DSO ENTITY
DSOs FOR EUROPE

Tariffs and incentives

A PREMIER FOR THE FUTURE

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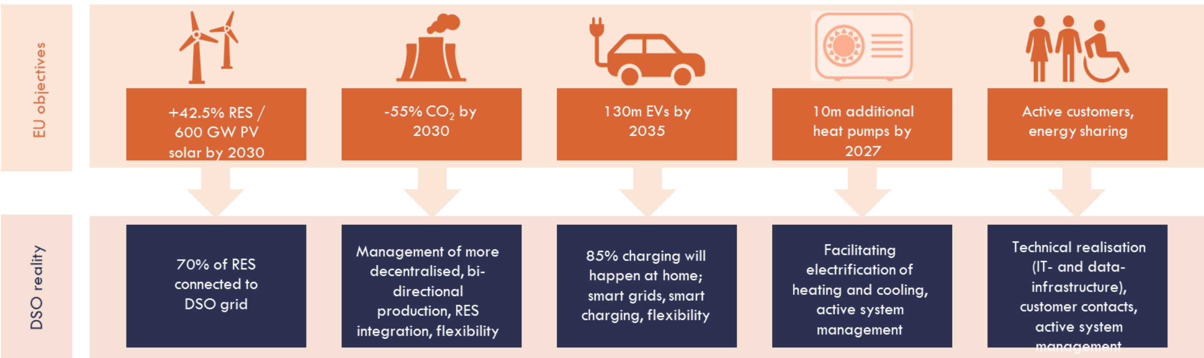
1. Prelude

The next few years will be crucial to ensure that the EU countries will be able to reach the ambitious net-zero goals set out by the European institutions. Recent events have underscored the urgent need of accelerating the energy transition, for reaching carbon neutrality and ensuring strategic independence for the continent. To achieve this objective, concrete targets have been introduced:



By 2030, with a 42.5% increase in Renewable Energy Resources (RES) and 70% of total RES connected to Distribution System Operator grids, DSOs face a transformative challenge. This “generation”-borne challenge is further amplified by a surge in demand for electricity coming, among other sources from the electrification of transport (with an political target of 130 million electric vehicles, with 85% of charging occurring at home and an uptake on electric busses and trucks) and of heating (with additional 10 million heat pumps by 2027) and large industrial processes including data centres and increasingly battery storage[1], all presenting an invigorating challenge for DSO to deliver the necessary capacities but also an opportunity for DSOs to innovate and adapt.

To obtain these objectives, some studies forecast that between now and 2050, around € 55-67 billion/year of investments will be required to make the European distribution grid fit for the exponential increase in demand of electricity.[2] This volume of investment is well above the historic levels of investment in the sector which then brings the additional challenge of obtaining the necessary funding to deliver them, while also ensuring affordability for customers.

To deliver the necessary network infrastructure on time and in an efficient volume some prerequisites must be met: Next to agile permitting, it is crucial that DSOs have access to equipment, skilled workers and other crucial inputs. However, nothing will be achieved if they do not have a way to (efficiently) generate the funds to pay for these inputs. As part of the work in its Task Force on investment funding

[1] Data centres represented between 1.8% and 2.6% of the total EU electricity use in 2022. Estimate providing in, Kamiya, G. and Bertoldi, P., Energy Consumption in Data Centres and Broadband Communication Networks in the EU, Publications Office of the European Union, Luxembourg, 2024, doi:10.2760/706491, JRC135926

[2] Eurelectric, 2024 Grids for speed. Available in https://powersummit2024.eurelectric.org/wp-content/uploads/2024/07/Grids-for-Speed_Report_FINAL_Clean.pdf. Please note that the “Grids for Speed” analysis does include neither data centres nor battery storage as an explicit expansion driver.

and finance, DSO Entity is considering the different approaches DSOs can use to efficiently deliver their financial needs. These approaches are considered in the diagram below:

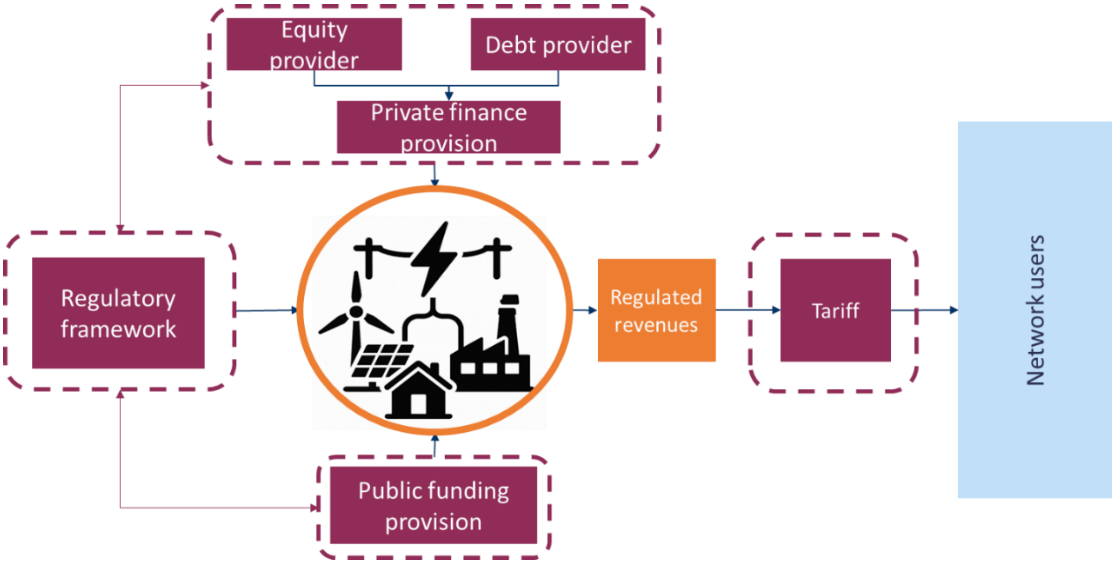


Figure 1: Approaches DSOs can use to efficiently deliver on their financial needs

When considering the financial needs, it is important to consider all the tools available for DSOs. This paper builds on previously published DSO Entity papers on anticipatory investments, regulation for innovation and funding (public and private) by considering the effects tariffs can have on the delivery of the energy transition. When considering this effect, this paper focuses on how regulatory allowances are recovered from customers via network charges, but it will not consider the methodology to set those regulatory allowances (already discussed in previous papers).

In addition, this paper also expands the DSO Entity's technical vision. That technical vision indicated that "*network tariffs can incentivise a certain customer behaviour, to mitigate congestion and voltage issues*". This paper expands on this topic by considering the main characteristics that tariffs would need to have to achieve those objectives.

The developments above underline the growing importance of tariffs as tools that shape system outcomes. Tariffs also incentivise network users. When constructed in an efficient manner, tariffs can, for instance, incentivise network users to shift demand towards periods of expected excess of renewable generation, reduce strain during peaks, and/or help avoid inefficient curtailment and the associated cost i.e., they support an efficient use of the dimensioning of the network. At the same time, they must continue to fulfil their primary functions: ensuring revenue recovery for DSOs, maintaining predictability and transparency to enable efficient economic decisions by network users, and safeguarding non-discrimination and fairness. The challenge is to ensure that tariff methodologies evolve to reflect the realities of a rapidly changing system without losing sight of the fundamental principles of good regulation (including long term financeability).

2. Introduction

Electricity network charges are[3] fees paid by network users, which aim to recover the costs of building, upgrading, maintaining and operating networks. Network charges include both (i) connection charges and (ii) fees for the use of the grid ("use-of-system charges" or UoS charges). In the decarbonisation of the power systems, network charges become very relevant since they must provide enough revenue for growing network investments and operating costs, while supporting access to affordable electricity.

Changes in the generation and consumption profiles – such as the introduction of renewables, electric vehicles, storage and flexible consumption – require assessing if the design of traditional network charge needs to evolve to adapt to the new challenges of the sector. As stated in the last report on network charges by ACER, about two-thirds of all Member States have made major changes in their network methodologies in the last years or plan to do it soon.[4] Members of DSO Entity are regularly involved in these reforms, and their active involvement is also reflected in this paper.

The possibility of improving network charge design is strongly linked to digitalisation, automation, and smart metering all of which enhance the capacity to implement more advanced tariffs. This is the case as smart meters enhance the measured values in at least two dimensions: a) they allow to meter the consumption much more frequently without incurring additional costs and b) they allow – either directly or by analytical operations - to answer the question what was the "peak load" (max. kW) that any network user had caused at certain moments in time.[5] The enriched metering features allow the creation of new and more cost-reflective tariff structures that are both more adaptive and easier to communicate.

This is relevant to ensure network charges provide the incentives to obtain an efficient evolution of the grid by using a number of approaches such as peak shaving, maximising the system integration of renewable energy, etc. In all cases, network charges must always follow principles set in the current EU regulatory framework as discussed below.

To facilitate the understanding of this report, it is important to clarify its scope. The scope of this paper is to identify the potential characteristics of the network tariffs that would allow DSOs to recover overall expenditure while supporting the EU objectives, including electrification of industry and the

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[3] In this report, network charges and tariffs will be unused interchangeable. Sometimes in EU legislation, charges seem to be linked to the amount paid by network users while tariffs refer to the process to decide the revenues of the regulated companies. However, this use is not consistent across various parts of the EU legislation.

[4] See ACER (2025). ACER report on network tariff practices. Getting the signals right: Electricity network tariff methodologies in Europe. Available in https://www.acer.europa.eu/sites/default/files/documents/Reports/2025-ACER-Electricity-Network-Tariff-Practices.pdf

[5] Dependent on their technical configuration smart meters might also allow to measure reactive power and more technical values like voltage, cos phi, length of possible outages (should they occur) etc. Enriched data collected from smart meters therefore play a role in a modern tariffs design but also in a more advanced "active" management of the system.

optimal behaviour of grid users ensuring an efficient and reliable use of the infrastructure. More concretely, this report focuses on **charges as a tool to provide incentives to network users while ensuring the cost recovery for DSOs.** This is essential to maintain the financial viability of DSOs and attract investment to develop, operate and maintain efficiently the power network and support the long-term energy system resilience and reliability.

It is also worth noting, however, that network charges aimed at supporting other policy objectives (e.g. social tariffs) will not be discussed in this paper. Tariffs designed to meet such policy objectives would not necessarily aim to achieve efficiency in planning and operations of grids and they should be supported using other specific policies and measures, e.g. subsidies for emerging technologies and social policies directly targeting vulnerable consumers that would be funded using the national budget or other taxation/subsidy mechanisms.

Furthermore, for simplicity, this report will not consider the interaction with other tools that can be used to obtain flexibility (e.g. flexible connection agreements or flexibility markets).

To finalise, this paper relies on one important assumption: the overall tariffs in the mass market will continue to integrate the use of system charges (UoS) to ensure the relevant objectives (i.e. supplier centric model). UoS charges are not the only component of the final price paid by network users. Users will face final prices that, in addition to network tariffs, include two main components (at least): generation costs (including portfolio management efforts) and taxes (with each component representing about 1/3 of the overall price). Therefore, their consumptions decisions will be based on that overall price.

This document is organised as follows. Section 3 introduces principles set in the regulation while section 4 analyses main design components of network charges. Section 5 discusses how the different components of the network tariffs might contribute to achieving the different policy objectives. Finally, section 6 provides some recommendations about the future development of tariffs.

3. Regulatory framework for tariffs

The principles for the development of network charges for access to network, use of the network and network reinforcements are set out in Article 18 of the Regulation (EU) 2019/943. Network charges must be cost-reflective, transparent and support overall system efficiency over the long run. Moreover, they shall not discriminate between network users receiving the same services and/or against energy storage, aggregation, self-generation, self-consumption or participation in demand response.

With that purpose, regulatory authorities shall recognise all relevant costs (OPEX, CAPEX and energy related) as eligible, including costs related to anticipatory investments[6]. Regulatory authorities introduce performance targets to provide incentives to TSOs and DSOs to increase overall system efficiency in their networks, including through energy efficiency, the use of flexibility services and the development of smart grids and intelligent metering systems.

Based on Article 18, national good practices and economic literature, CEER[7] identified a list of seven main principles for the development of electricity distribution network charges. These seven principles can be grouped into two main categories depending on how they affect the development of the tariff methodologies.

The first group are those principles that are required to ensure that tariffs contribute to the efficient development and operations of the distribution grid. This includes requirements that companies should be able to recover their full costs to ensure the efficient investment into the grid (i.e. the amounts recovered via connection tariffs and UoS charges include the overall regulatory allowance). In addition, tariffs should reflect the costs DSOs need to incur to provide the services to the relevant network user. This would provide these users with the right incentives to consume efficiently. Finally, tariffs should be set such as they do not distort the operations of the different markets where electricity can be traded, and they do not discriminate between users (i.e. it is expected that network users that receive the same services/quality should pay the same price).

[6] Anticipatory investments are defined by the European Commission as "as investments into grid infrastructure assets that proactively address network development needs beyond the ones corresponding to reinforcements relating to currently existing grid connection requests by generation or demand projects. " See Commission Notice (C/2025/3179) on a guidance on anticipatory investments for developing forward-looking electricity networks as available in https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=OJ:C_202503179
[7] See CEER, 2020, "CEER paper on electricity distribution tariffs supporting the energy transition" as available in https://www.ceer.eu/wp-content/uploads/2024/04/C19-DS-55-04_CEER-paper-electricity-distribution-tariffs.pdf

Czech Republic: network charges review to improve cost reflectivity

In the Czech Republic, a revision of the existing tariff structure is currently underway to reflect an allocation of network costs caused by active customers, renewable energy sources (RES), energy communities, and new types of consumption such as heat pumps and e-mobility.

The network charge structure revision has two main ambitions: first, to reform the current tariffs that cannot yet benefit from smart metering (its implementation at the low-voltage level is currently in progress); and second, to set up a charging system that will be able to take full advantage of smart metering.

This review will have two phases:

1. In the first phase, the new tariff structure aims primarily to make the tariffs more cost-reflective inter alia by increasing share of the fixed component of the price, introduce partial progressivity in the price component related to the circuit breaker payment, and increase the price difference for network usage between high and low tariffs (in the Czech Republic, a system is in place where the customer allows the distributor to control certain appliances to help regulate network load).
2. The second phase of the tariff structure revision is intended to fully leverage the potential of smart metering and, using data collected from the low-voltage level, optimise the payment for network usage based solely on the degree of its utilisation—that is, those who cause high network loads (peaks) should be charged accordingly. Consideration is being given to Time-of-Use (ToU) tariffs (which would be more flexible and responsive to network load) or a system of payments based on peak network usage (where the customer would pay only for exceeding a of set reserved capacity of network usage).

To deliver tariffs that facilitate the efficient development and operation of the sector, it is important that these principles are carefully considered as they will be the cornerstone to ensure that users have the right incentives when using the grid. For example, connection charges should have similar characteristics at TSO and DSO level as otherwise network users might be incentivised to connect on higher or lower voltage levels in the system. Coordination across these layers helps in balancing restrictions at the system level rather than being transferred from one part of the system to another.

A second group of principles are those that ensure that network users can comprehend the overall tariff framework so that they can take efficient decisions. This group includes three principles that will facilitate that network users react efficiently to tariffs: simplicity, predictability and transparency. Only if network users can 1) comprehend the tariffs they are facing (i.e. they are sufficiently simple and avoid unnecessary complexity), 2) predict the costs and 3) have transparency about the application of tariffs they will be able to react efficiently to the incentives that tariffs provide.

When considering how these principles are put into practice inside the regulatory framework, it is important to consider relevant trade-offs between them.

3.1 Trade-offs between principles

As stated by CEER, fully ensuring the cost-reflectivity principle might trade-off with other ones such as simplicity, predictability and transparency. For example, tariff structures that are simple are generally easier for network users to comprehend and engage with. However, simplicity will probably come at the expense of cost reflectivity, as straightforward designs may fail to reflect variations in capacity demand, network usage or system costs over time.

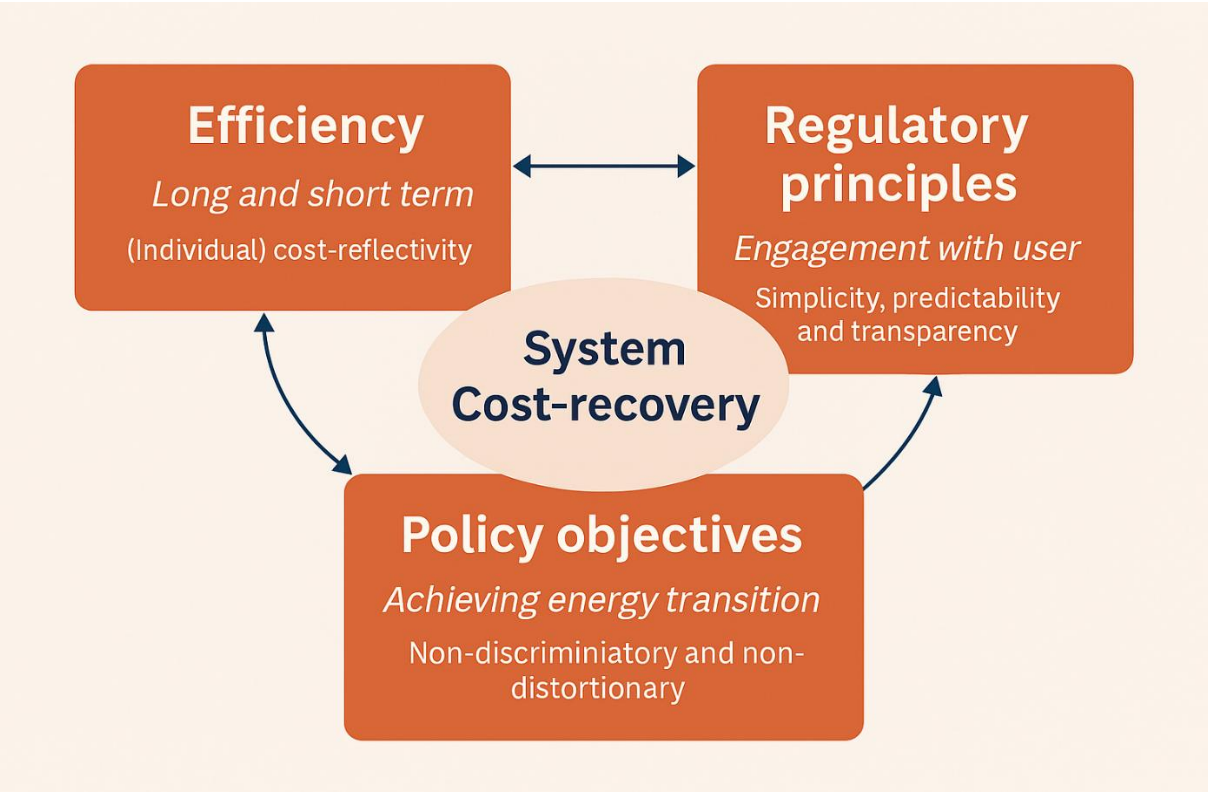

Figure 2: Three dimensions when defining network charges

The restrictions inherent in balancing CEER principles cannot be fully eliminated and their point of equilibrium will constitute a policy decision with advantages and disadvantages. As a result, it is a decision for policy makers to determine where to set this limit that NRAs will implement in their tariff methodologies. In addition, it is also possible to use additional policies out of the scope of network charges to facilitate this balance. For example, governments and regulators could promote technical solutions that could facilitate embedding all relevant prices signals into automated systems, allowing more cost-reflective tariffs to coexist with simplicity and transparency.

The precise balance between these principles is determined by policy and, as a result, it will be heavily influenced by the precise situation of each one of the Member States. At the European level, both the European Commission and ACER have published documents with recommendations that will affect these trade-offs. These recommendations are presented in the boxes below.

Main recommendations by European Commission[8]

- While cost cascading may still be justified, a more sophisticated approach could better ensure cost-reflectivity as generation becomes prevalent in distribution networks, even at low voltage levels.
- NRAs should use tariff design to incentivise the reduction of peak load consumption, including through adding a capacity element to the tariff structure that reflects peak load, combined with a time-of-use energy element to the tariff, especially at times when the grid risks being saturated, to reduce the cost of network expansion to the level needed.
- NRAs should include time-of-use elements in tariff structures, to correlate cost allocation with peak network usage to incentivise efficient use of the network.
- NRAs should promote the use of locational signals in network tariffs as they provide signals for more useful siting of necessary generation and consumption on the grid.
- Special tariff regimes can be offered to specific classes of grid users; however, the NRA should provide objective grounds that these grid users, based on their consumption profile, have a lower impact on the overall cost of the electricity network.
- Network tariffs for electricity storage can be used to incentivise grid friendly behaviour by storage operators, to direct storage investments to the most appropriate areas and to incentivise charging/discharging at times of most utility to the electricity system.[9]

Main recommendation by ACER[10]

- Increase transparency and enable comparability of network tariff methodologies by
  - differentiating the network tariff elements and corresponding cost categories along with the terminology proposed by ACER; and
  - 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.
- Ensure non-discrimination among network users by
  - assessing the potential allocation of costs for injections, both at transmission and distribution level, rather than excluding them by default;

[8] European Commission 2025, "Communication to the Commission: Approval of the content of the draft Commission Notice on Guidelines on future proof network charges for reduced energy system costs" as available in https://energy.ec.europa.eu/document/download/8789f345-a6ae-46b6-97d2-a7366e516cdc_en?filename=C_2025_4010_1_EN_annexe_acte_autonome_cp_part1_v4.pdf

[9] In that same document the European Commission also provided some recommendations for the development of regulatory frameworks that are outside of the scope of this paper.

[10] ACER, 2025, "Electricity network tariff methodologies in Europe" as available in https://www.acer.europa.eu/sites/default/files/documents/Publications/2025-ACER-Electricity-Network-Tariff-Practices.pdf

- avoiding unjustified exemptions, discounts, net-metering, or à la carte tariff regimes tailored to specific groups of network users; and
  - 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.
- Ensure cost-reflectivity and provide efficient price signals by
  - making network users contribute to the costs of the voltage levels used by them via adequate cost cascading;
  - applying time-differentiated energy and/or power-based charges rather than flat energy-based ones;
  - 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; and
  - considering locational signals where needed, e.g. by applying deep connection charges together with cost-sharing among current and future users.
- Engage with stakeholders ahead of each major revision of the tariff methodology by carrying out public consultations, providing the reasons for and underlying assessments of the proposed network tariff design, and favouring a multi-year transition process for grid users with significant tariff impact.

The objective of this report is highly aligned with these recommendations while adjusting the emphasis when necessary.

Moreover, context conditions (e.g., generation mix, consumption profiles or development of new agents) evolve over time, which requires the NRA and subsequently ACER and CEER to continuously monitor the performance of the tariffs implemented in each Member State. In this context, the last ACER report on network tariff practices[11] highlights the need to ensure the energy transition objectives with the compliance of the main principles for tariffs. The effectiveness of network tariffs clearly depends on the ability of network users to react to the overall price which is always a combination of the network tariffs and market prices for electricity set by retailers. In most cases, no 'one-design-fits-all' in tariff setting and the most suitable approach in each Member State should be identified.

[11] ACER (2025), "Getting the signals right: Electricity network tariff methodologies in Europe" as available in https://www.acer.europa.eu/sites/default/files/documents/Publications/2025-ACER-Electricity-Network-Tariff-Practices.pdf

4. Components of network charges

When setting tariffs, it is important to identify the specific objective(s) that, in addition to cost recovery, should be achieved (e.g. optimise capacity requests and grid use, manage congestion in the (local or overall grid) or incentivise RES). Only then, and with the principles discussed above, one will be able to identify the relevant attributes for these tariffs and how to use them to balance the different principles.

As discussed above, the focus of this paper is on two sets of tariffs: connection charges and use of the system charges (UoS charges). When setting these charges, the main attributes to be considered include:

1. **The basic variables used to calculate the network charges**, fixed component, energy consumption, subscripted capacity, installed capacity and/or used capacity.
2. **Particularities to consider specific conditions that lead to variations in some or all the basic charges**, examples of these particularities include:
    - locational components (e.g. system wide, zonal or local)
    - timing of the tariffs (e.g. periodicity (e.g. yearly, monthly, daily or hourly) and variability across time (e.g. flat tariff or time of use (ToU)); and/or
    - user differentiation (e.g. HV, LV, according to technologies (e.g. EV or storage) or types of network users (e.g. generators, residential and industrial)).

For simplicity, the following sections consider these topics separately. However, in practice there could be interactions that should be considered.

4.1 Variables used to calculate the network charge

Connection charges are generally calculated based on the specific characteristics of the connection and the national methodologies being used for the calculation of these charges.[12] A core variable being considered will be the capacity requested by the network user but other characteristics such as the distance and characteristics of the local grid, and the typology of the land (e.g. urban vs. greenfield areas) might also be considered.

In terms of connection charges, without entering into details, there are two main variables to be considered. The first of these variables is the types of costs the (future) network user will be facing i.e. connection charges can be deeper (lots/all the (upstream) reinforcement costs paid by the new user)[13], shallow (upstream reinforcement costs socialised widely among network users) or some intermediate point. The second variable is how these costs are calculated (i.e. whether an estimation

[12] Detailed explanations for tariff calculation are considered outside of the scope of this paper.

[13] At least in a first phase. In some cases, part of those costs could be reimbursed while new consumer commit to connect using some of the assets already in place (e.g., as more individual houses connection to the system, the original user could recover some of the costs it needed to incur).

of actual costs or standard costs are considered). The precise methodology can have effects on the incentives, but a detailed analysis of these methodologies is outside the scope of this paper.

For UoS charges, there are different options, and the right cost driver(s) for the objective that should be achieved will need to be selected. The main options being used in practice and most often in combination are:[14]

- **Contracted capacity (in €ct/kW)** – charges are based on their contracted capacity. This can ensure a stable (quasi fix) bill for consumers (as long as the tariff pattern does not change). This driver helps to limit the demanded capacity and therefore the consumption and generation of each individual user, thus reducing peaks in the grid. Used capacity exceeding the contracted capacity is usually priced with a surcharge;
- **Used capacity (in €ct/kW)** – charges are based on the actual network usage. This driver can be more volatile than the contracted capacity as it normally refers to maximum used capacity in a certain period, but this volatility can be smoothened by using, for example, average used capacity in a predetermined period. This driver can provide incentives for consumers to limit their capacity use thereby flattening their consumption or generation patterns to facilitate the operation of the grid. The effect will be a function of how the used capacity is calculated (i.e. the level of volatility); and/or
- **Energy consumed or injected (in €ct/kWh)** – charges are based on the actual energy consumed or injected from the network. In this case, network users' bills are directly related to their usage of the grid. Therefore, they can provide incentives for network users to change their short-term behaviour.

Capacity charges (€/kW) allow a more efficient recovery of grids' costs, that are mainly fixed and independent from the energy withdrawals from customers i.e., capacity charges provide price signals that are well aligned with the cost structures of energy infrastructure provision. On the other hand, network tariffs based on the energy component (€/kWh) can more easily also provide incentives for network users to change their short-term behaviour.

As indicated above, UoS charge designers could select one or a combination of them to obtain the relevant objectives. Examples of both options can be observed in the tables below.

[14] It is possible to set a fix tariff that is not related to any action of the network user. This, however, would not provide incentives to the consumer and, as a result, will not be considered in more detail in this report although many tariffs have a fixed component which is in line with the economic concept of a two-fold tariff to balance fix cost recovery and short-term marginal incentives.

Italy – different drivers for different types of consumers

An example of this working well in practice is the Italian one, where contracted power-based charges are generally applied to domestic and SME customers, for which a power limiter on the meter is applied. Differently, peak power-based charges are applied to those users without a power limiter on the meter (generally MV/HV industries).

Finland – proposals of combined capacity components

In Finland the current government proposal stipulates the framework: power-based use-of-network charges should be taken into use. Companies can use fixed fees, power-based and energy components in these charges. Given that the use of fixed fees based on main connection size is very common already in Finland, switching some of this to a flexible power component based on actual power usage is seen as giving customers more power to impact their cost.

4.2 Specific conditions: Additional incentives for timing

To obtain the relevant objectives, network charges can include different specific conditions based on the time of use of the network (i.e. this component is not used for connection charges [15]), namely implementing time-of-use or ToU conditions. However, this requires assessing whether the benefits of implementing ToU, both to the system and the network users, would outweigh the costs (e.g. higher tariff complexity, cost of systems' implementation).

From a network user perspective, ToU components could provide an opportunity to reduce its network bill by adjusting its consumption profile. At the same time, from a power system perspective, ToU may be a useful instrument for flattening electricity demand peaks which is why they are also being introduced into retail tariffs thereby "connecting" the consumers more directly with the wholesale market developments. For this to be effective, however, requires a pre-requisite: users need to be able to react to the price signals being provided.

When setting ToU components based on the grid conditions, charge designers need to determine:

- the starting and finishing points of each period (e.g. lower prices from 10pm to 8am each day or lower prices every year from May to September);
- frequency for which the charges are set (e.g. daily);
- the variations in the conditions (e.g. high/low price or capacity);
- the timeframe between the setting of the new charges and their application (e.g., today for tomorrow or twice a year for the next half year);

[15] Timing could also interact with connection charges when they are developed in combination with Flexible Connection Agreements (i.e., users could be connected faster when they accept a flexible connection). However, the discussion of those tools is outside of the scope of this paper).

- the frequency with which these variations are reviewed (e.g. high/low price set at the beginning of the year); and
- optionality of the ToU, i.e. ToU can be set mandatory or with an option to opt-in/opt-out.

When setting these components, based on its objectives and the conditions of the grid, charge designers can choose different degrees of granularity such as different hours of the day (e.g., day/night tariffs), days of the week (e.g., weekend tariffs), months or even seasons (e.g., winter vs summer tariffs). In addition, it is possible to combine different levels of granularity. For example, it is possible to set different prices between 5pm and 10pm in winter and between 7pm and 12pm in summer.

To comply with the principles discussed above, it is essential to assess under which conditions the grid users will react and assess whether the additional benefits coming from ToU, compensates the higher tariff complexity. In practice, this could be obtained by comparing the benefits/reduction in costs these tariffs would have (e.g. reducing in investment needs) against the costs their implementation could bring (e.g. actual implementation costs).

The literature in tariffs has often discussed one variety of these ToU components, dynamic tariffs,[16] which are ToU tariffs with a high degree of granularity and frequency of changes (e.g. changing the day before with 15 minutes frequency or even intraday). These tariffs, even if appealing for specific tariff objectives, could, however, require technical requirements that are currently not available to most network users. For dynamic tariffs to be effective, network users would need to react to the time signals. It is unlikely that lacking automation of the demand, most users can do so. As a result, dynamic tariffs would currently generate a level of complexity that would not compensate for any improvement in network usage.

When defining the variations in the conditions, it is essential to consider the electricity demand patterns, which include the peak and off-peak demand on weekdays and weekends and the demand price-elasticity[17]. These patterns can also change during the months of the year, and between different regions within a country. Such a more accessible approach is often referred to as “static” ToU.

Furthermore, the risk of inrush effects that a static ToU can entail should be noted. This can lead to new peaks, especially when combined with automation that activates devices at the start of a time slot with lower (network) tariffs. This risk argues for a model in which the parameters can be adjusted in a flexible manner e.g. limiting peak-off-peak ratio, flexible adjustment of off-peak hours.

When calibrating these components, an important issue to consider is whether the objective is set to be delivered at a local level or for the whole system. For example, the structure of the tariffs could differ depending on whether they are trying to reduce peaks in the whole system or peaks in a local

[16] CEER defines dynamic tariffs as “A dynamic tariff means that the price signal is defined at shorter notice, possibly close to real-time. This contrasts with static tariffs, where the price signals are associated with predetermined time periods.” In CEER (2020), “CEER Paper on Electricity Distribution Tariffs Supporting the Energy Transition” available in https://www.ceer.eu/wp-content/uploads/2024/04/C19-DS-55-04_CEER-paper-electricity-distribution-tariffs.pdf

[17] Demand price elasticity measures how much the quantity of a good or service demanded by consumers changes in response to a change in its price.

area. Local peak does not need to coincide with the time of a system peak. As a result, the ToU tariff can have different timing depending on the network challenges being addressed. When choosing between these options, tariff designers need to consider this choice can interact with the locational incentives for new network users as they could change their location to minimise the risk of higher network tariffs.

By encouraging demand shifting through mechanisms such as ToU pricing, peak-based charges, or hybrid models combining energy and capacity elements, tariff structures can send the right incentives to cost-effective grid usage and optimise the use of existing infrastructure including a less high loss profile if peaks can be avoided.

4.3 Specific conditions: Additional locational incentives

To obtain the relevant objectives, network charge designers can also introduce different conditions in different locations. These differences could then be used to provide economic signals such that new network users select efficiently (from a grid point of view) their location. Once the location decision has been made, however, locational components will have a limited effect on consumers decisions.[18] Electricity generators however might alter their production by activating generation facilities in different locations.

Setting different tariffs by location might be a controversial issue since some grid users might claim that they do not respect the non-discriminatory principle.

For connection charges it is necessary to consider that there are two possible ways of setting a locational component. On the one hand, two network users (generators and/or consumers) could face differences in connection charges because of the characteristics of their projects even if the methodology is the same (e.g. one project requires an extension to the current grid while the other does not). On the other hand, two generators and/or consumers could face different bills as a result of differences in the methodology being used (e.g. discounts to promote industrial hubs). The selection between these approaches is part of the design of the charges methodology.

The effectiveness of a locational component in connection charges depends on, at least, two factors. The first one is the capacity of the users to choose their location. Not all users have the same flexibility in their capacity to choose a location. For example, users looking to expand their capacity (i.e. with an already set location) or users who require characteristics that are not available in other locations (e.g. wind for new wind turbines, advantages due to local industrial hubs or proximity to work for households) have a limited choice if they want to invest. Equally, industries willing to upgrade their

[18] In some cases, a locational component could make a network user's decision of whether to expand capacity unprofitable. This would result on potential negative impacts on the economy with limited effect on the efficiency of the grid. It needs however to be debated nationally whether it is more sensible to use deeper fees and support certain electrification efforts with public money i.e., via the taxpayers, than shallow fees whereby only the users of the electricity grid in question are "supporting" the electrification effort via the implicit cross-subsidisation that happens. This second option can be a sensible solution if the additional demand lowers average fees in the longer term.

connection to electrify their processes could revert their electrification decision due to the local costs of upgrading their connection.

The effect of location signals in connection charges also depends on the approach used to calculate them. Without entering in detail on how these charges are calculated, shallow charges cannot be differentiated as they are just pricing the connection itself while deeper charges will have a stronger effect as the potential users will face a larger share of the costs generated by their connection. As for the previous characteristic, deep charges and their associated location characteristics can have negative effects as not all network users have the same capacity to react and change their location. Furthermore, deep charges could be inconsistent with anticipatory investments and could be challenged from land/regional policies. Therefore, other mechanisms could be put in place. For example, Danish DSOs use deep standard connection charges (as opposed to actual cost connection charges) which mitigate these issues.

Danish deep standard connection charges

The Danish tariff methodology uses rather deep and standardised connection charges. This is to provide cost reflectiveness, transparency and fairness when recovering the cost of grid expansion due to new connections. The new customers pay for the upgrades of the network that they cause on average. The deep and standard connection charges ensure that grid expansion is paid for by the new connection, and that new connections pay for the grid which will be built to them. This incentivises new connections to only ask for the grid capacity that they need, and thus limits over reservation of the grid. This approach also helps prevent cost-sharing issues.

Danish connection charges allow for geographical differentiation, reducing or raising the standardised deep connection charges depending on whether the connection is in a production-dominated area, a mixed or a consumption-dominated area. Currently geographical differentiation is implemented for new production units connected to higher voltage levels. Geographical differentiation for consumption connections on the higher voltage levels is awaiting the regulators approval and is expected to come into effect sometime in 2026.

Geographical differentiation is appropriately applied to the connection charges, as it is crucial at the time of connection to convey a pricing signal to the customer concerning their choice of geographical location.

For UoS charges, the main use of locational components would be to better reflect the system costs in each area. This could affect the location decision of new large network users (e.g. data centres) where electricity prices play an important role in their profitability. However as in most cases location is a one-time decision, one-time charges such as connection charges do result in more direct incentives.

Locational components, however, are not only different prices in different locations. A locational component could result in differences in the tariffs profiles depending on the location. For example, a ToU tariff could have different peak/off-peak prices depending on the location to manage local peaks even if the peak/off-peak prices are the same (e.g. to minimise local peaks, the high part timing of the ToU can be different between office and suburban areas).

In some cases, however, a lack of local components could also reflect better the costs for the overall system. For example, if a large share of renewable generation is connected to a specific DSO, it would not be cost reflective that the users of that grid pay for those costs once they are used for the whole system. Therefore, a tariff without a locational component could reflect better these costs.

When considering the introduction of locational components in charges, there is one type of tariffs that deserves special mention: injection tariffs. Generators might be facing such charges for their use of the grid.

According to the recent ACER's Electricity Tariff Methodologies Report, in the countries where they exist (8 for TSOs and 6 for DSO tariffs), 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. Given the growing volume of DSO connected generation, the possibility of recovering the relevant costs from generators has been growing in relevance.

In principle, this is an interesting proposition as it would ensure that all network users, including generators, contribute to the recovery of the costs of the grid (i.e. better delivery of the principles of cost reflectivity and non-discrimination). This interest, however, should be caveated. When setting these tariffs, it would be important to consider, at least, two main topics. The first of these topics is the scope of these injection tariffs. This is not a trivial answer as not all generators are the same. For example, some small users inject electricity into the grid (e.g. excess generation in prosumers or energy sharing in an energy community). As a result, if they are asked to pay a network usage fee, they would have less incentives to invest in the generation assets.

A second component is the generators' capacity to pass these costs back to consumers. A flat tariff could translate in a parallel increase in the national wholesale markets and a distortion of cross-country transactions. As a result, it would result in additional complexity to the tariff methodology without improvements in efficiency. However, these tariffs could also be designed to reflect the conditions of the grid (e.g. higher tariffs for generation units injecting energy in a congested node).

4.4 Specific conditions: User differentiation

The final factor to consider when setting a charging methodology is to determine whether different network user types will face different network charges. When determining these differences, it is important to consider the trade-off between cost reflectivity and simplicity. On the one hand, additional types of tariffs would facilitate cost reflectivity as smaller groups will tend to be more homogenous. On the other hand, however, a larger number of tariffs also results in a more complex system (and potentially less transparent). It also carries the necessity of differentiating network user by objective criteria.

As a rule, DSOs have no specific position concerning the network charges to be developed as long as they are consistent with CEER's principles discussed above. More concretely, to ensure the efficiency of investment and operations of the grid, it will be important that these network charges are cost reflective and they do not distort incentives from the network users (other than the ones they are specifically targeting). It is only under cost-reflectivity that network users will face the cost of their specific actions which would result in a more efficient use of the grid.

Equally, when considering special charges for certain customers, another principle that should be carefully considered is non-distortion. The introduction of special tariffs for certain users could introduce distortions in five areas:

- selection of technologies: when certain types of users or technologies face lower grid costs, this creates an incentive to invest in certain technologies or change behaviour to become a network user receiving preferential treatment i.e., it is at least possible that an overinvestment in certain technologies occurs, or network users behave in a way that is directly "unproductive" but creates an advantage in terms of network charges;[19]
- the results of electricity markets: flexibility markets, for example, could see their price distorted as certain technologies could provide lower bids as a result of a more favourable treatment in tariffs (e.g. batteries developed for flexibility provisions facing lower network charges than house batteries);
- grid investment decisions: some flexibility providers could face a situation where their business model is only profitable if they can be cross subsidised by other users of the grid (i.e. if they do not pay the costs they generate in the grid). This would result in inefficient demand for connections from those users which would introduce inefficiencies into the system. Equally, separate metering for certain types of users or technologies will be required which will create additional costs that must be considered to determine whether this is a (financially) viable option; and
- external assets investment decisions: because of the distortions in the electricity markets, those users with a special tariff could find their investment unprofitable. Therefore, this (potentially) more efficient investment would not take place.

To ensure the long-term efficiency of the system, it is not only necessary that investment in grid-friendly technologies takes place but that it takes place when it is efficient. Therefore, while network charges should not preclude investment, it should not be the case that the profitability of that investment depends on achieving favourable network charges as, in those cases, alternative technologies that would be profitable without those special tariffs would deliver a more efficient long-term result.

[19] The problem is amplified if only a small change or investment was necessary and consequently the UoS-charge for the whole energy consumption was being rebated. There are many real-world examples of such behaviour, but developments around storage battery systems are a recent real-world example of such an effect. As PV Magazine reported in September 2025 some **500 GW of battery storage capacity** request grid access in Germany currently (c.f., Germany battery storage grid-connection requests exceed 500 GW – pv magazine International). A number driven by the fact that battery storage is exempted from paying grid fees under §118 paragraph 6 of the German energy law which is a tremendous boost to the individual battery business case.

It is only when they deliver on those two principles (as well as on cost recovery) that these tariffs would not endanger the efficient use of the grid.

As discussed above, it is important that these trade-offs are considered at a national level as they constitute policy decisions. In addition, it will be necessary to ensure that the additional complexity, and likely lower transparency levels are necessary to deliver the objectives required to obtain an efficient planning of operation of the national DSOs.

Once tariffs are justified based on those principles, the NRA should consider the effect on other CEER principles such as simplicity and transparency of the tariff system.

4.5 Cost cascading

As defined by the European Commission: "cost cascading means that network users pay the costs of the voltage level of their connection and the cost relating to other voltage levels they may use."[20]

Reflecting that generation was mainly delivered via large plants connected to the transmission grid, traditionally, this resulted in transmission charges being cascaded to network user as a separated line or included in distribution charges. However, load flows have changed considerably in the last decades – and this change continues and accelerates. Central generation supplying all customers has been amended and partially replaced by decentralised generation and volatile load flows.

As a result, there are calls to review the principle of cost cascading. Answering to this question is not an easy task as there are trade-offs to be considered. On the one hand, based on the principle of cost reflectivity, it is necessary to acknowledge that all system users should contribute through their grid tariffs to the cost of system services. For example, a user connected at a medium voltage could need to pay for frequency control services provided by the TSO.

On the other hand, with alternating load flows there is no compelling reasons why users connected at a higher voltage level do not contribute to the cost of lower voltage levels. For example, they could also be needed to pay for the costs of managing local congestion the DSO provides to ensure the energy can reach medium voltage.

[20] European Commission 2025, "Communication to the Commission: Approval of the content of the draft Commission Notice on Guidelines on future proof network charges for reduced energy system costs" as available in https://energy.ec.europa.eu/document/download/8789f345-a6ae-46b6-97d2-a7366e516cdc_en?filename=C_2025_4010_1_EN_annexe_acte_autonome_cp_part1_v4.pdf

5. Links between potential policy objectives and network charges

Given the heterogeneity among the current and future grids in Member States, different DSOs face different planning and operational challenges to delivery on the energy transition. As a result, network charge methodologies will need to be tailored to the relevant challenges of each grid/Member State.

To deliver on these challenges, the first step would be to get a political decision about the objectives to be delivered via tariffs. It is only then that the tariff designers can combine the different components discussed above into one solid network charge methodology. One point to remark here is that when more than one objective is identified, it will be necessary to develop a solid prioritisation among the different objectives as in many cases, different objectives could enter in conflict.

To illustrate how different network charges could be used to obtain certain policy objectives, the table below identifies examples of potential (high-level) mechanisms that could be used to achieve certain objectives (inasmuch the table should not be read as to represent a full synopsis but rather as showing casing some potentials and ideas), provided that the benefits of their implementation outweigh the costs, as stated before:

Objective	Potential mechanism
Congestion management (by reducing demand)	The network charge will need to include components based on the network loads that would provide network users (all or part of them) with incentives, linked to the local congestion, to modify their consumption pattern to smooth consumption. These components can have different levels of granularity depending on the area being congested. The greater the granularity in the locational component, the greater the possibility of adapting the tariffs to the local conditions, but also with a major implementation and management cost (besides the potential conflicts with simplicity etc). Therefore, there will need to be a balance between the potential benefits and the implementation costs. When setting those components, network charge designers should also consider the frequency of local congestion under consideration. For example: • One-off/infrequent local congestion: DSOs need a mechanism that they can use to incentivise implicit flexibility for congestion episodes. This kind of charges could be difficult to implement because they would require that charges are revisited frequently (e.g. day ahead) which would bring them close to be a fully dynamic tariff with the limitations this brings. Equally, this could generate a significant implementation cost due to the frequency of the review of these tariffs which could make them inefficient as a solution. Examples of these tariffs are:

	○ energy consumed/injected tariffs with a ToU component the DSO can set higher when necessary (and lower outside of period of expected peak demand or when the specific area is oversupplied by RES); or ○ capacity used tariffs with a ToU component where the DSO can set higher capacity prices when peak demand is taking place. • Congestion arises regularly: DSOs would need access to flexibility regularly to reduce the need to reinforce the grid to serve those peaks. Ideally, to facilitate simplicity, this can be obtained using a relatively stable pattern (i.e. flexibility is always required at the same point in time. Examples of these tariffs are: ○ Energy consumed/injected UoS charges with higher prices during the peak period (e.g. day and night UoS charges); or ○ Capacity used UoS charge (with or without a ToU component) would provide network users to mitigate their peak demand. If those peaks are correlated with the ones of the local system, these tariffs would also reduce congestion.
Location of network users	Tariffs can also be used to persuade network users (consumers and/or generators) of selecting some regions to consume/inject. However, this should be balanced with a) the practicality of the proposal (e.g. in strongly and extensively congested systems), b) with the political constraints to address the proposal, c) with the legislation in MSs setting the unicity of networks charges throughout the whole territory (e.g. Spain), and d) with the consistency with the simplicity principle. To be consistent with CEER principles, the justification for these differences should be cost reflective (i.e. it generates lower costs) and non-distortionary (i.e. it should not distort the market where that consumer/generator operates).[21] However, they could still be directed towards specific consumers because of set policies (e.g. re-industrialisation of certain areas). These network charges may have a locational component to make some regions more interesting than others. Examples of these charges are: • Deep connection charges (based on real or standard costs): By facing deep connection charges new consumers/generators would be incentivised to choose areas where additional capacity is available as connection charges in those areas should be lower. • UoS charges differing between regions: Especially large consumers (e.g. heavy industry) do consider the overall price of electricity when deciding their location. Therefore, by introducing price differences it could be possible to affect these decisions.

[21] Governments can also use this approach to attract certain industries into the country (e.g. offering low electricity prices to attract aluminium producers). However, those policies are outside of the scope of this document.

Facilitating optimisation processes	Network charges could also be used to ensure DSOs obtain information they will require as part of their planning exercise. Examples of these of these charges are: • Contracted capacity based UoS charge: By requiring network users to pay in function of their contracted capacity means that consumers will have incentives to contract only the capacity they require. • Used capacity based UoS charge: These charges grant DSOs information not only about the capacity that consumers they would like to have (i.e. the capacity they require from the grid) but also about the capacity to move demand to smooth that peak capacity. This information will be valuable when identifying grid developments.

When trying to obtain several of these objectives, it could be possible to combine different types of network charge differentiations. However, in that case it will be crucial to consider whether there can be interactions between the different solutions to remove potential negative effects. Equally, some of these objectives could also be obtained using other mechanisms (e.g. FCAs or flexibility markets). The interaction between these different tools should also be carefully considered.

6. Recommendation on the development of tariffs

- **Network charges must be consistent with local specifics of power systems and the design in the different Member States while at the same time also being consistent with the simplicity and transparency criteria**. As a result, Member States must remain responsible of their tariff system. A European framework could make significant contributions to highlight important developments that need to be addressed in many or most Member States, but can never successfully specify the details.
- **Network charges should carefully evolve to future proofing the system by allocating the cost as best as possible and thereby making it more secure, inclusive, diverse and resilient**. However, every change into the tariff structure should be based on a detailed assessment of the expected benefits for both the network users and the system as a whole, compared to the costs of their implementation.
- **Network tariffs alone cannot resolve all operational challenges being faced by the grid operators.** Governments and regulators have a range of tools (e.g. market rules, flexibility products or tariffs) that can be used jointly to mitigate the operational challenges of the grid operators. These tools should be combined to provide network users with the incentives to use the grid in an efficient manner.
- **Capacity components in UoS tariffs improve cost-reflectivity and provide additional information about the capacity requirements of the local system (and as result the grid investment needs).** The capacity used/demanded is and will continue to be the main driver of the investment needs in the grid. Therefore, by creating a direct link between this driver and tariffs, this capacity component increases the expected efficiency in the system by incentivising network users to smoothen their peak use of the grid. Furthermore, this capacity tariff could have a bi-directional component as the directly used part of the grid can be used both for infeed and take-off.
- **Designing ToU component should be done carefully to ensure it delivers the relevant objectives, including contributing to incentivise implicit flexibility.** The development of these components is easier with energy-based tariffs as network users can see a direct linkage between their time of consumption and their bills. However, as stated by ACER and the European Commission, properly designed capacity-oriented tariffs could provide proper incentives in timing and are an alternative to ToU.
- **ToU components could be implemented in both energy and capacity-based tariffs.** ToU tariffs are usually less volatile when the energy component is altered. However, it is also possible to design ToU with a variable capacity component such as to limit unwanted volatility and increase predictability.
- **Connection charges methodology should be non-discriminatory to ensure an efficient connection of the network user, but they need to evolve to reflect the changing nature of demand for connections going forward**. They should be designed to account for anticipatory investment (i.e. deeper charges but based on standard costs) to avoid distorting the incentives to network users and DSO to continue to invest efficiently.

- **Locational components will be more effective when network users have the capacity to choose between different locations – this should be the case when network users take spatial decisions anyhow much more than when they are settled into a location already[22].** Network users who cannot choose different locations for generation or consumption will not be able to change their decision after the fact (i.e. react) to this incentive. As a result,
    a. UoS charges with local differentiation are in theory feasible, but will often be more complicated to implement and only in a few cases result in a change in behaviour when location decisions are made by system users; and
    b. Non-shallow connection charges are well suited to provide locational incentives for generators and some larger consumers at the moment of decision making. This is a one-time incentive for a one-time location decision.
- **More granular locational components provide additional options when addressing the challenges of the system:** Local components can be operated in coordination to address issues at higher levels in the electricity system. However, this option would not exist if tariffs were developed only for the overall system.
- **Special tariffs should only be included when they are justified in terms of cost reflectivity, and they do not distort other incentives (i.e. they should be technologically neutral).** Network tariffs should not incentivise explicit, but only implicit flexibility, e.g. through ToU tariffs where appropriate.
- **The introduction of energy-based injection tariffs could have a limited effect on efficiency even if it would increase cost reflectivity.** The introduction of energy-based injection tariffs to producers for the use of the network brings a number of challenges. For example, the need to allocate network costs between consumers and producers, considering the principle of cost reflectivity for each category and the avoidance of cross-subsidies. Furthermore, generators will be able to transfer those tariffs to network users via higher electricity prices. However, these tariffs also bring the opportunity to incentivise the use of the grid by introducing ToU components and provide more transparency and cost reflectivity into the system.

[22] Network users that have already taken their spatial decision (e.g., bought a house in a specific area) will still be incentivised to limit their capacity demand in a congested but also non-congested are through a more capacity-oriented tariff per se. This effect can be amplified if the price of capacity does change with (local or regional) capacity demand.