators own private recharging points solely for their own use'*(**art 33(2)**).

Derogation for EV charging facilities' ownership by DSOs

The e-Directive promotes a market-based solution for the ownership of EV charging infrastructure. It also provides a derogation for DSOs' ownership as a last resort and under certain conditions. **Art 33(3)** of the e-Directive states that:

'Member States may allow distribution system operators to own, develop, manage or operate recharging points for electric vehicles, provided that all of the following conditions are fulfilled:

(a) other parties, following an open, transparent and non-discriminatory tendering procedure that is subject to review and approval by the regulatory authority, have not been awarded a right to own, develop, manage or operate recharging points for electric vehicles, or could not deliver those services at a reasonable cost and in a timely manner;

(b) the regulatory authority has carried out an ex ante review of the conditions of the tendering procedure under point (a) and has granted its approval;

(c) the distribution system operator operates the recharging points on the basis of third-party access in accordance with Article 6 and does not discriminate between system users or classes of system users, and in particular in favour of its related undertakings.'

In case of a MS applying this derogation, a public consultation, to re-assess the condition of the derogation, shall be made at regular intervals or at least every five years by MSs or their designated competent authorities. In case a third-party becomes able to own, develop, operate, or manage EV charging points, MSs shall ensure the DSOs' ownership phase-out. NRAs may allow DSOs to recover the residual amount of investment that has been already made.

Highlights

- MSs shall promote market-based schemes Member States or their designated competent authorities shall perform for the ownership of EV charging infrastructure through providing the necessary regulatory framework to facilitate the connection of publicly accessible and private recharging points to the distribution networks.

- MSs may allow DSOs ownership of EV charging infrastructure under certain conditions, followed by a continuous monitoring and public consultation for emerging interested third-parties.

2.4.2. Limiting DSOs ownership of storage facilities

Storage units represent an attractive source of flexibility for the electricity system, especially with the increasing diffusion of RES-E and the challenges they create for system operation. **Art 36** of the e-Directive sets the measures with regard to DSOs ownership of storage facilities. It states that DSOs shall not be allowed to own, develop, manage, or operate energy storage facilities. However, derogations may be granted.

Derogation for storage facilities ownership by DSOs

The e-Directive differentiates two separate derogations for storage facilities ownership. This depends on whether the storage facilities are '<u>fully integrated network components</u>' or not. Fully integrated network components means according to **art 2(51)** of the e-Directive *'network components that are integrated in the transmission or distribution system, including storage facilities, and that are used for the sole purpose of ensuring a secure and reliable operation of the transmission or distribution system, and not for balancing or congestion management.'* The derogation for fully integrated network components was not included in the Commission proposal for the e-Directive but was introduced by the Council in its negotiating position. Fully integrated network components can include energy storage facilities such as capacitors or fly wheels, which help to ensure network security and reliability and to maintain synchronisation between different parts of the system. They must not be used to buy or sell electricity in the electricity markets. In general, the idea of limiting storage ownership is to prevent DSOs and TSOs from owning storage assets that they use in congestion management and balancing (for TSOs) as they should procure these services in a market based process and owning some of these assets by DSOs and TSOs would distort this process.

According to **recital 63**, *'where energy storage facilities <u>are fully integrated network components</u> that are not used for balancing or for congestion management, they should not, <u>subject to approval by the regulatory authority</u>, be required to comply with the same strict limitations for system operators to own, develop, manage or operate those facilities.* In case they are <u>not</u> fully integrated components, the derogation requires, according to **art 36(2)**, <u>all of the following conditions</u> to be fulfilled:

'(a) other parties, following an open, transparent and non-discriminatory tendering procedure that is subject to review and approval by the regulatory authority, have not been awarded a right to own, develop, manage or operate such facilities, or could not deliver those services at a reasonable cost and in a timely manner;
(b) such facilities are necessary for the distribution system operators to fulfil their obligations under this Directive for the efficient, reliable and secure operation of the distribution system and the facilities are not used to buy or sell electricity in the electricity markets; and
(c) the regulatory authority has assessed the necessity of such a derogation and has carried out an assessment of the tendering procedure, including the conditions of the tendering procedure, and has granted its approval.
The regulatory authority may draw up guidelines or procurement clauses to help distribution system operators ensure a fair tendering procedure.'

In case of the application of this derogation and similarly to the case of EV charging station ownership, a public consultation, to re-assess the condition of the derogation, shall be made at regular intervals or at least every five years by NRAs.

In case the public consultation indicates that third parties are able to own, develop, operate or manage such the storage facilities in a cost-effective manner, NRAs shall ensure that DSOs' activities in this regard are phased-out within 18 months.'[43] NRAs may allow DSOs, in this case, to receive reasonable

[43] This requirement was not included in the Commission proposal. The Council proposed a 24 months period.

compensation allowing them to recover the residual amount of investment that has been already made in storage facilities.

Highlights

- DSOs shall not be allowed to own, develop, manage or operate energy storage facilities.
- Two types of derogations are possible depending whether the storage facilities are fully integrated network components or not.
- For storage facilities, which are fully integrated network components, the NRA's approval is enough for DSO ownership.
- For storage facilities, which are **not** fully integrated network components, three conditions need to be fulfilled, including that no third party was awarded this right in the tender process.
- A public consultation shall be done by NRAs regarding third parties' capabilities and interest for the ownership of storage facilities, at regular intervals or at least every five years.

2.4.3. Neutral DSOs role in data management

Being in charge of the smart metering systems roll-outs in most of the EU MSs, DSOs have the role of pooling or collecting of data from consumers. This 'advantageous' position induces the need to ensure a neutral role for DSO in data management.

Art 34 of the e-Directive on 'tasks of distribution system operators in data management' states that MSs shall ensure that data eligible parties[44] have non-discriminatory, clear and equal access to data.[45] This should be under clear terms that respect the relevant data protection legislation, such as EU General Data Protection Regulation (GDPR). Indeed, in MSs where smart meters are implemented according to **art 19** of the e-Directive and DSOs are involved in data management, compliance programmes, ensuring that discriminatory conduct is excluded, shall include specific measures to exclude discriminatory access to data from eligible parties as provided in **art 23** on data management.

The same article adds that where DSOs are not subject to **art 35(1)**, **(2)** and **(3)**, on unbundling of DSOs, *'Member States shall take all necessary measures to ensure that vertically integrated undertakings do not have privileged access to data for the conduct of their supply activities.'*

Highlights

- Eligible parties shall have a non-discriminatory access to data under clear and equal terms, in compliance with the GDPR.
- Where smart meters are implemented and DSOs are involved in data management, compliance programmes shall be set to ensure that discriminatory conduct is excluded.
- Vertically integrated undertakings shall not have privileged access to data for the conduct of their supply activity.

[44] A minimum list of eligible parties was included in the **art 23** of the Commission proposal of e-Directive Directive, being the customers, suppliers, transmission and distribution system operators, aggregators, energy service companies, and other parties which provide energy or other services to customers. This minimum list was removed in the final version of the e-Directive.

[45] There is no clear provision on DSO profit from data. In the Commission draft Directive, regulated entity were not allowed to profit from data, a provision that does not exist anymore in the final version. Further data access provisions are presented in section 3.2.3.

2.5. The EU DSO entity

Being at the center of the European energy transition, the diverse DSOs' landscape demands closer inter-DSO cooperation. In this subsection, we will present the CEP measures for the establishment of the EU DSO entity and its tasks. The creation of this entity represents recognition for the role of DSOs in the energy transition and aims to foster cooperation between DSOs which are currently represented by different organisations as introduced at the beginning of this chapter in 2.1.

2.5.1. Establishment of the EU DSO entity

The CEP e-Regulation defines the EU DSO entity establishment procedure. The EU DSO Entity will be composed by European DSOs aiming to join this entity, without the unbundling condition that was introduced in the Commission proposal for the e-Regulation. **Art 52** of the e-Regulation states that DSOs[46] *'shall cooperate at Union level through the EU DSO entity, in order to promote the completion and functioning of the internal market for electricity, and to promote optimal management and a coordinated operation of distribution and transmission systems.'* Moreover, DSOs wishing to participate in the EU DSO entity shall have the right to become registered members of the entity. The registered members may participate in the DSO entity directly or indirectly, being represented by their national association designated by the MS or by a Union level association. A fair and proportionate membership fee shall be paid by the members of the EU DSO entity which shall be proportionate to the number of their connected customers.

The EU DSO entity should be an expert entity working for the general European interest. It, therefore, should not defend any particular interest. **Art 52(2)** adds that *'EU DSO entity shall neither represent particular interests nor seek to influence the decision-making process to promote specific interests.'*

Art 53 of the e-Regulation on the establishment of the EU DSO entity for electricity indicates that it *'shall consist of, at least, a general assembly, a board of directors, a strategic advisor group, expert groups and a secretary-general.'* It further sets the different establishment steps, that are explained in Figure 22:

'2. By 5 July 2020, the distribution system operators shall submit to the Commission and to ACER, the draft statutes, in accordance with Article 54, including a code of conduct, a list of registered members, the draft rules of procedure, including the rules of procedures on the consultation with the ENTSO for Electricity and other stakeholders and the financing rules, of the EU DSO entity to be established. The draft rules of procedure of the EU DSO entity shall ensure balanced representation of all participating distribution system operators.

3. Within two months of receipt of the draft statutes, the list of members and the draft rules of procedure, ACER shall provide the Commission with its opinion, after consulting the organisations representing all stakeholders, in particular distribution system users.

4. Within three months of receipt of ACER's opinion, the Commission shall deliver an opinion on the draft statutes, the list of members and the draft rules of procedure, taking into account ACER's opinion as provided for in paragraph 3.

5. Within three months of receipt of the Commission's positive opinion, the distribution system operators shall establish the EU DSO entity and shall adopt and publish its statutes and rules of procedure.

6. The documents referred to in paragraph 2 shall be submitted to the Commission and to ACER where there are changes thereto or upon the reasoned request of either of them. The Commission and ACER shall deliver an opinion in line with the process set out in paragraphs 2, 3 and 4.

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[46] The Commission proposal for e-Regulation stressed that the DSOs that are to form part of the DSO entity should be '<u>unbundled</u>', a requirement that has been removed in the final text.

7. The costs related to the activities of the EU DSO entity shall be borne by the distribution system operators that are registered members and shall be taken into account in the calculation of tariffs. Regulatory authorities shall only approve costs that are reasonable and proportionate.'

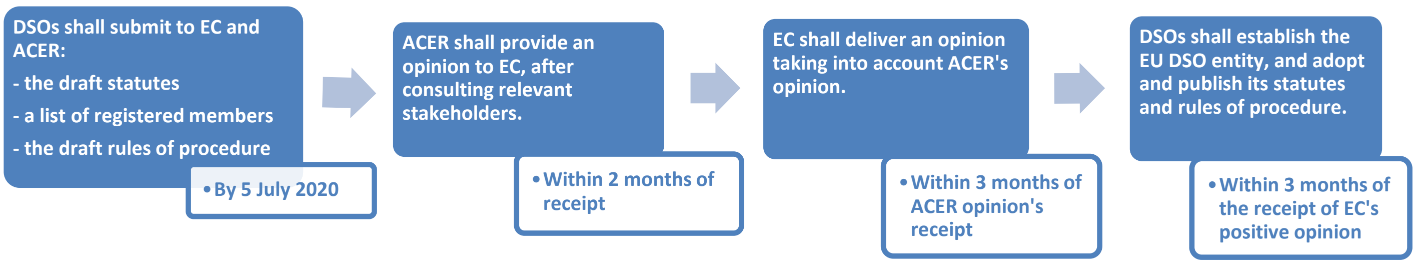

Figure 22: Main stages of the EU DSO establishment, source: own illustration

Art 54, on 'Principal rules and procedures for the EU DSO entity', sets more detailed rules and procedures for the EU DSO entity. It includes the conditions for the participation in the works of the entity, the rules for strategic decision and conditions for the general assembly decision-making process as well as the Board of Directors election and roles such as the lead of DSO-TSO cooperation. These specific rules were not included in the Commission proposal.

The Board of Directors is elected by the General Assembly for a maximum period of 4 years and has the tasks to nominate the President and the three Vice-Presidents from among the members of the board, propose Expert Groups, appointed by the General Assembly (**art 54(1)**). The board of directors shall also establish the Strategic Advisory Group, which consists of representatives of the European DSOs' associations and representatives of MSs that are not represented in the Board of Directors. The e-Regulation introduces, in **art 54(2)**, the composition of the 27 members of the Board of Directors. A 9/9/9 composition of which:

- 9 are representatives of members with <u>more than 1 million grid users;</u>
- 9 are representatives of members with <u>more than 100,000 and less than 1 million grid users;</u>
- 9 are representatives of members with <u>less than 100,000 grid users</u>.

This composition allocates the same number of representatives to the three categories of DSOs with regard to their number of customers. This aims, according to **art 54(2)** of the e-Regulation, to *'safeguard the fair and proportionate treatment of its members and shall reflect the diverse geographical and economic structure of its membership.'*

2.5.2. Tasks of the EU DSO Entity

We divide the EU DSO Entity tasks into three categories. In this subsection, we will present the proposed aggregated tasks for the DSO entity, its cooperation with ENTSO-E and its role in drafting network codes.

Aggregated tasks

Art 55(1) of the e-Regulation lists the tasks of the new EU DSO entity;

'(a) promoting operation and planning of distribution networks in coordination with the operation and planning of transmission networks;

(b) facilitating the integration of renewable energy resources, distributed generation and other resources embedded in the distribution network such as energy storage;

(c) facilitating demand side flexibility and response and distribution grid users' access to markets; (d) contributing to the digitalisation of distribution systems including deployment of smart grids and intelligent metering systems;

(e) supporting the development of data management, cyber security and data protection in cooperation with relevant authorities and regulated entities;

(f) participating in the development of network codes which are relevant to the operation and planning of distribution grids and the coordinated operation of the transmission networks and distribution networks pursuant to Article 59.'

Cooperation with ENTSO-E and other tasks

At the European level, TSOs and DSOs shall cooperate for the planning and operation of the network. The DSO entity should cooperate closely with ENTSO-E on the preparation and implementation of the network codes where applicable, i.e., areas related to distribution networks. **Art 55(2)** of the e-Regulation also brings the following additional tasks for the DSO entity related to cooperation with ENTSO-E putting them on the same footing. These additional tasks include:

'(a) cooperate with the ENTSO for Electricity on the monitoring of implementation of the network codes and guidelines adopted pursuant to this Regulation which are relevant to the operation and planning of distribution grids and the coordinated operation of the transmission networks and distribution networks;

(b) cooperate with the ENTSO for Electricity and adopt best practices on the coordinated operation and planning of transmission and distribution systems including issues such as exchange of data between operators and coordination of distributed energy resources;

(c) work on identifying best practices on the areas identified in paragraph 1 and for the introduction of energy efficiency improvements in the distribution network;

(d) adopt an annual work programme and an annual report;

(e) operate in accordance with competition law and ensure neutrality.'

Network codes drafting

When the matter of network codes is directly related to the operation of the distribution system and not primarily relevant for the transmission system, the Commission <u>may require</u> from the EU DSO entity, in cooperation with ENTSO-E, to convene a drafting committee and submit a proposal for a network code to ACER (**art 59(3)**). In the first Commission proposal, the EU DSO entity was originally tasked to convene a drafting committee <u>instead of ENTSO-E</u> and not <u>in cooperation with it</u>.

In addition, the DSO entity shall conduct an extensive consultation process while participating in the elaboration of new network codes. This consultation process should be done at an early stage of the development and in a transparent and open manner for the relevant stakeholders.[47] This process, as stated in **art 56(1)**, *'shall aim at identifying the views and proposals of all relevant parties during the decision-making process.'* In addition to that, *'the EU DSO entity shall indicate how it has taken the observations received during the consultation into consideration. It shall provide reasons where it has not taken such observations into account.'* (**art 56(3)**).

[47] *'That consultation shall also involve regulatory authorities and other national authorities, supply and generation undertakings, system users including customers, technical bodies and stakeholder platforms. It shall aim at identifying the views and proposals of all relevant parties during the decision-making process,'* according to **art 56(1)**.

Highlights
- The DSO entity will reinforce the DSOs representation at the European level.
- The DSO entity will be involved in the development of EU rules such as network codes in cooperation with ENTSO-E.
- The DSO entity will cooperate with ENTSO-E on issues of mutual concern, such as data management, balancing, planning, congestion, etc.
- The DSO entity will work on areas such as DSO/TSO cooperation, integration of RES, deployment of smart grids, demand response, digitalization and cybersecurity.
- A 9/9/9 composition of the board of the DSO entity, according to the DSO's number of customers, is introduced.
- The e-Regulation sets clear rules and procedures for the decision making process.

2.6. Interlinkage with Network Codes

The CEP introduces a more participative process for network codes development. In this part, we first present the second generation of network codes that has been foreseen in the CEP. Then we introduce the stakeholders' roles in network codes development and the newly proposed adoption process.

2.6.1. The second generation of network codes and guidelines

The e-Regulation brings two main new measures for the second generation of network codes and guidelines. In this subsection, we first present the scope of the second generation of network codes and guidelines. Second, we present the adoption process for network codes characterized by the introduction of the delegated acts adoption process for some focus areas of network codes.

Scope of the second generation of network codes and guidelines

Network codes and guidelines are Commission Regulations. They apply directly to all the EU Member States without being transposed into national laws or regulatory frameworks (Schittekatte et al., 2019). The electricity Regulation 714/2009 identified twelve focus areas for network codes. From these twelve areas, only seven are covered by the first generation of network codes that has been developed since the introduction of the third package. For the following six areas, network codes have not yet been developed;

-Third-party access rules;
-Data exchange and settlement rule;
-Interoperability rules;
-Transparency rules;
-Rules regarding harmonised transmission tariff structures incl. locational signals and inter-transmission system operator compensation rules;
-Energy efficiency regarding electricity networks;

In November 2016, the Commission draft for e-Regulation added four additional focus areas to be covered by NC:
-Rules for non-discriminatory, transparent provision of non-frequency ancillary services, including steady state voltage control, inertia, fast reactive current injection, black-start capability;
-Demand response, including aggregation[48], energy storage, and demand curtailment rules;
-Cyber security rules; and
-Rules concerning regional operational centres.

[48] An aggregator, according to **art 2(14)** of the e-Directive is *'a market participant that combines multiple customer loads or generated electricity for sale, for purchase or auction in any organised energy market.'*

The e-Regulation Commission proposal adds the harmonisation of distribution tariffs next to the transmission ones. They were both removed in the final text, as stated in 1.3.2. Also, the rules concerning regional operational centres were removed as the ROCs do not exist anymore in the final text while no specific area for network codes regarding RCCs has been included.

The final text of the e-Regulation has brought changes to this list. Indeed **art 59(1)** & **(2)** include an updated version of the focus areas compared to the first proposal. They also categorize the focus areas into the ones for which the Commission is empowered to adopt them as implementing acts and the other as delegated acts. We present the classification below. More details regarding the adoption process will be given in 2.6.3.

The areas where the Commission is empowered to adopt network codes as <u>implementing acts</u> (see Figure 23 for the process) are:

- Network security and reliability rules (existing, covered by SO GL guideline);
- Capacity-allocation and congestion-management rules (existing, covered by the CACM and FCA GL guidelines);
- Rules for trading related to technical and operational provision of network access services and system balancing (existing guideline EB GL);
- Rules for non-discriminatory, transparent provision of non-frequency ancillary services (new);
- Rules on demand response, including aggregation, energy storage, and demand curtailment rules (new); This area was highlighted as a priority area in Florence forum.

The areas where the Commission is empowered to adopt network codes as <u>delegated acts</u> (see Figure 24 for the process) are:

- Network connection rules (existing, covered by RfG, DCC HVDC network codes);
- Operational emergency and restoration procedures in an emergency (existing network code NC ER);
- Data exchange, settlement and transparency rules (partly by the SO GL and the transparency regulation No 543/2013[49]); This area was highlighted as a priority area in Florence forum.
- Third-party access rules (new);
- Sector-specific rules for cyber security aspects of cross-border electricity flows (new); Cybersecurity[50] was highlighted as a priority area in Florence forum.

The Commission is empowered to adopt Guidelines <u>in the same stated areas of the network codes</u>. The areas also condition the Commission adoption empowerment as either implementing or delegated acts for the guidelines.

In addition, **art 61(3)** states that the Commission is empowered to adopt, as delegated acts, guidelines relating to the inter-TSOs compensation mechanism. These different areas touch upon the areas covered by the Regulation No 838/2010 on laying down guidelines relating to the inter-transmission system operator compensation mechanism and a common regulatory approach to transmission charging. The guidelines shall specify:

- TSOs liability to pay compensation for cross-border flows;
- Details of the payment procedure;
- Details of methodologies for determining the cross-border flows hosted;

[49] The Regulation (EU) No. 543/2013 is called a 'transparency regulation'. It aims to make the pan-European electricity market information more transparent. It requires from TSOs to share data regarding generation, load, transmission and electricity balancing. it sets also transparency measures regarding market rules. It establishes also the ENTSO-E Transparency platform that publishes those TSOs data.

[50] Note that the reference was made to cybersecurity in general and not only the aspect related to cross-border flows.

- Details of the methodology for determining the costs and benefits incurred as a result of hosting cross-border flows;
- Details of the treatment of the inter-TSOs compensation mechanism when electricity flows originate or end in countries outside the European Economic Area;
- Participation of national systems which are interconnected through direct current (DC) lines (also partly covered by the HVDC network code);

Moreover, guidelines may specify, where appropriate, *‘details of rules for the trading of electricity’* and *‘details of investment incentive rules for interconnector capacity including locational* signals’ according to **art 64(4)** aiming to provide the minimum degree of harmonisation required. The Commission, according to **art 64(5)**, may also adopt guidelines on the implementation of operational coordination between TSOs at Union level. They shall be consistent with and build upon the network codes described at the beginning of this section and **art 59**.

Note that the matching between the network codes and guidelines focus areas of the e-Regulation and the existing network codes and guidelines is non-exhaustive. One focus area can be only partly covered by a network code or a guideline. It can also be covered by two or more.

Implementing acts versus delegated acts

Network codes, which are Commission Regulations, were only subject to Comitology adoption procedure through implementing acts under the Third Energy Package. With the CEP, the e-Regulation, as stated above, introduces the delegated acts adoption process for some focus areas of network codes while keeping the implementing acts adoption for others. In what follows, we will present the differences between these two adoption processes.

Network codes adoption as implementing acts, shown in Figure 23, can be divided into two phases. The pre-comitology process where the Commission undertakes legal and impact assessment of the network code as well as inter-service consultation within the Commission. Then the Comitology phase where the Commission submits draft implementing acts to a committee composed of representatives of each MS. The committee votes the Commission’s draft with three possible outcomes. In the first case, a qualified majority of MSs in favour of the act and where the Commission must adopt it. In the second case, where a qualified majority against where the Commission cannot adopt the act. In the third case, there is no qualified majority for or against and where the Commission may adopt the draft. More information regarding the process can be found in EC (2017).

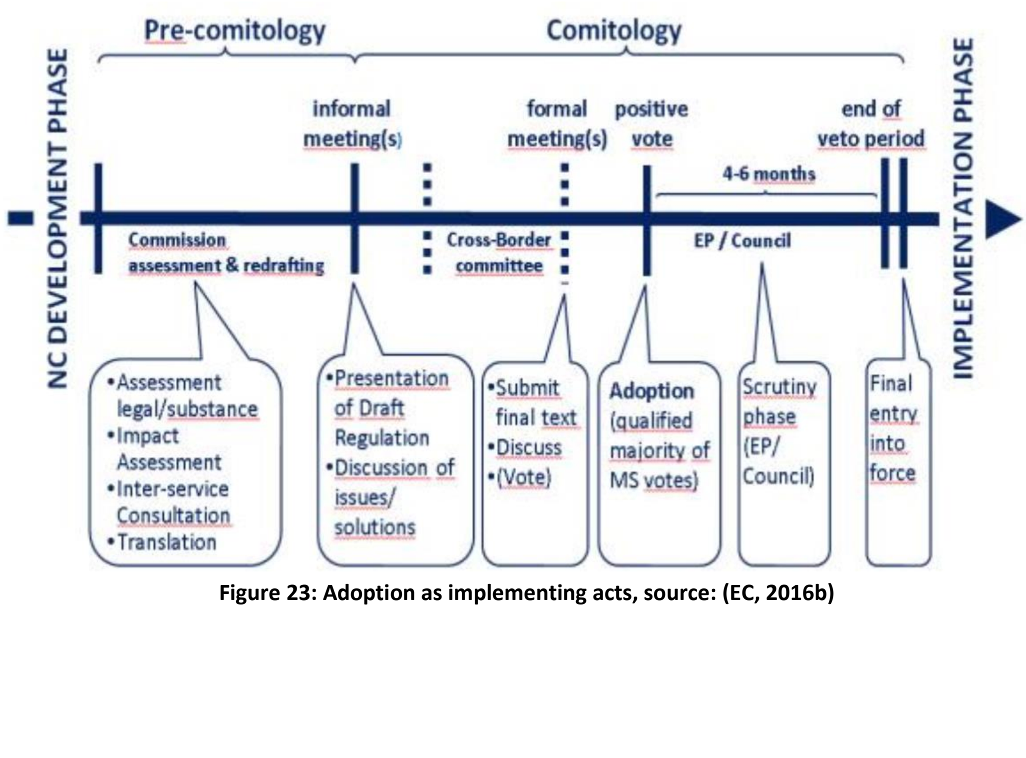

Figure 23: Adoption as implementing acts, source: (EC, 2016b)

Network codes adoption as delegated acts can be seen as a fast track adoption process as the major change compared to the implementing acts one is the abolition of the comitology committees. The Commission prepares and adopts delegated acts after consulting national expert groups, composed of representatives from each MS or can also take the form of studies (Christiansen and Dobbels, 2013). Citizens and other stakeholders can provide feedback on the delegated act draft within a 4-week period (EC, 2017b). Then, as shown in Figure 24, the Commission presents its draft delegated act simultaneously to both the European Parliament and the Council without asking the opinion of a committee. The European Parliament and Council generally have two months to formulate any objections. If they do not, the delegated act enters into force, as indicated in **art 290** of the TFEU.

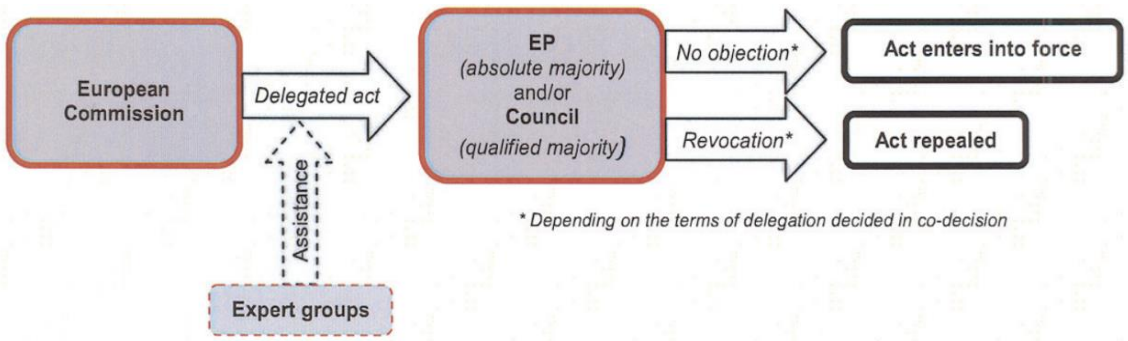

Figure 24: Adoption as delegated acts, source: (Stratulat and Molino, 2011)

2.6.2. Stakeholders' roles in network codes development process

The Commission starts with the establishment of a priority list every three years, identifying the focus areas to be developed in network codes from the list stated in **art 59** and the previous subsection. This shall be done, according to **art 59(3)**, after consulting ACER, ENTSO-E, the EU DSO Entity, and the other relevant stakeholders. ACER, following a request from the Commission, shall develop a non-binding framework guideline that sets out *'clear and objective principles for the development of network codes relating to the areas identified in the priority list (framework guideline).'* This shall be done after consultation with ENTSO-E, the EU DSO entity, and the other relevant stakeholders. If the Commission considers that the framework guideline does not contribute to market integration, competition, or efficient functioning, it may require ACER to review and re-submit it. If ACER *'fails to submit or resubmit a framework guideline within the period set by the Commission under paragraph 4 or 7, the Commission shall develop the framework guideline in question'* **art 59(8)**.

Based on the framework guideline, ENTSO-E or where appropriate the EU DSO entity in cooperation with ENTSO-E, shall convene a drafting committee to provide support for the development of the network code and submit it to ACER within twelve months. ACER shall then revise the network code and ensure that it is in line with the relevant framework guideline and submit it to the Commission within six months of the reception.

If ENTSO-E or the EU DSO entity fails to develop a network code within the set period of time set, the Commission may request ACER to prepare a draft network code based on the framework guideline. ACER may also launch further consultation on the development.

The Commission may adopt one or more network codes per focus area, on its own initiative, where ENTSO-E or the DSO entity have failed to develop it, <u>or</u> ACER has failed to develop it, <u>or</u> upon proposal of ACER after revising the submitted draft from ENTSO-E or the DSO entity. When the Commission decides so, it shall consult ACER, ENTSO-E and all relevant stakeholders regarding *'the draft network code during a period of no less than two months'* (**art 59(13)**).

2.6.3. The new adoption process for network codes and guidelines

The exercise of delegation in network codes and guidelines

The CEP provides the adoption of network codes by the Commission as implementing or delegated acts instead of the only implementing acts adoption empowerment of the 3rd Energy Package. The conditions for the Commission exercise of delegation are stated in **art 68**[51] of the e-Regulation for the establishment of network codes. The e-Regulation refers to the power to adopt delegated acts for network codes and guidelines in **art 59(2)** for the establishment of network codes and in **art 60** for the amendment of network codes. The area of empowerment for amending codes and guidelines follows the same areas as for their establishment in the **art 59**.

According to EC, (2017b), the Commission's power to adopt delegated acts is subject to strict limits:

- *'the delegated act cannot change the essential elements of the law*
- *the legislative act*[52] *must define the objectives, content, scope, and duration of the delegation of power*
- *Parliament and Council may revoke the delegation or express objections to the delegated act'*

The Commission prepares and adopts delegated acts after consulting expert groups[53], designated by each MS, which meet on a regular or occasional basis. Citizens and other stakeholders can provide feedback on the draft text of a delegated act during a four-week period. Once the Commission has adopted the act, the Parliament and the Council have two months to formulate any objections. If they do not, the delegated act enters into force. According to EC (2009) communication on the implementation of Article 290 of the TFEU, the Commission carries out the necessary preparatory steps from a political and institutional point of view to ensure that no objections will be made by Parliament or the Council. In case of an objection raised by one of these European institutions, the delegated act is revoked and cannot enter into force. Then the Commission can either adopt a new delegated act or amend where necessary while taking into account the expressed objections, if these objections are based on the fact that the Commission has overstepped the powers delegated to it. Another possibility, in case of objection, is that the Commission will decide not to do anything at all.

The adoption process of guidelines is described in **art 61**. It gives the Commission wider discretion especially in the development process under which there is no development role for ACER or ENTSO-E. According to **art 61(6)**, it shall consult ACER, ENTSO-E, the EU DSO entity and other stakeholders where relevant. There is no specific role assigned for the different stakeholders and not many steps as for network codes. Therefore, it could be seen as a way for the Commission to by-pass the different steps in a network code adoption process and adopt it as a guideline.

Regarding the existing network codes and guidelines, by 1 July 2025, the Commission shall review them in order to assess which of their provisions could be appropriately incorporated into legislative acts of the Union concerning the internal electricity market, according to **art 69(1)**. The Commission shall also assess how the empowerments for network codes and guidelines adoption pursuant to **art 59** and **art 61** of the e-Regulation could be revised. The Commission should submit a detailed report of the assessment to the European Parliament and to the Council by the same date. Then by 31 December 2026, *'the Commission shall, where appropriate, submit legislative proposals on the basis of its assessment'* **art 69(2)**.

[51] In addition to the network codes and guidelines areas in **art 59(2)** and **art 61(2)**, the e-Regulation refers also to the empowerment of the Commission to adopt delegated acts in other areas; **art 34(4)** concerning the geographical area covered by each RCC, **art 49(4)** on Inter-transmission system operator compensation mechanism, **art 63(11**) on new direct current interconnectors condition.

[52] Regulation, directive or decision.

[53] The Commission requests specialist advice from outside experts as a basis for sound policymaking. This may be provided by groups of experts or external consultants, or it can take the form of studies. For more information, see EC (2019b).

Regarding the exercise of delegation, **art 68(2)** of the e-Regulation states that the power to adopt delegated acts shall be conferred to the Commission until 31 December 2028 starting from the entry into force of the e-Regulation and not for an undetermined period of time which was stated in the Commission e-Regulation proposal. No later than nine months before the end of the empowerment period[54], the Commission shall draw up a report in respect of the delegation of power. The article adds that *'the delegation of power shall be tacitly extended for periods of eight years, unless the European Parliament or the Council opposes such extension not later than three months before the end of each period.'*

Amendments of network codes and guidelines

The **art 60(1)** on *'the Commission is empowered to amend the network codes within the areas listed in Article 59(1) and (2) in accordance with the relevant procedure set out in that Article. ACER may also propose amendments to the networks codes in accordance with paragraphs 2 and 3 of this Article.'*

Persons who have an interest in any network code may propose draft amendments to network codes to ACER. **Art 60(2)** defines them as an entity or persons including *'the ENTSO for Electricity, the EU DSO entity, regulatory authorities, transmission system operators, distribution system operators, system users and consumers.* Moreover '*ACER may also propose amendments on its own initiative'*, as is stated in the same article of the e-Regulation. Indeed, ACER may make proposals for amendments to the Commission, explaining how such proposals are in line with the network codes objectives and shall consult all the stakeholders in accordance with **art 14** of ACER Regulation (EU) 2019/942.

Regarding the amendment of guidelines, the Commission shall consult ACER, the ENTSO-E, the DSO Entity and other stakeholders where relevant as stated in **art 61(6).**

Highlights

- The Commission is empowered to adopt network codes as implementing acts or delegated acts depending on their focus area.
- The addition of the harmonisation of distribution tariffs, in the network focus areas, has been removed as well as the harmonisation of transmission tariffs (compared to the Commission proposal).
- ACER has Increased responsibilities the stakeholders' consultation of network codes.
- The Commission shall review the existing network codes and guidelines by 1 July 2025 and assess which of their provisions could be appropriately incorporated into legislative acts of the Union.
- The Commission empowerment to adopt delegated acts is conferred until 31 December 2028. This empowerment can be extended for periods of 8 years if there is no objection from the Parliament or the Council.

[54] and, if applicable, before the end of subsequent periods.

3. Empowering customers and citizens

In this section, we set the scene by describing customer and citizen empowerment from demand response to energy communities. We then focus on key measures of the CEP to enable these kinds of initiatives. This includes new rights for active customers regarding self-consumption, smart metering, data access and management, and dynamic pricing. We also present the new rules to facilitate the market entry of new customer intermediaries, aggregators and citizens energy communities.

3.1. Setting the scene: From Demand Response to energy communities

According to EC (2016e), the theoretical European potential of DR in 2016 adds up to about 100 GW and is expected to reach 160 GW in 2030. In almost all MSs, the highest share of DR potential is in the residential sector. The potential increase will depend on the roll-out of flexible technologies integration such as electric vehicles and heat pumps. Figure 25 shows its potential per Member State and share per sector.

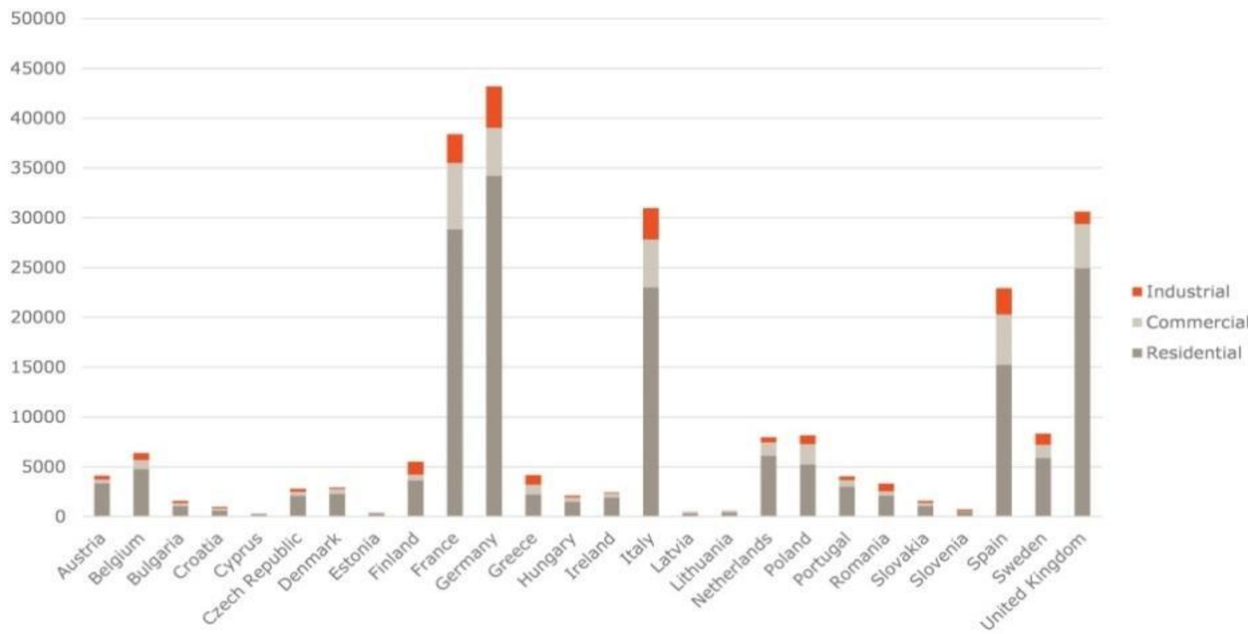

Figure 25: Theoretical demand response potential 2030 (in MW), source: (EC, 2016b)

The viable potential of demand response is limited, however, to approximately 30-40% of the theoretical one. This is due to the fact that not all facilities and devices can be technically controlled by the existing ICT and infrastructure (technical barrier) and due to the fact that only a proportion of the technically feasible potential can be used in a cost-efficient way (economical barrier). Also, there can be timing issues as the associated loads are unlikely to be available all at the same time. In 2016, around 21 GW (out of the 100 GW potential) of DR participated in the market; 15 GW come from large industrial customers through direct market participation, while approximately 6 GW come from residential customers who are on dynamic pricing contracts.

Demand response is actually a broad concept, ACER and CEER (2016) provides guidance on how to categorise DR. They divide DR into implicit or explicit:

- Implicit DR is to be understood as end-consumers adapting their electricity consumption patterns to price without explicitly buying or selling in a market. An example is a dynamic electricity contract, which reflects the real or expected cost of electricity provision to the consumer (energy and/or network) in different time periods. Consumers are rewarded for their flexibility services by reducing their electricity bill. Implicit DR potential should be measured through an estimation of the capacity (MW) and volumes (MWh) available through it. This requires:

- Monitoring the percentage of customers equipped with smart meters
- The percentage of them with dynamic pricing contracts (hourly or shorter-term); and
- Assessing customers' reaction to price signals

- Explicit DR means that demand response is explicitly sold by consumers, directly (for large industrial ones) or through demand response service providers/aggregators (supplier or a third party) to the market or to grid operators. They are rewarded for their willingness to change their demand for electricity at a given point in time, usually in response to a specific system operator's request. Explicit DR should be monitored, through the capacity (MW) contracted and volumes (MWh) sold into the different markets, in order to assess the flexibility share in each segment of the electricity market.

Enabling both types of DR is necessary to address different consumer preferences. Some consumers, especially large ones, may engage in both types of DR for different applications and time-scales (SEDC, 2017). Figure 26 gives an overview of the sequence of Demand-Side engagement.

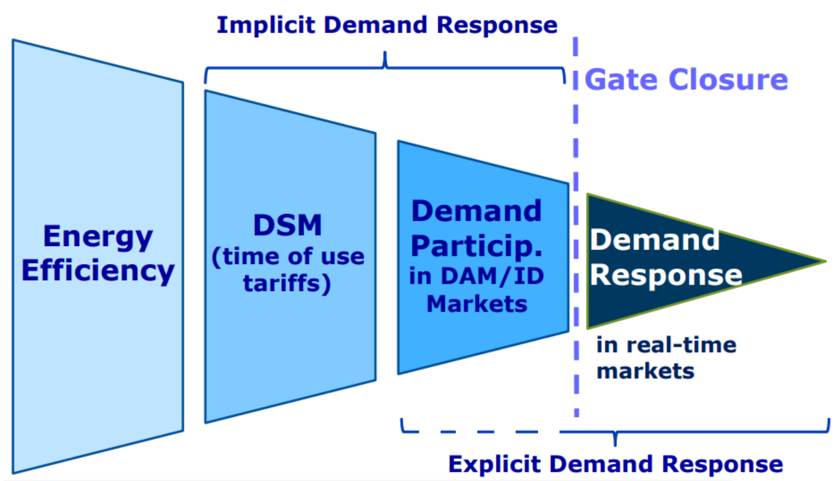

Figure 26: Demand-Side Engagement, source: (ACER, 2017)

Next to DR, another important concept introduced in this section is energy communities. Energy communities are not a new concept. Through energy communities or cooperatives, citizens may engage in generation, distribution, aggregation, supply, or storage services. REScoop (2015) stated that after the economic crisis of 1929, private investors were very cautious about undertaking new investments, and this applied to the electricity sector as well. In the first decades of the last century, local governments and cooperatives of citizens filled in the electricity supply gaps throughout Europe, as private and public undertakings were slow in delivering electrification, especially for rural and isolated areas. Germany, for instance, was hit by a tidal wave of 'electricity cooperatives.' Between 1895 and 1932, about 6,000 electricity cooperatives were created in Germany. For many reasons, explained in the REScoop (2015), only about 50 are still in existence. After the 1973 oil crisis, the anti-nuclear and pro-environmental movements emerged. Enthusiastic 'do it yourself' builders constructed their first wind turbines in Germany, Denmark, Belgium, the Netherlands and kept on collectively financing and operating them. As for their new regulatory framework in the CEP, several questions are worthy of discussion such as the local dimension of energy communities, being profit or value driven, and the provisions regarding grid management.

3.2. New rights for active customers

3.2.1. Self-consumption

Current practices

A very simple definition of active customers[55], who are often referred to as prosumers, is that they are electricity customers that are engaged in the consumption and production of electricity. Other roles can be added to this definition, such as storage, demand response, and energy efficiency. Active consumers can be both household customers and non-household customers. However, with reference to the 3rd Energy Package, only a final customer can be an active customer, and wholesale customers do not qualify as active customers (Butenko, 2017). Active customers emerged in Europe more than two decades ago, and their number has been slowly increasing. More recently, with the ongoing technological innovation (DER, batteries, smart metering...), their roles have been expanding and increasing more rapidly. In 2050 the European electricity system is expected to have millions of prosumers, electric vehicles and storage systems willing to provide energy and flexibility.

Legislators wanted to set guarantees for final customers to encourage them to engage in electricity generation and Demand Response. In Europe, national regulatory frameworks vary widely across MSs regarding this question. The EC (2017c) study on residential prosumers in the European Energy Union states three main indicators against which national regulation for residential prosumers can be assessed: the legal basis or definition in the national regulation, generation/consumption elements, and the power capacity cap reference[56].

First, most countries covered in the EC (2017c) study define and regulate prosumers under different types of legislation. Few of them, however, do not have any legally binding definition. For instance, Belgium Flemish Region, Ireland, and Romania only have definitions developed by the DSO in private codes, which do not have any legally binding character.

Second, there is the concept definition of prosumers or active customers with reference to consumption or production. Some MSs (Portugal, The Netherlands, France, Austria, Bulgaria, Denmark, Spain, and Lithuania) refer to self-consumption or auto-consumption. In Greece, prosumers are characterised as self-producers, instead of self-consumers. In Portugal, self-consumers are defined in relation to renewable energy as the persons who produce energy through renewable sources for self-consumption. In the Netherlands, the self-consumer definition is also related to renewable energy. In France, the production does not necessarily need to be from renewable energy sources. In Spain[57], self-consumption was defined as the *'consumption of electric energy from generation installations that belong to the consumer or from installations that are connected to the consumer through a direct line of electric energy connected to the*

[55] Note that three terms are used in the European Commission official documents with the same meaning, which are active customers, active consumers and prosumers. 20 to 30 years ago, the term prosumer was mainly used to refer to large industrial units with DG.

[56] Refers to the capacity of power generation and to the installation size.

[57] Spain has recently introduced a new regulation, Real Decreto 244/2019, setting new administrative, technical and economic requirements for promoting self-consumption transposing the e-Directive and the renewable energy Directive into the Spanish regulation (Energy Democracy, 2019).

grid,' which form an interesting definition combining consumption, production, and connection to the grid (EC, 2017c). This assessment indicator, however, does not have any consequences for the quality of the support system to the corresponding prosumers.

Third, MSs may also define residential prosumers in relation to the capacity of the installation by stating that it has to be below a certain threshold. For example, Ireland defines micro-generation as a source of electrical energy that operates in parallel to the energy distributor and is rated up to 6kW at low voltage with a single phase connection (230 Volt) and 11kW at low voltage with the three-phase connection. Some other MSs use the 10kW capacity as a threshold, such as Lithuania, Slovakia, Czech Republic, and the Flemish system operator. A third group (e.g., Spain, Romania, and also Norway[58]) uses a capacity cap of 100kW for defining residential prosumers.

The CEP measures for active customers

The CEP sets a regulatory framework that copes with the new technological developments and puts consumers at the heart of the energy market. This does not create a new category of customers, but it will enable active consumer participation while ensuring their rights and setting their duties. Indeed, even though consumers can generate and store electricity and easily manage their energy consumption, there are still some barriers in the current design of the retail market, preventing consumers from fully benefiting from such opportunities. The CEP measures aim to extend the level playing field in generation to the prosumers.

The e-Directive defines an 'active customer' as 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.'*

The active customer participation in the wholesale market is restricted to the sale of self-generated electricity and purchasing electricity <u>for their own use</u> while <u>not constituting a primary commercial activity</u>. The situation is similar for DR provision by active customers. They can place bid, alone or through aggregation, to sell demand reduction or increase at a price in an organised market. The contract of a final customer with an aggregator, according to **art 13** of the e-Directive, should be done directly, and without the prior consent of the final customer's electricity undertakings, referring to electricity suppliers.

Art 13(4) of the e-Directive requires MSs to ensure the rights of final customers to contract with aggregators <u>shall not be subject</u> *'to discriminatory technical and administrative requirements, procedures or charges by their supplier on the basis of whether they have a contract with a market participant engaged in aggregation.'*

Compared to the version of the Commission proposal of e-Directive, **art 15** in the final text brings more clarification on the framework to be established for active consumers. Indeed MSs shall ensure that active customers are;

'(a) entitled to operate either directly or through aggregation;

(b) entitled to sell self-generated electricity, including through power purchase agreements;

(c) entitled to participate in flexibility schemes and energy efficiency schemes;

(d) entitled to delegate to a third party the management of the installations required for their activities, including installation, operation, data handling and maintenance, without that third party being considered to be an active customer;

[58] Norway is not a EU MS.

(e) subject to cost-reflective, transparent and non-discriminatory network charges that account separately for the electricity fed into the grid and the electricity consumed from the grid, in accordance with Article 59(9) of this Directive and Article 18 of Regulation (EU) 2019/943, ensuring that they contribute in an adequate and balanced way to the overall cost sharing of the system;

(f) financially responsible for the imbalances they cause in the electricity system; to that extent they shall be balance responsible parties or shall delegate their balancing responsibility in accordance with Article 5 of Regulation (EU) 2019/943.'

MSs may apply different national governing provisions for individual and jointly acting final customers as long as all the mentioned rights and obligations are applied. In case of different treatment towards jointly acting active customers, it shall be proportionate and duly justified (**art 15(3)**).

In addition, regarding mostly feed-in tariffs schemes, **art 15(4)** adds that MSs *'have existing schemes that do not account separately for the electricity fed into the grid and the electricity consumed from the grid, shall not grant new rights under such schemes after 31 December 2023.'* Customers under these schemes shall have the possibility to opt for a new scheme accounting separately for the electricity fed into the grid and the electricity consumed as the basis for calculating network charges, at any time.

For residential storage, the final version of the e-Directive adds more clarification on the rights of active customers owning storage facilities. **Art 15(5)** states that MSs shall ensure that these customers:

- Have the right to a grid connection within a reasonable time, provided fulfilling all the conditions[59].
- Are not subject to any double charges when providing flexibility services[60] to system operators.
- Are not subject to disproportionate licensing requirements or fees.
- Are allowed to provide different services at the same time, if technically feasible.

Highlights

- Active customers can be both household and non-household final customers.

- Active customers activities regarding selling self-generated electricity or participating in flexibility or energy efficiency schemes, shall not constitute their primary commercial or professional activities.

- Network tariffs shall reflect the cost and value of the system infrastructure, including for active customers.

- Customers are entitled to direct contracts with aggregators, without prior consent of the supplier.

-No new rights shall be given to existing national schemes, not accounting separately for the electricity fed into the grid and the electricity consumed from the grid, after 31 December 2023.

3.2.2. Smart metering systems

Current levels of smart meter deployment

The electricity Directive 2009/72/EC of the 3rd Energy Package set, in ANNEX I(2), a target of 80% of total consumers being equipped with a smart metering system by 2020. Smart metering systems aim to support retail markets to fully deliver benefits to consumers and the electricity system through enabling demand response, dynamic pricing competition, and other energy services to evolve.

The decision to roll-out smart metering systems at MS levels was subject to national cost-benefit analyses, resulting in different coverage choices, technical characteristics, and implementation roadmaps. Figure 27

[59] Conditions such as balancing responsibility and adequate metering.

[60] This refers mainly to double charging when storing electricity for flexibility purposes.

shows the status of smart metering systems roll-out status in EU MSs at the end of 2017. Eight MSs and Norway have a roll-out that already reached more than 50% of household consumers. Italy (95%), Finland (97%) and Sweden (100%) are the EU frontrunners in smart meter coverage. In seven other MSs, the implementation has just started (ACER and CEER, 2018c). These significant variations among the Member States are due to the uncertain cost/benefit of the deployment, as well as concerns about security and data protection. EC (2016f) evaluation of the EU Framework for metering and billing of energy consumption, a report accompanying the CEP, points out the relatively low penetration rate of smart meters across most MSs. It adds that this indicates the limited effectiveness of the provisions in the 3rd Energy Package. Note that in the majority of MSs, the DSOs are in charge of the procurement of smart meters except in the UK where the suppliers are in charge of the implementation.

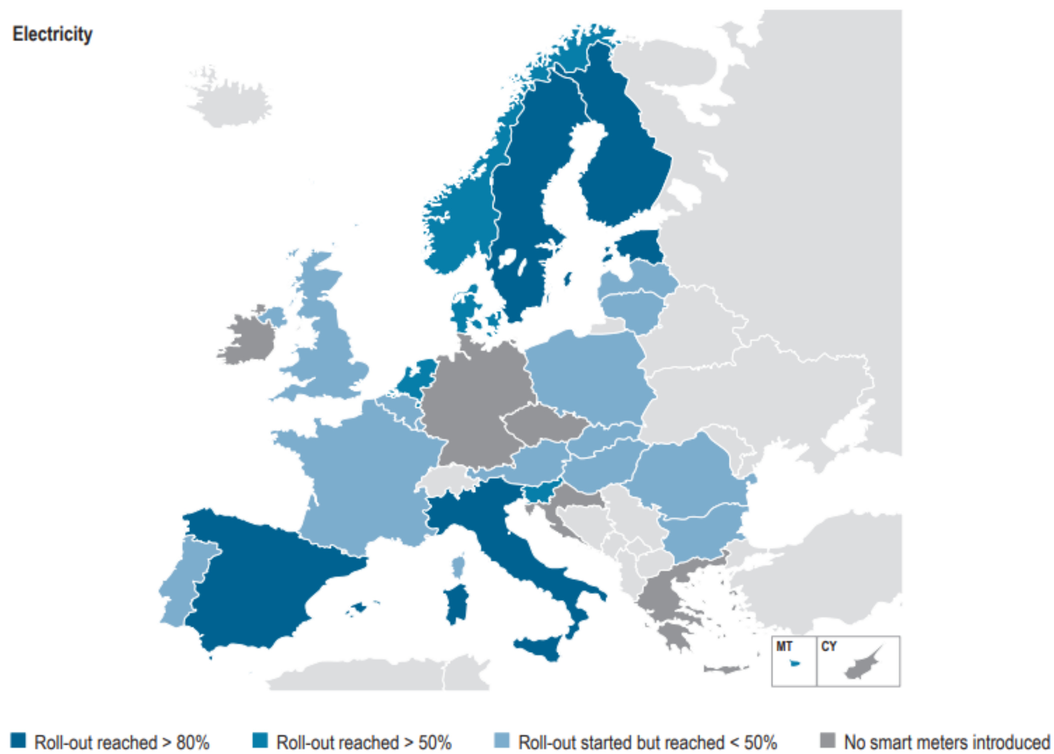

Figure 27: Electricity smart meter roll-out rates in EU MSs (and Norway) – 2017 (%), source: (ACER and CEER, 2018c)

By 2020 it is projected that 72% of European consumers will be equipped with smart meters for electricity (EC, 2016b). Figure 28 shows when the electricity smart meter roll-out 80% target has been or is planned to be reached.

-14 Member States: Sweden, Italy, Finland, Malta, Spain, Austria, the UK, Estonia, Romania, France, the Netherlands, Denmark, Luxembourg, and lately Latvia are targeting a nation-wide roll-out to at least 80% of customers by 2020 (with some of them already going much beyond the target of the e-Directive).

-2 Member States, Germany, and Slovakia, are moving to a deployment in a selected segment of consumers (to max. 23% by 2020).

-The remaining ones; Belgium, Bulgaria, Czech Republic, Greece, Ireland, Lithuania, Poland, and Portugal, have either decided against, at least under current conditions or have not made a firm commitment yet for a mass-scale or even a selective roll-out. For some MSs, like Hungary or Cyprus, no data were available.

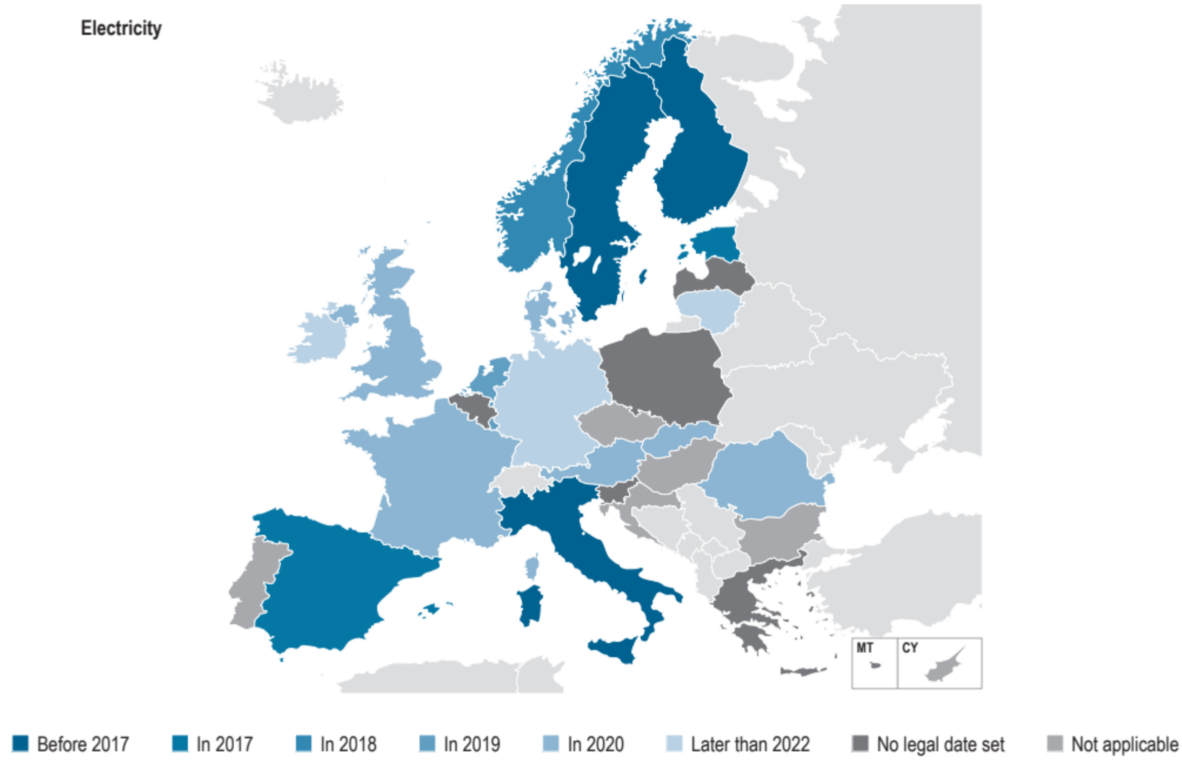

Figure 28: Target year by when the 80 % rate of electricity smart meters will be reached in EU MSs– as of end 2017, source: (ACER and CEER, 2018c)

The CEP measures for smart meter integration

A 'smart metering system' according to the e-Directive is *'an electronic system that is capable of measuring electricity fed into the grid or electricity consumed from the grid, providing more information than a conventional meter, and that is capable of transmitting and receiving data for information, monitoring and control purposes, using a form of electronic communication.'* They have a key role promoting energy efficiency and empowering final customers, in particular with regard to their interaction with consumer energy management systems and smart grids.

Incentives for smart metering systems

Smart metering is a key technology that allows consumers to engage in the electricity markets (**recital 52** of the e-Directive). It adds that '*smart metering systems empower consumers because they allow them to receive accurate and near real-time feedback on their energy consumption or generation, and to manage their consumption better, to participate in and reap benefits from demand response programmes and other services, and to lower their electricity bills.'* For DSOs, smart metering enables them to have better visibility of their networks. It reduces operation and maintenance costs. It could be considered as a sensor, which can 'open the door' to new services.

The roll-out of smart metering systems in a MS may be subject to cost-benefit analysis (CBA), as indicated in **art 19(2)** and following the principles laid down in Annex III of the e-Directive. The ANNEX II states that *'subject to that assessment, Member States or, where a Member State has so provided, the designated competent authority, shall prepare a timetable with a target of up to ten years for the deployment of smart metering systems.'*

Where smart metering is positively assessed or systematically rolled out, the MS shall implement smart metering systems in accordance with European standards and in line with the provisions of Annex II on 'Smart meters' as well as **art 20** of the e-Directive*.* If it is negatively assessed (negative CBA) and not systematically rolled out, the MS shall ensure that, on request, every final customer is entitled '*while bearing the associated costs, to have installed or, where applicable, to have upgraded, under fair, reasonable and cost-effective conditions, a smart meter that',* according to **art 21(1)**.

Positive CBA - Minimum smart meters functionalities

In case of a positive CBA, at least 80 % of final customers in the MSs shall be equipped with smart metering systems. This shall be done within seven years from the date of their positive CBA or by 2024 for MSs that have started the systematic deployment before 4 July 2019.

'Member States that proceed with the deployment of smart metering systems shall adopt and publish the minimum functional and technical requirements for the smart metering systems to be deployed in their territories, in accordance with Article 20 and Annex II,' as stated in **art 19(3)** of the e-Directive. These minimum functionalities should correspond, inter alia, to the ones listed in EC (2012) recommendations 2012/148/EU, based on best practices from CBAs for smart metering carried out in 11 MSs, *'as well as the best available techniques for ensuring the highest level of cybersecurity and data protection.'* These minimum functionalities cover:

- Accurate, direct and near-real-time reading for the customer and third parties designated by the consumer, at no additional cost;
- System security provision, privacy and data communications protection, in compliance with relevant Union security legislation ensuring the highest level of cybersecurity protection;
- Accounting for electricity injected into the grid and remote reading of meters by the operator;
- Appropriate advice and information shall be given to final customers;
- Enabling final customers to be metered and settled at the same time resolution as the imbalance period in the national market;
- Two-way communication between the smart metering system and external networks for maintenance and control of the metering system;
- Support of advanced tariff systems.

Note that **art 8(4)** of the e-Regulation states that imbalance settlement shall be 15 minutes[61] in all scheduling areas at wholesale and retail level by 1 January 2021, unless NRAs have granted a derogation or an exemption. Derogations may be granted only until 31 December 2024. Therefore, smart meters should allow the provision of data at least with this granularity level.

Also, flexibility and interoperability[62] play a large role for promoting smart meter implementation. **Art 19(3)** adds that '*(…) Member States shall ensure the interoperability of those smart metering systems, as well as their ability to provide output for consumer energy management systems.'* MSs shall use relevant available standards enabling interoperability, refer to best practices and be aware of the importance of the development of data exchange, future and innovative energy services, smart grids and the internal market in electricity.

Note that the different smart metering systems provisions shall apply to future installations as well as to installations replacing older smart meters. The already-installed systems, or for which the 'start of works' began, before 4 July 2019, may remain in operation over their lifetime. However, if they do not meet the requirements stated in this section and the e-Directive, they shall not remain in operation after 5 July 2031.

[61] It is currently 60 minutes in most Member States.

[62] *'Interoperability'*, is defined in the e-Directive in the context of smart metering as '*the ability of two or more energy or communication networks, systems, devices, applications or components to interwork to exchange and use information in order to perform required functions.'*

Customer contributions to smart metering systems costs

The e-Directive provisions state that final customers contribute to the costs of smart meters in a transparent and non-discriminatory manner. **Art 19(4)** states that '*Member States that proceed with the deployment of smart metering systems shall ensure that final customers contribute to the associated costs of the deployment in a transparent and non-discriminatory manner, while taking into account the long-term benefits to the whole value chain.'* MSs, or were provided the NRA, shall monitor smart metering systems' deployment in their territories regularly to assess the benefits provided for consumers.

Negative CBA - Consumers' right to a smart meter

When the smart metering systems' deployment is negatively assessed through the CBA, a MS shall ensure that a periodical revision, at least every four years, of this assessment is carried-out, or more frequently with regard to the changes in the underlying assumptions and market and technology developments. The updated economic assessment should be notified to the Commission, according to **art 19(5).**

Final consumers are still entitled to have a smart meter installed in the case of a negative national CBA, although they have to pay for the associated costs themselves as stated in **art 21(1)**. It should have the functionalities referred to in **art 20**, or be equipped with a set of minimum functionalities to be defined and published by MSs at the national level in line with the provisions in Annex II. The offer to the final customers requesting the smart meter should clearly state the functions and interoperability of the system as well as associated costs to be borne. In this framework, the MS or the designated competent authority shall ensure that smart metering systems are installed *'within a reasonable time, <u>no later than four months after the customer's request</u>*[63]*after the customer's request.'* They shall also, according to **art 21(2),** *'regularly, and at least every two years, review and make publicly available the associated costs, and trace the evolution of those costs as a result of technology developments and potential metering system upgrades.'*

Highlights

- Smart meter roll-out may be subject to a CBA analysis.

- Consumers will have the right to get smart meters to control their consumption, unless the CBA analysis in a given member state shows that the costs outweigh the benefits.

- In case of a positive CBA: a roll-out to at least 80% of final customers within 7 years from the date of the positive CBA or by 2024 for MSs that have started the systematic deployment before 4 July 2019.

- In case of a negative CBA: customers' entitlement to the installation or the upgrade of a smart meter with a set of defined minimum functionalities on request and under fair and reasonable conditions within 4 months, while bearing associated costs.

- More concrete and clear minimum set of functionalities for smart meters are set.

- The imbalance settlement period to be harmonised at 15 min across Europe by 2021, with possible derogation/exemptions.

3.2.3. Data access and management

Current practices

With the increased roll-out of smart meters across Europe, the experience from leading MSs in this process shows that robust and clear rules are necessary to ensure that the full benefits of smart metering data are realised, and that data privacy is respected (EC, 2016b). Such rules are not fully developed in the existing EU legislation, and national regulations may differ from one MS to another. This may harm the interests of market actors involved in data handling, meaning that they are unlikely to emerge without regulatory

[63] This was <u>three months</u> in the Commission proposal.

intervention. For example, studies from NRAs, according to EC (2016b) indicate that discriminatory access to information on potential customers represents a key barrier for new entrants to retail electricity markets in Europe. Indeed, as most DSOs are also electricity retailers, safeguards, and market monitoring are necessary to prevent them from adopting rules on discriminatory access and management of consumer data (i.e., smart metering data) and gaining a competitive advantage through information asymmetry between them (the incumbents) and the potential new entrants.

The CEP measures for data access and management

According to the EC (2016b) impact assessment, consumer data management rules should be put in place in Europe, and standardised national data formats – to facilitate data access – should also be implemented. The CEP defines responsibilities in data handling as well as criteria and principles to ensure the impartiality and non-discriminatory behaviour of entities involved in data handling. Each MS is required to apply these principles <u>independent from the data management model</u>. These measures aim to increase transparency, provide non-discriminatory access and enhance competition, while at the same time ensuring data protection. The final text of the e-Directive sets also interoperability requirements and procedures for access to data, instead of a common EU data format that builds upon national ones proposed initially by the Commission.

'When laying down the rules regarding the management and exchange of data, Member States or, where a Member State has so provided, the designated competent authorities shall specify the rules on the access to data of the final customer by eligible parties in accordance with this Article and the applicable Union legal framework.' according to **art 23(1)** of the e-Directive. '*Data shall be understood to include metering and consumption data as well as data required for customer switching, demand response and other services,'* for the purpose of the e-Directive. **Art 23(2)** adds that *'Member States shall organise the management of data in order to ensure efficient and secure data access and exchange, as well as data protection and data security.'*

MSs or the designated competent authorities shall also authorise and certify or, where applicable, supervise the parties that are managing data in order to ensure that they comply with the requirements of the e-Directive, according to **art 23(4)**. **Art 23(5)** states, regarding data access, that *'no additional costs shall be charged to final customers for access to their data or for a request to make their data available.'* The article adds that costs charged by regulated entities providing data services shall be reasonable and duly justified. This replaces the non-profit criteria of the provision of these services by regulated entities, stated in the Commission proposal for e-Directive.

Regarding customers' right to access their data, **art 13(3)** of the e-Regulation adds that, MSs shall ensure that when final customers are engaged in aggregation, they are entitled *'to receive all relevant demand response data or data on supplied and sold electricity free of charge at least once every billing period if requested by the customer.'* In addition to non-discriminatory data access, the e-Directive sets interoperability requirements and procedures for access to data. They replace the common data formats originally proposed by the Commission. According to **art 24** of the e-Directive, MSs shall facilitate the full interoperability of energy services within the EU in order to promote competition in the retail market and avoid excessive administrative costs for the eligible parties. Indeed the Commission '*shall adopt, by means of implementing acts, interoperability requirements and non-discriminatory and transparent procedures for access to data referred to in Article 23(1).'*

Art 24(3) adds that MSs *'shall ensure that electricity undertakings apply the interoperability requirements and procedures for access to data referred to in paragraph 2. Those requirements and procedures shall be based on existing national practices.'*

Highlights

- MSs are required to set principles ensuring the impartiality and non-discriminatory behaviour of entities involved in data handling and data access.

- MSs, or their designated competent authorities, shall specify the rules for access to final customers' data by eligible parties.

- Costs charged by regulated entities providing data services shall be reasonable and duly justified.

- Final customers engaged in aggregation shall have the right to receive, least once every billing period if requested, all their demand response data or data on supplied and sold electricity.

- MSs shall facilitate the full interoperability of energy services within the EU and apply requirements building on existing national practices.

3.2.4. Dynamic pricing

Dynamic pricing methods in Europe

Several dynamic pricing (DP) methods with different penetration levels among customers exist in Europe. The different methods depend on two main factors (ACER and CEER, 2016):

- The granularity of the period during which consumption is metered separately, and
- The dynamics/statics of ToU prices.

The impact on consumers depends on the combination of these two factors. They can be rewarded for positively reacting to price signals or penalized for not reacting. There are three main methods applied in the EU. Their implementation depends on the provided enabling framework.

- Static Time of Use (ToU): the end-user electricity price is set in advance for each fixed time band. It reflects the average wholesale price in the time band (low granularity-low dynamics). It can vary by time of day, the day of the week and/or the season of the year. Another form of 'static ToU', less common, that has high granularity-low dynamics, is where hourly consumption is priced at monthly average prices. This form is called 'spot market-based pricing'.
- Critical peak pricing (CCP): a higher end-user electricity price is charged in designated and limited periods corresponding to consumption peaks at the system level (low granularity-high dynamics)
- Real-time pricing: the end-user electricity price is posted in real time (typically at least hourly) and communicated automatically to the consumer as it changes (high granularity-high dynamics).

Figure 29 gives a classification of the DP methods in function of the two factors.

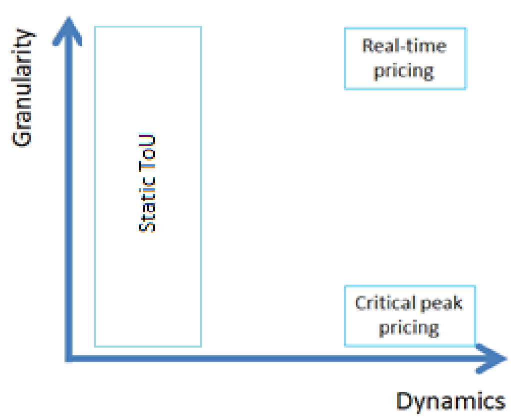

Figure 29: Methods of dynamic pricing for electricity, source: own illustration

Dynamic pricing in electricity supply

Figure 30 shows the different DP methods across MSs; countries are coloured according to the main dynamic pricing method used, as stated in the questionnaire presented in (ACER and CEER, 2016).

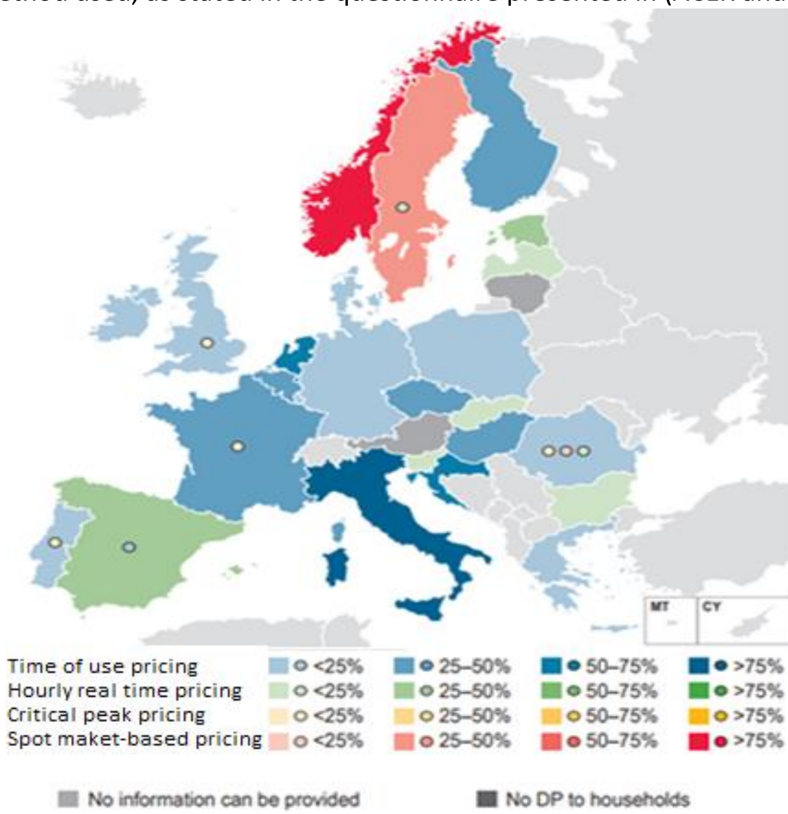

Figure 30: Share of standard household consumers supplied under dynamic pricing (DP), adapted from (ACER and CEER, 2016)

ToU pricing is applied in 17 out of 22 countries whose NRAs participated in the questionnaire. The most commonly applied type of ToU is a day/night differentiation. However, in some countries the number of time periods of ToU tariffs can be higher (e.g., in Italy, three-time bands are set based on the weekdays/weekends and peak/off-peak differentiation). Spot market-based pricing applies to a large share of electricity household customers in three countries (Denmark, Norway, and Sweden) through monthly spot-exchange prices. The hourly real-time pricing method is only used in five European countries: Sweden, the UK, Romania, Estonia and Spain with different penetration levels among households. For the latter two, between 25% and 50% of all households have access to supply tariffs based on hourly pricing. Critical peak pricing (CCP) applies to a smaller proportion of households in France, Romania, Lithuania, Portugal and the UK.

In some MSs, there are multiple DP methods in use. The additional dynamic pricing methods are represented by the coloured dots in Figure 30. As for Spain, between 25% and 50% of households incur hourly real-time pricing and ToU also applies to less than 25% of the households.

The CEP measures for dynamic contracting

The CEP sets measures for the expansion of dynamic price contracts in Europe to enhance consumer empowerment and participation in competitive retail markets. We will present here the new measures of the CEP in two parts, first, the entitlement to dynamic supply contracts and second the provision for dynamic network charges.

Customer's entitlement and implementation monitoring
The e-Directive defines a dynamic electricity contract *as 'an electricity supply contract between a supplier and a final customer that reflects the price variation in the spot markets, including in the day-ahead and intraday markets, at intervals at least equal to the market settlement frequency.'* Note that this definition focuses on real-tme pricing rather thanstatic Time-of-Use Tariff (ToU) and the critical peak pricing (CCP).

Art 11 of the e-Directive on *'Entitlement to a dynamic electricity price contract'* states that MSs shall ensure that every final customer, with a smart meter installed, should be entitled to a dynamic electricity price contract on request. The final customer should benefit from this right and conclude a dynamic electricity supply contract *'with at least one supplier and with every supplier that has more than 200 000 final customers.'* Final customers shall also be *'fully informed by the suppliers of the opportunities, costs and risks of such dynamic electricity price contracts, (…)'* according to **art 11(2)**. This includes the provisions of information regarding the type of meter needed for customers. In addition, dynamic contracts market developments shall be monitored by NRAs that also assess the risks that these new products and services may entail as well as the possible abusive practices. **Art 11(3)** states that the final customer's consent is required to be obtained by suppliers before that the customer is switched to a dynamic electricity price contract.'
Moreover, MSs or their NRAs shall monitor and publish a report annually for at least a ten-year period after the introduction of such contracts. The report shall contain the main developments of dynamic contracts and the impact on consumers' bills, specifically the level of price volatility.

Dynamic pricing for network charges in the CEP
Art 18 of the e-Regulation on *'Charges for access to networks, use of networks and reinforcement,'* focuses in paragraph 7 on distribution tariffs. They shall reflect the cost of use of the distribution grid by system users and may contain network connection capacity elements. They can be differentiated based on system user characteristics and generation/consumption profiles. It adds that in MSs that have rolled-out smart metering systems, NRAs shall consider and may introduce time differentiated network tariffs when fixing or approving their network tariffs or their methodologies. This aims to reflect *'the use of the network, in a transparent, cost efficient and foreseeable way for the final customer.'*

Highlights

- The new definition of DP excludes the less granular pricing methods.
- Every final customer shall be entitled to a dynamic electricity contract upon request.
- MSs shall ensure that final customers with a smart meter can request to conclude a DP contract with at least one supplier and with every supplier with more than 200 000 final customers.
- MSs, or their NRAs, shall publish an annual report on the main developments of DP contracts for at least ten years.
- Incentives are provided for the introduction of dynamic time differentiated network tariffs.

3.3. Market entry for new customer intermediaries

The CEP defines two new customer market intermediaries: aggregators and citizens energy communities. Furthermore, The CEP contains provisions on their regulatory framework, roles, and duties aiming to group the energy generation or consumption of several consumers. In this section, we discuss these two customer market intermediaries in detail.

3.3.1. Aggregators

The landscape of electricity aggregators

Aggregation, according to **art 2 (17)** of the e-Directive 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.'* An aggregator is, therefore, an energy service provider that can change the electricity consumption of a group of electricity consumers and provide demand-side flexibility to the grid. They represent important actors helping to enhance demand participation and to activate the DR potential (EC, 2016b).

Different aggregator models exist that are discussed both in stakeholders reports (NordREG, 2016) and academic literature (Poplavskaya and De Vries, 2018). First, aggregation can be carried out by the traditional energy service provider, i.e., the electricity supplier and the aggregator are one entity. Second, aggregation services can be provided by new entrants that are not the electricity supplier. They are called then independent aggregators. Figure 31 illustrates the access of independent aggregators to markets in Europe.

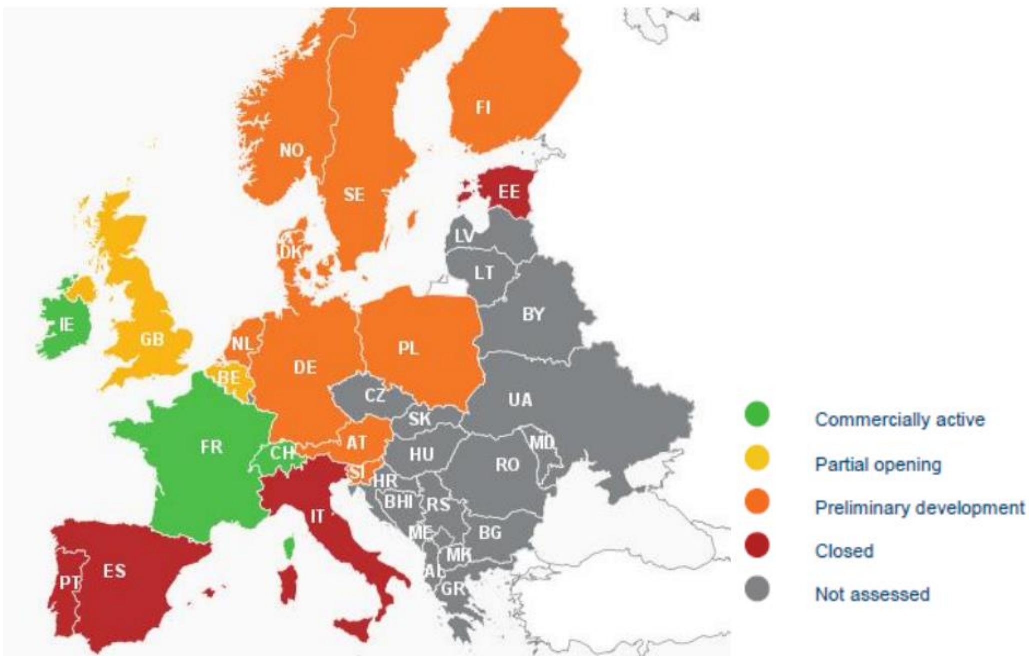

Figure 31: Independent aggregators' access to markets, source: (SEDC, 2017)

According to SEDC (2017), the MSs that currently provide the most supportive framework for the development of demand response and aggregation are France, Belgium, Finland, the UK and Ireland. Nevertheless, there are still regulatory issues that exist in these MSs.

France[64] has put in place detailed frameworks for independent aggregation, including the standardised roles and duties of market participants. In Belgium, upcoming legislation addressing the role of the aggregator and independent aggregation will soon be put in place. Spain, Portugal, and Estonia are in red in Figure 31, because aggregated demand-side flexibility is either not accepted as a resource in any of the electricity markets or not economically viable. Note that for Italy, which is also in red, a partial opening of balancing markets to aggregators occurred in 2018 (Bertoldi et al., 2017). For instance, in Italy, different

[64] In France, large industrial customers have been participating in balancing mechanisms since 2003. The provision of FCR by industrial customers started in 2014. Furthermore, demand was allowed to participate in automatic FRR since July 2014, and in the day ahead and intraday markets from January 2017 (SEDC, 2017).

types of aggregation model are being tested under the supervision of the Italian TSO Terna and the Italian regulatory authority ARERA (Terna, 2019).

Independent aggregators and electricity suppliers can have opposing interests due to their type of activity; the former sell flexibility while the latter sell electricity. In most MSs, except France, the UK, and Ireland, an aggregator needs permission from the supplier to access the supplier's customers, and this may constitute a market entry barrier for the aggregator to contract with these customers, though this may be changing.

The CEP measures for aggregators

The CEP establishes a regulatory framework that clarifies the roles and responsibilities of aggregators and thus removes barriers impeding independent aggregators from entering the market.

Consumers' right for aggregator contracting

Art 13 of the e-Directive on *'Aggregation contract'* sets a requirement from MSs to ensure that customers have the freedom to purchase or sell electricity service, including by means of aggregation. This is independent of customers' supplier contracts and could be agreed with an electricity undertaking they choose. In addition, MSs shall ensure that final customers' engagement with an aggregator shall not require the consent of the final customer's electricity undertaking as stated in **art 13(2)** and 3.2.1.

MSs shall ensure in turn that aggregators inform customers about all the terms and conditions of their offers and contracts. They shall also provide their customers with demand response data or data on the electricity supplied and sold at least once every billing period if requested by the customer, and this shall be free of charge.

These rights to customers shall be granted in a non-discriminatory way. Indeed, MSs, according to **art 13(4)**, shall safeguard customers and ensure that they *'are not subject to discriminatory technical and administrative requirements, procedures or charges by their supplier on the basis of whether they have a contract with a market participant engaged in aggregation.'*

Regarding contract termination with an aggregator, the rules were included in **art 12** and are similar to contract termination with supplier. Accordingly, the process of switching from market participant engaged in aggregation shall be concluded within a maximum of three weeks. By no later than 2026, the switching process shall take no longer than 24 hours and be possible on any working day.

Also similarly, *'Member States shall ensure that at least household customers, microenterprises and small enterprises are not charged any switching-related fees*[65]*' when* switching between aggregators according to **art 12(2)**. By way of derogation, MSs can allow aggregators to charge their customers contract termination fees, as long as they were included in the signed contract and were clearly communicated to the customer ex-ante. The fees shall be proportionate and not more than the aggregator's direct economic loss. **Art 12(3)** adds that '*<u>the burden of proving the direct economic loss</u> shall be on the supplier <u>or market participant engaged in aggregation,</u> and the permissibility of contract termination fees shall be monitored by the regulatory authority, or by an other competent national authority.'*

Rules for aggregators' market participation

Art 17 of the e-Directive, on *'Demand response through aggregation,'* requires MSs to foster DR participation of active customers directly, <u>or through aggregation,</u> in all electricity markets. MSs shall also ensure that TSOs and DSOs have a non-discriminatory behaviour towards market participants engaging in DR aggregation when procuring ancillary services.

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[65] *'Contract termination fee',* according to **art 2(16)** of the e-Directive, means *'a charge or penalty imposed on customers by suppliers or market participants engaged in aggregation, for terminating an electricity supply or service contract'.*

To promote aggregators' participation, **art 17(3)** states that MSs' regulatory frameworks should ensure that each market participant engaged in aggregation, including independent aggregators, has the right to enter the market without consent from other market participants. Clear and non-discriminatory rules shall be established to assign roles and responsibilities, including the data exchange between aggregators and other market participants.

For balancing responsibilities, the article adds that *'market participants engaged in aggregation to be financially responsible for the imbalances that they cause in the electricity system; to that extent they shall be balance responsible parties or shall delegate their balancing responsibility in accordance with Article 5 of Regulation (EU) 2019/943.'* Market participants engaged in aggregation may, however, be required to pay a compensation[66] to other market participants or market participants BRPs which are directly affected by DR activation. The financial compensation payments '*shall be strictly limited to covering the resulting costs incurred by the suppliers of participating customers or the suppliers' balance responsible parties during the activation of demand response.'* The calculation method for compensation shall be approved by NRAs or other competent authorities. It may take into account the benefits created by aggregators to other market participants. In this case, the aggregator may only contribute to the compensation if the benefit they create for all customers, their BRPs and suppliers are less than the incurred costs. The national regulatory framework shall contain *'a conflict resolution mechanism between market participants engaged in aggregation and other market participants, including responsibility for imbalance.'*

Also, regarding the technical requirements for DR participation, TSOs and DSOs in close cooperation with other market participants and final customers shall, according to **art 17(5)**, establish them in all electricity markets *'on the basis of the technical characteristics of those markets and the capabilities of demand response. Such requirements shall cover participation involving aggregated loads.'*

Highlights

- **Reducing entry barriers:** Aggregators can participate in the market without consent from other market participants, i.e., the customer's supplier.
- **Enabling consumer switching:** Final customers' contract termination with aggregators to be done within three weeks and within 24 hours by 2026.
- Aggregators shall be balance responsible and liable to pay a compensation in certain situations.
- A conflict resolution mechanism between market parties engaged in aggregation and other market participants, including responsibility for imbalance shall be included in MSs regulatory frameworks.

3.3.2. Citizens Energy Communities

The landscape of energy communities

The past decade or so has seen the emergence of increasing numbers of energy cooperatives through citizen initiatives, which produce and supply themselves with clean, renewable energy, and this trend is likely to continue in the future (see Figure 32). Energy communities may be a gathering of household consumers on a small scale or be a more structured larger group of citizens and stakeholders. Figure 32 gives an overview of the energy communities in Europe.

[66] This financial responsibility was not included in the Commission proposal for the e-Directive and it was only possible in exceptional cases subject to the approval of NRAs and monitored by ACER.

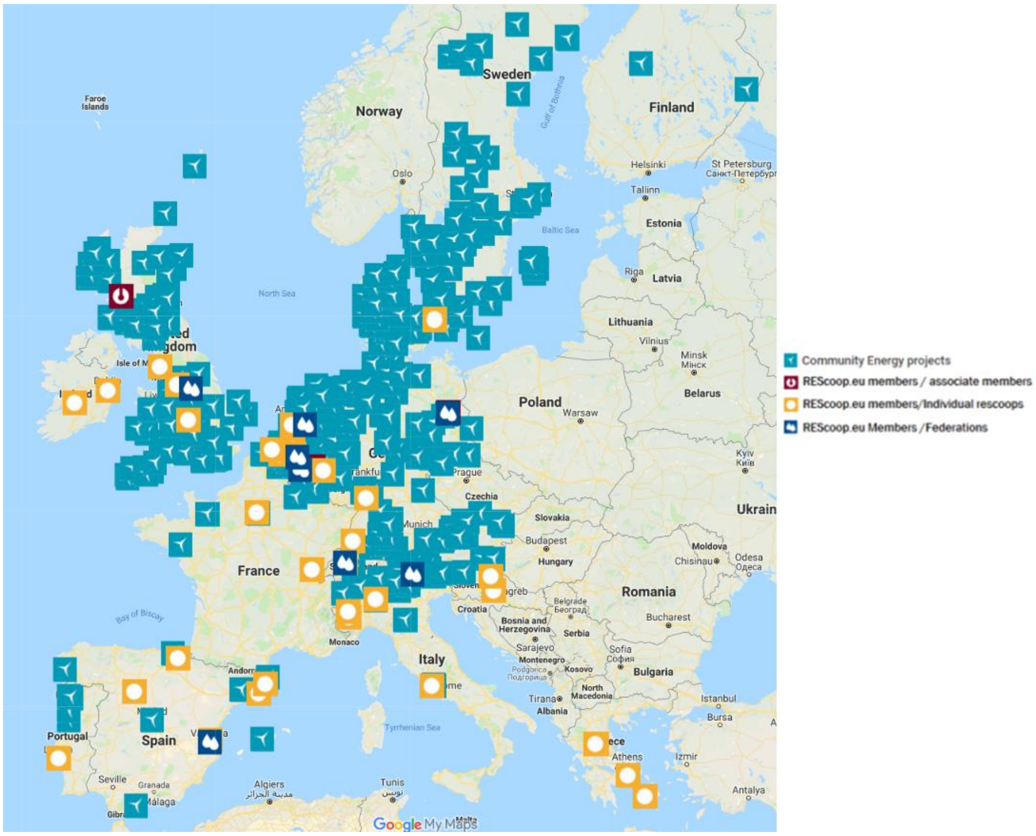

Figure 32: EU groups or cooperatives of citizens on renewable energy, energy efficiency, and e-mobility, (REScoop, 2019)

Recently citizen cooperatives have started looking at taking back the electricity grids as well. One of the most known examples is the one of Hamburg, where citizens voted to buy back the distribution grid from Vattenfall in early 2014. A similar campaign was attempted in Berlin but failed. However, the question of buying back the grid there has not yet been completely resolved (EC, 2015c).

The drivers for energy communities are not just the benefits from competitive energy prices and investment returns. Indeed by cooperating with their neighbours, energy communities aim to realize a fair energy transition and effectively fight climate (REScoop and Energie Cities, 2018).

EU citizens have started investing in energy communities and especially renewable energy cooperatives in countries like Spain, Croatia, France, and Greece. However, complexities of varying legal frameworks and lack of effective support mechanisms have prevented those countries from keeping up with the more developed energy community countries of the North, such as the Netherlands, Sweden, Denmark, Germany and Belgium (EC, 2015c).

The CEP measures for Citizens Energy Communities (CECs)

The e-Directive defines a 'citizens energy community[67], that replaced the term 'local energy community' in the Commission e-Directive, based on three dimensions; membership, primary purpose, and activities. **Art 2(11)** states that a CEC means *'a legal entity that:*

[67] A differentiation should be made between citizen energy communities and renewable energy communities introduced by **art 22** of the Renewable Energy Directive.

(a) is based on voluntary and open participation and is effectively controlled by members or shareholders that are natural persons, local authorities, including municipalities, or small enterprises;

(b) has for its primary purpose to provide environmental, economic or social community benefits to its members or shareholders or to the local areas where it operates rather than to generate financial profits; and

(c) may engage in generation, including from renewable sources, distribution, supply, consumption, aggregation, energy storage, energy efficiency services or charging services for electric vehicles or provide other energy services to its members or shareholders.'

Furthermore, CECs, according to **recitals 43** to **47** of the e-Directive, must be considered as a category of cooperation between citizens or local actors' and should be '*subject to recognition and protection under the Union law.'* Besides, CECs *'should not face regulatory restrictions if they apply existing or future ICT technologies to share electricity.'* Also, the electricity sharing process *'should not affect the collection of network charges, tariffs and levies related to electricity flows.'*

The CEP recognises CECs as a critical enabler for encouraging the involvement of the individual in the development of the electricity sector and requires MSs to ensure implementation of enabling legal frameworks and to guarantee the right to energy sharing. The provisions on CECs in the e-Directive '*do not preclude the existence of other citizen initiatives such as those stemming from private law agreements.'* Thus, MSs can provide that CECs can take any form of entity*, 'for example that of an association, a cooperative, a partnership, a non-profit organisation or a small or medium-sized enterprise, provided that the entity is entitled to exercise rights and be subject to obligations in its own name.'*

CECs membership shall be open to all categories of entities with <u>a restriction</u> in the members and stakeholders with decision making powers to the ones *'that are not engaged in large-scale commercial activity and for which the energy sector does not constitute a primary area of economic activity.'*

MSs shall adopt a legal framework for the establishment of CECs. **Art 16** of the e-Directive introduces a catalogue of applicable rights and obligations for CECs. Due to their type and status as new entrants in the electricity markets, they should cooperate in the market on a level-playing field without creating market distortions. It sets mandatory provisions for MSs regarding CECs membership as well as CECs participation in electricity markets. It also sets optional provisions that MSs can adopt regarding CECs cross-border participation as well as CECs ownership, establishment, purchase or lease of distribution networks.

Mandatory provisions for CECs enabling regulatory framework

For the mandatory provisions, **art 16(1)** states that shall provide that the enabling framework ensures that:

'(a) participation in a citizen energy community is open and voluntary;

(b) members or shareholders of a citizen energy community are entitled to leave the community, in which case Article 12 applies;

(c) members or shareholders of a citizen energy community do not lose their rights and obligations as household customers or active customers;

(d) subject to fair compensation as assessed by the regulatory authority, relevant distribution system operators cooperate with citizen energy communities to facilitate electricity transfers within citizen energy communities;

(e) citizen energy communities are subject to non-discriminatory, fair, proportionate and transparent procedures and charges, including with respect to registration and licensing, and to transparent, non-discriminatory and cost-reflective network charges in accordance with Article 18 of Regulation (EU) 2019/943, ensuring that they contribute in an adequate and balanced way to the overall cost sharing of the system.'

In addition, regarding electricity market access, balance responsibilities, self-consumption, **art 16(3)** brings further mandatory provisions for CECs aiming to ensure that they contribute in an adequate and balanced way to the overall cost sharing of the system and to be on equal footing with other market participants;

'(a) are able to access all electricity markets, either directly or through aggregation, in a non-discriminatory manner;

(b) are treated in a non-discriminatory and proportionate manner with regard to their activities, rights and obligations as final customers, producers, suppliers, distribution system operators or market participants engaged in aggregation;

(c) are financially responsible for the imbalances they cause in the electricity system; to that extent they shall be balance responsible parties or shall delegate their balancing responsibility in accordance with Article 5 of Regulation (EU) 2019/943;

(d) with regard to consumption of self-generated electricity, citizen energy communities are treated like active customers in accordance with point (e) of Article 15(2);

(e) are entitled to arrange within the citizen energy community the sharing of electricity that is produced by the production units owned by the community, subject to other requirements laid down in this Article and subject to the community members retaining their rights and obligations as final customers.

For the purposes of point (e) of the first subparagraph, where electricity is shared, this shall be without prejudice to applicable network charges, tariffs and levies, in accordance with a transparent cost-benefit analysis of distributed energy resources developed by the competent national authority.'

Optional provisions for CECs enabling regulatory framework

Apart from the mandatory elements to be included in the CECs' regulatory framework, MSs may decide to provide CECs with three additional rights in their national regulations. Indeed **art 16(2)** states that *'Member States may provide in the enabling regulatory framework that citizen energy communities:*

(a) are open to cross-border participation;

(b) are entitled to own, establish, purchase or lease distribution networks and to autonomously manage them subject to conditions set out in paragraph 4 of this Article;

(c) are subject to the exemptions provided for in Article 38(2).'

For MSs that allow CECs to network ownership and management, following art 16(2)(b), **art 16(4)** sets out specific conditions for CECs on aspects of distribution system operation without prejudice to the other provisions and rules applying to distribution system operation[68]. Indeed, **art 16(4**) states that where MSs provide the network ownership and management rights, they shall ensure that CECs:

'(a) are entitled to conclude an agreement on the operation of their network with the relevant distribution system operator or transmission system operator to which their network is connected;

(b) are subject to appropriate network charges at the connection points between their network and the distribution network outside the citizen energy community and that such network charges account separately for the electricity fed into the distribution network and the electricity consumed from the distribution network outside the citizen energy community in accordance with Article 59(7);

(c) do not discriminate or harm customers who remain connected to the distribution system.'

[68] This refers to the articles of Chapter IV of the e-Directive on designation, tasks and rules for DSOs as well as other rules and regulations applying to them.

Also, where MSs decide to allow CECs to become closed distribution system operators[69] in accordance with **art 38**, it may provide for NRAs to exempt the operator of a closed distribution system from (**art 38(2)**):

'(a) the requirement under Article 31(5) and (7) to procure the energy it uses to cover energy losses and the non-frequency ancillary services in its system in accordance with transparent, non-discriminatory and market-based procedures;

(b) the requirement under Article 6(1) that tariffs, or the methodologies underlying their calculation, are approved in accordance with Article 59(1) prior to their entry into force;

(c) the requirements under Article 32(1) to procure flexibility services and under Article 32(3) to develop the operator's system on the basis of network development plans;

(d) the requirement under Article 33(2) not to own, develop, manage or operate recharging points for electric vehicles; and (e) the requirement under Article 36(1) not to own, develop, manage or operate energy storage facilities.'

Art 38(3) adds that in case of an exemption grant, *'the applicable tariffs, or the methodologies underlying their calculation, shall be reviewed and approved in accordance with Article 59(1) upon request by a user of the closed distribution system.'*

Highlights

- Citizens energy communities (CECs) constitute a new type of entity having access to electricity markets.
- A catalogue of applicable rights and obligations for CEC is introduced by art 16.
- CEC membership is open to all categories of entities. The decision-making powers within a CEC should be limited to those members or shareholders that are not engaged in large scale commercial activity and for which the energy sector does not constitute a primary area of economic activity.
- CECs should be subject to appropriate network charges for the electricity consumed from an external network.
- DSOs, subject to a fair compensation, shall cooperate with CECs to facilitate electricity transfers between them.
- MSs are free to decide upon cross-border participation as well as for the right of CEC to own, manage, establish, purchase or lease the distribution network in their area of operation.
- MSs may choose whether to establish a framework allowing CECs to have the role of a DSO either under the general regime or as 'Closed Distribution System Operator'.

[69] A 'closed distribution system' according to **art 2(5)** of the Demand Connection Code (DCC) means '*a distribution system classified pursuant to Article 28 of Directive 2009/72/EC as a closed distribution system by national regulatory authorities or by other competent authorities, where so provided by the Member State, which distributes electricity within a geographically confined industrial, commercial or shared services site and does not supply household customers, without prejudice to incidental use by a small number of households located within the area served by the system and with employment or similar associations with the owner of the system'*

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