Final Report
Network Costs

Energy costs, taxes and the impact of government interventions on investments

Trinomics

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Presented by

Consortium led by:

Trinomics B.V.

Westersingel 34

3014 GS Rotterdam

The Netherlands

Contact person

Dr. João Gorenstein Dedecca

T: +31(0)6 1382 7132

E: joao.dedecca(at)trinomics.eu

Date

Rotterdam, 27 July 2020

Authors

João Gorenstein Dedecca, Liliana Guevara Opinska, Luc van Nuffel (Trinomics)

Matthias Altmann (LBST)

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Disclaimer

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Final Report – Network Costs

Study on energy costs, taxes and the impact of government interventions on investments in the energy sector

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CONTENTS

GLOSSARY

Term	Definition
Network costs	
Administration costs	The costs related to the general management of the transmission and distribution system operators, including support functions and central management (part of O&M costs).
Balancing	Measures of system operators on all time frames to meet short-term fluctuations in the supply and demand of electricity or gas.
Capacity remuneration	Remuneration of capacity resources (such as generation, storage, demand response) outside of energy markets to guarantee system adequacy during scarcity periods - applies to electricity only.
Cost type	Actual or Planned/Authorized: indicates if costs are actual ex-post costs or ex-ante costs planned by network operators or authorised by regulators.
Countertrading	A cross zonal exchange between TSOs between two bidding zones to relieve physical congestion - applies to electricity only.
EV infrastructure deployment	Investments and costs related to the deployment of secondary infrastructure for charging of electric vehicles are out of scope of the study, whether regulated or not.
Feed-in management	Management of the feed-in of renewable electricity/gas especially through curtailment to relieve a physical congestion, and possibly comprising compensation to renewable energy producers due to the curtailment.
Inter-TSO compensations	Costs related to the inter-TSO compensation (ITC) mechanism for transit flows in their area are excluded, in order to avoid double counting of costs (applies to electricity O&M costs only). The ITC mechanism provides compensation for: a) the costs of losses incurred by national transmission systems as a result of hosting cross-border flows of electricity, and b) the costs of making infrastructure available to host cross-border flows of electricity.
Investment costs	Investments comprise costs for network planning, construction and ownership for new network assets as well as major refurbishment (renovation) or replacement of existing assets. All investment costs are capitalised and recovered through depreciation costs. Investment costs comprise only regulated (recovered through regulated network tariffs) overnight investment costs in a single year. Financial investments are out of scope, e.g. for the purchase of participations (shares) in other network operators.
LNG facilities	Investments and costs related to the deployment of LNG terminals out of scope, whether regulated or not. According to the definition in the European Directive 2009/73/EC: "LNG facility" means a terminal which is used for the liquefaction of natural gas or the importation, offloading, and re-gasification of LNG, and includes ancillary services and temporary storage necessary for the re-gasification process and subsequent delivery to the transmission system, but does not include any part of LNG terminals used for storage."
Losses including CO_2	Costs related to energy losses in energy transmission, including associated costs of CO_2 if paid by the TSO, and of gas consumed in compressors.
Network planning costs	The analysis and planning of network expansion and network installations, including human and technical resources used in the planning.
Non-regulated services	Non-regulated services provided by the system operator to third parties are out of scope, e.g. consultancy services or operation of connection facilities, if not forecasted in the regulation.
Operation & Maintenance costs	O&M costs comprise the costs of physical network assets for energy transport and maintenance. O&M costs are not capitalised (and thus not included in the system operators' regulatory asset base). Energy losses incurred in transport as well as the associated cost of greenhouse gas emissions are also considered. The cost for services provided by third parties is included, when within the scope of operation & maintenance. System service costs for the safe operation of the system are not included in O&M.
Public service obligations	Public service obligations determined by legislation or regulation are out of scope, e.g. regulated tariffs to vulnerable consumers, supplier of last resort obligations or support to renewable energy sources applies to aggregated costs).
Re-dispatching	Orders by a network operator to change the generation and/or load pattern in order to alter physical flows in the transmission system and relieve a physical congestion - applies to electricity only.
Retail markets facilitation	Costs for the facilitation of retail markets are out of scope, for example the management of data hubs.

Term	Definition
Smart meter deployment	Smart meters are electronic devices used to record the consumption of electricity or gas and communicate the information to network operators and suppliers for monitoring and billing. Investments related to the roll-out of electricity or gas smart meters for small consumers are excluded when possible, whether mandated by regulation or not, to increase comparability across countries.
System services costs	System services costs are costs incurred to ensure the reliable operation of electricity or gas systems, such as balancing costs. These include among others ancillary services contracted to third parties. Costs incurred to guarantee the safety and operability of the physical infrastructure assets are considered as operation and maintenance costs.
Cost allocation	
Access tariff	Charges levied on connected network users for the use of the electricity or gas system.
Balancing cost recovery	User base from which costs for the different balancing services are recovered. For electricity, this comprises energy and capacity costs for the following balancing services: FCR: Frequency containment reserve (or primary reserve) FRR: Frequency restoration reserve (or secondary reserve) RR: Replacement reserves (or tertiary reserves) Costs may be recovered from (a subset of) network users through tariffs, from balancing responsible parties (BRP) or a combination of both.
Balancing costs recovered through market parties	Ratio of imbalance charges to balancing responsible parties (BRPs) over total balancing costs. Indicates the share of balancing costs recovered from BRPs as opposed to those recovered through network tariffs (i.e. residual balancing costs borne by network operators).
Balancing responsible party (BRP)	A market participant or its chosen representative responsible for balancing its injection versus offtake.
Balancing service provider (BSP)	A market participant with reserve-providing units able to provide balancing services (capacity and/or energy) to TSOs.
Connection tariffs	Charges levied on new network users for connecting to the transmission or distribution network, to recover (part of) the network operator's costs relative to the connection.
Connection cost allocation to network users	How connection costs that are allocated to a new network user, categorized as: a) Super-shallow connection costs where all costs are socialized via network tariffs of all network users. b) Shallow connection costs where new network users pay for the infrastructure to the network connection point, but not any network reinforcements beyond that point that may be needed. c) Deep connection costs where in addition to the costs paid under the shallow type, new users also pay all other reinforcements/extensions in the existing network.
Locational component in network tariff	Existence of varying access network tariffs depending on the location of the connection point of the user in the network.
Net metering	Existence of measures allowing prosumers to pay only for their net offtake from the network over a certain period (typically one month or year) rather than pay for their full offtake and be remunerated for their injection into the network separately.
Tariff components	Each of the main tariff components: capacity (e.g. in EUR/MW), commodity (i.e. energy, in EUR/MWh), fixed (e.g. in EUR per energy meter and/or connection point) and other charges (e.g. for separate specific services such as metering).
Tariff discount for specific users	Discount on network tariffs (connection and/or access), e.g. for users such as industry, with high average utilization of their connection capacity.
Tariff discount for storage	Discount on network tariffs for storage, e.g. to avoid the double imposition of tariffs in the charge/discharge cycle.
Tariff split - injection/withdrawal	Shares of the total cost of service recovered from the injection into the network (by generators/storage discharge/imports) and withdrawal (by consumers/storage charging/exports).
Time-related components	Access network tariffs dependent on the season, day (e.g. weekend/working day) or time of day (e.g. day/night). Network tariff can be dynamic (continuous tariff adjustment depending on network conditions), time of use (with a limited number of day/seasonal periods for tariffication) or peak-related (additional peak tariff component for moments of critical network congestion).

ABBREVIATIONS

ACER	Agency for the Cooperation of Energy Regulators
BRP	Balancing responsible party
BSP	Balancing service provider
capex	Capital expenditures
CEER	Council of European Energy Regulators
CPP	Coincident peak pricing
DSO	Distribution system operator
(E)HV	(Extra-)high voltage
ENTSO-E	European Network of Transmission System Operators for Electricity
ENTSOG	European Network of Transmission System Operators for Gas
FCR	Frequency containment reserve
FIT	Feed-in tariff
FRR	Frequency restoration reserve
IEA	International Energy Agency
ITC	Inter-TSO compensation
LNG	Liquefied natural gas
NRA	National regulatory authority
NC TAR	Network code on harmonised transmission tariff structures for gas
O&M	Operation & maintenance
opex	Operational expenditures
RAB	Regulatory asset base
RES	Renewable energy sources
RR	Replacement reserves
SC	System service costs
totex	Total expenditures
ToU	Time of use
TSO	Transmission system operator
WACC	Weighted average cost of capital

1 Introduction

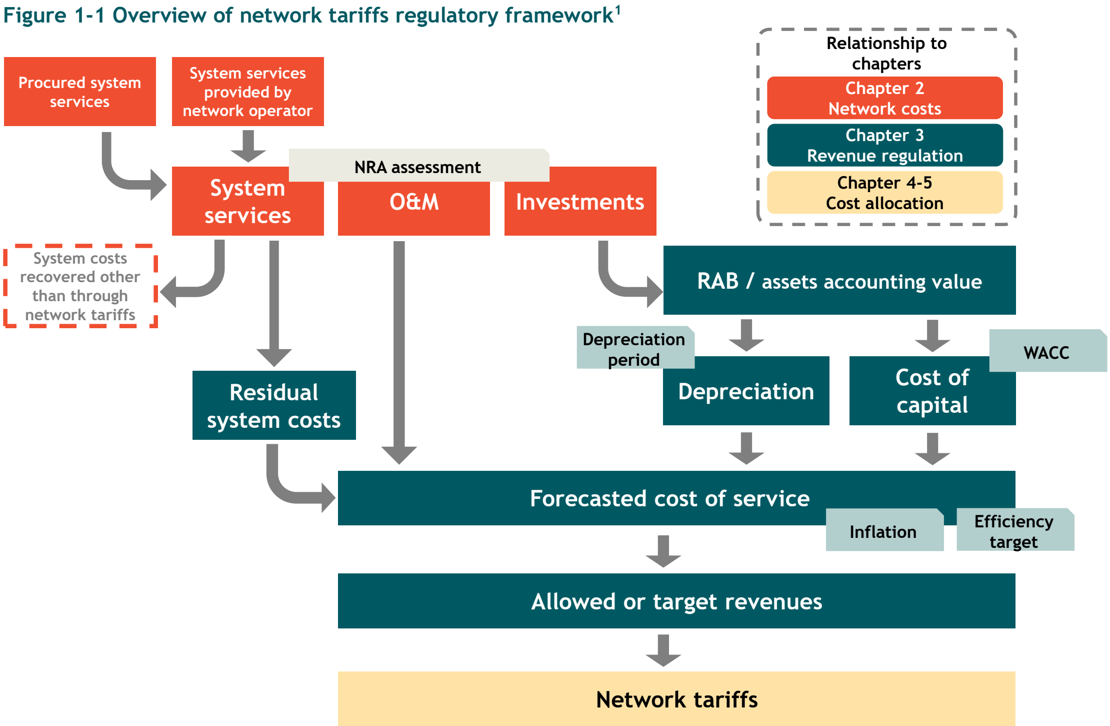
1.1 Objectives

The main objective of this report is to present electricity and gas network cost data split into three components (investments, operation & maintenance - O&M, and system service costs) for the EU27 Member States and non-EU G20 countries, for 2010, 2014 and 2018 (chapter 2). The report also provides a high-level analysis regarding the regulatory frameworks used for setting the allowed revenues of system operators for 2018 and discusses possible structural under- or over-recovery of network costs (chapter 3). Then, network cost allocation parameters to network users are assessed for the EU27 Member States for the three years of focus (chapter 4), and some specific cost allocation practices applied in non-EU27 countries are presented (chapter 0).

1.2 Methodology

Figure 1-1 provides an overview of the regulatory framework for determining network tariffs, indicating in which of the main sections of this report they are addressed. A full description of the data collection and analysis methodology is presented in Annexes C and D.

Figure 1-1 Overview of network tariffs regulatory framework[1]



To conduct the analysis, country-level data was collected for electricity and gas networks in three different categories: network costs, cost allocation parameters and network characteristics.
Other networks than electricity and gas, such as for heat, oil, hydrogen or CO_2 are out of the scope of this study, and other infrastructure costs, such as for electricity or gas storage, or for LNG terminals are also not included.

[1] Adapted from ACER (2018): Report on the methodologies and parameters used to determine the allowed or target revenue of gas transmission system operators. See the glossary for definitions.

The **energy networks focused on in this report are electricity and gas**, for which the network is mostly regulated in the European Union, generally highly integrated at supra-national level, and well developed for most of the EU and non-EU G20 countries. Non-regulated transmission and distribution networks in important non-EU countries (such as in the US) are included where significant and to the extent possible. The **network levels** covered comprise the transmission and distribution levels (separately).

Network costs covered in this report are investments, operations and maintenance (O&M) and system service costs[2] (the latter further disaggregated into different system services, such as balancing). These form the main costs of network operators, as indicated in Figure 1-1. Investments refer here to both the expansion and the renovation of physical network assets, and do not include financial investments for e.g. acquisitions of other companies or already commissioned projects.

It is important to differentiate between investments, O&M and system service costs from the elements which form the cost of service of network operators. The cost of service incorporates the remuneration of the capital of the network operators and the depreciation of investments, and ultimately determines the tariffs of network users. As shown in Figure 1-1, investments, O&M and system service costs precede the cost of service. Data is not collected nor analysed for the depreciation of assets or capital remuneration, and monetary volumes for the cost of service are not presented. Section 4.4 focuses on the allocation of the total cost of service among network users through the analysis of cost allocation parameters.

The analysis of network costs and cost allocation follows the following steps:

- ✓ Cross-country data collection by the core team from transversal sources;
- ✓ National data collection by country experts;
- ✓ Validation by the core team, individually per country focusing on data gaps and single data points requiring clarification, and following a cross-country comparison to identify outliers / explain observed dynamics;
- ✓ Validation by national regulatory authorities (for EU Member States).

The main data sources for the exercise were:

- ✓ Transversal sources for all countries: IEA electricity and natural gas statistics;
- ✓ Transversal sources for EU27 Member States:[3] Reports from ACER, CEER, European Commission services, ENTSO-E, ENTSOG;
- ✓ National data: Reports by and direct communication with national regulators and (associations of) network operators, as well as financial statements of network operators.

The project core team received final validated data from the NRAs of the following Member States: AT, BE, BG, CY, DE, EE, ES, FI, FR, HR, HU, IE, LT, LV, NL, PL, RO, SI, SK. Country experts had additional contacts with EU NRAs during the data collection phase. This report contains data submitted by country experts and NRAs until June 2020.

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[2] See glossary in the start of the report.

[3] Most transversal sources included data for the UK. This data has been used, but the EU27 is used for the analysis throughout this report.

Data availability for 2010, 2014 and 2018 is indicated in Table 1-1, measured as the ratio between the number of data points available and the number of data points aimed for, separately for electricity and gas (but aggregated for transmission and distribution for simplicity).[4] For conciseness, of the system services costs surveyed, balancing data coverage is presented.

Table 1-1 Network cost data availability (available data points relative to target)[5]

	Electricity			Gas		
	Inv.	O&M	Bal.	Inv.	O&M	Bal.
Austria	100%	83%	100%	83%	17%	0%
Belgium	100%	100%	100%	100%	100%	100%
Bulgaria	67%	67%	0%	50%	50%	0%
Cyprus	83%	100%	0%	NA	NA	NA
Czech Republic	50%	50%	100%	100%	100%	100%
Germany	100%	100%	100%	100%	100%	33%
Denmark	100%	100%	0%	100%	100%	0%
Estonia	100%	100%	0%	100%	100%	0%
Greece	100%	100%	100%	67%	67%	100%
Spain	100%	67%	100%	100%	17%	0%
Finland	100%	100%	100%	100%	0%	0%
France	100%	100%	67%	100%	100%	0%
Croatia	100%	100%	100%	83%	100%	67%
Hungary	100%	100%	100%	83%	67%	0%
Ireland	100%	100%	100%	100%	100%	0%
Italy	100%	100%	100%	67%	83%	100%
Lithuania	100%	100%	33%	100%	100%	67%
Luxembourg	67%	67%	33%	67%	67%	0%
Latvia	100%	100%	100%	67%	33%	0%
Malta	0%	0%	0%	NA	NA	NA
Netherlands	100%	100%	67%	100%	100%	100%
Poland	100%	100%	100%	83%	17%	33%
Portugal	83%	100%	67%	83%	100%	0%
Romania	100%	100%	100%	100%	100%	100%
Sweden	100%	100%	67%	100%	100%	67%
Slovenia	100%	100%	100%	83%	100%	100%
Slovakia	67%	67%	100%	100%	100%	100%
Argentina	100%	100%	0%	100%	100%	0%
Australia	100%	100%	100%	100%	100%	0%
Brazil	83%	100%	100%	100%	100%	0%
Canada	100%	100%	100%	100%	100%	0%
China	100%	0%	0%	100%	0%	0%
India	100%	100%	0%	100%	50%	0%
Indonesia	100%	100%	0%	83%	100%	0%
Japan	100%	100%	0%	100%	100%	0%
Korea	100%	50%	0%	67%	100%	0%
Mexico	83%	100%	33%	100%	67%	0%
Russia	100%	100%	100%	100%	50%	0%
Saudi Arabia	100%	100%	0%	17%	83%	0%
South Africa	100%	100%	0%	NA	NA	NA
Turkey	100%	100%	33%	100%	100%	0%
United Kingdom	100%	100%	100%	100%	100%	0%
United States	100%	100%	0%	100%	67%	0%

[4] To illustrate the table, Greece as an example has full coverage of electricity investment and O&M costs (six data points each for 2010, 2014 and 2018 for transmission & distribution), and balancing costs (one data point per year). For gas, availability is 67% for investments & O&M (all years and network levels, except 2010 and 2014 for distribution), while gas balancing cost data is available for all three years.
[5] Note that MT has no electricity transmission, nor gas transmission or distribution. CY has no gas transmission or distribution. Natural gas networks in South Africa are highly underdeveloped and represent a marginal share of domestic energy consumption.

2 Network costs in the EU27 and in non-EU G20 countries

2.1 Network characteristics and considerations on their impact on costs

This section presents a short overview of the main network cost drivers for both electricity and gas identified in the literature. These cost drivers are dependent on the physical characteristics of the networks, which in turn are different for electricity and gas networks.

Table 2-1 lists key characteristics of electricity and gas networks and highlights the similarities and differences between them. Although some similarities can be found between electricity and gas networks, there are important qualitative differences, which affect the cost drivers. A key difference is that the operation of the electricity system requires the instantaneous balancing of supply and demand at any moment, while in the case of gas, balancing capacity is to a certain extent available within the network (linepack). This difference has an impact on the physical design of the transmission system networks of the two energy carriers. The electrical network is designed as a meshed network of lines to avoid disruptions in the flow of power in the case of the loss of a line. This design exhibits low failure rates but has high construction costs associated to it. In contrast, the gas transmission system is radial, also due to the importance of extra-EU gas imports.

Moreover, while the availability of electricity storage is still limited and expensive, large gas storage capacities in underground geological formations or at liquefied natural gas terminals facilitate balancing from the (sub-)hourly to the seasonal time scales. Finally, the energy losses during transmission are significantly greater in the case of electricity due to energy being lost as heat due to the Joule effect, except if gas compression losses are considered.

Table 2-1 Comparison between key characteristics of electricity and gas networks[6]

Characteristic	Electricity	Gas
Energy type	Secondary (expected to become increasingly primary in the future)	Primary (expected to become increasingly secondary in the future)
Physical variable determining flows	Voltage	Pressure
Transmission system	Meshed	Radial
Transmission and distribution energy losses in % of final demand in the 2008-2017 period in the EU	7.2-7.4%	0.8-1.1% (gas consumed in compressors up to 6%)
Flexibility from infrastructure elements	None (storage not taken into account)	High (linepack, LNG terminals and underground storage)

CEER conducted two studies on benchmarking the cost-efficiency of transmission system operators (TSOs) in 16 European countries.[7] A detailed description of the cost drivers identified in the studies is

[6] Based on Rubio-Barros et al. (2012), Energy Carrier Networks: Interactions and Integrated Operational Planning. Losses calculated from Eurostat nrg_cb databases
[7] CEER (2019) "Project CEER-TCB18 Pan-European cost-efficiency benchmark for gas transmission system operators: main report"

presented in Annex B. In summary, it identified the normalised asset base[8] of the network operators, the installed transport capacity (e.g. transformer capacity), the line length and the number of network connections as the most important determinants of the network operators' costs.

The CEER study does not assess the impact of the various cost determinants on each cost component individually (investment, O&M, system service costs). This impact varies according to the cost component. O&M costs for example are partly fixed (administrative costs), partly correlated to physical infrastructure (e.g. maintenance) and partly correlated to capacity/volumes (e.g. network losses). Hence, network length should affect O&M more strongly than investment costs, as the latter depends on other factors. These could include new cross-border projects, connection of new network users, reinforcements of existing network components (due to increasing injection or off-take peaks), replacement of ageing assets for safety or reliability reasons (e.g. overhead lines, substations, compressor stations), implementation of smart technologies (smart meters, remote monitoring of substations), and adaptation of the network for technical reasons (conversion from low calorific to high calorific gas, reverse gas flows). Hence, for investments, the normalized asset base of the network operators and the installed transport capacity (e.g. transformer capacity) could be a more important determinant.

There is also a relationship between the network cost of service and the quality of the services provided. Regulatory frameworks in general need to provide incentives for network operators to reduce costs for network users, but also to guarantee adequate quality of service. It may be more difficult to provide adequate incentives for cost and quality control under traditional regulatory approaches such as rate-of-return regulation.[9] Incentive-based regulatory approaches should be designed in order for network operators not to over-prioritize cost reductions to the detriment of service quality. CEER indicates that the interruption indices for electricity provision in Europe have been stable or improving in the 2002-2016 period. Gas interruption indices are generally much lower (i.e. better) than for electricity, although fewer data is available (less countries monitor interruptions of gas supply) and for a shorter period (2010-2016).

2.2 Network costs

The analysis of network costs is organised according to the following structure:

- ✓ The network physical infrastructure costs (investments and O&M) and the system service costs are analysed separately due to the underlying different drivers;
- ✓ Each section analyses electricity transmission and distribution, then gas transmission and distribution, and finally compares both energy carriers;
- ✓ All costs are scaled to €$_{2018}$/MWh using IEA data on domestic energy consumption.[10] Investments are additionally also presented in absolute figures in million €$_{2018}$.

CEER (2019) "Project CEER-TCB18 Pan-European cost-efficiency benchmark for electricity transmission system operators: main report"
The CEER methodological approach was based on proposing a proxy for the diversified asset base of operators. The data analysed was made comparable by limiting the scope of comparable activities, and controlling for systematic variation in various parameters.
[8] Represents a total expenditure (totex) proxy encompassing the relevant assets (such as, for electricity, overhead lines, cables, transformers, and control centres) with weights corresponding to their impact on capex and opex.
[9] Ecorys et al. (2019) Do current regulatory frameworks in the EU support innovation and security of supply in electricity and gas infrastructure?
MIT and Comillas University (2016) Utility of the Future
[10] Defined here as production (from all sources) + imports - exports ± stock changes. Data on domestic energy consumption was retrieved from the International Energy Agency (IEA) World energy statistics.

Where necessary, the data collected and indicated has been adjusted to represent the total national network costs. For example, bottom-up electricity distribution investment data for 2010 in Denmark covers DSOs representing 95% of consumption at that level. It is linearly extrapolated to 100% in order to also include the DSOs whose data was not collected. The target level of coverage for the transmission and distribution network costs was at least 80% of energy consumption.

The investments, O&M and system service costs assessed result from the various main drivers indicated in section 2.1 (and others). The scaling by domestic energy consumption allows to compare costs across countries using a coherent parameter whose data is available for all countries and years. Moreover, network costs such as investments may lead to overall lower system costs. Thus, attention is needed when comparing costs to consider the underlying drivers, and lower network costs per MWh do not mean higher overall efficiency.

Comparison with data from other studies needs to pay attention to the scope of the present study and sources of data, which may not be the same as the present study. The great majority of the data presented here is sourced from direct contact or documents (reports, regulatory decisions & financial statements) from NRAs or (associations of) network operators.

2.2.1 Network physical infrastructure-related costs

Total electricity and gas network investments

Table 2-2 provides the aggregated electricity and gas investment costs for EU27 countries and non-EU G20 countries in the three years of analysis.[11]

Table 2-2 Total electricity and gas network investments for the EU27 and non-EU G20 countries (billion €$_{2018}$)

		Electricity				Gas			
Category	Year	Trans.	Distr.	Both	Total	Trans.	Distr.	Both	Total
EU27	2010	6.6	15.6	1.4	23.6	3.8	2.7	2.6	9.1
	2014	8.7	16.4	1.4	26.5	3.4	3.7	1.0	8.1
	2018	9.5	22.5		32.0	4.1	5.4	0.4	9.9
non-EU G20	2010	36.1	48.1	57.2	141.4	19.9	10.8	5.8	36.5
	2014	59.7	59.3	55.5	174.4	16.5	17.9	6.3	40.7
	2018	59.0	64.4	69.3	192.6	22.5	23.7	9.6	55.9

Note: both denotes aggregated transmission + distribution spending, when disaggregated date was not available.

In both country groups, investments in electricity networks are much higher than in gas networks. This is explained by the specific network investment costs, which are higher for electricity than for gas, as well as by specific drivers in the EU and non-EU G20 countries, detailed next.

In the case of the EU as a whole, the total investments in electricity networks have increased from 23.6 billion EUR in 2010 to 32 billion EUR in 2018. Investments in transmission increased by almost 3 billion

[11] It is important to note that, due to data availability, the coverage between years and network-levels might slightly differ. Nonetheless, the table does allows to identify general trends in electricity network investments over time. Also, the threshold between transmission and distribution voltages can vary significantly per country and be a determining factor in the ratio between transmission and distribution costs. However, many countries do not have a clear threshold, with overlaps between voltages operated by TSOs and DSOs.
The data presented refers to, when specific data is available, to overnight investments. Hence some investment peaks may be caused by the commissioning of strategic, large projects, especially in smaller systems. This is discussed in the text where appropriate.

EUR from 2010 to 2018. In the case of distribution investments, from 2010 to 2014 the increase was of 0.8 billion EUR and from 2014 to 2018 of 6.1 billion EUR to reach a total investment of 22.5 billion EUR in 2018. The NL was the only EU27 country where disaggregation between transmission and distribution investments was not available in the years 2010, 2014 (see Figure 2-1). The country reported an aggregated spending of 1.4 billion EUR in both 2010 and 2014.

While overall electricity consumption in the EU has remained stable in the period, a number of factors explain the increase in electricity network investments in the EU. Aspects related to market integration and security of energy supply help explain why in the EU27 investments in electricity networks have increased over time, whereas they have stagnated in the case of gas networks. Also, the increase has been driven especially by investments in electricity distribution, which usually form the larger share of total electricity investments in any case. The rapid increase in investments in electricity distribution networks could moreover be correlated to the increase of the share of distributed electricity generation (especially from renewable energy sources) in the period and electrification in general. Also, strict quality standards for electricity (and gas) in the EU trigger investments (and O&M).

For non-EU G20 countries, the change in total electricity network investments was from 141.4 billion EUR in 2010 to 192.6 billion EUR in 2018. In 2010, more than 36 billion EUR were spent on transmission network investments and more than 48 billion EUR on distribution. By 2014, investments in transmission networks increased by more than 23 billion EUR and those in distribution by more than 11 billion EUR. Finally, between 2014 and 2018 there was an increase in distribution investments of 5 billion EUR and a slight decrease in network transmission investments. In the case of G20 countries, electricity network investments are driven by a handful of countries, mainly CN, US, IN, SA, CA and BR (see Figure 2-2). The investment trends in electricity networks corroborate the ongoing electrification trends in G20 countries. Between 2010 and 2018 electricity consumption increased by 25 % in the G20 countries, compared to stable consumption in the EU27.

Total gas investments in the EU27 have not changed much between 2010 and 2018. During this time period, the investments in gas networks in the EU27 increased by only 9%, to 9.9 billion EUR in 2018,and with a dip in 2014. The stable investments are explained by contrasting drivers. On the one hand, gas consumption in the EU27 decreased by 11% during the 2010-2018 period. On the other hand, some drivers helped to maintain the investment level, including: renovation works, security of supply and market integration-driven projects (some gas investments for reverse flows, integration of isolated Member States), investment in some MSs with underdeveloped gas networks (e.g. LT), and biomethane development.

For non-EU G20 countries, total gas network investments increased from 36.3 billion EUR in 2010 to 55.9 billion EUR in 2018. This change represents a 57% increase in investments during the eight-year time period. The observed trend in gas network investments is related to changes in gas consumption for the two groups of countries. Whereas in the G20 countries gas consumption increased by around 24% between 2010 and 2018, in the EU27 gas consumption decreased by 11% as noted. Also, as can be observed in Figure 2-2 in the following section, G20 gas network investments in terms of overall investment volumes are mainly driven by a few countries, notably CN, RU and the US.

Detailed network investments for electricity

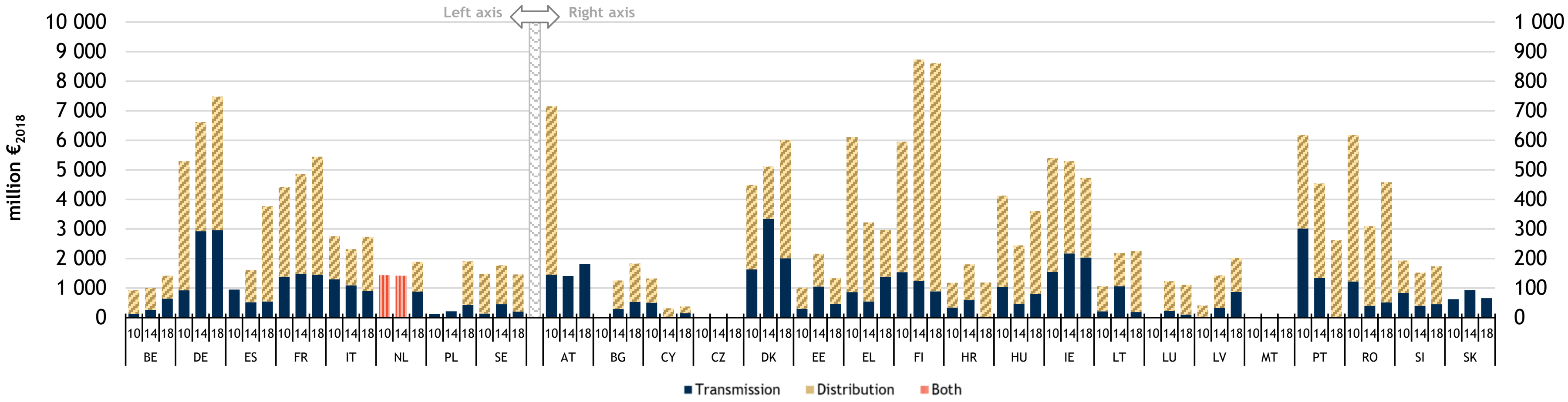
Figure 2-1 shows the electricity network investments in absolute terms for each EU27 Member State for transmission and distribution in the years 2010, 2014 and 2018. It is important to note that in some cases, investment data for transmission and/or distribution was not available, which does not necessarily indicate lack of investments for a given network level and year. The data presented refers to, when specific data is available, to overnight investments. Hence some investment peaks may be caused by the commissioning of strategic, large projects, especially in smaller systems. This is discussed in the text when possible.

The threshold between transmission and distribution voltages can vary significantly per country and be a determining factor in the ratio between transmission and distribution costs. However, many countries do not have a clear threshold, with overlaps between voltages operated by TSOs and DSOs (e.g. DE). EU27 MSs with a relatively high transmission/distribution threshold include CZ, HU, ES, SE (transmission includes lines at 220 kV and above) and RO (750 kV). This can, to a certain extent, account for the observed distribution in investments. No particularly high threshold in the non-EU G20 countries was identified. Low voltage thresholds are observed in ID (distribution comprises lines at 6 kV and lower) and JP (20 kV).

In terms of amounts of overall investments over time, no discernible trends can be observed across countries. There is a large variance in the absolute electricity network investment levels across countries and years. Annual spending in electricity networks ranges from less than 100 million EUR to more than 9 billion EUR. In Figure 2-1 the MS with investments below 1 billion EUR are grouped on the right and those with investments equal or surpassing 1 billion EUR on the left.

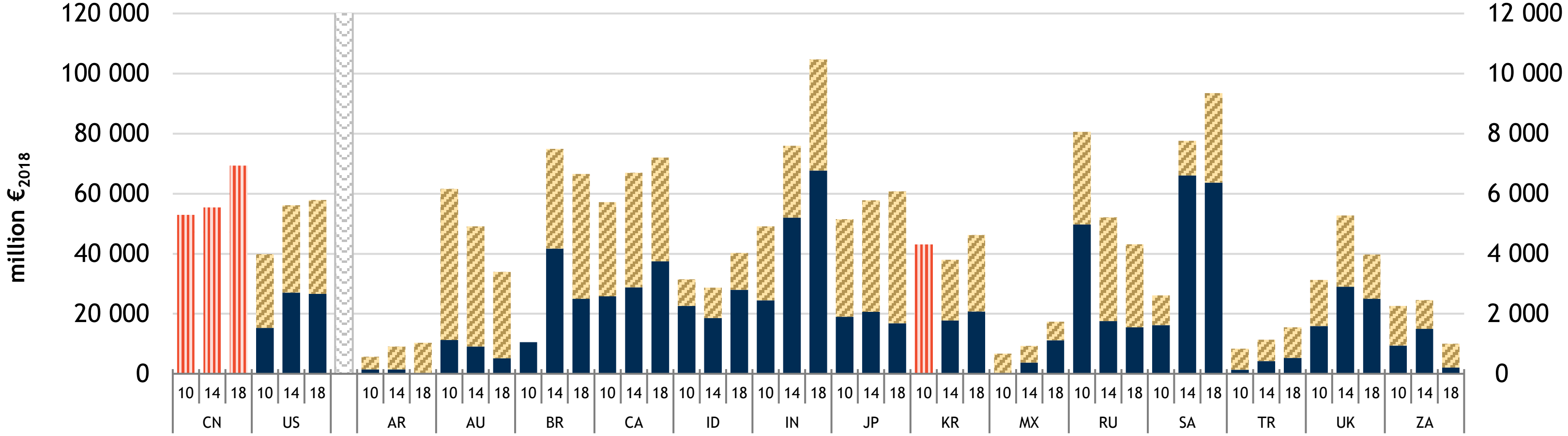
Based on the figure, the countries with the highest absolute investments in the electricity network are DE, FR, IT and, in 2018, ES. In DE, the total electricity network investments have increased from around 5.3 billion EUR in 2010 to close to 7.5 billion EUR in 2018. Whereas in 2010, the investments in electricity distribution networks were about 4.8 times those in transmission, in 2014 the investments in transmission networks more than tripled, lowering the ratio of distribution to transmission investments to a factor of ~ 1.3. In 2018, the investments in transmission remained almost constant compared to 2014 while investments in distribution grew, bringing the ratio to around 1.5.

Figure 2-1 Electricity network investments in the EU27 for transmission and distribution, 2010-2018 (million €2018)



Not shown (confidential): AT (2014, 2018 D), CZ (2010-2018 T&D), HR (2018 T), LV (2010 T), PL (2010-2014 D), SK (2018 D)

Figure 2-2 Electricity network investments in the non-EU G20 for transmission and distribution, 2010-2018 (million €2018)



In FR, the total investments in electricity networks grew from more than 4 billion EUR in 2010 to slightly less than 5.5 billion EUR in 2018. While investments in the transmission network remained relatively constant (with a small increase between 2010 and 2014), investments in distribution have increased over time. Only in the case of DK in 2014 transmission investments exceeded distribution ones.[12] In IT, total investments in electricity networks remained relatively constant between 2010 and 2018 at around 2.7 billion EUR with a slight dip in total investments in 2014 (~ 2.3 billion EUR). In the case of ES, investments in electricity networks increased from 1.6 billion EUR in 2014 to more than double in 2018 at ~ 3.8 billion EUR. In 2018, the investments in distribution networks were almost six times larger than those in transmission.

In SE, total investments in electricity networks were highest in 2014 at slightly less than 1.8 billion EUR. In 2010 and 2018 the total investments were a little above 1.4 billion EUR. In 2010, investments in distribution networks were 10 times higher than in transmission networks, but by 2014 investments in transmission increased such that the ratio of investments in distribution to transmission was ~ 3:1. This ratio doubled to 6:1 in 2018. For the NL, the total investments in electricity increased from 2014 to 2018. The total amount of investments in electricity networks has also increased over time in BE from below 1 billion EUR in 2010 to ~ 1.4 billion EUR in 2018. FI has seen an increase in total investments over time with the high investments in 2014 and 2018 amounting to more than 800 million EUR. DK has also increased in electricity networks from 2014 to 2018. In 2016 it spent 6 000 million EUR on investments in electricity networks.

Figure 2-2 shows the electricity network investments in absolute terms for non-EU G20 countries for transmission and distribution in the years 2010, 2014 and 2018. Like in the case of the EU27 countries, in terms of amount of overall investments over time, no discernible trends can be observed across countries. Investments in electricity networks for non-EU G20 countries across all three years of analysis range between around 1 billion EUR and 70 billion EUR, the overall scale of absolute investments in electricity networks being higher than in the EU27 Member States.

CN and US are by far the countries with the largest investments in electricity networks. The US is the country with the highest investments in electricity networks. In 2018, the US invested around 58 billion EUR, in 2014 close to 56 billion EUR and in 2010 ~40 billion EUR. Investments in distribution networks are higher than in transmission. This difference was highest in 2010 with a ratio of 1.6.

The remaining non-EU G20 countries analysed generally remain below the 10 billion EUR mark in network investments with the exception of IN which in 2018 slightly surpassed 10 billion EUR. In AU, investments have decreased over the time period analysed. In 2010 they amounted to more than 6 billion EUR, while in 2018 they were at ~ 3.4 billion EUR. While data for distribution investments in 2010 is not available for BR, a slight decrease in total network investments is also discernible between 2014 and 2018. This is also the case in RU, where total investments have decreased from ~ 8.1 billion EUR in 2010 to around 4.3 billion EUR in 2018. In contrast, in IN, JP, ID, SA and CA there has been an overall increase in investments between 2010 and 2018 (in some cases with a dip in 2014). In 2018, the investments in MX amounted to around 1.7 billion EUR, in TR to ~ 1.6 billion EUR, and in AR to a little more than 1 billion EUR. In the UK, the largest total investments in electricity networks for the time period analysed took place in 2014, amounting to about 5.3 billion EUR. In 2010, the total electricity

[12] Note that the threshold for defining transmission and distribution networks varies across Member States.

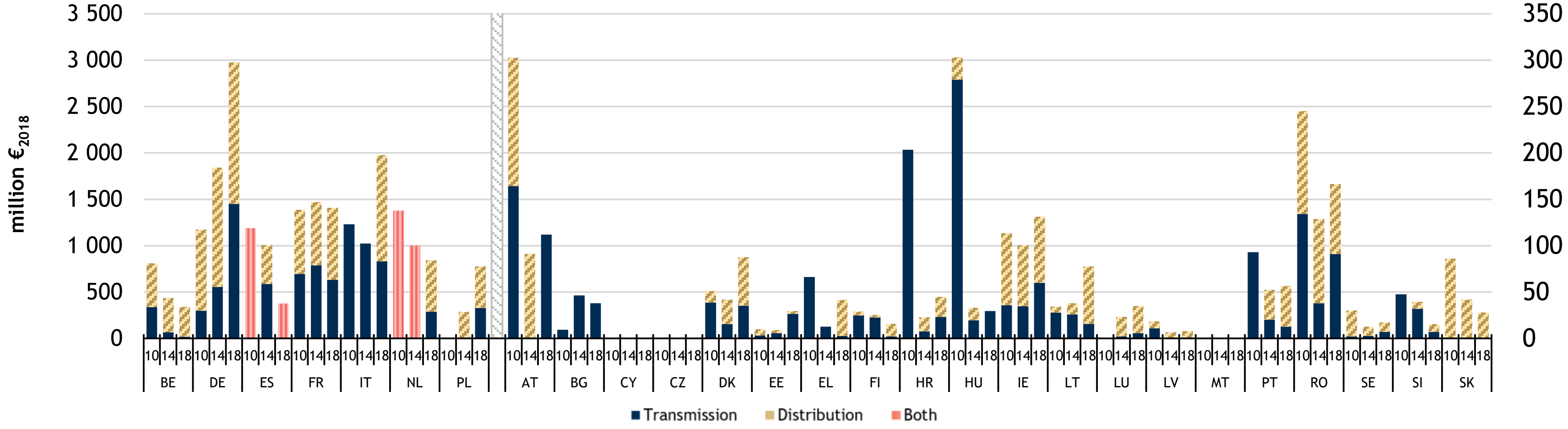
network investments amounted to a little more than 3 billion EUR, and in 2018 they reached 4 billion EUR.

Detailed network investments for natural gas

Figure 2-3 presents the data on gas network investments in the EU27 for transmission and distribution between 2010 and 2018. Similarly, to the absolute electricity network investments in the EU27, there is a large variance in the investments between countries and across years. Total investments range from below 50 million EUR to 3 billion EUR across countries and years.

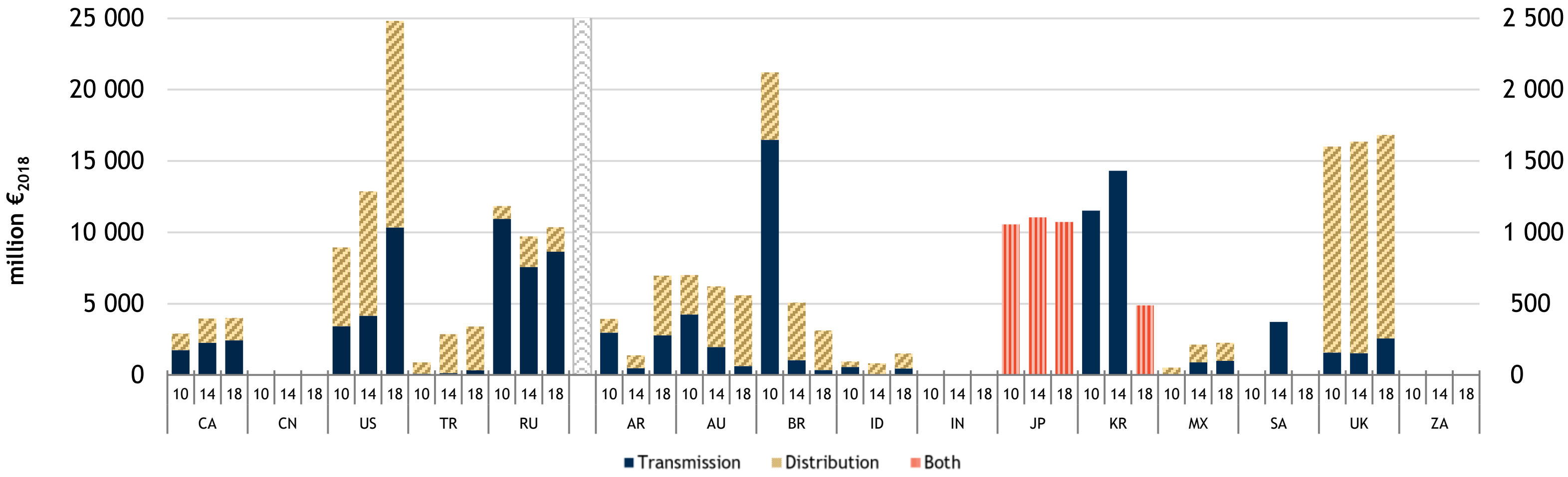
The threshold between transmission and distribution gas pressures can vary significantly per country and is a determining factor in the ratio between transmission and distribution costs. However, many countries do not have a clear threshold, with overlaps between pressures operated by TSOs and DSOs. EU27 MSs with a lower transmission/distribution threshold include HR (distribution lines have a pressure of 3 bar or lower), SI (4 bar). Low pressure thresholds are observed in JP (1 bar) and ID (4 bar). This can, to a certain extent, account for the observed distribution in investments.

Figure 2-3 Gas network investments in the EU27 for transmission and distribution, 2010-2018 (million €2018)



Not shown (confidential): AT (2014 T), CZ (2010-2018 T&D), PL (2010, 2014 T), SK (2014, 2018 T)

Figure 2-4 Gas network investments in the non-EU G20 for transmission and distribution, 2010-2018 (million €2018)



Not shown (confidential): CN (2010-2018 T&D), IN (2010-2018 T&D)

The countries with the highest absolute gas network investments are grouped on the left-hand side of the figure, amongst these DE, IT, NL, FR and ES having the highest overall investments. From the graph, we see that the investments in DE in 2018 represented by far the largest amount (almost 3 billion EUR). This amount represented a large increase compared to the 2014 investment level of ~1.8 billion EUR and the one in 2010 of about 1.2 billion EUR. IT was close to the 2 billion EUR mark in total gas network investments in 2018. This figure is made up of ~ 830 million EUR in transmission network investments and a little less than 1.2 billion EUR in distribution investments. No data for distribution investments is available for the years 2010 and 2014 in IT. The NL decreased their investment level in gas networks from a little less than 1.4 billion EUR in 2010 to around 840 million EUR in 2018. In FR, gas network investments remained relatively constant fluctuating at around ~1.5 billion EUR (in 2014) or a little less (in 2010 and 2018). In ES, the investments also decreased over time. In 2010 the total investment in gas networks accounted for about 1.2 billion EUR and in 2018 for 376 million EUR. The data for 2010 and 2018 does not contain information on the allocation between transmission and distribution. BE also saw a decrease in gas network investments over time, from ~809 million EUR in 2010 to ~ 342 million EUR in 2018. In 2018 less than 18 million EUR were invested in gas transmission networks in BE. AT, PT, RO and SK also exhibit a decrease in the total level of investments between 2010 and 2018. In the case of SK only gas distribution networks data is publicly available. In these countries, the investments were well below the 500 million EUR mark in any given year. In 2010, HU and HR reported unusually large investments in gas transmission networks; this was likely driven by the construction of network linkages between these two countries.[13]

Figure 2-4 shows the gas network investments in non-EU G20 countries for transmission and distribution in the years 2010-2018. From the figure, we can observe that the US invested close to 25 billion EUR in gas networks in 2018. Transmission investments made up close to 10 billion of the total amount. This figure represents almost the double of the investments made in the US in 2014. It also represents about twice as much as the investments made in RU, the country with the second highest investments in gas networks. In RU, investments in gas networks fell from close to 12 billion EUR in 2010 to about 10 billion EUR in 2018. Interestingly, the large majority of the spending in RU was directed towards investments in transmission networks, driven by gas exports. CN investments in gas networks increased from 2010 to 2018. In CA, the investments in gas networks increased from around 3 billion EUR in 2010 to about 4 billion in 2018. Investments in transmission make up a slightly larger portion of the total investments (between ~1,3 and 1.5). In BR, investments in 2010 amounted to a little more than 2 billion EUR. In 2018 they decreased to ~311 million EUR. Whereas in 2010 transmission investments were more than 3 times as high as distribution investments, this changed in 2014 and 2018. In the UK, the total investments in gas network infrastructure slightly increased over time from ~1.6 billion EUR to a little less than 1.7 billion EUR. Distribution network investments constituted the majority of total investments. For JP only total gas network investments are available. In JP investments have remained relatively stable at around 1 billion EUR for each of the years analysed. In AR, AU, MX and TR, investments were low, representing less than 1 billion EUR.

When comparing the absolute investments in gas networks between EU27 and non-EU G20 countries we see that, in general, G20 countries invest more in gas networks in absolute terms. CA, CN, US and RU all invest more than the highest investing country among the EU27 (DE). However, absolute investments do not reflect important differences in characteristics between countries regarding e.g. their size and

[13] Plinacro, " State of project Interconnection gas pipeline with Hungary", Available at: https://www.plinacro.hr/default.aspx?id=661

consequently also their domestic energy consumption or network length. Thus, the scaled data presented in Figure 2-5 to Figure 2-8 below allows for more meaningful comparisons.

Comparing absolute investments in electricity versus gas networks we find that generally, both in the EU27 and in the non-EU G20 countries, investments in electricity networks exceed those in gas networks. Whereas in the EU27 the range of investments on electricity networks varies between less than 100 million EUR to around 8 billion EUR (in DE), spending on gas networks is in the range of bellow 50 million EUR to 3 billion EUR (in DE) across countries and years. In the case of non-EU G20 countries the spending on electricity networks ranges between around 1 billion EUR and above 60 billion EUR whereas that for gas networks ranges from less than 500 million EUR to 25 billion EUR (in the US).

Scaled network investments

Table 2-3 provides the summary of the weighted average scaled network investments in $€_{2018}$/MWh for both electricity and gas networks at transmission, distribution and aggregated levels for all three years of analysis for the EU27 and non-EU G20. Special caution should be taken when interpreting these figures as the weighted averages do not reflect many of the country specificities.

Some interesting trends can be observed. Based on the data below, in 2018, EU countries invested on average more in both electricity and gas networks than non-EU G20 countries. In the case of scaled electricity network investment, 2018 is the only year where the total scaled investments in the EU exceeded those in non-EU G20 countries. These results contrast the pattern of Table 2-2, where absolute investments by the non-EU G20 group largely surpasses that of the EU27 for all years and carriers. Interestingly, in the EU electricity distribution network costs generally make up the larger part of the total network costs, in the case of ID, IN, MX and SA transmission investments are higher.

With the exception of the non-EU G20 2014 gas investments, in all other cases investments in distribution networks are higher than in transmission, or slightly below it.

Table 2-3 Weighted average scaled network investments for the EU27 and G20 ($€_{2018}$/MWh)

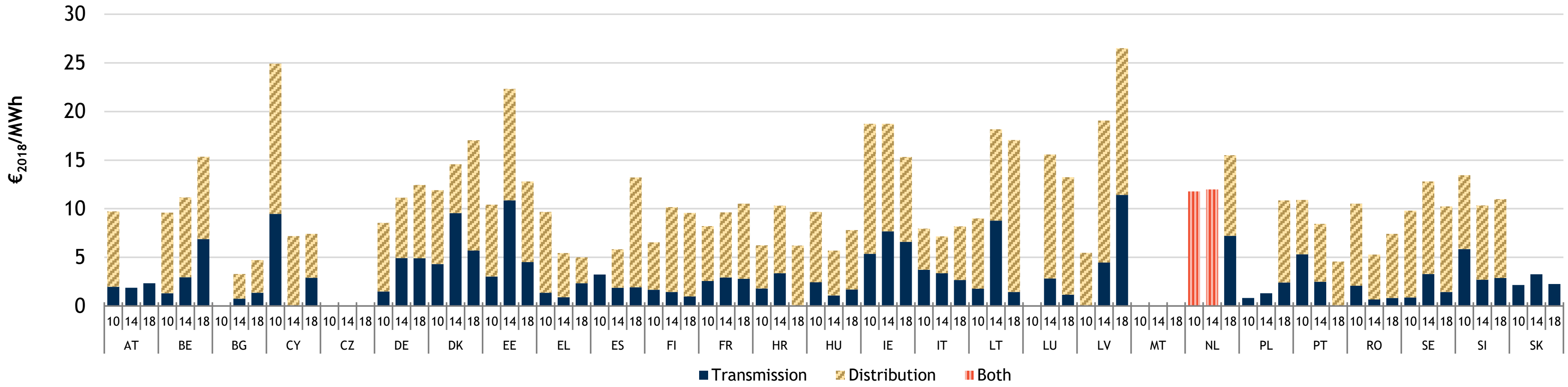
		Electricity				Gas			
Category	Year	Trans.	Distr.	Both	Total	Trans.	Distr.	Both	Total
EU27	2010	2.3	6.4	11.8	8.8	1.0	1.1	2.8	2.1
	2014	3.2	6.2	12.0	9.5	1.0	1.4	2.7	2.4
	2018	3.3	7.8		11.2	1.1	1.5	1.1	2.5
non-EU G20	2010	3.5	4.8	12.1	9.6	1.2	0.6	1.9	1.8
	2014	5.1	5.1	9.7	10.0	0.9	1.0	1.6	1.8
	2018	4.8	5.2	9.9	10.0	1.1	1.2	1.8	2.2

Figure 2-5 shows the electricity network investments in each EU Member State per domestic energy consumption for transmission and distribution in the years 2010, 2014 and 2018. On average, EU27 countries invested ~ 10 EUR/MWh in electricity networks. As in the case of electricity networks in absolute terms, no clear trends can be observed across countries based on total investments per energy consumption over time, due to the influence of various drivers mentioned in the section on total electricity and gas network investments above. These include stable electricity consumption, EU market integration, deployment of renewable energy generation, quality of service standards, among others. Total investments per energy consumption range from below ~ 3 EUR/MWh to more than 25 EUR/MWh across countries and years.

The countries that have the highest investments in electricity network costs in relative terms are CY, IE, LV and EE. The network investments of CY were exceptionally high in 2010 with ~ 24 EUR/MWh invested in transmission and distribution networks together. Interestingly, in 2014, the investment in electricity distribution was much lower, at around 3 EUR/MWh, the value for transmission is not available. Countries with relatively low investments in electricity network infrastructure compared to their domestic demand are BG and EL.

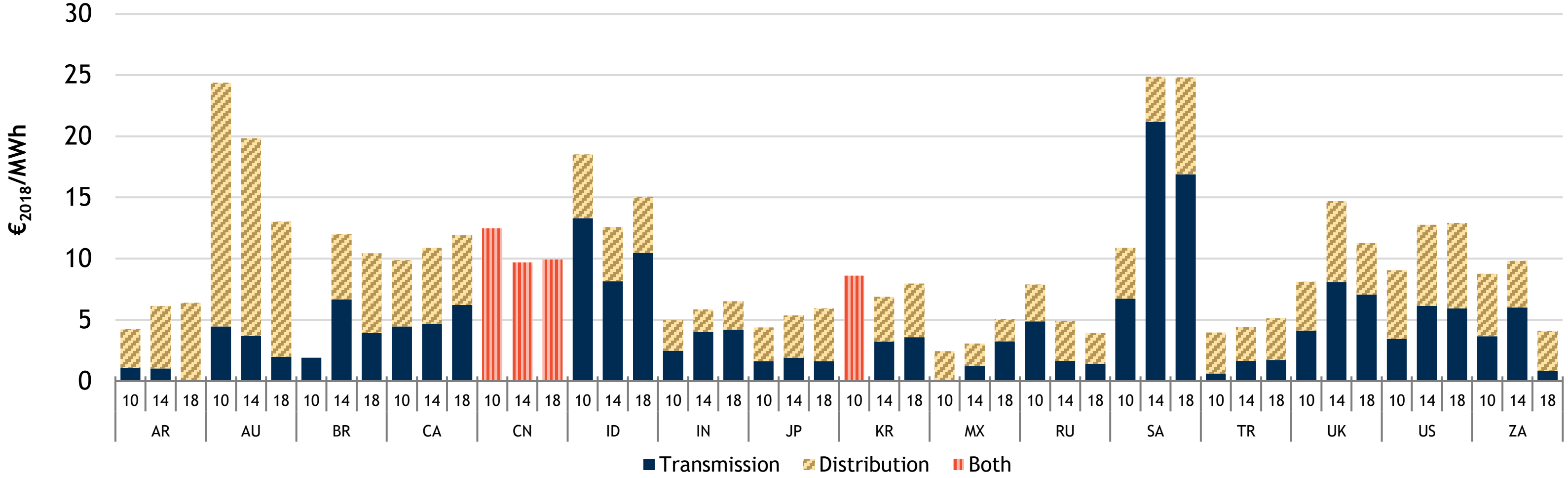
In the majority of EU countries, the relative investment levels in electricity distribution are higher than in transmission. For example, in EL in 2014 investments per MWh of consumption in distribution were almost 5 times as high as in transmission networks. In RO in 2014, investments in distribution networks were 6 times as high as in transmission. Similarly, in SE and FI the observed investments per MWh consumption in distribution were much higher than in transmission (~ 3 to 8.5 times). In contrast, in DK in 2014, investments in transmission were almost twice as high as in distribution.

Figure 2-5 Electricity network investments in the EU27 per domestic energy consumption for transmission and distribution, 2010-2018 (€2018/MWh)



Not shown (confidential): AT (2014, 2018 D), CZ (2010-2018 T&D), HR (2018 T), LV (2010 T), PL (2010-2014 D), SK (2018 D)

Figure 2-6 Electricity network investments in the non-EU G20 per domestic energy consumption for transmission and distribution, 2010-2018 (€2018/MWh)

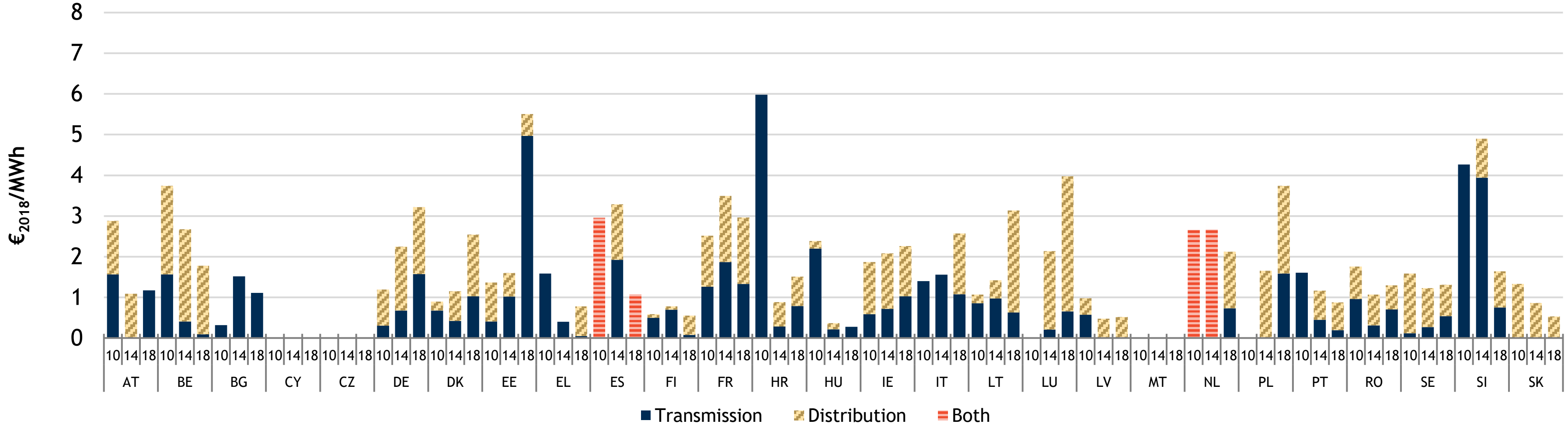


In the case of G20 countries the situation is different (see Figure 2-6). SA invested a significant amount corresponding to almost 25 EUR/MWh in electricity transmission networks in both 2014 and 2018. This is more than double the investment in 2010. In SA, transmission network investments made up the largest part of the total network investments per electricity consumed. AU is another G20 country that made large investments in electricity networks although these have decreased significantly from 2010 to 2018. Whereas in 2010, the total investment in transmission and distribution corresponded to more than 24 EUR/MWh they were only ~ 13 EUR/MWh in 2018. Another country with high network investments per domestic energy consumption is ID. In this country, like in SA, transmission costs make up the majority of the investments. In BR (except in 2010 where no distribution data is available), CA and US the electricity network investments per domestic energy consumption were around the 10 EUR/MWh mark. The investments in AR, IN, JP, KR, MX, RU, TR and ZA have been below the 10 EUR/MWh mark.

Figure 2-7 shows the scaled gas network investments in the EU27 per domestic energy consumption for transmission and distribution for the years 2010, 2014 and 2018. As in the case of absolute investments, no clear trends can be seen over time and between countries.

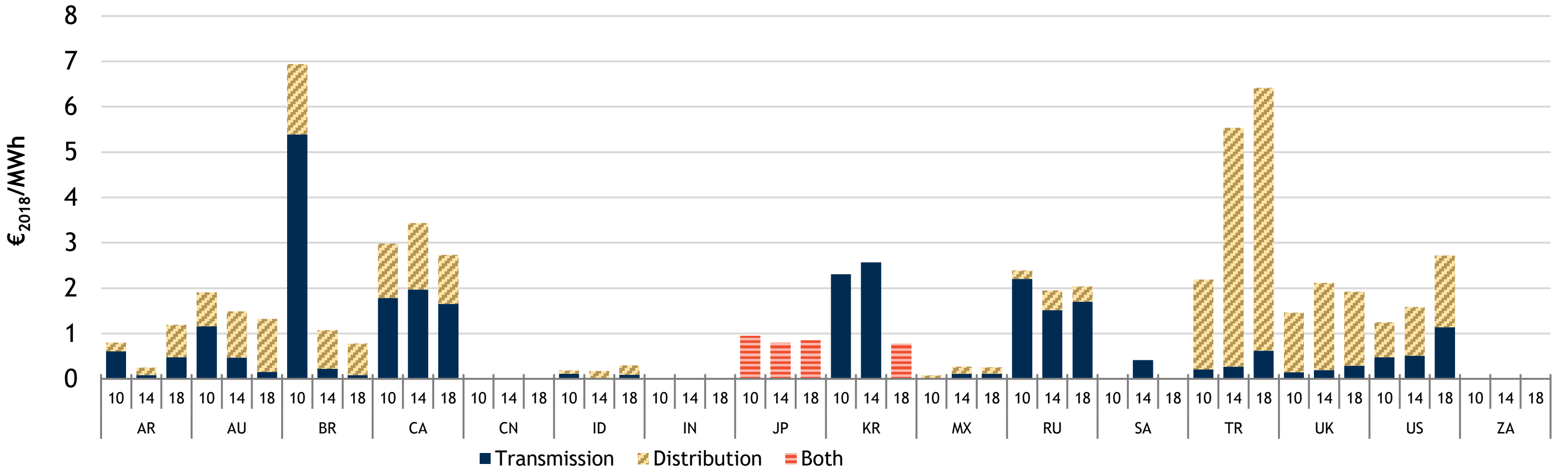
HR spent 6 EUR/MWh on transmission networks alone in 2010. Information on investment in distribution is not available for that year. Spending in gas networks per domestic energy consumption was substantially lower in 2014 and 2018 at ~ 1 EUR/MWh. In EE, large investments in gas networks were made in 2018 corresponding to ~ 5.5 EUR/MWh. The majority of these investments were on gas transmission networks. PL also had large spending on gas networks in 2018 of ~3.7 EUR/MWh. This spending was almost equally distributed between transmission and distribution networks. In SI, large investments in transmission networks were made in 2010 and 2014.The total investments in gas networks in SI decreased almost 3-fold from 2014 to 2018. In DE, DK, IE, LT and LU, investments in gas networks per domestic energy consumption increased over time. In LU, for example, the investments in gas networks per domestic energy consumptions almost doubled between 2014 and 2018. In contrast in BE and NL, investments in gas networks decreased over time. For SK only data on distribution investments can be disclosed, these investments have decreased over time. In ES, investments surpassed 3 EUR/MWh in 2014, but declined by ~ 2 EUR/MWh in 2018.

Figure 2-7 Gas network investments in the EU27 per domestic energy consumption for transmission and distribution, 2010-2018 (€2018/MWh)



Not shown (confidential): AT (2014 T), CZ (2010-2018 T&D), PL (2010, 2014 T), SK (2014, 2018 T)

Figure 2-8 Gas network investments in the non-EU G20 per domestic energy consumption for transmission and distribution, 2010-2018 (€2018/MWh)



Not shown (confidential): CN (2010-2018 T&D), IN (2010-2018 T&D)

In the case of non-EU G20 countries (Figure 2-8), BR exhibits the highest spending in 2010 at close to the 7 EUR/MWh mark due to the construction of major pipeline project between Brazil and Bolivia. TR spent ~ 5.5 EUR/MWh in 2014 and ~ 6.3 EUR/MWh in 2018. In 2010 and 2018, ~90% of these investments were directed towards distribution networks. In 2014 this percentage was even higher at ~ 95%. For CA, the highest spending of over 3 EUR/MWh was reported in 2014, in 2010 and 2018 the spending was slightly lower. In CN, investments in gas networks per domestic energy consumption decreased from 2010 to 2018. In contrast, in the US investments increased over time from ~ 1.2 EUR/MWh in 2010 to ~ 2.7 EUR/MWh in 2018. In the UK, investments remained relatively constant at ~ 2 EUR/MWh, which are largely made up of investments in distribution networks. AR surpassed the 1 EUR/MWh mark in 2018, but in previous years the investments were much lower. In AU, the investments in gas networks surpassed the 1 EUR/MWh in all 3 years; they were highest in 2010 with ~ 1.8 EUR/MWh. In IN, investments remained relatively constant over the period analysed. JP also maintained a constant investment of just below 1 EUR/MWh. In KR, only data on transmission investments is available. These investments significantly decreased between 2014 and 2018. MX is the non-EU G20 country with the lowest investments in gas networks per domestic energy consumption at below 0.3 EUR/MWh.

The investment ranges in gas networks per domestic energy consumption for the EU27 and non-EU G20 countries are generally comparable. No meaningful comparison can be made between trends on transmission versus distribution spending between both sets of countries as the variation within each set is too great.

The figures with scaled network investments support the previous analysis based on the absolute investments where investments in electricity networks are greater than in gas networks in both groups of countries. In the case of the EU27, total electricity investments per domestic energy consumption were in the range of around 3 EUR/MWh to more than 25 EUR/MWh across countries and years. In contrast, the amount spent on gas networks was in the range of between half a EUR/MWh to more than 6 EUR/MWh across countries and years. Whereas the average investments in electricity networks across countries and years were around 10 EUR/MWh, the average investments in gas networks were about 2 EUR/MWh, or a factor of 5 lower. In the case on non-EU G20 countries, total investments in electricity networks per domestic energy consumption ranged between around 3 EUR/MWh to 25 EUR/MWh across countries and years. In comparison, the investments in gas networks per domestic energy consumption were in the range of 0.25 EUR/MWh and slightly less than 7 EUR/MWh across countries and years. Thus, also in the case of non-EU G20 countries, investments in gas networks were much lower than in electricity networks. TR is the only country where the scaled network investments in gas exceeded those in electricity in all three years analysed.

Scaled network O&M costs

Table 2-4 provides the summary of the weighted average network O&M costs for both electricity and gas networks at transmission, distribution and aggregated levels for all three years of analysis for the EU27 and non-EU G20. Some interesting trends can be observed. In the EU27, the overall weighted average spending on both electricity and gas O&M has decreased between 2010 and 2018, although in the case of gas where was stable between 2010 and 2014. In the EU27, most of the weighted average spending on O&M is directed towards electricity distribution networks. In the G20 countries, the weighted average spending on electricity networks O&M remained stable around 6.4 EUR/MWh. The average spending on gas network O&M decreased, from 1.5 EUR/MWh in 2010 to 1.2 EUR/MWh in 2018. Hence, average spending on energy networks O&M per MWh in the non-EU G20 countries is between 40%

and 60% of that in the EU27. Multiple factors could contribute to that, including labour and material cost differences and higher service quality levels in the EU.

Table 2-4 Weighted average scaled network O&M for the EU27 and G20 (€$_{2018}$/MWh)

		Electricity				Gas			
Category	**Year**	**Trans.**	**Distr.**	**Both**	**Total**	**Trans.**	**Distr.**	**Both**	**Total**
EU27	2010	2.3	11.6		12.6	0.9	1.7		2.6
	2014	2.2	10.3		11.2	1.1	2.0		2.7
	2018	2.3	7.5		10.2	0.8	1.6		2.3
non-EU G20	2010	2.3	4.1	4.9	6.3	0.6	0.8	0.5	1.5
	2014	2.4	4.2	5.8	6.5	0.6	0.6	0.4	1.2
	2018	2.6	3.9	4.9	6.4	0.5	0.8	0.5	1.2

Figure 2-9 shows the spending on **electricity network O&M** in the Member States per domestic electricity supply for transmission and distribution in the years 2010, 2014 and 2018. It is important to note that there is, to a certain extent, a trade-off between investments and O&M in energy networks, with higher investments in new assets allowing to reduce the relative O&M. Also, lower O&M costs do not necessarily lead to lower system service costs, as these lower costs may result in lower quality of service and negatively impact network users.

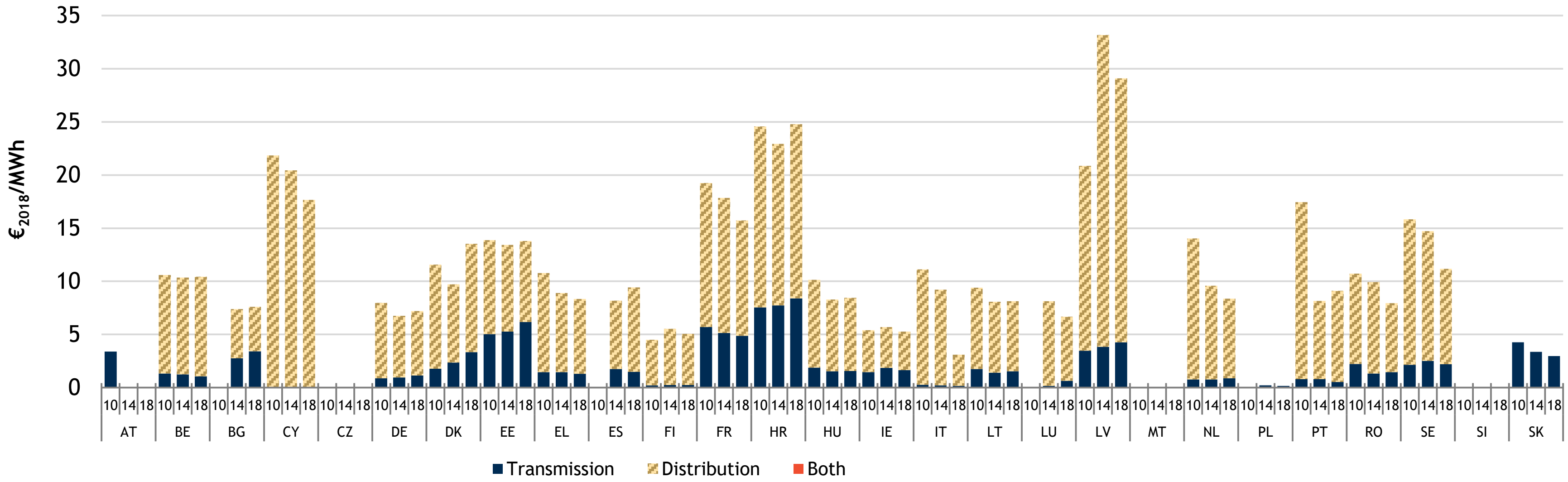
Countries with the highest spending on O&M per domestic energy consumption of electricity network are: CY, FR, HR and LV. LV's spending on O&M in 2014 was also very high, corresponding to ~ 33 EUR/MWh. This amount decreased in 2018 to ~ 29 EUR/MWh. CY's spending in 2010 was ~ 27.5 EU/MWh, decreasing to ~ 24 EUR/MWh, which is still a high value. HR spent around 25 EUR/MWh annually for the years analysed, while FR shows a decreasing trend, from slightly less than 20 EUR/MWh to approximately 15 EUR/MWh.

The following countries spent on average ~ 10 EUR/MWh or more on O&M: BE, DK, EE, NL, PT, RO and SE. The following countries spent close to or less than ~ 10 EUR/MWh: DE, EL, ES, FI, IE, HU, LT, and LU. In all EU27 countries and all years analysed, the costs of O&M for distribution networks is greater than that for transmission. In the case of LU in 2014, O&M costs for distribution networks were almost 50 times greater than for transmission. In the NL in 2010, they were 17 times greater.

In the case of non-EU G20 countries (see Figure 2-10), BR, AU and MX in 2018 were the biggest spenders on electricity network O&M per domestic energy consumption. In the case of BR, spending on O&M was highest in 2010 at ~ 15 EUR/MWh, decreasing to ~ 12 EUR/MWh during 2014 and remaining almost unchanged in 2018. In AU, spending on O&M decreased from ~12 EUR/MWh in 2010 to below 10 EUR/MWh in 2018. MX had the highest spending in 2018 amounting to close to 14 EUR/MWh. This amount represents an increase from 2014 and 2010: during both of those years, MX spent ~ 8 EUR/MWh. Information on O&M spending in ID was not available per network level. The country spent more than 8 EUR/MWh on O&M in 2010, 10 EUR/MWh in 2014 and more than 6 EUR/MWh in 2018. In the US and CA, spending on electricity network O&M remained relatively stable over the time period analysed at a little less than 8 EUR/MWh. In addition, in both countries the distribution between O&M for transmission and distribution is more or less equal. In IN, spending on O&M of electricity networks decreased over time from close to 6 EUR/MWh in 2010 to ~ 4 EUR/MWh in 2018. KR's and SA's spending over the three years analysed amounted to a little more than 4 EUR/MWh and remained relatively stable. JP's and RU's spending on O&M was below 4 EUR/MWh. In TR, spending on O&M of networks increased significantly from ~ 3.5 EUR/MWh in 2014 to ~ 6.4 EUR/MWh in 2018. This increase was largely driven by the almost tripling of spending on transmission network O&M.

On average, EU27 countries spend more on O&M of electricity networks per domestic energy consumption than non-EU G20 countries. In both sets of countries, the spending is mostly directed towards the O&M of distribution networks.

Figure 2-9 Electricity network O&M in the EU27 per domestic energy consumption for transmission and distribution, 2010-2018 (€2018/MWh)



Not shown (confidential): AT (2014, 2018 T&D), CY (2010-2018 T), PL (2010 T, 2010-2018 T&D), SI (2010-2018 T&D), SK (2018 D)

Figure 2-10 Electricity network O&M in the non-EU G20 per domestic energy consumption for transmission and distribution, 2010-2018 (€2018/MWh)

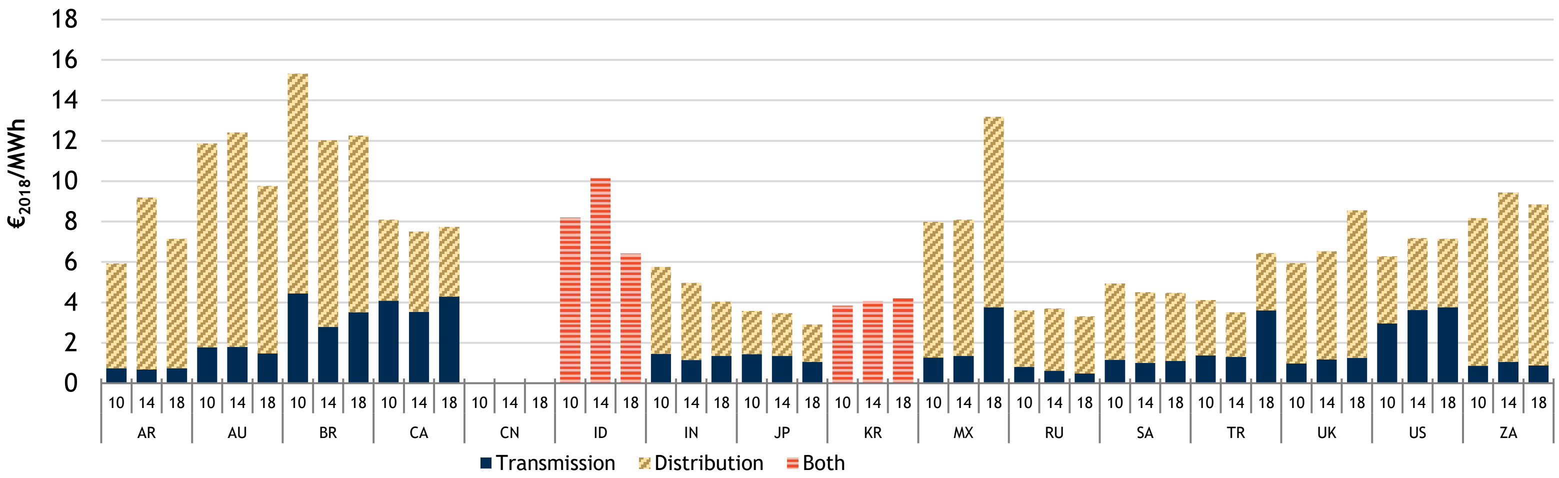


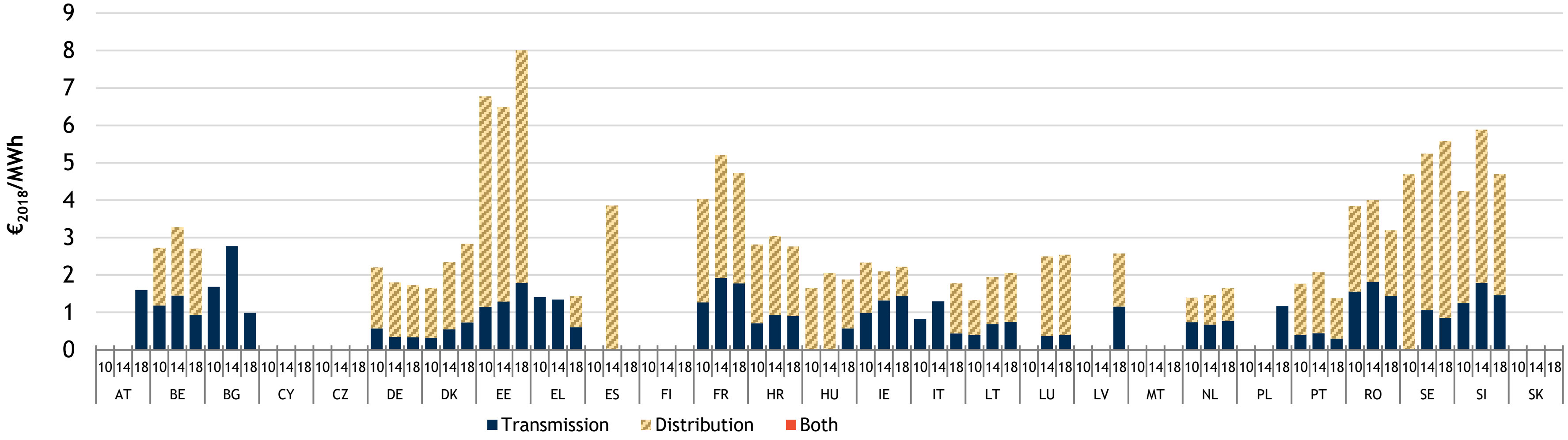
Figure 2-11 contains information on gas network O&M in the EU27 per domestic energy consumption for transmission and distribution in 2010, 2014 and 2018. In terms, of amount of overall investments over time, no clear trends can be observed across countries.

EE, FR, HR, SE and SI were among the countries with highest overall spending in gas network O&M per domestic energy consumption. HR in 2014 spent the highest amount of money on gas network O&M of all EU27 countries over all three years of analysis. This amount corresponded to ~ 9.7 EUR/MWh. This was reduced to ~7.5 EUR/MWh in 2018. In 2018, EE spent 8 EUR/MWh in gas network O&M. This amount was an increase from 2014 when the country spent ~ 6.5 EUR/MWh. SE spent ~ 5.8 EUR/MWh on gas network O&M in 2018. SI and FR both spent ~ 4.7 EUR/MWh on gas network O&M in 2018. BE, DE, DK, EL, IE, LT, LV, NL and PT spent between ~ 1.2 EUR/MWh and 2.9 EUR/MWh. In general, distribution networks received significantly larger budgets than transmission networks. IE in 2014 and 2018 and NL in 2010 constitute the only exceptions.

Figure 2-12 presents gas network O&M spending in the non-EU G20 per domestic energy consumption for transmission and distribution between 2010-2018. AR's O&M spending increased from ~ 1 EUR/MWh in 2010 to 5.5 EUR/MWh in 2018. In BR and CA, investments decreased over the same period. In BR, they decreased from ~ 3 EUR/MWh to slightly more than 1 EUR/MWh. In CA, the change was from more than 3 EUR/MWh in 2010 to ~ 2.1 EUR/MWh in 2018. In AU, gas network investments remained constant at around 1 EUR/MWh. Whereas for AR, AU and BR investments in distribution constitute the vast majority of the total network O&M this is not the case in CA. In 2018, CA spent 52% of its O&M on transmission. ID, RU, SA, TR and US spent ~ 1 EUR/MWh on gas network O&M. In 2018 JP spent half a EUR/MWh and MX spent ~ 0.34 EUR/MWh on gas network O&M.

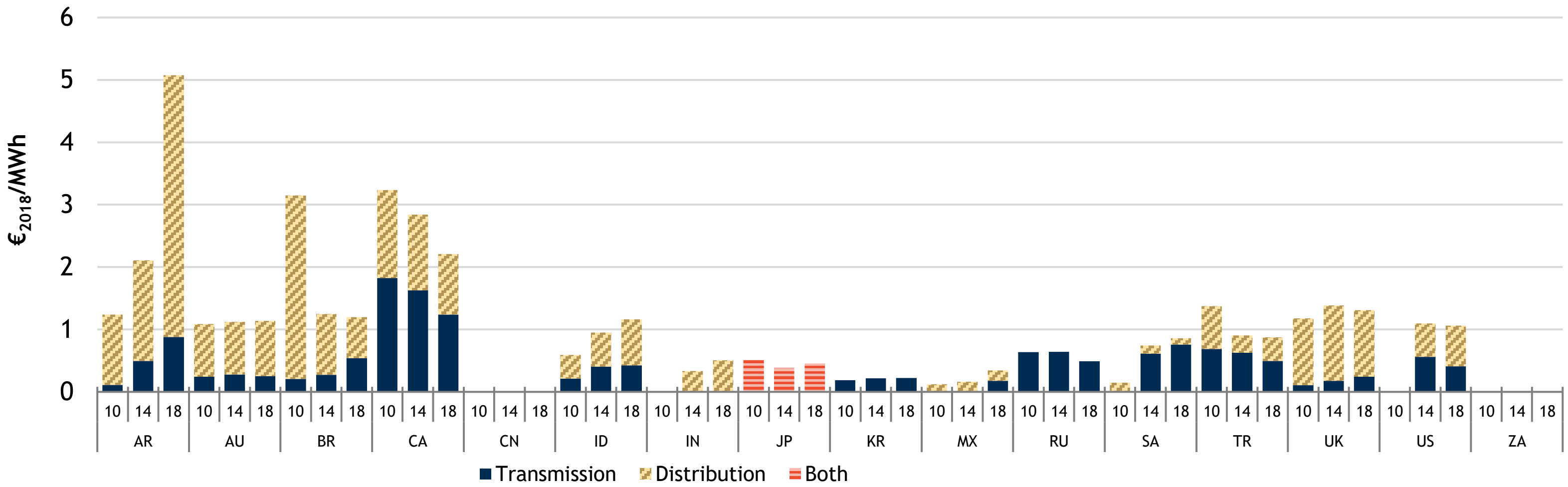
Generally, EU27 countries spend more on gas network O&M per domestic energy consumption than non-EU G20 countries. As in the case of investments, in general, O&M of electricity networks is more costly than O&M of gas networks in both sets of countries. In the case of EU27 countries, the cost of O&M of electricity networks across countries and time was in the range of 4 EUR/MWh (FI, 2018, only distribution) and 33 EUR/MWh (LV, 2014). In contrast, the money spent on O&M of gas networks across EU27 countries varied between ~ 1 EUR/MWh (PL, 2018) and close to 10 EUR/MWh (HR, 2014). In the case of non-EU G20 countries the variation in spending on electricity O&M across countries and across time was between less than 3 EUR/MWh (JP, 2018) and more than 15 EUR/MWh (BR, 2010). None of the countries analysed from either EU27 or non-EU G20 spent more on gas network O&M than on electricity network O&M.

Figure 2-11 Gas network O&M in the EU27 per domestic energy consumption for transmission and distribution, 2010-2018 (€2018/MWh)



Not shown (confidential): CZ (2010-2018 T&D), SK (2010-2018 T&D)

Figure 2-12 Gas network O&M in the non-EU G20 per domestic energy consumption for transmission and distribution, 2010-2018 (€2018/MWh)



2.2.2 System services costs

Figure 2-13 shows the electricity system cost components per domestic energy consumption in 2010, 2014 and 2018 in the EU27 Member States.

Interpreting the system services cost should be done with caution as it must be noted that some system services are not remunerated in Member States (possibly for only part of the period considered) or disaggregated data is not available, only for total system services costs. The lack of available data does not mean there are no system service costs for a particular country.

Natural gas system service costs have lower availability of data, but overall, for both electricity and gas data availability is much lower than for investments or O&M costs, for most Member States. Further actions should be taken to improve data availability and comparability on disaggregated system services costs. The ENTSOs transparency platforms constitute the best channel to advance data transparency and comparability.

Attention should also be paid to a differentiation between total and residual system service costs. Part of the system service costs may be recovered through organised markets (the most typical examples being the recovery of balancing costs from Balancing Responsible Parties), or wholly or partially (i.e. the residual system service costs) from network users, through tariffs. Typically, non-frequency ancillary services are recovered from network users through tariffs. Frequently, data is only available for the residual rather than the total system costs.

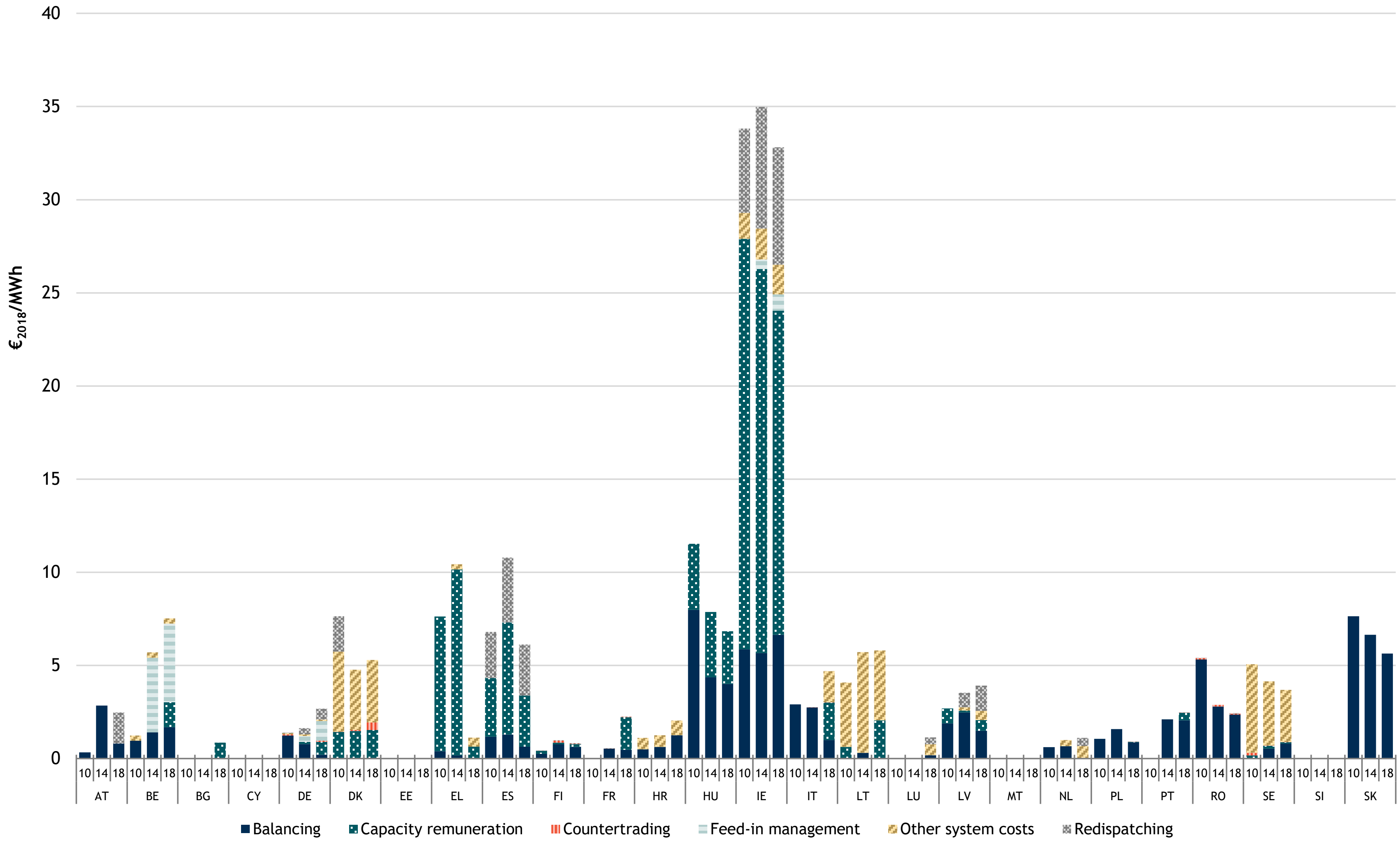
In IE total system costs amounted to almost 30 EUR/MWh in 2014 and ~28 EUR/MWh in 2018. These costs are largely made up of capacity remuneration, which in 2010 constituted 78% of all system costs and in 2018, 62%. The rest of the costs in IE were mostly composed of redispatching and balancing costs. In 2014 and 2018 feed-in management also made up a small portion of the total system costs. Capacity renumeration also made up a large portion of the system costs in EL and ES in 2014. In EL, in 2010 and 2014 capacity renumeration made up around 95% of the system costs with data available.

In BE feed-in management costs make up a large portion of the total system costs. In 2014 they made up 70% of all system costs and in 2018, 56%. In 2018, capacity renumeration constituted about 18% of system costs; however, it was not a component of system costs in 2014 or 2010. In DK, system costs were comprised mostly of capacity renumeration and other system costs. In 2010, on top of those costs, redispatching also constituted an important system cost. In 2018, countertrading represented around 8% of all system costs. In SE and LT other system costs are the major component of total system costs. In DK, HR, NL and LU other system costs also constitute an important component of total system costs.

In almost all Member States, balancing is an important system cost component. The increasing penetration of intermittent renewable energy sources can increase the balancing costs, especially if renewable energy projects are not incentivised to reduce imbalances[14] and in countries with other factors contributing to high balancing costs, such as MSs with limited interconnection capacity. In SK, balancing costs are high although they have declined from ~7.6 EUR/MWh in 2010 to about 5.6 EUR/MWh in 2018. In RO, balancing costs also declined from more or less 5.3 EUR/MWh in 2010 to about 2.3 EUR/MWh in 2018.

[14] CEER indicates that in mid-2018, out of 27 countries surveyed, RES producers had no balancing responsibilities in nine countries, while in selected RES producers had balancing responsibilities in further eight. See CEER (2018) Status Review of Renewable Support Schemes in Europe for 2016 and 2017.

Figure 2-13 Electricity system cost components per domestic energy consumption, 2010-2018 (€2018/MWh)



Not shown (confidential): CZ (all system cost components), LV (redispatching, other system costs), SK (Balancing, other system costs)

3 Network national regulatory frameworks and the cost of service in EU Member States

This section provides an overview of the national regulatory frameworks regarding the revenue-setting elements for network operators, and discusses the potential structural under- or over-recovery of network costs. The adequacy of national regulatory frameworks to achieve other objectives such as security of supply, sustainability, competition amongst market operators and innovation is out of the scope of this section.

National regulatory frameworks for determining allowed revenues of network operators are complex, and besides the multiple national specificities which influence network costs, are further affected by e.g. the corporate structure of the energy sector and the cost of equity and debt. National regulatory frameworks must thus be analysed holistically, and structural under- or over-recovery can only be determined after a thorough analysis.

Further distinction should be made between structural and temporary under- or over-recovery of costs. Most regulatory frameworks foresee the recovery of unavoidable temporary mismatches between the effective cost of service and allowed revenues of network operators in subsequent regulatory years. The focus of this section is structural under-/over-recovery, where abnormal shortfalls or surpluses are not compensated in subsequent years (until measures are taken to eliminate the structural mismatch). Differentiating abnormal from normal profits is also not straightforward, and not addressed here.

3.1 National regulatory frameworks in 2018

The CEER report on 2018 Regulatory Frameworks for European Energy Networks surveys the main revenue-setting regulatory parameters for gas and electricity transmission and distribution system operators in Europe.[15] The main findings for 2018 are described here, without reproducing the details, available in the report annexes. The CEER study covers 24 Member States (excluding BG, CY, MT and SK) plus NO. Significant data changes in the 2019 regulatory frameworks edition are also indicated in this section.[16]

Regulation generally allows to recover efficient operation and maintenance costs. For both electricity and gas, and transmission and distribution, most Member States applied some form of **incentive-based regulation**, with actual cost-plus regulation being rather rare. When the rate-of-return was used without price or revenue caps to determine allowed revenues, this was most commonly applied only to the capex building block, while opex were subject to some sort of cap.

Concerning the specific **efficiency incentives** in the national regulatory frameworks, most regimes applied such incentives to opex costs for electricity and gas in both network levels, in the form of an X-factor reducing the opex cap year-on-year. Regarding specific incentives to reduce electricity network losses, the 2nd CEER Report on Power Losses[17] indicates that, with the available information, 15 Member

[15] CEER (2019) Report on Regulatory Frameworks for European Energy Networks. C18-IRB-38-03
[16] CEER (2020) Report on Regulatory Frameworks for European Energy Networks 2019. C19-IRB-48-03c
[17] CEER (2017). CEER Report on Power Losses. C17-EQS-80-03

States in 2019 had regulatory incentives to reduce power losses in distribution,[18] and 9 in transmission.[19] CEER notes four main regulatory approaches for addressing losses: to include them in the general revenue cap, to pass-through losses up to a certain percentage cap to consumers, to give network operators a lump-sum ex-ante amount to cover losses, or to implement a reward/penalty system if losses are below/above a certain reference value, respectively.

For both energy carriers and network levels about one quarter of the national frameworks applied efficiency incentives to investments, thus less frequently than for opex. Nonetheless, this does not mean that in the other MSs there were no incentives for network operators to realize efficient investments, as generally the regulator approves their investment plans.

The **rate of return** for determining allowed revenues for electricity networks was most frequently a pre-tax nominal weighted average cost of capital (WACC), followed by the pre-tax real WACC (i.e. excluding inflation and before corporate taxes). For gas, the use of pre-tax nominal and real WACC accounted for around 50% and 30% of the cases, respectively. Four countries (BE, DE, DK and ES) did not use the WACC to determine the rate of return for electricity and gas transmission, while two countries (DE and ES) did not use it for electricity and gas distribution revenue setting.

The **regulatory asset base** (RAB) is a central determinant of the allowed revenues of network operators, and according to CEER, it should include 'the assets necessary for the provision of the regulated service in their residual (depreciated) value'. In addition to the commissioned physical assets necessary for the provision of the regulated services, regulatory frameworks may or may not include in the RAB elements such as assets under construction or working capital. The RAB was generally determined based on historical costs (around one third of the national regulatory frameworks). Nonetheless, CEER identified significant differences in the actual approach to determine the RAB between Member States and also between energy carriers and network levels.

Concerning the **depreciation** of the network operators' assets, almost all NRAs imposed a straight-line depreciation approach (except EE) for both electricity and gas networks. Depreciation periods for typical electricity and gas network assets (electricity lines and gas pipelines) at the transmission and distribution level averaged between 30 and 50 years. The following could also be identified:

- ✓ **Electricity vs gas depreciation periods**: The depreciation period (i.e. the regulatory asset base lifetime) within a single country was similar for typical electricity and gas network assets for the majority of Member States with data available;
- ✓ **Transmission vs distribution depreciation periods**: Electricity depreciation periods for distribution were the same as or longer than for transmission. Gas depreciation periods for distribution were the same as or shorter than for transmission.

[18] BE (Flanders and Wallonia) CZ, DE, DK, EL, ES, FR, HU, IT, NL, PL, PT, SE, SI, SK
[19] DE, DK, FR, HU, NL, PL, SE, SI, SK.
Although in their report CEER does not include DE as one of the countries with regulatory incentives to reduce losses in distribution or transmission, DE *de facto* does incentivises the reduction of power losses. In DE, power losses in distribution are included in the benchmarking process and the amount of power losses determined is fixed for the regulatory period. However, the prices are adjusted to the fluctuating market prices on a yearly basis. In the case of transmission, costs from power losses are treated as pass-through-costs, but a Bonus/Malus approach is applied.

3.2 Structural over- or under-recovery of the efficient network cost of service and influence of the national regulatory frameworks

The consequences of structural over- or under-recovery of the network cost of service are very different. With the former, network users are disproportionately burdened through excessive network tariffs, while structural under-recovery threatens the financial stability of network operators and their capacity to realize the necessary investments as well as operation and maintenance of the network. Both approaches can lead to suboptimal investment decisions and higher overall system service cost, as well as impacting the quality of the network services provided. A number of main risks for over- or under-recovery of the network cost of service are presented in Table 3-1.

Over-recovery of network costs may occur due to the remuneration of inefficient costs incurred by the network operators (e.g. remuneration for inefficient investments or maintenance), or due to the remuneration of efficient costs above the cost of capital of the operator and out of proportion with adequate efficiency incentives. This could result in a remuneration level for network operators that exceeds the market reference, taking into account the relatively low risk level for regulated network operators. Under-recovery will occur when allowed revenues do not cover the incurred efficient cost of service (including adequate remuneration of capital), and may lead to inefficient investment, operation and maintenance costs.

A differentiation must be made between the under-/over-recovery of network costs from the under-/over-recovery of other costs for the provision of energy to final consumers. For example, DG ECFIN[20] indicates that retail price regulation and the cost of renewable energy support represent major contributors to tariff deficits in the EU electricity sector. However, these two major causes are not directly related to network costs, although they may affect transmission and distribution system operators as these may have obligations for (last resort) supply or renewable energy support.

The CEER studies[21] on cost-efficiency benchmarking analysed 29 gas and 17 electricity transmission system operators (TSOs) as indicated. For gas, the study defines a final average efficiency of 79%, meaning that TSOs could save about 20% of the benchmarked comparable totex. The study also identifies six outliers and the four highly-efficient, best practice peers (out of 29 gas TSOs). For electricity, the final average efficiency is 89.8%, indicating the potential benchmarked comparable totex which could be saved is about 10%, and hence more limited than for gas. Four outliers and four best practice electricity TSOs are identified, a higher proportion than for gas given the sample of only 17 electricity TSOs.

[20] DG ECFIN (2014) Electricity Tariff Deficit - Temporary or Permanent Problem in the EU?
[21] CEER (2019) “Project CEER-TCB18 Pan-European cost-efficiency benchmark for gas transmission system operators: main report”
CEER (2019) “Project CEER-TCB18 Pan-European cost-efficiency benchmark for electricity transmission system operators: main report”
The methodological approach was based on proposing a proxy for the diversified asset base of operators. The data analysed was made comparable by limiting the scope of comparable activities, controlling for systematic variation in labour costs, standardising asset life-times and capital costs, controlling for joint assets and cost-sharing, removing country-specific elements influencing costs (e.g. specific taxes, land etc.) and adjusting capital costs for inflation.

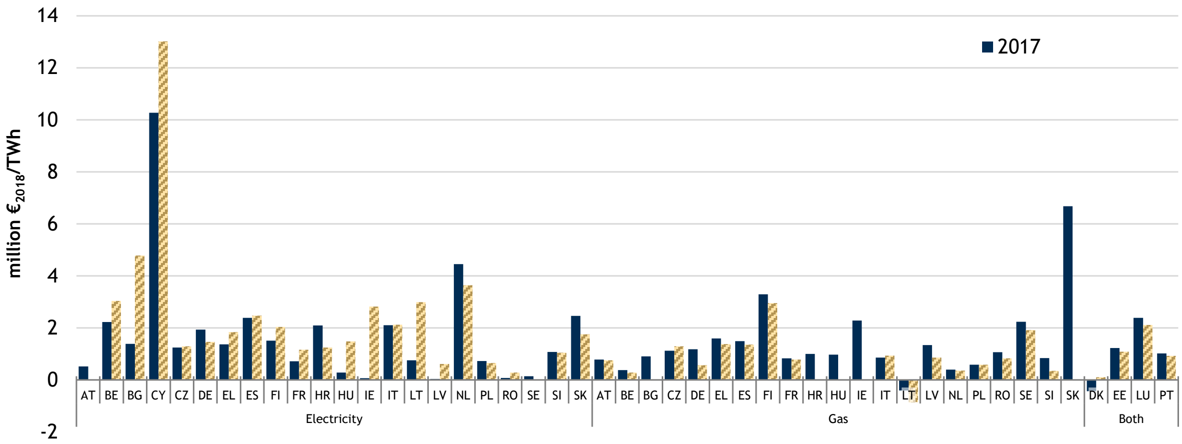
Table 3-1 Main risks for over- or under-recovery of the network cost of service

Risk	Description	Potential effect on over-/under-recovery
Lack of robust planning scenarios	Errors in the forecast of network connections and access will lead to differences in forecasted and actual revenues. Certain regulatory frameworks (e.g. price-cap) may (partially) place forecast risks to network operators.	Over- or under-recovery if not compensated in subsequent regulatory years.
Capex bias / gold-plating	The national regulatory framework may not require the balanced consideration of capex and opex solutions, to disincentivize overinvestment by network operators (to increase the capital remuneration).	Over-investment by network operators will lead to over-recovery as the capital remuneration is above the efficient level.
Incorrect asset depreciation rules	Depreciation periods may be significantly different than the actual technical lifetimes of network assets and/or the accounting depreciation periods.	Over-recovery of asset investments costs through the remuneration of the RAB in case of excessively long depreciation periods, and potential under-recovery in case of short depreciation.
Possible overestimation of WACC	The methodology may overestimate WACC, as debt and market (equity) risk premiums for regulated assets is lower than for assets exposed to market risks.	Over-recovery of the cost of service through 'excessive' remuneration of the RAB.
Inadequate economic efficiency incentives	Conservative setting of the economic efficiency incentive (e.g. X-factor) will not pressure network operators to increase the efficiency of their opex costs (and less frequently capex). Conversely, inadequate requirements on economic efficiency (e.g. excessive X-factor or inclusion of non-controllable costs) will not be attained by network operators.	Over- or under-recovery depending on conservative or excessive efficiency requirements.
Inadequate re-evaluation of RAB	If a re-evaluated RAB is used for determining the capital remuneration, incorrect methods or infrequent re-evaluation may lead to significant differences to the actual RAB.	Over- or under-recovery depending on market circumstances (e.g. strong inflation) and frequency (infrequent re-evaluations may lead to greater deviations from the actual RAB).
Incorrect remuneration of working capital	RAB components may include working capital. Only the necessary working capital for the operations should be remunerated.	Over-recovery due to the remuneration of non-efficient working capital, and this moreover incentivizes operators to increase working capital.
Incorrect remuneration of assets under construction	RAB components may include assets under construction. The cost of capital for construction could be included in the RAB.	Under-recovery (and/or under-investment) due to non-remuneration of the cost of capital of assets under construction, depending on national circumstances.
Third-party contributions are not excluded from RAB	Network operators may receive contributions to fixed assets from third parties, thus not incurring in the respective capital costs, entirely or partially.	Over-estimation of the RAB and thus excessive remuneration of capital leading to over-recovery.
Approach to leased assets	Leased assets may or may not be included in the RAB. Different treatments to capex and opex would affect leasing decisions if leased assets are treated as capex.	Over-recovery if network operators may increase remuneration by leasing assets and accounting as capex, hence included in RAB.
Tariff setting interference	Interference in network tariffs unjustified by policy objectives, using blunt (untargeted instruments) and not compensating network operators will impact revenues, e.g. depressing tariffs to control inflation.	Under-recovery due to uncompensated loss of revenue by network operators.

An overview of net (after taxes) profits or losses of electricity and gas TSOs in the EU for 2017 and 2018 is presented in Figure 3-1, based on their financial statements.[22] The overall profits or losses should not be compared, as besides some points pertaining to the parent companies which conduct other activities, the national context, regulation and accounting practices vary. Nonetheless, it can be seen that nearly all TSOs had a net profit in the considered years, with the exception of a gas TSO in Lithuania (Amber Grid) and a gas and electricity TSO in Denmark (Energinet, only in 2017).[23]

Therefore, there is no indication that transmission network tariff deficits for electricity and gas were a matter of concern in the large majority of Member States for the years surveyed. However, the covid-19 pandemic, and the resulting fall in energy demand and potential rise in energy bill payment defaults ensuing measures taken by governments should impact the most network operators' cost of service recovery. Already, delays in investment and planned network maintenance are taking place.[24] However, it is not within the scope of this study to address this aspect.

Figure 3-1 Profits/losses of electricity and gas TSOs (or parent companies) per energy consumption in the EU27, 2017-2018



[22] Or their parent companies when separate financial statements were not available. Profits or losses of TSOs in a same country are added up (TSOs in a same country all presented profits in the years of analysis). TSOs active in multiple countries (e.g. DE and NL) are assigned to the country of the parent company.
[23] The main reason for Amber Grid's losses was the value revaluation of property, plant and equipment. When the new regulatory period 2019-2023 for natural gas transmission services began, Amber Grid was already considering for the new period the methodology for determining the rate of return on investment approved by the Lithuanian regulator in 2015 for the previous period. The rate of return was then recalculated and set at 3.33%, lower than the rate applied in the previous regulatory period (7.09%) and leading to the observed losses (according to Amber Grid's 2018 Annual Report). In the case of Energinet, the net loss in 2017 was caused by the re-evaluation of the residual value of gas storage assets (Lille Torup) by DKK 320 million, due to environmental restrictions to the assets' operation (see Energinet's Årsrapport 2017).
[24] See for example Febeg (2020) Economische impact Covid-19 Energiesector; Energy Community Secretariat (2020) COVID-19: Security of energy supply monitoring; PV Magazine (2020) Impact of Covid-19 on the global energy sector.

4 Network cost allocation

4.1 Network tariff principles in EU legislation

This section introduces the network tariff principles used by regulators and, if applicable, network operators to define the allocation of the network cost of service to the different network users. CEER[25] indicates guiding principles for distribution network tariff structures, which can be generalized to all electricity and gas networks:[26]

- ✓ **Cost reflectivity**: Tariffs paid by consumers should reflect the network costs that they cause, as well as any benefits they bring to the network, so that tariffs are non-distortionary; decisions by users concerning connection and use of the network should not be influenced by non-cost reflective tariff components;
- ✓ **Cost recovery:** DSOs and TSOs should be able to efficiently recover incurred operational and investment costs, including connection charges and system service costs through the network connection and access tariffs;
- ✓ **Non-discrimination:** There should be no undue discrimination among network users. Tariff determination should be done on the basis of network costs caused or avoided due to the network user;
- ✓ **Transparency:** the methodology for calculating tariffs should be transparent and accessible to all stakeholders;
- ✓ **Predictability:** Tariffs should be predictable for the network users to enable their estimation of incurred network connection and access costs, and to facilitate investment decisions. This does not mean tariffs may not change, but rules for determining these should be clear and tariffs predictable, as far as possible;
- ✓ **Simplicity:** Tariffs should be easy to understand as far as possible, in order to support transparency and predictability, thus providing the adequate information for network users to take their investment and operational decisions.

It is not possible to fully satisfy all the tariffication principles, as they may be conflicting and more importantly, it is impossible to adequately assign all indirect costs to the concerned network users. For example, standardised network tariffs (postage stamp approach) without locational components are de facto not fully *cost-reflective*, while 'individualised' network tariffs would be *cost-reflective*, but not comply with other criteria such as *simplicity* and *predictability*. Also, the capital intensity and discrete (lumpy) nature of network investments induces the deployment of assets with excess capacity forecasting future growth of the network use, whose charging from present network users (in line with the *cost recovery* principle) would contradict the *cost reflectivity*, as future network users should bear part of the costs. Therefore, it is not possible to derive fully optimal network tariffs.

EU legislation[27] refers to the principles of *cost reflectivity, cost recovery, non-discrimination and transparency*, while *predictability and simplicity* are not explicitly addressed. The formulation of the principles for gas and electricity tariffs also slightly differs in the different EU legislative pieces. For example, *cost reflectivity* is addressed for both carriers and network levels in the Electricity and Gas

[25] CEER (2017) Electricity Distribution Network Tariffs - CEER Guidelines of Good Practice
[26] The seventh principle *non-distortionary* is combined with *cost reflectivity*
[27] Specifically, the Gas Directive and Regulation, and recast Electricity Directive and Regulation.

Regulations and Directives, while the recast Electricity Regulation only indicates that transmission tariffs should reflect fixed costs, not referring to variable costs.

Besides the principles above, network tariffs may be influenced by a number of other factors. It must first be noted that ACER[28] has indicated that network tariffs should not be used to subsidise energy technologies, which, if justified, should be done through specific policy mechanisms separate from network tariffs. In a broader sense, network tariffs should not (cross-)subsidize any network user, in alignment with the cost reflectivity and non-discrimination principles. Examples of cost-reflective tariff practices include partial discounts to eliminate double charging to storage.[29] Similarly, discounts to network users with high utilisation factors reflect their reduced contribution to network costs rather than constituting a policy measure. In addition, connection or access tariff discounts could be provided to certain users reflecting avoided investment (i.e. transmission or distribution investment deferral) or O&M expenditures by network operators.

However, certain policies may still influence tariff design in certain Member States, mainly related to industry competitiveness and energy and climate policies. Hence, not fully cost-reflective network tariff discounts are provided in certain Member States for e.g. energy-intensive or other businesses, and for renewable energy producers. Alternatively, net metering is a measure employed in multiple Member States to promote the behind-the-meter deployment of renewable energy sources. Also, significant discounts for new electricity storage such as full network tariff exemptions may be provided, motivated by energy policies aiming to increase the system flexibility through storage investments, while for natural gas storage and LNG terminals discounts on network tariffs are motivated by their contribution to security of gas supply.

Network cross-subsidies could occur if costs related to connection, access and system services are not recovered from the network users causing them. Care must be taken in considering cost allocation methods as (cross-)subsidies. A certain tariff structure rewarding the system benefits provided by certain network users (e.g. deferred investment costs thanks to distributed generation) may actually increase the cost-reflectiveness of network tariffs as indicated, and therefore should not be considered as cross-subsidization. This report does not analyse eventual reverse subsidization, that is the provision of monetary funds or positive externalities from system operators to authorities or the economy in general.

4.2 Network cost allocation in the EU Member States

The adequacy of the network connection and access tariffs vis-a-vis the tariff principles depends on multiple interacting aspects such as the relative tariff levels for energy injection and off-take, the split between capacity, commodity, fixed and other components, as well as the differentiation of tariffs according to time and location, among other aspects.

[28] ACER and CEER (2019). The Bridge Beyond 2025 Conclusions Paper.

[29] On energy storage the recast Electricity Regulation indicates that it should not be discriminated, either positively or negatively. Also, double charging should be avoided. The regulation indicates that *"a discount of at least 50 % shall be applied to capacity-based transmission tariffs at entry points from and exit points to storage facilities."* However, if a storage facility is connected to two different transmission systems or system operators, discount should not be applied as this *"would benefit these network users compared to other network users booking capacity products without a discount at interconnection points or using storage facilities to transport gas within the same system."*

The following sections assess some of the relevant aspects for the EU Member States, indicating which approaches are deemed to be compatible with the tariff principles, especially for cost-reflectiveness, recovery and non-discrimination.

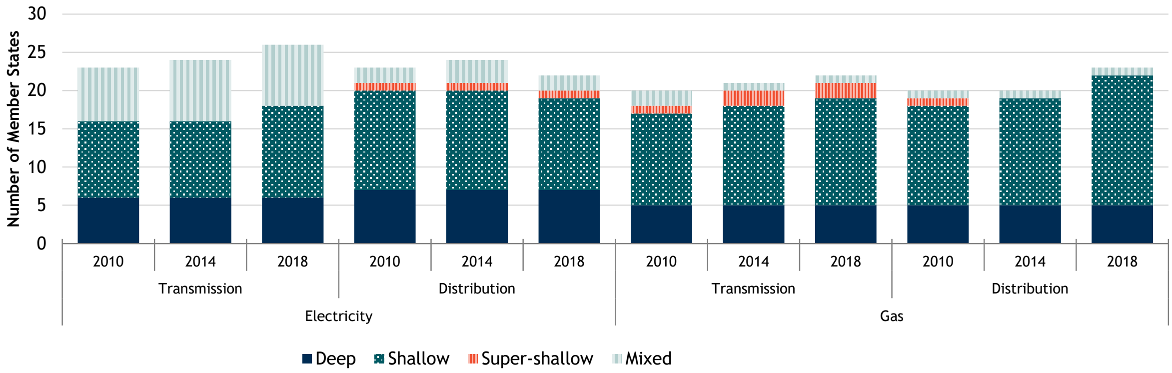
4.2.1 Cost allocation through network connection charges

Figure 4-1 presents the connection cost allocation[30] in the Member States with available data.

For **electricity transmission** in 2018, 12 out of 26 MSs applied shallow connection costs, while 6 applied deep connection costs and 8 mixed ones.[31] The number of MSs with deep connection costs remained unchanged from 2010 to 2018. However, the number of MSs reporting shallow connection costs increased from 10 in 2010 and 2014 to 12 in 2018. Similarly, the number of countries reporting mixed connection costs increased from 7 in 2010 to 8 in 2014 and 2018. For **electricity distribution** in 2018, 7 MS applied deep connection costs and 12 applied shallow ones. CZ was the only country applying super-shallow connection costs from 2010 to 2018. AT and FI applied mixed connection costs from 2010 to 2018..

In the case of **gas transmission**, in 2010 5 MSs applied deep connection costs, 12 applied shallow, SE and CZ applied mixed connection costs and SI applied super-shallow connection costs. In 2014 this picture remained unchanged, except data is available indicating one additional MS applied shallow connection costs then, and CZ went from applying mixed connection costs to applying super-shallow ones. The only change in 2018 compared to 2014 is that data is available indicating one additional MS (14 in total) using shallow connection costs. For **gas distribution**, 5 MSs applied deep connection costs and only SK applied mixed connection costs across all 3 years. PT applied super-shallow connection costs in 2010. Data is available indicating at least 13 MS applied shallow connection costs in 2010, 14 in 2014, and 17 in 2018.

Figure 4-1 Connection cost allocation in the EU (number of MSs applying approach)



There was a similar distribution of connection cost approaches in the EU, with shallow connection costs being most common among MSs, followed by a deep approach. Mixed connection approaches were more prevalent in electricity transmission. Full application of super-shallow approaches was much less common.

[30] How connection costs that are allocated to a new network user, categorized as:
a) Super-shallow connection costs, where all costs are socialized via network tariffs of all network users.
b) Shallow connection costs, where new network users pay for the infrastructure to the network connection point, but not any reinforcements beyond that point that may be needed.
c) Deep connection costs, where in addition to the costs paid under the shallow type, new users also pay for all other reinforcements/extensions in the existing network.
[31] A combination of deep and shallow or super-shallow and shallow connection cost approaches.

Concerning electricity transmission connection charges, ACER[32] indicates that some NRAs choose a deep approach to provide a locational signal and increase cost reflectiveness, while other NRAs opt for a shallow method to favour simplicity, as well as certainty and visibility to network users. The use of (mixed approaches employing) super-shallow connection charges can incentivise certain types of network users (such as renewable energy generators, which is applicable also to the distribution level). It is furthermore argued that deep connection charges are discriminatory to renewable energy projects, as RES availability is a strong determinant for their location.

In its analysis of transmission tariffs and their roles for the internal gas market in Europe, ACER[33] does not advocate for a certain connection cost approach. It nonetheless indicates the following practices for NRAs:

- ✓ Clarify the charging principles;
- ✓ Clarify whether the services are charged to the beneficiaries (i.e. use of deep/shallow approaches);
- ✓ Do not double charge connection costs by recovering them from beneficiaries and then again from network users through network tariffs. This can be achieved by not including the recovered connection costs in the RAB.

4.2.2 *Cost allocation through access charges*

Composition of transmission tariffs per component

Figure 4-2 presents the composition of transmission tariffs per component for 2018. Tariffs may be structured in capacity (e.g. in EUR/MW), commodity (EUR/MWh), fixed (EUR) and other components (the latter also fixed, but for the charging of specific services such as metering).

For **electricity transmission**, 20 out of the 26 Member States for which data was available had a structure combining capacity and commodity components (and a fixed component in one MS). Commodity components formed the majority of the network tariff structure for 14 Member States. Out of these, 5 MSs (BG, CY, DK, EE and RO) had only commodity-based transmission tariffs in 2018. In those Member States transmission tariffs were charged only through a EUR/MWh charge, and thus did not vary depending on the peak power reserved or effectively used maximum capacity to inject or withdraw energy from the network, nor was there a fixed tariff component (e.g. EUR per month or year). 11 MSs had a majority capacity component (BE, CY, DE, EL, IE, LT, LV, LU, NL, SE and SI), out of which NL's tariff structure is only based on capacity charges. The transmission tariff structure of IT is composed of 50% capacity and 50% commodity charges. This situation for electricity has not changed significantly from 2010 or 2014 to 2018 for most MSs. In IE, the capacity to commodity split was close to 50-50 in 2014 but by 2018 it shifted to ~60% commodity charges and 40% capacity charges. Conversely, in LT, LU, PT and SE the percentage of capacity charges has slightly increased at the expense of commodity charges from 2014 to 2018. FR's capacity component introduction in 2014 is due to disaggregation from the previously integrated electricity tariff. IT and FI introduced a capacity component in the period between 2014 and 2018.

For **gas transmission**, out of the 22 MSs with data available, 20 had in 2018 majority shares for the capacity component, with AT, DE, FR, NL, LV and SI having only capacity-based tariffs. Only DK and EE

[32] ACER (2019) Practice report on transmission tariff methodologies in Europe
[33] ACER (2020) The internal gas market in Europe: The role of transmission tariffs

had an almost pure commodity-based tariff, while SE and IT had a significant component recovering costs other than through commodity, capacity or fixed charges. In the case of SE, this other component referred to pressure reduction services, among others. As for electricity, few changes can be observed from 2010 to 2018, with only HR and RO switching from an (almost) purely commodity-based to a predominantly capacity-based tariff in the period.

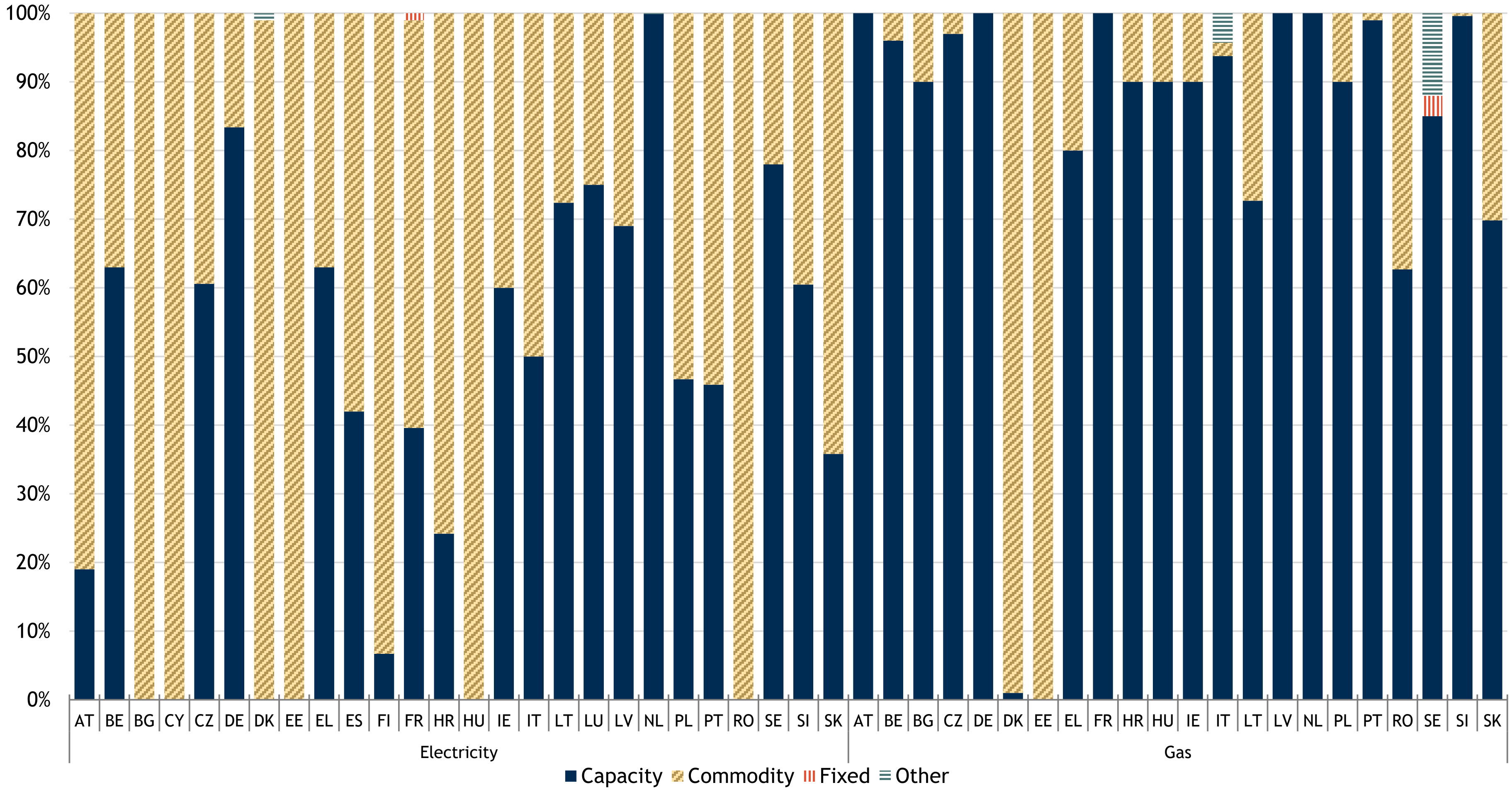
In general, capacity components were more common and also more important in gas than in electricity transmission tariff structures. Structures for both carriers have remained relatively stable in the period of analysis, although a few countries have introduced or increased their capacity-component.

The network code on harmonised transmission tariff structures for gas (NC TAR)[34] aims to reduce cross-border distortion and cross-subsidization among users, and to increase tariff transparency as well as cross-border trade. It establishes that transmission services should be recovered by capacity-based products, with potential exceptions for part of these services to be recovered through a flow-based or intended to cover a revenue recovery gap. Hence, as new tariff structures are phased in during the upcoming regulatory periods, they will become largely capacity-based. Out of the 22 MS with new gas transmission tariff structures (i.e. effective from 2019 or afterwards and complying with the NC TAR requirements) with data available, 9 have no commodity component while the lowest capacity component is of 70% (in DK).[35]

There are currently no requirements for the harmonisation of electricity transmission tariffs in the EU. ACER indicated in 2015[36] that “the need for a Framework Guideline and subsequent Network Code is not evident at the moment”. The Agency argued that the advantages and disadvantages of harmonisation would be more clearly appraised once numerous on-going reforms and market integration were implemented. The study commissioned by ACER[37] on the issue of harmonisation indicates that, as certain tariff structure components are more suited to reflect different underlying drivers (e.g. fixed costs are better recovered through capacity-based or fixed charges), a full set of harmonised tariff setting principles is a pre-requirement before any harmonisation of specific tariff structure aspects, such as the split between capacity, commodity and fixed components should be started.

[34] Commission Regulation (EU) 2017/460 establishing a network code on harmonised transmission tariff structures for gas
[35] ACER (2020) The internal gas market in Europe: The role of transmission tariffs
[36] ACER (2015) Scoping towards potential harmonisation of electricity transmission tariff structures – conclusions and next steps
[37] CEPA (2015) Scoping towards potential harmonisation of electricity transmission tariff structures

Figure 4-2 Composition of transmission tariffs per component, 2018



Box 4-1 Transmission tariffs and covid-19

In light of the energy consumption fall due to the covid-19 pandemic, the tariff structure is particularly relevant to cost recovery. A significant commodity component in the tariff structure combined with the fall in energy consumption should lead to the short-term under-recovery of the cost of service of network operators, compared to the original forecasts. While covid-19 is an extreme but rare example, cost recovery will also be influenced by other more frequent unforeseen events such as economic downturns driven by other factors (albeit with a lower impact).

In “the internal gas market in Europe: The role of transmission tariffs” report, ACER addresses the treatment of volume risk in gas tariffs, although focusing on volume risks related to transit flows (due to the TAR NC requirement for transit-related risks not to be allocated to domestic users). The Agency acknowledges that “mitigation of volume risk can lead to complex regulatory mechanisms that might not be compliant with the NC TAR”. The ACER requirements to ensure network efficiency could be relevant and tailored to future adaptation measures to covid-19:

- ✓ The volume risk addressed (fall in domestic and transit flows due to covid-19 in this case) should be based on costs at risk associated to the infrastructure used (i.e. costs related to non-depreciated assets);
- ✓ Where a risk premium embedded in the allowed revenue methodology is applied to manage the (materialised) volume risk, an assessment of this premium should be provided by the NRA. The premium should be proportionate to the risk faced by the operator and should be justified.

Similar to transmission, distribution tariffs may be structured with capacity, commodity, fixed and ‘other’ components. However, only the existence of such components in distribution tariffs is surveyed in this analysis, rather than the distribution of tariff revenues as is done for the transmission level. Given the complexity of distribution tariffs (multiple network user groups, tens and evens hundreds of DSOs in some MSs) the analysis focuses on whether the tariffs of all, some or none of the network user groups contain capacity, commodity, fixed or ‘other’ components.

For **electricity distribution,** commodity charges were in 2018 most common in the 18 MSs surveyed, being charged to all distribution users in 16 MSs, and some users in NL and SE. Next, fixed components were charged to all distribution users in 6 MSs, and to some users in 6 others. Capacity components were charged to all users in EL, ES, FR, LV, NL, PT and SI and to some users in 6 other MSs.

For **gas distribution**, the situation was in 2018 similar in the 15 MSs surveyed. 13 MSs had commodity components in the distribution tariffs for all users, while SE applied it to some. Fixed components were used for all users in 3 MSs, and for some users in 7 more, while capacity was used as basis for all users only in EL, HU and NL, and for some in 6 other MSs.

Therefore, for both electricity and gas, in 2018 commodity components in the distribution tariff structure were most common, followed by fixed and, to a lesser extent, capacity components.

Concerning electricity, CEER[38] acknowledges that historically commodity-based tariffs were predominant (with sometimes a small capacity-based component), given the lack of hourly metered peak load and the fact that this tariffication approach generally worked well. However, CEER notes that

[38] CEER (2020) Paper on Electricity Distribution Tariffs Supporting the Energy Transition

static, commodity-based tariffs do not provide adequate price signals, and furthermore may compromise cost recovery with the development of distributed generation. Capacity (measured or contracted) and fixed tariff components would be more cost-reflective and provide a forward-looking price signal to consumers, although regulators need to consider other principles, such as simplicity, as well as distributional effects.

Cost allocation between energy injection and withdrawal

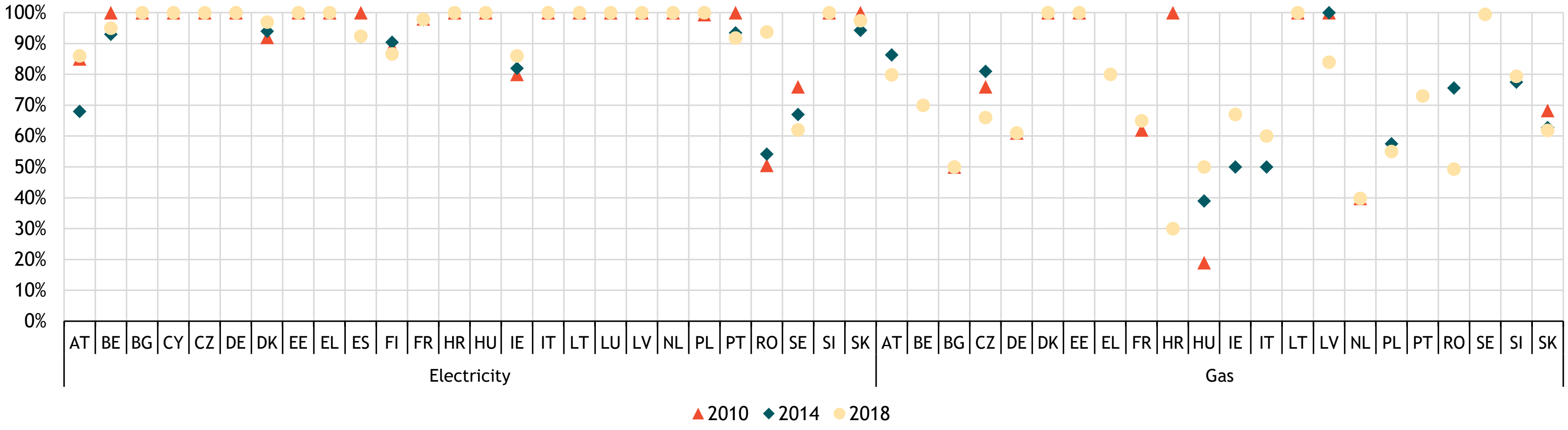
Figure 4-3 presents the percentage of transmission access tariffs allocated to withdrawal (that is, for consumption, charging of storage or exports) in the EU in the period 2010-2018. Logically, the remaining percentage to 100% is allocated to injections (which can be due to production, discharging of storage or imports).

For **electricity transmission**, most of the 26 MSs surveyed in this analysis had a high withdrawal component in the period of analysis. 15 MSs in 2018 had a 100% allocation to withdrawal of electricity, and only Sweden had a share under 70% (at ~ 62%). Variation in the period is rare, with the following splits varying by more than 10% over the years: AT (68% in 2014, from 85-86% in the other years), SE (decreasing from 76% in 2010 to 62% in 2018), and RO (from 54% in 2014 to 93% in 2018).

For **gas transmission**, greater variation is observed. From the 22 MSs surveyed, only 4 applied network tariffs to withdrawal only (DK, EE, LT and SE). Nonetheless, most MS charged at least 50% from withdrawal in 2018, except for HR, NL and RO. There were a few changes from previous years to 2018, with the most notable change being the reduction of the withdrawal share in HR from 100% in 2010 to 30% in 2018. AT, CZ, HU, IE, IT, LV and RO underwent changes between 2014 and 2018. From 2014 to 2018 the largest changes to the withdrawal share were undertaken by HU (from 39% to 50%), IE (from 50% to 67%), IT (from 50% to 60%), LV (from 100% to 84%) and RO (from 76% to 49%).

Thus, concerning the injection/withdrawal split, the share for energy withdrawal was larger in most countries for electricity than for gas (which is also related to the fact that gas is mostly imported while electricity is domestically produced and injected), and also generally increased in the period of analysis in the case of electricity.

Figure 4-3 Percentage of access tariffs allocated to withdrawal / consumption



The NC TAR does not impose a specific entry/exit split (i.e. the injection/withdrawal split in an entry/exit system) for gas transmission tariff structures in the new tariff methodologies, but only its publication. Regarding electricity, the study[39] commissioned by ACER on the harmonisation of electricity transmission tariffs additionally recommends not to apply commodity-based charges to generators "to recover infrastructure costs, given conflicts with basic cost reflectively principles". This is in line with ACER Opinion 09/2014, which recognises that commodity-based tariffs to generators could be efficient only regarding losses and ancillary services cost recovery. Moreover, the study noted that the regulation establishing the inter-transmission system operator compensation (ITC) mechanism[40] limits already in practice electricity transmission charges to producers. However, the study did not advocate a harmonisation of electricity transmission charging principles to generators at the time, noting that existing practices which seemed not to be cost-reflective could be addressed at the national level.

In its Opinion 09/2014, ACER deemed it useful to study the amendment of the ITC mechanism Regulation in order to harmonise charging principles for generators connected also at the distribution level and reduce distortions. Later, the recast Electricity Regulation included a provision that (eventual) network charges to generators should "not discriminate positively or negatively between production connected at the distribution level and production connected at the transmission level". CEER[41] advocates for NRAs to develop a common methodology for setting tariffs for generators connected at the transmission or distribution level.

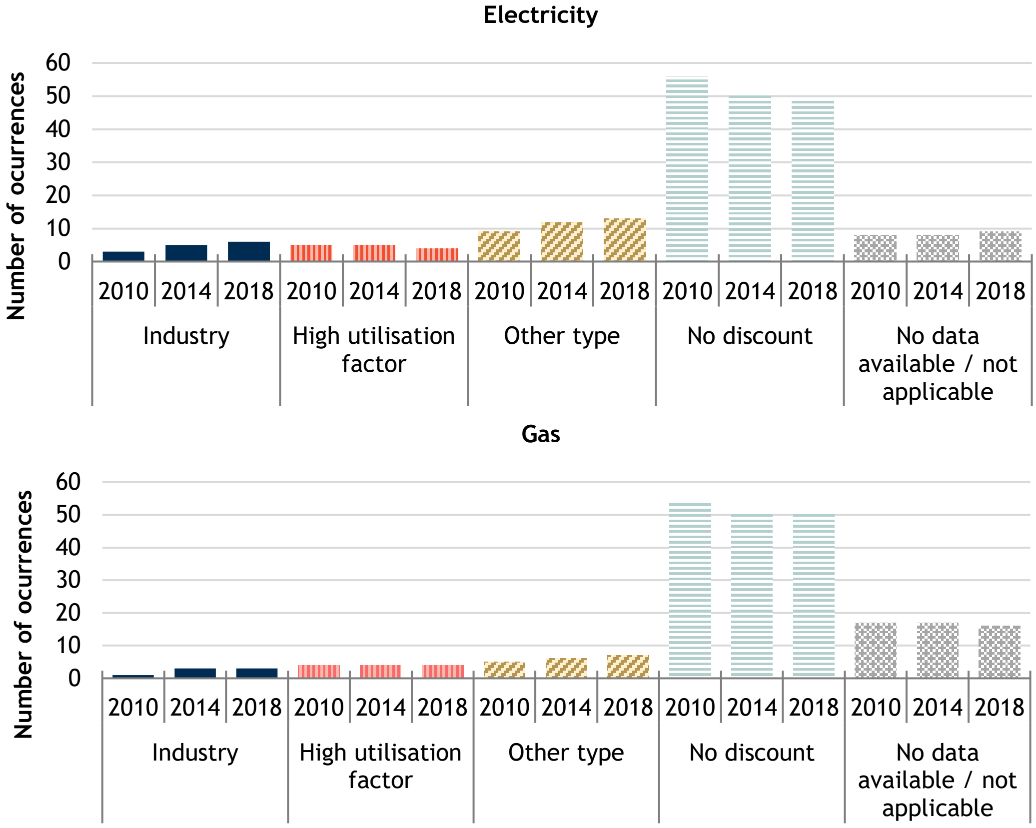
Tariff discounts for network users

Figure 4-4 presents the network transmission tariff discounts identified for specific users. The occurrence of discounts for industry, network users with high utilisation factors or other user types is indicated. As countries may provide discounts to multiple user categories (or not), the number of occurrences exceeds the number of countries analysed, as three data points are assessed per country.

For **electricity transmission**, data was obtained for 26 Member States[42]. The provision of network tariff discounts to industrial users slightly increased in the period, from three MSs in 2010 (BE, SI and SK) to 6 in 2018 (BE, FR, HU, PL, SI and SK). In contrast, the provision of discounts to users with a high utilisation factor decreased from five MSs in 2010 (DE, DK, NL, PL and SI) to four in 2018 (DK ceased to provide the discount). However, discounts were most commonly provided to other types of users: by 9 MSs in 2010, 12 in 2014 and 13 in 2018. Examples of these other electricity transmission user types include those with a temporary peak power consumption (DE), agricultural consumers with night-time consumption (EL), users with a low utilization factor (NL) and curtailable consumers willing to provide demand services .

[39] CEPA (2015) Scoping towards potential harmonisation of electricity transmission tariff structures
[40] Commission Regulation (EU) 838/2010 laying down guidelines relating to the inter-transmission system operator compensation mechanism and a common regulatory approach to transmission charging.
[41] CEER (2020) Paper on Electricity Distribution Tariffs Supporting the Energy Transition

Figure 4-4 Network tariff discounts for specific user types in the EU, 2010-2018



For **gas transmission**, , data was obtained for 23 Member States. The provision of network tariff discounts to industrial users slightly increased in the period, from DE in 2010 to DE, LU and PT in 2018. ES, SI and SK applied tariff discounts for users with a high utilisation factor throughout the period of analysis. PT had phase out this discount by 2018, and RO introduced it by the same year. Finally, five MS (BE, EL, FR, HU, and SK) applied tariff discounts to other customer types in 2018, which increased to seven by 2018, as PT and PL introduced such discounts by then. Examples of such other gas transmission user types include LNG terminals in PL and flexible users (such as gas-fired power plants) in BE.

Therefore, generally the majority of Member States did not provide any sort of discount to specific user groups in the period of analysis (not including storage, not analysed here). Slightly more discounts have been identified for electricity than gas, although this is related to the higher data coverage. Among discounts, the 'other' group has the highest number of occurrences. However, this is mostly due to the variety of discount types included in the category: discounts to industry and users with high utilisation factors are in general more frequent than discounts to other specific cases.

Cost allocation of electricity balancing services

Figure 4-5 presents the cost allocation of the following electricity balancing services[43]:

- ✓ Frequency containment reserves (FCR);
- ✓ Frequency restoration reserves (FRR);
- ✓ Replacement reserves (RR).

[43] There is not sufficient gas balancing cost data for analysis.

These can be further broken down in the procurement of balancing capacity, and eventually balancing energy, and FRR can be further divided in automatically and manually-activated reserves.

The following system users can be responsible for the costs of these balancing services: end-users, generators, network users in general, or balancing responsible parties (BRPs). Hybrid approaches recovering some costs from BRPs and from network users are also possible. Generally, residual balancing costs which cannot or should not be recovered from BRPs in particular are recovered through network tariffs from all or part of the network users.

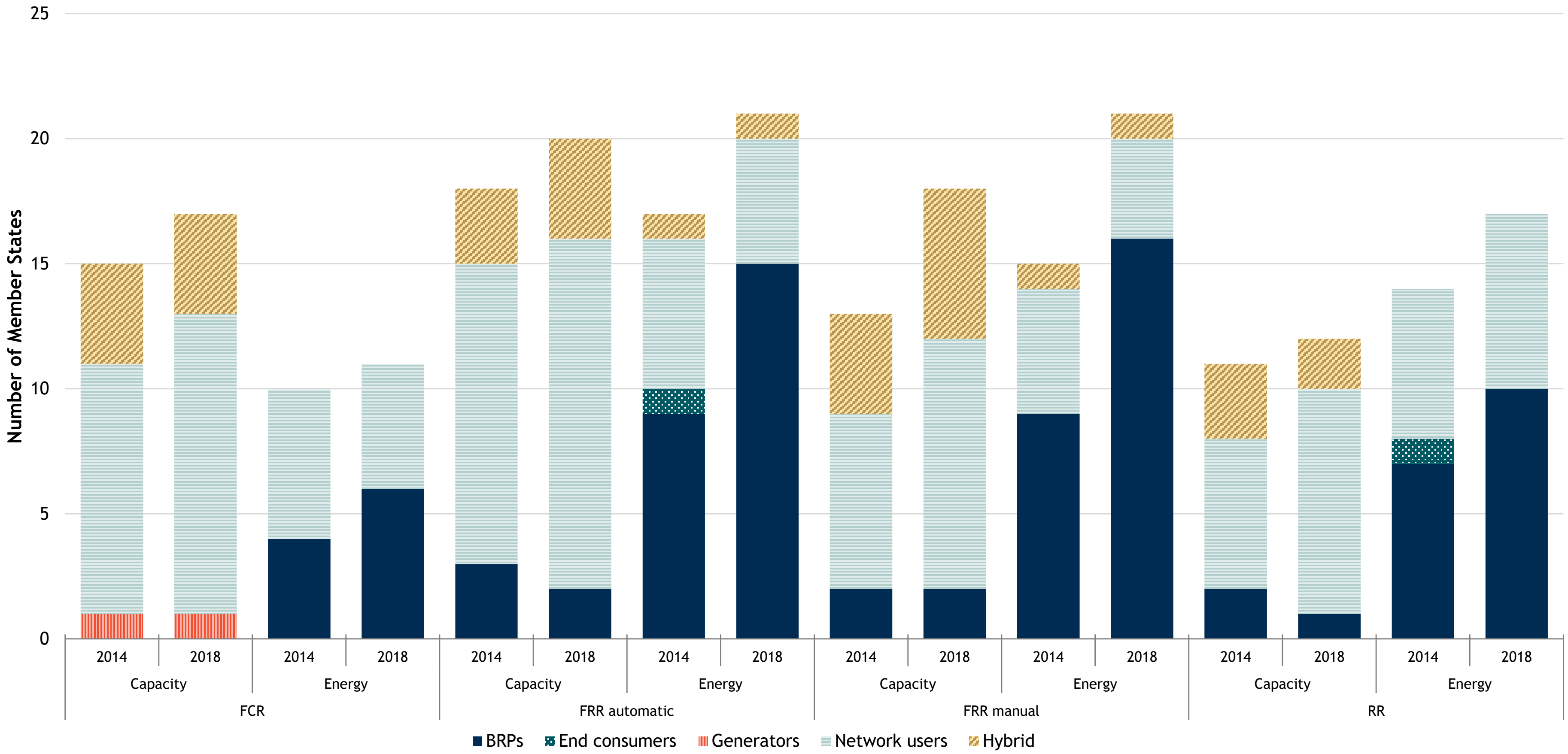
ACER[44] notes that, in 2019, FCR did not constitute a cost to TSOs in 7 Member States, being provided by generators on a mandatory basis (ES, HR, IT, RO, SI, PT) or free of charge (EE). Also, RR are not provided in 10 Member States (AT, BE, DE, DK, FI, HR, HU, LU, NL and SI).

The costs for **electricity balancing capacity reserve** were in 2018 recovered from network users in most MSs. FCR capacity costs were recovered from generators only in AT during 2014 and 2018. BRPs were not charged in any MS for this service in either of the two years of analysis. Regarding the costs for FRR automatic capacity, the following countries charged them in 2014 to BRPs: FI, PT and SE. In 2018 only FI and SE did so. The use of hybrid approaches, recovering costs both through network tariffs and BRPs, was more common for balancing capacity than energy-related costs, being employed in a few MSs for capacity FCR (CZ, SE, EL, FI), automatic capacity FRR (CZ, EL, AT and HR, the latter for 2018), manual capacity FRR (CZ, LT, FI, AT and SE and HR in 2018) and capacity RR (LT, ES, CZ, the latter in 2014).

Regarding **balancing energy**, the recovery of residual imbalance costs incurred by the TSO from the concerned BRPs is much more common, being more frequent than recovery from network users for automatic and manual FRR. AT was the only country to apply a hybrid cost recovery approach in both automatic and manual FRR during 2014 and 2018. For energy FCR related costs, in 2018 6 of the MSs surveyed recovered these costs from network users and 5 from BRPs. For RR energy procurement in 2018 more MSs recovered costs from BRPs (10 MS) than from network users (7 MS). In 2014, 6 of the MS recovered costs from network users and 7 from BRPs.

[44] ACER (2020) The internal gas market in Europe: The role of transmission tariffs

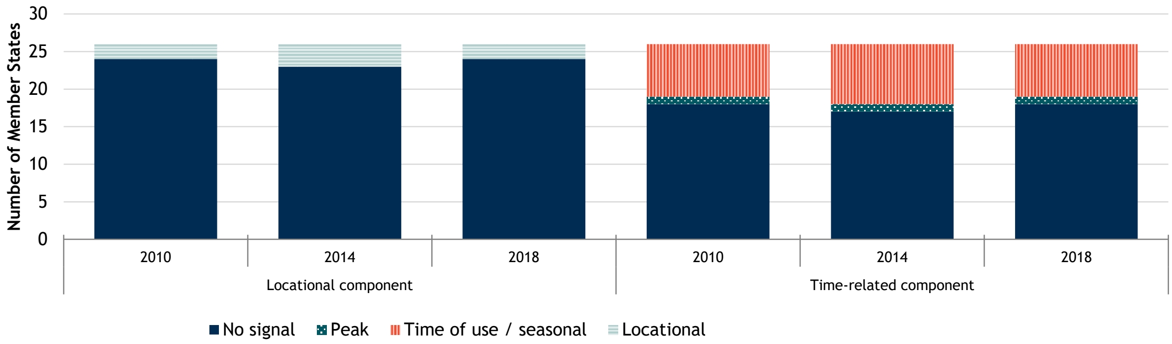
Figure 4-5 Cost recovery in balancing markets in the EU27 (number of Member States)



Locational and time-related network tariff signals

Figure 4-6 presents information on locational and time-related signals in **electricity transmission network tariffs**. The majority of MS do not have a locational signal component in their electricity transmission network tariffs. This has not changed significantly over the time period analysed. In 2018 only two countries included a locational signal in their transmission tariffs: SE, and IE. Compared to locational signals, more MS apply time-related signals, either time-of-use (ToU) or seasonal ones although they are still the minority. For those countries that apply a time-related tariff component the majority of them use ToU signals. In 2018 the countries that used ToU signals were: FI, EL, PT, ES, FR, HR and SI. Only EE applied a peak-type of temporal signal. The situation has not significantly changed over time.

Figure 4-6 Locational and time-related signals in electricity transmission network tariffs



Locational and time-related signals can improve the investment and operation decisions of network users, but require balancing principles such as cost-reflectivity and non-discrimination against the simplicity of tariff structures. Moreover, the absence of locational and time-related signals is preferred to the provision of inadequate signals, such as arbitrarily setting peak hours which do not coincide with the system peak, or location signals which distort generators' investment decisions rather than reflecting e.g. structural network congestion.

For electricity, ACER[45] does not provides recommendations regarding time-related signals for transmission tariffs, and this is also not further covered by the consultant's report to ACER.[46] At the distribution level, while CEER favours the development of electricity dynamic tariffs, it warrants that regulators should consider its costs given the smart metering and automation requirements. Moreover, noting that network users with access to flexibility resources (such as storage) could potentially avoid network costs in case important time-related tariff components existed, CEER highlights that all network users "should still make an appropriate contribution to DSO cost recovery".[47]

ACER[48] does not provide recommendations regarding locational signals in electricity transmission tariffs. Indeed, the study[49] commissioned for that purpose oversees not only the eventual benefits of a transmission locational signal, but also the difficulties and complexity of such a mechanism. Similarly, while acknowledging the potential benefits of locational signals for electricity distribution tariffs,

[45] ACER (2015) Scoping towards potential harmonisation of electricity transmission tariff structures - conclusions and next steps
[46] CEPA (2015) Scoping towards potential harmonisation of electricity transmission tariff structures
[47] CEER (2017) Electricity Distribution Network Tariffs - CEER Guidelines of Good Practice
[48] ACER (2015) Scoping towards potential harmonisation of electricity transmission tariff structures - conclusions and next steps
[49] CEPA (2015) Scoping towards potential harmonisation of electricity transmission tariff structures

CEER[50] indicates that important barriers exist, such as limited knowledge of distribution networks, complexity of calculations, and public acceptability.

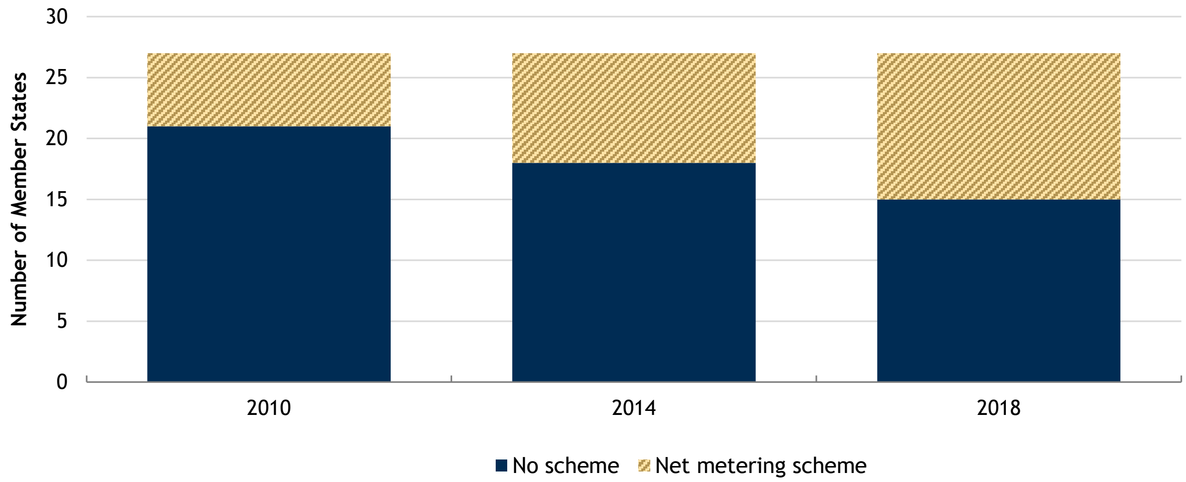
Concerning gas, an entry-exit tariff system may naturally provide indications to network users of the network access cost for different system entry/exit points. Concerning time-related signals, the NC TAR allows for the inclusion of seasonal multipliers in gas transmission tariffs.

Net metering for electricity injected into and withdrawn from distribution networks

Figure 4-7 shows that more MS have adopted net metering schemes for electricity over time. In 2010, only 6 MS had net metering schemes; these MS were: BE, DK, HU, IT, MT and EE. By 2014 CY, LT, PT and NL included net metering schemes but MT discontinued it. In 2018, three additional MS implemented net metering schemes, namely EL, SI and PL.

CEER is of the position that net metering for prosumers with generation and/or for storage capacity should be avoided, as it affects the cost-reflectiveness of the network tariffs charged to users and reduces incentives for network users to develop flexibility resources such as behind-the-meter storage.[51]

Figure 4-7 Member States with an electricity net metering scheme



[50] CEER (2020) Paper on Electricity Distribution Tariffs Supporting the Energy Transition
[51] CEER (2020) Paper on Electricity Distribution Tariffs Supporting the Energy Transition
CEER (2017) Electricity Distribution Network Tariffs – CEER Guidelines of Good Practice

5 Alternative network cost allocation practices in non-EU G20 countries

The purpose of this section is to identify alternative network cost allocation practices in non-EU G20 countries which could be considered in some or several EU Member States, for example in order to facilitate the integration of renewable energy sources and to increase the cost-reflectiveness of network tariffs. Their applicability to the context of the EU and individual Member States should be taken into account. The analysis references, where relevant, the network tariff principles of section 4.1.

The selected alternative practices comprise:

- ✓ Alternative electricity RES connection cost allocation in the US (New York State);
- ✓ Use of system-coincident peak electricity transmission capacity charges in the US (Texas);
- ✓ Distribution dynamic and time-of-use pricing in US and Canada;
- ✓ Critical ToU and peak pricing of network tariffs in Brazil;
- ✓ Differentiation of electricity tariff structures according to different purposes of transmission facilities in the US;
- ✓ Introduction of electricity capacity-based transmission charges to generators in Japan.

Alternative electricity RES connection cost allocation in the US (New York State)

A number of alternative approaches for the allocation of the connection cost of distributed energy projects have been proposed in various US states such as California, Hawaii and New York. This section focuses on examples from New York State and is largely based on Peterson's analysis for the National Renewable Energy Laboratory in the US on Alternative Methods for Interconnection Cost Allocation.[52] These approaches aim to present an alternative to a conventional deep connection cost allocation, where the costs of electricity network upgrades are paid solely by the distributed energy (usually a renewable energy) project that triggers them. This might be problematic as it does not take into account that future projects will share in the benefits provided by the upgrade, but do not share the costs. Thus, it does not fulfil the network tariff principle of cost reflectivity. Moreover, in some cases, the cost of upgrading the network might represent a large share of the total renewable energy project costs and can lead to delays in the connection and to stranded costs due to cancelled projects.

To address this problem, one of the proposed alternative approaches is the Post-upgrade Reimbursement methodology. It was implemented in 2017 by New York State Department of Public Service in order to distribute the cost of upgrades of the electricity distribution system among energy projects. Based on this approach, the distributed energy project that triggers the network upgrade is still required to pay upfront the full cost of the upgrade. However, subsequent distributed energy projects that connect to the network and thus benefit from the upgrade are required to pay a portion of the upgrade costs, to reimburse the original energy project developer which paid upfront. The amount that subsequent projects have to pay is calculated based on the fraction of their capacity to the total capacity of the projects (including proposed projects with aggregate capacity of 200 kW or greater that are submitted within 8 months of each other) benefiting (or that will benefit) from the

[52] Peterson, Z. (2018), "Alternative Methods for Interconnection Cost Allocation". Available at: https://www.nrel.gov/dgic/interconnection-insights-2018-08-31.html

upgrade. The prorated payment is made to the network operator[53], who in turn pays back the money to the initial developer. In New York, this mechanism was specifically applied to solar, wind, micro-hydropower, fuel cells and biogas projects with a capacity of 200 kW or above.

Although this method does provide a more cost-reflective distribution among all projects that benefit from the upgrade, it does not address the problem of upfront payment by only one project. Thus, project developers that do not have enough upfront capital must wait for another project to share the upfront connection costs. Moreover, such projects still face the risk of absorbing the full cost of the upgrade if there are no subsequent projects.

The Pre-emptive Upgrade Program is another alternative approach to connection cost allocation that aims to address the problem of upfront payment by developers requiring network upgrades to connect. A pilot project focused on this approach was implemented by the National Grid in the state of New York.[54] In this case, the network operator pays upfront for the upgrades, by pre-emptively installing network upgrades in areas where distributed energy projects are expected to arise. As in the case described above, the distributed energy projects connecting to the upgraded network subsequently have to reimburse the utility by paying a pro-rated fee. The fee is calculated based on the total cost of the upgrade, the network capacity and the capacity of the project(s). Thus, in this case the risk is transferred from the project developer to the network operator, and consequently to ratepayers.

Finally, a third type of solution is the Flexible Interconnect Capacity Solution. In this approach the project developers do not need to pay for the network upgrade, but accept that the system operator curtails their real power output if needed, to avoid violations of operational constraints. Such solution is being tested in a pilot led by Avangrid, a parent company to the New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation. The company contracted a technology platform to facilitate the management of network constraints, by monitoring in real time the network operations and controlling the curtailment of the distributed energy projects. Based on this approach, the project developers avoid capital costs associated with network upgrades (except for some marginal costs associated with the management system and connection to it). Nonetheless, this approach also faces some difficulties due to the fact that developers risk frequent power curtailment, which would affect the project profitability. Thus, in order to minimize uncertainty for the projects, clear rules must be established on the degree to which projects can be curtailed. In those cases where significant additional distributed energy projects are expected to connect to the network, this can become challenging. In Europe, a similar initiative has been taken up in Belgium by the Walloon authorities. In this program, renewable energy producers accept curtailment during a limited number of hours per year in order to avoid the need for network reinforcement.[55] If the effective curtailment is higher, the network operator has to compensate the concerned producer.

The abovementioned alternative connection cost allocation methods have their advantages and disadvantages, and their attractiveness will depend on the specific regional network characteristics and regulation and the economics of the distributed energy projects. Other alternative cost allocation approaches are being tested in the US and elsewhere. Further research and demonstration projects are

[53] In the US, the term utility is frequently used. The scope of the activities of utilities might differ from those of network operators in the EU, as it may include generation and supply activities.
[54] National Grid (2017), "Implementation Plan Distributed Generation Interconnection REV Demonstration Project Case 14-M-0101 Reforming the Energy Vision"
[55] Edora (2016), Raccordements flexibles: Résumé du projet d'Arrêté du Gouvernement wallon

needed to understand how the different mechanisms will impact network and system operators as well as distributed energy developers.

Use of system-coincident peak electricity transmission capacity charges in the US (Texas)

Coincident peak pricing (CPP) is an approach in which consumers' network capacity charges are defined in proportion to consumers' energy offtake as measured at the times of overall system peaks or peaks of a particular sub-system. This approach is used in several electricity systems to recover annualized capital costs of electricity network assets from end-users. CPP is most often used to recover transmission or distribution assets, although in principle it can also be used to recover generation assets in the case of vertically-integrated utilities. The network offtake measured at the time of the system peak can be used to set charges for the current pricing period or a subsequent one. The idea behind CPP is to recover the total annual revenue requirements to be able to finance the existing capacity, and potentially to finance the construction of new capacity needed to meet peak demand forecasted for the following year(s)/period(s).[56]

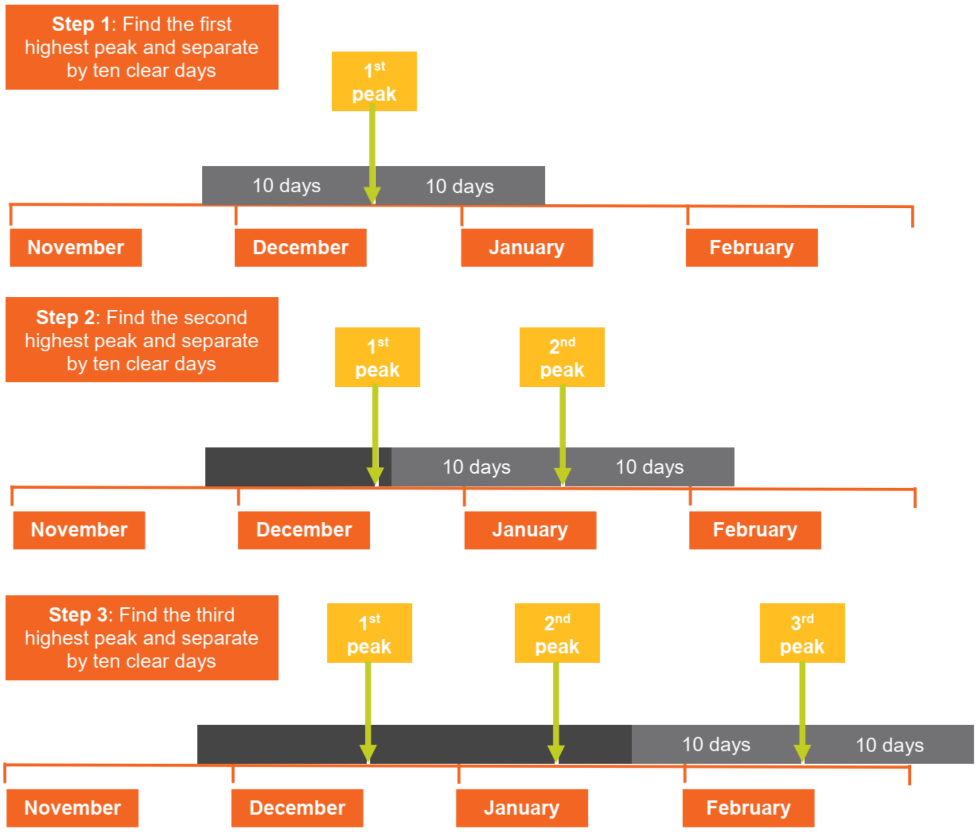
Non-coincident peak capacity charges tend to be more straightforward to understand for end-users and easier to administrate for network operators. However, CPP better reflects the cost causation, since the customers are charged based on their contribution to system loading during times that drive capacity costs.[57] Thus, CPP supports the cost reflectivity and cost recovery network tariff principles, but does not necessarily contribute to the simplicity principle (see section 4.1 above).

In Texas, the Electric Reliability Council of Texas (ERCOT) introduced the "four coincident peak" (4CP) program. Participants in the 4CP program have the opportunity to lower the transmission cost of service charges on their electricity bills. Under the 4CP, a significant component of the yearly electricity bill is set based on how much the customer contributes to the total peak load. The program works by allowing participants to reduce their energy consumption when electricity demand on the network is expected to be at its highest during a specific period of time – referred to as "15 minute peak events" - during the four summer months (June – September). The reductions in cost are applied for the next year.[58] For example, in 2016, the "15 minute peak events" happened on, June 15th, July 14th, August 11th and September 19th. The 4CP charges were charged between January – April 2017. Customers participating in the program are notified via email or text message of predicted upcoming peak dates so that they can plan to minimize their consumption accordingly. Charges based on the 4CP can account for up to 30% of the total energy bill.[59]

Coincident peak pricing is also used in the UK. Known at the "Triad" charges, referring to the three 30-minute settlement periods of highest demand in the British electricity transmission system between November and February, separated by at least 10 days .[60] The process for determining the triads is shown in the figure below.

[56] Baldick, R. (2018), "Incentive properties of coincident peak pricing", Journal of Regulatory Economics 54:165-194
[57] Rocky Mountain Institute (2016), "A Review of Alternative Rate Designs". Available at: www.rmi.org/alternative_rate_designs
[58] Baldick, R. (2018), "Incentive properties of coincident peak pricing", Journal of Regulatory Economics 54:165-194
Electric Choice, "Changes to the 4 Coincident Peak (4CP) Program in Texas". Available at: https://www.electricchoice.com/blog/4-coincident-peak-program/
[59] Engie, "VPower 4CP Management"
[60] NationalGridESO (2018), "What are electricity Triads?"

Figure 5-1 Method to determine Coincident Peak Pricing Triads in the UK[61]



The CPP and similar charging methodologies have been criticized by some researchers.[62] More specifically, the ERCOT's 4CP program has also received criticism. The main criticism is based on the fact that transmission costs are considered to be sunk costs. Thus, according to some, the 4CP program would not conform to the general principle of market design in which sunk costs should be allocated as to minimize their impacts on real-time markets given that allocating them based on real-time demand (or supply) can impact the real-time market efficiency. Hogan and Pope point out that "the 4CP transmission charge raises an issue for energy-only markets because the reduction in demand during peak periods is not occurring in response to energy prices, but instead is in response to avoiding an allocation of sunk transmission costs. The incremental cost faced by 4CP customers for additional power consumption during potential peak intervals is not equal to the energy price paid to energy suppliers at the same location at the same time."[63]

Distribution dynamic and time-of-use pricing in the US and Canada

Dynamic pricing refers to a demand-side management principle focused on reducing peak load based on charging different rates according to demand. It requires the frequent adjustment of rates, for example, every hour or every 15 minutes. In addition to reducing peak load, this practice allows for charging customers more accurately based on the demand in the system and for incentivising consumer behaviour to minimise offtake during times of high-demand. Dynamic pricing supports the principle of cost

[61] NationalGridESO (2018), "What are electricity Triads?"
[62] E.g. Borenstein, S. (2016) "The Economics of Fixed Cost Recovery by Utilities", The Electricity Journal, 29, 5-12
[63] Hogan, W. Pope, S. (2017) "Priorities for the Evolution of an Energy-Only Electricity Market Design in ERCOT"

reflectivity. In contrast to the standard practice of flat pricing, dynamic pricing reflects the fact that most peak time generation units have higher operating costs than base load units.[64]

It is important to note that the examples below pertain to the US and the Canadian electricity markets where utilities may be vertically integrated. The below information refers to both energy and network costs combined. Network tariffs and energy prices should preferentially be separate since they deliver different price signals, and as the underlying drivers of network and energy prices differ.

In the US, a number of pilot programs focusing on dynamic pricing have been launched over the last decade.[65] For example, the Sacramento Municipal Utility District (SMUD) started a two-year pilot project "The SmartPricing Options" in June 2012. SMUD together with 10 other utilities were part of the Consumer Behavior Study (CBS) program that looked at different dynamic pricing options. The programme was partially funded by the US Department of Energy's Smart Grid Investment Grant program.

The pilot consisted of three different pricing plans targeting a shift in peak summer demand from 4 pm to 7 pm. Under the Time of Use (TOU) option, participants were charged on-peak price of 27 cents/kWh between 4 p.m. and 7 p.m. on weekdays (excluding holidays) and then reverted to a rate of 8.46 cents/kWh for the first 700 kWh they consumed. Under the Critical Peak Pricing (CPP) option, participants were charged 75 cents/kWh during CPP event hours, when temperatures were expected to be very high, and then reverted to 8.51 cents/kWh for the first 700 kWh. The third rate option consisted of a combination of the TOU and CPP options. Based on the results from the pilot, SMUD found that about twice as many customers preferred the TOU option when compared to the CPP. Moreover, the network operator saw peak reductions of 6% to 26% across the TOU and CPP options. The study also compared the amount of energy savings for those customers that voluntarily opted-in versus those that participated in the pilot by default. The average peak-time reduction for opt-in customers was 0.17 kW as compared to 0.12 kW for customers defaulted into one of the options.[66] Finally, an important finding was that only 10% of the customers that had participated in the study by default decided to opt-out at the end of the pilot. The approach allowed SMUD to save on promotion and customer acquisition costs. Since 2019, SMUD uses Time-of-Day rates as the standard rates for all residential customers.

Moreover, based on the success of pilots like the one conducted by SMUD, the entire state of California has decided to start using TOU tariffs for all residential customers, and implementation of residential TOU tariffs has begun in 2019.[67] The effects of this state-wide roll-out in terms of peak load reduction and savings for customers are yet to be evaluated.

Interestingly, experts have pointed out that there are lessons to be learned for California from the implementation of TOU rates in Ontario, Canada. Ontario's 4 million customers use TOU rates as default. Ontario's TOU program is the second biggest in the world, after Italy. However, a 2017 study conducted by the University of Waterloo found that the program yielded small electricity savings,[68] although it must

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[64] Dutta, G. & Mitra, K. (2017), "A literature review of dynamic pricing of electricity", Journal of the Operational Research Society, 68, 1131-1145.
[65] Utility Dive (2013), "Dynamic pricing pilots: 5 utilities' programs, technology and results". Available at: https://www.utilitydive.com/news/dynamic-pricing-pilots-5-utilities-programs-technology-and-results/152381/
[66] Utility Dive (2015) "SMUD: Time-of-use in the future of rate design". Available at: https://www.utilitydive.com/news/smud-time-of-use-is-the-future-of-rate-design/397098/
[67] Farugui, A. (2018) Presentation: "Rate Design 3.0 and The Efficient Pricing Frontier"
[68] University of Waterloo News (2017). Available at : https://uwaterloo.ca/news/news/study-shows-big-smart-meter-investment-yielded-very-small

be noted that this is not a central objective of dynamic pricing approaches. According to the study, the Ontario's program demonstrates that it is possible to implement TOU rates at large scale without disruption, and that the impact on demand during peak times can be approximated by the off-peak price to peak price ratio (the larger the ratio the higher the incentive for the customer to switch to using electricity during off-peak times).

Other interesting examples of dynamic pricing include the SmartHours program developed by the Oklahoma Gas and Electricity Company. This program, which is available to customers during the summer months, is based on variable peak pricing (VPP) coupled to a smart thermostat, and featuring five levels of peak pricing. VPP is a hybrid of time-of-use and real-time pricing where the different periods for pricing are defined in advance but peak period prices change daily to reflect system conditions and costs. Around 20% of all of its customers have subscribed to the program. The results include an average drop in the peak load of approximately 40% and up to 20% on savings of the customer's bill.[69] In the state of Maryland both, the Baltimore Gas and Electricity (BGE) Company and Pepco Holdings Inc. (PHI) Delmarva Power subsidiary offer dynamic pricing rebates of 1.25 $/kWh to approximately 2 million households. The companies then bid the load reduction into the PJM market. [70] BGE has reported that about 80% of its customers have participated in the rebate program and that these customers have jointly saved about $40 million in electricity bills since the implementation of the program in 2013.[71]

Time of use network access tariffs in Brazil

In Brazil, transmission network access tariffs for all consumers are differentiated per time of use. In addition, distribution network users have a number of options in order to have a time of use component in their access tariffs.

Time of use signals in the transmission tariffs for consumers were introduced in Brazil in 2010,[72] for the 2011/2012 tariffication cycle, differentiating peak and off-peak tariffs. Transmission tariffs for producers are not differentiated by time of use. Previously, off-peak transmission tariffs for consumers were null, and the time of use tariffs were triggered by a request from network users for a change in the tariff structure. Peak periods are the consecutive 3 hour periods of highest network utilisation in the year, applicable exclusively on working days.

Brazilian transmission network tariffs are determined through nodal simulation for the so-called 'basic network'. There are also transmission network tariffs for the 'frontier network' facilities such as transformers for the connection of the transmission to the distribution network. Such tariffs are determined by allocating the allowed revenues caused by the frontier network assets to the users connected to that specific network point. Peak/off-peak tariffs apply both to the basic and to the frontier transmission networks.

For the 2018/2019 tariffication cycle,[73] off-peak tariffs for large consumers, self-producers and DSOs connected to the basic network could be higher or lower than peak tariffs, depending on the

[69] Farugui, A. (2018) Presentation: "Rate Design 3.0 and The Efficient Pricing Frontier"
[70] PJM is a regional transmission organization (RTO) in the US. The PJM Energy Market includes a real-time energy market (immediate delivery with prices calculate for a five minutes interview) and a day-ahead energy market.
[71] Ibid.
[72] Resolution Aneel REN 399/2010
[73] Aneel (2018) Nota técnica 146/2018-SGT. Estabelecimento das tarifas de uso do sistema de transmissão – TUST para o ciclo 2018-2019.

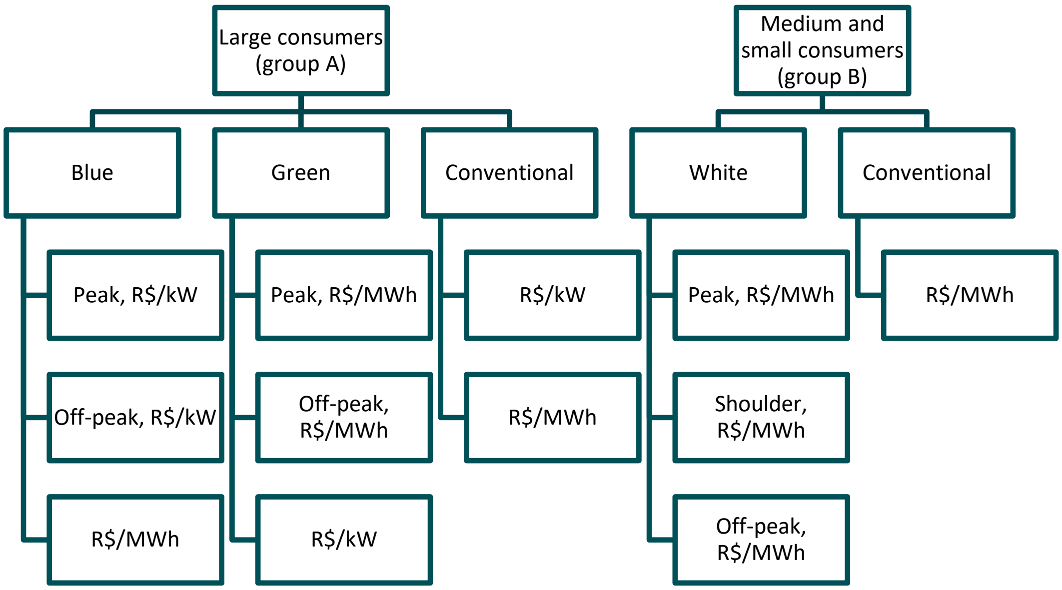
connection point, due to the nodal simulation and coincidence with the system peak. For DSOs, peak tariffs were higher than off-peak ones more frequently than for the other network user types.

Distribution network tariffs, in contrast to transmission network tariffs, are determined by the marginal expansion cost of the distribution system, and are set per voltage level.[74] The tariff structures for distribution costs in Brazil are separated for the consumer groups A and B (for most cases: with supply voltage level equal or above 2.3 kV, or lower, respectively).

Group A consumers had three choices for the distribution tariff structure: conventional (in R$/MWh and R$/kW), blue (with a flat R$/MWh as well as peak and off-peak R$/kW components) and green (with a flat R$/kW as well as peak and off-peak R$/MWh components). This is shown in Figure 5-2. Blue tariffs are supposed to favour users with a high utilization factor in peak hours, while green tariffs favour those with a low utilisation factor in such hours.

Group B consumers on the other hand had, until 2018, only a conventional, monomial tariff in R$/MWh. In 2018 the roll-out of the white tariff system ('tarifa branca') started. It was initially available only to consumers with a demand larger than 500 kWh/month, but since 2020 any consumer may choose this tariff structure. The white tariff is a tariff for all B group consumers with three distribution tariff levels: peak, shoulder and off-peak (all in R$/MWh).

Figure 5-2 Brazilian distribution network access tariff (*TUSD*) components[75]



The Brazilian Energy Planning Agency (EPE) notes that while the white tariff is not dynamic, it is an important step to incentivise distribution consumers to alter their consumption patterns away from the historical peak consumption period between 6 and 9 pm. It is furthermore complementary to the transmission tariff time of use signals, meaning that with it all network consumers have the option to benefit from more cost-reflective network access tariffs, with a reasonably simple structure. It must be recalled, however, that the so-called frontier transmission network assets are still not subject to such tariffs.

[74] Simões et al. (2012) Estrutura tarifária do uso do sistema de distribuição e transmissão.
[75] Aneel (2017) PRORET Submódulo 7.1, v. 2.4

Differentiation of electricity tariff structures according to different purposes of transmission facilities in the US

An important aspect to consider in tariff design is the differentiation of transmission networks assets based on their subfunction, as transmission lines and substations perform different functions based on their load and generation conditions, network typology and other factors. A theoretical overview on the topic is presented in Lazar el al. (2020), on which the following section is based.

One way to classify transmission assets is by voltage levels, but this can lead sometimes to cost of service allocation which are not cost-reflective. As an example, the transmission cost of service may in some cases in the US be allocated to customers connected to extra-high-voltage (EHV, say above 100 kV) and those connected to lower voltages. This transmission system at lower voltages is denominated sub-transmission. In some cases, customers connected directly to EHV lines are not charged costs caused by the sub-transmission system, whereas customers served at sub-transmission or distribution voltages are charged for both the EHV and sub-transmission network costs. This form of cost allocation does not reflect the fact that sub-transmission lines are in fact a lower cost option in those cases where the high capacity of EHV lines is not required. Hence, cost allocation should allocate transmission costs to all voltages, with all transmission assets serving a single function. If a differentiation in cost allocation is made between network users connected at the EHV and sub-transmission levels, this should not discriminate certain user classes (e.g. discriminate DSOs in favour of industrial users connected at the same network level).

Other ways of classifying the functions of transmission assets, rather than based on their voltage, exist. This could be used to determine e.g. the capacity/commodity/fixed component shares of tariffs for different asset groups. One way could be to consider any generation facilities transmission lines are connected to. Lines connecting to baseload generation or remote generation should be primarily considered as commodity (energy) driven. In contrast, lines connecting peak generation facilities should be treated as capacity (demand) related.

Another consideration in allocating costs would be the distribution of demand and generation facilities connected via the transmission system. For example, in the theoretical case where all the generators are the same and are evenly distributed (co-located) in relation to the load centres, economic dispatching would not be a consideration. Thus, the role of transmission would be limited to allowing reserve capacity in one centre to back up outages in another. In such a case, transmission costs would be fully capacity-driven. In contrast, where baseload generation is located away from remote generation facilities (e.g. wind in one location and hydropower in another) via additional transmission corridors and substations, the transmission lines between the load centres need to be able to back up the large units, and thus economic dispatching considerations to meet the load need to be taken into account. In this case, the incremental cost of electricity transmission could be largely commodity-related. This consideration in the cost allocation would reflect that although peak loads are an important cost-driver, a significant portion of transmission costs is also related to reducing commodity-related costs in this case.

In summary, different transmission segments may serve different purposes, and cost allocation methods may take this into consideration in order to enhance cost reflectivity of network tariffs.

Introduction of electricity capacity-based transmission charges to generators in Japan

The Japanese electricity system faces several challenges including the need for network infrastructure upgrades, and generally electricity networks should be capable of enabling Japan's "3E + S"[76] energy policy objectives, and the 3D principles of decarbonization, decentralization and digitalization. The challenges faced by the Japanese Transmission System include:

- ✓ Decrease of offtake from the electricity transmission network;
- ✓ Reduction in the utilization of networks (due mainly to increasing RES, the shut-down of nuclear reactors and decreasing population especially in the rural areas);
- ✓ Large investment needs to replace existing infrastructure.[77]

One of the elements proposed by Japan's Ministry of Economy, Trade and Industry (METI) to promote the medium- to long-term investments in transmission networks is the "generation side wheeling charge system" – that is, an access charge to generators. The charge is a transmission fee imposed on all types of generators, with the exception of residential solar projects smaller than 10 kW.[78] This measure is intended to distribute the burden of constructing, operating and maintaining the transmission system among electricity end-users through retailers and generators.[79] Although in the case of Japan the primary goal of the measure is focused on incentivising investments in transmission networks, it is argued that the redistribution of costs also supports the network tariff principle of cost reflectivity. In general, adequately designed charges to generators (known as G-charges) which are capacity-based are considered to increase the economic efficiency of generation dispatch and investment decisions, when compared to commodity-based G-charges.[80]

In Japan, the measure has faced strong criticism, especially from renewable energy generators that supply electricity under the Feed-In-Tariff (FIT) scheme. Whereas retailers have the ability to pass through the costs to their customers, renewable-generation projects will not have this ability due to the FIT Power Purchasing Agreement (PPA) structure that consists of a fixed rate tariff.[81] Thus the G-charge could have negative effects on the economics of renewable projects in Japan. Moreover, investors acquiring projects in the secondary market will also be impacted.

[76] Emphasis on energy security, economic efficiency and environmental protection without compromising safety.
[77] Shinkawa, T. (2018) Presentation: "Electricity System and Market in Japan"
[78] Fernandez, E for Infrastructure Investor (2019) "Japan's proposed transmission charge will hurt renewables – report". Available at: https://www.infrastructureinvestor.com/japans-proposed-transmission-charge-will-hurt-renewables-report/
[79] Baker McKenzie (2019) "Renewable Energy in Japan – recent Developments No. 47". Available at: www.bakermckenzie.co.jp/wp/wp-content/uploads/20190903_Client_Alert_Renewable_Energy_E_47.pdf
[80] European Commission (2017), "Study supporting the Impact Assessment concerning Transmission Tariffs and Congestion Income Policies"
[81] Fernandez, E for Infrastructure Investor (2019) "Japan's proposed transmission charge will hurt renewables – report"

Annex A - Country abbreviations

Table A-1 Country abbreviations list (ISO 2-digit codes)

EU27	Code	Non-EU G20	Code
Austria	AT	Argentina	AR
Belgium	BE	Australia	AU
Bulgaria	BG	Brazil	BR
Croatia	HR	Canada	CA
Cyprus	CY	China	CN
Czech Republic	CZ	India	IN
Denmark	DK	Indonesia	ID
Estonia	EE	Japan	JP
Finland	FI	Mexico	MX
France	FR	Russia	RU
Germany	DE	Saudi Arabia	SA
Greece	EL	South Africa	ZA
Hungary	HU	South Korea	KR
Ireland	IE	Turkey	TR
Italy	IT	United Kingdom	UK
Latvia	LV	United States	US
Lithuania	LT		
Luxembourg	LU		
Malta	MT		
Netherlands	NL		
Poland	PL		
Portugal	PT		
Romania	RO		
Slovakia	SK		
Slovenia	SI		
Spain	ES		
Sweden	SE		

Annex B – Network cost drivers

Physical network cost drivers

CEER conducted two studies on benchmarking the cost-efficiency of 29 gas and 17 electricity transmission system operators (TSOs) in 16 European countries.[82] These benchmarking have a greater access to more disaggregate confidential data than here, and are useful to highlight the main cost drivers for electricity and gas networks.

The **electricity study** developed a model which identified three main cost divers of the transmission network, described next:

- ✓ The **normalized asset base of the network operators** as represented by a cost proxy using average component costs and weighted by land-use area share with complexity factors);
- ✓ **Total installed transformer power** in MW (representing total network capacity);
- ✓ **Total line length** (weighted by share of angular towers and of steel towers).

The **normalized asset base** of the network operators represents a total expenditure (totex) proxy encompassing the relevant assets (such as overhead lines, cables, transformers, and control centres) with weights corresponding to their impact on capex and opex. The study found that the major impact from environmental factors (in the territorial sense) for electricity transmission was due to land use by the network, explaining both costs associated with construction (e.g. new build, reinforcement, site access) and operation of the network (e.g. maintenance access). The results are consistent with previous results from CEER that found infrastructure density to be a major factor affecting the normalized network cost component.

The **total transformer power**, indicating capacity provision, strongly complements the asset base parameter. The **line length** parameter represents the service provision by electricity TSOs, and accounts for the particularities associated with the electricity network based on infrastructure crossings, natural impediments and urban sprawls that require that electricity networks take longer paths. The share of angular towers has been incorporated into this parameter to account for the deviations of the transmission line from a straight route, which increases network costs. Thus, network length considering angular towers is a proxy for the cost impact of topography, high population and/or load density.

The CEER **gas study** follows the same logic to ensure comparability of the analysed data. The following main cost drivers were identified, and described next:

- ✓ The **normalized asset base of the network operators** (as represented by a cost proxy using average component costs and corrected for topography);
- ✓ **Total number of connection points;**
- ✓ **Total installed compressor power** in MW (representing transport capacity);

[82] CEER (2019) "Project CEER-TCB18 Pan-European cost-efficiency benchmark for gas transmission system operators: main report"
CEER (2019) "Project CEER-TCB18 Pan-European cost-efficiency benchmark for electricity transmission system operators: main report"
The methodological approach was based on proposing a proxy for the diversified asset base of operators. The data analysed was made comparable by limiting the scope of comparable activities, controlling for systematic variation in labour costs, standardising asset life-times and capital costs, controlling for joint assets and cost-sharing, removing country-specific elements influencing costs (e.g. specific taxes, etc.) and adjusting capital costs for inflation.

- ✓ **Total pipe length** (adjusted for land humidity).

Like in the case of electricity transmission, the **normalized asset base of the network operators** (with assets such as pipelines, compressors and control centres) was found to be the most important cost driver. The most important environmental factor influencing the asset base costs was topography, affecting both the costs of construction (due to new build, reinforcements, site access) and operation (due to maintenance access).

There are a number of different **connection points** in the gas transmission network[83], all of which are associated with certain costs of operation, metering, monitoring, etc. In the study, CEER found the sum of all these connections to represent an important cost driver.
The transport capacity of the transmission system represented by the sum of the **installed power of the compressor** units (irrespective of type of compressor unit) was found to be another important cost driver.

Finally, the study found that **pipeline installations** were subject to cost increases as a result of **high humidity and wet soil** which were greater than the costs of other assets under the normalized network parameter. This was due to the need for expensive construction site management, drainage and use of resources to evacuate water for repairs and preventive maintenance of the segments.

System services cost drivers

The effective **system cost drivers** for both electricity and gas networks vary significantly between different countries depending on their network topology, capacity and constraints, extent of penetration and type of renewable energy sources that inject into the electricity or gas network, end-use demand profiles, interconnections, use of the national network for transit flows. Common components of system service costs include injection and off-take volumes and especially (system or local peak coincident) capacities, balancing and other ancillary service needs, feed-in management (i.e. compensation for curtailed renewable energy) and further regulated services such as gas odorization.

A higher penetration of variable renewable energy (VRE) sources is an established cost driver of electricity system service costs; system service costs increase as the share of renewables increases in the generation mix. As the penetration of the electricity supply from intermittent renewable energy sources in the EU grows, the needs for system service provision will increase, especially balancing.[84] In the case of gas network system service costs the picture is less complex as at least the considerations regarding VRE are not applicable to the same extent, as the gas network is more resilient (linepack) and renewable gas sources such as biomethane or hydrogen may be stored to a greater extent. Nonetheless, system congestion may occur for example in the case of peak feed-in of biomethane at the distribution level during low gas demand in the summer. The major element of gas system service costs is balancing, provided by storage, supply-side and demand-side flexibility.[85] Moreover, system integration may provide further flexibility to the electricity and thus to the overall, coupled energy system.

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[83] According to the CEER study these are: injection from upstream net/production/injection from biogas/LNG; injection from production plant; injection from storage; delivery to downstream network; delivery to customers, direct withdrawal; delivery to neighbouring networks; delivery to storage.
[84] European Commission (2018) In-depth analysis in support of the Commission communication COM(2018) 773
[85] Keyaerts et al. (2008). Natural Gas Balancing: Appropriate Framework and Terminology.

Annex C – Data collection

Scoping and granularity of the data

Regarding the **covered period**, annual network data for 3 data points at 4-year intervals is collected and analysed, namely 2010, 2014 and 2018. These specific years are selected since the regulatory framework for energy networks in the EU was thoroughly updated in 2009 with the 3rd energy package.

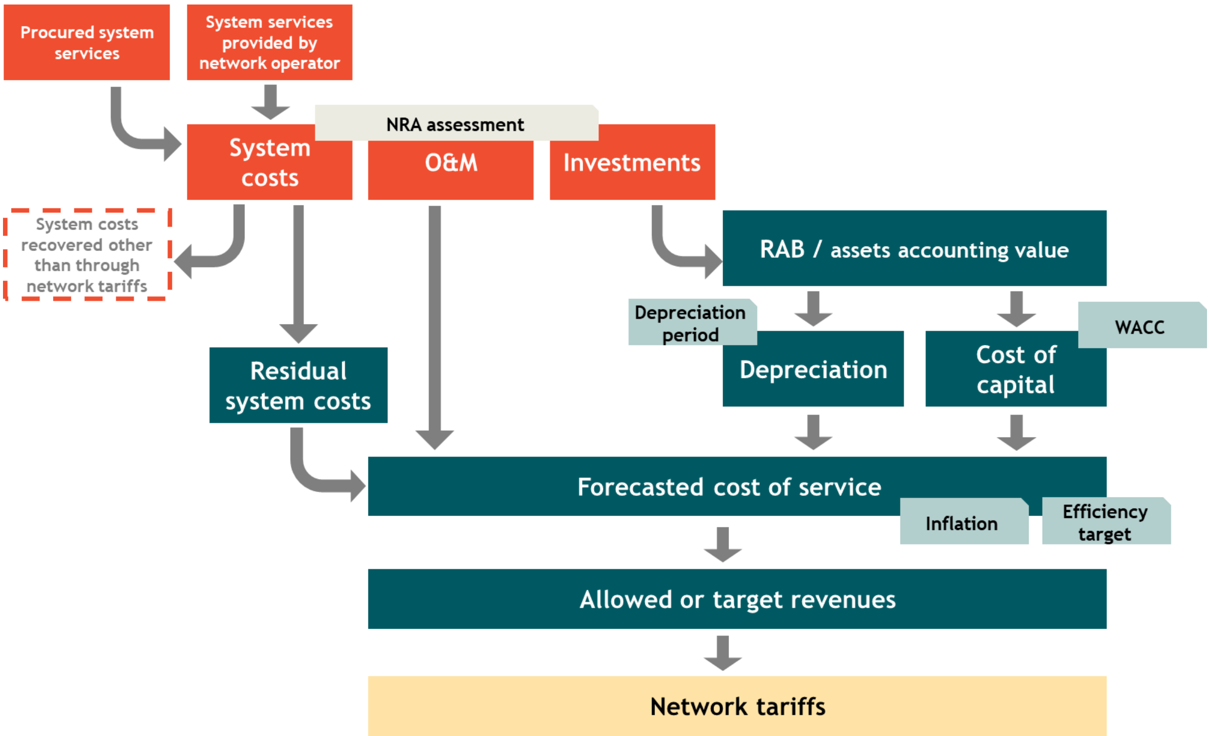
The **energy networks focused on in this report** are electricity and gas, for which the network is mostly regulated for the EU27, highly integrated at supra-national level, and well developed both in the EU and non-EU G20 countries. Non-regulated transmission and distribution in selected non-EU countries are included where significant and to the extent possible, especially in the US.

Given the focus on regulated infrastructure, storage costs are not collected, as much of the electricity and gas storage in the EU27 is neither regulated nor owned or operated by network operators themselves, due to unbundling requirements. Instead, storage is addressed on the energy investments report of the study, where the scope is not restricted to regulated activities.

The **network levels** covered comprise the transmission and distribution levels (separately). The separation of the transmission and distribution network vary by country, each having specific voltage levels for electricity and pressure levels for gas. The report collects and analyses data on network costs, cost allocation and network characteristics separately for these levels, as appropriate.

The report aims to collect network data referring to the **actual costs** of system operators, composed of the system service costs, operation & maintenance (O&M) expenditures and investments as illustrated in Figure C-1. It does not collect data or analyse the costs related to the depreciation and capital remuneration of investments by system operators. The report does not systematically collect data on the resulting cost of service and correspondent allowed or target revenues of network operators either, although potential over- and under-recovery of the cost of service is discussed, and after-taxes profits and losses of transmission system operators (TSOs) are collected for a brief analysis.

Figure C-1 Overview of network tariffs regulatory framework[86]



While information on actual costs may be unavailable, data on costs authorised by national regulators may be more readily accessible. Hence, when actual costs cannot be determined, authorised costs are used as a proxy. As authorised and actual costs do not match in a single year but do converge in the long run, this still provides correct average network costs across the years. Data on unit investment cost per transport technology is not collected (e.g. for high-voltage overhead AC lines separately).

Structure and description of the network costs

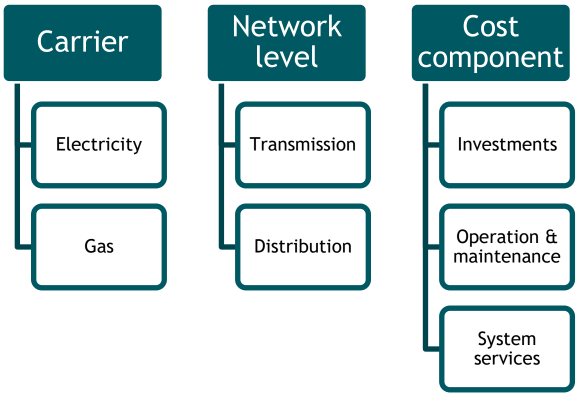
The **aggregated network cost** of regulated system operators comprises:

- ✓ Investments;
- ✓ Operation & maintenance;
- ✓ System services.

Therefore, the main data dimensions for network costs are the energy carrier, network level and cost component. Figure C-2 presents the values possible for each of these dimensions.

[86] Adapted from ACER (2018): Report on the methodologies and parameters used to determine the allowed or target revenue of gas transmission system operators

Figure C-2 Main network cost dimensions



Both investment and operation & maintenance costs are related to physical network assets. The main criteria differentiating these costs is that investment costs are capitalised and thus depreciated in several years, while operation & maintenance costs are not capitalised and thus recovered in the same year. System services costs on the other hand are costs incurred to ensure the safe operation of the electricity or gas systems (i.e. ancillary services in ENTSOE's definition).[87]

The specific cost items which are included in each network cost component are detailed here, although for comparability purposes the data is collected and analysed in aggregated values per component (i.e. values for investments, operation & maintenance, and system service costs, per carrier and per network level).

Investment costs comprise costs for network planning, construction and ownership for new network assets as well as major refurbishment (renovation) or replacement of existing assets, wherever possible. [88] All investment costs are considered to be capitalised and recovered via yearly depreciation costs, while decommissioning costs are usually recovered in the concerned year. When possible, investment costs are recorded as overnight costs occurring in the commissioning year. However, most frequently data is reported in the data sources as continuous, yearly incurred investments costs. Usually, there are no data sources available presenting investment costs in both an overnight and yearly expenditure form. Given secondary infrastructure such as electric vehicle recharging stations and alternative fuels refuelling stations are not the focus in this report, these are excluded from the costs and identified whenever they cannot be separated.

Operation & maintenance costs comprise the costs for energy transport and network maintenance including related services such as odorization, metering and data management, wherever possible. Operation & maintenance costs are not capitalised (and thus not included in the system operators regulatory asset base). The cost for services provided by third parties is included, when within the scope of operation & maintenance. Losses incurred in energy transport (transformation, gas compression, network losses) as well as the associated cost of greenhouse gas emissions are also considered as operation & maintenance costs.

As indicated, **system services costs** are costs incurred to ensure the reliable operation of the electricity or gas systems. This includes e.g. ancillary services contracted to third parties, wherever

[87] ENTSOE Glossary. Available at https://docstore.entsoe.eu/data/data-portal/glossary/Pages/home.aspx
[88] Following for gas Sumicsid (2016) Benchmarking European Gas Transmission System Operators - APPENDIX

possible. Costs incurred to guarantee the safety and operability of the physical infrastructure assets are considered operation & maintenance costs (such as personnel, equipment and operation security, operations management of interconnected networks, coupling and decoupling in the network).[89] Incurred system service costs may be considered efficient (e.g. financial expenses of balancing markets) or not (for example in the case of redispatching). For this reason, electricity system services costs are further divided in balancing, countertrading, redispatching, feed-in management (RES curtailment), capacity remuneration, and other system service costs, while gas system service costs are divided in balancing and other system service costs.

In order to assure the consistency of the data across countries and years, these three cost components can include certain cost items, while excluding others. This is indicated in Table C-1, which presents the scope of cost items per energy carrier and network level.

Table C-1 Cost items included per cost component and carrier

Component	Item	Electricity		Gas	
		Transmission	Distribution	Transmission	Distribution
Investments	Network planning	✓	✓	✓	✓
	Smart meter deployment	✗	✗	✗	✗
	EV infrastructure deployment	✗	✗		
	LNG/CNG vehicles charging infrastructure			✗	✗
	LNG facilities			✗	
Operation & maintenance	Administration	✓	✓	✓	✓
	Losses including CO_2 costs	✓	✓	✓	✓
	Non-capitalised decommissioning	✓	✓	✓	✓
	Inter-TSO compensation costs	✗			
	Retail market facilitation	✗	✗	✗	✗
System service costs	Balancing	✓		✓	
	Redispatching	✓			
	Countertrading	✓			
	Feed-in management	✓			
	Capacity remuneration	✓			
	Other system service costs	✓		✓	
All cost components	Taxes & levies	✗	✗	✗	✗
	Public service obligations	✗	✗	✗	✗
	Non-regulated services	✗	✗	✗	✗

✓ Cost item usually part of total cost for the given carrier and network level

✗ Cost item is out of scope for the given carrier and network level

In addition, the following costs items were considered outside the scope for both electricity and gas aggregated network costs and not considered whenever possible:

- ✓ **Taxes & levies**, such as financial contributions to energy sector organizations, such as national regulators and energy agencies (but not maintenance of independent system operators, which are within the scope);

[89] Following for gas Sumicsid (2016) Benchmarking European Gas Transmission System Operators - APPENDIX

- ✓ **Public service obligations of system operators** arising from energy policies such as support to renewable energy, distributed generation or combined heat and power (production and/or consumption), and protection of vulnerable consumers;
- ✓ **Non-regulated services** provided to third-parties and not related to network activities.

Especially outside of the EU, the functions of system operation, transmission asset operation and/or transmission asset ownership may be separated, e.g. between an independent system operator (ISO) and a system owner. In such cases, the ISO may bear any system and operation & maintenance costs, while investment costs are borne by the system owner. Nonetheless, the costs of both the ISO and the system owner are within the scope, and were added to obtain the total for investments, O&M and system service costs wherever possible.

Coverage of national network costs

Coverage thresholds are established on the minimum national consumption to be included at the transmission and distribution levels to arrive at representative network costs. The aim was to cover 90% of total consumption target threshold for transmission and 80% for distribution, both for electricity and gas. This means the data ideally includes the largest TSOs in order to cover at least 90% of total consumption in the transmission level and the largest DSOs in order to cover 80% in the distribution level for each EU27 Member State. If the number of DSOs required to achieve the target coverage is too high in a certain country (e.g. when several tens or even hundreds of DSOs are present with non-marginal numbers of customers), the coverage is adjusted for a lower number. Energy consumption is used (instead of number of consumers) as an indicator as it is a better proxy to transport capacity which is the main driver of network costs.

Network characteristics data

For verification and analysis of the cost and cost allocation data, the report collects the network characteristics data indicated in the table below.

Table C-2 Data sources on network characteristics used for data control and analysis

	Electricity		Gas	
	Transmission	**Distribution**	**Transmission**	**Distribution**
Deflators and exchange rates	World Bank for deflators and ECB for exchange rates			
Domestic energy supply	IEA World Energy Statistics			
Network levels in use	CEER database / Country experts		CEER database / Country experts	
Total network length – HV, MV, LV	CEER database / Country experts		Country experts	
Total network length – transmission & distribution	Country experts		CEER database / Country experts	

Network cost allocation data

This report collects cost allocation parameters which determine the rules on how costs are recovered from the different network users. Monetary volumes for these cost allocations are not collected.

The cost allocation parameters collected for the EU27 are:

- **Connection cost allocation,** where network users may pay only the costs to connect them to the closest connection point of the network (shallow charges), not pay any connection charges at all (super-shallow charges) or pay all costs including that of reinforcements beyond the connection point (deep charges);
- **Share of network costs charged according to capacity, commodity and fixed components or in other form,** that is how much of the tariffs are based on the user connection or effective peak capacity, energy utilization or neither, being recovered instead through fixed components;
- **Split of network operation charges between injection and withdrawal -** for electricity the distribution of generation (G) and load (L) charges;
- **Tariff discounts or full exemptions for specific consumers,** for example to energy-intensive industries or users with high utilization factors, i.e. users with high ratios of average consumption to their network connection capacity;
- **Tariff discounts for storage,** providing relief from volumetric tariffs paid at the charging and discharging of energy storage assets;
- **System services cost allocation,** such as for balancing, where some network users (such as small RES producers) may in some Member States be exempt from responsibility for imbalances;
- **Existence of locational or temporal signals in tariffs** as opposed to uniform tariffs (postage stamp), thus more adequately reflecting actual costs or benefits to the system from the network tie-in location of network users or the correlation of the user and the system consumption profiles;
- **Net metering for** electricity consumers with on-site generation (prosumers), charging volumetric tariffs only according to their net consumption in a given period (e.g. a month or year);

The parameters values as well as expected applicability to electricity and gas networks are presented in Table C-3. These parameters are collected by market area, if applicable.

Table C-3 Cost allocation parameters, data values and applicability to electricity and gas

	Cost allocation parameter	Parametrised input	Electricity		Gas	
			Transm.	Dist.	Transm.	Dist.
Incentive signals	Locational component in network tariff	Yes/No	✓	✓	✓	✓
	Time component in network tariff (seasonal)	Yes/No	✓	✓	✓	
	Time component in network tariff (daily/hourly)	None/time of use/dynamic/peak	✓	✓	✓	
Connection costs	Connection cost allocation to user	Super-shallow/ shallow/deep	✓	✓	✓	✓
Special incentives	Net metering	Yes/No		✓		
	Tariff discount for storage	%	✓		✓	
	Tariff discount for specific users	Industry/high utilization factor/NA	✓		✓	
Cost recovery	Frequency containment reserve (energy and capacity)	Network user/BRP[90]/hybrid/ Not applicable/Unavailable	✓			
	Frequency restoration reserve (automatic and manual, energy and capacity)		✓			
	Replacement reserve (energy and capacity)		✓			
	Gas system balancing		✓		✓	
Split of network tariffs	Injection/withdrawal tariff split (mainly production/consumption)	% / Yes/No	%	Y/N	%	Y/N
	Share/existence of capacity charges	% / Yes/No	%	Y/N	%	Y/N
	Share/existence of commodity charges	% / Yes/No	%	Y/N	%	Y/N
	Share/existence of fixed charges	% / Yes/No	%	Y/N	%	Y/N
	Share/existence of other charges	% / Yes/No	%	Y/N	%	Y/N

The cost allocation data collection focuses on EU Member States, as the comparability with relevant non-EU markets is limited (e.g. multiplicity of transmission areas in the US with different cost allocation structures). Instead, alternative cost allocation practices in non-EU G20 countries are surveyed in the report.

The objective of the **split of network operation charges between load and generation** is to assess the split between load and generation of the recovery of the total revenue of TSOs. Thus, country experts collect this data from reports or direct contact with regulators or TSOs, and the figures collected indicate the actual split of the total revenue recovery of the TSOs. Exceptionally, for most Member States, electricity data is available from ENTSO-E on the split of network charges. ENTSO-E determines a unit transmission tariff which employs a pre-defined 'base case' (a user connected to the extra-high voltage network, with a maximum demand of 40 MW and 5 000 hours of utilisation of the network). ACER data is also available for 2019.

Identification of data sources

The transversal literature providing information for multiple countries is indicated in Table C-4. Contacts were established with ACER, CEER, ENTSO-E and ENTSOG to identify transversal data for the EU27 which can be used to pre-fill the database.

[90] Balance responsible party

Table C-4 Key public network cost and cost allocation sources

Source category	Specific sources	Carrier	Network level	Data
ACER/CEER	Market Monitoring Reports (2018, 2019)	Both	Both	Electricity balancing costs Gas injection/withdrawal splits Total expenditures
ACER	Practice report on transmission tariff methodologies in Europe (2019)	Electricity	Transmission	Various cost allocation data
	The internal gas market in Europe: The role of transmission tariffs (2020)	Gas	Transmission	Various cost allocation data
CEER	Status Review of Renewable Support Schemes in Europe for 2016 and 2017 (2018)	Electricity	Both	Net metering
CEER	Benchmarking Report 6.1 on the Continuity of Electricity and Gas Supply (2016)	Both	Both	Network length Voltage and pressure levels
CEER	Benchmarking Report 7 on the Continuity of Electricity and Gas Supply (2020)	Both		Network length Voltage and pressure levels
CEER	Report on Power Losses (2019, 2017)	Electricity	Both	Network length Voltage and pressure levels Number of connections
EC	Subsidies and costs of EU energy (2014)	Both	Both	Cross-subsidies
	Study on tariff design for distribution systems (2015)	Both	Distribution	Tariff structure
ENTSO-E	Overview of transmission tariffs in Europe: Synthesis (various years)	Electricity	Transmission	Injection/withdrawal splits Tariff discounts
ENTSO-E	Survey on ancillary services procurement, balancing market design (various years)	Electricity	Transmission	System services cost allocation
ENTSO-E	Transparency platform	Electricity	Transmission	System services costs (residual)
ENTSOG	2nd TAR network code implementation report	Gas		Gas storage discounts
NRAs/TSOs	Publication according to transparency requirements of Art. 29 and 30 of the tariff network code (various years)	Gas	Transmission	Investments, O&M costs Injection/withdrawal split

Data collection template

The data collection template spreadsheet contains sheets for network costs, cost allocation and network characteristics. The structure of the template is shown in Table C-5.

Table C-5 Structure of the network costs, operation and subsidies template

Parameter	Example
General information	
Country	Country name
Energy carrier	Electricity/gas
Aggregation level	National/ Company (*only for company data*)
Network level	Transmission/distribution
Cost component	Investment/O&M/System service costs
System cost sub-category	Balancing/Countertrading/Redispatching/Capacity remuneration/Other system service costs
Covered network level consumption %	Energy consumption % for the network level covered by the data
Currency year	Explicitly mentioned by the source/report, or assumed to be same as year of publication for single-year reports
Currency unit	EUR/USD/national currency
Concerned network operator	Names of TSOs/DSOs (*only for company data*)
Yearly data	
2010	[Value / descriptive parameter / N/A]
2014	
2014	
Scope adjustments	
Within scope adjustments	In line with Table C-3
Out of scope adjustments	
Metadata	
Source	Reference to report or database/date and format of consultation with national organization
Link to the source	[link]
Notes/ remarks	Additional relevant information

Template piloting and guidelines

Data collection guidelines were provided to country experts. The templates were piloted with France and Brazil. Based on the feedback received, both the template and the guidelines were updated. The template guidelines comprised the data definitions and the detailed process for the country experts, including the priority of data sources, to guarantee that the data collected at the national level by the country experts is comparable. Once the data collection template was defined and prior to country experts collecting data, a guidance webinar was organized for all experts in order to instruct them on how to fill the template and clarify any doubts. Two helpdesk sessions were organized in the following two months to further assisted country experts with any doubts.

Collection of network data

The collection of network data was done according to the following steps:

- ✓ **Pre-filling of transversal data**: the template was pre-filled by the project team with information available from the transversal literature, for example on existing cost allocation measures as mapped by the ENTSO-E transmission tariff synthesis;
- ✓ **National data collection**: each country expert collected information for network costs, system operation and subsidies for its country. If necessary, country experts contacted the national regulator(s) and the selected system operators to complement any data not available in their reports.

Country data collection

The data templates as filled by the core team were verified and completed by the country experts. Each expert was responsible to collect all the information for network costs, system operation and cost allocation for his country.

Data collection for each country prioritized data aggregated at the national level covering all consumers, if available. If not, country experts collected company-level information on transmission and distribution system operators aiming for the coverage thresholds defined (90% for transmission and 80% for distribution).

For the prioritization of data sources, country experts were instructed to follow the order below:

1. Aggregated data: reports and direct contact with national regulators, energy agencies, associations of / country-wide network operators
    - Reports of associations
    - Contacts with national regulators
2. Company-level data: Reports and direct contact with regional system operators

Data aggregation

Third, country experts submitted to the core team the completed data collection templates. If disaggregated, the data for different TSOs and DSOs was aggregated by the project team to the country level into the main data template, keeping the separation between network levels (i.e. transmission versus distribution) and between energy carriers (electricity and gas).

Data control

The following steps were performed to verify the compiled network data. The following activities were conducted:

- ✓ Data completeness assessment by the core team: the core team assessed each template individually and requested further clarifications / gap-filling by the country experts;
- ✓ Cross-country verification: the results were compared across countries in order to further highlight issues which were only apparent through comparison, e.g. disproportionately high/low O&M costs
- ✓ Verification by national regulators: each template was sent to the respective national regulator for validation and eventual gap-filling.

These steps were conducted in iteration between the project team and the country experts, with some country experts correcting any inaccurate data or providing additional information in five iterations or more.

Annex D - Data analysis

Network cost data analysis

The analysis of the network cost data was conducted according to the following steps:

- ✓ **Selection of data points:** if multiple values were available based on different sources – the core team assessed and selected in the database the most appropriate data point based on expert knowledge and, if pertinent, in consultation with country experts;
- ✓ **Extrapolation for 100% cost coverage:** Where possible, the data collected was adjusted to represent the total national network costs. For example, bottom-up electricity distribution investment data for 2010 in Denmark covered DSOs representing 95% of consumption at that level. It was linearly extrapolated to 100% in order to also include the DSOs whose data was not collected. The target level of coverage for the transmission and distribution network costs was at least 80% of energy consumption.
- ✓ **Scaling:** besides domestic energy consumption (as a proxy for consumption which includes transportation losses), length, the number of customers (the latter for distribution) and transport capacity were identified as major drivers of network costs. Hence total network costs were analysed in relation to those parameters as applicable and pending data availability. IEA data was available for all countries for domestic energy consumption, making it the parameter of choice for the scaling and analysis of all network costs. Values scaled based on the remaining parameters are available in the databased accompanying this report.
- ✓ **Analysis:** from a number of perspectives based on different elements.
    - **Per network cost component**: investments, O&M and system service costs were initially analysed separately;
    - **Per energy carrier:** the analysis was conducted separately for electricity and for gas;
    - **Cross-country:** the analysis of network costs first compared data across countries for each energy carrier;
    - **Cross-temporal:** changes from 2010 and 2014 to 2018 were assessed for each energy carrier;
    - **Comparison of EU and non-EU G20:** data analysis for each carrier was presented for the EU27 and non-EU G20 separately, and then the two country groups compared based on country-data within each set of countries as well as aggregated data for the two sets.
    - **Comparison of electricity and gas data:** the final analysis compared, for each network cost component (investments, O&M, system service costs) the two carriers.

Network costs were described and analysed based on:

- **Absolute investments**: in constant 2018 Euros (€$_{2018}$), with a focus on the above listed elements. In addition to a cross country comparison, aggregated values of investments across all EU MS and all non-EU G20 countries across time were also presented and analysed;
- **Scaled investments:** in constant 2018 Euros per domestic energy consumption (€$_{2018}$/MWh).

Cost allocation data analysis

Cost allocation data was considered only for EU27 Member States and is based on both **quantitative** and **qualitative** information.

- ✓ **Analysis:** was disaggregated into the following components:
  - **Per energy carrier:** the analysis was conducted separately for electricity and for gas where applicable. Some of the data presented pertains only to the electricity network;
  - **Cross-temporal:** changes from 2010 and 2014 to 2018 were assessed for each energy carrier;
  - **Cross-country:** when applicable, a comparison across all EU27 was made such as in the case of components of transmission and distribution tariffs and percentage of access tariffs allocated to withdrawal/consumption.
  - **Aggregated data of all EU27 countries** was presented in the case of some figures where further disaggregation was not warranted. In these cases country-specific information was provided in the descriptive analysis, when of interest.

It is important to note that country data coverage across years and/or network levels and/or carriers might differ due to data availability.

Trinomics B.V.
Westersingel 34
3014 GS Rotterdam
The Netherlands

T +31 (0) 10 3414 592
www.trinomics.eu

KvK n°: 56028016
VAT n°: NL8519.48.662.B01

Trinomics