ACER

European Union Agency for the Cooperation of Energy Regulators

Getting the signals right: Electricity network tariff methodologies in Europe

ACER report on network tariff practices

26 March 2025

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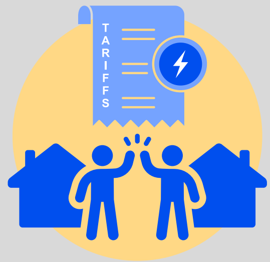


1 Massive power grid investment is needed to keep pace with the growth in renewable generation and to support electrification objectives. The current annual grid investment in Europe is estimated to double until 2050, reaching up to EUR 100 billion per year, with lower estimates at EUR 75 billion[1].

2 Grid investments, while bringing economic and social benefits, will likely exert significant upward pressure on network costs. For consumers the annual network costs may increase by 50% by 2050, or even 100% in the highest investment scenario[2]. To mitigate the increase, these investments should be made in the most-efficient manner[3].

3 In 2023, the European Union Agency for the Cooperation of Energy Regulators ('ACER') found that significant efficiency gains can be achieved by mitigating transmission system operators' bias towards capital expenditure-intense infrastructure solutions in grid planning, at the expense of alternative, potentially more cost-efficient grid technologies[4].

1 ACER report on electricity infrastructure development to support a competitive and sustainable energy system (December 2024, p. 30).

2 See footnote 1 (p. 4).

3 ACER emphasised better planning and the application of the 'efficiency-first' principle to grid development as important measures for accelerating on-target grid investment while sustaining affordability and competitiveness. See ACER Report on electricity infrastructure development to support a competitive and sustainable energy system (December 2024, p. 30).

4 ACER Report on investment evaluation, risks assessment and regulatory incentives for energy network projects (June 2023) focused on transmission system operators ('TSOs'). In its next report dealing with system operators' revenue setting, expected in 2026, ACER aims to expand its review to distribution system operators ('DSOs').

As grid costs are expected to become a main driver of electricity costs, containing their rise is a key for EU competitiveness and affordability of electricity prices.

4 As grid costs are expected to become a main driver of electricity costs, containing their rise is key for EU competitiveness and affordability of electricity prices. Dealing with this challenge requires 'future-proof' actions by regulators.

5 Regulators may feel pressured to unduly shift the burden from one user group to another. ACER cautions against the potential negative effects of such actions; they may inhibit the signals for flexibility and reduce system efficiency, raising even more the need for grid investment and overall system costs[5].

6 To mitigate the need for additional investments and reduce ensuing pressure on network tariffs, energy regulators should promote the efficient use and development of the grid. This requires designing adequate incentives through network revenues for grid operators and network tariffs for grid users, respectively.

Energy regulators should promote the efficient use and development of the grid.

Benefit-based incentives can facilitate smarter and cheaper grid solutions, compared to traditional 'build-out'.

7 ACER advocates for network companies to make better use of existing grids before building new ones and urges regulators to introduce benefit-based incentives for system operators. By sharing the benefits between the system operator and society, benefit-based incentives can facilitate smarter and cheaper grid solutions, compared to traditional 'build-out', as illustrated by practice in some Member States[6].

8 This is the latest (2025) edition of ACER's report on electricity network tariffs. The report deals with network tariff structures and the allocation of system operators' costs (or revenues) across network users, aiming to increase transparency and comparability in tariff setting and share best practices. It also identifies and discusses various tariff-related dilemmas faced by energy regulators.

9 Under the EU regulatory framework, network tariffs shall be cost-reflective and increase efficient use of the existing grid by providing price signals for network users to adapt their behaviour. The effectiveness of these price signals depends on the ability of network users to respond to them, the share of network tariffs in the final bill and the corresponding savings. The signals provided by network tariffs co-exist with the signals provided by market prices embedded in the energy component of the electricity bill. Regulators should carefully assess the cumulative effect of such signals on different services. Together, they provide a compound price signal to influence network users' behaviours at a certain time and in a certain location.

10 With the energy transition, the cost components in the electricity bill are expected to change. The expected rise in grid costs will have a knock-on effect on network tariffs. An increasing weight of network tariffs in the final bill is both a concern and an opportunity[7]. Getting the price signals right is key. This would optimise grid use and new build, ultimately keeping network costs down.

An increasing weight of network tariffs in the final bill is both a concern and an opportunity. Getting the price signals right is key.

5 All in all, shielding certain network users from network costs to promote some policies is likely to lead not only to increased network tariffs for other users, but also to raise the overall network costs. In contrast, ensuring a fair and efficient allocation of costs among network users (i.e. cost reflectivity) is best to keep overall system costs down. These two approaches demonstrate that, contrary to frequent allegations, network tariff reforms are often distinct from 'zero-sum' games.

6 Florence School of Regulation: Benefit-based remuneration of efficient infrastructure investments (May 2024). Study for ACER.

7 The higher share of network tariffs in the final bill can increase the effectiveness of the embedded price signals. If the network tariffs are badly designed the signals lead to enhanced distortions; well-designed tariffs lead to increased efficiencies.

Without regular fitness checks of network tariff methodologies, there is a risk of 'navigating blindly' in the energy transition.

11 As the electricity system evolves, network tariff methodologies may require adaptation. Without a regular electricity-system fitness check of network tariff methodologies, there is a risk of 'navigating blindly' in the energy transition. **ACER finds that about two-thirds of the EU countries made major changes in their network tariff methodologies in recent years or plan to do it soon**.

12 Several of these changes reflect previous ACER recommendations such as increasing the relevance of power-based tariffs[8] in alignment with the cost-causality principle (Austria, Belgium, Estonia, Luxembourg, Slovenia); introducing time-of-use signals (Belgium, Germany, the Netherlands); and removing unjustified discounts (in the Netherlands to large consumers, in Sweden to small generators).

13 While NRAs are committed to jointly develop best practices for network tariff structures, **no 'one-design-fits-all' or 'one-design-solves-all' solution can be easily found**; as such, best practices can vary across countries as local power-system context matters.

14 Particularly, for tariff aspects with cross-border relevance, such as setting network charges for generators or industrial users, NRAs should seek coordinated approaches to avoid unhealthy intra-EU Member State competition via network tariffs.

NRAs should seek coordinated approaches to avoid unhealthy intra-EU Member State competition via network tariffs.

15 Several national practices are presented in this report. Based on their relevance to tackle key challenges, or due to their novelty, a selection of such practices is included below. They deal with signals meant to help keep network costs down. ACER underlines that these practices are presented for informational and inspirational purposes and should be read in the national context they are applied.

16 Under EU rules, fixing or approving network tariffs or their methodologies falls within the responsibility of national regulatory authorities acting independently from any political body or other entity, while ensuring transparency and non-discrimination. ACER and NRAs closely follow and exchange views on instances of tariff reforms having been delayed or even reversed due to political pressure and/or stakeholders' opposition.

17 While regulatory independence should be preserved, the importance of adequate communication when introducing network tariff reforms should not be neglected. Early engagement with affected stakeholders is instrumental to ensure acceptability of new network tariff practices. **This report concludes with a set of 10 main recommendations for NRAs consideration ahead of setting or approving their next transmission or distribution tariff methodologies.**

The importance of adequate communication when introducing network tariff reforms should not be neglected.

8 Power-based (also called capacity-based) tariffs as opposed to energy-based (also called volumetric) tariffs.

Context / specific challenge	Selected national practice	Expected outcomes
More accurate price signals to reduce system peak The costs for building, upgrading and maintaining the network show correlation with system peak capacity. Power-based charges need to be adapted to varying system conditions during the day, week and across seasons, to provide an effective signal to reduce system peak and thus investment needs	**Belgium:** Combination of yearly and monthly peak power-based charges **Spain and Slovenia:** Multiple time variations of the power-based network tariff component (Section 5.2 'Tariff basis')	Enhanced cost reflectivity, efficient use of the grid and reduced need for network reinforcements
More accurate price signals to reduce network losses Some system operation costs, such as energy losses when they are procured by system operators, show correlation with market prices. To provide an accurate price signal, these varying costs should be reflected in network tariffs	**Norway:** Tariffication based on marginal grid losses, differentiated in each network node (Section 5.3 'Locational signals')	Enhanced cost reflectivity, reduction of grid losses and overall costs
Locational signals to address congestion Siting of generation and consumption is often uncorrelated, resulting in congestion between scarcity and surplus generation areas; while bidding zones can partly tackle this issue, within bidding zones, such congestion is not addressed via wholesale market price signals. Therefore, locational signals should also be provided by other means, such as network tariffs, to incentivise generation and demand to connect to the network where this would reduce congestion	**Denmark:** Denmark: Lower network charges for producers in areas with high demand surplus **Ireland:** Locational element of the generation charge **Romania:** Injection charge for producers connected to distribution networks covering losses due to excess generation that needs to be carried to other geographical zones (Section 5.3 'Locational signals')	Reduction in the costs of managing congestion and building new infrastructure
Dynamic price signals to address unpredictable congestions The occurrence of system peaks is increasingly unpredictable at particular locations of the network; as such, dynamic signals (i.e. closer to real time which better reflect actual system conditions) add value compared to what is offered by traditional static time-of-use or locational signals, and therefore reduce network costs	**Slovenia:** Locational dynamic pricing (Section 5.3 'Locational signals')	Reduction of costs for managing congestions and for building new infrastructure
Flexible connection agreements as a complementary measure to address congestions To address congestions, system operators can provide various economic signals, other than network charges, e.g. via flexible connection agreements. It is important to align these signals with the overall network tariffs design to avoid double-remuneration or undue charging	**The Netherlands:** Flexible connection agreements with discount on use-of-network charges (Section 5.4 'Flexible connection agreements')	Reduction in the costs of managing congestions and building new infrastructure
Consistent allocation of costs to network users across voltage levels, promoting self-consumption The traditional flow of electricity is top-down from higher to lower voltage levels; however, some network users can be regarded to consume energy generated locally and therefore rely less on upper voltage levels. Adopting the regular cost-cascading approach would reduce incentives to consume locally, potentially worsening congestions upstream	**Portugal:** Specific tariff regime for self-consumption using the public grid, exempting these users from charges of upper voltage levels (Section 5.5 'Specific tariff regimes: discounts, exemptions and other differentiated tariff treatments')	Enhanced cost reflectivity of charges, promoting consumption of local generation, potential relief of congestions upstream and reduced need for investments

18 **ACER recommends NRAs to:**

Increase transparency and enable comparability of network tariff methodologies by

1. Differentiating the network tariff elements and corresponding cost categories along with the terminology proposed by ACER (see paragraph 250);

2. Publishing information on network tariff structures and values in each country, together with relevant studies underlying key network tariffication choices, and progressively presenting all this information in a centralised EU repository, which could be managed by ACER and NRAs (see paragraphs 251-252).

Ensure non-discrimination among network users by

3. Assessing the potential allocation of costs for injections, both at transmission and distribution level, rather than excluding them by default (see paragraphs 86-87);

4. Avoiding unjustified exemptions, discounts, net-metering, or à la carte tariff regimes tailored to specific groups of network users (see paragraphs 213-216);

5. Accounting for both injections and withdrawals for bidirectional users (e.g. storage facilities) and applying cost-offsetting where separate charging would lead to unjustified double-charging (see paragraph 89).

Ensure cost-reflectivity and provide efficient price signals by

6. Making network users contribute to the costs of the voltage levels used by them via adequate cost cascading (see paragraphs 276-279);

7. Applying time-differentiated energy and/or power-based charges rather than flat energy-based ones (see paragraph 126);

8. In a context of rising grid capacity needs, correlate cost allocation with the network peak usage, by combining an adequate weight of power-based charges in network tariffs with adequate signals for network users to adapt their injections and withdrawals (see paragraph 126);

9. Considering locational signals where needed, e.g. by applying deep connection charges together with cost-sharing among current and future users (see paragraph 145).

Engage with stakeholders ahead of each major revision of the tariff methodology by

10. Carrying out public consultations, providing the reasons for and underlying assessments of the proposed network tariff design, and favoring a multi-year transition process for grid users with significant tariff impact (see paragraphs 237-239).

1. Introduction

19 Massive power grid investment is needed to keep pace with the growth in renewable generation and to support the electrification objectives. These investments, while bringing various societal benefits, will exert significant upward pressure on network costs and, consequently, overall electricity costs.

20 The ACER Report on electricity infrastructure development to support a competitive and sustainable energy system (December 2024) estimates the current annual grid investment in Europe to double until 2050, reaching up to EUR 100 billion, with lower estimates at EUR 75 billion. At that pace, total grid costs for consumers may rise considerably by 2050, reaching over 50% more than the current costs in 2050, or even nearly double in the highest investment scenario. Grid costs for distribution-connected consumers, including industry, will face the largest burden as they will cover about two-thirds of the future investment. Up to 90% of transmission costs are passed on to these consumers who also benefit from transmission services[9]. Some recently approved network tariffs already show their rise due to inflation and investment plans[10].

21 National Regulatory Authorities ('NRAs') see the rise in grid investment and commensurate knock-on effects on network tariffs as significant challenges ahead. As grid costs are expected to become a main driver of electricity costs, containing their rise is key for industry competitiveness and affordability of electricity within the EU. Dealing with this challenge requires 'future-proof' actions by regulators. Measures to alleviate one user group - for example, to enhance competitiveness of the industry or for social purposes, would increase costs for others and distort the efficiency signals in the network tariffs, likely raising even more the need for grid investment[11]. In the ACER and CEER Paper on challenges of the future electricity system (July 2024), energy regulators call for strong prudence from policymakers as to the possibly detrimental effects of such measures.

22 There is a strong need to optimise the utilisation of existing and future assets to lower the overall network costs, including by pursuing cost-effective solutions that would complement grid expansion and by applying advanced network tariffication models fit for a rapidly changing energy system.

23 Under the EU regulatory framework[12], network tariffs applied by network operators[13] shall be cost-reflective and non-discriminatory, take into account the need for network security and flexibility, reflect actual costs[14] and be applied in a non-discriminatory manner. Tariff methodologies shall provide appropriate incentives to the transmission system operators ('TSOs') and distribution system operators ('DSOs') to facilitate market integration, security of supply, efficient investments and innovation. They shall neutrally support overall system efficiency, not discriminate (positively or negatively) against production, energy storage and aggregation; and avoid creating disincentives for self-generation, self-consumption or participation in demand response.

9 See ACER Report on electricity transmission and distribution tariff methodologies in Europe (January 2023, p. 21).

10 For example, in Belgium, transmission tariffs approved for 2024-2027 provide for a rise by 77% (https://www.creg.be/fr/publications/communique-de-presse-pr231114). In Croatia, the increase for both DSO and TSO charges is 12% in 2025 (https://www.hera.hr/hr/docs/2024/Odluka_2024-12-09_04.pdf, https://www.hera.hr/hr/docs/2024/Odluka_2024-12-09_02.pdf). In the Netherlands, transport tariffs for households and businesses would increase by approximately 11% in 2025(https://www.acm.nl/en/publications/acm-publishes-tariff-proposals-distribution-system-operators-and-tennet-2025). In Ireland, network tariffs' average increase of EUR 8.42 per month on a domestic customer bill for the 2024/25 tariff year (https://www.cru.ie/about-us/news/cru-approves-network-charges-for-electricity-customers-for-202425/).

11 For example, to promote self-consumption, policy makers may be tempted to maintain a strict volumetric tariff approach, whereby network users are charged mostly based on the volumes of energy they withdraw or inject. Such an approach may lead to prosumers not holding responsibility for network costs despite relying on the network at peak times, in turn, this could disproportionally increase the financial burden on network users without access to self-generated electricity.

12 Cf. Regulation (EU) 2019/943, Article 18.

13 That is, network charges for access to networks, including charges for connection to the networks, charges for use of networks, and, where applicable, charges for related network reinforcements.

14 Insofar as they correspond to those of an efficient and structurally comparable network operator.

24 The effectiveness of the price signals from network tariffs to the network users to adapt their behaviour (i.e. injection and/or withdrawal profiles) depends on a number of factors such as the type of network user, the share of network costs in the final bill, the corresponding savings, and the parallel (enhancing or conflicting) cost signals given by energy pricing in the market. With the energy transition, the cost components in the final electricity bill are expected to change. As the share of network tariffs within the final bill is expected to increase over time, the price signal for network users will naturally increase.

25 Tariffs can be designed in multiple ways. Each tariff design requires a balance between various tariff-setting principles, including cost-recovery, cost-reflectivity, efficiency, non-discrimination, transparency, non-distortion, simplicity, stability, predictability and sustainability. Tariff setting is complex and no 'one-design-fits-all' or 'one-design-solves-all' solution can be easily found, as such, best practices can vary across countries: NRAs may identify different approaches as most suitable in each national context. At the same time, in tariff-setting areas raising cross-border concerns, such when setting network charges for generators or industrial users, NRAs should seek coordinated approaches to avoid a rally for unhealthy intra-EU Member State competition via network tariffs.

26 As the electricity system evolves, network tariff methodologies may require adaptation. In particular, rapidly changing energy systems[15] require regular reassessment ('electricity-system fitness check') of whether the tariff methodologies are still appropriate.

27 In order to increase transparency and comparability in tariff setting, ACER shall provide and update, a best practice report on transmission and distribution tariff methodologies at least every two years[16], while taking into account national specificities. NRAs shall duly take the best practice report into consideration when fixing or approving transmission or distribution tariffs, or their methodologies in line with Article 59(1)(a) of Directive (EU) 2019/944[17].

28 This report constitutes the fourth edition of the best practice report, following the Practice report on transmission tariff methodologies in Europe (December 2019), the Report on distribution tariff methodologies in Europe (February 2021) and the Report on electricity transmission and distribution tariff methodologies in Europe (January 2023).

29 In line with the previous editions, this report focuses on the determination of the tariff structures and allocation of allowed or target revenues to each of the tariff structure's items (i.e. charges paid by network users). It provides a review of transmission and distribution tariff methodologies across EU Member States, and in Iceland and Norway. (Note: Malta has no transmission network and therefore no transmission tariffs).

30 The setting of the system operators' allowed or target revenues is reviewed under a separate ACER activity. ACER Report on investment evaluation, risks assessment and regulatory incentives for energy network projects (July 2023) focused on TSOs[18]. In its next report dealing with system operators' revenue setting, expected in 2026, ACER aims to expand its review to cover DSOs in line with the priorities set by the European Commission's grid action plan.

31 This report is based on the input provided by NRAs mainly between May 2024 and June 2024 on their transmission and distribution tariff methodologies, in addition to the information presented in previous ACER network tariff reports. While the main report discusses the key tariff setting challenges and practices, the Annexes provides extensive information on the national transmission and distribution tariff methodologies as reported by NRAs.

15 For example, due to increased integration of renewable energy sources ('RES'), increased demand by electrification and the more active role of network users.

16 Cf. Regulation (EU) 2019/943, Article 18(9), amended by Regulation (EU) 2024/1747.

17 Cf. Regulation (EU) 2019/943, Article 18(10).

18 Most of the considerations and recommendations may also be valid for DSOs, as the fundamentals of cost recovery for these two regulated activities show great similarities.

32 As part of the preparation of this report, ACER organised a public workshop on 30 September 2024 in Brussels and invited several European associations of different network user groups to identify the most pressing network tariff dilemmas and suggest practices to address them. Furthermore, ACER invited all stakeholders to complete an online survey to share their views on a subset of specific network tariff issues, including power-based network charges, special tariff designs, locational signals and flexible connection agreements ('FCAs'). The stakeholders' views provided during the public workshop and the ones collected through the ACER online survey have been incorporated into this report[19] (summaries are provided in the 'Stakeholders views' subsections in this report).

33 The rest of this report is structured as follows:

- Chapter 2 provides definitions of key concepts
- Chapter 3 recaps the main findings of the previous ACER activity on revenue setting;
- Chapter 4 presents key challenges and recent developments in network tariff setting;
- Chapter 5 focuses on a subset of tariff-related topics ('focal topics') that were deemed of particular interest to NRAs and stakeholders:

  i. Section 5.1 characterises the cost categories recovered by means of transmission and distribution tariffs,

  ii. Section 5.2 investigates the tariff basis, in particular the different designs of power-based network charges,

  iii. Section 5.3 provides an overview of locational signals,

  iv. Section 5.4 reviews the tariff implications of FCAs,

  v. Section 5.5 investigates the application of discounts and exemptions and other differentiated treatment of particular network user groups and compares the tariffication of emerging network users, including power-to-gas facilities, public electric vehicle (EV)-charging stations and energy communities.

- Chapter 6 recaps information on other tariff-related topics and findings that were generally extent present in previous editions of the report;
- Annex 1 provides detailed data for each country reviewed;
- Annex 2 provides links to the tariff methodologies and some other tariff -related information for each country reviewed;
- Annex 3 presents ACER's regular monitoring of the appropriateness of the ranges of allowable transmission charges paid by producers (the 'G-charges'), pursuant to part B of Annex to Commission Regulation (EU) No 838/2010.

19 For further details, please refer to the ACER web page of the workshop (https://www.acer.europa.eu/public-events/acer-workshop-designing-electricity-network-tariffs-fit-energy-transition).

2. Definitions

34 According to the definitions set out in Directive (EU) 2019/944 and Regulation (EU) 2019/943:

- 'Distribution' means the transport of electricity on high-voltage, medium-voltage and low-voltage distribution systems with a view to its delivery to customers, but does not include supply;
- 'Distribution system operator' means a natural or legal person who is responsible for operating, ensuring the maintenance of and, if necessary, developing the distribution system in a given area and, where applicable, its interconnections with other systems, and for ensuring the long-term ability of the system to meet reasonable demands for the distribution of electricity;
- 'Producer' means a natural or legal person who generates electricity;
- 'Smart metering system' means 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;
- 'Transmission' means the transport of electricity on the extra high-voltage and high-voltage interconnected system with a view to its delivery to final customers or to distributors, but does not include supply;
- 'Transmission system operator' means a natural or legal person who is responsible for operating, ensuring the maintenance of and, if necessary, developing the transmission system in a given area and, where applicable, its interconnections with other systems, and for ensuring the long-term ability of the system to meet reasonable demands for the transmission of electricity;
- 'Flexible connection agreement' means a set of agreed conditions for connecting electrical capacity to the grid that includes conditions to limit and control the electricity injection to and withdrawal from the transmission network or distribution network.

35 In addition, for the purpose of this report, the following additional definitions apply:

- 'Distribution tariff methodology' defines the rules for allocating distribution costs to (groups of) network users. The tariff methodology as defined in this report does not include the determination of the allowed or target revenues of system operators;
- 'G-charge' means the transmission charges paid by producers in each Member State, as referred to in part B of the Annex to Commission Regulation (EU) No 838/2010, excluding connection charges, charges related to ancillary services and specific system loss charges;
- 'Household consumer' means a network user who withdraws electricity from the grid for their own household consumption, excluding commercial or professional activities;
- 'Injection charge' means all transmission and distribution charges paid by producers, except for charges for physical assets required for connection to the system or the upgrade of the connection (i.e. connection charges), but including non-connection charges (such as charges related to ancillary services and system losses);
- 'Network user' means a natural or legal person connected to the transmission or distribution network (excluding the DSO and TSO), who injects electricity in and/or withdraws electricity from the network;
- 'Public consultation' means a publicly announced consultation, in which any individual, group or organisation is allowed to participate;
- 'Tariff methodology period' means the period for which the general rules for the tariffs are set. During this period the tariff values may be updated several times;

- 'Time-of-use network tariffs' (or 'tariff time elements') means charges for network service(s) that vary according to when the service is used e.g. by peak/off-peak, season, month, weekdays/weekends, hour;

- 'Transmission tariff methodology' defines the rules for allocating transmission costs to (groups of) network users. The tariff methodology as defined in this report does not include the determination of allowed or target revenues of the system operators.

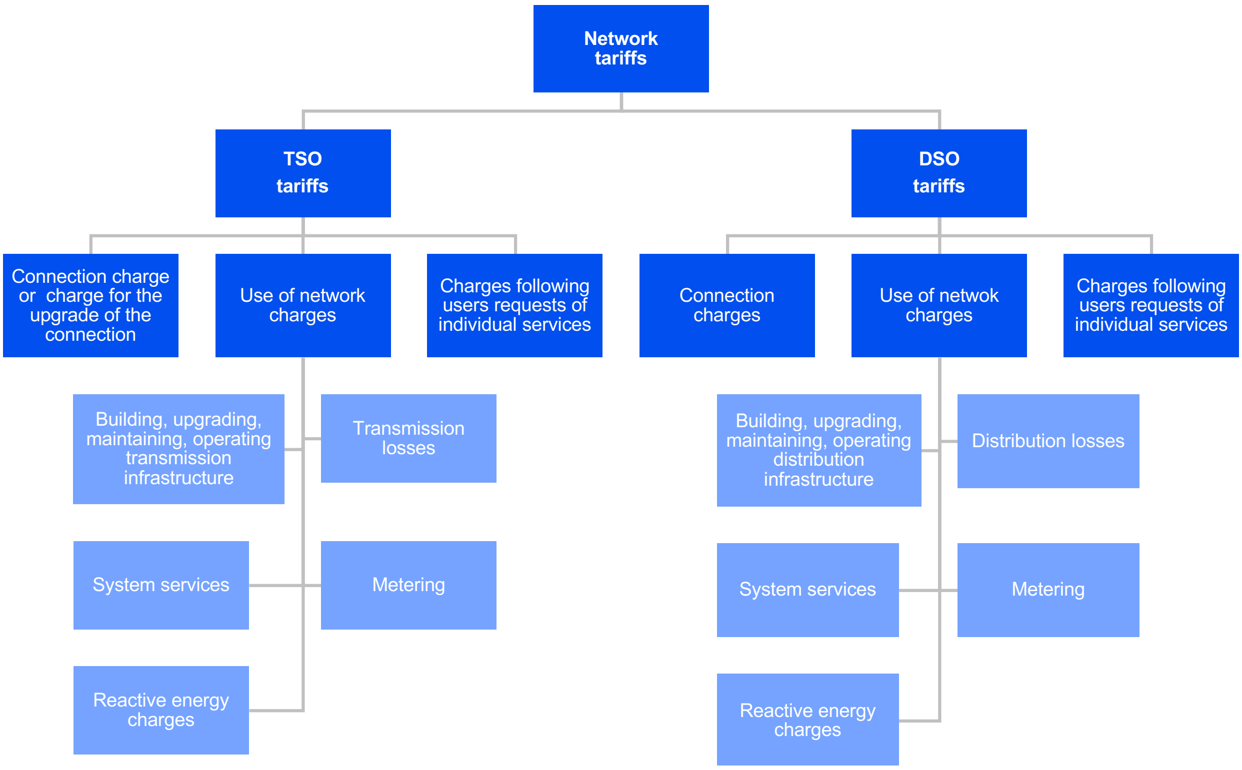
36 In this report, the term 'network charges' (or 'network tariffs') includes all charges paid to the TSO and DSO, except unrelated costs supporting unrelated policy objectives, which shall not be included in network charges under EU law. As shown in Figure 1 ACER differentiates between the following concepts within these charges:

- 'Use-of-network charges' include charges for building, upgrading, maintaining and operating the transmission and distribution infrastructure, charges for transmission and distribution losses, charges for system operators purchases of system services, charges for metering and charges for withdrawing and/or for injecting reactive power outside the allowed limits (i.e. payment for reactive energy/power), regardless of how they are named in the national tariff structures. Use-of-network charges are recurring and their values are approved for a given time interval, often a year;

- 'Connection charge' means a charge, typically a one-off charge, covering the costs (or part of the costs) of connecting new users to the transmission or distribution system or upgrading the connection. Connection charges may be shallow or deep. Shallow connection charges mean the network users pay for the infrastructure connecting their installation to the transmission or distribution grid (line/cable and other necessary equipment), while deep connection charges mean the network users (additionally) pay for the costs of other reinforcements/extensions required in the existing transmission or distribution grid to enable grid users' connection;

- Finally, there are charges for individual (specific) services provided by the TSO or DSO at the request of the network user (e.g. installation of a new meter upon the user's request or reconnecting a network user in the case of disconnection due to late payments).

Figure 1: Harmonised definition of network tariffs



3. Revenue setting methodology

37 NRAs shall take all reasonable measures in pursuit of ensuring that system operators and system users are granted appropriate short- and long-term incentives to increase efficiency[20]. Such measures encompass setting the system operators' allowed or target revenues as part of network tariff setting.

38 In order to avoid underinvestment or inefficient investment in the electricity network, system operators should receive fair remuneration for their investments that adequately rewards them for the risks they bear. System operators should also be incentivised to put forward the most beneficial and cost-efficient investments.

39 In 2023, ACER reviewed the national regulatory frameworks for transmission network development. In early 2024, jointly with CEER, ACER carried out additional assessments with a focus on anticipatory investments[21] for the system integration of renewables[22]. The ACER review had a very limited scope regarding distribution network development.

40 ACER found that the current approach of NRAs (i.e. assessing the level of systematic risk for the overall transmission activity and providing the same return to all electricity transmission infrastructure projects within a country[23]) is generally fit for purpose. The review also concluded that the regulatory treatment does not distinguish between anticipatory investment and other grid investments and, consequently they are subject to the same cost-recognition process, regulatory incentives and penalties once they have been approved by NRAs[24].

41 However, ACER also notes some key challenges:

- First, the TSOs often face capital expenditure ('CAPEX')-bias (i.e. preference for CAPEX-intensive solutions) due to the more favourable remuneration schemes for CAPEX, which is typically subject to rate-of-return regulation as opposed to operational expenditure ('OPEX'), which is often regulated by 'revenue caps'. Consequently, some investments may not be proposed by system operators despite their higher value for society, because the system operators are not incentivised to favour the available cost-efficient alternatives to grid investment.

- Second, while system operators often follow a forward-looking approach in network planning and anticipate future generation and demand, in some instances network planning lacks adequate infrastructure needs assessment and includes only the investments with actual/firm connection requests. In several countries, improvements are also needed in NRAs' evaluation of network development options, including the application of a cost benefit analysis methodology, in order to select the more cost-efficient solutions to reach the envisaged benefits/targets.

20 Cf. Article 18 of Regulation (EU) 2019/943, and Articles 59(7), and 58(f) and Article 59(1)(a) of Directive (EU) 2019/944.

21 The term 'anticipatory investments' means investments that are risky for society because they may turn out be underused, at least for a number of years, until developments take place on the generation side.

22 The Commission's grid action plan stresses the importance of anticipatory investments, in particular in relation to the expansion of meshed offshore grids, but also due to their relevance in areas with high untapped onshore photovoltaic (PV) potential, EV charging infrastructure or heat pump rollout. In accordance with this, the electricity market design reform underlines that NRAs cost recognition and tariff inclusion shall also include costs related anticipatory investment.

23 The rate of return in most Member States is calculated using the capital asset pricing model ('CAPM'). The weighted average cost of capital ('WACC') for each Member State are available in ACER Report on investment evaluation, risks and incentives (June 2023).

24 NRAs identified a number of tools that could enable anticipatory investments; such as the early inclusion of work-in-progress investments in the regulatory asset base; and the approval of costlier connection works and/or oversized grid developments to accommodate future network users. However, ACER notes that these measures often come with trade-offs, such as the expansion of the revenue caps, which can risk hampering the efficiency of network operations or interference with deep connection charging, while the measures can have a potentially high impact on network tariffs.

42 Total-expenditure ('TOTEX') regulation (with fixed CAPEX and OPEX shares, as already applied in some countries)[25], can efficiently mitigate CAPEX-bias, while benefit-based incentives - set directly to the measurable project benefits or major performance targets - incentivise the implementation of the most cost-efficient solutions to address an investment need[26]. Where the regulatory tools currently in place are insufficient to ensure that investment gaps are addressed in the most efficient manner, ACER recommends applying benefit-based incentives[27]. ACER also calls for detailed technical studies to identify investment needs and for cost benefit analysis at least of high CAPEX projects.

43 For more details and additional related recommendations, please refer to the ACER and CEER Position on anticipatory investments (March 2024), the ACER Report on investment evaluation, risk assessment and regulatory incentives for energy network projects (June 2023) and the ACER Recommendation on incentives for projects of common interest and on a common methodology for risk evaluation (June 2014).

25 For example, in Italy and Portugal.

26 As a practical implementation of this concept, ACER issued a consultancy study on 'benefit-sharing' in June 2024, in which the avoided network costs due to implementing a smart solution, instead of the traditional solutions to address a system need, is shared between the system operator and society. The concept has been applied by some NRAs in Europe already and ACER aims to facilitate further pilot projects together with NRAs.

27 The application should be systematic (i.e. not only upon request for individual projects).

4. Key challenges and recent developments in network tariff setting

Main findings

44 Based on NRAs' recent experiences, ACER identified several dilemmas and challenges in network tariff setting (see Figure 2), which can be grouped in the following categories:

- **Cost recovery:** The widespread and rising penetration of self-generation and newly forming energy communities has enabled several network users to reduce their energy withdrawals from the grid. Since the reduction in energy withdrawal is often not coincident with the system peak, the corresponding grid investment costs of the system operators keep increasing to accommodate new load and generation. The rising network costs exert upward pressure on network charges, which leads further network users to rely less on energy from the public grid, creating a vicious circle unless properly addressed in network tariffs.

- **Fair allocation of costs across network users:** In several countries, some network users are exempt from network charges (e.g. producers) or receive specific tariff treatment (e.g. net metering for prosumers, discounts for industry), thereby shifting costs to other network users. This challenge has multiple facets, such as the complexity in calculating a fair share of costs, the political sensitivity of any cost reallocation across network users and the alignment with other policy goals, such as renewable integration or industry competitiveness[28].

- **Economic signals to increase system efficiency:** The establishment of a cost-reflective tariff basis (and corresponding cost drivers) is often hindered by a lack of data, insufficient transparency and stakeholders' opposition. Reducing peak utilisation is critical and represents a common challenge across several countries. Related to this challenge, some NRAs point to difficulties in determining effective time of use ('ToU') signals, especially when the network utilisation peak is not aligned with the wholesale price peak.

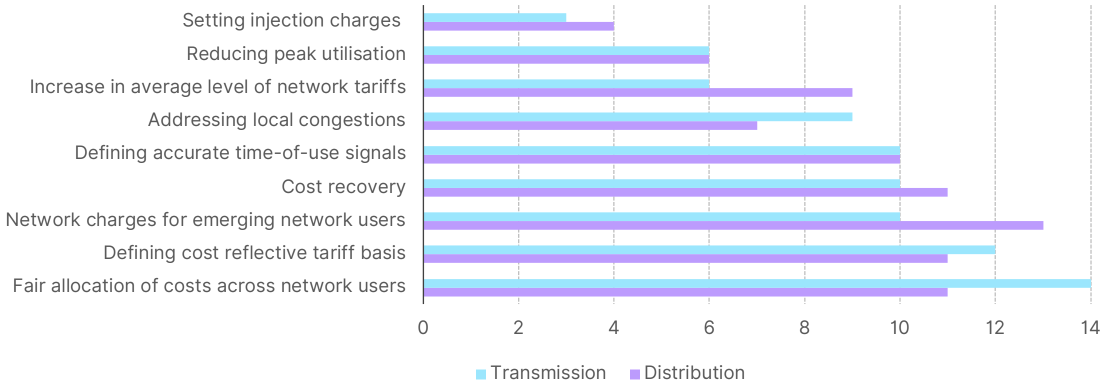
- **Treatment of users with potential bidirectional energy exchange:** In the context of the energy transition, energy storage, EVs and energy communities have gained attention for their potential to improve overall system efficiency. However, particularly where they are capable of bidirectional use, it can be difficult to quantify the net impact of their network utilisation (e.g. avoided network costs) and what counts as unjustified double charging[29].

- **Addressing local congestion via network charges:** Providing accurate and effective locational signals is often hindered by difficulties defining the borders for accurate geographical discrimination, especially where congestion is not structural, but rather keeps changing over time. Meanwhile, some national laws do not allow such differentiation of network charges.

28 For instance, applying injection charges, without using consistent principles, can create distortions in the internal market, while removing discounts for energy-intense industry can increase their costs.

29 For instance, EV charging can contribute to system efficiency by smartly charging and potentially discharging EV batteries but it may also increase the capacity need in distribution grids and thus the costs. Similarly, energy communities can reduce network reinforcement costs and losses and the need for system services at the upper voltage levels by not using them; however, to reflect network utilisation from energy sharing over the public grid, NRAs must take into account the relative positions of production and consumption in the public grid, the possibility of having a storage facility, and the existence of reverse power flows to upper voltage levels.

Figure 2: Number of countries reporting main challenges in network tariff setting



Note: NRAs reported one or more challenges. For six countries no information was provided on the current challenges.

45 About two thirds of the countries reported recent, ongoing or planned tariff reforms or studies to address the challenges listed, while a third of them did not report or specify such reforms. The categorisation is not straightforward, as several changes effect multiple aspects of tariff design; however, certain trends can be observed (see also Figure 3):

- gradual shift towards more **power-based charges** (4 countries in transmission and 11 countries in distribution);
- increasing the **generation's share in cost recovery** (four countries in transmission and five countries in distribution);
- providing **locational signals** to producers (two countries in transmission and three countries in distribution);
- introduction of new **ToU signals** or revision of existing signals (four countries in transmission and six countries in distribution);
- introduction or expanded use of **FCAs** to speed up renewable connection (five countries in transmission and three countries in distribution);
- tariffication of **specific network user groups**, in particular large consumers or storage facilities (six countries in transmission and seven countries in distribution);
- revision of **connection charges** (reported for three countries in transmission and three countries in distribution).

Figure 3: Recent trends in network charge changes

Network tariff aspect	Recent, ongoing or planned tariff reform/study
Tariff basis	• **Austria**: It aims to replace lump sum charges for household-consumers with power-based charge. • **Belgium**: Brussels region plans to introduce in 2028 for low-voltage customers equipped with a smart meter a charge based on subscribed capacity (replacing the lump sum charge based on an installed capacity threshold of 13 kVA) in addition to the energy-based charge; Flanders region introduced new power-based tariff structure in 2023. • **Croatia**: It introduced a charge for withdrawal (transmission and distribution) based on contracted capacity; the tariff value is currently set at 0 EUR/kW. • **Denmark**: From 2025, it plans charges based on measured power for users connected to the transmission grid above 10 kV and for prosumers (above 10 kW) connected to the distribution grid above 0.4 kV; a fixed element in the system tariff recovers residual costs. • **Estonia**: In 2024, it introduced charges based on contracted capacity in transmission. In distribution, it is currently in the process of implementing lump sum charges for all network users (currently, households can choose a solely energy-based tariff). • **Finland**: The harmonisation of the power-based charge over the next few years is under consideration. • **Hungary**: There are plans for charges based on measured peak power for low-voltage consumers who have smart meters. • **Iceland**: The introduction of a capacity-based charge is under consideration (transmission and distribution). • **Italy**: From 2024, the power-based percentage of DSO payments to the TSO was increased to 93% (transmission charging). • **Lithuania**: The introduction of a capacity-based charge is under consideration (for households, distribution). • **Luxembourg**: From 2025, for low-voltage consumers the withdrawal charge lump sum component is replaced by a power-based component (reference power level and fees for excess). • **Slovenia**: It increased the share of power-based charge in cost recovery, with a withdrawal tariff applied to additional users (storage). • **Sweden**: Some DSOs plan to implement power-based charges for smaller customers.
Charges for producers	• **Austria**: From 2024 onwards, instead of a fixed 20% share, the network cost split has been adopted yearly based on the relation of quantities supplied to the quantities injected by producers; in 2024 the relation was 48:52. • **Belgium**: In Flanders region, since 2023, the injection charge applies for the recovery of network costs instead of grid losses, system services and other costs (pension schemes and local retributions). • **Croatia**: It introduced injection charge in the tariff methodology, but currently its value is set at zero. • **Denmark**: From 2023, injection charge applies also for distribution costs (before only for transmission costs). • **The Netherlands**: An injection charge is under consideration. • **Romania**: From 2025, the injection charge extended to distribution-connected producers in producer surplus areas and covers losses due to electricity generation surplus to local consumption. • **Sweden**: Since 2023, there have been no exemptions from paying injection charges for smaller producers. There is ongoing reassessment of costs allocation between generation and load at all network levels.
Locational signals	• **Denmark**: In 2023, the TSO introduced locationally differentiated injection tariffs, but change is under consideration from 2025. • **Romania**: From 2025, an injection charge applies for producers connected to distribution networks where excess electricity is generated and carried to other geographical zones to be consumed; the charge covers losses due to electricity generation surplus to local consumption. • **Sweden**: There is ongoing assessment of locational signals in transmission/distribution use-of-network charges.

Network tariff aspect	Recent, ongoing or planned tariff reform/study
ToU signals	• **Belgium**: New ToU signals have been implemented in transmission. In Brussels region, new ToU signals will be implemented. In Flanders region, day/night tariffs have been phased out from 2023. In Wallonia region, a new pricing structure based on ToU tariffs for low-voltage consumers is expected to be set up in 2026 (as an opt-in system). • **France**: Peak and off-peak network hours have been redefined to be more reflective of network use, especially in the low season (summer) at the distribution level. • **Latvia**: ToU signals were phased out in distribution tariffs from 1 July 2023. • **Germany**: In 2025 optional ToU tariffs were introduced for interruptible devices at the low-voltage level. • **Netherlands**: In January 2025, ToU signals in transmission tariffs for withdrawal were introduced. • **Portugal**: A preliminary analysis to update the ToU schedule was published at the end of 2024. • **Slovenia**: From 1 October 2024, time-block differentiation applies for all consumer groups based on more detailed consumption and generation data (using 15-minute intervals).
FCAs[30]	• **Austria**: A revision of the interruptible tariffs and the introduction of a load-adjustable tariff is under consideration. • **Belgium**: The NRA is currently discussing a detailed regulatory framework for connections with flexible access at the transmission level. This framework could affect network tariffs. • **Denmark**: The TSO is currently implementing 'limited network access', which allows transmission-connected users to apply limits to 100% of their agreed capacity in exchange for a lower network tariff. Updates are under consideration that would allow for network users to get only part of their capacity limited. A pilot project has been introduced by the TSO for the temporary connection of production facilities[31]. • **Netherlands**: Three types of FCAs have been introduced to reflect lower costs of pure off- peak use of the grid. • **Portugal**: The general conditions applicable to agreements on flexible connections (or connections with restrictions) were approved on 21 January 2025.
Tariffication of specific network user groups	• **Belgium**: In Wallonia region, from 2025, standalone storage facilities are exempt from injection charges, taxes and surcharges on DSO tariffs and exemption from TSO tariffs (except for reactive energy tariffs), apart from those for their own consumption (i.e. battery losses) netted yearly. • **Denmark**: A reduction in the TSO system tariff was introduced for large consumers as regards their consumption exceeding 100 GWh annually. • **France**: From August 2026, the NRA will introduce a specific network tariff for storage facilities, as they can help to resolve network constraints linked to both injection and withdrawal. • **Germany**: The NRA has started a determination procedure for a follow-up provision to Section 19(2) of the Electricity Tariff Ordinance (discounts for baseload and atypical grid users). The ordinance will phase out at the end of 2028. The new provision will set incentives to provide flexibility with regard to price signals from the electricity market. • **Netherlands**: In 2024, for large consumers, the volume correction scheme (i.e. discounts) was abolished, because it was deemed not to be in line with EU legislation. The NRA investigated the need to introduce specific tariffs for storage facilities but concluded that discounts should not be based on technology, but rather on grid usage. • **Portugal**: Since July 2023, autonomous storage facilities are exempted from network charges for withdrawal (when they participate in energy sharing over the public grid specific rules apply). This exemption is valid until the end of 2029. • **Slovenia**: In the new tariff methodology, storages became subject of network charges for withdrawal. • **Sweden**: An assessment of behaviours of EV chargers and energy storage was performed.

30 The figure does not include all instances of recently introduced or planned FCAs but focusing on those with network tariff discounts. For more information on FCAs, please refer to Figure 18 of this report.

31 DK: A pilot project has been introduced by the TSO for the temporary connection of production facilities to overhead lines, allowing producers to connect temporarily to transmission network while awaiting network expansion for permanent connection.

Network tariff aspect	Recent, ongoing or planned tariff reform/study
Connection charges	• **Austria**: There are plans to combine both connection charges (system admission charge and system provision charge) to form a new connection charge, which will include a flat charge and a cost-reflective part. The system provision charge has only applied to consumers and never to producers in the past. • **Croatia**: The NRA issued the new connection charge methodology in 2022, but still requires a decision to be made on the unit prices for network reinforcement costs. • **Czechia**: A new tariff structure for high-voltage and medium-voltage users will apply from 2027; it will have the same structure regardless of technology. • **Denmark**: From 2025, new connection fees for consumers and prosumers are planned, introducing geographically differentiated connection fees for consumers connected above 10 kV, which is similar to the approach in the production connection fees introduced in 2023. • **Germany**: There are shallow and deep connection charges at the transmission level.

46 ACER notes that several changes reflect previous ACER recommendations such as; increasing the relevance of power-based tariffs in alignment with the cost-causality principle (Austria, Belgium, Estonia, Luxembourg, Slovenia), introducing ToU signals (Belgium, Germany, the Netherlands) and removing unjustified discounts (in the Netherlands for large consumers; in Sweden for small generators).

47 ACER also notes that some changes do not seem to fit into the recently observed trends noted in paragraph 45. For example, Denmark has recently introduced a reduction in the TSO system tariff for large consumers as regards their consumption exceeding 100 GWh annually, while Latvia has phased out ToU signals from distribution tariffs. The explanations of those changes are provided in Section 5.5 and Section 6.6 of this report, respectively.

48 ACER notes that many of the changes are politically sensitive and increase pressure on NRAs. During the discussions, several NRAs expressed that their tariff reforms are slowed down or reversed, due to stakeholder opposition or political interventions.

Stakeholders' views

49 Challenges mentioned by European associations of different stakeholder groups largely echo the challenges identified by NRAs[32]; stakeholders provided additional reflections on existing challenges and proposals on how to tackle them, which can be summarised as follows.

- Some call attention to varying approaches to grid charges across Europe and highlight the importance of applying cost-reflective injection charges to balance the cost allocation between consumers and producers and consequently foster efficiency.
- Some are concerned about industrial competitiveness due to rising network charges; they recommend power-based charges[33], argue for tariff discounts for large consumers[34] and call for caution regarding locational signals and dynamic network charges.
- Some urge transparency, simplicity and fair cost burdens (e.g. avoiding discriminatory tariffs to incentivise technologies or favor local industry).
- Some emphasise that various options could foster efficiency (e.g. power-based charges, connection charges with spatial differences, ToU tariffs, injection charges, cost-reflective discounts). However, they note that these options come with trade-offs and require careful implementation.

32 https://www.acer.europa.eu/sites/default/files/events/documents/2024-10/ACER_Hybrid_Workshop_Tariffs_30092024.pdf

33 Some claim that the power-based network charge should reflect individual power peaks, be based on subscribed capacity and make use of higher (i.e. 15-minute) granularity.

34 Some claim that transmission investments to meet the needs of by industrial consumers are generally made closer to the actual need and utilised more efficiently.

- Some advocate regional coordination to ensure a level playing field, reflecting flexibility/benefits in the network tariffs (i.e. via tariff reduction), ensuring ex post redistribution ('cable pooling') of connection costs, avoiding double-charging and keeping fair balance between power and energy-based components in the tariffs.

- Some underline that the cost reflectivity of network tariffs comes with complexity, that smart meters are enablers for adoption of more sophisticated tariffs (although their roll-out is lagging in some countries) and that EU guidance on cost-reflectiveness is high level, leaving significant discretion to individual Member States in terms of implementation.

ACER considerations

50 ACER welcomes the fact that several recent, ongoing or planned changes in the transmission and/or distribution tariff methodologies have resulted in convergence towards ACER recommendations put forward in previous reports.

51 ACER underlines, that besides the need to preserve regulators' independence, it is of the utmost importance that NRAs implement good communication practices regarding the network tariff reforms.

5. Analysis of national tariff practices: Focal topics

5.1. Recovery of system operator costs

Main findings

52 The costs of development and operation of the electricity network are mainly borne by the TSOs and DSOs, and - to the extent these costs are not covered by EU, national or local co-financing instruments and congestion income - mainly recovered from network users in the form of use-of-network charges (see Figure 1).

53 In some countries parts of the transmission or distribution costs are not incurred by the system operators; instead the corresponding costs are borne directly by producers, suppliers or other entities[35]. Furthermore, in some countries, parts of the network operators' costs are not recovered through network charges, but recovered by other means - for example, fees levied on balance-responsible parties. These other means are not part of the network tariff structure.

54 It is important to differentiate between the costs driven by individual users and the costs driven by multiple users. In all countries, the costs resulting from a network user's individual request - such as connecting to the grid[36], upgrading a connection or reconnecting after disconnection - are paid by the network user through one-off connection charges or other individual one-off fees. The other costs, which are driven by multiple network users, are typically paid through use-of-network charges for each billing period.

55 There is a link between the connection charges and the use-of-network charges. One-off connection charges may also cover part of the network reinforcement required upstream of the connection, which is likely to benefit multiple existing or future users connected to that grid area. These are called deep connection charges. Connection costs may also be partially paid through use-of-network charges if connection charges do not reflect actual costs.

56 In 2023, the overall amount of the transmission use-of-network charges was about EUR 20 billion, and the overall amount of the distribution use-of-network charges was about EUR 60 billion[37]. On average[38], the bulk (about two thirds) of these costs was related to building, upgrading, maintaining and operating the network ('CAPEX and OPEX'). However, the costs of losses also accounted for significant shares of these charges in both transmission and distribution: 11% and 16% respectively. The share of system services costs was significant in transmission but rather low in distribution, while the share of metering costs was low in both transmission and distribution, even being rather negligible in distribution.

35 For instance, generators may have to provide some system services for free on a mandatory basis. In some countries, suppliers are required to purchase, in addition to their clients' electricity consumption, an additional amount to compensate for the associated grid losses.

36 This includes the cost of the infrastructure connecting a network user's installation to the transmission or distribution grid (line/cable and other necessary equipment).

37 Use-of-network charges include charges for the costs of building, upgrading, maintaining and operating the transmission and distribution infrastructure (CAPEX and OPEX), the costs arising from (purchasing) losses, the costs of (purchasing) system services, metering costs and the costs due to reactive power. However, Use-of-network charges do not include connection charges or charges for individual TSO services provided upon requests. (See Figure 1). Note: The DSO charges in some countries may include a large part of the transmission costs which is cascaded from transmission to distribution implicitly via the DSO charges (as opposed to explicit TSO charges for distribution connected users). Responses for the statistics were available in 23 countries at the transmission level and 24 countries at the distribution level.

38 Data were available for 17 countries at the transmission level and 12 countries at the distribution level.

57 The costs of building, upgrading, maintaining and operating the transmission and distribution infrastructure[39] are covered only by use-of-network charges in about half of the countries; in the other half, connection charges are deep for at least some users, thus also contribute to covering network reinforcement costs.

58 The costs of grid losses, including payments for the inter-TSO compensation ('ITC') mechanism, in most countries (23 out of 28) are procured by system operators and recovered through use-of-network charges[40]. However, four countries (GR, IT, ES, PT) are exceptions, where TSOs and DSOs do not bear the costs of grid losses, as the losses are procured directly by suppliers or large customers in the market. In one country (BE) parts of the grid losses are covered in kind by balance-responsible parties ('BRPs')[41].

59 The cost recovery for various system services (reserves, black start, congestion management and voltage control, payments for interruptible loads) follows different approaches across countries. In most countries (more than two thirds), at least some system services costs are recovered through use-of-network charges, but some (e.g. frequency containment reserves) are frequently provided by the generators for free[42]. In at least six countries, other means - mainly those outside the network tariff structure - contribute to the recovery of system services purchased by the system operator[43].

60 Metering costs (not accounting for the cost of installing the meter) are recovered through use-of-network charges in most countries. Four countries (HR, CY, LV, ES) reported applying other means (i.e. those outside the network tariff structure) to recover at least part of the metering costs. In two countries (DE[44], NL[45]), metering is partially a deregulated activity.

61 ACER additionally reviewed the recovery of some specific cost items, such as (a) costs of managing customers switching suppliers, (b) fees that system operators contribute to the European Network of Transmission System Operators for Electricity ('ENTSO-E') or the EU DSO entity, (c) costs related to market operation (e.g. nominated electricity market operators, local markets for congestion management and voltage control services), (d) research and development and (e) costs related to data hub activities. ACER notes that, in most countries, all of these costs are recovered through network charges. Other means (e.g. non-TSO and non-DSO fees) of partially recovering these costs for the TSO or DSO are applied in 10 countries[46]; however often no specifics were provided. No country reported that any of these costs are not recovered for the DSO or TSO. However, in several countries some of these costs are not applicable, as no such costs are borne by the DSO or TSO.

62 As shown in Figure 4, in about two thirds of the countries, the customer's final bill includes cost items that cannot be classified as TSO or DSO costs but are still collected/administered by the TSOs or DSOs. In most instances, these costs are related to schemes supporting renewable energy

39 The cost of losses, the cost of system services and the cost of direct connection to the grid are presented and accounted for under separate findings. Payments related to cross-border cost allocation decisions are recovered via use-of-network charges in all countries, which provided such information (i.e. 15 out of 28).

40 Grid losses may be separated from other losses (e.g. theft), which are not recovered in some countries. Some countries (e.g. Austria) have a separate tariff that covers costs of system losses.

41 BE: Grid losses at voltage levels above 70 kV are covered in kind by balance-responsible parties, while grid losses at voltage levels of 70 kV and below are covered by the TSO and the cost is recovered via transmission tariffs, same approach as at the DSO level.

42 AT, BE, BG, HR, CY, CZ, DK, EE, FR, GR, IT, LT, LU, NL, NO, RO, ES, SI.

43 In Austria, the costs arising from frequency containment reserves, automatic frequency restoration and manual frequency restoration are recovered and valued using the market prices. In Portugal, system services costs are recovered through a different tariff (a global use-of-system tariff). In Greece, the costs of reserves are covered through the balancing market and borne by suppliers. In Sweden, the replacement reserve is recovered through a government-set special capacity reserve fee and black start capability is recovered using a contingency fee.

44 DE: Smart metering is a deregulated activity in Germany.

45 NL: For large non-household consumers the metering is deregulated.

46 BG (DSO managing switch of suppliers, ENTSO-E and EU DSO entity fee, market operation, research and development, data hub), CY (TSO/DSO managing switch of suppliers), CZ (wholesale market operation), LT (EU DSO entity fee), MT (EU DSO entity fee, research and development, as a part of the DSO costs is financed through state budget), NO (TSO data hub ('Elhub') users pay a fee), PT (wholesale market operation), ES (TSO/DSO managing switch of suppliers) and SE (research and development for DSO).

sources, co-generation of heat and power or energy efficiency, but ACER also observes instances where they cover measures for ensuring adequacy[47], support schemes for demand response[48] and/or they are related to social measures[49] or taxes other than value added tax. These measures and their costs are often set by national legislators.

63 In most countries, these non-TSO and non-DSO costs are clearly separated from the network tariffs. However, ACER notes that, in some countries (BE[50], IE[51], SK[52]) these costs are bundled into network tariffs and are not clearly separated in the bill.

Figure 4: Non-TSO and non-DSO costs collected by system operators

	Not separate from other TSO/ DSO costs in final bills[53]	Separate from TSO/DSO costs in final bills[54]
Costs of schemes supporting RES, co-generation of heat and power or energy efficiency	2: BE (Brussels region), SK	13: AT, BE, CY, EE, DE, HU, IT, LU, NO, PT, RO, SI, ES
Costs of measures for ensuring adequacy or support schemes for demand response	2: BE, IE	3: BG, FI, PT
Costs of social measures or taxes other than value added tax (e.g. energy tax)	2: BE (Brussels region), PT	3: CY, FI, SE

Note: The figure does not include instances where reduced network charges act as a RES support scheme or where the classification was unclear. For more information, please refer to Tables 59 in Annex 1.

Split of transmission/distribution system operator costs between generation and load

64 The TSO and DSO costs recovered via use-of-network charges can be levied on the injection of energy into the grid (also referred to as 'generation') or withdrawal of energy from the grid (also referred to as 'load')[55].

65 ACER finds that transmission and distribution cost recovery relies heavily on withdrawal charges in all countries, while the application of injection charges varies widely across countries (see Figure 5):

- in more than half of the countries (16 out of 29), generation does not pay use-of-network charges for injection (14 out of 29) or pays only marginal charges (2 out of 29: NL, MT)[56];
- in four countries (BG, IE, FR[57], RO) generation pays only transmission costs;
- in one country (EE) generation pays only distribution costs;
- in eight countries (AT, BE, DK, FI, NO, LV, SK, SE) generation contributes to both transmission and distribution costs.

47 The adequacy measures refer to strategic reserve power plants, support for 'peakers' or other relevant capacity remuneration mechanisms other than system services.

48 Others than costs of local/flexibility markets.

49 For example, pensions contributions, rural areas, emergency social support measures to mitigate the price increase in recent years.

50 BE: Measures for ensuring adequacy are part of the TSO charges in accordance with the national law. In Brussels region part of public street lighting costs, costs of supporting energy transition and costs related to temporary supply of power in the public space (e.g. during fair) are separate tariff lines within DSO charges but are not separated in the final bill.

51 IE: The costs of measures for ensuring adequacy and the costs of support schemes for demand response are not separated from system operators' costs in the final bill.

52 SK: The costs of support schemes for RES, cogeneration of heat and power and fossil fuels are recovered by the system operation tariff.

53 'Separate' means that the cost is recovered by a separate/dedicated charge, levy or tax (i.e. the cost is clearly separated from TSO/DSO costs in the bill).

54 'Non-separate' means that the cost is recovered by a charge but is not clearly separated from TSO/DSO costs in the bill.

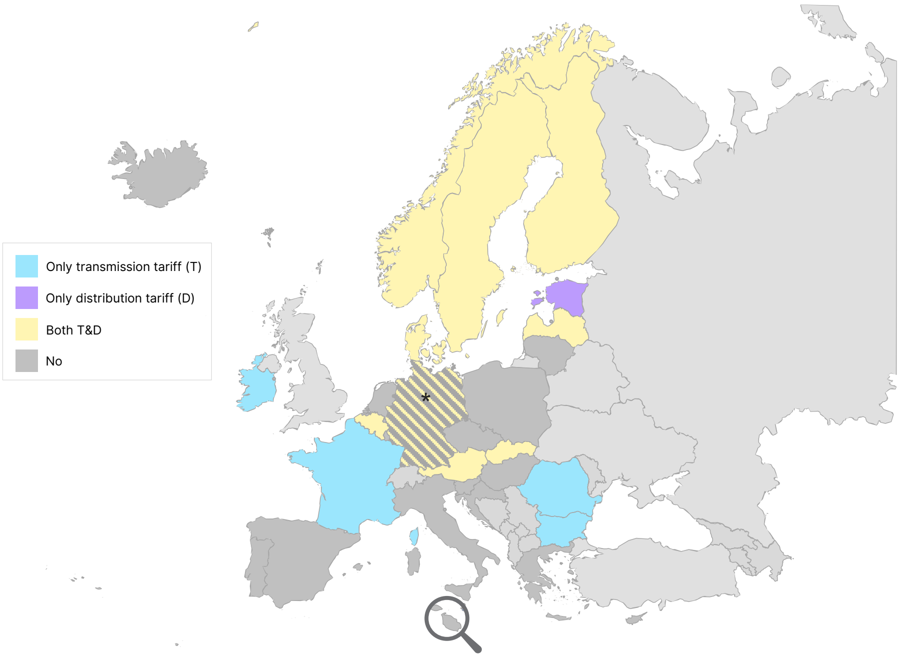
55 Use-of-network charges can be charged to network user for the possibility to inject into and/or withdraw from the grid, regardless of whether injection or withdrawal is actively taking place.

56 In Malta and the Netherlands, the charge is a small lump sum fee for metering, administrative and/or management costs.

57 In France, generation pays only marginal charges at the distribution level.

66 In three countries (DE, NO, SE), producers and bidirectional users[58], are paid for avoided network costs under certain conditions, and thus may have negative share in the cost recovery. In one of these countries (DE), only negative injection charges apply to generation[59], while in the other two countries (NO, SE) the overall payments of producers and bidirectional users can be positive or negative[60].

Figure 5: Application of injection charges in Europe



(*) Germany applies negative injection charges

Note: In the figure, 'No' covers countries with no injection charge or where the injection charge is marginal (i.e. in France at the distribution level, Malta and the Netherlands) or set at zero. In Ireland and Romania, transmission charges for injection apply at the distribution level as well, but there are no distribution charges for injection.

67 Generation at the transmission level pays only transmission costs, but the treatment of generation at the distribution level varies across countries, paying only transmission costs, only distribution costs or both transmission and distribution costs[61].

68 In terms of simple average (excluding zero and marginal shares), the share of generation in the costs collected through use-of-network charges is rather small: 13.7% in transmission and 4.1% in distribution in 2023. If the average value is calculated for all countries (i.e. including those with zero or marginal shares), the average share of generation within use-of-network charges is only 4.4% in transmission and 1.1% in distribution. As shown in Figure 6, regarding transmission costs, out of eight countries which this reported data[62], in two countries (FR, LV) the share of injection charges within transmission costs was below 3%, in three countries (DK, IE, RO) it was ranging between 7% and11% and in three countries (AT, BE, SE) the share was more significant, ranging from 18% up to 38%. Regarding distribution costs, generation had a share of 5% or less in six of the seven countries which reported this data, while Sweden had a higher share (for regional DSOs).

58 Bidirectional users (also referred to as 'prosumers' in this report) are network users who are able to both inject into and withdraw from the grid.

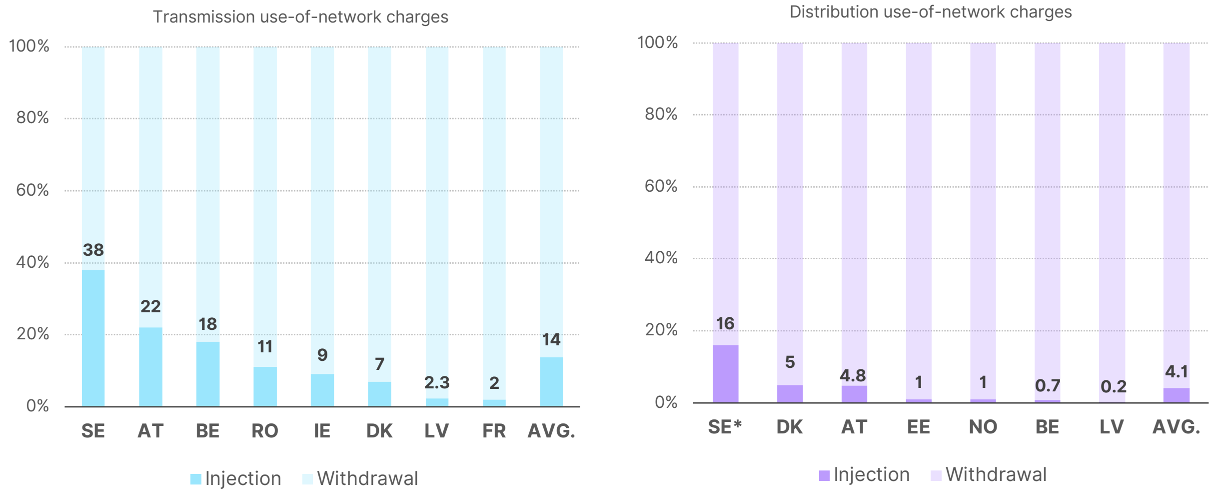
59 In Germany, non-intermittent decentralised generators receive the avoided network charges in return for their system-beneficial impact (i.e. avoided network costs at the upper voltage levels), as the electricity that is injected into the grid by decentralised generators does not have to be drawn from the upstream grids by DSOs. The avoided network charges are paid according to the regular network tariff sheet (for withdrawal) of the upstream voltage level.

60 In Norway, a network tariff element is set based on the marginal loss in each node. The price of the marginal losses is the marginal loss percentages for each node multiplied by the actual spot price for the area in a given hour. In Sweden, distribution-connected producers are paid when a reduction in losses (and thus actual network benefits) is identified but, in contrast to Germany, the producers are also subject to non-negative injection charges.

61 For more information, please refer to Tables 18 and 19 in Annex 1.

62 Norway had an overall negative injection charge in 2023and is therefore not accounted for in the statistics.

Figure 6: Generation/load split within use-of-network charges, 2023



(*) In Sweden, for regional DSOs, the share is approximately 16% (as shown in the figure), while for local DSOs the share of generation is approximately 1%.

Note: The figure includes only those countries with injection charges where a (positive and non-marginal) value was provided. The same applies to the average value.

69 Beyond paying use-of-network charges, generation may contribute to the recovery of transmission and distribution costs through connection charges or other means. As shown in Figure 7, in 10 countries the generation pays deep connection charges (i.e. part of the network reinforcement costs) for both transmission and distribution connections; while in two countries only for connection to the transmission grid and in five countries only for connection to the distribution grid. In several countries generation contributes to transmission costs by paying in kind for losses (i.e. by injecting additional energy without compensation) and/or providing system services with no payment[63]. In eight countries[64], generation does not pay any transmission costs, while in 11 countries[65] it does not pay any distribution costs, neither via injection charges nor deep connection charges.

Figure 7: Transmission and distribution cost burden on generation

		AT	BE	BG	HR	CY	CZ	DK	EE	FI	FR	DE	GR	HU	IS	IE	IT	LV	LT	LU	MT	NL	NO	PL	PT	RO	SK	SI	ES	SE
Transmission	Use-of-network charges	●	●	●				●		●	●					●		●			N/A	○	●			●	●			●
Transmission	Deep connection charges				●			●	●					●				●	●		N/A		●		●	●		●	●	●
Distribution	Use-of-network charges	●	●					●	●	●	○							●			○	○	●				●			●
Distribution	Deep connection charges		●		●			●	●	●			●	●				●			●		●		●	●	●		●	●

Note: In Denmark semi-deep connection charges apply at the transmission level. The 'grey-marked dot' means the injection charges are negligible. In Ireland and Romania, transmission charges for injection apply at the distribution level as well, but there are no distribution charges for injection. For other means of cost recovery reported, please refer to paragraphs 58-60 of this report.

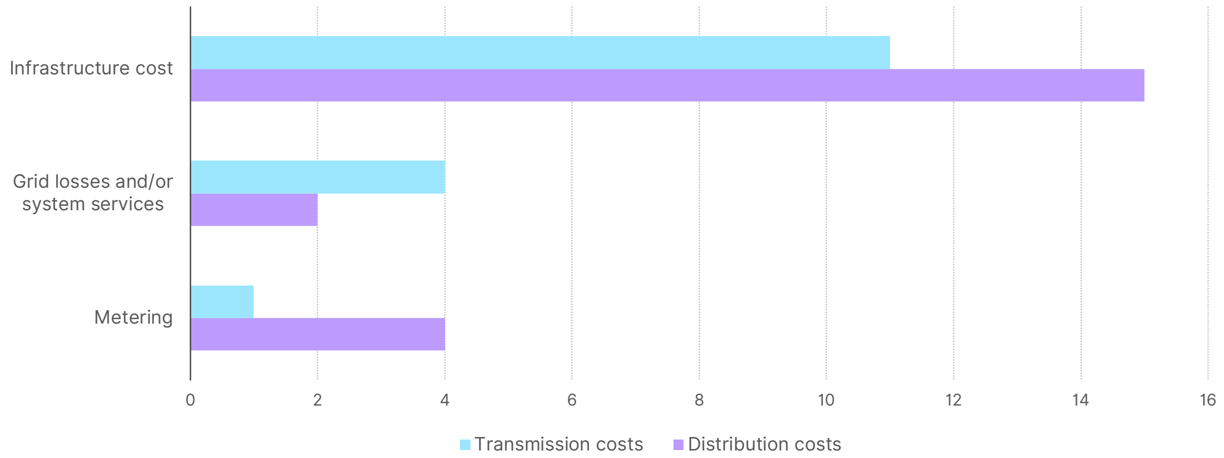
63 See paragraphs 58-59 of this report.

64 CY, CZ, DE, GR, IS, IT, LU, PL.

65 BG, CY, CZ, DE, IS, IE, IT, LT, LU, PL, SI.

70 Countries apply different approaches with regard to which cost categories are recovered from generation as shown in Figure 8. generation most frequently contributes to infrastructure costs[66] and less commonly to grid losses, system services, metering and/or management costs[67]. Deep connection charges typically recover infrastructure costs, while injection charges are slightly more frequently related to payment for losses, system services and metering. In some countries, the injection charges are used to recover multiple cost categories or to recover part of the TSO and/or DSO costs without specifying the cost category[68]. None of the countries recovers non-TSO/non-DSO costs using injection charges.

Figure 8: Number of countries recovering costs partially from generation using network charges



Note: The figure accounts for any transmission or distribution cost recovery from generation via use-of-network charges and deep connection charges. Infrastructure costs include costs of building, upgrading, maintaining and/or operating infrastructure. In seven countries the injection charge covers part of the TSO/DSO costs without link to a specific cost category.

71 NRAs typically motivate the use of charges for generation by referring to the principle of cost-reflectivity. Not using injection charges for generation is often argued by NRAs with concerns regarding cross-border competition, the harm of previous investment decisions, a distortion between new and existing generation, disincentives for generators, difficulties in calculating relevant shares of costs or legal restrictions[69].

72 ACER notes that only four countries (BE, FR, LV, NO) reported that a study was carried out to assess the cost impacts (including the additional or avoided costs of the system) triggered by producers and bidirectional users before the introduction, change or phase-out of injection charges.

73 Probably in relation to this fact, only some NRAs reported a breakdown of the costs corresponding to injection and those corresponding to withdrawal and set the charges accordingly, which can be a rather complex process. In several instances, the split is administrative and achieved by setting the injection charges using caps or by benchmarking or sharing the costs based on fixed percentages[70].

74 None of the NRAs identified any remarkable competitive disadvantage for the producers within their countries vis-à-vis producers of other countries due to the applied injection charges, which is often explained by the marginal impact of injection charges on electricity prices. Similarly, none of the NRAs reported any distortion in competition within their countries, often referring to the fact that the same injection charges are applied to all producers.

66 In form of injection charges and/or deep connection charges, generation contributes to both transmission and distribution infrastructure costs in HR, EE, HU, LV, NO, PT, RO, ES and SE. Generation contributes only to distribution infrastructure costs in BE, DK, FI, GR, MT and SK. Generation contributes only to transmission infrastructure costs in LT and SI.

67 AT, BE, DK, EE, FR, MT, NL, RO. (In MT and NL only metering/management costs are recovered).

68 BG, DK, EE, FI, LV, NO, SE.

69 The application of injection charges is prohibited by national law in DE, PL and SI.

70 For more details, please refer to Table 9, Table 18 and Table 19 in Annex 1.

75 Commission Regulation (EU) No 838/2010 stipulates that the variations in transmission charges faced by producers across the EU should not undermine the internal market and should be kept within a range that helps to ensure that the benefits of harmonisation are realised.

76 The legal range of annual average transmission charges paid by producers is set by part B of Annex to the Commission Regulation[71]. The range, which is not identical for all countries, applies only to the G-charge, which does not include the charges paid by producers for physical assets required for connection to the system or the upgrade of the connection, the charges paid by producers in relation to ancillary services and the specific system loss charges paid by producers. For these costs, NRAs can set any cost-reflective charge, as there is no such ceiling set by EU law.

77 ACER shall monitor the appropriateness of the range of the G-charge in each Member State. The results of ACER's most recent monitoring activity are provided in Annex 3 to this report.

ACER considerations

78 Increasing interconnection and integration of the European electricity market implies an increasing risk that non-cost-reflective injection charges could distort competition and investment decisions in the internal market.

79 In order to ensure cost-reflectivity and avoid market distortions, the cost caused by a network user should be properly reflected in their charges. All network users should contribute to network costs unless the non-payment of network charges is justified by system-beneficial impacts or the corresponding costs are already paid by these users through other means.

80 ACER considers that, regardless of whether (and to what extent) costs are pass-through from one network user to another (and to what extent) the initial allocation of the TSO/DSO costs on network users can improve overall system efficiency, particularly if there is a generation scarcity or surplus in some part of the network and the injection charges provide adequate economic signals to reflect this[72]. In contrast, a lack of injection charges can result in unintended distortions in decisions around generation investments because the true cost of using the network is not adequately signalled to them.

81 While the ceilings on G-charges set by the Commission regulation limit the potential negative impacts arising from approaches to injection charges differing between countries, they can create a barrier for cost reflectivity and do so in practice in some Member States[73]. Therefore, ACER considers it unnecessary to propose restrictions on the level of G-charges and recalls its recommendation to the European Commission to remove them[74].

82 When setting network charges, consideration of the overall cost burden on a network user is essential. Deep connection charges, use-of-network charges and other means of recovering transmission and distribution costs (e.g. when costs are borne directly by generation or consumers) may aim to recover the same cost categories and, if they are set in isolation or without due regard to each other, they could lead to unjustified double-charging.

83 ACER understands that a network user paying separate charges for injection and withdrawal does not necessarily represent unjustified double-charging. Similarly, applying only an injection charge or only a withdrawal charge to a network user who both injects into and withdraws from the grid, does not necessarily ensure non-discrimination across network users, even if applied to all users under the same terms.

71 Decision of the EEA Joint Committee No 7/2011 sets a legal range of annual average transmission charges paid by producers in Norway.

72 The signals may be either long-term cost signals regarding the siting of generators or short-term signals reflecting congestion.

73 For example, this barrier was reported in Denmark.

74 In its Opinion No 09/2014 on the appropriate range of transmission charges paid by electricity producers (April 2014, pp. 2-3), ACER proposed not having a ceiling for cost-reflective power-based and lump sum G-charges, while suggesting that energy-based injection charges should not be used to recover infrastructure costs.

84 In the case of bidirectional network use, a cost-offsetting effect may take place related to the associated costs of network use (i.e. while using the network in one direction may justify current or future network investments, using the network in the other direction may result in avoided network costs, which should be reflected in the network charges).

85 Non-TSO/non-DSO costs if not related to network use can distort network tariff signals and/or lead to distributional effects between different groups of network users. ACER underlines that pursuant to the EU electricity market regulation, network charges shall not include unrelated policy costs[75].

Recommendations

86 Injection should not be excluded from transmission and distribution cost recovery by default.

87 The advantages and disadvantages of applying injection charges should be (re)assessed and the decision on whether applying them or not should be duly justified by relevant studies focusing on efficiency gains and potential distortions to the internal market.

88 When setting network charges, all network-related costs borne by the concerned network users should be considered, regardless whether recovered via network charges or other means.

89 If a network user withdraws from and injects into the grid, both network uses should be considered in tariff setting, accounting for potential cost-offsetting and overall cost-impact to the network.

5.2. Tariff basis

Main findings

Tariff basis for different cost categories:

90 Network charges across the EU predominantly make use of the following bases[76]:

- energy-based charges (also referred to as ‘volumetric charges’), which are charges payable on every unit of energy withdrawn/consumed from and/or produced/injected into the grid (e.g. EUR/MWh);
- power-based injection charges (also referred to as ‘capacity charges’), which are charges payable on the contracted/connected power capacity, on the yearly or multi-year peak demand/output (‘non-coincident peak’) or on the demand/output under peak conditions (‘coincident peak’) (e.g. EUR/MW);
- lump sum charges, which are charges that do not vary with the user’s behaviour and may be differentiated based on size, profile or technical characteristics (e.g. EUR/year)[77].

91 The selection of the tariff basis of the different cost categories shows some similarities across countries, but there are several deviations from the prevailing practices. In general, power-based charges or mixed tariff bases are more frequent for the recovery of costs of building, upgrading and maintaining infrastructure, while energy-based charges are more common for the recovery of losses and system services. The use-of-network charge components often simply recover a part of the overall costs, without specifying which basis is applied to which costs. More specifically,

75 Cf. Article 18(1) of Regulation (EU) 2019/943.

76 In addition, reactive energy injections and withdrawals may be used for setting reactive energy charges.

77 According to ACER Opinion No 09/2014, lump sum charges are fixed at the start of a given charging period and do not depend on capacity connected, on yearly or multi-year peak output or on output under peak conditions, unless these are taken into account in the form of an average over a period of at least five years. Moreover, lump sum charges may take into account the average annual load factor or the average of other output-related factors, as long as these averages are calculated over a minimum of five years.

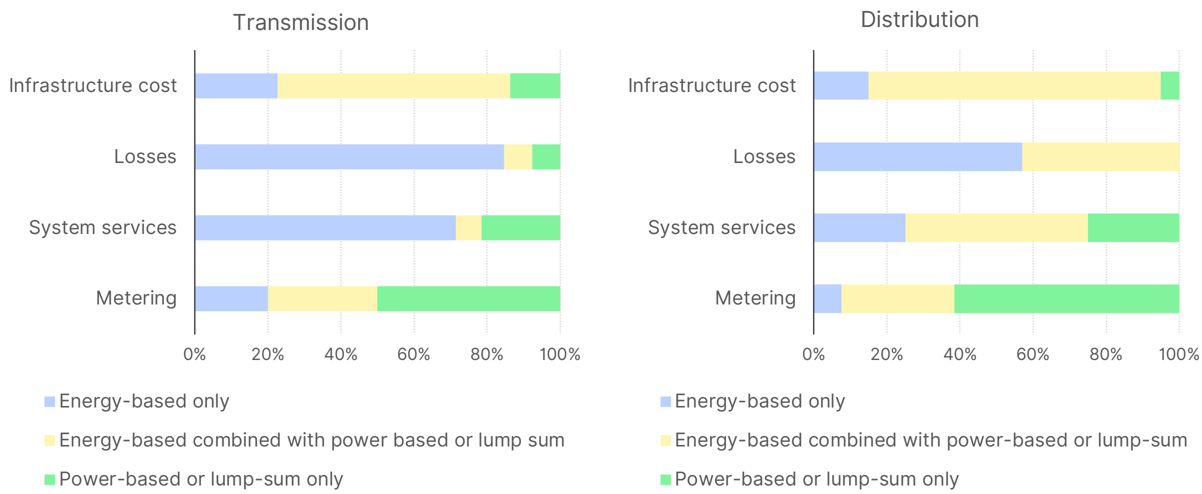
as shown in Figure 9, the following findings apply where cost drivers are allocated to specific cost categories:

- The **cost of infrastructure**[78] (CAPEX and OPEX) is recovered mostly through mixed tariff bases that often have a major energy-based component but also include a power-based part. However, some countries use only energy-based or only power-based charges.

- In the vast majority of countries costs of **losses and system services** are primarily recovered through energy-based charges. In the remaining countries these costs are primarily recovered through a combination of energy- and power-based charges.

- The **metering costs** are mainly unrelated to the injected or withdrawn volume of energy or power. They are either recovered through the same energy- and/or power-based tariff element as other network costs or recovered using lump sum charges.

Figure 9: Tariff basis for different cost categories (both injection and withdrawal charges)



Note: The figures consider both injection and withdrawal charges. No data were provided for several countries[79].

Tariff basis for withdrawal charges versus injection charges:

92 In most countries, the transmission and distribution tariffs for withdrawal have a combined tariff basis (22 out of 28 and 27 out of 29 respectively, see Figure 10). For transmission tariffs, five countries (CY, DK, FI, HU, RO) apply exclusively (or almost exclusively) an energy-based component, while two countries (CY, RO) do so for distribution tariffs. One country (NL) applies a fully power-based or lump sum charge, but only for transmission tariffs.

93 Injection charges in most countries are either energy-based or power-based, which seems correlated with the fact that, in most countries the injection charges recover only a specific cost category (e.g. network reinforcement costs or costs of losses and/or system services). In the remaining countries, the injection charges are a mix of energy-based and power-based or lump sum charges.

78 The cost of infrastructure includes the costs of building, upgrading, maintaining and operating the transmission or distribution network.

79 The tariff basis for infrastructure costs was specified in 21 countries at the transmission level and 19 countries at the distribution level. The tariff basis for losses was specified in 13 countries at the transmission level and 14 countries at the distribution level and the tariff basis for system services was specified in 14 countries at the transmission level and 8 countries at the distribution level. The tariff basis for metering was specified in 10 countries at the transmission level and 13 countries at the distribution level. Where the injection charge was power-based and the withdrawal charge was energy-based for a cost category, the country was added to the combined tariff basis category.

Figure 10: Tariff basis for injection and withdrawal

	Transmission			Distribution		
	Energy-based	Power-based / lump sum	Combined	Energy-based	Power-based / lump sum	Combined
Injection	6: AT, BE, BG, DK, FR, RO	4: IE, LV[80], NL[(a)], SK	3: FI, NO, SE	1: BE[81]	6: FR[(a)], LV, MT[(a)], NL [(a)], SK, SE	7: AT, BE[82], DK, EE, FI, DE[83], NO[84]
Withdrawal	5: CY, DK, FI, HU[85], RO	1: NL	22	2: CY, RO		27

[(a)] Country applies only marginal injection charges.

Note: 'Combined' means that the energy-based tariff or tariff element is combined with a power-based or lump sum tariff or tariff element. Countries where the injection charge is set at zero (e.g. Croatia, where it is 0 EUR/kW) are not covered in the figure.

Variation of tariff basis with voltage, time and location:

94 Withdrawal charges are subject to variation in the vast majority of countries (see Figure 11). The main factors for variation are the voltage level[86] and the integration of a time element into the tariff[87], with both being more frequent for distribution than for transmission[88]. On the contrary, variation by location - unrelated to the location of a specific DSO to which network the network user connects to - is applied in six countries (one in both transmission and distribution).

95 Injection charges are less often subject to variation. In a number of countries, uniform injection charges apply. Injection charges sometimes vary across voltage levels[89] and/or based on location[90]. The main reason for this variation is to provide economic signals for efficient siting of energy generators. Injection charge variation based on the ToU was reported in only two countries[91].

96 For more information on the application of ToU signals and locational signals please refer to Section 6.6 and Section 5.3, respectively).

80 LV: The power-based charge (EUR/MW) is calculated by using the 0.5 EUR/MWh cap set by EU law.

81 BE: In Flanders region.

82 BE: In Wallonia region.

83 DE: Negative injection charges are applied.

84 NO: Both an energy-based injection charge and a lump sum charge are applied based on 10-year historical average of production.

85 HU: The power-based charge share is about 1-2%.

86 Variation per voltage level may occur, for example, due to cost cascading within transmission or within distribution or due to different tariffication rules (e.g. tariff basis). Variation per voltage level for withdrawal charges was reported for 10 countries (AT, BE, HR, CY, EE, FR, HU, IT, NL, PT) in transmission and all almost countries (except Malta) in distribution. For Iceland no data was provided.

87 In this report variation does not account for differentiation based on other features of the network users (e.g. technology, size, commissioning date).

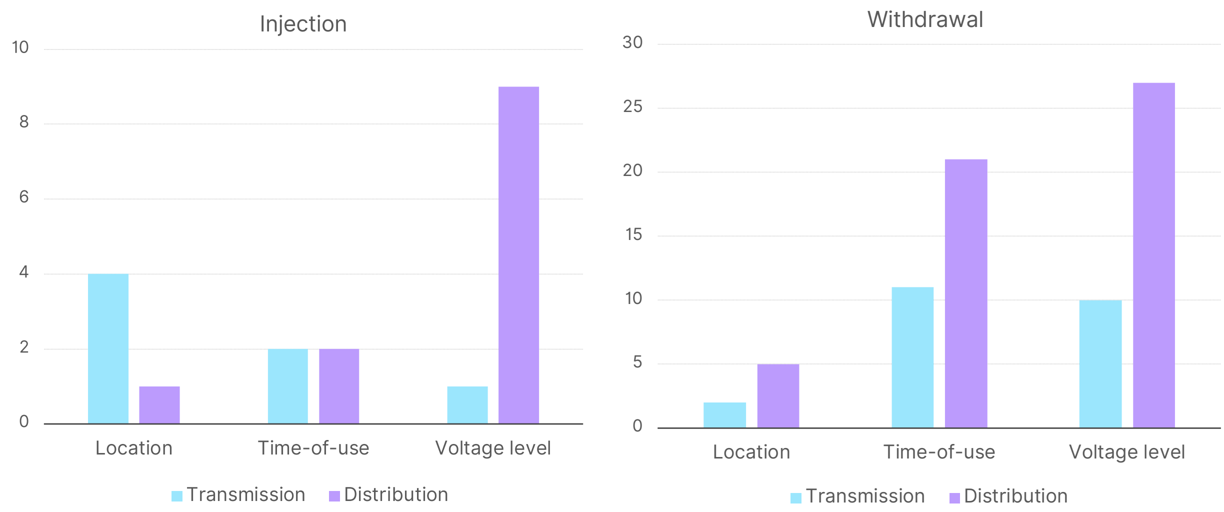
88 The less frequent variation of network charges at the transmission level than at the distribution level may partially be explained by transmission networks typically comprising fewer sub-networks than distribution grids. In some countries, while the tariff does not vary across voltage levels, the voltage level can still play a role – that is, an exemption can apply to network users under certain voltage levels.

89 Variation per voltage level for injection charges was reported for one country (NL) in transmission. It was reported for nine countries (AT, BE (only for Wallonia region), DK, EE, FR, DE (for negative injection charge), NL, SK, SE) in distribution.

90 In four countries locational signals embedded in the injection charges applied at the transmission level (one of them applies locational signal for the injection charges at the distribution level as well).

91 Norway applies no static ToU tariff, but does apply marginal loss tariffication. In Sweden, there is no static ToU tariff in transmission, but there is a time-differentiated tariff component that varies with actual market prices per bidding zone. In distribution, some DSOs have tariff elements that are subject to similar or more static ToU differentiation.

Figure 11: Number of countries with variation of the tariff basis for injection and withdrawal



Share of different bases in cost recovery:

97 Figure 12 shows the split of the total transmission and distribution use-of-network charges based on how much is recovered by each of the charging variables. Data is mainly provided for 2023.

98 For transmission, the weights of the energy- and power-based charges are rather balanced. In terms of the simple average (i.e. not weighted by the revenues in each country)[92], energy-based components and power-based components account for about 54% and 46% respectively. In 10 countries, the power-based charge has a larger share. The lump sum charges play a relatively small role: on average less than 0.3%.

99 For distribution, the weight of energy-based charges is significantly higher than the weight of power-based charges in most countries. On average, energy-based components account for 60% of the network charges, while power-based components account for 33%, albeit in eight countries[93] ower-based charges have a more significant weight and represent more than 30% of the tariff basis. Lump sum charges represent a small (on average, 7%) share of the tariff basis in all 12 countries where they are applied, except in one country (SE) where it represents a relatively high share of the tariff base[94].

92 The average is based on data for 15 countries.

93 AT, CZ, GR, IT, LV, PT, SI, SE.

94 SE: The share of lump sum charges is 39%.

Figure 12: Share of tariff bases in transmission and distribution use-of-network charges

Note: The share of energy-based charges is calculated as the sum of transmission (or distribution) use-of-network charges via energy-based charges (e.g. EUR/MWh) divided by the sum of the transmission (or distribution) use-of network charges (see the list of charges in Figure 1). The calculation took both injection and withdrawal charges into account.

Approaches to power-based charges:

100 Power-based charges (defined either as EUR/kVA or EUR/kW) are designed in various ways (see Figure 13). They can be set using the installed (connected) capacity (which may not be increased without upgrading the connection), contracted or subscribed power capacity (which may be periodically increased or decreased upon request to adapt to network users' needs) or measured (actual) power-based on maximum or average values.

101 The vast majority of countries (27 out of 29) apply power-based charges to at least some network users; either based on installed capacity (2 countries)[95], based on contracted or subscribed capacity (16 countries) and/or based on measured power (21 countries, either measuring power input directly or measuring energy and converting this into a power-based charge). ACER notes that the two approaches to power-based charges are fairly balanced in both transmission and distribution, and several countries apply both forms (either as a combined charge for network users or varying the approach depending on the network user). Power-based charges are applied neither in transmission nor in distribution in two countries (CY, RO). In one country (HU) power-based charges are applied only in transmission; in two countries (DK, MT) power-based charges are applied only in distribution[96].

95 Finland and Latvia apply charges based on installed (connected) capacity for injection in transmission.

96 In Malta, there is no transmission network.

Figure 13: Power-based network charges in Europe

		AT	BE	BG	HR	CY	CZ	DK	EE	FI	FR	DE	GR	HU	IS	IE	IT	LV	LT	LU	MT	NL	NO	PL	PT	RO	SK	SI	ES	SE
Transmission	Contracted capacity		●	●	●		●		●	● (grey)	●		●			●	●	● (grey)	●		N/A	●		●			●	●		●
Transmission	Measured power	●	●	●	●							●	●		●					●	N/A	●	●	●	●		●	●	●	
Distribution	Contracted capacity		●		●		●		●		●		●	●	●	●	●		●			●		●	●			●	●	●
Distribution	Measured power	●	●	●	●			●	●	●		●	●		●		●	●		●	●	●	●		●		●	●	●	●

Note: In Belgium's Brussels region a lump sum charge applies which is based on an installed capacity threshold of ≤13kVA. The 'grey-marked dot' means that the country applies installed (connected) capacity-based charges. No capacity/power-based charges apply in four countries (CY, DK, HU, RO) at the transmission level and in two countries (CY, RO) at the distribution level. Malta has no transmission network.

Contracted (subscribed) capacity-based charges

102 As shown in Figure 14, for charges based on contracted (subscribed) capacity, the most common period to adapt the contracted capacity is one year in both transmission and distribution. However, the contracted terms in several countries can be changed every month, while in other countries (in particular in distribution) the terms are not predefined and can be changed upon the user's request.

103 In some countries, the network users can sign up for different capacities for different time intervals (e.g. 'peak/off-peak', or 'seasonal') under the same subscription. However, this practice is rather uncommon, applying in only two countries (FR, ES) in transmission and four countries (FR, GR, PL, ES) in distribution.

Figure 14: Capacity-based charges: period for subscription (frequency of potential changes)

	Transmission	Distribution
Yearly or once per year	7: BE, CZ[(a)], LT, NL, PL[(b)], ES, SE	6: CZ[(a)], FR, HU, NL, ES, SE
Twice a year	1: EE	0
Monthly	4: CZ[(a)], FR, PL[(b)], SI	3: BE, CZ[(a)], SI
Not defined / any time	2: HR, IE	6: HR, EE, IT, LT, PL, PT

[(a)] *In Czechia both yearly and monthly subscriptions apply depending on the network user.*
[(b)] *In Poland the subscription period is yearly for DSOs and monthly for end-users at the transmission level.*

Note: The figure shows how often the users can change their subscription level. No data were provided for several countries.

104 Where contracted (or subscribed) capacity applies as a basis, it needs to be addressed what happens if the network user exceeds their contracted capacity (see Figure 15). There are different practices across Europe: (a) in some countries, excess leads to disconnection; (b) in some countries, the capacity subscription is altered (retrospectively or for the future); and (c) in some countries, excess capacity charges (or penalties) apply. These excess capacity charges are, in practice, a result of measuring power input or output and comparing it with the contracted amount; therefore, they can be considered hybrid power-based charges, mixing measured and unmeasured elements.

105 The unit price of the charges based on contracted capacity typically varies across voltage levels and sometimes also varies based on the ToU, while locational differentiation was not reported, except for instances of different ToU schedules based on geographical location.

106 In transmission, the charges based on contracted capacity typically apply to all network users, while in distribution they are often limited to some network user groups[97]; for example, they may apply to smaller users, while larger users are charged based on measured power or they may apply only to larger users, as smaller users are charged using energy-based or lump sum charges)[98].

Figure 15: Capacity-based charges: consequences of exceeding the contracted capacity

	Transmission	Distribution
Disconnection / cost of fuse replacement	SI	PT, SI, ES[a]
Increase of subscription	HR[b], NL[c]	HR[b], NL[c]
Charge for excess using energy-based charges	IE, LT, PL, SE	HU, PL
Charge for excess using power-based charges	EE, ES	EE, HU, ES[a]
Penalty (not defined)	BE, CZ, FR, PL	BE (Flanders region), FR, CZ, LT

[a] Spain applies multiple consequences for excess use (household consumers are, in most instances, temporally disconnected).
[b] In Croatia the increase of subscription applies for the future.
[c] In the Netherlands, the increase of subscription applies retrospectively.

Note: No information was provided for four countries (BG, GR, IT, SK) at the transmission level and four countries (GR, IS, IE, SK) at the distribution level.

107 Finally, ACER notes that charges based on contracted capacity are a long-standing tradition: in most countries that apply them, they were introduced more than one or two decades ago[99]. Recent introductions or revisions were reported in five countries[100], while application or extension to additional users is under consideration in Denmark (at the transmission level) and Romania.

Measured power-based charges:

108 As shown in Figure 16, charges based on measured power are also designed in various ways. In most countries, they are based on individual peak within the year or month or an average of a number of the highest individual inputs/outputs. In the remaining countries, they are explicitly linked to system peaks, either by measuring the individual peak input/output (kW) during the peak periods in certain billing period or by measuring the energy withdrawal (kWh) during the peak period and dividing it by the total peak hours to obtain an average power value.

97 In transmission, eight countries apply these charges to all voltage levels and network users, while three countries apply them only for high voltage or only for medium voltage. In distribution, 3 countries apply these charges to all voltage levels and users, while 11 countries base application on voltage level or connection capacity. In several countries, no information was provided on the users to whom these charges are applied.

98 In one country (GR) the differentiation is based on metering regimes.

99 Five countries have applied these charges in transmission for more than 20 years.

100 At the transmission and distribution levels: HR (2022), ES (2021). Only at the transmission level: EE (2024), FR (2021). Only at the distribution level: BE (Flanders region) (2023).

109 In most instances for which such information was reported[101], the meters measure the peak inputs/outputs at 15-minute intervals. However, ACER also observes some instances where only hourly intervals are available[102].

110 In countries where power-based charges are linked to peak hours, the classification of peak hours follows from the ToU schedule applicable to energy (and often has seasonal variation). The power-based charges set based on individual peaks can also be designed to include time-differentiation. In one country (BE) the tariff is different between summer and winter season, while in other countries ToU power-based charges apply to some users (IS, NL, SE (in some DSO areas)).

111 ACER notes that the application of charges based on measured power are often applied above certain voltages or contracted power levels (i.e. typically excluding small households). ACER notes that in a number of countries[103], the network users subject to these charges have access to information on their power use in (close to) real time, while in other countries this information is only available to some users (BE, HR) or not available to the users (DK, EE, PL).

112 Finally, ACER notes that charges based on measured power are a long-standing tradition: in most countries that apply them, they were introduced more than a decade ago. Recent introductions or revisions (over the past five years) were reported in five countries[104], while in another two countries (DK, RO) application is planned or under consideration.

Figure 16: Measured power-based charges: setting the charge

Basis	Transmission	Distribution
Individual peak (yearly)	BE[(a)], DE[(a)], LU, PL[(b)], PT[(a)]	DE[(a)], LU, MT, PT[(a)]
Individual peak or average of multiple individual peaks (monthly)	AT, BE[(a)], DE[(a)], NL[(c)105], SI	AT, BE, EE, DE[(a)], IT, NL[(c)], SI, SE[106]
Individual peak during system peak hours	HR[107]	HR[107]
Energy withdrawal during peak hours converted into power (kWh/h)	GR, NO, PT[(a)]	DK[108], NO, PT[(a)]

(a) The country applies multiple bases.
(b) In Poland the basis is historical peak between July of year n-2 and July of year n-1.
(c) In the Netherlands for some users the basis is weekly peak.

Note: For several countries no information was provided.

101 In transmission: HR, DE, GR, LU, NL, PT, ES (i.e. 7 out of 9 countries); in distribution: BE, HR, DE, LU, NL, PT, ES (i.e. 7 out of 9 countries).

102 For example, in EE and IS.

103 Eight countries reported that the information on power use in (close to) real time is available at the transmission and distribution levels (HR, DE, IS, LU, NL, PT, SI, ES) and in additional two countries at the distribution level (BE (Wallonia region), MT). However, several countries did not report on it.

104 At the transmission and distribution levels: BE (2024), ES (2021). Only at the distribution level: DK (2025), PT (2024), SI (2024).

105 NL: In the Netherlands for some users the basis is weekly peak.

106 SE: The basis varies across DSOs, but is often an average of a number of peak hours per month.

107 HR: The power-based charge has two components: one is based on the individual maximum withdrawal during the peak and the other component (currently set at zero) is based on the contracted power, which has to be changed in case of excess.

108 DK: Power-based withdrawal charges have been in place since March 2022, but only for consumers on 10-60 kV. The effect/power unit is calculated by taking the average consumption of the 10 hours with the highest effect in the last 12 months. Every month, the effect unit is adjusted according to the average of the last 12 months. The power-based charges only cover 25% of the cost that high voltage DSO-connected consumers give rise to, the other 75% is covered by a time differentiated energy charges.

Stakeholders' views

113 Stakeholders bring arguments both for and against moving from energy-based charges to power-based charges. Most of the stakeholders agree that power-based charges (or network charges with a high share of power-based components) are the best or the more suitable tool for the recovery of cost related to network development (CAPEX), being more cost-reflective than energy-based charges. Other costs, such as energy losses, are deemed by many as better recovered using energy-based charges.

114 The solution proposed by most stakeholders is a mixed tariff based on fixed lump-sum charges, power-based and energy-based charges. Additionally, some stakeholders argue that the mix of power and energy charges might differ between voltage levels or network users. The mixed tariff bases combined with ToU signals according to most stakeholders is the best tool to enhance cost-reflectiveness and make the charge more flexible.

115 Nonetheless, some stakeholders warn that complex tariff structures might harm small consumers that are not able to change their behaviours or claim that power-based solutions might be more suitable for areas with special grid requirements, like offshore wind infrastructures or for scarce capacity areas.

ACER considerations

116 The structure of network charges (power, energy, lump sum or a mix of them), should seek to reflect the cost drivers underlying system operators' regulated activities. Different cost categories show correlation with different cost drivers. In order to set cost-reflective network charges, NRAs should identify the cost drivers for the relevant cost categories and allocate these costs to the tariff structure accordingly[109]. However, the simplicity of the tariff structure has to be taken into account as well. The objectives of cost reflectivity and simplicity have to be balanced.

117 The determination of the most suitable cost drivers, and their temporal and spatial variation, requires continuously monitoring sufficiently granular data on network development (e.g. need for grid reinforcement) and network utilisation (e.g. energy flows, load/injection profiles at network nodes, grid utilisation rate, location and time of frequent congestion, number of users) in both transmission and distribution.

118 In ACER's view, flat energy-based tariffs are no longer adequate for today's power systems, characterised by a vast amount of self-generation, as they unduly shift the cost burden across network user groups, in particular in regimes that apply net metering over longer time intervals and/or where prosumers still heavily rely on the grid during peak hours[110]. Furthermore, with a high share of self-generation, energy consumption volumes are harder to predict accurately, increasing the difficulty of matching allowed and actual revenues.

119 When setting the adequate charging basis for network users, the system peak is particularly important, as large parts of the electricity networks are designed to accommodate the highest collective power demand of all network users[111]. Therefore, power-based charges that consider network use during system peak are appropriate to allocate costs correlated with the system peak, while providing networks users with a signal to change how they use the network. Under certain conditions, other indicators - such as contracted capacity or maximum capacity - may also be used as a proxy[112]. However, the relevant peak may not necessarily be related to the demand

109 Cost drivers, among others, can include energy flow, power load, and number of meters. The cost categories proposed by ACER for this purpose are described in Section 6.2.

110 Prosumers are, in general, no less dependent on reliable access to the grid than traditional consumers because they still use the grid, especially at peak hours. The distortion is particularly pertinent with net metering and should be avoided, as it shifts undue costs to other network users. Furthermore, if the energy-based charge significantly exceeds the short-term variable costs, it sends misleading signals to network users, as a small reduction in consumption translates into large cost savings for network users, while there is no significant cost saving for the system.

111 The system peak often determines the size (capacity) of the grid, which is not equal to the sum of the individual peaks.

112 For example, if contracted capacity or maximum capacity is measured separately for the different time periods, and higher network charges are applicable to the grid's peak periods, this also incentivises grid-friendly behaviour.

side. In some areas, the injection peak can be the basis for grid dimensioning (e.g. a high ratio in peak in wind or solar injection in comparison to maximum withdrawal by network users).

120 Power-based network tariffs, especially when calculated for actual maximum power during peak load periods, may be criticised for having a negative impact on some tariff principles, such as simplicity, predictability and transparency. However, ACER considers that while the preference for energy-based charges could be explained by these concerns in the past[113], this barrier has become less significant with the roll-out of smart meters and the possibility of some degree of automation in home appliances[114].

121 Power-based network tariffs may also be criticised for hindering demand response or encouraging consumption at times of system stress, resulting in increased costs for all by driving excessive investment in underutilised grid infrastructure. This may be the case, for example, where the network tariff is charged in respect of the individual peak of the network user, which is not coincident with the system peak, while the system peak drives the costs. However, as discussed above, network tariffs should be cost-reflective and account for varying utilisation levels and congestion of the grid.

122 If adequately designed, use-of-network tariffs (including power-based ones) could serve as a complementary instrument for demand response[115] and reinforce the incentives for rational behavior. Therefore, moving to increasingly power-based transmission and distribution tariffs, in a context of rising network investment needs, is appropriate. ACER acknowledges that, conceptually, time-differentiated energy-based tariffs with sufficient granularity may achieve similar cost reflectivity as power-based tariffs.

123 In general, ACER notes that ToU periods need to be carefully set for both power- and energy-based charges. ACER calls for caution when averaging excessive number of records of power/energy use measurements over a long observation horizon, as this might distort the precision of the signals (i.e. capture of the network peak).

124 Finally, ACER stresses that network costs are not solely determined by the system peak. The energy injected or withdrawn is also a variable and correlates with losses and system services costs, to which energy-based charges may fit better. Some costs are likely to correlate with neither capacity nor energy, but rather with the number of network users or meters (e.g. billing, metering or administrative costs). In principle, these costs should be recovered via lump sum charges to avoid distortions.

113 For example, because there was the lack of knowledge and visibility of the individual peak load, given the absence of adequate meters.

114 The status of smart electricity meter deployment among households at the end of 2023 is provided in ACER-CEER Market monitoring report - Energy retail – Active consumer participation is key to driving the energy transition: how can it happen? (September 2024, pp. 21-22). In most countries the roll-out rate is above 80%.

115 Energy efficiency and demand response can be incentivised through a wide range of instruments.

Recommendations

125 NRAs should identify the key drivers of infrastructure costs in their systems and set charges that correlate with such cost drivers. From a cost-reflectivity perspective,

- power-based charges fit best with costs of building, upgrading and maintaining the network[116];
- energy-based charges fit best with costs of losses and system services;
- lump sum charges, which show correlation with neither power nor energy usage, fit best with costs which do not vary with the user's behaviour (injection and/or withdrawal profiles).

126 In a context of rising grid capacity needs, NRAs should correlate cost allocation with network peak usage, by

- combining an adequate weight of power-based charges in network tariffs, with adequate signals for network users to adapt their injections or withdrawals[117];
- avoiding using flat-rate energy-based charges, i.e. those that do not include any time element correlated to peak network usage.

127 Concerning power-based charges, NRAs should

- evaluate different approaches to power-based charging to identify those that best contribute to overall system efficiency;
- apply them to all voltage levels, unless studies show that it would not be cost effective.

116 Conceptually, time-differentiated tariffs with sufficient granularity may achieve similar cost reflectivity as power-based tariffs.

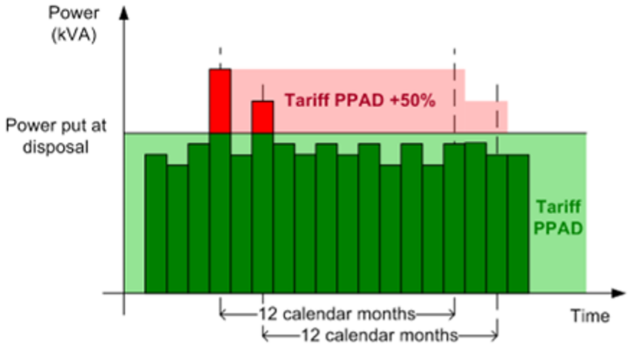
117 For the purpose of this recommendation time-differentiated charges focused on energy withdrawals in a selected number of peak hours are deemed equivalent to 'power-based'.

National practices

Belgium:
Time-of-use variation of measured power-based charges to better reflect system conditions

Description of practice:

For the management and development of the transmission grid, power-based charges are set based on both contractual power (PPAD) and measured power. The measured power-based element is set on monthly peak and yearly peak (kW) and applies for the users at the 30-380 kV voltage levels. The annual peak is measured from November to March, during the 17:00-20:00 period from Monday to Friday (except public holidays). The monthly peak is applied the whole year, except during summer off-peak periods, defined as the weekends from 10:00 to 19:00, between April and September.



Source: CREG

Challenge to address / reason for introduction:

The tariff structure aims to recover TSO costs while sending the right signals to network users to foster efficient use and operation of the grids. The main challenge is finding equilibrium between TSO cost recovery, cost-reflectivity, simplicity, non-discrimination, efficient use of the network and efficient imbalance price signals.

The power-based charge was introduced in 2012, while the ToU signal for yearly peak tariff was introduced in 2016, with ToU element to minimise the synchronous peak, which triggers investments. The exact occurrence of the synchronous peak cannot be known in advance, but statistics offer a high probability of occurrence. Empirical analysis showed how on a monthly basis the highest load appears only between November and March (see Figure 1). On a daily basis, it appears only during weekdays (see Figure 2), while on an hourly basis it is mostly between 17:00 and 20:00 (see Figure 3).

300qh			
2019	2020	2021	2022
80,0%	54,7%	51,3%	89,7%
5,3%	9,0%	36,0%	6,7%
0,0%	0,0%	0,0%	0,0%
0,0%	0,0%	0,0%	0,0%
0,0%	0,0%	0,0%	0,0%
0,0%	0,0%	0,0%	0,0%
0,0%	0,0%	0,0%	0,0%
0,0%	0,0%	0,0%	0,0%
0,0%	0,0%	0,0%	0,0%
0,0%	0,0%	0,0%	0,0%
5,7%	1,0%	3,3%	0,0%
9,0%	35,3%	9,3%	3,7%
100,0%	100,0%	100,0%	100,0%

Figure 1: Monthly loads (January-December)

300qh			
2019	2020	2021	2022
13,7%	12,3%	23,7%	14,3%
17,0%	16,3%	18,7%	21,3%
19,3%	35,0%	22,3%	38,3%
34,3%	21,3%	23,0%	16,3%
15,7%	15,0%	12,3%	9,7%
0,0%	0,0%	0,0%	0,0%
0,0%	0,0%	0,0%	0,0%
100,0%	100,0%	100,0%	100,0%

Figure 2: Daily loads (Monday-Sunday)

	50qh			
Heure du jour	2019	2020	2021	2022
00:00	0,0%	0,0%	0,0%	0,0%
01:00	0,0%	0,0%	0,0%	0,0%
02:00	0,0%	0,0%	0,0%	0,0%
03:00	0,0%	0,0%	0,0%	0,0%
04:00	0,0%	0,0%	0,0%	0,0%
05:00	0,0%	0,0%	0,0%	0,0%
06:00	0,0%	0,0%	0,0%	0,0%
07:00	2,0%	0,0%	0,0%	0,0%
08:00	6,0%	4,0%	0,0%	0,0%
09:00	18,0%	14,0%	4,0%	0,0%
10:00	0,0%	0,0%	8,0%	0,0%
11:00	2,0%	0,0%	8,0%	0,0%
12:00	0,0%	0,0%	8,0%	0,0%
13:00	0,0%	0,0%	8,0%	0,0%
14:00	0,0%	0,0%	0,0%	0,0%
15:00	0,0%	0,0%	0,0%	0,0%
16:00	0,0%	0,0%	0,0%	2,0%
17:00	24,0%	38,0%	18,0%	34,0%
18:00	40,0%	42,0%	34,0%	58,0%
19:00	8,0%	2,0%	12,0%	6,0%
20:00	0,0%	0,0%	0,0%	0,0%
21:00	0,0%	0,0%	0,0%	0,0%
22:00	0,0%	0,0%	0,0%	0,0%
23:00	0,0%	0,0%	0,0%	0,0%
Période entre 17:00 et 20:00	72,0%	82,0%	64,0%	98,0%

Figure 3: Hourly loads

Source: CREG

In addition to the annual peak tariff, the monthly peak tariff was introduced in 2024 to encourage consumption while electricity is abundant and reduce the risk of incompressibility (i.e. when production is higher than consumption and RES are to be curtailed to maintain the balance of the system).

It appears that those tariffs applied during fixed periods offer simple, clear and stable tariff signals.

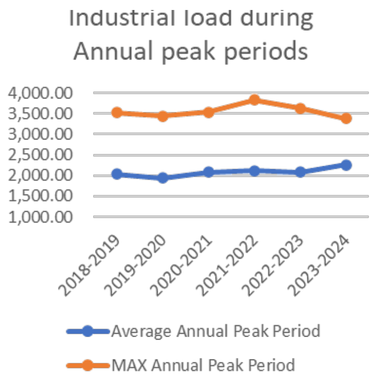


Figure 4: Industrial load during annual peak periods

Expected / actual results:

Between 2019 and 2024, the industrial synchronous peak decreased by 4% while average withdrawals increased by 10%. (see Figure 4). The NRA expects a similar impact of the monthly ToU signal, leading to a load transfer for a better use of the network. In this case, the NRA expects a lowering of the occurrence and intensity of periods of RES curtailment and negatives prices.

Spain:
Time-of-use variation of excess power-based charge to better reflect system conditions

Description of practice:

The tariff structure includes both energy and power-based charges, with the power-based component having the larger weight (i.e. 75% at the transmission level and 84.6% at the distribution level). The power-based component is set based on the contracted (subscribed) capacity, while an additional charge applies for excess power withdrawal. Network users with meters that can measure and register data every 15 minutes pay for the excess power every time the measured power exceeds the contracted power. Network users whose meters only register the maximum withdrawn power by different time periods pay if the measured power exceeds the contracted capacity at least once during the month. Different unit prices apply to different voltages for all consumers and network users with meters that can measure and register data every 15 minutes have also different prices by period. Real time information is available through a platform. The tariff is applicable to all users and it was introduced in June 2021.

The ToU tariff is embedded in the power and energy charges. The charge is divided into six periods (P1-P6), which depend on the season, day of the week and time of the day (as illustrated in the table below):

- within the day there are six time-bands: 09:00-14:00, 14:00-18:00, 18:00-22:00, 22:00-24:00, 00:00-08:00, 08:00-09:00);
- within the week, the days are divided into five types: A (Monday–Friday, excluding holidays, during the high season), B (Monday–Friday, excluding holidays, during the medium-high season), B1 (Monday–Friday, excluding holidays, during the medium season), C (Monday–Friday, excluding holidays, during the low season) and D (Saturday, Sundays, holidays and 6 January);
- within the year, the months are divided into four[118] seasons: high season (January, February, July and December), medium-high season (March and November), medium season (June, August and September) and low season (April, May and October).

118 These seasons apply to peninsular Spain. Canary Islands, Balearic Islands, Ceuta and Melilla apply slightly different definitions of seasons.

Time period	Type of day				
	Type A	Type B	Type B1	Type C	Type D
P1	From 9 am to 2 pm From 6pm to 10pm	–	–	–	–
P2	From 8 to 9 am From 2 to 6 pm From 10pm to midnight	From 9 am to 2 pm From 6pm to 10pm	–	–	–
P3	–	From 8 to 9 am From 2 to 6 pm From 10pm to midnight	From 9 am to 2 pm From 6pm to 10pm	–	–
P4	–	–	From 8 to 9 am From 2 to 6 pm From 10pm to midnight	From 9 am to 2 pm From 6pm to 10pm	–
P5	–	–	–	From 8 to 9 am From 2 to 6 pm From 10pm to midnight	–
P6	From 0 to 8 h	From 0 to 8 h	From 0 to 8 h	From 0 to 8 h	All hours of the day.

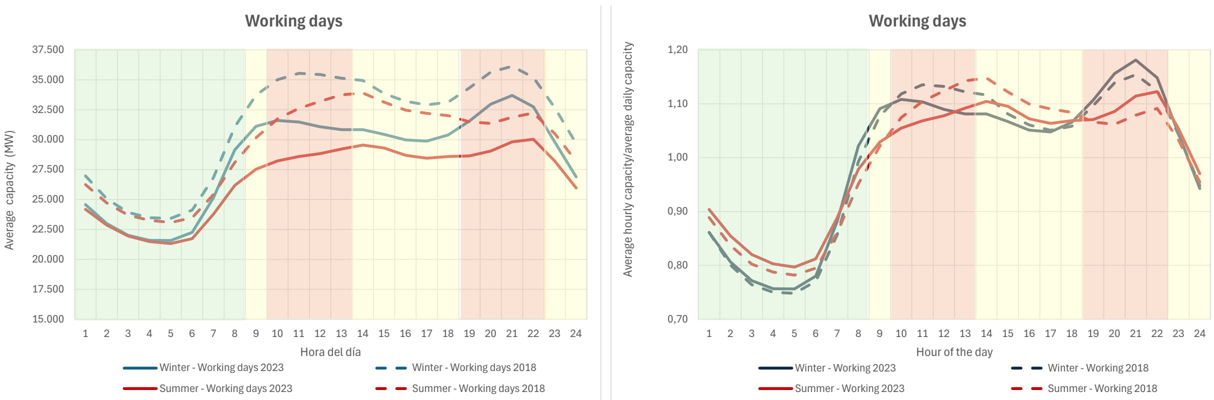
Source: Circular 3/2020, CNMC

Challenge to address / reason for introduction:

The most relevant cost driver in network design is the capacity demand by users. A good approximation of the demanded capacity is the contracted capacity. The introduction of a ToU signal in the capacity charge brings contracted and demanded capacity closer together. To reach the decarbonisation goals, it is important to give a price signal to network users that induces efficient behaviors: increasing consumption without increasing capacity of the same magnitude and minimising investments in networks.

Expected / actual results:

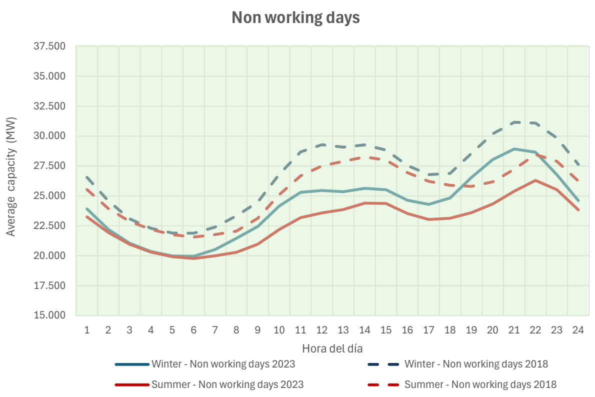
Evidence shows, on average, this methodology reduced transmission and distribution charges by 5.6% with respect to the previous year (comparison between 2019 and 2020). However, the impacts were not the same for all consumers. Consumers connected to higher voltage experienced higher reductions in all charges, while the reductions for consumers connected at low-voltage were lower than average. This is mainly due to the change in the use of electricity at lower voltages. Consumers with a contracted capacity lower than 15 kW recorded savings of close to 10%. This methodology enables bigger savings for consumers able to adapt to the price signals. However, even consumers that do not change their consumption patterns will experience reductions, with charges reducing by 0.6 % for those connected at low voltages. Higher voltage consumers will face a 1.7 % increase, with the exception of consumers connected to the transmission network. For those consumers, the reduction will be 2.0 %. Further assessments show that, regarding the capacity charge in network tariffs, price signals had a greater effect on morning peak and morning off-peak than on afternoon peak periods. For further information, please refer to the related study by CNMC[119].

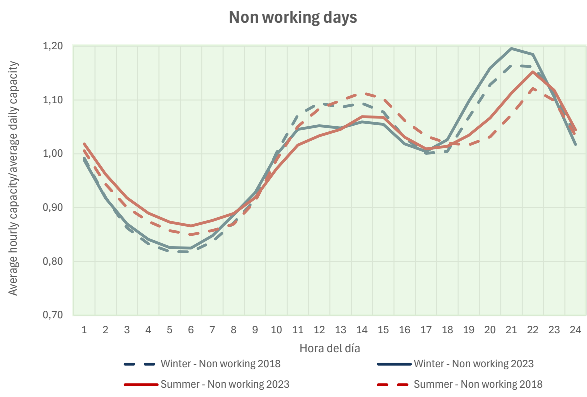


Source: Capacity charge of Network Tariffs. CNMC. (2023)

119 https://www.cnmc.es/sites/default/files/2808025_51.pdf

Even on non-working days (off-peak), there was more consumption in the off-peak and less in morning peak, but also there was more consumption in afternoon peak.





Source: Capacity charge of Network Tariffs. CNMC. (2023)

Slovenia:
Time-of-use variation of power-based charge to better reflect system conditions

Challenge to address / reason for introduction:

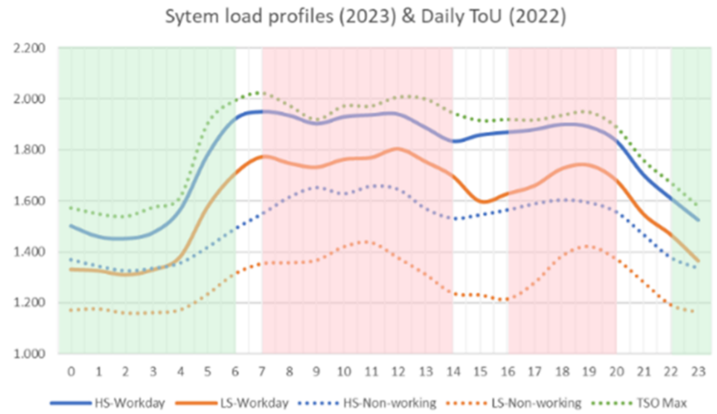
The design of the new tariff setting methodology and the resulting tariffs are similar to those applied in Spain. The methodology builds on the level of digitalisation in Slovene distribution (existence of national data hub) and the almost finished roll-out of smart metering (95% of households are equipped with smart meters). The key finding based on initial impact analysis during the development phase was the greater redistribution of network cost coverage among customers groups – the smallest customers were charged too much under the previous methodology due to administratively determined contracted power. One of the implicit goals of the reform set by the NRA was to ensure fair financial burdens for all customers before the planned raise of overall eligible network costs due to the grid expansions necessitated by increases in consumption and peak load.

The most relevant cost driver in network design is the capacity demand by network users impacting the extent of network utilisation. Maximum network utilisation levels when they are close to network capacity limits are responsible for network expansions. The demand of each user is reflected by the contracted capacity determined at the individual level based on measurement of the user's peak load in the period of maximum system utilisation. The new methodology tries to address the decarbonisation goals by means of efficient use of networks. As in Spain, the tariff design rewards the increased consumption without increasing capacity of the same magnitude as it minimises the investments needed in networks and thus promotes electrification of heating and smart EV charging. The power-based ToU charges implicitly reward self-sufficiency within the 15-minute metering interval, providing incentives for investments in storage in combination with photovoltaics (PVs). The special provisions provide the framework for applying network charges to members of energy communities, whereas the same concept could be applied also for energy-sharing. The new methodology also equalises the positions of active customers and generators on the energy market.

The tariff structure includes both an energy-based and a power-based charge. Until 30 September 2024, the ToU differentiation was applied to the energy-based charge only, with just two time blocks per day and no differences between seasons. This tool was no longer using the grid in the most efficient and distributed RES (e.g. the impact of PVs) were not considered in this design.

Description of the practice:

The new tariff reform, in use from 1st October 2024, introduces time differentiation for capacity charges as well. The year is now divided into high and low seasons, with five time blocks per year, four per month and three per day (depending on high/low season and working/ non-working day). The most expensive time block is only during working days of the high season, whereas the cheapest is only during non-working days in the low season. Season differentiation is critical for ensuring cost reflectivity and system efficiency incentivising the right levels of contracted capacity[120] according to the expected network use. It also addresses, through constraints of the extent of demand flexibility, the other dominant cost driver in the distribution grids in the low season - voltage issues due to minimal consumption - by stimulating an increase in consumption though significantly cheaper network price signals than those in the high season. The system load profiles (average 10 / average 20 peaks) from 2023 and daily time blocks (red – high, white – medium and green – low network utilisation (MW)) set in 2022 are depicted in the figure below. The ToU reassessment recently performed on load profiles from 2024, urges the update of ToU, due to impact of the significant increment of PVs integrated into distribution grids in recent years. The enforcement of the new ToU is planned for 2026.



Time block *b:*

Season	Period		1	2	3	4	5
	HIGH	working day	7.00 - 14.00 16.00 - 20.00	6.00 - 7.00 14.00 - 16.00 20.00 - 22.00	0.00 - 6.00 22.00 - 24.00		
	HIGH	non-working day		7.00 - 14.00 16.00 - 20.00	6.00 - 7.00 14.00 - 16.00 20.00 - 22.00	0.00 - 6.00 22.00 - 24.00	
	LOW	working day		7.00 - 14.00 16.00 - 20.00	6.00 - 7.00 14.00 - 16.00 20.00 - 22.00	0.00 - 6.00 22.00 - 24.00	
	LOW	non-working day			7.00 - 14.00 16.00 - 20.00	6.00 - 7.00 14.00 - 16.00 20.00 - 22.00	0.00 - 6.00 22.00 - 24.00

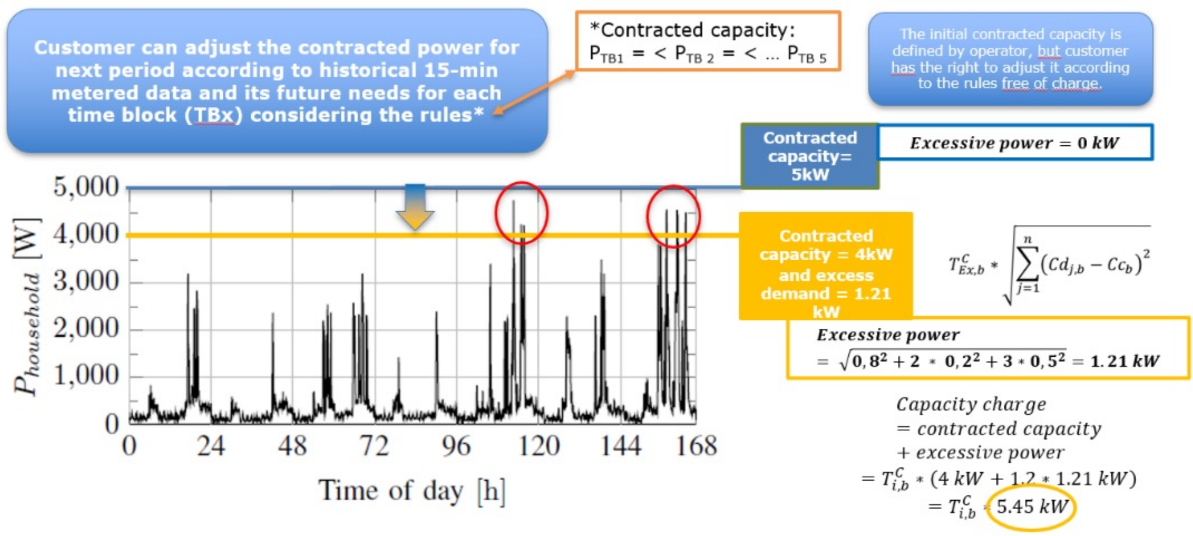
Hourly intervals

Source: AGEN-RS

The new approach places greater weight on capacity charges, with the effect particularly for lower voltage levels, and introduces ToU neutrality of energy charges (for 2024 and 2025). Capacity charges ensure cost recovery for infrastructure maintenance and development, in addition reflecting the cost of ensuring network reliability during peak demand periods. By introducing more granular ToU, this reform provides incentives for demand-side management and grid optimisation. The charge is based on 15-minute metered data.

The approach for charging for power is based on the concept of contracted capacity, which can be adjusted each month for desired period of time using the national data hub, and that of excessive power. The excessive power charge safeguards against speculative lowering of contracting power and encourages the mindful adjustment of demand to newly set contracted power levels. The concepts of contracted and excessive power are depicted in the figure below.

120 Contracted capacity is predetermined by system operator on a yearly basis based on the customer's use of the network in the past period. It is capped by the connection capacity set in the connection contract. The customer is informed of the new levels of contracted capacity per time block for the next calendar year in a timely manner on their bills and through the national data hub. The customer can then adjust the contracted capacity for the desired period (in months) in advance free of charge according to their planned network use. If the customer does not adjust the contracted capacity levels proposed by the system operator, the proposed contracted capacity is treated as 'agreed' and is applied for billing until the next update by the system operator or adjustment by the customer.



Source: AGEN-RS

The 15-minute metered data are available at the D-1 level and real-time data are available to all customers with smart meters from the customer port (P1) on the meter - access to real time data is free of charge. In order to enable customers, particularly the smallest ones, to get used to the concepts of contracted and excessive power, a gradual transition is in place through the two-year exemption of charges for excessive power for households and the one-year exemption for business and industrial customers (from 1 January 2025).

Actual and expected results:

The NRA performs monthly impact assessments based on selected key performance indicators ('KPIs'). After the first three months (October - low season; November and December – high season) the relief in terms of network utilisation at the 2025 system level was more than 50 MW (2.4 % of the hourly system peak in 2024) in the period of highest system stress measured based on the aggregated reduction in contracted power for January 2025[121]. The emerge of active customer based on network price signals was observed: there were >1500 new active customers (those changing their contracted power) with an average monthly growth rate of >85%. On average, 67% of all customers managed to keep their peak loads below the newly adjusted levels of contracted power (i.e. no excess power was charged). New business models, products, services and solutions supporting demand response have emerged. The first new static retail energy supply product is now offered by the biggest supplier that follows seasonal differentiation of network tariffs and better aligned to average day-ahead market prices.

The NRA expects more efficient use of the network by all customer groups, with evolving positive effects and minimisation of the network expansions needed. In addition, the NRA is expecting better acceptability of the reform by minor customer groups exposed to higher but justified network costs after the first six months of charging for network use under the new regime. It is of the utmost importance that customers, particularly bigger ones, are informed of their individual network use in greater depth and detail as soon as possible to enable the planning of measures for demand response and investments in green technologies that can lead to cost optimisation.

121 SI: The root cause of the planned network load shedding cannot be unequivocally attributed to the network price signal.

5.3. Locational signals

Main findings

128 Locational signals in network charges provide a spatial variation in the structure or values of network charges. They can be embedded in one-off connection charges and/or use-of-network charges.

129 As shown in Figure 17, there are various methods implementing locational signals[122] in transmission and/or distribution, including:

- setting deep connection charges based on actual costs, thus reflecting different grid reinforcement costs in different parts of the network; this practice is applied in most countries;
- providing discounts or exemptions or otherwise differentiating connection charges based on the geographical location of the network user (e.g. rural versus urban, demand surplus areas versus generation surplus areas, residential versus non-residential, costal versus inland); applied in nine countries (HR, BE[123], CZ, DK, FI, FR, GR, NO, LU);
- applying different static ToU schedules at different geographical locations; applied in three countries (FR, PT, ES);
- calculating the use-of-network charges by using a locational factor; applied in two countries (DK, IE);
- applying dynamic network tariffs (including locational elements) or tariffs with nodal/market-based elements; applied in three countries (NO, SI, SE), in transmission and/or distribution;
- providing discounts or exemptions or otherwise differentiating use-of-network charges based on the geographical location of the network user; applied in one country (AT).

130 ACER concludes that providing locational signals in connection charges is applied in most countries, particularly in distribution. In use-of-network charges, on the other hand, locational signals are observed in only a few countries (mostly at the transmission level and for injection).

131 Additionally, in Romania, an injection charge has been introduced in 2025 for producers connected to distribution networks where electricity generation is in excess and carried to other geographical zones to be consumed. This injection charge covers losses due to this electricity generation surplus to local consumption (see 'National practices' box in Section 5.3.)

132 In four countries (EE, PT, ES, SE)[124], the application of locational signals (in transmission and/or distribution) is prohibited by law. In one of these countries (EE) and two additional countries (DK, FR), the introduction or expansion of locational signals in network charges is currently under consideration, mainly at the transmission level.

122 Shallow connection charges based on actual costs or pre-determined fixed charges per unit of distance, variation of network charges per different voltage levels, differences between transmission and distribution charges due to different TSOs or DSOs are not considered as location signal in this section.

123 BE: The practice is applied only in Wallonia region.

124 In Estonia, Portugal and Spain, national law requires tariffs to be uniform in the national territory, preventing network charges from being differentiated between locations. In Sweden, there is a ban on locational signals in distribution, with an exemption for producers at the regional grid level.

Figure 17: Locational signals

	Transmission		Distribution	
	Injection	Withdrawal	Injection	Withdrawal
Locational signals via use-of-network charges	DK (geographical differentiation of injection charges) IE (power-based component of injection charge has locational element) NO (calculation of marginal losses in each node for losses) SE (injection charge differs between nodes)	PT (different ToU schedules depending on the location)[125] SE (tariff has time-differentiated energy-based component, based on actual hourly market prices per bidding zone and power-based component that differs between nodes)	SE (in some DSO areas at the regional grid level)	AT (energy-based tariff is different across network areas which are unrelated to DSO areas) FR, PT, ES (different ToU schedules depending on location)[125] SI (local dynamic tariff reform in October 2024)
Locational signals via connection charges	Deep connection charges: HR, DK, EE, HU, LV, LT, PT[126], RO, SI, ES, SE Other: CZ (urban versus rural), DK (generation surplus areas versus demand surplus areas), FR (offshore versus onshore)	Deep connection charges: HR, EE, HU, LV, LT, NO, PT[126], SI, ES, SE Other: CZ (urban versus. rural), GR, NO (customers connected capacity relative to total new available capacity)	Deep connection charges: BE, HR, DK, EE, FI, GR, HU, LV, LT, MT, NO, PT[126], RO, SK, ES, SE Other: DK (generation surplus areas versus demand surplus areas), LU	Deep connection charges: BE, HR, DK, EE, FI, DE, GR, HU, LV, LT, MT, NO, PT[126], RO, SK, ES, SE Other: AT (network areas), BE[127] (residential zones versus non-residential zones), CZ (rural versus. urban), FI, FR, GR (coastal areas), LU

Note: Several countries listed in the figure apply a mix of shallow and deep charges: FI, DE, GR, HU, LV, LT, MT, RO.

Stakeholders' views

133 Several stakeholders claim that well-designed locational signals might be beneficial for the energy systems as they might be effective ways of tackling local congestion in congested areas. Some stakeholders underline that this tariff design might be more suitable for connection charges than use-of-network charges.

134 Some stakeholders warn that this signal entails complex calculations and risks not being cost-reflective and fair, while the signals can create market distortions. Instead, these stakeholders stress the need to improve grid planning and transparency in relation to the adopted tariff methodologies.

135 Some stakeholders are concerned that locational signals in some areas may discourage further investments in renewable technologies (solar, wind), thus hindering decarbonisation.

136 Some stakeholders claim that for some network users (e.g. households), it is hard to react to locational signals (i.e. to relocate) and therefore the locational signals might be ineffective if those network users are the main targets of efforts improve flexibility. Instead, these stakeholders propose ToU tariffs and/or incentives for consumption taking place geographically close to generation.

125 PT: The time schedules are different between mainland Portugal and the autonomous regions of Azores and Madeira (arquipélagos). Since 2024, a new option at the network tariff level (including transmission and distribution tariffs), has three different ToU schedules for mainland Portugal separated into three different grid areas.

126 PT: Although part of the connection charge is uniform on each connection level and independent from location, another part depends on the distance to the grid, thus incentivising locations closer to the grid.

127 BE: In Wallonia region.

ACER considerations

137 Connecting to or using the network can entail different costs, depending on the grid topology and the individual network user's geographical location. For example, a consumer in a rural area typically generates high network costs to connect to the grid. However, if that consumer is located within a mostly exporting (generation surplus) area, the associated costs of using the network can be very low or even negative (i.e. avoided costs). Areas with excess grid capacity face low marginal costs of delivering power through the grid. Constrained areas, on the other hand, face significant marginal costs due to the need for congestion management or network reinforcement. In generation surplus and demand surplus regions it is essential that investments are steered to the right geographical locations to mitigate increases in overall system costs.

138 As locational signals reflect spatial variations of network costs, they ensure a more cost-reflective allocation of cost between network users, while also influencing users' decisions to site and operate at a given geographical location. Therefore, the signals can play an important role in integrating renewables and reducing overall system costs in the long-term.

139 All the countries reviewed apply market models using 'zonal pricing', which assumes that there is no internal congestion within a market zone, but this is often not the case. As such, wholesale market prices do not provide locational signals within market zones (e.g. to reflect losses and mitigate congestion problems)[128]. In the zonal-pricing paradigm, network tariffs can provide network users with cost-reflective signals of both grid losses and grid congestion.

140 Locational signals embedded in connection charges or use-of-network charges can enhance the cost-reflectivity of network tariffs and may guide network users to connect to specific grids that are less congested and have more favourable tariffs.

141 The spatial differentiation of connection charges provides a one-off signal only (for siting of generation or consumption), but it does not reflect the continuously varying grid topology and network conditions and does not incentivise network users changing their behaviour once the connection-siting decision has been made. However, locational signals in use-of-network charges can be inefficient as well, as congestion is hard to predict in advance (e.g. due to intermittent generation changes from hour to hour) and often changes following network reinforcement or other grid reconfiguration (e.g. power line outage due to maintenance), making the locational signals unstable and the network charges more volatile. Where locational signals are introduced to reflect the spatial variation of network costs, NRAs should continuously monitor their adequacy. Non-cost-reflective locational signals can lead to market distortions, redundant grid expansion and undue shifts in societal welfare.

142 Dynamic network tariffs, by adapting the network charges to actual system conditions, can increase cost-reflectivity and incentivise efficient network behaviour. Such combined spatial and temporal differentiation is particularly relevant for EVs, electric heating (through heat pumps) and storage assets that can provide more flexibility at a system level. If this flexibility is adequately reflected in the network charges, it can help speed up the decarbonisation of the transport sector, electrification of heating systems and integration of renewables.

143 Dynamic network tariffs can be effective if combined with smart meters and smart grids. However, dynamic differentiation is rather complex, requires a sufficient level of automation (and therefore implementation costs) and involves more frequent and complex rate calculation and billing (meters, data processing, etc). It may therefore contradict other principles - such as simplicity, predictability and transparency - if not implemented effectively. Therefore, its added value for some network users (e.g. households) has to be studied.

128 In a nodal pricing model (or zonal model with smaller zones), such locational (grid) constraints would be revealed with a higher spatial granularity with prices in the nodes reflecting those constraints.

144 Locational signals by network tariffs are nonetheless not the only option to address variation of network costs and mitigate congestion or system stress without additional network reinforcement. Alternatives or complementary measures exist; for instance, ToU tariffs combined with locational signals (see Section 6.6), tariff discounts/rebates for shifted load (see Section 5.5), options to contract different power levels for different time intervals (see Section 5.2), participation in local markets offering products for system operation services (see Table 44 in Annex 1) or flexible connection agreements[129] and direct remote control by a system operator of specific user appliances[130] (see Section 5.4).

Recommendations

145 NRAs should consider introducing locational signals in network tariffs to reflect costs more accurately and/or to tackle congestion, complementing market-based solutions pursuing the same goal. Options like locationally differentiated connection charges with cost-sharing among current and future users should be investigated.

National practices

Denmark:
Geographically differentiated network charges for produces with lower network charges for areas with high demand surplus.

There are locational signals in both transmission and distribution and they are embedded in both injection charges and connection charges, but only for producers.

Description of practice - Distribution:

The one-off connection charges for producers connected to networks with voltages higher than 10 kV are geographically differentiated using standardised deep connection charges for the cost of connection and network reinforcement. The geographical differentiation is based on the balance between injection and withdrawal in the location grid area, offering lower connection charges in areas with high withdrawal surplus and higher connection charges in areas with high injection surplus, thereby reducing bottlenecks. In 2025, a similar connection charge regime is envisaged for consumption, but this is currently pending approval from the NRA. The signal would be based on a cost-reflective evaluation of whether injection or consumption (or both) drive grid investment in the area. New legislation in 2023 widened the possibilities for industrial-scale co-located production and consumption with one connection point to the grid with the aim of encouraging the co-location of RES and consumption.

Deep connection charges for DSO-connected producers are differentiated by three kinds of geographical zones: producer-dominated zones, consumer-dominated zone and mixed zone. The maximum exchange with a 132-150/10-60 kV station (transmission net) is the indicator of whether consumption or production drives the power requirement. The evaluation is based on hourly data from past years. Hour-based consumption or production profiles for new customers with capacity larger than 5 MW, with whom a connection agreement has been concluded, but which has not yet been commissioned will determine the type of geographical zone. The zones are updated yearly (or, in some areas, weekly) based on the abovementioned data. Production dominated zones are where, numerically, the 100th lowest hourly measurement (production) (out of 8760 measurements per year) is greater than the 100th highest hourly measurement (consumption). By contrast, the consumption-dominated zone is where there are 100 or fewer hours per year, when the exchange goes from the distribution network up to the transmission network (in the production direction). If the station does not meet the criteria either for the production-dominated zone or the consumption-dominated zone, the payment for expanding the network must be shared. The DSOs recover production-related operational expenses (OPEX) and network loss costs through injection charges, measured in DKK per kWh. DSO-connected producers with an effect higher than 50 kW contribute to recovering transmission network costs (as discussed in the next section on the transmission practice).

129 These maybe designated in some cases as ‘interruptible’ or ‘non-firm’ agreements.

130 This means the system operator activates consumption by specific user appliances (e.g. heat boilers) or restricts their use during system peaks.

Description of practice – Transmission:

The TSO also introduced a geographically differentiated 'semi deep' connection charge and G-charge in January 2023, but is considering changing this from 2025. The reason for introduction of the G-charge and connection charge for production was cost reflectiveness and the phasing out of a RES subsidy scheme, effective from 1 January 2023. The G-charge and part of connection charge are geographically differentiated in order to send locational signals to the producer. TSO introduced two geographical areas in Denmark, production dominated area and consumption dominated area. The tariff/G-charge for the production-domination area is 1.2 EUR/MWh (because of the EU legal cap on transmission tariff on production) and 0.4 EUR/MWh in the consumption-dominated area. The TSO has proposed abolishing the geographical differentiation of the G-charge. The proposal is under NRA evaluation. Furthermore, the connection charge includes a station charge, which is differentiated by voltage level and is not geographically differentiated. The TSO differentiates between transmission- and distribution-connected users regarding the station costs, where transmission-connected users pay station charge, while distribution-connected users pay a transformer charge (although this only applies to distribution-connected users located in the production-dominated areas). The TSO also charges a connection fee (DKK/MW) for recovering the cost of the 'close/local transmission network'. This charge is also geographically differentiated: the charge is higher for production-dominated areas and lower for consumption-dominated areas. Both distribution- and transmission-connected producers with an effect higher than 50 kW pay 'the connection charge of the close network'.

Challenge to address / reason for introduction:

The challenges were bottlenecks between grid areas and cost-reflectivity – that is, considering whether generation or consumption is driving network reinforcement costs.

Expected / actual results:

A main challenge that the Danish TSO is still facing, is the connection charge for large batteries which currently pay the same connection charge as producers while their behaviour is not the same. The TSO is considering ways to address this problem, but has not started any tariff change regarding large batteries. The planned introduction of geographically differentiated connection charges for consumers is also a cost-reflective improvement relevant for emerging users such as storage. By law, network tariffs must be cost-reflective and non-discriminatory. Therefore, special tariffs favouring certain end-user technologies or purposes are not legal. The tariff methodology improvements have increased customers' ability to optimise their use of the grid and therefore payment, which is relevant to both emerging grid users, such as storage and industrial-scale prosumers, and conventional consumers considering the adoption of technologies such as storage in connection with existing facilities.

Ireland:
Locational element of the generation charge

Description of practice:

The Generator Transmission Use of System ('GTUoS') tariff comprises a postage stamp and a locational component. The postage stamp portion is intended to recover a minimum of 70% of the total GTUoS revenue and is applied evenly across all generators, while the locational element is intended to provide for recovery of a maximum of 30%. The following factors that vary year-on-year have a major impact on the locational aspect of the tariffs: the overall revenue requirement to be recovered via the GTUoS tariffs, power flows (which depend on network configuration and dispatch), levels of generation and the contribution to the direction of flows on each network reinforcement, the assets included in the cost file including the planned network development and associated costs, and interconnector flows.

Challenge to address / reason for introduction:

The 30% locational element of the GTUoS tariff was introduced based on one of the stated objectives of the all-island Single Electricity Market ('SEM'), which stated that 'Generators should pay a locational charge as part of their Transmission Use of System, i.e. they should pay more to contribute to the cost of the deep reinforcement which their shallow connection has caused'. The intention of the locational charge was to encourage users to make informed decisions concerning their use of the transmission system, which should lead to more efficient development and use of the transmission system. The 70:30 ratio between the postage stamp and locational elements of the tariff was selected as it was deemed that it strikes a balance between the need for providing a locational signal and protecting against volatility in tariffs from year to year.

Expected/actual results:

In the consultation that led to the setting of the current GTUoS methodology, where a ratio of 60:40 was initially proposed. However, respondents argued that other mechanisms, such as shallow connection charges and firm access quantities, provide the main locational signals, and that little notice is taken of signals provided through GTUoS tariff. Respondents also expressed concern about locational charging as they felt that this was an increased risk for generators. This view was particularly common amongst renewable generators. These responses led to a revision of the proposed ratio; however, the locational element was still chosen based on the reasoning set out above. There are currently no plans to revise the locational element of the GTUoS tariff.

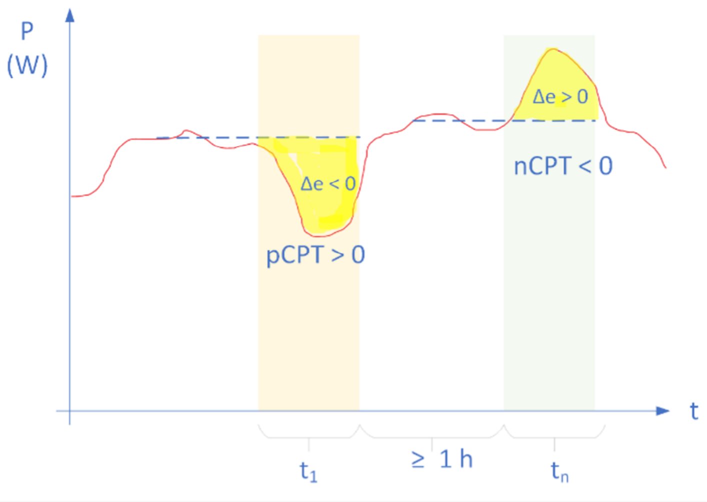
Slovenia:
Locational dynamic pricing

Description of practice:

A new framework for dynamic local tariff is developed based on the pilot phase that was conducted through three regulatory periods (2016 – 2022). The local dynamic tariff for pilot phase was defined by the NRA, aiming to reduce the consumption at critical peak load times and increase the consumption during the critical net-generation in the local network. It was based on voluntary participation of customers. The additional charge is a positive or negative CPT combined with adjusted standard ToU tariffs and its magnitude should be significantly (higher/lower) than the regular tariff in the same hours to incentivise adequate response. The CPT can be positive (pCPT: standard tariff = 15:1) and negative (nCPT; standard tariff = 0,25:1). There were 50 activations performed per year in the first phase for pCPT [2016 – 2018], between 30 and 100 during the second phase [2019 – 2021] and a maximum of 3650 for nCPT. DSO notifies the customer in advance about the occurrence of a critical period (24 hours for non-automated customers), there is no penalty for customers who are not responding.

Challenge to address / reason for introduction:

The new reform introduces a complementary dynamic local tariff to the system wide ToU tariff aimed to manage local congestion and reduce losses. The main goal of the new charge was to involve active customers with voluntary participation in controlled implicit demand response by reducing the consumption at critical peak load times and increasing the consumption during the critical net-generation in the local network. It is also aimed at being an operator's tool to selectively mitigate the voltage problems due to PV injections and the problem with simultaneous load triggered by ToU tariffs differentiation. As in the pilot phase, the complementary dynamic local tariff to the system wide ToU tariff can be introduced by system operator upon NRA approval in selected network area. NRA approves or not the proposed tariff by DSO based on cost benefit analysis, definition of the process and data-exchange, aspects of publication etc. The magnitude of critical peak tariff (CPT) should be significantly (higher/lower) than the applicable regular tariff in the same hours, in order to incentivise the adequate response. Compliance with high-level regulatory framework should be assured: baseline definition, minimum time between activations. Positive or negative CPT applicable onto energy component can be applied. Customers are significantly rewarded for the amount of decreased or increased load based on notifications or activation signals. Voluntary participating customers are exempted from payment of excessive power for their participation in system services based on implicit demand response mechanism.



Network charge – energy:

$$NC^{E}_{CPT} = \sum_{t=1}^{n} \boldsymbol{xCPT \cdot \Delta e \le 0} \quad \boldsymbol{x} = \{n,p\}$$

$$NC^{E} = NC^{E}_{d} + NC^{E}_{p} + \boldsymbol{NC^{E}_{CPT}} \text{ [EUR]}$$

Network charge – power:

$$NC^{P} = NC^{P}_{c} + NC^{P}_{excess} = NC^{P}_{c} \text{ [EUR]}$$

Network charge – SUM: $\boldsymbol{NC^{P} = NC^{P} + NC^{E}}$

Source: AGEN-RS

Actual results (pilot phase):

More than 1500 households and SMEs participated during the pilot phase [2016 – 2022]. The load reduction per customer was between 40 W and 122 W for non-automated customers and between 359 and 822 W for automated ones. The aggregated load reduction of customer groups was between 6.85% and 34%.

Majority of customers adapted their consumption to CPT activations. Adaptation to activations was easy and did not affect the daily routines of customers and savings were in line with expectations. 24 hours' notice is optimal for users and the most suitable activation duration for users is 60 minutes. According to customers, SMS is the best channel to notify about CPT activations followed by notification on mobile applications and e-mail.

Expected results:

based on the first announcement of application of such a tariff in distribution in 2024 we expect that this tool will be used by operators in the period lacking mature local flexibility markets. The scalability will depend on first lessons learned from the operator's and NRA perspective.

Norway:
Tariffication based on marginal grid losses, differentiated in each network node

Description of practice:

A network tariff element is set based on marginal loss in each node. The price of marginal losses is the marginal loss percentages for each node multiplied by the actual spot-price for the area in the actual hour. Marginal loss percentages in each node are calculated each week differentiated by day/night and weekend. The calculations of marginal loss percentages are based on projected load flows in the Nordic network. The marginal loss rate is symmetrical around zero for feeding and drawing power at each individual connection point. The marginal loss rates are administratively restricted to ±15 per cent. This tariffication aims at providing a more correct price signal in each node reflecting the changes in overall losses in the system by a marginal input/output.

Challenge to address / reason for introduction:

The energy charge based on marginal losses aims to incentivise grid users to adapt their grid use to the current conditions.

Expected / actual results:

The tariff element is dependent on energy prices and the marginal loss calculation. With increased energy prices, the tariff element has become increasingly significant, and there are claims that the price signal has become too strong as a result. Norwegian producers are, in total, net recipients of marginal charges. In combination with the cap on the fixed g-charge component, it leads to producers covering a smaller proportion of the grid costs compared to consumers.

Romania:
Injection charge for producers connected to distribution networks covering losses based on electricity surplus to the local consumption.

Description of practice:

From 2025, an injection charge is introduced for producers connected to distribution networks where electricity generated is in excess and carried to other geographical zones to be consumed. This injection charge covers losses due to electricity surplus generation to the local consumption. The geographical zones are not equal to DSO areas. ANRE conducted a study elaborated by an external consultant to get the method to find out the amount of losses due to the transit of electricity in HV distribution network (110 kV) because of the generation surplus in the zone. All DSOs and TSO participated in the study. The NRA organised discussions and meetings with system operators and producers to present the findings and the method. Finally, producers accepted the situation thanks to the discussions and explanations.

Challenge to address / reason for introduction:

Big losses in high voltage distribution networks in areas where there are many and large generation units, resulting in high generation surplus. In Romania, distribution costs were recovered only through withdrawal charges, so all costs of losses had to be recovered only from consumers in that area via withdrawal charges.

Expected /actual results:

For 2025, the NRA approved the injection charge for producers with a capacity exceeding 5 MW, connected to distribution networks in two geographical zones from the total of eight zones. The injection charge covers only losses in HV distribution network due to electricity surplus generation to the local consumption and it is in one case 6% and in the other 17% of the withdrawal charge approved for the same voltage level. The immediate result of the measure is the correct allocation of the cost. We also expect this to be a serious signal for new producers to locate in other geographical zones with demand surplus.

5.4. Flexible connection agreements

Main findings

146 NRAs' responses indicate an increased level interest in offering non-firm, interruptible or flexible grid connection or network use to network users[131]. Most countries apply some form of interruptibility for network users, as shown in Figure 18, 15 out of 29 countries do so under the framework of flexible connection agreement ('FCA'), which includes conditions to limit and control injection into and withdrawal from the transmission or distribution network. In some instances, NRAs reported that other direct load control or interruptibility schemes apply[132]. The introduction of FCAs is currently being developed or under consideration in some countries[133].

147 The use of FCAs are fairly balanced in transmission and distribution: eight countries apply them in both transmission and distribution, four countries (AT, BE, FI, SE) apply them only in distribution (they are considering expanding coverage to transmission) and two countries (EE, IE) apply them only in transmission (they are considering expanding coverage to distribution).

131 See ACER Report on electricity transmission and distribution tariff methodologies in Europe (January 2023, p. 45).

132 In Belgium's Flanders and Wallonia regions, an exclusive night regime applies to loads that are only activated during the off-peak period. The activation signal is controlled by the DSO. In Croatia, interruptible load in the form of direct load control has been in place in the tariff model 'Crni' for households since 2008. In Czechia, the DSO's remote-control tool blocks certain devices in peak hours and powers them later in off-peak hours. In France, new boilers are set to work during off-peak hours automatically and to turn off during peak (through smart meters), unless customers set them differently.

133 HU, LV, MT, ES, PL, RO.

148 FCAs have multiple aims: support system balancing, reduce system peaks driven by injection or withdrawal, reduce need for grid reinforcements and/or facilitate faster connection of flexible RES or demand (if there is lack of sufficient firm capacity).

149 The conditions of the FCAs (e.g. mandatory or voluntary, linked with network tariff discounts or not) vary across and often within the countries (i.e. between transmission and distribution or between network user groups).

- FCAs are mainly offered on a voluntary basis, but there are a few countries, where it is mandatory for some users (BE, CZ, DE).
- FCAs slightly more frequently target injection. Out of the 15 countries with FCAs, 6 countries (EE, DK, FI, FR, NL, NO) apply them to network users regardless of whether they inject or withdraw, 5 countries apply them only to injection (AT, BE[134], HR, CZ, PT[135]) and 3 countries have FCAs only for consumers (DE, LU, SE).
- FCAs are often linked with network tariff discounts. Out of the 15 countries with FCAs, 5 provide such discounts in the form of reduced or different use-of-network charges (AT, BE, DK, DE, NL) and 3 provide reduced connection charges (DK, EE, NO). In three countries (FI, FR, PT), there are no tariff discounts. In seven countries the terms of the compensation mechanism were not specified by the NRA or they are decided on a case-by-case basis in bilateral contracts.
- The exact designs of the tariff discounts or other compensation mechanisms are diverse. In some countries, network users do not need to pay a charge for flexible capacity, network users do not pay the contracted capacity component of the network charge, or the terms are subject to bilateral agreements with system operators. In countries where no discounts apply, network users are likely to still benefit from subscribing to the FCA to connect to the grid earlier.

Figure 18: Flexible connection agreements and corresponding tariff discounts

Country	Transmission or distribution	Eligible network users	Mandatory / voluntary	Tariff discount
Austria	Distribution (some DSOs)[136], but under consideration for transmission	Producers, storage and prosumers	Voluntary	Reduced use-of-network charge
Belgium[137]	Distribution (in Wallonia region), but under consideration for transmission and other regional jurisdictions	Producers, storage facilities and prosumers	Mandatory above 250kW capacity	Injection tariff for flexible capacity is 0 EUR/kVA
Croatia	Transmission and distribution (but no TSO contract in practice yet)	Producers and storage facilities	Voluntary	Conditions are specified in bilateral contract

134 BE: In Wallonia region.

135 PT: Applicable to producers and autonomous storage facilities.

136 AT: Individual DSO-decision to offer interruptible tariffs.

137 BE: In Belgium, at the transmission level the regulatory framework under construction, currently interruptible connection agreements are allowed only if the TSO cannot guarantee firmness and until necessary reinforcement are completed. FCAs are under consideration in Flanders and Wallonia regions.

Country	Transmission or distribution	Eligible network users	Mandatory / voluntary	Tariff discount
Czechia	Transmission	Producers and high-voltage prosumers	Mandatory	Compensation mechanism for blocking production if there is congestion (defined by law), but no tariff discount
	Distribution (since 2010)	Prosumers	Mandatory	Compensation mechanism for blocking production, but no tariff discount
Denmark	Transmission (since autumn of 2024)	Consumers (>10 kV)[138]		Offers a lower connection charge (shallow actual costs). Users with limited network access (through FCA) contribute to tariff for use of the network (net tariff) at a third of the rate of users with full network access
	Distribution (since 2019)	Consumers (since 2019) and producers (since 2023)		Offers a lower connection charge (shallow actual costs). There is no reduction in the use-of-network tariff.
Estonia	Transmission, but planned for distribution[139]	All network users	Voluntary	Reduced connection charge
Finland[140]	Distribution (since 2021), but under consideration for transmission	All network users	Voluntary	No tariff discount
France[141]	Transmission (since 2021)	Producers and consumers	Voluntary	No tariff discount (but results in lower connection charge)
	Distribution (since 2021)	Producers and storage facilities	Voluntary	No tariff discount (but results in lower connection charge)

138 DK: Available for consumers (business customers) with capacity connected to the medium and high-voltage grid (10-60 kV), as these consumers are typically of such a size that they can provide significant grid support when a bottleneck situation arises.

139 EE: The largest DSO is developing the same principles applied to the transmission

140 FI: Although a connection agreement must be based on firm capacity, the NRA is aware of one case where the DSO has agreed an additional flexibility service agreement with an existing larger consumption connection. The agreement requires the user to modulate consumption based on the DSO's instructions. No compensation is given for modulation, but this has allowed the user to connect the additional demand to the network before grid reinforcements could be finalised. Only the additional capacity is tied to the agreement.

141 FR: For producers, the minimum non-guaranteed injection capacity is less than or equal to 30% of the requested connection capacity and the energy capped annually does not exceed 5% of the annual production of the connected installation.

Country	Transmission or distribution	Eligible network users	Mandatory / voluntary	Tariff discount
Germany	Transmission (since 2023)	Consumers (over 5 MW)	Voluntary	Tariff discount on use-of-network charges
	Distribution (since 2024)	Private EV charging/storage/ heat pumps up to 4.2 kW	Mandatory	Tariff discount on use-of-network charges; multiple options available[142]
Ireland	Transmission (since 2007), but pilot projects running in distribution	Producers and consumers[143]	Voluntary	Additional revenue stream (not specified)
Luxembourg	Distribution (one DSO applies them), but expansion is under consideration	Consumers	Single case[144]	Allows user to withdraw at night, avoiding high loads during peak
Netherlands	Transmission and distribution (since 2024)	Network users (both producers and consumers) in congested areas	Voluntary	Reduced use-of-network charges
Norway	Transmission (since 2021)	All network users	Voluntary	Reduced connection charges; terms are subject to agreement between the user and the TSO
	Distribution (since 2019 for injection; since 2023 for withdrawal)	All network users (in practice, only if >1 MW)	Voluntary	Reduced connection charges; terms (e.g. reduced connection charge) are subject to agreement
Portugal	Transmission and distribution (since 2025)[145]	Producers and storage facilities	Voluntary[146]	No discount
Sweden	Distribution (for more than 20 years for large scale district heating), but under consideration for transmission	New consumers; applied to different grid levels and more common in congestion areas	Voluntary	Methodology for determining agreement terms is subject to NRA approval

142 DE: Option 1: The first module provides a lump-sum reduction. There is a nationwide determination for each grid operator to determine the lump-sum reduction. Depending on the grid area, the reduction can be between 110 and 190 EUR per year. Option 2: The second module includes a percentage reduction up to 40 percent of the capacity-based price component (ct/kWh) in low-voltage level. Option 3: If the operator of controllable devices has selected Module 1, they can also opt for a time-variable grid charge from April 2025. This newly added time-variable grid charge is intended to reduce peak loads in the grid. The DSO sets different price levels within a day (LT, ST, HT), which take into account the typical utilisation of its grid. Consumers are incentivised to shift their consumption to times when grid utilisation is low by means of a particularly low charge.

143 IE: Demand Side Units (DSUs) and Aggregated Generating Units (AGUs). Demand Side Units (DSUs) must be available 24 hours a day year-round. DSUs that are available for demand reduction are eligible for a capacity payment in the Single Electricity Market (SEM).

144 LU: Currently one DSO uses an FCA in a specific and local situation. The requested capacity could not be provided for an EV fleet operator without network expansions. The FCA allows to withdraw mainly in the night, avoiding high loads during peak times.

145 PT: The general conditions applicable to agreements on flexible connections (or connections with restrictions) were approved on 21 January 2025. No discounts on use-of-network or connection charges have yet been specified.

146 PT: To be offered by the network operator when it is not feasible to offer the requested connection capacity on a firm basis.

Stakeholders' views

150 Some stakeholders argue that FCAs are a valid alternative to network investments (or that they at least buy time), especially in areas with urgent additional capacity needs. They claim that FCAs represent a valuable tool to manage network congestion in the short term and they can speed up RES integration, allowing faster connection at desired locations until the necessary grid reinforcements are completed. Some stakeholders also claim that FCAs are transparent and fairly cost-reflective, and thus able to increase overall efficiency.

151 Some stakeholders claim that FCAs might hinder grid investments and shift the focus away from long-term solutions, opening arbitrage opportunities and distorting the cost signals embedded in the tariff structures. Some stakeholders warn that abuse of FCAs might compromise the stability of the whole system, while some consider it an additional risk for offshore wind generation.

152 Several stakeholders remarked that the terms and conditions of FCAs should be clear, precise and standardised, including regarding how network tariffs are adapted to them. Some stakeholders argue that network tariffs should reflect both the costs and the benefits of FCAs over full duration of the agreements.

153 Some stakeholders stress that FCAs should be used as an exception, and they suit (and should target) only specific network users (e.g. large consumers and/or agriculture). Some stakeholders are of the view that existing users should have access to FCAs only on a voluntary basis.

154 Some stakeholders note alternatives to FCAs, such as specific markets remunerating network users for demand response and other financial incentives encouraging users to shift their loads to off-peak hours.

ACER considerations

155 Flexibility can be provided for different purposes, including system balancing and managing congestion. Flexibility for congestion purposes is typically limited to smaller geographical areas and aims to postpone or avoid investment.

156 Network users can provide flexibility by changing their electricity injection or withdrawal in reaction to overall price signals or specific requests, while simultaneously benefiting from doing so. Flexibility can be provided on a voluntary or mandatory basis, through manual or automated actions, and implicitly (by reacting to cost signals coming from network tariffs) or explicitly (by participating in market-based procurement of local services or using FCAs or other forms of interruptibility).

157 In principle, NRAs should work towards enabling innovative grid tariff structures and well-functioning markets - such as the day-ahead market, the intraday market, various balancing services and market-based procurement of local services - to incentivise flexibility. However, designing such grid tariffs and markets can be complex and take time.

158 FCAs have great potential in terms of speeding up the connection of new users, while reducing local congestion and interruptions of other network users and mitigating system peaks which are one of the main drivers of needs for network reinforcements. FCAs are often considered relatively easy to implement, and thus it is worth exploring their use.

159 The need for FCAs should be assessed together with opportunities for the other solutions mentioned above, such as market-based re-dispatching, and innovative grid tariff structures (featuring various temporal and/or spatial forms of differentiation).

160 FCAs shall not interfere with the legal requirement for network tariffs to be non-discriminatory and cost-reflective; users that offer a valuable service through flexible grid use can be offered lower tariffs that reflect the lower costs and additional value they create (e.g. temporarily avoided network reinforcement costs), but this requires an assessment of the system and market impacts of the network users when an FCA is applied. Care should be given to considering other payments

(e.g. by system operators to network users for providing system operation services) received due to the same service, to avoid any double-remuneration.

161 The recent electricity market design reform[147] requires the development of a framework for system operators to offer the possibility of establishing FCAs in areas with limited or no available network capacity for new connections. That framework shall ensure that (a) flexible connections do not delay network reinforcements in the identified areas, (b) there is a conversion from flexible to firm connection agreements once the network is developed and (c) for areas where network development is not the most efficient solution, enable, where relevant, FCAs as a permanent solution.

162 If system operators set up FCAs as a permanent solution, they can become a barrier to other types of market-based flexibility, such as demand response, storage or distributed generation, which latter tools are considered more efficient by ACER[148].

163 When designing or approving FCAs, NRAs must also take into account the provisions in Article 13 of Regulation (EU) 2019/943[149], in particular they shall assess whether curtailments of renewable energy do not exceed 5% of the annual electricity generated by RES installations directly connected to the respective grid (unless injection by RES power-generating facilities or high-efficiency co-generation represents more than 50% of the annual gross final consumption of electricity).

Recommendations

164 To tackle congestion, NRAs should evaluate the advantages and disadvantages of flexible connection agreements, considering system-wide impacts, together with other market and non-market based solutions pursuing the same goal.

165 NRAs should ensure that the costs and system beneficial impacts attributed to the flexible connection agreements are properly reflected in the respective network charges, while avoiding any double-remuneration of the concerned network users.

National practices

Netherlands:
Flexible Connection Agreement (FCA) for all network users aligned with use-of-network charges

Description of practice:

Three types of FCAs are offered:

1. Fully flexible FCA (completely non-firm) is in place since 1 February 2024 and available only in congested areas of the transmission and distribution networks. Grid users do not pay for contracted capacity but pay a tariff for their monthly peak. The reason for this type of FCA is that users do not put a claim on capacity and does not pay for grid investments.

2. Minimal availability agreement (starting 1 April 2025) is available in- and outside congested areas, but only in transmission networks. However, users cannot increase their actual peak, even when there is capacity. The availability of transport capacity is guaranteed 85% of the time. As for fully flexible FCAs, grid users pay a tariff for their monthly peak, but not for contracted capacity.

147 https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=OJ:L_202401711.

148 See ACER Market monitoring report. Demand response and other distributed energy resources: what barriers are holding them back? (December 2023).

149 Adjusted by Commission Delegated Regulation (EU) 2024/1366 and Regulation (EU) 2024/1747.

3. Timeslot agreement (starting 1 April 2025) is available in- and outside of congested areas, but only in distribution networks. The transport capacity is available during contracted timeslots. Unlike other tools, under this agreement grid users pay part of the tariff for contracted capacity, as well as a tariff for their monthly peak.

An additional energy agreement is in its pilot phase; it could be combined with a firm connection agreement.

Challenge to address / reason for introduction:

More frequent congestion has been observed in the network due to the energy transition. As a consequence of congestion during peak hours, capacity is scarce or unavailable in many locations around the country. Despite being a voluntary tool, FCAs might be the only solution available in congested areas.

Expected/actual results:

It is possible for new grid users to gain at least partial grid access, there is an incentive for current grid users to switch to new contracts and open up peak capacity, and there is a lower cost-reflective tariff for grid users that supports the grid.

5.5. Specific tariff regimes: discounts, exemptions and other differentiated tariff treatments

5.5.1. Introduction

166 In several countries some network users are subject to specific tariff regimes - for example, they receive exemptions, discounts or other differentiation in their tariff treatment compared with that of other network users. Some of these specific tariff regimes reflect different (e.g. lower or negative) cost impacts and therefore may be justified on a cost-reflectivity basis. Specific tariff regimes may also be established for some network users for practical reasons (e.g. different metering capabilities or administrative costs), but still aim to achieve cost-reflectivity. However, in some instances, the specific tariff regime aims to support particular network user groups (e.g. industry or households) or facilitate the penetration of new technologies (e.g. RES generation) to reach the energy and climate policy goals.

167 While ACER urges NRAs to provide a justification for any tariff differentiation, such justification is often missing.

5.5.2. Producers

168 Producers are not subject to injection charges, or the charges are set at a marginal level or zero, in more than 60% of countries. Where injection charges apply, they are typically paid to the TSO at the transmission level and to the DSO at the distribution level. However, there are some cases where (a) the TSO charge applies also to distribution-connected producers, (b) only transmission-connected producers or only distribution-connected producers pay injection charges or (c) the injection charge is negative[150]. ACER also notes that the injection charges at the transmission and distribution levels are often set differently (e.g. have different tariff bases).

150 See Section 5.1 for more information.

169 As shown in Figure 19 and detailed in Table 28 in Annex 1, tariff methodologies typically (10 out of 13)[151] provide discounts on injection charges based on the size of the generators (e.g. <5 MW or 100 kW), the voltage level of the connection (e.g. <150 kV), the technology (e.g. RES) and/or the purpose (e.g. provision of system operation services). In Germany, a negative injection charge for system-beneficial impacts applies for distributed generators only if they meet certain criteria.

170 In general, producers are subject to connection charges in all countries at the transmission and distribution levels. In most instances, their connection charges are shallow and set based on actual costs, but ACER notes that deep connection charges are more frequent for producers than consumers.

171 Some countries provide exemptions, discounts or differentiation regarding the connection charge for some producers based on size (i.e. small producers, the thresholds are ranging between 5 MW and 10 kW) or technology (i.e. RES, offshore, co-generation). In some other countries[152], the connection charges differ between producers and consumers. The discounts are varied in type - including full exemptions, exemption from a component of the connection charge or a fixed percentage reduction -, and differ across countries.

Figure 19: Exemptions, discounts or different treatment of producers

	Use-of network charges	Connection charges
Small producers or connection under certain voltage levels	6: AT, FI, FR, NO, RO, (SE)[153]	5: (BE)[154], FI, FR, IT, PL
RES producers	2: (DK)[155], MT	3: AT, DK, FR
Non-variable producers in distribution	1: DE	0
Ancillary services providers	1: SK	0

172 In some instances, NRAs have justified these specific tariff regimes through the corresponding cost impacts[156], but, in most instances, no such justification has been provided or the exemption or discount is motivated by non-network-related policy reasons (e.g. incentivising certain generation technologies). ACER also observes instances where some of the exemptions, discounts or specific tariff treatments are required by national law (AT, DK, FI, SE).

173 Finally, ACER notes that one country (SE) recently abolished the specific tariff regime for small producers, as the discount was not deemed cost-reflective.

151 In Ireland, producers with installed capacity of below 5 MW do not pay any network tariff for injection. In order not to discriminate between producers, all producers are exempted from charges on this amount and pay the incremental capacity from 5 MW onwards (e.g. a 7 MW generator is charged for 2 MW that is 7-5 MW). However, this may not qualify as a specific tariff regime, as none of the producers is subject to payment up to that threshold.

152 See Table 28 in Annex 1.

153 SE: DSOs may apply other differentiation, exemption or discount to some producers (e.g. depending on the size of the producer).

154 BE (Wallonia region): It is a marginal discount, that is, producers smaller than 10 kW receive detailed connection studies for free.

155 DK: It is not available for new producers.

156 For example, the injection by small producers at the distribution level is consumed at the same level, and thus payment for transmission costs is not justified.

5.5.3. Storage facilities

174 Pumped-hydro energy storage ('PHES') or other storage facilities (e.g. batteries) are connected to the network in the vast majority of countries[157]. In most countries, they are subject only to withdrawal charges (because there are no injection charges), but there are some countries where they pay both injection and withdrawal charges[158]. The withdrawal and injection charges for storage are typically the same as those applied to consumers and producers[159]. In most countries, the need for cost-offsetting was not identified by NRAs, as only a withdrawal charge is applied or the injection charge is very small.

175 Nonetheless, storage facilities often receive exemptions or discounts regarding use-of-network charges. As shown in Figure 20 (and further detailed in Table 30 in Annex 1), in five countries at least some storage facilities are fully exempt from use-of-network charges. In 13 countries storage facilities are subject to tariff discounts based on their distinctive features - for example, their commissioning date, technology, size, efficiency or purpose[160].

176 Six countries established specific regimes concerning connection charges for (at least some) storage facilities, including exemptions from or discounts on connection charges.

Figure 20: Exemption, discount or different treatment of storage facilities

	Withdrawal charges		Injection charges		Connection charges	
	Exemption	**Discount**	**Exemption**	**Discount**	**Exemption**	**Discount**
Countries	5: CY, IT, ES, PT[161], SI	13: AT, BE, HR, FI, FR, DE, HU, IE, LT, PL, RO, SK, SE	2: BG, FR[162]	0	2: CZ, SK	4: AT, HU, LT, PL

177 The reasons for specific tariff regimes for storage facilities are varied, but they are explained mainly by the beneficial impact to the system, increased security of supply, and their role in avoiding discrimination vis-à-vis auxiliary generation services, consumers or producers. In some instances, the exemption, discount or different treatment is set out by national law (LT, PL, SI).

178 ACER notes that several recent changes and changes under consideration reported by NRAs concern network charges for storage facilities[163], which may indicate a more widespread need for revision of the network charges currently applied to them (e.g. whether to differentiate them from those applied to producers and consumers due to their impacts on the network).

157 This applies to 19 countries at the transmission level and in 22 countries at the distribution level.

158 At least some storage facilities are subject to withdrawal charges in 14 countries: BE (Brussels region), BG, HR, CZ, FR, DE, GR, HU, IE, LT, MT, NL, PL, SK. At least some storage facilities are subject to both injection and withdrawal charges in six countries (AT, BE, FR, NO, RO, SK) at the transmission level and in seven countries (AT, BE (Flanders and Wallonia regions), DK, FI, NO, SK, SE) at the distribution level. In Germany, storage facilities are subject to the same negative injection charges as producers with particular features.

159 That is, the gross withdrawal is considered and charged through the same withdrawal tariff, without any charge for injection.

160 For example, BE (commissioned before or after July 2018), LT (the capacity is below or higher of a 1 MW threshold), SK (the capacity is below or higher of a 5 MW threshold), PL (efficiency of the storage facility), PT (energy-sharing), SK (ancillary services).

161 PT: Non-PHES storage facilities that do not participate in energy sharing over the public grid. In case they do participate, there is no exemption from the applicable network charges, although the facilities may still benefit from an exemption from energy policy costs.

162 FR: For distribution only.

163 See Figure 1 of this report.

5.5.4. Prosumers

179 In most countries prosumers pay only for withdrawal (because there are no injection charges). Where network charges apply for injection, prosumers[164] pay both charges, with a few exceptions where they pay only an injection charge or only a withdrawal charge. In two instances, NRAs reported cost-offsetting against double-charging for the same network costs through application of both injection and withdrawal charges[165]. Applying similar reasoning to that in the case of storage facilities, NRAs explained the lack of cost-offsetting with reference to no injection charge applying to prosumers, or its level being very low.

180 None of the countries exempts prosumers from all use-of-network charges, while storage facilities which are fully exempted in some countries. NRAs mainly explained this through the users' different natures (i.e. prosumers are final energy users) and their roles in the system (i.e. in some countries prosumers do not offer system services).

181 Nonetheless, as shown in Figure 21, several countries apply tariff discounts or other tariff differentiation to prosumers as well. The tariff discounts and other differentiations are often based on the type of prosumer, the connected power, the relative position of the generation and consumption facilities or their purpose.

182 The most common discount provided for prosumers is the net metering - that is, the energy-based component of the network charge is levied on the net withdrawal from the network (i.e. the injection is deducted from the gross withdrawal). While this instrument is not available for new users, it is applied to those who were already part of such a regime in the past[166].

183 In the vast majority of countries, prosumers are subject to the same connection charges as consumers. Three countries have established specific regimes concerning connection charges for prosumers, with one providing a different calculation and the other two providing discounts for prosumers.

Figure 21: Exemption, discount or different treatment of prosumers

	Injection charge exemptions	Withdrawal charge exemption	Net-metering	Cost-offsetting	Different tariff structure	Connection charge discount
Countries	12: AT, BE[167], CZ, DK, FI, FR, DE, IE, LT, NO, RO, SE	5: BE[167], BG, DK, FI, IE	9: BE[168], HR, CY, FI, HU, LU, NO, PL[169], SI	2: LV, SK	3: (DK)[170], EE, IT[171]	3: HU, LT, PL

184 The exemptions, discounts and different tariff treatments are mainly explained using energy and climate policy reasons (i.e. facilitating distributed RES); in only a few countries were they justified by system-beneficial impacts or avoided network costs. In Denmark, exemptions or discounts are set by law.

164 In this report, non-storage network users who can both inject into and withdraw from the grid are labelled 'prosumers'.

165 In Latvia, the principle is implemented in the DSO tariff structure. Network users are subject to both injection and withdrawal charges. In order to avoid double-charging through charges based on connected/contracted capacity (and are paid for infrastructure CAPEX and OPEX costs), if a prosumers' load capacity is higher or equal to the production capacity, the prosumer does not have to pay the capacity fee for injection. If the prosumer's production capacity is higher than the load capacity, they have to pay both injection and withdrawal charges. In Slovakia, if network users both inject and withdraw, their costs for access to the grid are based on only the higher capacity of the two.

166 See Article 15(4) of Directive (EU) 2019/944.

167 BE: In Flanders and Wallonia regions.

168 In Belgium's Wallonia region, prosumers without smart meters are subject to net metering.

169 PL: Free-of-charge withdrawal is possible up to a certain threshold of injected energy.

170 DK: Currently, large prosumers (above 50 kW) pay an energy tariff on the part of the production they consume themselves, while small prosumers pay a fixed yearly fee. These will be phased out, and prosumers on 0.4 kV will pay a fixed charge based on installed capacity and prosumers on above 10 kV will pay charges based on measured power.

171 IT: Connection charges for active users differ between small RES/combined heat and power generators and other active users.

5.5.5. Consumers

185 In all countries, consumers are subject to withdrawal charges. However, the structure of the withdrawal charges (e.g. tariff basis, time-differentiation) for consumers varies significantly across voltage levels. For example, power-based charges are more prominent at the transmission level, while ToU charges are more frequent at the distribution level. These differences are often explained by NRAs with reference to different metering capabilities and administrative costs.

186 Seven countries apply tariff discounts to large consumers, five countries apply discounts to households and two countries apply discounts to agricultural users (see Figure 22). Justifications for these discounts are largely missing. ACER notes that the Netherlands has recently abolished the discount for large consumers, as it was not deemed cost-reflective[172], while Denmark has recently introduced a reduced TSO system tariff for large consumers as regards their consumption exceeding 100 GWh annually[173].

187 In all countries, consumers are subject to connection charges. In most instances, the connection charges for consumers are shallow and based on individual actual costs. However, it is more common to have predetermined lump sum or standardised unit charges for consumers (at the distribution level) than for other network users.

188 ACER observes that, in several countries, vulnerable customers, households or very small business receive discounts on connection charges or are subject to different rules than other network users at the same voltage level to reflect some particularities of consumers' connections.

189 ACER notes that a number of countries apply additional network tariff discounts or offer specific tariff regimes to interruptible consumers (see Section 5.4), power-to-X facilities (see Section 5.5.6) or EV charging stations (see Section 5.5.7).

Figure 22: Exemption, discount or different treatment of consumers

Consumer group	Use-of-network charges	Connection charges
Large consumers	7: DK, FR, DE, GR, NO, PL, SK	0
Households, very small businesses or vulnerable customers	5: AT, BE, HR, IT, PT	8: AT, CY, HU, LV, LT, MT, PL, SI
Agricultural consumers	2: GR, LT	0
Interruptible or load-shifting consumers	3: HR, DK, DE	0

Note: The figure does not account for the cases where there are different tariff structures (bases) for different voltage levels or where consumers and producers pay different connection charges.

172 NL: For large consumers, the NRA decided to abolish the volume correction scheme (i.e. the volume discounts that system operators give to the energy-intensive industry) by the start of 2024, because it was deemed not to be in line with EU legislation.

173 DK: According to the NRA, the rationale behind the tariff reduction comes from a cost reflectiveness perspective, where it is assumed that those who paid the full tariff for their 100 GWh consumption have covered most of the system services cost that they have created. However, the NRA's approval of the tariff reduction for consumption of above 100 GWh annually is conditioned to ensure that the TSO provides documentation for cost reflectiveness of the method based on the actual data after two years of implementation of the tariff methodology, i.e. by early 2026. The duration of the approval is also limited to the end of 2029. The tariff reduction only applies to the system services cost recovery (system tariff). The reduction does not apply to the costs of building, upgrading, maintaining and operating transmission infrastructure (CAPEX and OPEX), nor to the costs of purchasing losses. In Denmark, these aforementioned costs are covered by the net tariff (use-of-network costs).

5.5.6. Power-to-X facilities

190 As shown in Figure 23, in total, six countries reported existing connection of power-to-gas or other power-to-X facilities (both referred to as 'P2X'). Except for those in one country (ES), the installed P2X facilities only withdraw from the grid, but do not inject. They are more frequent in distribution: in one country, P2X facilities are connected to both transmission and distribution grids, in one country only to the transmission grid and in five countries only to the distribution grid.

Figure 23: Power-to-gas and other power-to-X facilities

	P2X facilities connected to the grid	Tariff discount
Transmission	Only withdrawing: 2: FI, ES Both withdrawing and injecting: 1: ES	0
Distribution	Only withdrawing: 5: AT, DK, FR, DE, ES Both withdrawing and injecting: 1: ES	2: AT, DE

191 In two countries, a specific tariff regime has been established for P2X facilities by national law:

- in Austria, P2X facilities with at least 1 MW capacity do not pay use-of-network charges for the first 15 years after their installation, and they are also exempted from connection charges if their grid connection quotient does not exceed a certain threshold[174].
- in Germany, P2X facilities do not pay use-of-network charges, without any restrictions.

192 In the remaining five countries, the tariff treatment of P2X facilities is not different from that of other network users, meaning that they are subject to the same withdrawal charges as the consumers at the same voltage level and subject to the same connection charge rules as other consumers.

5.5.7. Electric vehicle recharging

193 In all the countries reviewed, there are operators of public recharging stations for EVs, in the form of publicly accessible EV recharging points, connected to the distribution grid (see Figure 24). A bidirectional charging option is available in 9 out of 23 countries with information available (39%)[175], while it is not available in 14 countries (61%)[176].

Figure 24: Specific tariff regimes for public EV recharging stations

	Publicly accessible EV-recharging points	Specific regime for use-of network charges	Discount on connection charges
Countries	29	8: CZ, IT, MT, PT, SK, SI, ES, (SE)[177]	2: FR, PL[178]

194 Two third of the countries (i.e. 19 out of 29) reported that the same tariff structure applies to the operators of publicly accessible EV-recharging points, as applied to other network users, while one third of the countries (i.e. 10 out of 29) reported some differences: eight countries reported specific use-of-network tariff regimes and two countries reported discounts on connection charges for publicly accessible EV-recharging points.

174 The threshold is 200 lfm/MWel. If the required grid connection does not exceed 200 linear metres per installed megawatt of capacity, the facility is exempt from connection charges.

175 BE (Wallonia region), BG, CY, DK, FI, DE, HU, LV, SE.

176 For six countries the information was not provided. For more information, please refer to Table 36 in Annex 1.

177 SE: One DSO also applies specific tariffs to public EV-recharging points. However, these are not regulated by the NRA.

178 PL: EV-recharging points (parks) are charged with a discounted connection charge, which equals 6.25% of connection CAPEX.

195 The specific tariff regimes applied to operators of public EV charging stations are mostly the same as those observed by ACER two years ago and include:

- a different tariff structure, offering a solely energy-based charge or the same mixed tariff bases as for other network users but with a greater weight for the energy-based component (applied in four countries: IT, PT, ES, MT);
- a specific off-peak withdrawal charge (during certain periods of the day or week) that is lower than that for other consumers (applied in two countries: CZ[179], MT);
- a specific tariff (applied in one country: SK);
- discounts on connection charges for EV charging stations compared to other network users (applied in two countries: FR, PL).

196 In some countries (IT, ES), the different tariff structure is optional for the operator of the EV charging stations and they can decide to be subject to the same charges as other users; but in most countries no choices are offered.

197 ACER observers that:

- vehicle-to-grid usage does not affect the network charge;
- no distinction in network charges is applied between fast and slow charging;
- the network charge is levied on the aggregate of the chargers under a single connection point and not calculated for each individual charger separately, except in one country (CY).

198 ACER recalls that two countries previously reported pilot projects/experimental initiatives on efficient EV charging, both dealing with private EV charging:

- in Italy, some low-voltage consumers were allowed a special increase of their technically available capacity during some off-peak periods when network usage is lower;
- in Portugal, the system-beneficial impacts and the corresponding tariff savings were tested with vehicle-to-grid injection.

199 Ongoing or soon-to-start reviews, consultations or studies were reported by several countries, including Belgium (Flanders region), Cyprus, Ireland, Italy and Luxembourg. Additional NRAs mentioned that revision of the tariff structures aims to incentivise limiting peak capacity use and shift EV charging to off-peak periods.

5.5.8. Energy Communities

200 As shown in Figure 25, more than half of the countries with information available (i.e. 15 out of 28) reported that an energy community is connected to the grid, mostly to the distribution grid[180]. In 13 countries, neither a citizen energy community ('CEC') nor a renewable energy community ('REC') is connected to the grid[181].

179 CZ: Specific tariffs (for small businesses and households) apply at the low-voltage level for EV, with eight hours (during the night hours of 18:00-08:00, automatically switched by the DSO) of low tariff (withdrawal tariff).

180 Directive (EU) 2019/944 (Article 2) defines the concept of energy communities – that is, renewable energy communities (RECs) and citizen energy communities (CECs). The main differences between the two definitions relate to the rules on membership, admissible generation technologies, the geographical scope and the allowed activities. This report refers to both as energy communities.

181 Among these countries, frameworks similar to the definitions of energy communities, pursuant to Article 2 of Directive (EU) 2019/944, may also exist. For example, in Hungary, 'apartment building energy communities' were introduced in a higher-level regulation, but they do not qualify as energy communities under EU terminology.

Figure 25: Connection of energy communities and the application of specific tariff regimes

	Energy communities connected to the grid	Specific tariff regime
Transmission	3: BG, GR, PT	1: PT
Distribution	15: AT, BE, BG, DK, FI, FR, GR, IE, LV, LT, LU, NL, PT, SI, SE	6: AT, BE, FR, LU, PT, SI

Note: For transmission, three countries (BG, GR, PT) reported only REC. For distribution, eight countries (AT, BE, BG, DK, GR, LT, LU, SI) reported both CEC and REC and five countries (FI, FR, IE, NL, SE) reported only CEC, three countries (LV, LU, PT) reported only REC. No data for Iceland.

201 In six countries, the energy communities are subject to a specific tariff regime. In most, it is limited to actual energy-sharing; in two countries (LU[182], SI), the treatment of energy communities is the same as the specific tariff regime for individual prosumers.

202 The specific tariff regimes applied to energy communities or collective self-consumers include:

- exemption from network charges for costs arising from the use of higher voltage levels (PT[183]);
- reduced use-of network charges for the quantities not withdrawn from the public grid by the community (AT);
- reduced or specific use-of-network charges on shared (self-consumed) electricity within the community or collective of self-consumers (e.g. same facility or based on contract and perimeter criteria) (FR, BE[184]);
- separate charging of each community member according to its use of the public network (SI, for new energy communities without yearly net metering)[185];
- net metering (i.e. charging only for the difference between withdrawal and injection by the energy community, not applicable to new users), similar to the regime that applies to individual prosumers (SI, not applicable to new energy communities);
- quarter hourly netting of production and consumption at a certain voltage level and within a certain geographical perimeter (LU)[186].

182 LU: The treatment for energy communities is the same as the specific tariff regime for individual prosumers, but is only valid on the low-voltage grid and within a geographical perimeter of 300 m.

183 PT: The answers provided for Portugal consider the tariff regime applicable to self-consumption using the network (i.e. energy sharing over the public grid).

184 BE: In Wallonia region, final customers located in the same building get an 80% rebate on network tariffs, excluding taxes and surcharges, on shared electricity generated in the building. For more information on the regime in Brussels region, please refer to the Brugel study from 2023 and the tariffs applicable to energy sharing in 2025–2027.

185 Community members pay network charges at adjusted tariff rates for the part of the electricity consumed that is generated by their share of the community's generation installations. The adjusted tariff rates are determined according to the extent of the network between the community's nearest generating installation and the individual community member. For the remaining electricity consumed, community members pay the network charge at the same tariff rates as other consumers in the same user group.

186 LU: The treatment for energy communities is the same as the specific tariff regime for individual prosumers, but is only valid on the low-voltage grid and within a geographical perimeter of 300 m.

203 A recent study was completed on energy sharing in Belgium (Flanders region)[187]. Ongoing or soon-to-start reviews or studies were reported in Denmark[188], Croatia[189], Cyprus, Ireland and Luxembourg.

Stakeholders' views

204 Some stakeholders are in favour of specific (tailor-made) tariff regimes for emerging network users that might make the system more flexible (e.g. publicly accessible EV charging stations or heat pumps) to exploit such potential. Some suggest differentiation of the network charges for industrial users versus households or for vulnerable consumers.

205 Some stakeholders stress that specific tariff regimes might be discriminatory and not cost-reflective, leading to excessive subsidisation and undermining competition for market participants not subject to special tariff treatment. Some stakeholders considers that the costs of designing such specific instruments might be higher than benefits. Some stakeholders claim that the target group (e.g. vulnerable consumers) may not be easy to clearly identify and thus the decisions could be highly political and arbitrary.

206 Some stakeholders are of the view that differentiation of consumers' network tariffs should be based on generally applied criteria, such as full load hours, voltage level, and whether they use the network during peak versus off-peak.

ACER considerations

207 Specific tariff regimes (exemptions, discounts and other differentiated tariff treatment) for particular network user groups may be beneficial to pursue policy goals (e.g. penetration of renewables or strengthened competitiveness of industry). However, if they do not reflect the corresponding network costs, they can not only distort system efficiency - further increasing the need for grid investment and overall system costs - but they can also lead to an intra-European subsidy race, ultimately harming the internal market. Unrelated policy goals should not determine the design of network charges; as this may lead to unintended consequences, such as reducing the efficiency of grid planning.

208 In line with the principles of cost-reflectivity and non-discrimination, ACER considers that specific tariff regimes should be applied only if they are duly justified by corresponding network impacts. Since applying different tariff structures to different network users and attributing different shares of network costs to them does not necessarily mean deviation from these principles, it is often not straightforward to judge what differences in network charges constitute undue tariff exemptions or discounts. Answering that question will require in-depth analysis.

209 In some instances, there is broad agreement that a tariff discount is not cost-reflective. For example, in the case of net metering[190], where prosumers are charged for net withdrawal instead of gross withdrawal, prosumers receive a discount compared to consumers; while in terms of their network impact, the opposite may be required in those cases where the injection takes place in periods of excess supply and withdrawal takes place during peak demands. This distortive impact increases

187 BE (Flanders region): The study shows that energy sharing does not necessarily lead to better grid usage and that the current distribution tariffs are not a barrier to energy sharing. Therefore, the regional regulator has not introduced specific tariffs or exemptions for energy communities (they are treated the same as individual consumers and prosumers).

188 DK: A method has been proposed on the basis of a new provision in Danish law. It introduces a tariff for a new customer category 'local associations of network users'. Local associations of network users are made up of one or more network users who together control both consumption and production and who are charged locally based on the consumption and production in the association. The method is under NRA evaluation and has not been approved yet.

189 HR: The NRA should undertake cost benefit analysis of the distributed generation using energy sharing pursuant to national law.

190 In this report, net metering is understood as the practice of charging network users the energy-based charges on the net value between energy withdrawal and injections over a relatively long time interval (e.g. month, year). In some examples of net metering, network users are entitled to an energy credit when injection exceeds withdrawal, and are allowed to use it against energy withdrawal in a later billing period.

with the length of the time interval for netting[191]. Similarly, for generation technologies without distinctive injection profiles and lower cost impacts, tariff discounts can create discrimination between producers.

210 ACER underlines that not only specific tariff regimes can create discrimination, but inconsistent tariff methodologies between transmission and distribution as well. Network tariffs should not incentivise a network user connecting to the transmission network instead of the distribution network (or vice versa), unless justified by the associated network efficiencies.

211 Even if unjustified exemptions or discounts in network tariffs are deemed by NRAs unavoidable in the short term (e.g. due to grandfathering clauses or network users requiring time to adapt to new tariffs), they should be phased out in the longer term, while providing an advance notice to network users of the timeline for this.

212 Finally, ACER deems it important that sufficient transparency regarding exemptions, discounts or specific tariff regimes is provided, including in relation to the quantified impact on network tariffs.

Recommendations

213 Unjustified exemptions, discounts or specific tariff regimes, including net-metering regimes, should be avoided and phased out.

214 Network tariff structures (e.g. tariff basis) and the price signals should be mandatory, without a possibility to opt-out or choose from an ‘a la carte’ menu of network charging options. Optionality may be temporarily reasonable during transition from one regime to another and the tariff impact on individual users is high.

215 If a tariff discount, exemption or specific tariff regime is granted,

- a detailed explanation of the pros and cons should be provided in the tariff methodology[192];
- the reduction of network tariffs for the concerned network users should be quantified and validated, indicating also which network users bear the impact;
- the necessity of the tariff discount should be reevaluated at least every 5 years, and the reason to keep the discount shall be provided.

216 Where net-metering regimes are not planned to be phased out yet, the time interval for netting should be decreased.

191 Several NRAs have indicated that they apply a short-term version of net metering, on the shortest time interval for billing purposes (e.g. 15 minutes), without granting any energy credit for later periods. As the power exchange between the user and the grid is more stable over short time intervals, net metering over very short time intervals does not appear to share the same detrimental incentives as net metering over longer time periods.

192 An accompanying document to the tariff methodology is deemed equivalent.

National practices

Portugal:

Specific tariff regime for self-consumption using the public grid, reflecting their network use

Challenge to address / reason for introduction:

Under the regime of self-consumption using the public grid, which can be labelled as an energy sharing scheme over the public grid, the cost-cascading approach in the tariff design is not adequate, whenever both the generation and consumption units are not directly connected to the transmission network.

Description of practice:

In Portugal, Decree-Law 15/2022 of 14 January, establishes rules for self-consumption, - namely, those on the application of tariffs. It establishes that, if the sharing of electricity from self-consumption uses the public grid, then access network tariffs apply. These tariffs are determined by the NRA. Access network tariffs for self-consumption using the public grid apply to the consumption point and correspond to the access network tariffs at the voltage level of consumption, deducted, totally or partially, of the use of the network tariffs of voltage levels above the production unit for self-consumption (UPAC). The deduction depends on the location of the UPAC and whether there are energy flows from lower to upper voltage levels (i.e. inverted power flows). Also, the Government can also determine the partial or total exemption from costs of general economic interest.

Note that if the electricity is shared using only the internal grid of a building (e.g. sharing of energy from a rooftop PV across the same building), no network tariffs apply. If the shared energy must use the grid beyond the internal grid (e.g. sharing with other buildings), network tariffs are applied based on the voltage levels involved in transmitting energy from generation to consumption as stated above. For example, and considering there are no inverted power flows, if both generation and consumption are located in the low-voltage grid, only the low-voltage distribution tariff applies; if generation is located in medium-voltage and consumption in low-voltage, then both the medium-voltage and low-voltage distribution tariffs apply. Therefore, if self-consumption does not use upper voltage levels of the public grid (e.g. transmission), it is exempted from the respective network tariffs for the use of the system.

Expected/actual results:

The expected result is increased cost-reflectivity for this new form of network utilisation.

6. Analysis of national tariff design practices: Other topics

6.1. Setting and approval of the tariff methodology

Main findings

217 As shown in Figure 26, in the majority countries, NRAs have sole responsibility for setting transmission and distribution tariff methodologies. This applies in 89% of countries (i.e. 24 out of 27) at the transmission level and 79% (i.e. 22 out of 28) at the distribution level[193]. In three countries (GR, IE, MT) at the distribution level and in one country (DK) at the transmission and distribution levels, the network operator proposes the tariff methodology, but it is subject to NRA approval. In two countries (FI, SE) the system operators individually set the tariff methodology based on the legal framework, and it is not subject to NRA approval.

218 ACER notes that the NRA's tariff-setting responsibilities have been enhanced in recent years in Germany where the network tariff methodology used to be set in (governmental) ordinances. Following the European Court of Justice ('ECJ') ruling that the competence for setting the network tariff methodology is now under the NRA's jurisdiction[194].

219 NRAs often report that certain tariff design elements are governed by national law, such as the prohibition of locationally differentiated network tariffs, bans on injection charges, or the provision of specific tariff regimes to some network users (small producers, prosumers, storage facilities or others)[195].

Figure 26: Setting and approval of the tariff methodology

Responsible body	Transmission tariff	Distribution tariff
Energy regulator sets	24	22
NRA approves, following a proposal from the network operator	1: DK	4: DK, GR, IE, MT
Network operator sets	2: FI, SE	2: FI, SE

Note: No information for Iceland.

220 As shown in Figure 27, in two thirds of the countries with information available (18 out of 27), the transmission tariff methodologies are set for a fixed period of time, typically four or five years; in the other nine countries, the period is longer or not predefined. In less than half of the countries (13 out of 28) the distribution tariff methodologies are set for a fixed period of time, while in more than half of the countries (15 out of 28), the distribution tariff methodologies are set for an indefinite period and revised as deemed necessary.

193 In Belgium, the distribution tariff methodologies are not set by the national regulatory authority, but by regional regulators for the Brussels, Flanders and Wallonia regions.

194 Judgment of 2 September 2021, Commission v Germany, C-718/18, EU:C:2021:662.

195 For more information, please refer to paragraph 133 (prohibition of locational signals, paragraph 71 (prohibition of injection charges), paragraph 178 (discounts for storage facilities), paragraph 173 (discounts for producers), paragraph 185 (discounts for some prosumers), paragraph 187 (discounts for some consumers) and paragraph 72 (discounts for P2X).

221 The transmission and distribution tariff values are typically updated on a yearly basis[196]. However, ACER observes three countries where the tariff values are updated more frequently[197]. In some countries, the frequency of the tariff value update is not predefined. Inflation is a variable that is frequently taken into account in network tariff updates.

Figure 27: Frequency of revision of the tariff methodology and update of the tariff values

	Transmission		Distribution	
	Fixed period	**No defined period**	**Fixed period**	**No defined period**
Tariff methodology	18: BE, BG, CY, CZ, FI, FR, GR, HU, IE, IT, LT, LU, NL, PL, PT, RO, SK, ES	9: AT, HR, DK, EE, DE, LV, NO, SI, SE	13: BE, BG, CY, CZ, FR, HU, IT, LU, NL, PT, RO, SK, ES	15: AT, HR, DK, EE, FI, DE, GR, IE, LV, LT, MT, NO, PL, SI, SE
Tariff values	27	1: EE	24: AT, BE, BG, HR, CY, CZ, FR, DE, GR, HU, IS, IR, IT, LV, LT, LU, NL, NO, PL, PT, RO, SK, SI, ES	5: DK, EE, FI, MT, SE

Note: Some information was not provided for Iceland.

222 Within every country a single transmission tariff methodology is applied to each TSO. While the distribution tariff methodology is typically also the same for each DSO, there are a few exceptions. In these instances, either the NRA sets different methodologies for different DSOs (AT, PL)[198] or the DSOs are free to choose their own tariff structures within certain legal restrictions and, as a result, the tariff structures are indeed not identical for all DSOs (DK, SE)[199].

223 Carrying out public consultations prior to setting transmission and distribution tariff methodologies is a common practice in most countries[200]. In four countries (AT, DE, HU, PL), only specific stakeholders, such as system operators, are involved in the consultations. The setting of the distribution tariff methodology is not preceded by any systematic consultation in three countries (FI, MT, SE).

ACER considerations

224 Pursuant to Article 59(1)(a) of Directive (EU) 2019/944, each NRA has the duty of fixing or approving network tariffs or their methodologies, or both.

225 Network tariff setting is the result of a three-step process[201]:

- first, the allowed or target revenues of the system operators (including the remuneration method for TSO or DSO costs) are determined.

196 In two countries (BE, SI), the tariff values are set ex ante, but separately for each year of the regulatory period.

197 Transmission: CY, IS, LV.

198 In Austria, a different methodology is used for non-audited DSOs (about half of DSOs), which can charge the tariffs valid in the local network area without being part of the benchmarking procedure. In Poland, there are some differences between the tariff methodologies for the five legally unbundled DSOs and those for smaller DSOs.

199 In Denmark and Sweden, the DSOs are free to choose their own tariff structures (in Denmark, most DSOs apply the same ones). In France, the tariff methodologies are not legally required to be the same for all DSOs, but there is currently no difference.

200 In some countries, public consultations are complemented by additional consultations: for example, in Portugal, a dedicated tariff council also provides inputs; in Croatia the NRA is legally obliged to consult the consumer protection associations before issuing a decision on network tariff values.

201 These three steps are closely linked, and the duty of the NRA pursuant to Article 59(1)(a) of Directive (EU) 2019/944 shall be read in conjunction with Article 18 of Regulation (EU) 2019/943 encompasses them all.

- second, the tariff structure is defined.
- third, the costs/revenues are allocated to each of the tariff structure's items (i.e. charges paid by network users).

226 ACER considers it essential that NRAs are provided with sufficient regulatory control over the three steps in the tariff setting process in order to ensure that methodologies are free from any political or commercial interest, which is ensured by NRAs' independence guaranteed by EU law. NRAs shall be provided with adequate human and financial resources for this purpose, pursuant to Article 57(5) of Directive (EU) 2019/944.

227 ACER welcomes the fact that, in some countries, NRAs' tariff setting responsibilities have recently been enhanced. However, some of the national legal provisions may still be unduly limiting NRAs' regulatory control over the tariff setting process pursuant to Article 59(1)(a) of Directive (EU) 2019/944 read in conjunction with Article 18 of Regulation (EU) 2019/943.

228 Electricity systems in Europe are rapidly changing due to the energy transition[202] and require quick adaptations of network tariffs to facilitate efficient network use. At the same time, the regulated entities and network users require sufficient time to adapt and face fewer uncertainties regarding their investment decisions[203].

229 ACER is of the view that setting the tariff methodology for at least four years allows for (a) adequate implementation of new tariff structures, (b) appropriate analysis of the possible actions to be taken, (c) effective stakeholder involvement and (d) resource savings compared with higher frequencies. At the same time, more regular updates of tariff values can result in better cost-reflectivity, and, if done based on a predefined methodology, still preserve a level of predictability. The volatility observed in different inflation metrics over recent years provides an additional argument justifying a yearly update of tariffs.

230 ACER considers that if a new tariff methodology significantly affects the tariff values for grid users, a multi-year transition process can increase its acceptance. If combined with proper monitoring, this can also enable interventions to take place in a timely manner, where necessary.

231 ACER underlines that inconsistent tariff methodologies across the transmission and distribution levels can result in discrimination between network users and distortions in overall system efficiency - for example, where a network user is incentivised (by lower network charges) to connect to a particular network level, despite this creating higher overall system costs than connecting to other voltage levels. Inconsistencies are a particular risk where different entities set the transmission and distribution tariff methodologies, or where different tariff methodologies apply to different DSOs.

232 ACER considers that, in the context of the energy transition and particularly with the changes in the distribution grids[204], ensuring transparent and effective stakeholder involvement is of paramount importance for well-informed regulatory decisions and better public acceptance. In addition, public consultations are the most appropriate means of interacting transparently and inclusively with stakeholders.

233 Changes in tariff methodologies may entail significant cross-border impacts. Therefore, public consultation should be accessible to the stakeholders in neighbouring countries within the EU internal market which are affected by the change. Additionally, information sharing among NRAs within this tariff report and beyond by direct consultations is of the utmost importance. For example, in case of injection charges, which has an impact on generator's competition in the internal market, coordinated approaches amongst Member States are highly preferable compared to what might otherwise become intra-EU Member State competition through network tariffs.

202 E.g. increased penetration of intermittent distributed energy, innovative technologies, EV charging, demand-side response.

203 The past review of national tariff frameworks showed that stability appeared as key objective being pursued when setting network tariffs so far.

204 The role of DSOs and the way distribution grids are operated are being significantly impacted by the increased integration of RES, increased electrification, the more active roles of some network users and the deployment of smart meters.

234 ACER's opinion on the appropriate range of transmission charges paid by electricity producers (ACER Opinion No 09/2014) remains valid, and NRAs should consider it when designing and/or issuing decisions determining injection charges (e.g. regarding the impact of energy-based injection charges on wholesale prices and the use of power-based injection charges to recover infrastructure costs).

Recommendations

235 NRAs should directly set the transmission and distribution tariff methodology or as a strict minimum approve the methodology proposed by the respective system operators, without undue restrictions by national law[205].

236 NRAs must ensure that the methodologies are consistently defined across the transmission and distribution networks.

237 The tariff methodology period should be set for at least four years, providing for

- a revision under justified circumstances;
- a multi-year transition process to protect grid users with significant tariff impact[206];
- tariff value updates with at least a yearly frequency based on variations of the drivers defined by the tariff methodology and accounting for inflation.

238 One or more public consultations should be carried out systematically by the national regulatory authorities or the system operators, as decided by the national regulatory authority, ahead of each major revision of the tariff methodology to interact transparently and inclusively with stakeholders.

239 The consultation documents should include the reasons for the proposed network tariff design and corresponding assessments underlying it.

6.2. Transparency

Main findings

240 In the context of tariff methodologies, transparency can be understood as the public availability of information on the network tariff methodologies themselves, on the cost categories recovered by the network tariffs, the specific amounts recovered by individual tariff elements and the applied tariff values. As shown in Figure 28, ACER finds that the level of transparency regarding transmission and distribution tariffs differs across the countries assessed. Transparency is generally higher for transmission tariffs than distribution tariffs.

205 NRAs' regulatory control over the tariff-setting process is ensured by Article 59(1)(a) of Directive (EU) 2019/944 read in conjunction with Article 18 of Regulation (EU) 2019/943.

206 Significant tariff impact should be assessed in conjunction with the overall impact on the final electricity bill.

Figure 28: Tariff information that is not publicly available

	Transmission	Distribution
Detailed network tariff methodology	3: AT, FI, PL	3: FI, MT, SE
Cost categories recovered by each network tariff element	1: AT	10: AT, FI, HU, IE, LV, LU, MT, SK, SI, SE
Amount recovered by each network tariff element (separately)[(a)]	15: AT, BE, CY, CZ, DK, EE, DE, HU, LV, LU, PL, RO, SK, SI, ES	22: AT, BE[207], BG, CY, CZ, DK, EE, FI, DE, GR, IE, LV, LT, LU, MT, NL, NO, PL, RO, SK, SI, SE
Network tariff value for each network user group	0	1: LU

[(a)] The figure does not account for instances where the transmission/distribution tariff information is available only in aggregated form, not per tariff element.

Note: No data for Iceland.

241 In the vast majority of countries (89%, or 25 out of 28)[208], both the transmission and the distribution tariff methodology is publicly available (unless non-applicable), while in one country (SE) only the transmission tariff methodology is published and in two countries (AT, PL) only the distribution tariff methodology is published. In one country (FI), neither the transmission nor the distribution tariff methodology is published.

242 The information on what specific cost categories are recovered by the network tariffs is publicly available in almost all countries (i.e. 26 out of 27) at the transmission level and 61% of countries (i.e. 17 out of 28) at the distribution level.

243 Information about the amounts recovered by each tariff element is publicly available in significantly fewer countries; 44% (i.e. 12 out of 27) at the transmission level and 18% (i.e. 5 out of 28) at the distribution level. The vast majority of countries do not publish the cost data or publish them only in a more aggregated form.

244 As illustrated in Figure 1, within use-of-network charges, ACER advocated for a differentiation between network tariffs or tariff elements for building, upgrading, maintaining and operating the grid, for grid losses, for system services, for metering and for reactive power.

245 As shown in Figure 29, in most countries, such differentiation is only partially implemented, and some of these cost categories are bundled into a single tariff or tariff element.

207 BE: In Brussels and Wallonia regions.

208 Malta is also accounted for in this value due to its lack of transmission network.

Figure 29: Separate tariffs or tariff elements in transmission and distribution tariff structures

Tariffs / tariff elements	Transmission	Distribution
Building, upgrading, maintaining and operating the grid	6: AT, BE, HU, IS, PL, ES	5: AT, HU, MT, ES, (SE)
Grid losses	6: AT, HU, IS, PL, SK SE	5: AT, HU, IE, MT, (SE)
System services	9: AT, BE, CZ, HU, LT, NO, PL, RO, SK	4: AT, LT, MT, (SE)
Metering	6: AT, CY, FR, DE, IS, LU	12: AT, BE (Brussels and Wallonia regions), CY, DK, FR, DE, HU, IS, LU, MT, NL, (SE)
Reactive energy	14: AT, BE, BG, HR, FR, IT, LV, LT, NO, PL, PT, RO, SI, ES	18: BE, HR, CZ, EE, FI, FR, HU, IT, LV, LT, NL, NO, PL, PT, RO, SK, SI, ES

Note: the cases where a cost category is not applicable, (e.g. no such cost to the TSO/DSO), were not added to the Figure. In Sweden, at distribution level, the answer applies only to some DSOs.

246 ACER observes that NRAs obtain cost data with different granularity depending on the country and often also the network (i.e. transmission or distribution):

- in most countries the NRAs possess at least some of the transmission and distribution cost data (listed by ACER), recorded separately for each cost category, but in some countries they are bundled with one or more other cost categories[209];
- in about 40% of countries[210], the transmission or distribution cost data (at least in an aggregated form) are available per different transmission (e.g. extra-high, high) or distribution (e.g. medium, low) voltage level.

ACER considerations

247 ACER considers that the varying network tariff structures across the countries and cost categories recovered by each element thereof hinder a straightforward comparison of network tariffs in Europe and risks of making any such comparison misleading. In order to increase clarity, a more harmonised terminology of the network tariff elements would be necessary.

248 ACER is of the view that the availability of fundamental tariff-related information, presented in a structured way and including a clear and understandable description of the tariff-setting method, is of the utmost importance in order to ensure transparency and comparability in network tariff setting and to verify whether other tariff principles are being addressed[211]. For this purpose, in addition to national platforms, it would be beneficial to establish a central EU repository where tariff information is available in a structured manner using harmonised terminology.

249 In order to make well-informed tariff decisions and adequately allocate costs across the network tariff structure, NRAs should improve data collection processes. More precisely, NRAs should obtain sufficiently granular information regarding network conditions, network use and corresponding cost impacts to identify the appropriate cost drivers of different cost categories and set time-differentiated and/or locationally differentiated network charges, where required.

209 Transmission costs in GR and distribution costs in DK, FI, GR, RO, ES.

210 AT, BE, CY (only distribution), HR (only transmission), EE, IS, LT (only distribution), LU, NL (only transmission), RO, SK.

211 This is also underlined by the provisions in Article 59(9) of Directive (EU) 2019/944.

Recommendations

250 NRAs should differentiate at least the following cost categories[212] for the purpose of allocating costs to transmission and distribution tariff structures[213]:

- transmission infrastructure costs, such as return on capital, depreciation and operational expenditures[214];
- distribution infrastructure costs, such as return on capital, depreciation and operational expenditures;
- costs of transmission losses[215];
- costs of distribution losses;
- costs of metering services;
- costs of system operators purchases of system services[216];
- costs of withdrawing and/or injecting reactive power outside the allowed limits.

251 NRAs or system operators, as decided by the NRA, should publish:

- the detailed transmission and distribution tariff methodologies;
- the cost categories recovered by each transmission and distribution tariff element;
- the estimated or actual amounts recovered by each transmission and distribution tariff element;
- the transmission and distribution tariff values for each network user group (for each year);
- studies (or at least their summaries) underlying key network tariffication choices;
- specific tariff regimes, exemptions and discounts with justifications.

In addition, NRAs and system operators are encouraged to publish a tariff model that details the computation of the transmission and distribution tariffs.

252 The above information on network tariff structures and values in each country should be progressively presented in a centralised EU repository that could be managed by ACER and NRAs[217].

212 ACER notes that some of the costs listed are not applicable in some countries, because they are recovered by means outside the network tariff structure.

213 The recommendation does not predefine a final network tariff structure, which may further split some of these cost categories into different network tariff elements or merge some of them into a single tariff element. However, NRAs should be able to differentiate the share of each cost category listed above at the level of individual network charges.

214 It also includes costs related to cross-border payments related to cross-border cost allocation decisions.

215 It also includes costs related to the Inter-TSO compensation mechanism.

216 It also includes costs related to reserves, congestion management, voltage control and reactive power support, black-start capability and system balancing.

217 For DSOs, collection and inclusion of data may be envisaged only for DSOs serving above a certain threshold of number of customers.

6.3. Cost allocation model

Main findings

253 The term 'cost allocation model' refers to the conceptual approach for determining the unit prices of a network charge, allocated to network users, given the level of allowed or target revenues to recover and the level of forecasted quantities[218]. National approaches can be categorised according to three cost allocation models: (a) average cost, (b) incremental cost and (c) forward-looking cost.

254 The average cost model determines unit prices of the network charge by dividing the allowed or target revenues by the forecasted quantities of a cost driver. In contrast, the incremental and forward-looking cost models determine the unit prices by estimating the additional costs due to an incremental increase of a cost driver[219]. Incremental or forward-looking cost models need to employ some adjustment to ensure full cost recovery, bringing the residual cost to zero[220].

255 80% of countries (i.e. 23 out of 29) follow an average cost approach, while 20% (i.e. 6 out of 29: HR, EE, FR, NO, PT, SE) apply either an incremental or a forward-looking cost model for the power-based component and/or the energy-based component[221]. In the second group, the residual costs are recovered either through additive or multiplicative adjustment of the unit prices, through the network operator's request for approval of new network charges or through separate charges[222].

256 All countries apply the same cost allocation model across transmission and distribution tariffs.

ACER considerations

257 ACER notes that, in general, applying the same cost allocation model across transmission and distribution networks within a country supports having a coherent tariff methodology across transmission and distribution.

258 In theory, incremental and forward-looking cost models are better approaches to signal the true cost of using the network than an average cost model, if the residual cost is recovered in a non-distortive way[223] and balance is maintained with other tariff-setting objectives, such as non-discrimination, fairness or sustainability.

218 Cost allocation models are not to be confused with the methodology for setting the allowed or target revenues of the network operator.

219 In the incremental cost allocation model, the increments in network costs are associated with increments in cost drivers, where the data used refer mainly to historical data. In the forward-looking cost allocation mode, the increments in network costs are associated with increments in cost drivers, where the data used refer mainly to forecasted data and/or simulation models. In both instances, the incremental cost per cost driver represents a long-run marginal cost and the application may result in residual costs that need to be accounted for to ensure full cost recovery.

220 For more information on how each of these cost allocation models ensure cost recovery, please refer to [ACER Report on transmission and distribution tariff methodologies in Europe](#) (January 2023, pp. 14-23).

221 An incremental or a forward-looking cost model is applied to power-based charges: SE, PT; to energy-based charges: NO (marginal losses assessment in each connection point), EE; and to a combination of energy- and power-based charges: HR, FR.

222 In Croatia, in year Y, the residual financial flow (excess income or residual costs) is transposed from year Y-1 when setting network charges for year Y+1, adjusted for inflation. In Estonia, the law does not allow for the application of any additive or multiplicative adjustment to account for any residual cost. If network costs are higher than the revenues obtained from the incremental unit price, the network operator has the right to submit a request for approval of new network charges. France and Portugal apply a multiplicative adjustment of the unit charges to account for the residual cost. Norway recovers the residual costs through fixed and power-based charges. Sweden applies a separate component to recover the residual cost.

223 That is, they are fixed using lump sum charges or, if that is not feasible, using a rule of Ramsey pricing.

259 The widespread use of average cost models is probably related to the advantages in terms of cost recovery (as, by design, the models ensure recovery of the allowed or target revenues), the complexities involved in modelling incremental or forward-looking costs and the lack of information on the effectiveness and impact of these signals[224].

260 However, the application of incremental or forward-looking approaches may gain momentum with the energy transition, as they can better ensure that the costs of the necessary additional grid investments are allocated to those network users in whose interest they incur. Therefore, NRAs should consider these models as options for cost allocation.

Recommendations

261 NRAs should evaluate the advantages and disadvantages of applying incremental or forward-looking cost allocation approaches and consult the results of such studies with their stakeholders, aiming at better alignment of network user behaviour with the needs for future investments.

262 Where NRAs decide to apply incremental or forward-looking approaches, NRAs should explain in their tariff methodology[225] how the recovery of the residual costs ensures non-discrimination, fairness and sustainability.

6.4. Cost cascading

Main findings

263 Cost cascading means that network users pay the costs of the voltage level of their connection and the costs related to other voltage levels they use. Network costs in all 29 countries are cascaded only in a top-down paradigm, meaning from higher to lower voltage levels. There was no instance of reverse cost cascading reported, as a result of inverted power flows in the grid[226].

264 Cost cascading can occur in three forms: (a) from transmission to distribution, (b) from transmission to transmission and (c) from distribution to distribution. Cost cascading from transmission to distribution is the most common form, applied in 28 countries (i.e. all where applicable)[227]. Cost cascading from distribution to distribution is also very common (i.e. 83% or 24 out of 29 countries apply it)[228]. Cost cascading from transmission to transmission is less common (i.e. 38% or 10 out of 26 countries apply it)[229].

224 In these cost models, a backward-looking perspective could still be relevant to achieving cost reflectivity. The dimensioning of the grid by the network operator assumes a stochastic use of the network (e.g. simultaneity factors for supply and demand) and is therefore based on predictions. If network users significantly change their utilisation profile or connection requests do not materialise under the expected terms, they may result in new network costs or imply that previously incurred costs could have been avoided.

225 An accompanying document to the tariff methodology is deemed equivalent.

226 According to previous (2023) ACER findings, two countries (DE, SE) were considering implementing reverse cost cascading, while other countries were not for various reasons (e.g. inverted power flows are not a frequent phenomenon, there is no evidence of benefits for higher voltage users from low-voltage investments, data on costs broken down by voltage level are not collected or lack of sufficient information on the flows in the network). See ACER Report on electricity transmission and distribution tariff methodologies in Europe (January 2023, p. 22).

227 Malta has no transmission network.

228 Exceptions: BG, IS, IE, LT (upon DSO's choice) and MT.

229 Where transmission costs are not determined per transmission voltage level, this effectively prevents cost cascading from transmission to transmission; therefore, transmission cost allocation to transmission-connected network users in bulk is not considered as a form of cost cascading in this report.

265 The transmission costs that are cascaded to distribution may be billed to network users explicitly as a transmission tariff element of their final bill or implicitly as part of their distribution tariff. In about half of the countries, the cascaded costs are included in a separate tariff or tariff element providing information on the magnitude of this cost cascading, while in the other half of the countries no separate tariff or tariff element quantifies the value of the cost-cascading effect[230].

266 In the vast majority of countries, cost cascading is applied to all cost categories under the same rules. In the remaining countries some of the cost categories are not subject to cost cascading; or they are subject to different cost-cascading rules. For example, cost cascading does not apply to some cost categories because the costs are more directly related to serving users connected at a certain voltage level (e.g. metering and billing) or the costs cannot be differentiated according to voltage levels (e.g. some system services)[231].

267 ACER observes that two countries (AT, PT) reported exemptions from cost cascading for specific groups of network users. In both countries, network users can be exempted from network costs related to voltage levels above the level of connection of the energy injected into the grid in case of energy sharing over the public grid.

268 As described in Section 6.3 of this report, information on the network costs per voltage level in most of the countries is not available[232].

ACER considerations

269 ACER considers that the cascading of those costs that are not specific to a particular connection point or voltage level represents an important element of cost reflectivity. In order to avoid the application of 'postage stamp' tariffs (i.e. identical across all voltage levels), which do not consider cost causality, network users should contribute to the costs of each network level they use.

270 The top-down paradigm of cost cascading reflects the traditional organisation of the power sector in which generators are connected at the higher voltage levels. However, following the large-scale penetration of distributed generators, this paradigm is already being challenged.

271 In countries where the predominant direction of the electricity flow is still from transmission to distribution, the principle of cost cascading from a higher voltage level to a lower voltage level is appropriate. However, in countries where inverted power flows[233] are becoming a more frequent phenomenon, a thorough review of this principle and some form of partial or reverse cost cascading may be necessary to adequately reflect the physical use of the network.

272 Some network users (e.g. the special cases of energy communities) may be regarded as consuming energy generated locally and therefore relying less on upper voltage levels. Therefore, applying the same cost allocation from the cost-cascading approach in tariff design for them may not be cost-reflective; instead, the rules should adequately reflect these users' cost impact.

273 However, ACER also notes that, regardless of the energy flow (and its direction) between the higher and lower voltage levels, a network user at the lower voltage level may still benefit from the ancillary services provided by the transmission grid (e.g. frequency). Any differentiation between network users regarding the application of the cost cascading principle should be justified and regularly re-evaluated, particularly under changing system conditions, to avoid any negative or positive discrimination.

230 For more information on cost cascading from the transmission level to the distribution level, please refer to Table 2 in Annex 1.

231 For more information on countries where a cost category or a network user is not subject to cost cascading or subject to different cost-cascading rules, please refer to Table 2 in Annex 1.

232 See also paragraph 246 of this report and Table 49 in Annex 1.

233 That is, power flows from a lower voltage level to a higher voltage level.

274 ACER considers that data collection on network costs and network use broken down by voltage level and on the power flows between various voltage levels (as described in Section 6.3) is a prerequisite for properly applying any cost cascading principle. Depending on the complexity of attributing the relevant network costs to specific voltage levels, different levels of granularity in data collection may be justified for different cost categories.

275 When deciding how much of the transmission cost (which is allocated to withdrawal) should be cascaded from the transmission level to the distribution level, a simplified cost-cascading proxy as shown in Figure 30 could be applied. The proxy assumes that the higher the generation at the distribution level, the less the distributed consumption uses the transmission level. Therefore, the higher the share of distributed generation, the lower the proxy and the share of transmission costs to be allocated to distribution.

Figure 30: Cost cascading proxy

Proxy = [$G \times (C + c)/(G + g) - C$]/[$G \times (C + c)/(G + g)$]

Where:
G = generation at transmission (MWh)
g = generation at distribution (MWh)
C = consumption at transmission (MWh)
c = consumption at distribution (MWh)

Example
Where *G* = 80 MWh, *g* = 20 MWh, *C* = 20 MWh and *c* = 60 MWh:
Proxy = 69% = 44/64 [80 × (20 + 60)/(80 + 20) – 20]/[80 × (20 + 60)/(80 + 20)] = (64 – 20)/64

Note: If there is no consumption at the transmission level, the proxy equals 100 %, meaning all costs should be borne by distribution. When distributed generation represents a share of total generation that is equal to the share of consumption at the distribution level, the proxy equals 0 %, meaning there should be no cost cascading, as each level is self-sufficient on average. The higher the share of distributed generation, the lower the proxy.

Recommendations

276 NRAs should make each network user contribute to the costs of each voltage level used by them via adequate cost cascading.

277 Where cost cascading is not applied, or not applied uniformly[234], NRAs should provide the economic rationale for this decision in the network tariff methodology[235].

278 NRAs should not cascade the cost of connection- and voltage-specific services - such as metering, billing and metering-related customer services - from one voltage level to another.

279 NRAs should regularly reassess the appropriateness of the applied cost-cascading rules under changing system conditions, especially when the yearly (gross) injection from a lower to higher voltage level exceeds 10% of the yearly (gross) withdrawal between the same voltage levels.

280 To apply cost cascading, NRAs should collect network costs and volumes of injection and withdrawal per voltage level.

234 This includes the following cases: (a) a cost category or a network user is not subject to cost cascading, (b) a cost category or a network user is subject to different cost-cascading rules and (c) cost cascading is not applied between two differentiated voltage levels.

235 An accompanying document to the tariff methodology is deemed equivalent.

6.5. Reactive energy charges

Findings

281 One of the effects of the energy transition is the reduced availability of traditional thermal generation units and capabilities to control network voltages. Therefore, in several countries, the costs related to controlling network voltages and managing reactive power have increased over the last few years and reactive energy charges have gained importance.

282 Charges for reactive energy are applied in most countries: in 19 out of 28 countries[236] (i.e. 68%) at the distribution level and in 15 out of 26 countries[237](i.e. 58%) at the transmission level. Out of these, all countries apply charges to reactive energy withdrawals and a large majority of countries (around 75% for distribution, around 70% for transmission) apply charges to reactive energy injections.

283 In several countries, capacity thresholds or voltage connection levels are used to differentiate consumers who are subject to reactive energy charges from those who are not subject to them (i.e. exempting those under a particular threshold or voltage level)[238].

284 In the vast majority of countries, charges are set on the basis of reactive energy exchanges that exceed the threshold for withdrawals and, where applicable, the threshold for injections. The limit power factor (or limit percentage) varies across countries. The most frequently used thresholds are: (a) a power factor of 0.95 or, in broadly equivalent terms, reactive power withdrawal at 33% of the active power or (b) no reactive injection allowed (=power factor 1)[239].

285 With very few exceptions, the values of reactive charges range from 3 EUR/Mvarh to 20 EUR/Mvarh. In about half of the countries, the same values apply to reactive withdrawals and reactive injections (when charged), while in the other half, the charges are differentiated, without a common pattern. In about half of the countries, different values apply in transmission and distribution.

286 In a few countries, the charges are differentiated by voltage level[240] and/or by time-of-use[241] and are constructed using stepwise increases of the unitary value[242], where reactive withdrawals increase.

236 BE, HR, CZ, EE, FI, FR, HU, IE, IT, LV, LT, NL, NO, PL, PT, RO, SK, SI, ES (Table 37 in Annex 1).

237 AT, BE, BG, HR, FR, DE, IT, LV, LT, NO, PL, PT, RO, SI, ES (Table 37 in Annex 1).

238 BE, CZ, IT, PT, RO, SI.

239 For reactive energy withdrawals, seven countries apply a power factor of 0.95 and two countries apply a narrower limit, while in four countries the limit is less stringent. For reactive energy injections, eight countries do not allow any reactive injection, while in five countries a power factor limit other than 1 is used. In Finland and Norway, the DSOs are free to set the tariff structure and, consequently, the power factor both for reactive withdrawals and injections. In Portugal, the DSOs can decide not to charge for reactive energy injections (the corresponding charge is approved by the NRA).

240 Higher values apply to for lower voltages and lower values apply to users connected to high-voltage grids where such grids are defined as distribution grids.

241 In four countries (BE (Brussels region), IT, PT, ES), the charges are differentiated between day-time and night-time (or between peak and mid-peak versus off-peak hours), where reactive withdrawals are charged in peak- and mid-peak conditions, but are not relevant and critical in off-peak hours.

242 In tree countries (IT, PT, ES), the charges for reactive withdrawals are applied stepwise, with increasing values when the reactive exchanges are significantly higher than the first threshold.

ACER considerations

287 Current NRA practices suggest that reactive energy charges are a relevant cost signal to reflect the costs of compensating reactive energy exchanges. Setting cost-reflective reactive energy charges require monitoring the evolution of costs due to voltage control and reactive energy management, including those due to risks of overvoltage in off-peak hours.

Recommendations

288 Where costs related to voltage control and reactive energy management are deemed significant by the NRA, the NRA should consider a review of reactive energy charging, taking into account the benchmark for reactive charging thresholds and the values provided in this report.

6.6. Time-of-use charges

289 Time-differentiated or time-of-use network charges (i.e. 'ToU charges') give cost signals to network users through higher charges that encourage them to use the network less in some periods during the day, week or year when network utilisation is closer to the technical limits (local or system peak) and through lower charges that encourage them use it more in periods when network utilisation is lower[243]. An adequate cost signal to reduce peak energy flows can decrease the need for additional investments to expand the network's capacity.

290 ToU charges can be static, where the different time periods are defined in advance (e.g. when setting the tariff methodology or annually), or they can be more dynamic, where the peak period and/or price of network use is set only at short notice, close to real time (e.g. a few days in advance or within the day)[244].

291 Use of static ToU signals is very common in Europe, more at the distribution level and less at the transmission level (see Figure 31). Static ToU charges are currently applied almost exclusively for withdrawal, but not for injection[245].

292 For distribution, 21 out of 28 countries (78%) apply static ToU tariffs, while 7 countries do not apply them. For transmission, 11 out of 27 countries (40%) apply static ToU signals (each of them also applies it for distribution), while 16 countries do not apply them. The arguments presented by NRAs on why they do not apply ToU tariffs include the lack of efficiency or effectiveness of time signals in terms of affecting network users' behaviours in their national context or limitations based on the meters' capabilities[246].

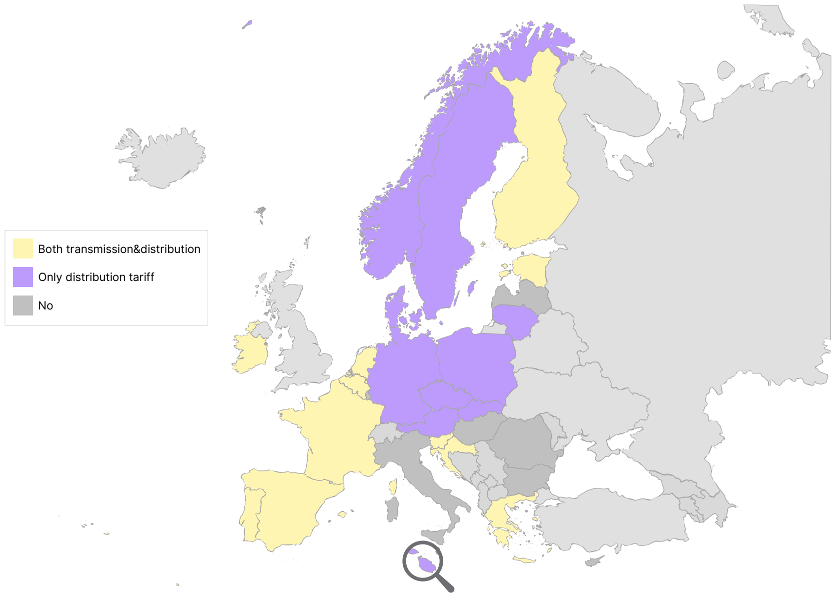
243 The coincident rising use of the network during peak periods may induce the need for network reinforcement, thus justifying a higher network charge. Use of the network in off-peak periods does not lead to additional costs and thus a lower charge is justified.

244 In a critical peak pricing regime, the critical peak pricing applies to a limited number of days or hours when the network has a higher probability of being constrained. The critical peak periods are activated on short notice, but the price is known in advance. In a real-time pricing regime, the network charge is determined very close to the event (or only ex post) and prices are potentially dynamic, subject to the varying system conditions (e.g. grid bottlenecks, congestions).

245 In the past, Portugal applied a static ToU injection charge. In Sweden, it is applied by some DSOs.

246 For example, claims include the following: energy market prices provide better signals, signals embedded in the network tariff may contradict energy price signals, network users are unwilling to react to ToU signals, the complexity of implementing ToU network tariffs may not outweigh the benefits, and there is a low penetration of smart metering systems.

Figure 31: Static time-of-use network tariffs in Europe



Note: In Cyprus, the ToU tariffs are allowed by the tariff methodology, but are not currently applied (i.e. values are the same). For Norway and Sweden no static transmission ToU tariffs, but dynamically varying tariff elements, while the application of distribution ToU tariffs is determined by each DSO. In the Netherlands, ToU tariffs in distribution have a very limited application (revision ongoing). In Greece, the ToU signal is applied in the form of charging demand only during predefined system peak periods. In Germany, from 2025, optional ToU tariffs are introduced for interruptible devices on the low-voltage level. No data were provided for Iceland.

293 Higher granularity of time-variation through dynamic tariffs or market-based elements in network charging has been reported in four countries. Practices include: (a) setting 'mobile peak periods' closer to real time, (b) calculating marginal losses in each node, (c) linking the energy-based component to actual hourly market prices per bidding zone and (d) applying dynamic tariffs in congested areas[247].

294 Since the 2023 ACER network tariff report, the following developments have been observed:

- In Belgium, new ToU signals have been implemented at the transmission and distribution level. For transmission, in addition to the annual peak tariff that applies between November and March, a monthly peak tariff was introduced in 2024 that applies all year long, except in some off-peak periods[248] from April to September. For distribution, in Brussels region new ToU signals will be implemented; in Flanders region, day/night tariffs were phased out from January 2023 and an exclusive night tariff applies to accumulation heating, while in Wallonia region, from 2026 onwards, (a) weekend days and holidays will be considered as regular days and (b) peak, medium-peak and off-peak tariffs will be implemented as opt-in options for low-voltage users, besides regular off-peak and peak, or normal tariffs[249].

- In France, redefining peak and off-peak network hours is under consideration to make them more reflective of network use, especially in the low season (summer) at the distribution level.

- In Germany, from 2025 onwards, the NRA has introduced optional ToU tariffs for interruptible devices at the low-voltage level[250].

247 In France, at the medium-voltage level, a 'mobile peak period' option is available to network users. This option is composed of a given number of peak days that are not set long beforehand. Network users who have subscribed to this option only know the day before when a peak period (with the highest price) will happen, depending on the TSO's forecast, in order to match actual congestion as closely as possible. In Norway, a network tariff element is set based on marginal losses in each node. For more information, please refer to the 'National practices' box in Section 5.3 of this report. In Sweden, the transmission tariff has a time-differentiated energy-based component, which is based on actual hourly market prices per bidding zone. In Slovenia, locational dynamic charges apply.

248 For more information, please refer to the 'National practices' box in Section 5.2 of this report.

249 Off-peak: 01:00-07:00 and 11:00-17:00; medium-peak: 07:00-11:00 and 22:00-01:00; peak: 17:00-22:00.

250 DE: Determination by NRA based on national law.

- In Latvia, in July 2023, the ToU tariffs were phased-out; the NRA explained the change using a combination of reasons, mainly related to the inefficiency and ineffectiveness of the signals in the current national context[251].
- In the Netherlands, since January 2025, peak/off-peak ToU signals have been included in the power-based transmission tariffs, comprising five price levels and variation based on the hour of the day, weekday or weekend, and month (seasonal).
- In Portugal, a preliminary analysis to update the ToU schedule was published at the end of 2024.
- In Slovenia, since October 2024, the new tariff methodology has included time-block differentiation for all consumer groups based on more detailed consumption and generation data (measured in 15-minute intervals) to increase cost-reflectivity.

295 As shown in Figure 32, ToU differentiation is embedded mainly in the energy-based component of the network charges and less often in the power-based component. However, several countries have introduced ToU signals in the power-based components as well.

Figure 32: Tariff basis embedding the time-of-use signal

		AT	BE	BG	HR	CY	CZ	DK	EE	FI	FR	DE	GR	HU	IS	IE	IT	LV	LT	LU	MT	NL	NO	PL	PT	RO	SK	SI	ES	SE
Transmission	Energy (€/MWh)		●		●				●	●	●		●			●					N/A		○		●			●	●	○
	Power (€/MW)		●		●						●		●			●					N/A	●	○		●			●	●	○
Distribution	Energy (€/MWh)	●	●		●		●	●	●	●	●		●			●			●		●	○	●	●	●		●	●	●	●
	Power (€/MW)				●		●		●	●	●		●												●		●	●	●	●

Note: In Denmark, the TSO has considered introducing ToU tariffs and submitted a tariff methodology to the NRA for approval. In Greece, charging is based on energy demand measured during predefined system peak periods, which is converted into a power-based component. In the Netherlands, in distribution, only some non-household users pay energy-based ToU-tariffs (two periods), the power-based tariff currently has no ToU-signal[252].

296 As shown in Figure 33, typically, ToU tariffs vary within a day, as (blocks of) hours are defined during which a higher or lower unit price is charged for using the network. The within-day signals are in most instances divided into two or multiple periods (e.g. day/night, peak/off-peak), where the periods may range from a few hours up to several hours. More than two periods within the day are defined in seven countries[253].

297 It is also common to distinguish weekend days (and sometimes holidays) from other days of the week, usually by applying lower charges. Further variation is introduced in some countries through a seasonal element that makes unit charges vary across months. Seasonal signals are, in most instances, divided into two seasons; in some countries the seasonal differentiation is higher (i.e. three or four seasons)[254]. In most of the countries assessed, the peak months are typically from November until the end of March, suggesting that European countries tend to have winter-peaking power systems.

251 LV: The reasons include: (a) the increased share of the fixed network tariff component makes the time-differentiation of the variable component economically unjustified; (b) the tariff is designed with a focus on simplicity and clarity for consumers; and (c) given the availability of dynamically priced electricity market products, the current price signals generated by electricity prices are sufficient to meet the system's operational requirements. From a system operation perspective, there is currently no evidence of a need to further influence consumers' consumption behaviour through tariff price signals to shift consumption to off-peak hours.

252 NL: Various changes (application of ToU-signals to all users, increase in the number of periods, application to power-based tariff as well) are currently being studied and expected to be implemented in 2027.

253 DK, EE, FR, IE, PT, ES, SI.

254 In France, there are three seasonal periods; in Spain, there are four seasonal periods.

Figure 33: Static Time-of-use tariff variants

		AT	BE	BG	HR	CY	CZ	DK	EE	FI	FR	DE	GR	HU	IS	IE	IT	LV	LT	LU	MT	NL	NO	PL	PT	RO	SK	SI	ES	SE
Transmission	Daily peak/ off-peak		●		●				●	●	●		●			●					N/A	●			●			●	●	
Transmission	Weekdays/ weekend		●						●		●		●								N/A	●			●			●	●	
Transmission	Seasonal		●		●				●	●	●		●								N/A	●			●			●	●	
Distribution	Daily peak/ off-peak	●	●		●		●	●		●	●					●			●		●	●			●		●	●	●	●
Distribution	Weekdays/ weekend		●				●		●										●		●	●		●	●		●	●	●	
Distribution	Seasonal	●			●				●															●	●			●	●	●

Note: Daily peak/off-peak option also includes day/night. Weekdays/weekend option also includes holidays/non-holidays. In Denmark, the application of peak/off-peak tariffs depends on the consumer category.

298 The ToU signals are typically the same for all network users subject to ToU tariffs[255], but in some countries they are differentiated[256]. There are also some countries where the ToU signals vary by the location of the network user (e.g. the peak period starts or ends at a different time)[257].

299 In all nine countries where ToU is applied to transmission and the information was available, it is mandatory for network users withdrawing from the network, and thus these users cannot opt out of being exposed to the time signal. Network users who connect at the transmission level typically make use of meters capable of recording ToU bands. The meters typically use 15- or 60-minute time intervals.

300 In most countries where ToU is applied to distribution and the information was available (i.e. 14 out of 19), at least some network users can opt-in or opt-out of being exposed to the time signals, while there is no such possibility in the other 5 countries[258]. Network users connected at the distribution level do not always have meters capable of recording ToU bands, which is one of the most frequently reported reasons to exclude them from ToU tariffs, while in other instances NRAs reported that for some voltage level or specific consumers a ToU schedule is not applied as it would not be cost-reflective[259].

301 With regard to the effectiveness and efficiency of ToU tariffs as a signalling instrument, pilot projects and impact studies have been performed before introducing or revoking ToU tariffs in about half of the countries[260]. Studies evaluating the effectiveness of ToU schemes (e.g. how ToU schemes have changed the behaviour of network users and the corresponding network costs) have been performed in less than a third of the countries. Of those countries that do not apply ToU tariffs in transmission and/or distribution, only a few reported any pilot project or impact assessment to support that decision[261].

255 For example, different signals apply for households and non-households or different signals apply depending on the contracted capacity level. The ToU tariffs may also differ within the country due to some DSO's freedom to choose their own ToU signals and/or because the network users are allowed to choose from different ToU tariff options offered to them.

256 For example, in Belgium (Wallonia region), weekend days and holidays are considered 'night' and an exclusive night tariff is in place for heating applications. From 2026, weekend days and holidays will be considered the same; differences between DSOs might apply. In Denmark, the application of peak/off-peak tariffs depends on the consumer category. In the Netherlands, the ToU tariffs apply to only some non-households. In Portugal, the ToU tariff is applied on an optional basis only at the low-voltage level for power of 41.4 kVA or less.

257 ES, PT.

258 Option to opt-in/opt-out: BE, HR, CZ, EE, FR, IE, LT, MT, NO, PL, PT, SK, SI, SE. No option to opt-in/out-out: AT, DK, DE, GR, ES. The information was not specified for FI and NL.

259 In Estonia and in France, the time of use tariff does not apply to consumers above 330 kV and 400 kV respectively, as system peak is not considered the main cost driver for those consumers.

260 For more information on the studies, please refer to the ACER Report on electricity transmission and distribution tariff methodologies in Europe (January 2023, p. 55).

261 CY, HU, PL.

ACER considerations

302 The use of time signals can be a useful tool for reducing network peak load, which is the main driver of network investments, thereby promoting network efficiency. ToU tariffs, if adequately designed, facilitate cost reflectivity of network tariffs and/or promote demand response (e.g. load shifting in order to mitigate the need for network investments).

303 While ACER acknowledges that, today, not all users are likely to react to such signals to the same extent, with further penetration of distributed generation and flexible resources (e.g. batteries, electric heating and EVs) and roll-out of smart metering systems, ACER expects network users' ability to respond to time signals to increase, and ToU tariffs to gain a higher importance.

304 ACER considers that time differentiation can be an important tariff design element to prevent the creation of disincentives for demand response. For example, when power-based charges are set based on the individual peak, regardless of what time period it occurs in, the network users may not be incentivised to reduce their consumption during system peak or to increase their consumption in times of excess generation if coincident with the individual peak, even if this would be beneficial for the system and would result in avoided network costs.

305 In particular, at the medium- and high-voltage levels, system operators can offer power-based ToU network tariffs to activate grid-optimising demand-side response. These tariffs give incentives to network users with controllable loads to reduce their demand during expected peaks in the network. With sufficient levels of granularity, time-differentiated energy-based network charges could reach a similar impact.

306 With 'critical peak pricing tariffs'[262], system operators can send stronger price signals to stimulate greater demand response compared to what achieved with traditional ToU tariffs. This is important, especially as intermittent generation capacity from wind and solar generating sources increases and, therefore, distribution system capacity constraints may become less predictable. Hence, tariff designs that can respond to actual system conditions may become more valuable than more stable tariff designs, such as static ToU.

307 'Real-time pricing' or 'dynamic network tariffs'[263] is sometimes discussed as another option to tackle potential local grid bottlenecks or manage congestion. Although dynamic network tariffs offer increasing cost-reflectivity in tariffs and incentivise efficient network behaviour, such differentiation is rather complex, requires a sufficient level of automation and may therefore contradict other principles, such as simplicity, predictability and transparency, if not implemented effectively.

308 Encouraging flexibility through competitive procurement (e.g. local markets for system operation services) is an alternative or complement to ToU network tariffs. Until such markets are established, as a temporary solution, other economic instruments such as flexible or interruptible contracts might be effective ways to activate flexibility from consumers, prosumers and other distributed generators.

309 In ACER's view, the introduction of ToU signals requires impact assessment studies to confirm the need to introduce these signals from a cost-efficiency and/or network congestion point of view. Such studies should aim to identify which elements (that may be local) affect the effectiveness and efficiency of ToU signals in order to justify a decision to apply such signals or not in a given context. ACER notes that the need for ToU network tariffs may depend on the network voltage levels.

310 Over time, the load patterns and network conditions can change significantly (e.g. where peaks shift to different hours); therefore, the impacts and appropriateness of the applied time bands and tariff signals should be monitored continuously, evaluated on a regular basis and adjusted, where necessary.

262 In a critical peak pricing regime, the critical peak pricing applies to a limited number of days or hours when the network has a higher probability of being constrained. The critical peak periods are activated on short notice, but the price is known in advance.

263 In a real-time pricing regime, the network charge is determined very close to the event (or only ex post) and prices are potentially dynamic, subject to the varying system conditions (e.g. grid bottlenecks, congestions).

311 Where ToU tariffs are introduced to reflect system costs, providing the option for network users to decide whether to be exposed to the given tariff structures would fall short in terms of cost reflectivity. Optionality may be temporarily reasonable (with a clear timeline of implementation) when transitioning to a new ToU schedule in order to limit tariff impacts on network users.

312 NRAs should improve data collection and analysis regarding individual network users, subject to the roll-out of fit-for-ToU meters (i.e. meters that are capable of recording the ToU, - for example, different time bands), in order to support the design of more cost-reflective ToU tariffs by also allowing higher granularity in their temporal differentiation. Where fit-for-ToU meters are largely missing, as a temporary solution, NRAs may design network tariffs by determining the contribution of different user profiles to the system peak.

313 While care should be given to the potentially conflicting time signals between dynamic wholesale energy prices and static ToU network tariffs, ACER also underlines that it is important to preserve the price signals provided by the ToU network tariffs, as opposed to 'bundling' the network charges with other price components, - for example in order to or with the effect of shielding consumers from such signals. These practices, observed in some jurisdictions, could act as a barrier to demand response, ultimately increasing the overall system costs that are to be paid by end consumers[264].

314 Similarly, retail price setting, in particular the energy component of the final bill, should to a relevant extent reflect the variability of wholesale prices. ACER sees less of a role here for ToU network tariffs, which, as mentioned above, relate more to cost impacts of injections and withdrawal patterns at times of peak load and beyond. While retail price setting and network tariffs may at times correlate, they may also not, as each is linked to distinct, ideally cost-reflective, signals.

Recommendations

315 NRAs should regularly investigate the need to introduce or revise the application of time-of-use signals. As part of these investigations, NRAs should aim to determine the most representative hours of system peaks over recent years, which may also vary based on the location.

6.7. Connection charges

Main findings

316 Connection charges are typically one-off charges paid for the costs of connecting new users to the transmission or distribution networks. Since the reinforcement of the network due to new connections can also benefit other grid users, part of those costs is often recovered through use-of-network charges, creating a link between connection charges and the use-of-network charges.

317 Connection charges may be shallow or deep, depending on whether a network user pays only for their own direct connection costs or, beyond that, also pays for network reinforcement deemed necessary by the network operator.

318 As shown in Figure 34, national practices show a great variety. Some countries apply only deep charges (to all network users) in both transmission and distribution (5 out of 28), some apply only shallow charges (to all network users) in both transmission and distribution (10 out of 28) and the remaining countries apply both shallow and deep charges[265].

319 Among the countries that do not follow the same charging approach across transmission and distribution, the use of mixed approaches occurs more frequently at distribution level, while at the transmission level they tend to select one of the two charging approaches (deep or shallow).

264 ACER Market monitoring report. Demand response and other distributed energy resources: what barriers are holding them back? (December 2023).

265 For example, shallow for low-voltage users and deep for medium-voltage users, or shallow for consumers and deep for producers.

Figure 34: Shallow and deep connection charges in Europe

		AT	BE	BG	HR	CY	CZ	DK	EE	FI	FR	DE	GR	HU	IS	IE	IT	LV	LT	LU	MT	NL	NO	PL	PT	RO	SK	SI	ES	SE
Transmission	Shallow	●	●	●		●	●	●		●	●	●	●			●	●			●	N/A	●		●		●	●	●		
	Deep				●				●			●		●				●	●		N/A		●		●	●		●	●	●
Distribution	Shallow	●		●		●	●	●	●	●	●	●	●	●		●	●	●	●	●	●	●		●		●	●	●		
	Deep		●		●			●	●	●		●	●	●				●	●		●		●		●	●	●		●	●

Note: No data were provided for Iceland.

320 Connection charges (deep or shallow) may be either (a) levied based on the actual costs of the connection, which are calculated on a case-by-case basis ('individual actual cost'), or (b) predetermined (standardised) as a lump sum charge per connection, a unit value per connected capacity or a unit value per distance and/or set based on unit values for other criteria (i.e. cost drivers). It is also possible for part of the connection charge to be based on the actual costs of connection, while the other part is predetermined by specific criteria.

321 As shown in Figure 35, in transmission, connection charges are typically based on individual actual costs, while in distribution applying standardised connection charges is more common. The dimensions most frequently used to set those predetermined charges are the voltage level[266], connected capacity and distance.

Figure 35: Tariff basis for connection charges

Basis	Transmission	Distribution
Individual actual cost	18: AT, BG, CY, DK, EE, FR, DE, GR, HU, IE, IT, LV, LT, LU, NL, PL, SK, SE	3: NO, PL, SE
Standardised basis[267]	1: BE[268]	7: BG, DK, CY, IT, LT, SI, ES
Mix of individual actual costs and other basis	8: HR, CZ, FI, NO, PT, RO, SI, ES	17: AT, BE, HR, CZ, EE, FI, FR, GR, HU, IE, LV, LU, MT, NL, PT, RO, SK

Notes: No data for Iceland. In Germany, no particular regulation of connection charges in distribution.

322 The basis of the network charges and their unit values may be differentiated by voltage level (inside transmission or distribution), network user group (e.g. between producers and consumers or inside these groups), geographical location or firmness of the connection and/or based on other dimensions[269].

266 It has been reported for 24 countries at the distribution level and 6 at the transmission level.

267 The connection charge is calculated based on a single variable or a mix of variables, such as lump sum (EUR) per connection; distance (EUR/m); contracted power (EUR/MW).

268 BE: Basis is mainly lump sum per connection (EUR) based on length, voltage level and type (primary/secondary). Some costs (studies) are individually estimated.

269 In about half of the countries, the connection charge is based on individually estimated or actual costs, so that the level of charges ultimately depends on the situation in the grid and provides an incentive (location signal) to connect to the grid, where the grid is strong (i.e. the accompanying connection costs are low). In these instances, the variation of the connection charge is implicit and not considered in the statistics of this section.

323 In several countries (16 in transmission and 9 in distribution), the rules for setting the connection charges are the same for all network users at the same voltage level. In some countries (three in transmission and nine in distribution) shallow charges are applied for consumers and deep charges for producers. Other countries apply the same type of connection charges (i.e. shallow or deep) to all network users, but provide discounts or differentiate between producers and consumers in other ways.

324 Variations of connection charges based on the voltage level are implemented in most countries - more frequently at the distribution level, than at the transmission level[270]- in the form of either lower charges at the lower voltage levels or different connection charge structures across voltage levels[271].

325 Additional differences in connection charges across network users have been discussed in several sections of this report, including different bases or unit values apply for different geographical location (see Section 5.3), different bases or unit values of the connection charges based on the firmness of the connection (see Section 5.4) and specific tariff regimes (see Section 5.5).

326 For deep connection charges, a cost-sharing problem may arise between network users, - namely, that extending and reinforcing the network to serve one particular network user may lead to high connection costs for that user but ultimately reduce the costs to connect other users in the future.

327 In order to address this problem about half of the countries[272] apply refunds or cost-sharing methods between network users. In the remaining countries, this problem was not identified by the regulators, it is under consideration or no information was provided.

328 Four countries (DK, FR, HU, NO)[273] reported an explicit transfer or split of some of the connection charge revenues between DSOs and in one country (LU) this transfer is done implicitly through tariff equalisation between DSOs. Other countries assessed do not transfer or split any of the connection charge revenues between DSOs.

ACER considerations

329 Connection charges, if well designed, can provide locational signals to network users to connect at points of the network that are more cost efficient from a system point of view[274].

330 There are pros and cons for both shallow and deep connection charges. Countries that apply shallow connection charges appear to value their simplicity, higher certainty and visibility to the network users, while deep connection charges can provide stronger locational signals and can be useful to steer investment to the right place in the grid. This can happen by charging consumers less in generation surplus regions and more in demand surplus regions and by charging producers less in demand surplus regions and more in generation surplus regions.

270 This could largely be explained by the fact that individual actual costs are typically charged to the network users at the transmission level, while predefined unit charges are more often applied in distribution. In addition, at the transmission level, splitting between voltage levels is less common.

271 HU, LU, PL.

272 HR, DK, FR, GR, HU, IE, LV, LT, NO, PT, RO, SI, ES, SE.

273 DK: If different DSOs own different voltage levels in a given area, there are two models in use: (a) no split, but if the lower-level DSO feeds in more maximum load to the overlying grid, the underlying grid has to pay extra for that right; and (b) a split based on which DSO owns which of the essential grid assets. FR and HU: the cost-based connection charge is paid to the operator of the network to which the network user will directly connect. The network operator is obliged to transfer the share of the connection charge covering the costs of other network operator's investments. NO: Each DSO calculates connection charges for their own investments. The connection charges associated with the same connection are bundled, and charged to the relevant customer. The connection charge is split between the DSOs, based on the costs they are responsible for.

274 It should be added that connection charges may play a small role in the choice of a location for a new production or load due to several other constraints and factors that need to be to considered (e.g. availability of natural resources, permitting, taxes, logistics).

331 Need for locational signals and need for increased cost-reflectivity are among the most frequently reported reasons for the application of deep connection charges. This is particularly true in the case of generators, which are not subject to use-of-network charges or are subject to only marginal charges in more than 60% of the countries. However, calculating deep connection charges may be more difficult.

332 The choice to apply different connection charges to different network levels can be explained by their distinguishing features, such as magnitude and variation in connection costs and the number of network users. At the higher voltage levels, the connection costs are typically higher and vary more across network users than at the lower voltage levels, which may increase the need for more differentiated connection charges to ensure they are cost-reflective. At the same time, at the lower voltage levels, the number of network users is significantly higher, which may create a high administrative burden for the system operators if they are to calculate connection charges individually, while resulting in less predictability and transparency for network users.

333 Deep connection charges that carry a strong locational signal for new customers may constitute a barrier for connecting to an already saturated system. If incorrectly designed, however, they may discriminate unfairly among consumers connected at the same part of the grid, depending on when they connected. For instance, once the grid has been reinforced, a consumer with the same characteristics as the preceding user may connect to the same point while paying a lower one-off charge.

334 Where deep connection charges apply and the connection of a network user serves future network users, it should be considered whether cost-sharing (e.g. in the form of standardised deep connection charges or future rebates to network users) is necessary to ensure a fair and non-discriminatory treatment of network users (to avoid cross-subsidies across them), also taking into account the administrative costs for the TSOs and DSOs. For this purpose, deep connection charges may be standardised, by fairly allocating across future network users overall network reinforcement costs associated with expected volume of connections.

335 Deep connection charges, together with alternative instruments, can contribute to addressing the virtual grid saturation or queue management issues[275] by disincentivising parties (without a business case) from acquiring the right to connect and increasing the costs or lead time for other network users.

Recommendations

336 Where deep connection charges apply, NRAs should consider cost-sharing among current and future users benefiting from the same connection.

337 NRAs should consider providing an online tool to estimate at least the standardised connection costs.

275 Virtual saturation arises when network capacity is reserved for a long time by developers without making any contribution to the costs of the existing grid or for future reinforcements and without a business case for constructing the facility. These developers may prevent other investors from obtaining a cheaper or firm connection.

List of figures