# Allocation of Electricity Network Charges to Different Consumer Groups in Selected Countries

22 March 2019

Department of Business, Energy and Industrial Strategy

**FINAL REPORT**

## Important notice

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# EXECUTIVE SUMMARY

## Objective of study

CEPA has been commissioned by the Department for Business, Energy and Industrial Strategy (BEIS) to conduct a study into the allocation of electricity network charges to different consumer groups in nine European countries – Ireland, Norway, Sweden, Germany, Netherlands, Belgium, France, Italy, Spain.

This study focuses on differences in network costs and how network charges faced by different consumer groups are affected by decisions regarding the allocation of network costs. The focus of the study is on 'use-of-system' (UoS) network charges. It does not include policy costs or other non-network costs recovered through network charges.

## Main findings

The report finds that:

- **Consumers at lower voltage levels of connection pay a proportionally higher share of the overall network cost**, reflecting the assumption that energy flows from generators connected at high voltages to demand customers connected at lower voltages. This is reflected in the "cost cascading" allocation method, commonly applied across the countries analysed, whereby users contribute towards the cost of the network at their voltage level of connection as well as all higher voltage levels.

- **Cost recovery approaches differ between consumer groups and countries in terms of charging structure** (e.g. the balance between energy, capacity and fixed charges). In all countries, the way that network users are charged for access and use of the electricity grid depends primarily on their voltage level of connection. In addition to voltage level, other factors that can determine the tariff type that a customer is on include type of metering, capacity, and consumption profile.

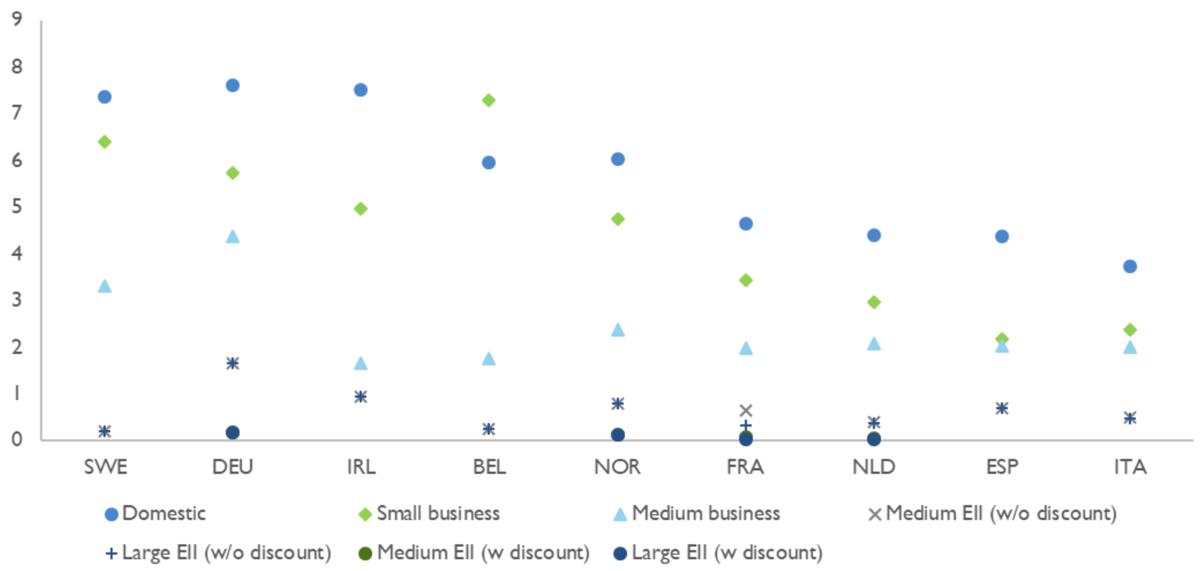
  Countries that rely predominantly on capacity charges for cost recovery typically justify this with reference to capacity or peak consumption being a key driver of network costs. However other countries, such as France, have concluded that energy charges provide better incentives to reduce both overall energy consumption, with time differentiated energy charges used to encourage lower consumption in peak periods.

- **Discounts of up to 90% are available for certain categories of consumers, particularly large industrial customers.** These discounts are typically justified in terms of system stability benefits from users with certain characteristics (e.g. baseload, stable or off-peak consumption); although considerations around international competitiveness also play a role in determining discounts. These discounts are funded by higher charges for other users.

## Impact of network tariffs on customer bills

We have estimated the impact of network charges on customer bills for five illustrative customer profiles representing typical GB domestic, small business, medium business, medium energy intensive industry (EII) user and large EII demand users. The figure below presents UoS charges in cents per kWh of electricity consumed, by country and customer profile.

*Figure 1: Use of System charges (T+D) by country & customer profile, c€ / kWh (nominal prices)*




*Source: CEPA analysis of published tariff data for 2018-19. For Belgium, estimates cover the region of Flanders only.*

Charges per kWh generally decrease with the size of the customer. Any comparison of charges per kWh between countries should be treated with care because of differences between countries such as

- **Depth of connection charges** (i.e. balance of costs recovered from customer-specific connection charges, and ongoing UoS charges). Socialising more of the connection costs through UoS charges ("shallow" connection regime) means that network users pay higher UoS charges (but lower connection costs). Most countries (including GB) apply a form of shallow connection regime with the exception of France, Sweden and, starting in 2019, Norway.
- **Allocation of costs between generation and demand.** In most cases, all network costs are allocated to demand users (unlike in GB), but in Sweden, Norway, Ireland, Spain, and, to a smaller extent, France a proportion of the costs at least at the transmission level are recovered from generators. It is expected that those charges paid by generators will feed into wholesale prices and ultimately customer bills.
- **Scope of UoS charges.** In some countries, UoS charges also recover wider system costs which are not part of network UoS charges in other countries (e.g. network losses, system balancing). Where possible we have excluded these costs from the tariff calculations.
- **Consumption assumptions.** Results are sensitive to assumptions such as level of consumption, time profile of consumption; and mapping to tariff groups. The results for all countries are for an average consumer in terms of location and demand profile.

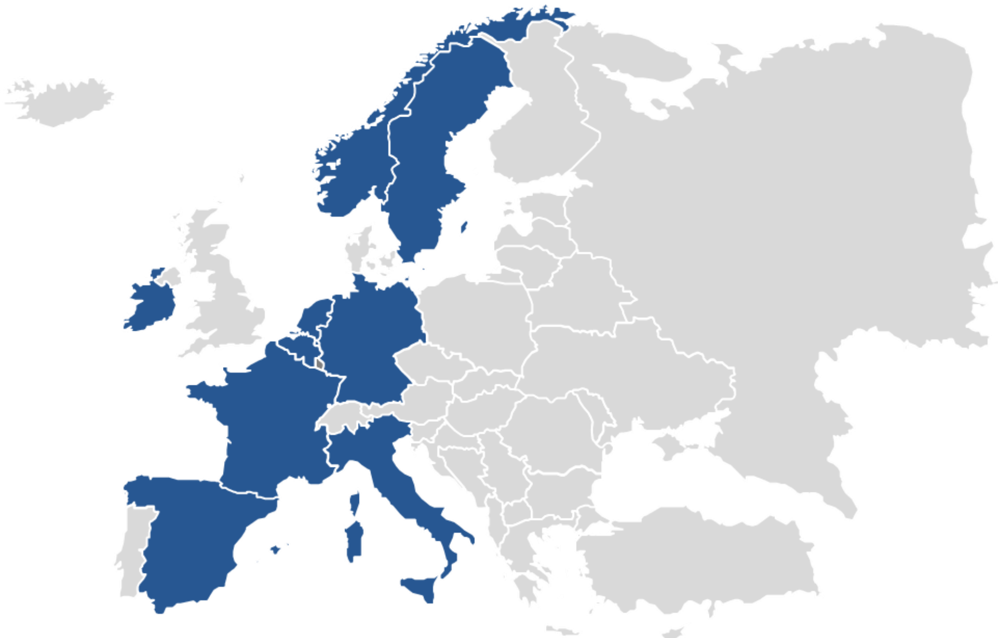
# OVERVIEW OF THE STUDY

Cambridge Economic Policy Associates (CEPA) has been commissioned by the Department for Business, Energy and Industrial Strategy (BEIS) to conduct a study into the allocation of electricity network charges to different consumer groups in selected European countries.

This study focuses on differences in network costs and how network charges faced by different consumer groups are affected by decisions regarding the allocation of network costs.  The focus of the study is on 'use-of-system' (UoS) network charges. It does not include policy costs or other non-network costs recovered through network charges.

We have reviewed transmission and distribution charges for different customer types in nine European countries which are displayed in Figure 2 below.

*Figure 2: Countries analysed as part of this study*



## Allocation of network costs between categories of network users

For this study, we were asked to review the legal basis and justifications for allocating network costs to different consumer groups. The principles or justifications for how costs are allocated between different types of network users are not often explicit. In most countries, cost reflectivity, non-discrimination and transparency are common principles underlying the tariff methodologies, but it is not always clear there is a common understanding or application of these principles. Cost reflectivity, for example, is often understood as an average cost concept, by setting overall network revenues in line with the efficient costs of building, maintaining and operating the network. It can also be interpreted as applying network charges that reflect the marginal costs that a network user imposes on the system (as is typically the case in GB).

In the countries analysed in this study, network costs are not allocated explicitly to different types of users. The level of network tariffs paid by an individual customer, or groups of customers, is the outcome of the following set of regulatory decisions regarding the charging structure.

**The depth of the connection regime,** i.e. balance of costs recovered from customer-specific connection charges, and ongoing UoS charges, affects the total amount of revenue recovered through UoS charges. Socialising more of the connection costs through UoS charges ("shallow" connection regime) means that network users pay higher UoS charges (but lower connection costs). Most countries, including GB, apply a form of shallow connection regime with the exception of France, Sweden and, starting in 2019, Norway.

**The allocation of costs between generation and demand** impacts on the share of costs recovered from different consumer groups. In most cases, all network costs are allocated to demand users (unlike in GB). The exceptions are Sweden, Norway, Ireland, Spain, and, to a smaller extent, France where a proportion of the costs at least at the transmission level are recovered from generators. EU regulations currently limit the amount that can be recovered from generators, but this limit varies across countries. For most countries, this limit is €0.5/MWh although among the countries studied Sweden and Norway have a higher limit of €1.2/MWh and Ireland (and the UK) has a limit of €2.5/MWh. The share of transmission costs recovered from generators is shown in the table below. For comparison, 16% of transmission costs in GB in 2018-19 are paid for through generators' TNUoS charges. At the distribution level, the allocation of costs between generation and demand is less straight-forward as many distributed generators can receive credits (i.e. negative charge) or are embedded with demand and can help reduce the amount of energy offtaken from the grid (and depending on the charging structure, the UoS bill) for demand users.

*Table 1: Share of transmission costs recovered from generators*

| Country | % of costs recovered from generators |
|---|---|
| Sweden | 38% |
| Norway | 25% |
| Ireland | 25% |
| Spain | 10% |
| France | 3% |

*Source: CEPA*

**The allocation of costs to different voltage levels** is reflected in the fact that charges for consumers tend to vary most commonly by voltage levels of connection. A commonly applied principle of cost allocation is that users contribute towards the cost of the network at their voltage level of connection as well as all higher voltage levels. This is reflected in the "cost cascading" allocation method that is commonly used to determining the split of network costs recovered from users at different voltage levels. Firstly, network costs are calculated for each voltage level, then the costs of the higher voltage levels are split between users connected at that voltage levels and the lower voltage levels. This means that consumers connected at lower voltage levels, such as households and small businesses, pay a proportionally higher share of the overall network costs compared to larger users connected at higher voltage levels, reflecting the fact that they are assumed to use more of the network. The impact of this approach on the level of network charges faced by different consumer groups (on a per MWh basis) can be seen in in our analysis of the impact of tariffs on retail prices.

## Allocation of network costs to individual network users

Once costs are allocated to different categories of network users, the total amount recovered from individual consumers depends on:

- the factors that determine the tariff paid by each network user;

- the allocation of specific pots of network costs into different tariff components;
- any specific discounts available for specific types of network users.

In all countries, the way network users are charged for access and use of the electricity grid depends primarily on their voltage level of connection. In addition to voltage level, other factors that can determine the tariffs that consumers pay include:

- **Type of metering**: in Belgium, Norway and Germany, consumers with simple meters are predominantly charged based on their energy consumption and sometimes a fixed charge whereas capacity charges (determined as either peak consumption or contracted capacity) play a bigger role for consumers with hourly/peak metering.
- **Capacity**: for users connected at the same voltage level, the tariff that the customer is on can differ based on their contracted capacity, as is the case in Italy, for example. In the Netherlands, the charging structure for consumers connected at low voltage levels depends on their capacity, derived based on their fuse size.
- **Consumption profile**: the "peakiness", or the ratio of annual/average demand to peak demand, can also determine charges paid by consumers in some countries. The most obvious examples are in Germany where the balance between capacity and energy charges for most consumers is determined based on their 'load duration', and in France, where some consumers can choose between different tariff versions to reflect the shape of their consumption profile.

In addition, a specific distinction is made in Ireland between rural and urban domestic consumers.

## Tariff components

The UoS charging structures in the countries analysed usually include one or more of the following components:

- a fixed annual charge (e.g. €/year);
- a capacity component (e.g. €/kW) typically based on the user's installed capacity or peak offtake; and
- a volumetric energy charge (e.g. €/kWh) applied to each unit of consumption.

How costs are allocated between these components can have an impact on the total network costs recovered from different consumer groups. Some countries rely more on capacity-based charges while others on energy-based charges. The rationale for this choice differs. Where capacity charges are predominantly used, the justification usually comes down to capacity or peak consumption being a key driver of network costs and thus capacity charging being more aligned with the principle of cost reflectivity. In countries such as Italy and Spain, where network charging reforms introduced in the last few years have placed a greater emphasis on capacity charges, the decision was also driven by cost recovery problems caused by network users reducing their contribution to network costs paid through energy charges due to increased levels of embedded renewable generation.

However other countries, such as France, have considered placing more of the cost recovery on capacity charges but concluded that energy charges provide better incentives to reduce overall energy consumption as well as peak consumption through time differentiated energy charges.

As shown in Table 2 below, our research indicates that capacity charges (typically applied on installed capacity or the user's peak consumption) are part of the charging structures for transmission connected consumers in all countries analysed. All countries except Netherlands and Belgium also apply an energy charge. Fixed charges are not normally used to recover network costs from transmission connected consumers with the only exception being Netherlands and, to a smaller extent, France (but only for administrative costs). Out of the countries studied, only Norway applies a similar charging approach to GB where transmission connected demand consumers are charged on a p/kW basis based on their consumption during system peak periods.

Capacity charges are also widely applied to larger consumers connected at the distribution level. For residential consumers volumetric energy charges are applied in all countries except Netherlands. In addition to the energy charge, residential consumers in most countries are charged a fixed and/or capacity charge. Capacity based charges have been introduced or have become more important in recent years in countries such as Italy, Spain, Norway and the Netherlands. In GB, consumers connected at lower voltage levels are predominantly charged a fixed and energy tariff component, while larger distribution connected consumers are typically charged all three tariff components.

*Table 2: Number of countries (out of maximum of nine) applying each tariff component by type of consumer*

| Consumer type | Fixed | Capacity | Energy |
|---|---|---|---|
| Residential consumer | 7 | 5 | 8 |
| Distribution connected non-domestic consumer | 6 | 9 | 9 |
| Transmission connected consumer | 2 | 9 | 7 |

*Source: CEPA*

*Note: The tariff structure for each type of user in each country can include one or more of the tariff components shown above.*

Other high-level features of charging structures that affect the allocation of costs across individual consumers include:

- **Locational charges:** in most countries, there are also regional differences between tariffs. These usually reflect differences in costs and network characteristics between different network companies rather than different allocation of costs within the same network. In Norway, Sweden and Ireland (generators only), explicit locational elements are included in the charging structure at the transmission level (as is the case in GB). In France, Spain and Italy, there are no locational differences with tariffs set equal across all network companies.
- **Time-of-use elements:** we find that there is no specific geographical pattern to time differentiated tariffs. Time-of-use differentiation of tariffs is most widely applied in Spain and France where tariffs can vary by both time of day and season. More limited time-of use elements are applied in the Netherlands (mostly for small non-domestic consumers), Belgium (day/night tariffs for small consumers), Norway (seasonal tariffs for large consumers) and Ireland (day/night tariffs). In Italy and Germany there is no time differentiation of tariffs.

## Discounts for specific network users

Finally, specific discounts for certain categories of network users also plays an important role in the allocation of network costs. In four out of nine countries analysed in this report, discounts on UoS charges are available to certain consumer groups, typically large energy users. The level of reduction depends on individual consumer characteristics (e.g. seasonal or hourly consumption profiles, annual electricity consumption, electro-intensity of production) and can range up to 90% as shown in the table below. The foregone revenues resulting from discounts are recovered from network users that do not benefit from these reductions affecting the overall allocation of costs between consumer groups.

*Table 3: Discounts on UoS charges*

| Country | Discount level | Reduction base | Groups eligible for discounts |
|---|---|---|---|
| Germany | 80-90% | Network charges | Atypical network users<br>Intensive network users |
| Netherlands | Up to 90% | Charging base (capacity or energy volume used to calculate charges) | Large energy users |
| France | 5-90% | Network charges | Stable users<br>Counter-cyclical users<br>Large network users |
| Norway | Up to 75% | Capacity charge rate | Large energy users |

*Source: CEPA*

In addition to the countries included in this table, the Republic of Ireland has reduced tariffs for large energy user groups as a whole rather than applying discounts to individual consumers.

Most countries cite the benefits that large energy users bring in terms of system stability and reduction of system costs as the primary reasons for introducing these discounts. For example, Germany has justified discounts through the fact that stable and predictable network use allows the network operator to manage large amounts of intermittent renewable generation and contributes to overall network stability. Considerations around the international competitiveness of energy intensive industries also play a large role in determining discounts. Both the Ireland and France cite concerns regarding the international competitiveness of their industries as a key motivation for discounts for large energy users. In the Netherlands, one objective of the tariff discounts was to maintain a level playing field for large energy users between the Netherlands and Germany.

## Impact of network tariffs on customer bills

As part of our work, we have estimated the impact of network charges on customers' bills. We have done this for five illustrative customer profiles representing typical GB domestic, small business, medium business, medium energy intensive industry (EII) user and large EII demand users. The 'domestic' and 'small business' profiles are assumed to connect at the low voltage level, while the 'medium business' profile connects to the high voltage distribution network, and the EII profiles connect directly to transmission.

The results should be interpreted with care.

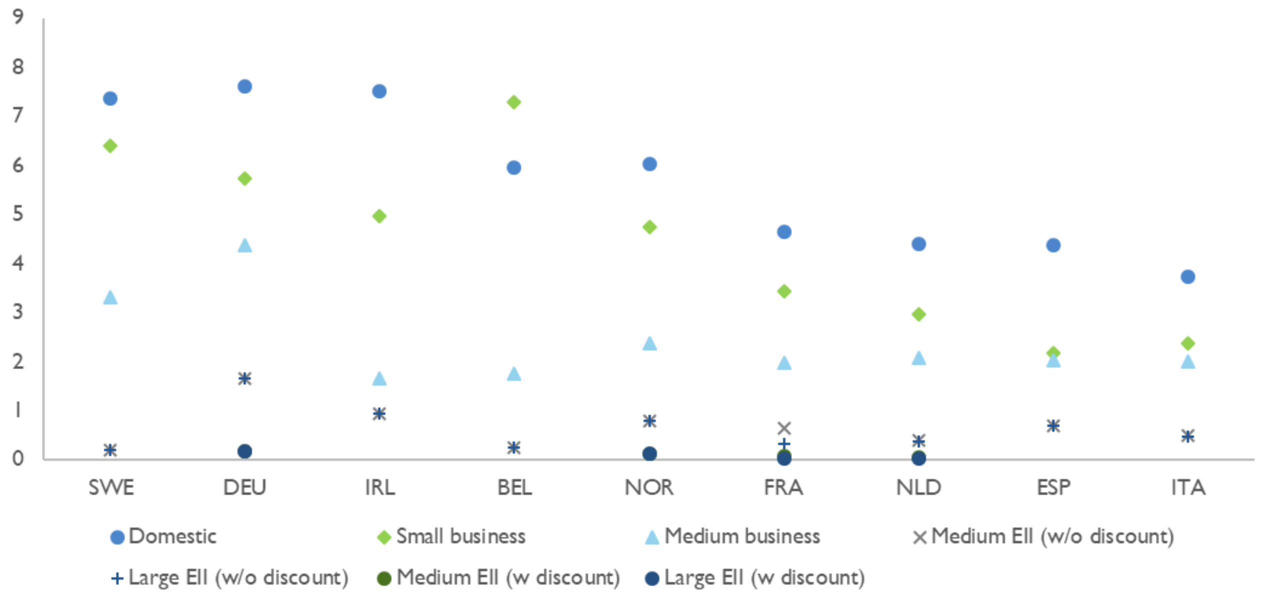
There are important differences between countries in how costs are directly recovered from different network users – e.g. in terms of connection regimes (split between upfront and ongoing costs) and allocation of costs to generators (which will ultimately feed through into wholesale prices).

In some countries (Germany, Netherlands, France, Sweden, Norway), the charges used to calculate these tariff impacts also include other costs which are not included in our definition of UoS charges and we have not been able to exclude these from individual tariff levels, such as costs of network losses and system balancing. This may affect the comparability of absolute tariff impacts across countries, but we do not expect it to have a significant impact on the comparability of results across consumer profiles within the same country.

Results are sensitive to assumptions about consumption particularly those concerning peak consumption; distribution of consumption across time periods; and mapping to tariff groups. The results for all countries are for an average consumer in terms of location and demand profile.

The figure below presents UoS charges in cents per kWh of electricity consumed, by country and customer profile.

*Figure 3: Use of System charges (T+D) by country & customer profile, c€ / kWh (nominal prices)*




*Source: CEPA analysis of published tariff data for 2018-19. For Belgium, estimates cover the region of Flanders only.*

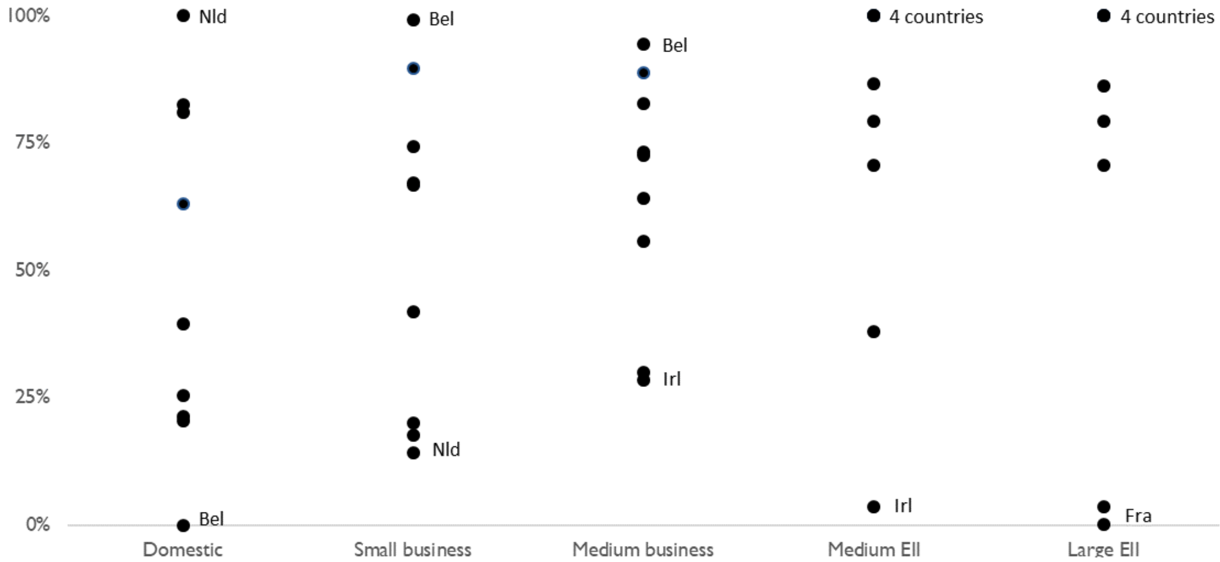
Sweden and Germany tend to have the largest charges for most categories of users. This partly reflects the fact that UoS charges in those countries include additional costs that could not be excluded from the calculation.

Charges per kWh generally decrease with the size of the customer. The charges for domestic and small business consumers follow similar patterns (where domestic consumer pay relatively high charges, so do small business users). This is because users are normally required to contribute towards the cost of network levels above their own connection, so the smaller customers are allocated more of the network costs compared to larger customers. Benefits also accrue to larger customers because they tend to use their connection more intensively which means they can spread the fixed and capacity-related charge elements across a larger consumption base – giving a lower charge per kWh.

Medium business users face a similar level of charges – except in Sweden and Germany. Charges for EII users are all below €1/MWh (even before discounts) apart from in Germany (where discounts for large users are available). In eight out of the nine countries, charges for the medium and large EII users are the same as both these consumers are connected to the transmission level. In France, the charges for the large EEI user are slightly lower because there is a specific tariff for users connected above at voltage levels above 350kV.

We also found large differences in how charges are weighted between volumetric and fixed or capacity components, as illustrated in Figure 4.

*Figure 4: Proportion of average UoS tariffs collected through fixed or capacity charges, %, instead of energy charges*




*Source: CEPA analysis. For Belgium, estimates cover the region of Flanders only.*

This demonstrates that there is no consistent approach to the balance of fixed/capacity and volumetric elements across countries, or even between network levels. In some countries (e.g. Sweden, Germany, Belgium and Norway), the share of network charges collected through fixed/capacity charges increases with size and voltage level. In other countries, such as Spain and Italy, there is a roughly constant share of costs allocated between fixed/capacity and energy charges across customer groups.

# 1. INTRODUCTION

Cambridge Economic Policy Associates (CEPA) has been commissioned by the Department for Business, Energy and Industrial Strategy (BEIS) to conduct a study into the allocation of electricity network charges to different consumer groups in selected European countries.

This piece of research has been commissioned in the context of the Government's commitment to reduce the cost of energy to GB consumers, discussions about the cost of operating energy networks in GB and ongoing reforms to the GB network charging structure (e.g. Ofgem's Targeted Charging Review and Reform of electricity network access and forward-looking charges).

This study focuses on how network charges faced by different consumer groups are affected by decisions regarding the allocation of network costs. We have compiled detailed case studies on transmission and distribution charging structures and cost allocation methodologies in nine European countries

The focus of the study is on 'use-of-system' (UoS) network charges, the equivalent of Transmission Network Use of System (TNUoS) charges and Distribution Use of System (DUoS) charges in GB. Hence we have excluded where possible non-network costs recovered through network charges – such as system operation, network losses, metering and policy costs.

## 1.1. Scope of work

The ITQ set out eight specific research questions listed in Table 4 below. As specified in the ITQ, these questions have been listed in order of priority. We considered these questions in two groups: qualitative questions relating to **charge design**; and questions requiring **quantitative analysis**. This is reflected in the structure of this report. We show below how each of the research questions is addressed in the rest of this report. We address the qualitative questions (questions 1-5 in the table above) in Section 3 of the report, while questions 6 and 7 which rely on quantitative analysis are addressed in Section 4 of the report.

*Table 4: High-level research questions*

| No | High level research questions posed by BEIS | Section of the report |
|---|---|---|
| 1 | **How are the charges for the electricity transmission and distribution networks designed, including variable and fixed network charges?** | **3.3** |
| 2 | **How are these network charges allocated amongst different electricity consumer groups, including households and businesses?** | **3.2 and 3.3** |
| 3 | **What are the legal justifications to allocate these network costs to different electricity consumer groups?** | **3.2 and 3.3** |
| 4 | **What is the form of seasonal (peak) charges in place in the countries in scope if applicable or any factors (e.g., geography) for their absence?** | **3.3** |
| 5 | **How do other countries incentivise users, in particular large energy users, to reduce or increase demand at times of system stress?** | **3.3** |
| 6 | **How does the above translate in average retail electricity prices of the different consumers group identified?** | **4.2** |
| 7 | **What is the total annual network cost to be recovered by network charges in the countries in scope?** | **4.1** |
| 8 | **How might potential forthcoming changes to the network arrangements under discussion in the countries in scope impact on the allocation of network costs.** | **3** |

## 1.2. Approach

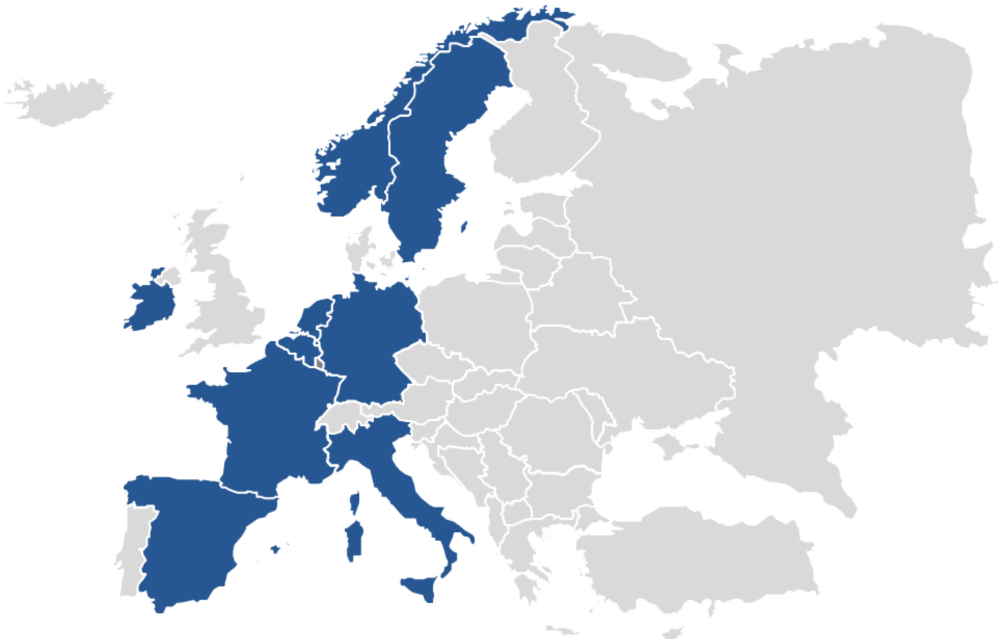
We have answered the qualitative questions of this study through a combination of the existing understanding of our team of experts, desk-based research, and conversations with national regulatory authorities (NRAs). The most relevant national documents included electricity sector legislation, network codes, regulatory decision documents, standalone charging methodologies, published charging models, related explanatory materials and final charges published by Transmission System Operators (TSOs) and Distribution System Operators (DSOs).[1] To inform and focus our research, we have also drawn on information available in secondary literature.

For the quantitative analysis, we estimated the impact of network charges on the energy prices paid by consumers (in €/kWh), as far as possible on a comparable basis across the countries studied. This analysis relies on the granularity and transparency of actual tariff information available for each jurisdiction, and a range of assumptions about typical consumer consumption profiles. We have agreed the typical consumer profiles with BEIS.

## 1.3. Countries covered in case studies

The selected case studies agreed for this study are shown in Figure 5 below.

*Figure 5: Countries analysed as part of this study*



In most countries, the electricity network is split into transmission (high voltage) and distribution (low voltage) networks. In Norway and Sweden, a regional grid level sits between transmission and distribution. However, the regional grid is classified as distribution for the purposes of EU regulations.

[1] In this study, we refer to TSOs and DSOs although in some cases they may not be the same as the transmission or distribution network operator or asset owner.

Table 5 outlines the industry structure in each of the countries analysed noting where there are differences in the charges applied by the different companies and whether network users are charged separate tariffs covering transmission and distribution costs.[2]

*Table 5: Industry structure*

| Country | Number of TSOs | Number of DSOs | Separate DUoS /TUoS charges | Regional differences in charges |
|---|---|---|---|---|
| Germany | 4 | 890 | No | Differences across TSOs and DSOs |
| Netherlands | 1 | 7 (three significantly larger than the others) | No | Differences across DSOs |
| France | 1 | 148 (eight large DSOs with one, Enedis, covering 95% of distribution network) | No | Uniform charges across all DSOs |
| Spain | 1 | More than 300 (five large) | No | Uniform charges across all DSOs |
| Belgium | 1 | 11 DSOs (Flanders) | Yes | Differences across DSOs |
| Italy | 1 | 140 (one dominant covering 85% of the market) | Yes, except for households | Uniform charges across all DSOs |
| Norway | 1 | 119 DSOs plus 78 regional grid companies | No | Differences across DSOs/regional grids |
| Sweden | 1 | Approx. 160 DSOs plus 6 regional grid companies | No | Differences across DSOs/regional grids |
| Rep. of Ireland | 1 | 1 | Yes | - |

*Source: CEPA*

In all cases except Germany there is one single TSO operating the transmission network. In Germany there are four TSOs applying different transmission charges although a transition to a nationally uniform transmission tariff is currently underway.

At the distribution level, the industry structure tends to be more fragmented and mixed with almost 900 DSOs operating in Germany, more than 300 in Spain, and over 100 DSOs in France and Italy but just one DSO operating in Ireland. Most of these DSOs are however very small often municipal networks, with less than 100,000 customers and thus not subject to the unbundling requirements between electricity distribution and supply set out in EU regulations. Despite the large numbers of DSOs in some countries, in many cases there is one or a few DSOs that cover most of the market as in France and Italy, for example.

The presence of multiple DSOs can be a source of locational variation in charges in most countries as network tariffs reflect the (varying) costs of different DSOs even if the same tariff structure applies across the sector. In France, Italy and Spain, however, tariff levels are the same across all DSOs reflecting a policy

[2] Where individual transmission and distribution charges are not separate, it means that transmission-connected consumers pay a charge covering transmission costs, while distribution connected consumers pay a charge covering distribution and transmission costs.

decision to avoid regional differences in network charges. In these cases, there are revenue reconciliation mechanisms in place to ensure that each DSO recovers its regulated revenues.

For the purposes of this study, we have generally focused on larger DSOs with more than 100,000 connections. In order to make the analysis manageable to produce and to understand, we have also:

- Focused on the largest DSO(s) where one or a few DSOs cover a significant share of the market (e.g. Enedis in France covering 95% of the distribution network).
- Selected a sample of DSOs to focus on where a large number of companies of similar sizes operate (e.g. Germany, Norway, Sweden). We explain our choice of DSOs in each individual case study.
- In the case of Belgium, where responsibility for the regulation of the distribution network is split between three regional regulators, we focused our distribution network analysis on the region of Flanders.

## 1.4. Report structure

The rest of the report is structured as follows:

- The main body of the report focuses on cross-country comparisons split into two main sections:
    - In Section 2, we present our findings on the structure of network tariff structures in place in the different countries studied;
    - In Section 4, we present our estimates of the impact of network tariffs on electricity prices for different consumers types;
- Appendix A contains information on our methodology for calculating tariff impacts;
- Appendix B contains detailed case studies for each country.

# 2. ANALYSIS OF NETWORK TARIFF STRUCTURES

In this chapter we discuss the electricity network charging structures in place across the countries studied identifying common themes and highlighting any exceptions.

We present the findings of our research across the following topics:

- responsibility for setting UoS charges;
- rules and approach for the allocation of network costs between users;
- design of network charging structures; and
- discounts for specified types of network users.

## 2.1. RESPONSIBILITY FOR SETTING CHARGES

In eight out of nine countries, the National Regulatory Authority (NRA) plays an important role in the network tariff process by either setting or approving UoS charges or setting the methodology used for calculating these. One notable exception is Spain where network charges are currently set by the Government. The Spanish Government has recently published a Royal Decree Law by which the regulator, CNMC, will take over responsibility for setting electricity network tariffs from 2020.[3]

Table 6 illustrates that the level of involvement of the NRA ranges from calculating and setting tariffs (e.g. Italy and France) to approving or overseeing tariffs calculated and published by network companies based on an agreed methodology (e.g. Germany, Ireland, Norway and Sweden).

The role of the NRA in setting charges is closely linked to the industry structure and policy regarding regional variation in distribution tariffs. In both France and Italy, network tariffs are uniform across all DSOs which means that a single set of tariffs must be set at the national level rather than by each individual company. Where tariffs are set separately for each company, it is common for the network companies to calculate their tariffs and for the regulator to approve.

Where network companies are responsible for calculating and publishing network tariffs, these are set in line with revenue caps set by the regulator and following detailed rules on the charging structure approved by the regulator. In Norway and Sweden, there is more flexibility for network companies in setting their tariff structure.

[3] Real Decreto-ley 1/2019, Boletín official del estado, 12.01.19.

*Table 6: Setting network charges*

| Country | Responsibility for setting charges | Frequency of charge setting |
|---|---|---|
| Germany | Regulator approves TSO/DSO's proposals | Annual |
| Netherlands | Regulator based on TSO/DSO proposals | Annual |
| France | Regulator | Set for a four-year period, with annual indexation |
| Spain | Government - will soon change to NRA (CNMC) | Annual |
| Belgium | Regulator approves - CREG for TSO, VREG for DSOs in Flanders | Annually for DSOs, every four years for TSO* |
| Italy | Regulator | Annual |
| Norway | Network companies subject to NRA oversight | Annual* |
| Sweden | Network companies subject to NRA oversight | Annual* |
| Rep. of Ireland | Network companies calculate and publish tariffs following regulator's approval | Annual |

*Source: CEPA*

**Note: In Belgium, TSO tariffs can be subject to more frequent updates. In Norway and Sweden, network charges can be set more frequently subject to notification periods, however, in practice, tariffs are set annually.*

The high-level principles for network charging are usually set out in primary legislation such as energy sector laws. In some cases, specific features of the tariff structure are set out in legislation (e.g. discounts for users with consumption profiles that contribute for grid stability). The detailed methodologies and cost allocation methods are normally published in decisions of the regulator.

## 2.2. Allocation of network costs between categories of users

Network charges are meant to recover the allowed revenues of transmission and distribution network companies. Individual UoS charges for different categories of network users are set such that the target amount of revenue is raised from all network users.

Network costs are not normally allocated explicitly to different types of users. The level of network tariffs paid by an individual customer or groups of customers is the outcome of what can be considered as a two-stage process:

- **Allocation of overall network costs between different categories of users** which is a result of the following decisions (discussed further in this sub-section):
  - **Nature of connection regime, i.e. allocation of costs between connection and UoS charges:** this has an impact on the total amount of revenue recovered through UoS charges. Socialising more of the connection costs through UoS charges means that network users pay higher UoS charges (but lower connection costs).
  - **Allocation of costs between generation and demand:** this impacts on the share of costs recovered from other network users.
  - **Allocation of costs to different voltage levels:** A commonly applied principle of cost allocation is that users contribute towards the cost of the network at their voltage level of

connection as well as all higher voltage levels. This is reflected in the "cost cascading" allocation method (described further below).

- **Allocation of individual pots to individual network users or similar groups of users** (which we discuss in the next sub-section).

The principles or justification for how costs are allocated between different types of network users are not often explicit. In most countries, cost reflectivity, non-discrimination and transparency are common principles underlying the tariff methodologies, but it is not always clear there is a common understanding or application of these principles. Cost reflectivity, for example, is often understood as an average cost concept, by setting overall network revenues in line with the efficient costs of building, maintaining and operating the network. It can also be interpreted as applying network charges that reflect the marginal costs that a network user imposes on the system (as is more typically the case in GB).

The nature of the connection regime can have an impact on the charging structure and the tariff levels paid by network users. Although the specific details of connection regimes can vary significantly across countries, the type of connection regime can usually be classified as either:

- **Shallow connection regime** where the connecting party pays only for the costs of new assets required to connect to the existing network while wider network reinforcement costs are recovered through UoS charges applied to all network users.

- **Deep connection regime** where the full connection cost, including network reinforcement, are charged to the connecting party.

A shallow connection regime means more network costs are recovered through UoS charges which, all else being equal, would translate into higher UoS tariffs for network users (but lower connection costs). Most countries (including GB) apply a form of shallow connection regime, with the exceptions being France, Sweden and, starting in 2019, Norway.[4]

The allocation of costs between generation and demand impacts on the share of costs recovered from other network users. In most cases, all network costs are allocated to demand users (unlike in GB). European Commission Regulation (EU) no 838/2010 currently limits the amount that can be recovered from generators through transmission charges, but this limit varies across countries. For most countries, this limit is €0.5/MWh although among the countries studied Sweden and Norway have a higher limit of €1.2/MWh and Ireland a limit of €2.5/MWh.

In Table 7 below we set the nature of the connection regime, whether transmission network costs are allocated to generators in each of the countries analysed and the percentage of transmission level revenue recovered from generators. For comparison, 16% of transmission costs in GB in 2018-19 are paid for through generators' TNUoS charges. At the distribution level, the allocation of costs between generation and demand is less straight-forward as many distributed generators can receive credits (i.e. negative charge) or are embedded with demand and can help reduce the amount of energy offtaken from the grid (and depending on the charging structure, the UoS bill) for demand users.

[4] The connection regime may differ between types of consumers even within the same country. In France, for example, the connection regime becomes shallower at lower voltage levels. In Sweden, a deep connection regime applies at the transmission level (where no demand consumers are connected), however the connection regime for demand consumers at lower voltage levels is less clear.

*Table 7: Connection regime and transmission network costs allocated to generation*

| Country | Connection regime | Costs allocated to generators | % of costs recovered from generators** |
|---|---|---|---|
| Germany | Shallow | No | - |
| Netherlands | Shallow | No | - |
| France | Deep* | Yes (small) | 3% |
| Spain | Shallow | Yes | 10% |
| Belgium | Shallow | No | - |
| Italy | Shallow | No | - |
| Sweden | Deep (at least at transmission level)* | Yes | 38% |
| Rep. of Ireland | Shallow | Yes | 25% |
| Norway | 'Deeper' regime introduced in 2019 | Yes | 25% |

*Source: CEPA analysis, ENTSO-E Overview of Transmission Tariffs*

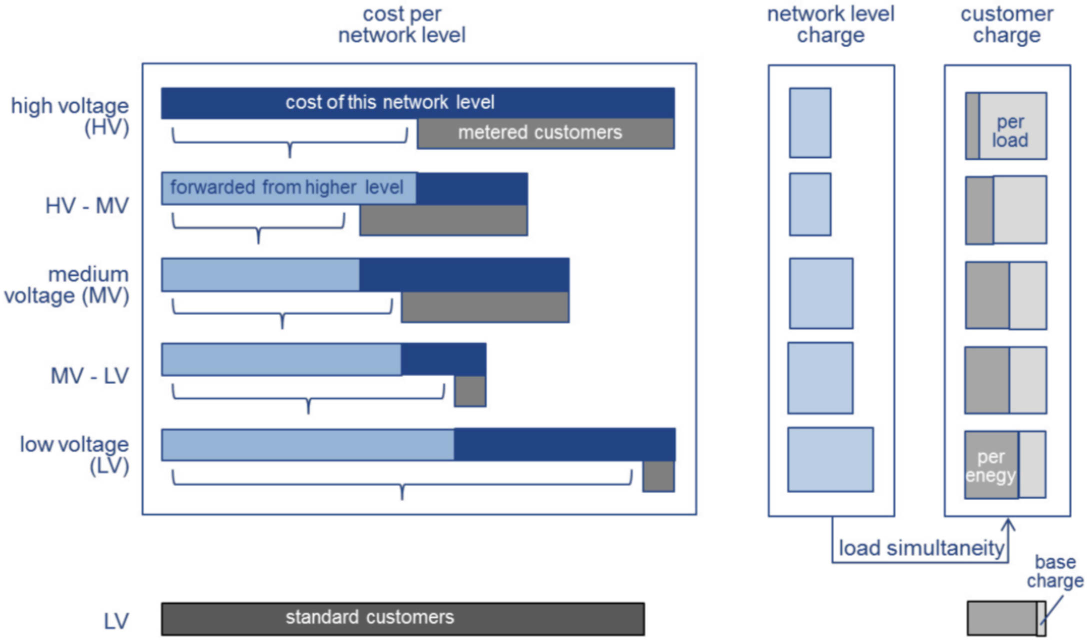
**Note: In France, a deep connection regime applies to generators. The regime becomes shallower for consumers especially those connected at lower voltage levels who pay around 60% of their connection cost with the rest socialised. Similarly, in Sweden, a deep connection regime is in place at the transmission level (where only generators are connected).*

***Note: % of transmission costs recovered from generators. In Ireland, generator TUoS charges are set to recover 25% of allowed revenue for transmission (including SONI's allowance with respect to the Northern Ireland transmission network).*

An explicit cost allocation principle applied across most of the jurisdictions studied is that costs associated with a given voltage level are allocated to users connected at that voltage level as well as users connected at lower voltage levels. This by definition means that consumers connected at lower voltage levels, such as households and small businesses, pay a proportionally higher share of the overall network costs compared to larger users connected at higher voltage levels. This is supported by the findings of our tariff impact analysis in Section 4.

This is often reflected in the so-called 'cascading' of costs where, firstly, network costs are calculated for each voltage level, then the costs of the higher voltage levels are split between users connected at that voltage levels and the lower voltage levels. The figure below illustrates the cost cascading principle as applied in Germany.

*Figure 6: Cost cascading between network voltage levels in Germany*




*Source: Brunekreeft, Brandstätt, et al (2015, p. 16) BEWP.*

The allocation of network costs according to the cascading principle reflects the traditional view of electricity networks flowing power top-down from large generation at transmission level to customers. The ongoing transformation of electricity systems leading to more decentralised, embedded generation, may challenge this view.

## 2.3. ALLOCATION OF COSTS TO INDIVIDUAL NETWORK USERS

Once the first stage allocation of network costs has been established, the costs collected from individual users are determined by the specific tariffs charged to each user. This depends on:

- The factors that determine the individual tariff paid by each consumer.
- The use of fixed, capacity and energy charges as well as whether there are locational of time-of-use elements included in the tariff structure.
- Any specific discounts available for specific types of network users.

Table 8 describes the key factors that determine the tariff for different network users. In all countries, the way network users are charged for access and use of the electricity grid depends primarily on their voltage level of connection. We discuss detailed charging structures for different types of users later in this section but, in many countries, different types of charges (fixed, capacity or energy) apply and the relative importance of these different charges varies between different consumer groups based on their voltage level.

In addition to voltage level, there are other factors that can determine the tariffs that consumers pay including[5]:

[5] In some cases, these features result in different consumers being charged different tariff *levels* rather than different types of tariffs.

- **Type of metering**: in Belgium, Norway and Germany, consumers with simple meters are predominantly charged based on their energy consumption and sometimes a fixed charge whereas capacity charges (determined as either peak consumption or contracted capacity) play a bigger role for consumers with hourly/peak metering.
- **Capacity**: for users connected at the same voltage level the tariff that a customer is can differ based on their contracted capacity, as is the case in Italy, for example. In the Netherlands, the charging structure for consumers connected at low voltage levels depends on their capacity, derived from their fuse size.
- **Consumption profile**: the "peakiness" or the ratio of annual/average demand to peak can also determine the charges in some countries. The most obvious examples are in Germany where the balance between capacity and energy charges for most consumers is determined based on their 'load duration' (calculated as the ratio of annual demand to peak consumption ), and in France, where some consumers can choose between different tariff versions to reflect the shape of their consumption profile.[6]

In addition, a specific distinction is made in Ireland between rural and urban domestic consumers.

*Table 8: Factors that determine the tariff paid by individual network users*

| Country | How charges vary |
|---|---|
| Germany | Voltage level<br>Consumption profile<br>Type of meter |
| Netherlands | Voltage level<br>Capacity (fuse size) |
| France | Voltage level<br>Consumption profile |
| Spain | Voltage level<br>Capacity |
| Belgium | Voltage level<br>Type of meter |
| Italy | Voltage level<br>Capacity |
| Sweden | Voltage level<br>Capacity (fuse size) |
| Rep. of Ireland | Voltage level<br>Urban/rural domestic consumers |
| Norway | Voltage level<br>Type of meter |

*Source: CEPA*

[6] The 'long use' tariff version is best suited to profiles with high average utilisation relative to peak demand whereas the 'short use' tariff version is more suited to users with low average utilisation and stronger peaks in demand. Capacity charges are higher and energy charges are lower in the 'long use' tariff version.

### 2.3.1. Tariff components

In this part of the report we present in more detail the type of charges applied for different consumers groups across the countries studied. As previously mentioned, the charging structure can differ across consumer groups, with voltage level being the most common factor determining these differences. We present the charging structure across three different consumer groups:

- residential consumers connected at the lowest voltage levels;
- non-domestic consumers connected at the distribution network; and
- large consumers connected at transmission level.

The UoS charging structure usually include one or more of the following components:

- a fixed annual charge (e.g. €/year);
- a capacity component (e.g. €/kW) typically based on the user's installed capacity or peak offtake; and
- a volumetric energy charge (e.g. €/kWh) applied to each unit of consumption.

The allocation of costs to the different tariff components differs from country to country. Some countries rely more on capacity-based charges while others on energy-based charges. The rationale for this choice differs. Where capacity charges are predominantly used the justification usually comes down to capacity or peak consumption being seen as a key driver of network costs and thus capacity charging being more aligned with the principle of cost reflectivity. In countries such as Italy and Spain, where network charging reforms introduced in the last few years have placed a greater emphasis on capacity charges, the decision was also driven by cost recovery problems caused by network users reducing the amount paid through energy charges due to increased levels of embedded renewable generation.

However other countries, such as France, have considered placing more of the cost recovery on capacity charges but concluded that energy charges provide better incentives to reduce overall energy consumption with reductions in peak consumption encouraged through the use of time differentiated energy charges.

An interesting example of how costs are allocated between capacity and energy charges is provided by the use of the simultaneity factor in Germany. This factor means that users with a higher coincidence of their individual peak usage with the yearly peak load at their voltage level pay a higher share of network costs reflecting higher cost-causation. This again reflects the importance as a cost driver of the contribution to network peak. The simultaneity function is constructed such that users with a high average utilisation pay a relatively higher capacity and lower energy charge than users at the same network level with a low average utilisation. Also, users at higher voltage levels pay a higher portion of their network bill through capacity charges.[7]

As the analysis and information presented below shows, capacity charges are widely applied to transmission connected consumers and larger consumers connected at the distribution level, while energy charges are the most common type of tariff used for residential consumers.

For residential consumers, all countries except Netherlands apply a volumetric energy charge as shown in Table 9. In addition to the energy charge, residential consumers in most countries are charged a fixed

[7] More details on the use of the simultaneity factor and the charging structure in Germany can be found in Appendix B.1.

and/or capacity charge. This is in line with the existing charging structure in GB where residential consumers are charged a fixed and an energy tariff component.

Energy based charges have historically been applied for residential consumers given that traditional energy meters could only measure total consumption over a period of time. Capacity based charges have been introduced or have become more important in recent years in countries such as Italy, Spain, Norway and the Netherlands. This has been partly driven by the arrival of more advanced meters able to measure peak consumption.

*Table 9: Tariff components for residential consumers*

| Country | Fixed | Capacity/Peak | Energy |
|---|---|---|---|
| Germany | Yes | - | Yes |
| Netherlands | Small fee | Yes | - |
| France | Yes (for administration costs) | Yes | Yes |
| Spain | - | Yes | Yes |
| Belgium | - | - | Yes |
| Italy | Yes | Yes | Yes |
| Sweden | Yes | - | Yes |
| Rep. of Ireland | Yes (for distribution tariffs) | - | Yes |
| Norway | Yes | Only for consumers with hourly metering | Yes |

*Source: CEPA*

Capacity based charges are more common for larger non-domestic consumers connected at the distribution level. The tariff structures for these users in all countries include both capacity and energy charges. This reflects the fact that hourly/peak metering has been more common for these users.

*Table 10: Tariff components for non-domestic consumers connected at distribution level*

| Country | Fixed | Capacity/Peak | Energy |
|---|---|---|---|
| Germany | - | Yes | Yes |
| Netherlands | Yes (only a small fee) | Yes | Yes |
| France | Yes (for administration costs) | Yes | Yes |
| Spain | - | Yes | Yes |
| Belgium | - | Yes | Yes |
| Italy | Yes (for distribution tariffs) | For distribution tariffs at LV and MV and for transmission tariffs at HV and EHV | Yes |
| Sweden | Yes | Yes | Yes |
| Rep. of Ireland | Yes (for distribution tariffs) | Yes | Yes |
| Norway | Yes | Yes (for consumers with hourly meters) | Yes |

*Source: CEPA*

*Table 11: Tariff components for transmission connected consumers*

| Country | Fixed | Capacity/Peak | Energy |
|---|---|---|---|
| Germany | - | Yes | Yes |
| Netherlands | Yes | Yes | - |
| France | Yes (for administration costs) | Yes | Yes |
| Spain | - | Yes | Yes |
| Belgium | - | Yes | - |
| Italy | - | Yes | Yes |
| Sweden | - | Yes | Yes (for losses) |
| Rep. of Ireland | - | Yes | Yes |
| Norway | - | Yes | Yes (for losses) |

*Source: CEPA*

For transmission connected consumers, capacity charges (typically applied on contracted capacity or the user's peak consumption) are part of the charging structure in all countries. Most countries also apply an energy charge. Fixed charges are not usually used to recover network costs from transmission connected consumers with the only exception being Netherlands and, to a smaller extent, France (where a fixed charge is applied to recover administrative costs).

Out of the countries studied, only Norway applies a similar charging approach to GB where transmission connected demand consumers are charged on a p/kW basis based on their consumption during system peak periods.

### Locational and time-of use elements

In Ireland (for generators only), Norway and Sweden, explicit locational elements are included in the charging structure at the transmission level (as is the case in GB). These locational signals are meant to reflect flow patterns on the transmission network and the costs imposed by users in particular parts of the network. The locational element means that final consumers connected in areas of the transmission network with generation deficit pay higher charges than final consumers located in generation surplus areas. In France, Spain and Italy, there are no locational differences with tariffs set equal across all network companies.

In most countries, there are also regional differences between distribution tariffs. These usually reflect differences in costs and network characteristics between different network companies rather than locational variation in charges within the same network.

*Table 12: Locational and time-of-use elements in charging structures*

| Country | Locational charges | Time differentiation |
|---|---|---|
| Germany | No but differences between TSOs/DSOs | No |
| Netherlands | No but differences between DSOs | For one user group at low voltage level only |
| France | No | Yes |
| Spain | No | Yes |
| Belgium | No but differences between DSOs | Yes, for small consumers |
| Italy | No | No |
| Norway | Yes (at transmission level and differences between DSOs) | Yes, seasonal for larger consumers |
| Sweden | Yes (at transmission level and differences between DSOs) | Yes (at distribution and regional grid level) |
| Rep. of Ireland | Yes (for generators at transmission level and differentiation of rural/urban domestic consumers) | Yes |

*Source: CEPA*

Charging structures also differ across countries in the extent to which they include time-of-use elements. We find that there is no specific geographical pattern to these differences. Time-of -use differentiation of tariffs is most widely applied in Spain and France where tariffs can vary by both time of day and season.[8]

More limited time-of use elements are applied in the Netherlands (mostly for small non-domestic consumers), Belgium (day/night tariffs for small consumers) and Norway (seasonal tariffs for large consumers) and Ireland (day/night tariffs). In Italy and Germany there is no time differentiation of tariffs.

### Incentives for reduced peak consumption

Across all the countries analysed, we find that the charging structures in place generally offer weaker explicit incentives for reduced consumption at times of system stress than the GB Triad arrangement. Incentives for reduced peak consumption work mostly through time-of-use elements, i.e. charging higher tariffs during periods with generally higher system demand. There are also incentives for individual users to reduce their individual peak consumption in some countries where capacity charges are calculated based on a user's peak consumption however this does not necessarily coincide with system peak.

Countries where incentives for a reduction of peak consumption are most pronounced are Norway and Belgium. In Norway, transmission network users are charged based on their maximum consumption at system peak based on a five-year average.[9] In Belgium, the TSO's yearly capacity charge is based on the maximum peak consumption during the quarter-hours of the year that make up the yearly peak tariff period.[10] France also offers a tariff charged based on a "moving peak". The moving peak are the 10-15 days per year with highest national consumption. Notice of whether the peak period applies is published one day in advance. However, this tariff is only available to consumers on the HTA (1-50kV) network and consumers can choose different tariff options.

## 2.3.2. Discounts for specific network users

Four out of nine countries analysed in this report offer discounts on UoS charges paid by certain consumer groups, typically large energy users. The level of reduction depends on the individual consumer characteristics (such as their consumption profile or annual consumption levels) and can range from 0-90%.

Germany, the Netherlands, France and Norway apply a similar discount structure for their energy intensive users. Eligibility is typically based on load duration factors (defined as the ratio of annual consumption to peak load), and annual consumption. Discounts apply according to certain country-specific thresholds which are detailed in the individual case studies in Appendix B.

Norway and France also apply additional criteria. In France, the level of discount is further determined by the electro- and trade intensity of the business. Counter-cyclical users with a high off-peak grid utilisation are also eligible for discounts. In Norway, users connected at transmission level can qualify for discounts based on their hourly demand variation and consumption profiles during the summer.[11]

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[8] In France, capacity and energy charges can differ by season and time period according to five time slots. In Spain, a number of time-of-use elements, which vary by time of day and time of year, are applied to most tariff categories.

[9] Defined as the hour between November March where consumption was the highest.

[10] This period covers weekdays from 5-8pm from November to March.

[11] A separate discount is available for all consumer types (including lower voltage grids) in Norway depending on the balance between peak consumption and available winter generation capacity at their connection node. This can result in a reduction of up to 40% in the capacity charging base (kW). This represents a locational differentiation of charges rather than a discount for specific types of users.

The Republic of Ireland's rebalancing of network tariffs in 2009 effectively served a similar purpose as the discounts described above although it resulted in a general reduction of tariffs for large energy users rather than on an individual case-by-case basis as is the case in the other countries discussed above. The Irish Government directed CRU to rebalance network tariffs in favour of large energy users, which resulted in a reduction of DUoS and TUoS charges by 45% for these users. These reductions were financed through an increase in domestic DUoS tariffs. This is similar to Germany, where the discounts granted to large energy users are socialised to other consumer groups through a surcharge on their UoS bills.

*Table 13: Discounts on UoS charges*

| Country | Discounts available | Discount level | Reduction base | Groups eligible for discounts | Eligibility criteria |
|---|---|---|---|---|---|
| Germany | Yes | 80-90% | Network charges | Atypical users<br>Intensive users | Load duration<br>Annual consumption |
| Netherlands | Yes | Up to 90% | Charging base (capacity or energy volume used to calculate charges) | Large energy users | Load duration<br>Annual consumption |
| France | Yes | 5-90% | Network charges | Stable users<br>Counter-cyclical users<br>Large network users | Load duration<br>Annual consumption<br>Off-peak grid utilisation<br>Electro intensity of business<br>Trade intensity |
| Spain | No | | | | |
| Belgium | No | | | | |
| Italy | No | | | | |
| Sweden | No | | | | |
| Rep. of Ireland | No* | | | | |
| Norway | Yes | Up to 75% | Capacity charge rate | Large energy users | Load duration<br>Hourly demand variation<br>Summer consumption |

** The Republic of Ireland has generally reduced tariffs for large energy user groups rather than applying discounts to individual consumers as discussed above.*

*Source: CEPA*

Most countries cite the benefits that large energy users bring in terms of system stability and reduction of system costs as the primary reasons for introducing these discounts. For example, Germany has justified discounts through the fact that stable and predictable network use allows the network operator to manage large amounts of intermittent renewable generation and contributes to overall network stability. Considerations around the international competitiveness of energy intensive industries also play a large role in determining discounts. Both the Ireland and France cite concerns regarding the international competitiveness of their industries as a key motivation for discounts for large energy users. In the Netherlands, one objective of the tariff discounts was to maintain a level playing field for large energy users between the Netherlands and Germany.

# 3. ANALYSIS OF NETWORK TARIFF IMPACTS

This section compares network charges across countries in terms of their quantitative impact on customers' bills.

For the purposes of comparison, we have defined five illustrative customer profiles for which we calculate UoS charges (in €/kWh) in different countries. The five profiles are intended to represent typical GB domestic, small business, medium business, medium EII and large EII demand users.

*Figure 7: Customer profile characteristics*

| | | Domestic residential | Small business user | Medium business user | Medium EII user | Large EII user |
|---|---|---|---|---|---|---|
| Annual (gross) energy demand | MWh | 3.44 | 260.00 | 11,000.00 | 100,000.00 | 2,000,000.00 |
| GB connection level | text | LV | LV | HV | T | T |
| Connection voltage | kV | 0.23 | 0.23 | 11.00 | 275.00 | 400.00 |
| Metering | text | NHH | HH | HH | HH | HH |
| **DUoS-charging characteristics** | | | | | | |
| Assumed GB DUoS tariff | text | Domestic Unrestricted | LV HH Metered | HV HH Metered | | |
| Import capacity | kVA | 4.00 | 138.11 | 4,208.68 | | |
| **TUoS-charging characteristics** | | | | | | |
| Energy demand 1600-1900 (NHH) | MWh | 0.57 | | | | |
| Average triad power usage (HH) | kW | | 45.97 | 1,944.94 | 17,681.23 | 353,624.65 |
| Average system peak power usage (HH) | kW | | 51.49 | 2,178.33 | 19,802.98 | 396,059.61 |

Annual consumption numbers for each profile were provided by BEIS.[12] We based other characteristics on scaled GB averages for similar classes of customer. Appendix A describes our assumptions and modelling approach.

Comparisons should be drawn with care. Results are sensitive to assumptions, particularly those concerning peak profiles, distribution of consumption across time periods, and mapping of an illustrative customer profile to tariff groups. For countries with a very large number of DNOs we have taken weighted averages across the largest DNOs with sufficient data. We have excluded non-UoS charges from the tariff calculation where possible. However, in some countries, UoS charges include additional costs such as costs of network losses and system balancing that could not be excluded from the individual tariff levels.

## 3.1. TOTAL NETWORK COSTS

The impact of tariffs on different consumer groups depends on the cost allocation described in Section 3 but also on the overall level of network costs in each country. To put our results into context we have calculated in Table 14 an average whole network cost per kWh of energy supplied by dividing network costs for transmission and distribution by the energy supplied at a whole-network level. As a measure of network costs, we used the annual allowed revenues for TSOs and DSOs in each country as these determine the amount collected through network charges.

[12] Based on the assumed annual energy demand, our residential consumer corresponds to a medium household consumer (Band DC) in Eurostat data, while our non-domestic consumer profiles correspond to Band IB (our small business user), Band ID (our medium business user), Band IF (our medium EII/ user) and Band IFG (our large EII user).

*Table 14: Estimated allowed revenues and energy consumption (2018 prices)[13]*

| | Units | RoI | Bel* | Fra | Swe | Deu | Nld | Esp | Ita | Nor |
|---|---|---|---|---|---|---|---|---|---|---|
| Allowed revenues (T&D) | EURm | 1,398 | 1,519 | 18,370 | 4,100 | 16,210 | 3,275 | 7,185 | 7,482 | 2,369 |
| Energy consumption (Total) | TWh | 26 | 77 | 442 | 128 | 517 | 106 | 233 | 286 | 114 |
| Network cost / energy consumption | c€/kWh | 5.47 | 4.69 | 4.15 | 3.22 | 3.13 | 3.10 | 3.09 | 2.62 | 2.09 |

**Note: For Belgium, estimates cover the region of Flanders only.*

*Source: CEPA analysis of TSO/DSO publications, Eurostat data on final electricity consumption for 2016*

Based on this analysis, Norway, Italy and Spain appear to have the lowest overall network costs per unit of electricity supplied, while Ireland appears to have the highest cost.

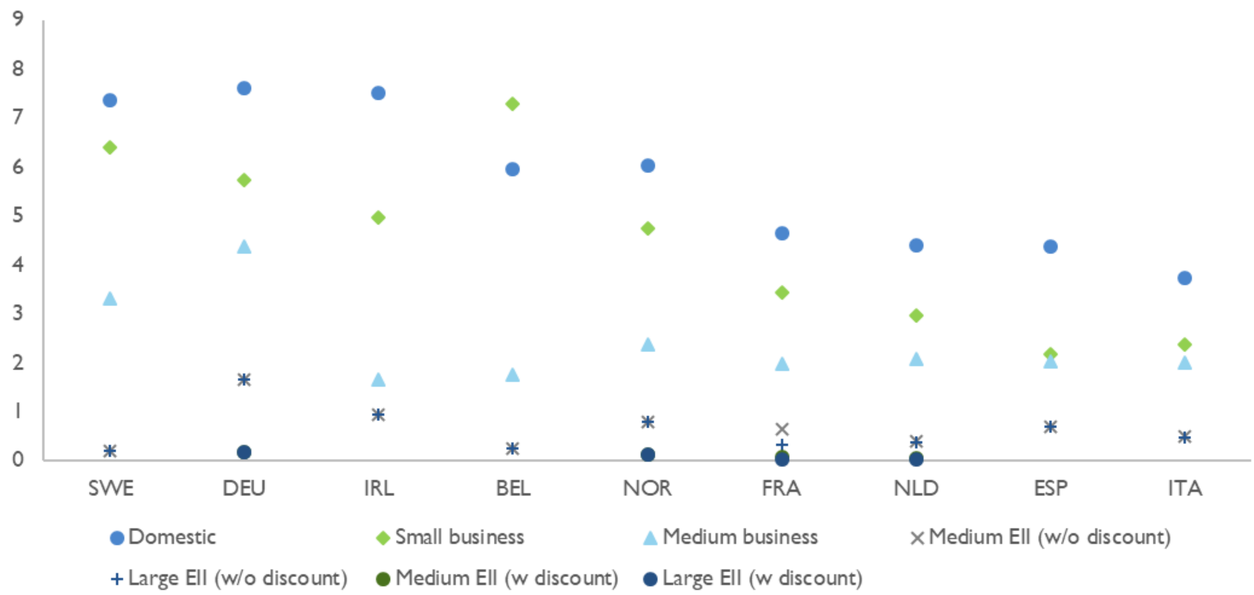
## 3.2. IMPACT OF NETWORK TARIFFS ON RETAIL ELECTRICITY PRICES

Figure 8 presents combined UoS charges in cents per kWh, by country and customer profile. Any comparison of charges per kWh between countries should be treated with care because of differences between countries such as

- **Depth of connection charges** (i.e. balance of costs recovered from customer-specific connection charges, and ongoing UoS charges). Socialising more of the connection costs through UoS charges ("shallow" connection regime) means that network users pay higher UoS charges (but lower connection costs). Most countries (including GB) apply a form of shallow connection regime with the exception of France, Sweden and, starting in 2019, Norway.
- **Allocation of costs between generation and demand.** In most cases, all network costs are allocated to demand users (unlike in GB), but in Sweden, Norway, Ireland, Spain, and, to a smaller extent, France a proportion of the costs at least at the transmission level are recovered from generators. It is expected that those charges paid by generators will feed into wholesale prices and ultimately customer bills.
- **Scope of UoS charges.** In some countries, UoS charges also recover wider system costs which are not part of network UoS charges in other countries (e.g. network losses, system balancing). Where possible we have excluded these costs from the tariff calculations.
- **Consumption assumptions.** Results are sensitive to assumptions such as level of consumption, time profile of consumption; and mapping to tariff groups. The results for all countries are for an average consumer in terms of location and demand profile.

[13] Allowed revenues are not always easily available, especially for countries with a large number of network companies. For France and Italy, we used estimated allowed revenues for the largest DSO and assumed allowed revenues for the remaining DSOs are proportional to their size. For Italy, regulated revenues were sourced from the network companies' annual reports. For Belgium, we show estimated allowed revenues and consumption for the region of Flanders only.

*Figure 8: Use of System charges (T+D) by country & customer profile, c€ / kWh (nominal prices)*

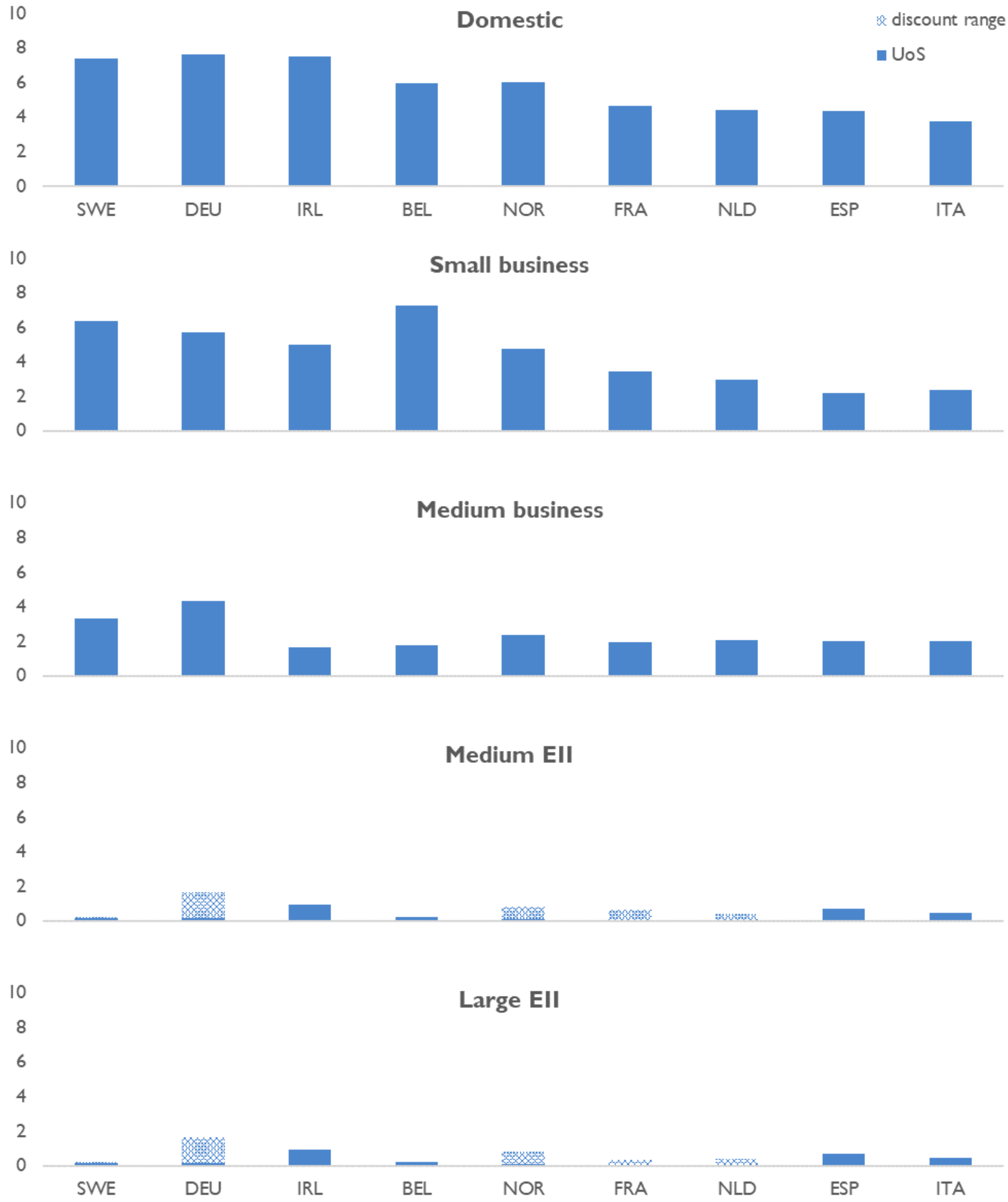



*Source: CEPA analysis of published tariff data for 2018-19. For Belgium, estimates cover the region of Flanders only.*

Figure 9 presents the same results, with easier comparison of customer profiles across countries. Each bar represents the UoS charges paid by a customer profile in a given country.

The shaded regions represent TUoS charges subject to discounts. Discounts in France, Netherlands and Germany are offered up to 90% of standard UoS charges (not 100%, as the chart may appear to suggest).

*Figure 9: Use of System charges (T+D) by country & customer profile, c€ / kWh (nominal prices)*




*Source: CEPA analysis of published tariff data for 2018-19. For Belgium, estimates cover the region of Flanders only.*

The main observation we draw from this is that charges per kWh generally decrease with the size of the customer. The 'domestic' and 'small business' profiles are assumed to connect at the low voltage level, while the 'medium business' profile connects to the high voltage network, and the EII profiles connect directly to transmission. Users are normally required to contribute towards the cost of network levels above their own connection, so the smaller customers are allocated more of the network costs compared to larger customers. Benefits also accrue to larger customers because they tend to use their connection more intensively. For example, the 'domestic' and 'small business' users are assumed to connect at the same network level, but the latter spreads fixed and capacity-related charge elements across a larger consumption base – giving a lower charge per kWh.

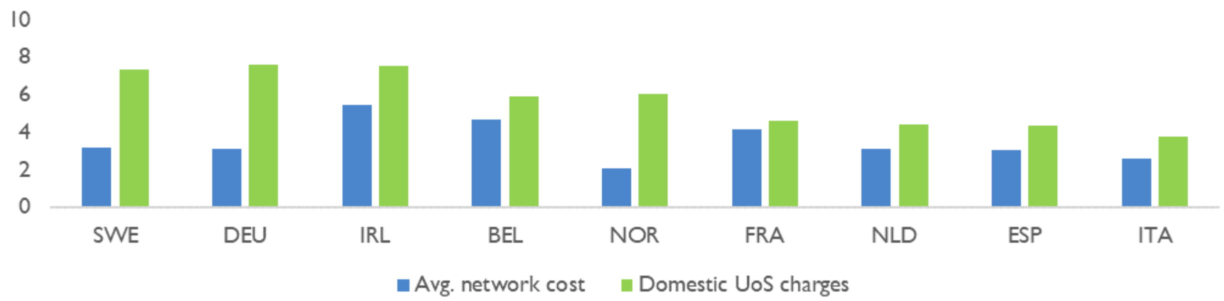
Sweden and Germany tend to have the largest charges for most categories of users. This is partly driven by the fact that UoS charges in those countries include additional costs that could not be excluded from the calculation. In the case of Sweden, charges for transmission connected users are relatively lower because in that case we have excluded energy charges that recover the cost of network losses. For distribution connected consumers, it was not possible to exclude the cost of losses from the individual tariff charged to network users. In Germany, system operation cost, such as the cost of network losses, system reserves and redispatch, make up close to 12% of the total revenue recovered through UoS charges.

Charges are also driven, in some countries, by the extent to which a class of customer's peak load coincides with system peak. That is, 'domestic' customers may be charged more than 'small business' customers because they are expected to consume relatively more energy and require more capacity during peak periods.

There is one exception to the general rule of larger users receiving lower cents/kWh charges. The 'small business' profile is charged more per kWh than the 'domestic' profile in Belgium. We believe that this is because UoS charges are energy-based for domestic customers but capacity-based for all others, and because the tariff applied to the 'small business' profile has a much higher charge for capacity than higher voltage tariffs (see Appendix B.5 for further details).

At the domestic level, we find a wide range of charges from c€7.6/kWh in Germany to c€3.7/kWh in Italy. This variation seems to be driven to some extent by underlying differences in the average cost of the network in each country.

*Figure 10: Comparison of 'domestic' UoS charges & average network costs, c€ / kWh*

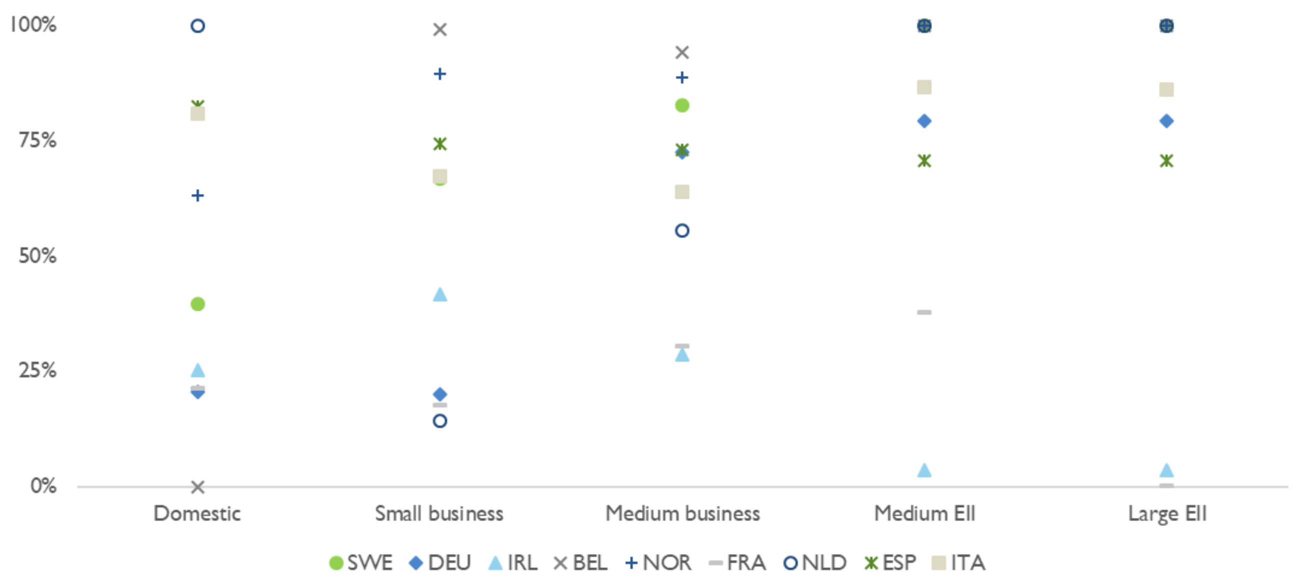



*Source: CEPA analysis. For Belgium, estimates cover the region of Flanders only.*

The factors driving variations at the transmission-connected EII level are less clear. Variation is far greater than for the distribution-connected customer profiles. Some of this may be linked to underlying differences in transmission network costs, but even after taken costs into account significant differences remain. Even where no discounts are applied, implicit discounts may be built into "normal" charges. For instance, the TSO in the Republic of Ireland currently receives a EUR 50m transfer from the DSO expressly mandated by government to improve competitiveness for large users. Extra care should be taken when comparing TUoS charges for large users because they are especially sensitive to assumptions concerning peak load profiles.

We also found large differences in how charges are weighted between volumetric and fixed or capacity components, as illustrated in Figure 11.

*Figure 11: Proportion of average UoS tariffs collected through fixed or capacity charges instead of energy charges, %*




*Source: CEPA analysis. For Belgium, estimates cover the region of Flanders only.*

Figure 11 demonstrates that there is no consistent approach to the balance of fixed/capacity and volumetric elements across countries, or even between network levels. The overall picture is not immediately clear, but most countries seem to fall into one of two categories:

- **Share of fixed or capacity charges increases with size and network level** (e.g. Sweden, Germany, Belgium, Norway).

  It is technically difficult to assess the capacities of domestic and small business users, so network companies generally assume a 'deemed' capacity requirement per connection. Energy consumption is easier to measure, and lets companies allocate costs more fairly than a pure fixed charge. These considerations do not apply at higher voltage levels, where power usage is more closely monitored. As a result, more weight may be placed on capacity / fixed elements at higher network levels. This is also the case in GB, where domestic users are mostly charged against volumes and transmission-connected charges are entirely based on capacity during triad periods.

- **Share of fixed or capacity charges is broadly constant despite size and network level** (e.g. Spain, Italy).

  These are examples of countries that have moved towards a greater recovery of network costs from capacity charges for all categories of users. This may be in response to uptake of behind-the-meter solar generation as a way of avoiding paying volumetric UoS charges.

The three remaining countries present interesting exceptions:

- **France** is unusual because its TSO offers a separate tariff at the very highest voltage level (350-500kV) which waives all capacity-related charges (and offers a very low non-time-of-use volumetric charge). The rationale for this treatment rests on the regulator's assertion that flows at that level are stable across the day and year, so there is little need for a capacity element.[14] When the

[14] https://www.cre.fr/content/download/15125/178565 (section 1.4.2.1)

energy-only tariff was introduced in 2016, the TSO apparently did not support the proposal, which seems likely to have been designed (at least partly) to attract very large-scale EIIs.

- **The Netherlands** is unusual because they have adopted 100% capacity-based charging for domestic users. Domestic users are assessed on their likely capacity requirements, but not charged for actual energy used. Transmission charges are also entirely covered by capacity and fixed charges, but larger distribution-connected users still face some volumetric charges.
- The **Republic of Ireland** is exceptional because its TSO sets predominantly volumetric charges even for its larger users, with only a small capacity-based component. Users face very little incentive to move usage away from periods of system peak.

# APPENDIX A **METHODOLOGY**

This appendix describes the assumptions and approach used to quantify network charges.

## Customer characteristics

BEIS requested results for five customer profiles defined by the following annual energy demands:

*Figure A.1: Annual (gross) energy demand characteristics for illustrative customer profiles*[15]

| | | Domestic residential | Small business user | Medium business user | Medium EII user | Large EII user |
|---|---|---|---|---|---|---|
| Annual (gross) energy demand | MWh | 3.44 | 260.00 | 11,000.00 | 100,000.00 | 2,000,000.00 |

Further characteristics used in determining network charges (e.g. voltage level, granularity of metering, capacity, time profile, etc.) were selected to mimic the profile of a typical GB customer with the specified level of annual demand. We have set these assumptions out below.

We assumed that the domestic and small/medium business users would be connected to the distribution network, and energy intensive users would be connected directly to transmission.

For distribution, we calculated average characteristics for GB customers by tariff reported in published 2019-20 distribution charging (CDCM) models[16]; matched each illustrative customer profiles to the closest distribution tariff; and scaled the relevant characteristics to align with annual (gross) energy demand. Since CDCM models do not provide capacities for non-half-hourly tariffs, we based the 'domestic residential' import capacity on the deemed capacity assumption used by Ofgem for their recent Targeted Charging Review.[17]

For transmission, we estimated power usage during triad periods and at system peak (except for the domestic customer, which we assumed is not half-hourly metered) based on average GB ratios calculated from FES 2018[18] and National Grid's published 2018 TNUoS tariffs[19].

The time periods used to set time-of-use charges vary between (and sometimes within) countries. We used average half-hourly domestic demand profiles provided by BEIS to map volumes to country-specific time periods for the 'domestic' profile. For the small and medium business profiles, we mapped volumes from the red / amber / green time periods used in GB to the equivalent periods, with adjustments if necessary. Where EII users had time-varying energy-based charges we applied the same profiles as for small and medium business users.

We assumed no behind-the-meter generation, which means that gross demand and net demand are equal for all customer types.

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[15] Based on the assumed annual energy demand, our residential consumer corresponds to a medium household consumer (Band DC) in Eurostat data, while our non-domestic consumer profiles correspond to Band IB (our small business user), Band ID (our medium business user), Band IF (our medium EII/ user) and Band IFG (our large EII user).

[16] Common Distribution Charging Methodology (CDCM) models are published by GB DSOs each year, following the same methodology.

[17] https://www.ofgem.gov.uk/system/files/docs/2018/11/targeted_charging_review_minded_to_decision_and_draft_impact_assessment.pdf

[18] http://fes.nationalgrid.com/fes-document/

[19] https://www.nationalgrid.com/sites/default/files/documents/Final%20TNUoS%20Tariffs%20for%202018-19%20-%20Report.pdf

The table below sets out customer profile characteristics used in this analysis.

*Figure A.2: Customer profile characteristics*

| | | Domestic residential | Small business user | Medium business user | Medium EII user | Large EII user |
|---|---|---|---|---|---|---|
| Annual (gross) energy demand | MWh | 3.44 | 260.00 | 11,000.00 | 100,000.00 | 2,000,000.00 |
| GB connection level | text | LV | LV | HV | T | T |
| Connection voltage | kV | 0.23 | 0.23 | 11.00 | 275.00 | 400.00 |
| Metering | text | NHH | HH | HH | HH | HH |
| **DUoS-charging characteristics** | | | | | | |
| Assumed GB DUoS tariff | text | Domestic Unrestricted | LV HH Metered | HV HH Metered | | |
| Import capacity | kVA | 4.00 | 138.11 | 4,208.68 | | |
| **TUoS-charging characteristics** | | | | | | |
| Energy demand 1600-1900 (NHH) | MWh | 0.57 | | | | |
| Average triad power usage (HH) | kW | | 45.97 | 1,944.94 | 17,681.23 | 353,624.65 |
| Average system peak power usage (HH) | kW | | 51.49 | 2,178.33 | 19,802.98 | 396,059.61 |

## Approach to calculating tariff impacts

Applying published charges from multiple countries to these customer characteristics typically requires some assumptions. The most common and material assumptions include:

- **Matching to tariffs**. Each country has its own distinct way of allocating customers to tariff groups at the distribution level. We therefore mapped our illustrative customers to the relevant tariff – based on details such as name, connection voltage level, and typical volumes (if available). Where there was more than one reasonable option, we choose the tariff which required fewer assumptions to apply (e.g. flat-rate rather than multi-rate). Where there were locational tariff elements or significant differences between the tariffs applied by different TSOs/DSOs, we either used the most applicable or took an average.

- **Non-network costs**. We aimed to only include charge components which would be collected by a GB TNO or DNO with respect to its regulated network allowance – that is, excluding policy-related items such as Ireland's Public Service Obligations. This was not always straightforward. For instance, the combined French UoS charge schedule includes charges for contributions to employee pension funds. We took the view that this should not be included, though it could be argued that it is within the normal business of a utility company.

- **Time profiles**. The time profile of power and energy use is an important input to charging since it distinguishes between usage which contributes to system or local network peak, and usage which does not. The customer characteristics we used are based on typical GB splits (e.g. unit rate 1, 2, 3), which need to be mapped onto charging periods used in other countries (e.g. by season, month, day of week, time of day, and coincidence with peak periods). We chose to base time splits on typical GB users for practicality (we did not have time profiles for all countries).

- **Comparability of results.** Some of our assumptions have a bearing on interpretation of results. For instance, our illustrative customers are typical for GB, but may be very atypical in other countries. In Sweden or Norway, our 'domestic residential' customer would appear to be a very low energy user (due to higher energy consumption for space and water heating in Nordic countries), and in Spain or Italy they could appear to be a very high user. Similarly, the coincidence between peak customer and system demand may differ markedly between countries. Therefore, our results do not indicate what a "typical" customer would pay in their own country but rather what the “typical” GB consumer would pay in other countries assuming it maintains the same pattern of energy usage.

- **Interpretation.** The findings should be interpreted with caution because the distinction between volumetric and fixed / capacity charges may not always be obvious depending on the tariff structure in each country. For example, the GB approach of setting charges according to power usage during triad periods is based on capacities, but is closely related to actual usage patterns rather than pre-agreed fixed or capacity elements.

# APPENDIX B CASE STUDIES

## B.1. GERMANY

### B.1.1. Overview

The German transmission network is operated by four TSOs:

- 50Hertz (privately owned);
- Amprion (majority privately owned);
- TenneT TSO Germany (publicly owned by the Dutch Government); and
- TransnetBW (a subsidiary of EnBW Group, a majority publicly owned company).

There are nearly 900 DSOs in Germany of which 81 are larger DSOs with more than 100,000 connections and thus subject to European regulations around unbundling of distribution and retail activities. Most DSOs are regulated by the federal regulator Bundesnetzagentur (BNetzA); only a minority of small DSOs are regulated by state regulators.[20]

We focus our analysis on all four TSOs and on four selected large DSOs, which have been selected from different regions of the country thus reflecting the geographical variation in network charges.

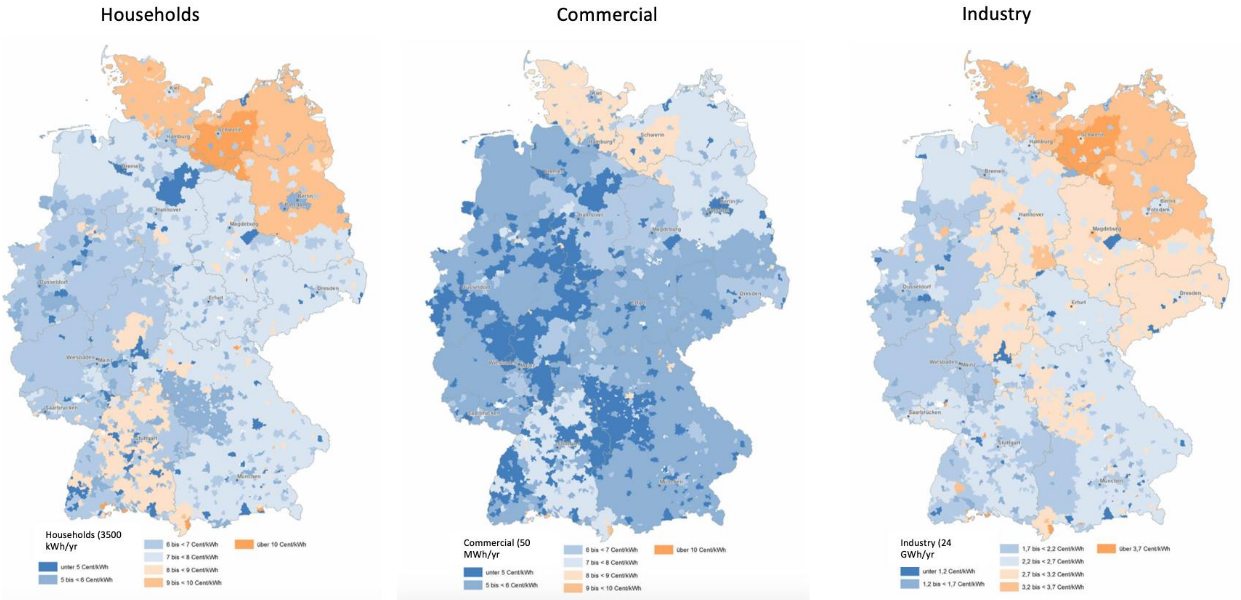
There is significant variation in the regional level of network charges paid by network users in Germany as shown in the figure below, where orange represents higher charges and blue represents lower charges. This indicates that the highest network charges are found in the north-east part of the country while the west and south of the country tend to have lower charges. This reflects factors in the north-east of the country such as:

- the investment in electricity networks that had to be undertaken after reunification in the eastern part of the country;
- the need to upgrade the networks to connect wind generation in recent years;
- more sparsely populated areas; and
- a lower demand base.

Electricity network charges also tend to be higher in rural areas and lower in urban areas.

[20] State regulators are responsible for the regulation of network companies which operate exclusively within a state area and have less than 100,000 customers.

*Table 15: Regional disparities of network charges*




*Source, BNetzA, 2018, p. 157 ff. (Monitoringbericht 2018)*

The four DSOs selected for our analysis are:

1. EWE-Netz (operating in the **north-west,** publicly owned**,** allowed revenues in 2018: €421m)
2. E.DIS Netz (operating in the **north-east,** publicly & privately owned; partly E.ON**,** allowed revenues in 2018: €564m)
3. NetzeBW (operating in the **south-west,** publicly owned; EnBW**;** allowed revenues in 2018: €1,067m)
4. Stadtwerke München Infrastruktur (operating in the **south** in a heavily urban area, publicly owned**,** allowed revenues in 2018: €234m)

Total annual costs for the transmission network amount to just over €2bn while total distribution network costs amount to roughly €14bn. Per unit of electricity supplied, total annual network costs in Germany amount to approximately €31/MWh.

### B.1.2. **Tariff setting process**

#### Responsibility for setting charges

The TSOs and DSOs are responsible for the calculation of network use of system charges, with the regulator (BNetzA) responsible for the approval of the charges. The rules for the structure of the network charges are laid down in the StromNEV (see legislation below), and the maximum level of charges is determined by the revenue cap set through the price control (ARegV).

#### Legislation and methodology for setting network charges

The tariff determination is based on the following legislation and regulatory decisions:

- **Energy Act**[21] (*Energiewirtschaftsgesetz* (EnWG) 2005, last update 2018): this is the federal energy act, which sets out the framework for the entire energy sector; rules concerning network charges are set out in part 3 of the act.

- Ordinance for electricity network charges (*Strom Netzentgelt Verordnung* (**StromNEV**[22]) 2005, last update 2018): this ordinance sets out the rules that determine the structure of network charges (especially UoS charges).

- Ordinance for network connection[23] (Netzanschlussverordnung (**NAV**) 2006, last update 2018): this ordinance sets out the rules and regulations for network connection, including cost contributions and technical rules.

- Ordinance for incentive regulation[24] (Anreizregulierungsverordnung (**ARegV**) 2007, last update 2018): this ordinance determines the price control rules for the energy network operators and thus implicitly determines a cap on network charges.

The Energy Act states that network charges should be "reasonable, non-discriminatory, (and) transparent". Moreover, art. 21 of the Energy Act emphasizes the principle of cost-reflectiveness, which is interpreted as setting the allowed revenues for network operators to the level of an *efficient* network operator.

### Review of network charges

Network use of system charges are updated annually.

### B.1.3. Charging design

Currently, network costs in Germany are allocated entirely to load consumers (i.e. no charges levied for generators). There is no explicit allocation of network costs to different user groups. Differences in charges between different user groups follow implicitly from the network charging structure, based on the voltage level of connection and user consumption profile.

This allocation of network costs relies on three important rules (laid down in the StromNEV):

- Cascading of network costs at different network levels which means that costs related to a given voltage level are allocated to users connected at that voltage level and the lower voltage level (as described below).

- Differentiation of charges between different network levels.

- Users with a higher coincidence of their individual peak usage with the yearly peak load at their voltage level pay a higher share of network costs reflecting higher cost-causation. This reflects the importance as a cost driver of the contribution to network peak.

The principle of cascading network costs as applied in Germany is as follows:

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[21] https://www.gesetze-im-internet.de/enwg_2005/

[22] https://www.gesetze-im-internet.de/stromnev/

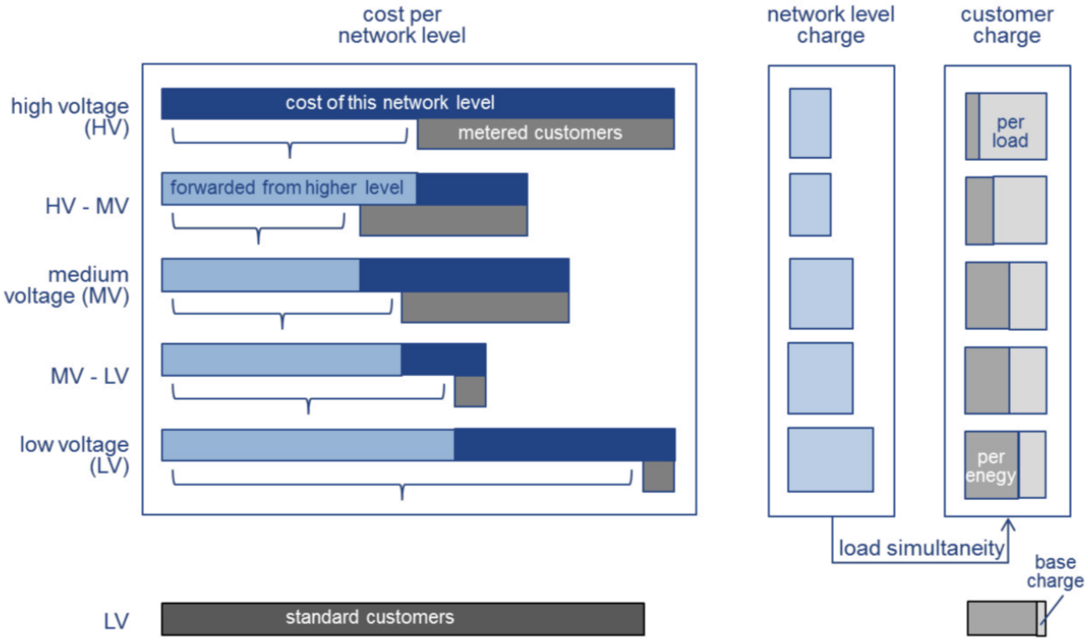
[23] https://www.gesetze-im-internet.de/nav/

[24] https://www.gesetze-im-internet.de/aregv/

- First, network costs are allocated to each network level following administrative cost-causation rules or according to a predetermined key for common costs.
- Second, starting at the highest network level, a price per kW ("postage stamp") for this network level is calculated using the annual peak load at that voltage level.
- Using the "simultaneity factor" (discussed below), a network charge structure is derived for this network level. Users at this network level pay according to this network charge and their network usage.
- The remaining costs of this network level (i.e. costs not recovered from users connected directly at that network level) are rolled-over ("cascaded") to the next level, where the process is repeated until the lowest network level is reached. Cascading only takes plays within a company and not between companies. Hence, there is no cascading of costs between TSO and DSO.

The process is illustrated below for a typical DSO.

*Figure 12: Cost allocation for a typical German DSO*




*Source: Brunekreeft, Brandstätt, et al (2015, p. 16) BEWP.*

We discuss the network charging structure in Germany in the text box below.

**Box B.1.1: Charging structure**

The basic structure of UoS charges applies to all users and all network levels. Consumers are distinguished by three different criteria:

- voltage level of connection;
- load duration factor (<>2,500 hours/year) – this is a calculated figure based on the annual energy consumption divided by the peak load over a year;
- peak metered versus non-peak metered.

The basic structure is summarised in the figure below.

| load-metered end-users | | | | |
|---|---|---|---|---|
| **Load duration** | < 2,500 h/a | | ≥ 2,500 h/a | |
| **UoS charges** | Capacity charge (€/kW/a) | Energy charge (ct/kWh) | Capacity charge (€/kW/a) | Energy charge (ct/kWh) |
| **Network level 1** | | | | |
| **…** | | | | |
| **Network level 7** | | | | |

| non-load-metered end-users | | |
|---|---|---|
| **UoS charges** | Fixed charge (€/a) | Energy charge (ct/kWh) |
| **Used energy** | | |

Hourly/peak metered consumers are charged a capacity and an energy charge. Non-peak metered consumers are charged a fixed charge (per year) and an energy charge.

The structure of the charges (i.e. the ratio of capacity and energy charges) is determined by the **simultaneity factor**.

The simultaneity factor is based on the probability that a consumer individual peak coincides to the yearly peak load of the network level to which the user is connected. This probability informs the ratio between capacity and energy charges for the network users.

The simultaneity function consists of two straight lines intersecting at 2,500 utilization hours. The simultaneity function is constructed such that users with a high load duration factor (≥2,500 hours) pay a relatively higher capacity and lower energy charge than users at the same network level with a low load duration factor (<2,500 hours).

There is also a different simultaneity function applied for each network level. Users at higher voltage levels pay a higher portion of their network bill through capacity charges. This is summarised in the table below, which depicts the share of the capacity charge/ fixed fee per network level and differentiated for the two load-duration groups. It can be noted that whether a user has a high or low load duration factor is the key determinant of the share of costs recovered from capacity charges. For non-peak metered consumers, most of which are likely to be households, around 88% of network costs are collected through the energy charge.

*Figure 13: Share of fixed/capacity charge per network level in Germany*

| Network level | Share of the capacity charge/fixed fee (load duration <2,500 hours) | Share of the capacity charge (load duration >2,500 hours) |
|---|---|---|
| EHV | 25.5% | 83.4% |
| HV | 29.4% | 74.3% |
| MV | 19.8% | 72.2% |
| LV | 18.4% | 57.1% |
| LV without load metering | 11.8% | |

*Source: BNetzA, 2015b, p. 14 (Bericht zu Entgeltsystematik)*[25]

There are no explicit locational elements in the charging structure of the same network operator in Germany. However, there are implicit locational signals due to the differences in charges between the various TSOs/DSOs. Each network calculates each own network charges and therefore any difference in costs will be reflected in the levels of network charges.

Factors contributing to regional difference in network charges include:

[25] BNetzA (2015): *Bericht Netzentgeltsystematik* Elektrizitaet.

- low utilised capacity of the network due to lack of industrial production or decreased population;
- population density;
- integration of renewable energies including the costs for injection management;
- the age of the network – the west of Germany typically has older networks than the eastern part, which is reflected in the network value that is included in allowed revenues.[26]

We note that a nationally uniform transmission charge is being gradually implemented, starting in 2019 and will be fully in place by 2023. This is designed to address the regionally unequal effect of the energy transition. Differences in network charges between DSOs will however remain.

There are no time-of use network tariffs in Germany.

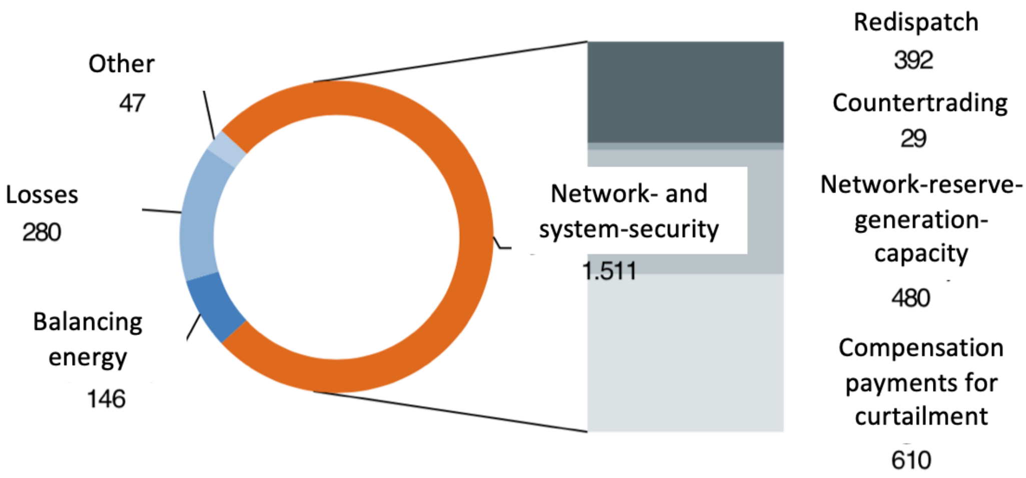
Given the tariff structure and the lack of time differentiated tariffs, there are little or no incentives for an individual user to reduce consumption at system peak. While the simultaneity factor can be regarded as a form of indirect peak pricing, the ability of an individual consumer to influence the simultaneity factor through a change in consumption is negligible.[27] Moreover, many small end-users have no peak metering and thus no peak-load component but only a fixed charge per year.

## Non-network costs included in UoS tariffs

The German UoS charges include network losses, redispatch costs and cost of generation capacity reserves for network stability. These costs can be significant. Congestion in the German electricity system causes very high redispatch and RES-curtailment costs, which are also reflected in the network use of system charges.

The figure below shows the breakdown of costs related to system operation across all TSOs and DSOs in 2017. The total cost is close to €2 billion.

*Figure 14: Breakdown of system operation costs across system operators*




*Source: BNetzA, 2018, p. 181 (Monitoringbericht 2018)*

[26] https://www.bundesnetzagentur.de/SharedDocs/FAQs/DE/Sachgebiete/Energie/Verbraucher/Energielexikon/Netzentgelt.html

[27] Large industrial users have an incentive to avoid the system peak to increase their rebate. This is discussed in more detail below.

Additional charges applied on top of the network use of system charges described above include:

- Metering charges;
- Imbalance charges covering the cost of providing balancing energy;
- Policy support costs and taxes: these include a CHP-surcharge, offshore liability surcharge, a surcharge for disruptable load, surcharge rebates for individual UoS charges and a concession fee (regionally different).

### Connection costs

Network connection charges are shallow and cover only the immediate cost of connection from the nearest network connection point to the customer's facilities (§9 NAV). The shallow charge applies to all demand consumers (§9 NAV), to RES generators and to power plants at higher voltage levels.

However, in addition to the shallow charges, network operators may collect a "deep-ish" charge (Baukostenzuschuss) from connections at the low voltage network covering up to 50% of the cost incurred for upgrading the existing grid to accommodate the new connection (§11 NAV). The application of this provision is by exception, rather than as the default.

### Discounts on network charges

Individual network charges are offered to specific users according to §19 StromNEV, which constitute rebates on use of system charges. Discounts are offered for the following consumer groups:

- Consumers with **atypical network use**: This reflects exceptionally low probabilities that a user's individual peak coincides with the network peak.[28] The rebate can be up to 80%.
- **Intensive network users**: users with a load duration factor of at least 7,000 hours and usage of at least 10 GWh at a connection point are eligible for a rebate.[29] This is considered to reflect the stable and predictable contribution to the system, thereby reducing network costs. The argument is that the large, stable and predictable network use allows the network operator to manage large amounts of intermittent renewable generation. Depending on load duration, the rebate ranges from 80%-90%. Compared to other consumers, large industrial users thus have incentives to reduce peak consumption in order to increase the rebate.
- **Single use assets:** This applies if a user uses specific network assets alone. in this case, the cost of the assets is allocated to this user exclusively and individually.

The foregone revenues resulting from such rebates are socialized over all network users as a separate surcharge on the network charge, the so-called §19.2 surcharge. A report by the federal regulator indicates an increase in the total sum of these rebates between 2014 and 2018. The sum of rebates in 2018 for atypical users is €368 million and for electricity-intensive users €535 million.[30]

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[28] §19.2.1 StromNEV

[29] §19.2.2 StromNEV

[30] BNetzA (2018): *Monitoringbericht 2018*, p. 168

The rebates in the current form apply since January 2014. Individual network charges had been applied since 2005. In 2011, the arrangement for intensive network users was changed with a rebate of up to 100% being applied, i.e. a full exemption of network charges. This was cancelled by court (OLG Düsseldorf, March 6, 2013) and the European Commission found that the full exemption constituted non-compatible State Aid.[31]

The EC decisions also confirmed that a partial discount is justified if it reflects reduction of system costs.

### B.1.4. **Tariff impacts**

Based on 2019 published network tariffs, we have estimated the impact of UoS charges on electricity prices, in cents per kWh, for each customer profile. The tariff impacts are estimated based on energy, capacity and fixed charges applied to network users in Germany. We have excluded from our calculation other tariff components such as the metering charge and policy support costs.

To estimate these tariff impacts, we have also made the following assumptions:

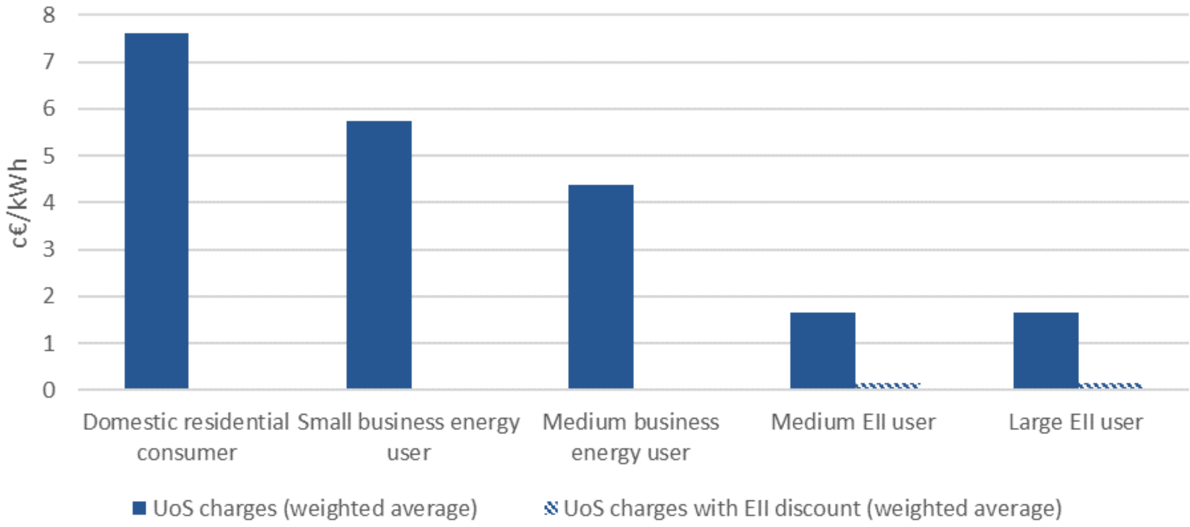
- As a result of our assumed consumer profiles, residential and small business energy consumers have a load duration factor of less than 2,500 hours/year. Users connected to the transmission network have a load duration above 2,500 hours/year.

Figure 15 below shows the tariff impact for each consumer profile as a weighted average of the four TSOs and four DSOs we have considered in this analysis. As network users in Germany pay a single combined transmission and distribution tariff, it is not possible to also present a breakdown between transmission and distribution charges.

The UoS tariffs used for the calculation include the cost of network losses, system reserves and redispatch. These costs are included in the overall revenues that are recovered through UoS charges in Germany and could not be excluded due to lack of information on the allocation of costs between the different consumer profiles. **Overall, these system operation costs represent close to 12% of the total costs recovered through UoS charges.**

[31] EU Commission (2013): *State aid: Germany needs to recover illegal aid from certain large electricity users exempted from network charges in Germany in 2012-2013.*

*Figure 15: UoS charges in Germany by consumer profile, weighted average, c€/kWh*

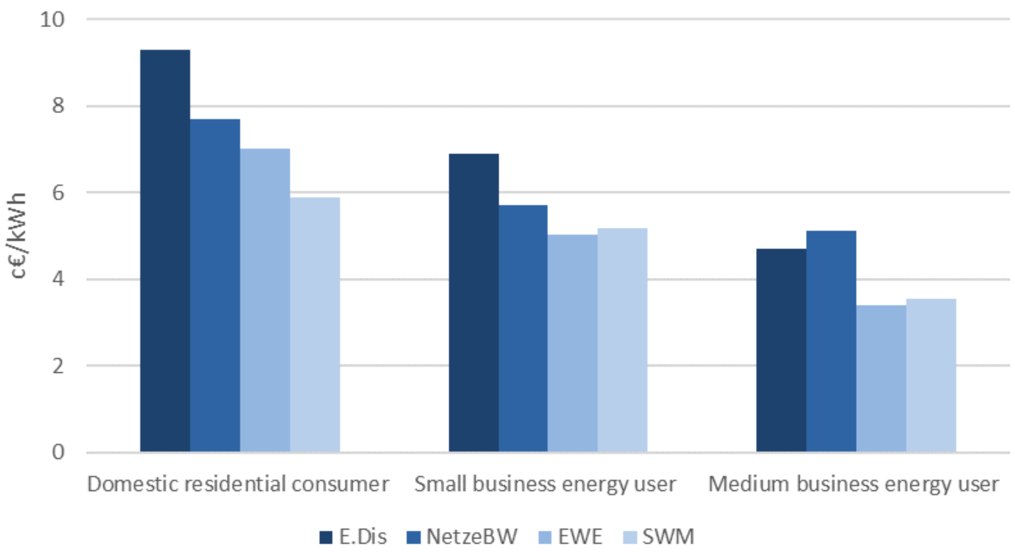



*Source: CEPA analysis*

Network charges in Germany, per kWh consumed, decrease with the size of the customer because larger customers do not need to contribute to the cost of lower network levels and also because larger consumers can spread the fixed/capacity charges over a larger energy consumption base. For our medium EII and large EII users, the impacts are shown with and without discounts. Without any discounts on UoS charges, a large EII user can be expected to face UoS charges of around c€1.33/kWh. Assuming the full possible discounts of 90% of network charges, UoS charges are likely to be c€0.13/kWh for a large EII user.

Figure 16 and Figure 17 detail use of system charges for each DSO and TSO considered in our analysis.

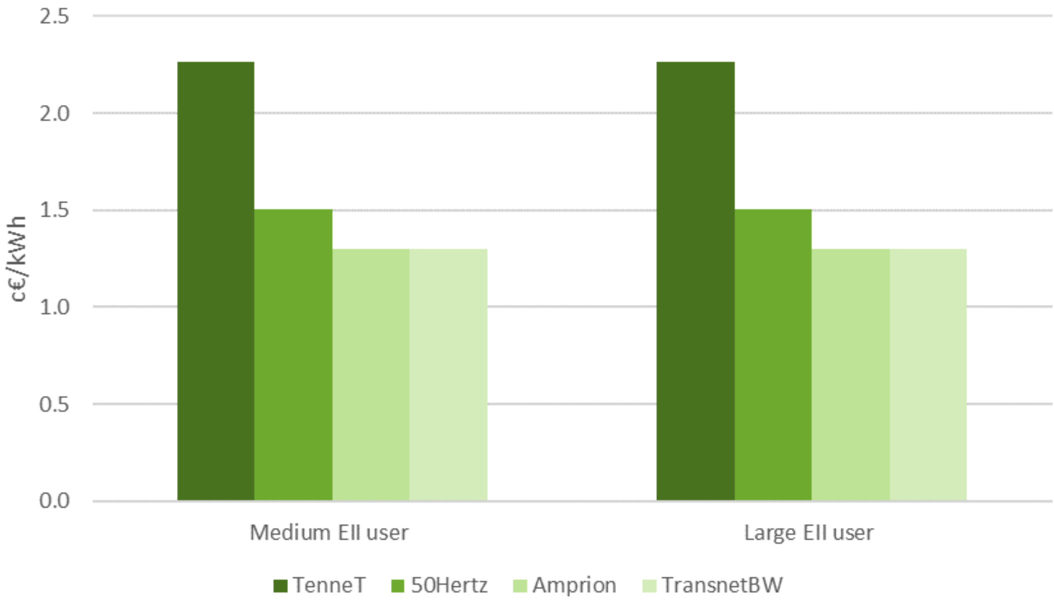
*Figure 16: UoS charges by DSO, c€/kWh*




*Source: CEPA analysis*

Figure 16 gives an indication of the regional disparities of UoS charges between DSOs in Germany. The regional differences are higher for domestic consumers, where UoS charges can range from an estimated c€6.17/kWh to as high as c€9.53/kWh.

*Figure 17: UoS charges by TSO, c€/kWh*

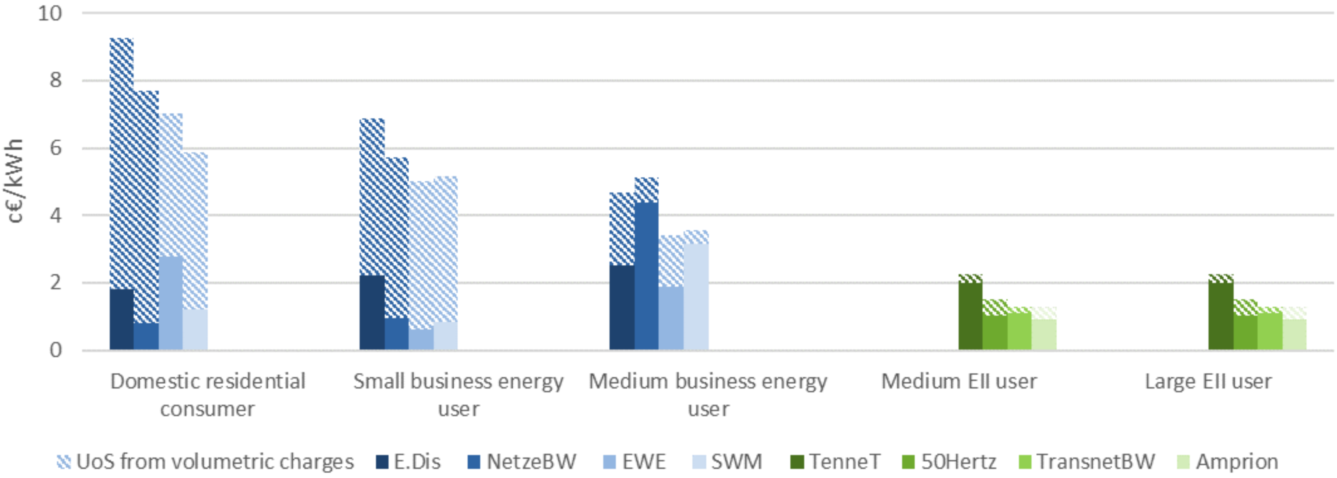



*Source: CEPA analysis*

At the transmission level, regional variations in network charges are markedly less than at the distribution level. Only very small differences in UoS charges are present between Amprion and TransnetBW TSOs. Network charges are almost identical at around c€1.30/kWh for medium and large EII users for these TSOs. The remaining TSOs, 50Hertz and TenneT, have higher UoS charges for both intensive energy user groups. 50Hertz operates the transmission network in Eastern Germany, where many of the factors contributing to higher network costs such as newer electricity networks and less population density apply. TenneT operates a big part of the transmission network in Northern Germany which experiences higher deployment of renewable energies.

Figure 18 below shows a detailed breakdown of the charging components of the UoS charge. Due to the differences in the charging structure between DSOs and TSOs, we present the breakdown both by consumer profile and system operator. The hatched bars show the volumetric component of UoS charges, while solid bars represent capacity/fixed charges on a per kWh basis.

*Figure 18: UoS charge components in Germany by consumer profile and system operator, c€/kWh*




*Source: CEPA analysis*

The share of network charges collected through energy charges is highest for residential and small business consumers and declines for larger users, as expected given the charging structure in Germany.

Customers directly connected to the transmission network pay almost identical c€/kWh UoS charges, but the composition of these charges differs between the four TSOs. Although TransnetBW, TenneT and Amprion have almost identical c€/kWh charges, the share of volumetric charges as a percentage of the final bill ranges from 12% to 31%.

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## B.2. THE NETHERLANDS

### B.2.1. Overview

The Dutch transmission network is operated by one TSO (TenneT). There are seven DSOs, three of which (Enexis, Liander and Stedin) are significantly larger than the others in terms of connected consumers and allowed revenues, as illustrated in the figure below. We focus our analysis on these three larger DSOs. All network operators are publicly owned.

*Figure 19: Dutch electricity distribution network*


*Source: Netbeheer Nederland, 2018: "Betrouwbaarheid van elektriciteitsnetten in Nederland – Resultaten 2017"*[32]

Allowed revenues for the TSO in 2019 are set at around €538m.[33] For the three largest DSOs, the allowed revenues for 2019 are set at:[34]

- Enexis: approx. €877m; ca. 32% of total DSO allowed revenues
- Liander: approx. €1,054m; ca. 38% of total DSO allowed revenues
- Stedin: approx. €669m; ca. 24% of total DSO allowed revenues

The other four (Coteq Netbeheer, Enduris, RENDO Netwerken, Westland Infra) each have allowed revenues significantly below €100 million.

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[32] Netbeheer Nederland (2018): *Betrouwbaarheid van elektriciteitsnetten in Nederland – Resultaten 2017.*

[33] ACM (2019): *Tarievenbesluit TenneT 2019.*

[34] ACM (2019): *Berekening totale inkomsten 2019 regionaal netbeheer elektriciteit.*

### B.2.2. **Tariff setting process**

## Responsibility for setting charges

The Electricity Act 1998 (E-wet 1998, art. 33.1) states that the network operators, in cooperation with stakeholders, work out a proposal for the network charges; these are subsequently reviewed and approved by the energy regulator *Autoriteit Consument en Markt* (ACM; https://www.acm.nl.. The regulator publishes allowed revenues and network charges for both the DSOs and the TSO (TenneT) annually.[35]

## Legislation and methodology for setting network charges

The tariff methodology is based on the following legislation and regulatory decisions:

- The Electricity Act (*Elektriciteitswet* 1998)[36]: this sets out the general framework for the electricity system. Article 36 refers to principles underlying network charges.
- The Tariff code for electricity (*Tarievencode elektriciteit* 2016)[37]: this sets out the structure of all network charges (connection and UoS and others).
- Method-decisions and tariff-decisions per DSO/TSO by the regulator ACM[38]: these decisions specify the principles for network price controls, the allowed revenues and the regulated network charges per network operator.

The main principles for the design of the charging system set out in the Electricity Act (E-wet, art 36 f) are:

- objectivity;
- transparency;
- non-discrimination; and
- cost-reflectiveness.

These reflect the principles laid down in EU regulations however the principles are not explicitly defined in the legislation. Cost reflectiveness has been interpreted as charges being in line with the efficient costs of the service being provided.

The primary focus of the charging structure is on cost-recovery and a reasonable and fair distribution among users. At the same time, the charging structure is meant to reflect cost drivers, e.g. through capacity charges applied on peak use.

## Review of network charges

Network charges for both transmission and distribution networks are reviewed and published annually.

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[35] ACM: *Method-decisions and tariff-decisions.*

[36] Elektriciteitswet 1998.

[37] Tariff code electricity 2016 (*Tarievencode elektriciteit* 2016).

[38] ACM: *Method-decisions and tariff-decisions.*

### B.2.3. **Charging design**

Currently, there are no UoS charges applied to generators hence all network costs are recovered entirely from load consumers.

As a rule, there is no ex-ante cost allocation for different user groups; the differences follow ex-post from the charging structure and user profiles. The Tariff Code (2016, §3.7.x) distinguishes consumer groups according to network voltage level and specifies different tariff structures for these user groups. The voltage levels are:

- Extra high voltage (EHS), 380/220 kV
- High voltage (HS), 150/110 kV
- Intermediate voltage (TS), 50/25 kV
- Transformer HS+TS / MS
- Medium voltage (MS), 1-20 kV
- Transformer MS / LS
- Low voltage (LS), 0.4 kV

The EHS and HS network levels belong to the TSO, TenneT (with a minor exception in the case of one DSO, Liander, which also has consumers connected at HS network level). Transmission tariffs are charged to DSOs and large consumers connected directly to the transmission network. Consumers connected at the distribution level pay for transmission costs through their distribution charges.

Cost allocation between voltage levels within a network company follows the (top-down) cascading principle. Firstly, network costs are calculated for each voltage level. Then the costs of the higher voltage levels are split between users connected at that voltage levels and the lower voltage levels.

The network charging structure is presented in the text box below.

**Box B.2.1.: Charging structure**

The network charging structure in the Netherlands includes four components:

- a **fixed charge** that differs per network level and per user-profile;
- a **kW**$_{max}$ charge which depends on the maximum load that a consumer has achieved in one specific month (or week[39]); this corresponds to the user's individual peak demand;
- a **kW**$_{contracted}$ charge based on the maximum power that a customer expects to have in advance in one year. When the actual maximum power realized exceeds the contracted power, the contracted power is raised to the same level;
- a **kWh** charge based on consumption.

The structure of the network charges differs for each network voltage level:

[39] A separate tariff regime applies to customers on the four highest network levels with an operating time of no more than 600 hours per year. The rate component kWmax is determined for these customers on the basis of the weekly power peak (kWmax per week) instead of per month (kWmax per month).

- The highest network levels (EHS, HS, TS and transformer HS+TS/MS) charge only for $kW_{max}$ and $kW_{contracted}$; each component should cover 50% of the network costs at these voltage levels.
- The medium network levels (MS and transformer MS/LS) charge all three components, where $kW_{max}$ and $kW_{contracted}$ should each cover 25% and kWh 50% of network costs.
- At the low voltage level (LS), the charging structure differs between two user groups:
    - Users with a connection higher than 3*80A are charged for $kW_{contracted}$, which covers 16% of network costs, and for kWh (for off-peak) and kWh (normal) to cover 84% of network costs.
    - Users with a connection equal to or lower than 3*80A are charged for a calculated capacity (in kW) only. There are six such categories according to the connection capacity.[40] This should cover 100% of the allocated network costs.

Almost all domestic and smaller commercial end-users have a connection equal to or lower than 3*80A and are only charged the capacity charge (kW) based on calculated capacity. CEER (2017, p. 31) mentions two potential reasons for this decision:

- ACM considers that grid costs mostly depend on the capacity of the grid rather than on usage, thus capacity charging is more cost-reflective.
- Administrative costs are lower for DSOs when the calculated capacity charges are applied.

There are no explicit locational elements in the charging structure. However, there are implicit locational effects as network charges differ between DSOs.

For most users, there are no time-of-use elements. One exception is for users connected at low voltage level with a connection higher than 3*80A (usually non-domestic) who are charged for contracted capacity and for normal and off-peak energy consumption.

There are no explicit incentives to reduce consumption at system peak times. There are incentives for users to reduce their individual peak demand especially for users connected above the low voltage level which are charged based on their maximum load, but this does not necessarily coincide with the network peak.

Small end-users (with a connection equal to or lower than 3*80A) are allocated in one of the six calculated capacity groups. This sets very low incentives for these users to change their total or peak demand.

Large industrial users have an incentive to avoid system peak as this increases the rebate of network charge according to E-wet art. 29.7 and 29.8 (volume correction mechanism, discussed further below).

### Non-network costs included in UoS tariffs

System operation costs including the cost of balancing the system, reserve capacity and black-start are allocated to the costs of the transmission network. For 2019, the system operation costs for TenneT are around €132m or about 25% of total allowed revenues.[41] These are passed through into the regulated revenues (€538m) and thus into network charges.

[40] The connection is technically expressed in Ampere, which has been transformed (by the regulator) in kW.

[41] ACM (2019): *Tarievenbesluit TenneT 2019.*

The Tariff Code allows a separate charge for reactive power, but this is used only in exceptional cases.

The DSOs pay local taxes which are included in the revenue base. In 2019, these taxes come up to €72m.

### Connection costs

The connection regime in the Netherlands is shallow. There are separate connection charges which recover the shallow connection costs. These connection charges are:

- paid by consumers and producers;
- regulated, but individually cost-based;
- two types: one-off (initial connection) and periodic charges (maintenance).

Deep connection costs are recovered through UoS charges.

### Discounts on network charges

Discounts on network charges are available for large energy users. These are applied through the so-called "volume correction mechanism" (*volume-correctie*). These rebates are stipulated in the Electricity Act and have applied since January 2014. The justification for the discounts relates to the benefits certain users bring to system stability and reduction of system costs (cf. D-Cision et al, 2013, chapter 4.2). Another motivation was to maintain a level playing field for large energy users relative to Germany where similar discounts apply.

The Electricity Act (art. 29.7 and 29.8) provide exact details as to the workings of the rebate:

- The rebate applies to end-users (hence, not network operators) with a load duration factor > 65% and consumption > 50 GWh.[42]
- The calculated volume correction is a reduction (in %) of the volume drivers in the network charge invoice (kW and/or kWh), with a maximum reduction of 90%.
- It is calculated as the product of relative (off-peak) load duration (in excess of 65%) and relative usage (in excess of 50 GWh). If (off-peak) load duration and consumption are relatively high, the volume correction will be high and the discount will consequently be high.

## B.2.4. Tariff impacts

Based on 2019 published network tariffs, we have estimated the impact of UoS charges on electricity prices, in cents per kWh, for each customer profile. The tariff impacts are estimated based on energy, capacity and fixed management charges applied to network users in the Netherlands.

To estimate these tariff impacts, we have also made the following assumptions:

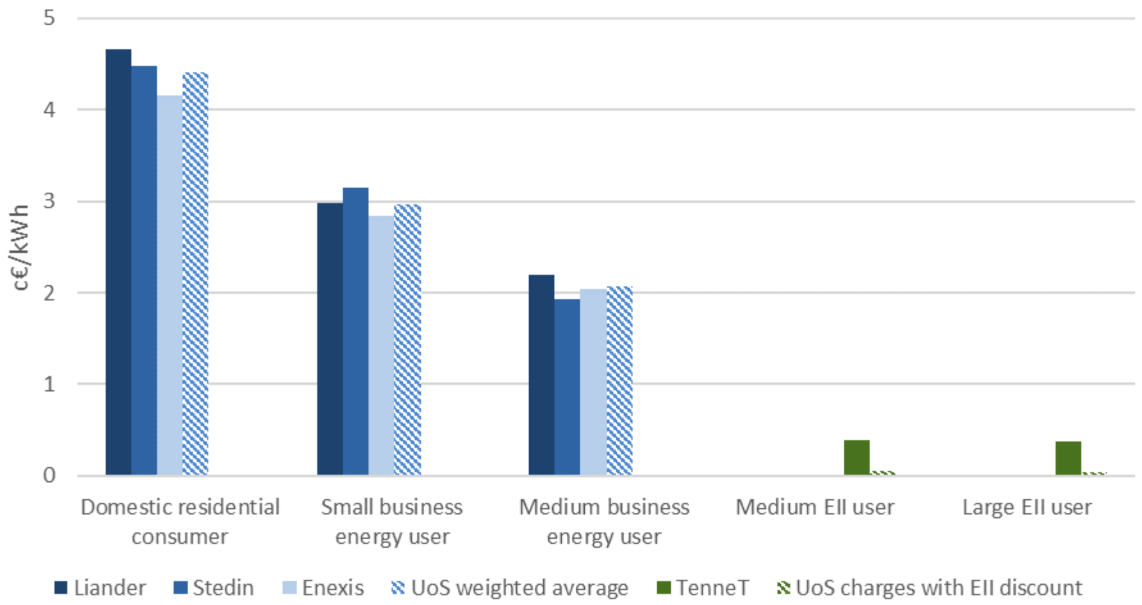
- Where tariffs required assumptions about consumption profiles during different periods of the day and the year, we used the available information on GB usage to map consumption for the corresponding tariff periods in the Netherlands.

[42] The load duration factor is calculated in a similar way as in Germany by dividing annual consumption by peak load.

- Different tariffs apply for users connected to at the medium voltage level depending on whether they are connected to the distribution or transmission grid. We assumed medium business energy users to be directly connected to the distribution grid.
- A special tariff regime applies to users with operating time less than 600 hours/year. Based on the assumed consumer profiles, none of our typical consumers falls into the category.

Figure 20 below shows the tariff impact for each consumer by DSO and an average UoS charge, weighted by the annual electricity supplied by the respective DSOs. The UoS tariffs used for the calculation also include the cost of system operation, including balancing, which accounts for around 25% of total allowed revenues.

*Figure 20: UoS charges in the Netherlands by consumer profile and DSO, c€/kWh*



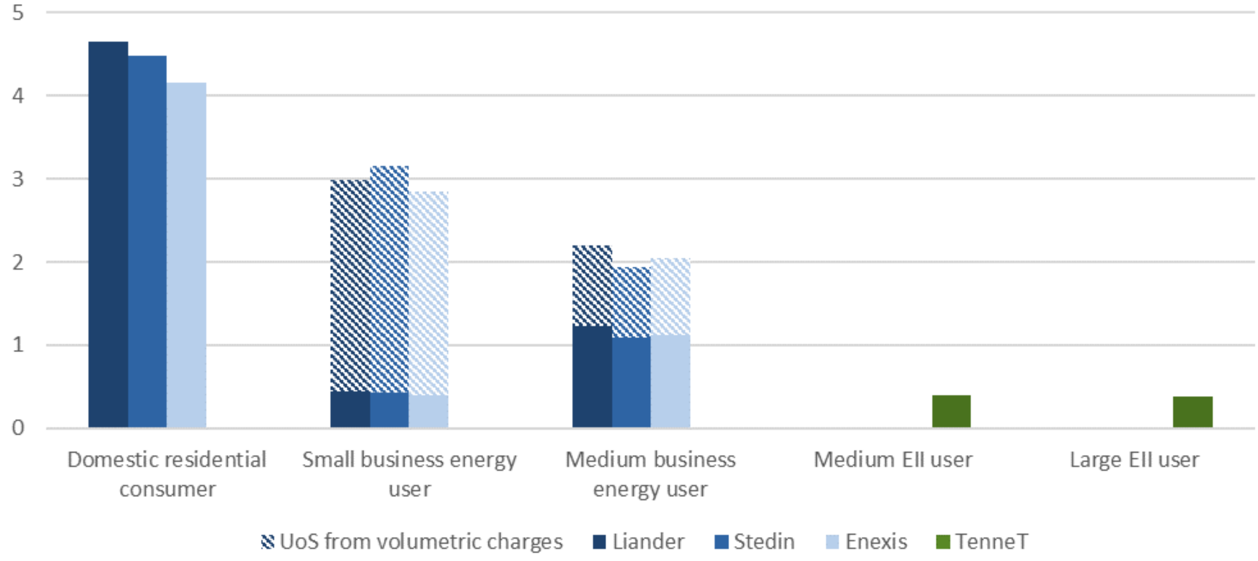

*Source: CEPA analysis*

Network charges in the Netherlands vary by DSO. For consumers directly connected to the transmission network, tariffs are applied by TenneT. Network charges, per kWh consumed, decrease with the size of the customer because larger customers do not need to contribute to the cost of lower network levels and because they can spread fixed charges over a larger consumption base.

For our medium EII and large EII users, the impacts are shown with and without discounts. Without any discounts on UoS charges, a large EII user can be expected to pay c€0.38/kWh in UoS charges. Assuming the full possible discounts of 90%, UoS charges would be just c€0.04/kWh for a large EII user.

Figure 21 below shows a more detailed breakdown of the UoS charge into fixed or capacity-based and volumetric tariff components.

*Figure 21: UoS charge components in the Netherlands by consumer profile, c€/kWh*




*Source: CEPA analysis*

Network charges are recovered through different components depending on the consumer group. For residential consumers, charging is based on calculated capacity only. For larger users connected to the distribution network, the volumetric charge component declines with higher voltage levels. Users directly connected to the transmission network are charged on a capacity/fixed component basis only.

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## B.3. FRANCE

### B.3.1. Overview

The transmission network in France is operated and owned by RTE, who is owned by:

- EDF (50.1%);
- Caisse des Dépóts (public institution) (29.1%);
- Caisse National de Prévoyance (CNP, also mostly owned by public institutions). (20%).

There are 148 DSOs, seven of which are large DSOs serving over 100,000 customers and are hence subject to unbundling rules under European regulations.[43] Enedis, a 100% subsidiary of EDF, is the largest French DSO, accounting for 95% of the French distribution network.

The electricity network in France is divided into extra high and high voltage levels (HTA, HTB) and low voltage lines (BT, below 1kV). RTE manages the extra high and high voltage lines above 50kV (HTB), while the lines below 50kV typically correspond to the distribution network (HTA and BT).

Total annual network costs for the transmission grid have been just over €4 billion in recent years, which translates into around €10/MWh of electricity supplied. In the distribution network, annual network costs total around €13 billion for Enedis' distribution grid, equalling approximately €32/MWh.

### B.3.2. Tariff setting process

#### Responsibility for setting charges

The French use of system charges are recovered through the 'TURPE' – a single tariff for using the public electricity transmission and distribution networks. The tariff for using the public electricity transmission and distribution networks (TURPE) is set by the French Energy Regulatory Commission (CRE). The French Government can ask the CRE to review its decision.

#### Legislation and methodology for setting network charges

The tariff determination is based on four main principles set out by the French Energy Code ('code de l'énergie'):

- **Postage stamp principle**: Pricing is independent of the distance travelled by the contracted power to the end user.
- **Tariff equalisation principle** ('péréquation tarifaire'): tariffs are the same across all regions.
- **Two-part (binomial) tariff:** The tariff depends on the voltage level of the connection, and in general is divided into a power and an energy component. This excludes very high voltage connections (HTB3) and injections into the grid.
- **Principle of hourly/seasonal adjustments:** The cost of the energy component varies according to seasons, days and/or hours of use. This is meant to incentivise consumers to limit consumption at times of high system demand.

[43] Namely Enedis, SER, URM, Gérédis, SRD, GEG, EDF SEI.

The relevant methodology for determining the allocation and methodology of use of system charges for TURPE 5 (2017-2021) was published in the Journal Officiel de la République Française N. 24 from January 2017, with the yearly update for 2018 published in Délibération N. 2018-104 (high voltage) and Délibération N. 2018-148 (low voltage).[44]

### Review of network charges

Use of system charges are set during the price control for a period of four years based on the allowed revenues of the network companies but are updated annually for changes in the consumer price index and under/over recovery from previous years.

### B.3.3. Charging design

Network user charges are paid as a single tariff and include the cost for the use of both the distribution and transmission network. As outlined before, charges are identical across the country (tariff equalization principle) and the pricing is independent of the distance travelled by the energy (postage stamp principle) but varies by voltage level of connection.

Currently, transmission network costs are mainly allocated to load consumers (97% of the charging revenue is recovered from load consumers, and only 3% of the charges are accounted for by generators). Generators only pay an injection fee at the 130kV-500kV voltage connection levels.

The implementation of the current network access charging regime (2017-2020) introduced several changes in the allocation of network charges. Before August 2017, very high voltage level consumers (HTB 3) were charged only based on capacity and fixed components. Now this is based on the energy (kWh) component only. The CRE argued that charging based on contracted power is justified if the network is built to ensure maximum capacity can be delivered to all consumers. The CRE found little variation in the power flows at the EHV level and considered this variation unrelated to demand from users connected to this network level. Based on this, they considered an energy-based tariff as more adequately reflecting user costs. More complex tariff discounts for electro-intensive industries (discussed further below) were also introduced by the 2016-141 decree in February 2016.

Furthermore, France has introduced several changes with the aim of supporting self-consumption in the context of renewable energy technologies. Before 2016, there was no specific framework for self-consumption in France. Only the surplus fed into the grid was remunerated. The current network access charges improve conditions for self-consumers, lowering the fixed fee administration component for self-consumers applied in previous periods.

The network charging structure in France is presented in the text box below.

**Box B.3.1.: Charging structure**

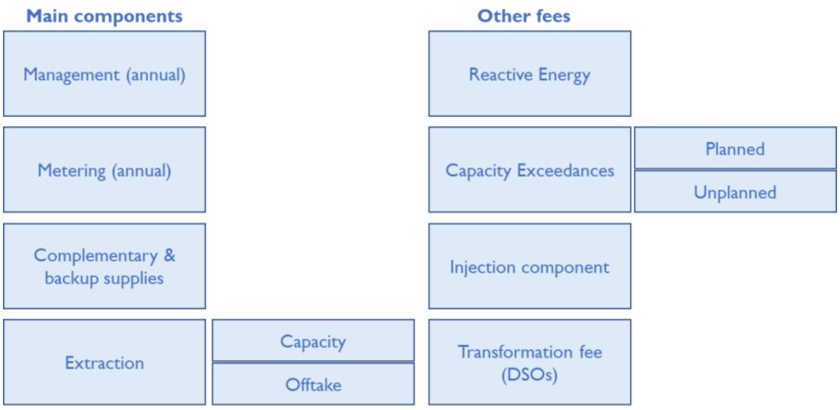
The charging structure includes fixed, capacity and volumetric components and can vary by season and daytime.

The setup of the general charging structure in France is shown in the figure below. The main components include a capacity and energy (offtake) charge for load consumers (extraction). These vary

[44] Note that the methodology for low voltage connections (hence the DSO tariff) has been updated following appeals by Enedis, EDF regarding the allowed revenues of the DSO. This is reflected in the 2018-148 decision from June 28, 2018.

by time period and contract option). There are also separate annual fixed charges covering administrative management fees and metering. Additional fees are charged to DSOs (transformation fee) as well as for exceeded capacity (planned or unplanned) and reactive energy.

*Figure 22: Network tariff components in France*




*Source: RTE (2018): TURPE 5 – Network tariff – Understanding the tariff; CEPA analysis*

Users are classified according to their voltage level of connection. The main distinctions are low voltage connections (<1kV, two different classifications), and high voltage connections HTA/MV (between 1kV and 50kV, two different classifications), and HTB (50kV-500kV, three different classifications).

Capacity and energy charges can differ by season and time period according to five time slots, which distinguish between high and low season (off-) peak hours. Both capacity and energy components can be time differentiated. For time variant capacity charges, the user can specify contracted capacity for each time range.

In addition, for certain tariff categories at both high voltage and low voltage levels, users can choose between up to three tariff versions (short, average and long use) which correspond to different consumption profiles. The optimal tariff for each consumer is meant to reflect the ratio between energy consumed and maximum power demand. The 'long use' tariff version is best suited to profiles with high average utilisation relative to peak demand whereas the 'short use' tariff version is more suited to users with low average utilisation and correspondingly stronger peaks in demand. Capacity charges are higher and energy charges are lower in the 'long use' tariff version compared to the 'short use' version.

Some user groups connected to the HTA voltage level of the distribution network can also choose between a fixed and a "moving" peak profile, where the former applies to ex-ante fixed peak hours and the latter involves "moving" peak hours determined by the peak periods of the national capacity mechanism.[45] The exact "moving" peak periods are not defined in advance. The TSO publishes these periods one day in advance on their website. This system is intended to reduce peak consumption.

Consumers connected to the DSO's network lines can choose between having a network access contract directly with the DSO ("CARD"), or a "unique contract" with a supplier who invoices both network access costs and energy supply in a single bill. The administration fee differs between the two types of contract, with a lower administration fee charged to unique contract consumers.

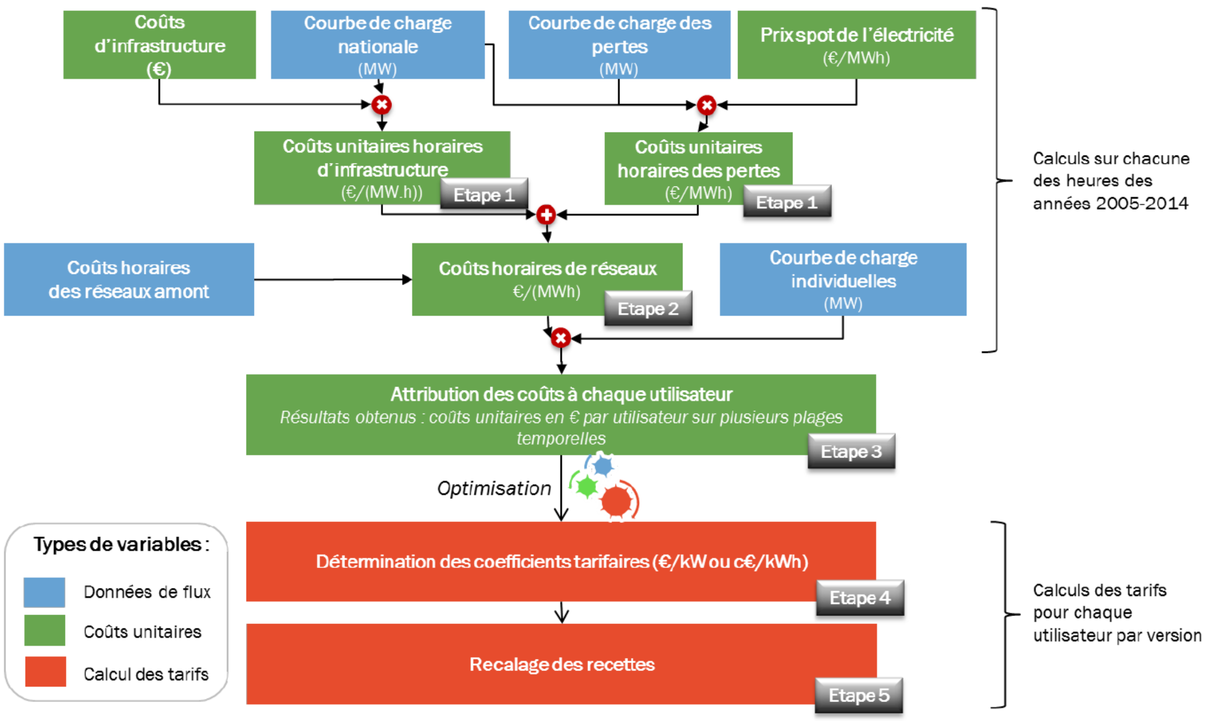
## Calculation of use of system charges

The capacity and energy UoS charges are determined taking into account the actual costs each consumer type generates. Total network costs are first allocated to different voltage levels and, then for each voltage level, are allocated to different hours of the year. Hourly unit costs are calculated for each

[45] These peak periods reflect the 10 to 15 days per year, where the consumption during the period of 7 AM to 3 PM and from 6 PM to 8 PM is the highest.

voltage level taking into account the infrastructure costs and costs due to network losses at both the voltage level of the user as well as higher voltage levels. Infrastructure costs are allocated to different hours by dividing the cost required to meet the lowest power demand in a year across all hours of the year and then sequentially adding the cost of a network increment associated with additional load across all hours where this load occurs. Figure 1 below (in French) outlines the calculation process for the withdrawal components.

*Figure 23: Allocation of unit costs*




*Source: CRE (2017): Notice explicative – tariffs HTA.*

The resulting ex-ante allocation for 2017 of the distribution network costs between the lower voltage connection levels (BT and HTA) were 17.17% for HTA, 13.87% for BT>36kVA, and 68.96% allocated to BT ≤36kVA. This allocation reflects the fact that users connected at the BT≤36kVA level tend to consume more at peak times compared to other users.

In the latest tariff determination, CRE discussed the issue of capacity and energy tariffs. The purpose of energy tariffs is to encourage network users to limit their consumption particularly at peak times. Therefore, the regulator considered it would not be appropriate to significantly increase the share of costs recovered through capacity-based tariffs as these would not provide the same incentives to reduce energy consumption.

## Non-network costs included in UoS tariffs

UoS charges include the cost associated with network losses as well as system balancing costs. For Enedis, the cost associated with network losses for the current tariff period has been estimated at close to €1bn annually, or around 8% of total allowed revenue at the distribution level (i.e. excluding transmission costs). Likewise, the cost associated with network losses for the transmission network is around €500m per year or 12% of total allowed revenue at the transmission level.

Additional charges are paid by network users on top of the TURPE. These complementary fees include the TCFE, the CSPE, and the CTA.

The TCFE comprises both regional and communal taxes on the final consumption of electricity. The CSPE constitutes an additional component of the TCFE, which has been included since January 1, 2016. This 'contribution to the public service of electricity' contributes towards financing the higher costs incurred by providing electricity in France's overseas regions, as well as support of renewable energies and the production of electricity from gas-fired cogeneration plants. It also contributes towards financing social tariffs for vulnerable customers. It is currently charged at €22.5/MWh.

Additionally, a transmission tariff contribution (CTA) is levied as a surcharge for energy sector pensions, which differs between transmission and distribution services. The CTA amounts to 10.14% of the fixed component of the TURPE for consumers directly connected to the transmission grid or connected to the distribution grid above 50kV. For all other consumers connected to the distribution grid it amounts to 27.04%.

## Connection costs

The connection regime is "deep" for generators, who bear 100% of the cost. Load consumers connected to the (very) high voltage grid (HTB) pay 70% of the cost, consumers connected to the low-voltage HTA/BT pay 60% of the cost of their main connection. The remaining shares are mutualised through grid tariffs.

## Discounts on network charges

Network UoS charges are subject to several discounts for certain user groups.

**Electro intensive industrial consumers** can qualify for a discount of between 5 to 90% of their transmission tariff. Discounts are offered to baseload and very large, energy intensive consumers. The Energy Code states that discounts up to 90% should be offered to these consumers taking into account the positive impact that the consumption profiles of these users have on the electricity system.

Other statements from industry sources or Government ministers indicate that these discounts are part of the strategy to preserve the international competitiveness of French industry.[46]

The revenue shortfalls due to discounts are recovered through increased transmission tariffs for other network users. The magnitude of the discount depends on the user's demand (consumption and load duration factor during different periods), on the importance of electricity in their process, their storage capabilities and the degree of international competition.

Consumers can qualify for a discount under the following conditions:

- an annual offtake of over 10GWh and at least 7000 hours of load duration ('stable profile');
- annual offtake of over 20GWh and an off-peak grid utilisation of at least 44% ('counter-cyclical profile'); or
- annual offtake of over 500GWh and off-peak grid utilisation between 40 and 44% ('large consumers').

The discount value depends on whether they are classified as hyper electro intensive consumers (over 6kWh of power consumption per Euro of value added, trade-intensity of over 25%), electro-intensive

[46] See for example, the response of the Economy and Finance Ministry to a parliamentary question on support for electro-intensive industries (http://questions.assemblee-nationale.fr/q15/15-189QOSD.htm).

consumers (over 2.5kWh/€ of value added, trade intensity >4% and annual power consumption of over 50GWh), power storage sites or other sites.

**DSOs** can also qualify for discounts on their network charges. These include:

- DSOs directly connected to the lowest voltage level of a transformer belonging to the TSO can apply the (transformation) tariff of the transformer's highest voltage level.
- A discount applies if the DSO owns lines of the same voltage level as the TSO's lines it is connected to.
- A discount on capacity overruns when actual temperatures are very low compared to average temperatures.

The so-called *chèque énergie* aims at supporting **low-income households** by offering reduced energy bills. However, this discount does not apply solely to use of system charges but is levied on the general energy bill.

Additional special tariffs include:

- A specific tariff for energy withdrawals and exceedances for second connections used for emergency situations.
- Multi-location customers are subject to a tariff component which considers a unique virtual site through summing all load of the concerned sites, and calculates an annual fee proportional to the required length of the network to connect these sites (regrouping of connections).
- A discount on the exceeded capacity component for two weeks provided the TSO is informed in advance.

### B.3.4. Tariff impacts

Based on 2018 published network tariffs, we have estimated the impact of UoS charges on electricity prices, in cents per kWh, for each customer profile. The tariff impacts are estimated based on energy, capacity and fixed management charges applied to network users in France. We have excluded from our calculation other tariff components such as the metering charge, complementary and back-up supplies charge, reactive energy and exceeded capacity charges as well as other additional contributions that recover policy costs.

To estimate these tariff impacts, we have also made the following assumptions:

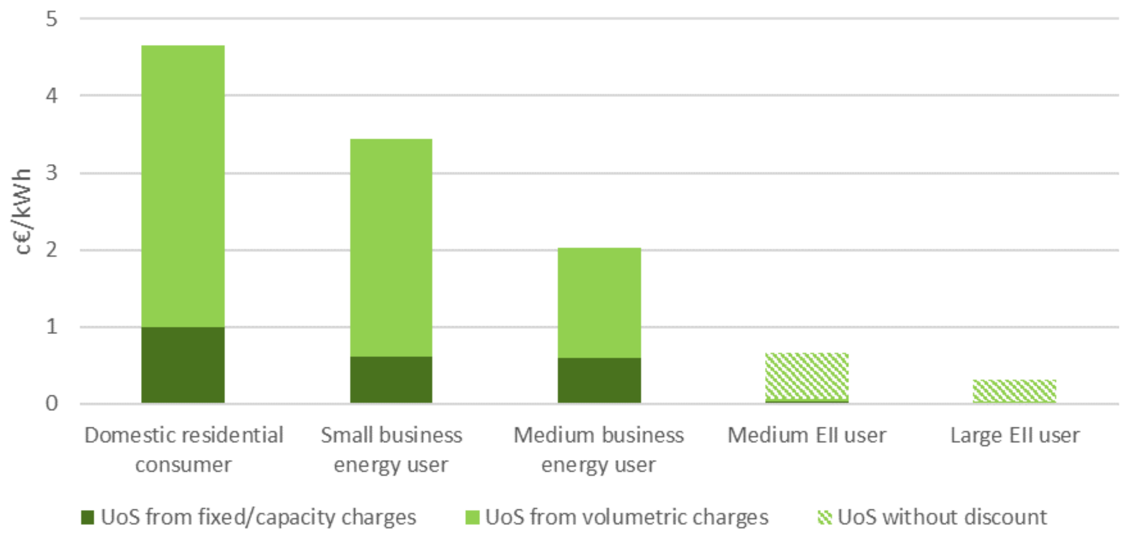
- We assumed that consumers have a separate contract for network access directly with the DSO ('CARD') rather than a unique contract with the supplier.
- We assumed that users that have the choice between different tariff versions (e.g. long use and short use) will choose the version which is most beneficial to them (i.e. results in the lowest tariff bill) given the assumed consumption profile.
- For all consumer types, we chose the tariff which required fewer assumptions to be made. For example, we assumed all consumers are on a fixed peak tariff option i.e. where peak hours are set in advance. For residential consumers, we have applied the tariff with no time-of-use differentiation for energy charges.

- Where tariffs required assumptions about consumption profiles during different periods of the day and the year, we used the available information on GB usage to map consumption for the corresponding tariff periods in France. We also assumed that contracted capacity does not vary by time of day/season.

Figure 24 below shows the tariff impact for each consumer broken down by fixed or capacity-based tariffs and volumetric tariffs. As network users in France pay a single combined transmission and distribution tariff, it is not possible to also present a breakdown between transmission and distribution charges.

The UoS tariffs used for the calculation also include the cost of network losses which are excluded from the calculation in most other countries. There is no transparency in the allocation of the costs of network losses between customer groups which means that we cannot confidently calculate a UoS tariff that does not include network losses. Overall, network losses represent close to 9% of the costs recovered through UoS charges.

*Figure 24: UoS charge components in France by consumer profile, c€/kWh*




*Source: CEPA analysis*

Most of the network charges in France are collected through energy charges. Network charges, per kWh consumed, decrease with the size of the customer as is the case in most countries analysed.

For our medium EII and large EII users, the impacts are shown with and without discounts. Without any discounts on UoS charges, a large EII user can be expected to face UoS charges of around c€0.3/kWh. Assuming the full possible discount of 90% of network charges, UoS charges amount to just c€0.03/kWh for a large EII user.

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## B.4. SPAIN

### B.4.1. Overview

The sole transmission system operator (TSO) in Spain is Red Eléctrica de España (REE), which is 20% owned by the Industrial Holding Company SEPI (state-owned), while 80% of the shares are publicly traded.[47]

The distribution system is characterised by over 300 DSOs. Five of these are large DSOs with more than 100.000 customers, and hence are subject to European regulations requiring the unbundling of distribution and retail activities:[48]

- Iberdrola Distribución Eléctrica, S.A.U,
- Endesa Distribución Eléctrica, S.L.U,
- Hidrocantábrico Distribución Eléctrica, S.A.U,
- Viesgo Distribución Eléctrica, S.L.; and
- Unión Fenosa Distribución, S.A..

Total annual transmission network costs amount to around €1.7bn in 2018.[49] The corresponding annual distribution costs amount to €5.4bn. With a total energy consumption of approximately 246 TWh in 2018[50], this implies annual network costs of approximately €23/MWh for the distribution network, and around €7/MWh for the transmission network.

Spain has grappled with a 'tariff deficit' problem where the tariff revenue has not been sufficient to cover all costs of regulated network companies over a number of years. A market and network regulation reform process has been introduced in 2013 although not all provisions have yet been implemented, as discussed in more detail in the text box below.

**Box B.4.1.: Spain Electricity Market Reform**

In 2013, Spain began an electricity market reform process, with the main aim of eliminating a persistent and significant 'tariff deficit' estimated at around €30bn in 2013.[51] The Spanish Parliament passed a new Electricity Law in December 2013[52] (Law 24/2013), which was followed by a range of new secondary regulations in 2014.[53]

[47] REE website: Shareholder structure.

[48] See CNMC (2018): DJV/DE/001/18, available under https://www.cnmc.es/sites/default/files/2143403_8.pdf.

[49] CNMC (2018): *Informe sobre la propuesta de orden por la que se establecen los peajes de acceso de energía eléctrica para 2019.*

[50] Ibid.

[51] European Commission: *Electricity Tariff Deficit: Temporary or Permanent Problem in the EU?.*

[52] Electricity Sector Law 24/2013 (26 December).

[53] European Commission (2014): *Country reports – Spain.*

The main reform to the charging structure introduced by the new rules in 2013/14 was a shift in most of the revenue recovery from volumetric energy charges to capacity charges for all categories of consumers.

The new law also introduced the concept of 'access tolls' (*peajes de acceso*) which cover the cost of transmission and distribution networks and 'charges' (*cargos*) which recover separate non-network costs. Nevertheless, this separation is not yet in force, since a transitory provision in the Electricity Law establishes that non-network costs will be recovered through access charges until the government has developed the methodology of these non-network charges.[54]

In addition, Spain also introduced provisions targeted specifically at self-consumers. In October 2015, Spain adopted the so-called 'sun tax' which requires consumers to pay tolls/charges on the electricity produced on their premises alongside the electricity sourced from the grid. The new Electricity Law sets out the requirement that self-consumption units should in general pay for the system costs in the same proportion as the rest of network users although there can be reductions where self-consumption brings reductions in system costs, and for consumers with capacity (consumption and self-generation) no greater than 10 kW.

### B.4.2. **Tariff setting process**

#### Responsibility for setting charges

The government is currently the main body responsible for setting network use of system charges. The 2013 Spanish Electricity Law passed responsibility for establishing the methodology for calculating network charges to the national regulatory authority, the National Commission on Markets and Competition (Comisión Nacional de los Mercados y la Competencia, CNMC).

#### Legislation and methodology for setting network charges

The CNMC published their proposed methodology for determining network access charges in July 2014 (Circular 3/2014).[55] However, law 32/2014 set out that the legal authority to establish the structure and conditions applicable to access tariffs remained with the Government, so that the CNMC methodology passed in July 2014 is currently not in force.[56] Consequently, the Government remains the main body responsible for both determining the access tariffs as well as the underlying methodology. The methodology used to determine the current tariffs is not publicly available, as far as we are aware.

The Spanish Government has recently published a Royal Decree Law by which CNMC will take over responsibility for setting both electricity and gas tariffs from 2020.[57]

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[54] CNMC (2018): *Spanish Energy Regulator's National Report to the European Commission 2018*, *Electricity Sector Law 24/2013* (26 December), CNMC (2017): *Informe sobre peajes de acceso de energía eléctrica para 2018 e Informe sobre peajes, cánones y retribución asociados al acceso a terceros a las instalaciones gasistas 2018* – nota de prensa.

[55] CNMC (2014): *Circular 3/2014* – Boletín official del estado, 19.07.2014, Núm. 175.

[56] CNMC (2018): Spanish Energy Regulator's National Report to the European Commission 2018, p.16.

[57] Real Decreto-ley 1/2019, Boletín official del estado, 12.01.19.

## Review of network charges

Access charges are determined on an annual basis. The network tariffs applicable for 2018 were set by the Ministry of Energy, Tourism and Digital Agenda on December 22, 2017.[58] For most network users, the tariffs have remained unchanged since 2014.

### B.4.3. Charging design

## Network charging structure

The network charging structure in Spain is explained in the box below. As the methodology used to set charges is not clear, there is no visibility of any ex-ante allocation of network costs between different consumer groups. Overall, around 10% of transmission charging revenue is collected from generators, with the rest recovered from demand consumers.[59]

**Box B.4.2: Charging structure**

The 2013 electricity market reform has shifted most of the revenue recovery from volumetric energy charges to capacity charges for all categories of consumers. All consumers are charged with both an energy and a capacity component. No fixed charges apply. At the transmission level, it was estimated that the power component accounted for 42% of the total transmission charges paid by consumers, versus 58% for the energy-related component.[60]

Note that the DSOs do not pay access tariffs for the transmission network. Access tariffs for distribution network users are meant to recover network costs at both their own voltage level and a share of the network costs at higher voltages including transmission networks.[61]

Spain distinguishes between consumers by voltage level of connection and capacity. Time-of-use elements are applied to most tariff categories. The tables set out below provide an overview of the different tariff dimensions (voltage, capacity and number of seasonal/daily periods).

*Table 16: Low voltage levels tariff groups*

| Tariff | 2.0A | 2.0DHA | 2.0DHS | 2.1A | 2.1DHA | 2.1DHS | 3.0A |
|---|---|---|---|---|---|---|---|
| Voltage | <1kV | <1kV | <1kV | <1kV | <1kV | <1kV | <1kV |
| Capacity | ≤10kW | ≤10kW | ≤10kW | >10kW ≤15kW | >10kW ≤15kW | >10kW ≤15kW | >15kW |
| No. of periods | 1 | 2 | 3 | 1 | 2 | 3 | 3 |

58 Orden ETU/1282/2017, the Boletín Oficial del Estado núm. 314.

59 ENTSOE (2018): *Overview of Transmission Tariffs in Europe: Synthesis 2018*.

60 Ibid.

61 Ibid.

*Table 17: High voltage levels tariff groups*

| Tariff | 3.1A | 6.1A | 6.1B | 6.2 | 6.3 | 6.4 |
|---|---|---|---|---|---|---|
| Voltage | >1kV<br><36kV | ≥1kV<br><30kV | ≥30kV<br><36kV | ≥36kV<br><72.5kV | ≥72.5kV<br><145kV | ≥145kV |
| Capacity | ≤450kW | >450kW | | | | |
| No. of periods | 3 | 6 | 6 | 6 | 6 | 6 |

Consumers connected at low-voltage levels have the option to choose a charging system that varies by period. Charges for consumers connected at high voltage levels vary by time of day and time of year. Periods are defined ex ante and vary by season (summer, winter, particular months), days (weekends and public holidays) and time of day.

Consumers connected at low voltage levels (below 1kV) and with a contracted capacity equal to or less than 15kW can choose between three types of tariff structures (i.e. either 2.0A/2.0DHA/2.0DHS or 2.1A/2.1DHA/2.1DHS):

- Flat rate: Access tariff is not time dependent.
- "Night time" rate: access tariff is time dependent – peak (in the morning), off-peak (at night), and different peak and off-peak periods during winter and summer.
- "Super valley" rate: In addition to the night time rates, there is an additional cheaper time period at night called "super valley", which is conceived for EV charging.[62]

The time of use differentiation of tariffs incentivises network users to vary their consumption according to the charging profile.

UoS charges do not vary by location except for the variable auto-consumption charge, which differs for the islands, and use of system charges for the exclaves Ceuta and Melilla.

## Non-network costs included in UoS tariffs

The current network tariffs, which recover the distribution and transmission network costs, also include non-network costs such as policy support costs for renewable energy, deficits from previous years, compensation for non-peninsular costs (due to the uniform tariffs across regions but higher network costs on the islands), and system and market operator and interruption charges.[63] This is because the introduction of separate tariffs for non-network costs as envisaged under the 2013 Electricity Law has not yet been implemented. Total annual costs considered for the current network tariffs consist to approximately 40% of network related costs, while the rest includes non-network costs as explained above.[64]

[62] Eurelectric (2017): *Dynamic pricing in electricity supply*.

[63] AF-Mercados, REF-E & Indra (2015): *Study on tariff design for distribution systems*, and Energia y Sociedad: *7.1. Los peajes de acceso y cargos: estructura, costs y liquidación de los ingresos*.

[64] This figure defines deficits carried over from the previous regulatory period as non-network costs rather than network costs.

Network tariffs do not include costs associated with system losses or system/ancillary services. A separate reactive energy component charge is applied to reactive energy consumption exceeding 33% of the active energy consumption and is applicable to all consumers connected above 1kV, hence not for household consumers.

### Connection costs

The Spanish connection charging regime can be characterised as shallow which means that most costs associated with connecting new network users are recovered through UoS charges.

### Discounts on network charges

We understand that there are currently no discounts on UoS charges available for specific categories of network users.

A "social tariff" for vulnerable customers is in place which gives discounts on general tariff levels, not just on use of system charges.

There is also a special access tariff for pumped hydro electricity storage facilities.[65]

For consumers with on-site generation, there is currently no net-metering regulation in place in Spain.[66] Discounts for use of system charges are offered for self-consumers on islands, where their production contributes to system stability.

## B.4.4. Tariff impacts

Total network costs are not recovered evenly from all consumer groups. Using data published by the regulator, we estimate that the share of total network costs recovered from each customer segment is significantly different from the share of electricity demand for each consumer category. Low voltage connections (below 1kV) account for less than half of annual energy consumption, but more than 75% of (wider) network costs are recovered from these consumers. Medium voltage users (1-36kV) account for 31% of consumption but contribute approximately 20% to the access charge revenues. Finally, high voltage connections of more than 36kV account for almost 5% of total revenue recovered from the Spanish network charges, although they account for over 22% of annual consumption. Consumers directly connected to the transmission network recover a particularly low relative share of total revenue.[67] This suggests that in Spain, in line with our findings for other countries, consumers connected at the lower voltage levels pay a proportionally greater share of network costs because they contribute to the costs of all network levels above their own.

Based on 2018 published network tariffs, we have estimated the impact of UoS charges on electricity prices, in cents per kWh, for each customer profile. Rather than using the entire published network tariff values that include both network and non-network costs (e.g. policy costs), we used estimates of implied

[65] ENTSOE (2018): *Overview of Transmission Tariffs in Europe: Synthesis 2018*.

[66] Creara (2016): *Development limited by regulation – self-consumption in Spain*.

[67] CNMC (2019): *Acuerdo por el que se remite la dirección general de política energética y minas datos para la elaboración del scenario de ingresos y costs del sistema eléctrico para 2019*.

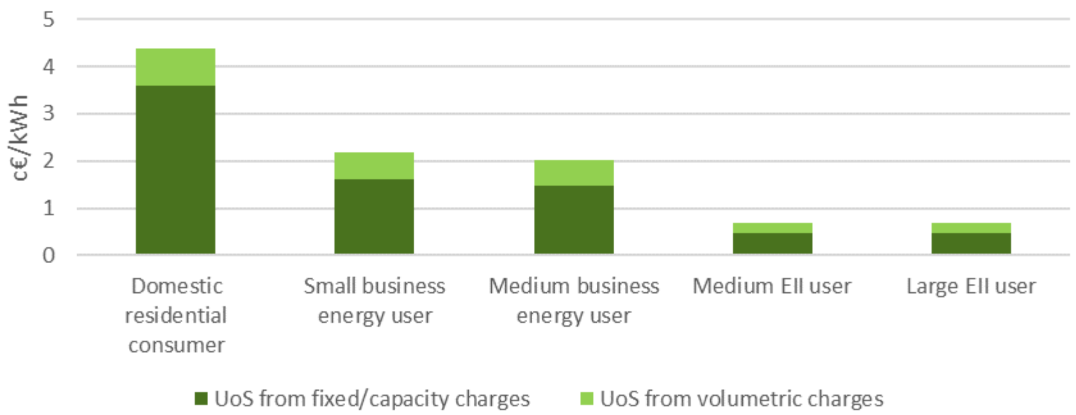
network costs[68] published by the national regulator CNMC, which give a more precise picture of actual UoS charges.

To estimate these tariff impacts, we have also made the following assumptions:

- For all consumer types, we chose the tariff which required fewest assumptions to be made. For example, we have applied the tariff with no time-of-use differentiation for energy charges for residential consumers.
- Where tariffs required assumptions about consumption profiles during different periods of the day and the year, we used the available information on GB usage to map consumption for the corresponding tariff periods in Spain.

Figure 25 below shows the tariff impact for each consumer broken down by fixed or capacity-based tariffs and volumetric tariffs. As network users in Spain pay a single combined transmission and distribution tariff, it is not possible to also present a breakdown between transmission and distribution charges.

*Figure 25: UoS charge components in Spain by consumer profile, c€/kWh*




*Source: CEPA analysis*

Most of the network charges in Spain are collected through capacity charges for all out typical consumer profiles. Network charges, per kWh consumed, decrease with the size of the customer.

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[68] CNMC (2017): Informe sobre la propuesta de orden por la que se establecen los peajes de acceso de energía eléctrica para 2018.

*pertenecientes a grupos integrados, a no crear confusion a los consumidores en la información, presentación de marca* e *imagen de marca*, DJV/DE/001/18.

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*Ley 1/2019*, Boletín official del estado, 12.01.19.

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*Orden ETU/1282/2017,* Boletín Oficial del Estado núm. 314.

REE website.

## B.5. **BELGIUM**

### B.5.1. **Overview**

The Belgium electricity network is regulated by the national regulatory authority CREG and the three regional regulatory authorities CWaPE (Wallonia), VREG (Flanders) and Brugel (Brussels). Due to regional differences in regulatory methodologies and tariff design, we focus our analysis on the national transmission network and the distribution network in the region of Flanders, which is home to 57% of the Belgian population.

Elia is Belgium's only TSO. It is a listed company, almost 50% owned by Publi-T, a cooperative company representing Belgian municipalities and intermunicipal companies. In 2018, there were eleven distribution grid operators in Flanders. These are 100% publicly owned by municipalities and provinces.[69]

Table 18 below shows the market shares of Flemish distribution grid operators in 2018.

*Table 18: Indicative market shares of Flemish electricity distribution grid operators*

| DSO | Market share |
|---|---|
| Imewo | 17.5% |
| Iverlek | 15.3% |
| Inter-Energa | 13.7% |
| Gaselwest | 13% |
| Iveka | 11.2% |
| Imea | 9.2% |
| Intergem | 9% |
| Infrax West | 4.1% |
| Iveg | 2.7% |
| PBE | 2.7% |
| Sibelgas | 1.8% |

*Source: CREG (2018): A European comparison of electricity and natural gas prices for residential and small professional consumers.*

Total annual network costs amount to approximately €1bn for the distribution network in Flanders, and around €0.9bn for the entire Belgian transmission network. Taking into account electricity consumed, this translates into a distribution cost of approximately €31/MWh of electricity consumed in Flanders and a transmission cost of approximately €16/MWh of electricity consumed.

[69] Eandis (2018): *Investor Presentation*, May 2018.

### B.5.2. **Tariff setting process**

#### Responsibility for setting charges

The federal regulator, CREG, is responsible for the regulation of the electricity transmission and corresponding tariffs charged by the TSO. It sets out the tariff methodology and approves the transmission tariffs.

Since July 2014, the three regional regulators (VREG, CWaPE, BRUGEL) have been responsible for approving tariffs for the public gas and electricity distribution networks.[70]

The VREG is responsible for distribution tariffs and (social) public service obligations in Flanders. It approves and publishes the distribution tariffs put forward by the individual DSOs. The regulatory period differs from the regulatory period for electricity transmission (2016-2019) and currently runs from 2017-2020.

#### Legislation and methodology for setting network charges

There are several legislative and regulatory decision documents that are relevant for the network charging process:

- The current transmission tariff methodology is set out in CREG decision on the "tariff methodology for the electricity transmission network and for electricity networks with a transport function" from December 2014.[71]
- The allocation of UoS charges to different charging components and consumer groups is determined in the CREG decision (B)151203-CDC-658E/36 from December 2015 which sets out the tariffs for the entire regulatory period.[72] Elia has requested several increases of the tariffs throughout the regulatory period which have been assessed and granted by the CREG.[73]

The methodology for distribution tariffs was published by the VREG in August 2016 ("Tariefmethodologie voor distributie elektriciteit en aardgas gedurende de reguleringsperiode 2017-2020").[74]

Cost reflectivity is mentioned as the primary rationale for the UoS charging structure. In allocating distribution costs, these costs are cascaded from higher network levels to lower network levels. The costs associated with a given voltage level are allocated to lower voltage levels proportional to energy offtake. These costs are allocated to customer groups per network level proportional to their network usage.

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[70] European Commission (2014): *Country Reports – Belgium.*

[71] CREG (2014): *Arrete (Z)141218-CDC-1109/7 fixant la "méthodologie tarifaire pour le réseau de transport d'électricité et pour les réseaux d'électricité ayant une fonction de transport*

[72] CREG (2015): *Decision (B)151203-CDC-658E/36 relative à "la demande d'approbation de la proposition tarifaire adaptée introduite par la SA Elia System Operator pour la période régulatoire 2016-2019".*

[73] See e.g. CREG (2017): *Annual Report.*

[74] VREG (2016): *Tariefmethodologie voor distributie elektriciteit en aardgas gedurende de reguleringsperiode 2017-2020.*

### Review of network charges

Distribution tariffs are updated on a yearly basis. Transmission tariffs are set for the entire regulatory period of four years but can be subject to updates.

### B.5.3. Charging design

Network users are charged separate transmission and distribution tariffs. Both transmission and distribution charges differ between DSOs. Transmission tariffs charged by the DSOs vary in part due to geographical particularities such as different rates of network losses.[75]

Generators do not contribute towards the recovery of infrastructure grid costs although they are charged tariffs that cover the cost of power reserves (at transmission level) and system management (at DSO level).

### Cost components of UoS charges

The charging structure varies between transmission and distribution tariffs. Consumers connected to the distribution grid receive a single invoice for both transmission and distribution UoS charges, with the different components outlined separately. The respective structures are outlined in the boxes below.

**Box B.5.1: Transmission tariff charging structure**

Network users can connect to Elia's high voltage transmission network at different voltages between 30kV and 380kV.

The grid access tariffs for the transmission network provided by Elia include the following components:[76]

- **Operation and development of grid infrastructure:** this consists of two peak load components (€/kW) charged based on the monthly and yearly peak offtake[77] and a tariff (€/kVA) for the power put at disposal (i.e. contracted capacity). Different tariff levels for each of the components apply depending on the voltage level of connection reflecting the fact that users connected at lower voltage levels on the transmission network will benefit more from the grid infrastructure. If the capacity contracted for offtake is exceeded, a tariff 50% higher than the user's standard capacity tariff will be applied to the exceeded capacity part for the next 12 calendar months. Consumers connected to the distribution network pay slightly different transmission charges depending on their DSO. The charges are capacity based for peak load metered consumers and include a simultaneity coefficient, while for non-peak load metered consumers a volumetric charge is applied.
- **Operation of the electricity system:** this component includes the tariff for the operation of the electric system and a tariff for the offtake of additional reactive energy
- **Compensation of imbalances:** includes costs relating to power reserves and black start

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[75] VREG website.

[76] Elia: *Objective, transparent and regulated grid access tariffs.*

[77] The monthly peak for users directly connected to the transmission network refers to the 11th measured peak during this month. For users of the distribution grid, this component is measured as the monthly peak. Yearly peak capacity is based on the maximum peak during the quarter-hours of the year that make up the yearly peak tariff period. This period covers weekdays from 5-8pm from November to March.

- **Market integration:** this includes TSO services such as the operation of interconnections, coordination with neighbouring countries, and the development and integration of an effective and efficient energy market.
- **Taxes, levies and public services obligations:** These costs include partial funds for renewable energy support costs. Specifically, these finance the support of policies to reduce greenhouse gas emissions, federal offshore wind contributions, regional contributions to purchase green and Cogen certificates at guaranteed minimum prices, and the financing of green certificates. These are added to the network charges invoice as separate components.[78]

Network losses on the federal transmission network are charged separately from transmission tariffs. For our calculations, we focus on the tariff components that are charged for the operation and development of grid infrastructure.

The TSO publishes one tariff schedule without regional discrimination. However, transmission tariffs charged by the DSOs vary between DSOs in part due to geographical particularities such as increased network losses on the distribution network, which vary dependent on the region (rural vs. urban)[79]. Generally, there is no locational variation in use of system charges for the transmission network for clients of the same DSO.

**Box B.5.2.: Distribution tariff charging structure**

Network users are differentiated by their level of connection to the network.[80] The tariff is divided into the following cost components:

- **Network usage**: This tariff component includes charges for subscribed and additional capacity[81], system services and metering. The withdrawal charge can consist of a capacity charge and an additional volumetric charge for certain consumer groups. Residential consumers and small business users are subject to a volumetric charge only. A 'flattening coefficient' is applied to capacity-based charges which effectively flattens the power peaks for individual consumers. This cost component is also subject to a maximum tariff rate for certain types of users.[82]
- **Public service obligations:** These obligations apply in Flanders in addition to the national public service obligations levied through the transmission tariffs. They include costs for social tariffs, rational energy use, public streetlights and combined heat and power certificates.
- **Support services:** This includes network losses and reactive energy charges.

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[78] Deloitte (2017): *Benchmarking Study of Electricity Prices between Belgium and neighbouring countries*.

[79] https://www.creg.be/fr/professionnels/acces-au-reseau/electricite-transport/tarifs-de-reseau-elia, and https://www.vreg.be/nl/wat-het-transmissienettarief

[80] The groups are: <1kV, 1kV-26kV, >26-36kV and the high voltage network.

[81] This "basic network tariff" includes costs for network studies, general management, depreciations, financing costs and the corporation tax.

[82] The maximum tariff rate applies, in the case of Gaselwest, to peak metered low and medium voltage users with a capacity of up to 5MW.

- **Other surcharges:** This includes financing of pensions, redistribution, costs of the regulatory authority and other taxes.

For the purposes of this study we are only considering the network usage tariff components.

The distribution tariffs for network usage charges include energy offtake (capacity/volumetric), system services (volumetric) and metering (fixed) components. The charging basis for the offtake component depends on the consumer group. Consumers without peak load metering pay a volumetric charge, with a distinction between day and night tariffs.[83] Consumers with peak load metering pay a capacity charge, based on the monthly peak of power offtake[84], and in some cases an additional energy charge. The remaining tariff components outlined above are charged on a per kWh basis.

### Non-network costs included in UoS tariffs

While policy costs and charges for e.g. market integration are included in the transmission and distribution tariff structure, these are charged as separate components from network usage charges. Thus, our analysis distinguishes between these non-UoS and UoS charges. Network losses on the federal transmission network are charged separately to transmission tariffs but are included in the transmission tariffs charged by distribution companies to distribution-connected consumers. There is a separate tariff component that covers the cost of network losses at distribution level.

### Connection costs

The connection regime can largely be characterised as shallow.

### Discounts on network charges

We are not aware of any discounts to either transmission or distribution tariffs for specific categories of users. Electro-intensive users benefit from a discount but this is not applied to taxes, levies and certificates (e.g. green certificates for renewable energies and a certificate system for combined heat and power), rather than network costs. The maximum available reduction depends on the consumer group, and can reach between €2.5 to €11.7/MWh.[85]

## B.5.4. Tariff impacts

According to the regulator, network costs make up 26.2% of consumers' electricity bill in Flanders (without taxes and additional fees).[86] Based on 2018 published network tariffs, we have estimated the impact of UoS charges on electricity prices, in cents per kWh, for each customer profile. The tariff impacts are estimated based on energy and capacity charges, as well as a system management charge levied for the use of the distribution network. We have excluded from our calculation other tariff components such as metering

[83] Exclusive night tariffs are also available.

[84] The monthly peak for consumers connected to the distribution grid is determined each month as the maximum peak of the offtaken power during each quarter of an hour of the month concerned.

[85] CREG (2018): *A European comparison of electricity and gas prices for large industrial consumers*, pwc report, 14 May 2018.

[86] CREG website: https://www.creg.be/fr/consommateurs/prix-et-tarifs/comment-est-compose-le-prix-de-lenergie

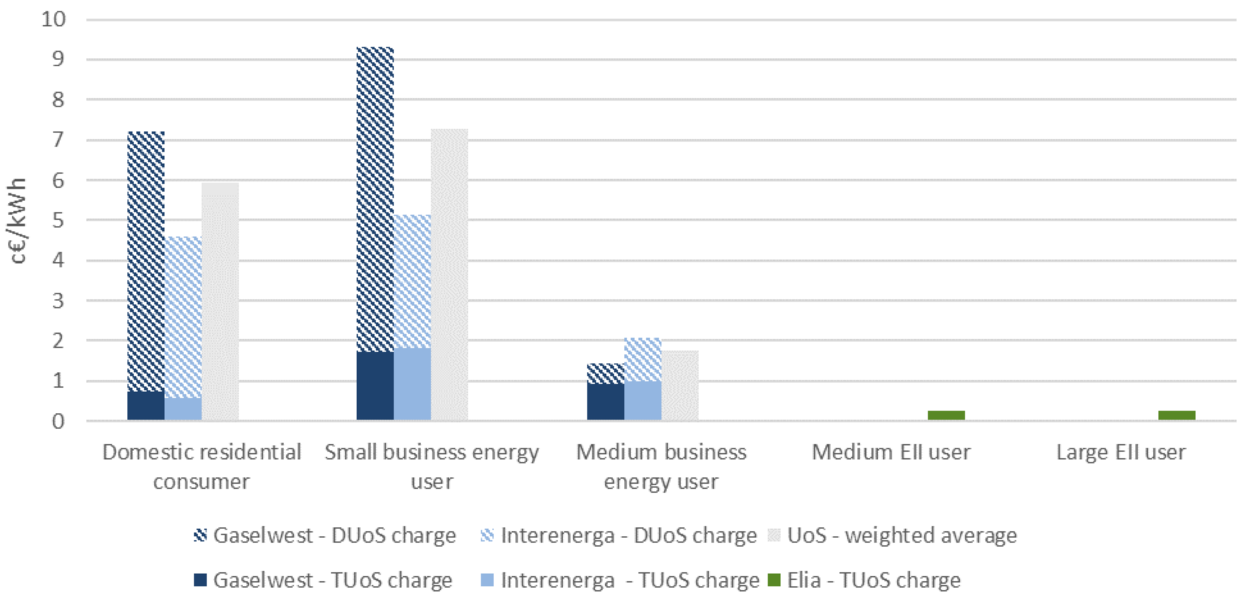
charges, reactive energy and capacity exceedance charges, network losses (at distribution level), management of the electric system, and policy support (PSO) and market integration costs.

To estimate these tariff impacts, we have also made the following assumptions:

- The exact time period for night and day tariffs, respectively, differs by ±1 hour between DSOs. For consistency across DSOs, we have assumed one simplified night pricing period for all Flemish DSOs.
- We assumed that all customers, other than residential ones, are subject to peak load metering.
- Where tariffs required assumptions about consumption profiles during different periods of the day and the year, we used the available information on GB usage to map consumption for the corresponding tariff periods in Belgium.
- We only estimate UoS charges for consumers' main point of connection.

Figure 26 below shows the tariff impact for each consumer broken down by distribution and transmission charges. We have estimated distribution tariff impacts for two DSOs. Since UoS charges differ between DSOs, the distribution charge component presented below is calculated as a weighted average (by share of total customer connections) of the DSO tariffs of the two DSOs Gaselwest and Interenerga.

*Figure 26: DUoS/TUoS charges in Flanders by consumer profile, c€/kWh*

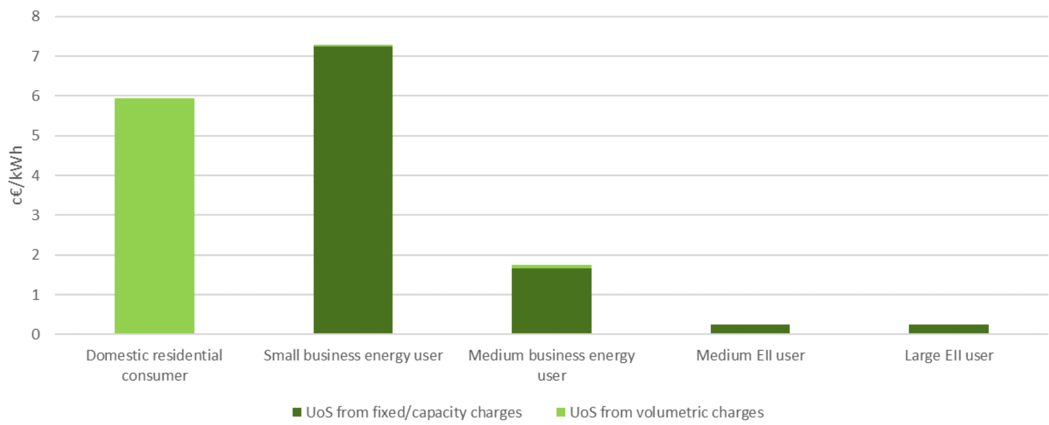



*Source: CEPA analysis*

Distribution charges represent the majority of UoS charges for domestic residential and small business consumers. For the remaining consumer profiles, transmission charges make up the majority of the UoS bill.

Figure 27 below shows the composition of the UoS charge between fixed/capacity charges and volumetric charges of the overall UoS tariff. Domestic consumers are almost entirely charged on a volumetric basis, while the remaining consumer profiles are almost entirely charged based on their contracted capacity and fixed charges.

*Figure 27: UoS charge components in Flanders by consumer profile, c€/kWh*




*Source: CEPA analysis*

Residential consumers pay a lower per kWh charge than small business energy users. This is unusual compared to other countries included in this study. One cause of this may be that domestic consumers are mainly charged on a per kWh basis, while small business energy users are charged mainly based on their contracted capacity, as depicted in Figure 27 above.

### B.5.5. Sources


Arrete (Z)141218-CDC-1109/7 fixant la "méthodologie tarifaire pour le réseau de transport d'électricité et pour les réseaux d'électricité ayant une fonction de transport https://www.creg.be/sites/default/files/assets/Publications/Others/Z1109-7FR.pdf

CREG (2018): *A European comparison of electricity and gas prices for large industrial consumers*, pwc report, 14 May 2018.

CREG (2018): *A European comparison of electricity and natural gas prices for residential and small professional consumers*, pwc report, 28 June 2018.

CREG (2017): Annual Report.

CREG (2015): *Decision (B)151203-CDC-658E/36 relative à "la demande d'approbation de la proposition tarifaire adaptée introduite par la SA Elia System Operator pour la période régulatoire 2016-2019*", December 3 2015.

CREG: *Tarifs de réseau Elia*

Deloitte (2017): *Benchmarking Study of Electricity Prices between Belgium and neighbouring countries*.

Eandis (2018): *Investor presentation*

Elia: *Objective, transparent and regulated grid access tariffs*.

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VREG (2016): *Tariefmethodologie voor distributie elektriciteit en aardgas gedurende de reguleringsperiode 2017-2020*.

VREG website.

## B.6. ITALY

### B.6.1. Overview

TERNA is the state-owned TSO in Italy and owns over 99% of the transmission assets. There are also several other small transmission asset owners.

There are approximately 140 DSOs in Italy, with the main distribution companies based on the volume of energy distributed being:

- E-distribuzione (Enel group) (85%);
- Unareti (A2A group) (4.2%);
- Areti (Acea group) (3.7%);
- Ireti (Iren group) (1.3%).

Distribution network charges in Italy are uniform across all regions of the country despite the fact that DSOs receive different revenues. The uniform network charge is calculated so that, on aggregate, the sum of the DSO allowed revenues equals the amount expected to be raised through tariffs. The DSOs are then made whole through an 'equalisation' process (called 'perequazione'), which provides for any differences between total revenue raised nationally from charges and the total revenue that should be earned by the electricity DSOs in total.

The regulatory regime for setting allowed revenues for network companies in Italy is different from the other countries included in this study. The form of price control is part cost of service regulation (for capex) and part price-cap (for operating costs) instead of a more totex approach to setting allowed revenues. There is also less transparency, at least in regulatory documents, over the total regulated revenues of network companies. According to TERNA's annual report, the total regulated revenue for the transmission network was close to €2bn in 2017.[87] Based on total electricity demand in Italy, this translates into a transmission cost of approximately €7/MWh of electricity consumed. For the distribution network, we have estimated the total regulated revenue to be around €5.35bn[88] or around €19/MWh of electricity consumed.

### B.6.2. Tariff setting process

#### Responsibility for setting charges

Tariffs are set by the Italian *Autorità di regolazione per energia reti e ambiente* (Regulatory Authority for Energy Networks and Environment, ARERA), formerly known as AEEGSI.

Distribution and transmission tariffs are updated annually.

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[87] TERNA (2017): *Annual report.*

[88] Based on allowed revenues for Enel for 2016 (*Preliminary assessment of effect on Enel Group of new 2016-2023 regulatory period for distribution in Italy).* For the remaining DSOs, we assumed allowed revenues are proportional to their share of the market.

## Legislation and methodology for setting network charges

The relevant legislation for determining UoS charges in Italy includes:

- The regulatory determination for the latest regulatory period (2016-2019) as amended by ARERA's annual regulatory decisions.[89]
- ARERA decision on the network tariff reform for domestic consumers[90]

Italy provides an example of a jurisdiction that has moved towards a greater reliance on capacity charges for the recovery of network costs, as discussed in the text box below.

**Box B.6.1: Recent reforms to tariff structure**

Italy has recently moved towards a larger share of distribution costs being attributed to fixed and capacity tariff components (in the past most of the costs were recovered through the volumetric charge). The tariff structure is seen to be broadly in line with efficient charging principles – i.e. recovering (most) fixed costs through fixed and capacity charges. The tariff structure has been supported by the widespread availability of smart meters in Italy.

In December 2015, the Italian Regulatory Authority for Electricity Gas and Water (AEEGSI) adopted its final decision on the fifth electricity transmission and distribution price control review (for the period 2016-2018). Following this decision, the capacity component of the tariff tripled and the fixed component for households increased by 66%.

### B.6.3. Charging design

The transmission and distribution charging structure in Italy is described in the text box below. Generation does not pay transmission tariffs in Italy, so all costs are recovered from load. All distribution connected users except households are charged separate tariffs covering the cost of the transmission and distribution networks.

**Box B.6.2: Charging structure**

The following voltage levels are defined in the Italian charging structure:

- Extra High Voltage (EHV) refers to a voltage level greater than or equal to 220 kV;
- High Voltage (HV) refers to a voltage level of between 35 kV and 220 kV;
- Medium Voltage (MV) refers to a voltage level greater than 1 kV and lower than or equal to 35 kV;
- Low Voltage (LV) refers to a voltage level lower than or equal to 1kV.

From 2016, Italy adopted a new **transmission tariff** structure. The tariff for all final users but households is differentiated by class:

- A two-part tariff (capacity and energy) was introduced for HV and EHV users only:
    a. a capacity component - TRASp (€cents/kW); and

[89] ARERA (2016): *Testo Integrato delle Disposizioni per l'erogazione dei servizi di trasmissione e distribuzione dell'energia elettrica (TIT).*

[90] ARERA (2015): *Deliberazione 582/2015/R/EEL.*

b. an energy component - TRASe (€cents/kWh);

- LV and MV users are charged a single part volumetric tariff TRASe (€cents/kWh)
- A two-part tariff (capacity and energy) is also charged for electricity injected and withdrawn (included losses) from the transmission network by DSOs.

For households, transmission costs are included in the distribution tariff paid by households.

The **electricity distribution** grid tariff for LV and MV consumers consists of three components:

- a fixed component (€/point of delivery);
- a capacity component (€/kW); and
- a volumetric component (€/kWh).

For network users connected at the HV level, the distribution tariff consists of a fixed component and an energy component while for users connected at the EHV level, there is only a fixed tariff component.

For non-domestic users connected at the LV and MV levels, the tariff levels vary depending on the user's contracted capacity.

The tariff structure is considered to be cost-reflective. The fixed charge (€/point of delivery) covers the customer related costs. The capacity charge and variable charge cover the cost of the network.

Until recently a progressive volumetric tariff was applied for households with higher volumetric unit charges applied at higher levels of consumption. This was a departure from the 'ideal' cost reflective tariff to reflect equity concerns about the impact of allocating network costs in a cost-reflective way to lower-income households (i.e. households with low levels of electricity consumption).

There are no time-of-use or locational elements to network charges. As previously mentioned, distribution charges are uniform across all DSOs.

### Non-network costs included in UoS tariffs

There are separate charges for reactive power, balancing costs and policy support costs such as support for renewable energy and cogeneration. There are also separate charges to cover metering costs.

### Connection costs

The connection regime in Italy is shallow with network reinforcements socialised through UoS charges.

### Discounts on network charges

As far as we are aware, there are no discounts for specific categories of network users in Italy.

### B.6.4. Tariff impacts

According to analysis by the Italian regulator, network charges account for around 18% of the total retail energy price faced by a typical domestic energy consumer.[91]

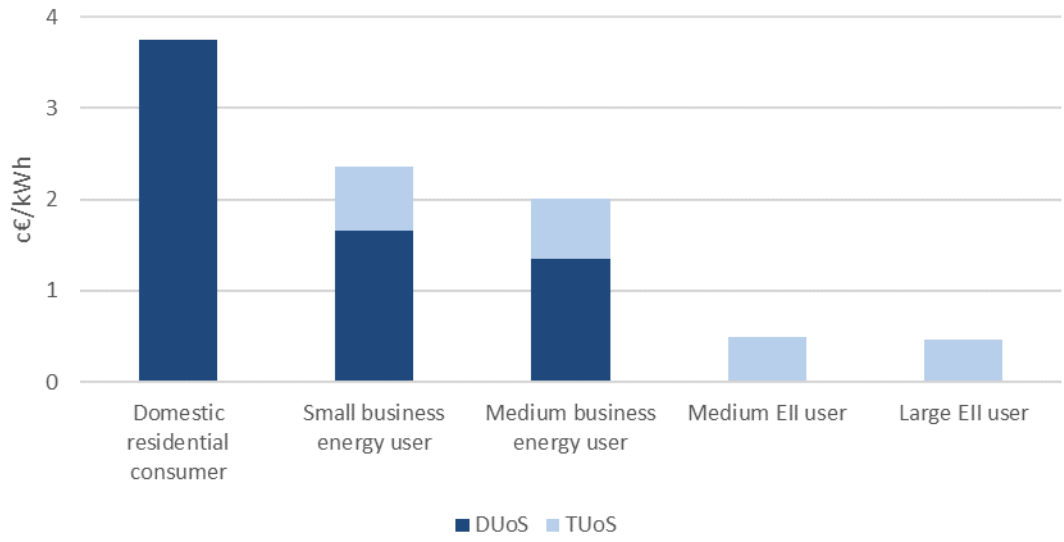
We have estimated the impact of UoS charges on electricity prices, in cents per kWh, for each customer profile, based on 2018 published network tariffs, The tariff impacts are estimated based on energy, capacity

[91] https://www.arera.it/it/dati/ees5.htm

and fixed charges. We have excluded from our calculation other tariffs such as metering charges and reactive power.

For non-domestic network users, we have considered the TRASe and TRASp (where applicable) plus the three-part distribution tariffs for non-domestic users connected at distribution level. For domestic users, we have applied the single, combined transmission and distribution tariff. Figure 28 below shows the share of UoS charges attributed to distribution and transmission tariffs.

*Figure 28: DUoS/TUoS charges in Italy by consumer profile, c€/kWh*

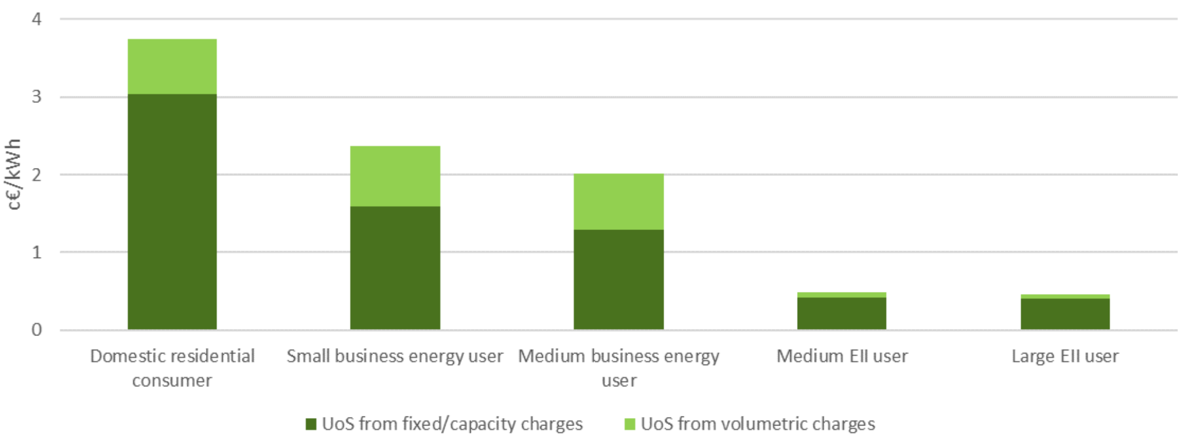



*Source: CEPA analysis*

The share of distribution tariffs of the overall UoS charge declines for larger consumers connected at higher network levels. For domestic consumers the split cannot be determined due to the combined distribution and transmission tariff that is charged to this group.

Figure 29 below shows the tariff impact for each consumer broken down by fixed or capacity-based tariffs and volumetric tariffs.

*Figure 29: UoS charge components in Italy by consumer profile, c€/kWh*




*Source: CEPA analysis*

Most of the network charges in Italy are collected through fixed/capacity charges for all consumer groups as a result of the charging reforms introduced. Residential consumers pay an estimated c€3.75/kWh in network charges. Network charges, per kWh consumed, decrease for larger consumers connected at higher voltage levels.

### B.6.5. Sources


AF-Mercados, REF-E & Indra (2015): *Study on tariff design for distribution systems*, report commissioned by DG Energy, final report.

ARERA (2016): *Testo Integrato delle Disposizioni per l'erogazione dei servizi di trasmissione e distribuzione dell'energia elettrica (TIT)*, https://www.arera.it/allegati/docs/16/782-16tit_agg.pdf.

ARERA (2015): *Deliberazione 582/2015/R/EEL* https://www.arera.it/allegati/docs/15/582-15.pdf.

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TERNA (2017): *Annual report*, http://download.terna.it/terna/0000/1042/46.PDF.

## B.7. NORWAY

### B.7.1. Overview

The Norwegian electricity grid includes three separate administrative levels: the transmission grid, the regional grid, and the distribution grid. The regional grid is classified as distribution under the rules set out in the EC Electricity Directive (2009/72/EC).

The distinction between the regional and transmission grid is based on the overall functionality of network components as well as the voltage level. 132 kV assets may be part of the regional grid in some areas and the transmission grid in other areas, particularly areas where 132 kV is the highest voltage level. There are around 2.9 million customers in the distribution grid.

Statnett is the designated Transmission System Operator (TSO). Statnett is in the process of purchasing the remaining transmission assets and is responsible for setting the transmission tariffs based on the total revenue caps of the network companies owning transmission assets (i.e. Statnett leases the assets the company does not yet own). The table below gives an overview of the grid structure and ownership as of 2016.

*Table 19: Overview of Norwegian electricity network structure*

| Grid level/ voltage level | Grid companies | Ownership | Book value of grid assets (end of 2016) | Annual network costs |
|---|---|---|---|---|
| **Transmission grid, 132-420 kV** | Statnett (>95%), 17 regional grid companies | Norwegian State (Statnett), and municipalities | €3.1 billion | €0.7 billion |
| **Regional grid, 33-132 kV** | 78 | Mainly municipal, but some private and indirect state ownership through Statkraft | €1.7 billion | €0.3 billion |
| **Distribution grid, 0-22 kV** | 119 | Mainly municipal, but some private and indirect state ownership through Statkraft | €4.4 billion | €1.3 billion |

Source: Norwegian Water Resources and Energy Directorate, Europower.com, THEMA analysis

Around 80 TWh of electricity are delivered to end-users in the distribution grid annually. In 2016, 17 TWh were delivered to end-users in the regional grid and 76 TWh to underlying distribution grids (there is some feed-in from small-scale hydro in the distribution grid). In the transmission grid, 20-30 TWh are delivered to end-users in power intensive industries and the petroleum sector, while around 70-75 TWh are typically fed into the transmission grid from connected generators. Most of the remaining generation (typically 60-70 TWh) is fed into the regional grids. Net deliveries from the transmission grid to the regional grids are in the region of 40-50 TWh. Note that due to hydrological conditions nationally and regionally energy transport levels at the higher grid levels can vary significantly on an annual basis.

Total annual network costs have been in the region of €1.6 billion annually in recent years (distribution and regional grids), plus around €700 million for the transmission grid. Consumption taxes on electricity and financing of the Energy Fund (a support mechanism for energy efficiency and innovative renewables) are collected by the DNOs and come in addition to these allowed revenues.

### B.7.2. Tariff setting process

#### Responsibility for setting charges

The tariffs are set by the network companies subject to the total cap on revenues. The tariffs are set by each network operator within its grid area and can only be differentiated between customers according to objective and non-discriminatory criteria.

#### Legislation and methodology for setting network charges

Network companies are, to some extent, free to design the tariffs they set for their customers within a set of principles determined by NVE (Norwegian Water Resources and Energy Directorate) through secondary legislation described in more detail below. For example, the network companies individually decide how to distribute their allowed income between the fixed and energy component in the tariff. The chosen design affects the price per kWh.

While the companies have significant freedom with respect to tariff design, the basic structure is similar across all companies in the distribution grid with a fixed charge per meter, an energy charge per kWh consumed and for some customers also a capacity charge per kW (see more detailed description below). The basis for the capacity charge can however vary in the current model (e.g. either based on installed capacity, maximum use at specific times or as an average of reference hours etc.).

The high-level tariff principles are set out in the Energy Act and the Energy Act Regulation, while the detailed principles are set out by NVE in the Control Regulation ("Regulation on economic and technical reporting, revenue cap for the network activities and tariffs").

The main rationale behind the tariff methodology has been economic efficiency, which is the stated objective of the Energy Act.

#### Review of network charges

Statnett's transmission tariffs are updated annually subject to approval by the company's board. The tariffs can in principle be changed at any time given a "reasonable" notification period to the customers and information to NVE within a week after the change has been implemented. In practice the network operators set tariffs for a year at a time.

### B.7.3. Charging design

#### B.7.3.1. General principles

The objectives of the regulatory framework for tariffs are established in the Energy Act. The tariffs should contribute to efficient use and development of the network. They should ensure access to the energy market for all customers in a non-discriminatory way. The network companies are obliged to offer all customers a non-discriminatory service with objective tariffs and terms. The tariff can only be differentiated according to grid-related criteria. Examples of grid-related criteria include energy consumed and capacity (installed or actual use).

The main principles for setting the tariffs can be summarised as follows:

- Tariffs related to grid use should consist of energy charges and capacity charges. Energy charges should as a main rule reflect the marginal cost of losses. An exemption is made for small end-users in the distribution grid without hourly metering. A capacity charge can be used to balance demand for grid capacity and available capacity (in practice this is not used in the regional or distribution grids, and in the transmission grid through bidding zones).

- Customers in the distribution grid who are not subject to a capacity charge should pay both an energy charge and a fixed charge. The energy charge should as a minimum cover the marginal cost of losses and can be used to recover a share of other costs that are not recovered through the fixed charge. The fixed charge should cover customer-specific costs (administration, metering, billing etc.) and a share of other fixed network costs.
- For customers in the distribution grid subject to a capacity charge the energy charge should as a minimum cover the marginal cost of losses. The capacity charge should be based on actual capacity use in defined periods. This has historically applied to end-users with an annual expected consumption above 100 000 kWh. For these customers hourly metering is mandatory.
- Customers in the regional and transmission grid should pay an energy charge that reflects the marginal cost of losses. Capacity-based charges should be calculated on the basis of the actual load per customer in defined reference hours that to the largest possible extent should not be foreseeable for the customers. A minimum load base can be set, and several metering values can be used.

There is no ex ante distribution of costs between customer groups, nor between generation and demand. In recent years the fixed charges for generation have been set at the maximum allowed for Norway in the EC Regulation 838/2010, €1.2/MWh. There are also no provisions for special consumer groups, although power intensive industries connected to the transmission grid has been given significant tariff discounts according to grid-related criteria (described below). In 2018, large consumers paid around 6% of the total costs in the transmission grid (minus revenues from energy charges, congestion revenues and connection charges). Generation paid 25% and ordinary consumption (i.e. underlying regional grids) paid around 70%.

Details on the types of charges are given in the text box below.

**Box B.7.1.: Charging structure**

In the transmission grid, stability of consumption (hourly and seasonal), load factor and co-location of consumption and generation are used to differentiate either the tariff itself or the charging base in kW. Another example is the time of use, which forms the basis to categorise customers between households, holiday homes and industry. Price sensitivity of demand is on the other hand not considered to be a grid-related criterion.

Network companies can impose a larger tariff on holiday homes than households. The reason is that holiday homes contribute to a lesser extent to cover the fixed costs of the network company through the energy component, even if they impose equal costs on the network.

The tariff consists of a fixed component and an energy component depending on the use of electricity. The fixed component includes a fixed annual amount per customer and a load or capacity component.

## Energy charges

The energy charge reflects the marginal cost on the network of the customers use of electricity. The source of the costs is energy loss happening when electricity is transported within the network.

In the transmission network, the energy charge is calculated per node. The nodal charges reflect the marginal cost of losses and should contribute to an efficient use and development of the grid. The charge is positive or negative per kWh of generation or consumption, based on load flow forecasts updated weekly. The charge can amount to up to +/- 15% x Nord Pool area price and is differentiated between weekday and time of day.

No requirement is currently imposed on having nodal charges for consumers in the distribution network. Here, the loss percent and the energy charge are the same for all customers in the area of the network company. Network companies are obliged to offer seasonally differentiated (higher in winter) charges to customers with expected consumption above 8000 kWh per year.

The energy charge for customers without smart metering can be above the cost of marginal losses to cover a part of the fixed costs in the network, which has also been used by practically all network companies historically.

The energy component is measured in øre/kWh.

### Fixed charges

The fixed charge covers the fixed costs of the network company and ensures a reasonable profit of investments in the network. The charge is a defined yearly amount per customer. The charge should be neutral and should to the least possible extent affect the running production and consumption.

All customers pay the fixed charge. It covers customer specific costs in addition to a part of the other costs related to the network. The network companies divide their customers into groups who they offer different tariffs based on objective and grid-related criteria. In practice the fixed charges only apply to customers in the regional and distribution grids.

The fixed component is measured annually in NOK/customer.

### Capacity charges

The load component is optional for the network companies to impose on customers without hourly metering. Historically, a load component has been mandatory for end-users with expected annual consumption above 100 000 kWh as hourly metering has been mandatory for these customers. The load charges are calculated based on the customers use of load in defined periods of time.

Network companies where the smart meter rollout is completed have tended to introduce load charges for all customers. It can both be based on average load measured at different times or maximum load per month or year within the current regulation.

As with the fixed component, this charge should also be neutral in the sense that it should to the least possible extent affect consumption.

The charging base can vary between DNOs. Some use fuse size (installed capacity), while others use monthly peaks or different averages.

All customers in the low voltage grid (below 1 kV) pay the same price for load up to the first threshold and lower prices per kW at higher thresholds (so that the average price per kW declines).

In the transmission grid, the charging base for capacity charges is the **maximum consumption at system peak** (5-year average) adjusted for a so-called k-factor per node. The k factor is a measure of the balance between generation (available winter capacity. i.e. a derated capacity measure) and maximum capacity use in each node. The k factor can give a maximum of 40% reduction in the charging base and applies to consumption only, not generation (a maximum of 50% reduction applied until the end of 2018):

$$k = \frac{Avg.\,5year\ total\ capacity\ use\ of\ all\ customers\ at\ the\ node\ at\ system\ peak}{Available\ winter\ capacity + Avg.\,5year\ total\ capacity\ use\ of\ all\ customers\ at\ node\ at\ system\ peak}$$

E.g. if the measured consumption in a node is 100 MW and the available winter capacity is 150 MW, the k factor is calculated as 100 / (100 + 150) = 0.4, which is then adjusted to 0.6 to account for the maximum reduction of 40 per cent. The charging base for consumers in the node is then 60 MW instead of 100.

Statnett is currently considering replacing the nodal adjustment with a factor that reflects the capacity balance at area level (where the definition of an area is also an item for discussion) as outlined in the company's consultation document on the future transmission tariff model from January 2018.

The load component is measured in NOK/kW.

### Potential upcoming reforms

The regulatory authority NVE has had several consultations in recent years on the future tariff model for the distribution grid following the rollout of smart metering that is due to be completed in 2019. Key elements considered include limitation of energy-based charges to the marginal cost of losses, and the introduction of mandatory capacity-based charges for all costumers (previously only mandatory for large consumers above 100 MWh expected annual consumption). The rationale for the proposed changes includes shifting to a more cost-reflective design that can result in better network utilisation and development. Following negative responses from both utilities and consumer organisations, a new consultation on capacity-based charges is expected in Q1 2019. Statnett is also considering several elements of the future transmission tariff model, including the model for discounts to large users and the use of locational signals in the fixed charges payable by consumers and generators.

There is also an ongoing political debate on harmonisation of network tariffs between grid areas. This will not affect the revenues of the companies but will mean redistribution of tariff revenues between companies. This will provide lower tariffs for customers in the relatively expensive grid areas, typically rural districts. In previous years a harmonisation scheme has been financed via the state budget, but this is currently not in use.

## Total charging base

The charging base includes all network costs including the cost of losses and any costs related to ancillary services, balancing and reactive power. The latter amounts to €50-60 million in recent years according to Statnett's accounts. The cost of losses in the transmission grid is around €60-70 million annually. In the regional grid, 2017 cost of losses was around €70 million and in the distribution grid €100 million. The costs of ancillary services, balancing and reactive power is close to zero in the regional grid and zero in the distribution grid. The latter costs should be considered in light of the fact that Statnett has the responsibility for balancing the regional grid as well as the transmission grid.

Assets financed by connection charges and other third-party financing are not included in the regulatory asset base.

## Connection costs

Connection charges have historically been shallow and mainly used in the distribution grid for customer-specific investments. Network companies have been largely free to use connection charges at their discretion.

From 2019 the following rules will apply, moving the model towards a deep and mandatory regime:

- Connection charges will be mandatory at all grid levels.
- The charges should include all investment costs triggered by the increased consumption or generation, reduced by 0.5, for network assets with several grid users the costs are divided according to the required capacity increase by the customer divided by the total capacity increase.

- The reduction factor does not apply for customer-specific investments,
- Customers <1 MW are exempted from the requirement to pay for investments in the meshed grid, but will still have to cover customer-specific investments.
- The cost base can be reduced in special circumstances.
- Network companies can charge for grid studies.

The move to deeper connection charges in the regional and transmission grids is motivated by the regulator's stated intent to strengthen the locational signals for network investments.[92] This should be viewed in light of the large network investment plans in the coming years at all grid levels, partly driven by growth in renewables (wind power and small-scale hydro) and the increasing interest for connections from new consumers (e.g. electrification of petroleum sector facilities onshore and offshore, data centres, new power-intensive industries).

### Discounts on network charges

In the transmission grid, reductions in the capacity tariff level are available for users to reflect certain network stability factors (load factor, seasonal and hourly variation in consumption). Users that benefit from these discounts are typically large consumers, and the discount can be up to 75 per cent on the capacity charge rate (up to 90 per cent until the end of 2018).[93] Specifically, the tariff discount is calculated according to the following parameters:

- Load factor (discount for users with high load duration):

  Customer's annual consumption (MWh) / Customer's peak load (MW)
  5000 hours as minimum, maximum of 50% discount applied at 8760 hours of consumption (linear interpolation)

- Hourly variation (discount for users with stable consumption profiles across the day):

  Average absolute value of hourly change (MW) / Customer's peak load (MW)
  1.8% as maximum for qualifying for the discount, zero variation (i.e. stable demand) gives 15% reduction (linear interpolation)

- Summer consumption (discount for users with stable load over the summer period):

  Average consumption per hour in June, July, August (MW) / Average consumption per hour rest of the year (MW)
  Minimum value of 80% to qualify for discount, 100% or more gives a 25% discount (linear interpolation)

- Total maximum discount available is 75% (theoretically the individual parameters sum to 90%, but from 2019 the cap is set at 75%)
- Peak load defined as the 95% highest hour in the calendar year.

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[92] The consultation document published by NVE (in Norwegian only) can be found at: http://publikasjoner.nve.no/hoeringsdokument/2018/hoeringsdokument2018_06.pdf

[93] These discounts are customer-specific, and they apply only to individual consumers connected directly to the transmission grid. Regional grids do not qualify even though their aggregate consumption may meet the stability criteria.

The approach to discounting network charges is not explicitly mandated in any regulatory documents but has been approved by the TSO's board. The discounts for network stability were based on estimates by the TSO of system operation costs and investment savings due to different stability indicators. However, a consultancy report commissioned by Statnett in 2017 argued that the stability discount should be significantly lower, perhaps only in the region of 20% of the 2017 level. As a consequence, Statnett has reduced the maximum discount from 90 to 75% from 2019 and have indicated that the discount should be reduced further.

In 2018 Statnett proposed to replace part of the stability discount with a differentiation mechanism based on price sensitivity (as measured by energy intensity and exposure to international competition).[94] However, this has not been implemented and the principle has historically been opposed by regulators on the grounds that it does not meet the criterion for tariff differentiation based on grid-related factors.

Customers on contracts for interruptible consumption get a discount of up to 95 per cent on the capacity charge depending on notification time and the duration of the interruption.

### B.7.4. **Tariff impacts**

Based on 2019 published network tariffs, we have estimated the impact of UoS charges on electricity prices, in cents per kWh, for each customer profile.[95] The tariff impacts are estimated based on energy, capacity and fixed charges applied to network users in Norway. We have excluded from our calculation other tariff components such as the reactive energy and exceeded capacity.

The UoS charges include some non-UoS network costs such system operation. For transmission tariffs, we have excluded the energy charge from our calculation because this only recovers the cost of network losses. For distribution charges, we have included in our calculations the energy charge that recovers both the cost of network losses and a share of other network costs.

We present tariff impacts for two Norwegian DSOs, Hafslund and Agder Energi. These are two of the largest DSOs in Norway (covering about a third of the total system) and have fairly representative tariff structures. Since distribution tariffs differ between DSOs, impacts might be different between DSOs.

To estimate these tariff impacts, we have also made the following assumptions:

- Maximum discount 75% on volume drivers for users connected to the transmission level.
- Where tariffs required assumptions about consumption profiles during different periods of the day and the year, we used the available information on GB usage to map consumption for the corresponding tariff periods in Norway.
- In the transmission grid, the charging base for capacity charges is adjusted for the k-factor per node as discussed above. The k-factor can give up to a 40% reduction in the charging base. We present minimum and maximum values of Norwegian UoS charges for comparison below, applying a maximum k-factor reduction and no reduction.

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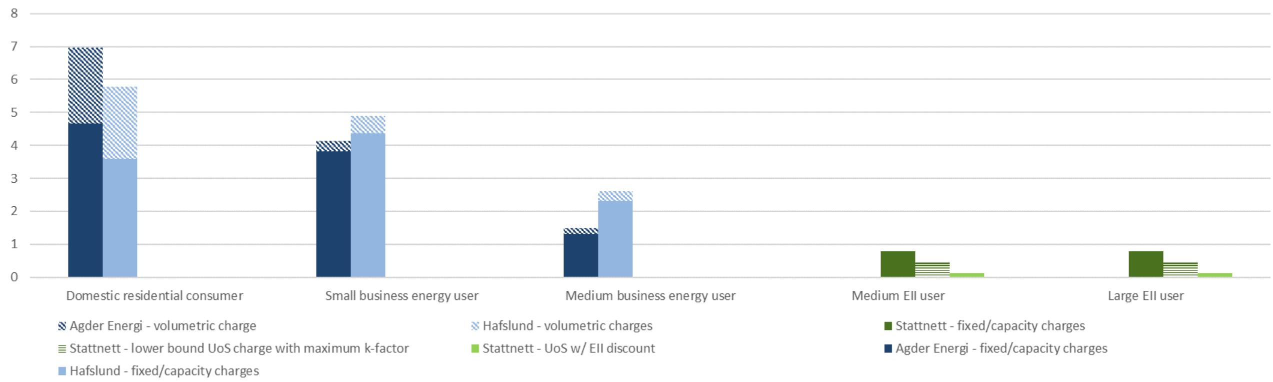
[94] The Statnett consultation can be found here, in Norwegian only: https://www.statnett.no/globalassets/om-statnett/nyheter-og-pressemeldinger/nyhetsarkiv-2018/rapport-statnett---forslag-til-tariffmodell-fra-2019---horingsversjon.pdf

[95] Tariff data denoted in Norwegian krone (NOK) was converted into Euros based on the ECB reference exchange rate in mid-February 2019.

Figure 30: UoS charge components in Norway by consumer profile, c€/kWh




*Source: CEPA analysis*

Most of the network charges in Norway are collected through capacity/fixed charges. Despite the different level of charges between the two DSOs Agder Energi and Hafslund, the share of capacity/fixed charges compared to volumetric charges is very similar. Network charges, per kWh consumed, decrease with the size of the customer because larger customers do not need to contribute to the cost of lower network levels. For the medium and large EII users, UoS charges are recovered from capacity charge only because the energy charge for these consumers covers only the cost of network losses.

For our medium EII and large EII users, the impacts are shown both with and without discounts and with and without a k-factor adjustment. Without any discounts on UoS charges and no k-factor adjustment, a large EII user can be expected to face UoS charges of around c€0.80/kWh. If a maximum k-factor adjustment of 40% is applied, this charge is reduced to around c€0.48/kWh. Assuming the full possible discounts of 75% of the capacity charge rate, UoS charges are likely to add just c€0.12/kWh to the electricity price for a large EII user.

### B.7.5. **Sources**

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NVE (2018): *National Report 2018*, report to CEER, http://publikasjoner.nve.no/rapport/2018/rapport2018_74.pdf

Statnett: *Transmission grid tariffs for 2019*, https://www.statnett.no/globalassets/for-aktorer-i-kraftsystemet/tariff/2019-tariff-booklet.pdf

## B.8. SWEDEN

### B.8.1. Overview

The Swedish electricity grid consists of three administrative levels: the transmission grid, the regional grid and the distribution grid. As in Norway, the regional grid is classified as distribution under the rules set out in the EC Electricity Directive (2009/72/EC).

The TSO Svenska kraftnät is the only company allowed to own transmission assets.

*Table 20: Overview of Swedish electricity network structure*

| Grid level/ voltage level | Grid companies | Ownership | Book value of grid assets (end of 2017) | Annual network costs** |
|---|---|---|---|---|
| **Transmission grid, 220-420 kV** | Svenska kraftnät | Swedish state | €2.2 billion | €0.8 billion |
| **Regional grid, 30-130 kV** | 6 regional grid owners, 14 single line owners, 1 interconnector* | Municipal, state and private | €2.7 billion | €0.7 billion |
| **Distribution grid, 0-24 kV** | Approx. 160 grid owners | Municipal, state and private | €10.3 billion | €2.6 billion |

Source: Swedish Energy Markets Inspectorate, THEMA analysis. *The interconnector Baltic Cable has a voltage level of 450 kV but is classified as a regional grid in the regulatory reporting. **Annual average based on total revenue cap set for the period 2016-2019 for Svenska kraftnät. Estimate based on total network income minus costs of overlying grid in regional and distribution grids from regulatory accounts 2017. Does not include Baltic Cable.

Total energy fed into the transmission grid was 122 TWh in 2017, while energy delivered to end-users in the distribution grid was 94 TWh. There are no end-users connected to the transmission grid in Sweden, only regional grids and large generators. Local generation in the distribution grid amounted to around 11 TWh in 2017. Total energy transported in the regional grid amounted to 130 TWh excluding losses. The energy transport in the regional grid includes direct consumption from large consumers and delivered energy to underlying distribution grids, plus some transit in the transmission grid.

### B.8.2. Tariff setting process

#### Responsibility for setting charges

The network companies are responsible for setting the charges in their respective grids. This applies to all grid levels. The regulatory authority does not approve individual charges but can carry out tariff reviews to ensure that the tariffs meet the criteria set out in the legislation. Hence the tariff principles used in practice are to a large extent founded in case law and individual decisions by the regulator. This is a legacy of the traditional light-handed ex post-approach to both tariff and revenue regulation in Sweden.

#### Legislation and methodology for setting network charges

The objectives of the regulatory framework for tariffs are established in the Swedish Electricity Act and the supporting Electricity Regulation. The tariffs should contribute to efficient use and development of the network and ensure that all customers get access to the energy market in a non-discriminatory way. The network companies are obliged to offer all customers a non-discriminatory service with objective tariffs and terms.

Amendments to the Electricity Regulation (2013:208, amended through 2018:585) in 2018 authorise the regulatory authority, the Swedish Energy Markets Inspectorate (Ei), to implement regulations on principles for network tariffs to promote efficient use of the grid. Ei has set tariff principles on its working agenda but is yet to publish any proposals. An internal project is due to be launched in 2019. The TSO Svenska kraftnät is currently carrying out a tariff review which may result in proposals for changes. Any proposals are however unlikely before late 2019 at the earliest. In recent years, there have also been studies by the regulator on topics such as tariff harmonisation between urban and rural areas and the impact of tariffs on incentives for demand flexibility and energy efficiency.

### Review of network charges

Tariffs in the transmission grid are set annually. In the distribution and regional grid we also understand that it is customary to adjust charges annually, although the timing within the year may vary.

## B.8.3. Charging design

In the transmission grid, it has been a stated aim of Svenska kraftnät to increase the share of costs paid by generators in recent years. The current generator share is 38% of total transmission load-based charges, up from 20-25% a few years ago. The EU Regulation 838/2010 will however limit the absolute tariff increase for generation as Svenska kraftnät's revenue cap is expected to increase significantly in the near future due to high investments. Hence further increases in the share of costs paid by generators risks violating the limit of €1.2/MWh for Sweden that is defined in Regulation 838/201. There are no ex ante constraints on tariff levels for demand customer groups.

**Box B.8.1.: Charging structure**

The charging structure varies by voltage level of connection and fuse size. It includes:

- energy and capacity charges at the transmission level;
- fixed, energy and capacity charges at the regional grid level;
- at the distribution level, domestic consumers (fuse size 63A and lower) pay energy charges and fixed charges. Large consumers pay a fixed charge, energy charge and load charge.

Capacity charges are based on contracted capacity in the transmission level. In the regional and distribution level, capacity charges can be based on either contracted capacity or peak measured demand during a specified period. It is also possible to subscribe for extra capacity for shorter periods. Consumption in excess of subscribed capacity is subject to charges levied at higher rates.

At the transmission level, nodal rates apply for both energy and capacity charges. Regional and distribution tariffs can vary between network operator, although tariffs are uniform within a network operator's area. Tariffs in the distribution network vary by voltage level and type of contract.

There are no time-of-use tariffs in the transmission network. In the regional grid, peak capacity charges and time-differentiated energy charges can apply. Peak periods in this case are defined ex ante. In the distribution grid, smaller domestic consumers may choose a time-differentiated energy charge.

### Non-network costs included in UoS tariffs

Balancing costs and reactive power are covered by the tariffs. Cost of network losses amounts to around €100 million in Svenska kraftnät's accounts for 2017. The cost of losses is approximately the same in the distribution grid according to the regulatory accounts for 2017 and around half (€50 million) in the regional grid. Redispatch and transit costs are around €10 million in 2017 in the transmission grid. Costs of ancillary services were estimated at around €25 million annually in Ei's revenue cap decision for Svenska kraftnät 2016-2019.

The energy consumption tax is also collected by the network companies. In addition, network companies are obliged to collect a so-called electricity safety, grid monitoring and contingency planning tax. The latter amounts to 57.50 SEK/year for low voltage customers (<1 kV) and 3 797 SEK/year for high voltage customers.

### Connection costs

For transmission, connection costs are as a general rule covered through the connection charge. The connection charges are deep in principle, but it is not clear to what extent deep connection charges are actually used in practice. In the distribution grid a shallow connection charge is applied. Connection charges are also used in the regional grids. We have not found any publicly available information on the depth of the regional connection charges.

### Discounts on network charges

We are not aware of any discounts offered to specific user groups. Discounts can be offered on use of system charges in the regional and distribution grids for interruptible consumption. In the transmission grid such discounts are not used.

### B.8.4. Tariff impacts

Based on 2019 published network tariffs, we have estimated the impact of UoS charges on electricity prices, in cents per kWh, for each customer profile.[96] The tariff impacts are estimated based on energy, capacity and fixed charges applied to network users in Sweden. We have excluded from our calculation other tariff components such as reactive energy, capacity exceedance and temporary subscription charges as well as the costs of network losses for transmission connected consumers. We also excluded contingency planning, electric safety and grid monitoring fees.

To estimate these tariff impacts, we have also made the following assumptions:

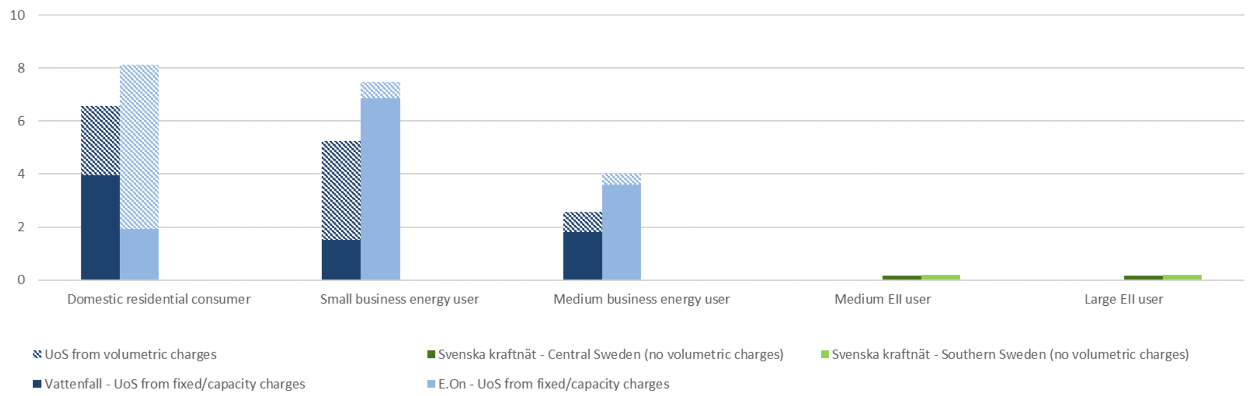
- For all consumer types, we chose the tariff which required fewest assumptions to be made. For residential consumers for example, we have applied the tariff with no time-of-use differentiation for energy charges.
- We assumed medium and large EII users to be connected to the EHV transmission grid in accordance with their voltage level of connection. This is to be consistent with the assumptions made for this customer class in GB. In practice no consumers are directly connected to the transmission network in Sweden apart from generators and regional grids.
- We have further assumed that medium business users are connected to the regional high voltage grid rather than the distribution grid.

[96] Tariff data denoted in Swedish krona (SEK) was converted into Euros based on the ECB euro reference exchange rate in mid-February 2019.

- For residential consumers we assume consumers live in an apartment complex rather than a house, for which a higher fixed charge would apply.
- We show distribution tariff data for two of the largest Swedish DSOs, E.ON and Vattenfall. Distribution tariffs differ across DSOs and tariff impacts might thus be different depending on the DSO.
- For consumers connected at the transmission level, different tariffs apply at each node on the system. We have calculated an average tariff based on two price zones: Southern Sweden and Central Sweden 2. Average charges are higher in the latter zone, which results in higher per kWh charges for consumers. The remaining two price zones Central Sweden 1 and Northern Sweden have lower capacity charges than the price zones displayed above.

Figure 31 below shows the tariff impact for each consumer broken down by fixed or capacity-based tariffs and volumetric tariffs. As network users in Sweden pay a single combined transmission and distribution tariff, it is not possible to present a breakdown between transmission and distribution charges.

Figure 31: UoS charge components in Sweden by consumer profile, c€/kWh




*Source: CEPA analysis*

For non-residential consumers in Sweden, network charges are mainly collected through fixed/capacity charges. Small business energy users of Vattenfall constitute an exception, where volumetric charges account for more than 70% of total UoS charges.  Domestic consumers pay only fixed and volumetric charges. UoS charges for Central Sweden are slightly lower than for Southern Sweden, amounting to c€0.18/kWh. Network charges, per kWh consumed, decrease with the size of the customer as we observed for most of the other countries studied.

### B.8.5. **Sources**

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## B.9. REPUBLIC OF IRELAND

### B.9.1. Overview

The Republic of Ireland has a single TSO – EirGrid Plc. and a single DSO – ESB Networks Ltd.

Both companies are owned by the Irish Government and regulated by the Commission for Regulation of Utilities (CRU). EirGrid took over operation of the national power system from ESB in 2006, though ESB still owns the physical transmission assets.

The allowed revenues for 2019 are €547m for the TSO (including amounts accruing to ESB as the transmission asset owner) and €850m for the DSO (2018 € per year), leading to average network costs of around 21€/MWh for the transmission network, and 33€/MWh for the distribution network.[97]

The TSO covers voltage lines from 110kV upwards (110, 220, 400kV), and the DSO covers voltage lines from 38kV and below (38, 20, 10kV).

We are not aware of any current network charging developments, but note that CRU *"expects to engage with ESB Networks regarding DUoS tariff structures in early 2019"*.[98]

### B.9.2. Tariff setting process

#### Responsibility for setting charges

EirGrid and ESB are responsible for setting and publishing UoS charges annually, which are subject to the regulator's approval. Generator TUoS charges are set jointly by EirGrid and SONI at the all-Ireland level, which are then approved by the SEM Committee (including CRU and the Northern Ireland Utility Regulator).

#### Legislation and methodology for setting network charges

CRU is charged with approving the form and basis of charges to be applied for the connection to and use of the transmission and distribution system under the Electricity Regulation Act 1999. Although CRU approves UoS charges, the tariff calculations are effectively left to the network companies. Neither company publishes its charging models or an up-to-date written methodology. The closest thing to a charging methodology in the public domain is a 2003 review of tariff structures by CRU.[99] The review set out guiding principles including cost-reflectivity, incentivising efficiency, non-discrimination, and preventing cross-subsidisation.

Although the Irish Government is not normally involved in setting charges, it intervened in 2009 by directing the regulator to "rebalance" network charges by reducing the amount paid by large energy users.

[97] These numbers are based on values of electricity consumed sourced from Eurostat.

[98] https://www.cru.ie/wp-content/uploads/2018/08/CRU18146-Electricity-Distributioution-Tariffs-2018-2019-DLAF.pdf

[99] https://www.cru.ie/wp-content/uploads/2003/07/cer03298.pdf

**Box B.9.2: "Rebalancing" in favour of large energy users**

In 2009, the Irish Government directed CRU to rebalance network tariffs in favour of Large Energy Users (LEUs), effective from 1 October 2010.[100] CRU was directed to reduce tariffs for LEUs by €50m per annum, which should be collected from domestic users instead. It was for CRU to determine the details of how exactly this would be implemented. The rebalancing replaced a temporary rebate introduced in October 2009 to protect LEUs from network charge increases.

CRU arranged for ESB to add the €50m to domestic DUoS tariffs – initially recovered through a €10 addition to the fixed charge and a c.14% increase to unit charges – while DUoS and TUoS charges for LEUs were both reduced by 45%. An annual transfer from ESB to EirGrid would ensure that both still recovered their revenue allowances.

The rationale for the rebalancing was recorded in CRU publications, which noted the Government's *"continuing concern about the impact of energy prices on LEUs, who contribute so substantially to employment"*, and that it had *"made it clear that industry competitiveness must be facilitated as much as possible in relation to energy costs"*. [101]

The following extract from a 2015 speech by the Irish Minister for Energy is also revealing:[102]

*"In 2008, energy prices for large energy users were more than 40% above the Eurozone average. That had fallen to 3-6% in the first half of 2014. This Eurostat data also shows that Irish electricity prices for large energy users are below those in the UK. These are significant achievements which have improved our competitiveness very considerably."*

This action arguably contravened the guiding principles set by the CRU in its 2003 note on network charging, which include preventing *"cross subsidisation between and within different customer categories in the market"*.[103]

### B.9.3. Charging design

**DUoS charges** in the Republic of Ireland follow a similar structure to GB, with similar tariff groups, voltage levels, and charge structures:

- Energy charge per kWh
- Fixed charge per MPAN
- Capacity charge per kVA of maximum import capacity
- Exceeded capacity surcharge per kVA (six times capacity charge)
- Reactive power charge per kVArh

All users except domestic consumers are charged an energy, capacity and fixed charge components. Domestic consumers are charged based only on energy and fixed components.

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[100] https://www.cru.ie/wp-content/uploads/2009/07/cer09117.pdf

[101] https://www.cru.ie/wp-content/uploads/2010/07/cer10198.pdf

[102] https://www.dccae.gov.ie/en-ie/news-and-media/press-releases/Pages/Minister-Alex-White-meets-European-Commissioner-Ca%C3%B1ete-on-energy-policy-and-climate-change.aspx

[103] https://www.cru.ie/wp-content/uploads/2003/07/cer03298.pdf

Time-of-use charges apply to larger users and to domestic users with a capable meter, but only two time periods are used – day (0800-2300) and night (2300-0800). This is a simple time-of-use structure in that (i) it does not distinguish the evening from the rest of the day; (ii) it does not distinguish weekdays from weekends and public holidays; and (iii) it has no seasonal element.

**TUoS charges** are more different to the GB system. All customers receive a day/night unit charge per kWh. Larger customers also receive a flat capacity charge. This offers very little incentive to shift power usage away from peak times (in contrast to the GB "triad" system).

TUoS charges for generation are location-specific and set using a common approach for the whole Island of Ireland. Generator TUoS charges are set to recover 25% of allowed revenue for transmission (including SONI's allowance with respect to the Northern Ireland transmission network). The remaining 75% is collected from demand users. Of revenue allocated to generation, 30% is collected from a locational, cost-reflective component meant to provide a forward-looking signal for efficient use of the network. 70% is collected from a uniform "postage stamp" component which seeks to recover the historical sunk cost of the network. All generation charges are capacity-based (per MW of export capacity).

Auto-producers (demand customers with embedded generation) pay capacity charges as either a demand user or generation user – determined by the higher of their maximum export and import capacities.

All charges for demand are non-locational (both DUoS and TUoS), with the exception of the domestic DUoS tariff which includes an extra fixed charge for "rural"[104] customers on the grounds that they require a greater network length per customer and therefore higher costs of installation, operation and maintenance.[105] For the 2018/19 charging period, rural domestic customers were charged €30 more than urban domestics.

## Non-network costs included in UoS tariffs

UoS charges exclude policy support costs, which are collected from suppliers through a separate **Public Service Obligation (PSO) levy**. The levy was introduced by the Government of Ireland in 2003 to cover various renewable subsidy schemes. For 2018/19, the levy was set at €209 million, down from €472 million the previous year.[106] The levy is allocated between domestic, small non-domestic and large non-domestic users in proportion to their collective peak power usage. Within the domestic and small non-domestic groups, the levy is divided by the number of customers and added to the fixed charge. For large non-domestics, the levy is collected through a capacity charge. For 2018/19, charges were set at €41.76 for domestic users; €143.64 for small non-domestics; and €15.84 per kVA for large non-domestics.

## Connection costs

ESB and Eirgrid's[107] **connection charging** policies are both shallow – i.e. connectees pay for connection assets but not for network reinforcements. Generation users are required to pay for all connection assets. Demand users, by contrast, are only charged for 50% of their connection assets (the other half is recovered through UoS charges).

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[104] Rural customers are defined as those fed from a single-phase overhead network.

[105] https://www.esbnetworks.ie/docs/default-source/publications/rules-for-application-of-duos-tariff-group.pdf

[106] https://www.cru.ie/wp-content/uploads/2018/03/CRU18148-2018-19-PSO-Decision-Paper.pdf

[107] http://www.eirgridgroup.com/site-files/library/EirGrid/Connection-Charging-Statement.pdf

### Discounts on network charges

We are not aware of any explicit discounts for specific network user groups in Ireland, however we note the rebalancing of network tariffs in favour of large energy users explained above.

## B.9.4. Tariff impacts

We have estimated the impact of UoS charges on electricity prices, in cents per kWh, for each customer profile, based on 2018 published network tariffs, The tariff impacts are estimated based on energy, capacity and fixed charges. We have excluded from our calculation other tariff components such as reactive power or capacity exceedance charges.

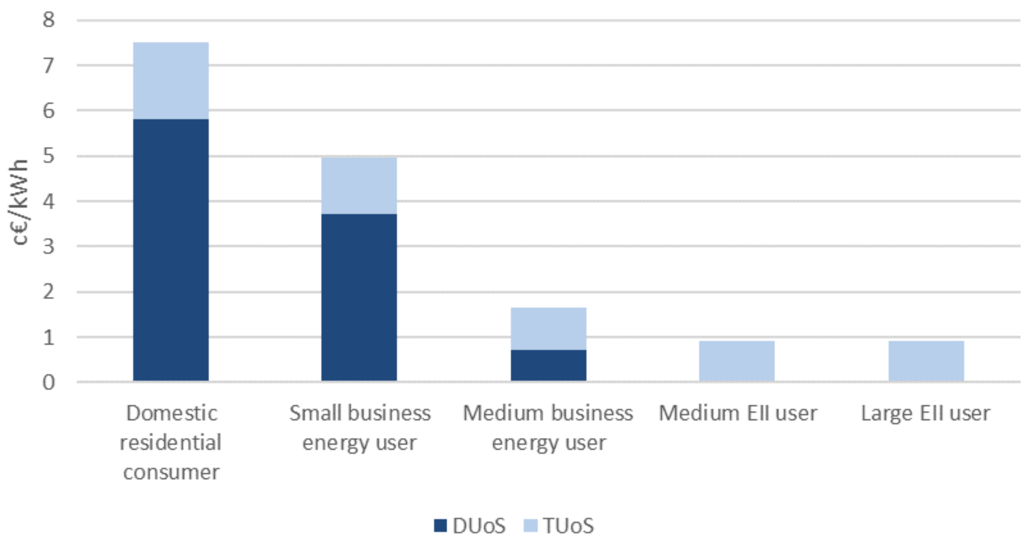
Network tariffs in Ireland have increased in the last few years due to costs associated with introduction of the new I-SEM and DS3 system services.

To estimate these tariff impacts, we have also made the following assumptions:

- Where tariffs required assumptions about consumption profiles during different periods of the day and the year, we used the available information on GB usage to map consumption for the corresponding tariff periods in Ireland.
- We also chose the tariff which required fewest assumptions to be made. For residential consumers, we have applied the tariff with no time-of-use differentiation.
- We used the urban domestic consumer tariff which has a lower fixed charge than the rural consumer tariff.
- Transmission tariffs for distribution connected consumers include distribution loss factors.

Figure 32 below shows the tariff impact for each consumer broken down by transmission and distribution charges.

*Figure 32: DUoS/TUoS charges in Ireland by consumer profile, c€/kWh*

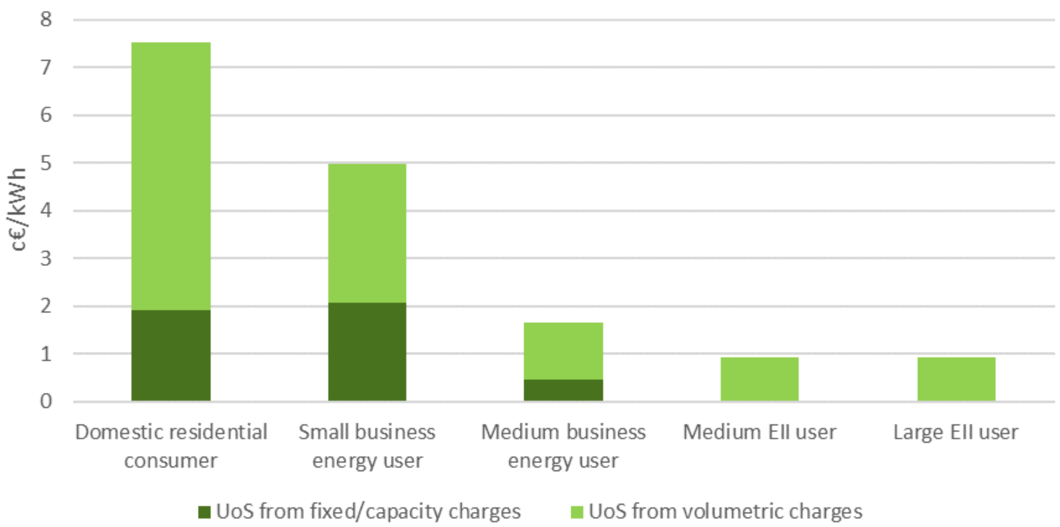



*Source: CEPA analysis*

Network charges, per kWh consumed, decrease with the size of the customer because larger customers do not need to contribute to the cost of lower network levels and can spread the fixed charges over a larger consumption base. Distribution charges are the majority of the final UoS bill for domestic and small business energy users, while the situation is reversed for medium business energy users.

Figure 33 below shows the tariff impact for each consumer broken down by fixed or capacity-based tariffs and volumetric tariffs.

*Figure 33: UoS charge components in Ireland by consumer profile, c€/kWh*




*Source: CEPA analysis*

Most of the network charges in Ireland are collected through energy charges. Unlike most other countries considered in this report, EII users are mainly charged on a per kWh basis. Large customers also receive a flat capacity charge, but this makes up less than 4% of their final UoS bill.

### B.9.5. Sources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