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CEER Paper on Electricity Distribution Tariffs Supporting the Energy Transition

Distribution Systems Working Group

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Abstract

This document (C19-DS-55-04) presents CEER's conclusions on electricity distribution network tariffs within today's electricity system and how they can support expected changes. Besides building upon CEER's earlier work on tariff principles, this document goes further in considering different tariff types, including static and dynamic network tariffs. In addition, it considers how tariffs could support the energy transition – including the areas of interaction with the procurement of flexibility, storage and electric vehicles – and the impact of the Clean Energy for All Europeans package.

Target Audience

European Commission, energy suppliers, distribution system operators, other network operators, traders, electricity/gas customers, electricity/gas industry, consumer representative groups, Member States, academics and other interested parties.

Keywords

Distribution networks, Regulation, Tariff Principles, Tariffs, Costs, Electricity, Energy transition, Flexibility Procurement, Storage, Electric Vehicles.

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Related Documents

CEER documents

- CEER Recommendations on Dynamic Price Implementation, Ref: C19-IRM-020-03-14, 3 March 2020
- CEER Conclusions Paper on New Services and DSO Involvement, Ref: C18-DS-46-08, 22 March 2019
- CEER Conclusions Paper on Flexibility Use at Distribution Level, Ref: C18-DS-42-04, 17 July 2018
- CEER Conclusions Paper on Incentives Schemes for Regulating Distribution System Operators (DSOs), including for innovation, Ref. C17-DS-37-05, 19 February 2018
- Distribution and Transmission Network Tariffs and Incentives, CEER White Paper series on the European Commission's Clean Energy Proposals, paper # I, 11 May 2017
- CEER Guidelines of Good Practice for Electricity Distribution Network Tariffs, Ref. C16-DS-27-03, 23 January 2017
- CEER Position Paper on Renewable Energy Self-Generation, Ref: C16-SDE-55-03, September 2016

EU Legislation

- Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity, https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A32019L0944
- Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity, https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A32019R0943
- Regulation (EU) 838/2010 of the European Commission of 23 September 2010 on laying down guidelines relating to the inter-transmission system operator compensation mechanism and a common regulatory approach to transmission charging, https://eur-lex.europa.eu/eli/reg/2010/838/oj
- Regulation (EC) 714/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the network for cross-border exchanges in electricity, https://eur-lex.europa.eu/legal-content/EN/ALL/?uri=CELEX%3A32009R0714
- Directive (EC) 2009/72 of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in electricity, https://eur-lex.europa.eu/legal-content/EN/ALL/?uri=CELEX%3A32009L0072

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EXECUTIVE SUMMARY

Distribution system operators (DSOs) are responsible for operating and investing in the distribution networks, in order to transport electricity to and from their network users. DSOs charge distribution tariffs to network users in order to recover the amount of allowed/target revenues set by the national regulatory authority (NRA). There are multiple ways in which these tariffs can be designed, all having specific consequences with regard to, for example, how costs are allocated to network users, how network users react to tariff signals and how fair tariffs are perceived by users.

With this paper, CEER aims to aid NRAs, DSOs and stakeholders in their thinking on electricity distribution tariff design. The need emerges from the energy transition, especially through digitalisation, decarbonisation and decentralisation. In addition, EU Regulation 2019/943 also provides requisites for distribution tariffs. In this paper, CEER comes to the following conclusions for electricity distribution tariff design:

- There is not a one-size-fits-all tariff model that is appropriate for all Member States when it comes to distribution tariffs. Rather, tariff design should take a number of principles into account. Cost-reflectivity, leading to economic efficiency, is the key principle, while the additional principles are non-distortion, cost recovery, non-discrimination, transparency, predictability and simplicity. Regulators should seek to find a balance between these principles.

- In order to have cost-reflective tariffs, it is important to be aware of the cost structure of distribution networks in the short term (losses and congestion costs) and over the long term (infrastructure costs). Tariff design should reflect that electricity networks have high fixed costs and low variable costs in the short-term. Customers should be exposed to forward-looking price signals to reflect changes in their utilisation of the grid affects future network costs. The tariff design should be targeted at reducing system peak and individual peaks.

- The tariff structure can consist of just one component or a selection from multiple components, being fixed (per point of delivery), energy-based (per kWh) and power-based (per kW, either used and measured or contracted) components. These components can be further differentiated, such as by time (static or dynamic), location and interruptibility.

- Advanced differentiation in time and location, for example through dynamic tariffs or interruptibility, will most likely increase how cost reflective tariffs are for specific network users and may also incentivise beneficial network behaviour. More advanced differentiation is, however, rather complex and can have a negative impact on other principles, such as simplicity, predictability and transparency, if not implemented effectively. Dynamic tariffs require a sufficient level of automation. As the level of automation varies among customers, dynamic tariffs might be more appropriate for larger customers than for small customers in the short term. Moreover, the signals stemming from dynamic network tariffs could be diluted by other factors, such as dynamic retail prices.

- Incentivising network-beneficial customer behaviour is not only possible through dynamic tariffs, but also through procurement of flexibility. Both can contribute towards limiting or postponing network investments. Where dynamic tariffs trigger implicitly a change in behaviour, an advantage of the explicit procurement of flexibility through contracts is that it creates more certainty for DSOs and allows customers willing to provide flexibility to be adequately remunerated.

- The procurement of flexibility and dynamic tariffs are two instruments for achieving flexibility that can be applied. If applied at the same time, their interaction should be carefully considered. Introducing fully dynamic network tariffs in combination with flexibility procurement by DSOs is more complex than in combination with static tariffs.

- NRAs should develop smart distribution tariffs that strike an adequate balance between reflecting the cost drivers of distribution networks and ensuring that network users equipped with smart technologies are able to react to the signals.

- Further, NRAs should consider if increased decentralised generation requires the introduction or increase of tariffs for production, while taking into account that network charges should not discriminate positively or negatively between production connected at the distribution level and the transmission level. Increased decentralised generation requires NRAs to monitor the cost allocation between voltage levels, for example, when the cascading principle is applied NRAs should see if it holds. CEER considers that net metering of self-generators should be avoided

- Distribution tariffs applied to customers with energy storage facilities should reflect the use of the network in terms of both energy withdrawal and injection. CEER considers that any double charging for storage facilities should be avoided. Also, NRAs should take into account developments in the field of electric vehicle (EV) charging, when exploring changes in the tariff structures.

- CEER emphasises the need for NRAs to review the current tariff structures to identify how they can be improved, for example, to create stronger incentives for efficient usage of the grid. Topics that require further thinking about include dynamic network tariffs' potential and the interaction with procurement of flexibility. NRAs – and where required also legislators – will need to anticipate circumstances, such as the completion of the smart meter roll-out and aggregators offering flexibility for procurement by DSOs, in order to allow for a smooth introduction of improved tariffs structures.

1 Introduction

Distribution system operators (DSOs) are responsible for operating and investing in the distribution networks, in order to transport electricity to and from their network users. DSOs charge distribution tariffs to network users in order to recover the amount of allowed/target revenues by the national regulatory authority (NRA). There are multiple ways in which these tariffs can be designed, all having specific consequences with regard to, for example, how costs are reflected in tariffs, how customers react to tariff signals and how fair tariffs are perceived by users. NRAs oversee, and in most cases decide on, tariff design to ensure there is the right balance between competing tariff principles, manage complex trade-offs between different options and consider impacts on all network users.

The way that tariff structures are designed is something that NRAs need to reassess periodically. While many leading tariff principles that were relevant in the past will remain relevant in the future, the balance between principles might shift in the context of a changing electricity system. At the moment, some of the most prominent aspects that are driving the need to reassess distribution tariffs are:

- **Digitalisation**. Digitalisation enables smarter evaluation of the network state and needs, allows for more dynamic tariffs and enables the availability of more information, even at household level, allowing the DSO to operate the grid more efficiently.[1]
- **Decarbonisation**. The increasing demand for electricity and greater penetration of intermittent renewable energy sources (RES) is likely to require substantial investments in distribution networks. More cost-reflective distribution tariffs could enable faster decarbonisation at a lower cost.
- **Decentralisation**. The presence of several active network users scattered across the network increases the complexity in local network use and may require adjustments to tariffs.

A comparison between Regulation (EU) 2019/943 and Regulation (EC) No 714/2009[2] highlights some differences in what each of them expects from network tariffs, in particular regarding distribution tariffs. While Regulation (EU) 2019/943 has kept a lot of the requirements from Regulation (EC) No 714/2009, it includes as additional requirements the consideration of network flexibility and a reference to not including unrelated policy objectives. In addition, it stipulates the non-discrimination of generation connected to distribution, when compared to transmission-connected producers, as well as the need to ensure non-discrimination towards energy storage, self-generation, self-consumption and demand response.

Moreover, Regulation (EU) 2019/943 includes separate sections on distribution tariffs (Article 18 (7) and (8)). This requires NRAs to consider the use of time-differentiated tariffs in Member States where smart metering systems have been deployed. It also suggests providing incentives to DSOs for the procurement of services that enable more cost-efficient operation and development of distribution systems. These services include in particular, energy efficiency, flexibility and the development of smart grids and intelligent metering systems.

With this paper, CEER aims to aid NRAs, DSOs and stakeholders in their thinking on tariff design. It builds upon earlier CEER work, while contributing to further thinking in key areas, such as principles and the balance between conflicting principles (chapter 2), providing further

[1] See also the CEER Conclusions Paper on Dynamic Regulation to Enable Digitalisation of the Energy System, 10 October 2019.

[2] These Regulations are part of the Clean Energy for All Europeans package and the 3rd Energy Package.

development of different tariff types (chapter 3), investigating the interaction of static and dynamic tariffs with the procurement of flexibility (chapter 4) and looking into tariff design challenges, in light of the energy transition (chapter 5). Chapter 6 summarises the conclusions.

2 Tariff principles

All markets seek to incentivise efficient consumer and producer behaviour and so this should also be a rationale for the regulation of DSOs. From the standpoint of economic theory, efficiency implies that every resource is optimally allocated to serve each individual or entity in the best way, while minimising total system costs. This means that goods or services are consumed by whoever benefits most from them and that they are produced at the lowest cost. Securing the lowest cost distribution services is a matter for the regulatory framework for revenue-setting by the NRA, which is beyond the scope of this paper.[3] However, a tariff design that sends price signals to network users can also contribute to lower costs. With regards to optimal allocation, this depends on the cost structure of distribution services, and should also be reflected in distribution tariffs.

2.1 What tariffs are for and the meaning of cost-reflectivity

Network tariffs are the prices that network users (households, companies, etc.) pay for the service of having electricity transported from the point of production to where the electricity is used. Typically, electricity is transported through the transmission (electrical highways) network, the distribution (local grid) network and the connection to the network user. These are regarded as separate services and hence are paid for with different tariffs.[4] This paper only addresses the issue of setting electricity distribution network tariffs.

Distribution tariffs send price signals that convey information to network users, which they, in principle, are able to respond to by either increasing or decreasing the quantity (energy or capacity) demanded. This implies that network users' behaviour can be incentivised through tariffs, so that each network user is prompted to use the amount of distribution services that reflects what they are willing to pay for.

The purpose of distribution tariffs is the remuneration of distribution costs. How and to what extent DSOs are remunerated for their costs depend on the way that NRAs set the allowed revenues. Setting allowed revenues is very important, but as mentioned before, beyond the scope of this paper. This paper addresses tariff setting, which is the way that the allowed revenues are collected from network users. In some jurisdictions, setting tariffs is left to the DSO, although NRAs either supervise or define the methodologies applied.

In order for price signals to work in an efficient manner, two requirements must be met. First, consumers must be able to observe the price signal and, even more importantly, be able to react to the price signal. Secondly the price signal, in this case the tariffs, should reflect the relevant costs of the service (cost-reflective tariffs). Article 18(7) of Regulation (EU) 2019/943 also sets out that *Distribution tariffs shall be cost-reflective taking into account the use of the distribution network by system users including active customers*. If either of the requirements are not met, network users could act in inefficient ways, where they will consume either too much or too little network capacity or energy, compared to the optimal consumption level. If they consume too much, when they could instead have regulated their demand, it will lead to a situation where the network is overly expensive, as it would need to be expanded to accommodate this demand, compared to a situation with cost-reflective tariffs, which signal whether network users should regulate their demand. If too little is consumed, the opposite situation will occur, leading to overpriced distribution services and an underutilised network, which deviates from the optimal level of social welfare.

[3] For further reading on incentive regulation and revenue-setting, CEER refers to the CEER Conclusions Paper on Incentives Schemes for Regulating Distribution System Operators (DSOs), including for innovation.

[4] The tariffs of separate services can be combined in a final network tariff. For example, transmission tariffs can be cascaded to the distribution network and become part of distribution network tariffs. In a majority of EU countries, network tariffs are part of the final bill that comprises network tariffs, retail energy prices and levies/taxes.

Cost-reflectiveness implies that the cost a network user imposes on the distribution network should be reflected by the distribution tariff, i.e. one should pay the price for the cost of their own actions. The cost that a network user's consumption drives at a given point in time is dependent mainly on two aspects: the available capacity in the network and the amount of electricity consumed. If the available capacity is limited, additional demand for electricity will lead to investment to increase the available capacity. The availability of capacity depends on the consumption of other network users and will therefore, fluctuate throughout the day with the behaviour of network users (consumption patterns). In the evening (peak hours) there will be less capacity available, when people are cooking, etc., than during the night (off-peak hours). In addition to electricity consumed by users, transporting electricity through the network results in electricity losses, which are the difference between the energy entering the electricity distribution network and the energy leaving it. Network losses are due to the friction of the network and implicitly carry a cost.[5]

Closely related to the principle of cost-reflectiveness, Article 18(1) of Regulation (EU) 2019/943 prescribes that network tariffs should not include unrelated policy objectives. Costs or tariffs being driven by unrelated policy objectives would not be caused by the individual actions of network users.

If tariffs are not cost-reflective, it means that network users will not receive economic signals to allow them to identify the correct trade-off between utilising the network and adjusting their consumption. Cost-reflective tariffs are a prerequisite for a cost-efficient outcome, where, for example, inefficient reinforcement or replacement can be avoided or postponed. If the tariffs are set to reflect the costs that network users' consumption induces, one can say that the tariffs are cost-reflective, although, that does not imply that all costs are reflected in the tariffs.

The implementation of smart meters provides more granular information to users about the times that they use the network, which may enable DSOs or NRA to develop tariffs based on actual capacity and a more time varying demand response by the network users. This makes the issue of cost-reflectivity more relevant today than in the past, as costs are closely linked to demand for capacity, which varies across the time of day.

When trying to create a cost-reflective tariff structure, one needs to know what costs to reflect, i.e. what drives the cost of distribution services. In the table below, the different costs of a DSO are categorised according to how they relate to customers' use of network services. For example, the costs of network losses are dependent on the amount of electricity transported through the network at a given moment in time and could therefore be categorised as short-run marginal costs, while costs related to future capacity could be seen as long-run marginal costs.

Generally speaking, economic theory suggests that costs are best reflected if the energy-related tariff component includes the short-run marginal costs of providing the distribution service. The short-run marginal costs echo the system costs incurred, due to customers' use, and are typically costs of network losses, congestion and expected loss of load. Long-run marginal costs are the costs related to the future capacity of a network and may be the cost of increasing network capacity.

The costs related to all historic investment in the network are a large part of the total distribution cost, but are not dependent on the network users' consumption, and are basically sunk costs. In this paper, sunk costs are referred to as *residual* cost. How residual costs are covered by the tariff structure is a matter of economic efficiency (minimising economic distortions) and a collective and

[5] See also the *2nd CEER Report on Power Losses*, 23 March 2020.

fair remuneration from all users. This basically implies an optimal lump-sum charge, i.e. a fixed rate paid collectively by all users of the network (e.g. some kind of subscription fee), in cases where costs cannot be linked with a specific network user.[6]

Table: DSO costs

	Present cost			Future cost
Cost categories	**Short-run marginal costs**	**Customer specific costs**	**Residual (sunk) costs**	**Long-run marginal costs**
Description	Network losses and variable payment related to DSR	Metering and data processing	Other costs for coverage according to the regulation	Cost for increasing capacity (wire and non-wire option)
Preferred tariff design	Marginal pricing (Energy Time of Use)	Cost-based (Fixed)	Cost-based (capacity, Fixed)	Semi-marginal pricing (Energy Time of Use, capacity peak pricing)

In order to have cost-reflective tariffs, it is important to be aware of the DSO's cost structure. This means to distinguish between short-run marginal costs, long-run marginal costs, customer-specific costs and residual costs and, as far as practical, to mimic that in the tariffs, e.g. variable tariff components reflect variable costs. That said, tariff structures must necessarily make concessions with respect to cost-reflectivity. A tariff that is recovering residual costs efficiently, might not reflect short-term operational costs, and vice versa. If a simple tariff design is the primary objective, regulators should evaluate which costs are most important when choosing the appropriate tariff structure.

The long-run marginal costs of distribution depend mainly on peak utilisation of the network. This implies that tariffs should include a component reflecting peak utilisation. However, when defining the necessary price signals, there exists an inherent mismatch in time between the infrastructure costs and the network user's utilisation. The infrastructure costs included in present distribution tariffs have already been incurred, and changes in the user's network utilisation will not lead to a reduction or increase in the infrastructure costs already incurred (i.e. residual costs). However, the network utilisation will impact on the need for new network investment and congestion management services. As a result, the part of the distribution tariff related to infrastructure costs is said to have a long-term perspective and is consequently forward-looking. Therefore, the link between present distribution tariffs sending price signals for future infrastructure network costs is necessarily of a theoretical nature, and can be interpreted in different ways across different jurisdictions. In the case of short-run marginal costs, e.g. network losses, it is easier to establish the causality between the network user's behaviour and the resulting costs.

[6] For further information on tariff structures and cost categories, see for example Schittekatte, T. and Meeus, L. 'Cost Distribution Network Tariff Design in Theory and Practice', RSCAS Research Paper No. 2018/19. http://cadmus.eui.eu//handle/1814/53804.

2.2 CEER's principles of distribution tariff design

While CEER thinks that economic fundamentals should be the driving principle for network tariff design, there are a number of competing principles that need to be balanced in order to develop appropriate arrangements.

There are a number of recent papers which discuss the principles of network tariff-setting, not least the CEER (2017) paper on distribution tariffs[7], where CEER proposed a set of seven non-exhaustive principles for distribution tariff design:

- **Cost-reflectivity**: For efficient use and development of the network, as far as practicable, tariffs paid by network users should reflect the cost they impose on the system and give appropriate incentives to avoid future costs;
- **Non-distortionary**: costs should be recovered in ways that avoid distorting decisions around access to and use of the network, and market offers;
- **Cost recovery**: DSOs should be able to recover efficiently incurred costs. As well as tariffs for use of the distribution system, DSOs may also recover costs through connection charges and regulated services;
- **Non-discriminatory**: there should be no undue discrimination between network users;
- **Transparency**: Distribution tariffs and the methodologies to calculate them should be transparent and accessible to all stakeholders;
- **Predictability**: it is important that network users can effectively estimate the costs of their use of the distribution system, facilitating efficient long-term investment by network users. However, the changing nature of the energy system means network tariffs will need to evolve over time;
- **Simplicity**: As far as possible, tariffs should be easy to understand and implement. The simpler they are, the easier they are for network users to respond to.

2.3 Tariff principles in practice – balancing competing principles

It is easy to see that some of these principles can be contradictory. This is especially the case when balancing the principle of cost reflectivity against the other principles. For example, a fully cost-reflective tariff regime may have highly volatile prices, large differentials in price across a region and a complex methodology that sits behind it. This type of arrangement may be in direct conflict with the principles of simplicity, predictability and transparency. A balance needs to be struck when designing distribution tariffs.

It is the role of the regulator to approve or design distribution tariffs that achieve a balance of these principles and meet the needs of all the stakeholders, including the protection of consumers. These stakeholders include consumer representatives (both small and large users), network companies, system operators, generators (both large and small, low-carbon and carbon intensive, flexible and inflexible), suppliers and third parties.

The regulator could use approaches based on multi-criteria analysis to determine how to balance these competing principles. The Brattle Group proposed a simple multi-criteria assessment (MCA) approach to the Victorian Distribution Company in Australia, to consider the balance between simplicity, economic efficiency, adaptability, affordability and equity.[8] There are, however, more detailed MCA approaches available that could be used by regulators to develop a more robust approach for balancing the tariff design principles. Furthermore, as relevant characteristics and circumstances in each country can differ, there is not a single tariff model that is appropriate for all Member States.

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[7] See the CEER *Guidelines of Good Practice on Electricity Distribution Network Tariffs*, 23 January 2017.

[8] https://brattlefiles.blob.core.windows.net/files/14255_electricity_distribution_network_tariffs_-_the_brattle_group.pdf

3 Tariff design

Traditionally, energy-based network tariffs have been the predominant design in Europe. The energy transition and significant electrification (e.g. of heat and transport) put a higher importance on capacity utilisation, and will require different and more precise price signals, if we are to achieve electrification at least cost. The principle of cost-reflectivity implies that the cost of capacity should be reflected in the tariff. Furthermore, incentivising efficient capacity utilisation would require additional price signals. In this chapter, CEER presents various tariff types that give more precise price signals regarding capacity utilisation (in the following also referred to as "power") and time of consumption.

3.1 The three primary design options: power, energy and fixed component

In principle, tariffs can be comprised of three components: an energy component (€/kWh, also named "volumetric" component), a power component (€/kW) and a fixed component (€/year). The basic starting point is a purely non-time-dependent tariff. However, both the energy and power-based components have many possible designs, e.g. through the level of time differentiation (see section 3.2) and interruptibility.

3.1.1 Energy component

How costs are covered through the various components, depends on the status of the network, technological possibilities and public acceptance of more precise price signals, etc. For smaller customers, a flat energy component has traditionally been used to cover the majority of network costs, with remaining costs recovered through the fixed component. While some countries have introduced a power-based component, e.g. based on each customer's fuse size, the lack of hourly metered data has historically limited the potential for other methods of designing this part of the tariff, although this is changing with the introduction of smart meters.

A non-time-dependent volumetric energy charge is still an important component for the recovery of the residual costs of the network. Historically, such tariffs have worked relatively well, given the strong correlation between energy and power, and the lack of quarterly/hourly data from conventional meters. However, such tariffs primarily incentivise an ongoing reduction in electricity consumption at any time, because the reduction is valued equally at every moment. This means a network tariff based only on flat energy charge does not give the correct price signals to customers. Distributed electricity production also makes them less well suited for cost recovery, as active customers can reduce their bill by offsetting their demand, without reducing network costs accordingly.

3.1.2 Fixed and power components

The cost structure of the grid, with high fixed costs and low variable costs, suggests that the majority of network costs should be covered through a fixed or power component of the tariff. A fixed component can be advantageous when applying a Ramsey principle[9], but may be challenging to implement in practice, when the fairness of cost distribution is taken into consideration. An advantage of a power component is that, because it can differ, based on a customer's power usage, and customers can adapt this, the power component can be used to give forward looking price signals.

Power components can be divided into two main types: measured capacity and contracted capacity. Measured capacity uses the highest peak during a set interval, e.g. the daily, monthly or yearly peak of the customer or network, to calculate the customer's power component of the

[9] Ramsey pricing states that consumers with an inelastic demand should cover a higher share of the residual costs, as this would limit the welfare loss due to prices being above the marginal cost.

tariff. Contracted capacity uses defined criteria, such as the fuse size or a pre-determined subscription level, to calculate the power component of the tariff. A subscription level can be set based for example on the historical power consumption in a bandwidth chosen by the individual customer. In such an approach, the customer pays a low variable tariff within the subscription level, and a higher variable tariff when consuming more than the subscription level.[10]

The type of power component that is most suitable varies, depending on the situation on the network. Where policy makers are mostly concerned with the recovery of residual costs, e.g. because there are no capacity constraints in the network, the power component should not give strong forward-looking signals to stimulate behaviour adaptation. For example, changing the physical fuse size would be a relatively comprehensive undertaking for most small-scale customers and therefore the fuse size could be used as an efficient way of differentiating the cost distribution between smaller and larger customers, even with a relatively fixed power component.

However, electrification and increases in power consumption suggest that tariffs should include a forward-looking price signal to a larger extent, to ensure customers consider how choices taken today may affect network costs in the long run. Both measured capacity and subscription methods might be suitable approaches for achieving this aim, especially if the level of the power component is related to the long-term marginal cost of developing the network.

When designing the power component, NRAs should also consider the trade-off between simplicity and cost-reflectivity. For example, monthly or yearly measured peaks, based on network utilisation, could give relatively precise signals but might be difficult for smaller customers to relate to if they do not have adequate smart-meters and intermediaries such as aggregators to support them. In addition, the economic consequence of “making mistakes” could be high. Daily measured peaks are less precise and could require additional power components to ensure that all customers pay their share of grid costs. However, they are easier for customers to understand, and might give a better customer response, in practice.

New technology and automation can lead to the possibility of implementing more complex and cost-reflective tariff designs, while preserving simplicity and predictability in the information given to the customer. For customers with real-time information on their electricity consumption, and the ability to invest in smart technology, a subscription level might work well. Over time, the level of the subscription reflects the customer’s demand for power.

3.2 Static time differentiation of tariffs

Power consumption is not the only determinant of the level of network costs. As the network requires enough capacity for peak consumption, the time-of-use is also important to consider. Time-differentiated “static” tariffs are characterised by offering different price signals for energy and power, based on discrete time periods (or “time-bands”) that are fixed in advance, possibly differing between relevant locations on the network. This is separate from pure static energy-based or power-based tariffs, which don’t send signals to users about the times when they are causing costs on the system.[11] Both the energy and the power component of the tariff can be time differentiated using time-of-use principles.

Generally, with time-differentiated static tariffs the time periods and the price signals themselves do not change for several years. Relatively short time periods targeting expected peak hours may

[10] Such a model is described e.g. in DNV GL, *Effective and cost reflective distribution tariffs* (2019). See also the Norwegian case in Annex 4. The two approaches can also co-exist: In Italy, for instance, contracted capacity is used for smaller customers (up to 15 kW) and measured capacity for all customers above 15 kW.

[11] Interruptibility is basically a time differentiation principle, where the customer receives a lower tariff for not demanding full service in peak hours.

be implemented, with some variations depending on the voltage level and the delivery point. Time-differentiated static tariffs offer a reasonable balance between efficiency and complexity, but lack the most desirable advantage of dynamic tariffs, i.e. short-term changes in prices, reflecting the actual network conditions. This is especially true when actual critical peak hours are highly volatile.

There are a number of different static tariff types that have been implemented throughout Europe and the rest of the world, which have been described in the literature (including CEER's last paper on this topic, issued in 2017). Broadly, these tariff types can be either time-of-use energy, or time-of-use power (see section 5.1). Time-of-use, whether energy, power or any mixture are generally considered to be more cost-reflective than time independent tariffs, as they are aligned to predicted peak times.

However, static time-of-use differentiated tariffs could also pose a challenge if they lead to large loads being shifted in and out of the network simultaneously (e.g. at the change of hours). For example, such shifts could happen when the price variation in the energy charge is high between two hours and an increasing degree of home automation results in a large number of users responding at once. Tariffs giving such signals could lead to new network peaks. Time-of-use tariff designs would need to avoid these sudden load changes. This could be achieved by using automation to stagger when smart appliances, EVs, etc switch on or similar mechanisms, as has been done in Great Britain.

The price signal has the potential to be counterproductive if it is set for an area that is larger than the congested zone, e.g. by incentivising a response from customers where it is not needed, although it is unlikely that this will be more distortive than a flat tariff. Policy makers should keep these issues in mind, including how the pricing zones are defined, when designing static time-of-use tariffs.

3.3 Further developments in tariff design: Dynamic tariffs

Improvements in the available information about the real-time status of the network and the consumption of each individual customer make it more realistic to implement dynamic tariffs. 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. Dynamic tariffs are one way that DSOs could make use of flexibility to avoid or defer reinforcement, which is due to increasing intermittent production and variation in consumption/load.[12] One way of implementing dynamic tariffs is through a critical peak price (CPP).

The objective of a dynamic network tariff is to promote more efficient network use under a scenario where network use has become more uncertain (e.g. due to intermittent production or new consumption patterns) and where new technological solutions are enabling demand response (smart meters, automation, storage). Being dynamic, the price signals can be sent closer to real time, increasing the cost-reflectiveness of the network tariff, which should achieve a more cost-efficient system, benefitting all network users.

A dynamic network tariff should not be confused with the dynamic electricity price contracts envisaged by Electricity Directive (2019/944) or other forms of valuing flexibility. Dynamic electricity price contracts reflect the price variation in the wholesale spot markets, including in the day-ahead and intraday markets.[13] Thus, they are designed to send scarcity price signals about

[12] The relationship between network tariffs and other flexibility instruments are explained in detail in chapter 4.
[13] For further information, see *CEER's Recommendations on Dynamic Price Implementation*, 3 March 2020.

the matching of supply and demand on the wholesale market (at system level, due to system marginal price), independently from the scarcity that may occur locally in the distribution network.

A truly dynamic end-user price is the sum of a dynamic network tariff and a dynamic (spot market) electricity price. The sum of the two price signals would enable the consumer to decide at each moment how much to consume for a given price. Obviously, the two price signals would not always be aligned since they are measuring scarcity on different levels: while a dynamic retail price measures scarcity in the wholesale market at system level (which could be regional, encompassing several countries), the dynamic network tariff measures scarcity on the distribution (or transmission) network at a local level.

The main differences between dynamic network tariffs and dynamic retail prices are:

- **Monopoly regulation *vs* Competition** – network tariffs are regulated while dynamic retail prices are set by the market.
- **Granularity** – while dynamic wholesale prices are related to bidding zones through the wholesale market, dynamic network tariffs need local granularity to send cost-reflective signals, due to the complexity of the network.
- **Estimation of avoided costs –** savings in dynamic wholesale prices are determined by short-term avoided energy costs (e.g. of the marginal power plant). Avoided network costs have a long-term perspective, and it might be difficult for flexibility providers to estimate when and how much the tariff savings will be. Due to this difficulty there is risk of over-compensating flexible network users at the expense of other users (see section 4.2).

To some extent, the introduction of dynamic network tariffs shares the same pre-requisites as dynamic retail prices, namely:

- Introduction of smart meters in order to measure consumption in short time intervals, according to the time unit, as determined by the imbalance settlement period. This is on track across Europe with the widescale roll-out of smart meters.
- Feedback about metering data to enable a user to control their energy use (e.g. through an app or a technical device). This is the stated intention of the Clean Energy Package.
- Technological solutions for flexible use and power reduction within property, housing and industry (e.g. automation and storage).

However, the introduction of dynamic network tariffs also requires a second layer of pre-requisites:

- A detailed forecasting model, which would be used by the DSOs to determine the critical periods by network area/point. The complexity needs for these models to accurately forecast critical periods would be exponentially greater where the tariffs also vary within a DSO area. Notably, DSOs need to become increasingly responsible for the operation of their networks, and this includes modelling of future congestions.
- Robust estimates about long-term avoided costs.
- IT infrastructure to send price signals to network users, possibly differentiated by network area/point, in order to ensure users are able to predict charges and respond to them.

Dynamic tariffs raise numerous regulatory questions. These issues include how customers should be informed of tariffs, how regulators should regulate tariff setting, and how they should be integrated into the system of tariff or revenue cap incentive regulation applied in most Member States of the EU. NRAs should also consider carefully the fact that dynamic tariffs come with administrative costs and complexity, as it is a difficult task to calculate the required tariffs for a specific place and/or time.

Similarly as for static time-of-use tariffs, dynamic tariffs, which are set for a larger region or timeframe than required to avoid the actual congestion, could be counter-productive, as they could influence customer behaviour in a way that is not necessary to solve the congestion. With regards to small customers and the implications that dynamic tariffs could have for them, the principles of simplicity and predictability are especially relevant. In general, dynamic tariffs would be far more complex in comparison to static tariffs. Also, when there are differences in network tariffs, based on the (local) supply and demand, they will be more volatile and harder to predict.

However, the growth of smart technology and the entrance of new independent aggregators are likely to address this gap in the future. Apps are already available that allow customers to set their real-time price-ceilings before their heating cuts off, and aggregators are offering services to alter customer demand in response to real-time price signals. Dynamic tariffs could promote the spread of this innovation to support the system. Supporting this innovation would have to be weighed against the costs DSOs incur when providing the required signals to the market.

Finally, the consequences for cost distribution could be unclear, especially between customers with and without automation. If a high degree of cost recovery is done through the dynamic tariff signal, costumers who are unable to respond through technology are likely to pay higher network costs. This depends on a number of aspects, e.g. on whether the dynamics tariffs are voluntary for customers and how the costs would be distributed between dynamic and static tariff users. Through the resulting tariffs it should be ensured that a reasonable distribution of costs among all network users is achieved. CEER emphasises that principles such as simplicity and predictability are especially important for small customers, while other principles have more weight for larger customers at the DSO level.

Critical peak pricing

A first step for a more dynamic tariff is providing price signals that reflect the critical periods that need to have significantly higher prices. CPP is a dynamic form of a time-varying tariff, where the peak price would be significantly higher on a limited number of days (typically 10 to 15) or hours per year, when the capacity of the system is most likely to be constrained, and lower for the rest of the year.

With this type of pricing, customers face a high price for their usage during the days or hours identified as “critical events”. The customers can avoid paying these high prices by reducing their electricity usage during these critical periods of high demand (which may only occur up to a pre-determined number of times per year) and benefit from a price for non-critical hours, which would be slightly lower than a flat rate. This pricing may provide a strong incentive for customers to reduce consumption during critical event days or hours (in case there is any elasticity to their consumption behaviour), but provides no incentive to reduce use on non-event days or hours.

With CPP tariffs, DSOs can send stronger price signals (either capacity or volumetric-based, depending on metered values) to stimulate greater demand response than would be achieved with traditional time-of-use tariffs. This is because CPP applies to a limited number of days, when the network has a higher probability of being constrained. That is important, especially as intermittent generation capacity from wind and solar generating sources increases and, therefore, distribution system capacity constraints may become less predictable.[14] Hence, tariff designs that can respond to actual system conditions may become more valuable than more stable tariff designs as static time-of-use.

[14] Note that the opposite also can be true. If there are a larger number of unpredictable peak events, the number of CPP required to avoid network reinforcement could be significant – reducing the benefit and difference for a time varying tariff.

There can be variants applied to a CPP tariff design, such as where:

- The time and duration of the price increase are predetermined when events are called.
- The time and duration of the price increase may vary, based on the electric network's need to have loads reduced.
- The tariff is a clear dynamic price signal, meaning the network tariff for critical periods can be variable.

CPP can lead to more efficient network operation, as increased demand side flexibility during extreme circumstances can reduce peaks and therefore the risk of disconnection to manage constraints. But a disadvantage is that, because the main portion of network costs are residual, a CPP tariff structure still faces the challenge of allocating these costs in a way that creates as few distortions as possible. Therefore, when considering the principles for a CPP tariff, NRAs should evaluate whether these should be combined with efficient methods of covering the residual costs of the network, e.g. through a power component.

Studies have shown that CPP tariffs provide incentives for customers to change their consumption pattern. Results from France, Great Britain[15], Slovenia[16] and Japan show that customers react on CPP pricing, which means that the peak load can be reduced.[17] Plans to introduce or actual implementation of CPP tariffs can be found in countries including Slovenia, China, USA, Japan and France. For example, in France, time-of-use and variable-peak signals have been used for 50 years. The example of France is described in annex 3.

Locational variation of tariffs

In some jurisdictions, network tariffs vary by location. This could be both between DSOs and within a DSO area. The justification for this is, for instance, that there are locational variations in the historical cost of serving users across the distribution and transmission networks. Furthermore, the need to send signals about capacity constraints may differ between areas.[18] Thus, the consumer should take into account the locational price signal.

The local variation of network costs can be driven by:

- User density.
- Distance from generation or demand.
- Network asset profile and characteristics (meshed/radial, overhead/underground).
- Differences in the short-term marginal costs due to utilisation or spare capacity, of the network.

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[15] Industrial consumers connected to the transmission network in Great Britain are incentivised to avoid the three critical peaks of demand on the system each year between November and February through a system called 'triads'. The peak periods are determined ex-post.

[16] Report on the Energy Sector in Slovenia 2017 (page 58-59) – https://www.agen-rs.si/documents/54870/68629/a/78f74b68-dbfc-415e-ab88-882652558d94

[17] The examples of CPP-tariffs are from both unbundled distributions utilities responsible only on distribution tariffs and bundled vertically integrated utilities responsible for both distribution and retail supply on an integrated basis. Brattle Group 2018, Electricity Distribution Network Tariffs Principles and analysis of options.

[18] Several other advantages are described in Wolak (2019), "The role of Efficient Pricing in Enabling a Low-Carbon Electricity Sector".

The main options for introducing locational tariffs are nodal, zonal, or archetypical. Nodal tariffs require detailed understanding of the network, and are typically based on load flow models, resulting in large numbers of tariffs for different nodes (such as Electrical High Voltage (EHV) tariffs in Great Britain, or Locational Marginal Price (LMP) approaches in, for example, the Pennsylvania-New Jersey-Maryland interconnection). Zonal tariffs are simpler to implement, and can be based on geographical regions, electrical connectivity, or an understanding of where there are major load flow constraints (this approach was taken in the ERCOT transmission system in Texas in the process of transitioning to a full LMP model). Archetypical tariffs could be based on user characteristics, such as population density or user type, or network characteristics.

While the drivers of the locational variation in network costs are known, there are several limitations, when implementing locational variation in distribution network tariffs. The actual knowledge of the network (such as electrical connectivity, assets, network load flows) may be limited, particularly at the lower voltages. Other limitations include the fact that the volume of calculations would be several orders of magnitude higher for LV than for EHV, and public acceptability: it may not be politically viable to charge users in different parts of the same country vastly different prices for the same level of service. The public perception of fairness might also make it difficult to implement locational signals, especially within a DSO area. These considerations may limit the preciseness of the price signal, when implemented in practice.

CEER concludes that NRAs should consider dynamic network tariffs as one of the tools to improve the cost-reflectiveness of network tariffs but, as a starting point, should consider whether technology is sufficiently mature within the Member State to allow the efficient use of such tariffs on smaller users as it requires a sufficient smart meter roll-out and a high level of automation. The option of dynamic tariffs will become more viable as data systems develop. Implementing dynamic tariffs requires piloting of such tariff structures to test their ability to promote a more efficient electricity system. Finally, implementation of dynamic network tariffs must be preceded by a thorough cost-benefit analysis, namely to account for the monitoring and communication requirements needed to implement such a scheme.

3.4 Overview of tariff types

This section provides an overview of the different tariff components and the possible dimensions for those tariffs.

Tariff components	Description
Fixed	A flat annual or monthly tariff, often based on the customer category or voltage level a user is connected to. This is used to recover fixed “per customer” costs or the residual.
Energy	Tariffs set on a volumetric (per kWh) basis. Often with a time-of-use element (see below) to encourage users to shift consumption away from peak demand.
Power (measured and contracted)	Tariffs are set on a power consumption (per kW) basis, which can be contracted ahead of time (ex-ante) or based on measured power consumption (ex-post). These tariffs can encourage users to reduce their capacity requirements or manage their own peaks.
Time (static time of use)	Time-of-use tariffs are used widely to encourage users to shift consumptions away from peaks. Can be done on a daily basis or seasonally, based on pre-defined peak tariff blocks. With increasing automation, such signals should be used with care to avoid peak shifting.

Tariff dimensions	Description
Time (dynamic)	Dynamic time varying tariffs could mean either the time during which the charge is dynamically set, or that the tariff is dynamically set. Under CPP, which is used by a small number of distribution companies, users are given notice of an upcoming “critical peak period”, during which tariffs will be significantly above normal. CPP has been shown to reduce peak demand in some countries (e.g. France). Theoretically, real time pricing of the network (under which the tariff is dynamically set) may be possible, although it has not been implemented anywhere on the distribution network.
Location	Network costs are inherently locational and vary by either the asset mix in a location or the extent of spare capacity of the network in that location. However, network tariffs are often set on a national or regional level. Zonal or nodal pricing options can introduce more cost reflectivity, although there may be feasibility and political acceptability issues with these approaches.
Interruptibility	Customers’ availability to be interrupted, according to a predefined set of conditions (approved by the NRA), is sometimes used in combination with agreed power, in order to enforce the pre-agreed limits that users have signed up to. This can help the DSO to manage and plan the network, while reducing the need for future reinforcement. Tariffs that have some limited interruptibility, agreed by users (for a reduction in their tariff), are being considered in Great Britain. This would allow users to offer flexibility to the network (for fair remuneration), if they value it (for example by allowing their EV charging or heat pumps to be interrupted), while also reducing the need for reinforcement.

4 Network tariffs and flexibility

As mentioned above, the tariff structure is not the only instrument to incentivise implicitly beneficial network behaviour of grid users. Another instrument is to explicitly procure both production and demand side flexibility for purposes such as congestion management or to reduce or delay the need for network expansion. Flexibility services procurement could be useful for increasing efficiencies in the operation and development of the networks. According to article 32 paragraph 1 of the Directive (EU) 2019/944 on common rules for the internal market for electricity, Member States are obliged to enable and incentivise DSOs to procure flexibility services. Especially on the low voltage level, the potential for explicit flexibility instruments to be attractive to users depends on the cost-benefit relationship, based on the specific average consumption, which differs between Member States. In cases of low average consumption, there is little incentive for flexibility, as the monetary profit will be limited. This chapter further investigates the interaction between both static and dynamic tariffs and the procurement of flexibility.

4.1 Interaction between static network tariffs and flexibility procurement

As discussed in the previous chapter, different tariff types can incentivise network user behaviour in different ways. Network users can also be incentivised through explicit flexibility procurement. Technological progress – such as digitalisation, storage, the ongoing growth of electric mobility and automation – boosts the range of available options for this instrument.[19] CEER expects the availability of flexibility that can be procured to increase in the future. Important developments in this area include initiatives around developing market platforms for flexibility, on which grid users that are engaged in demand response (e.g. through storage facilities) can offer flexibility to the DSO.[20] In addition, aggregators could make available procurable flexibility provided by a portfolio of small customers, including households. As the procurement of explicit flexibility contributes to avoiding or delaying network expansion, it has an impact on the network operators' cost structure and subsequently on distribution network tariffs.

Combined with static network tariffs, the impact of flexibility procurement should be easy to identify. Provided the procured flexibility is contracted for a sufficient period of time, the procuring network operator will be able to avoid network expansion. This leads to an overall reduction of the DSO's costs in most cases in the long run. Thus, network users will be charged lower tariffs than would have been the case without the procured flexibility. Supporting this, the NRA could include the cost of procuring flexibility in revenue regulation where it will be socialised and passed on to all network users. When (pure) static tariffs are applied, users connected in a congested area and users connected in a region with sufficient capacity bear the same amount of flexibility costs, as without locational differentiation there is no geographical variation in tariffs.

NRAs should also take into consideration that the existence of additional (flexible) loads, like EVs on the low voltage level, can also lead to higher costs. The additional use of the grid would require additional investments or cost of flexibility procured to avoid simultaneous load. These costs will mainly be imposed upon small consumers, as there is no further cascading to other users. Such effects need to be considered, when evaluating the benefit that procurement of flexibility can have at the low voltage level.

Where static time signals do not prompt the desired demand response, the procurement of flexibility forms a beneficial instrument for avoiding costs. This creates the potential to use flexibility, while allowing network tariffs to fulfil the tariff principles of simplicity, predictability and

[19] In this paper CEER goes into the interaction between network tariffs and the procurement of flexibility. For more information and CEER's view on the procurement of flexibility itself, CEER refers to earlier publications, such as CEER's *Conclusions Paper on Flexibility Use at Distribution Level* (2018).

[20] CEER aims to publish a paper that goes deeper into flexibility later in 2020.

non-discrimination. The combination of flexibility procurement with static tariffs, which are generally predictable in nature, means participants are able to factor them into their bid under competitive flexibility procurement. It will be more complex when flexibility procurement is considered alongside dynamic tariffs, as discussed below.

4.2 Interaction between dynamic network tariffs and flexibility procurement

Dynamic network tariffs and the procurement of flexibility are different instruments for changing network use. In some cases and scenarios they may be similarly effective, as they both have the same goal of pricing the cost of a constraint and allowing market participants to offer the cheapest solutions to resolve it. It should be noted however, that a combination of both would not necessarily lead to an increase in the realisation of their shared objectives. A customer's flexibility can be used to respond to dynamic network tariffs, as well as to offer flexibility services in a procurement. As such, the interaction between these instruments needs to be considered.

Dynamic network tariffs and flexibility procurement differ in that under the procurement of flexibility, the DSO explicitly contracts for it with the customer or their intermediary, while with dynamic tariffs, the flexibility provided by customers is implicit. Thus, the effectiveness of the latter firstly depends on the actual existence of customer flexibility and, secondly, on the interaction between the network tariff signals and other behaviour-influencing factors.

CEER emphasises that worldwide there is limited experience of full dynamic network tariffs at the distribution level. Nonetheless, there are a couple of observations that can be made, when they are compared with the procurement of flexibility. First of all, the effectiveness of both instruments might currently be limited at the DSO level, as it depends on the potential for flexible behaviour. For small customers, such as private households and small businesses that are mostly connected to the low voltage level, it might be questionable whether there are currently available sufficient (technological) possibilities for providing flexibility.

The incentive created by dynamic network tariff signals might be weakened by other factors, for example, dynamic retail prices (see also section 5.1). This should be taken into account, in case the end costumers at the low voltage level cannot not distinguish between network tariffs and other parts of their electricity bill, when the retail price and network tariffs are integrated into a single component. This makes explicit flexibility procurement likely to be simpler, especially in the case of an acute need for flexibility, e.g. for curative redispatch. Another aspect is that the development of dynamic network tariffs requires smart meters to be available and – to trigger sufficient flexibility – a certain level of automation and price elasticity. If these are not available, then customers would either not react, because the prerequisites are not fulfilled, or would limit their response, due to the (transaction) cost of responding being higher than their benefits. A third aspect is that, to ensure dynamic tariffs are cost-reflective and fair, universal network monitoring coverage might be required, so that the network monitoring needed to support flexibility procurement can be targeted to congested areas.

As stated in section 4.1, static tariffs result in the costs of services such as procured flexibility being imposed upon all network users equally, without having regard for everyone's individual contribution to the need for these services. Dynamic tariffs aim at mirroring the constraint costs users cause in what they pay (polluter-pays principle), and to allow users to benefit implicitly from the contribution they make to supporting the system with flexibility, promoting efficient cost allocation. However, when we take into account the complexity of dynamic tariff calculations, there is a risk of incorrect cost allocation. The calculation of dynamic tariffs can be a complex task as they need to properly reflect a network's congestion. If they fail to do so, this would lead to unjustified charges for the affected network users, because they would have to pay different prices for network usage, without any potential congestion to justify it.

The complexity of dynamic tariff calculation is also an important factor when discussing the potential effects of dynamic tariffs and flexibility procurement being applied simultaneously. Realising the benefits of dynamic network tariffs is even more complex when explicit flexibility is applied, because the interaction between both instruments makes the effects of any behaviour change in response to tariffs harder to predict. Under a system of continuously changing tariffs and network load situations, it will be very difficult to effectively allocate and (subsequently) apply explicit flexibility. This again might lead to problems regarding location decisions, e.g. for new storage facilities.

The combination of static network tariffs and procured explicit flexibility might be the most reliable way to reduce network costs. For DSOs, higher levels of explicit procurement with static tariffs may be simpler than lower levels of explicit procurement with dynamic tariffs. The trade-off between these two should be considered further.

In chapter 3, CEER mentioned that dynamic tariffs might be more appropriate for larger customers and for small customers where sufficient means for flexibility and automation are available. Although customers differ in their level of automation (e.g. availability of smart meters), for now a combination of procurement of flexibility and maintaining static time-of-use tariffs where needed would be more suitable, at least until the level of automation for customers at lower voltage levels has reached sufficient maturity. This approach means the availability of flexibility can still be used, although this of course depends on the level of automation and could change over time.

5 Challenges for distribution tariffs in the energy transition

Distribution tariffs influence network utilisation through the price signal conveyed to network users and, therefore, the need for future network investments. A cost-reflective tariff design will consequently be fundamental for the energy transition, promoting efficient utilisation of the existing network and signalling the cost of expanding the network further.

Entities responsible for distribution tariff design, such as NRAs and DSOs, need to be aware of the future developments and challenges for distribution tariffs that will be encountered during the energy transition, while ensuring that the solutions to those challenges comply with the provisions in the 'Clean energy for all Europeans package'.[21] In this chapter, CEER addresses a number of those developments and challenges.

5.1 Developing markets: billing the customers

To an increasing degree, retailers and new third-party actors are offering supplemental products (e.g. steering of power consumption) to customers, allowing them to lower their network bills. However, it is important that this is not done in a way that distort price signals about the efficient utilisation and development of the network. Where network charges and electricity prices are charged jointly, NRAs need to make sure that this happens in a way that does not create barriers to the introduction of more cost-reflective tariffs.

The offerings provided by retailers and other third party actors give customers a better opportunity to respond to more complex tariff signals than they would have on their own, for example through new technology that allows engaged users to react to the information from their smart meters (e.g. by offering their flexibility for the potential to save money). More conservative users may be able to fix their prices (for a premium) and reduce their exposure to price volatility. "Behind the meter" options using smart technology to react to various price signals, would also make it easier for retailers and other third-party actors to combine retail offerings with storage, EV charging management and aggregation, etc.

Given their direct contact with energy users, retailers or new third-party actors could be well placed to understand their needs and constraints, creating retail offerings that would be popular, while also adding value to the network. A challenge in many places is that the lack of more cost-reflective tariffs makes it difficult to build a business model around such products. To ensure efficient utilisation of new technology it is therefore important that more cost-reflective tariffs providing incentives for an efficient use of the network are introduced.

5.2 Developing smart and cost-reflective distribution tariffs

In the past, the opportunity to pass more sophisticated price signals on to end users, especially households connected to the low voltage level, was rather limited. Distribution tariffs were often based on flat volumetric charges, together with fixed charges (or in a few cases, differentiated per consumption blocks). However, in a smarter environment, with smart appliances, aggregators and price comparison tools, regulators should develop distribution tariffs that are equally smart.

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[21] See Annex 3 for a brief summary of what has changed in the Clean energy for all Europeans package compared to the 3rd Energy Package on the topic of distribution tariffs.

Consider the example in Southeast Queensland, Australia, where the tariff design was sending the wrong price signals to network users,[22] because the volumetric tariff structure gave strong incentives for energy-saving technologies, such as rooftop solar. Over a period of five years, the number of households with rooftop solar increased from nearly zero to 25%. The reduction in energy consumption from the network, combined with the volumetric tariff structure, led to tariffs increasing by 112% from 2009 to 2014. That development further increased the incentive to reduce consumption of energy from the network, again increasing the burden on those unwilling or unable to make similar investments.

A smart distribution tariff needs to strike an adequate balance between reflecting the cost drivers of distribution networks and ensuring that network users equipped with smart technologies are able to react to the signals. In the case of Great Britain[23] and Norway, the regulators are conducting thorough reviews of their distribution tariffs.

CEER considers that regulators and DSOs should share their expertise on a pan-European level to enable more cost-reflective tariffs. The upcoming reports on distribution tariffs, to be developed by ACER, pursuant to Regulation (EU) 2019/943, can give additional guidance. Notwithstanding, CEER continues to believe that a one-size-fits-all approach will not succeed with distribution tariffs because the diversity in network topology and market circumstances mean that national distribution tariffs need to balance design trade-offs in a different manner in every jurisdiction.

5.3 Cost cascading and the generation-load split

Once a tariff structure is defined, with the components that best reflect different cost drivers, it is still necessary to set cost allocation rules. Common approaches so far have included the application of a cost cascading principle and the allocation of all distribution costs to loads and not to generation.

When it comes to cost allocation across voltage levels, many NRAs apply a cost cascading principle. That principle is based on the simplifying assumption that energy flows from the highest to the lowest voltage level. As a result, distribution tariffs have traditionally been allocated on the grounds that each network user should pay for the voltage level of connection, as well as for all voltage levels above. A network with substantial decentralised generation, together with storage facilities and prosumers, might observe inverted power flows (from lower voltage layers to higher voltage ones) on a frequent basis. This will open the debate about whether network users connected at higher voltage levels should be charged for lower voltage grids.

Since large industrial network users are usually connected to upper network levels, they pay on average less in network costs, due to the cost cascading principle. Adjusting the cost cascading principle in order to take into account reverse power flows may lead to significant impacts on network users. NRAs are advised to perform impact assessments on an ex-ante basis and to be transparent about who will be positively and negatively affected by new cost allocation approaches. If impacts are significant, a smooth transition should be considered by regulators.

[22] Simshauser, Paul. (2015), 'Distribution network prices and solar PV: Resolving rate instability and wealth transfers through demand tariffs', Energy Economics 54 (2016), p. 108–122.

[23] In 2017 Ofgem launched a significant code review on how residual network charges should be set and recovered in Great Britain. In 2018 it launched a parallel significant code review of electricity access and forward-looking charging. Implementation of resulting changes is expected to occur between 2021 and 2023. See Annex 4 for more details.

The energy transition will also challenge the way network tariffs are charged to producers and consumers. In a traditional power system, generation reacts in a passive manner to changes in consumption and, as a result, most tariff structures allocate almost the entire cost of distribution tariffs to consumption. In a modern power system, with network investment required to facilitate distributed generation and more elastic demand and intermittent generation, that rationale could be questioned. NRAs should assess the need for introducing network tariffs for producers, where they are not yet applied, and (where they are already applied) assess the risks of increasing distribution tariffs for producers, with regards to avoid creating distortions in the wholesale market and the development of a decentralised power system.

Article 18(1) of Regulation (EU) 2019/943 includes a provision that network charges – if applied to producers – shall '*not discriminate positively or negatively between production connected at the distribution level and production connected at the transmission level*'. In CEER's view, NRAs should develop efforts to have a common methodology to set network tariffs for producers connected at both distribution and transmission levels, taking into account availability of information and the need to aggregating data. Regulation (EU) 838/2010 is relevant in this context, as it sets limits on the transmission tariffs that can be charged to producers in different Member States.

5.4 Energy storage

A significant penetration of energy storage will be one of the crucial factors for integrating more renewable energy into the power system, because it enables a combination of intermittent RES with rather inelastic demand, while meeting the technical requirement that power supply matches demand at all times in the network.

Regulation (EU) 2019/943 establishes that "*network charges shall not discriminate either positively or negatively against energy storage*".[24] Since a storage facility may withdraw energy from or inject energy into the distribution network, it can be regarded as both a consumer and a producer located at the same network connection point. As such, non-discrimination would suggest that energy storage should be subject to distribution tariffs applicable to both energy withdrawals and, where applicable, energy injections.[25]

Notwithstanding this, the cumulative charges for withdrawal and injection must reflect the value of storage to the system. A storage facility operated with the purpose of improving network utilisation can decrease the need for future network investment, while a storage unit operated inefficiently from a network perspective can increase future distribution costs. The distribution tariff design should be able to reflect the positive or negative impact that storage facilities might have.

In practice, there will not only be standalone storage facilities, but also storage that could be combined with withdrawal or injection (or both) behind a single point of connection. Also, energy storage is likely to develop further where there are explicit instruments of flexibility procurement for them. In those cases, it is important to ensure that storage units are not remunerated or charged twice for a single service provided to or requested from the network.

[24] Article 18(1) of Regulation (EU) 2019/943.

[25] Moreover, Articles 15 and 16 of Directive (EU) 2019/944 state that active consumers and citizen energy communities should be subject to "*network charges that account <u>separately</u> for the electricity fed into the grid and the electricity consumed from the grid*".

CEER recommended in its Guidelines of Good Practice for Distribution Network Tariffs that net metering[26] for self-generators should be avoided, insofar as it can prevent a fair contribution towards the payment of network tariffs, including volumetric charges. The same recommendation extends to network charges applied to storage facilities. Therefore, CEER considers that net metering of storage facilities should be avoided.

In the short run, behind-the-meter storage will probably increase more than network-scale storage solutions. NRAs should review whether their current tariff design, with special attention to volumetric charges, is providing adequate incentives for storage equipment or equivalent network utilisation, such as self-consumption or energy communities.

5.5 Integration of electric vehicles

Electrification of transport is one of the pillars for decarbonisation. Integrating a large amount of EVs represents a challenge because it may increase the need for more capacity on the distribution network, in particular on the low voltage network. But it also represents an opportunity, because an efficient charging regime can encourage flexibility, enabling better integration of intermittent RES.

As background information, CEER notes that charging stations – not EVs – are distribution network users. For a dedicated charging station, the connection to the network is normally unique for the whole station, although it may include electricity usage that is different from EV recharging.[27] In the same way, energy used for EV recharging at home is in most cases metered by the same meter for the whole household. This is relevant because the network tariff is applied to the energy and power metered at the point of connection, therefore including both EV recharging and other (ordinary) electricity uses.

Cost-reflective distribution tariffs are an important prerequisite and may play a crucial role for a successful integration of EVs. A report made for the Norwegian energy regulator[28], NVE, concluded that the difference between “unsmart” and smart charging may amount to a gross increase in demand for capacity during the afternoon of 2,400 MW. This would require investments in the local distribution grid of around 11 billion NOK, or approximately € 1.1 billion, at an average cost of € 450 per kW. For countries not already having electrified residential heating and cooling, the costs of “unsmart” charging could be even higher.

[26] As defined in Commission Staff Working Document “Best practices on Renewable Energy Self-generation“, Commission Staff Working Document, July 2015, COM(2015) 339 final, “*Net metering is a regulatory framework under which the excess electricity injected into the grid can be used at a later time to offset consumption during times when their onsite renewable generation is absent or not sufficient. In other words, under this scheme, consumers use the grid as a backup system for their excess power production*.”

[27] See CEER Conclusion Paper on New Services and DSO Involvement, in particular paragraph 5.4 on EV Charging.

[28] NVE external report nr. 51/2019. See English summary on pages 5-8. http://publikasjoner.nve.no/eksternrapport/2019/eksternrapport2019_51.pdf

These costs could be reduced through incentivising smart charging, i.e. charging during hours where the network has available capacity. This has been an important motivation for the work on new tariff designs in Norway.[29] Several other reports have also studied how to successfully integrate EVs into the grid using better price signals. A report from the Regulatory Assistance Project[30] concluded that smart pricing[31] for EV charging can enable EVs as flexibility providers. The report recommends a smart pricing approach for EVs, the implementation of time and locational signals and the need to monitor the effectiveness of retail pricing in enabling the integration of EVs. One of the examples mentioned in that report is the German case, where DSOs offer discounts to network tariffs, in exchange for the ability to directly control the charging point for the purpose of managing the load on the network and the coincidence of loads. At present, Germany is considering reversing this mechanism and moving towards a system where conditional network use is standard and unconditional network use is an option that is available for higher compensation. In Italy, smart meters are used for time-of-use capacity limitation for EV owners who recharge at home.[32] A report by Eurelectric also identifies smart charging solutions as a path to integrate EVs.[33]

The EV sector also illustrates the risk of poor price signals. With a volumetric tariff, charging an EV using a fast charger costs the same as using a slower charger. However, the two technologies impose very different costs upon the distribution network.

In light of this discussion, CEER considers that NRAs should explore changing tariff structures, to take into account developments in the field of EV charging. CEER emphasises that network users with similar characteristics should be treated similarly. Hence, new tariff structures applied to EVs should be made available to other network users as well, unless operational reasons justify different treatment.

[29] See case study in Annex 4.

[30] Hildermeier, J., Kolokathis, C., Rosenow, J., Hogan, M., Wiese, C., and Jahn, A. (2019). Start with smart: Promising practices for integrating electric vehicles into the grid. Brussels, Belgium: Regulatory Assistance Project.

[31] The report argues that EV integration must involve a triple smartness, namely smart pricing, smart technology and smart infrastructure.

[32] More information on the Italian approach is provided in Annex 4.

[33] Eurelectric (2019). The Value of the Grid: Why Europe's distribution grids matter in decarbonising the power system.

6 Conclusions

With this paper, CEER aims to aid stakeholders and NRAs in their thinking on tariff design. It builds upon earlier CEER work, while contributing to further thinking in key areas. In this paper, CEER comes to the following conclusions:

- There is not a one-size-fits-all tariff model that is appropriate for all Member States when it comes to distribution tariffs. Rather, tariff design should take a number of principles into account. Cost-reflectivity, leading to economic efficiency, is the key principle, while the additional principles are non-distortion, cost recovery, non-discrimination, transparency, predictability and simplicity. Regulators should seek to find a balance between these principles.

- In order to have cost-reflective tariffs, it is important to be aware of the cost structure of distribution networks in the short term (losses and congestion costs) and over the long term (infrastructure costs). Tariff design should reflect that electricity networks have high fixed costs and low variable costs in the short-term. Customers should be exposed to forward-looking price signals to reflect that changes in their utilisation of the grid affects future network costs. The tariff design should be targeted at reducing system peak and individual peaks.

- The tariff structure can consist of just one component or a selection from multiple components, being fixed (per point of delivery), energy-based (per kWh) and power-based (per kW, either used and measured or contracted) components. These components can be further differentiated, such as by time (static or dynamic), location and interruptibility.

- Advanced differentiation in time and location, for example through dynamic tariffs or interruptibility, will most likely increase how cost reflective tariffs are for specific network users and may also incentivise network beneficial behaviour. More advanced differentiation is, however, rather complex and can have a negative impact on other principles, such as simplicity, predictability and transparency, if not implemented effectively. Dynamic tariffs require a sufficient level of automation. As the level of automation varies among customers, dynamic tariffs might be more appropriate for larger customers than for small customers in the short term. Moreover, the signals stemming from dynamic network tariffs could be diluted by other factors, such as dynamic retail prices.

- Incentivising network-beneficial customer behaviour is not only possible through dynamic tariffs, but also through procurement of flexibility. Both can contribute towards limiting or postponing network investments. Where dynamic tariffs trigger implicitly a change in behaviour, an advantage of the explicit procurement of flexibility through contracts is that it creates more certainty for DSOs and allows customers willing to provide flexibility to be adequately remunerated.

- The procurement of flexibility and dynamic tariffs are two instruments for achieving flexibility that can be applied. If applied at the same time, their interaction should be carefully considered. Introducing fully dynamic network tariffs in combination with flexibility procurement by DSOs is more complex than in combination with static tariffs.

- NRAs should develop smart distribution tariffs that strike an adequate balance between reflecting the cost drivers of distribution networks and ensuring that network users equipped with smart technologies are able to react to the signals.

- Further, NRAs should consider if increased decentralised generation requires the introduction or increase of tariffs for production, while taking into account that network charges should not discriminate positively or negatively between production connected at the distribution level and the transmission level. Increased decentralised generation requires NRAs to monitor the cost allocation between voltage levels, for example, when the cascading principle is applied NRAs should see if it holds. CEER considers that net metering of self-generators should be avoided

- Distribution tariffs applied to customers with energy storage facilities should reflect the use of the network in terms of both energy withdrawal and injection. CEER considers that any double charging for storage facilities should be avoided. Also, NRAs should take into account developments in the field of electric vehicle (EV) charging, when exploring changes in the tariff structures.

- CEER emphasises the need for NRAs to review the current tariff structures to identify how they can be improved, for example to create stronger incentives for efficient usage of the grid. Topics that require further thinking about include dynamic network tariffs' potential and the interaction with procurement of flexibility. NRAs – and where required also legislators – will need to anticipate circumstances, such as the completion of the smart meter roll-out and aggregators offering flexibility for procurement by DSOs, in order to allow for a smooth introduction of improved tariffs structures.

Annex 1 – List of abbreviations

Abbreviation	Definition
ACER	Agency for Cooperation of Energy Regulators
CEER	Council of European Energy Regulators
CEP	Clean Energy for All Europeans package
CPP	Critical Peak Pricing
DSO	Distribution System Operator
DSR	Demand Side Response
EC	European Commission
EV	Electric Vehicle
GGP	Guidelines of Good Practice
LMP	Locational Marginal Price
LRMC	Long Run Marginal Costs
MCA	Multi Criteria Assessment
MS	Member States
NRA	National Regulatory Authority
RAV	Regulatory Asset Value
RES	Renewable Energy Source
TSO	Transmission System Operator
ToU	Time of Use

Annex 2 – Glossary

Term	Definition
Electricity consumption (kWh)	Consumption of electricity over a time period, typically one year.
Power consumption (kW)	Consumption of power, e.g. the instantaneous outtake of electricity. When measured e.g. through a smart meter, it is typically the electricity consumption during an hour (kWh/h) or per 15 minutes.
Contracted power (kW)	Agreed level of outtake, e.g. as a subscription or based on fuse size, between DSO and network customer.
Capacity based tariff	Tariff where network costs are mostly recovered through fixed and power components.
Volumetric tariff	Tariff where network costs are mostly recovered through energy components.
Static tariff	Tariff where the price of each component is set (well) in advance.
Dynamic tariff	Tariff where the price of each component may change close to the hour of consumption, given the situation of the network.

Annex 3 – Distribution Tariffs within the Clean Energy for All Europeans package

The Clean Energy for All Europeans package (also known as the Clean Energy Package, CEP), with its pieces of legislation approved during 2018 and 2019, represents the follow-up to the 3rd Energy Package, which was approved in 2009. Distribution tariffs are directly addressed in the Electricity Directive and the Electricity Regulation of each legislative package.[34]

In general, the CEP provides more detail on the requirements that distribution tariffs must fulfil, while acknowledging that it remains an NRA competence. This annex presents the main changes for distribution tariffs that result from the CEP, compared to the 3rd Package.

Electricity Directive

One important point is that the Electricity Directive continues to clearly state that the task of setting or approving distribution tariffs or their methodologies remains a duty of NRAs.[35]

In regard to the changes in the CEP compared to the 3rd Package, the Electricity Directive refers to network charges in the context of new network users foreseen in the CEP, such as active customers[36], citizen energy communities[37] and energy storage. These market agents shall be subject to "*cost-reflective, transparent and non-discriminatory network charges that account separately for the electricity fed into the grid and the electricity consumed from the grid*".

Furthermore, Article 15 of Directive (EU) 2019/944 on active customers mentions explicitly the avoidance of double charging of network charges, in particular with regards to stored electricity within premises and when providing flexibility services.

Electricity Regulation

The Electricity Regulation, being an EU Regulation, is directly applicable to all Member States and does not require a transposition into the national legal framework, as opposed to an EU Directive. Under the 3rd Package, distribution tariffs had to comply with Article 14 of Regulation (EC) 2009/714, while under the CEP, distribution tariffs have to comply with Article 18 of Regulation (EU) 2019/943.[38] Regulation (EU) 2019/943 is much more detailed about the requirements that network charges must satisfy.

Firstly, Regulation (EU) 2019/943 specifies in more detail what should be understood as 'charges for access to networks'. While Regulation (EC) 2009/714 only mentioned the existence of charges for access to networks, Regulation (EU) 2019/943 details that these charges include "*charges for connection to the networks, charges for use of networks, and, where applicable, charges for related network reinforcements*".

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[34] Under the 3rd Package, the relevant pieces are Directive (EU) 2009/72 and Regulation (EC) 2009/714. Under the CEP, the relevant pieces are Directive (EU) 2019/944 and Regulation (EU) 2019/943.

[35] The same provisions apply to transmission tariffs.

[36] 'Active customer' means a final customer, or a group of jointly acting final customers, who consumes or stores electricity generated within its premises located within confined boundaries or, where permitted by a Member State, within other premises, or who sells self-generated electricity or participates in flexibility or energy efficiency schemes, provided that those activities do not constitute its primary commercial or professional activity.

[37] 'Citizen energy community' means a legal entity that: (a) is based on voluntary and open participation and is effectively controlled by members or shareholders that are natural persons, local authorities, including municipalities, or small enterprises; (b) has for its primary purpose to provide environmental, economic or social community benefits to its members or shareholders or to the local areas where it operates rather than to generate financial profits; and (c) may engage in generation, including from renewable sources, distribution, supply, consumption, aggregation, energy storage, energy efficiency services or charging services for electric vehicles or provide other energy services to its members or shareholders.

[38] These Articles deal with charges for access to networks, which includes distribution tariffs and transmission tariffs.

Secondly, Regulation (EU) 2019/943 establishes a more exhaustive list of requirements to be met by charges for access to networks. Regulation (EC) 2009/714 stated that these charges shall:

- be transparent;
- take into account the need for network security;
- reflect actual costs incurred insofar as they correspond to those of an efficient and structurally comparable network operator;
- be applied in a non-discriminatory manner; and
- not be distance-related.

Regulation (EU) 2019/943 adds to this list that charges for access to networks shall:

- be cost-reflective;
- take into account the need for flexibility;
- not include unrelated costs supporting unrelated policy objectives;
- neutrally support overall system efficiency over the long run through price signals to customers and producers;
- be applied in a way which does not discriminate positively or negatively between production connected at the distribution level and production connected at the transmission level;
- not discriminate either positively or negatively against energy storage or aggregation; and
- not create disincentives for self-generation, self-consumption or for participation in demand response.

Thirdly, Regulation (EU) 2019/943 establishes that ACER shall perform a monitoring exercise of distribution and transmission tariff methodologies, with the purpose of identifying best practices. The recommendations from that report shall be taken into account by NRAs.[39]

Fourthly, Article 18(2) adds explicit requirements about tariff methodologies for transmission and distribution – that they shall reflect the fixed costs of the TSOs and DSOs, while ensuring that incentives on network operators shall be properly aligned, with regards to efficiency, market integration, security of supply, investments and research activities. Moreover, they shall foster innovation in areas of interest to consumers, namely digitalisation, flexibility services and interconnection.

Fifthly, Article 18(3) establishes that the level of tariffs shall provide locational signals at EU level and shall take into account network losses, congestion caused and investment costs.

Finally, Articles 18(7) and 18(8) provide additional requirements specifically for distribution tariffs. Article 18(7) requires that distribution tariffs shall be cost-reflective and refers to some tariff design options, such as connection capacity (differentiated by use profiles) and time-differentiation. Article 18(8) states that distribution tariff methodologies shall promote cost-efficient development and utilisation of the network, including the procurement of services in an efficient manner.

[39] Articles 18(9) and 18(10) of Regulation (EU) 2019/943.

Annex 4 – Case studies

This annex contains four case studies on tariffs in practice. Those are derived from Great Britain, France, Norway and Italy.

Great Britain: case study on time-of-use and locational signals

In Great Britain there are two broad approaches to network tariffs at the distribution level. These are separated out for the Extra-High Voltage network (EHV – above 33 kV) and for the Medium voltage[40] network (MV – below 33 kV).

At the EHV level, the tariff calculation is based on a nodal load flow model, which has the advantage of being able to calculate unique tariffs for all users. The methodology takes into account spare capacity, and charges users a time-independent agreed capacity tariff and a static seasonal consumption-based tariff. However, while these arrangements are considered to be cost reflective, there are concerns about whether the small size of the increment will actually incentivise users to change their behaviour, as well as in regard to the volatility of tariffs and transparency of the tariff calculation that limit the ability of users to respond to the tariff signals. Ofgem (the NRA for Great Britain) is currently reviewing the arrangements with a view to resolving issues around volatility and transparency.

At the MV level, the tariff calculation is simpler, and the tariffs are a combination of agreed capacity and time band-based time-of-use tariffs, which vary, depending on the customer category. Tariffs for network use are different across the 14 DSO[41] regions, and in some cases, the time bands also differ between regions, reflecting the underlying cost drivers. However, given that many households do not have smart metering, or do not have time-of-use tariffs with their suppliers, the impact of cost reflective tariffs is dampened. Ofgem are currently reviewing these arrangements with a view to making them more cost reflective.

France: case study of time-of-use and variable-peak signals

In France, time-of-use and variable-peak signals have been used for 50 years, first created by the historical monopoly. They have been used at several voltage levels to shave daily peak (from 10 GW in summer to 20 GW in winter, due to economic and human activity patterns) and seasonal peak (40 GW between summer and winter, mainly due to the high degree of penetration of electrical heating). Coupled with controlled water heating, these tariffs have shifted about 10 GW of consumption from morning peak hours to night off-peak hours. However, the shift has spread over many years, illustrating the need to anticipate the system peak issues with a long-term view.

Nowadays, at the medium voltage level, network tariffs have five time periods: annual peak, high season peak, high season off-peak, low season peak, low season off peak. Annual peak periods may be fixed, or variable, depending on the option selected by the user:

- Fixed periods are concentrated on expected peak hours: 2 hours during morning peak, 2 hours during evening peak, Sunday excluded, from December to February; and
- Variable periods are linked to critical hours of the national capacity mechanism: 10 hours during the 10 to 15 days of the variable peak period triggered by the TSO day-ahead. Studies suggest that at the medium voltage level, local and national peak days are the same 80% to 90% of the time.

[40] Note that, in Great Britain, the network below 33 kV is separately identified as High Voltage and Low Voltage networks.

[41] Note that, in Great Britain, the DSOs are known as Distribution Network Operators.

The degree of complexity of the price signal, which contributes to smoother flow profiles at the medium voltage level, seems adapted to large users. Especially engaged users may chose the variable peak option that requires day-ahead flexibility.

At the low voltage level, new network tariffs were introduced in 2014, with four time periods and no variable peak. The main goal is to signal the high concentration of critical demand for the local network during high season peak hours, while continuing the daily peak shaving:

- The 16 daily peak hours are fixed by the network company at the local level;
- The high season lasts five months, and is fixed by the network company, also at the local level, depending on specific consumption patterns (e.g. electrical heating vs. air conditioning). The high season is a new device designed to tackle the very high winter peak in France, without being too complex for households and small professional users.

Norway: case study on the process to implement power-based tariffs

In Norway, tariffs for customers with less than 100 kW power consumption, are still predominantly volumetric. For a typical household consumer, the energy charge constitutes 2/3 of the network tariff, while the remaining 1/3 is covered through a fixed charge. Both issues regarding the distribution of costs and the lack of incentives to reduce power consumption challenge the current tariff structure.

The national regulator, NVE, proposed in 2017 a shift to a model of subscribed capacity. The model was based on a subscription level of power consumption, and an overspending charge (per kWh) during hours where the customer exceeded the subscription. However, stakeholders were critical that such a model could be too complex for customers to understand, and that it would be difficult to implement in practice. DSOs also commented that they would like to have the opportunity to implement other models, such as measured capacity and variants of time-of-use.

NVE presented a revised proposition in February 2020. The proposition takes a more principle-based approach, with an emphasis on the division of costs between various tariff elements, rather than enforcing only one tariff model. Importantly, the new regulation will make a distinction between fixed and variable costs. Roughly 1/6 of distribution system costs are variable in the short term, representing the marginal cost of losses in the network. The remaining 5/6 of costs are fixed in the short-to-medium-term and should be treated accordingly in the tariff structure.

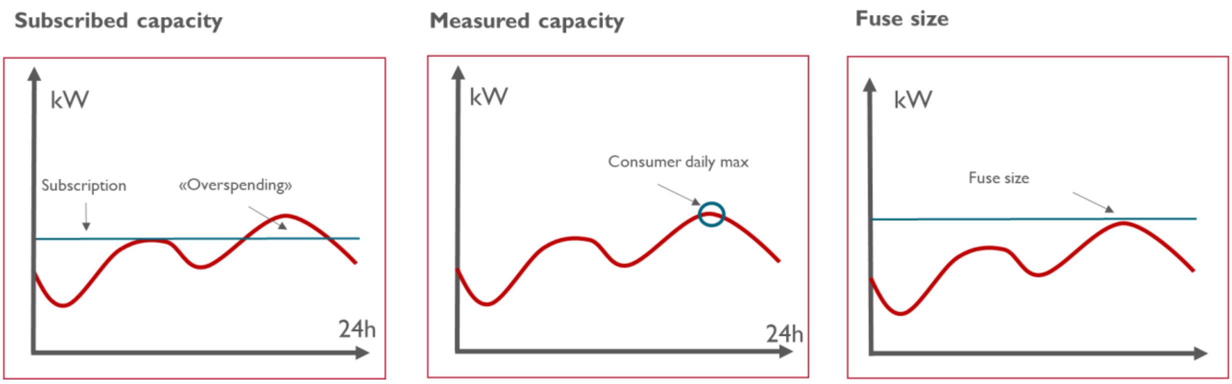

Figure: The three "main" models in the public consultation document presented by the Norwegian regulator, NVE.

As such, future tariff models shall consist of an energy charge, equal to the cost of marginal losses, when there is sufficient capacity in the network. When capacity is expected to be constrained, the DSO may use time-of-use principles, setting the energy charge higher to incentivise reduction of consumption. However, this price should, in principle, be capped at the long-term marginal cost of expanding the network. Finally, the remaining residual costs will be covered through a fixed charge differentiated by the individual customer's demand for power. This charge will, in practice, be fixed in the short-to-medium term but can be affected by investments or lasting behavioural changes. Thus, the consumer also has an incentive to optimise the long-term utilisation in accordance with the actual willingness to pay for the network service. Power consumption could also be time differentiated, to ensure that consumers utilising the network in constrained hours pay a higher share of the residual costs.

Italy: case study on the use of smart meters for time-of-use capacity limitation for EV owners who recharge at home

In Italy, the regulator recently proposed[42] to introduce a special tariff arrangement for customers who have to recharge their own EV at home, in order to accommodate private EV recharge within the existing contracts. This is possible, due to the functionality of smart meters already rolled out over the whole national customer base, households included, for many years (roll-out of the first generation of smart meters started in 2001 and was completed by 2010; roll-out of the second generation started in 2017).

As background, in Italy around 90% of household contracts for electricity supply are based on a nominal contractual capacity of 3 kW, that implies a limitation at 3.3 kW for indefinite time ("technically available capacity") and between 3.3 and 4 kW available for 3 hours at maximum (provided that at any time the instantaneous power usage over 1 second is lower than 3.96 kW). When the capacity limitation is reached, the breaker on the meter trips the home circuit off; the customer can re-start their own supply, after having shut off some of the involved appliances.

If a customer needs further capacity – and this is almost unavoidable for a complete recharge of the EV's batteries, if contemporarily other electricity appliances are run – the increase of contractual capacity requires a one-off payment of around 60 euro per each additional kW of increased capacity as a connection charge, and an increase in the yearly network tariff of around 25 euro per additional kW of increased contractual capacity (all figures are 10% VAT included). With such an increase of the contractual capacity, the new capacity is ensured at any time.

The proposal of the Italian energy regulator is to allow for a special increase of capacity only during night hours (from 23:00 to 7:00), plus all the hours on Sundays and holidays, when network usage is lower. This time band is known as "F3" and meters already register energy separately for this time band for low voltage customers, households included. With second generation smart meters, static time bands will be abandoned and suppliers will be able to offer customised time bands, given that the second generation meters allow for registration of energy every 15 minutes, for all customers. The change of technically available capacity only in time band F3 for customers who own an EV can be done by the DSO through remotely managed firmware updates to these specific delivery points.

The increase in night-time capacity does not change the contractual capacity, and therefore the tariff paid by the customer, because during all other time bands the nominal contractual capacity would remain set at 3 kW. The proposal – on which a public consultation has collected a large favourable response from stakeholders – is to increase "technically available capacity" to 6.0 kW (instead of 3.3 kW), and therefore to allow a full recharge of around 40 kWh in 8 hours by night (taking into account also the likely usage of other appliances connected under the same point of delivery) without any intervention of the capacity limitation breaker and maintaining the same total

[42] ARERA, consultations paper (in Italian) n. 318/2019/R/eel (Part IV: www.arera.it/allegati/docs/19/318-19.pdf) and n. 481/2019/R/eel (Ch.24 and Appendix A3: https://www.arera.it/it/docs/19/481-19.htm).

expenditure for the tariff distribution network that is fully capacity-based (up to 16.5 kW, contractual capacity is used for sake of simplicity; actual usage of power is used above 16.5 kW).

Annex 5 – About CEER

The Council of European Energy Regulators (CEER) is the voice of Europe's national regulators of electricity and gas at EU and international level. CEER's members and observers (from 39 European countries) are the statutory bodies responsible for energy regulation at national level.

One of CEER's key objectives is to facilitate the creation of a single, competitive, efficient and sustainable EU internal energy market that works in the public interest. CEER actively promotes an investment-friendly and harmonised regulatory environment, and consistent application of existing EU legislation. Moreover, CEER champions consumer issues in our belief that a competitive and secure EU single energy market is not a goal in itself, but should deliver benefits for energy consumers.

CEER, based in Brussels, deals with a broad range of energy issues including retail markets and consumers; distribution networks; smart grids; flexibility; sustainability; and international cooperation. European energy regulators are committed to a holistic approach to energy regulation in Europe. Through CEER, NRAs cooperate and develop common position papers, advice and forward-thinking recommendations to improve the electricity and gas markets for the benefit of consumers and businesses.

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More information at http://www.ceer.eu