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7TH CEER-ECRB BENCHMARKING REPORT ON THE QUALITY OF ELECTRICITY AND GAS SUPPLY

2022

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CEER Energy Quality of Supply Workstream of the Distribution Systems Working Group

ECRB Customers and Retail Markets Working Group

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FOREWORD

European energy regulators are committed to promoting well-functioning and competitive energy markets in Europe in order to ensure that consumers receive fair prices, a wide choice of suppliers and the best quality of supply. Now, in a time high prices and challenging times for European energy markets, this work is of particular importance. Since 2001, the Council of European Energy regulators (CEER) produced six Benchmarking Reports that provide an in-depth survey and analysis on the quality of supply of electricity and, since 2016, of gas as well. In addition, CEER published updates on some of the key data contained in these Reports in 2014, 2015 and 2018.

In this 7th Benchmarking Report on the Quality of Electricity and Gas Supply, for the first time jointly written by CEER and the Energy Community Regulatory Board (ECRB), the main focus is on monitoring of the quality of electricity and gas supply, which constitutes an essential tool in the overall supervision of well-functioning energy markets. CEER and ECRB seek to provide valuable information on the practices regarding quality of supply and the regulatory framework, with associated recommendations for good regulatory practices and incentives that could be adopted in Europe.

We are delighted to see that our work in providing an extensive analysis of quality of supply issues continues to develop. Expanding on the previous Reports, the data cover 39 countries, coming from respondents from CEER Members and Observers and Energy Community Contracting Parties. These data are included in the main body, which facilitates easier benchmarking of the quality of supply in Europe. Case studies from three CEER/ECRB respondents are also covered in chapters on voltage quality and electricity commercial quality. Additional information on three countries from the Association of Mediterranean Regulators (MEDREG) is provided as fact sheets in an annex. This report is an excellent example of the cooperation between the three associations that has followed from our December 2018 Memorandum of Understanding.

A few findings to highlight include that, excluding exceptional events, the majority of countries decreased or at least maintained their unplanned minutes lost and the number of interruptions per customer from the beginning to the end of the observed period for electricity. Interruptions in gas, while much less common than those in electricity, can lead to a high risk of safety, resulting in greater efforts to avoid an interruption than in electricity. Even though gas interruptions are less frequent, they usually last longer than those in electricity. Many countries reported improved continuity of supply (a shorter duration or a lower number of interruptions) when incentive regimes/compensation schemes were implemented, even with indicators that are not regulated.

We hope you will find the data and analysis of interest and that the Report is useful for your work. If you would like to obtain more information about any part of the Report, please do not hesitate to contact the CEER Secretariat, Energy Community Secretariat ECRB section or your national energy regulatory authority.

Dr Annegret Groebel
CEER President

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EXECUTIVE SUMMARY

Since 2001, the Council of European Energy Regulators (CEER) has routinely surveyed, analysed and reported on the quality of electricity and (since 2016) gas supply in European countries, the results of which are presented in its Benchmarking Reports. Over the last two decades, CEER has produced six full Benchmarking Reports as well as updates on the key data published in February 2014, February 2015 and July 2018.

In an improvement over previous editions, this 7th CEER-Energy Community Regulatory Board (ECRB) Benchmarking Report covers the quality of electricity and gas supply for both the CEER and the ECRB participants in the main body of the Report, enabling easier benchmarking for most of Europe. The Energy Community Contracting Parties (EnC CPs) have previously only been covered in a separate annex, but the new approach of this Report raised the total number of countries[1] participating in the main Report to 39.

As before, this Report addresses three major aspects of the quality of supply. For electricity, these are its availability including incentives used to improve it, in addition to technical characteristics of grids (continuity of supply (CoS)), technical properties of supplied electricity (voltage quality (VQ)) and the speed and accuracy with which customer requests are handled (commercial quality (CQ)). For gas, these are its availability and technical characteristics of the grid (technical operational quality), its chemical composition (natural gas quality) and the speed and accuracy of handling customer requests (CQ).

Each chapter of this Report presents the results of benchmarking through the following steps:

- An explanation of the quality aspects and the importance of regulation;
- A summary of the past CEER work;
- Specific details on which indicators are monitored as well as a review of how the specific aspects are monitored and regulated; and
- Data and results available from monitoring and regulation.

The overall goals of the quality of supply regulation are to guarantee a good level of CoS, VQ and good services for energy consumers across Europe. These goals were considered in the Report's findings and recommendations.

CONTINUITY OF SUPPLY

Electricity CoS is monitored in all responding countries (38 in the corresponding chapter), but vast differences exist in the type of interruptions monitored, indicators used, their calculation and the voltage levels included in them. Interruptions originating on high and medium voltage are monitored in all countries where those voltage levels are defined. Unplanned interruptions are monitored in every responding country (regardless of whether legal obligations for monitoring exist) while planned interruptions are not. This monitoring usually covers long interruptions (defined in most countries as those longer than three minutes but there are exceptions) whereas less than half of respondents collect data on short or transient interruptions. Most countries exclude transient interruptions from monitoring altogether.

Excluding exceptional events, the majority of countries decreased or at least maintained their unplanned minutes lost and the number of interruptions per customer from the beginning to the end of the observed period. There are, however, exceptions to this observation. Large variations exist among the respondents, with the number of minutes lost due to unplanned interruptions excluding exceptional events ranging from nine to 4,982 minutes per customer, and the number of interruptions ranging from 0.20 to 55.31 per customer. Variations are large for planned interruptions too, with the System Average Interruption Duration Index (SAIDI) ranging from 0.23 to 5,144 minutes per customer and the System Average Interruption Frequency Index (SAIFI) from 0.00 to 45.47 interruptions per customer.

The chapter on CoS also explores regulatory incentive regimes implemented at system and individual user level. Overall (system level) incentive-based schemes are in place in 19 responding countries. These schemes are implemented to improve the CoS or at least maintain it at a good level. The majority are applied in distribution but there are also incentive schemes in transmission. Most countries use a combination of rewards and penalties, while very few respondents have regimes that focus exclusively on penalties. No country reported using only rewards in its CoS incentive schemes.

Individual compensation to customers is in place in two thirds of responding countries. In most cases, financial compensation is awarded if a single interruption, or the total duration of yearly interruptions, exceeds a certain duration or if the yearly number of interruptions exceeds a certain limit. Each country has its own regulation on how long a customer would have to be out of power, however the rules might also depend on voltage level, connected capacity or even weather conditions. Compensation can be automatic or on customer request. Automatic compensation is offered in 14 countries.

To facilitate easier benchmarking, CEER and ECRB recommend harmonising the methodology to calculate the CoS indicators. Common weighting methods and rules for aggregation of subsequent short interruptions should be introduced. Moreover, it is recommended to include all incidents at all voltage levels in interruption statistics. Monitoring of short interruptions should be extended to countries that currently monitor only long interruptions. Monitoring of transient interruptions could be introduced in as many countries as possible. CEER and ECRB also recommend establishing the definition of exceptional events in each country. It is important to harmonise these definitions at the European level in the interest of achieving comparable indicators.

1 For the ECRB members, the term 'countries' refers to the EnC CPs.

CEER and ECRB recommend applying adequate incentive schemes to maintain the CoS levels or improve them, if economically viable, in both distribution and transmission. In addition, adequate compensation payments for network users affected by very long interruptions should be implemented.

VOLTAGE QUALITY

In nearly three quarters of responding countries, the national regulatory authority (NRA), either acting alone or working with other competent authorities, possesses powers and duties to define the voltage quality (VQ) regulation which influence the role the NRAs have in the regulation of power quality, as well as awareness and education. All countries that answered the relevant question apply the European technical standard CENELEC EN 50160 for VQ or their requirements for VQ are based on this European standard. This ensures a harmonised understanding of VQ phenomena throughout Europe. There are countries, however, where additional requirements have been implemented, mainly to enforce stricter limits.

VQ is monitored in grids (either transmission or distribution but in most cases both) of 24 responding countries, but indicators that are monitored differ between them. Supply voltage variations is the most monitored VQ indicator. The majority of respondents indicated that their system operators are obliged to measure VQ on request from end-users. In a few countries, the end-user must pay for this service. Most responding countries indicated that they have requirements for smart meters and that the meters allow the monitoring of VQ, but the penetration rates vary between close to no smart meters installed and a near completion of the full roll-out.

In some countries, end-users are subject to compensation or a lower tariff if the standard for VQ is not met. Approximately 58% of respondents have national regulation(s) directly or indirectly imposing maximum levels of disturbances concerning VQ such as emission limits for installations.

Since approximately 42% of the countries do not have regulations that limit the emissions from end-users, CEER and ECRB recommend considering responsibility sharing between the Distribution System Operators (DSO)/Transmission System Operators (TSO) and end-users in the national regulations. Informing the end-users about the VQ, either on their request or by publishing the VQ monitoring data is also recommended by CEER and ECRB.

Education and awareness on how VQ issues might affect the network and the consumers will contribute to reducing inconveniences due to voltage disturbances. It is recommended that more countries increase awareness and education on VQ to be better prepared to deal with VQ issues.

With distributed generation and smart meter penetration growing at a fast pace, it is recommended to perform more investigations on the use of smart meters for VQ monitoring. It is also recommended to do further investigations on the way VQ is influenced by distributed generation and prosumers.

GAS TECHNICAL OPERATIONAL QUALITY

Network users expect a high level of CoS for both electricity and gas. Interruptions in gas, while much less common than those in electricity, can lead to a high risk of safety, resulting in greater efforts to avoid an interruption than in electricity. It is one of the roles of system operators to optimise the continuity performance in a cost-effective manner. Even though gas interruptions are less frequent, they usually last longer than those in electricity.

CoS indicators can also be used for gas. Some respondents use indicators for both frequency and duration, and some distinguish between planned and unplanned interruptions. Most countries that monitor CoS use SAIDI, Average System Interruption Duration Index (ASIDI), SAIFI, and Customer Average Interruption Duration Index (CAIDI) as indicators. The use of more than just one indicator to quantify CoS results in more information being available and more possibilities to compare the results among different countries.

Technical safety plays a very important role in the gas sector with indicators, such as leaks, used to describe the technical quality of the infrastructure. The effect of leaks on CoS can differ, since not every leak inevitably entails an interruption for the customer.

In 28 responding countries, DSOs have some obligations regarding gas odorisation, which gives an improved level of safety. Odorisation is part of risk management and is required to detect the presence of gas before it can reach combustible levels and cause fires or explosions.

Regarding infrastructure, gas storage facilities are used in 19 responding countries and regulated in ten. Regulation of the storage infrastructure could apply to the maximum storage, injection or withdrawal capacity, to tariffs, or to the minimal quantity of gas to be stored. Liquefied natural gas (LNG) infrastructure is used in 12 countries and regulated in ten. LNG, which can be imported by sea, offers an alternative to common gas supply which typically uses (cross-border) gas pipelines. Since the EU energy policy aims at providing its consumers with safe, balanced and competitive energy at affordable prices, LNG plays an important role in this policy, especially in guaranteeing the security of supply as well as raising the integration and competitiveness of the gas market.

NATURAL GAS QUALITY

Some natural gas parameters represent the chemical composition of natural gas (methane, sulphur, carbon dioxide, etc.). Other parameters such as Wobbe Index (WI), relative density or water/hydrocarbon dew point are considered important quality parameters. They are sometimes stipulated in contractual specifications and enforced throughout the natural gas supply chain all the way to end-users.

Out of 28 participants in the Natural Gas Quality chapter, most countries monitor gross calorific value (24 countries), water/hydro dew point (22 countries) and WI (22 countries). On the other hand, organo halides and radioactivity are monitored in only one country. WI is the main indicator of the interchangeability of fuel gases and is used to compare the combustion energy output with different composition of fuel gases. It is frequently defined in the specifications of gas supply and transport utilities. This important parameter has a range in every country, but the minima and the maxima can also have variations across Europe.

The European Commission had signalled its intent to amend the Interoperability Network Code (INT NC) by including the European Committee for Standardization (CEN) standards EN 16726. The European Network of Transmission System Operators for Gas (ENTSOG) concluded a detailed impact analysis which showed that a whole EU chain implementation of the EN 16726, despite providing certainty on the rules and removing any contracting difficulties, would face significant legal barriers and produce widespread negative impacts across segments of the gas supply chain and Member States (MS). If the CEN standard were made binding, TSOs might need to invest in costly treatment processes to accept the gas that would be outside of specification of that standard. The alternative would be to refuse the gas not meeting the CEN standard, potentially creating security of supply issues in the future. ENTSOG thus recommended not to amend the INT NC.

Any attempt to harmonise gas quality should first clarify the problem, then consider the impact of making the standard binding and avoid having any unintended consequences on security of supply.

Nevertheless, even without a legally binding standard, the Natural Gas Quality chapter shows that many countries already rely on CEN standards, which, in the long term, might contribute to reducing restrictions in cross-border gas flows and increasing commercial market efficiency.

ELECTRICITY AND GAS COMMERCIAL QUALITY

Findings of chapters on electricity and gas CQ are similar and show that there is an increased focus on the quality of services provided to customers. According to CEER/ECRB analysis, 21 different indicators are used in electricity, while 14 are used in gas. The most monitored indicators are 'time duration of connecting customers to network' in electricity (26 countries, with one using two different indicator types) and 'time for response to customer request and/or complaint' in gas (26 countries as well). Most CQ obligations focus on DSOs.

There are significant differences concerning the nature and the number of indicators monitored across countries. Some elements can be measured in different ways (for example, starting point to measure time limits). Each country has its own regulatory system with specific time limits, standards, compensation levels, penalty amounts, etc. NRAs should set the CQ regulations while considering their national, political, cultural and economic specificities. At the same time, progress in harmonisation has been achieved compared with the previous CEER Benchmarking Reports. This Report reveals that the number of identical or partially identical regulations concerning these indicators has grown considerably. CEER and ECRB recommend further harmonisation of CQ indicators.

The analysis of the results confirms that there is a general trend over time to move toward Guaranteed Indicators (GIs) for which customers must receive compensation (subject to certain exemptions) if the required service level is not provided. This trend was already identified in previous Benchmarking Reports. Compensations can be paid automatically or upon customer request, as the amount subtracted from the bill or as a direct payment to the customer. In some countries, a maximum yearly amount that a customer can receive for non-compliance with GIs has been introduced. For the most important indicators, a combination of Overall Indicators (OI) with economic sanctions (like penalties) and GIs is recommended to both improve the average performance and to protect customers from the worst service conditions. In addition, automatic compensation, which is increasingly applied, should be extended to every country.

CQ in electricity is mainly focused on residential customers connected to a low voltage (LV) network because they represent the largest group and because small domestic customers often need more protection. In gas, the same is true for customers on low-pressure (LP) level.

There is a noticeable need for a substantive response from the DSO/supplier to any customer request within a reasonable time. The data reveals that the current emphasis is placed on DSOs' performance regarding written forms of communication, but other forms (telephones, websites) have developed and are widespread. In some countries, the more traditional approach of visiting local customer centres continues. In addition, there are countries where oral claims are still not considered, and only written complaints are counted. A limited number of countries introduced indicators related to call centres and customer centre services. CEER and ECRB recommend taking into account all types of responses for CQ regulation.

It is important to regularly review the CQ indicators, taking into consideration the development of national conditions and customer expectations. CEER and ECRB recommend evaluating customer priorities before creating new regulatory frameworks. To further develop CQ regulation, satisfaction surveys (although costly) could be implemented to have qualitative elements, since they could help assess how customers actually perceive the quality of service achieved by the system operator.

Finally, having accurate billing based on the actual, measured consumption is becoming more and more important both for customers and system operators. Recognising this need, many countries aim to collect monthly (or even more frequent) meter data with meter readings through the roll-out of smart meter programmes.

01
INTRODUCTION

1 INTRODUCTION

1.1 BACKGROUND

The Council of European Energy Regulators (CEER) periodically surveys and analyses the quality of electricity and (since 2016) gas supply in its member and observer countries. These surveys and analyses take the form of CEER Benchmarking Reports on the Quality of Electricity Supply (hereafter Benchmarking Reports). The first report was issued in 2001 [1], followed by the 2nd, 3rd, 4th, 5th and 6th editions in 2003, 2005, 2008, 2011 and 2016 respectively [2], [3], [4], [5], [6]. Moreover, updates on the key data were published in 2014, 2015 and 2018 [7], [8], [9]. The 6th Benchmarking Report was the first to analyse the quality of both electricity and gas supply, a practice that is repeated in this 7th Benchmarking Report.

The publication of these Benchmarking Reports has facilitated the availability of information on the regulation of quality of supply and its implications in each country. In addition, the Benchmarking Reports provide good practices for regulating the quality of supply in electricity and gas grids, which have been adopted by many European countries. Since the first edition, the benchmarking exercise has steadily spread throughout Europe as displayed in Figure 1-1.

1.2 COVERAGE

Previous Benchmarking Reports already included the Energy Community Regulatory Board (ECRB) Contracting Parties, but

FIGURE 1-1: Contribution to the CEER Benchmarking Reports over its first 6 editions (2001-2016)

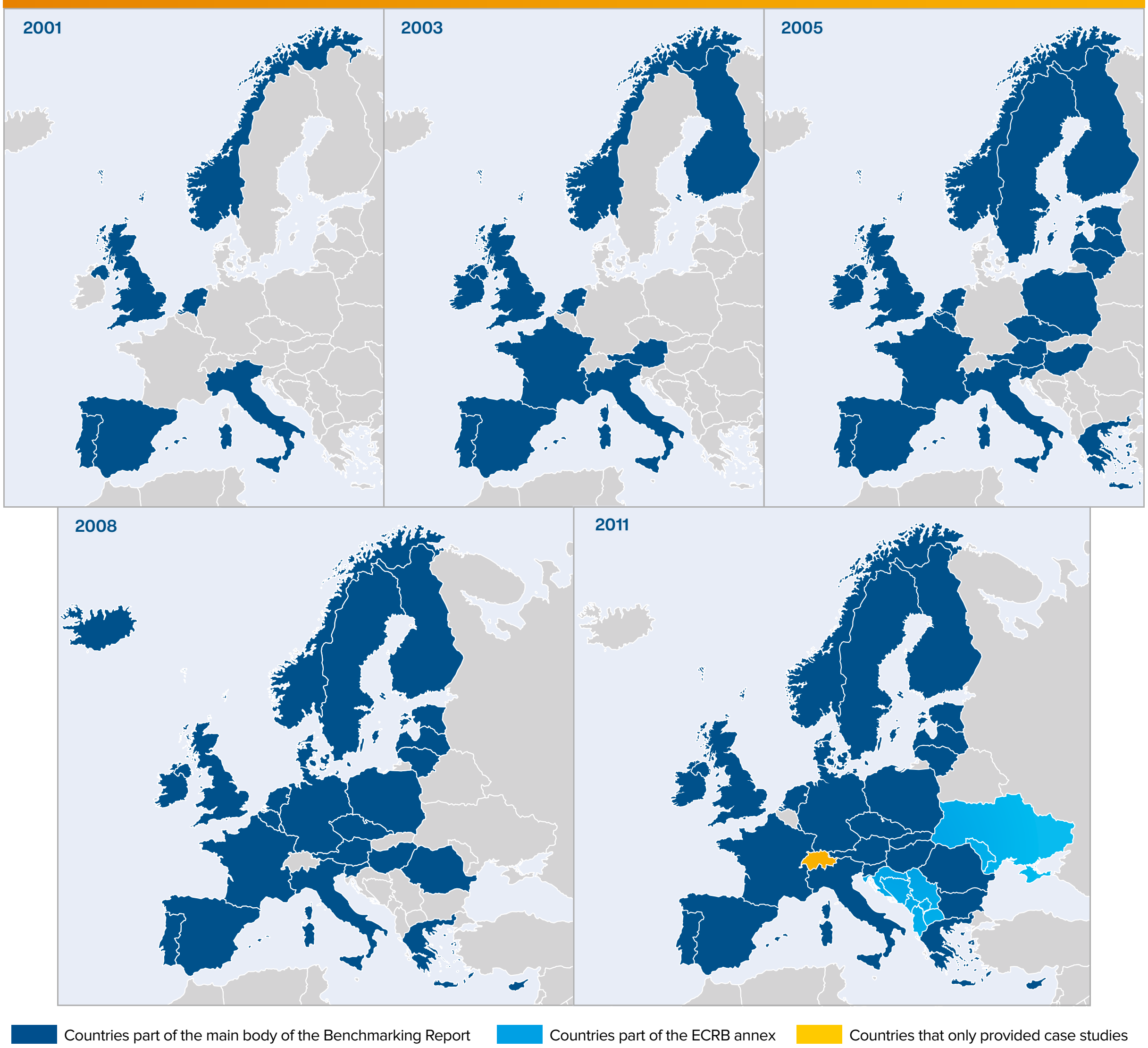
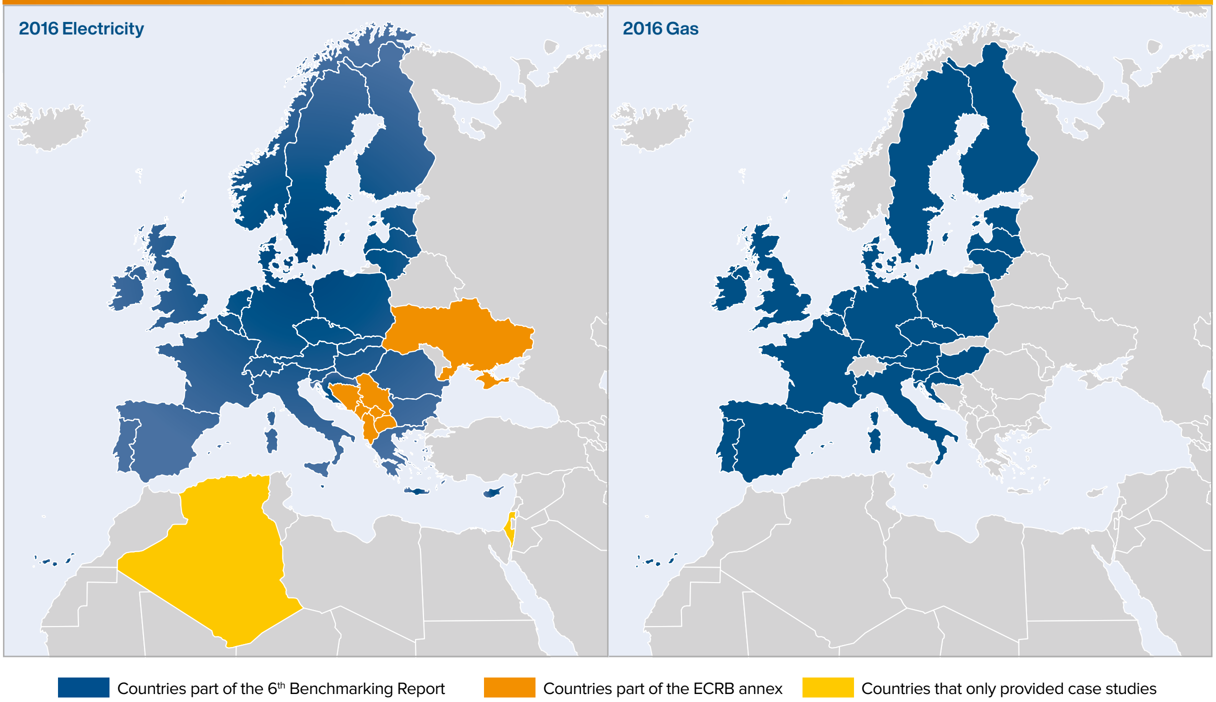


FIGURE 1-1: Contribution to the CEER-ECRB Benchmarking Reports over its first 6 editions (2001-2016)



only as an annex to the main document. This 7th Benchmarking Report is the first to be co-written by the CEER and ECRB drafters and include the ECRB participants in the main body of the report. It is based on input from 39 CEER and ECRB countries which are sometimes listed by their abbreviations in tables: Albania (AL), Austria (AT), Belgium (BE), Bosnia and Herzegovina (BA), Bulgaria (BG), Croatia (HR), Cyprus (CY), the Czech Republic (CZ), Denmark (DK), Estonia (EE), Finland (FI), France (FR), Georgia (GE), Germany (DE), Great Britain (GB), Greece (EL), Hungary (HU), Ireland (IE), Italy (IT), Kosovo*[2] (KS*), Latvia (LV), Lithuania (LT), Luxembourg (LU), Malta (MT), Moldova (MD), Montenegro (ME), the Netherlands (NL), North Macedonia (MK), Norway (NO), Poland (PL), Portugal (PT), Romania (RO), Serbia (RS), Slovakia (SK), Slovenia (SI), Spain (ES), Sweden (SE), Switzerland (CH) and Ukraine (UA). Participation is illustrated in Figure 1-2.

Not every question from the questionnaire applied to every country and not all countries answered every question. This means not every country is included in every table or figure. In addition to CEER countries and the Energy Community Contracting Parties (EnC CPs), Annex A includes short fact sheets on three participants (Jordan, Lebanon and Turkey) from the Association of Mediterranean Energy Regulators (MEDREG). These countries answered a different, shorter questionnaire meant to provide an overview of their networks and regulatory frameworks in addition to the most important elements of the quality of supply regulation in their countries.

In some countries, an answer pertains only to a certain region or entity within it. Belgium consists of three autonomous regions: Flanders, Wallonia and the Brussels-Capital Region. Likewise, Bosnia and Herzegovina consists of two autonomous entities: the Federation of Bosnia and Herzegovina and Republika Srpska (in addition to the Brčko district). If an answer applies only to a specific region or entity, this is indicated either in the text or in the footnotes. As in previous Benchmarking Reports, all British answers apply only to England, Scotland and Wales, but not to Northern Ireland.

This report's CoS data is from 2010 to 2018. General information in other chapters is CEER's/ECRB's best assessment of the latest correct information at time of drafting in 2021-2022, unless otherwise stated.

1.3 STRUCTURE

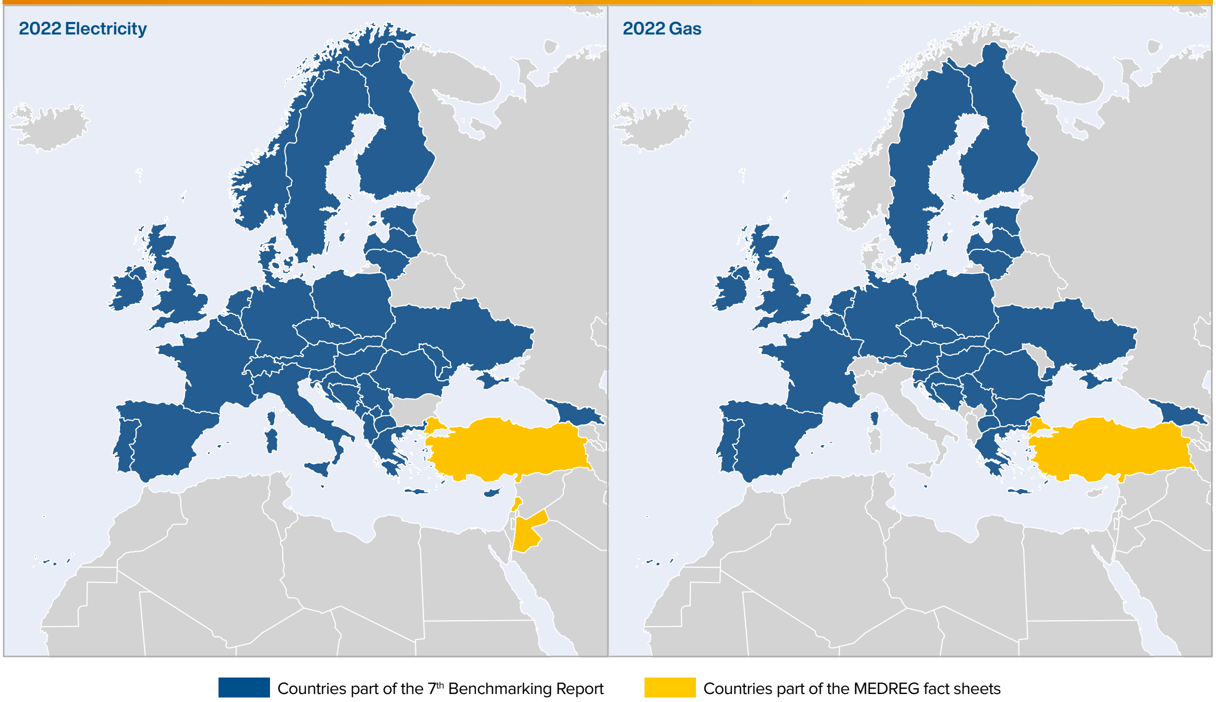
As with its predecessors, this 7th Benchmarking Report addresses three major aspects of the quality of supply. For electricity, these are its availability (continuity of supply, (CoS)), technical properties (voltage quality (VQ)) and the speed and accuracy with which customer requests are handled (commercial quality (CQ)). These elements are treated in Chapters 2, 3 and 4, respectively. For gas, these are its supply (technical operational quality), composition (natural gas quality) and CQ, which are treated in Chapters 5, 6 and 7, respectively.

Each chapter presents the benchmarking results in the following steps:

- An explanation of the quality aspect and the importance of its regulation;
- A summary of the past work; and

2 Per ECRB standard practice, throughout this document the symbol * refers to the following statement: This designation is without prejudice to positions on status and is in line with UNSCR 1244 and the ICJ Advisory Opinion on the Kosovo declaration of independence. For more details on the Energy Community and ECRB see: www.energy-community.org

FIGURE 1-2: Contribution to the 7th Benchmarking Report (2022)



- Specific details on the following topics:
  - A review of what is monitored;
  - A review of how the specific aspects are monitored and regulated; and
  - Actual data and results.

A more detailed analysis of practices in certain countries was included in the form of case studies, which illustrate the varying approaches to the regulation of quality of supply and reflect the conditions specific to each studied country.

1.4 CONCLUSIONS

The general goal of the quality of supply regulation is to guarantee a good level of CoS, VQ, gas quality and good services for consumers across Europe. These goals were considered in findings and recommendations at the end of the chapters that reflect the key information and aspects concerning the covered topics. CEER members and observers as well as the EnC CPs should consider the implementation of these recommendations.

02
ELECTRICITY – CONTINUITY OF SUPPLY

2 ELECTRICITY – CONTINUITY OF SUPPLY

2.1 WHAT IS CONTINUITY OF SUPPLY AND WHY IS IT IMPORTANT TO REGULATE IT?

Continuity of Supply (CoS) concerns interruptions in electricity supply and focuses on the events during which the voltage at the supply terminals of a network user drops to zero or nearly zero[3]. CoS can be described by various quality dimensions. The ones most commonly used are number of interruptions, unavailability (interrupted minutes) and energy not supplied (ENS) per year.

Network users expect a high CoS[4] at an affordable price. The fewer the interruptions and the quicker the return of electricity supply, the better the continuity from the network user's point of view. Therefore, one of the roles of network operators is to optimise the continuity performance of their distribution and/or transmission network in a cost-effective manner. The role of the National Regulatory Authorities (NRA) is to ensure that this optimisation is carried out in the correct way, taking into account users' expectations and their willingness to pay.

CoS indicators are traditionally important tools for making decisions on the management of distribution and transmission networks. Regulatory instruments now mostly focus on accurately defined CoS indicators: frequency of interruptions, their duration, and ENS due to interruptions. These instruments normally complement incentive regulation, which (either in the form of price-cap or revenue-cap mechanisms) is commonly used across Europe at present. Incentive regulation provides motivation to increase economic efficiency over time. However, it also carries a risk of network operators refraining from carrying out investments and proper operational arrangements for better continuity to lower their costs and increase their efficiency. To account for this drawback in incentive regulation, a large number of European NRAs adopt additional regulatory instruments to maintain or improve CoS.

2.2 MAIN CONCLUSIONS FROM PAST WORK ON CONTINUITY OF SUPPLY

The 1st Benchmarking Report published in 2001 [1] identified two main features of the CoS regulation as:

- Guaranteeing that each user can be provided with at least a minimum level of quality; and
- Promoting quality improvement across the system.

The comparative analysis of available measurement and CoS regulation in the 1st Benchmarking Report shows that NRAs have generally approached continuity issues by first looking at long interruptions affecting low voltage (LV) network users and treating planned and unplanned interruptions separately. In several countries, both the number and the duration of interruptions were available. However, the choice of the indicator used varies by country. Moreover, many countries record short interruptions as well as long interruptions. Different approaches to CoS regulation combined with different geographical, meteorological and network characteristics, make benchmarking of actual levels of CoS difficult. CEER urged NRAs in the 1st Benchmarking Report to pay attention to implementation and control issues and identified the most important of these:

- Regular internal audits by distribution companies and sample audits by the NRA; and
- Accuracy and precision indicators to assist in auditing and to inform decisions about sanctions.

In the 2nd Benchmarking Report [2], the number of countries included in the comparison was extended and the comparisons were more detailed. Distinctions were made between planned and unplanned interruptions, different voltage levels and load density areas, and interruptions were classified by their cause. It was noted that further harmonisation of data and definitions between NRAs remained necessary. The 2nd Benchmarking Report also concluded the level of quality of supply had not decreased significantly in European countries even after the privatisation of utilities, increasing supply competition, price-cap regulation for monopolistic activities and legal unbundling of businesses.

A number of encouraging trends were also observed in the 3rd Benchmarking Report [3], such as:

- The duration of unplanned interruptions showed significant improvement (downward trend) for most countries;
- The number of unplanned interruptions showed improvement (downward trend) for most countries;
- Excluding exceptional events from unplanned performance figures highlighted the significant improvements made by many European countries in terms of the duration and the number of interruptions;
- Countries with previously low levels for duration and number of interruptions were able to make further improvements; and
- The number of short interruptions had generally not risen despite an increased move to automation and remote-control techniques.

CEER concluded in the 2nd and 3rd Benchmarking Reports [2], [3] that audit procedures had been put in place in almost all countries that adopted reward/penalty schemes as measurement rules, and that audit procedures become more important when some kind of economic incentive is used for CoS.

3 According to EN 50160.
4 The terms 'availability of electricity supply' and 'reliability of supply' can be used interchangeably with CoS. However, this Report adopts the term 'continuity of supply' as in the previous CEER Benchmarking Reports.

The 4th Benchmarking Report [4] introduced precise definitions of continuity indicators to ensure an appropriate homogeneity between European countries. Very detailed chapters on exceptional events and a short presentation of on-site audits on continuity data were also added.

Between the 4th and the 5th Benchmarking Reports [4], [5], CEER commissioned Norwegian research organisation SINTEF to undertake a consultancy report: 'Study on Estimation of Costs Due to Electricity Interruptions and Voltage Disturbances' (Cost Estimation Study) [10] and published 'Guidelines of Good Practice on Estimation of Costs due to Electricity Interruptions and Voltage Disturbances' [11]. Two key messages emerged:

- Results from cost estimation studies on costs due to electricity interruptions are of key importance for setting proper incentives for CoS; and
- The CEER Guidelines of Good Practice (GGP) should be used as a reference when performing a nationwide cost estimation study, always taking into account country-specific issues and needs.

CEER representatives contributed significantly to the European Committee for Electrotechnical Standardization (CENELEC) technical report 'Interruption indexes' issued in 2010 [12]. This covered guidance on how to calculate CoS indices, as well as recommendations on a set of indices - System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI) and Momentary Average Interruption Frequency Index (MAIFI) - suitable for pan-European benchmarking of distribution network performances. The report recognised its shortcomings in not addressing rules on the aggregation of interruptions, in particular short interruptions, and proposed to describe aggregation rules in a second version of the technical report.

In the 5th Benchmarking Report [5], a case study from Switzerland was included in the main document and nine EnC CPs were included as an annex to the Report. The Report offered a more detailed look into: the correlation between interruptions and percentage of underground cables; level of detail in the indicators; contributions to duration and frequency of interruptions based on voltage level; and differences between interruptions in urban, suburban and rural areas of certain EU Member States (MS). In addition, descriptions of quality incentive schemes were presented for many countries.

The 6th Benchmarking Report [6] expanded the number of participants in the main body of the chapter to 30, in addition to the annex where EnC CPs were analysed. Case studies from the Czech Republic, as well as MEDREG members Algeria and Israel, were also included. The distinction between urban, suburban and rural areas was dropped due to difficulties in obtaining data. The Report provided an insight into: interruptions in distribution and transmission; technical characteristics of electricity networks; percentage of underground cables; and incentive schemes for continuity of supply across Europe. For the first time, indicators for interruptions in gas were presented (in a separate chapter on gas technical operational quality).

2.3 STRUCTURE OF THE CHAPTER ON CONTINUITY OF SUPPLY

The chapter on CoS takes a closer look at the monitoring practices, indicators, technical characteristics of the networks and regulation, standards, and incentives both on system level and on single-user level. It concludes with findings and recommendations on CoS.

The chapter is based on input from 38 countries: Albania, Austria, Belgium, Bosnia and Herzegovina, Croatia, Cyprus, the Czech Republic, Denmark, Estonia, Finland, France, Georgia, Germany, Great Britain, Greece, Hungary, Ireland, Italy, Kosovo*, Latvia, Lithuania, Luxembourg, Malta, Moldova, Montenegro, the Netherlands, North Macedonia, Norway, Poland, Portugal, Romania, Serbia, Slovakia, Slovenia, Spain, Sweden, Switzerland and Ukraine.

2.4 CONTINUITY OF SUPPLY MONITORING

CoS refers to the availability of electricity to all network users. All countries that participated in this Benchmarking Report stated that they monitor CoS in their electricity networks. However, there are significant differences in monitoring among the participants (which consist of CEER MS and EnC CPs). Differences arise in the type of interruptions monitored, the reported level of detail as well as the interpretation of various indicators. This section presents the methods used for monitoring in different countries.

2.4.1 Definitions of voltage levels

Before discussing the monitoring of interruptions on different voltage levels, it is important to first address how those voltage levels are defined. As the terms low voltage (LV), medium voltage (MV), high voltage (HV) and extra high voltage (EHV) have different meanings across Europe, Table 2-1 should be consulted when referencing a specific voltage level. Some countries did not provide answers for this Benchmarking Report. Given the importance of voltage level definitions, those countries' definitions were taken from the 6th Benchmarking Report [6] and shown in parentheses in Table 2-1 and Table 2-2.

The minimum value on LV level was sometimes reported as single-phase (mostly 0.23 kilovolts (kV) or 230 volts (V)) and sometimes as three-phase (mostly 0.4 kV or 400 V), depending on the country. Although presented differently, these values are essentially equivalent. In the case of Ireland, the potential 10% deviation was also taken into account for LV values.

In some cases, the actual voltage level is not strictly defined. Some levels can correspond to both transmission and distribution, as is the case in **Belgium**, where grids with voltages between 30 kV and 36 kV are usually considered HV with local transmission function. However, Distribution System Operators (DSOs) in Belgium have built grids with voltages between 30 kV and 36 kV that have a distribution function. These grids are mainly developed to directly connect local generation units that are too large to be connected to the existing distribution grid.

The exact definition of distribution in Belgium also depends on the region:

- In Flanders some DSOs have agreements with the Transmission System Operator (TSO) to construct and operate networks of up to 36 kV that are used specifically for decentralised generation;
- In Wallonia, a decree from 2001 states that the distribution network operates at a voltage less than or equal to 70 kV and is used for the transmission of electricity to end customers at regional or local level, with the exception of the local transport network; and
- In Brussels, distribution is defined as having a voltage of less than 36 kV, meaning there is also an overlap with transmission.

In **Albania**, although the maximum distribution is 35 kV, the separating border between distribution and transmission systems are the 110 kV busbars.

Although **Bosnia and Herzegovina** does not define EHV, some of its answers still list EHV as a voltage level in use (such as the table that illustrates the voltage levels included in each indicator). In this case, EHV in Bosnia and Herzegovina should be considered as part of HV, as defined in Table 2-1.

In the **Czech Republic**, select 110 kV lines are included in transmission, while other 110 kV lines, in addition to 0.23/0.4 kV, 1.5 kV, 3 kV, 6 kV, 10 kV, 22 kV, 25 kV and 35 kV, are part of the distribution network.

The transmission network of **Estonia** has a voltage of at least 110 kV but includes some lines on MV level (over 10 kV). These connect to networks of other countries that are necessary to ensure the functioning, administration and development of the system as a whole.

In **France**, in addition to what is typically referred to as the transmission network, there is also a sub-transmission network. The transmission network carries electricity on 225 kV and 400 kV voltage levels and serves interconnectors with neighbouring countries, large generation facilities (nuclear, hydroelectric and thermal plants), as well as the sub-transmission networks. These networks carry electricity to distribution networks and to the largest, typically industrial, customers at high voltages (63 kV to 225 kV). Intermediate-sized power plants also feed-in energy to the network. The distribution networks in France supply electricity to end-consumers, households and businesses (retailers, light industry, etc.) at medium and low voltages through a tree-structured network design.

In **Great Britain**, MV is not defined. Instead, HV starts at a low 1.1 kV and goes up to 20 kV. EHV reaches 132 kV and is considered part of the distribution grid. Transmission starts at 275 kV (or 132 kV in Scotland) and includes voltages up to 400 kV.

The distribution network of **Greece** consists of networks and infrastructure on MV and LV across the entire country. This includes HV networks and infrastructure in autonomous island systems and HV infrastructure within the national capital region. The transmission network consists of networks and infrastructure on HV and above in the continental part of the country and includes inland and offshore interconnections on HV and above but excludes HV infrastructure within the national capital region.

In **Ireland**, the TSO voltages are 110 kV, 220 kV and 400 kV. Radially-supplied 110 kV customers also form part of the TSO system. Radially-supplied 110 kV stations form part of the DSO system.

In **Malta**, as it does not operate a transmission grid, the entire power grid is considered to be distribution.

In **Moldova**, the voltage levels of transmission and distribution overlap as lines between 35 kV and 110 kV could be considered either transmission or distribution, depending on what they are used for.

Transmission in **Norway** includes lines with voltage levels above 200 kV or those with special importance to system security.

Transmission in **Portugal** only consists of its EHV lines.

The transmission network in **Serbia** encompasses:

- Power lines with voltages of 400 kV and 220 kV;
- Overhead/underground 110 kV power lines that end at distribution transformers with the primary voltage of 110 kV;
- Transformer stations with the primary voltage of 400 kV or 220 kV;
- Distribution switchgear facilities with voltages of 400 kV or 220 kV;
- Terminal switchgear facilities of 400 kV and 220 kV in transformer stations with the primary voltage of 400 kV or 220 kV to which the facilities of customers or producers are connected;
- Distribution switchgear facilities of 110 kV;
- Terminal switchgear facilities with 110 kV in transformer stations, with the primary voltage of 110 kV where the facilities of customers or producers are connected to the transmission network and electricity metering devices at all points of takeover, to and from the transmission system.

Telecommunication infrastructure (even if it is in distribution facilities) and control centres/systems necessary for performing the activities of the TSO are also included. Voltages typically used in distribution in Serbia are 0.4, 10, 20, 35 and 110 kV.

Analogous to Great Britain, MV is not defined in **Slovakia**. Instead, HV starts at 1 kV and voltages greater than 52 kV are considered EHV.

The transmission network in **Spain** consists of lines, transformers and other elements with voltages greater than or equal to 220 kV, although it also has installations that fulfil transmission functions that are operated on less than 220 kV. Transmission on the islands is carried out at voltages greater than or equal to 66 kV.

Distribution in **Sweden** is divided into regional DSOs and local DSOs. There is no formal lower limit for the LV network, but it is almost always 0.4 kV.

Other than the power lines, power grids in Europe usually include the equipment related to metering, protection, control, security, information and telecommunications that are necessary for the operation of a (transmission or distribution) system.

TABLE 2-1: Definitions of voltage levels

Country	LV Network		MV Network		HV Network		EHV Network	
	Min kV	Max kV	Min kV	Max kV	Min kV	Max kV	Min kV	Max kV
Albania	0.4	6	6	35	110	400		
Austria		1	>1	36	>36	<220	220	380
Belgium	0.23[5]	1	1	30-36[6]	30-36[7]	150	220	380
Bosnia and Herzegovina	0.4	1	6	35	110	400		
(Bulgaria)		(1)	(1)	(35)	(110)	(110)	(220)	(400)
Croatia	0.4	0.4	10	35	110	110	220	400
Cyprus	0.23	0.4	11	22	66	132		
Czech Republic	0.4	1[8]	1[9]	52[10]	52[11]	300[12]	300[13]	800[14]
Denmark	0.4	0.4	0.4[15]	10[16]	10[17]	50[18]	50	132
Estonia	0.4	1	6	36	110	220	220	330
Finland	0.4	1	1	70	70	110	220	400
France	0.23	1	1	45	63	150	225	400
Georgia	0.22	0.38	6	35	110	500		
Germany	0.23	1	10	30	60	110	220	380
Great Britain	0.23	1			1.1	20	22	<132
Greece	0.4	0.4	6.6	22	66	150	400	400
Hungary	0.23	0.4	10	35	120	120	220	750
Ireland	0.23[19]	0.4[19]	10[20]	20[21]	38[22]	110[23]	150	400
(Italy)		(1)	(>1)	(35)	(>35)	(150)	(>150)	
Kosovo*	0.4	1	1	35	110	400		
Latvia	0.23	1	6	20	110	330		
Lithuania		0.4	6	35	110	400		
Luxembourg	0.4	1	1	35	35	110	110	220
Malta	0.23	0.4	11	33	132	132	230	230
Moldova	0.4	0.4	10	10	35	400		
Montenegro	0.4	0.4	10	35	110	400		
Netherlands, The		1	>1	35	>35	150	>150[24]	350
North Macedonia	0.4	0.4	6	35	110	400		
Norway	0.23	1	1	22	36	132	220	420
Poland		1	>1	<110	110	110	220	400
Portugal		<1	1	<45	45	<110	110	
Romania	0.4	1	>1	36	>36	110	>110	750
Serbia	0.4	1	10	35	110	400		
Slovakia	0.4	1			1	52	>52	300
Slovenia	0.4	0.4	10	35	110	110	220	400
Spain	0.125	1	1	36	>36	<132	132	400
Sweden		1	>1	36	36	150	220	400
Switzerland	0.23	<1	1	36	>36	<220	220	380
Ukraine[25]	0.4	0.4	6	35	110 (154)	110 (154)	220	800

5 Flanders: 0.23 kV. Wallonia: minimum voltage in LV network is 0.
6 Wallonia: maximum voltage in MV is 36 kV.
7 Grids with voltages between 30 and 36 kV. Wallonia: minimum voltage in HV is 36 kV.
8 The maximum operated voltage is 0.6 kV, but that is rare.
9 The minimum operated voltage is 3 kV, but that is rare.
10 The maximum operated voltage is 35 kV.
11 The minimum operated voltage is 110 kV.
12 The maximum operated voltage is 220 kV.
13 The minimum operated voltage is 400 kV.
14 The maximum operated voltage is 400 kV. There is also a definition of ultra high voltage (UHV) which is the voltage higher than 800 kV, but no lines are operated on this level.
15 For SAIDI/SAIFI, the lower limit of MV is taken as 1 kV.
16 For SAIDI/SAIFI, the upper limit of MV is taken as 24 kV.
17 For SAIDI/SAIFI, the lower limit of HV is taken as 25 kV.
18 For SAIDI/SAIFI, the upper limit of HV is taken as 99 kV.
19 Ireland uses 230/400 nominal volts in LV network, but the upper and lower limits they indicated include the possible variation of 10% (230 V +/- 10% and 400 V +/- 10%).
20 This is nominal voltage, with a lower limit that is variable according to operating conditions, and an upper limit of 11.1 kV.
21 This is nominal voltage, with a lower limit that is variable according to operating conditions, and an upper limit of 22.1 kV.
22 This is nominal voltage, with a lower limit that is variable according to operating conditions, and an upper limit of 43 kV.
23 This is nominal voltage, with a lower limit that is variable according to operating conditions, and an upper limit of 120 kV.
24 EHV network is either 220 kV or 350 kV.
25 MV level minimum voltage is 6 – 10 kV, maximum voltage is 27.5 – 35 kV; HV level can be 110 kV or 154 kV.

TABLE 2-2: Definitions of distribution and transmission systems

Country	Distribution		Transmission	
	Min kV	Max kV	Min kV	Max kV
Albania	0.4	35	110	400
Austria	0.4	<110	110	380
Belgium	0[26]	70[27]	30	380
Bosnia and Herzegovina	0.4	35	110	400
(Bulgaria)			(110)	(400)
Croatia	0.4	35	110	400
Cyprus	11	22	66	132
Czech Republic	0.4	110	110	400
Denmark	0.4	100	100	400
Estonia	0.4	36	110	330
Finland	0.4	110	110	400
France	0.23	63	63	400
Georgia	0.22	110	220	500
Germany	0.23	125	72.5	380
Great Britain	0.23	66/132[28]	132/275[29]	400
Greece	0.4	150	66	400
Hungary	0.4	120	120	750
Ireland	0.23[30]	110[31]	110	400
Kosovo*	0.4	35	110	400
Latvia	0.23	20	110	330
Lithuania	6	35	110	400
Luxembourg	0.4	110	110	220
Malta[32]	0.4	230		
Moldova	0.4	110	35	400
Montenegro	0.4	35	110	400
Netherlands, The	0.4	50	110	380
North Macedonia	0.4	110	110	400
Norway	0.23	132	132	420
Poland	0.4	110	110	400
Portugal	0.23	60	132	400
Romania	0.4	110	>110	750
Serbia	0.4	110	110	400
Slovakia	0.4	110	220	400
Slovenia	0.4	110	110	400
Spain	0.125	132	220[33]	400
Sweden	0.4	<220	220	400
Switzerland	0.23	<220	220	380
Ukraine	0.4	110 (154)	220[34]	800

26 Wallonia: 0 kV. Flanders: 0.23 kV.
27 Wallonia: 70 kV. Brussels and Flanders: 36 kV.
28 66 kV in Scotland.
29 In England and Wales, transmission starts at 133 kV and goes up to 400 kV (lines are at 275 kV and 400 kV). Transmission in Scotland includes the 132 kV lines.
30 This is nominal voltage with a variable tolerance of +/- 10%.
31 This is nominal voltage, with a lower limit that is variable according to operating conditions, and an upper limit of 120 kV.
32 No transmission grid in Malta.
33 On islands, transmission is carried out on lower voltages: ≥66 kV.
34 The TSO owns and operates a few lines with voltage that is ≤110 kV.

2.4.2 Definitions of interruptions based on duration

In Table 2-3, definitions of interruptions based on duration are illustrated and divided into long, short and transient interruptions. It is important to note that some countries do not define all types of interruptions, such as transient, while others consider transient interruptions to be included in short interruptions. Since many respondents did not answer this specific question, it was decided to include the answers from the 6th Benchmarking Report [6] in the table below. As in the previous section, these answers are shown in parentheses.

The provided definitions of short interruptions reveal that there are cases when boundaries between interruptions of different duration are blurred, as there is no clear distinction between long and short interruptions. Sometimes only interruptions above certain minimum durations are defined (e.g. five seconds in the Netherlands), but the definition itself does not distinguish between different lengths of interruptions. Most of the countries that differentiate between long and short interruptions are in line with the EN 50160 standard regarding voltage characteristics in public distribution systems [13]. Long interruptions are monitored in all countries that answered the questionnaire.

TABLE 2-3: Definitions of long, short and transient interruptions

Country	Transient interruption	Short interruption	Long interruption
Albania	Not defined	1 sec<T≤10 min	T>10 min
Austria	Not defined	1 sec<T≤3 min	T>3 min
Belgium[35]	T≤1 sec	1 sec<T≤3 min	T>3 min
Bosnia and Herzegovina	Not defined	1 sec<T≤3 min	T>3 min
(Bulgaria)	(T<1 sec)	(T<3 min)	(T>3 min)
Croatia	Not defined	T≤3 min	T>3 min
Cyprus	Not defined	Not defined	Not defined
Czech Republic	Not defined	1 sec≤T≤3 min	T>3 min
(Denmark)	(No distinction between long and short interruptions. An interruption has a duration of at least 1 minute.)	(No distinction between long and short interruptions. An interruption has a duration of at least 1 minute.)	(No distinction between long and short interruptions. An interruption has a duration of at least 1 minute.)
Estonia	Not defined	Not defined	T>3 min[36]
Finland		T<3 min	T≥3 min
France	T<1 sec	1 sec≤T≤3 min	T>3 min
Germany	T≤1 sec	1 sec< T≤3 min	T>3 min
Georgia	Not defined	T<5 min	T≥5 min
(Great Britain)	(Same category as a short)	(T<3 min)	(T≥3 min)
Greece	Not defined	T≤3 min	T>3 min
Hungary	T≤1 sec	1 sec<T≤3 min	T>3 min
(Ireland)	(Not defined)	(Not defined)	(T≥3 min)
Italy	T≤1 sec	1 sec<T≤3 min	T>3 min
Kosovo*	Not defined	T≤3 min	T>3 min
(Latvia)	(Not defined)	(T≤3 min)	(T>3 min)
(Lithuania)	(Not defined)	(T<3 min)	(T≥3 min)
Luxembourg	Not defined	T≤3 min[37]	T>3 min
Malta	This definition is not used	This definition is not used	This definition is not used
Moldova	Not defined	1 sec<T≤3 min	T>3 min
Montenegro	Not defined	Not defined	T>3 min
Netherlands, The	Not defined	No distinction between long and short interruptions. An interruption has a duration of at least 5 seconds.	No distinction between long and short interruptions. An interruption has a duration of at least 5 seconds.
North Macedonia	Not defined	T≤3 min	T>3 min
Norway	Included in short[38]	T≤3 min	T>3 min
Poland	T≤1 sec	1 sec<T≤3 min	T>3 min
Portugal	Not defined	1 sec≤T≤3 min	T>3 min
Romania	T≤1 sec	1 sec<T≤3 min	T>3 min
Serbia	Not defined	Not defined	T>3 min
Slovakia	Not defined	1 sec<T≤3 min	T>3 min
Slovenia	Not defined	T≤3 min	T>3 min
Spain	Not defined	T≤3 min	T>3 min
Sweden		100 ms≤T≤3 min[39]	T>3 min
Switzerland	Not defined	T<3 min	T≥3 min
Ukraine	Not defined	T<3 min	T≥3 min

35 Definitions pertain to distribution in Brussels and Wallonia. In transmission, transient and short interruptions are in the same category.
36 There is no specific definition, but the regulation states that an outage of up to three minutes is not considered an interruption.
37 Not explicitly defined.
38 Transient interruptions are logged and reported as short interruptions with duration of T≤1 sec.
39 Interruptions with less than 100 ms are not monitored.

2.4.3 Rules for planned interruptions

Other than the unexpected interruptions that are traditionally referred to as unplanned, there are those that are very much planned by the system operators and in the majority of cases communicated to network users in advance. Most countries use separate classifications for planned and unplanned interruptions. The concept of 'planned interruption' is cited in EN 50160 [13] (the term 'prearranged interruption' is used) as an interruption for which network users are informed in advance, typically due to the execution of scheduled works on the electricity network. Most countries consider advance notification to affected network users to be sufficient and necessary for an interruption to be classified as planned.

While most respondents have a definition of planned interruptions, the requirement for advance notice varies significantly with specific requirements for notification being between 24 hours and 30 days. Moreover, Estonia requires notification by the 15th of the month preceding the interruption which could potentially result in an obligation to notify network users more than 30 days in advance. In some cases, the rules are less strict and depend on an agreement between network operators and customers. There are also respondents without a specified minimum requirement for notifications (Finland, Luxembourg, Sweden). Many countries with a lower share of planned interruptions in the overall duration of interruptions (e.g. Portugal) make use of live works, portable generators and reconfiguration of networks to prevent such interruptions or mitigate their impact [14]. The following paragraphs look into the rules for planned interruptions across Europe.

In **Albania**, the minimum time required to notify affected customers prior to a planned interruption is 48 hours. The DSO is obligated to notify its clients through appropriate public communication tools such as TV, newspapers or social media.

In **Austria**, the affected users must be notified by a DSO at least five days before the planned interruption but the notification can also be given less than five days in advance in case of individual mutual agreements.

In transmission in **Belgium**, in addition to the frequent definition where customers have to be notified in advance, plans for interruptions are submitted to these customers for approval, without prejudice to the need to interrupt connections for maintenance reasons. The deadline to notify customers depends on the region and the voltage level within that region.

In Flanders, customers on LV level have to be notified five days in advance while those on MV and HV levels have to be notified ten days before planned interruption.

In Wallonia (except for emergency situations), DSOs should inform the users of HV distribution network, as well as the balance manager for connection power of more than 630 kilovolt-amperes (kVA) at least ten days in advance. This period is reduced to five working days if it concerns temporary repair. The balance manager can inform the supplier (SP) if necessary. DSOs should also inform the users of LV distribution network at least two working days in advance except for interruptions of less than 15 minutes. In both cases, interruption duration should also be communicated in advance. In addition, DSOs publish an updated programme of planned interruptions, as well as the expected duration and causes.

In Brussels (except for emergency situations), users of HV distribution network are given information on the beginning and likely duration of a planned interruption by the DSO at least ten days in advance. This is reduced to five days in case of a temporary repair. In LV, this has to be done at least two days in advance except for interruptions of less than 15 minutes.

In the Republika Srpska entity of **Bosnia and Herzegovina**, the DSO is obliged to inform the producers, end-consumers and their suppliers no later than 24 hours before the interruption, about the date and the expected duration of the interruption as follows:

- MV end-consumers and producers: directly by telephone with written information details, or by fax or e-mail;
- LV end-consumers and producers: through the mass media, in a clear and comprehensible manner; and
- Suppliers: by fax or e-mail.

In the entity of Federation of Bosnia and Herzegovina, the DSO is obliged to inform the users of the distribution system within the deadline set by their contract. The suppliers are obliged to inform end-consumers at least 48 hours in advance, through their websites, notifications at customer service offices, daily press or other media.

The notification deadline for planned interruptions in **Croatia** is 48 hours in advance for customers on EHV, HV, MV and LV above 20 kilowatts (kW) connection capacity, and 24 hours in advance for customers on LV below and including 20 kW connection capacity. Notification should be provided through e-mail (or if that is not possible, by phone, Short Message Service (SMS) or other type of direct communication) for customers on EHV, HV, MV and LV above 20 kW connection capacity and on the system operator's website and other media for customers on LV below and including 20 kW connection capacity.

Similarly, the minimum time required to notify customers ahead of a planned interruption in **Cyprus** is 48 hours. The notification is either written or provided through a website.

In transmission in **Estonia**, written information has to be provided by the 15th of the month preceding the interruption. In distribution, DSOs notify each customer individually by e-mail or SMS at least two working days before the scheduled interruption.

Customers in **Finland** must be informed a reasonable time before the interruption, although the procedure for giving notice is not specifically described.

In transmission in **France**, the planning procedure differs starting from one year (or even more for important works) to one month before the interruption. The final confirmation is given at least 15 days in advance. In distribution, the operator must agree with MV customers on the date of planned interruption at least ten days in advance (except in case of emergency). Small customers (<36 kVA) are notified of planned interruptions by press or by individualised information.

In **Georgia**, the minimum time required to notify customers prior to a planned interruption is one day and the maximum is five days. Notification should be provided through SMS.

Great Britain defines a planned interruption as an interruption where all affected customers are notified at least 48 hours in advance and where the interruption does not commence before the time notified to customers. Notification is provided in writing.

The minimum notification time for planned interruptions in **Greece** is 24 and 48 hours, in transmission and distribution respectively. The rule used in distribution reflects the practice adopted by the DSO, although this has not yet been defined through regulation. Customers in distribution are mainly informed by notices placed at prominent spots close to affected installations. Announcements through mass media communication channels (press, radio or TV stations) or local authorities may also be used. Critical customers (such as industrial facilities and hospitals) may receive personalised notices. Furthermore, the DSO runs an open-access web-based service through which network users can retrieve information on planned interruptions in their area. In transmission, the TSO is obliged to issue standardised notices on its website regarding planned unavailability of system components and its effects on system users.

In **Hungary**, there are two different notification rules depending on the customer connection capacity. Those with capacity of less than 200 kVA should receive a notification 15 days ahead of a planned interruption via a leaflet in the mail or a public notification. Those with capacity of 200 kVA or above should be informed by personal letter 30 days prior to the planned work.

A minimum notice of two working days must be provided in **Ireland**. Customers are usually notified by postcards or email, but in LV network, notifications could be personal as there is no systemised model for LV.

According to the 'Rule on Electricity Service Quality Standards' [15] in **Kosovo***, customers must be notified at least 48 hours before the planned interruption takes place. The minimum time for giving information in advance of a planned interruption is defined as the minimum time between the date of dispatch of the notification and the date the planned interruption starts.

Prior to the approved Rule on Electricity Service Quality Standards, different standards were in place in Kosovo*. It was specified that in transmission, the minimum period for the TSO to notify the DSO and affected customers of a planned interruption was 48 hours for 90% of the cases. In distribution, the DSO had to inform customers at least 24 hours in advance for at least 90% of affected customers. Those standards are no longer in use.

The procedure for notifying customers is through public communication, including nationwide TV and newspapers in addition to the local TV of municipalities. Moreover, notifications are published on system operators' websites 48 hours prior to the planned interruption.

Grid users in **Latvia** should be warned of planned discontinuation of supply at least five days in advance. If disconnection is necessary for the inspection or replacement of an electricity meter, for commercial accounting of electricity, or instrument transformers and the period of disconnection does not exceed 30 minutes, the system operator should warn the user immediately before the disconnection. Notification is typically done by SMS, e-mail or letter.

The minimum time to notify customers is not defined in the legal framework in **Luxembourg**. The law only stipulates that this is done "as early as possible and in advance". The procedure is not prescribed either, but a notification is usually done by a letter from the DSO.

Malta set the minimum time for notification to at least three days prior to a planned interruption. A notification management tool is used to enter details of a planned interruption which is then approved by the energy services provider's communications office and posted on social media.

In **Moldova**, a notice must be provided three days ahead of a planned interruption. Commercial and industrial customers are individually notified in writing, while households are notified via mass-media.

According to the Rules on the Minimum Quality of Electricity Delivery and Supply [16] in **Montenegro**, system operators should record as planned any interruption that:

- Commenced and was completed within the announced termination period; and
- Occurred as a result of a market disturbance established by law and was executed according to the plan which was duly announced.

If announced in accordance with these rules, supply interruptions are considered planned, otherwise they are considered unplanned. Notification is required at a minimum of 24 hours prior to a planned interruption and is usually done via the media and the system operator's website.

In **the Netherlands**, a planned interruption is an interruption of which the network operator has informed the affected customers at least three working days in advance. This limit is used for LV, while in MV and HV, customers are notified ten working days in advance. No criteria exist for the procedure of giving notice. For industrial customers on MV and HV network, the time for a planned interruption can only be established after consulting the customer and taking their interests into account.

According to the Grid Code for Electricity Distribution [17] in **North Macedonia**, the minimum time to inform grid users about a planned interruption is 24 hours in advance. The notice is given through the public media, daily newspapers and the DSO's website. If producers, consumers whose electricity supply must not be interrupted according to the Rules on Electricity Supply [18], or users who need electricity for uninterrupted operation are to be affected by planned interruption, the DSO notifies them in writing, electronically or by telephone.

The minimum time to notify customers in **Norway** is 24 hours, although two working days is the generally accepted rule. Non-household customers must be given individual notice. For households, a public notice, such as information on a website or in newspapers is sufficient, but it is common to send an SMS to all affected end-users.

A planned interruption in **Poland** is an interruption resulting from the power grid operational programme. The duration of this interruption is counted from the moment a circuit braker is opened until the power supply is resumed. An unplanned interruption is caused by the occurrence of a failure in the grid. Duration is counted from the moment the energy company receives information about its occurrence until the power supply is resumed. The minimum time to notify customers of a planned interruption is five days, however the procedure for this depends on the voltage level. For up to 1 kV, a general announcement is sufficient while for customers connected to a voltage level of over 1 kV, an individual notification is required.

The minimum time to notify customers in **Portugal** is 36 hours ahead of a planned interruption. If the interruption is a matter of public interest, the entity responsible for the network must inform, whenever possible, and with a minimum prior notice of 36 hours, the customers who may be affected by the interruption.

If the interruption is due to service reasons, DSOs can agree with customers on the best time for the interruption. If an agreement is not possible, the interruptions must occur, preferentially, on Sundays, between 05:00 and 15:00 hours and with a maximum duration of eight hours per interruption and five Sundays per year, per customer affected. A DSO must inform a customer with a minimum of 36 hours prior notice.

If the interruption is due to a customer's actions, the supply interruption may only take place following prior notice, with minimum advanced warning of eight days before the interruption. If the customer installation emits perturbations to the network, the operator establishes, in accordance with the customer, a time frame for solving the problem.

Planned interruptions in transmission or distribution grids of **Romania** are defined in Performance Standards [19] [20] as interruptions necessary for development, refurbishment, operation or maintenance of the network and announced beforehand, according to the provisions of the standard. The minimum time to notify customers before an interruption depends on voltage level and the type of customer:

- At least 15 working days in advance for customers connected to the transmission grid (above 110 kV), big business customers and vulnerable customers connected to the distribution grid;
- At least five working days for other customers connected to the HV and MV distribution grid; and
- At least two working days for customers connected to the LV distribution grid.

Before the start of a planned interruption, the DSOs notify customers or their suppliers directly through letters, e-mail, phone, websites or mass media about the affected zone, interruption date, time and duration.

The minimum time to notify customers of a planned interruption in **Slovakia** is 15 days in advance. Electricity consumers are informed by a DSO no later than 15 days prior to the start of the planned interruption. This is done via local communication channels and by publication on the DSO's website of the start and duration of any planned restriction or interruption of electricity distribution. A DSO should restore electricity supply immediately after the causes of the restriction or interruption have been eliminated. Customer notification is not mandatory when performing essential operational work on LV level if the restriction or disruption of supply does not last longer than 20 minutes within 24 hours. However, a DSO is obliged to exert appropriate effort to avoid damages that could be incurred by customers as a result of restriction or disruption of supply in distribution.

In **Slovenia**, customers should be notified at least 48 hours prior to a planned interruption. The system operator should notify the users in a timely manner in writing or in another direct way. If this concerns a large number of customers and if personal communication is not cost-effective, such information should be published in the media or on the internet at least 48 hours in advance.

In **Spain**, customers in transmission should be notified at least 72 hours, and those in distribution at least 24 hours, ahead of a planned interruption. Those connected to networks over 1 kV must be notified individually. Those connected to networks below 1 kV are notified through advertising posters located in visible places and through two of the most widespread written media in the province.

There is no minimum requirement for customer notification in **Sweden**. The 'Electricity Act' requires that the affected customers be notified 'in a timely manner' prior to a planned interruption [21]. They are informed personally or, where appropriate, by notice.

Ukraine defines a planned interruption as an outage of part of a network and equipment made by a DSO for the purpose of scheduled repairs or maintenance of electrical networks. Planned interruptions are divided into those with and those without a notice to consumers. Planned interruptions without notice are included in calculations of continuity indicators (for regulatory purpose) if they are due to a DSO's fault.

An unplanned (emergency) interruption is defined as temporary suspension of power supply to consumers as a result of de-energizing of part of the network due to the fault of other DSOs, consumers, a force majeure event, fault of others or technical failures in the electrical network of the DSO.

The minimum time to notify consumers is five days in advance. An interruption should be deemed planned with notice if there is appropriate documentation proving the existence of the warning to consumers notifying them of such interruption and advertisements in mass media as well as on the DSO's website.

2.4.4 Voltage levels and types of interruptions monitored

Not all countries monitor interruptions originating on all voltage levels, but all generate statistics for incidents on more than one voltage level as presented in Table 2-4.

Interruptions originating on MV level are monitored in all countries except Great Britain and Slovakia which do not have a definition of MV.

Estonia records all interruptions, but only divides them into those in transmission and those in distribution, rather than per voltage level. This means that interruptions originating on LV and MV are one group while those originating on HV and EHV are another.

Interruptions originating on LV are monitored in all responding countries except Estonia (where it is not monitored individually, but grouped with those originating on MV), Malta and Slovenia.

Interruptions originating on HV are monitored in all responding countries.

Interruptions originating on EHV are monitored in fewer countries than those originating on lower voltage levels, but it should be kept in mind that EHV is not defined in every country included in Table 2-4. Countries that do not differentiate between HV and EHV, usually classify both as HV.

TABLE 2-4: Monitoring of voltage levels where interruption originated

Country	LV	MV	HV	EHV
Albania	×	×	×	
Austria	×	×	×	
Belgium	×	×	×	
Bosnia and Herzegovina	×	×	×	
Croatia	×	×	×	×
Cyprus	×	×	×	
Estonia[40]	×	×	×	×
Finland	×	×	×	×
France	×	×	×	×
Georgia	×	×	×	
Germany	×	×	×	×
Great Britain	×		×	×
Greece	×	×	×	×
Hungary	×	×	×	×
Ireland	×	×	×	
Kosovo*	×	×	×	
Latvia	×	×	×	
Luxembourg	×	×	×	×
Malta		×	×	×
Moldova	×	×	×	
Montenegro	×	×	×	
The Netherlands	×	×	×	×
North Macedonia	×	×	×	
Norway	×	×	×	×
Poland	×	×	×	×
Portugal	×	×	×	×
Romania	×	×	×	×
Slovakia	×		×	×
Slovenia		×	×	×
Spain	×	×	×	×
Sweden	×	×	×	×
Switzerland	×	×	×	×
Ukraine	×	×	×	×

Table 2-5 shows the legal obligation to monitor different types of interruptions. Planned interruptions have a legal obligation to

40 All interruptions are recorded, but they are divided into those in transmission and those in distribution. In other words, interruptions originating on HV and EHV are monitored together as are those originating on MV and LV.

be monitored in more countries than those that are unplanned, even though in practice, unplanned interruptions are monitored in more countries. There is a legal obligation to monitor long interruptions in all responding countries except Ireland and Malta. As for short interruptions, the obligation exists in less than half of respondents while the obligation to monitor transient interruptions is only in force in six countries.

TABLE 2-5: Types of interruptions for which there is a legal obligation to monitor

Country	Long interruptions	Short interruptions	Transient interruptions	Planned interruptions	Unplanned interruptions
Albania	Yes	No	No	Yes	Yes
Austria	Yes	Yes		Yes	Yes
Belgium	Yes	Yes	Yes	Yes	Yes
Bosnia and Herzegovina	Yes	Yes	No	Yes	Yes
Croatia	Yes			Yes	Yes
Cyprus	Yes	No	No	Yes	No
Estonia	Yes	No	No	Yes	Yes
Finland	Yes	Yes	Yes	Yes	Yes
France	Yes	Yes	Yes	Yes	Yes
Georgia	Yes	No		Yes	Yes
Germany	Yes	No	No	Yes	Yes
Great Britain	Yes	Yes	No	Yes	Yes
Greece	Yes	Yes		Yes	Yes
Hungary	Yes	Yes	Yes	Yes	Yes
Ireland	No	No	No	No	No
Kosovo*	Yes			Yes	Yes
Latvia	Yes	Yes	No	Yes	Yes
Luxembourg	Yes	No	No	Yes	Yes
Malta	No	No	No	Yes	Yes
Moldova	Yes	No	No	Yes	
Montenegro	Yes	No	No	Yes	Yes
Netherlands, The	Yes			Yes	Yes
North Macedonia	Yes	Yes		Yes	Yes
Norway	Yes	Yes	Yes	Yes	Yes
Poland	Yes	No	No	Yes	Yes
Portugal	Yes	Yes	No	Yes	Yes
Romania	Yes	Yes	Yes	Yes	Yes
Slovakia	Yes	No	No	Yes	Yes
Slovenia	Yes	Yes	No	Yes	Yes
Spain	Yes	No	No	Yes	Yes
Sweden	Yes	Yes	No	Yes	Yes
Switzerland	Yes			Yes	Yes
Ukraine	Yes	Yes	No	Yes	Yes

2.4.5 Monitoring of planned interruptions

Monitoring of planned interruptions is also used, albeit in fewer countries when compared to monitoring of unplanned interruptions. Out of 34 respondents to this question, 29 indicated some data availability. France and Serbia did not provide details, but out of the countries that did, both frequency and duration are available in all but one (only duration is available in Austria) for either all voltage levels, or only for MV/LV or HV/MV in a few cases. Data availability and voltage levels for which long planned interruptions per customer are monitored are presented in Table 2-6.

TABLE 2-6: Data availability and voltage levels for which long planned interruptions per customer are monitored

Country	Data availability for planned interruptions	Voltage levels
Albania	Yes: frequency and duration	HV, MV, LV
Austria	Yes: duration	Occurrence: all voltage levels Customers: all voltage levels
Belgium	Yes: frequency and duration	HV: Flanders and Brussels MV: Flanders and Wallonia LV: Flanders
Bosnia and Herzegovina	Yes: frequency and duration	HV: whole country MV, LV: Republika Srpska
Croatia	Yes: frequency and duration	All voltage levels[41]
Cyprus	No	
Estonia	Yes: frequency and duration	All voltage levels
Finland	Yes: frequency and duration	All voltage levels
France	Yes	MV, LV
Georgia	Yes: frequency and duration	All voltage levels
Germany	Yes: frequency and duration	MV, LV
Great Britain	Yes: frequency and duration	LV, HV, EHV, 132 kV
Greece	Yes: frequency and duration	With respect to where an incident occurs: all voltage levels. With respect to where a customer is connected: MV, LV.
Hungary	No	
Ireland	Yes: frequency and duration	HV, MV and some LV
Kosovo*	No	
Latvia	Yes: frequency and duration	MV, LV
Luxembourg	Yes: frequency and duration	All voltage levels
Malta	Yes: frequency and duration	11 kV substation level (frequency and duration), LV (only duration but no indicators).
Moldova	No	
Montenegro	Yes: frequency and duration	
Netherlands, The	Yes: frequency and duration	All voltage levels
North Macedonia	Yes: frequency and duration	HV, MV
Norway	Yes: frequency and duration	All voltage levels
Poland	Yes: frequency and duration	All voltage levels
Portugal	Yes: frequency and duration	All voltage levels
Romania	Yes: frequency and duration	Transmission: EHV, HV (duration in hours/year) Distribution: HV, MV, LV (frequency)
Serbia	Yes	
Slovakia	Yes: frequency and duration	All voltage levels
Slovenia	Yes: frequency and duration	HV, MV
Spain	Yes: frequency and duration	All voltage levels
Sweden	Yes: frequency and duration	All voltage levels
Switzerland	No	
Ukraine	Yes: frequency and duration	HV, MV, LV

2.4.6 Measurement techniques

Identification of grid users who are affected by interruptions can be done in different ways with the main points summarised in Table 2-7. More than half of the respondents use automatic logging or automatic identifications when recording interruptions, with automatic logging being implemented in more countries. Fifteen respondents indicated that they use both.

Belgium has different practices depending on the region. In Flanders, LV interruptions are based on reporting only, while HV and MV interruptions are based on a mixture of automatic (system) reporting and manual reporting. In Wallonia, DSOs identify affected customers and compensation is available on request. The Walloon electricity and gas decrees define a set of conditions under which affected customers may receive flat-rate compensation from a DSO (which is a simpler and faster means of providing compensation than that which would result from the application of civil law). DSOs must report once a year to the Walloon energy regulator on compensation requests. In Brussels, identification is automatically done by supervisory control and data acquisition (SCADA) system on MV, whereas on LV, this is done by estimating.

41 SAIDI and SAIFI: all voltage levels regarding where the interruption originated (the voltage level of the switch that interrupted the supply).

In Hungary, interruptions on MV are either automatically logged by the remote-control system and SCADA system or the process starts with a customer call to the call centre, meaning affected customers are automatically identified. Interruptions on LV are usually reported by customers through call centres and the customer identification is either automatic by the SAP (customer information) system of the DSO or is estimated by the DSO's staff during the repair on site. In 2012, the NRA issued a regulatory decision on the rules of estimation of customers affected by MV and LV interruptions. In the case of estimation on LV, all circuits would entail assuming the number of customers and whether they are supplied by single-phase or three-phase circuits.

TABLE 2-7: Measurement techniques for interruptions

Country	Identification of affected network users	Automatic identification	Automatic logging
Albania	Through substations.	No	No
Austria	No common rules.		No
Belgium	Flanders: LV interruptions are based on reporting only. HV and MV interruptions are based on a mix of automatic (system) reporting and manual reporting. Wallonia: Identification of affected customers due to network failure is by DSO. Brussels: On MV, SCADA system can automatically identify affected substation. On LV, by estimate (average customer number per km of cable).	Yes	Yes
Bosnia and Herzegovina	Republika Srpska: on the basis of the switching state of the distribution network, identification of transformer areas and transmission lines that remained unplugged and the withdrawal of end customer data from the database of another billing program. Federation of Bosnia and Herzegovina: no identification.	Yes	Yes
Croatia			Yes
Cyprus	By calls received at the contact centre and by notification from the Transmission Energy Control Centre which monitors and controls the status of the breakers of MV feeders in primary substations.	No	No
Estonia	DSOs have own programs.	Yes	Yes
Finland	Customers are identified through metering points on different voltage levels.	Yes	Yes
France		No	No
Georgia	DSOs register the source of the outage (substation, feeder or transformer). It is known in each case how many customers are connected to that specific substation, feeder or transformer. As soon as interruption is identified, everything is registered automatically in the DSO database.		Yes
Germany	There is no standardised way of identifying the affected customers. The way of estimating differs from one network operator to another.	No	No
Great Britain	Priority services register	Yes	
Greece	Distribution: interrupted customers are not individually identified. They are estimated implicitly through interrupted network capacity (MV/LV transformers, LV feeders) and customer density in the affected DSO region (number of customers per unit of network capacity). Manual logging of interruptions is the main measurement technique employed. It is backed up by SCADA logs at HV/MV substation level and by smart meters installed at MV and large LV customer facilities.	No	No/Yes
Hungary	MV: either logged automatically by the remote-control and SCADA systems or the customer's calls to report interruptions are logged. LV: customer calls. Identification is either automatic by the SAP system or is estimated by the DSO's staff during repair.	Yes	Yes
Ireland	Through Operations Management System.	Yes	Yes
Kosovo*	Through 10 kV feeders.	Yes	No
Latvia	The largest DSO: by SCADA system. Others: manually.	Yes	Yes
Luxembourg	Number of connection points in affected area. No details on how DSOs identify affected customers.	No	
Malta	Affected substations are identified from the network operating diagram.	No	Yes
Moldova	A list of affected customers is created for every interruption. If the continuity index exceeds the established value, the information is transmitted to the billing system.	No	No
Montenegro	Transmission: SCADA. Distribution: identification by substation staff or by customer notification.	Yes	Yes
Netherlands, The	Mostly automatic identification through registration in geographic information system.	Yes	Yes
North Macedonia	Identification is done through data collected from SCADA and Outage Management System.		Yes
Norway	Network topology and breaker logs allow for identification of affected costumers for non-LV interruptions. For LV interruptions, there is manual registration of connection and disconnection instead of logs.	Yes	Yes
Poland	EHV, HV, MV: SCADA system.	Yes	
Portugal	Interruptions with origin at EHV, HV, MV: SCADA system. Interruptions with origin at LV: affected customers are identified based on phone calls.	Yes	Yes
Slovakia	By system operator.		No
Slovenia	By SCADA system.	Yes	Yes
Spain	By customer connection point to the network.	Yes	Yes
Sweden	By a unique ID for each customer.	Yes	Yes
Switzerland	By system operators.		
Ukraine	Through DSO's billing systems (automatic for interruptions on HV and MV level, possibility of manual correction of the number affected customers interruptions on LV).	Yes	Yes

2.5 CONTINUITY OF SUPPLY INDICATORS

European countries use different indicators and different weighting methods when evaluating interruptions. This presents a challenge for comparing national continuity data across Europe. While Section 2.6 analyses the values of national data, this section will examine the various indicators used for long and short interruptions.

The two main groups of indicators are those that deal with duration and those that deal with the frequency of interruptions. SAIDI and SAIFI (duration and frequency, respectively) are the basic indicators reported in almost all countries, sometimes under different names and with different methods of weighting the interruptions. The weighting impacts the results and leads to different biases towards different types of network users. When it is based on the number of network users, all users are treated equally regardless of their size and consumption levels.

When weighting is based on interrupted power or ENS, an interruption gets a higher weighting whenever the total interrupted power is higher. This might happen when network users with larger demand are interrupted or when the interruption takes place during a period of higher consumption. Weighting based on contracted power, rated power or annual power consumption makes the contribution of an incident during high load the same as in the case of an incident during low load.

Any weighting based on power and energy is biased towards network users with larger demand. As these users typically suffer fewer and shorter interruptions, this is expected to result in lower values for frequency and duration of interruptions than weighting based on the number of network users.

It is important to remember that both SAIDI and SAIFI can be presented with or without exceptional events. In this Report, more than half of countries that answered the relevant question have a definition of exceptional events, which mostly includes natural causes such as strong winds, snowstorms, floods and earthquakes. The individual definitions, however, are far from harmonised. Non-natural causes include among others, wars, sabotage, acts of terrorism and embargos.

Customer Average Interruption Duration Index (CAIDI) gives an average duration of an interruption (in minutes per interruption) and along with SAIDI and SAIFI constitutes the main indices used in the majority of the responding countries. As stated in the 4th Benchmarking Report [4], reduction in SAIDI and SAIFI indicates improvement in CoS, but their reduction could still result in an increased value of CAIDI. This is the reason why an indicator like CAIDI is not suitable for comparisons or trend analysis.

An indicator can also have different names in different countries. Customer Minutes Lost (CML) is used in Great Britain as a synonym for SAIDI. Customer Interruptions (CI) is used as a substitution for SAIFI. It is calculated in the same way as SAIFI but expressed as the number of interruptions per 100 customers per year. Indices like Average System Interruption Duration Index (ASIDI) and Average System Interruption Frequency Index (ASIFI) are similar to SAIDI and SAIFI but are weighted by the rated or contracted power rather than by the number of customers affected. Equivalent interruption time related to the installed capacity (TIEPI) and equivalent number of interruptions related to the installed capacity (NIEPI) are used in Spain (TIEPI is also used in Portugal) for average duration and number of interruptions, weighted by the rated or contracted power like ASIDI and ASIFI.

Sometimes the assumptions are a simplification of the actual consequences of interruptions. A good example of this is ENS that gives the total amount of energy that would have been supplied to the interrupted customers if there would not have been any interruption. The fact that there is no energy consumption during the interruption makes it impossible to exactly measure the value of this indicator.

The indicators such as Customer Average Interruption Frequency Index (CAIFI) and Customer Total Average Interruption Duration Index (CTAIDI) give a better impression of the CoS as experienced by those network users that are affected by at least one interruption. The differences in value between SAIFI and CAIFI, and between SAIDI and CTAIDI, give an impression of the spread in the number of interruptions between different network users. The distribution of the number of interruptions experienced by each individual user gives this information in a more direct way, but results in more indicators, making comparisons and trend analysis more complicated.

CTAIDI is currently only used by Norway, while CAIFI is used by Norway and Slovenia. Customer Experiencing Multiple Interruptions (CEMI), a similar indicator that measures percentage of customers experiencing more than one interruption, is used by Sweden. Table 2-8 lists this indicator as CEMI-X to allow the use of different numbers. For example, CEMI4, which Sweden uses for local DSOs (those with an area concession), represents the share of customers experiencing four or more interruptions in a year.

There are additional indicators used in distribution. Portugal, for example, uses Energy Not Distributed (END). Ireland has an indicator called Worst-Served Customers (WSC). Its definition is provided in the 'Standards for and regulations of continuity for supply' section of this Report.

There are some indicators that are specific to transmission. Average Interruption Time (AIT) and Average Interruption Frequency (AIF) are used in many countries. System Average Restoration Index (SARI) is used in transmission by Portugal to quantify the average duration of interruptions. Power Not Supplied (PNS) was used by Sweden until 2020, but it, along with ENS, was replaced by AIT and AIF. Outage rate, an indicator denoting the ratio of ENS and energy supplied (ES), is used by Hungary. In some cases, indicators have different names in different countries. Spain uses an indicator *Tiempo de Interrupción Medio* (TIM) which translates to average interruption time.

MAIFI is used for short interruptions. Slovenia additionally has an indicator called Momentary Average Interruption Event Frequency Index (MAIFI-E) which is also used for short interruptions.

2.5.1 Indicators for long interruptions

Indicators used across Europe to quantify the number and duration of long interruptions are listed in Table 2-8 while some interesting examples are described in the following paragraphs. The table also provides information on the weighting method used. The exact definitions are given in the 4th Benchmarking Report [4]. Please see the list of abbreviations for the meaning of individual indicators.

Belgian DSOs use a uniform approach to calculate SAIDI and SAIFI which is based on a common technical prescription called Synergrid C10/14. This calculation is based on a substation level rather than an end-consumer level. Since not all substations have an equal load or an equal number of network users, an empiric correction factor of 0.85 is applied. The objective of this factor is to take uneven distribution of interrupted capacity per substation into account. This approach is based on an earlier European method introduced by the International Union of Producers and Distributors of Electrical Energy (UNIPEDE).

Other than using AIT and ENS in transmission and SAIDI, SAIFI and CAIDI in distribution, **Croatia** also classifies interruptions by their cause (external, internal or exceptional event) and by whether they are planned or unplanned.

Distribution in **Finland** uses absolute interruption details related to SAIDI and SAIFI. The indicators used by the DSOs on LV and MV are collected to verify the level of actual supply reliability figures: absolute number of interruptions; average number of interruptions weighted by the distributed energy of the specific voltage level; average annual interruption duration weighted by the voltage level; and annual distributed energy (for both planned and unplanned interruptions). For the DSOs that operate the HV network, data on unplanned interruptions originating in other networks and absolute interruption time are collected in addition to the indicators collected by other DSOs. In transmission, the same information is collected but on the 110, 220 and 400 kV levels.

Distribution network in **Hungary** uses SAIDI, SAIFI and CAIDI for planned and unplanned interruptions on LV, MV and HV. Outage rate (the ratio of ENS and ES) is used on MV and HV, as indicated in Table 2-8. The following additional indicators are used in distribution in Hungary:

- Proportion of customers to whom the supply was restored within three hours following a long unplanned interruption;
- Proportion of customers to whom the supply was restored within 18 hours following a long unplanned interruption;
- Proportion of customers to whom the supply was restored within six hours following a long planned interruption;
- Proportion of customers to whom the supply was restored within 12 hours following a long planned interruption;
- Number and proportion of customers affected by a long unplanned interruption lasting less than 0.5 hours;
- Number and proportion of customers affected by a long unplanned interruption lasting between 0.5 and three hours;
- Number and proportion of customers affected by a long unplanned interruption lasting between three and ten hours;
- Number and proportion of customers affected by a long unplanned interruption lasting more than ten hours;
- Number and proportion of customers affected by less than three long unplanned interruptions per year;
- Number and proportion of customers affected by more than three but less than six long unplanned interruptions per year;
- Number and proportion of customers affected by more than six but less than ten long unplanned interruptions per year; and
- Number and proportion of customers affected by more than ten long unplanned interruptions per year.

The transmission network in Hungary uses ENS, AIT and the outage rate, as indicated in Table 2-8. The following additional indicators are used in transmission in Hungary:

- Annual demand;
- System minutes;
- Peak load;
- Number of interruptions;
- Severity index;
- Average unavailability of main elements of the transmission network;
- Selective operation of HV fault protection systems;
- Annual distribution peak load;
- Number of substation equipment faults;
- Number of substation equipment faults causing customer interruptions;
- Average restoration time of substation equipment faults causing customer interruptions;
- Number of faults on transmission power lines;
- Number of faults on transmission power lines causing customer interruptions;
- Average restoration time of faults on transmission power lines causing customer interruptions;
- Number of interruptions on 400 kV networks relative to the length of the 400 kV network; and
- Number of interruptions on 220 kV networks relative to the length of the 220 kV network.

Montenegro uses SAIDI, SAIFI, ENS and AIT as indicators for long interruptions. In distribution, SAIDI and SAIFI are weighted by the number of metering points at the end of the year. AIT is weighted by the amount of energy delivered by transmission system.

Romania uses SAIDI, SAIFI, ENS and AIT as indicators for long interruptions. SAIFI is calculated by dividing the total number of users affected by an interruption by the total number of users served. SAIDI is calculated by dividing the cumulative duration of long interruptions by the total number of users served by the DSO.

TABLE 2-8: Indicators for long interruptions

Country	Indicators	Weighting
Albania	ENS, SAIDI, SAIFI, time required to restore the electricity supply service after a distribution system outage.	By the number of customers.
Austria	SAIDI, SAIFI, ASIDI, ASIFI, CAIDI, (CML, ENS).	Weighted by both the transformer power and by the number of customers affected, depending on the indicator.
Belgium	Transmission: ENS (Indicator for internal use), AIT (indicator used to compare performances with other TSOs). Distribution in Flanders, Wallonia: SAIDI, SAIFI, CAIDI, ENS, PNS. Distribution in Brussels: SAIDI, SAIFI (planned and unplanned), CAIDI (planned and unplanned).	Calculation of SAIDI and SAIFI is based on a substation level rather than an end-user level. Since not all substations have an equal load or an equal number of network users, an empiric correction factor of 0.85 is applied.
Bosnia and Herzegovina	Transmission (HV): planned and unplanned SAIDI, SAIFI, AIT, ENS. Distribution: planned and unplanned SAIDI, SAIFI.[42]	By the number of customers (Republika Srpska) and by the power affected on HV voltage (transmission).
Croatia	Transmission: AIT and ENS. Distribution: SAIDI, SAIFI and CAIDI.	
Cyprus	SAIDI, SAIFI.	By the number of customers.
Estonia	Transmission: SAIFI, SAIDI, CAIDI, ENS, AIT. Distribution: SAIFI, SAIDI, CAIDI.	By the number of customers and per connection point.
Finland	Distribution: absolute number of interruptions, average number of interruptions weighted by the distributed energy of the specific voltage level, average annual interruption duration weighted by the voltage level and annual distributed energy (for both planned and unplanned interruptions). DSOs that operate the HV network: data on unplanned interruptions originating in other networks and absolute interruption time in addition to the indicators collected by other DSOs. Transmission, the same information is collected but on the 110 kV, 220 kV and 400 kV levels.	By the annual energy consumption.
France	LV, MV: SAIDI, SAIFI. Transmission: AIT, AIF.	By affected customers on LV level and by the power affected on MV level.
Georgia	SAIDI, SAIFI.	By the number of customers.
Germany	LV: SAIDI, SAIFI MV: ASIDI, SAIFI	By the number of customers.
Great Britain	Minutes lost per customer per year: unplanned with and without exceptional events, weighted and unweighted, and planned. Number of interruptions per customer per year: unplanned with and without exceptional events, weighted and unweighted, and planned.	Distribution: planned incidents. Transmission interruptions have a lesser weighting.
Greece	Transmission: ENS Distribution: SAIFI, SAIDI	By the power affected.
Hungary[43]	Distribution: SAIDI, SAIFI, CAIDI for planned and unplanned interruptions (LV, MV and HV), outage rate (MV, HV). Transmission: AIT, ENS, outage rate.	By the number of customers.
Ireland	SAIFI, SAIDI, WSC.	By the number of customers.

42 Federation of Bosnia and Herzegovina: only MV level. Republika Srpska: HV, MV and LV levels. In Republika Srpska, another criterion for classification is the number of interruptions longer than four hours per voltage level.
43 Additional indicators are listed before the table.

TABLE 2-8: Indicators for long interruptions

Country	Indicators	Weighting
Kosovo*	Transmission: ENS, AIT. Distribution: SAIDI, SAIFI, CAIDI. Individual indicators in both transmission and distribution: duration of an individual long planned interruption for a single customer, duration of an individual long unplanned interruption for a single customer, total number of long interruptions in the reporting period for a single customer.	By the number of customers.
Latvia	SAIDI, SAIFI, CAIDI.	By the number of customers.
Luxembourg	SAIDI, SAIFI.	By the number of customers.
Malta	SAIDI, SAIFI and CAIDI for each interruption but not classified as long, short and transient.	By transformer kVA installed on MV level.
Moldova	Distribution: SAIDI, SAIFI, CAIDI. Transmission ENS, AIT.	By the number of customers.
Montenegro	Distribution: SAIDI, SAIFI. Transmission: ENS, AIT.	By the number of customers/metering points (SAIDI and SAIFI). By the amount of energy delivered by transmission system (AIT).
Netherlands, The	SAIDI, SAIFI, CAIDI.	By the number of customers.
Norway	SAIDI, SAIFI, CAIDI, CAIFI, CTAIDI, ENS.	Different weighting methods depending on the indicator. SAIDI and SAIFI are weighted by the number of customers.
Poland	Transmission: SAIDI, SAIFI, MAIFI, ENS, AIT. Distribution: SAIDI, SAIFI, MAIFI.	By the number of customers.
Portugal	Transmission: ENS, AIT, SAIFI, SAIDI, SARI. Distribution (consumption installations): SAIFI HV, SAIDI HV, END MV, AIT MV (TIEPI), SAIFI MV, SAIFI LV, SAIDI MV, SAIDI LV. Distribution (generation installations): SAIDI HV, SAIFI HV, SAIDI MV, SAIFI MV.	SAIFI and SAIDI: weighted by delivered points (transmission, HV and MV) and by the number of customers (LV). AIT MV (distribution – TIEPI) and END (distribution): weighted by installed power. ENS (transmission): estimated. AIT (transmission): by ENS and ES.
Romania	SAIDI, SAIFI, ENS, AIT.	By the number of customers.
Slovakia	SAIDI, SAIFI and ISS (indicator for supply standards).	By the number of customers.
Slovenia	Distribution: SAIDI, SAIFI, CAIDI, CAIFI. Transmission: SAIDI, SAIFI.	By the number of customers.
Spain	Distribution: TIEPI, NIEPI, percentile 80 of TIEPI, percentile 80 of NIEPI. Transmission: ENS, TIM (average interruption time), facility available percentage.	By the power affected.
Sweden	Distribution: for statistical purposes, SAIFI, SAIDI, CAIDI, CEMI-X. Transmission: AIF, AIT, PNS, ENS. In the incentive regulation: AIT and AIF for both transmission and distribution.	By the number of customers.
Switzerland	SAIDI, SAIFI.	By the number of customers.
Ukraine	Transmission: ENS, AIT. Distribution: SAIFI, SAIDI, ENS.	By the number of customers. AIT: by the average power of the system.

2.5.2 Indicators for short and transient interruptions

Less than half of the responding countries collect data on short or transient interruptions. These are Austria, Belgium, Bosnia and Herzegovina, Cyprus, Finland, France, Great Britain, Hungary, Latvia, Norway, Portugal, Romania, Slovenia, Sweden and Ukraine. More information on this is provided in Table 2-9. The number of short interruptions per year is used in most countries listed in the table. Only three respondents have indicators for transient interruptions. They are Finland, France and Hungary. France uses the average number of transient interruptions per customer while Hungary uses MAIFI-E. Most countries exclude transient interruptions from monitoring altogether.

In addition to MAIFI in distribution, Hungary uses short interruption indicators not mentioned in Table 2-9. These are:

- Number and proportion of customers affected by less than ten short interruptions per year;
- Number and proportion of customers affected by more than ten but less than 30 short interruptions per year;
- Number and proportion of customers affected by more than 30 but less than 70 short interruptions per year; and
- Number and proportion of customers affected by more than 70 short interruptions per year.

TABLE 2-9: Indicators for short and transient interruptions

Country	Short	Transient
Austria	SAIDI, SAIFI, ASIDI, ASIFI, CAIDI.	None
Belgium	Transmission: MAIFI (indicator for internal use). Flanders: number of short interruptions according to NBN EN 50160[44]	None
Bosnia and Herzegovina	Distribution in Republika Srpska: unplanned MAIFI.	None
Cyprus	SAIDI, SAIFI.	None
Finland	Distribution: absolute number of interruptions, average number of interruptions weighted by the distributed energy of the specific voltage level (for both planned and unplanned interruptions). Transmission: Absolute number of interruptions.	Distribution: absolute number of interruptions, average number of interruptions weighted by the distributed energy of the specific voltage level (for both planned and unplanned interruptions). Transmission: Absolute number of interruptions.
France	SAIFI, MAIFI.	Average number of transient interruptions per customer.
Great Britain	Number of short interruptions per customer per year.	None
Hungary	Distribution network: MAIFI.[45]	Distribution network: MAIFI-E.
Latvia	MAIFI on MV level.	
Norway	SAIDI, SAIFI, CAIDI, CAIFI, CTAIDI, ENS.	
Portugal	Transmission and distribution (consumption and generation installations): MAIFI.	None
Romania	MAIFI	None
Slovenia	MAIFI, MAIFI-E (distribution).	None
Sweden	MAIFI for statistical purposes. In the incentive regulation short interruptions are included in calculation of AIF on transmission and sub-transmission (regional distribution) level.	None
Ukraine	Transmission: AIT, ENS. Distribution: MAIFI.	

2.5.3 Level of detail in indicators

CoS indicators are often captured for different categories, areas, causes and voltage levels, as well as on the single-customer or on the system level within a single country.

Table 2-10 and Table 2-11 provide an overview of the level of detail for which indicators are calculated and collected. Only Kosovo* and Latvia do not monitor indicators on system level, while six countries monitor them both on the system and on the single-customer level. With respect to areas, indicators are mostly monitored on national and regional levels.

44 This is the Belgium-specific version of EN 50160 published by CEB-BEC (Belgian Electrotechnical Committee).
45 Additional indicators are listed before the table.

TABLE 2-10: Monitoring of continuity indicators on single-customer and system level

Country	Single-customer level	System level
Albania		×
Austria		×[46]
Belgium	×[47]	×[48]
Bosnia and Herzegovina		×[49]
Croatia	×[50]	×[51]
Cyprus		×[52]
Estonia		×[52]
Finland		×[53]
France		×[52]
Georgia		×[54]
Germany		×[55]
Greece		×[56]
Hungary		×[52]
Ireland	×	×[57]
Kosovo*	×[58]	
Latvia	×[59]	
Luxembourg		×[52]
Malta		×[60]
Moldova[61]	×	×
Montenegro		×[62]
Netherlands, The		×[63]
Norway		×[64]
Poland		×[65]
Portugal[66]	×	×
Romania		×[67]
Serbia		×[52]
Slovakia		×[68]
Slovenia		×[69]
Spain		×[70]
Sweden		×[71]
Switzerland[72]	×	×
Ukraine		×[73]

46 Nationwide, system operator area, other analysis on demand (e.g. control area).
47 Transmission: EHV and HV level for direct customers of the TSO.
48 DSO level in Flanders and Wallonia, Brussels is monitored as a region.
49 National level for HV and regional/provincial/district level for MV and LV.
50 All end-consumers.
51 Nation and distribution area (21 in total, even though there is one DSO in Croatia).
52 Nationally.
53 In each DSO area of responsibility.
54 National.
55 Indicators are published for each state and for the whole country.
56 Transmission: nationwide. Distribution: per DSO region (59 regions in total, roughly aligned with provinces).
57 Spatial scope of monitoring: nation, region, planner group, station, outlet, protective device.
58 Indicators are monitored on 10 kV and 0.4 kV feeders. According to the Rule on Electricity Service Quality Standards, monitoring of continuity indicators can be done per voltage level and for urban and rural areas.
59 All customers.
60 On 11 kV substation level.
61 All indicators are monitored on single-customer level. On system level, they are monitored nationally and per district.
62 Indicators are monitored on national level but can be processed on regional level too.
63 National and system operator level.
64 Indicators are monitored on system operator and county level.
65 In each DSO area of responsibility and TSO area.
66 Indicators are monitored on national level through Nomenclature of Territorial Units for Statistics - NUTS III (25 subregions), on municipality level and on voltage level, for consumption and generation installations. On a single-customer level, continuity indicators are monitored for all customers.
67 System operator level.
68 National and regional level.
69 Distribution: MV feeder from substation. Transmission: HV substation.
70 National, regional and provincial level.
71 National, regional, DSO level, type of customer etc.
72 System level: nationally and regionally. Single-customer level: 100 largest customers.
73 Nationally and urban/rural areas. Urban/rural areas are only used for distribution indicators and only for 0.4 kV and 6-20 kV levels.

In most responding countries, interruptions are recorded separately according to their cause and the voltage level on which they originated.

In **Albania**, the voltage levels in which interruptions are recorded are 400, 220, 110, 35, 20, 10, 6 and 0.4 kV.

Austria separately records interruptions originating on HV, MV and LV and based on whether they are planned or unplanned.

Belgium monitors the same levels as Austria. Belgium has the following rules for cause categories when monitoring interruptions:

In transmission, the categories are material failure, human error caused by TSO, system response, fault/failure outside the grid, weather, human error (of third party/customer/DSO), animal and unknown causes.

In distribution in Wallonia, the causes of unplanned interruptions are the network, third party and bad weather among others. Distribution in Flanders divides causes into seven categories:

- Cable breakage (no specific reason);
- Cable breakage by a third party (digging work);
- Defect on MV or HV power supply;
- Defect on MV or HV power supply caused by a third party or bad weather conditions;
- Defect in substation managed by a system operator;
- Defect in MV or HV transformer of the grid user; and
- Defect in another network (TSO).

There are eight categories in Brussels. These are:

- Unavailability following localised fault on a MV cable managed by a DSO and having nothing to do with a cable break caused by third parties;
- Unavailability following a cable break on the MV network, managed by the DSO reporting the interruption, due to atmospheric circumstances or caused by third parties;
- Unavailability due to a defect occurring under normal atmospheric conditions on a MV line managed by the DSO reporting the interruption;
- Unavailability following a fault on a MV line managed by the reporting DSO and resulting from bad weather conditions or caused by third parties;
- Unavailability following a fault located in a MV substation, managed by the reporting DSO, on the MV side;
- Unavailability following a fault located in an average substation;
- Unavailability due to a fault on a network other than that of the DSO; and
- Unavailability following actions for network operation, managed by the reporting DSO.

In **Bosnia and Herzegovina**, one of the cause categories is the third-party responsibility. These are interruptions caused by third parties such as damage to conductors, damage to lines, theft, sabotage, terrorism and others.

In **Croatia**, the recorded voltage levels are those with more than 35 kV (EHV and HV), between 20 kV up to and including 35 kV (MV), between 1 kV and including 20 kV (also MV) and up to and including 1 kV (LV). The cause categories used for long planned interruptions are internal and external sources. For long unplanned interruptions, they are internal, external sources and exceptional events (force majeure). Interruptions caused by ‘external sources’ include those caused by other system operators and third parties.

Finland separately records interruptions on LV, MV and HV in distribution, as well as on 110, 220 and 400 kV in transmission. The NRA does not collect the cause data, but DSOs do.

France records all interruptions but those on MV and LV levels are recorded separately. The cause categories used in transmission are exceptional events and planned maintenance.

Cause categories in **Georgia** can be internal or external. The latter category is divided into: force majeure (wind, landslide snow, flooding, earthquake), damage caused by a third party (car accident, vandalism etc.), dispatch licensee request, third party request (municipalities, road construction authorities etc.), trees, animals and others (which must be specified). Interruptions are recorded separately on the following voltage levels: 500, 400, 330, 220, 110, 35, 10, 6, 0.38 and 0.22 kV.

In **Germany**, interruptions are recorded separately on all voltage levels. Cause categories are atmospheric impact, third party, responsibility of the network operator, others (planned), feedback effects caused in other networks, meter replacement and force majeure.

Great Britain records all interruptions on LV, HV, EHV and 132 kV levels. Cause categories are weather, tree-related and fault switching.

Voltage levels recorded in **Greece** are EHV (400 kV) and HV (150 kV and 66 kV) in transmission and MV (6.6 kV to 22 kV) and LV (0.4 kV) in distribution. Interruptions registered on MV level also include those originating in the distribution network on HV level (66 kV and 150 kV). In transmission, there is no categorisation by cause. In distribution, planned and unplanned interruptions attributed to exceptional events are classified by cause. Cause categories of unplanned interruptions are upstream network (transmission/generation) interruption, intervention by public authorities, third party interference, DSO labour union strikes, extreme weather and other unforeseeable circumstances. Cause categories of planned interruptions are upstream network (transmission) interruption, network user requests and DSO labour union strikes.

Interruptions in **Hungary** are typically recorded separately according to the voltage level of their origin, but, if, for example, a primary side fuse of an MV/LV transformer is affected, the DSO is usually notified of this by customers calling the DSO’s call centre. The interruption would then be registered as an LV interruption until the DSO repair staff classifies it as an MV interruption while on site. The classification of causes is within the competence of the DSOs and the TSO.

Voltage levels recorded in **Ireland** are 2-phase LV, 3-phase LV, 2-phase 10 kV, 3-phase 10 kV, 2-phase 20 kV, 3-phase 20 kV, 38 kV and 110 kV used in distribution. Causes used when recording interruptions are weather, environment, asset damage and third-party interference.

Interruptions in **Kosovo*** are recorded separately for all voltage levels (LV, MV and HV). Cause categories are internal, external and force majeure.

Luxembourg separately records interruptions on 220, 150, 65, 37, 20, 5 and 0.4 kV voltage levels. The cause categories used are planned, atmospheric conditions, force majeure, third-party damage, internal cause, failure initiating on a higher voltage level and failure initiating on a lower voltage level.

Cause categories in **Malta** are outage type, faulty equipment and reason for outage.

Moldova records interruptions on all voltage levels, but those on voltages higher than LV (0.4 kV) and MV (6-10 kV) are reported separately. Causes are divided into exceptional events, actions of third parties, interruptions caused by customer installations and others (when the operator is responsible for the interruption).

Montenegro records all interruptions but groups them based on voltage level: HV is one group and MV and LV (35, 10 and 0.4 kV) are recorded separately. Although interruptions are not recorded separately according to their cause, these causes are used when classifying interruptions: responsibility of TSO, responsibility of DSO, responsibility of third-party and force majeure.

The Netherlands records all interruptions separately per voltage level. As in Montenegro, interruptions are not recorded separately according to their cause, but there are still different classifications of causes: manufacturing fault, network design, operating faults, aging/wear, moisture, soil movement, weather influence, overload, internal defect, unknown despite research, assembly fault (by network operator), other external causes and excavation work (such as digging, piling, drilling, etc).

Only interruptions affecting customers on specific voltage levels are recorded in **North Macedonia**. These are: 110, 35, 20 and 10 kV. Interruptions are recorded separately on HV and MV but are calculated on LV. Cause categories are force majeure (exceptional events), third parties, causes in the transmission system, causes in the distribution system (defects) and disconnection requested by authorities.

Norway separately records interruptions on the following voltage levels: 0.23-1 kV, 1-22 kV, 33-110 kV, 132 kV, 220-300 kV and 420 kV. The causes are divided into eight main categories: surroundings, people (staff), people (others), operational stress, technical equipment, design/installation, others and cause unknown. These main categories are further divided into subcategories. In audits, the NRA emphasises the importance of trying to avoid using the 'cause unknown' category.

Portugal separately records interruptions on every voltage level for consumption and generation installations. Cause categories depend on whether interruptions are planned or unplanned. For planned interruptions, the causes are: reasons of public interest, service reasons and other networks or installations. For unplanned interruptions, they are further divided into exceptional events after approval by the NRA (security reasons, strikes, extreme natural conditions, odd objects in the network, fire or flood, vandalism, third party) and nonexceptional events (security reasons, strikes, extreme natural conditions, odd objects in the network, fire or flood, vandalism, third party, atmospheric conditions, maintenance, network protections, electrical equipment, technical reasons, human intervention, unknown reasons, other networks or installations). Some of the subcategories are the same for both planned and unplanned interruptions.

All interruptions are recorded in **Romania**, separated by voltage level. Cause categories are: planned, unplanned caused by special weather conditions and unplanned caused by network users or third parties (consumption places, generators or another DSO).

Slovenia records interruptions only on EHV and HV levels in transmission and MV level in distribution. Cause categories are planned and unplanned interruptions. Causes of unplanned interruptions are divided into: cause by TSO/DSO, cause by a third party and force majeure.

All interruptions are recorded in **Spain**. Cause categories depend on the origin of interruption: planned in distribution, planned in transmission, unplanned caused by generation, unplanned caused by transmission, unplanned caused by distribution, unplanned caused by third parties and unplanned caused by force majeure.

Sweden records all interruptions on all voltage levels. The voltage level is reported for every customer. The NRA does not collect cause categories, but Swedenergy (a non-profit industry and special interest organisation for companies that supply, distribute, sell, and store energy in Sweden) categorises interruptions in the system called Darwin that most DSOs use for statistics.

Switzerland also records all interruptions on all voltage levels. Cause categories are: planned interruption, human error, natural event, operational cause, external forces, system perturbation, other cause and force majeure.

Ukraine records all interruptions on LV, MV, HV and EHV levels. Cause categories for planned interruptions are with or without notice. For unplanned interruptions, cause categories are: fault of other DSOs or consumers, fault of other persons, force majeure and technical disturbances in DSO's electrical networks.

Table 2-11 provides information on whether interruptions are recorded separately according to their cause and the voltage level on which they originated.

TABLE 2-11: Monitoring of continuity indicators based on voltage level and cause

Country	Voltage level	Causes
Albania	Yes	No
Austria	Yes	Yes
Belgium	Yes	Yes
Bosnia and Herzegovina	Yes	Yes[74]
Croatia	Yes	Yes
Cyprus	Yes	Yes[75]
Estonia	No	Yes[76]
Finland	Yes	No
France	Yes	Yes
Georgia	Yes	Yes
Germany	Yes	Yes
Great Britain	Yes	Yes
Greece	Yes	Yes
Hungary	Yes	Yes
Ireland	Yes	Yes
Kosovo*	Yes	Yes
Latvia	Yes[77]	Yes
Luxembourg	Yes	Yes
Malta	No	Yes
Moldova	Yes	Yes
Montenegro	Yes	No
Netherlands, The	Yes	Yes
North Macedonia	Yes	Yes
Norway	Yes	Yes
Poland	No	Yes
Portugal	Yes	Yes
Romania	Yes	Yes
Slovakia	No	No[78]
Slovenia	Yes	Yes
Spain	No	Yes
Sweden	No	No
Switzerland	Yes	Yes
Ukraine	Yes	Yes

2.6 ANALYSIS OF CONTINUITY BY NATIONAL DATA

It is clear from the tables presented in previous sections, that a wide range of indicators are used to quantify CoS across Europe. This has resulted in a greater availability of information and better possibility to observe trends.

When interpreting the results, and especially when comparing between countries, differences in the way individual countries calculate their indicators should be considered. These include differences in the treatment of multiple subsequent interruptions of electricity supply, which may result in diverging ways of calculating the key indicators that are used to benchmark CoS. In

74 Republika Srpska: force majeure, third party responsibility, DSO responsibility. The Federation entity does not have cause categories.
75 Transmission fault, generation fault (TSO), planned interruptions, faults etc. (DSO).
76 Unplanned (by fault and by force majeure) and planned.
77 All voltage levels.
78 Only 'vis major'.

addition, differences are affected by varying practices regarding weighting methods, data collection, inclusion or exclusion of exceptional events, voltage levels and specific types of interruptions, each affecting comparability of indicator values.

A notable example is Spain, which does not use SAIDI and SAIFI as indicators and which has (as in previous Benchmarking Reports) provided its TIEPI and NIEPI values where SAIDI and SAIFI are typically used. This means that every figure where SAIDI and SAIFI are illustrated only shows TIEPI and NIEPI for Spain, demonstrating that the comparison of values between countries is not always easy and straightforward.

Voltage levels used for each indicator are not standardised and could thus present another difficulty in benchmarking. Table 2-12 and Table 2-13 provide an overview of voltage levels included in various indicators across Europe.

TABLE 2-12: Voltage levels included in various CoS indicators across Europe

Indicator	LV	MV	HV	EHV
Unplanned SAIDI without exceptional events	CH, CY, CZ, DE, DK, EL, ES, FR, GB, GE, HR, HU, IE, IT, KS*, LT, LU, LV, ME, PL, PT, RO, RS, SE, SK, UA	AT, CH, CY, CZ, DE, DK, EL, ES, GE, HR, HU, IE, IT, KS*, LT, LU, LV, MD, ME, PL, PT, RO, RS, SE, SI, UA	CH, CY, CZ, DK, ES, GB, GE, HU, IE, IT, KS*, LU, LV, PL, PT, RO, RS, SE, SK, UA	CH, ES, GB, IT, LU, PL, SK
Unplanned SAIFI without exceptional events	CH, CY, CZ, DE, DK, EL, ES, FR, GB, GE, HR, HU, IE, IT, KS*, LT, LU, LV, ME, PL, PT, RO, RS, SE, SK, UA	AT, BE[79], CH, CY, CZ, DE, DK, EL, ES, GE, HR, HU, IE, IT, KS*, LT, LU, LV, MD, ME, PL, PT, RO, RS, SE, SI, UA	CH, CY, CZ, ES, GB, GE, HU, IE, IT, KS*, LU, LV, PL, PT, RO, RS, SE, SK, UA	CH, ES, GB, IT, LU, PL, SK
Unplanned SAIDI including exceptional events	BE[80], CH, CY, CZ, DE, DK, EE, EL, ES, GB, HR, HU, IE, IT, LT, LU, LV, ME, NL, NO, PL, PT, RO, RS, SE, UA	AT, BE[80], CH, CY, CZ, DE, DK, EE, EL, ES, FI, HR, HU, IE, IT, LT, LU, LV, MD, ME, MT, NL, NO, PL, PT, RO, RS, SE, SI, UA	BA, BE[80], CH, CY, CZ, DK, EE, EL, ES, GB, HU, IE, IT, LU, LV, MT, NL, NO, PL, PT, RO, RS, SE, UA	BA, BE[80], CH, EE, EL, ES, GB, IT, LU, MT, NL, NO, PL
Unplanned SAIFI including exceptional events	BE[80], CH, CY, CZ, DE, DK, EE, EL, ES, GB, HR, HU, IE, IT, LT, LU, LV, ME, NL, NO, PL, PT, RO, RS, SE, UA	AT, BE[80], CH, CY, CZ, DE, DK, EE, EL, ES, FI, HR, HU, IE, IT, LT, LU, LV, MD, ME, MT, NL, NO, PL, PT, RO, RS, SE, SI, UA	BA, BE[80], CH, CY, CZ, EE, EL, ES, GB, HU, IE, IT, LU, LV, MT, NL, NO, PL, PT, RO, RS, SE, UA	BA, BE[80], CH, EE, EL, ES, GB, IT, LU, MT, NL, NO, PL
Planned SAIDI	CH, CY, CZ, DE, DK, EE, EL, ES, FR, GB, GE, HR, HU, IE, IT, KS*, LT, LU, LV, ME, NL, NO, PL, PT, RO, RS, SE, UA	AT, BE[79], CH, CY, CZ, DE, DK, EE, EL, ES, FI, GE, HR, HU, IE, IT, KS*, LT, LU, LV, ME, MT, NL, NO, PL, PT, RO, RS, SE, SI, UA	BA, CH, CY, CZ, EE, EL, ES, GB, GE, HU, IE, IT, KS*, LU, LV, MT, NL, NO, PL, PT, RO, RS, SE, UA	BA, CH, EE, EL, ES, GB, IT, LU, MT, NL, NO, PL
Planned SAIFI	CH, CY, CZ, DE, DK, EE, EL, ES, FR, GB, GE, HR, HU, IE, IT, KS*, LT, LU, LV, ME, NL, NO, PL, PT, RO, RS, SE, UA	AT, BE[79], CH, CY, CZ, DE, DK, EE, EL, ES, FI, GE, HR, HU, IE, IT, KS*, LT, LU, LV, ME, MT, NL, NO, PL, PT, RO, RS, SE, SI, UA	BA, CH, CY, CZ, EE, EL, ES, GB, GE, HU, IE, IT, KS*, LU, LV, MT, NL, NO, PL, PT, RO, RS, SE, UA	BA, CH, EE, EL, ES, GB, IT, LU, MT, NL, NO, PL
Unplanned MAIFI	FR, GB, LT, NO, PL, RO, SE, UA	FI, HU, LT, LV, NO, PL, PT, RO, SE, SI, UA	BE, GB, NO, PL, PT, RO, SE, UA	BE, GB, NO, PL
Unplanned MAIFI-E	IT, NO	HU, IT, NO, SI	CY, IT, NO	IT, NO

79 Brussels.
80 Flanders.

TABLE 2-13: Voltage levels included in transmission CoS indicators across Europe

Indicator	HV	EHV
Unplanned AIT (transmission) without exceptional events	BA[81], BE, CY, CZ, EE, EL, ES, FR, HR, HU, IT, LT, LV, MD, ME, PL, RO, RS, SI, SK, UA	BA[81], BE, CZ, EE, EL, ES, FR, HR, HU, IT, NO, PL, PT, RO, SE, SI, UA
Planned AIT (transmission)	BA, CY, CZ, EE, HR, ME, PL, RS	BA, CZ, EE, HR, NO, PL, PT, SE
Unplanned ENS (transmission) without exceptional events	BA[81], BE, CY, CZ, EE, EL, ES, FR, HR, HU, IT, KS*, LT, MD, ME, PL, RO, RS, SI, UA	BA[81], BE, CZ, EE, EL, ES, FR, HR, HU, IT, NO, PL, PT, RO, SE, SI, UA
Planned ENS (transmission)	BA, CY, CZ, EE, HR, KS*, ME, PL, RS	BA, CZ, EE, HR, NO, PL, PT, SE

In addition to monitoring of duration and frequency of interruptions, whether interruptions were planned or unplanned can also be considered. Section 2.4.3 provides more information on the rules for notifying the affected network user for planned interruptions (minimum time-requested, procedures for giving notice, etc.). In addition, the same indicators (for example SAIDI or SAIFI) could include or exclude interruptions caused by exceptional events. What occurrences are considered exceptional events can be determined in different ways. Some countries have a more statistical approach, while others focus their definition on the causes of exceptional events.

In **Albania**, the definition of exceptional events is established in standards. Exceptional events are considered interruptions due to force majeure and are excluded from interruption statistics.

Austria has been applying the concept of exceptional events since 2002, but the definition has been in law since 2012. Exceptional regional events are events that, according to previous experience, cannot be expected to occur in a given region and during which facilities constructed and maintained with due care cannot be operated without failure. The NRA has responsibility for classifying events as exceptional. The most frequent causes of interruptions that are considered exceptional events are winds over 130 km/h, huge area floods (as in 2002 and 2013), snow and ice storms.

The definition in **Belgium** depends on the region. On the federal level (transmission), exceptional events are:

- Natural disasters (earthquakes, floods, etc.);
- Storms, cyclones or other recognised (by a public authority) exceptional climatological circumstances with less than one occurrence per decade;
- Nuclear or chemical accident and its consequences;
- Inability to operate the transmission network or facilities that are functionally part of it because of social conflict;
- Acts of sabotage, acts of a terrorist nature, acts of vandalism, criminal acts, coercion of a criminal nature and threats of the same nature;
- Explosion of war ammunition;
- War declared or not, threat of war, invasion, armed conflict, embargo, revolution, revolt;
- Blackout;
- Interruption that the TSO, Elia, would be forced to provoke under the rules of the load shedding plan provided for by the ministerial decree of 3 June 2005[82];
- Triggering of Elia facilities at the request of the public authorities for security reasons; and
- The fact of the prince[83].

In Flanders, force majeure is defined and includes a list of exceptional events:

- Natural disasters including earthquakes, floods, storms, cyclones or other exceptional climatic conditions;
- Nuclear or chemical explosion and its consequences;
- Unforeseen unavailability of electricity distribution network for reasons other than age, the lack of maintenance of the installations or the qualification of the operators, including a computer crash, whether or not caused by a computer virus, provided that all preventive measures have been taken that are technically and economically feasible;
- Temporary or continuous technical inability to use the electricity distribution network or exchange electricity due to malfunctions within the control zone caused by electricity flows that are the result of energy exchanges within another control zone or between two (or more) other control zones, and where the identity of the operators involved in those exchanges are unknown and may not be reasonably known by the electricity DSO;
- Fire, explosion, sabotage, acts of terrorism, acts of vandalism, damage caused by criminal acts and threats of the same nature; and
- Order from the government.

In Wallonia, the following situations, provided that they are unavoidable and unforeseeable, are considered force majeure by the DSO for the purposes of regulation:

81 In Bosnia and Herzegovina, this indicator includes exceptional events.
82 FR: 3 Juin 2005. — Arrêté ministériel établissant le plan de délestage du réseau de transport d'électricité.
NL: 3 Juni 2005. — *Ministerieel besluit tot vaststelling van het afschakelplan van het transmissienet van elektriciteit.*
https://www.ejustice.just.fgov.be/mopdf/2005/08/18_1.pdf#Page14
83 '*Le fait du prince*' (the fact of the prince) is a concept that refers to an arbitrary act of government or head of state. The term is used in administrative law to designate a measure taken by the administration which has an impact on a contract to which it is a party.

- Natural disasters resulting from earthquakes, floods, storms, cyclones or other climatological circumstances recognised as exceptional by a public authority authorised for this purpose;
- Nuclear or chemical accident and its consequences;
- Sudden unavailability of the installations for reasons other than obsolescence, lack of maintenance or qualification of the operators, including the unavailability of the computer system, whether or not caused by a virus, while all the preventive measures had been taken;
- Technical inability, temporary or permanent, for the distribution network to supply electricity due to a sudden lack of energy injection from the local transport or transmission network and not compensated by other means;
- Inability to operate the distribution network or the facilities that are functionally part of it because of a collective dispute and which gives rise to a unilateral measure of employees (or groups of employees) or any other social conflict;
- Fire, explosion, sabotage, acts of a terrorist nature, acts of vandalism, damage caused by criminal acts, coercion of a criminal nature and threats of the same nature;
- War (declared or not), the threat of war, invasion, armed conflict, embargo, revolution, revolt; and
- The fact of the prince, including the situations in which the competent authority invokes urgency and imposes exceptional and temporary measures on the network operators or users of the distribution network in order to maintain or restore the safe and reliable operation of all the networks.

There is no definition of exceptional events in Brussels. In Flanders and Wallonia, the definition is established in law, while regional regulators classify events as exceptional. The statistical method to define 'major event days' in Wallonia refers to the National Meteorological Institute.

The entity of Republika Srpska in **Bosnia and Herzegovina** has a definition of exceptional events that was established in internal guidelines in 2008 that were incorporated in the General Conditions [22]. When amendments to the General Conditions enter into force, circumstances where the DSO is exempted from responsibility for supply interruptions are prescribed. The network operator classifies events as exceptional and informs the NRA. The most common causes of interruptions classified as exceptional events are excessive snow and ice, wind, flood.

Croatia has had a legal definition of exceptional events since 2017. Force majeure or exceptional events are: snow with added weight, icy rain, atmospheric discharge, salt, storm, wind, fire, landslide, flood, earthquake, war, terrorism and others. The network operator classifies events as exceptional and must keep documentary evidence for at least ten years. The documentation should prove that: there were conditions that were not envisaged, there was a state of emergency and/or an interruption happened as a result of an exceptional event. As in many other countries, indicators are available both with and without exceptional events. The three most frequent causes in 2018 were atmospheric discharge, storm and snow with added weight.

The most common cause of interruptions being classified as exceptional events in **Cyprus** is the loss of large generating units leading to shedding of consumer load because of underfrequency.

In **Estonia**, the definition of an exceptional event was established as a standard in 2005. If the interruption is caused by an event that the network operator is objectively unable to prevent (such as a natural disaster, wind or icing that exceed design norms, or hostilities), the interruption shall be rectified within three days after the end of that event. The most frequent causes are strong storms and winds with speeds of around 30 m/s.

Since the NRA of **Finland** has not defined the term 'exceptional event', DSOs only report indicators that include all interruptions.

France has a definition of exceptional events, established in law since 2009:

- Destruction due to acts of war, riots, looting, sabotage, attacks, delinquency;
- Damage caused by accidental and uncontrollable events, attributable to third parties, such as fires, explosions, airplane crashes;
- Natural disasters within the meaning of Law N° 82-600 of 13 July 1982;
- Sudden and simultaneous unavailability of several production facilities connected to the transmission network;
- Interruptions decided by the public authorities for reasons of public safety or the police, since this decision does not result from the behaviour or inaction of the electricity network operator; and
- Atmospheric phenomena of exceptional magnitude with an impact on the networks, characterised by an accident probability of less than 5% for the geographical area as soon as at least 100,000 consumers supplied by the transmission and/or distribution networks are interrupted.

The network operator classifies events as exceptional based on the definition above and the government is responsible for declaring natural disasters. Interruptions due to exceptional events are excluded from interruption statistics. The most frequent cause of interruptions classified as exceptional events are storms.

There is no regulatory definition of exceptional events in **Georgia**. System operators contact the NRA, GNERC, with requests to exclude certain interruptions from calculations because they were caused by exceptional events. GNERC staff review all interruptions submitted on a case-by-case basis. As in many other countries, indicators are available both including and excluding exceptional events.

Germany established a definition of exceptional events in internal guidelines in 2006. To be exceptional, an event must be unpredictable, could not be avoided by any activities, be very rare and not be within the responsibility of the network operator.

The network operator classifies events as exceptional and, on request, explains the details of the event to the NRA during an ex-post control of the data. The network operator must explain where the event (e.g. a storm) took place and the NRA validates events with external information. The most frequent causes of interruptions caused by exceptional events are high level water, floods and storms/hurricanes.

In **Great Britain**, the definition was established as a standard in 2011. Where a Distribution Network Operator's (DNO) incentivised interruptions performance is affected by exceptional circumstances as defined in the licence, an exceptional event has occurred. In such cases, the network operator asks for the approval of the NRA that can classify the event as exceptional.

A definition of force majeure is included in the Distribution Network Code in **Greece** [23]. It is defined as any event or situation beyond the control of the network operator that could not be foreseen even by proper due diligence on its part and that makes it impossible to implement the provisions of the Code, in part or in whole.

Incidents of force majeure are, in particular: extreme weather events, unforeseen interventions by public authorities (e.g. police, fire brigades), strikes or other labour mobilisations that last for more than five consecutive days and substantially affect the operator, acts of war, revolutions or popular uprising and stance, earthquake or other seismic activity exceeding network plant specifications, damage from third parties that cannot be avoided such as plane crashes, sabotage or terrorist acts. The criteria for the recognition of force majeure is the nature and extent of an event, as well as the likelihood of occurrence in relation to the characteristics and environmental conditions of the affected section of the network. Events that fall within normal or reasonably expected network operation and/or expected environmental conditions do not constitute force majeure. Furthermore, certain non-force majeure conditions/events can also be classified as exceptional. These are: extreme weather conditions and interference by third parties, network users or public authorities.

The system operator is obliged to separately register interruptions attributed to exceptional events. Interruption statistics are available with values both excluding and including exceptional events. The most common causes of interruptions classified as exceptional events are extreme weather (major event days), interruptions in upstream systems (transmission/generation) and other unforeseeable events.

For each DSO region, a day where the number of unplanned interruptions exceeds three times the daily average in the reporting year is considered an 'exceptional condition period'. Greece uses the term 'extreme weather conditions' for classifying interruptions according to this rule, although the underlying cause(s) for the high number of events may vary.

There is no definition of exceptional events in **Hungary**, although there is a definition of 'extreme weather' in the Regulatory Decision on Guaranteed Standards [24]. An event is considered as 'extreme weather' if the number of MV interruptions in a 24-hour interval reaches or exceeds a predetermined value for each DSO. The classification of an event as extreme weather is as follows:

- A DSO sends a report, including the number of MV interruptions, the number of affected customers, duration and ENS (among others) and asks the NRA to classify the event as a Category 1-4 extreme weather event; and
- Based on the report, the NRA classifies the event and determines the required restoration time.

In addition, there is a definition of 'other events' which includes the following: system collapse, terrorist attacks and any event classified as 'other' by the NRA. Interruptions caused by extreme weather conditions are classified as 'other event' if the strain caused by the event (e.g. wind speed over 100 km/h) exceeds the design requirements of the network. The classification of an event as 'other event' is as follows:

- A DSO first sends a short report (within a few days of the interruption), followed by a comprehensive report which includes detailed information on the interruption (duration, location, affected customers, damages, cause of the damages, etc.) and all documents (including a meteorological study and/or a study of the actual strain on the network elements) which confirm that the network elements were damaged due to weather conditions exceeding the design requirements of the network; and
- Based on this report, the NRA decides whether or not to classify an interruption as 'other event'. This classification would allow a DSO to exclude the impact of an event from its continuity indicators.

In Hungary, statistics are available both including and excluding exceptional events. The three most common causes of interruptions classified as exceptional events are vegetation, windstorms and snowstorms.

In **Ireland**, the definition of an exceptional event was established in a standard in 2018. An exceptional event is defined as a single event outside the control of the DNO. The classification as a one-off event is based on the impact of an event exceeding 25,000 customer interruptions and 2,000,000 CML. No exceptional events have occurred to date.

Kosovo* does not have a definition of exceptional events, but Article 16 of the Rule on Electricity Service Quality Standards [15] specifies the exceptional rules for special cases of CoS monitoring. Exceptional rules should be applied for the following special cases with regard to the monitoring of CoS:

- Customers belonging to one DSO and supplied from another one; and
- MV feeders to and from an MV switchgear.

The Rule on Electricity Service Quality Standards specifies that force majeure is an event that the system operator was unable to control or prevent, with environmental parameters outside the latest boundaries determined by taking into consideration the design conditions of network elements, or the state of emergency declared by the governmental decision. This concept was established in 2016 in the Law on Electricity [25]. The national government classifies events as exceptional and interruptions due to exceptional events are excluded from the statistics.

Although there is no regulatory definition in **Latvia**, exceptional events are defined and classified by the network operator. Statistics are available both including and excluding exceptional events.

Luxembourg defines exceptional events as natural disasters such as floods and earthquakes. This definition was established in 2011. In case of exceptional events, the network operator reports these cases along with other outages and the NRA may audit them in case of doubt.

In **Malta**, exceptional events are reported together with other events as there is no regulatory definition. In the case of an exceptional event, the DSO is required to inform the NRA regarding unavailability of generation capacity and faults at 33 kV level or above which could have an adverse effect on the security and quality of supply. However, interruptions due to such events would still be included in the calculation of CoS indicators.

Moldova established the regulatory definition of exceptional events in internal guidelines in 2014: severe natural phenomena manifested by strong winds, rainfall deposits, heavy rainfall and other natural disasters that caused mass interruptions of the electricity transmission or distribution service. The most frequent causes of interruptions classified as exceptional events are strong winds, ice deposits, heavy rainfall and snowfall.

Montenegro does not have a regulatory definition of exceptional events, but events can be classified as exceptional if there is any justification by the system operator to confirm that an exceptional event has really occurred. There are plans to include a definition of exceptional events in future developments on Rules on the Minimum Quality of Electricity Delivery and Supply [16].

There is a regulatory definition in **the Netherlands**, although they are not separately reported by network operators. An exceptional event is defined as an unforeseeable event or situation that is not reasonably within the control of a network operator and that is not due to a fault of the network operator. This could include earthquakes, floods, exceptional weather conditions, terrorist attacks and war. There have been no exceptional events since 2012.

North Macedonia also has a regulatory definition of exceptional events. The broader definition of force majeure is in the 'Rules for Reimbursement of Damage caused to Producers and Consumers' [26]. It is defined as:

- Natural disasters of greater magnitude and intensity, such as earthquakes, floods, landslides, droughts, volcanic eruptions, storm surges, snowfalls, heavy rains, lightning, fires, epidemics and similar natural events, with impacts of natural disasters assessed in accordance with the technical specifications of the equipment, plants, devices and installations used by the operator, as well as the standards for the design and performance of the operator's facilities;
- Damage, demolition or blocking of other energy, telecommunication or traffic infrastructure not owned by the operator;
- War or martial law, state of emergency declared in accordance with law, comprehensive military mobilisation, invasion, armed conflict, blockade or serious threat from such situations;
- Civil war, rebellion, uprising, revolution, military coup, terrorist acts, sabotage, civil unrest, mass violence;
- Actions of state authorities taken in accordance with the law or actions taken for the sake of necessity not caused by actions taken or not taken by the operator;
- Disruptions, strikes, boycotts or occupations of facilities by employees; and
- Declaration of an energy crisis in accordance with the Law on Energy.

The most common causes are weather conditions. In the case of an exceptional event, system operators take appropriate measures to mitigate the impact of the event. Interruptions due to exceptional events are not excluded from interruption statistics.

Norway, **Romania** and **Sweden** do not have a regulatory definition of exceptional events.

In **Poland**, the definition of an exceptional event is established in law as catastrophic interruptions – those lasting more than 24 hours. The most common cause of interruptions classified as exceptional are strong winds (hurricanes), storms and exceptionally strong freeze.

In **Portugal**, the Quality of Service Code [27] establishes the concept of exceptional events as incidents with all of the following characteristics:

- Low probability of occurrence of the event or its consequences;
- The event causes a significant decrease in the quality of supply;
- It is not reasonable, in economic terms, for network operators, suppliers, last-resort suppliers or producers to avoid all of its consequences; and
- The event and its consequences are not attributable to network operators, suppliers, last-resort suppliers or producers.

An incident should only be considered an exceptional event after approval by the NRA, ERSE, following a request by network operators, suppliers or last-resort suppliers. The definition above was established in law in 2014. The three most frequent causes of interruptions classified as exceptional events are falling trees, birds and lightning.

In **Slovakia**, the definition of exceptional event was established in law in 2012. A state of emergency in the electricity sector means: a sudden deficiency, or a threat of deficiency of energy; frequency change in the electricity grid above or below the level set for technical means ensuring automated disconnection of facilities from the system in compliance with the technical conditions of the TSO; or a disruption in the parallel operation of transmission systems that may cause a considerable reduction or interruption in energy supply or put energy facilities out of operation or endanger the life and health of people living in a specific territory or part thereof as a consequence of:

- Extraordinary events and emergency;
- Measures during economic mobilisation;
- Accidents that occur at facilities for electricity generation, transmission and distribution, even outside the defined territory;
- Situations posing threat to safety and operational reliability of the system;
- Shortage of energy sources; and
- Act of terrorism.

The national government classifies events as exceptional. The three most frequent causes of interruptions classified as exceptional events are natural disasters, end-user/third party not providing the cooperation necessary to comply with quality standards and damage on the transmission or distribution system equipment by a third party.

The definition of exceptional events in **Slovenia** was established in law in 2015. Force majeure is a natural event outside the scope of TSOs' or DSOs' activity whose effect on power interruptions cannot be prevented by expectation. Such events include precipitation (snow or ice), storm, hurricane, avalanche (snow or earth), fire, flood, earthquake or other natural disasters for which a crisis is declared. In special cases, force majeure may be recognised as the cause of interruption in case of lightning strikes. Events that have nothing to do with natural disasters, but for which a crisis is declared (such as war, demonstrations etc.) can also be classified as force majeure.

The network operator informs the NRA in case of an exceptional event (in addition to declaring them as such). The three most frequent causes of interruptions caused by exceptional events are trees falling due to strong wind, lightning strikes and heavy snow. A system for reporting daily data on CoS has been in place since 2019. The NRA plans to introduce the classification of exceptional events based on the 'IEEE Guide for Electric Power Distribution Reliability Indices' (IEEE 1366) [28] standard when at least five years of daily continuity data is available.

Spain established a definition of exceptional events in law in 2009. The national government classifies events as exceptional. An event may be authorised as exceptional by the General Directorate of Energy Policy and Mines if: it has natural causes and occurs in general in at least 10% of municipalities of the peninsula, or in at least 50% of electrical subsystems; and that, in accordance with the technical regulations applicable to the facilities, is not provided for in the design of the system.

The definition of exceptional events was established in 2011 in internal guidelines in **Switzerland**. They are defined as events that:

- Occur only with a very low probability;
- Are unpredictable and cannot be avoided with economically justifiable measures;
- Result in a long-lasting failure for many end-users; and
- Belong to one of the following groups: exceptional weather conditions, governmental arrangements, labour disputes and riots, disasters, third-party influence, terrorism, or declaration of crisis.

In **Ukraine**, the definition of exceptional events was established in law in 2014. An interruption resulting from force majeure is any interruption caused by the appearance of emergency and insurmountable circumstances, the effects of which cannot be prevented by using highly professional staff practices, and which may be caused by exceptional weather conditions or disasters (such as a hurricane, storm, flood, accumulation of snow, ice, earthquake, fire, subsidence and landslide) or any other unforeseen situations. DSOs define exceptional events but the occurrence of such events should be documented in the order established by law (i.e. with confirmation from emergency state authorities or state hydrometeorological centre). The NRA checks the existence of such documents selectively.

It should also be noted that indicators representing the number of interruptions, for example SAIFI, are not always easily comparable among countries. The reason for this is that the aggregation rules for interruptions differ across Europe. In some countries, all interruptions occurring during a specific period are considered as a single interruption.

In 2019, CEER conducted research on practices of aggregation of interruptions and performed a survey across Europe to determine whether, and in which way, aggregations are performed in the case of multiple subsequent interruptions. This is only one of the many issues that hinder full comparability of indicators. The survey included an electricity-sector example with a series of consecutive interruptions and intervals of energy supply, with all interruptions assumed to be caused by the same event.

Analysis of answers from 31 respondents showed that there are significant differences in the way individual countries calculate corresponding indicators driven by several factors including rules on aggregation, among which are:

- Around half of the countries that responded to CEER research aggregate interruptions of electricity in some capacity, while others count every interruption separately;
- There are countries that aggregate multiple interruptions into one if the return of energy supply between interruptions is short;
- In some cases, even the restoration of energy supply counts as an interruption if the restoration is short enough; and
- Other countries would interpret the entire series in the example as a single interruption.

It is important to stress that an example such as the one used in the CEER survey is very unlikely to occur in practice, meaning the differences between the calculated indicator values may be less pronounced than what was revealed by the CEER research.

Figures on the following pages illustrate the values of various indicators for CoS between 2010 and 2018. If a country or its value for a specific year has been omitted from a graph, this is because the values were not provided. Detailed data by country is set out in the tables in Annex B.

SAIDI and SAIFI are presented for: planned, unplanned interruptions without exceptional events and unplanned interruptions with exceptional events. In addition, ENS and AIT are presented for unplanned interruptions. The wide spread of indicators makes the reading of some graphs more difficult, therefore **a logarithmic scale is used for SAIDI, SAIFI, ENS and AIT** so that all countries can be included in a single graph. There are, however, graphs where countries are divided into groups, as described in the next paragraph. **The figures dealing with MAIFI do not use a logarithmic scale** since the number of countries is significantly lower, meaning graphs are easier to read even with a conventional scale. Boxplot graphs are also included for every indicator if the values for a specific country were available for at least four years. These graphs provide multiple values for each country: the minimum, the maximum (all other values are in the grey area between them), the average (red cross) and the latest available value (green square), which is from 2018.

Many countries provided their CoS values for this Report. While increased participation is welcome, the disadvantage of an increased number of countries is that it makes it difficult to read the lower half of a figure, regardless of which scale is used. For this reason, additional figures for SAIDI and SAIFI are included where countries are divided in two groups: one where the cut-off value was not exceeded by any country in any of the years and one where all countries exceeded the said value in at least one year. This has no effect on results and has only been presented in this way to improve clarity.

2.6.1 Planned interruptions

Planned interruptions relate to minutes without supply experienced by network users who were given prior notice of the interruption. The general and national rules related to definition and treatment of this kind of interruption can be found in Section 2.4.3.

Minutes lost per customer per year (SAIDI) due to planned interruptions are presented in Figure 2-1 as a time series and Figure 2-4 as a boxplot. The values show a very wide range among countries, from less than one minute to over 5,100 minutes per year.

The number of interruptions per customer per year (SAIFI) due to planned interruptions is presented in Figure 2-5 as a time series and Figure 2-8 as a boxplot. As with SAIDI, there are significant differences across Europe as the values range from nearly zero to over 45 interruptions per customer per year. Since only two decimal points are used, the Portuguese values from 2017 (0.0024) and 2018 (0.0015) appear to be zero.

As explained in the previous section, there are figures that only include some countries, depending on whether they exceeded a cut-off value or not. Figure 2-2 and Figure 2-3 show the same indicator as Figure 2-1, but with countries divided into those not exceeding 100 minutes per customer and those exceeding 100 minutes per customer in at least one year. Likewise, Figure 2-6 and Figure 2-7 show the same indicator as Figure 2-5, but with countries divided into those not exceeding 0.5 interruptions per customer and those exceeding that limit.

The differences between countries may be due to variations in the design of the distribution network (with or without redundant supply paths) and the amount of maintenance and building in the distribution network. A temporary high level of planned interruptions could be a sign of high investment in distribution networks, aiming at reducing the number of unplanned interruptions in the future. High levels of planned interruptions can also be due to replacement and repair of components that were provisionally restored after a major storm or due to a widespread replacement of energy meters.

FIGURE 2-1: Planned long interruptions, SAIDI (minutes per customer per year) – time series

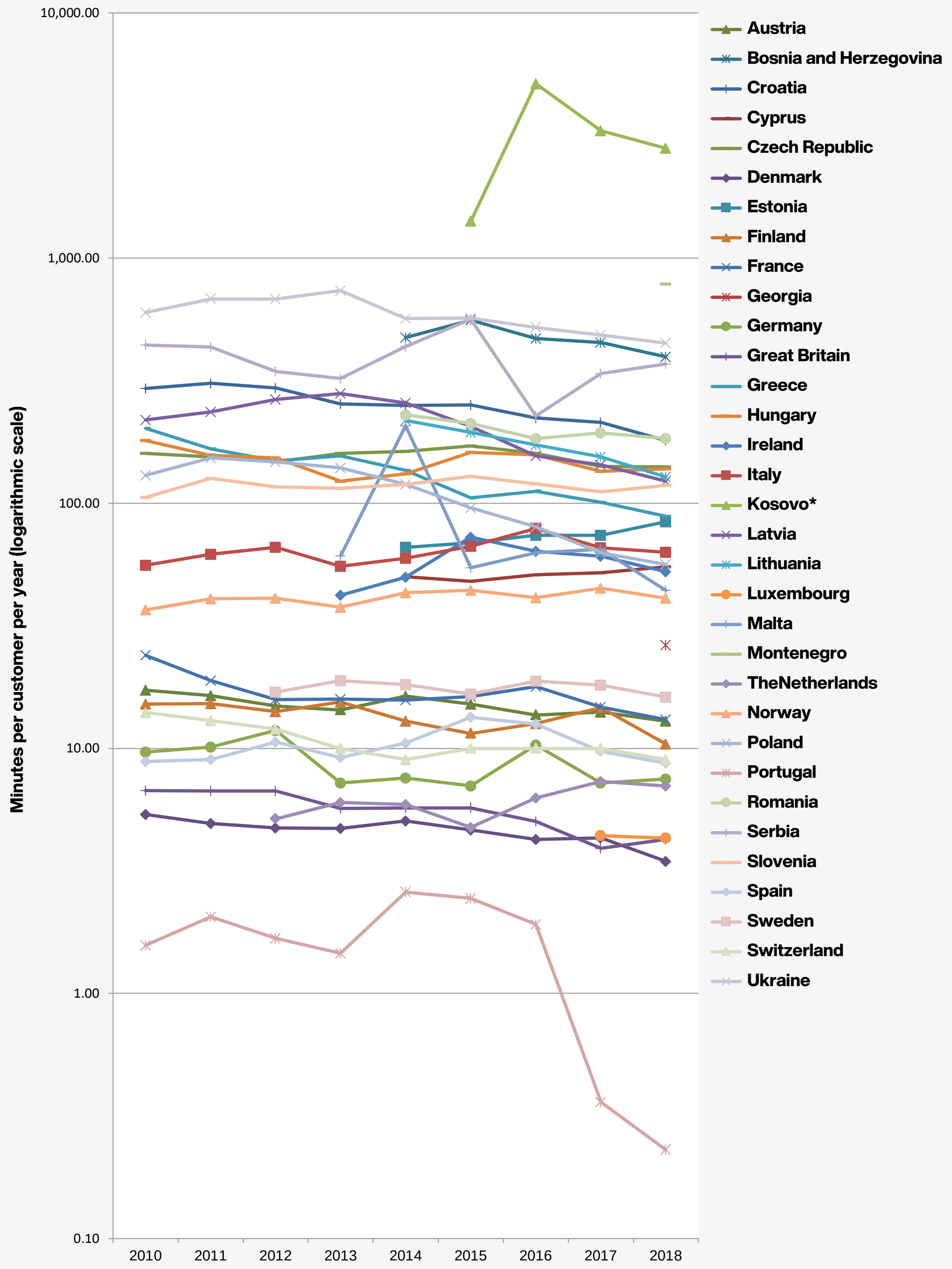


FIGURE 2-2: Planned long interruptions, SAIDI (minutes per customer per year) – countries not exceeding 100 minutes per customer in any of the years in the time series

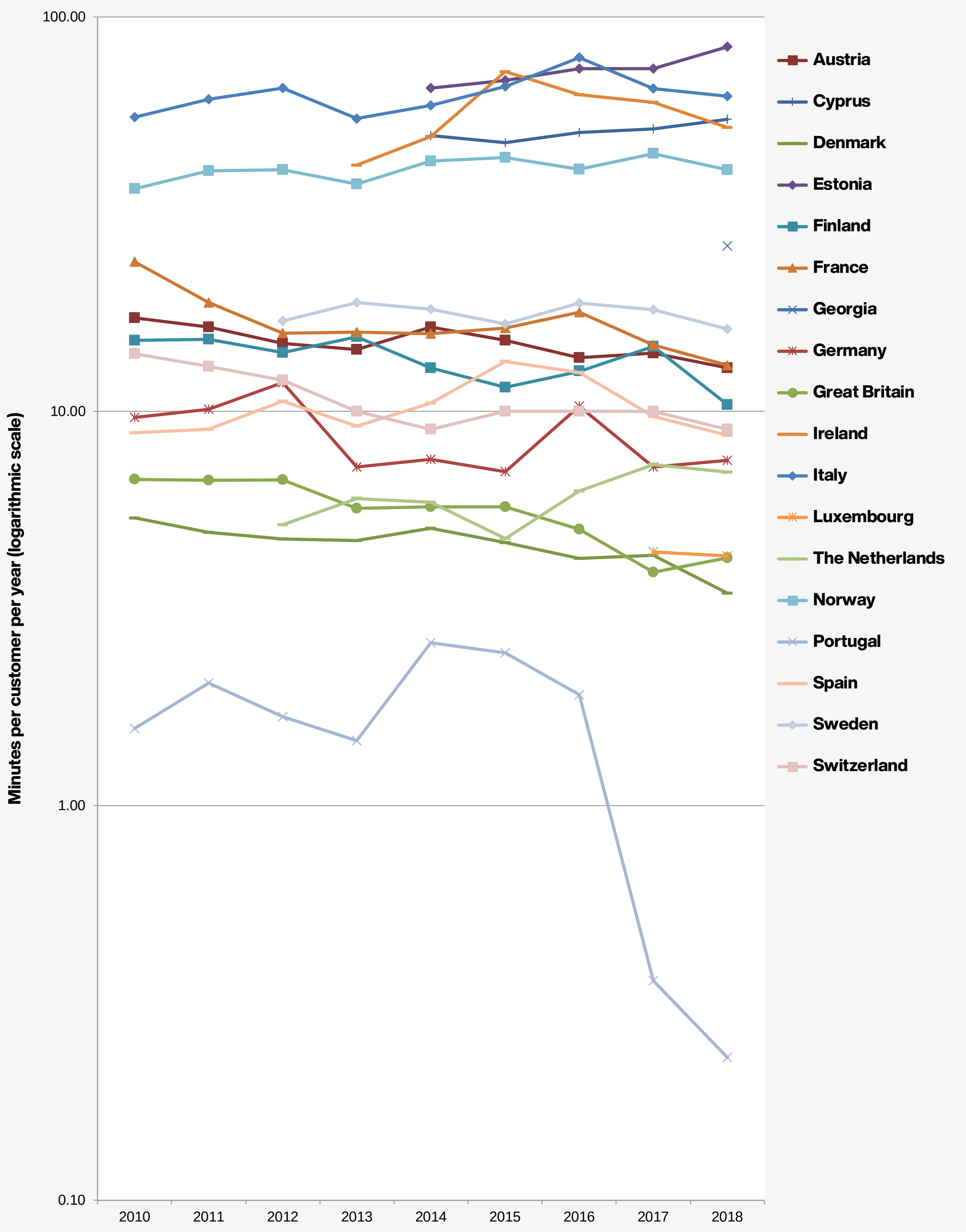


FIGURE 2-3: Planned long interruptions, SAIDI (minutes per customer per year) – countries exceeding 100 minutes per customer in at least one year in the time series

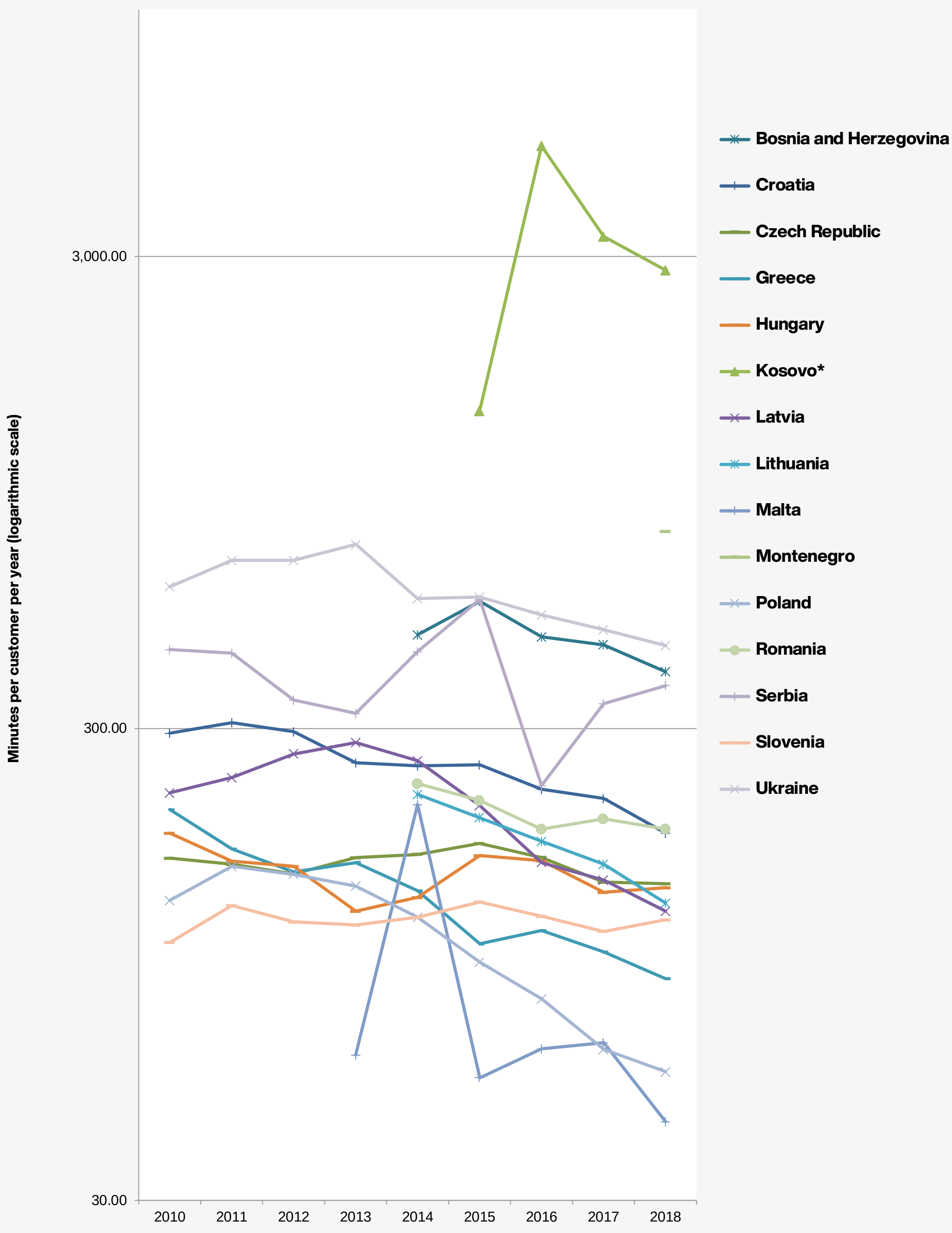


FIGURE 2-4: Planned long interruptions, SAIDI (minutes per customer per year) – boxplot

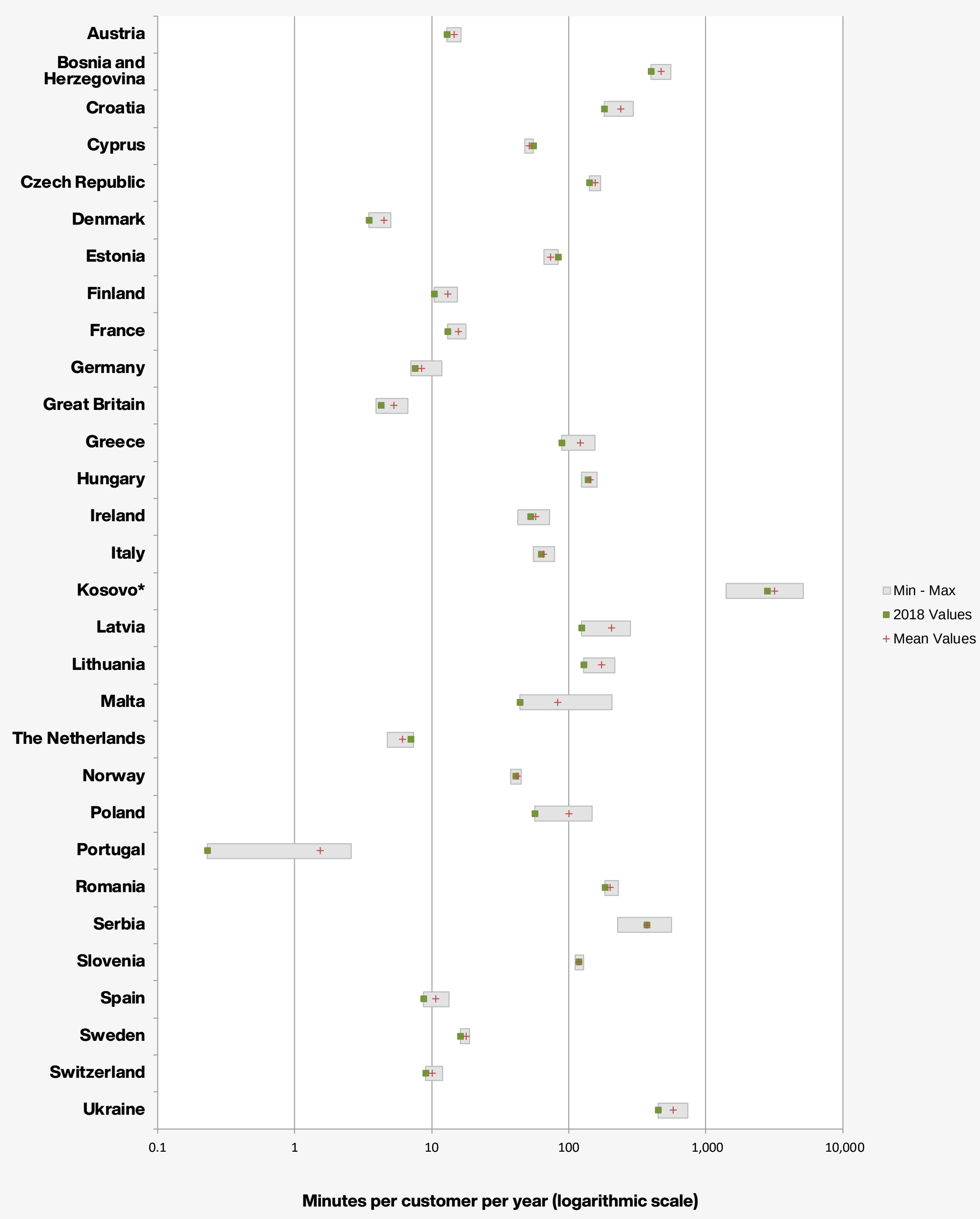


FIGURE 2-5: Planned long interruptions, SAIFI (interruptions per customer per year) – time series

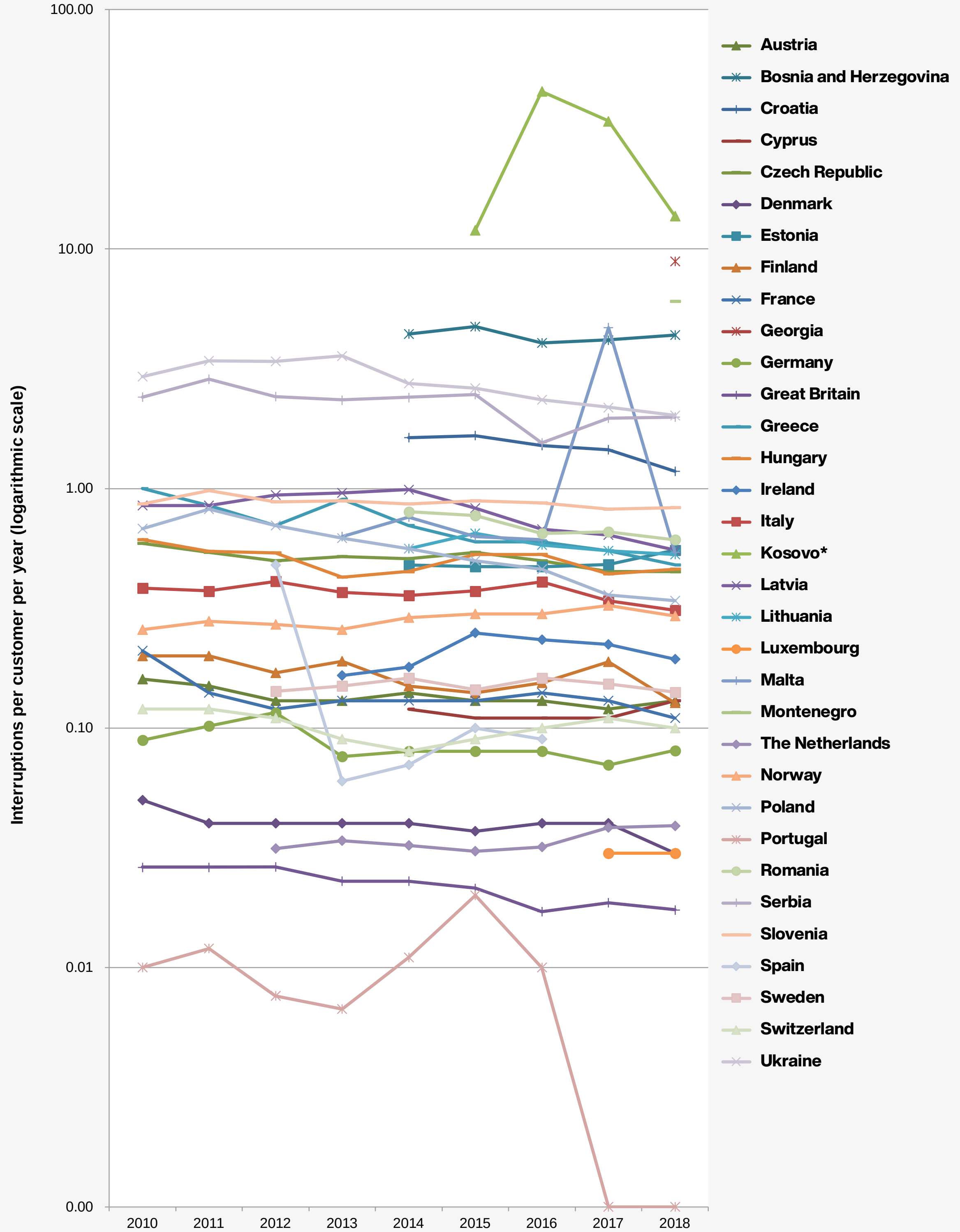


FIGURE 2-6: Planned long interruptions, SAIFI (interruptions per customer per year) – countries not exceeding 0.5 interruptions per customer in any of the years in the time series

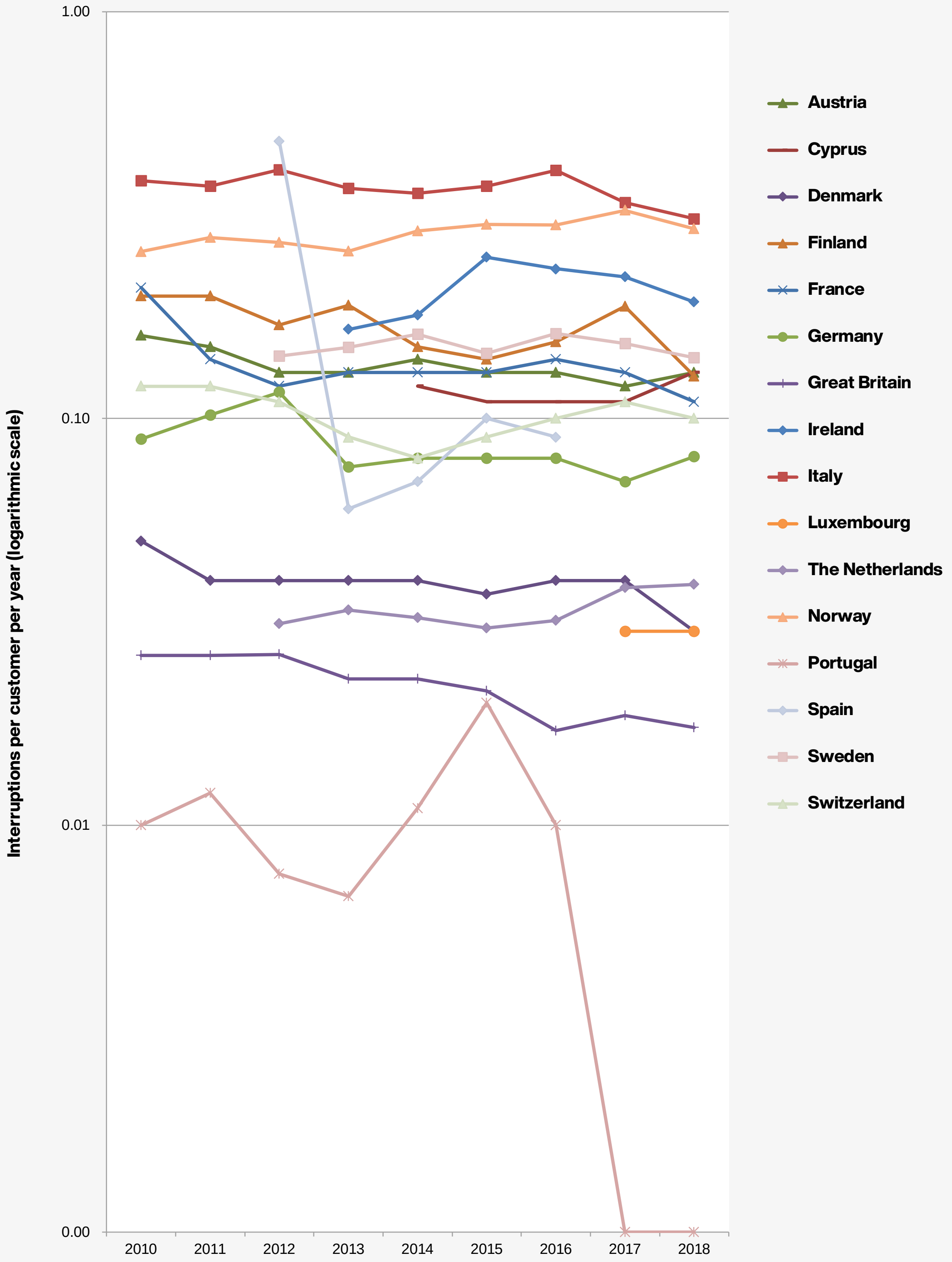


FIGURE 2-7: Planned long interruptions, SAIFI (interruptions per customer per year) – countries exceeding 0.5 interruptions per customer in at least one year in the time series

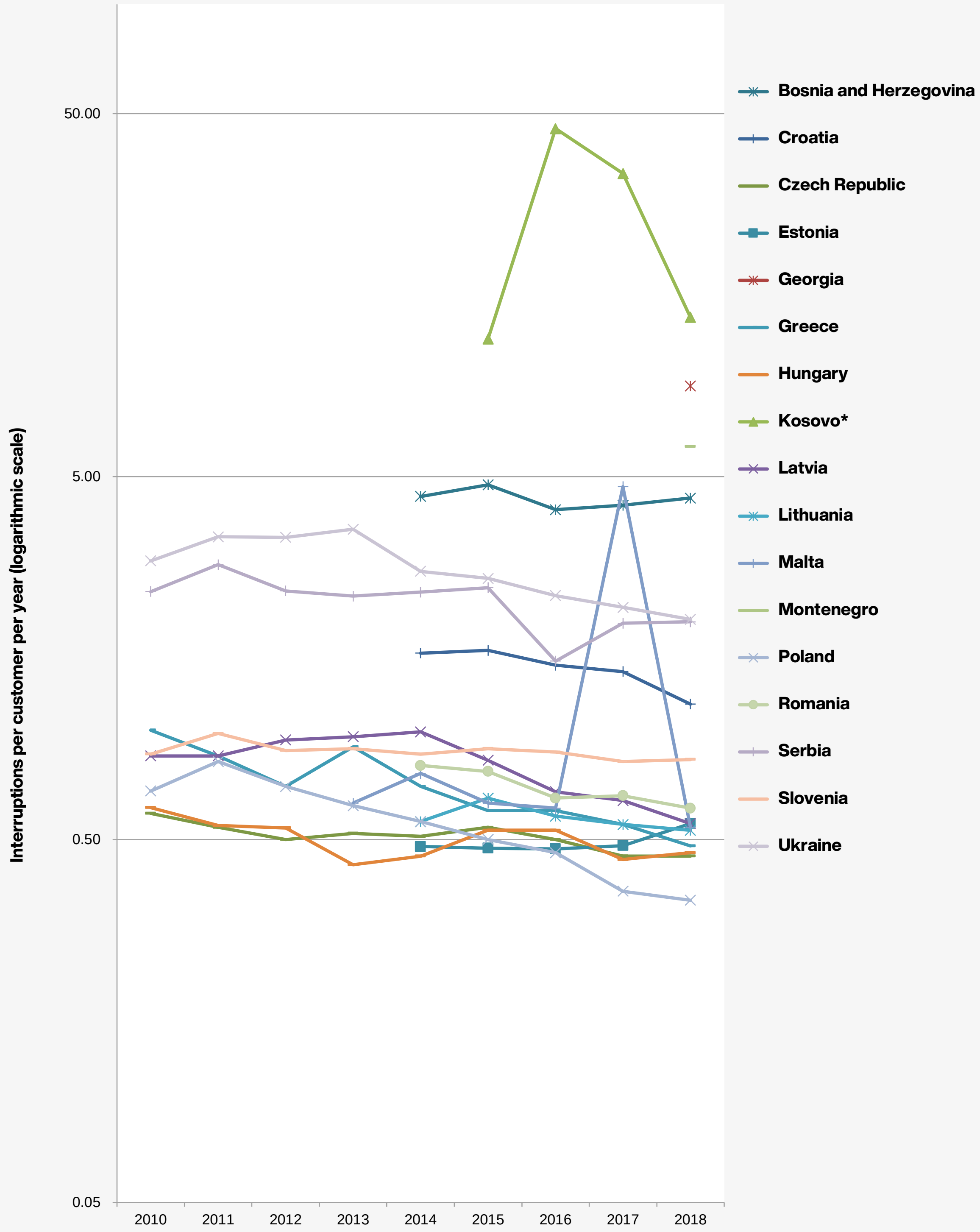
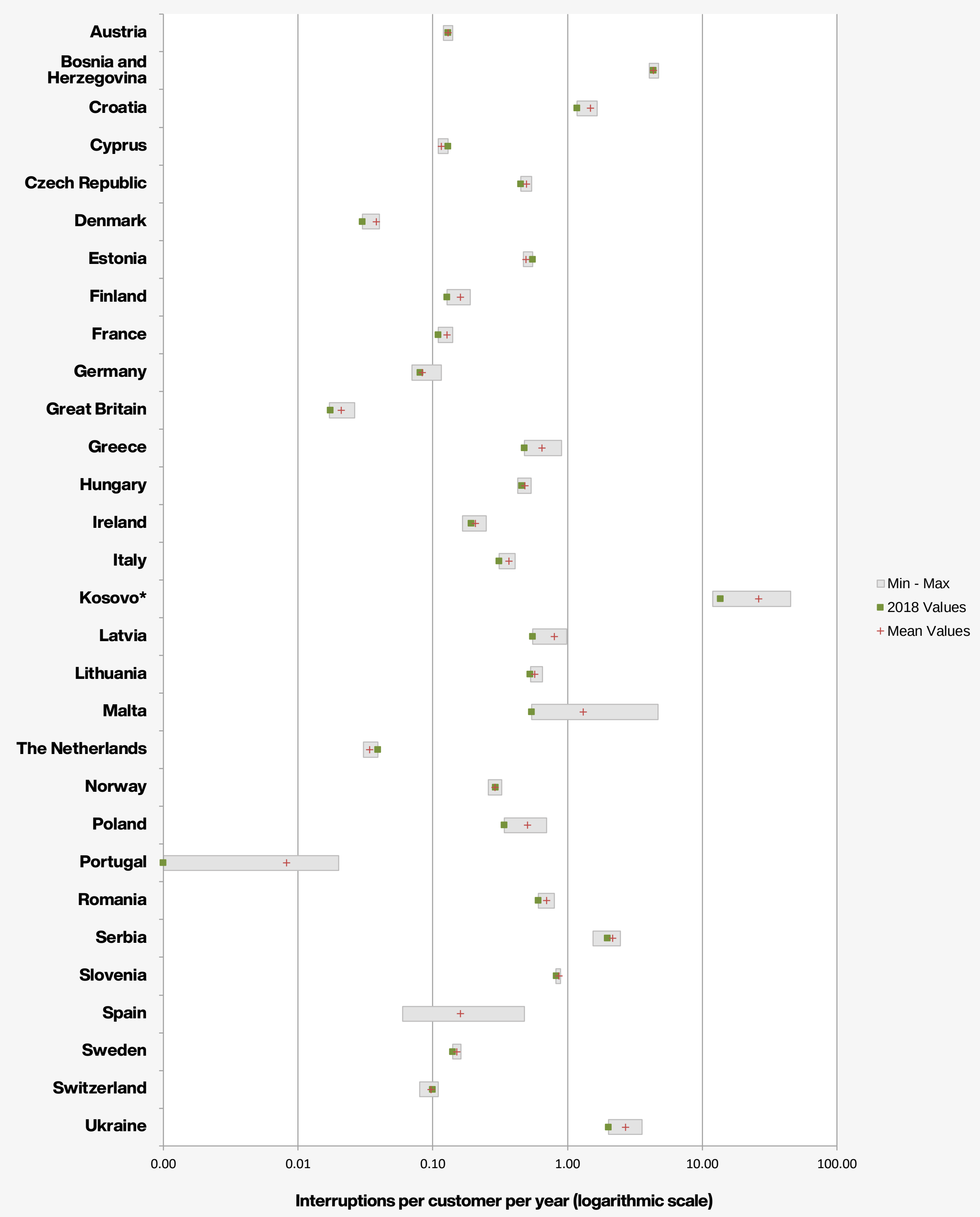


FIGURE 2-8: Planned long interruptions, SAIFI (interruptions per customer per year) – boxplot



2.6.2 Unplanned long interruptions, all events

Unplanned interruptions are most commonly defined as those for which no advance notification was provided to affected consumers. The term 'all events' signifies that every unplanned interruption is taken into consideration, even those caused by exceptional events. Definitions of interruptions based on their duration can be found in Table 2-3.

Unplanned minutes lost per customer per year (SAIDI) are presented in Figure 2-9 as a time series and Figure 2-12 as a boxplot. Again, the values show a very wide range among countries, from nine minutes to over 2,400 minutes per year.

The number of unplanned interruptions per customer per year (SAIFI) is presented in Figure 2-13 as a time series and Figure 2-16 as a boxplot. As with SAIDI, there are significant differences across Europe as the values range from 0.2 to over 13 interruptions per customer per year.

Figure 2-10, Figure 2-11, Figure 2-14 and Figure 2-15 illustrate SAIDI and SAIFI for unplanned long interruptions, with countries again being divided into two groups. The cut-off limits are 100 minutes per customer per year and one interruption per customer per year.

FIGURE 2-9: Unplanned long interruptions, SAIDI, all events (minutes per customer per year) – time series

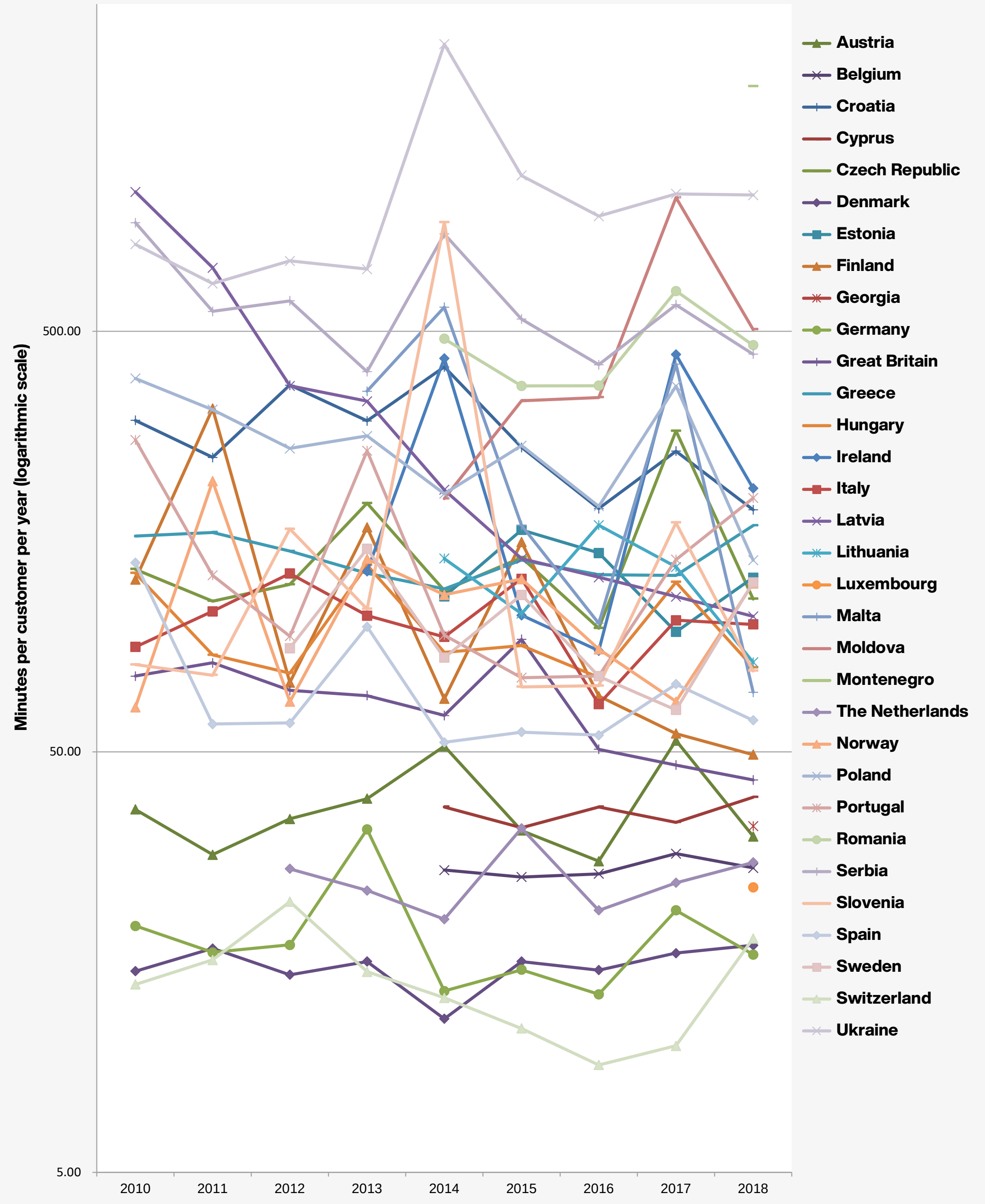


FIGURE 2-10: Unplanned long interruptions, SAIDI, all events (minutes per customer per year) – countries not exceeding 100 minutes in any of the years in the time series

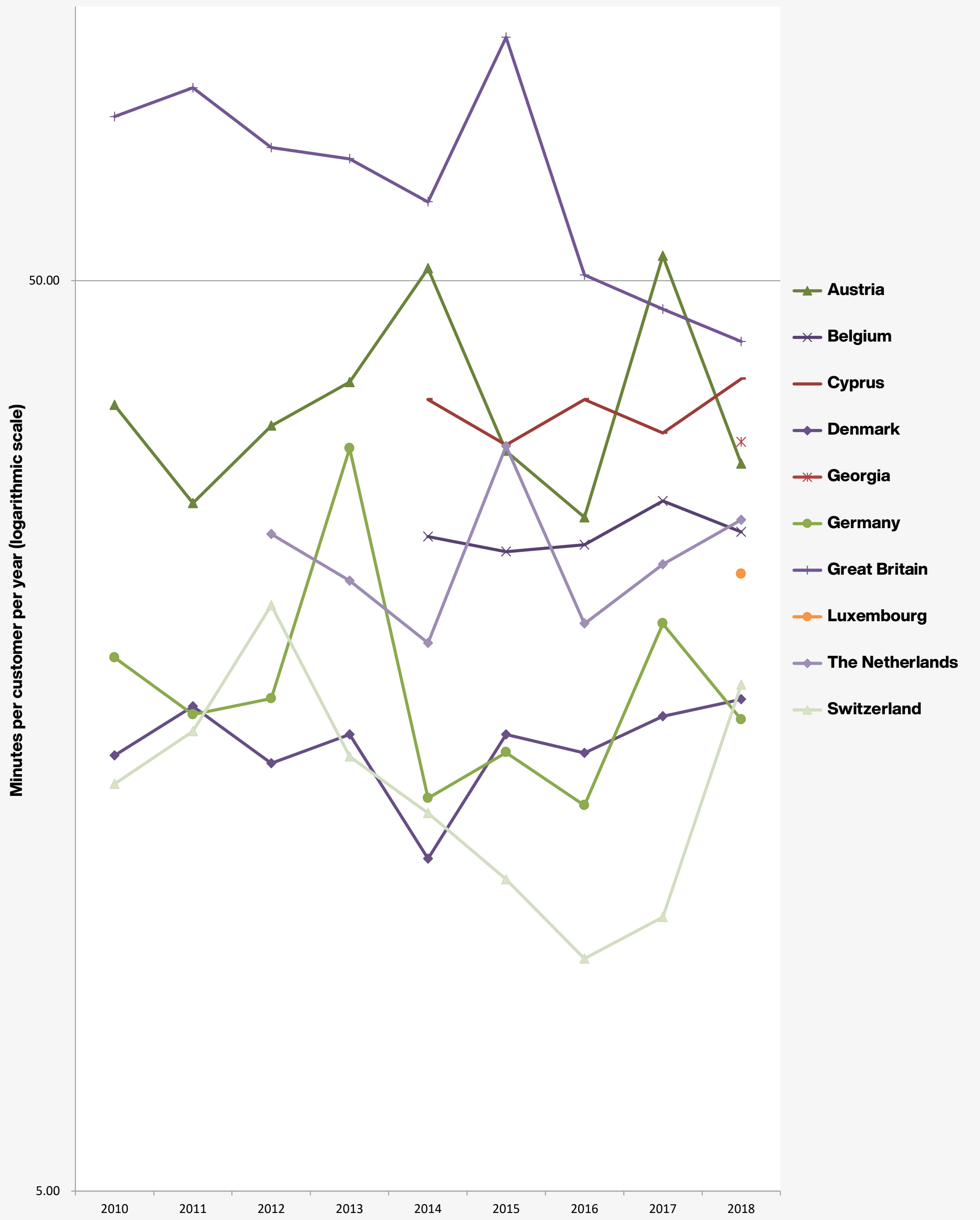


FIGURE 2-11: Unplanned long interruptions, SAIDI, all events (minutes per customer per year) – countries exceeding 100 minutes in at least one year in the time series

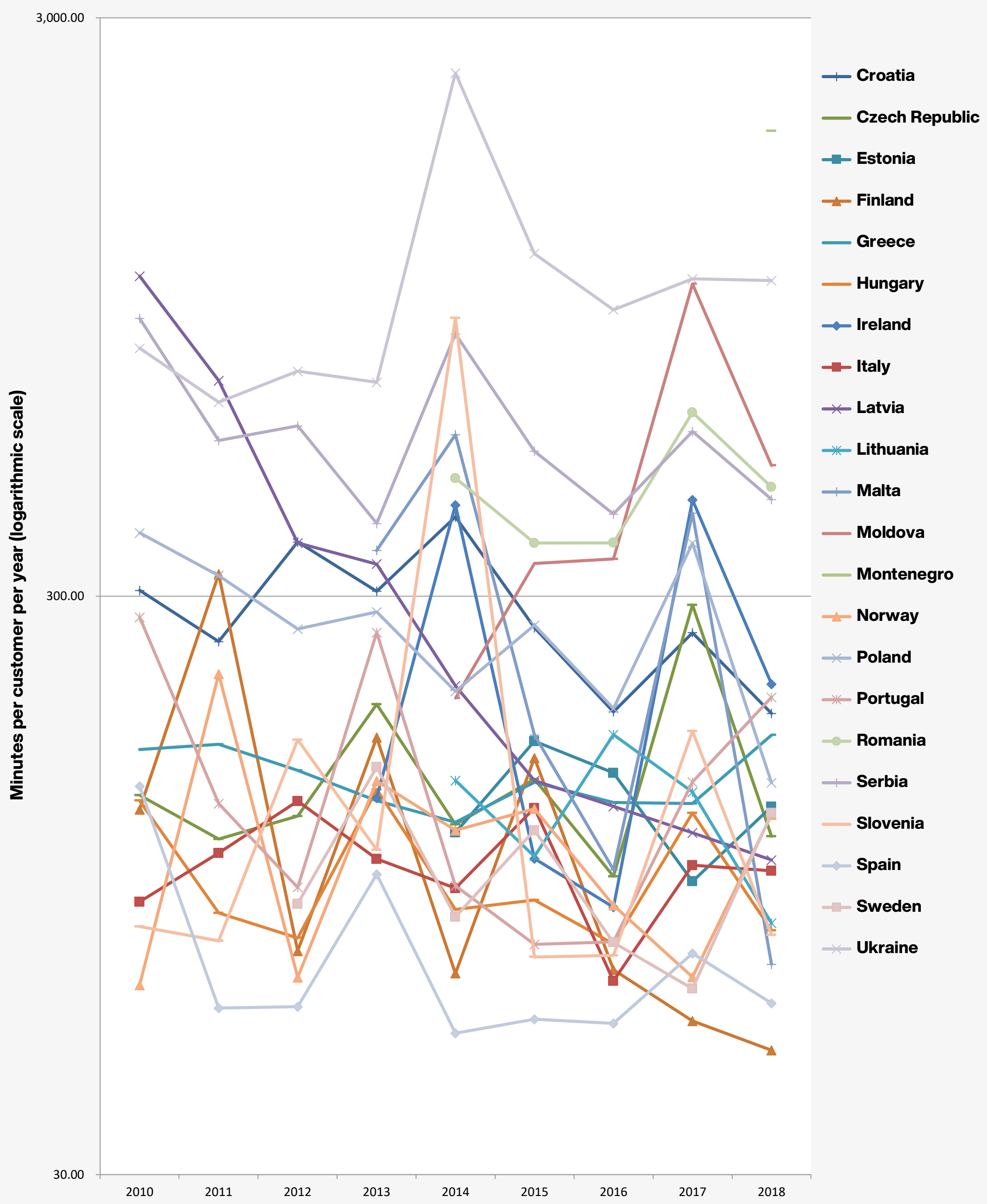


FIGURE 2-12: Unplanned long interruptions, SAIDI, all events (minutes per customer per year) – boxplot

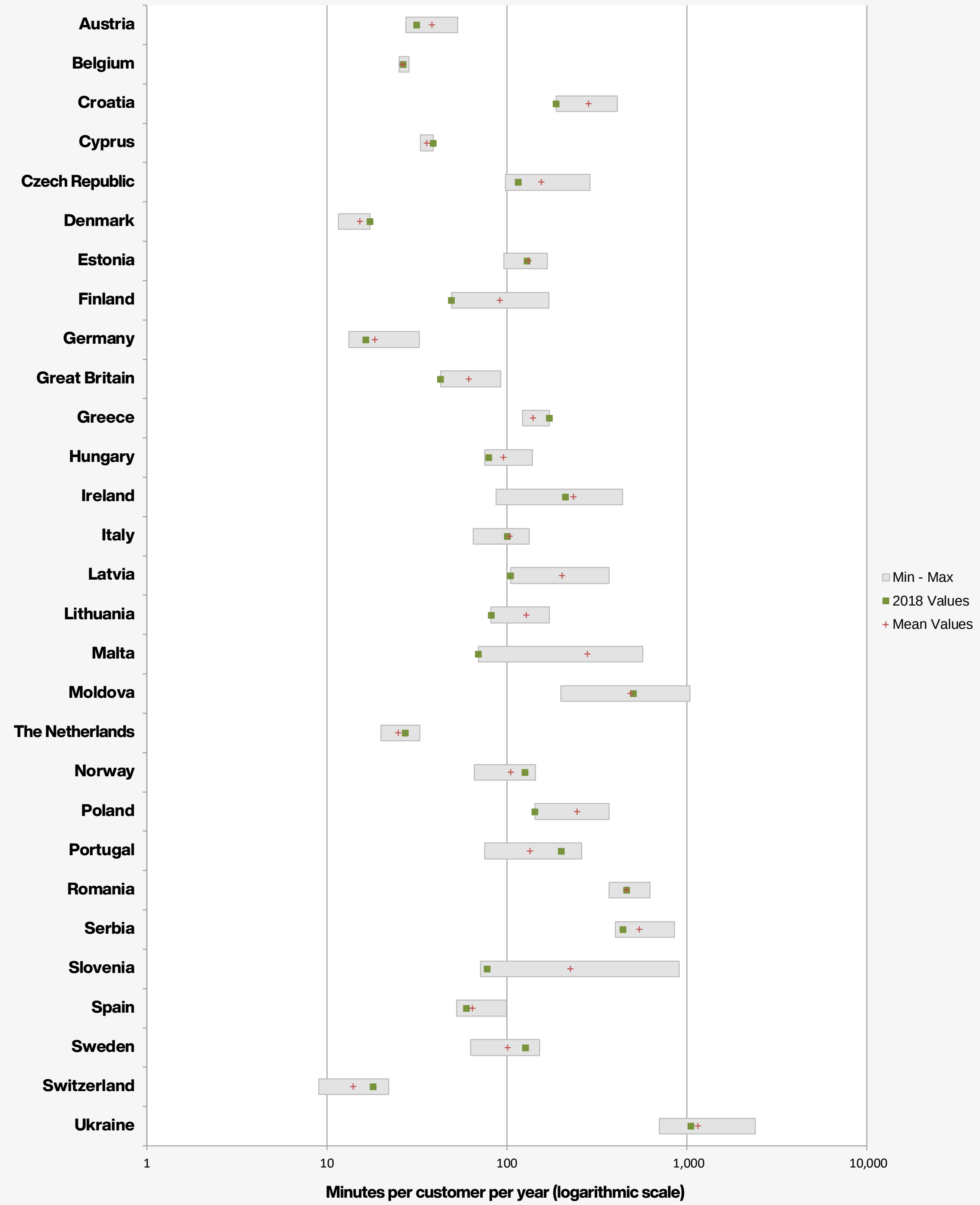


FIGURE 2-13: Unplanned long interruptions, SAIFI, all events (interruptions per customer per year) – time series

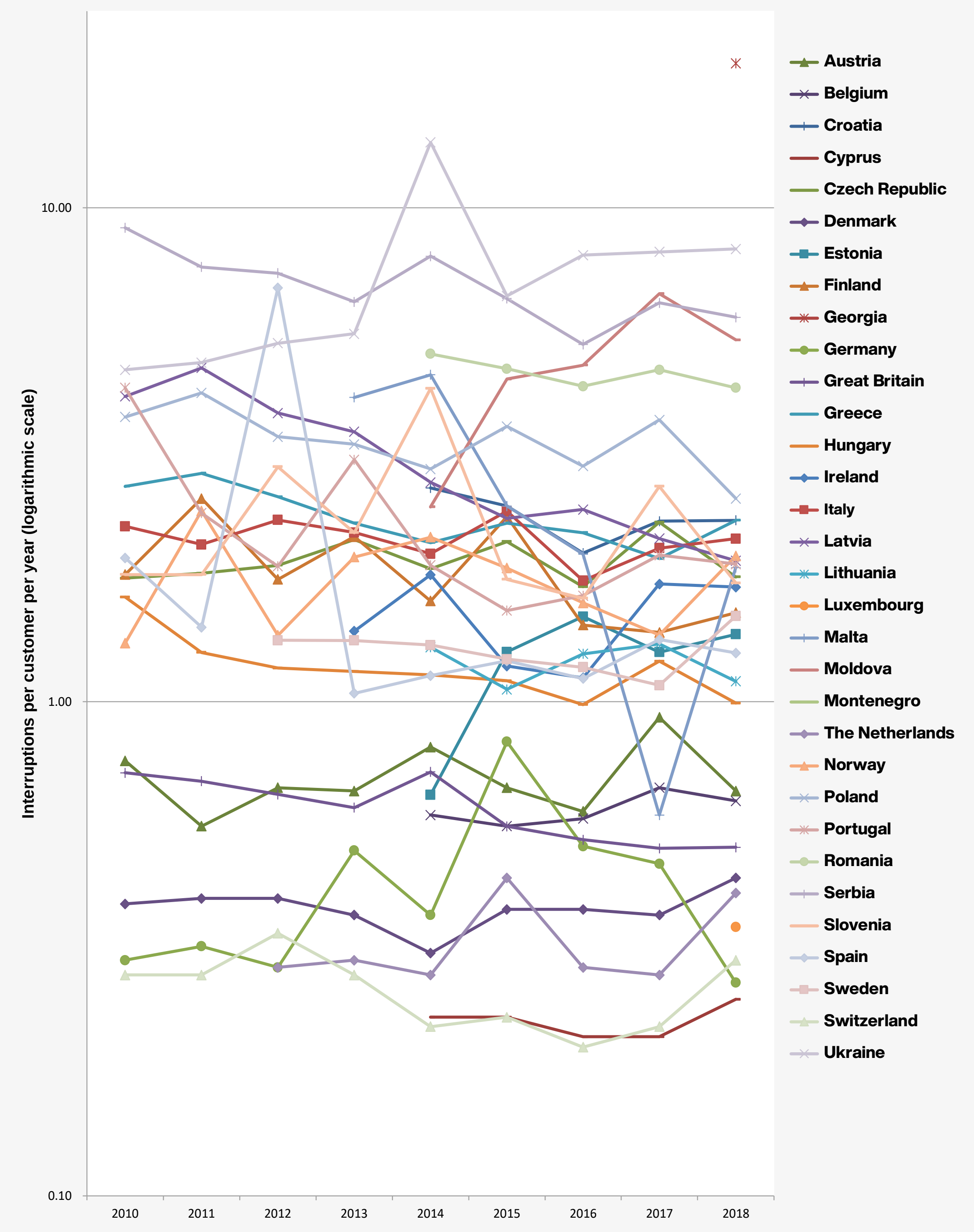


FIGURE 2-14: Unplanned long interruptions, SAIFI, all events (interruptions per customer per year) – countries not exceeding one interruption in any of the years in the time series

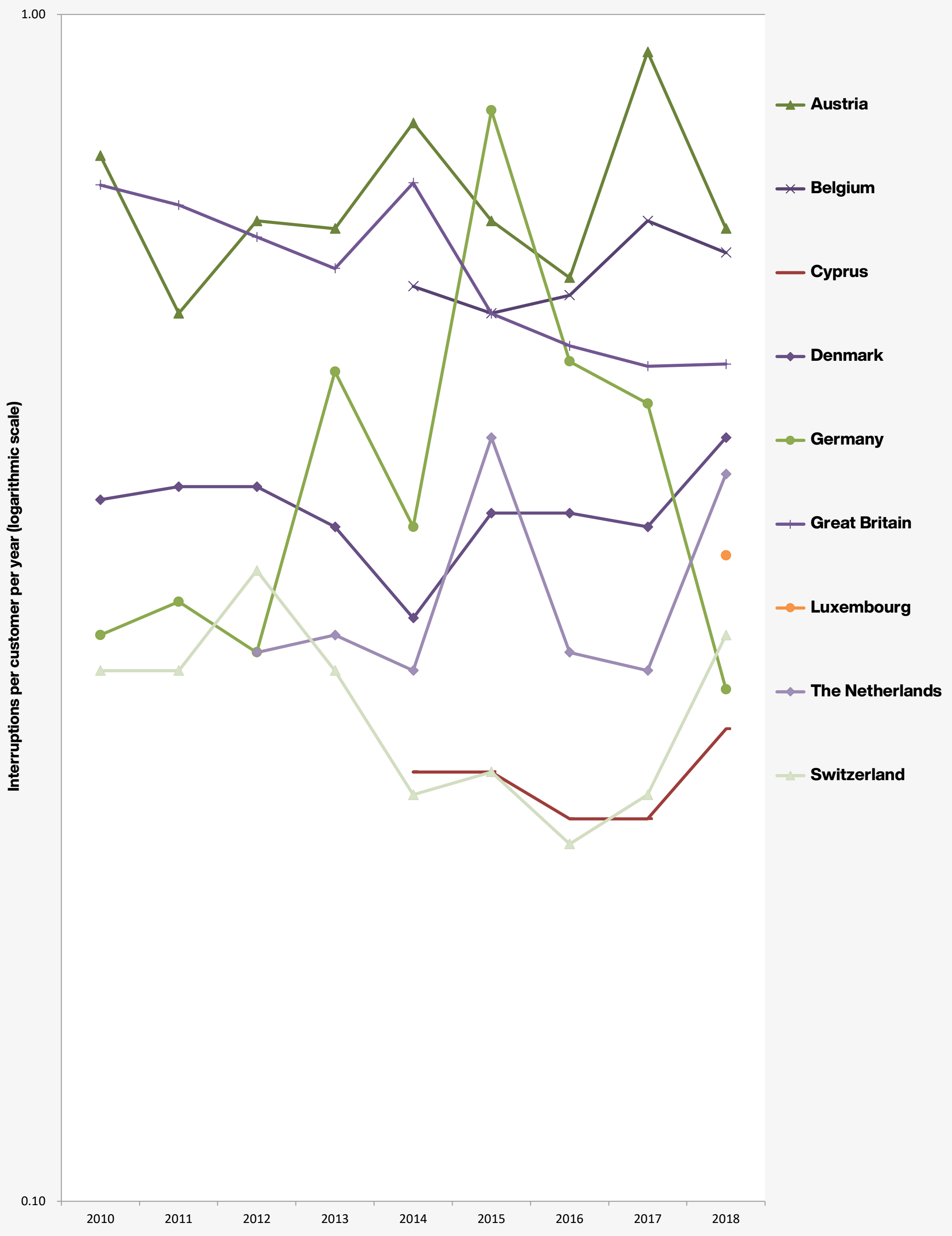


FIGURE 2-15: Unplanned long interruptions, SAIFI, all events (interruptions per customer per year) – countries exceeding one interruption in at least one year in the time series

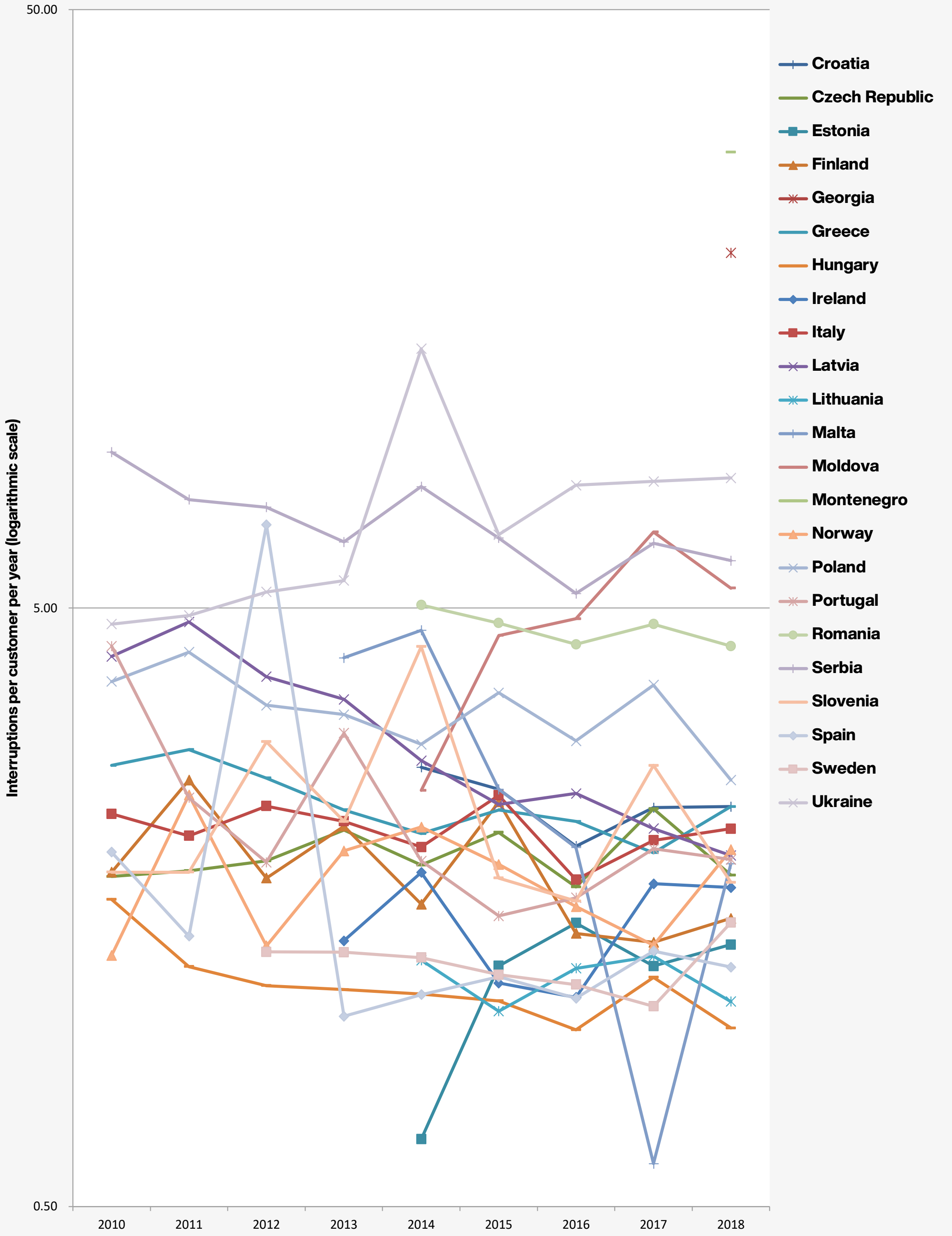


FIGURE 2-16: Unplanned long interruptions, SAIFI, all events (interruptions per customer per year) – boxplot

2.6.3 Unplanned long interruptions excluding exceptional events

Data were also obtained for SAIDI and SAIFI excluding exceptional events. When comparing the values without exceptional events between countries, significant care must be taken as each country has its own methodology and rules to determine what constitutes an exceptional event, making a direct comparison more difficult. In any case, the SAIDI and SAIFI values are lower than those that include all interruptions.

Figure 2-17 and Figure 2-20 show the minutes lost per customer per year (SAIDI) for unplanned interruptions excluding exceptional events as a time series and a boxplot, respectively. The values display less year-to-year variations than the values in figures where all interruptions are included. Figure 2-21 and Figure 2-24 show the number of interruptions per customer per year (SAIFI) as a time series and a boxplot, respectively.

As in the previous sections, Figure 2-18, Figure 2-19, Figure 2-22 and Figure 2-23 use cut-off limits to divide countries into two groups to make graphs easier to read.

FIGURE 2-17: Unplanned long interruptions excluding exceptional events, SAIDI (minutes per customer per year) – time series

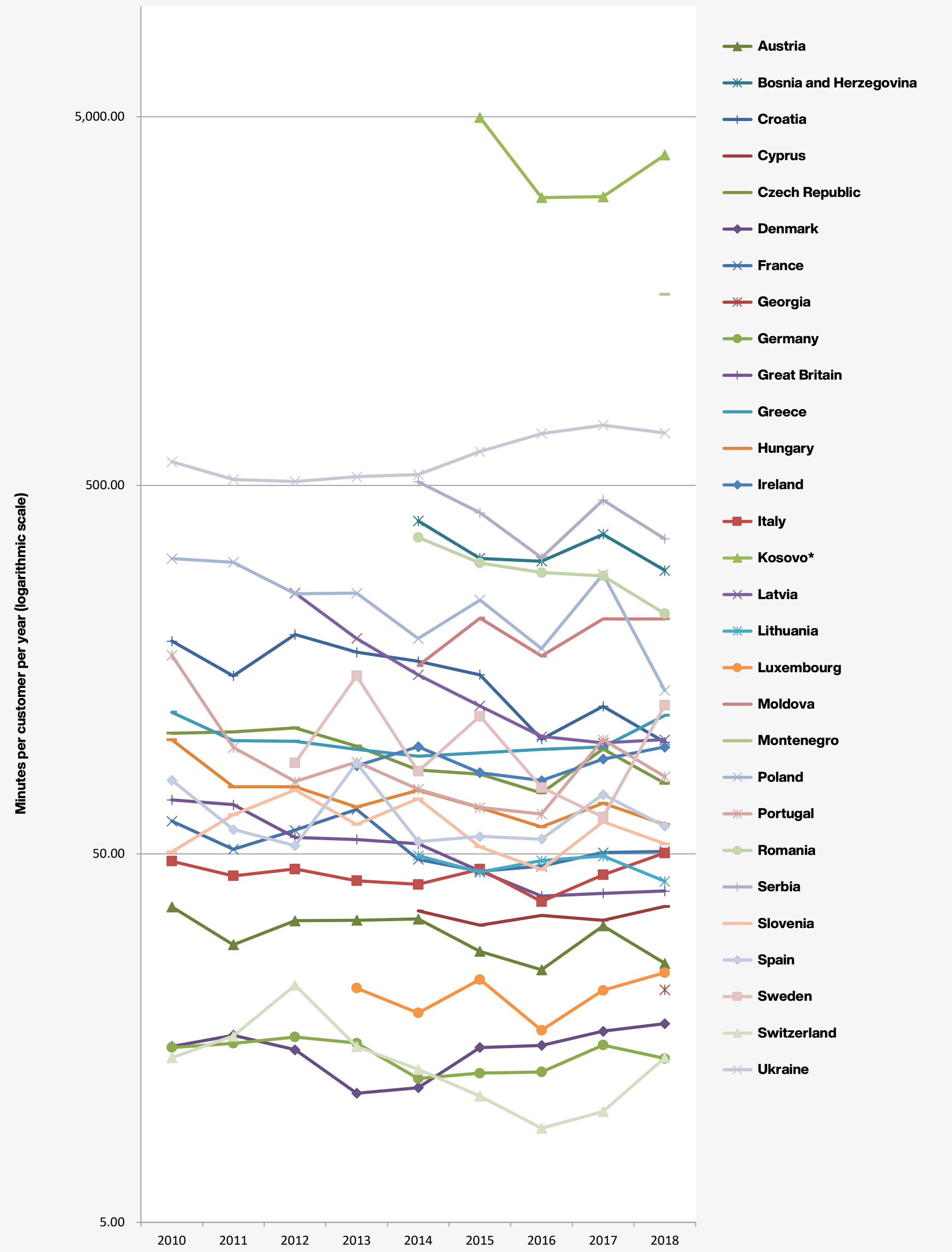


FIGURE 2-18: Unplanned long interruptions excluding exceptional events, SAIDI (minutes per customer per year) – countries not exceeding 100 minutes in any of the years in the time series

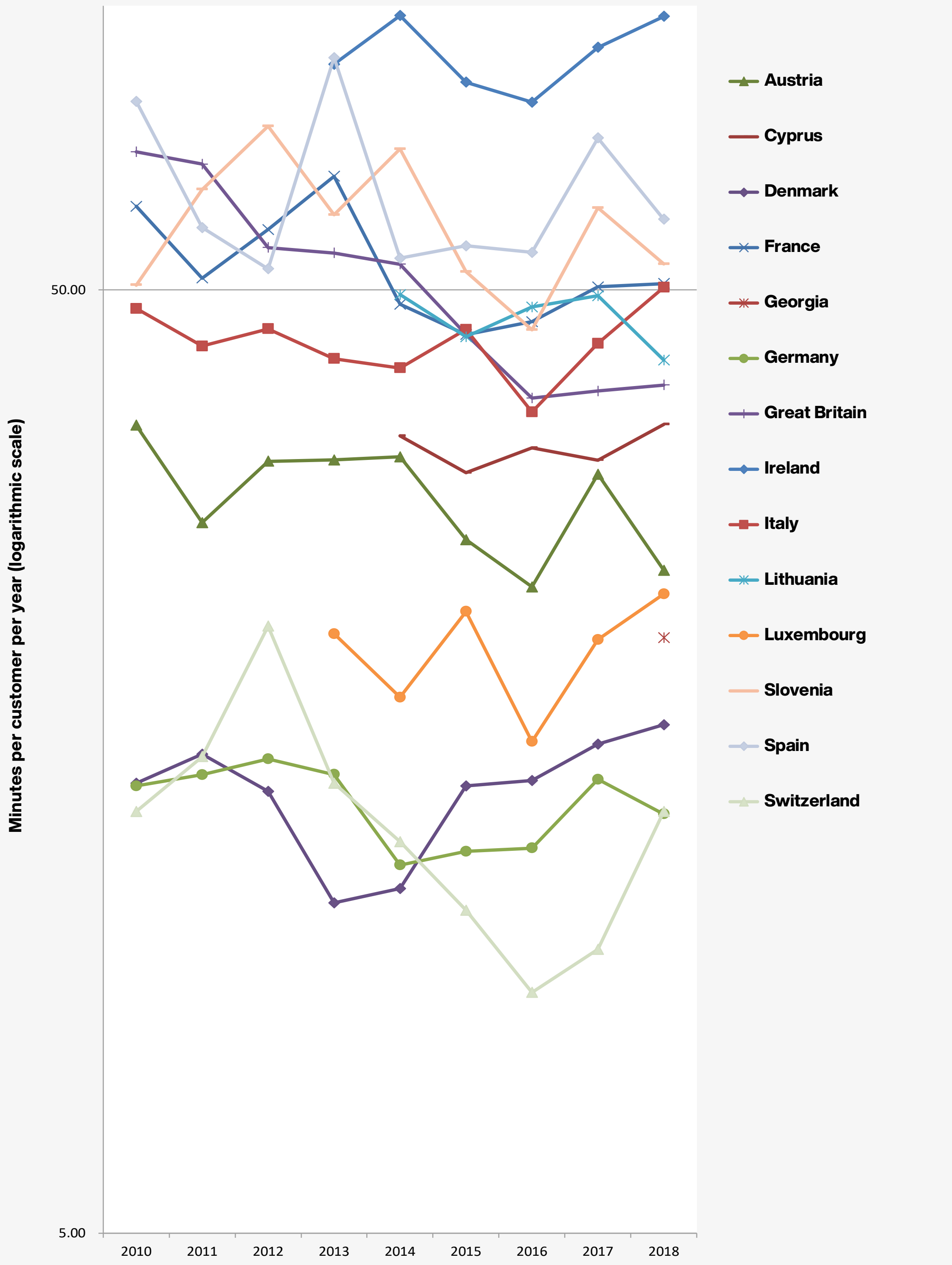


FIGURE 2-19: Unplanned long interruptions excluding exceptional events, SAIDI (minutes per customer per year) – countries exceeding 100 minutes in at least one year in the time series

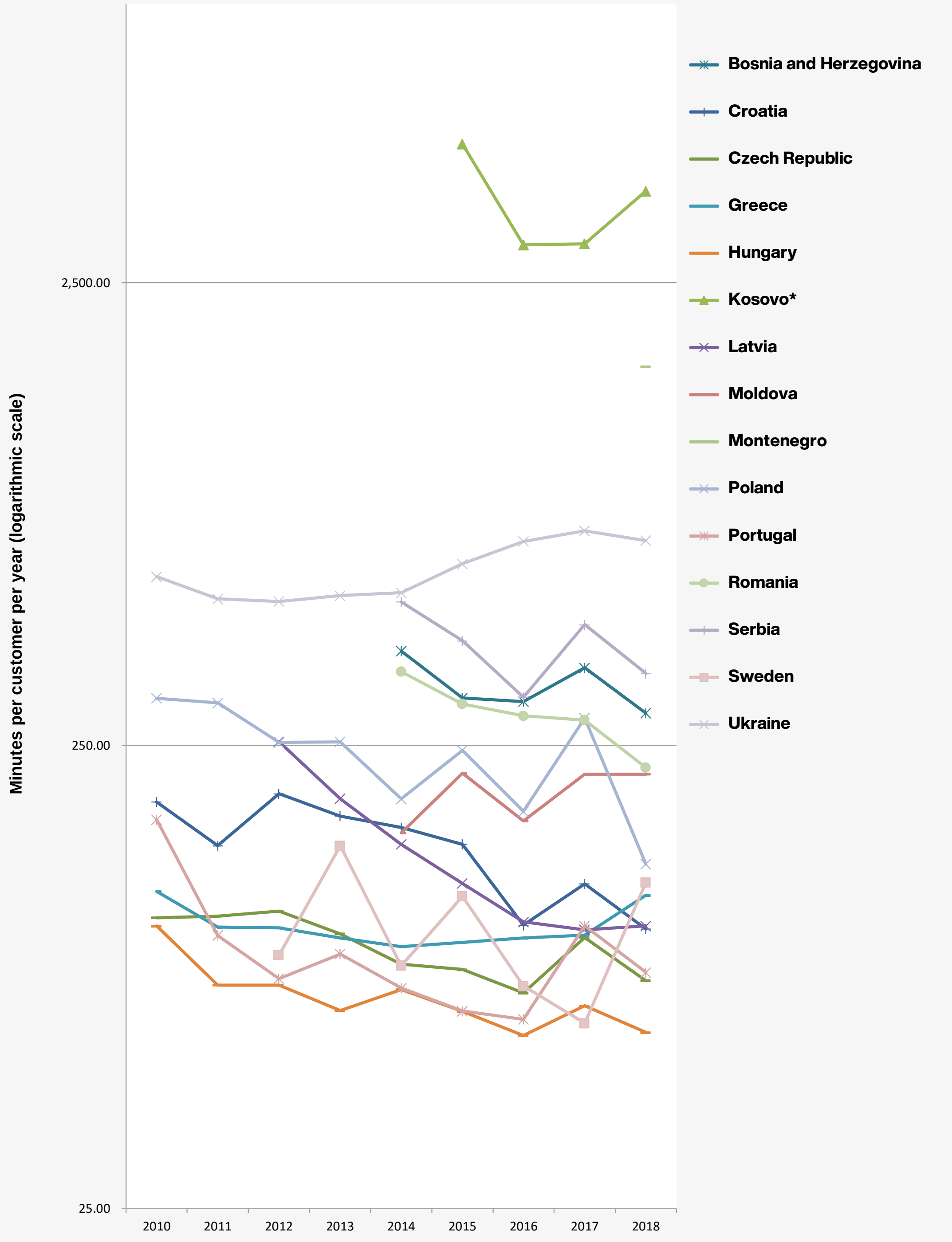


FIGURE 2-20: Unplanned long interruptions excluding exceptional events, SAIDI (minutes per customer per year) – boxplot

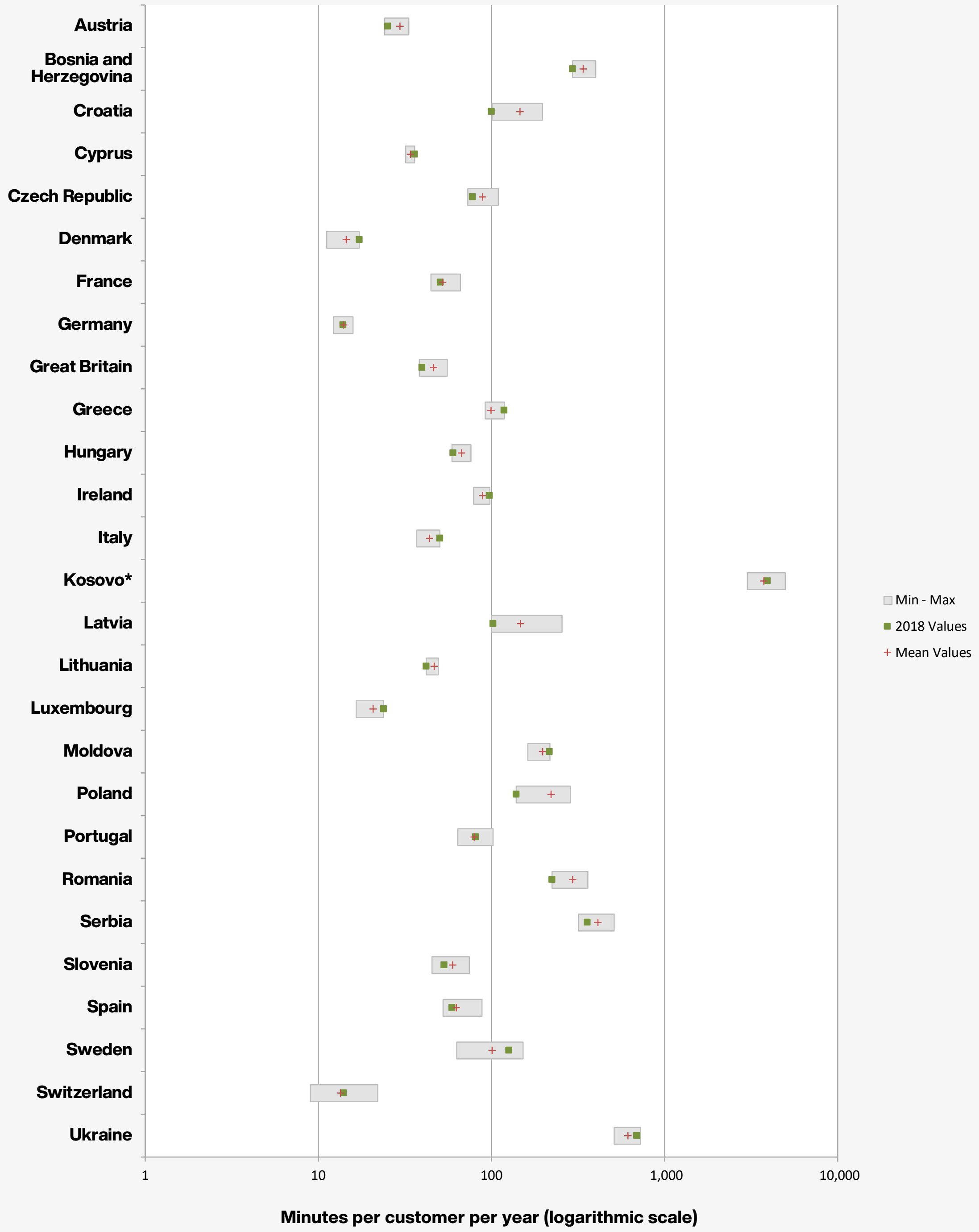


FIGURE 2-21: Unplanned long interruptions excluding exceptional events, SAIFI (interruptions per customer per year) – time series

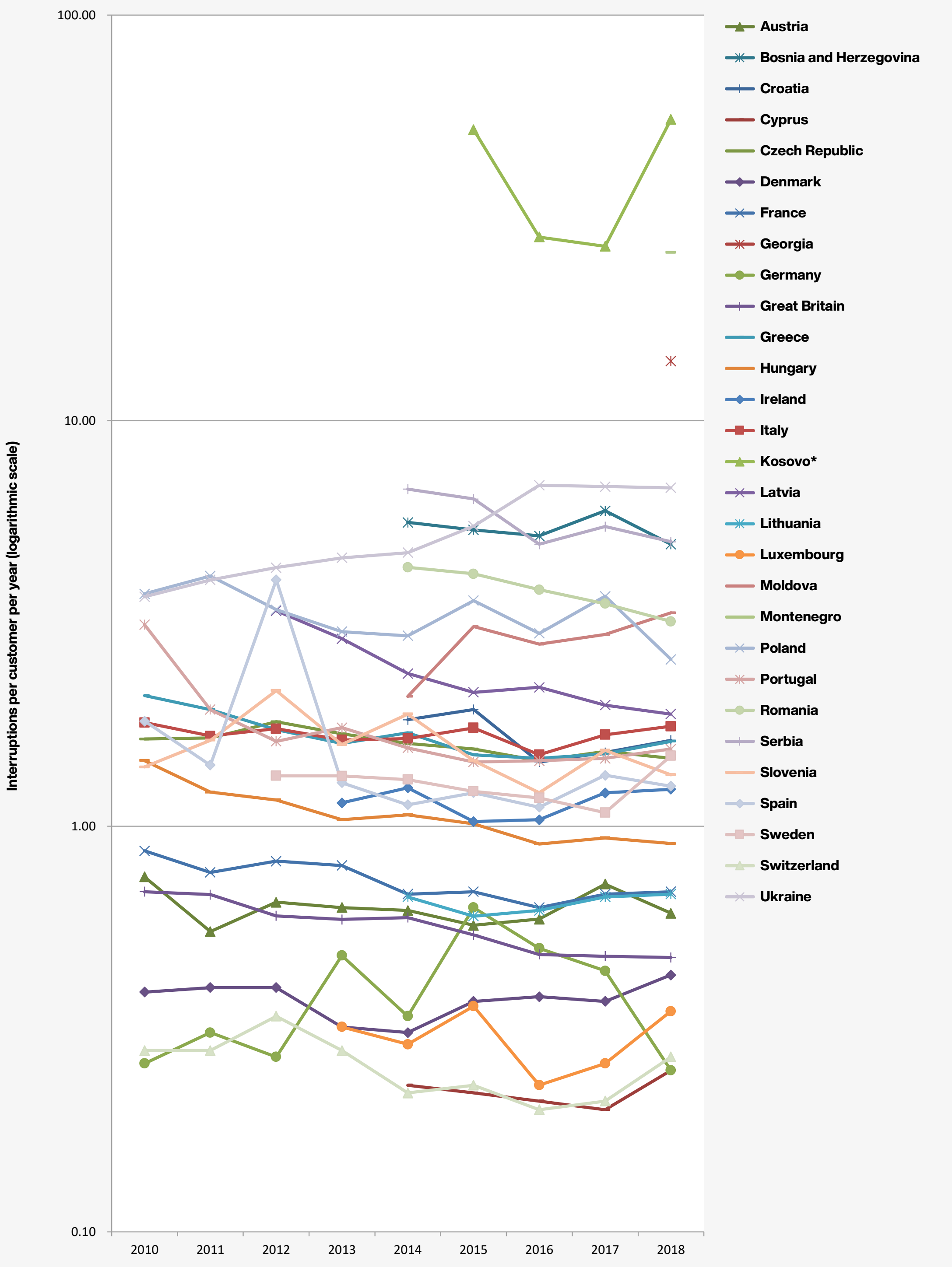


FIGURE 2-22: Unplanned long interruptions excluding exceptional events, SAIFI (interruptions per customer per year) – countries not exceeding one interruption in any of the years in the time series

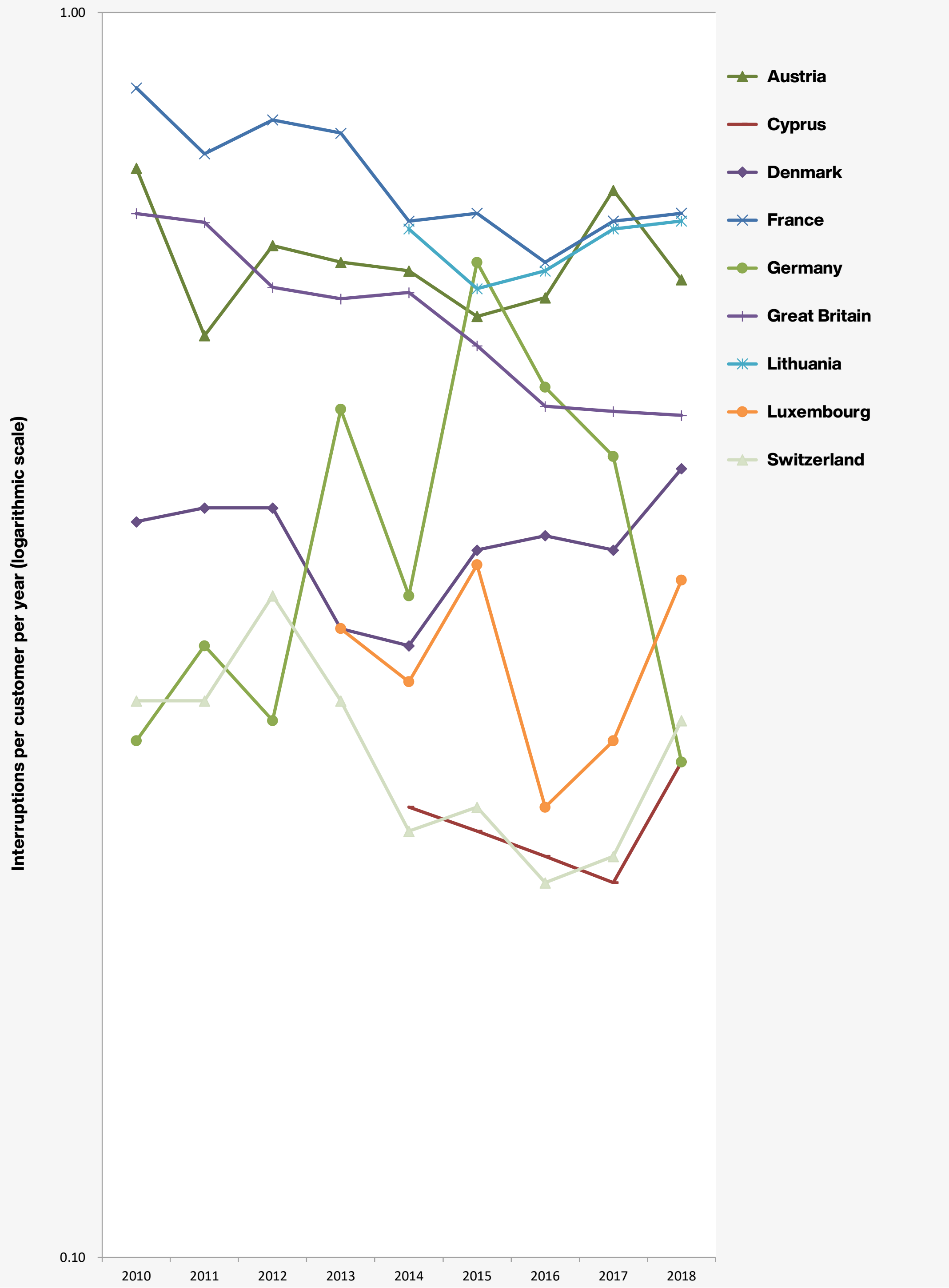


FIGURE 2-23: Unplanned long interruptions excluding exceptional events, SAIFI (interruptions per customer per year) – countries exceeding one interruption in at least one year in the time series

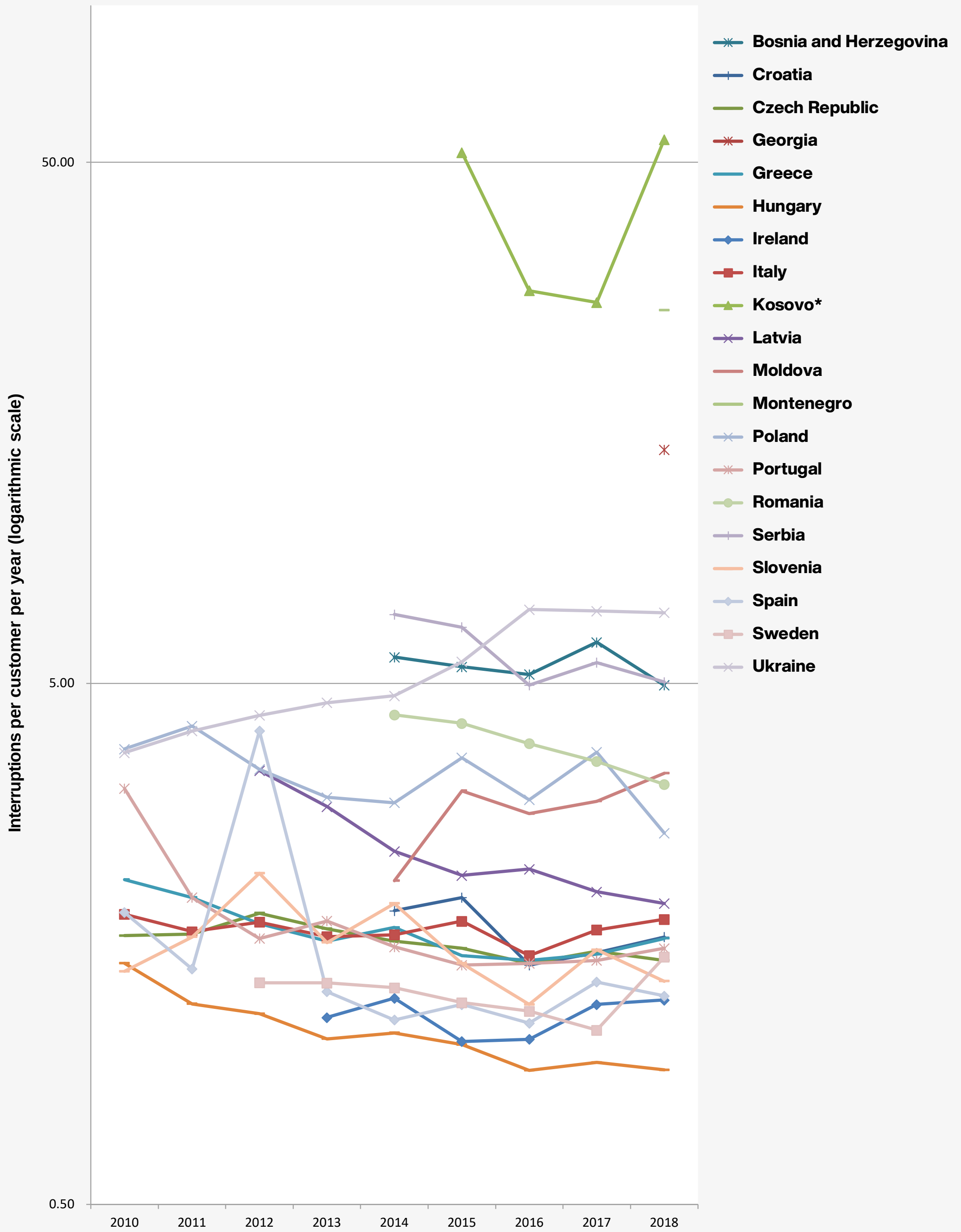
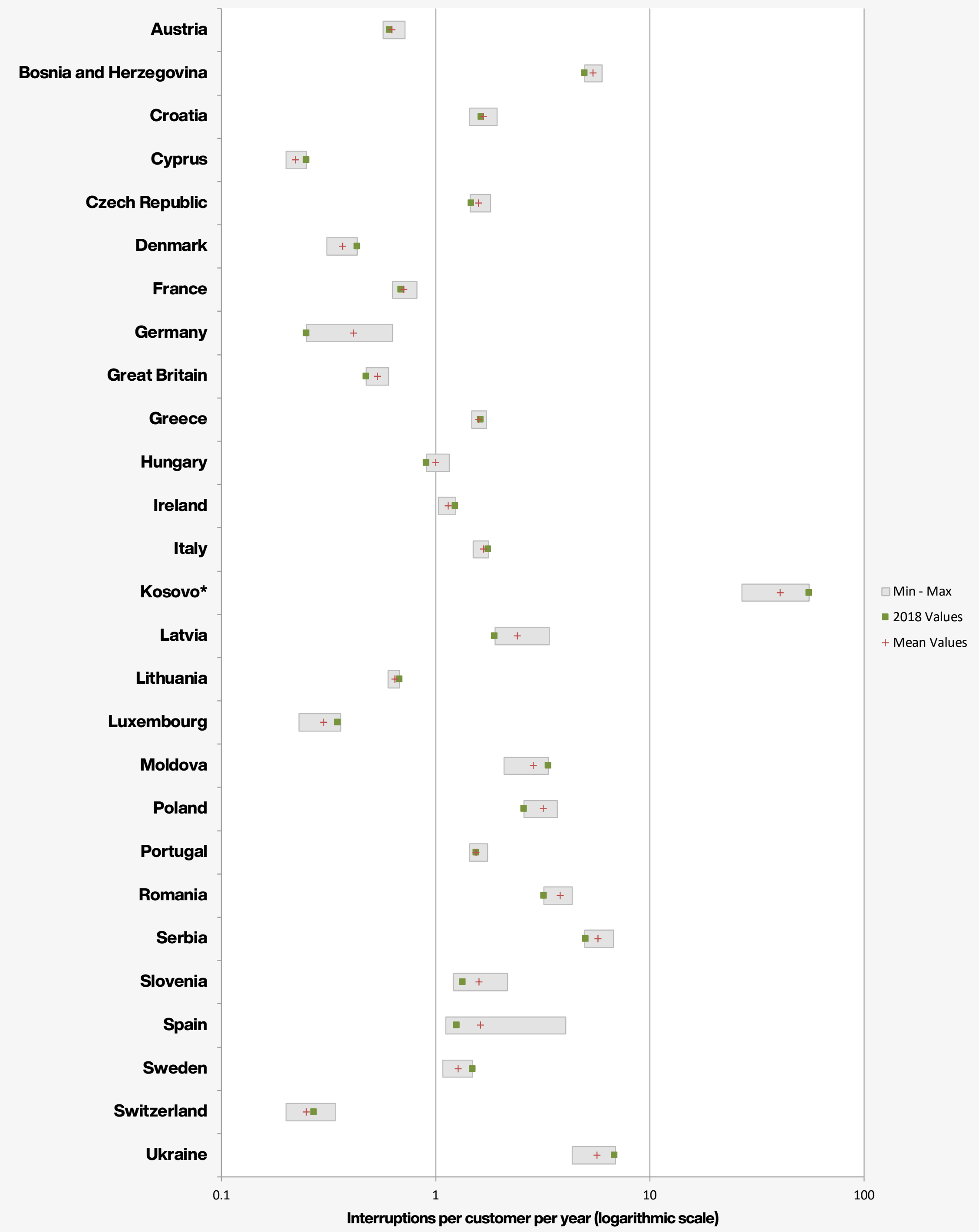


FIGURE 2-24: Unplanned long interruptions excluding exceptional events, SAIFI (interruptions per customer per year) – boxplot



2.6.4 Short interruptions

As previously explained, the three-minute mark is used to differentiate between short and long interruptions in most countries, but there are exceptions to this rule. Additionally, the few countries that have a definition of transient interruptions use the time limit of one second as a boundary between transient and short interruptions.

The most commonly used indicator for short interruptions is MAIFI which gives the average number of times per year that the supply to a customer is interrupted for a duration of three minutes or less. It is calculated in the same way as SAIFI, the difference being that only short interruptions are taken into consideration. Less than half of the participating countries are seen in figures where MAIFI values are illustrated since the indicator is not widely used. In the period between 2010 and 2018, the values varied between 0.05 and 14.27. It should be noted that the boxplot figure has one country less than the time series. This is due to Romania only providing its MAIFI value for 2018, making it impossible to calculate the values typically presented in boxplot graphs.

When calculating MAIFI, the so-called time aggregation rules are very important. As explained in the introduction to Section 2.6, multiple interruptions during a short period may be counted as one event or as multiple events. The rules on aggregation could significantly impact the value of MAIFI.

FIGURE 2-25: Unplanned interruptions, MAIFI (short interruptions per customer per year) – time series

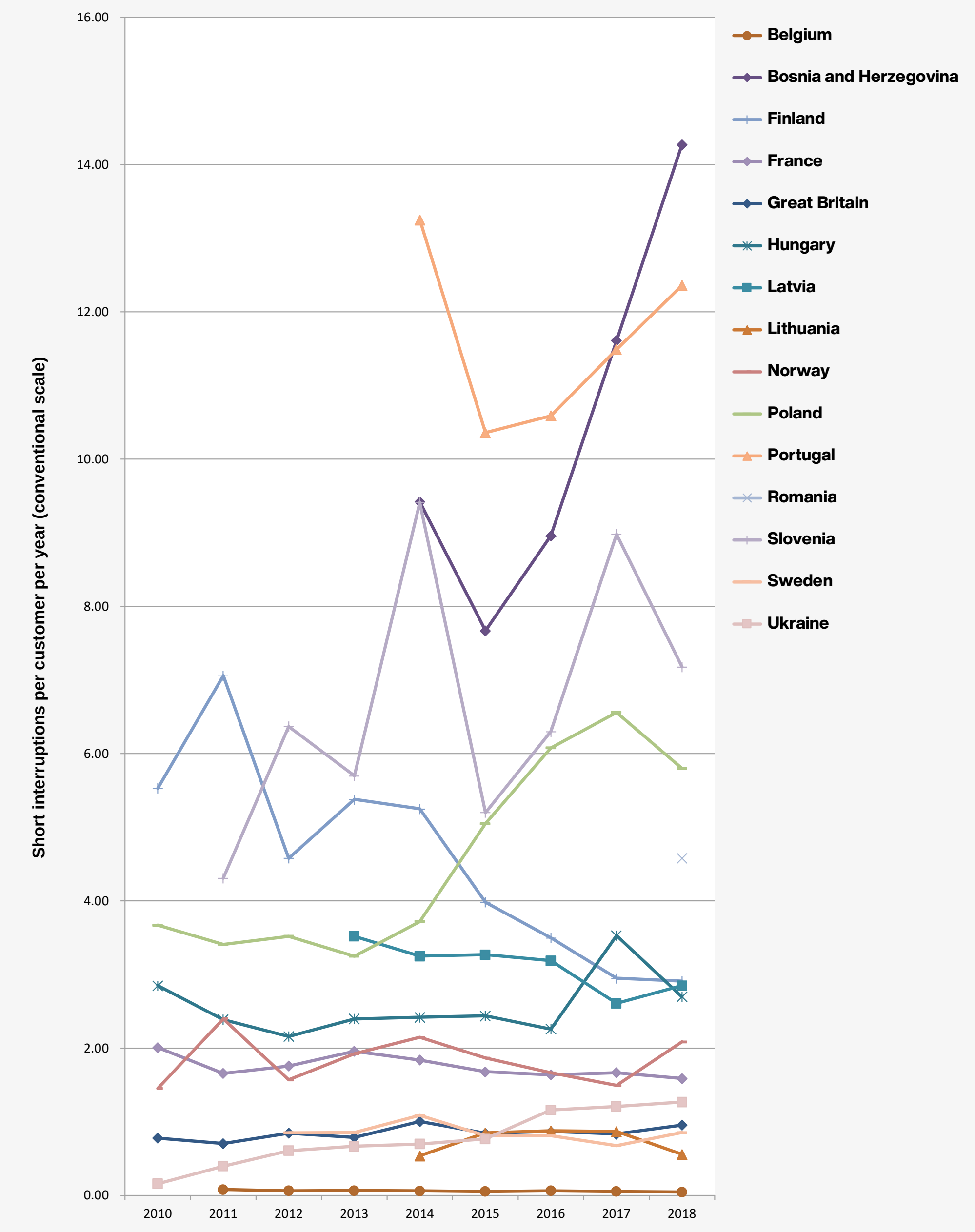
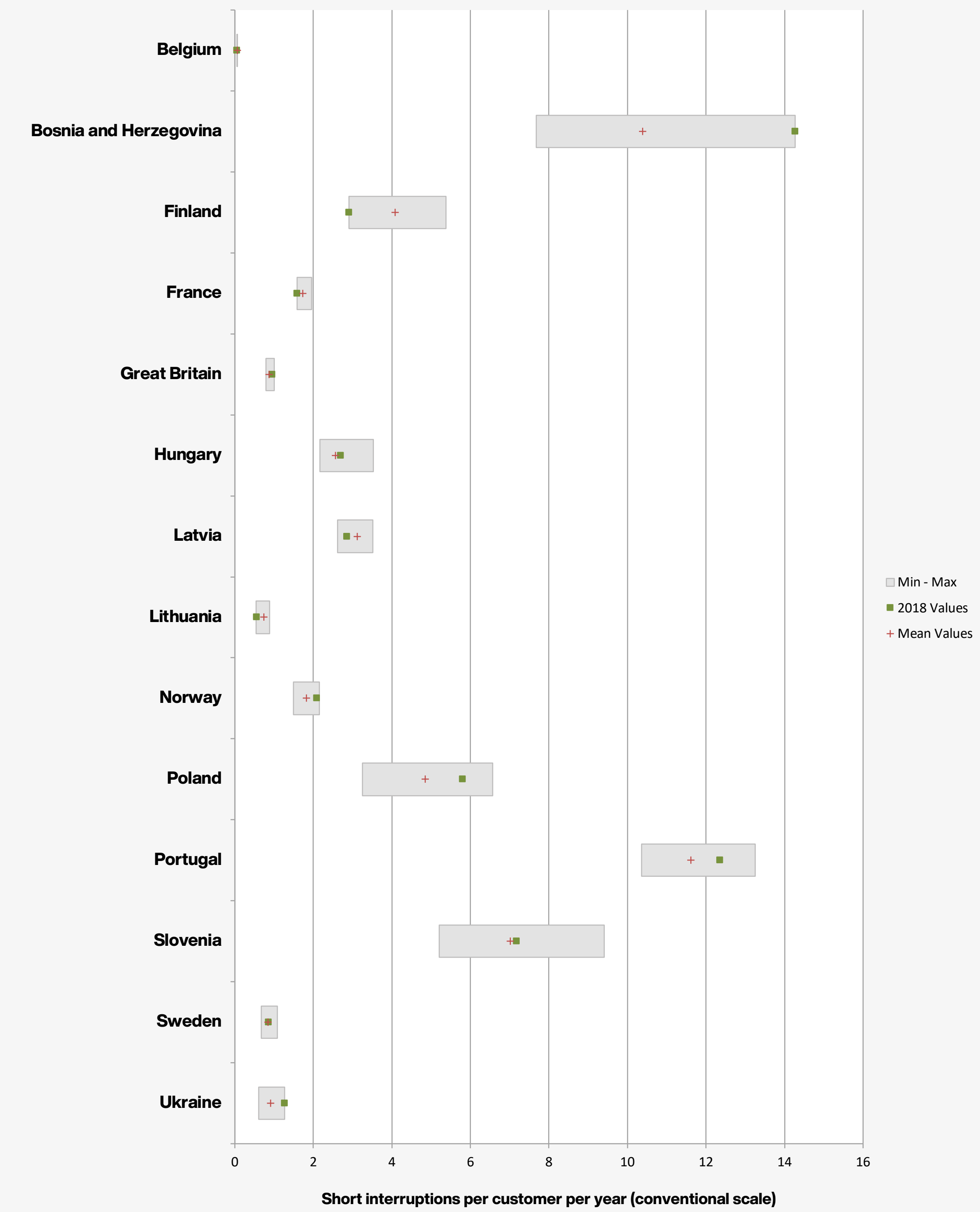


FIGURE 2-26: Unplanned interruptions, MAIFI (short interruptions per customer per year) – boxplot



2.6.5 Interruptions in transmission networks

Looking at Section 2.4.1 and Table 2-2, it is clear that what constitutes a transmission network can widely vary depending on the country. These country-specific definitions should be kept in mind when comparing the values of interruptions in transmission presented in the graphs that follow.

The most common indicators for measuring CoS in transmission networks are ENS and AIT. ENS is not exclusive to transmission and could also be used in distribution, but the questionnaire this Report is based on specifically asked for the values in transmission only. ENS gives the total amount of energy (in megawatt-hours (MWh)) that would have been supplied to users had there been no interruption. AIT is expressed in minutes per year and calculated as 60 times the ENS (in MWh) divided by the average power supplied by the system (in megawatts (MW)).

It is important to note that ENS can be applied to both long and short interruptions in countries where these interruption types are defined. This is different from the calculation of SAIDI for distribution networks, which normally refers only to long interruptions. The different definition can be explained by the meshed nature of transmission networks, which normally leads to shorter interruption times compared to interruptions in radial distribution networks. As a consequence of shorter interruption times, the impact of short interruptions on ENS and AIT indicators tends to be greater than their impact on SAIDI.

Unplanned AIT is presented in Figure 2-27 as a time series and Figure 2-28 as a boxplot. As in previous sections, the values show a very wide range among countries, from nearly zero to 2,250 minutes per year.

Unplanned ENS is presented in Figure 2-29 as a time series and Figure 2-30 as a boxplot. As with AIT, there are significant differences across Europe as the values range from 0.2 to over 59,000 MWh per year.

FIGURE 2-27: Average Interruption Time, AIT, unplanned (minutes per year) – time series

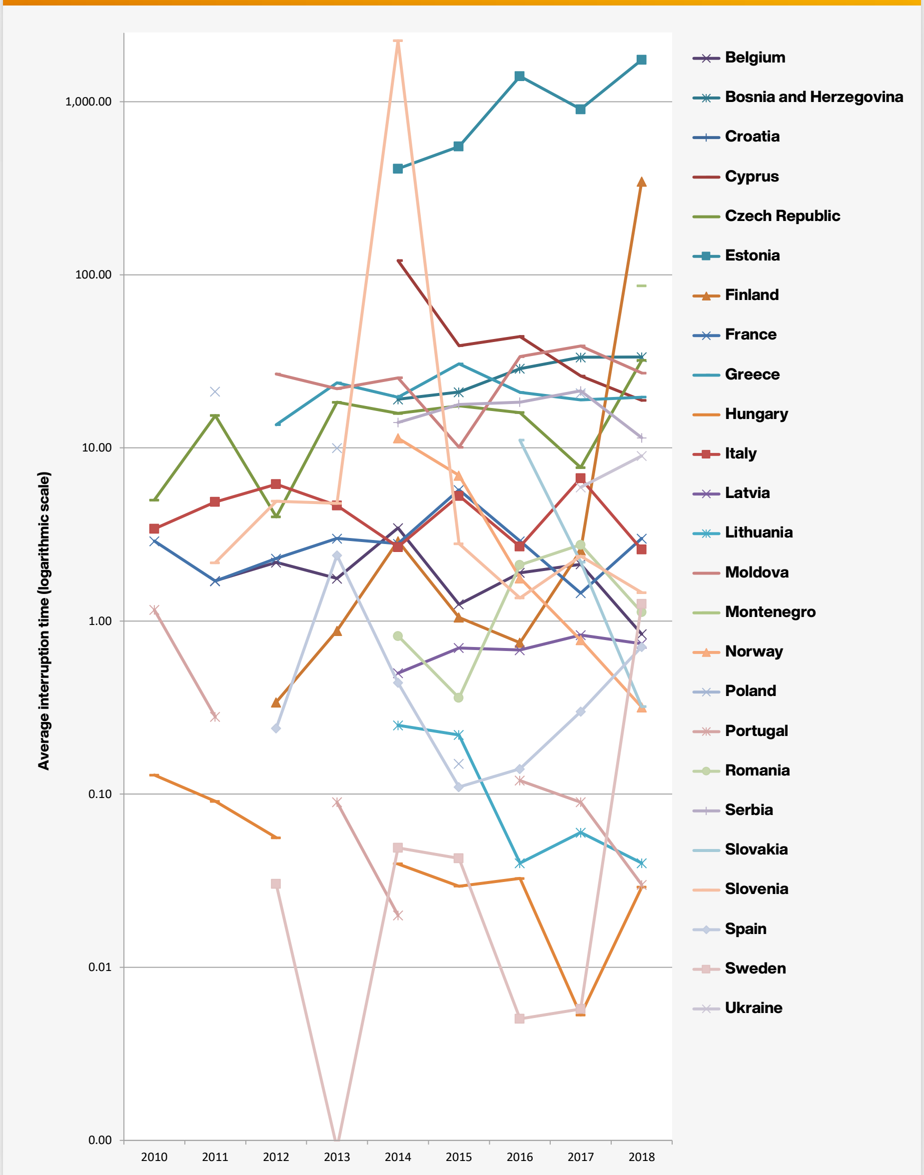


FIGURE 2-28: Average Interruption Time, AIT, unplanned (minutes per year) – boxplot

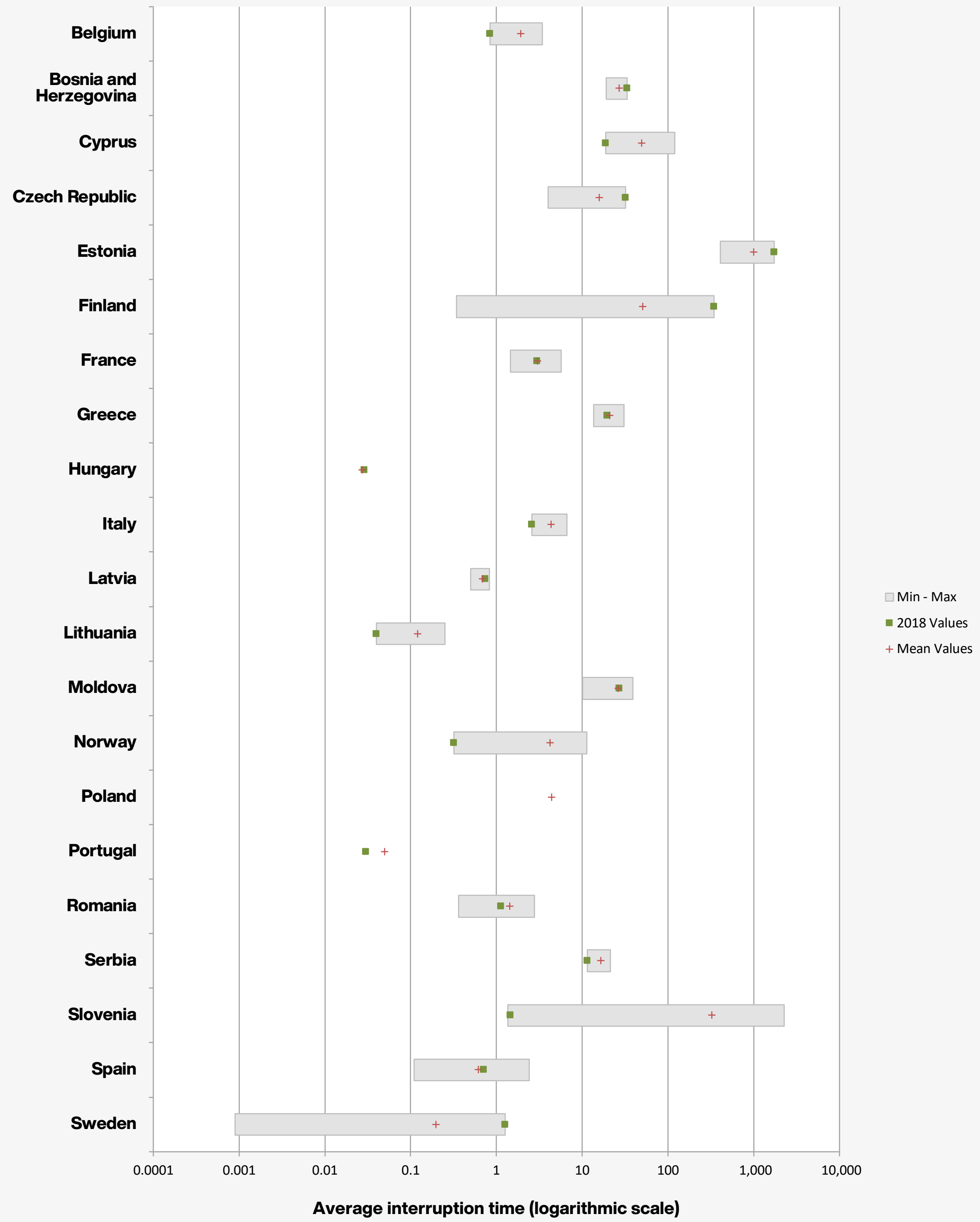


FIGURE 2-29: Energy Not Supplied, ENS, unplanned (MWh) – time series

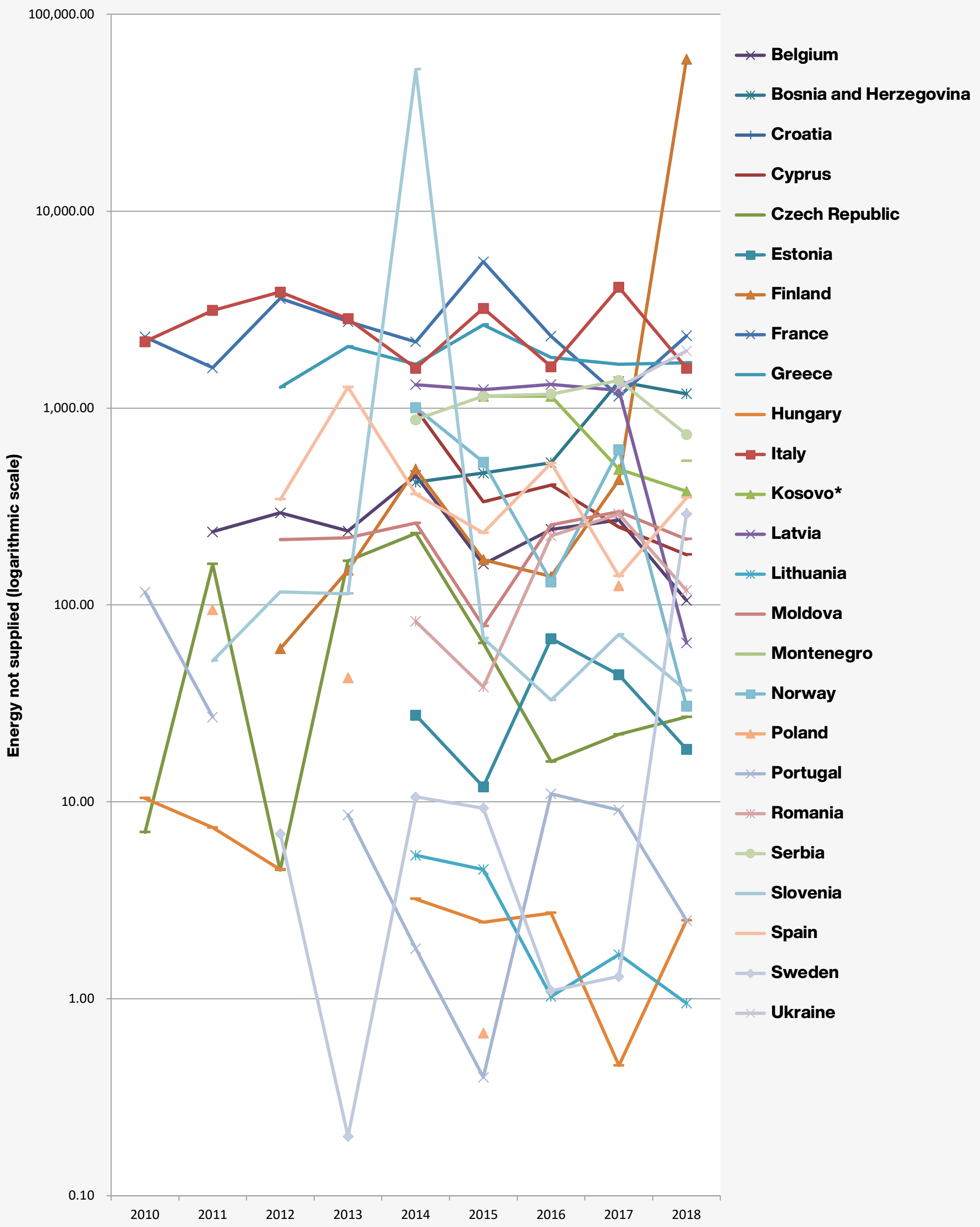


FIGURE 2-30: Energy Not Supplied, ENS, unplanned (MWh) – boxplot

2.6.6 Other indicators

In addition to indicators shown in previous sections (SAIDI, SAIFI, MAIFI, ENS and AIT), some countries use additional, less common indicators for CoS in their grid.

Austria uses ASIDI and ASIFI in addition to the more common SAIDI and SAIFI. The difference is that ASIDI (expressed in minutes per year) and ASIFI (expressed in interruptions per year) are weighted by the rated power rather than by the number of affected customers. Both these indicators are used for unplanned interruptions without exceptional events.

TABLE 2-14: ASIDI and ASIFI values in Austria

Indicator	2010	2011	2012	2013	2014	2015	2016	2017	2018
ASIDI	31.45	27.62	36.44	33.21	27.08	24.11	22.19	30.33	24.49
ASIFI	0.65	0.54	0.67	0.66	0.56	0.49	0.54	0.70	0.60

Table 2-8 shows that many countries employ CAIDI, which is the average interruption duration in minutes, or estimated sum of all interruption durations divided by the number of interruptions. One such country is **Belgium**, where this indicator is used in the regions of Flanders and Brussels. The values of CAIDI in Flanders were:

- 2014: 42.41;
- 2015: 44.13;
- 2016: 42.25;
- 2017: 43.66; and
- 2018: 41.72.

The region of Wallonia uses a similar indicator under a different name: 'Duration of Recovery'. It is a ratio of SAIDI and SAIFI. The values were:

- 2014: 48;
- 2015: 46;
- 2016: 83;
- 2017: 44; and
- 2018: 43.

Croatia started monitoring CAIDI in 2018. That year, the value of CAIDI for unplanned interruptions was 80.87 while that of planned interruptions was 153.14.

Estonia also monitors CAIDI for planned and unplanned interruptions.

TABLE 2-15: CAIDI values in Estonia

	2014	2015	2016	2017	2018
CAIDI unplanned	180.60	133.50	99.80	76.40	94.77
CAIDI planned	138.00	147.00	156.00	155.00	152.00

Finland has indicators for 'Standard Compensations' which can either refer to the total paid compensation in euros or the number of customers who received them. Compensation is paid if a single interruption lasts for over 12 hours. The amount is higher for longer interruptions up to a maximum of €2,000.

TABLE 2-16: Standard compensations in Finland

	2013	2014	2015	2016	2017	2018
Total paid (€)	22,840,460	1,412,315	21,287,029	7,361,479	4,913,083	2,321,306
Number of compensated customers	251,785	32,737	230,573	104,851	36,801	22,884

Ireland has indicators 'Worst-served Customer' (including and excluding storms) and 'System Minutes Lost'. The former is defined as a customer who has experienced 15 or more outages over three years, which includes at least five outages in the most recent year. The latter is only used in transmission and is defined as an index that measures the severity of each system disturbance relative to the size of the transmission system. It is determined by calculating the ratio of unsupplied energy during an outage to the energy that would be supplied during one minute, if the supplied energy was at its peak value.

TABLE 2-17: Other indicators in Ireland

	2013	2014	2015	2016	2017	2018
Worst-served customers including storms	47,475	99,421	75,810	58,294	75,902	104,261
Worst-served customers excluding storms	23,163	38,993	42,745	31,916	31,530	36,664
System minutes lost (transmission)			0.05	0.57	0.30	0.41

Latvia also uses CAIDI without exceptional events. CAIDI can also be viewed as the average restoration time. The values were:

- 2013: 66;
- 2014: 64;
- 2015: 59;
- 2016: 47;
- 2017: 51; and
- 2018: 54.

Values for CAIDI are available in **North Macedonia**, but CAIDI is not used as an indicator.

Two unique indicators are in use in **Romania**: INDLIN (average unavailability of the overhead lines) and INDTRA (average unavailability of transformers and autotransformers). They are both monitored for planned and unplanned events and expressed in hours per year. No values were provided for these two indicators.

TABLE 2-18: Transmission indicators in Slovenia

Transmission indicators	2011	2012	2013	2014	2015	2016	2017	2018
SAIDI excluding exceptional events	2.11	3.07	6.35	3,678.61	4.82	1.67	73.40	0.99
SAIDI all events	3.20	25.77	17.26	3,680.32	4.82	1.67	73.97	1.04
SAIFI excluding exceptional events	0.06	0.19	0.11	0.25	0.16	0.05	0.22	0.04
SAIFI all events	0.17	0.42	0.22	0.45	0.16	0.05	0.27	0.05

In **Slovakia**, ISS is defined as the ratio of the volume of electricity not delivered to consumers (due to unplanned interruptions in distribution caused by a failure of the distribution system) to the total volume of electricity supplied to the consumers. It is calculated for each DSO, and it typically does not surpass 0.0005 per calendar year. The reported values are:

- 2016: 0.0001;
- 2017: 0.0001; and
- 2018: 0.0002.

In addition to using SAIDI and SAIFI in distribution, **Slovenia** also has unplanned SAIDI and SAIFI (with and without exceptional events) in transmission where it refers to HV and EHV levels.

2.6.7 Technical characteristics of electrical grids

Table 2-19 shows the length of circuits in countries that provided data in the questionnaire. Circuits are categorised by voltage level (LV, MV, HV and EHV) and, on LV and MV level, by type: underground cable circuits and overhead lines (both bare and insulated). It should be noted that voltage levels have different definitions in different countries and that not all countries have all voltage levels categorised in this way. It is recommended to consult Table 2-1 in Section 2.4.1 of this Report.

Additionally, according to the questionnaire, subsea cable circuits should be included in total length of circuits, but not in underground cable circuits. Therefore, any larger differences between total length of circuits and the sum of underground cable circuits and overhead lines should be attributed to subsea cable circuits. This is the case in Norway, where subsea cables in MV have the length of 2,019 km, which is the exact difference between their total length of circuits and their sum of overhead lines and underground cables in MV. The same applies to LV where the difference of 414 km is also due to subsea cables. In the same way, Greece has approximately 1,001 km of subsea cables on MV, which is included in the total length of circuits, but not in the underground cables. Smaller differences (of one to two km) can be attributed to rounding and other errors, and as such were ignored.

TABLE 2-19: Length of circuits in European countries in 2018 (km)

Country	LV				MV				HV	EHV
	Total length of circuits	Length of underground cable circuits	Length of overhead lines	Percentage of underground cables	Total length of circuits	Length of underground cable circuits	Length of overhead lines	Percentage of underground cables	Total length of circuits	Total length of circuits
Albania	24,973	1,835	23,138	7.3%	16,350				3,388	
Austria	173,570	142,584	30,987	82.1%	67,864	43,086	24,778	63.5%	11,507	6,763
Belgium	128,758	81,195	47,563	63.1%	76,787	71,736	5,051	93.4%	9,400	1,975
Bosnia and Herzegovina	70,952	6,147	64,804	8.7%	27,572	5,595	21,977	20.3%	6,402	
Croatia[84]	97,058	30,119	66,938	31.0%	41,731	17,872	23,471	42.8%	5,298	2,493
Cyprus	16,482	6,411	10,071	38.9%	9,881	3,940	5,941	39.9%	1,357	
Denmark[85]	89,123	89,069	54	99.9%	60,729	60,266	331	99.2%	8,190	
Estonia	35,745	11,034	24,711	30.9%	29,307	9,012	20,295	30.7%	3,568	1,943
Finland	249,183	122,354	126,829	49.1%	151,783	48,139	103,644	31.7%	16,341	7,039
France	721,000	330,015	390,985	45.8%	644,901	319,782	325,119	49.6%	80,000	25,000
Germany[86]	1,200,500	1,088,821	111,686	90.7%	519,200	424,404	94,807	81.7%	94,600	36,700
Great Britain	392,789	333,055	59,735	84.8%					330,882	55,006
Greece	126,941	15,045	111,894	11.9%	112,295	11,030	100,264	9.8%	12,945	4,736
Hungary	87,999	23,163	64,836	26.3%	67,202	13,616	53,586	20.3%	8,465	4,645
Ireland	72,552	13,255	59,297	18.3%	93,705	10,027	83,678	10.7%	14,390	
Italy	873,393	332,572	540,821	38.1%	394,584	180,450	214,134	45.7%	48,766	22,319
Kosovo*	20,088	2,534	17,555	12.6%	7,637	1,452	6,184	19.0%	1,377	
Latvia	57,634	25,360	32,274	44.0%	35,541	7,876	27,665	22.2%	5,339	
Lithuania	69,910	22,625	47,285	32.4%	55,166	15,051	40,115	27.3%	7,144	
Luxembourg	6,777	6,450	327	95.2%	4,087	3,099	988	75.8%	821	345
Malta[87]	3,376	1,275	2,101	37.8%	1,595	1,505	75	94.4%	91	118
Moldova	33,163				21,829				5,732	
Montenegro	13,294	2,073	11,221	15.6%	6,224	1,711	4,513	27.5%	1,351	
Netherlands, The	148,376	148,315	61	100.0%	106,463	106,463	0	100.0%	9,759	3,023
North Macedonia	16,406	4,145	12,261	25.3%	11,657	3,047	8,610	26.1%	2,447	
Norway[88]	212,319[89]	124,118	87,787	58.5%	103,758[90]	43,983	57,756	42.4%	19,138	12,608
Poland	469,207	161,442	307,765	34.4%	298,872	79,838	219,034	26.7%	33,769	14,888
Portugal	142,834	33,543	109,291	23.5%	73,042	14,436	58,606	19.8%	9,516	8,907
Romania	183,723	50,820	132,905	27.7%	120,313	30,137	90,176	25.0%	22,245	8,850
Serbia	115,639	16,638	99,002	14.4%	53,537	14,197	39,340	26.5%	9,980	
Slovakia	55,083								33,649	6,880
Slovenia	45,009	24,734	20,275	55.0%	18,009	6,440	11,569	35.8%	2,823	997
Spain	456,479	195,528	260,951	42.8%	278,195	87,363	190,832	31.4%	117,547	21,079
Sweden	319,373	265,039	54,334	83.0%	202,723	132,267	70,456	65.2%	31,057	14,903
Switzerland	144,783	137,120	7,663	94.7%	44,765	35,307	9,458	78.9%	8,683	6,652
Ukraine	422,469	34,844	387,625	8.2%	372,057	42,755	329,302	11.5%	35,984	19,933

84 Length of subsea cable circuits on MV is 388 km.
85 Length of subsea cable circuits on MV is 132 km.
86 Differences between the total length of circuits and the sum of the lengths of underground cables and overhead lines are most likely due to rounding errors.
87 Length of subsea cable circuits on MV is 14.5 km.
88 132 kV level grid is included in both EHV and HV, depending on if it is classified as transmission grid or not.
89 The length of subsea cables in LV is 414 km.
90 The length of subsea cables in MV is 2,019 km.

Figure 2-31 and Figure 2-32 show the length of underground cable circuits and overhead lines for LV and MV levels. As mentioned above, this equates to total length of circuits without the subsea cable circuits, if any.

FIGURE 2-31: Length of LV circuits in 2018 (km)

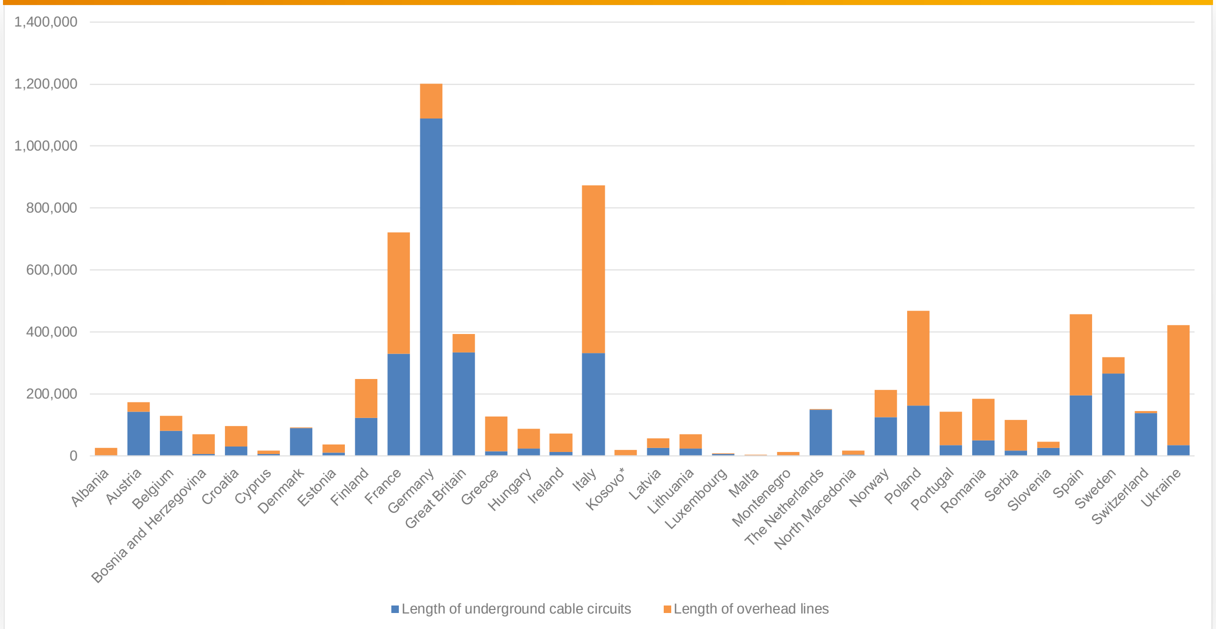


FIGURE 2-32: Length of MV circuits in 2018 (km)

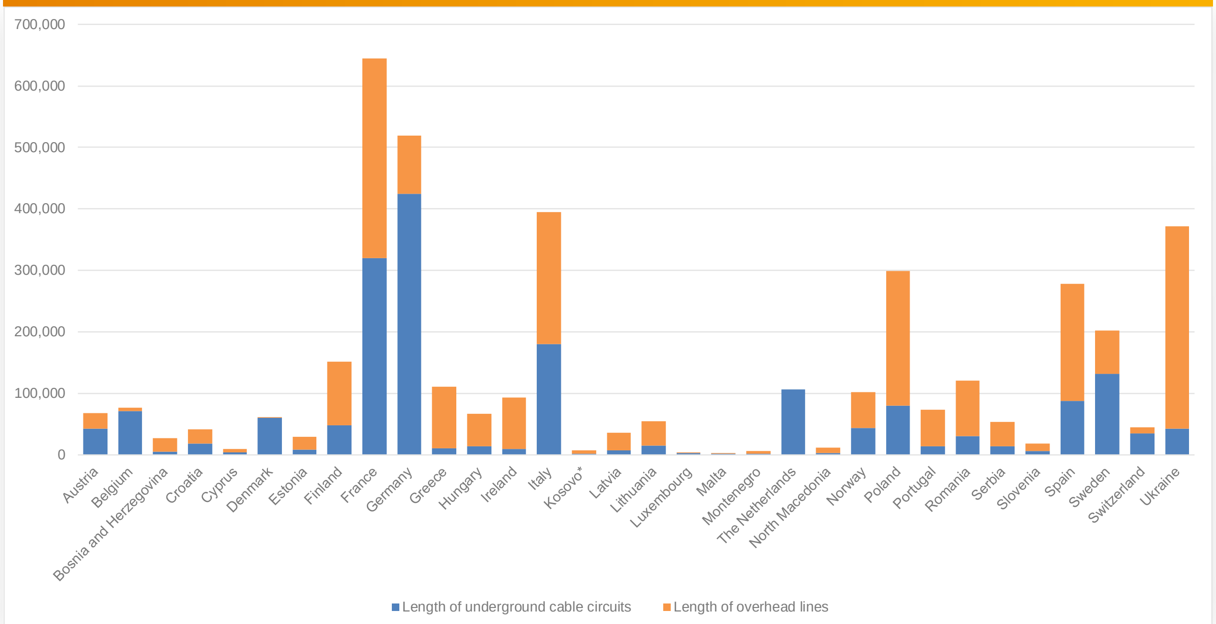


Figure 2-33 and Figure 2-34 show the percentage of underground cable circuits with regard to total length of circuits for LV and MV levels. Great Britain does not have MV, while Albania did not provide values, resulting in these two countries being presented with only one column in Figure 2-33. Moreover, Figure 2-34, only includes the respondents for which it was possible to calculate the cable percentage in both LV and MV networks. Countries that have a high percentage of underground cables (especially on MV) generally have lower (better) values of the corresponding interruption indicators. This is the case with Denmark and the Netherlands which have an incredibly high percentage of cables in both LV and MV grids and among the best values of SAIDI and SAIFI indicators for unplanned interruptions.

FIGURE 2-33: Percentage of LV and MV underground cables (1)

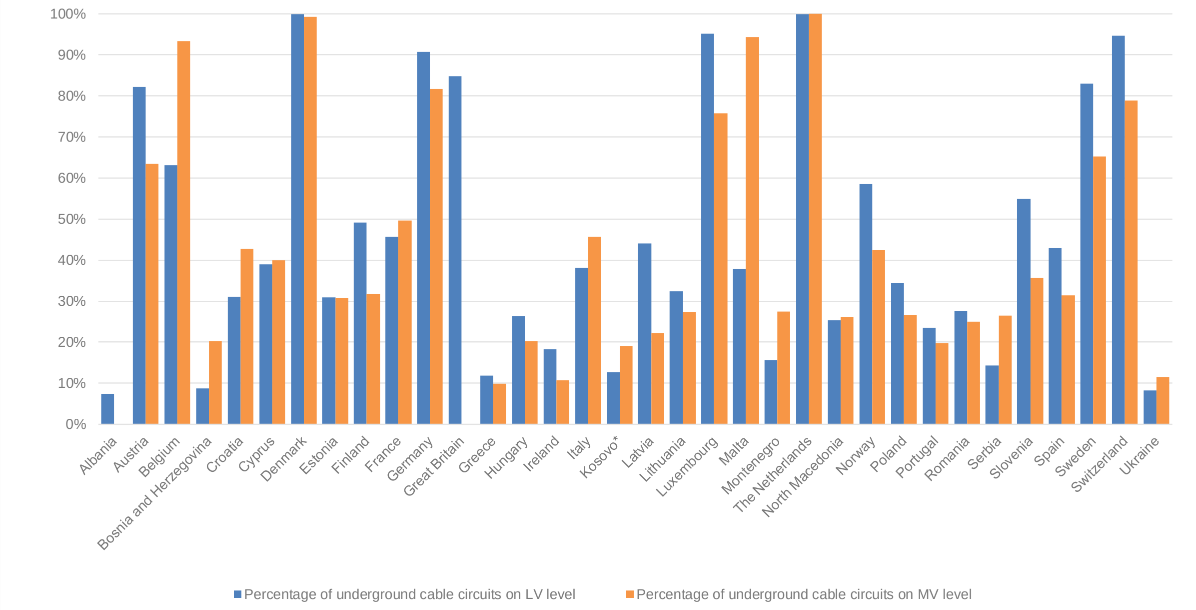
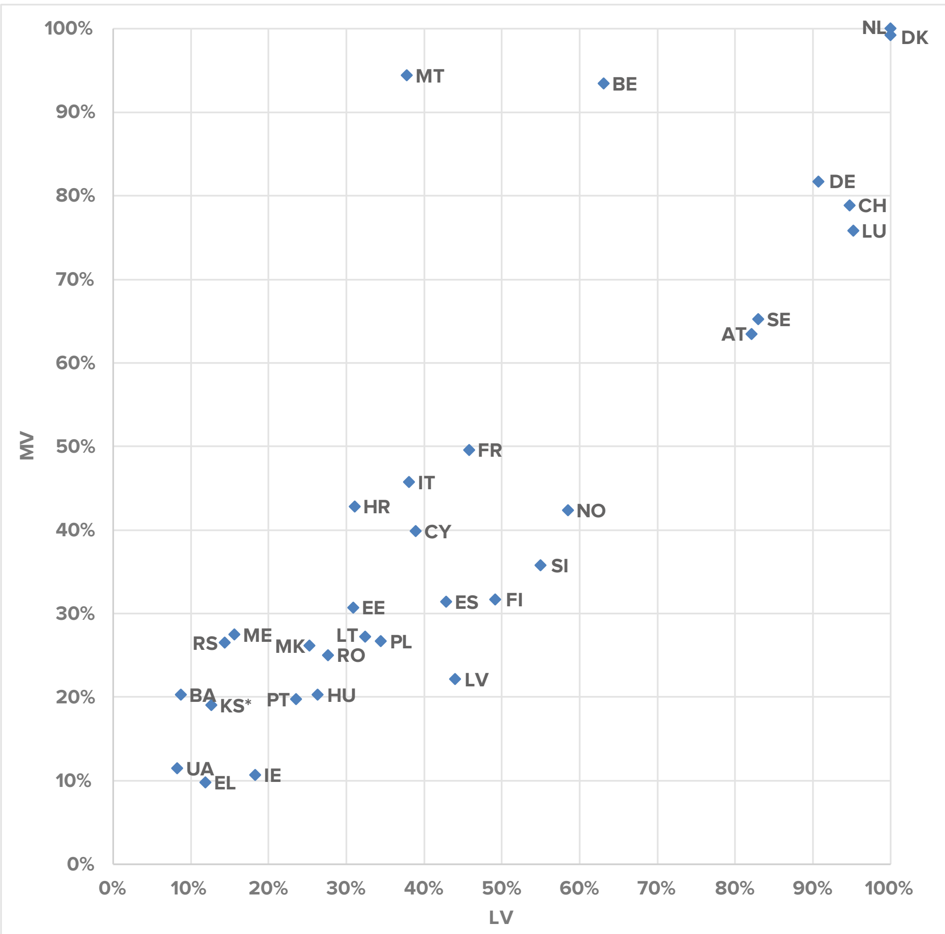


FIGURE 2-34: Percentage of LV and MV underground cables (2)



2.7 AUDITS OF CONTINUITY DATA

Continuity data are provided by network operators themselves. Therefore, a risk regarding correctness and accuracy of data exists. This short section surveys the ways in which the NRAs have approached the problem of both controls (by the operators themselves or their own associations) and/or audits (by the NRA or third parties) of continuity data provided by network operators.

TABLE 2-20: Audits on continuity data

NO	YES, AUDITS	YES, CONTROLS	YES, BUT NO AUDITS/CONTROLS YET
AT, CY, DE, EE, EL, HR, LU, LV, MK, MT, PL, RO	AL, BA, BE[91], FI, HU, NL, NO, PT, SE, SI, UA	CH, ES, IE, ME, SK	FR[92], GE, KS*, MD, RS

As seen in Table 2-20, about two thirds of the responding NRAs have approached the problem of controls/audits of continuity data provided by the system operators. Sixteen of them implement some kind of audit or control, while five indicated that even though the problem has been approached, they still do not perform audits or controls in their countries.

Albania indicated that they audited two system operators each year from 2016 to 2018. Since there is only one DSO and one TSO in Albania, this likely means that both are monitored yearly.

In the Wallonia region of **Belgium**, the regional NRA designs the guidance for this. Auditing was used for the first time in the year the response to the CEER questionnaire was provided. A sample of monitor interruptions was included in audit. In 2018, seven system operators were audited in Wallonia.

The auditing in **Bosnia and Herzegovina** encompasses a recording procedure of interruptions with very long duration and of ENS (more than 10 MW for transmission). The regulatory authorities are tasked with performing the audits and developing internal guidelines. The frequency is every year for transmission and at least once every three years in distribution of the Republika Srpska entity. The audit contains a sample of monitored interruptions both in transmission and in distribution (in Republika Srpska). The TSO and three DSOs were checked yearly between 2016 and 2018.

In **Finland**, all data that is delivered to the NRA is evaluated by comparing DSOs' data to data submitted earlier and other similar DSOs' data. If deemed necessary, spot checks/ad hoc audits are carried out. Details and data to audit are randomised and may differ yearly and/or between DSOs. There is case-specific guidance to follow, designed by the NRA. The audits contain a sample of monitored interruptions to check the recorded data, but are limited to assessing recording procedures. Finland's answers indicate that they had yearly routine checks in 2016 and 2018, but in 2017 they had one audit in addition to yearly routine checks.

The NRA of **Hungary** performs yearly audits which also involve sampling of monitored interruptions. Between 2016 and 2018, all six DSOs were audited every year.

In **Ireland**, the audit assesses recording procedures and analyses the SAIFI and SAIDI data in the Operations Management System. The audit is annual and there is a policy document governing the procedures that are applied to data integrity.

In **Kosovo***, the plan for audits is to focus on compliance with the rules for registration and reporting[93] by having the following two key objectives:

- Verifying that the service providers are correctly applying the instructions and guidance for collecting and reporting; and
- Verifying that the service providers meet the specific minimum levels of accuracy while performing these tasks.

Auditing of the quality of electricity service is specified in the Rule on Electricity Service Quality Standards, which was approved in June 2019 [15]. No audits have yet been performed, but they would be carried out as either an:

- External audit, performed by the NRA or by an independent consultant engaged by the NRA; or
- Internal audit, performed by the service provider, according to rules set by the NRA.

The frequency is not specified, but will be at the discretion of the NRA. The NRA is also required to design the audit procedure. According to the Rule on Electricity Service Quality Standards, it is specified that the NRA should define the following three fundamental elements:

- Instructions for the service providers to ensure the traceability of all reported data;
- Indicators of accuracy and minimum acceptable levels of these indicators; and
- Corrective actions to be taken in case of non-compliance with the minimum levels (and possibly, associated financial penalties).

The NRA of **Montenegro** performs controls on the data submitted by system operators, however no audits are in place. During the first two years of data collection (August 2017 to August 2019), controls were performed frequently, almost each month. There is currently no guidance for audits, however, a

91 Wallonia.
92 Methodology is audited.
93 This is part of the Rule on Electricity Service Quality Standards.

sample was included of monitored interruptions, as controls were focused on checking consistency of recorded data.

Recorded data and the recording procedure are monitored yearly by the NRA of **the Netherlands**. Instructions on how to fill in the data request are developed by the NRA and available for the DSOs/TSO. There is a non-structural audit of procedures, usually after large outages. Between 2016 and 2018, seven DSOs per year were audited (which equals the total number of DSOs since 2017).

The NRA of **Norway** controls a selection of CoS data reported every year from all system operators. In addition, the NRA completes on-site audits at a selection of operators (approximately six to ten per year) to assess compliance with regulations related to the quality of supply in the Norwegian power system. When visiting operators for an audit, the focus is on their methodologies and routines for data registration and reporting rather than on the actual CoS data. In 2016, six DSOs were audited, followed by none in 2017 and eight in 2018.

Audits in **Portugal** are carried out by independent entities who also define the guidelines. The terms are then approved by the NRA. The control/audit also contains a sample of monitored interruptions to check the recorded data. Portugal monitored the main DSO in 2018 (on the 2015 quality of service data) and the TSO in 2016 (on the 2014 and 2015 quality of service data). The audited parameters are:

a. Verification of compliance of systems and procedures for collecting and recording quality of service information;
b. Evaluation of the operation and robustness of control, detection and correction of errors/anomalies;
c. Evaluation of methodologies and criteria used in calculation of technical and CQ of service indicators applicable to the system operator, as provided for in the Quality of Service Code [27], including the possible replication of the calculation procedures to a sample of the values under analysis, where applicable; and
d. Verification of compliance with the NRA-approved power quality monitoring plan and verification of existence and application of procedures related to the topic of power quality.

Compliance with the legislation is monitored in **Slovakia**. The NRA performs the audits and was responsible for developing audit guidance. In 2016 and 2017, two system operators were audited (in each of those years) while only one was audited in 2018.

The NRA of **Slovenia** audits (typically once a year) the CoS indices (SAIDI and SAIFI) reported by the DSO to the NRA. Special focus is placed on the following:

- Effectiveness of the quality of supply monitoring process;
- Accuracy of event logging;
- Accuracy of parameter calculation; and
- Correct identification of the causes of interruption.

Guidance was designed by the NRA and is outlined in the Legal Act on the Rules for Monitoring the Quality of Electricity Supply [29]. Audits are based on a sample of monitored CoS indices and their origin of causes. In 2016, no system operator was audited in Slovenia. In 2017, there was one audit of a DSO for the year 2014 and in 2018, there was an audit of a DSO for the year 2017.

In **Spain**, all data provided must be audited by a third-party that is independent from the network operator. Some operators are also directly inspected by the NRA (CNMC). The audits are performed yearly. The national government designs the guidelines which state that the operators must comply with certain verifications, although these verifications are described in general terms. Audits are limited to assessing recording procedures. From 2016 to 2018, all 333 DSOs were audited every year.

The NRA of **Sweden** performs yearly audits of data quality, documentation and routines. They are currently limited to assessing recording procedures. The following number of DSOs were audited between 2016 and 2018: 171 in 2016, 169 in 2017 and 166 in 2018 which corresponds to all DSOs that were operating in Sweden in each of those years.

Switzerland checks the reported interruptions based on:

- Reports from previous year (100%);
- Media reports regarding outages; and
- Reports from neighbouring operators (upstream or downstream).

The audit is performed as an annual sample by the NRA.

The NRA of **Ukraine** performs yearly planned and unplanned audits of the reports and electronic registers that have been submitted. The NRA, NEURC's, decree on 'Approval of Reporting Forms Related to Indicators of Electricity Quality of Supply' [30] serves as a guideline. Audits contain a sample of monitored interruptions to check the recorded data.

2.8 STANDARDS FOR AND REGULATION OF CONTINUITY OF SUPPLY

A performance-based regulation of CoS consists of the following main aspects:

- **Continuity measurement**: a prerequisite for setting standards and incentive regimes. Here, robust and reliable data is needed in terms of the actual continuity levels;
- **Maintenance or improvement of general continuity levels**: the investment decisions of network operators influence current and future quality levels. Depending on the actual quality level, the NRA must make sure that the current status is either maintained (if CoS has already reached good levels) or improved (if CoS is not yet satisfactory). Preferred regulatory actions to reach these goals include publishing continuity data and implementing incentive schemes; and

- **Continuity ensured for each network user**: the focus is placed on individual users. Minimum standards for quality levels accompanied by associated payments will ensure that single users will be compensated if the standard is not met by the network operator.

The basis for regulation of CoS is the measurement of actual continuity values which can typically be performed on two different levels: system level (overall regulation) and user-specific level (individual regulation). Both approaches are described in this chapter.

While the measurement on system level is usually done on an aggregate basis, measurement on user level is often based on surveys about customer satisfaction, expectations, willingness to pay for higher quality or willingness to accept lower quality levels. Private households could have diverging interests from business or industrial consumers and will thus probably have diverging views regarding the required quality of electricity supply (in this case, CoS). The implementation of adequate continuity measurement is essential for setting standards and regulation/incentives on both system and individual user level.

Different standards and regulations can be attached to continuity indicators. This section aims to survey those that are currently adopted in both distribution and transmission across Europe.

CoS is regulated by the NRA in most responding countries with various degrees of responsibility.

The **Austrian** NRA monitors and publishes the CoS data for the whole country but individual DSOs monitor and publish indicators for their own network area.

Belgium has multiple regulatory authorities. For transmission in all of Belgium and distribution in Flanders, the local governments set up the CoS standards while the regulators monitor them. The regional distribution regulator of Wallonia ensures the correct application of energy law and technical regulation (i.e. it deals with complaints, checks force majeure/emergency cases etc). The distribution regulator of Brussels is tasked with setting up the CoS standards in Brussels.

In **Bosnia and Herzegovina**, the transmission regulator, SERC, has the responsibility to regulate the CoS on EHV and HV levels whereas the responding entity's regulator (RERS in Republika Srpska) is tasked with regulating CoS on MV and LV level. The specific duties such as supervision, dispute resolution and others are defined by law.

The **Croatian** NRA brought into force the Requirements for Quality of Electricity Supply [31] and is responsible for monitoring its application. The aforementioned document regulates CoS as part of the quality of supply, and includes classification of interruption, standards (individual and global), indicators, electronic registry and reporting etc.

According to the Electricity Market Act [32] of **Estonia**, quality requirements for network services (and the conditions for the reduction of connection charges in the event that those quality requirements are violated) should be established by the minister responsible for that specific area. In other words, the Minister for Economic Affairs and Communications establishes the regulations that are supervised by the NRA.

In **Germany**, the responsibility of regulation of CoS is shared between the NRA and the regional regulatory authorities of the federal states. Network operators with less than 100,000 connected customers and/or whose network does not cross state borders are regulated by the regional regulatory authorities. All other network operators are regulated by the NRA (BNetzA).

The NRA of **Finland** ensures that the DSOs operate according to the law.

The **French** NRA defines the objectives for the distribution and transmission system operators.

In **Georgia**, the NRA sets the minimum standards, creates incentive-based regulation to improve continuity and reviews data submitted by system operators.

Similarly, the NRA of **Greece** proposes and enforces regulations and standards and monitors the operator's performance.

The Electricity Act [33] of **Hungary** stipulates that the NRA is tasked with introducing quality standards for the activities of system operators in terms of minimum requirements and expected level of service. These quality standards cover: the reliability, continuity and security of supply, communication with customers, measurable and verifiable quality features of electricity and the quality of specific services provided by system operators related to their basic activities. Furthermore, the NRA has the power to introduce quality requirements applicable to all customers or only to specific customers, including sanctions to be imposed for cases of non-compliance with such requirements.

The **Irish** NRA has regulatory oversight of continuity performance.

According to the Law on Electricity in **Kosovo***, the NRA is responsible for developing rules on quality of supply that cover CoS [25].

The NRA of **Malta** monitors the performance of the DSO and approves the performance objectives related to quality of supply.

According to the Law on Electricity [34] in **Moldova**, the regulator, ANRE, is charged with elaborating and implementing the regulation of the quality of supply for distribution and transmission systems. The NRA can establish general indicators and apply penalties (of up to 10% of the distribution or transmission tariff) for non-compliance with these indicators. ANRE can also establish nominal compensations for final customers in case of non-compliance with established guaranteed indicators (GIs) (allowed number and duration of interruptions).

Based on the Energy Law [35], the NRA of **Montenegro** is obliged to monitor and analyse energy utilities in terms of quality of supply and interruptions, to establish rules on minimum quality of supply (including CoS) and to perform the role of the second instance authority in case of a complaint related to the quality of supply/delivery.

The Energy Law [36] of **North Macedonia** states that CoS is regulated in the transmission/distribution grid codes, but the codes are approved by the NRA. The system operators are obliged, in a manner determined by the appropriate grid code, to submit to the NRA yearly statistical reports on the indices of CoS and quality of service determined by the NRA, as well as on the number of complaints from the users of the system and consumers regarding CoS and quality of service.

In **Norway**, up until November 2019, the Ministry of Petroleum and Energy delegated authority to the NRA, NVE-RME, providing it with the sole power to issue regulations concerning CoS. This was mainly covered by the following two regulations:

- Reg N° 1557 of 30 November 2004: Regulations related to the quality of supply in the Norwegian power system [37]; and
- Reg N° 302 of 11 March 1999: Regulations governing financial and technical reporting, income caps for network operations and transmission tariffs [38].

Since November 2019, only the Ministry of Petroleum and Energy has had the authority to issue regulations related to the quality of supply in the Norwegian power system (Reg N° 1557 of 30 November 2004).

Similarly, the NRA of **Portugal** established indicators and standards, the NRA of **Romania** approves the transmission and distribution standards, while the NRA of **Serbia** monitors the continuity data.

The responsibility of the NRA of **Slovenia** lies in the purpose of the regulation of the quality of supply and the goal to reach the level of CoS so that interruptions are kept to a minimum and as short as possible or that the minimum standards of the quality of supply are reached by following reasonable costs.

In **Spain**, the responsibilities of regulating CoS lie with the national government. These are: establishing the quality and safety requirements to govern the electricity supply; and providing, within the scope of competence, instructions related to the expansion, improvement and adaptation of transmission and distribution electrical grids and installations to guarantee adequate quality and safety of the energy supply with minimal environmental impact.

In **Sweden**, the NRA regulates CoS by supervision.

In **Ukraine**, the NRA sets targets for CoS, imposes fines for providing false information, sets GIs for interruptions and is planning to set the q-factor in their tariff formula.

TABLE 2-21: Continuity standards for individual customers

Yes	No
BE[94], EE, EL, ES, FR, GB, HR, HU, KS*, LV, MD, ME, NL, PL, PT, SE, SI, UA	AL, AT, BA, CY, DE, FI, GE, IE, MK, MT, NO, RO, RS, SK

As seen in Table 2-21, slightly more than half of responding countries have continuity standards for individual customers in force. The standards are not consistent but differ from country to country. The following paragraphs provide an overview of practices across Europe.

The CoS standard in the Wallonia region of **Belgium** is the maximum hours of duration of a single interruption and it is set to six hours. The standard applies to distribution and local transport (<70 kV). The only exception would be power outages due to force majeure.

Croatia uses the following 12 CoS standards in transmission (for HV customers) and/or distribution (for MV and LV customers):

1. Maximum duration of a single planned long interruption for a customer on HV, set to 480 minutes;
2. Maximum duration of a single unplanned long interruption for a customer on HV level, set to three minutes;
3. Maximum yearly duration of unplanned long interruptions for a customer on HV level, set to three minutes;
4. Maximum yearly number of unplanned long interruptions for a customer on HV level, set to one interruption;
5. Maximum duration of a single planned long interruption for a customer on MV level, set to 360 minutes for cable feeder lines and 600 minutes for overhead feeder lines;
6. Maximum duration of a single unplanned long interruption for a customer on MV level, set to 600 minutes for cable feeder lines and 900 minutes for overhead feeder lines;
7. Maximum yearly duration of unplanned long interruptions for a customer on MV level, set to 240 minutes for cable feeder lines and 720 minutes for overhead feeder lines;
8. Maximum yearly number of unplanned long interruptions for a customer on MV level, set to four interruptions for

94 Wallonia.

cable feeder lines and nine interruptions for overhead feeder lines;

9. Maximum duration of a single planned long interruption for a customer on LV level, set to 360 minutes for cable feeder lines and 600 minutes for overhead feeder lines;
10. Maximum duration of a single unplanned long interruption for a customer on LV level, set to 600 minutes for cable feeder lines and 900 minutes for overhead feeder lines;
11. Maximum yearly duration of unplanned long interruptions for a customer on LV level, set to 240 minutes for cable feeder lines and 720 minutes for overhead feeder lines; and
12. Maximum yearly number of unplanned long interruptions for a customer on LV level, set to four interruptions for cable feeder lines and nine interruptions for overhead feeder lines.

The quality requirements in **Estonia** apply to all customers in distribution and transmission and set the maximum acceptable interruption duration. The time limits are different for summer and winter periods. For distribution, an interruption caused by a fault should be eliminated within:

- 12 hours in the period from 1 April to 30 September and 16 hours in the period from 1 October to 31 March;
- 72 hours if the power is supplied through a single 110 kV transformer or line.

The acceptable annual accumulated interruption duration (if caused by faults) is 50 hours. Planned interruptions may last up to ten hours in the period from 1 April to 30 September and eight hours in the period from 1 October to 31 March. The acceptable annual accumulated planned interruption duration time is 64 hours.

For transmission, the acceptable interruption caused by faults should be eliminated within two hours if the power is supplied through two or more 110 kV transformers or lines and 120 hours if the power is supplied through a single 110 kV transformer or line.

Great Britain uses these standards for all distribution customers:

- Maximum hours of duration of a single interruption (normal and severe weather). The standard is set to 12 hours for normal weather and any subsequent 12-hour period and 24 hours for severe weather and any subsequent 24-hour period; and
- Maximum number of interruptions for customer's premises in a year. The standard is set to four interruptions of three hours (or longer) in a year.

In **Greece**, the CoS standard is the maximum duration of a single planned or unplanned interruption affecting all MV customers connected to the Hellenic Distribution Network in the entire country. It is set to 12 hours, but this limit also depends on the area of the country. On specified small islands where DSO personnel from other islands would need to be mobilised, the standard is 24 hours. For unplanned interruptions reported to the DSO by customers during non-working hours, restoration time is counted from the beginning of working hours the following day.

The standard used in **Hungary** is the maximum yearly number of short interruptions. That number should be less than ten on MV cable lines and not more than 70 on MV overhead lines. There is an additional rule that the number of short interruptions experienced by customers in a 90-day period (regardless of the type of line used for supply) should not exceed 40.

In **Kosovo***, the individual CoS indicators for customers connected to transmission and distribution are:

- Duration of an individual long planned interruption for a single customer;
- Duration of an individual long unplanned interruption for a single customer; and
- Total number of long interruptions in the reporting period for a single customer.

However, even though these standards have been decided upon, there are still no fixed limits/numerical values as the CoS standards are not yet in effect.

The CoS standard in **Latvia** is the maximum hours of duration of a single interruption and it is valid for all customers in transmission and distribution. It is set to 24 hours but depends on weather and network conditions.

Moldova uses the following standards to regulate CoS for customers in distribution:

- Duration (planned) of regular works, set to eight hours;
- Duration (planned) of complex works, set to 24 hours;
- Duration (unplanned) in an urban area, set to six hours;
- Duration (unplanned) in a rural area, set to 12 hours;
- Annual number of planned interruptions in an urban area, set to seven;
- Annual number of planned interruptions in a rural area, set to ten;
- Annual number of unplanned interruptions in an urban area on MV, set to six;
- Annual number of unplanned interruptions in an urban area on LV, set to nine;
- Annual number of unplanned interruptions in a rural area on MV, set to nine; and
- Annual number of unplanned interruptions in a rural area LV, set to 12.

In **Montenegro**, the standard called 'maximum hours of duration of an unplanned interruption' is set to 24 hours (or 36 for rural areas or if the cause of interruption is an underground cable on a voltage level above 1 kV). If restoration of an interruption is not possible due to an exceptional event, the deadline is extended for the duration of the exceptional event. The standard applies to all customers connected to transmission or distribution grids.

Similarly, 'maximum hours of duration of a single interruption' is a CoS standard used in **the Netherlands**. Compensation levels (in case of violation of the standard) distinguish between the voltage levels where the interruption was caused and the customers' connected capacity. The standard is applicable to both transmission and distribution and is set to:

- Four hours for interruptions due to a failure in a network with a voltage level up to and including 1 kV;
- Two hours for interruptions due to a failure in a network with a voltage level greater than 1 kV up to and including 35 kV; and
- One hour for interruptions due to a failure in a network with a voltage level greater than 35 kV.

Poland uses the following standards (for LV customers):

- Maximum duration of a single planned interruption: 16 hours;
- Maximum duration of a single unplanned interruption: 24 hours;
- Maximum yearly duration of planned interruptions: 35 hours; and
- Maximum yearly duration of unplanned interruptions: 48 hours.

For MV and HV customers, standards for planned and unplanned interruptions are defined in contracts with the operator.

Portugal employs the following standards for long interruptions (excluding exceptional events) in transmission and distribution:

1. Maximum yearly duration of long unplanned interruptions per single customer:
   - EHV customers: 0.75 h/year;
   - HV customers: urban: 3 h/year, suburban: 3 h/year, rural: 3 h/year;
   - MV customers: urban: 4 h/year, suburban: 8 h/year, rural: 12 h/year; and
   - LV customers: urban: 6 h/year, suburban: 10 h/year, rural: 17 h/year.
2. Maximum yearly number of long unplanned interruptions per single customer:
   - EHV customers: 3/year;
   - HV customers: urban: 6/year, suburban: 6/year, rural: 6/year;
   - MV customers: urban: 8/year, suburban: 12/year, rural: 18/year; and
   - LV customers: urban: 10/year, suburban: 15/year, rural: 20/year.

Slovenia similarly uses different values of standards, depending on the voltage level and the area density. The standards refer to unplanned interruptions only caused by the operator (not attributable to third-party or force majeure). They are:

- Maximum yearly duration and/or number of long unplanned interruptions, set to 450/150/150 (rural/mixed/urban) minutes per year for MV, 6/5/4 (rural/mixed/urban) interruptions per year for MV, 950/350/350 (rural/mixed/urban) minutes per year for LV, 16/10/8 (rural/mixed/urban) interruptions per year for LV;
- Maximum yearly number of short interruptions, set to 1 for HV, 28/18/10 (rural/mixed/urban area) for MV, 35/22/13 (rural/mixed/urban) for LV;
- Maximum duration of single unplanned interruption; and
- Maximum duration of single planned interruption.

Spain uses standards for the maximum duration and number of long interruptions for all customers in transmission and distribution calculated as TIEPI and NIEPI. As in Slovenia, the standards depend on voltage level and population density (urban, semiurban, rural concentrated and rural dispersed). Over time, they have evolved to be more restrictive. The standards are:

- Maximum number of long interruptions;
- Maximum duration of long interruptions;
- Maximum number of long interruptions in LV in urban area, set to ten interruptions/year;
- Maximum number of long interruptions in LV in semiurban area, set to 13 interruptions/year;
- Maximum number of long interruptions in LV in rural concentrated area, set to 16 interruptions/year;
- Maximum number of long interruptions in LV in rural dispersed area, set to 22 interruptions/year;
- Maximum duration of long interruptions in LV in urban area, set to five hours/year;
- Maximum duration of long interruptions in LV in semiurban area, set to nine hours/year;
- Maximum duration of long interruptions in LV in rural concentrated area, set to 14 hours/year;
- Maximum duration of long interruptions in LV in rural dispersed area, set to 19 hours/year;
- Maximum number of long interruptions in MV in urban area, set to seven interruptions/year;
- Maximum number of long interruptions in MV in semiurban area, set to 11 interruptions/year;
- Maximum number of long interruptions in MV in rural concentrated area, set to 14 interruptions/year;
- Maximum number of long interruptions in MV in rural dispersed area, set to 19 interruptions/year;
- Maximum duration of long interruptions in MV in urban area, set to 3.5 hours/year;
- Maximum duration of long interruptions in MV in semiurban area, set to seven hours/year;
- Maximum duration of long interruptions in MV
- in rural concentrated area, set to 11 hours/year;
- Maximum duration of long interruptions in MV in rural dispersed area, set to 15 hours/year;
- Maximum duration of long interruptions in HV, set to 3.5 hours/year; and
- Maximum number of long interruptions in HV, set to 7 interruptions/year.

Each customer in **Sweden** is entitled to a good quality of supply as per the Swedish Electricity Act, and power outages are monitored per customer [21]. No single interruption should have a duration longer than 24 hours, with the limit decreasing with increasing load. For loads greater than 2 MW up to and including 5 MW, the maximum duration is 12 hours; for loads greater than 5 MW up to and including 20 MW, it is eight hours and for loads greater than 50 MW, it is two hours. The standards apply to all customers (transmission and distribution) although not all standards apply to the TSO.

The CoS standard in **Ukraine** is the maximum duration (in hours) of a single interruption experienced by customers in distribution. This is normally set to 22 hours, however, for planned interruptions with prior notice to consumers, the duration should not exceed a total of 12 hours per day or six hours in the winter months. Exceptions to this are: planned interruptions that occurred as a result of carrying out capital repairs, construction, technical re-equipment, reconstruction, modernisation of electrical networks, if the implementation of such works is provided in the DSO investment programme and/or the annual DSO repair programme, and/or in the implementation of contracts for connection to electricity distribution networks in accordance with applicable regulations. Duration of such interruptions should not exceed 24 hours or eight hours in the winter months if the provision of backup power is not possible.

Individual standards/regulations of CoS are static (they do not change with time) in more than half of the responding countries. In others, they are dynamic although the frequency with which they are changed/updated significantly differs. Some examples are provided in the footnotes to Table 2-22.

TABLE 2-22: Individual continuity regulations/standards that change with time

Fixed	Dynamic
BE[95], EE, GB, HR, HU, KS*, LV, ME, NL, PT	EL[96], ES[97], MD[98], RO, SE[99], SI[100], UA[101]

Several countries indicated that the establishment of individual regulations or standards is foreseen. In Austria, details are under consideration but are not yet finalised. The Republika Srpska entity of Bosnia and Herzegovina indicated that it is not yet certain which standards will be adopted, but standards for unplanned interruptions and the total duration of planned interruptions have been discussed. Serbia is also planning to establish individual standards in the future.

On the other hand, many countries indicated that introducing such standards or regulation is not foreseen or necessary. The Flanders region of Belgium stated that the number of complaints regarding interruptions is so low that CoS standards are unnecessary. After an interruption in Norway, the TSO/DSOs must restore full supply to affected end-users without undue delay even though continuity standards are not used. Based on complaints or audit findings, NVE-RME investigates and decides whether the specific provision has been fulfilled or not. This applies to all customers, all voltage levels and all interruptions. NVE-RME has the authority to demand improvements of CoS in individual cases. Slovakia responded that it does not plan to establish individual regulation of CoS.

TABLE 2-23: Continuity standards on country level

Yes	No
AL, AT, EE, ES, FI, FR, GB, GE, HR, HU, IE, KS*, LV, ME, PL, PT, RO, RS, SE, SI, SK, UA	BA, BE, DE, EL, MK, NL

As seen in Table 2-23, most responding countries use CoS standards that are applicable to the entire country. There are only a few exceptions: Belgium, Bosnia and Herzegovina, Germany, Greece, the Netherlands and North Macedonia. The following paragraphs provide an overview of practices across Europe.

The standard used in **Albania** is the total duration/total number of interruptions and applies to all customers in transmission and distribution. The value of the standard is calculated for a year and differentiated based on the affected area. It is set to:

- Duration: 2h/4h/24h (capital city/urban areas/rural areas); and
- Number of interruptions: 2/5/10 (capital city/urban areas/rural areas).

Taken into account are long planned and unplanned interruptions excluding exceptional events and originating on HV, MV or LV levels.

Austria uses three-year averages of SAIDI and ASIDI. They are set to 170 minutes for SAIDI and 150 minutes for ASIDI and the standard has to be met by every grid operator. Interruptions taken into consideration are long and short, planned and unplanned originating on LV, MV and HV level. Considered causes are internal, external, weather causes or grid perturbations, while interruptions caused by exceptional events are excluded.

95 Wallonia.
96 Individual standards may be reviewed and updated by regulatory decree, as required (for instance, at the beginning of a regulatory period).
97 Changes periodically (during the last 20 years it has changed only once).
98 The regulated level of SAIDI changes every three years. Individual standards are static.
99 Standards are updated when needed.
100 Changes typically each regulatory period (every three years).
101 Standard was defined in 2017 and improved in 2021.

Croatia uses these five standards to regulate CoS in the entire country:

1. ENS (for transmission), set to 700 MWh;
2. AIT (for transmission), set to 17 minutes;
3. SAIFI (for distribution), set to three interruptions per customer for cable feeder lines and six interruptions per customer for overhead feeder lines;
4. SAIDI (for distribution), set to 400 minutes per customer for cable feeder lines and 700 minutes per customer for overhead feeder lines; and
5. CAIDI (for distribution), set to 130 minutes per interruption for cable feeder lines and 120 minutes per interruption for overhead feeder lines.

The standards are general system standards for transmission and distribution and are valid only for long interruptions (both planned and unplanned), originating on all voltage levels.

For **Estonia**, the rules mentioned for individual standards are also applicable here. Interruptions taken into account are planned and unplanned long interruptions, including exceptional events, originating on EHV/HV and MV/LV levels. The standards apply both to transmission and distribution.

In **Finland**, standard compensation is paid when a single interruption is longer than 12 hours, regardless of the cause, but force majeure is excluded. Planned and unplanned interruptions originating on all voltage levels and lasting longer than 12 hours are taken into consideration. Some DSOs pay compensation voluntarily even if an interruption in shorter (typically six hours). Normally, only exceptional weather conditions (e.g. snow or storms) lead to outages, but the cause does not play a role for standard compensation.

In terms of security of supply criteria, the maximum government-allowed duration of a single interruption caused by storm or snow load, is six hours in urban areas and 36 hours in rural areas for about 50% of customers (excluding summer houses). By 2036, this will be expanded to 100% of customers. The standard is calculated for and applicable to single interruptions for all customers in distribution. DSOs can set their own limits for customers who meet both of the following criteria:

- The metering point is on an island that does not have a bridge or other solid connection or a regular ferry connection; and
- The electricity consumption at the metering point was less than 2,500 kilowatt-hours (kWh) during the previous three calendar years, and investment costs would be unusually high because of the metering point's long distance to other metering points.

The standard implemented in **France** is that the maximum duration of a single interruption is set to five hours in distribution (i.e. DSOs must pay compensation for interruptions lasting more than five hours). The standard takes into account long planned and unplanned interruptions originating on MV and LV level, including exceptional events.

SAIDI is used as a standard in **Georgia**, although the numerical value was not indicated. The standard is applicable to DSOs and depends on the region of the country, density, grid condition, load and the number of customers connected to the grid. It considers the sum of long unplanned and planned interruptions originating on LV, MV and HV.

For standards used in **Great Britain**, long planned and unplanned interruptions originating on 132 kV, EHV, HV and LV are taken into account for all customers in distribution. There is a differentiation between those occurring during normal and during severe weather. The standards are:

1. Maximum hours of duration of a single interruption (normal and severe weather), set to 12 hours for normal weather and any subsequent 12-hour period and 24 hours for severe weather and any subsequent 24-hour period; and
2. Maximum number of interruptions for customers' premises in a year, set to four interruptions of three hours (or longer) in a year.

The NRA of **Hungary** takes long interruptions into account for quality standards. As the required quality levels are determined for three-year averages, the requirements determined for 2016 to 2018 are presented below. Most of the indicators used for the distribution networks have dynamic requirements, with required levels for 2016 to 2018 included below. As the requirements are differentiated for each of the DSOs, the minimum and maximum requirements (in the form of a range) are indicated. The requirements of the standards used for the transmission networks are fixed. The standards used are:

1. Unplanned SAIFI, set to 1.35-1.647 interruptions/customer (in distribution). Only long unplanned interruptions without exceptional events originating on HV, MV and LV count;
2. Unplanned SAIDI, set to 78.141-85.077 minutes/customer (in distribution). The same type of interruptions counts as for standard 1;
3. Outage rate, set to 0.0788-0.0964‰. This applies to long unplanned interruptions originating on MV and HV and applies to all DSOs;
4. Planned SAIFI, set to 0.393-0.673 interruptions/customer (in distribution). This pertains to long planned interruptions originating on HV, MV and LV;
5. Planned SAIDI set to 107.55-180.4 minutes/customer (in distribution). The same type of interruptions is considered as for standard 4;
6. The proportion of customers for which the supply was restored within three hours following a long unplanned interruption, set to 80- 88% (in distribution). Long unplanned interruptions originating on HV, MV and LV count;
7. The proportion of customers for which the supply was restored within six hours following a long planned interruption, set to 58-70% (in distribution). Long planned interruptions originating on HV, MV and LV count;
8. Number of long unplanned interruptions in MV networks per 100 km, set to 6.32-7.873 interruptions/100 km. Only interruptions originating on MV are counted (but not those caused by exceptional events);

9. Average restoration time in case of MV interruptions, set to 1.232-1.391 hours/interruption. Long unplanned interruptions originating on MV and not caused by exceptional events are counted;
10. Outage rate (for transmission networks), set to 0.7‰. Long unplanned interruptions originating on HV and EHV but not caused by exceptional events are counted; and
11. Average unavailability of main elements of the transmission network, set to 6‰. The same type of interruptions counts as for standard 10.

In **Ireland,** all customers in distribution have equal weighting regarding SAIDI and SAIFI, while there is an additional parameter 'Worst-served Customers' for rural customers. The standards used are maximum yearly duration of interruptions and maximum number of long interruptions, calculated as SAIDI, SAIFI and WSC. Long unplanned interruptions (all causes) originating on all distribution voltages are counted. When a 24-hour period exceeds 57,091 customer hours lost (commencing at 00:00 and ending at 23:59), this day is replaced with an annualised average of the non-storm normal days.

Kosovo* divides its standards into three different groups:

1. Individual CoS indicators in transmission and distribution network:
   - Duration of an individual long planned interruption for a single customer;
   - Duration of an individual long unplanned interruption for a single customer; and
   - Total number of long interruptions in the reporting period for a single customer.
2. General CoS indicators in transmission network:
   - Unsupplied energy (ENS); and
   - Average duration of interruptions (AIT).
3. General CoS indicators in distribution network:
   - Average power supply interruption frequency in the system (SAIFI);
   - Average cumulative duration of power supply interruption in the system (SAIDI); and
   - Average power supply interruption duration per customer (CAIDI).

As the Rule on Electricity Service Quality Standards was only approved in June 2019 [15], the values of the standards have not yet been set, however, the NRA has initiated a working group with the TSO, DSO and the supplier to determine the values of the standards.

The maximum duration (in hours) of a single interruption is the standard used in **Latvia** for customers in both transmission and distribution. The maximum duration is 24 hours for each interruption. Long, short, planned and unplanned interruptions (excluding exceptional events) originating on HV, MV and LV count towards the standard.

In **Moldova**, the standards for the quality of electricity transmission and distribution services are set out in regulations approved by the NRA.

As explained in the 'individual standards' section, 'maximum hours of duration of an unplanned interruption' is the standard used in **Montenegro** and is set to 24 hours (or 36 for rural areas or if the cause of interruption is an underground cable on a voltage level above 1 kV). If restoration of an interruption is not possible due to an exceptional event, the deadline is extended for the duration of the exceptional event. The standard applies to all customers connected to transmission or distribution grids and interruptions taken into consideration are: long, unplanned, originating on HV, MV and LV, but not those caused by exceptional events or a third-party.

As well as the legal requirements in **Poland**, the NRA additionally applies a regulation with quality elements, where each DSO has individual long-term quality targets. The goals are individually developed on the basis of SAIDI and SAIFI (excluding exceptional events) and are defined separately for large cities, county cities, cities and rural areas.

Correspondingly to information outlined in the 'single customers' section, **Portugal** uses the following standards for long unplanned interruptions (excluding exceptional events) affecting customers on all voltage levels:

1. Maximum yearly duration of long unplanned interruptions per single customer:
   - EHV customers: 0.75 h/year;
   - HV customers: urban: 3 h/year, suburban: 3 h/year, rural: 3 h/year;
   - MV customers: urban: 4 h/year, suburban: 8 h/year, rural: 12 h/year; and
   - LV customers: urban: 6 h/year, suburban: 10 h/year, rural: 17 h/year.
2. Maximum yearly number of long unplanned interruptions per single customer:
   - EHV customers: 3/year;
   - HV customers: urban: 6/year, suburban: 6/year, rural: 6/year;
   - MV customers: urban: 8/year, suburban: 12/year, rural: 18/year; and
   - LV customers: urban: 10/year, suburban: 15/year, rural: 20/year.

Continuity standards in **Romania** are used for long interruptions originating on all voltage levels and are differentiated by the system they apply to.

- For transmission:
  - Maximum hours of duration of a single planned interruption, set to 24 hours; and
  - Maximum hours of duration of a single unplanned interruption, set to 12 hours.
- For distribution:
  - Maximum hours of duration of a single planned interruption, which is, in normal weather conditions, set to six hours in urban areas, four hours in municipalities, 12 hours in rural areas, and, in special weather conditions, to 48 hours;

- Maximum hours of duration of a single unplanned interruption, set to eight hours;
- Maximum number of long planned interruptions, set to four interruptions in urban areas and eight interruptions in rural areas;
- Maximum number of long unplanned interruptions on HV and MV level, set to three interruptions in any area; and
- Maximum number of long unplanned interruptions on LV level, set to 12 interruptions in urban areas and 24 interruptions in rural areas.

Slovakia uses standards for:

- Restoring electricity supply after an unplanned interruption due to a fault in the distribution system;
- Announcing the start and end date of a planned limitation or interruption of electricity supply; and
- Restoring electricity to supply points connected to the system after an interruption due to an event in the upstream system.

The standards for restoration of supply depend on the number of supply points: 62 minutes for a distribution system with more than one million points of supply, 77 minutes for a system with over 700,000 to one million points of supply, 140 minutes for a system with up to 700,000 points of supply and 92 minutes for local DSOs. Only long unplanned interruptions originating on HV and LV but not caused by exceptional events are counted. The standards apply to transmission (TSO and large enterprises) as well as distribution (DSOs, local distribution system[102] and final consumers).

Slovenia uses SAIDI and SAIFI for the standards 'maximum yearly duration of long unplanned interruptions' and 'maximum yearly number of long unplanned interruptions', respectively. The SAIDI standard is set to 25 minutes/customer in urban areas and 65 minutes/customer in rural areas. The SAIFI standard is set to 0.75 interruptions/customer in urban and 1.60 interruptions/customer in rural areas. Both standards are calculated for one year and are valid only for customers in distribution. They refer to long unplanned interruptions originating on MV level and due to operator's cause only (not attributable to third-party or force majeure).

The standards used in **Spain** are the same as those listed in the 'individual customers' section. They depend on the voltage level and the area density (urban, semiurban, rural concentrated, rural dispersed) and are used for long interruptions affecting all customers in transmission and distribution.

As described in the 'individual customers' section, there is an obligation to transmit electrical power in **Sweden**. The Swedish Electricity Act states that the network concessionaire should ensure that outages in the transmission of electrical power to an electricity consumer never exceed 24 hours [21]. This rule does not apply if the DSO shows that the outage resulted from a defect outside of the DSO's control and which the DSO could not reasonably be expected to have anticipated and the consequences of which the DSO could neither have reasonably avoided nor overcome.

If the transmission of electrical power is discontinued completely during a consecutive period of at least 12 hours, electricity consumers are entitled to a compensation for the outage from the DSO. However, electricity consumers are not entitled to compensation for outages if:

- The outage results from the neglect of the electricity consumer;
- The transmission of electrical power is discontinued so that measures can be taken that are justified for electrical power safety reasons, or in order to maintain good operational and supply security and the outage does not last longer than the measures require;
- The outage is attributable to a fault in a concessionaire's cable network and the fault results from a defect outside the concessionaire's control that the concessionaire could not reasonably have been expected to have anticipated and whose consequences the concessionaire could neither reasonably have avoided nor overcome; and
- The outage is attributable to a fault in a cable network where the cables have a voltage of 220 kV or more.

The transfer of LV electricity to a customer is classed as good quality, with respect to the number of unplanned long interruptions, when the number per calendar year does not exceed three at a point of delivery. If the number of unplanned long interruptions per calendar year exceeds 11 at a point of delivery, the transfer of electricity to a customer is deemed to be not of good quality. Interruptions that occur during debugging and troubleshooting should not be included in the calculation of the number of interruptions.

Interruptions taken into account for the above-mentioned standards are long unplanned interruptions originating on HV, MV and LV. Not all standards apply to the TSO, but they are applicable to all entities/customers in distribution.

The standard in **Ukraine** is applicable to all DSOs and is the maximum value of SAIDI (planned interruptions without notice plus unplanned (emergency) interruptions due to technical failures in the electrical network of the DSO), separately for urban and rural areas. Only long interruptions originating on and affecting customers on MV and LV level are counted. Interruptions caused by exceptional events do not count towards the standard.

Overall standards/regulations of CoS are static (they do not change with time) in the majority of the responding countries, similar to their counterparts for individual customers. In seven responding countries, they are dynamic but the frequency with which they are changed/updated significantly differs. Some examples are provided in the footnotes to Table 2-24.

102 Distribution system used to connect end-consumers to electricity network and to ensure the supply of electricity to the consumer and their offtake point, or their building, apartment, office, etc. The distribution system is operated by licensed distribution companies in the territory defined by these licenses. Local distribution systems can arise wherever there are several consumers connected to the distribution network through one connection point, namely to upstream distribution system. These are typically commercial zones, shopping centres, industrial zones, apartment complexes and family houses.

TABLE 2-24: Overall continuity regulations/standards that change with time

Fixed	Dynamic
AL, AT, EE, FI, FR, GB, HR, KS*, LV, MD, ME, PT, SK	GE[103], HU[104], IE[105], RO, SE[106], SI[107], UA[108]

Several countries indicated that the establishment of overall regulations or standards is foreseen. Greece is planning on enacting such standards as part of its performance/quality regulation (penalty/reward scheme). It aims to establish a relationship between tariffs and quality, promote improvement in areas with lower performance and encourage decision making consistent with economically efficient outcomes regarding CoS. The plan is to set this up for SAIFI and SAIDI of long planned and long unplanned interruptions affecting all customers connected to the Hellenic Distribution Network. North Macedonia and the entity of Republika Srpska in Bosnia and Herzegovina are also planning to establish overall standards in the near future.

Nine responding countries indicated that they have set additional standards or requirements that focus on the network security of supply. These are Albania, Georgia, Great Britain, Hungary, the Netherlands, Poland, Spain, Sweden and Ukraine.

In Georgia, the additional standard requires the duration of unplanned interruptions caused by internal reasons to not exceed 12 hours in 80% of cases. Great Britain has a Security and Quality of Supply Standard [39], while the Netherlands implemented the N-1 obligation[109] for their TSO.

The following indicators are in place for the security of supply of MV and HV networks in Hungary: outage rate, number of long unplanned interruptions in MV networks per 100 km, average restoration time in case of MV interruptions and average unavailability of 120 kV lines.

In Spain, regional governments can set additional technical standards.

In Sweden, there is a regulatory requirement for DSOs as follows: power lines above 25 kV, power lines that transmit electricity to other grid owners' networks and power lines that lead to or from certain plants that produce electricity and that have significance for the operation of the electricity grid from a supply safety point of view, must be secured from falling trees. Moreover, all DSOs have to report every year a brief summary of their work on risk and vulnerability analyses and a summary of their action plan.

Ukraine defines three different reliability categories in their process of connections:

- Operating rooms in hospitals, pumping stations, some plants etc. The maximum duration of interruption is the time of automatic restoration from the reserve power source;
- Hospitals, educational institutions etc. The maximum duration of interruption is the time of manual restoration from the reserve power source; and
- Other customers. The maximum duration of interruption is 22 hours.

Only four responding countries indicated that they have a definition of worst-served customers, defined by their respective NRAs. These countries are: Great Britain, Hungary, Ireland and Portugal.

In Great Britain, the worst-served customers are those experiencing 12 or more higher voltage unplanned interruptions over a three-year period with a minimum of three higher voltage unplanned interruptions each year.

In Hungary, there is an indicator for monitoring the number and percentage, but with no requirements linked to it. The worst-served customers are those affected by one or more unplanned long interruptions longer than three hours, more than six unplanned long interruptions or more than 30 short interruptions in a year.

Ireland defines worst-served customers as those who have had at least 15 outages over three years and at least five outages in the most recent year. It also indicated that climate change is having a dramatic impact on worst-served customers with 65% of outages occurring on storm days.

In Portugal, this indicator is defined as the worst-served 5% of customers regarding the SAIDI value on MV.

Ireland and Portugal indicated that they have CoS regulation to improve (or maintain) the CoS level of worst-served customers. The DSO of Ireland is subject to financial incentives in respect of its use of allocated funding to improve the service quality of worst-served customers, aligned to funding of 6.7 million euros. In cases where the incentive target is not reached, this would result in a penalty of 6.7 million euros (offsetting the value of the funding awards, resulting in a net payment of 0). Surpassing the incentive target of 6,000 customers would result in an award

103 Changes are upon consideration of the NRA. They depend on implementation of investment projects by DSOs in specific regions.
104 Dynamic for distribution, fixed for transmission. The standards have not been updated since the regulatory decision was issued. There is a yearly required improvement for the following indicators in distribution: planned and unplanned SAIFI, planned and unplanned SAIDI, outage rate, the number of long unplanned interruptions in the MV networks per 100 km and average restoration time in case of MV interruptions. Fixed requirements are set for the following indicators in distribution: the proportion of customers for whom the supply was restored within three hours following a long unplanned interruption and the proportion of customers for whom the supply was restored within six hours following a long planned interruption.
105 Updated every Price Review Period.
106 Updated when needed.
107 Typically updated each regulatory period (every three years).
108 Updated yearly.
109 The N-1 criterion ensures system availability in case of component failure or shutdown. The remaining elements should be capable of accommodating the new operational situation without violating operational security limits.

payment for the DSO (per customer) up to the total incentive cap of 6.7 million euros. In Portugal, the incentive mechanism for CoS has a component to improve the CoS of the worst-served 5% of customers on MV level.

Great Britain, Ireland, Portugal and Spain indicated that they have special mechanisms to protect the worst-served customers. Great Britain provides an allowance for companies to implement schemes to improve the service for worst-served customers. In Spain, a DSO with poor service in a certain region must develop a specialised plan to solve quality problems. Ireland uses 'reputation incentives' based on customer service, while Portugal's incentives have a component to improve CoS of the worst-served customers, as stated in the previous paragraph.

2.8.1 Overall regulation

Overall incentive-based schemes are in place in 19 responding countries: Belgium (distribution in Flanders and Brussels, and transmission in all of Belgium), Bosnia and Herzegovina (only in the Republika Srpska entity), Finland, France, Georgia, Germany, Great Britain, Hungary, Ireland, Luxembourg, Moldova, the Netherlands, Norway, Poland, Portugal, Slovenia, Spain, Sweden and Ukraine. The majority of incentives are implemented in distribution but there are countries that apply incentive schemes to their TSOs.

In Germany, the same reward/penalty system is generally valid in both transmission and distribution, but a key reason for it not being applied in transmission is the lack of reliable continuity data on HV and EHV levels.

Luxembourg's scheme is no longer entirely theoretical. A quality factor is defined in the network tariff regulation and, since the regulation period 2021-2024, the multiplication factor for penalties/rewards was given a monetary value.

Spain recently established a new incentive framework for distribution activity which was approved by the NRA rather than the government, as was previously the case. In this new framework, the incentive to improve the quality of service has doubled and now applies to both TIEPI and NIEPI in the regulatory period from 2020-2025.

Sweden uses a combination of rewards and penalties in both distribution and transmission. AIT and AIF are currently used in transmission while ENS and PNS were used prior to 2020. AIF is calculated by dividing PNS with the average annual power, which, in turn, is calculated as annual reported energy divided by the number of hours during a year. In distribution, Sweden also uses AIT and AIF indicators, along with CEMI4 which is only used for local DSOs (DSOs with an area concession), and which represents the share of customers experiencing multiple (in this case four or more) interruptions in a year. The indicator CEMI4 only has an effect of attenuating the incentives based on the AIT/AIF indicators: if AIT/AIF performance warrants a bonus for a DSO, that bonus could be reduced by up to 25% if CEMI4 is not satisfactory and vice versa (the penalty could be reduced by up to 25% if CEMI4 is at a good level even if AIT/AIF performance is unsatisfactory).

While most countries use a combination of rewards and penalties, there are a few that exclusively employ penalties depending on the performance of their system operators. Details on schemes and indicators used in incentives can be found in Table 2-25. If a country is not included in the column 'continuity indicators used' but is included in 'rewards' or 'penalties' or 'combination' columns, this means that it regulates CoS on a system level, but its answers did not specify the indicators used.

TABLE 2-25: Continuity of supply regulation at system level

System	Rewards	Penalties	Combination	Continuity indicators used
Distribution		BA[110], MD, NO, UA	BE[111], DE, ES, FI, FR, GB, GE, HU, IE, LU, NL, PL, PT, SE, SI	**BE** (unplanned SAIDI and SAIFI originating on LV and MV level)[112], **DE** (SAIDI on LV and ASIDI on MV), **ES** (TIEPI, NIEPI), **FI** (planned and unplanned interruptions, momentary interruptions), **FR** (SAIDI, SAIFI for LV and MV), **GB** (for planned and unplanned interruptions: average number of minutes lost per customer per year, average number of long interruptions per customer per year), **GE** (unplanned SAIDI), **HU** (unplanned SAIDI and SAIFI and outage rate), **IE** (SAIDI, SAIFI, WSC), **LU** (SAIDI), **MD** (SAIDI), **NL** (unplanned SAIFI, unplanned CAIDI), **PL** (individual indicators based on SAIDI I SAIFI), **PT** (ENS[113], SAIDI[114]), **SE** (AIT, AIF[115], CEMI4[116]), **SI** (long unplanned SAIDI, SAIFI caused by operators but not third parties and excluding force majeure), **UA** (unplanned SAIDI excluding force majeure and third parties, planned SAIDI without prior notice to consumers).
Transmission		FR[117], HU, NO	BE, ES, FI, SE	**BE** (AIT), **ES** (availability facility index[118]), **FI** (planned and unplanned long interruptions), **FR** (AIT, AIF[119]) **HU** (outage rate, average unavailability of the main elements of the transmission system), **SE** (AIT and AIF[120]).

TABLE 2-26: Plans to introduce continuity-tariff link in the near future

Yes, in distribution	Yes, both in distribution and transmission	No
BE[121]	EL, ME	AL, AT, EE, HR, KS*, RO, SK

Several respondents indicated that they are evaluating whether to introduce any continuity-tariff links in the near future. The region of Wallonia in Belgium is contemplating introducing key performance indicators for the period 2024 to 2028 which might, in addition to CoS indicators SAIDI and SAIFI, include CQ indicators such as connection times, satisfaction of customers and integration of decentralised production, among others. Greece intends to introduce a Q element in the regulatory formula focusing on key indicators for transmission (ENS) and distribution (SAIDI and SAIFI). Montenegro is considering the same indicators as Greece in addition to AIT for transmission. Luxembourg's tariff methodology already includes a SAIDI-based indicator which is applied to the maximum allowed revenue of a system operator. The following formula is used for DISPt=(DISPref-DISPind) being greater than 10 or being below -10: DISPt × number of network users × incentive factor (currently 0.10 €/min/user), with DISPref = average SAIDI over the reference period and DISPind = average SAIDI of the past two years. In case of a negative DISPt, the network operator is required to publish a report explaining the decrease in performance.

In Albania there is a transitory period regarding the CoS for customers connected to the transmission and distribution grid. At the end of this period, the NRA will take appropriate actions regarding this issue. In the Requirements for Quality of Electricity Supply [31], legislation developed by the NRA, HERA, in Croatia, there is a provision that states that future incentive regulation for DSO will use SAIDI for long interruptions caused from internal sources. However, there are no detailed plans as to how it will be implemented.

110 Only in Republika Srpska.
111 In Flanders and Brussels.
112 Indicators used in Flanders and Brussels: unplanned SAIFI originating on MV level (without exceptional events): 38.5%; unplanned SAIFI originating on LV level (without exceptional events): 16.5%; unplanned SAIDI originating on MV level (without exceptional events): 31.5%; unplanned SAIDI originating on LV level (without exceptional events): 13.5%.
113 ENS is used in the mechanism set to improve the overall continuity of supply.
114 SAIDI (on MV level) is used in the mechanism set to improve the continuity of supply of the worst-served 5% of customers.
115 Before 2020, ENS/PNS was used for regional DSOs and SAIDI/SAIFI for local DSOs.
116 CEMI4 is only used for local DSOs (DSOs with an area concession).
117 The mechanism has been asymmetrical since 2021 which means that only penalties apply to the French TSO.
118 Average percentage of assets in service throughout the year.
119 SAIFI + MAIFI.
120 Before 2020: ENS and PNS.
121 Wallonia.

As for additional incentive schemes, Albania has an investment plan financed by tariffs and approved by their NRA, which targets the elimination of the most critical conditions of the system networks. In Moldova, investments can be done only after approval of the annual investment plan by the NRA. At the same time, investments for elimination of critical conditions are recognised ex-post by the NRA. The specified investments are automatically recognised by the NRA, without prior approval.

In transmission, **Belgium** uses explicit treatment of CoS indicators and establishes the incentive for a single year based on AIT of the previous seven years. The aim of the incentive is to at least maintain the quality level. The reward or penalty is calculated according to a logarithmic formula that takes the value of lost load (VoLL) and the net yearly electricity consumption into account. The optimal level (based on AIT of the previous seven years) is calculated and valid for a year, but minimum improvement is not required and a dead band is not set. In transmission, the incentive is proportional to the difference between the actual performance level and the standard. For the year y, it is calculated with the following formula:

$$Incentive(y)=1.2 + \log\left(\frac{AITref}{AIT(y)}\right) \times AITref \times incentive\ rate$$

Where:

- Incentive rate = total net electricity consumption (y) × VoLL / 8760 / 60; and
- VoLL = 8.3 euro/kWh.

The cap and floor for the TSO are two million euros and zero, respectively. The incentives in transmission are funded by all customers and are included in total revenue. The total amount of incentives to promote CoS in transmission was:

2016: 1.542 million euros;
2017: 1.412 million euros; and
2018: 2 million euros.

For distribution in Flanders, the incentive scheme is a combination of both explicit and implicit treatment of the CoS indicators involving an annual benchmarking and the Qi (quality) element in the regulatory formula. There was no cost estimation survey, but surveys from other countries were studied. By Flemish decree, customers already receive compensation from the DSO when the interruption is longer than four hours. The main aim in this tariff methodology was to introduce competition in CoS between DSOs. Before setting the monetary value of incentives, a consultation with the DSO and the public on the proposed financial impact was conducted. The indicators used in this scheme are:

- Unplanned SAIFI originating on MV level, without exceptional events: 38.5%;
- Unplanned SAIFI originating on LV level, without exceptional events: 16.5%;
- Unplanned SAIDI originating on MV level, without exceptional events: 31.5%; and
- Unplanned SAIDI originating on LV level, without exceptional events: 13.5%.

The cap and floor for distribution in Flanders can in theory have values of up to 1.5% of allowed revenue across all indicators (not just the quality of supply indicators). The cap is proportional to the results obtained for quality indicators and the years observed. This is linked to a revenue-cap regulatory regime that is based on a yardstick principle. In practice, the values are below 0.1% for each DSO. No target or reference level is defined in Flanders. The incentive is a zero-sum game: DSOs with good CoS values are allowed higher revenues while the opposite applies to those with bad CoS values. As in transmission, the incentive is included in total revenue in distribution in Flanders. For the current regulatory period (2021-2024), a Qi value is determined for each DSO based on their performance in the previous regulatory period (2017-2019). This Qi value is fixed for the whole period and is therefore used every year to adjust the allowed income. It is only applied to the endogenous base part of the allowed income. The total allowed income is equal to the sum of exogenous, endogenous basic and endogenous supplementary terms. The shares of these three components in the total allowed income for electricity in 2022 are: 48% exogenous, 46% endogenous basic and 6% endogenous supplementary. Other quality aspects are also assessed, but they are related to CQ.

In distribution in Brussels, the tariff methodologies of 2020-2024 contain a mechanism of incentive regulation based on objectives of quality of services of the DSO. This incentive regulation is based on indicators that are linked to different tasks of the DSO including the quality of supply. The indicators used in this case are SAIDI and SAIFI for MV and LV grids. The maximum amount available for remuneration of Sibelga (the DSO in Brussels), as defined by the tariff methodology, was 632,755 euros (2.75% of the equitable profit margin) for electricity in 2020. This amount would have been granted to Sibelga if it had reached 100% of the 17 indicators in all of its tasks and not only in quality of supply. Based on the KPI measured for 2020, the distribution regulator, Brugel, granted a total of 135,322.39 euros of supplementary remuneration issued through incentive regulation.

In **Finland**, the incentive scheme uses a combination of rewards and penalties and includes both implicit and explicit treatment of the CoS indicators (both long and momentary interruptions). The cost of interruptions is included in both efficiency benchmarking and in a separate incentive scheme on CoS. The regulation was designed by using a cost estimation survey, the results of which were partially applied in the incentive scheme. Finland uses a macroeconomic (top-down) approach to determine the monetary value of penalties. The level of incentives is determined by the difference between the reference level and the actual performance of a system operator but there is no minimum improvement required. A cap and floor of 15% of annual reasonable profit is set for both distribution and transmission. Incentives are funded by all customers and included in total revenue in a revenue-cap regulatory regime.

There is an additional incentive scheme in Finland that aims to improve the security of supply and applies only to DSOs (except DSOs on EHV level). To achieve a six-hour maximum interruption time caused by storm or snow load in urban areas and a 36-hour maximum interruption time in rural areas by 2028 (or 2032 or 2036 for some system operators), DSOs may need to replace some of their equipment unnecessarily early, i.e. before their regular lifetime replacement interval. Replacement investments that have been made early to meet the security of supply criteria are covered by this incentive. The NRA of Finland reviews (and approves or rejects) the requests for early replacement of equipment. The impact of the security of supply incentive is financed by customers and is deducted when calculating the realised adjusted profit.

France uses explicit treatment of the CoS indicators with a predefined target for both DSOs and the TSO that takes their previous performance into account. Monetary value of penalties is determined with a bottom-up approach. ENS is used as a fixed parameter to calculate the incentive amount. The value of ENS in case of long interruptions (>3 min) is estimated at 26 euros/kWh. The value of ENS in case of short interruptions (>1 sec and <3 min) or voltage dips is estimated at 3 euros/kWh. In practice, the amount of the incentive is calibrated in the following way:

- 75% of the value of ENS in case of interruption for the SAIDI;
- 50% of the value of ENS in case of interruption for the SAIFI for LV consumers; and
- 17% of the value of ENS in case of interruption for the SAIFI for MV consumers.

The scheme requires a minimum improvement for the system operators with the calculated target values being updated every four years. Objectives for SAIDI are set as rewards/penalties per minute and depend on whether a DSO performed better or worse than the predefined target. They amount to 6.4 million euros/minute on LV and 5.9 million euros/minute on MV level (difference from the target in minutes). Objectives for SAIFI are similar except that the units are different: 4 million euros/interruption on LV and 20 million euros/interruption on MV level (difference from the target in the number of interruptions per year).

Rewards and penalties are covered by customer tariffs and included in total revenue in transmission and distribution. The cap and floor are set in transmission as a percentage of TSOs' turnover. This is to protect TSOs from exceptionally bad performance and to protect tariff-paying customers from exceptionally good performances by operators.

In transmission, the incentive (in million euros) is capped at 45 million euros per year and is calculated with the following formula for the year y:

$$I_y = Min(17 \times (TCE_{ref} - TCE_y) + 109 \times (FMC_{ref} - FMC_y); 0)$$

Where:

- TCE_{ref} is the reference value for AIT, set at 2.8 minutes/year for the period from 2021 to 2024;
- FMC_{ref} is the reference value for AIF, set at 0.48/year for the period from 2021 to 2024;
- 17 (million euros/minute) corresponds to 75% of the valuation of the ENS[122]; and
- 109 (million euros/interruption) is the valuation of a failure[123].

Incentive schemes in **Georgia** are of both explicit and implicit nature. Target indices of supply reliability standards are established according to territorial districts in each DSO region. In case of fulfilment or non-fulfilment of target indices by a DSO, the NRA is authorised to increase or reduce the allowed revenue according to the Q factor. The NRA approves the target indices of reliability standards of the tariff year(s) for each calendar year of the tariff regulatory period. Target indices of supply reliability standards are established while taking into account the system operator's grid topology and service area, according to regions and territorial districts.

The index of improvement/worsening of average duration of interruptions of a DSO according to territorial districts in each region of its service area, is calculated by using the following formula:

$$Q_{a,t\text{-}i} = SAIDI^{Ref}_{a,t\text{-}i} - SAIDI^{Act}_{a,t\text{-}i}$$

Where:

- $Q_{a,t\text{-}i}$ is the index of improvement/worsening of the system average interruption duration in the specific region of DSO's service area for territorial district 'a' for the relevant tariff year(s);
- $SAIDI^{Ref}_{a,t\text{-}i}$ is the annual target SAIDI for territorial district 'a', established by the NRA for the tariff year(s) in the specific region of DSO's service area;
- $SAIDI^{Act}_{a,t\text{-}i}$ is the actual annual SAIDI for territorial district 'a', in the specific region of DSO's service area for the relevant tariff year(s);
- a represents the territorial districts defined by Article 11 of the Quality of Service Rules [40]; and
- i is the i-calendar year of the tariff regulatory period.

The total amount of financial incentivising or sanctioning of a DSO for the j-region of its service area is calculated by using the following formula:

$$Q^{Reg}_{j,t\text{-}i} = \left(\sum_a q_{a,t\text{-}i} \right) \times N^{Reg}_{t\text{-}i} \times P_e$$

Where:

- $Q^{Reg}_{j,t\text{-}i}$ is the amount of financial incentivising or sanctioning of a DSO for the j-region of its service area for the relevant tariff year(s) in GEL;

122 The ENS was valued at 26 €/kWh, based on the CRE-commissioned FTI-CL study on incentive regulation of the quality of supply for transmission and distribution, September 2016.
123 Based on the value of an interruption at 3 €/kW (according to the FTI-CL recommendation).

- $\sum_{a} q_{a,t-i}$ is the total of the indices of improvement/worsening of the average duration of outages of the DSO in the j-region of DSO's service area, according to the territorial district 'a' for the relevant tariff year(s);
- N_{t-i}^{Reg} is the actual number of subscribers in the j-region of DSO's service area by December 31 of the relevant tariff year(s);
- P_e is the rate of incentivising/sanctioning, established by the NRA for ENS, which shall be calculated in compliance with Annex 3 of these rules; and
- i is the i-calendar year of the tariff regulatory period.

The total amount of financial incentivising or sanctioning of a DSO in the i-calendar year is calculated by using the following formula:

$$Q_{t-i} = \sum_{j=1}^{n} Q_{j,t-i}^{Reg}$$

Where:

- Q_{t-i} is the total amount of financial incentivising or sanctioning of a DSO in GEL;
- $Q_{j,t-i}^{Reg}$ is the amount of financial incentivising or sanctioning of a DSO for the j-region of its service area for the relevant tariff year(s) in GEL;
- j is the specific region of DSO's service area; and
- n is the number of regions within DSO's service area.

Monetary values of the incentive scheme have been established by using a top-down approach with the following formula used for ENS:

$$P_e = \frac{VoLL \times AvgCon}{\frac{60\ GEL}{min}}$$

Where:

- P_e is the rate of incentivising/sanctioning for ENS;
- $VoLL$ is the cost of the electricity not supplied; and
- $AvgCon$ is the average annual customer load (kW/customer).

Furthermore, the other variables in the equation above are calculated as:

$$VoLL = \frac{GVA}{FC}$$

Where:

- GVA is the total added value created in Georgia in current prices, taken from the data of the National Statistics Office of Georgia, for the base year period (million GEL); and
- FC is the final consumption of electricity in Georgia for the test year period, taken from the actual balance of electricity supply of Georgia (million kWh).

$$AvgCon = \frac{TotCon}{TNC} \times \frac{1}{8760\ h}$$

Where:

- $TotCon$ is the total annual customer consumption (kWh); and
- TNC is the total number of customers connected to the network of the DSO of the relevant sector.

Incentives are included in total revenues for distribution and paid by all DSO customers. There is no dead band in the incentive scheme and no minimum improvement is required. A cap for incentives is in place and should not exceed 1% of the DSO's allowed revenue. A target or optimal level is defined in this scheme as a dynamic reference value. Calculated target values are updated every year. Optimum levels are calculated taking into consideration the load, customer number and network length of a region. At this stage, the methodology to define targets in each region is being finalised and prepared to be included in the legislation in the near future.

Incentive-based regulation has been used in **Germany** since 2009 while quality-based regulation has been in effect since 2012. For every system operator (transmission and distribution), an individual, efficiency-based revenue-cap is fixed for one regulatory period (five years). Within this time, system operators have to cut their costs to a previously calculated efficient level. Regarding CoS, they are rewarded or penalised depending on their overall performance compared to those of other operators.

Overall performance of a DSO is measured by SAIDI on LV and ASIDI on MV level. Each system operator is benchmarked against an individual reference level (SAIDI_i*). This level, however, is not obligatory and it is up to a DSO to decide whether the option of pursuing the reference level or the option of paying penalties is financially more feasible. The difference between the continuity reference level and the network operator's SAIDI level is turned into a monetary amount (reward or penalty) by multiplication with a price of quality per unit and the number of customers connected to that specific operator's grid:

REWARD/PENALTY =
(SAIDI_i* – SAIDI_i) × CUSTOMERS_i × PRICE OF QUALITY

To control for stochastic influences in network reliability, both the specific operator's continuity level and the continuity reference level are calculated as a mean value of a continuity indicator for the past three years. Structural differences in overall reliability are taken into account when calculating the reference values. Therefore, load density (the ratio of peak load and geographic area) is used and a load density-dependent reference value for each network operator is calculated.

The monetary value of incentives is determined by using a macroeconomic approach which is used to estimate the VoLL, based on data from national accounting. Data from private households and industry are used and turned into one value for all sectors.

Minimum improvement is not required in this incentive scheme. The cap and floor for rewards and penalties is set to a fixed percentage of allowed revenues and serves as a way of risk mitigation. The amounts of rewards and penalties are funded by redistribution of the revenues. The existing revenue caps increase or decrease with the quality of supply, but the overall amount of revenue is not affected. Incentives are included in the total revenue in a revenue-cap regulatory regime. The aim of the quality regulation system in Germany is to achieve a socio-economically acceptable level of CoS but this level is not set by the German NRA.

Great Britain uses an incentive scheme in its distribution grid. The scheme involves the indicators 'average number of minutes lost per customer per year' and 'average number of long interruptions per customer per year' for both planned and unplanned interruptions. The calculated target values are valid for one year in the case of planned interruptions and five to eight years in the case of unplanned interruptions. These values are updated based on the last three years for planned targets and are set at the beginning of the price control mechanism for unplanned targets. There is no dead band set, and no minimum improvement is required.

The overall financial performance on regulated equity of network companies is assessed using a measure called the return on regulatory equity (RoRE). RoRE is an estimate of the financial return achieved by shareholders during a price control period. It is a useful way to gain an overall picture of how regulated equity is performing under the price control compared to the assumed return used in setting allowed revenues.

Incentives are calculated as the difference between the performance and target, multiplied by the incentive rate, multiplied by the tax rate. There is a 2.5% RoRE incentive reward and penalty cap, meaning the return can be increased or decreased by up to 2.5% depending on the performance. These incentives are included in total revenue for distribution and paid for by all customers. The total amount of incentive remuneration to promote CoS in the distribution grid of Great Britain was:
2016: 152.52 million pounds[124];
2017: 148.29 million pounds; and
2018: 124.08 million pounds.

The 'interruptions incentive scheme' is the largest incentive in electricity distribution of Great Britain.

The incentive scheme in **Hungary** involves an explicit treatment of the CoS indicators. Incentives are proportional to the difference between the standard and the actual performance level. For DSOs, the incentive system has a dual structure. It includes a capital expenditure (CAPEX) reward/penalty system and another penalty regime which can result in compulsory reduction of distribution network charges in addition to a possible penalty of 150,000 or 300,000 euros. For the TSO, there is only a penalty regime with a possible sanction of 150,000 or 300,000 euros in case of non-fulfilment of requirements.

The CAPEX reward/penalty system for the DSOs has the following approach: for indicators SAIDI, SAIFI and outage rate (the ratio of ENS and ES), if the attained value is more than 5% better than required, there is a 0.25% CAPEX reward and if it is more than 10% better, there is a 0.5% CAPEX reward. The same logic is applied to CAPEX penalties. According to the other penalty system, if a DSO fails to meet the requirements, its network charges are automatically decreased by 1% for half a year if the deviation from the requirements is between 5% and 10%, or by 2% for half a year if the deviation from the requirements is more than 10%.

If the TSO fails to meet the requirements, a predefined or a calculated penalty is imposed with the amount depending on the deviation from the requirement. If the deviation is between 5% and 10%, the penalty imposed is equal to the higher of the following two amounts: 150,000 euros or 2% of the annual turnover (without any taxes) arriving from the transmission system operation activity. If the deviation is higher than 10%, the penalty imposed is equal to the higher of the following two amounts: 300,000 euros or 5% of the annual turnover (without any taxes) arriving from the transmission system operation activity.

For the DSOs, three quality indicators (SAIDI, SAIFI and outage rate) are linked to financial incentives for each of them and a required yearly improvement is defined. The required quality levels (differentiated for each DSO) were determined for the three-year average performance of 2004-2006 based on the actual data provided by the six DSOs for the period of 2002-2004. This means that the required performance determined for the three-year average of 2004-2006 is used as a basis when calculating the requirements for the next three-year periods. In addition, the DSOs are obligated to meet a predefined annual improvement, the degree of which is higher if the difference between the actual performance of the company and the predefined threshold (which is the same for all DSOs) is high but decreases as the company's performance is improving.

For the TSO, two quality indicators - 'outage rate' and 'average unavailability of the main elements of the transmission system' (elements such as transmission lines and network connections) - are linked to financial incentives and a constant requirement is defined for both.

Due to the required yearly improvement, the target values change year by year. There is a requirement for minimum improvement of DSOs as well as a cap and a floor. A 5% dead band is set for the system operators both in distribution and transmission. The incentive is funded by customers as well as by network operators with the worst quality results.

A combination of rewards and penalties are in place in the distribution grid of **Ireland**. In the incentive scheme, in the previous price control period (Price Review 4, which was in effect from 2016 to 2020), the DSO could be rewarded with up to €55.1 million or penalised with up to €48.7 million (of the annual allowed

124 For reference, the European Central Bank exchange rate at the end of 2021 was 0.84028 British pounds per euro.

revenue) if the SAIDI and SAIFI values were not satisfactory. In addition to these amounts the rewards and penalties can be up to €6.7 million in the case of the worst-served customers. The penalties/rewards are capped at +2.14%/-1.89% of annual allowed revenues. In the current price control period (Price Review 5, which is in effect from 2021 until 2025), the rewards and penalties are set to a maximum of +/-€10 million per year or +/-€50 million over the entire period.

Moldova uses a combination of implicit and explicit schemes to set incentives for its CoS indicators. These incentives are not included in allowed revenue because they are funded by penalties. The first step in setting the scheme was to establish a goal for the annual level of SAIDI for five years. After this initial period, the quality regulation stipulates that the regulated level of SAIDI will be updated and approved by the NRA every three years, while taking into account the statistical information from the previous five years, as well as the current situation in the distribution system.

A minimum improvement is required, however there is a tolerance band in which the economic effect is set to zero. In other words, the penalties are only applied in cases where the annual SAIDI exceeds the regulated value by more than 30 minutes. Specifically, if the regulated level of SAIDI is exceeded by:

- 30 to 60 minutes, the penalty is 0.5% of the distribution tariff;
- 60 to 120 minutes, the penalty is 2% of the tariff; and
- more than 120 minutes, the penalty is 5% of the tariff.

The CoS incentive scheme in Moldova incorporates no rewards and only penalties (without a cap or floor) which are established in the Law on Electricity [34].

The Netherlands has made no changes to its incentives since the 6th Benchmarking Report [6] was published. The incentive scheme applies to distribution, is linked to the yardstick regulatory regime and is based on a combination of rewards and penalties. Each DSO is compared to the average value of the quality level of supply and receives a reward or penalty depending on whether it performed better or worse than the average. The average continuity level achieved by all DSOs is used as a standard for the quality factor. Thus, the incentives are equal to the difference between the actual performance level (the value of the quality level of the DSO) and the standard (the average value of the quality level of all DSOs). The estimation of the quality level of supply is based on a cost estimation survey and on the SAIFI and CAIDI indicators.

The DSOs are incentivised to find an optimal level, although there is no minimum improvement required. The incentive is capped at 5% of the total income of the DSO and no tolerance or dead band is used. The monetary value of the rewards was determined by customer survey, although the incentive is not funded by customers but by network operators with the worst results in quality (zero-sum incentive scheme). The continuity incentive is part of the formula which determines the total income of a DSO. For transmission, the incentive is set to zero to prevent a trade-off between quality and safety/security. More information can be found on pages 54-55 of the 6th Benchmarking Report [6].

In **Poland**, the incentive scheme uses a combination of rewards and penalties. Each DSO has individual long-term indicator targets. The goals are individually developed on the basis of SAIDI, SAIFI and time for connection to the grid. The incentive scheme (regulatory model) takes into account the quality indicators in the calculation of regulated revenue.

The basic elements of the scheme are:

- The SAIDI, SAIFI index has been replaced by four area category indices based on the Polish administration: selected large cities, cities, towns and smaller urban areas and rural areas;
- Eliminating catastrophic weather events from the calculation of qualitative indicators - using the 2.5 beat statistical method and additional confirmations of the Institute of Metrology and Water Management;
- Penalty in every year is determined to be up to 2% of regulated revenue and up to 15% of the return on capital; and
- Granting a bonus for the fulfilment of the long-term end goals of the quality regulation in the amount of 3% to 5% of the amount of return on capital.

Portugal's scheme uses an explicit treatment of CoS indicators. To establish the incentive mechanism, economic studies on consumers and DSOs based on a historical data analysis were taken into account. The monetary value of rewards/penalties was determined with a macroeconomic (top-down) approach without estimating an optimal level. The incentive only applies to the DSO operating on the HV/MV level.

There are predefined target/reference levels that are valid for the entire regulatory period of three years (and are updated as often) but the improvement (target level) should be reached yearly. A minimum improvement is not required, however there is a dead band set. This is used to avoid the incentive activation when small performance improvements or deterioration is experienced. The incentives are proportional to the difference between the actual performance level and the standard. In order to avoid overstating the impact of the incentive on the economic results of the DSO, the maximum amounts of reward and penalty are defined. Reward and penalty limits are symmetrical and currently fixed at five million euros. When the performance improvement or deterioration is placed between the dead band boundaries and the reward and penalty limits, the amount of the incentive is computed based on the value of END.

The incentive scheme is linked to the price-cap regulatory regime, is part of the MV network tariffs, is funded only by the customers of areas/operators entitled to incentives and is included in total revenue for distribution. This incentive has two goals:

1. To improve the global CoS in distribution network (Component 1)
   Component 1 of the incentive depends on the value of END, considering unplanned interruptions lasting more than three minutes, excluding interruptions originating in other networks and those classified by the NRA, ERSE, as exceptional events.
2. To improve the CoS of the worst-served customers (Component 2)
   Component 2 of the incentive depends on the moving average of the last three years of the value of SAIDI on MV level of the 5% of transformation stations (i.e. MV customers and public distribution MV/LV substations) with the worst performance of SAIDI on MV level. It considers unplanned interruptions lasting more than three minutes but excludes interruptions from other networks and those classified by ERSE as exceptional events.

The total amount of incentive remuneration to promote CoS of DSOs in Portugal was:

- 2014: 0.28 million euros;
- 2015: 3.17 million euros; and
- 2016: 3.67 million euros.

In 2017, two major fires occurred with a significant impact on CoS. The main Portuguese DSO asked ERSE to consider these to be exceptional events. However, since legal proceedings were underway to determine responsibilities, including those of the network operator, it was not yet possible for ERSE to make a decision. Thus, the decision-making procedure for the classification of these two events as exceptional was suspended. Consequently, this incentive was suspended for 2017 (for both components).

Since Component 2 takes into account the values of SAIDI on MV level recorded in three previous years (these are 2017, 2018, and 2019) and since the value of SAIDI on MV level in 2017 has not yet been determined, Component 2 of the incentive had its application suspended for years 2018 and 2019 also. After the final decision on the classification of these events, the incentive for years 2018 and 2019 will be calculated.

Slovenia applies explicit treatment of CoS indicators. The Q factor is calculated annually as the deviation between the reached level and the reference level of the CoS. The reference level is set according to the initial level of CoS and taking into account the required level of improvement.

A cost estimation survey was used for the DSO; a study was performed to appraise the value of the ENS to different types of customers. This value has acted as a reference point for determining compensation in cases where the guaranteed standards in the CoS regulation have been violated. The monetary value of penalties/rewards has been determined by experience with the intention of not endangering the DSO financially.

Optimal (long-term) targets are set according to the gradual improvement in the level of CoS, which also takes into account the multi-year historical values of continuity indicators. Long-term targets are redefined at the start of each new regulatory period (typically every three years). Targets (reference values) are set each year according to the reached values and the degree (percentage value) of the required improvement. The reward/penalty scheme is designed as a linearly increasing formula with some fixed intermediate segments which represent the dead band. The reason for this approach lies in avoiding overinvestments while aiming for improvement of the CoS.

Incentives are proportional to the difference between the actual performance level and the standard (target). The reward/penalty scheme is designed as a mathematically determined partly linear function expressed by the mathematical model of the 'quality class method with edge interpolation' with an upper and lower limit.

There is a cap and floor set that is calculated from the base value (base = annual operations and maintenance () costs and activated assets of infrastructure):

- Rewards: 1.5% of base (urban area); 3.0% of base (rural area); and
- Penalty: 1.0% of base (urban area); 2.0% of base (rural area).

Incentives are included in total revenue for distribution. They are funded through eligible costs of the DSO and paid by consumers through network charges. The total amount of remuneration through incentives in distribution was:

- 2014: 4 million euros;
- 2015: 4 million euros;
- 2016: 4 million euros;
- 2017: 4 million euros; and
- 2018: 6 million euros.

In 2020, a new incentive methodology was implemented in **Spain**. This methodology is based on the comparison between the quality of the sector and the performance of each DSO. Both the number and duration of interruptions over three consecutive years are taken into consideration.

The DSO quality coefficient for the number/duration of interruptions is defined as the deviation of the number/duration of interruptions of a DSO with respect to the sector average. That coefficient indicates whether a DSO obtains a penalty or a reward and determines its scope. The amount of money collected from penalties is distributed among the DSOs having the right to a reward and ranked according to their performance, so that the scheme has zero cost.

The Spanish methodology does not impose a quality threshold to companies since it relies on whole sector improvements. A wtolerance band is established to limit both the penalties and the rewards. A dynamic cap and floor for incentives are in effect: +/-2% of total remuneration of each DSO without incentives in the first three years and +/-3% in the last three years of the regulatory period.

This scheme is linked to a revenue-cap regulatory regime. It is worth noting that such an incentive scheme has no impact on customers as bonuses are financed through penalties. However, since it is dual incentive, it has two indices: one for the number and one for the duration of interruptions. The whole mechanism can provide a maximum variation of +/-4% in the first three years (+/-2% for the number and +/-2% for the duration of interruptions) and +/-6% in the last three years (+/-3% for the number and +/-3% for the duration of interruptions) of the regulatory period for a DSO.

This methodology will be applied for the year 2020 for the first time: the NRA, CNMC, estimates that about 26.5 million euros of rewards collected through penalties from the worst performing DSOs will be distributed to the best performing DSOs. Previously, the reward amounts were 92.6 million euros in 2014, 89 million euros in 2015 and nine million euros in 2016. These rewards were mainly funded by customers and no significant improvement was observed. Afterwards, CNMC modified the framework for the new regulatory period, which covers six years (2020 to 2025).

Sweden uses an implicit incentive scheme. The TSO and the regional DSOs are compared to their own historical levels. For local DSOs, the following methodology is used: those that are better than the benchmark are compared only to their historical levels, while the others are assessed by a combination of the benchmark and their own historical level. These historical levels are as follows: for DSOs it is a four-year norm period ending two years before the beginning of a regulatory period, while the norm period for the TSO is ten years.

The monetary value of incentives is based on customer surveys; a research group was commissioned to develop cost parameters based on customer surveys and interviews. The optimal level is a predefined target recalculated every four years and defined only for local DSOs (those with an area concession). Before each four-year regulatory period, norm functions of 20 indicators are calculated for all local DSOs by using the least square method. It is based on historical values (an average of a four-year norm period) and takes the customer density (the number of customers per km feeder) into account.

A target should be reached but is not defined. If the DSO's historical level is worse than the benchmark, that DSO gets a norm that linearly approaches the benchmark level over the period of four years. If the DSO's historical level is better than the benchmark, it instead has its own historical level as the norm for all four years. This is then recalculated before the next period with a new historical norm.

The incentives require no minimum improvement, contain no tolerance or dead band and are proportional to the difference between the actual performance level and the standard:

For the TSO, the incentive is

$$([Indicator\_n] - [Indicator\_o]) \times [CP\_I] \times [P\_a\_cg]$$

Where:

- $Indicator\_n$ is the norm value for an indicator (AIT or AIF regarding one of the six possible customer groups (the TSO does not have all six)) regarding interruptions notified or not notified in advance;
- $Indicator\_o$ is the yearly outcome of the same indicator;
- CP_I is the cost parameter for the specific indicator; and
- P_a_cg is the average power for the customer group.

For DSOs, the formula structure is the same, however there are differences between the TSO/regional DSOs and local DSOs. The difference is in how the norm values are calculated and whether short interruptions are included in AIF or not. For local DSOs, the yearly outcome can be adjusted by the outcome of CEMI4 as described earlier in this section.

There is a cap and floor for both distribution and transmission and the sum of all incentive schemes (not only CoS, but also efficient utilisation with incentives for losses and load factor) is not allowed to affect the regulated revenue by more than +/-33.33% per year.

The incentive is linked to a revenue-cap regulatory regime. For DSOs, the revenue cap is the sum of operational costs, the 'pass-through' operational costs and the capital costs. Operational costs are based on the DSOs' own historic values, reduced by an individual efficient requirement based on data envelopment analysis. The 'pass-through' operational costs are based on forecasts and later adjusted due to outcomes. The capital costs consist of the revenue and depreciation and are based on the reported information (category and age) of all components using the norm prices and regulated depreciation times. The weighted average cost of capital (WACC) calculation is regulated in law. The regulated return can be decreased or increased due to CoS and efficient utilisation incentive schemes. For the TSO, the revenue cap formula is the same as for DSOs, but with actual purchasing costs instead of norm prices that are used for DSOs.

In both distribution and transmission, the incentives are included in CAPEX revenue and could lead to an increase or decrease of revenue depending on the outcome after the regulatory period. For an individual DSO, the revenue asset base could be increased or decreased by up to a third. Customers pay a little more if their DSO provides better quality than the norm and the opposite is true if the quality is worse than the norm. The total sum for all DSOs is close to zero as some receive rewards and others penalties. In transmission, the TSO is compared to its own historical levels for the norm period of ten years. For the assessment of the incentive for the TSO, the indicator share of network loss is used. For the regulatory period 2020-2023, the standard level for the TSO is based on reported data for the years 2008–2017. After the regulatory period, the outcome is compared with the standard level.

Ukraine implemented an incentive scheme in 2021 for distribution. The scheme involves penalties for DSOs for non-compliance with SAIDI indicators. The incentive regulation uses a Q-factor for 25 (but not all) DSOs in the tariff formula for 2021. The 25 DSOs must reach their target value of SAIDI over 13 years (three regulatory periods), which is 150 minutes in urban and 300 minutes in rural area. The maximum penalty is 5% of the annual revenue (without any bonuses). The target value of SAIDI for a given year is calculated with the following formula:

$$SAIDI_{ref(t)} = SAIDI_0 - \frac{(SAIDI_0 - SAIDI_{ref(13)}) \times N}{NN}$$

Where:

- $SAIDI_{ref(t)}$ is the target SAIDI for the year t;
- $SAIDI_0$ is the basic SAIDI due to the DSO's fault (average value for the last three years before transition to incentive regulation. In this case, the basic SAIDI is the average SAIDI for 2018-2020);
- $SAIDI_{ref(13)}$ is the target SAIDI (150 minutes for urban and 300 minutes for rural areas);
- N is the number of the year t from the beginning of the transfer to the incentive regulation; and
- NN is the number of the year from the beginning of the transition to incentive regulation in which the target value must be achieved (13 years).

Q-factor is calculated with the following formula:

$$Q = (SAIDI_{ref(t)} - SAIDI_t) \times P \times \frac{E_t}{365 \times 24 \times 60}$$

Where:

- $SAIDI_{ref(t)}$ is the target SAIDI for the year t;
- $SAIDI_t$ is the actual SAIDI for the year t;
- P is the price of ENS (20 times the price of universal service); and
- E_t is the distributed energy in year t.

If $(SAIDI_{ref(t)} - SAIDI_t) > 0,$ then $Q = 0$

It should be noted that the target SAIDI in the formula above is not the actual value of SAIDI, but the SAIDI corrected by the results of the annual audit carried out by the NRA. During the audit, indices for a random selection of interruptions are calculated: accuracy index (AI ≥ 90%), precision index (-5% ≤ IP ≤ 5%) and correctness index (IC ≥ 90%). In cases where one of the indices does not meet the above conditions, the CoS data are considered invalid. If the precision index IP is greater than 0 (which means that SAIDI for the random selection is higher than what was reported by the DSO), then the target SAIDI in the tariff formula is adjusted for the IP index (although not more than 20%). Other DSOs (that are not included in the 25 mentioned above) have a different tariff formula (without the regulatory asset base) with a softer Q-factor (i.e. 18 year targets and a maximum penalty of 1%).

2.8.2 Individual regulation

Individual compensation to customers is in place in 21 responding countries: Belgium (distribution only), Croatia, Estonia, Finland, France, Great Britain, Greece, Hungary, Moldova, Montenegro, the Netherlands, North Macedonia, Norway, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden and Ukraine. This is illustrated in Table 2-27. In most cases, financial compensation is awarded if a single interruption (or the total duration of yearly interruptions) exceeds a certain duration or if the yearly number of interruptions exceeds a certain limit.

Each country has its own regulation on how long a customer would have to be out of power andthe rules might also depend on voltage level, connected capacity or even weather conditions. Of the countries listed above, automatic compensation is offered in Estonia, Finland, France, Great Britain, Greece, Hungary, the Netherlands, Norway, Portugal, Romania, Slovakia, Spain, Sweden and Ukraine. The minimum interruption time required to warrant automatic compensation depends on the country and other factors such as voltage level or the number of transformers/lines that supply the power.

The minimum interruption time varies between three minutes for unplanned interruptions on HV in Croatia and 72 hours for unplanned interruptions in distribution if the power is supplied through a single 110 kV transformer or line in Estonia. Not every standard applies to all customers. The standard in Norway took effect in 2021 and applies only to households and holiday homes. Moreover, not every standard a country uses is automatically compensated in cases where it was not met. In Hungary, compensation in the case of nonfulfillment of the requirements for the guaranteed standards has been automatic since 2011. The following paragraphs provide more detail on individual compensation practices across Europe.

TABLE 2-27: Individual compensation to customers for continuity standards

Yes	No
BE[125], EE, EL, ES, FI, FR, GB, HR, HU, MD, ME, MK, NL, NO, PL, PT, RO, SE, SI, SK, UA	AL[126], AT, BA, BE[127], DE, GE, KS*, IE, LU, LV

125 Distribution only.
126 The scheme will only enter into force after the state of emergency in the power supply ends on 31 December 2022. The state of emergency was first declared by the decision of the Council of Ministers number 584 on 8 October 2021 and subsequently revised by decision number 256 on 29 April 2022. https://www.ere.gov.al/images/files/2022/05/27/vendim-2021-10-08-584.pdf, https://www.ere.gov.al/images/files/2022/05/27/vendim-2022-04-29-256.pdf
127 Transmission only.

In **Albania**, based on the provisions of the Agreement for Ensuring the Electricity Distribution Service between Electricity Distribution Operator in Albania and the Supplier [41], the DSO will compensate the supplier which will, in turn, be responsible for compensating the end-consumers who have a contract for power supply with the supplier. In case of non-compliance with the standard criteria of service quality, the supplier is obliged to provide compensation to its customers at their request, based on regulatory provisions regarding the value of compensation. After the submission of the customer's compensation request and the verification of non-compliance with the standard criteria of service quality, according to the deadlines set out in the Regulation for Handling the Complaints Submitted by Customers and Settling the Disputes between the Licensee on Power and Natural Gas Sector [42], the supplier compensates the customer in the next electricity bill. In the invoice, the value of the compensation must be outlined under the heading 'customer compensation for non-compliance with standard service quality criteria approved by the ERE'. According to the legislation, if the client is not satisfied with the amount of compensation received for the damage caused, they still have the right to address the court, which may have a different assessment of the damage caused.

Regarding CoS, the indicators for which customers may be eligible for compensation are SAIDI, SAIFI and 'time required to restore the service following a distribution system outage'. The compensation depends on the duration of an interruption (i.e. the higher the SAIDI value, the higher the compensation). The allowed average SAIDI rate is 47.17. For the time required to restore the service, customers are entitled to compensation if the restoration time surpasses the following values:

- MV and LV: 2.78 hours;
- 35 kV: in urban area 1.73 hours, in rural area 1.77 hours;
- 20 kV: in urban area 1.34 hours, in rural area 1.70 hours;
- 6 to 10 kV: in urban area 2.54 hours, in rural area 2.74 hours; and
- 0.4 kV: in urban area 1.07 hours, in rural area 1.5 hours.

The scheme described for Albania will only enter into force after the state of emergency in the power supply ends on 31 December 2022. The state of emergency was first declared by the decision of the Council of Ministers number 584 on 8 October 2021 and subsequently revised by decision number 256 on 29 April 2022 [43].

In **Austria**, there is no procedure for fining or penalising operators in such cases (failure to meet the standard). The NRA has not publicly committed to introducing guaranteed continuity standards nor is it planning to introduce them in the near future.

Belgium offers individual compensation for customers in all of its three distribution regions, but not in transmission. Local DSOs must report the compensation requests and amounts actually paid to customers to the local energy regulatory authority every year. These data are published (per system operator) in a specific annual report. Customer compensation is not supported by tariffs and includes no penalty caps for total compensation per customer or per year in any region. Moreover, no energy regulatory authority has committed to introducing guaranteed continuity standards. Schemes implemented in the three regions are as follows:

- Flanders: in LV/MV network, customers have the right to lump-sum compensation for unplanned long interruptions longer than four hours if there is a technical reason for it. For commercial customers, the lump-sum compensation is 20% of the distribution tariff paid in the month before the interruption, with a minimum of 35 euros. For household customers, the compensation is 35 euros with an additional 20 euros for each new period of four hours of interruption. Exceptional events (force majeure) are excluded when considering the minimum guaranteed standards. The starting time of an exceptional event is defined as the beginning of an unplanned interruption. Compensation payment is on request and information on requesting compensation is provided online. The total amount of compensation paid to customers for non-compliance with continuity standards in a year was: 32,034.11 euros in 2015 and 93,933.02 euros in 2016. In Flanders, customers are eligible for compensation only in the case of unplanned interruptions.
- Wallonia: unplanned interruptions of six consecutive hours are subject to compensation payments except if caused by force majeure. Compensation levels are not differentiated according to the voltage level or customer type. As in Flanders, interruptions due to exceptional events are not subject to compensation and the starting time of such an event is defined as the beginning of an unplanned interruption. Compensation payment is on request while information on how to request it is available online. The total amount of compensation paid to customers in 2018 was 9,285.43 euros.
- Brussels: compensation payments on request are also offered for unplanned interruptions of six consecutive hours, except if a third party is liable or in the case of force majeure. The starting time of exceptional events is automatic on MV level and counted with the first customer call on LV level. For interruptions longer than six hours, payments are 100 euros. As in other regions in Belgium, compensation payments are on request in Brussels, but there is no mechanism that informs consumers about compensation requests. If the interruption was caused by an incident on an interconnected network (upstream or downstream), affected customers are not eligible for compensation.

In the Republika Srpska entity of **Bosnia and Herzegovina**, there are no procedures for fining or penalising system operators. However, in cases where there is an unjustified interruption, the distributor must restart the end-consumer's electricity supply within 24 hours. In addition, the regulatory authority of Republika Srpska is planning to introduce individual guaranteed continuity standards in near future. It has been working on documents regarding guaranteed continuity standard since 2013.

The NRA of **Croatia** has defined individual standards and associated compensation in the 'Requirements for Quality of Electricity Supply' [31]. Compensation for customers (on their request) was introduced in two stages. In 2020, compensation for individual planned and unplanned long interruptions was introduced. The standards depend on voltage level and on whether the customer is supplied by an underground cable or by on overhead line. For example, for long interruptions on HV level, the standard is 480 minutes for planned and only three minutes for unplanned interruptions. Compensation also depends on the voltage level. On HV, for unplanned interruptions, customers can receive 30,000 HRK[128] and 3,000 HRK for planned interruptions. Compensation is 1,000 HRK on MV and 300 HRK on LV levels (both for planned and unplanned interruptions). In 2021, compensation for the total yearly duration of long unplanned interruptions was introduced. As in the scheme for individual interruptions, the standards depend on voltage level and whether the customer is supplied by an underground cable or an overhead line.

In **Estonia**, new requirements in the regulation on the 'Quality Requirements for Network Services and the Conditions for Reducing Network Charges in Case of Violation of Quality Requirements' [44] came into force on 1 October 2021. According to the Regulation, the requirements are as follows:

1. If the market participant's electrical installation is connected to the network at low voltage through a main breaker of up to 63 A, the amount by which the network operator reduces the network charge may not be less than:
   - 24 euros if elimination of the interruption exceeds the period stated in the requirements by up to 48 hours;
   - 48 euros if elimination of the interruption exceeds the period stated in the requirements by 48 to 96 hours; and
   - 72 euros if elimination of the interruption exceeds the period stated in the requirements by more than 96 hours.
2. If the market participant's electrical installation is connected to the network at low voltage through a main breaker of over 63 A, the amount by which the network operator reduces the network charge may not be less than:
   - 0.40 euros per each ampere of the main breaker, if elimination of the interruption exceeds the period stated in the requirements by up to 48 hours;
   - 0.80 euros per each ampere of the main breaker, if elimination of the interruption exceeds the period stated in the requirements by 48–96 hours; and
   - 1.15 euros per each ampere of the main breaker, if elimination of the interruption exceeds the period stated in the requirements by more than 96 hours.
3. If the market participant's electrical installation is connected to the network at a voltage of 6–35 kV, the amount by which the network operator reduces the network charge may not be less than:
   - 2.30 euros for each kW of used capacity of the network connection, if elimination of the interruption exceeds the period stated in the requirements by up to 48 hours;
   - 4.60 euros for each kW of used capacity of the network connection, if elimination of the interruption exceeds the period stated in the requirements by 48–96 hours; and
   - 6.90 euros for each kW of used capacity of the network connection, if elimination of the interruption exceeds the period stated in the requirements by more than 96 hours.
4. The amount by which the transmission network operator must reduce the network charge on exceeding the permissible period of interruption may not be less than 7,669.41 euros for each MW of hourly capacity for the previous year of the point of consumption that was cut off from electricity supply.

The following time limits for interruptions are valid:

- In distribution: 12 hours from 1 April to 30 September, 16 hours from 1 October to 31 March and 72 hours if the power is supplied through a single 110 kV transformer or line. The acceptable annual accumulated interruption duration is 50 hours. In addition, ten hours for planned interruptions from 1 April to 30 September and eight hours for planned interruptions from 1 October to 31 March. The acceptable annual accumulated interruption duration in this case is 64 hours.
- In transmission: two hours if the power is supplied through two or more 110 kV transformers or lines and 120 hours if the power is supplied through a single 110 kV transformer or line.

If an interruption time exceeds these limits, a customer should receive a compensation payment. In other cases, there is no compensation. Exceptional events are excluded, except if specified in a contract (with large business customers, for example). Compensation payments are automatic and are supported by tariffs.

In **Finland**, the Electricity Market Act [45] states that the DSOs should pay standard compensation to consumers if the interruption time is 12 hours or more. No events are excluded, unless a DSO can prove that the interruption was caused by force majeure. Some DSOs pay compensations even under 12 hours, although it is not required by law. If the interruption time is at least 12 hours, the standard compensation is 10% of the consumer's annual network access charges. The compensation increases stepwise with the interruption time. The maximum compensation is 200% of the annual network charges when the interruption time has exceeded 12 days. Maximum compensation per incident rose to 2,000 euros on 1 January 2018. The regulatory framework of Finland does not have a definition of exceptional events, but the standard compensation volumes are a consequence of exceptional events. This is due to the fact that only exceptional weather conditions lead to outages, in which case the standard compensations are paid.

128 For reference, the European Central Bank exchange rate at the end of 2021 was 7.5156 Croatian kuna per euro.

The compensation payment levels are as follows for interruptions lasting:

- >12 hours: 10% of the customer's annual network access charges;
- 24-72 hours: 25%;
- 72-120 hours: 50%;
- 120-192 hours: 100%;
- 192-288 hours: 150%; and
- >288 hours: 200%.

These levels are set as the percentage of the customer's annual grid access charges and are not differentiated according to the voltage level or the type of customer. Compensation payments are automatic.

In 2018, due to interruptions of 12 hours or more, electricity DSOs paid standard compensation in the total amount of 2.3 million euros to approximately 22,900 customers. In 2017, this was 4.9 million euros to 36,800 customers.

For each individual DSO, data on the number of compensated customers and total payments are collected and differentiated by the payment level. Compensation is paid for by tariffs and the sum is subtracted from the acceptable profit for DSOs.

In **France**, the standard subject to compensation is the maximum hours of duration of a single interruption. Compensation is automatic and differs depending on the voltage level. For LV, it is 2 euros/kVA of contracted power for each block of five hours of interruption. This means that a customer with a contracted power of 12 kVA whose power supply was interrupted for 15 hours would receive a compensation of 72 euros (2 euros/kVA × 12 kVA × 15h/5h). For MV, it is 3.5 euros/kVA of contracted power for each block of five hours of interruption.

Exceptional events are included in compensation except if they affect more than 20% of all final consumers supplied by the public distribution grid. In its answers, France indicated that 62 million euros were paid as compensation to consumers in a single year. The total amount paid is collected every year by the DSOs. The compensation is limited to 40 blocks of five hours of interruption, but the monetary limit will depend on the contracted power of the affected customer. The scheme is partially supported by tariffs; if the total amount of compensation exceeds the limit of 80 million euros/year, compensation payments above this amount are then financed by tariffs.

Georgia does not offer individual compensation to customers. However, there is an overall standard which stipulates that the duration of unplanned interruptions should not exceed 12 hours. If 80% of interruptions are not resolved within 12 hours, the standard is deemed not to be fulfilled. In this case, the DSO is penalised by a decreased tariff. The tariff is decreased by 0.01% of the allowed revenue for each 1% below the target. Conversely, a DSO can also be rewarded by the same amount for exceeding the target. The NRA of Georgia is neither planning to introduce, nor has it committed to introducing, guaranteed continuity standards.

In **Great Britain**, the following standards are subject to compensation if the standards are not met:

- Maximum hours of duration of a single interruption (normal and severe weather); and
- Maximum number of interruptions for customers' premises in a year.

The compensation levels are as follows:

- For normal weather: 75 pounds for every 12-hour failure for domestic customers, 150 pounds for non-domestic customers and 35 pounds for additional 12-hour failures; and
- For severe weather: 70 pounds for every 24-hour failure, 70 pounds for additional 12-hour failures and 75 pounds for multiple interruptions. The compensation limit in the case of severe weather is 700 pounds per customer.

Compensations are automatic and awarded even in cases of exceptional events (if the supply is not restored within 24 hours in the case of severe weather). The starting time of an exceptional event is taken as the moment when the number of HV incidents exceeds the relevant threshold. In Great Britain, the number of failures and the compensation paid are collected from the network operators. In 2018, the total compensation paid to customers amounted to 2,051,550 pounds.

Greece offers automatic compensation if the standard for the maximum duration of a single planned or unplanned interruption is not met. The compensation amount is 150 euros, although there is no obligation to compensate in the case of force majeure or in exceptional conditions (extreme weather, DSO labour union strikes, loss of supply from other upstream networks/systems etc.). As with many other countries that offer compensation on an individual level, Greece also collects data on the total number of interruption events and the number of cases when the standard is not met.

For the near future, the NRA is considering extending the current standard 'maximum duration of single interruption' to also include LV customers and may be looking at the maximum number of interruptions or the maximum total interruption time in a year.

Hungary offers compensation in the case of nonfulfillment of the requirements for the guaranteed standards. Compensation is therefore valid for the following guaranteed continuity standards/indicators:

- Time for restoration of supply in case of an unplanned interruption (automatic compensation);
- Time until the start of restoration of supply following a failure of DSO's fuse (automatic compensation); and
- Maximum number of short interruptions (on customer request).

For the first two, the compensation is 15 euros for residential customers, 30 euros for non-residential LV customers and 91 euros for MV customers. For 'maximum number of short interruptions', compensation is 15 euros for customers with profile-based billing and 30 euros for those with no profile-based billing.

In Hungary, extreme weather events are classified into four categories depending on the number of MV interruptions in any 24-hour period and the number of affected customers. In cases where the DSO fails to comply with the requirements linked to weather events in guaranteed standards, compensation is also offered in Categories 1-3 but not in Category 4. However, there are some exceptions. In case of Category 1-3 weather events, DSOs are not obliged to meet the requirements of the following GIs:

- Time until the start of restoration of supply following a failure of DSO's fuse;
- Time for connecting new customers to network or extending connection capacity;
- Punctuality of appointments with customers;
- Time for answering the voltage complaint;
- Time between the date of the answer to the VQ complaint and the elimination of the problem;
- Time for meter inspection in case of meter failure; and
- Time for restoration of supply following disconnection due to non-payment.

The requirement for the indicator 'time until the restoration of supply in case of unplanned interruption' is moderated (required restoration time increases to 24, and 48 hours, etc.) in the case of Category 1-3 extreme weather events, while in the case of Category 4 events there is no required restoration time. The starting time of an exceptional event is the first interruption connected with the extreme weather event.

Data is collected on the performance of the following continuity standards/indicators: number of cases (affected customers) falling under the GIs, number of cases (affected customers) in which the requirements have not been met, number of compensations automatically paid in cases where the requirements have not been met, total number of compensations paid and total amount of compensation paid. Compensation payments in Hungary are not supported by tariffs.

Kosovo* is planning to introduce individual compensation on customer request. The Rule on Electricity Service Quality Standards states that the customer should be entitled to financial compensation from the service provider if the individual indicator from its jurisdiction does not reach the level of the guaranteed quality standard [15].

The guaranteed/minimal standards for the CoS indicators (both for the TSO and the DSO) are:

- Duration of an individual long planned interruption of a single customer;
- Duration of an individual long unplanned interruption of a single customer; and
- Total number of long unplanned interruptions of a single customer in the reporting period.

Although the Rule on Electricity Service Quality Standards was approved in June 2019, the above-mentioned rules are not yet in effect as the financial compensation has not been set by the NRA. In the NRA, ERO's, 2022 work plan the creation of working groups is foreseen. Its work will serve as the basis for developing possible financial compensation procedures and values.

The NRAs of **Latvia** and **Luxembourg** have stated they are not planning to introduce individual guaranteed continuity standards in the near future.

In **Moldova**, the following standards are subject to compensation payments: duration of a planned/unplanned interruption and the annual number of planned/unplanned interruptions. Compensation is on request and is paid for every hour or every interruption above the established standard, except in case of exceptional events.

The level of compensation is calculated depending on the average daily consumption at a certain time. This way, customers with higher consumption will receive higher compensation. Using this methodology, there is no necessity to divide customers into different groups.

System operators are obliged to provide information on requesting compensation in every office for relations with customers[129]. In 2018, the total compensation amounted to approximately 1,000 euros. There is an annual report on the quality of supply for distribution and transmission services, where information on performance is presented.

Compensation is supported by tariffs. The amount is calculated based on the regulated electricity tariff for final customers used for the area of activity of a specific operator and the average daily consumption of the affected customer.

The NRA is planning to introduce guaranteed standards in the future. The standards will remain the same, but the compensation payment will be automatic. Several meetings with civil society and organisations for customer protection have already been held in this regard.

Montenegro has had a mechanism for individual compensation on customer request since August 2018. In cases where a standard related to the duration of interruption (excluding exceptional events) is not met, the compensation payment level for customers connected to the transmission grid is 200 euros, while it is 20 euros for all others.

Information about the compensation mechanism is available on the NRA's website and the supplier is preparing to distribute an information sheet to all customers. On a monthly basis, system operators submit data on interruptions that took place, their cause, duration, whether they were planned or unplanned as well as the number of cases in which the standards have not been met. Compensation in Montenegro is not supported by tariffs.

129 These do not have to be customer service offices. Post offices are used as well.

In **the Netherlands**, individual compensation for interruption duration (excluding exceptional events) is automatic and involves a complex scheme that determines compensation based on duration, type of connection and/or voltage level. The exact compensation levels were presented in Table 2.16 of the 6th Benchmarking Report [6]. The total amount of compensation paid in 2018 was 14,410,102 euros. As in many other responding countries, data are collected on the number of times the compensation had to be paid and on the amount. The scheme involves all customers in distribution, but not in transmission. Payments to customers are not required if an interruption is caused in HV or EHV networks.

In **North Macedonia**, compensation for CoS (and VQ) is offered on customer request with rules and procedures for compensation being published on the DSO's website. Compensation level does not differ depending on the type of customer and/or different standards. The claim for damages can be filed as:

- Request for payment of standard damage compensation determined in accordance with the 'Rules for Reimbursement of Damage Caused to Producers and Consumers' [26]; or
- Claim for damages caused to the consumer's property due to reduced delivery or interruption of electricity supply.

The standard compensation is determined as a percentage of the total fee for using the grid, paid by the consumer in the preceding 12 months as follows: 10% for the first six hours after the expiration of the time limit for restoration of the electricity supply and 20% for every subsequent 24 hours after the first six hours.

Exceptional events are not included. The total standard damage compensation may not exceed 50% of the total compensation for the use of the grid paid by the consumer in the last 12 months prior to the moment the damage occurred. The total standard damage compensation should be reduced by 50% if the consumer has three unpaid invoices for the use of the network to which they are connected.

The operator is not obliged to pay compensation for damage if it is determined that there are grounds for releasing the operator from liability for damage, i.e. if the damage occurred due to:

- An interruption caused by the feedback of consumers' devices on the grid;
- Actions of third parties not engaged by the operator;
- Force majeure i.e. events and conditions set forth in Article 12, paragraph (1) of the Rules [26], or events and conditions set forth in the contract for connection and use of the grid i.e. the general rules set forth in the grid rules and which constitute grounds for releasing the operator from liability for damage; or
- Planned outage, and for which the supplier or the consumer:
  - Have been notified by the system operator in a manner determined by the relevant network rules;
  - Have been notified of a change in term that will be interrupted in a manner determined by the relevant network rules; or
  - The term for the planned outage was previously harmonised with customers who, according to the electricity supply rules and the relevant grid rules, must not be cut off, or consumers who need electricity for the smooth running of their production process.

Furthermore, the operator has no obligation to pay compensation for damage if:

- The consumer has more than three unpaid invoices for the use of the network to which they are connected, unless they are included in the category of vulnerable consumers;
- The NRA Energy Regulatory Commission approved the connection even though the operator refused, and the user stated that they would not complain about the quality of electricity; or
- The NRA ordered the connection of private networks not owned by the operator.

Individual compensation in North Macedonia is not supported by tariffs.

Customers in **Norway** are entitled to compensation for very long interruptions i.e. those that are longer than 12 hours. Previously customers had to apply to the DSO to receive payment, but as of 1 January 2021, the payment is automatic. This arrangement only applies to households and holiday homes (summer houses, cabins, etc.).

Until 1 January 2021, compensation levels were independent of the type of customer and amounted to: 60 euros for interruptions shorter than 24 hours, 140 euros for interruptions shorter than 48 hours and 270 euros for interruptions shorter than 72 hours. There is an additional payment of 130 euros for each new 24-hour period after the first 72 hours. On 1 January 2021, compensation levels changed. For households, compensation starts at 50 euros for an outage of 12 hours plus an additional rate of four euros per hour. For holiday homes, compensation starts at 12.5 euros for an outage of 12 hours plus an additional rate of one euro per hour. The amounts have been set to what is considered reasonable for an ordinary household. The total payment to a customer may not exceed what the customer pays in grid tariff.

Poland offers compensation on request if the following standards are not met:

- Maximum duration of a single unplanned interruption (24 h);
- Maximum duration of a single planned interruption (16 h);
- Maximum yearly duration of unplanned interruptions (48 h); and
- Maximum yearly duration of planned interruptions (35 h).

In the event of exceeding the permissible standards for each undelivered unit of electricity, a consumer connected to the network with a rated voltage of not more than 1 kV, is entitled to a discount of ten times the price of electricity for the period in which there was a break in the supply of this energy. The amount of undelivered electricity on the day on which the interruption took place is determined on the basis of energy consumption on the relevant day of the previous week, taking into account the time of permissible interruptions specified in the contract for the provision of distribution services or separate regulations.

In **Portugal**, automatic payments are offered to customers if the standards for the number and duration of unplanned interruptions are not met (excluding exceptional events). In 2017, customers received 151,000 euros in compensation for HV, MV and LV levels. In 2016, they received 322,000 euros in compensation for the same voltage levels.

The amount depends on the voltage level (EHV, HV, MV and LV) and is based on estimates of customer costs for interruptions. The overall amount of compensation payable to each customer for non-compliance with individual continuity of service standards is limited to 100% of a customer's annual network tariff for the previous year.

The number of non-compliance cases related to the duration and number of interruptions, as well as the monetary value of compensations are collected. Compensation in Portugal is not supported by tariffs.

In **Romania**, there are automatic compensation payments for:

- Transmission standard: 2,000 RON[130]/event/affected user (non-compliance with the maximum hours of duration of a single unplanned interruption) and 2,500 RON/event/affected user (non-compliance with the maximum hours of duration of a single planned interruption); and
- Distribution standard: between 30 and 300 RON/event/affected user. In distribution, the minimum guaranteed standards are different (more permissive) for special weather conditions.

Compensation depends on the voltage level and is based on estimated costs of interruptions, although there is no compensation in the case of exceptional events. In 2018, the total amount paid for the distribution standard was 837,442 euros. The limits for this standard are:

- Maximum 300 RON for users connected at HV/month x 12 months;
- Maximum 200 RON for users connected at MV/month x 12 months; and
- Maximum 30 RON for users connected at LV/month x 12 months.

The following data on the performance of the distribution standard are collected: type of interruption (planned/unplanned), its date, its voltage level, number of affected customers, number of customers affected by the exceeding of the duration of supply provided by standard, cause of non-compliance and number and total amount of compensation payments. Compensation paid by distribution operators is not recognised as a justified cost in the distribution tariff calculation.

The following standards are subject to compensation in **Slovakia**:

- Restoration of electricity distribution after interruption;
- Restoration of electricity distribution after unplanned interruption;
- Notification of the start and end dates of the planned limitation or interruption; and
- Keeping the announced start and end date systems after interruption of electricity.

The levels have been set according to customer costs for interruptions. Compensation is automatic but is not paid if interruptions were caused by exceptional events. It should be payable to the affected person within 60 days of the removal of the cause of non-compliance with the standard (if their identity is known at that time), or within 60 days of the identification of the affected person (if their identity is unknown at the time of the removal of the cause of non-compliance with the quality standard). The scheme is not supported by tariffs. The total amount paid in compensation to customers in a year is 576,583.18 euros. Data are collected on the amount and number of compensation payments.

Slovenia offer compensation on request if the following standards are not met:

- Maximum yearly duration and/or number of long unplanned interruptions;
- Maximum duration of a single unplanned interruption; and
- Maximum duration of a single planned interruption.

For the first standard, the compensation level depends on how much the standard is exceeded over a maximum yearly duration and/or the number of long unplanned interruptions. It also depends on the type and voltage level of a customer and their average interrupted power. For the second and third standards, the compensation levels are five euros for households, 20 euros for other customers on LV and 200 euros for MV level. Interruptions caused by exceptional events are not included in the standards set for interruption duration. The NRA does not currently plan to introduce any other guaranteed standards. A switch to automatic compensations has been discussed, but no final decision has yet been made.

There is publicly available information about consumer rights available on mediums such as web sites and reports etc. Customers are informed once per year of the type and name of MV-feeder to which they are connected. At the same time, they receive information on the overall standard of CoS. No other special mechanism is currently in force.

The scheme is not supported by tariffs. Although no compensation has yet been paid, the NRA is certain that some guaranteed standards have been exceeded on the customer level. It is highly likely that customers are still not aware that they have the right to be compensated in the case of a guaranteed standard not being met, and this is likely the main reason why no claims for compensation have yet been made. The NRA believes that the introduction of an automatic compensation

130 For reference, the European Central Bank exchange rate at the end of 2021 was 4.9490 Romanian lei per euro.

mechanism would bring different results and that customers would be compensated in this case.

In **Spain**, automatic compensation for the number and duration of interruptions is offered to individual customers in cases where the individual and zonal quality indicators are not complied with. Interruptions under 3 minutes or interruptions caused by exceptional events are not taken into account in this scheme. Compensations are awarded as a discount on the first bill of the following year and are calculated according to the formulas below.

For the number of hours (interruption duration):

$$Discount = Pw \times DH \times 5 \times P$$

Where:

- Pw is the billed annual average power;
- DH is the difference between the number of consumer interruption hours and the hours set by the required standards; and
- P is the kWh price.

For the number of interruptions:

$$Discount = \frac{Pw \times H \times P \times DN}{8}$$

Where:

- Pw is the billed annual average power;
- H is the number of interruption hours valued to the kWh price of tariff;
- P is the kWh price; and
- DN is the difference between the number of consumer interruptions and the number of interruptions set by the required standards.

Compensation levels are not differentiated according to different standards and are not supported by tariffs. The amount is limited to 30 euros or 10% of the first full bill of the next year. In case of non-compliance with both standards, the most favourable one for the consumer will be taken. For standards such as TIM and ENS, there are no compensation payments if the operator fails to meet them. In their regulatory account, each DSO must declare the total money discounted to customers due to penalties for not complying with the guaranteed quality standards. This is provided on a yearly basis.

In **Sweden**, there are automatic compensation payments for interruptions lasting 12 hours or longer, as defined in the Swedish Electricity Act [21]. They amount to:

- 12.5% of the network tariff or a minimum of 1,000 SEK[131] for interruptions lasting 12 to 24 hours;
- 25% of the network tariff or a minimum of 2,000 SEK for interruptions lasting 24 to 48 hours;
- 50% of the network tariff or a minimum of 3,000 SEK for interruptions lasting 48 to 72 hours and so on.

The maximum compensation is 300% of the network tariff. For small customers such as households, the minimum compensation as mentioned above is often applied.

Exceptional events are partly considered; the time workers must spend waiting due to safety risks (e.g. exceptional weather during the night) can be subtracted from total interruption time. The total compensation paid to customers was 60 million SEK in 2018 with the average from 2006 to 2018 being 160 million SEK. Electricity consumers are not entitled to compensation for outages if:

- The outage results from the neglect of the electricity consumer;
- The transmission of electrical power is discontinued so that measures can be taken that are justified for electrical power safety reasons or in order to maintain good operational and supply security and the outage does not last longer than the measures require;
- The outage is attributable to a fault in a concessionaire's cable network and the fault results from an impediment outside the concessionaire's control that the concessionaire could not reasonably have been expected to have anticipated and whose consequences the concessionaire could neither reasonably have avoided nor overcome; and
- The outage is attributable to a fault in a cable network where the cables have a voltage of 220 kV or more.

Data is collected on the number and the amount of compensation payments. Before 2020, compensations were not supported by tariffs but after a change in law, they may be partially covered by the revenue cap to avoid a double penalty. The reason for this is that outages over 12 hours are no longer excluded from the incentive scheme in the revenue cap regulation from 2020. The NRA proposed that outages longer than 24 hours should not be supported by tariffs, but there is no precedent for this.

In **Ukraine**, there is automatic customer compensation based on the maximum duration of interruption (excluding exceptional events) within 24 hours (22 hours from 2022) and differentiated by customer type. The approximate amounts in euros are: 9.28 euros for households, 15.47 euros for small non-households and 21.66 euros for other non-households. All affected customers are eligible. In 2018, the total compensation paid amounted to 67,227 euros. Data on performance related to continuity standards is collected on (among others) the name and type of consumer, date and amount of compensation and date of non-compliance with GIs. The scheme is not supported by tariffs. Instead, DSOs pay compensation out of their profits.

In 2021, new types of compensation were introduced: compensation for the maximum duration of a planned interruption, which is 12 hours (six hours in winter months) and compensation for the maximum number of interruptions longer than one hour in the last 12 months (which is not automatic

131 For reference, the European Central Bank exchange rate at the end of 2021 was 10.2503 Swedish kronor per euro.

but by customer request). The maximum number of unplanned interruptions, (excluding force majeure and third parties) and planned interruptions without notice to the consumer, is six in urban areas and eight in rural areas. The maximum number of planned interruptions with notice to the consumer (not counting those caused by works to be performed in accordance with the investment programme) is 11.

2.8.3 Effects of the continuity of supply incentive regimes

This section aims to survey the real effects of CoS incentive regimes by evaluating changes in CoS after incentive regimes were implemented in responding countries. Many countries reported improved CoS (shorter duration or a lower number of interruptions), even with indicators that are not regulated, but there are exceptions to this (Spain).

Belgium introduced its CoS incentive scheme in 2016 for transmission with the goal of maintaining the low level of AIT. A scheme was also introduced in 2017 for distribution in Flanders (regulatory period of the tariff methodology 2017-2020), however, it only had an impact on the allowed revenues of DSOs in the regulatory period 2021-2024. There has also been an incentive scheme in Brussels since 2020, although it is too early to determine its effects on the CoS values.

The NRA and the TSO were involved in implementation of the incentive regime. There were public consultations on an external study and on the framework of the tariff methodology. The incentive is correlated to the price control period with a duration of four years. All system operators are involved in this scheme; the Belgian TSO and the ten DSOs operating in Flanders. In transmission, the incentives have maintained the quality of the CoS. It is too early to determine the effects in distribution as they were only introduced in 2017.

There has also been an effect on non-regulated CoS indicators. In transmission, the average AIT has had these values:

- 2008-2014: 2.55 minutes;
- 2016: 1.90 minutes;
- 2017: 2.13 minutes; and
- 2018: 0.84 minutes.

The effects of the incentive regime on network operational expenditures and investments have not been evaluated.

In **Finland**, the incentive scheme is also correlated with the price control period of four years. All system operators are involved. Overall CoS has improved, which might have decreased the cost of maintenance, although it is not certain that this is a consequence of the incentive regime. Variation in the number and duration of interruptions is high due to varying weather conditions. There is an ongoing evaluation of the effects of the incentive regime on investments and operational costs.

At the beginning of this incentives scheme, interruption costs were not included in efficiency benchmarking. Currently, all interruptions are included, but the effect of this incentive is limited to 15% of annual allowed revenue. Interruption costs are now also part of the efficiency benchmarking.

In **France**, the incentive scheme includes the TSO and eight larger DSOs, while the DSOs serving less than 100,000 consumers are excluded. The observed effect is that the overall duration of interruptions is decreasing. Since first introduced, the regime has been changed; indicators have been added and objectives modified.

Incentives in **Georgia** are aimed at both of its DSOs. Two main effects have been noticed:

- The accuracy of registration of interruptions dramatically increased. The DSOs developed additional means for registration (new software, restructuring, hiring new personnel etc.); and
- DSOs started to focus on the SAIDI indicator and began developing investment projects which will have a positive effect on SAIDI.

Before introducing the 'Electronic Journal' and daily monitoring of interruptions, the DSOs calculated CoS indicators according to their own assumptions, but the calculation process was not transparent.

In **Germany**, the incentive scheme involves all four TSOs, but is only valid for electricity DSOs on LV and MV level with more than 30,000 customers. Approximately 200 system operators are involved in the incentive scheme. Since its introduction, the main change was a switch to a yearly adjustment of CAPEX instead of keeping a budget for the regulatory period.

Great Britain's incentive scheme is correlated to its price control period of eight years. All 14 DSOs take part in this scheme. The main effect is that the average number and length of interruptions has been driven down. There has been an evaluation of the effects of the incentive regime by the National Audit Office and the conclusion is, that since the introduction of the Interruptions Incentive Scheme in 2002, the number of interruptions has fallen by around 50% and the duration of interruptions has decreased by around 60%. Changes have been made to the incentive rate and targets at the beginning of each price control.

To improve its customer service, **Ireland** has updated its CoS incentive regime since the 6th Benchmarking Report [6] was published to ensure that the targets remained efficiently ambitious as well as achievable. This regime was implemented through a public consultation process and finalised by the NRA, CRU, after feedback from stakeholders was considered and taken into account. The regime involves both the DSO and the TSO and is correlated with the price control period of five years (being 'Price Review 5', the latest electricity price review which covers the 2021-2025 period).

Moldova introduced a CoS incentive regime in 2011 to tackle the problem of a long duration and the large number of interruptions. The NRA and DSOs were involved in the implementation. The indicators were monitored for five years prior to the introduction of the incentive regime. The DSOs were against capping of the SAIDI level and penalties for non-compliance. After this reaction, a new regulation of the quality of service was approved by the NRA.

The regime is not correlated with the price control period. An effect of the scheme was that SAIDI was halved from 2011 to 2015. CoS indicators outside of the regulated ones have also improved. Since SAIDI is affected mostly by interruptions in the MV grids, establishing a regulated level of SAIDI stimulated the DSOs to invest more in the grid. Over the years, it was set forth that to maintain SAIDI at a certain level, a specific budget for investments was needed. If the value of investments in the grid decreased, the SAIDI level would grow proportionally after two years.

Since the Law on Electricity [34] was changed, the regulation, approved by the NRA was also changed since first being introduced. In comparison with earlier versions of the regulation, the latest one includes the increased level of penalties.

The incentive regime in **the Netherlands** involves only the DSOs and is correlated with the price control period, which is between three and five years. After the introduction of the regime, CoS remained high, but it is unknown what would have happened without these incentives. Since first introduced, the regime was changed by simplifying the technical aspects of the equation to increase predictability.

After initially monitoring its indicators since 2001, **Portugal** introduced a CoS incentive regime in 2003. Only the main DSO is involved but this DSO covers 99% of customers. Since the introduction of the regime, indicators have consistently improved over the years.

To encourage system operators to provide a better quality of service, **Slovakia** first monitored their indicators from 2009 until 2012 before introducing an incentive regime in 2012. Its implementation involved cooperation of the NRA, system operators, the Ministry of Environment and the Ministry of Economy. The proposal received mixed reactions from system operators, so their justified suggestions were incorporated by the NRA into legislation. Since introducing the regime (which involves both the TSO, and large and small DSOs), the quality of CoS has improved.

The NRA of **Slovenia** has also implemented an incentive regime to improve the CoS. The NRA began collecting CoS data as early as 2008. Later in 2011, when three years of CoS data were collected, the NRA started to introduce the penalty/reward regime.

The network operators regularly opposed the presented introduction of overall and guaranteed standards. In response to public consultations, they usually proposed less strong criteria for introduced standards. The NRA mostly accepted final decisions as a compromise between the NRA proposal and the operators' response (where reasonable). There were also decisions where the NRA did not deviate from proposed standards.

The incentive regime is correlated with the price control period (usually three years). It applies only to distribution, although closed distribution systems are excluded from the regulatory regime. The NRA has observed a positive effect and a progressively improving CoS level with both the regulated (SAIDI, SAIFI) and other CoS indicators (CAIFI, MAIFI, MAIFI-E) improving over the years of data monitoring. An internal analysis has been done by the NRA which found a moderate correlation between investments and the CoS level.

The reward/penalty scheme is fully adjustable with changes having been introduced for each regulatory period. The NRA changed the maximum value of the allowed reward/penalty as well as the symmetry between them. At the beginning of the scheme only penalties were introduced. Later on, both rewards and penalties came into force symmetrically (values for rewards and penalties were equal). The current scheme also covers both rewards and penalties, but asymmetrically.

Spain currently uses an incentive regime in both transmission and distribution which correlates with the price control period 2020-2025. The non-regulated CoS indicators have remained at the same levels or even worsened in certain regions (for certain DSOs) in the last few years. Since first introduced, the incentive regime has been changed to consider the number of interruptions separately.

In **Sweden**, the first version of the current incentive scheme was introduced in 2012. There have been major developments since 2016, such as applying benchmarking for local DSOs and dividing customers into six groups. There have also been additional developments since 2020 such as including new cost parameters that were excluded before (outages longer than 12 hours) and using power-weighted indicators (AIT/AIF) instead of the previously used SAIDI/SAIFI for local DSOs and ENS/PNS for regional DSOs and the TSO.

Sweden strives to continuously evaluate and improve the incentive scheme (rather than create a new one from scratch) while taking into consideration costs and benefits of implementing changes. The rules were developed by the NRA, but the TSO, DSOs and customer groups were consulted during the process and were provided with an opportunity to comment on proposed changes. A research group at Gothenburg's University was involved in updating cost parameters that were introduced in 2020. Moreover, the decision to change the indicators from customer-weighted (SAIDI/SAIFI) to power-weighted (AIT/AIF) has been received positively by the system operators.

The Swedish incentive regime is correlated with its revenue-cap price control period of four years (currently from 2020 to 2023). Before each new period, norm values of all indicators for the upcoming four years are calculated. After the control period is over, the outcome is appraised and the revenue cap adjusted. This regime is implemented in both transmission and in distribution, with all DSOs being involved.

There has been an increased commitment from DSOs as well as indications of improvements in the CoS although it is hard to tell if the improvements are due to these or other incentives. In addition, there has been a partial evaluation of the effects of the incentive regime on network operational expenditures and investments, but these are also difficult to evaluate because of other incentives.

2.9 FINDINGS AND RECOMMENDATIONS

FINDING #1:
CoS is monitored in all responding countries.

All countries that provided answers to this chapter monitor their CoS, but not all of them have a legal obligation for monitoring. The exceptions to legal obligations are Ireland and Malta. As for short interruptions, the obligation exists in less than half of respondents while the obligation to monitor transient interruptions is only in force in six countries.

Legal obligations to monitor planned interruptions is in force in more countries when compared to unplanned interruptions, but in practice, unplanned interruptions are monitored in every responding country (regardless of their legal obligations) while planned interruptions are not. This monitoring usually covers long interruptions (see Table 2-3 for definitions of duration) whereas less than half of respondents collect data on short or transient interruptions. Most countries exclude transient interruptions from monitoring altogether.

FINDING #2:
Differences in monitoring include voltage levels where interruptions originated.

Not all countries monitor interruptions originating on all voltage levels, but all generate statistics for incidents on more than one voltage level. Interruptions originating on MV level are monitored in all countries except Great Britain and Slovakia, which do not have a definition of MV. Estonia records all interruptions, but only divides them into those in transmission and those in distribution, rather than per voltage level. Interruptions originating on LV are monitored in all responding countries except Malta and Slovenia. Interruptions originating on HV are monitored in all responding countries. Interruptions originating on EHV are monitored in fewer countries than those originating on lower voltage levels, but it should be kept in mind that EHV is not defined in every country. Countries that do not differentiate between HV and EHV, usually classify both as HV.

FINDING #3:
There are differences in CoS indicators and the way they are calculated.

Diverse indicators and weighting methods are employed for evaluation of CoS across Europe. The use of multiple indicators enables the collection of more information and offers more possibilities to observe trends. The most commonly used indicators are SAIDI and SAIFI for long interruptions and MAIFI for short interruptions. Indicators AIT and ENS are typically used for interruptions in transmission. However, even the use of the same indicator does not guarantee easy comparison. In addition to different voltage levels that might be included or excluded, there are variations in weighting methods, in inclusion and definitions of exceptional events, and in treatment of multiple subsequent interruptions, which might either be treated as separate interruptions or aggregated into one. All these differences can affect the comparability of indicator values.

FINDING #4:
There are different approaches to planned interruptions and exceptional events.

While most respondents have a definition of planned interruptions, the requirement for advance notice varies significantly, with specific requirements for notification typically being between 24 hours and 30 days, depending not only on the country, but on the voltage level as well. Most countries consider advance notification to affected network users to be sufficient and necessary for an interruption to be classified as planned. In addition, many countries calculate the same indicators (for example, SAIDI and SAIFI) with or without exceptional events. What constitutes an exceptional event can significantly differ as there are no uniform rules and many countries define these events based on their experience or geographic reasons. This makes the benchmarking of indicators that include all events even more difficult.

FINDING #5:
Incentive schemes are used to regulate CoS in distribution and transmission networks.

Overall incentive-based schemes are in place in 19 responding countries. These schemes are implemented to improve the CoS or at least maintain it at a good level. The majority of incentives are applied in distribution but there are also incentive schemes in transmission, as seen in Table 2-25. Most countries use a combination of rewards and penalties, while very few respondents have regimes that focus exclusively on penalties. No country reported using only rewards in their CoS incentive schemes.

FINDING #6:
Incentives for continuity level of individual customers are widely used.

Individual compensation to customers is in place in approximately two thirds of responding countries. In most cases, financial compensation is awarded if a single interruption (or the total duration of yearly interruptions) exceeds a certain duration or if the yearly number of interruptions exceeds a certain limit. Each country has its own regulation on how long a customer would have to be out of power, but the rules might also depend on voltage level, connected capacity or even weather conditions. Compensation can be automatic or on customer request. Automatic compensation is offered in 14 countries.

RECOMMENDATION 1

EXPAND THE MONITORING OF CoS.

Many recommendations from previous Benchmarking Reports are still relevant and will be repeated here. To continue improving the CoS, it is recommended to include all incidents at all voltage levels in interruption statistics. Monitoring of short interruptions should be extended to countries that currently monitor only long interruptions. Monitoring of transient interruptions could be introduced in as many countries as possible.

RECOMMENDATION 2

HARMONISE CALCULATION OF CoS INDICATORS.

To facilitate easier benchmarking, CEER and ECRB recommend harmonising the methodology to calculate the CoS indicators. Common weighting methods and rules for aggregation of subsequent short interruptions should be introduced.

RECOMMENDATION 3

ESTABLISH AND HARMONISE THE DEFINITION OF EXCEPTIONAL EVENTS.

CEER and ECRB recommend establishing the definition of exceptional events in each country. It is also important to harmonise these definitions at the European level in the interest of achieving comparable indicators.

RECOMMENDATION 4

IMPLEMENT AN INCENTIVE SCHEME FOR MAINTAINING OR IMPROVING GENERAL CONTINUITY LEVELS.

CEER and ECRB recommend applying adequate incentive schemes to maintain the CoS levels or improve them, if economically viable, in both distribution and transmission. Results obtained by cost-estimation studies on customer cost due to interruptions are of key importance to be able to set proper incentives.

RECOMMENDATION 5

IMPLEMENT COMPENSATION PAYMENTS FOR NETWORK USERS AFFECTED BY VERY LONG INTERRUPTIONS.

CEER and ECRB recommend implementing adequate compensation for each voltage and/or capacity level. This individual compensation scheme could be based on a customer survey.

03

ELECTRICITY – VOLTAGE QUALITY

3 ELECTRICITY – VOLTAGE QUALITY

3.1 WHAT IS VOLTAGE QUALITY AND WHY IS IT IMPORTANT TO REGULATE IT?

Voltage quality (VQ) covers a wide range of voltage disturbances and deviations in voltage magnitude or waveform from the optimum values. In this Benchmarking Report, VQ is used to refer to all disturbances in the supply of electricity, excluding interruptions that are covered in the chapter on CoS. Disturbances to VQ could occur as a consequence of the operation of the power grid and/or of units connected to the grid. Examples of voltage disturbances are supply voltage variations that, for instance, could accrue in case of large load changes at the network user level, voltage dips that could be caused by short-circuits in the grid, or rapid voltage changes that could be caused by changes in production. Details of frequency variations are not included in this Report as these are deemed to be mainly a system operation issue.

Everyone connected to the power grid could influence the quality of voltage delivered at their own connection point or at other connection points throughout the power grid. Any VQ regulation must consider both the cost for specific customers as a result of equipment malfunction or damage and any direct or indirect increased cost of improving the grid, which could lead to increased tariffs for all customers. Whereas interruptions affect all network users, voltage disturbances do not affect all customers in the same way.

VQ is becoming an increasingly important issue due to, among other things, the increasing susceptibility of end-user equipment and industrial installations to voltage disturbances. At the same time, increased emissions of voltage disturbances by end-user equipment could be predicted. This increase of emissions could be expected, among other reasons, as a result of the use of energy-efficient equipment that could include rapid load switching. Since the 6th Benchmarking Report [6], distributed generation has grown significantly and is expected to continue growing, which could result in further increases in voltage disturbances.

3.2 MAIN CONCLUSIONS FROM CEER'S PREVIOUS WORK ON VOLTAGE QUALITY

The 1st and 2nd Benchmarking Reports [1] [2] devoted their attention to CoS and CQ. CEER began addressing VQ in 2005 when preparing the 3rd Benchmarking Report [3]. In 2006, CEER started cooperating on VQ with the European standardisation organisation, CENELEC, to revise the European standard EN 50160 [13], which gives an overview of all VQ disturbances and sets limits or indicative values for many of them[132].

The 3rd Benchmarking Report discussed how a good knowledge of actual VQ levels is a first step towards any kind of regulatory intervention. In 2005, there were ongoing processes in many countries for VQ monitoring. In general, network users were entitled to verification of actual VQ levels at their point of connection. Recommendations from the 3rd Benchmarking Report were to make use of monitoring and publication of the most critical VQ performances and do further research on power quality contracts.

In 2007, a handbook developed as a joint effort by CEER and the Florence School of Regulation (FSR) on Service Quality Regulation in Electricity Distribution and Retail [46] (Handbook) mapped the limited practices of VQ regulation into four regulatory instruments:

- Publication of data;
- Minimum requirements/standards;
- Reward/penalty schemes attached to standards; and
- The adoption of power quality contracts.

Before adopting any of these instruments, the Handbook commented on the availability of reliable measurements as a very critical issue, especially in the area of VQ.

In 2008, the 4th Benchmarking Report [4] assessed the monitoring schemes for VQ in 11 countries. The Benchmarking Report concluded that the monitoring programmes suffered from lack of harmonisation. Measurements by all available meters can provide important information on voltage deviations and can offer preliminary information for further measurements. The 4th Benchmarking Report recommended that countries should consider continuous monitoring of VQ, publish results and disseminate experiences. Furthermore, it was recommended that all countries should adopt the obligation for system operators to provide individual verification of VQ upon request by end-users, and that countries should investigate whether it is feasible to use smart meters for measuring VQ parameters in an efficient way.

In 2009, CEER, in cooperation with Eurelectric, organised a joint workshop on 'Voltage Quality Monitoring', following the recommendation on disseminating experiences of voltage quality monitoring (VQM). The workshop concluded that there was a need for clear responsibility-sharing between the relevant stakeholders, increased awareness and participation among network users, and for the relevant stakeholders to remain involved in international expert groups like those set up by the International Council on Large Electric Systems (CIGRE) and the International Conference and Exhibition on Electricity Distribution (CIRED).

132 In this chapter the term 'standard' refers to a technical specification for repeated or continuous application, with which compliance may not be compulsory, and which can be an international standard, a European standard, a harmonised standard on the basis of a request by the European Commission or a national standard. The rules for individual voltage parameters are usually referred to as 'limits' or 'requirements' when they relate to VQ (whereas they are normally called 'standards' when relating to CoS or CQ).

In 2010, CEER commissioned its Cost Estimation Study focusing on the problems and costs of VQ disturbances [10]. The Cost Estimation Study found that activity in this area was at different levels of development across European countries. Results from cost-estimation studies on customer costs due to voltage disturbances are important for determining the consequences of various voltage disturbances when deciding where to focus regulation. Following the Cost Estimation Study, CEER published 'Guidelines of Good Practice on Estimation of Costs due to Electricity Interruptions and Voltage Disturbances' [11] and encouraged NRAs to perform nationwide cost-estimation studies on electricity interruptions and voltage disturbances.

In 2012, the 5th Benchmarking Report [5] focused on the improvements made to the new 2010 version of the EN 50160 standard [13]. Some of the major changes to the standard were: a division of continuous phenomena and voltage events, improved definitions and standardisations of voltage dips and voltage swells. A description of additional changes and further recommendations for the EN 50160 standard were included in the 5th Benchmarking Report.

Key findings of the 5th Benchmarking Report [5]:

- Voltage characteristics are regulated through EN 50160 in combination with stricter national requirements;
- Verification of actual voltage levels at individual connection points is guaranteed in most countries;
- Regulation of emission levels of network users varies across countries;
- Many countries have VQM systems;
- Differences exist between countries in the choice of monitored VQ parameters and in the reported voltage dip data; and
- VQ data is publicly available in some European countries.

In 2012, the CEER/ECRB report 'Guidelines of Good Practice on the Implementation and Use of Voltage Quality Monitoring Systems for Regulatory Purposes' [47] was published. The GGP highlight several different applications and drivers for launching a VQM programme. VQM is a useful tool for further understanding the relations between network properties and voltage disturbances and for verifying compliance. Moreover, a VQM programme facilitates the collection of data for benchmarking, education and improving technical standards. Regarding the specific location for monitoring, the GGP recommends implementing VQM at all EHV/HV, EHV/MV, HV/MV substations and a selection of MV/LV substations/transformers. The GGP also recommends implementing VQM at connection points for EHV and HV customers and at other connection points where voltage disturbances may be expected. In LV networks, VQM is recommended at a random selection of connection points. The GGP also suggests making use of smart meters to monitor some VQ parameters in some points of LV networks, while keeping the price of meters (and consequently the tariffs for network users) affordable.

In 2016, the 6th Benchmarking Report [6] analysed the quality on customer level, awareness of how VQ issues might affect the network and the customers themselves, the role of smart meters in quality monitoring, individual VQ verification, emission limits and others. The 6th Benchmarking Report also looked into monitoring systems including the number of VQM instruments as well as the types of network points monitored. The main recommendations were: publishing the monitored data or statistics, increasing the awareness and education on VQ to be prepared to deal with potential issues, investigating the use of smart meters for VQM and further analysing the way VQ is influenced by distributed generation and prosumers.

3.3 STRUCTURE OF THE CHAPTER ON VOLTAGE QUALITY

This chapter first describes how VQ is regulated in Europe including the standards that apply for VQ and national rules which differ from EN 50160 [13]. The chapter then looks into the indicators and parameters which are monitored across Europe in addition to requirements regarding monitoring instruments and emission limits. Information on smart meters is provided along with practices regarding data collection, aggregation, analysis and publication. Actual data on voltage dips from seven countries are presented in Annex C.

This chapter is based on data provided from the following 34 countries: Albania, Austria, Belgium, Bosnia and Herzegovina, Croatia, Cyprus, Estonia, Finland, France, Georgia, Germany, Greece, Hungary, Ireland, Italy, Kosovo*, Latvia, Lithuania, Luxembourg, Malta, Moldova, Montenegro, the Netherlands, North Macedonia, Norway, Poland, Portugal, Romania, Serbia, Slovakia, Slovenia, Spain, Sweden and Ukraine. As in other chapters of this Report, it should be noted that not all countries have submitted answers to all questions. The term 'power quality' – which usually refers to the combined effect of the quality of network voltage and the characteristics of the loads connected to it - used in responses by several countries and, thus, this chapter considers the term to be equal to 'voltage quality'.

3.4 REGULATION OF VOLTAGE QUALITY

As stated in the previous Benchmarking Reports, VQ is a technically complex component of the quality of supply. Monitoring of disturbances, as well as choosing appropriate indicators and setting their limits are of paramount importance in the VQ regulation. This regulation must consider both the costs for consumers due to equipment damage or malfunctioning and any increase in tariffs due to improvements in the electrical grid. The consequences and level of disturbances are determined by multiple stakeholders which can make it difficult to lay the responsibility on a single stakeholder.

3.4.1 Responsibilities for regulation of voltage quality

The impact of different types of voltage disturbances can vary for different individual users. Since end-user equipment is the same throughout Europe, there should be a harmonisation regarding limits on voltage disturbances. However, the regulation and standards on VQ vary between the European countries.

In Table 3-1, the responsibility of VQ regulation is presented for each reporting country. About two thirds of the NRAs have powers/duties to define VQ regulations either alone or together with other competent authorities. Each NRA's duties and powers in VQ regulation influence the role the NRA takes in regulation of VQ, as well as in awareness and education. In most countries, the powers for regulating VQ sit with government ministries and are delegated to the NRA or given to the industry or authorities for national standardisation with approval procedures from the NRA. The term 'regulation' includes setting standards, rules, minimum requirements, implementing rewards, monetary penalties and other sanctions, publishing data (benchmarking or yardstick regulation) and – in a broader sense – setting obligations for VQM.

TABLE 3-1: Responsibility of VQ regulation

Country	Does the NRA have exclusive powers/duties to define VQ regulation?	Does the NRA have powers/ duties to define VQ regulation together with other competent authorities?	Authority
Austria	Yes	No	
Belgium	No	Yes	Flanders: via regional technical regulation (TRDE) Wallonia: via regulation RTDE[133] and norm NBN EN 50160
Bosnia and Herzegovina	No	Yes	With National Assembly of Republika Srpska
Croatia	Yes	No	
Estonia	No	No	
Finland	No	No	
France	Yes	Yes	NRA has powers/duties partially delegated from the Ministry.
Georgia	Yes	No	
Greece	Yes	Yes	
Hungary	Yes	-	
Italy	Yes	No	
Kosovo*	Yes	-	Rule on Electricity Service Quality Standards: NRA develops and approves. Grid code: operator develops, NRA approves.
Latvia	Yes	No	
Luxembourg	Yes	No	
Malta	-	Yes	Competent Authority for National Standards.
Moldova	No	No	
Montenegro	Yes	-	
Netherlands, The	Yes	Yes	The standards are set by the NRA. The method of measuring and reporting the VQ is discussed with the relevant grid operators and a consulting firm, these parties also carry out the measurements.
North Macedonia	Yes	No	
Norway	No	No	
Poland	No	No	The regulation of the Minister of Economy
Portugal	Yes	No	
Romania	Yes	No	
Slovakia	No	No	
Slovenia	No	No	
Spain	No	No	
Sweden	Yes	No	
Ukraine	Yes	No	

133 RTDE stands for *Règlement Technique pour la gestion des réseaux de Distribution d'Électricité*. These are the technical regulations for the management of electricity distribution networks in the Walloon Region. TRDE stands for *Technisch Reglement Distributie Elektriciteit* (technical regulations for the management of electricity distribution networks). It has an equivalent function to RTDE, but applies to Flanders.

The following countries have regulations on VQ: Austria, Belgium, Bosnia and Herzegovina, Croatia, Cyprus, Estonia, Finland, France, Georgia, Hungary, Italy, Kosovo*, Latvia, Lithuania, Luxembourg, Moldova, Montenegro, the Netherlands, North Macedonia, Norway, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden and Ukraine. How the VQ is regulated differs between countries and an overview is given below.

In **Austria**, the requirements of the EN 50160 need to be fulfilled. VQ data is analysed by the DSOs and checked by the NRA. In cases where problems occur, the NRA contacts the DSO.

VQ in **Belgium** is regulated by technical regulations, the DSOs themselves and the law.

In **Bosnia and Herzegovina**, occasional monitoring of VQ is carried out at certain points in the transmission and distribution network. The TSO and DSOs are obliged to carry out systematic measurements of VQ in addition to measurements of VQ at the request of the customer. The NRA, SERC, is responsible for the EHV and HV system. The regional regulator RERS (in Republika Srpska) is responsible for the MV and LV system.

In **Croatia**, the VQ regulation revolves around the HRN EN 50160[134] standard. There is one individual indicator and one general (system) indicator. There are currently no penalties, it is used as a statistic and a tool to determine which parts of the network require investment. For example, in the Requirements for Quality of Electricity Supply, brought into force by the NRA, the DSO has a yearly obligation to send data to the NRA regarding all VQ complaints, as well as substations with more than 5% of customers (connected to that substation) with poor VQ [31].

VQ in **Cyprus** is regulated by Transmission and Distribution Rules [48].

The standard for VQ is voluntary in **Estonia**. However, network operators have chosen to comply with this standard on a voluntary basis (for some points). The standard is set out in the contracts' standard terms and conditions. The standard states that except for outages, fluctuations of voltage cannot exceed ±10% of the nominal voltage (U_n) in normal operating conditions. This applies for electricity supplied by public distribution networks.

In **Finland**, if a consumer complains that the VQ is not what was agreed in the connection contract (the DSO/TSO cannot change the quality level to lower than the standards set out in contracts) and the DSO/TSO has not done enough to rectify this or denies violating the contract, the NRA can step in and investigate. If necessary, the NRA can order the system operator to take corrective actions. In the case of several violations, the NRA can investigate if a DSO has violated its legal obligation to design, build and maintain the network so that VQ is acceptable.

The NRA of **France**, CRE, gives advice on decrees and technical texts including those dealing with VQ but does not have for the ability to approve or define the standards regarding VQ. The government ministries define these standards. However, since 2008, CRE has approved the models for transmission grid access contracts, including the VQ commitments. During the approval process, CRE issues public consultations including on VQ, and specifically on voltage dips. The models for distribution grid access contracts are notified to CRE, but not approved by it.

In **Georgia**, the NRA approves Grid Codes that set VQ standards for TSO and DSOs.

In **Hungary** supply voltage variation is regulated in a regulatory decree in the form of a guaranteed standard, which includes automatic compensation to customers in the case of non-fulfilment. In addition, there is a regulatory recommendation on the VQM activity of the DSOs that provides guidance to DSOs on the number of monitoring devices, technical requirements of the devices, duration of the measurements and VQ parameters to be monitored, etc.

In **Italy**, the EN 50160 standard is applied as an NRA requirement for VQ on MV and LV distribution networks, different from supply voltage variations in LV networks and from frequency variations. For supply voltage variations in LV networks, the Italian standard CEI 8-6 [49] is enforced by NRA decision. For frequency variations, the transmission grid code (which is verified by the NRA) and the Italian standard CEI 0-16 [50] (which is enforced by NRA decision) are applied.

VQ regulation in **Kosovo*** is based on regulations approved by the NRA (Grid Codes). The regulator approved the Rule on Electricity Service Quality Standards in June 2019, which includes an article regarding VQ indicators [15]. According to the Law on Electricity [25], the regulator has the duty to develop and approve the Rule on Electricity Service Quality Standards. Issues regarding VQ are also part of the Grid Codes that the system operator develops, and the regulator approves.

In **Latvia**, the mandatory standard for VQ is defined in regulations made by the Cabinet of Ministers of the Republic of Latvia.

In **Lithuania**, the VQ is regulated by the TSO. The main quality criteria are to maintain frequency and voltage values within specific ranges.

In **Luxembourg**, EN 50160 applies. Luxembourg does not currently see a need for further regulation, as it has not received any complaints regarding VQ in recent years.

VQ in **Moldova** is regulated by the old standard GOST 13109-97 [51]. The new standard EN 50160:2010 was approved by the Institute for Standardisation of Moldova in 2014 but has not yet been put into application.

134 This is the Croatia-specific version of EN 50160 published by HZN (Croatian Standards Institute).

In **Montenegro,** the grid code for the DSO defines VQ standards. In addition, the 'Rules on the Minimum Quality of Electricity Delivery and Supply' [16] introduced a Guaranteed Indicator (GI) related to VQ. If proven that the standard was not met, the DSO should resolve the problem within the predefined time limits:

- Three days if the problem can be resolved by changing the mode of operation; or
- Three months if it is necessary to conduct works or interventions (other than construction).

If the DSO does not resolve the problem within the given timeframe and the voltage improvement is not a condition of completing investment work contained in the DSO's investment plan approved by the NRA, the customer has a right to compensation.

In **the Netherlands**, system operators, together with a consulting firm, measure the different VQ parameters. The results are published online and in an annual report. The NRA monitors the results of these measurements as well as complaints from connected consumers. If the VQ report and/or consumer complaints indicate poor VQ, the NRA enforces the VQ standards with penalty fines or other regulatory interventions.

VQ in **North Macedonia** is regulated in the Grid Code for Electricity Distribution [17] which is approved by the NRA, the Energy Regulatory Commission. It obliges DSOs to implement standard MKC EN 50160:2012[135].

In **Norway,** VQ is regulated through regulation N° 1557 of 30 November 2004 on quality of supply in the Norwegian power system [37], which includes requirements for VQ, and registration and reporting of the VQ. The regulation also manages the DSOs' procedures in the event of dissatisfaction regarding the VQ.

In **Poland,** the quality parameters of electricity are set out in Ministry of Energy regulations, which comply with EN 50160. In addition, the NRA approves TSO and DSOs' Grid Codes where the same VQ standards are set.

In **Portugal**, VQ is regulated in the Quality of Service Code [27], which is approved by the Portuguese NRA. It obliges DSOs to use the standard EN 50160:2010.

VQ in **Romania** is regulated through transmission and distribution standards.

In **Slovakia**, VQ is regulated through the quality standards regulation.

Annual Reports on Quality of Electricity Supply in **Slovenia** for the TSO and DSO are made public and include (mandatory) data on continuous VQM. This approach is considered to be in accordance with the regulatory requirement regarding public disclosure of VQ data. Further, there is a guaranteed standard (on CQ) which addresses the supply voltage variations parameter.

In **Spain**, the VQ of the product refers to the set of characteristics of the voltage wave, which can be affected, mainly, by variations in the root mean square (r.m.s.) value of the voltage and frequency, and by service interruptions and voltage dips.

In **Sweden,** the regulation of quality of supply is found in the Electricity Act [21], and furthermore in the secondary regulation EIFS 2013:1 [52]. The limiting values for the voltage phenomena are mostly based on the standard EN 50160 but not all are, e.g. the limiting values for voltage swells are not based on the standard. The voltage levels are also not based on the standard as they have been adjusted to better fit the structure of the Swedish electricity system. It should be noted that not all VQ parameters that are included in the standard are included in the regulation (for example, flicker is not).

In **Ukraine,** EN 50160 is implemented in the distribution network code. It sets the requirements for VQM in distribution networks (started in 2021) and the requirements for individual VQ verification.

3.4.2 Voltage quality standardisation (EN 50160)

The European standard EN 50160 [13] gives an overview of all VQ disturbances and sets limits or indicative values for many of them. This document has become an important basis for VQ regulation throughout Europe. A further important contribution comes in the form of the standard on power quality measurements, EN 61000-4-30 [53] which has resulted in common methods for VQM.

Some of the limits set by EN 50160 for voltage disturbances are presented in Table 3-2. In the case of supply voltage variations, limits are set only for LV and MV networks. In the standard, the following definitions of voltage levels are used:

- LV with a nominal r.m.s. value of $U_n \leq 1$ kV;
- MV with a nominal r.m.s. value of 1 kV < $U_n \leq 36$ kV; and
- HV with a nominal r.m.s. value of 36 kV < $U_n \leq 150$ kV.

Some countries use different definitions of voltage levels. These definitions are shown in Table 2-1 of the CoS chapter.

135 This is the North Macedonia-specific version of EN 50160.

TABLE 3-2: Standard EN 50160 – summary of continuous phenomena

Voltage disturbance	Voltage level	Voltage quality index (limit)	Explanation
Supply voltage variations	LV	• 95% of the 10-minute mean r.m.s. values for 1 week (±10% of nominal voltage) • 100% of the 10-minute mean r.m.s values for 1 week (+10% / -15% of nominal voltage)	The r.m.s.-value is the DC-equivalent to the AC-voltage. Instead of using the sine wave when calculating, an r.m.s-value is calculated and used. The r.m.s. value is given for one period of the sine wave. In EN 50160, the term 'mean r.m.s.' is the mean of all calculated r.m.s.-values over the period of 10 minutes. [13]
	MV	• 99% of the 10-minute mean r.m.s. values for 1 week below +10% of reference voltage and 99% of the 10-minute mean r.m.s. values for 1 week above -10% of reference voltage • 100% of the 10-minute mean r.m.s. values for 1 week (±15% of reference voltage)	
Flicker	LV, MV, HV	• 95% of the P_{lt} values for 1 week, should be less than or equal to 1	P_{lt} is the long-term flicker. P_{st} is the short-term flicker. It is the flicker measured over a period of ten minutes. P_{lt} is calculated from 12 P_{st}-values over an interval of 2 hours: $P_{lt} = \sqrt[3]{\sum_{i=1}^{12} \frac{P_{sti}{}^{3}}{12}}$
Unbalance	LV, MV, HV	• 95% of the 10-minute mean r.m.s. values of the negative phase sequence component divided by the values of the positive sequence component for 1 week, should be within the range of 0% to 2%	
Harmonic voltage	LV, MV	• 95% of the 10-minute mean r.m.s. values for 1 week lower than limits provided by means of a table • 100% of the THD values for 1 week (≤ 8%)	THD is the total harmonic distortion: $THD = \sqrt{\sum_{h=2}^{40} (u_h)^2}$ where u_h is the individual harmonic voltage
	HV	• 95% of the 10-minute mean r.m.s. values for 1 week lower than limits provided by means of a table	
Mains signalling voltages	LV, MV	• 99% of a day, the 3-second mean value of signal voltages less than limits presented in graphical format	

In Table 3-3, the relation to the European technical standard for each reporting country is presented. The 2010 version of the standard EN 50160 [13] had been translated and applied in the majority of countries. In three countries, Georgia, Germany and Latvia, the 2007 version of the standard is still in force. In Albania, Malta and Slovakia an even older version of the standard is implemented.

In 12 countries, the application of the standard is defined in the regulation, whereas in 12 other countries there are references to the EN 50160 in the national legislation. In **Belgium**, there is reference to the standard in both the regulation and the legislation. The implementation of the EN 50160 standard is voluntary in four countries.

TABLE 3-3: EN 50160 – Implementation and use in VQ regulation

Country	Is the European technical standard CENELEC EN 50160 applied?	What version of the standard is implemented?	How is the standard implemented?
Albania	Yes	Older version	In the regulation
Austria	Yes	2010	In the regulation
Belgium	Yes	2010	Reference in the legislation and regulation
Bosnia and Herzegovina	Yes	Republika Srpska: 2010 The entire country: postponed to 2022	Reference in the legislation
Croatia	Yes	2010	Reference in the legislation
Cyprus	Yes	2010	In the regulation
Estonia	Yes	2010	Is a voluntary standard
Finland	Yes	2010	Reference in the legislation
France	Yes	2010	In the regulation
Georgia	Yes	2007	In the regulation
Germany	Yes	2007	Is a voluntary standard
Greece	Yes	2010	Reference in the legislation
Hungary	Yes	2010	Is a voluntary standard
Ireland	Yes	2010	In the regulation
Italy	Yes	Latest edition of the Italian standard (currently 2020 variant of EN 50160:2010)	In the regulation
Kosovo*	Yes	2010	In the regulation
Latvia	Yes	2007	In the regulation
Lithuania	Yes	2010	In the regulation
Luxembourg	Yes	2010	In the regulation
Malta	Yes	Older version	Other
Moldova	Yes	2010	Other
Montenegro	Yes	2010	Reference in the legislation
Netherlands, The	Yes	2010	Other
North Macedonia	Yes	2012	Reference in the legislation
Norway	Yes	2010	Other
Poland	Yes	2010	Is a voluntary standard
Portugal	Yes	2010	Reference in the legislation
Romania	Yes	2010	Reference in the legislation
Serbia	Yes	2010	Other
Slovakia	Yes	Older version	Reference in the legislation
Slovenia	Yes	2010	Reference in the legislation
Spain	Yes	2010	Reference in the legislation
Sweden	Yes	2010	In the regulation
Ukraine	Yes	2010	Reference in the legislation

In **Hungary**, the standard is implemented as a voluntary standard. Some of the requirements are included in the DSOs' standard service agreement.

In **Serbia**, certain issues of the standard are applied in secondary legislation acts, such as grid codes and the 'Decree on Conditions for Electricity Delivery and Supply' [54].

The standard was adopted in **Luxembourg** as ILNAS-EN 50160:2010/A1/2015[136] by the national standardisation body and it is referred to in the technical connection codes (regulations).

In **Poland**, the standard was introduced into the collection of Polish standards as PN-EN 50160[137] by the discretionary method but most standards are implemented in national regulations (grid codes).

In **North Macedonia**, the standard is not implemented via primary legislation, but is referenced in the 'Grid Code for Electricity Distribution' [17]. In other words, it is in a bylaw (regulation) but not in a law (legislation).

The Network Code [55] in **Malta** refers to EN 50160 only for certain voltage parameters that require compliance to this standard. The Network Code was developed by the DSO and was subject to consultation before adoption. This Code defines the technical aspects of the working relationship between the DSO and all users of the distribution system. The Network Code has to be approved by the NRA.

In **Moldova**, the standard was approved as a national standard but has not been put into application. An old standard is used instead (from the former Soviet Union) - GOST 13109-97 [51]. There is no final decision regarding the transition to the new EN 50160-2010 although this transition is expected to be made in the next few years.

In **the Netherlands**, specific standards regarding VQ are formulated for the < 1 kV, 1 to 35 kV, and > 35 kV voltage levels. For all aspects not covered by these standards, the EN 50160:2010 standard applies.

In **Norway**, the Regulation N° 1557 of 30 November 2004, 'Regulations relating to the quality of supply in the Norwegian power system' [37] gives the requirements for VQ. Most of the requirements are similar to the standard, but some are different.

The regulation in **Sweden** is largely based on EN 50160. A section on short-duration voltage dips has been added to the regulation and parts of the standard that have not been included are still valid as an industry standard (for example, regarding flicker). Detailed information on the parameters which deviate from the standard is provided in Section 3.4.3.

3.4.3 National legislation and regulations that differ from EN 50160

Standard EN 50160 [13] remains the basic instrument for VQ assessment in reporting countries. However, in some countries, different requirements are implemented in national legislation. The reasons for the existence of such differences differ from country to country and are usually related to the fact that the 2010 version of the standard still does not cover EHV levels. An additional reason is that stricter limits have been used at national level than those established by the standard.

In **Ireland**, the range of supply voltage variations applied to MV was set by the DSO long before EN 50160 was introduced and are still in force.

In **Italy**, the range of supply voltage variations in LV networks is +/-10% of the nominal voltage under ordinary network operating conditions.

In **Lithuania**, the grid is operated in parallel with the Integrated Power System / Unified Power System (IPS/UPS) grid of Russia (with plans of de-synchronisation), thus it follows a different frequency standard. In addition, the other parameters for voltage higher than 150 kV are stricter than the characteristics defined in EN 50160.

Malta has differences in the tolerance limits for certain VQ characteristics between its Network Code [55] and EN 50160. The Network Code is prepared by the DSO and approved by the NRA following stakeholder consultation.

In **the Netherlands**, the national law defines different requirements than those provided in EN 50160. The purpose of this is to apply more elaborate voltage fluctuation standards.

In **Norway**, it is assumed that the standard EN 50160 has some important and crucial weaknesses and is therefore not suitable for satisfactory public regulation of the quality of electricity supply in the Norwegian power system. One of the important issues is that for several areas, the standard only defines limits that apply 95% of the time. Further, it only defines limits to some of the quality parameters. For some of the parameters, the standard only describes what can be expected in Europe. The opinion of the Norwegian NRA is that it is not acceptable that the quality delivered to the grid customers lacks values for eight hours (up to 5% of the time) every week for several important parameters.

The same definitions in EN 50160 are used in **Sweden**, but with the alteration that limits should not be exceeded 100% of the time, similarly to Norway. This is done to allow for tracking of all situations that do not fulfil the requirements. Another deviation from the standard in Swedish regulation applies to voltage levels given that Sweden applies the voltage level of 45 kV instead of the standard's 36 kV.

Table 3-4 presents the requirements for supply voltage variations in countries where they are different than those in EN 50160. Further, Table 3-5 and Table 3-6 show requirements for other VQ indicators for the countries that differ from EN 50160 [13].

136 The European norm EN 50160:2010/A1/2015 was adopted as a Luxembourgish standard under the reference ILNAS-EN 50160:2010/A1/2015.
137 The PN-EN 50160 standard has a non-obligatory status, as a translation of the English version of the European standard EN 50160.

TABLE 3-4: Voltage quality regulation differing from EN 50160 – supply voltage variations

Voltage disturbances	Country	Indicator	Voltage level	Integration period	Time	Limit
Supply voltage variations	FR	r.m.s. voltage	LV	10 min	100%	±10% of U_n
		r.m.s. voltage	MV	10 min	100%	±5% of U_n
	IT	r.m.s. voltage	LV	undefined	100%	±10% of U_n
	LT	r.m.s. voltage	HV (110 kV)	-	-	+11.8% / -10% of U_n
		r.m.s. voltage	HV (330 kV)	-	-	+9.7% / -10% of U_n
		r.m.s. voltage	HV (400 kV)	-	-	+5% / -10% of U_n
	MT	r.m.s. voltage	LV	10 min	100%	±10% of U_n
		r.m.s. voltage	MV (11 kV)	10 min	100%	±5% of U_n
		r.m.s. voltage	MV (33 kV)	10 min	100%	+5% / -10% of U_n
		r.m.s. voltage	HV	10 min	100%	±6% of U_n
	NL	r.m.s. voltage	LV, MV	10 min	100%	+10% / -15% of U_n
		r.m.s. voltage	LV, MV	10 min	95%	±10% of U_n
		r.m.s. voltage	HV, EHV	10 min	99.9%	±10% of U_n
	NO	r.m.s. voltage	LV	1 min	100%	±10% of U_n
	SE	r.m.s. voltage	LV, MV, HV	1 min	100%	±10% of U_n

(1): EHV is not covered by the EN 50160: 2010
(2): For HV no supply voltage variations limits are given by the EN 50160: 2010
(3): The measurement period for all the above requirements is one week
(4): Cells with (-) means no available parameter information

TABLE 3-5: Voltage quality regulation differing from EN 50160 – other variations

Voltage disturbances	Country	Indicator	Voltage level	Integration period	Time	Limit
Flicker	MD	P_{st}	LV, MV	-	-	≤ 1.38
		P_{lt}	LV, MV	-	-	≤ 1
	ME	P_{st}	LV, MV	-	-	≤ 0.7
		P_{lt}	LV, MV	-	-	≤ 0.5
	MK	P_{st}	LV, MV	10 min	95%	≤ 0.8
		P_{lt}	LV, MV	10 min	95%	≤ 0.5
	MT	P_{st}	LV, MV	10 min	-	≤ 0.7
		P_{lt}	LV, MV	2 h	-	≤ 0.5
	NL	P_{lt}	HV, EHV	10 min	100%	≤ 1
		P_{lt}	HV, EHV	10 min	95%	≤ 5
	NO	P_{st}	LV, MV	-	95%	≤ 1.2
		P_{st}	HV, EHV	-	95%	≤ 1
		P_{lt}	LV, MV	-	100%	≤ 1
		P_{lt}	HV, EHV	-	100%	≤ 0.8
	PL	P_{lt}	HV	-	95%	≤ 0.8
	RO	P_{st}	HV	-	95%	≤ 0.8
		P_{lt}	LV	-	95%	≤ 1
		P_{lt}	HV	-	95%	≤ 0.6

TABLE 3-5: Voltage quality regulation differing from EN 50160 – other variations

Voltage disturbances	Country	Indicator	Voltage level	Integration period	Time	Limit
Voltage unbalance	LT	V_{un}	HV (110 kV)	-	-	≤ 1.4%
		V_{un}	HV (330 kV)	-	-	≤ 0.8%
	ME	V_{un}	LV, MV	-	-	≤ 3%
	MK	V_{un}	LV	10 min	95%	≤ 3%
		V_{un}	MV	10 min	95%	≤ 2%
	MT	V_{un}	LV, MV	-	-	≤ 1.3%
	NL	V_{un}	LV, MV	10 min	95%	≤ 2%
		V_{un}	LV, MV	10 min	100%	≤ 3%
		V_{un}	HV, EHV	10 min	99.9%	≤ 1%
	NO	V_{un}	LV, MV, HV, EHV	10 min	-	≤ 2%
	PL	V_{un}	HV	10 min	95%	≤ 1%
	SE	V_{un}	LV, MV, HV	10 min	-	≤ 2%
Harmonic voltage	ME	THD	LV	-	-	≤ 2.5%
		THD	MV (11 kV)	-	-	≤ 2%
		THD	MV (35 kV)	-	-	≤ 1.5%
	MK	THD	LV, MV	10 min	95%	≤ 8%
	NL	THD	MV	10 min	95%	≤ 8%
		THD	MV	10 min	99.9%	≤ 12%
		THD	HV	10 min	95%	≤ 6%
		THD	HV	10 min	99.9%	≤ 7%
		THD	EHV	10 min	95%	≤ 5%
		THD	EHV	10 min	99.9%	≤ 6%
	NO	THD	0.23 kV ≤ U ≤ 35 kV	10 min	100%	≤ 8%
		THD	35 kV ≤ U ≤ 245 kV	10 min	100%	≤ 3%
		THD	U > 245 kV	10 min	100%	< 2%
		THD	LV, MV	1 week	100%	≤ 5%
		Individual	LV, MV, HV	10 min	100%	Table with values
	RO	THD	LV, MV	-	95%	≤ 8%
		THD	HV, EHV	-	95%	≤ 3%
	SE	THD	U ≤ 36 kV	10 min	100%	≤ 8%
		THD	36 kV < U ≤ 150 kV	10 min	100%	≤ 8%
		Individual	LV, MV, HV	10 min	100%	Table with values

(1): The measurement period for all the above requirements is one week
(2): Cells with (-) indicate that no parameter information was available

TABLE 3-6: Voltage quality regulation differing from EN 50160 – events

Voltage disturbances	Country	Voltage level	Description
Voltage dips	NO	LV, MV, HV, EHV	Sudden reduction of the r.m.s. value of the supply voltage to less than 90%, but greater than 5% of the declared voltage level for a duration lasting from 10 milliseconds (ms) to 60 seconds.
	RO	LV, MV, HV	A sudden reduction of the supply voltage in a point of the network to a value between 90% and 5% of the declared voltage. When applying this standard, the duration of a voltage dip is between 10 ms and 1 minute.
	SE	U < 45 kV	U > 40% of declared voltage and 1 sec < t < 60 sec: should not occur. 40% < U < 70% and 5 sec < t < 60 sec: should not occur. U < 40% and 10 ms < t < 1 sec: DSO should perform reasonable actions to fix the variations. 50% < U < 70% and 500 ms < t < 60 sec: DSO should perform reasonable actions to fix the variations.
		U > 45 kV	U < 80% and 600 ms < t < 60 sec: should not occur. U < 70% and 100 ms < t < 600 ms: DSO should perform reasonable actions to fix the variations. 70% < U < 90% and 150 ms < t < 600 ms: DSO should perform reasonable actions to fix the variations. 80% < U < 90% and 600 ms < t < 60 sec: DSO should perform reasonable actions to fix the variations
Voltage swells	NO	LV, MV, HV, EHV	Sudden increase in the r.m.s. value of the voltage to more than 110% of the declared voltage level for a duration lasting from 10 ms to 60 seconds.
	RO	LV, MV, HV	The threshold at which the voltage starts to rise (the beginning of the swell) is equal to 110% of the reference voltage.
	SE	LV	U ≥ 135% of declared voltage and 10 ≤ t ≤ 5,000 sec: should not occur. U ≥ 115% of declared voltage and 5,000 < t ≤ 60,000 sec: should not occur. 135% > U ≥ 115% of declared voltage and 10 ≤ t ≤ 5,000 sec: grid owner is obliged to remedy voltage swells to the extent that the measures are reasonable in comparison with the inconveniences for the affected end-consumers. 115% > U ≥ 111% of declared voltage and 200 < t ≤ 60,000 sec: grid owner is obliged to remedy voltage swells to the extent that the measures are reasonable in comparison with the inconveniences for the affected end-consumers.
Single rapid voltage change	LT	HV	If the single rapid voltage change occurs ≤ 4 a day - voltage can drop 3-5% of the nominal value. If the single rapid voltage change occurs ≤ 2 per hour and ≥ 4 per day - voltage can drop 3% of the nominal value. If the single rapid voltage change occurs ≥ 2 per hour and ≤ 10 per hour - voltage can drop 2.5% of the nominal value.
	NO	LV, MV, HV, EHV	Number of voltage changes per 24 hours: $\Delta U_{steady\ state}$ ≥ 3%: ≤ 24 0.23 kV ≤ U ≤ 35 kV ≤ 12 35 kV < U ΔU_{max} ≥ 5%: ≤ 24 0.23 kV ≤ U ≤ 35 kV ≤ 12 35 kV < U
	SE	-	A change in the value of r.m.s. voltage which is faster than 0.5% per second and where the r.m.s. value before, during and after the change ranges between 90-110% of reference voltage. Rapid voltage changes are decided from a stationary and maximum voltage change where $\Delta U_{steady\ state}$ is the difference between the r.m.s. voltage value before and after the change and ΔU_{max} is the maximum voltage change during the event. The total number of single rapid voltage changes and the number of voltage swells for area A defined in tables 3 and 4 of the Energy markets inspectorate's secondary legislation concerning quality of supply of electricity (EIFS 2013:1[138]) should not exceed the following limits: dU_steady state ≥ 3 %: 24 if U is less than 45 kV; 12 if U is larger than 45 kV. dU_max ≥ 5 %: 24 if U is less than 45 kV; 12 if U is larger than 45 kV. Voltage swells from area A are specified as follows: For voltages up to and including 45 kV: 90 > U ≥ 40 (%) and 10 ≤ t ≤ 200 (ms) 90 > U ≥ 70 (%) and 200 < t ≤ 500 (ms) For voltages exceeding 45 kV: 90 > U (%) and 10 < t < 100 (ms) 90 > U > 70 and 100 < t < 150 (ms)
Transient overvoltages	MK	LV, MV	The change of voltage relative to the rated voltage at the point of connection of a generating plant to a transient mode of operation, i.e., when the generator unit is switched on or off, should not exceed the permissible value: 1) 2% if the connection point is in the MV grid and switches causing voltage changes are frequent (1 to 10 minutes). 2) 3% if the connection point is in the LV grid and switches causing voltage changes are frequent (one in 10 minutes). 3) 3% if the connection point is in the MV grid and the switches causing voltage changes are less frequent. 4) 6% if the connection point is in the LV grid and switches causing voltage changes are less frequent.

138 EIFS is short for (swe.) Energimarknadsinspektionens föreskrifter och allmänna råd om krav som ska vara uppfyllda för att överföringen av el ska vara av god kvalitet.

3.5 VOLTAGE QUALITY MONITORING PRACTICES

TABLE 3-7: Voltage quality monitoring

Country	Transmission	Distribution	No VQM
Albania	×	×	
Austria		×	
Belgium	×	×	
Bosnia and Herzegovina	×	×	
Croatia	×	×	
Cyprus	×	×	
Estonia			×
Finland			×
France	×	×	
Georgia	×	×	
Germany			×
Greece			×
Hungary		×	
Ireland	×	×	
Italy	×	×	
Kosovo*	×	×	
Latvia	×	×	
Lithuania			×[139]
Luxembourg			×
Malta			×
Moldova	×		
Montenegro			×
Netherlands, The	×	×	
North Macedonia	×	×	
Norway	×	×	
Poland	×	×	
Portugal	×	×	
Romania	×	×	
Serbia			×
Slovakia	×	×	
Slovenia	×	×	
Spain			×
Sweden	×	×	
Ukraine	×	×	

Table 3-7 illustrates the practices in VQM across Europe. Out of the countries that responded to this question, 24 monitor VQ in their grids (either in transmission or distribution but, in most cases, both), while ten countries do not. In several countries, the system operators monitor VQ on a voluntary basis. Portable monitoring instruments are used in Albania, Austria, Belgium (all three distribution regions), Bosnia and Herzegovina, Cyprus, Georgia, Greece, Hungary, Ireland, Latvia, Malta, Moldova, Norway, Portugal, Romania, Slovenia and Ukraine.

Four countries indicated that they intend to start monitoring new parameters. Cyprus stated that it will start monitoring MV substations, while Kosovo* is planning to monitor the harmonics and voltage flickers. Lithuania foresees implementation of around 50 power quality analysers distributed throughout the 110 kV and 330 kV networks. Hungary also intends to start monitoring new VQ parameters but could not provide detailed information.

139 In transmission, frequency and voltage are measured continuously in order to maintain values within the permitted range.

Predefined tariffs for monitoring are used in only three countries: Belgium (only the Flanders region), France, where they are included in network tariffs and Slovenia, where temporary monitoring on customer request is paid by the customer in cases where the results of measurements do not show non-compliance with the standard. This VQ service costs 224.09 euros. The following paragraphs provide more details on VQM practices across Europe.

In **Albania**, VQM is promoted by the NRA (its purpose is regulation) while the system operators pay the costs of monitoring. As of 2018, the following network points are monitored continuously in Albania: HV substations, HV end-user sites and MV busbars in HV/MV substations.

Austria monitors VQ for the purposes of statistics but only on MV (however, measuring VQ on LV level is also done for some customers). As mentioned above, Austria indicated that portable monitoring instruments are used. However, the statistical approach does not differentiate between fixed and portable instruments. Monitoring is both permanent and temporary which is carried out for three weeks on average but may differ depending on the monitored point. As of 1 January 2020, 100% of the 450 HV/MV substations are monitored. Additionally, around 4,300 potential measuring points are identified on MV level (out of 70,000) and 400 of these are randomly selected (360 measured over three weeks and 40 measured all year). The cost of monitoring is included in the cost base and financed by tariffs.

In **Belgium**, Wallonia and Brussels monitor VQ on MV only, while Flanders monitors on MV and LV levels. Implementation of this system in transmission was recommended by the NRA, while the regional regulatory authorities recommended it for distribution in Wallonia and Brussels with statistical and regulatory goals in mind. In Flanders, it is voluntarily implemented for MV and supported by regional legislation for LV (required functionality of smart meters).

The TSO, Elia, monitors the HV substations and installs a monitoring instrument:

- Systematically in all its substations where at least one customer is connected (an exception is made for railway, subway and DSO substations);
- In some (but not all) substations connecting the above categories/exceptions; and
- Substations which are interconnected to other TSOs (abroad).

For voltage levels between 30 kV and 380kV, the TSO has to report these quality parameters on a yearly basis: interruptions, voltage dips, flicker and harmonic distortion of the voltage. As of 2018, the number of monitored points in transmission is: 32 on 380 kV, 19 on 220 kV, 112 on 150 kV, 80 on 70 kV, 97 on 36 kV and 8 on 30 kV.

MV busbars in HV/MV substations are monitored in all distribution regions. In Wallonia and Brussels, 100% of such network points are monitored (180 in Wallonia and 52 in Brussels). In addition, LV busbars in MV/LV transformers are monitored in Brussels. The number is very low, however, with less than 50 LV busbars being monitored (out of 3,500). Flanders also monitors 111,000 of its LV end-user sites and this number is rapidly increasing as a result of the smart meter rollout.

Portable instruments are included in all three distribution regions in Belgium. As for fixed instruments, 52 were used on MV level in Brussels as of 2019. Belgian distribution monitors its network points continuously and the cost is borne by the DSOs. Predefined tariffs for monitoring exist only in Flanders.

Bosnia and Herzegovina monitors VQ on all voltage levels but MV and LV are only monitored in the Republika Srpska entity. The DSOs are obliged to measure VQ parameters at pre-defined time periods. The TSO is obliged to monitor voltage level continuously and this data (EHV and HV level) should be published at least once a year. The scheme applies to the following network points: HV substations, HV end-user sites, MV busbars in HV/MV substations, MV end-user sites, LV busbars in MV/LV transformers and the LV end-user sites (the last three are monitored by five DSOs in Republika Srpska). The system was recommended by the regulatory authorities (the NRA, SERC, and the regional regulator of Republika Srpska, RERS) through secondary legislation and implemented by the system operators.

The parameters monitored in distribution are: power frequency, supply voltage variations, flicker, supply voltage unbalance, harmonic voltage and mains signalling voltages. Portable instruments appear to be the only type of instrument used, at least from 2014 to 2018. The duration of temporary monitoring is one week in distribution and three weeks in transmission. The cost of monitoring is paid by the system operators.

Croatia monitors VQ on all voltage levels, but only on request. The purpose is mostly statistical and for recognising what part of the grid requires the most investment. The monitoring system on request was implemented many years ago and was followed by the NRA bringing into force the Requirements for Quality of Electricity Supply, which prescribe one individual indicator and one general (system) indicator [31].

Cyprus monitors VQ on 132 kV and as per the terms of connection agreements on 11 kV and 0.4 kV. This is taken from the requirements in the Transmission and Distribution Rules [48] and aims to maintain the power quality within approved and standardised limits.

Monitoring on higher voltage levels is carried out on a continuous basis at points of connection of large customers/ producers. Monitoring is paid by end-users, but the operation (collection of data) is paid by system operators.

The TSO reported that network points are continuously monitored, but the DSO indicated that portable monitoring devices are installed at specific network points according to the complaints received. The average duration of temporary monitoring is ten days. As of 2018, there was a total of five HV end-user sites that were monitored (these are fixed monitoring instruments). In addition, five out of 27 large solar farms (with capacity larger than 500 kW) were also monitored in 2018. As stated in the introductory paragraph, Cyprus also plans to start monitoring MV substations.

The NRA of **Finland** does not collect VQ data, however, the DSOs and the TSO may collect data for their own purposes while paying for the costs themselves. If a customer calls for an investigation, metering points may be monitored to validate the quality. The average duration of monitoring is two weeks and all instruments in use are portable.

All voltage levels are involved in VQ monitoring in **France**, although there is no obligation for monitoring. This is done for the purpose of statistics, to provide information to customers and to ensure that standards in legislation and contracts to individual customers are fulfilled. All customers pay through grid tariffs. The network points are usually monitored continuously and they include: HV substations, HV end-user sites (with approximately 12% of points monitored; 208 out of 1,720), MV busbars in HV/MV substations (with 60% of points monitored; 3,000 out of 5,000), MV end-user sites (with 50% of points monitored; 48,000 out of 96,000) and LV end-user sites (with 270,000 monitored points which roughly corresponds to 1% of the total number).

VQM in **Georgia** was promoted by the NRA for the purpose of statistics and regulation development. System operators pay the cost of monitoring which is carried out on the following voltage levels: 0.4 kV, 6(10) kV, 35 kV, 110 kV, 220 kV, 330 kV and 500 kV. Most instruments used are portable, with temporary monitoring of two weeks on average. Since 2015, four fixed instruments have been used. All four network points in HV substations are monitored.

Greece specified that it does not have systematic monitoring of VQ on end-user level. Its DSO performs measurements as required, mainly to investigate customer complaints regarding VQ and to determine compliance with emission limits when generators are connected to the network. As of 2018, all instruments used are portable.

Hungary monitors VQ only in distribution (on LV and MV), with DSOs bearing the cost. Monitoring was initiated by the NRA, which provided 400 devices for DSOs to perform monitoring of their own network for six months in a rotational system. The monitoring goal is to identify weak points of the network before customers encounter problems. Despite there being no obligation to monitor, all DSOs have created their own monitoring programme in accordance with the regulatory recommendation. The parameters involved are: supply voltage variations, voltage unbalance, total harmonic distortion (THD), voltage dips and swells.

As of 2018, there were 340 fixed instruments in addition to those that are portable. Network points on MV are monitored continuously while those on LV are monitored temporarily with an average duration of 11 days. MV busbars are constantly monitored in all HV/MV (120 kV on the primary side) and MV/MV substations and approximately 2% of the MV customers' connection points. In LV, DSOs usually measure VQ of an area supplied by a certain MV/LV transformer using three to four portable devices (one on the LV side of the MV/LV transformer and the other devices on the end points of the LV lines). The total number of monitored points is 6,381 on LV and 325 on MV.

The system in **Ireland** was implemented voluntarily for the purpose of compliance with the standards and resolution of voltage complaints. Quality on the following voltage levels is monitored: 400 kV, 220 kV, 110 kV, 38 kV, 20 kV and 10 kV. Both fixed and portable instruments are in use with approximately 300 fixed instruments in service in 2019. Network points are monitored continuously, and the DSO bears the cost.

Ireland indicated that, as of 2018, VQM is broken down as follows:

- HV substations: the total number of points is approximately 700 and the number of monitored points where the secondary voltage is 38 kV is approximately 80 (roughly 11% of points are monitored);
- HV end-user sites: the total number of points is 54 and the number of monitored points is 0;
- MV busbars in HV/MV substations: the total number of points is approximately 550 and the number of monitored points where the secondary voltage is MV is approximately 30 (roughly 5.45% of points are monitored);
- MV end-user sites: the total number of points is 1,697 and the number of monitored points is 0;
- LV busbars in MV/LV transformers: the total number of points is 250,000 and the number of monitored points is 0;
- LV end-user sites: the total number of points is 2.3 million and the number of monitored points is 0; and
- Other points: generators greater than 300 kVA connected to distribution network at voltage levels of 38 kV, 20 kV and 10 kV. The total number of these points is approximately 200 and the number of monitored points is the same (100% of points are monitored).

In **Italy**, the monitoring of VQ (voltage dips) in the transmission grid is carried out by the TSO, which annually monitors the VQ levels on sample nodes and compares them to expected levels. Individual regulation of voltage dips and transient interruptions is implemented for some HV customers who previously participated in specific monitoring. The monitoring of VQ (voltage dips) in distribution networks is carried out annually at all DSOs' HV/MV substations and about 4,200 MV busbars. The results (average number of severe dips per customer, for each DSO) have been published by the Italian NRA since 2021.

In **Kosovo*,** an advanced metering system monitors harmonic voltage distortion while voltage level is monitored on 400 kV, 220 kV and 110 kV levels in accordance with grid code requirements. Monitoring in the distribution network is performed by SCADA system on 35 kV and 10 kV voltage levels. Portable measurement instruments are not used, but the network points such as HV substations and MV busbars in HV/MV substations are monitored continuously. The latter type has a total of 1,294 points in distribution, while the total number of points that could be monitored through relays is 1,131. All 1,131 of these points (100%) have been monitored since the installation of SCADA system in all HV/MV substations. The costs in distribution are covered by the DSO. In transmission, costs are covered through tariffs. As stated earlier in this section, Kosovo* is planning to start monitoring voltage flickers and harmonics.

VQ in **Latvia** is monitored on request, although the NRA can carry out control measurements of random grid users in distribution. In the case of the former, the DSO pays the costs. In the case of the latter, the NRA bears the cost. As of 2018, only portable instruments are used on LV, and the network points are monitored temporarily with an average duration of one week. The number of monitored LV end-user sites is 50. In addition, there are 532 LV network points that are monitored by the DSO (with portable equipment) on user request.

Malta does not monitor VQ, however, a survey on the topic was carried out by the NRA in 2013-2014 with the aim of obtaining a data sample for all voltage characteristics to better understand the existing level of the quality of supply. In the audit carried out by the NRA, most of the sites were monitored for 15 days (using portable instruments). The survey was mainly based on ECRB guidelines and on EN 50160. A random sample of 104 single-phase LV customer points and two three-phase LV customer points were monitored.

The DSO has access to voltage data recorded by smart meters (the minimum and maximum levels). The readings are mainly used to investigate customer complaints regarding VQ. This is used in addition to voltage monitoring performed by the DSO on a case-by-case basis in the case of complaints.

Moldova indicated that it monitors VQ only in transmission. Both portable and fixed instruments are used for temporary monitoring of network points. As part of the SCADA system, the TSO has installed VQ analysers (PLA-34) in most transmission substations but most of them are used to monitor only the voltage level. They could, however, be set up to monitor all VQ characteristics. The full range of quality indicators is monitored at key HV/MV substations. There are 28 fixed monitoring instruments for complex analysis of VQ in the system: four at the 330 kV and 400 kV substations and 24 at the 110/35/10 kV substations. Out of 300 total network points on MV busbars in HV/MV substations, 250 are monitored. Most HV/MV substations in Moldova are owned and operated by the TSO (except a small number of substations, operated by one of the DSOs) and are part of the transmission network. As for the busbars in distribution substations, only the voltage level is monitored (but not all voltage characteristics). The costs are borne by system operators.

The VQM system in **the Netherlands** involves all voltage levels (EHV, HV, MV and LV) and was initiated by the grid operators but improved upon after an intervention by the NRA. The monitored parameters are: slow voltage fluctuations, fast voltage fluctuations, wave form asymmetry, THD and the distortion of individual harmonics. System operators pay the costs of monitoring. All 652 instruments in use (as of 2018) are fixed and these network points are monitored continuously:

- HV end-user sites: with 73 monitored points out of a total of 98 (74%);
- MV end-user sites: with 270 monitored points; and
- LV end-user sites: with 254 monitored points out of a total of 8,588,855.

In **North Macedonia**, the system for VQM is selected by network operators and involves the 110 kV, 35 kV, 20 kV and 10 kV voltage levels. Network points (HV substations and MV busbars in HV/MV substations) are usually monitored continuously. If monitored on a temporary basis, the duration is at least seven days. Per article 84 of the Grid Code for Electricity Distribution, DSOs are obliged to monitor, control and improve the following characteristics of the voltage in the distribution system: frequency variation, fast and slow variations of the r.m.s. value of the voltage, flicker, harmonics, sinusoidal form of the voltage, voltage asymmetry and the power factor [17]. Per the 'Rulebook for Control of Electricity Quality' [56], issued by the Ministry of Economy, VQ is regularly monitored by the Technical Inspectorate in accordance with the previously adopted annual programme for monitoring ten measuring points monthly.

System operators in **Norway** are obliged to perform continuous monitoring of quality on all voltage levels except for LV. Smart meters, however, are able to monitor voltage levels for each end-user. The VQ parameters are voltage dips, swells and rapid voltage changes with ΔUmax >3%. From 2014 onwards, system operators were also obliged to report THD, long-term and short-term flicker severity. The TSO and DSOs need to be able to provide explanations for historical values of quality in their networks and to be able to estimate the future quality of their networks. As of 2018, there are approximately 315 fixed instruments in the grid. Portable instruments may be used as a substitution during calibration of the fixed instruments.

Since the TSO and DSOs are tasked with continuous monitoring of VQ, they must also cover the costs of installation, maintenance and operation of the monitoring system. The operators must decide how many instruments are necessary to create reliable statistics on VQ. Each DSO and the TSO must have at least one instrument installed in each different characteristic area. Important elements to consider when dividing the network into characteristic areas are: underground cables/overhead lines, system earthing, extent of the network, customer categories connected, climatic differences and short circuit power.

In **Poland**, the DSOs and the TSO may monitor VQ for their own purposes while paying for the costs themselves. If a customer calls for investigation, metering points may be monitored to validate the quality. On customer request, the energy company checks compliance with quality parameters of electricity supplied from networks specified in Article 38 (1) and (3) of the Regulation [57] or in the contract, through the implementation of appropriate measurements. If the measured parameters comply with the standards specified in the Regulation or in the contract, the costs of checking and measuring should be borne by the customer on the terms specified in the energy company's tariff.

VQM in **Romania** involves the EHV, HV and MV levels with the aim of keeping parameters within normal limits. It was voluntarily implemented by system operators and approved by the NRA. Continuous monitoring is used for certain network points (transmission substations, connection points between transmission and distribution, connection points of end-users) while temporary monitoring is used for end-user connection points in the distribution network if the quality verification comes at the request of the end-user.

In a total of 275 HV substations, there are 331 points that are monitored. In distribution, there is continuous monitoring of 25% of the total number of electrical substations with quality analysers according to SR EN 61000-4-30[140]. Temporary monitoring for verification of individual VQ requested by end-users lasts for a minimum of seven consecutive days. The cost of monitoring is borne by system operators. However, if poor quality is due to the end-user site or if there is a second unfounded request for quality verification (when the DSO paid the first time), the cost has to be bourne by the end-user. The monitored parameters are: yearly registered frequency values, framing the frequency and the voltage within the normed limits of variation, quality of the voltage curves and duration of framing in the normed parameters of quality of the voltage curves during the monitoring period.

VQ is monitored in both transmission and distribution in **Slovakia**. The system was promoted by the NRA for the purpose of statistics, regulation and quality improvement and the system operators pay the costs. Portable instruments are not deployed.

Slovenia uses continuous monitoring on EHV, HV and MV levels. In transmission, all parameters of the EN 50160 standard are monitored except for transient overvoltages and DC component. Individual monitoring is also applied on LV level on customer request. The system was enacted by the NRA through the requirements outlined in the Electricity Supply Act [58] and the NRA's Legal Act on the Methodology for Determining the Regulatory Framework and Network Charges for the Electricity Distribution System [59]. Other than statistics, the quality is also monitored for regulation with guaranteed standards for voltage variations.

For the network points monitored temporarily, the duration is usually up to two weeks with a minimum of one week. As of 2018, all 187 points at HV substations (including HV end-user sites) are monitored, while on MV busbars in HV/MV substations, all 333 points are monitored. The cost for installation, maintenance and operation of continuous monitoring is covered through the transmission and distribution network charge. In cases where the measurement results of temporary monitoring on customer request do not show non-compliance with the standard, the customer bears the cost of the measurements.

In **Sweden,** the NRA does not collect VQ data, but the DSOs and the TSO may collect them for their own purposes while paying for the costs themselves. If a customer reports bad VQ, an investigation is required, and connection points may be monitored with portable meters to validate quality. The regulated duration is specified in SS-EN 61000-4-30[141]. All Swedish DSOs will be supervised during the period 2020-2025 with respect to VQ and all customer complaints regarding VQ should be reported to the NRA, which publishes a report of the findings every year.

In **Ukraine**, the obligation to monitor was set out in network codes in 2018 with the intention of analysing the statistics and the possibility of future regulation. VQM started in 2021 in distribution and in 2019 in transmission, with the following parameters: frequency, voltage, imbalance, harmonics and flickers. In transmission, all connection points to DSOs and customers connected to transmission networks must be monitored. In distribution, the network code establishes the minimum number of network points that must be covered by the VQM programme on each voltage level. Fixed or portable monitoring instruments must be installed (with monitoring duration of not less than one week) and the following points monitored:

- On MV busbars in HV/MV substations – not less than once per year;
- On MV busbars in MV/MV substations (10 kV busbars in 35/10 kV substations) - not less than once in four years;
- 1% of MV customer sites per year; and
- 0.5% of LV busbars in MV/LV transformers.

In VQM statistics, all smart meters with a VQM function must be included.

As shown in Table 3-8, the supply voltage variations requirements are enforced in 22 countries and monitored in 17. Greece responded that the indicators are enforced implicitly through the implementation of EN 50160. Similarly, Finland commented that there is reference to EN 50160 in the law and hence the indicators are enforced on national level. The DC component indicator is only enforced in Belgium and Finland. In addition, Belgium is the only responding country where it is monitored.

The indicators - supply voltage violations, flicker, voltage unbalance, harmonic voltage, voltage dips and voltage swells - are used at national level for VQM purposes and campaigns in many countries, as shown in Table 3-8. However, it can also be observed that transient overvoltages, interharmonic voltage, mains signalling voltage and rapid voltage change indicators are used in only a few countries.

140 This is the Romania-specific version of EN 61000-4-30.
141 This is the Sweden-specific version of EN 61000-4-30.

TABLE 3-8: Monitoring and enforcement of VQ indicators

VQ indicator	Is this VQ indicator monitored in your country?		Is this indicator enforced at national level (by law and / or regulation)?		Is this indicator used at national level for VQM purposes and campaigns in your country?	
	Yes	No	Yes	No	Yes	No
Supply voltage variations	AT, BE, CY, GE, HU, IE, IT, KS*, LT, LU, LV, MD, NL, PT, RO, SI, SK	BA, EL, FI, ME, NO, SE, UA	AT, BE, CY, EL[142], FI[143], GE, HU, IT, KS*, LT, LU, LV, MD, ME, NL, NO, PT, RO, SE, SI, SK, UA	BA, IE	AT, BE, GE, LV, NL, PT, RO, SI, SK	BA, CY, EL, FI, HU, IE, IT, KS*, LT, LU, MD, ME, NO, SE, UA
Flicker	AT, BE, CY, GE, IE, LV, MD, MK, NL, NO, PT, RO, SI, SK	BA, EL, FI, HU, IT, KS*, LT, LU, ME, SE, UA	AT, BE, CY, EL[142], FI[143], GE, LV, ME, MK, NL, NO, PT, RO, SI, SK, UA	BA, HU, IE, KS*, LT, LU, MD, SE	AT, BE, CY, GE, LV, NL, NO, PT, RO, SI, SK	BA, EL, FI, HU, IE, KS*, LT, LU, MD, ME, SE, UA
Voltage unbalance	AT, BE, CY, HU, IE, IT, LV, MK, NL, PT, SE, SI, SK	BA, EL, FI, GE, KS*, LT, LU, MD, ME, NO, UA	AT, BE, CY, EL[142], FI[143], LV, ME, MK, NL, NO, PT, SI, SK, UA	BA, GE, HU, IE, IT, KS*, LT, LU, MD, SE	AT, BE, CY, LV, MK, NL, PT, SI, SK	BA, EL, FI, GE, HU, IE, IT, KS*, LT, LU, MD, ME, NO, SE, UA
Harmonic Voltage	AT, BE, CY, HU, IE, IT, LV, MD, MK, NL, PT, RO, SE, SI, SK	BA, EL, FI, GE, KS*, LT, LU, ME, NO, UA	AT, BE, CY, EL[142], FI[143], LV, ME, MK, NL, NO, PT, RO, SE, SI, SK, UA	BA, GE, HU, IE, IT, KS*, LT, LU, MD	AT, BE, CY, LV, NL, PT, RO, SI, SK	BA, EL, FI, GE, HU, IE, IT, KS*, LT, LU, MD, ME, MK, NO, SE, UA
Voltage dips	AT, BE, CY, GE, HU, IE, IT, MD, NL, NO, PT, RO, SI, SK	BA, EL, FI, KS*, LT, LU, ME, SE, UA	BE, CY, EL[142], FI[143], GE, IT, NL, NO, PT, RO, SE, SI, SK, UA	BA, HU, IE, KS*, LT, LU, MD, ME	AT, BE, CY, GE, IT, NL, NO, PT, RO, SI, SK	BA, EL, FI, HU, IE, KS*, LT, LU, MD, ME, SE, UA
Voltage swells	BE, CY, GE, HU, IE, IT, NL, NO, PT, RO, SI	BA, EL, FI, KS*, LT, LU, SE, UA	BE, CY, EL[142], FI[143], GE, IT, NL, NO, PT, RO, SE, SI, UA	BA, HU, IE, KS*, LT, LU	AT, BE, CY, GE, NL, NO, PT, RO, SI	BA, EL, FI, HU, IE, IT, KS*, LT, LU, SE, UA
Transient overvoltages	BE, IT, MK, NL, SK	BA, CY, EL, FI, GE, HU, LU, MD, ME, NO, SE, SI, UA	BE, EL[142], FI[143], MK, NL, NO, SK, UA	BA, CY, GE, HU, IT, LU, MD, ME, SE, SI	BE, NL, SK	BA, CY, EL, FI, GE, HU, IT, LU, MD, ME, NO, SE, SI, UA
Interharmonic voltage	BE, LV, SI, SK	BA, CY, FI, GE, HU, IT, KS*, LU, MD, ME, NL, NO, RO, SE, UA	BE, FI[143], LV, NO, SI, SK, UA	BA, CY, GE, HU, KS*, LU, MD, ME, NL, RO, SE	BE, LV, SI, SK	BA, CY, FI, GE, HU, KS*, LU, MD, ME, NL, NO, RO, SE, UA
Mains signalling voltage	BE, LV, SI, SK	BA, CY, EL, FI, GE, HU, IT, KS*, MD, ME, NL, NO, SE	AT, BE, EL[142], FI[143], LV, NO, SI, SK	BA, CY, GE, HU, KS*, MD, ME, NL, SE	BE, LV, SI, SK	BA, CY, EL, FI, GE, HU, KS*, MD, ME, NL, NO, SE
Single rapid voltage change	BE, NL, NO, SI	BA, CY, FI, GE, HU, IT, KS*, LT, LU, MD, ME, SE	BE, FI[143], NL, NO, SE, SI	BA, CY, GE, HU, KS*, LT, LU, MD, ME	BE, NL, NO, SI	BA, CY, FI, GE, HU, KS*, LT, LU, MD, ME, SE
DC component	BE	BA, CY, FI, GE, IT, KS*, LU, MD, ME, NL, SE, SI	BE, FI[143]	BA, CY, GE, KS*, LU, MD, ME, NL, SE, SI	BE	BA, CY, FI, GE, KS*, MD, ME, NL, SE, SI

142 Implicitly, through implementation of EN 50160.
143 There is a reference to EN 50160 in the law.

3.5.1 Monetary penalty and sanctions when the legislation, the regulations or the standards on voltage quality are not met

In some of the countries there are monetary penalties and/or other types of sanctions when the legislation, regulations or standards are not met. These are explained in the following paragraphs.

In **Belgium**, any direct damage, bodily or material, suffered by an end-user connected to the distribution network because of an interruption, non-conformity or irregularity of the supply of electrical energy, is subject to compensation by the responsible DSO or TSO. There is no compensation in the case of force majeure. In addition, the compensation does not include planned interruptions or damage due to an administrative error.

In **Hungary**, automatic compensation is paid to the customer if the guaranteed standard for supply voltage is not met. If the standard for the number of short interruptions is exceeded, compensation is paid on the request of the customer.

In **Italy**, the individual regulation of transient interruptions and voltage dips for HV customers who have joined the VQM system, provides that these customers are compensated if the VQ is lower than certain thresholds.

In **Latvia**, if the VQ characteristics are not met, the DSO should apply a lowered tariff for services of the electricity system. The lowered tariff is calculated by applying the coefficient 0.5 to the electricity transmission component of the tariff for the relevant group of users. In addition, the TSO should reimburse losses to the grid user, which have arisen due to providing a poor service quality of the electricity system.

There is compensation for any disturbance in VQ in **Moldova**. This is also the case in **Romania** and **Slovenia**.

The NRA of **the Netherlands** can impose sanctions, for example fines, on the grid operators when the requirements are not met. The applied penalty varies from case to case.

Similarly, the NRA of **Malta** has the right to impose sanctions if there are user complaints.

In **Norway**, the NRA may issue orders necessary to implement the regulations. It can stipulate a correctional fine, which applies for all provisions set out in the regulation, including all VQ limits. In addition, it can issue violation fines if certain aspects of the regulation are violated. This applies to certain provisions, including correction without undue delay, notification from end-users and customer treatment.

Consumers in **Poland** are entitled to discounts specified in the tariffs of energy companies (TSO, DSO) in cases of non-compliance with the permissible levels of voltage deviations from the rated voltage.

In **Ukraine**, the payment for distribution services is reduced by 25% for the period of non-compliance.

3.6 VOLTAGE QUALITY AT CUSTOMER LEVEL

The 6th Benchmarking Report [6] found that a number of countries had introduced legislation regarding emissions by individual customers. The concept of responsibility-sharing for adequate VQ between the network operator, the customer and the manufacturer was identified. Of the responding NRAs, 16 foresaw penalties for customers in the case of violation of disturbance limits. Further, the 6th Benchmarking Report recommended that investigations should be made to identify the responsibility for voltage disturbances according to the concept of responsibility-sharing described in the Report. To verify whether the network operator, the customer or the manufacturer is responsible, it is necessary to describe the factors that should be taken into account when identifying the responsible party. It is interesting to observe that no respondent indicated that it carried out cost-estimation studies to detect end-users' costs due to poor VQ.

3.6.1 Individual contracts regarding voltage quality

All European countries have regulations on VQ which apply to all customers, DSO(s) and TSO(s). In Bosnia and Herzegovina, Croatia, Italy, Lithuania, Montenegro, Norway and Poland, it is also possible to arrange individual contracts regarding VQ.

In the Republika Srpska entity of **Bosnia and Herzegovina**, the DSOs and the customer can enter into an agreement on special conditions concerning the VQ. This applies to MV and LV levels. In the Federation of Bosnia and Herzegovina entity, which is regulated by FERK, such agreements are not possible. On EHV and HV level, the TSO and the customer can make an agreement on special conditions concerning the VQ.

In **Croatia**, a customer can request higher quality of supply than the one which is prescribed, but the customer is expected to bear all associated (real) expenses that come from those higher standards.

In **Italy**, a DSO and a customer can agree on higher standards of the quality of supply than the standards applied nation-wide. This is usually done upon customer payment, but the DSO would have to pay in the case of underperformance.

In **Lithuania**, the Kruonis pumped-storage power plant (PSPP) is used as a synchronous condenser to ensure the quality and the level of voltage. The service is paid hourly and the price is approved by the NRA. Kruonis PSPP is connected to the 330 kV grid.

In **Norway**, it is possible to arrange individual contracts regarding VQ. If private agreements concerning quality of supply other than what is stipulated by the regulations is agreed upon, the TSO or DSOs should provide an explicit account of the consequences this will have for the grid customer. It is, however, a premise that no other customers, who are not a part of the contract, experience a poorer quality because of this contract. Such individual contracts regarding the VQ are not commonly used.

In **Poland**, for entities connected to HV and EHV, energy quality parameters of mains electricity can be completely or partly replaced with other quality parameters as defined by the parties. The energy company may determine, for individual connection groups, permissible levels of parameter disturbances that are not worse than the parameters specified in Article 38 (1) and (3) of the Regulation [57] or specified in the electricity sales contract or transmission contract.

3.6.2 Individual information on voltage quality

In a few of the reporting countries, network operators are obliged to inform customers about the actual VQ levels (in practice, the measured levels from the recent past). Table 3-9 shows an overview of obligations on the DSO/TSO to present information to the customers on request. The type of information provided will depend on the request.

TABLE 3-9: Obligations for DSOs/TSOs to inform customers about the past (or expected future) VQ levels

Country	DSO	TSO	No obligation	Comment
Albania			×	
Austria			×	
Belgium			×	There is no specific obligation of information, but the DSO will have to do what is necessary to carry out the work to restore a power quality in accordance to the standard.
Bosnia and Herzegovina			×	No, but in the Republika Srpska entity, customers can get the information on request.
Croatia			×	
Cyprus	×	×		As per EN 50160. With the Connection Agreement. Changes are to be included in revised issues of the Transmission and Distribution Rules. Customers must be able to follow up. The information is only provided on changes.
Estonia			×	
Finland			×	
Georgia			×	
Germany			×	
Greece			×	
Hungary			×	
Ireland			×	
Italy	×			Every year, each DSO communicates the information on voltage dips to its MV users, even without request.
Kosovo*			×	
Latvia			×	Only on request of customers.
Lithuania			×	
Luxembourg			×	
Malta	×			Network Code obliges the DSO to provide certain information on the local network conditions to customers on request.
Moldova			×	
Montenegro			×	
Netherlands, The			×	
Norway	×	×		At the request of a current or future network customer, the TSO/DSOs should provide information within one month about VQ in their own installations. The TSO/DSOs are obliged to save the information on VQ for at least 10 years.
Portugal	×	×		TSO and DSO are obligated to publish VQ data on the Internet.
Romania	×			Voltage, frequency, fast variations of the voltage in normal regime, asymmetry, flicker. At customer request. The information must be provided in maximum 20 days from customers request.
Serbia			×	
Slovakia			×	
Slovenia	×	×		Parameters from the continuous monitoring, which is applied on EHV, HV and MV levels. TSO and DSO inform customers about past VQ levels in their Annual Quality of Supply Report which is public. The information is provided annually for the previous year.
Spain			×	
Sweden			×	
Ukraine			×	

3.6.3 Individual voltage quality verification

In the majority of countries, a DSO, a TSO or both are required to provide a VQ recorder when an end-user wants to monitor VQ at their own connection point. Please note that the questionnaire did not specify whether the requirement only includes monitoring after a customer complaint or not.

The cost of performing VQ measurements upon receiving an enquiry is generally covered in two ways:

- The cost is borne by the TSO/DSO; or
- The cost is borne by the TSO/DSO if the quality does not conform to national legislation or EN 50160. The customer pays if the QV level meets the standard (Belgium, Croatia, Portugal, Slovenia).

Table 3-10 gives an overview of the system operator's obligations. The respondents were asked whether or not their country had a predefined payment by the customer for the measuring service. Please note that the countries that have answered no may still have a payment which is not predefined.

TABLE 3-10: System operator's obligation to provide a VQ recorder on customer request

Country	DSO	TSO	No obligation	Is there a pre-defined payment by the user for this service?	Specification of payment	Comment
Albania		×		No		
Austria	×	×		No		
Belgium	×			Yes	Flanders: The cost (€163 on LV network) is to be paid by the DSO if the VQ is outside the EN 50160 range, otherwise, it is to be paid by the end-user. Wallonia & Brussels: The costs are at the expense of the grid user if the VQ is found to comply with EN 50160; they are paid by the DSO if the VQ does not comply with EN 50160.	
Bosnia and Herzegovina	×			No		In the Republika Srpska entity: VQ measurement is carried out on request for one week, this service is not charged by the DSO.
Croatia	×	×		Yes	2,500 HRK (including VAT)[144] for customers in transmission and 537.50 HRK (including VAT) for customers in distribution. In either case, customer only pays if the request for VQM was unfounded (i.e. VQ meets the standard). If the quality does not meet the standard, network operator bears this cost.	
Cyprus	×			No		
Estonia	×	×		No		
Finland	×	×		No		
France	×	×		Yes	DSO: €438.9 TSO: €2,265 a year	
Georgia	×	×		No		
Germany	×	×		No		
Greece	×			Yes	Not yet defined (as of October 2019)	
Hungary			×			
Ireland			×			
Italy	×			No	Costs are charged to the end-user.	
Kosovo*	×	×		No	User is responsible for covering the costs (first purchase and recurring costs) for the equipment (modems, etc.) needed to read the metering device remotely, full integration of metering data to TSO's remote metering centre and IT for market operator, which must comply with the metering code, connection charging methodology and be in accordance with market rules.	
Latvia	×	×		No		
Lithuania			×			
Luxembourg			×			

144 For reference, the European Central Bank exchange rate at the end of 2021 was 7.5156 Croatian kuna per euro.

TABLE 3-10: System operator's obligation to provide a VQ recorder on customer request

Country	DSO	TSO	No obligation	Is there a pre-defined payment by the user for this service?	Specification of payment	Comment
Malta	×			No		VQ recorder provided by the DSO free of charge.
Moldova	×			No		
Montenegro	×	×		No		
Netherlands, The			×			
North Macedonia	×			Yes	€65.75 for 7 days of measurement	
Norway	×	×		No		Upon a customer complaint, the TSO/DSOs are obliged to carry out necessary measurements in order to detect whether the regulation is violated or not, and if so, detect the cause of the violation. Costs related to such measurements should be paid by the DSO/TSO.
Poland	×	×		Yes	Approx. €25 for assembly and disassembly of the control and measurement device installed to check the compliance with the quality parameters of energy supplied by the DSO grid	In case of compliance of the measured parameters with standards specified in § 38 sec. 1 and 3, the system regulation or in the contract, the costs of checking and measurements are borne by the recipient with the terms set out in a separate contract between the recipient and the operator. In other cases, the costs of checking and measuring are borne by the operator.
Portugal	×	×		Yes	LV: € 23.89 MV: € 2,007.24 HV: € 6,436.70 EHV: € 6,436.70 (VAT is added to abovementioned values at the legal rate in force)	End-users only pay if the request for VQM was unfounded (i.e. the VQ meets the EN 50160 standard). If the quality does not meet the EN 50160 standard, the network operator bears this cost.
Romania	×			No		Temporary monitoring of the VQ parameters to the end-users' connection points for at least 7 consecutive days, at request of end-users for individual VQ verifications.
Serbia			×			
Slovakia	×	×				
Slovenia	×	×		No/Yes	VQ service: €224.09 (inc. VAT).	In case the results of measurements do not show non-compliances with the standard, the customer should bear all the costs of measurements.
Spain			×	No		
Sweden			×	No		A two-week monitoring of the VQ at the connection point is initiated if an investigation of the customer complaint concludes that the connection point could be subjected to bad VQ.
Ukraine	×			No		In case of customer's compliant, DSO is obliged to carry out necessary measurements if it wants to reject the complaint.

If a customer complains about the VQ at their connection point, the system operators in several countries are obliged to perform measurements to verify the levels of all relevant VQ parameters.

Some countries allow for end-users to install their own VQ recorders when results are to be used in a dispute between the end-user and the DSO/TSO. To ensure valid measurements, most of the countries require that the measurements are performed by certified personnel and/or that the VQ recorders meet the national standards and regulations. Further information on this topic is given in Table 3-11.

In several countries, the legislation does not hinder cases where the end-user wants to install their own VQ recorder, as long as the installed device is approved by the DSO/TSO and/or both the end-user and the DSO/TSO agree upon the installation.

TABLE 3-11: Are end-users allowed to install their own VQ recorder if results are to be used in a dispute between the end-user and the DSO/TSO?

Country	Answer	Comment	If yes, what are the conditions for end-user installations and for accepting the results of measurement?
Belgium	Yes		Flanders: It is only informative, only the official DSO measurement is valid in case of dispute. The smart meter that is rolled-out is providing basic VQ information for free (voltage level every second on the local user interface). Wallonia: This is allowed but in this case, it is likely that the DSO will carry out its own measurements as well. Brussels: Yes, as long as the two parties agree.
Bosnia and Herzegovina	Yes	In the Republika Srpska entity.	Approval should be given by the DSO.
Croatia	No		
Cyprus	Yes		Not defined.
Estonia	No		
Finland	No		
Georgia	Yes		Installation can be done under technical conditions and the results of measurements are used for dispute cases as a proof for VQ violation by end-user.
Germany	No		
Greece	No		
Ireland	No		
Italy	Yes		The device must be able to measure the VQ parameters defined in the EN 50160 standard according to the measurement methods in EN 61000-4-30.
Kosovo*	Yes		The device should support the EC standards and must be calibrated every 3 years. In addition, the device should be connected with KEDS ('Kosovo Electricity Distribution and Supply'). Every user connected to the transmission network can install his control metering system and he has the right to read the meters at any time. The reading can be either manual or electronic.
Latvia	Yes		Measurements should be carried out by an appropriately certified person or company with calibrated equipment.
Lithuania	No		
Luxembourg	Yes		
Malta			No regulation in place.
Moldova	Yes		The measurement instruments have to be certified.
Montenegro	Yes		Grid codes for DSO prescribe possibility for end-users to engage other relevant institution (other than DSO) to conduct this activity and results will be accepted by DSO.
North Macedonia	No		Only if the technical inspectorate installs the equipment.
Norway	Yes		Stakeholders other than the TSO and DSOs may perform VQ measurements. If the purpose of such measurements is verification of VQ according to the regulation, the measurement methods must be according to the regulation.
Portugal	Yes		End-users are allowed to install their own VQ recorders. The device must be able to measure the VQ parameters defined in the EN 50160 standard according to the measurement methods in EN 61000-4-30.
Romania	Yes		Conditions: • the payment will be supported by the end-user, • the location of the quality analyser, the assembly, the sealing, the programming and the extraction of information must have been agreed between the parties (end-user and DSO).
Slovakia	No		
Slovenia	Yes		In case VQ recorder is calibrated or certified by an accredited institution or body.
Spain	Yes		There must be an agreement with DSO and it must be approved by Regional Government.
Sweden	No		
Ukraine	Yes		The customer should have the right to, upon a written consent of DSO, and at the customer's expense, arrange such measuring; at the same time the right to measure VQ parameters may be granted to an organisation, which has the respective powers or permits.

3.6.3.1. Requirements regarding voltage quality monitoring instruments

To verify whether the supplied voltage is within the legislation or standards, it is crucial to have a standardised method for monitoring the different VQ parameters. Some NRAs have introduced specific requirements regarding VQM instruments for measurements performed for quality contracts and in the case of litigation. In Norway, Sweden and Ukraine these requirements are to follow the EN 61000-4-30 standard, or national legislation based on the EN 61000-4-30 [53].

The NRA of **Cyprus** approves technical requirements set by the TSO/DSO and requires their correct implementation. Current/voltage transformers and transducers are of the same accuracy as those used for metering specified by the Transmission and Distribution Rules [48].

In **Kosovo***, all documents (such as codes, electrical standards and other technical rules), including a draft of the connection agreement, are subject to comments from the NRA before approval. In June 2019, the regulator approved the Rule on Electricity Service Quality Standards. The rule includes an article on VQ and an article on quality measurement and registering [15].

In **the Netherlands**, the VQ measuring process has to comply with the 'Measurement Guide for Voltage Characteristics' [60] set up by the grid operators and consulting firm.

In **Norway** and **Sweden**, measurements performed with the purpose of verification of quality of supply should be carried out in accordance with the relevant standards prepared by the International Electrotechnical Commission (IEC) or CENELEC. The instruments used should be calibrated in accordance with the instrument suppliers' specifications with respect to frequency and methodology. The calibration traceability for the individual measurement parameters should be documented. The precision and limitations for the measuring equipment should be stated in the documentation of the measurement results. The measurement results in connection points, plus uncertainties, should be within the limit values specified in the regulations.

3.6.4 Emission limits

The VQ in the grid and at the end-user's connection point could potentially be influenced by how the grid is operated by the grid operator, how the grid is dimensioned by the grid owner as well as the design and use off all units connected to the grid. Since both the source of the voltage disturbances and the solution to reduce the voltage disturbances could be in the grid or the unit connected to the grid, responsibility-sharing has been identified by CEER as an important principle for VQ regulation. This concerns, among other things, the setting of maximum levels of voltage disturbances at the point of delivery between the network operator and its customers and emission limits for installations. Emissions from individual customers need to be limited to keep the voltage disturbance levels within the requirements.

It is an important aim to ensure that the functioning of equipment is not impacted by voltage disturbances coming from the grid. The probability of malfunctioning due to voltage disturbances from the grid is kept low in Europe through a set of standards on electromagnetic compatibility issued by IEC and taken over by CENELEC as European harmonised standards. The Electromagnetic Compatibility (EMC) Directive [61] limits electromagnetic emissions from equipment to ensure that, when used as intended, such equipment does not disturb other equipment. These documents regulate the emission of disturbances by individual devices as well as by installations and regulate the immunity of individual devices to any disturbances. Although the spread of disturbances across the electricity network is taken into consideration when setting the various limits, additional regulation of network operators in terms of VQ is necessary.

To regulate the impact that customers have on the VQ of the networks, a number of countries have introduced legislation regarding the emissions by individual customers. Detailed information is given in Table 3-12. Countries not using this type of regulation are not planning to implement it in the next few years, with the exception of Sweden where it is currently under review.

TABLE 3-12: National regulation(s) directly or indirectly imposing maximum levels of disturbances concerning VQ (i.e. emission limits for installations)

Country	Yes/no	If yes, a detailed description of the regulation(s)
Albania	No	
Austria	Yes	Described in the general terms and conditions of system operators (parameters are consistent with those in EN 50160) and the technical organisational rules (reference to EN 61000-3-2, EN 61000-3-3, EN 61000-3-11, EN 61000-3-12, EN 61000-2-2) [62], [63], [64], [65], [66].
Belgium	Yes	
Bosnia and Herzegovina	Yes	RERS: Rulebook on Technical Standards for Low Voltage Electrical Installations (Official Gazette of Yugoslavia, N° 53/88 and N° 54/88) [67]. SERC: Grid Code for EHV&HV
Croatia	Yes	*'Mrežna pravila prijenosnog sustava'* (for transmission) and *'Mrežna pravila distribucijskog sustava'* (for distribution). They are only available in Croatian. All unwanted feedback (including the one that influences VQ) is defined as 'negative feedback' to the grid (from the installations of the grid user). Possible feedback is calculated before the potential user is connected and it is monitored during operation as well. Network operator has the right to decline connection for potential users or disconnect an existing grid user if it fails to comply with the standards. Distribution system operator can allow connection without detailed assessment for users with low connection power or with lower ratio of devices that inject disturbances into the network if the ratio of short-circuit power (at connection point) to connection power is greater or equal to 1,000 for MV or 150 for LV.
Cyprus	Yes	Transmission and Distribution Rules: T1.10.12 (Power Quality) (TDR) [48]. Obligation of the user to ensure that their installations would not cause any disturbance to the transmission system[145] exceeding the limits recommended by the relevant IEC standards.
Estonia	No	
Finland	No	
France	Yes	Order of 24 December 2007 on quality levels and technical requirements regarding the quality of public electricity distribution and transmission grids [68].
Georgia	No	
Germany	No	
Ireland	Yes	Emission limits for voltage flicker, harmonics and unbalance are stated in the Distribution Code section DCC6.8 [69].
Italy	Yes	Emission limits must be set taking into account the level of: planning adopted, emissions from other plants / users already connected to the same network, emissions transferred from the rest of the network and the future emissions of any new plants.
Kosovo*	Yes	Grid Code - Connections Code [70]
Latvia	Yes	End-users are obligated to connect to the network and to use only such electricity installations that do not cause unacceptable electricity quality changes in the network of the system operator or damages to the electricity meter for the commercial accounting of electricity. Connection of electrical installations of the user according to the instruction for use stipulated by the manufacturer of electrical installations should be ensured.
Lithuania	Yes	Name of the regulation: 'TSO permitted frequency and VQ parameters regulation' [71]. The scope does not differ from 50160:2010, but the standard is not applicable for voltage levels higher than 150 kV, thus the values have been defined based on good engineering practices. Disturbances concerned: single rapid voltage change, flickers, supply voltage unbalance, harmonic voltage, voltage dips/swells, interruptions of the supply.
Luxembourg	Yes	Voltage behaviour is regulated in the technical connection codes (LV, MV and HV). These are based on CENELEC and DIN VDE norms.
Malta	Yes	Users are obliged to comply with the limits of the Network Code [55]. A user found to be operating outside the technical limits specified in the Network Code, has to rectify the situation/disconnect the apparatus causing the problem from the electrical system immediately or within such time as agreed with a DSO. Failure to rectify the situation may lead to disconnection of the user from the system.
Moldova	No	
Montenegro	Yes	Grid codes for transmission network and Grid codes for distribution network.
Netherlands, The	No	
North Macedonia	No	According to the network codes for distribution, DSOs control and monitor the influence of end-user appliances connected to the distribution network.
Norway	Yes	The installations connected to the networks should be able to operate within the limits of the VQ parameter. Emission from the installations connected to the networks should not cause violation of the VQ parameter limits. If violation of the VQ limits occur, countermeasures to rectify the situation must be taken by the responsible stakeholder.
Poland	No	
Portugal	Yes	The Quality of Service Code imposes maximum levels of flicker, unbalance and harmonic distortion [27].
Romania	Yes	The parameters are described in the Performance standards for transmission and distribution networks, approved by the NRA, ANRE, Order N° 46/2021 (distribution) [19] and by Order 12/2016, modified by Order 36/2021 (transmission) [20].
Slovakia	No	
Slovenia	Yes	National grid codes for transmission and distribution system. Installations and appliances of end-user customers must be assessed according to Instructions for assessing the impact of the appliances on the network (appendix to the National grid code for distribution system). The TSO and DSO are mainly responsible for VQ of supply in accordance with the standard EN 50160. In the case of customers causing interference on the network that deviates from the standard, the TSO or DSO can disconnect them from the network if they continue to do so after being alerted.
Spain	No	
Sweden	No	The regulation is currently under review and this could potentially be introduced if the review concludes it.
Ukraine	No	

145 Even though T1.10.12 refers only to transmission systems, according to the TDR all provisions under section T1.10 (Power quality and Protection) concern the DSO, the producers and the transmission system. Hence, the regulation on the VQ levels applies to all users connected to transmission and distribution.

In addition to regulation directly or indirectly imposing maximum levels of disturbances concerning VQ, the NRAs were asked how the responsibility for improving overall VQ and/or for rectifying situations when experiencing various voltage disturbances is allocated. The answers show that in most countries, the responsibility lies only with the TSO/DSO, or is shared between the TSO/DSO and the customers. In the latter case, the responsibility lies with the customer if they cause poor VQ. Detailed information of the respondents is given in Table 3-13. More information on responsibility-sharing is provided in the 6th Benchmarking Report [6].

TABLE 3-13: Allocating responsibility for improving overall VQ and/or for rectifying situations when experiencing various voltage disturbances

Country	Responsible party
Austria	The overall responsibility is with the system operator. If one customer can be singled out as the source of poor VQ (upon request of the system operator), the responsibility lies with that customer.
Belgium	The technical regulation has some rules regarding responsibility of the source of voltage disturbances.
Bosnia and Herzegovina	RERS (Republika Srpska): efforts are being made to eliminate the causes of poor voltage conditions, which are most commonly found on the distribution network.
Croatia	There is only one TSO and one DSO and responsibility is divided between their networks.
Cyprus	By the defined requirements of Transmission and Distribution Rules and the connection agreements.
Estonia	The network operator must ensure the VQ.
Georgia	Responsibilities are allocated between TSO, DSO and end-user under grid code.
Hungary	In case of voltage disturbances, the responsibility depends on the location of the fault or the ownership of the faulty device.
Italy	When supply voltage variations are outside the allowed limits, following a network user request to check them, the DSO is responsible to communicate to the network user a maximum time to restore the compliant voltage variations and to rectify the problem.
Kosovo*	The responsibility belongs to the party causing the disturbances or improving the overall VQ.
Latvia	Responsibility lies with the network operator in whose grid the disturbance needs to be resolved.
Lithuania	The responsibility is not defined in the regulations/legislations.
Malta	The DSO has the overall responsibility of the VQ of the system and the monitoring and testing. However, users are obliged to comply with the Network Code.
Moldova	The party that caused disturbances is in charge of repairing the damages and possibly paying compensations to final customers.
Netherlands, The	The grid operator is responsible for the VQ experienced by the connected consumers.
Norway	Those covered by these regulations should, if their installations are to blame for non-compliance with the provisions of these regulations, rectify the situation without undue delay. Sometimes there is a question whether the end user's installation is too demanding, or the grid is too weak. The duty to rectify does not apply to grid customers if the limits are exceeded only in their own connection point, and the DSOs/TSO to which they are connected does not experience any problems as a consequence of this.
Romania	The frequency monitoring is the TSO's responsibility at the national level.
Slovenia	TSO and DSO are mainly responsible for VQ of supply in accordance to the standard EN 50160. In case customers with their actions on the network cause an interference that deviates from the standard, the TSO or DSO can disconnect them from the network if they continue to do so after being alerted.
Sweden	DSO is responsible for the delivery of electricity and VQ is seen in legislation as part of the responsibility of delivering electricity.
Ukraine	Improving the overall VQ is financed through investment plans of the TSO/DSOs.

Penalties for customers in cases of violating maximum levels of disturbance are foreseen in 16 countries. In some countries, the end-user causing the disturbance has to take the necessary measures to avoid violating the maximum levels of disturbances. In ten countries, the TSO and/or DSO can disconnect the end-user causing the violation of the maximum levels of disturbance. In most countries, the end-user must be given a warning and have the opportunity to rectify the VQ prior to disconnection. Detailed information is given in Table 3-14.

TABLE 3-14: Penalties for grid users (such as disconnection) in case of violation of the maximum level of disturbances

Country	Penalty	If yes, please describe
Austria	Yes	
Belgium	Yes	Flanders: According to the technical regulation, the DSO can disconnect the grid user causing the disturbance if no measurements are taken within a defined timeframe. There is a procedure defined in the technical regulation. If damage is caused to other grid users because of this disturbance, the DSO can reclaim these costs from the grid user causing the disturbance. Wallonia: Disturbance levels are governed by sections III.8, III.9 and III.17 of the RTDE [72]. Article 57 states that the DSO may implement the technical means required for the reactive energy compensation or, more generally, for the compensation of any disturbing phenomenon, when the load of a user of the distribution network connected to the distribution network causes disturbances. The grid user causing the disturbance must cover the costs for the installation and use of technical means.
Croatia	Yes	Network operator can disconnect 'troublesome' grid users.
Cyprus	Yes	The TSO examines the frequency level of this condition. If the problem is somehow permanent, the user should take corrective action. Until then, the TSO has the right to disconnect the user from the system.
Estonia	Yes	If customer's equipment interferes with the network operator's grid, the customer must purchase equipment that eliminates this problem. If they fail to do so, the network operator may disconnect the customer from the grid.
France	No	
Greece	Yes	End-users may be disconnected from the network in case they fail to comply with requirements regarding emission levels and disturbances, following a warning by the DSO.
Ireland	Yes	Only in a case where the end-user does not cooperate in working towards a solution of the problem.
Italy	No	
Kosovo*	Yes	The connection agreement between the TSO and end-user explains that if the end-user is not in the compliance with the Grid Code and causes network instability, then the TSO has the right to disconnect the user. Additionally, the Grid Code - Connections Code foresees the disconnection of a user in cases of violation of maximum levels of disturbances.
Latvia	Yes	The system operator has the right, upon prior warning of the user, to completely or partly disconnect his or her electrical installations if a reduction in the quality of supply of electricity that interferes with normal work of the electricity installations of other users or the system operator occurs due to user's fault.
Lithuania	No	
Luxembourg	Yes	The DSO/TSO can request end-users to take technical measures to reduce their level of disturbance to levels below the tolerated limits.
Malta	Yes	The DSO may disconnect users under certain circumstances after giving due prior notice if this does not endanger safety.
Montenegro	No	
Norway	Yes	The end-user should, if their installations are to blame for non-compliance with the provisions of the regulations, rectify the situation without undue delay. The duty to rectify does not apply to grid customers if the limits are exceeded only in their own connection point, and the DSOs/TSO to which they are connected does not experience any problems as a consequence of this.
Portugal	Yes	Network operator can disconnect the customers disturbing public VQ.
Romania	Yes	The cost is paid by the end-user if the poor quality is due to the end-user consumption site or in case of a second unfounded request for verification when the first cost was borne by DSO.
Slovenia	Yes	TSO and DSO are mainly responsible for VQ of supply in accordance with the standard EN 50160. In case customers with their actions on the network cause an interference that deviates from the standard, the TSO or DSO can disconnect them from the network if they continue to do so after being alerted.
Sweden	Yes	This depends on the contract between the end-user and the DSO. If there is a certain condition for disconnections in the contract, it could occur.

3.7 SMART METERS

Most responding countries indicated that they have requirements for smart meters and that the meters allow monitoring of VQ. Countries without requirements are Albania, Hungary, Latvia, Moldova, Montenegro, the Netherlands and Ukraine. Smart meter penetration rates vary widely among the participants. On one end, there are countries with close to zero percent of installed smart meters (Cyprus, Georgia, Germany, Greece, Moldova and the Brussels region of Belgium) and on the other, there are those approaching 100% (Estonia, Finland, Italy, Norway and Spain).

In **Austria**, there is no nation-wide smart metering in place yet, however, there is an ongoing infrastructure rollout. Smart meters in Austria allow monitoring of VQ, although this is voluntary. There are open legal questions regarding data protection issues. As of 2018, the smart meter penetration rate is 15%.

All distribution regions in **Belgium** have requirements for smart meters, however VQM (specifically the voltage level) is only allowed in Flanders and not in Wallonia. Penetration rates are as follows: 3% in Flanders in 2019, 0.2% in Wallonia in 2018 and 0% in Brussels in 2019. In Brussels, pilot projects are currently being deployed and a segmented deployment has been decided. In Flanders, all smart meters use the DLMS/IDIS standard.

There are requirements for smart meters both in transmission in **Bosnia and Herzegovina** and in distribution in its Republika Srpska entity, which allow monitoring of VQ parameters. The standard used for smart meters (15.34% penetration rate in 2018) is the technical specification of electricity meters and communication devices for meters.

Requirements for smart meters in **Croatia** are very broad and do not explicitly mention monitoring VQ or specific parameters, although the network operator is allowed that functionality. As of 2018, about 4% of metering points in Croatia were equipped with smart meters.

Smart meters in **Cyprus** allow monitoring of VQ which is required within the specifications of the advanced metering infrastructure (AMI) rollout. Although Cyprus has requirements for smart meters, the reported penetration rate for 2019 was 0%.

Estonia reported a smart meter penetration rate of 99.6% as of 2017.

Although smart meters in **Finland** allow monitoring of VQ, there are no explicit specifications regarding the parameters to be monitored. DSOs typically observe ten-minute samples for validating EN 50160 and interruptions longer than one second. As with many other responding countries, Finland has requirements for smart meters and has the highest reported smart meter penetration rate with 99.86% (in 2018).

France's requirements allow for monitoring of VQ, specifically the parameter 'slow supply voltage variations' (from ten-minute to one-minute intervals). At the end of 2018, the smart meter penetration rate was 50%.

As of 2018, under 0.01% of metering points in **Georgia** were equipped with smart meters. According to the latest amendments to the Electricity Distribution Grid Code [73], all multistore buildings that are to be connected to the distribution grid should be equipped with smart meters.

The requirements for smart meters in **Germany** allow for monitoring voltage, current and phase angle as VQ parameters. The penetration rate is very low at almost zero.

There is a generic requirement to proceed with the rollout of smart meters in **Greece**, however, the specific requirements and capabilities regarding VQM have not yet been defined. Existing electronic interval meters have simple capabilities to register voltage dips and swells, but not to EN 50160 standard (low sampling frequency). The smart meter rollout has not yet started and existing electronic interval meters that are currently read remotely, account for 1% of MV and LV end-users.

The requirements in **Ireland** allow for monitoring of the minimum, maximum and average, as VQ parameters. All its smart meters (1% of metering points in 2019) use the DLMS-COSEM standard.

In **Italy**, smart meters detect supply voltage variations and interruptions according to EN 50160 and EN 61000-4-30 standards. The penetration of smart meters is nearly 100% of all LV network users.

In **Kosovo***, requirements for smart meters allow monitoring of voltage, current and power. Regarding voltage, monitored parameters are: the over/under voltage events and the average voltage in 15-minute intervals. All smart meters in Kosovo* use the 'meters and more' standard. The penetration rate is 8.76% as of September 2019, however, the answer also indicated that the rate in transmission was already at 90% by 2017.

Although there are no smart meter requirements in **Latvia**, the penetration rate was 48% as of 2018. Only voltage dips and interruptions are monitored by the meters. The standard used is IDIS with country-specific extension, G3 PLC.

Similarly, **Montenegro** does not have requirements, but its smart meters (penetration rate 74.2% in 2018) allow monitoring of both voltage interruptions and voltage variations according to EN 50160.

Malta reported a smart meter penetration rate of 81%, representing a total of 259,822 smart meters in 2018.

Moldova reported 0% smart meter penetration.

There are also no requirements in **the Netherlands**, however, 54% of Dutch households were equipped with smart meters in 2019. The registration and dissemination of data should be done by 'international open standards' and all smart meters in the Netherlands must adhere to this.

All smart meters in **Norway** must meet at least the following functional requirements:

- Store the meter values with a maximum time resolution of 60 minutes, and be able to be converted into a minimum time resolution of 15 minutes;
- Have a standardised interface that facilitates communication with external devices based on open standards;
- Be connected and communicate with other types of meters;
- Ensure that stored data is not lost during power outages;
- Be able to break and limit the power in each meter point, except for transformer-metered customers;
- Be able to send and receive information about electricity prices and tariffs, as well as to transfer management and fault information;
- Provide protection against misuse of data and unauthorised access to control functions; and
- Register the flow of active and reactive power in both directions.

Norway reported a very high penetration rate of 98% in 2019.

Romania reported a smart meter penetration rate of 9.6% for 2018. The requirements for smart meters allow monitoring of VQ by recording the voltage level deviations to a programmed value (+/-5% from the nominal value for LV) and by registering long interruptions (longer than three minutes).

Serbia responded that it has requirements for smart meters but did not provide further details.

Slovakia has requirements for smart meters (which allow monitoring of VQ parameters) and reported a penetration rate of 20% in 2020.

In **Slovenia**, the requirements allow monitoring of the following VQ parameters: under-voltage, over-voltage, missing voltage, normal voltage, voltage dip, voltage swell, voltage cut and voltage asymmetry. The penetration rate in 2018 was 66% and the standard used on all smart meters is G3-PLC Alliance DLMS-COSEM.

Spain has a high penetration rate of 98% (2019) and uses two different standards for smart meters: 'prime' (used on 56.33% of devices) and 'meters and more' (43.64% of all Spanish smart meters).

Smart meters in **Sweden** have a minimum level of indicative VQ measurement functionality set out in the regulation. In the regulation, the DSO is obliged to have replaced all meters with smart meters by 1 January 2025.

Ukraine has no official requirements for smart meters except for recording of voltage. Electronic meters installed at points of connection of LV consumers could be used for monitoring of voltage deviations. For these purposes they should record the following: in cases where there is a deviation in the average value of voltage on a ten-minute time interval by 10% of standard nominal voltage, the average value of voltage in this interval, and time of start of such deviation, should be registered. The penetration rate in 2017 was 6.8% of households.

The capabilities implemented in smart meters are listed in Table 3-15.

TABLE 3-15: Informational transmission protocols and capabilities implemented in smart meters

	Yes	No
Automatic meter reading (AMR): remote reading of energy and power for billing	AL, BA, BE, CY, DE, ES, FI, FR, GE, IE, IT, KS*[146], LV, MT, NL, NO, RO, SE, SI, SK	MD
Remote reading of quality parameters	BA, BE, CY, DE, ES, FI, FR, GE, IE, IT, KS*[147], NL, NO[148], RO, SE (indicative), SI, SK	LV, MD
Change of tariffs, periods, contracted power etc.	BA, BE, CY, DE, ES, FI, FR, GE, IE, IT, KS*[146], NL, RO, SI, SK	LV, MD, NO, SE
Remote synchronisation (at least every reading cycle)	BA, BE, CY, ES, FI, FR, GE, IE, IT, KS*[146], LV, MT, NL, NO, SE, SI, SK	MD, RO
Meter software update	BA, BE, CY, DE, ES, FI, FR, GE, IE, IT, KS*[147], NL, NO, RO, SE, SI, SK	LV, MD
Remote reading of events	AL, BA, BE, CY, ES, FI, FR, GE, IE, IT, KS*[146], LV, NL, NO, RO, SE, SI, SK	MD
Remote disconnection and reconnection: management of registration and cancellation of household customers	BA, BE[149], CY, ES, FI, FR, GE, IE, IT, KS*[147], LV, NL, NO, RO, SE, SI, SK	MD
Remote disconnection and reconnection: roll out demand control plan	BA, CY, ES, FR, GE, IT, KS*[147], LV, NL, SE, SI[150], SK	BE, IE, MD, RO
Ability to manage demand: load reduction during peak demand	CY, ES, FI, GE, IT, NL, NO, SI[151], SK	BA, BE, DE, IE, KS*, LV, MD, RO, SE
Ability to send different messages to customers	BE, CY, FR, IT, SK	BA, DE, ES, FI, GE, IE, KS*, LV, MD, NO, RO, SE, SI

146 Yes also applies to the TSO.
147 No for the TSO.
148 For example, voltage deviation or earth faults.
149 Disconnection only.
150 Installed at customers that are not yet integrated with advanced metering infrastructure.
151 Remote power limiter is an option for load reduction on majority of meters since 2011 but it is not in use.

3.8 DATA COLLECTION, AGGREGATION, ANALYSIS AND PUBLICATION

VQ data are collected and stored in more than half the responding countries, as shown in the table below.

TABLE 3-16: VQ data collection and storage

Yes	No
AL, BA[152], BE, CY, FI, FR, GE, HR, HU, IE, IT, LV, MK, NO, PT, RO, SI, SK	AT, EE, EL, ES, KS*, LT, LU, MD, ME, NL, RS, SE, UA

In most responding countries, VQ data are stored by a system operator (distribution or transmission or both). This approach is used in Albania, Belgium (Flanders and Brussels), Cyprus, Finland, Georgia, Hungary, Italy, Slovakia and Slovenia.

In Bosnia and Herzegovina, data are stored on servers, but no further explanation was provided on who operates the servers. The NRA of Finland does not collect data, but the DSOs collect them for their own purposes.

In Croatia, all VQ data and documents are stored in an electronic registry for at least ten years, while Romania stores them for seven. Ireland uses two proprietary databases to collect and store the data which are then transferred to a single database for analysis.

In Latvia, the NRA or network operators store the data, depending on who took the measurements. In Norway, since 2006, the TSO/DSOs have been obliged to store the continuously measured VQ parameters for at least ten years and are obliged to provide data upon request. Since 2014, the NRA has been collecting data each year.

Only a small number of countries make VQ data publicly available. This includes Belgium (only in Wallonia and not in other regions), Italy, the Netherlands, Norway and Portugal. Since 2006, the TSO and all DSOs in Norway have been obliged to provide data on request. Since 2014, five specified VQ parameters have been reported by the system operators, along with some key information about the measurement points:

- Name of the measurement location;
- GPS coordinates of the measurement location;
- Name of county and municipality of the measurement location;
- Nominal voltage at the measurement location;
- Short circuit current for the measurement location;
- Type of grid at the measurement location (EHV, HV, MV with overhead lines, MV with cables, mixed MV); and
- Earthing system at the measurement location (i.e. insulated, Petersen coil, directly earthed).

The Netherlands and Slovenia indicated that they publicly identify the monitored points. Slovenia includes the list of monitored points in both transmission and distribution network level and on different voltage levels in its annual Report on the Quality of Supply. In the Netherlands, monitored points are superimposed on a map of the country.

In most responding countries, system operators are responsible for the analysis of VQ data, sometimes together with the NRA (Austria, Kosovo*, Norway and Slovakia). In Serbia, the responsibility lies only with the NRA. In Montenegro, the DSO and TSO are obliged to comply with the VQ standards, but according to Energy Law [35], an inspector is in charge of monitoring compliance. In the Netherlands, the joint grid operators and a consulting firm are responsible for analysis of VQ data. The data is published by grid operators in an annual report on VQ available to download on their websites. The TSO and DSOs of Norway may perform analyses according to their individual needs.

There are different ways to aggregate and prepare data for publication.

Austria aggregates for each network region and for the entire country.

In the Flanders region of **Belgium**, VQ data are aggregated by DSO and then reported to the regional regulator. In the region of Wallonia, the results are prepared by the DSO but not published.

A study into the distribution network of the Republika Srpska entity in **Bosnia and Herzegovina** has served as a starting document for analysis and measurement of VQ. Subsequently, thirteen cycles of VQ measurements have been performed at different locations in distribution, and a report of the results prepared.

In **Croatia**, the DSO's reports on the quality of electricity supply include a general (system) indicator: the percentage of connections that satisfied HRN EN 50160[153] of the total connections that had their VQ measured in the observed year. The report is published for the whole system and per distribution area.

Georgia aggregates VQ data for each voltage level whereas **Kosovo*** aggregates but does not publish its data.

The NRA of **Norway** publishes the number of short-term voltage dips per week at a national level for the 22 kV grid.

In its annual report, **Slovenia** publishes data such as the total number of weeks for each monitored parameter of standard, the number of compliant and non-compliant weeks for each monitored parameter of standard and the number of voltage dips and swells.

152 Distribution in Republika Srpska and transmission in all of Bosnia and Herzegovina.
153 This is the Croatia-specific version of EN 50160 published by HZN (Croatian Standards Institute).

Table 3-17 shows what entities are responsible for the publication of VQ data in countries where it is published. In most responding countries, the data are published annually, while in Bosnia and Herzegovina it is published once or twice a year. Romania performs a yearly update of its database of at least the five previous years' VQ indicators, which are then published on system operator websites. Table 3-18 clarifies whether VQ data are available by request to or from the NRA. The majority of countries provide aggregated data on request.

TABLE 3-17: Responsibility for the publication of VQ data

Country	DSO	TSO	NRA	Other
Belgium			×[154]	
Bosnia and Herzegovina	×	×	×	
Croatia	×			
France		×[155]		
Georgia			×	
Hungary			×	
Italy		×	× (distribution)	
Latvia			×	
Netherlands, The				×[156]
Norway			×	
Portugal	×	×		
Romania	×	×		
Slovakia	×	×	×	
Slovenia	×	×	×[157]	
Ukraine	×	×		

TABLE 3-18: Availability of VQ data upon NRA request

Yes, aggregated	Yes, individual	No
AL, AT[158], BA[159], BE[160], FR, HR, HU, KS*, ME, RO, SI, SK	CY, GE, FI[161], IE, IT, LV, MD, NO[162], PT, UA	NL, RS, SE[163]

3.9 ACTUAL DATA ON VOLTAGE DIPS

Clear and consistent definitions of voltage dip indicators are necessary for interpreting the results from measurement campaigns and for effectively enforcing limits. The calculation of voltage dip indicators consists of three stages:

- Calculation of the 'dip characteristics' (also known as 'single-event indicators') from the sampled voltage waveform. This calculation is often performed by the monitoring instrument;
- Calculation of the 'site indicators', typically the number of dips per year with certain characteristics; and
- Calculation of the 'system indicators', for example the average number of dips per year per site.

These three levels of indicators, including their definition in international standards and similar documents, were discussed extensively in the 5th Benchmarking Report [5]. Annex C also provides an overview of the VQ data that seven countries have provided in response to the questionnaire for this Benchmarking Report: Austria, Belgium, Hungary, Ireland, Kosovo*, Portugal and Slovenia. The tables in the annex include voltage dips, reported according to the classification of voltage dips recommended in EN 50160 [13], with the exception of Hungary, which has a slightly different classification of residual voltage and duration.

154 Regional regulator of Flanders in case of VQ in distribution. No publication in Wallonia and Brussels.
155 In annual reports on their website.
156 Joint grid operators and a consulting firm.
157 The NRA also publishes the Annual Report on the Quality of Supply based on the TSO/DSO data.
158 The NRA can also get individual in addition to aggregated data, but these are not made public.
159 Distribution in Republika Srpska.
160 In all three distribution regions: Flanders, Wallonia and Brussels.
161 If collected during dispute between consumer and DSO.
162 All system operators are obliged to provide data on request.
163 The NRA could impose on the grid owner to share their data with the NRA.

3.10 FINDINGS AND RECOMMENDATIONS

FINDING #1:
NRAs have a significant role in VQ regulation.

In nearly three quarters of responding countries, the NRA (either acting alone or working with other competent authorities) possesses powers and duties to define the VQ regulation. This influences the role the NRAs have in regulation of power quality, as well as awareness and education.

FINDING #2:
EN 50160 is used in every responding country.

All countries that answered the relevant question apply the European technical standard EN 50160 for VQ, or their requirements for VQ are based on the European standard. This ensures a harmonised understanding of VQ phenomena throughout Europe. The majority of countries (28) apply the 2010 version of the standard, or newer, while six countries apply older versions. There are countries, however, where additional requirements have been implemented, mainly to enforce stricter limits.

FINDING #3:
There are differences in monitored VQ indicators across Europe.

VQ is monitored in grids (either transmission or distribution, but in most cases both) of 24 responding countries, but indicators that are monitored differ between them. Supply voltage variations is the most commonly monitored VQ indicator.

FINDING #4:
Compensations for unfulfilled VQ standards are sometimes available.

In some countries, end-users are subject to compensation or a lower tariff if the standard for VQ is not met.

FINDING #5:
DSOs are usually required to measure the VQ on customer request.

Most respondents indicated that their system operators are obliged to measure the VQ on request from end-users. In a few countries, the end-user must pay for the service.

FINDING #6:
More than half of respondents have regulations regarding the upper limit of VQ disturbances.

Approximately 58% of countries have national regulation(s) directly or indirectly imposing maximum levels of disturbances concerning VQ such as emission limits for installations.

RECOMMENDATION 1

INFORM END-USERS ABOUT THEIR VQ.

It is recommended to inform the end-users of the VQ, either on their request or by publishing the VQM data.

RECOMMENDATION 2

SHARE RESPONSIBILITY FOR VQ DISTURBANCES.

Responsibility-sharing between the DSO/TSO and end-users in the national regulations should be considered. Approximately 42% of responding countries do not have regulations imposing maximum levels of disturbances concerning VQ (i.e. emissions from end-users).

RECOMMENDATION 3

RAISE AWARENESS AND UNDERSTANDING OF VQ.

As was recommended in the previous Benchmarking Report, education and awareness on how VQ issues might affect the network and consumers will contribute to reducing inconveniences due to voltage disturbances. It is recommended that more countries increase awareness and education on VQ to be better prepared to deal with VQ issues.

RECOMMENDATION 4

INVESTIGATE THE INFLUENCE OF DISTRIBUTED GENERATION ON VQ, ALONG WITH THE USE OF SMART METERS FOR MONITORING.

With distributed generation and smart meter penetration growing at a fast pace, it is recommended to perform more investigations into the use of smart meters for VQM. It is also recommended to do further investigations into the way VQ is influenced by distributed generation and prosumers.

3.11 CASE STUDY – SITUATION IN NORWAY

In Norway the situation is as follows:

- Power frequency – local areas. Applies to: EHV, HV, MV and LV. Definition: as in EN 50160:2010, clause 3.5 [13]. Limit values: in systems temporarily without physical connections to adjacent transmission grids, the TSO (Statnett) shall ensure that the voltage frequency is normally kept within 50 Hz +/-2%.
- Power frequency – interconnected areas. Applies to: EHV, HV, MV and LV. Definition: as in EN 50160:2010, clause 3.5. Limit values: voltage frequency and time deviations are normally kept within the provisions of the Nordic system operation agreement.

- Supply voltage variations. Applies to: LV. Definition: as in EN 50160:2010, clause 3.21. Limit values: r.m.s. voltage = V_N +/-10%, measured as one-minute mean values in connection points in the LV network.
- Flicker. Applies to: EHV, HV, MV and LV. Definition: as in EN 50160:2010, clause 3.3 and 3.4.

TABLE 3-19: Limit values for long and short-term flicker severity in Norway

	LV and MV	HV and EHV	Time interval
Short-term flicker severity P_{st} [per unit]	1.2	1.0	95% of the week
Long-term flicker severity P_{lt} [per unit]	1.0	0.8	100% of the time

- Voltage swells, voltage dips and single rapid voltage change:
  - Voltage swells. Applies to: EHV, HV, MV and LV. Definition: sudden increase in the r.m.s. value of voltage to more than 110% of declared voltage level for a duration lasting from ten ms to 60 seconds. Limit values: the NRA, NVE-RME, may order those covered by these regulations to implement measures to reduce the scope or consequences of voltage swells. Note: if a rapid voltage change increases above 10%, it is defined as a voltage swell.
  - Voltage dips. Applies to: EHV, HV, MV and LV. Definition: sudden reduction of the r.m.s. value of voltage to less than 90%, but greater than 5% of declared voltage level for a duration lasting from ten ms to 60 seconds. Limit values: NVE-RME may order those covered by the regulation to implement measures to reduce the scope or consequences of voltage dips. Note: if a rapid voltage change dips below 10%, it is defined as a voltage dip.
  - Single rapid voltage change. Applies to: EHV, HV, MV and LV. Definition: a single rapid variation of the r.m.s. value of the voltage between +/-10% of declared voltage that is varying faster than 0.5% of declared voltage per second. Rapid voltages are expressed by its steady state and maximum voltage changes:

$$U_{steady\ state} = \frac{\Delta U_{steady\ state}}{U_{declared}} \times 100\%$$

and

$$\%U_{max} = \frac{\Delta U_{max}}{U_{declared}} \times 100\%$$

Where:

- $\Delta U_{steady\ state}$ is the steady state voltage change after a rapid voltage change;
- ΔU_{max} is the maximum voltage difference during a rapid voltage change; and
- $U_{declared}$ is the declared voltage.

The limit values for single rapid voltage changes, voltage swells and voltage dips are presented in the table below. Please note that the limits are given for the three parameters altogether.

TABLE 3-20: Limit values for rapid voltage changes, voltage swells and voltage dips in Norway

Rapid voltage changes, voltage swells and dips	Maximum number per floating 24-hour period	
	LV and MV	HV and EHV
$\Delta U_{steady\text{-}state} \geq 3\%$	24	12
$\Delta U_{max} \geq 5\%$	24	12

- Transient overvoltage. Applies to: EHV, HV, MV and LV. Definition: high frequency or over frequency overvoltages that normally last for less than one half cycle (10 ms). The rise time can vary from less than a microsecond up to a few milliseconds. Limit values: NVE-RME may order those covered by these regulations to implement measures to reduce the scope or consequences of transient overvoltages.
- Voltage unbalance. Applies to: EHV, HV, MV and LV. Definition: as in EN 50160:2010, clause 3.33. Limit values: the TSO and the DSOs shall ensure that the degree of voltage unbalance does not exceed 2% in connection points, measured as a ten-minute mean value.
- Harmonic voltage. Applies to: EHV, HV, MV and LV. Definition: as in EN 50160:2010, clause 3.6. Limit values:
  - LV and MV: the TSO and the DSOs shall, in connection points with nominal voltages from 230 V to 35 kV, ensure that individual harmonic voltages, measured as ten-minute mean values, do not exceed the following values:

TABLE 3-21: Limit values for harmonic voltages for LV and MV in Norway

Odd harmonics				Even harmonics	
Not multiple of 3		Multiple of 3			
Order h	U_h	Order h	U_h	Order h	U_h
5	6.0%	3	5.0%	2	2.0%
7	5.0%	9	1.5%	4	1.0%
11	3.5%	>9	0.5%	>4	0.5%
13	3.0%				
17	2.0%				
19, 23, 25	1.5%				
>25	1.0%				

- HV and EHV ≤ 245 kV: the TSO and the DSOs shall, in connection points with nominal voltages from 35 kV to 245 kV, ensure that individual harmonic voltages, measured as ten-minute mean values, do not exceed the following values:

TABLE 3-22: Limit values for harmonic voltages for HV and EHV ≤ 245 kV in Norway

Odd harmonics				Even harmonics	
Not multiple of 3		Multiple of 3			
Order h	U_h	Order h	U_h	Order h	U_h
5	3.0%	3	3.0%	2	1.5%
7, 11	2.5%	9	1.5%	4	1.0%
13, 17	2.0%	15, 21	0.5%	6	0.5%
19, 23	1.5%	>21	0.3%	>6	0.3%
25	1.0%				
>25	0.5%				

- EHV above 245 kV: the TSO shall, in connection points with nominal voltages above 245 kV, ensure that individual harmonic voltages, measured as ten-minute mean values, do not exceed the following values:

TABLE 3-23: Limit values for harmonic voltages for EHV > 245 kV in Norway

Odd harmonics				Even harmonics	
Not multiple of 3		Multiple of 3			
Order h	U_h	Order h	U_h	Order h	U_h
5, 7	2.0%	3	2.0%	2	1.0%
11, 13, 17, 19	1.5%	9	1.0%	4, 6	0.5%
23, 25	1.0%	15, 21	0.5%	>6	0.3%
>25	0.5%	>21	0.3%		

- Total harmonic distortion. Applies to: EHV, HV, MV and LV. Definition: as in EN 50160:2010, clause 3.6. Limit values:
  - LV and MV: the TSO and the DSOs should ensure that the THD of the voltage waveform does not exceed 8%, measured as a ten-minute mean value, and that it does not exceed 5%, measured as a one-week mean value in connection points with nominal voltages from 230 V to 35 kV;
  - HV and EHV ≤245 kV: the TSO and the DSOs should ensure that the THD of the voltage waveform does not exceed 3%, measured as a ten-minute mean value in connection points with nominal voltages from 35 kV to 245 kV; and
  - EHV above 245 kV: the TSO should ensure that the THD of the voltage waveform does not exceed 2%, measured as a ten-minute mean value in connection points with nominal voltages above 245 kV.
- Interharmonic voltage. Applies to: EHV, HV, MV and LV. Definition: as in EN 50160, clause 3.8. Limit values: NVE-RME may stipulate limit values for interharmonic voltages in connection points.
- Mains signalling voltage. Applies to: EHV, HV, MV and LV. Definition: as in EN 50160, clause 3.10. Limit values: NVE-RME may stipulate limit values for mains signalling voltages superimposed on the supply voltage in connection points.

04 ELECTRICITY – COMMERCIAL QUALITY

4 ELECTRICITY – COMMERCIAL QUALITY

4.1 WHAT IS COMMERCIAL QUALITY AND WHY IS IT IMPORTANT TO REGULATE IT?

The first engagement consumers have with companies regarding their energy supply is established through commercial interaction. Commercial quality (CQ) plays an important role in this relationship and deals with the quality of all processes involving transactions between consumers and energy companies.

Until now, energy could be supplied to consumers through a single contract with a supplier or separate contracts with a supplier and a DSO. New types of affiliations are being promoted by regulation to ensure consumer empowerment.

Nowadays, CQ is directly associated with transactions between electricity companies (either DSOs or suppliers, or both) and consumers, but implementation of the recent Directive (EU) 2019/944 of the European Parliament [74] will introduce new affiliations and agents (such as local energy communities, flexibility and others) that are not addressed in this Report.

CQ covers not only the supply and sale of electricity, but also the various forms of contacts established between electricity companies and customers. New connections, disconnections, meter reading and verification, repairs and elimination of VQ problems, claims processing, etc. are all services that involve some CQ aspect. The most frequent CQ aspect is the timeliness of services requested by customers.

The CEER-BEUC 2030 Vision for Europe's Energy Customers[164] establishes six principles: affordability, simplicity, protection, inclusiveness, reliability and empowerment (the ASPIRE principles). These principles have been renewed and enhanced to be future-proof for the energy transition to a sustainable and carbon neutral society, underpinned by a commitment that no one is left behind. Reliability is characterised as continuous and reliable supply as well as a reliable customer service. Hence, from a CEER perspective, CQ services are considered to be highly important for customer satisfaction and positive engagement with energy markets.

Where it concerns the need for CQ indicators, a distinction should be made between the deregulated energy market and the regulated market of network operation. An NRA does not usually intervene in a deregulated market, as competition between retailers is expected to result in the sufficient quality. However, in some cases, a certain level of consumer protection is needed. The need for such protection differs among different types of consumers.

The NRA intervention in a regulated market, usually establishes minimum requirements in CQ indicators to compensate for the absence of competition. As a complement to this regulation, in some countries, a regulatory framework based on financial incentives (e.g. an award/penalty system) has been set: if the operator's performance reaches the expected quality level, it can receive an award/bonus equal to or higher than zero, and if not, it will have to pay a penalty and/or compensation to the affected customer. Numerous CQ aspects (e.g. times for connections) in the deregulated electricity market are also related to distribution networks and therefore, given their monopolistic nature, should still be regulated.

EU legislation provides a framework for CQ measures. Directive 2019/944/EC and Directive 2009/73/EC [74], [75] require that MS should take appropriate measures to protect end-consumers, to ensure that they:

- Have a right to a contract with their electricity service provider that specifies: the services provided, the service quality levels offered, as well as the time needed for the initial connection; any compensation and the refund arrangements which apply if contracted service quality levels are not met, including inaccurate and delayed billing; and information relating to customer rights, including on the complaint handling and all of the information referred to in this point, clearly communicated through billing or website;
- Have access to simple, fair, transparent, independent, effective and efficient out-of-court mechanisms for the settlement of disputes concerning rights and obligations; and
- Benefit from transparent, simple and inexpensive procedures for dealing with their complaints. In particular, all customers shall have the right to a good standard of service and complaint handling by their electricity/gas service provider.

Based on these Directives, NRAs have a duty to monitor the time taken by TSOs and DSOs to make connections and repairs. While these requirements concern the regulated part of energy markets, their functioning is essential for retail markets as a whole. Therefore, it is important to monitor these key network services and their timely provision by DSOs so as to provide a full picture of market functioning from a consumer perspective.

4.2 STRUCTURE OF THE CHAPTER ON ELECTRICITY COMMERCIAL QUALITY

As with the previous editions, this 7th Benchmarking Report is focused more on the CQ performance of the DSOs than on the performance of the operators of the deregulated electricity market. The impact of market opening on CQ is not discussed in this edition.

164 CEER-BEUC 2030 Vision for Energy Consumers: LET'S ASPIRE!, CEER/BEUC, October 2020.

Regarding CQ, the 7th Benchmarking Report adopts a similar structure as the 5th and the 6th Reports [5], [6]. First, it presents the main aspects of CQ and categorises indicators into four groups. Then it provides the list of indicators including performance times and compensations in case of non-compliance in various countries, in addition to approaches to regulating CQ.

The contents of this chapter are based on answers provided by 34 countries: Albania, Austria, Bosnia and Herzegovina, Belgium, Croatia, Cyprus, Denmark, Estonia, Finland, France, Georgia, Germany, Greece, Hungary, Ireland, Kosovo*, Latvia, Lithuania, Luxembourg, Malta, Moldova, Montenegro, the Netherlands, North Macedonia, Norway, Poland, Portugal, Romania, Serbia, Slovakia, Slovenia, Spain, Sweden and Ukraine. It should be kept in mind that not every country answered every question.

The results of benchmarking are presented in Section 4.4, organised by main groups of CQ aspects. Section 4.5 presents a comparison between actual standards and the performance declared by countries. A summary of the results is provided in Section 4.6. Finally, Section 4.7 includes a list of findings and recommendations on CQ and a review of the implementation of CQ recommendations made in previous Benchmarking Reports.

4.3 MAIN ASPECTS OF ELECTRICITY COMMERCIAL QUALITY

Commercial transactions between electricity companies and consumers are traditionally classified as follows:

- Pre-contract transactions, such as information on connection to the network and prices associated with the supply of electricity. These actions occur before the supply contract comes into force and incorporate actions by both the DSO and the supplier. Generally, customer rights with regard to such actions are set out in codes (such as connection agreements and the general conditions of supply contracts) and are approved by the NRA or other governmental authorities; and
- Transactions during the contract period, such as billing, payment arrangements and responses to consumers' complaints. These transactions occur regularly (billing and meter readings, for instance) or occasionally (when a customer contacts a company with a query or a complaint).

The quality of service during these transactions can be measured by the time the company needs to provide a proper reply. These transactions could relate to the DSO, the supplier/universal supplier (USP) or to the meter operator (MO) and could be regulated according to the regulatory framework of a particular country. This chapter focuses on residential electricity consumers with connection to the LV network as this is the largest group and because small domestic consumers often need more protection.

4.3.1 Main groups of commercial quality aspects

To simplify the approach to such a complex matter as CQ, indicators relating to electricity CQ have been traditionally classified into four main groups:

- Connection (Group I);
- Customer care (Group II);
- Technical service (Group III); and
- Metering and billing (Group IV).

4.3.2 Commercial quality indicators and their definitions

In this 7th Benchmarking Report, 'standard' once again refers to the minimum levels of service quality, as defined by the NRAs, that a company is expected to deliver to its customers. Indicators are defined as a way to measure dimensions of service quality. NRAs can define standards for indicators, or they can define indicators without standards and simply publish the indicator values of the companies. Therefore, 'overall' and 'guaranteed' describes the indicators and not the standards, as 'overall' and 'guaranteed' refer to the nature of the indicator. A standard is a limit, a value (e.g. a percentage). Thus, this Report includes three types of indicators: guaranteed indicators (GI), overall indicators (OI), and other requirements (OR).

For example, as illustrated in Figure 4-1 below, for the OI 'time to respond to a customer request for a new grid connection', the time taken should not exceed two working days in a specific country. The response should inform the customer of the process, the estimated schedule and requests for information required from the customer, including contact details. For the standard in the example below, the time taken to respond to a customer request for a connection to the grid should not exceed two working days in 90 % of the cases.

FIGURE 4-1: Example of a CQ indicator and standard (electricity)

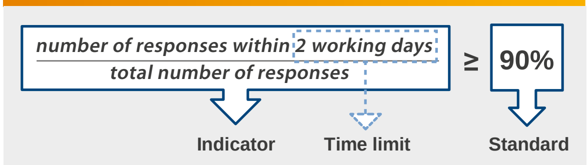


Table 4-1 shows the electricity CQ indicators included in the survey and their definitions for the purposes of this 7th Benchmarking Report. There is an indicator 'minimum frequency of meter readings per year' that was deliberately excluded from this table (and the entire chapter) due to differences in interpretation of the question, which would make benchmarking impossible.

TABLE 4-1: CQ indicators surveyed (electricity)

Group	Indicator	Definition
I. Connection	I.1 Time for response to customer claim for network connection	Time period between the receipt of customer's written claim for connection and the written response (date of dispatch), if no intervention is necessary on the public network.
	I.2 Time for the cost estimation for simple works	Time period between the receipt of customer's written claim for connection and the written response including a cost estimation of works (date of dispatch), if connection can be executed by *simple works* (connection that requires no more than one day of work at the customer's premises).
	I.3 Time duration of connecting customers to the network	Time period between the receipt of customer's written claim for connection and the date the customer is connected to network, if no intervention is required in the network.
	I.4 Time for disconnection upon customer's request	Time period between the receipt of customer's request for disconnection and the date the customer is disconnected.
	I.5 Time to switch supplier on customer request	Time period between the receipt of customer's written request to switch their supplier and the date the switch takes effect.
II. Customer care	II.1 Punctuality of appointments with customers	The personnel appear at the customer site within the time range (period of hours) previously agreed with the customer.
	II.2 Time for response to customer complaints	Time period between the receipt of customer's complaint and the response to it.
	II.3 Time for response to customer enquiry	Time period between the receipt of customer's enquiry and the response to it.
	II.4 Time for response to customer voltage and/or current complaint	Time period between the receipt of customer's voltage and/or current complaint and the response to it.
	II.5 Time for response to customer interruption complaint	Time period between the receipt of customer's interruption complaints and the response to it.
	II.6 Time for response to questions in relation to costs and payments (excluding connection)	Time period between the receipt of customer's question (excluding cost estimation for connection) and the response to it.
	II.7 Time limit for waiting in call centres (telephone contact)	Time period between the receipt of customer's call and the answer given by the call centre operator (telephone contact).
	II.8 Time limit for waiting in call centres specifically regarding emergency and/or failure calls	Time period between the receipt of customer's call and the answer given by the call centre operator specifically regarding emergency and/or failure calls.
	II.9 Time limit for waiting in customer centres	Time period between the arrival of a customer and the answer given by the customer centre employee.
III. Technical service	III.1 Resolution of VQ problems	Time period between the answer to the complaint and the resolution of the VQ disturbance.
	III.2 Time until the start of restoration of supply following failure of DSO's fuse	Time period between the failure of DSO's fuse and the start of fuse repairs.
	III.3 Time for giving information in advance of a planned interruption	Time period between the advance notice of a planned interruption and the beginning of the planned interruption.
	III.4 Time until the restoration of supply in case of unplanned interruption	Time period between the beginning of an unplanned interruption and the restoration of supply to the individual customer affected.
IV. Metering and billing	IV.1 Time for meter inspection in case of meter failure	Time period between the meter problem communicated by the customer and the inspection of the meter.
	IV.2 Time from the notice to pay until disconnection	Time period between the notice to pay / notice of disconnection after missing payments and the disconnection of the customer.
	IV.3 Time for restoration of power supply following disconnection due to non-payment or other non-compliance	Time period between the payment of debts or resolution of other non-compliance issues by the customer and the restoration of supply to the customer.

The main results of the benchmarking are described in Section 4.5 distinguishing between the four main groups. The results in CQ should be interpreted with prudence, as some elements can be measured in different ways and data were not always available for every country. Importantly, as each country has its own regulatory system (with specific time limits, standards, compensation levels and penalty amounts), the performances of operators in each country are not easy to compare.

4.3.3 How to regulate commercial quality

For this 7th Benchmarking Report, there are **three types of requirements** for CQ:

- **Guaranteed Indicators** (GIs) refer to service quality levels that must be met in each individual case. If the company fails to provide the service level required by the GI for a specific service, the customer affected must receive **compensation**, subject to certain exemptions. The definition of GIs includes the following features:
  - A performance standard, which sets the expected level of service for each case (e.g. estimation of the costs for the connection);
  - Maximum time before execution of the performance (response or fulfilment time); and
  - Economic compensation to be paid to the customer in the case of non-compliance.

- **Overall Indicators** (OIs) refer to a given set of cases (e.g. all customer requests in a given region for a given transaction) and must be met with respect to the whole population in that set. A penalty has to be paid in the case of non-compliance with the indicator. OIs are defined as follows:
  - Performance covered (e.g. connection of a new customer to the network); and
  - Minimum level of performance (commonly in percent of cases), which has to be met in a given period (e.g. 90 % of new customers have to be connected to the distribution network within 15 working days).

- **Other Requirements** (ORs). In addition to GIs and OIs, NRAs (and/or other competent parties) can issue requirements to achieve a certain quality level of service. These quality levels can be set as the NRA wishes, e.g. a minimum level which must be met by all customers at all times. If the requirements set by the NRA are not met, the NRA could impose sanctions (e.g. financial penalties) in most cases.

4.4 MAIN RESULTS OF BENCHMARKING COMMERCIAL QUALITY INDICATORS

4.4.1 Commercial quality indicators applied

Table 4-2 shows whether a country monitors and/or applies a requirement (GI, OI or OR) for the different CQ aspects. In the last column, the total number of countries where an indicator is in effect is shown. The most common indicators are the ones concerning connection (Group I) and customer care (Group II) issues. The results show that 32 countries apply some type of indicator for electricity CQ.

Regarding the connection category (Group I), the time for response to customer claim for network connection (I.1) and the time duration of connecting customers to the network (I.3) are the indicators most commonly applied. Indicator I.1 is monitored in 24 countries while indicator I.3 is monitored in 27 instances in 26 countries (since it is used as GI and OI in Hungary).

In the customer care category (Group II), time for response to customer complaints (II.2) is the most commonly used indicator, implemented in 24 countries.

Time for giving information in advance of a planned interruption (III.3) is the most frequently used indicator in the technical service category (Group III) and is also applied in 24 countries.

All three indicators in the metering and billing category (Group IV) are each implemented in 19 countries.

In total, 20 countries use at least ten indicators: Albania, Austria, Belgium, Bosnia and Herzegovina, Croatia, Estonia, France, Georgia, Greece, Hungary, Kosovo*, Latvia, Montenegro, the Netherlands, Portugal, Romania, Serbia, Slovenia, Spain and Ukraine.

TABLE 4-2: Summary of countries that employ CQ indicators (electricity)

Group	Indicator	AL	AT	BA	BE	CY	EE	EL	ES	FI	FR	GE	HR	HU	IE	KS*	LT	LU	LV	MD	ME	MK	MT	NL	NO	PL	PT	RO	RS	SE	SI	SK	UA	Total
I. Connection	I.1 Time for response to customer claim for network connection	1	1	1	1	0	1	1	1	1	0	1	1	1	1	1	0	1	1	0	1	0	0	1	0	0	1	1	1	1	1	1	1	**24**
	I.2 Time for cost estimation for simple works	1	1	1	1	0	0	1	1	1	1	0	0	1	0	1	0	0	1	0	0	0	0	1	0	0	1	0	0	0	1	0	0	**14**
	I.3 Time duration of connecting customers to the network	1	1	1	1	0	0	1	1	1	1	1	1	2	1	1	1	1	1	1	1	1	0	1	0	0	1	0	1	1	1	1	1	**27**
	I.4 Time for disconnection upon customer's request	1	0	1	1	0	1	1	0	0	1	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0	1	0	1	1	0	0	1	**12**
	I.5 Time to switch supplier on customer request	1	1	1	1	0	1	1	1	0	1	0	1	1	0	1	0	1	1	0	0	1	0	1	1	1	1	0	1	1	0	0	1	**21**
II. Customer care	II.1 Punctuality of appointments with customers	1	1	0	0	0	0	0	0	0	0	0	0	1	1	1	0	0	0	0	1	0	0	0	0	0	1	0	0	0	1	0	0	**8**
	II.2 Time for response to customer complaints	1	1	1	1	0	1	1	1	0	1	1	1	1	0	1	1	1	1	1	0	1	0	1	0	1	1	1	1	1	0	1	0	**24**
	II.3 Time for response to customer enquiry	1	1	1	0	0	1	1	0	1	1	1	1	1	0	1	0	0	1	0	1	0	0	1	0	1	1	0	0	0	0	0	1	**17**
	II.4 Time for response to customer voltage and/or current complaint	1	0	1	0	0	0	1	0	0	1	1	1	1	1	1	0	0	0	0	1	0	0	1	0	1	1	1	1	0	1	1	1	**18**
	II.5 Time for response to customer interruption complaint	1	0	0	1	0	1	0	0	0	1	0	1	0	0	0	0	0	0	0	0	1	0	0	0	1	0	1	1	0	0	0	0	**9**
	II.6 Time for response to questions in relation to costs and payments (excluding connection)	0	0	0	0	0	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	1	0	1	1	1	**7**
	II.7 Time limit for waiting in call centres (telephone contact)	0	0	1	0	0	0	0	1	0	0	1	1	1	0	1	0	0	0	0	0	0	0	0	0	0	1	1	0	0	0	0	1	**9**
	II.8 Time limit for waiting in call centres specifically regarding emergency and/or failure calls	0	0	0	0	0	0	0	0	0	0	0	0	1	1	0	0	1	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	**4**
	II.9 Time limit for waiting in customer centres	0	0	1	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	**4**
III. Technical service	III.1 Resolution of VQ problems	0	1	1	1	0	0	0	0	0	1	0	0	1	1	0	0	0	0	1	1	0	0	1	0	0	0	1	0	0	1	0	1	**12**
	III.2 Time until the start of restoration of supply following failure of DSO's fuse	0	1	1	1	0	1	1	0	0	0	0	1	1	1	0	0	0	1	0	0	0	0	1	0	0	1	1	1	0	1	0	1	**15**
	III.3 Time for giving information in advance of a planned interruption	0	1	1	1	0	1	0	1	1	0	1	1	1	1	1	1	0	1	1	1	1	0	1	0	1	1	1	1	0	1	1	1	**24**
	III.4 Time until the restoration of supply in case of unplanned interruption	0	1	1	1	0	1	1	0	0	0	1	1	1	1	1	1	0	1	1	1	0	0	1	0	0	0	1	1	0	0	1	1	**19**
IV. Metering and billing	IV.1 Time for meter inspection in case of meter failure	0	0	1	1	1	1	0	1	0	0	1	1	1	0	1	1	0	0	0	1	0	0	0	1	1	1	1	1	0	1	1	1	**19**
	IV.2 Time from the notice to pay until disconnection	0	1	1	1	0	1	1	1	1	0	0	0	1	0	1	1	1	1	0	0	0	0	1	1	1	0	1	1	1	0	0	1	**19**
	IV.3 Time for restoration of power supply following disconnection due to non-payment or other non-compliance	0	1	1	0	0	0	1	1	0	0	1	1	1	0	0	1	1	1	1	1	0	0	1	0	0	1	1	1	0	1	1	1	**19**
Total number of indicators per country		**10**	**13**	**17**	**13**	**1**	**12**	**12**	**10**	**6**	**10**	**11**	**13**	**19**	**9**	**14**	**7**	**7**	**11**	**6**	**10**	**5**	**0**	**13**	**3**	**9**	**16**	**12**	**15**	**6**	**11**	**9**	**15**	**325**

In Table 4-3, various CQ indicators are shown along with the type of company they refer to (DSO, Supplier, USP, MO and TSO) indicating the number of companies for which these indicators are used.

DSOs are the entities most affected by CQ indicators, no matter which group of indicators (connection, customer care, technical service or billing and metering) is considered. This high number of indicators applied to DSOs can be clearly explained by the need of simulating competition. This pressure is mainly related to connections (Group I) and customer care (Group II) indicators.

The second type of entities most affected by CQ indicators are the suppliers (SP and USP), but the existence of competitive pressure in this deregulated activity explains a lower number of CQ indicators in use. Because of their nature, no country has established indicators for their SPs, USPs and MOs related to technical service (Group III) and a very reduced number of countries employ metering and billing indicators (Group IV) for these types of stakeholders.

The limited number of commercial relations that TSOs must carry out with other entities explains why TSOs are the group with the third highest number of CQ indicators. Although their use is greatly reduced compared to DSOs, there is surprisingly a symmetrical implementation of all groups of indicators.

TABLE 4-3: Number of CQ indicators (GI, OI, OR) per group and per company type (electricity)

Group	Indicator	TSO	DSO	SP	USP	MO	Total
I. Connection	I.1 Time for response to customer claim for network connection	9	25	7	7	2	**50**
	I.2 Time for cost estimation for simple works	2	12	0	0	0	**14**
	I.3 Time duration of connecting customers to the network	6	21	0	0	0	**27**
	I.4 Time for disconnection upon customer's request	3	9	1	1	1	**15**
	I.5 Time to switch supplier on customer request	6	16	15	8	1	**46**
II. Customer care	II.1 Punctuality of appointments with customers	2	8	2	2	1	**15**
	II.2 Time for response to customer complaints	11	18	13	10	1	**53**
	II.3 Time for response to customer enquiry	6	15	10	8	0	**39**
	II.4 Time for response to customer voltage and/or current complaint	4	14	2	2	2	**24**
	II.5 Time for response to customer interruption complaint	6	9	1	1	0	**17**
	II.6 Time for response to questions in relation with costs and payments (excluding connection)	3	5	5	3	0	**16**
	II.7 Time limit for waiting in call centres (telephone contact)	2	9	3	5	0	**19**
	II.8 Time limit for waiting in call centres specifically regarding emergency and/or failure calls	1	3	1	1	0	**6**
	II.9 Time limit for waiting in customer centres	1	3	2	3	0	**9**
III. Technical service	III.1 Resolution of VQ problems	0	9	0	0	0	**9**
	III.2 Time until the start of restoration of supply following failure of DSO's fuse	3	12	0	0	0	**15**
	III.3 Time for giving information in advance of a planned interruption	9	21	0	0	0	**30**
	III.4 Time until the restoration of supply in case of unplanned interruption	8	17	0	0	0	**25**
IV. Metering and billing	IV.1 Time for meter inspection in case of meter failure	8	15	3	1	1	**28**
	IV.2 Time from the notice to pay until disconnection	6	14	6	4	0	**30**
	IV.3 Time for restoration of power supply following disconnection due to non-payment or other non-compliance	7	17	5	4	1	**34**
Total		**103**	**272**	**76**	**60**	**10**	**521**

Table 4-4 shows the number of CQ indicators per country, distinguishing between OIs, GIs and ORs. It is evident that NRAs make more use of GIs and ORs than OIs. However, in many countries, requirements applicable to each transaction are applied as well, albeit without compensation to the customer in cases of non-compliance. From the customer protection point of view, the most efficient regulation is based on GIs, or minimum requirements set by the NRA where sanctions can be issued. It is very important to note that this table shows more indicators than Table 4-2. The reason for that is that it includes an indicator regarding obligations for meter readings which, due to contradicting interpretation by different respondents, had to be excluded from other tables.

TABLE 4-4: Number of CQ indicators surveyed (electricity)

Country	OI	GI	OR	Total
Albania	0	0	10	**10**
Austria	10	0	4	**14**
Belgium	0	0	14	**14**
Bosnia and Herzegovina	0	9	10	**19**
Croatia	0	12	2	**14**
Cyprus	0	0	2	**2**
Estonia	6	2	4	**12**
Finland	0	0	7	**7**
France	2	2	6	**10**
Georgia	3	8	0	**11**
Greece	0	10	2	**12**
Hungary	6	13	1	**20**
Ireland	1	8	0	**9**
Kosovo*	0	9	6	**15**
Latvia	0	0	12	**12**
Lithuania	0	0	8	**8**
Luxembourg	2	5	0	**7**
Malta	0	0	1	**1**
Moldova	1	3	2	**6**
Montenegro	0	10	0	**10**
Netherlands, The	1	1	12	**14**
North Macedonia	1	4	0	**5**
Norway	0	0	3	**3**
Poland	0	9	0	**9**
Portugal	3	12	1	**16**
Romania	5	6	2	**13**
Serbia	0	0	16	**16**
Slovakia	0	9	0	**9**
Slovenia	4	8	0	**12**
Spain	2	5	4	**11**
Sweden	1	2	4	**7**
Ukraine	1	10	5	**16**
Total	**49**	**157**	**138**	**344**

Although the most common approach to regulate is a hybrid approach using several types of indicators, it is worth highlighting that Estonia, France, Hungary, Moldova, the Netherlands, Portugal, Romania, Spain, Sweden and Ukraine make use of all three types of indicators.

Only Montenegro, Poland and Slovakia make use exclusively of GI indicators while Albania, Belgium, Cyprus, Finland, Latvia, Lithuania, Malta, Norway and Serbia solely use OR indicators.

4.4.2 Group I: Connection

This group concerns CQ indicators that are applicable mainly to DSOs and are applied by a high number of NRAs. The reason for this is two-fold: firstly, both speedy clarification of the network access conditions, and timeliness of connections are of high priority to customers, and secondly, connection is mainly associated with distribution and is therefore strictly related to the regulation of a monopoly activity (although, in a few countries, this activity can be performed by independent companies).

Table 4-5 contains data for household customer connections. Countries are grouped by the type of applied indicators, while time limits and compensation are shown. Several countries provided data for indicators for customers connected to multiple voltage levels.

TABLE 4-5: Types of indicators used in Group I (electricity)

Indicator	Countries grouped by types of indicators			Time limit	Compensation
	OI	GI	OR		(median value and range)
I.1 Time for response to customer claim for network connection	AT, EE, SI, NL	BA, EL, ES, GE, HR, HU, IE, KS*, LU, ME, PT, RO, SK, UA	AL, BE, FI, LV, RS, SE	Median: 30 days (range: 2-90 days)	€30[165] (range: €20-€200)
I.2 Time for cost estimation for simple works	AT, FR	BA, EL, ES, HU, KS*, PT, SI	AL, BE, FI, LV, NL	Median: 14 days (range: 5-30 days)	€40 (range: €15-€100)
I.3 Time duration of connecting customers to the network	AT, HU, MK, SE, SI	BA, EL, ES, GE, HR, HU, IE, KS*, LU, MD, ME, PT, SK, UA	AL, BE, FI, FR, LT, LV, NL, RS	Median: 20 days (range: 2-730 days)	€20 (range: €6.22-€250)
I.4 Time for disconnection upon customer's request	EE	EL, GE, KS*, PT, SE	AL, BA, BE, FR, RS, UA	Median: 5 working days (range: 2-30 days)	€8.86 (range: €1.36-€20)
I.5 Time to switch supplier on customer request	EE	BA, KS*, LU, MK, PL, SE	AL, AT, BE, EL, ES, FR, HR, HU, LV, NL, NO, PT, RS, UA	Median: 21 days (range: 5-30 days)	

As described in the 6th Benchmarking Report [6], connection activities are closely interrelated. Several countries reported that some indicators of the CEER-ECRB questionnaire are not entirely identical with the ones they apply.

The indicator 'time for response to customer claim for network connection' (I.1), is used in 24 countries, mainly as a GI. Time limit varies between two and 90 days, with a median of 30 days. The minimum number of days is observed in Spain and the maximum in Montenegro.

With the exception of Latvia, Georgia and Romania, all countries reported an average performance time below the European median value observed for this indicator. In cases where an indicator deals with time, reporting a value below the median means that it takes less time to respond to a customer claim for network connection, and therefore is better than having a value above the median.

Compensation payments associated with non-compliance with the 'time for response to customer claim for network connection' CQ indicator, have a European median value of €30[165] and range between €20 and €200. The maximum and minimum compensation payment for non-compliance with this indicator is observed in Romania.

The indicator 'time for cost estimation for simple works' (I.2) is used in 14 countries, again, predominantly as a GI. The time limit established for this indicator in countries that use it, is 14 days (as a median value) and varies between five and 30 days. For this standard, the minimum number of days is observed in Spain and the maximum in Austria.

Only two countries, Greece and Slovenia, have provided data for the average performance time of indicator I.2. Values reported by these two countries are below the European average for the standard, meaning that the provision of a cost estimation in these two countries takes a shorter time period.

Compensation payments associated with non-compliance with indicator I.2 have a median value of €40 and range between €15 to €100. In Austria, non-compliance with this indicator does not involve compensation to customers, but a potential administrative fine of up to 75,000 euros for the system operator. The same scheme is applied when connecting new customers to the network (indicator I.3).

The maximum compensation payment for non-compliance with the 'time for cost estimation for simple works' CQ indicator, is observed for HV customers in Slovenia, while the minimum compensation is observed in Greece.

The 'time duration of connecting customers to the network' indicator (I.3) is monitored by 26 countries with 27 instances of using an indicator. Hungary is the only country that employs a GI and an OI for this indicator. The median time limit is 20 days, while the values vary between two days in Moldova and two years in Sweden (presented as 730 days in the table). Lithuania also has a long duration of 22 months, which is slightly shorter than Sweden's.

Hungary, Malta, Slovakia and Ukraine reported average performance time values below the European median. Compensation payments for this indicator range between €6.22 (Ukraine) and €250 (Slovakia).

The indicator 'time for disconnection upon customer's request' (I.4) is monitored by 12 countries, mainly through ORs. The median duration for disconnection is five days with a range between two (Kosovo*) and 30 days (Albania). Only Latvia and Serbia have been able to provide data for average performance time for this indicator and their values are below the European median, meaning shorter waiting times for disconnection upon customer request. Compensation payments associated with non-compliance with this standard have a median of €8.86 with countries reporting compensation ranging from €1.36 (Georgia) and €20 (Portugal).

165 The median values and ranges of compensation also include countries that do not use euro as currency. Throughout this chapter, the exchange rates used are from mid-2021 which might differ from exchange rates used in other chapters due to prolonged preparation of this Benchmarking Report.

The 'time to switch supplier on customer request' indicator (I.5) is monitored by 21 countries, mainly through ORs. Time to switch ranges from five (Hungary) to 30 days (Albania), with a median of 15 days.

Only Portugal provided data on average performance time for this indicator, and it is below the European median for the standard. Compensation payments for this standard have not been reported.

4.4.3 Group II: Customer care

While indicators in Group I (connection) refer exclusively to DSOs, those in Group II can apply not only to DSOs, but TSOs and suppliers as well. In addition, some responding countries have specified that certain indicators in Group II cannot be unambiguously interpreted. Most indicators associated with customer care are GIs with compensation provided to customers in cases of non-compliance. Table 4-6 illustrates the ranges of standards and compensation payments across Europe.

TABLE 4-6: Types of indicators used in Group II (electricity)

Indicator	Countries grouped by types of indicators			Time limit	Compensation
	OI	GI	OR		(median value and range)
II.1 Punctuality of appointments with customers	AT, SI	HU, IE, KS*, ME, PT	AL	Median: 5 hours (range: 2-720 hours)	€17.5 (range: €15-€20)
II.2 Time for response to customer complaints	AT, FR, HU, LU	EL, ES, GE, HR, KS*, MK, PL, PT, RO, SK	AL, BA, BE, EE, LT, LV, MD, NL, RS, SE	Median: 15 days (range: 4-60 days)	€ 18.18 (range: €1.33-€202.10)
II.3 Time for response to customer enquiry	AT, PT	EL, GE, HR, HU, KS*, ME, PL, UA	AL, BA, EE, FI, FR, LV, NL	Median: 15 days (range: 5-30 days)	€10.61 (range: €1.33-€20)
II.4 Time for response to customer voltage and/or current complaint	SI	EL, FR, GE, HR, HU, IE, ME, PL, PT, RO, SK, UA	AL, BA, KS*, NL, RS	Median: 30 days (range: 5-1,080 days)	€13 (range: €1.35-€35)
II.5 Time for response to customer interruption complaint	-	FR, HR, MK, PL, RO	AL, BE, EE, RS	Median: 30 days (range: 1-30 days)	€20 (range: €8-€200)
II.6 Time for response to questions in relation with costs and payments (excluding connection)	-	PL, SI, SK, UA	EE, FR, RS	Median: 30 days (range: 5-30 days)	€20 (range: €3-€100)
II.7 Time limit for waiting in call centres (telephone contact)	ES, GE, HU, PT, RO, UA	HR, KS*	BA	Median: 60 seconds (range: 30-80 seconds)	-
II.8 Time limit for waiting in call centres specifically regarding emergency and/or failure calls	HU, IE, LU, PT	-	-	Median: 60 seconds (range: 30 seconds-120 minutes)	-
II.9 Time limit for waiting in customer centres	HU, PT	-	BA, RS	Median: 20 minutes	-

In this Group, 'time for response to customer complaints' (II.2) is the most monitored indicator (24 countries, mainly through GI or OR), with a broad range of compensation payments (€1.33 to €202.10). The median time for response to customer complaints is 15 days, with the minimum reported by Hungary and the maximum by North Macedonia. Only three countries (Hungary, Portugal and Ukraine) provided their average performance data. Indicators 'time limit for waiting in customer centres' (II.9) and 'time limit for waiting in call centres specifically regarding emergency and/or failure calls' (II.8) are each monitored in only four responding countries. In Hungary and Portugal, the time limit for waiting in customer centres is shorter than the median of the four countries that provided their average performance values.

The 'time limit for waiting in customer centres' indicator (II.9) is monitored by Hungary and Portugal as OI, and Bosnia and Herzegovina and Serbia as OR, with the median time limit of 20 minutes. Hungary and Portugal also provided the average performance time, which is lower than the median value.

'Punctuality of appointments with customers' (II.1) is used in eight countries, mainly through GIs and stretches from two to 720 hours, which is a considerable time difference. No country has provided information about its average performance time for this indicator. Typical compensation payments are between €15 and €20.

The 'time for response to customer enquiry' (II.3), is monitored by 17 countries and is evenly split between GI and OR, with two countries (Austria and Portugal) using OI. The median time limit is 15 days with the lowest and highest number being in Austria and Estonia, respectively. Five countries provided their average performance values for this indicator: Ireland, Kosovo*, Lithuania, the Netherlands and North Macedonia. Compensation payments for non-compliance are slightly over ten euros as a median value but range between €1.33 and €20.

'Time limit for waiting in call centres specifically regarding emergency and/or failure calls' (II.8) is the only indicator in this Group that is monitored as an OI.

'Time for response to customer voltage and/or current complaint' (II.4), is monitored by 18 countries, mostly through GIs. The median time is 30 days with another case of significant difference between the minimum (five days) and the maximum (three years). Average performance time was provided by only Georgia, Kosovo*, Latvia and Slovenia. Compensation payments are between €1.35 and €35, with a median of €13.

'Time for response to customer interruption complaint' (II.5), is monitored by nine countries, with GI and OR being evenly split as implemented indicator types among these countries. The median time is 30 days while the median compensation in case of non-compliance is €20.

'Time for response to questions in relation to costs and payments (excluding connection)' (II.6) is split between GI and OR among the seven countries that monitor it. As is the case with indicator II.5, the median time is 30 days while the median compensation is €20. Latvia, Serbia, Slovenia and Ukraine provided their average performance time which was below (shorter than) the European median for all four countries.

'Time limit for waiting in call centres (telephone contact)' (II.7) is monitored mostly as OI. Average performance time of Hungary, Latvia and Portugal exceeds the median of the countries where this indicator is used.

4.4.4 Group III: Technical service

Group III includes indicators used for technical service and are applied exclusively to system operators (DSOs or TSOs).

Handling voltage complaints normally involves two steps: the first is to verify, through performing measurements, whether any regulation or norm has been violated, and the second is the correction of voltage problems through appropriate works on the network. It is important that any customer complaint related to voltage disturbance is rectified without undue delay. The exact time needed to rectify the problem or to implement temporary solutions will vary greatly and will depend on the complexity of the given situation. Table 4-7 illustrates the ranges of standards and compensations across Europe.

TABLE 4-7: Types of indicators used in Group III (electricity)

Indicator	Countries grouped by types of indicators			Time limit	Compensation
	OI	GI	OR		(median value and range)
III.1 Resolution of VQ problems	-	HU, IE, ME, SI, UA	AT, BA, BE, FR, MD, NL, RO	Median: 90 days (range: 3-720 days)	Median: €20 (range: €15-€50)
III.2 Time until the start of restoration of supply following failure of DSO's fuse	-	EE, EL, HR, HU, IE, PT, RO, SI, UA	AT, BA, BE, LV, NL, RS	Median: 9 hours (range: 3-24 hours)	Median: €20 (range: €6-€100)
III.3 Time for giving information in advance of a planned interruption	AT, EE, ES, GE, MD	BA, HU, IE, ME, MK, PL, SI, SK	BE, FI, HR, KS*, LT, LV, NL, PT, RO, RS, UA	Median: 2 days (range: 1-15 days)	Median: €21.5 (range: €2.5-€130)
III.4 Time until the restoration of supply in case of unplanned interruption	GE	EE, EL, HR, HU, IE, MD, ME, NL, RO, SK, UA	AT, BA, BE, KS*, LT, LV, RS	Median: 12 hours (range: 1-24 hours)	Median: €30 (range: €6-€200)

Indicator III.1 ('resolution of VQ problems') is monitored by 12 countries, through GI and OR only. The time limit has a median of 90 days, with the minimum observed in Austria and the maximum of 720 days in Slovenia. Compensation payments in cases of non-compliance with the standard vary between €15 and €50. Latvia was the only country to provide its average performance time, which is nearly ten times over the median of the 12 countries where this indicator is in use.

'Time until the start of the restoration of supply following failure of DSO's fuse' (III.2), is monitored by 15 countries with a time range between three and 24 hours, and compensation between €6 and €100. For this standard, the minimum time is observed in Ireland, while the maximum is observed in Serbia and Latvia. The average performance time of Portugal is eight times the European median, while Slovenia reported a value lower than the median, signifying a quicker restoration of supply in cases where a DSO's fuse fails.

For the remaining two standards in this group, OIs are used in addition to GIs and ORs. 'Time for giving information in advance of a planned interruption' (III.3) is the most monitored indicator in this Group (24 countries). The average time reported by Latvia is significantly higher than the median of the standard. 'Time until the restoration of supply in case of unplanned interruption' (III.4) is monitored in 19 countries, with times as high as 24 hours and compensation being up to €200.

4.4.5 Group IV: Metering and billing

Group IV includes a set of CQ indicators related to metering and billing. Most of these standards refer to DSOs and are summarised in Table 4-8. Compensation in case of non-performance is applied in a low number of responding countries.

TABLE 4-8: Types of indicators used in Group IV (electricity)

Indicator	Countries grouped by types of indicators			Time limit	Compensation
	OI	GI	OR		(median value and range)
IV.1 Time for meter inspection in case of meter failure	EE, RO	BA, GE, HR, HU, ME, PL, PT, SI, SK, UA	BE, CY, ES, KS*, LT, NO, RS	Median: 7.5 days (range: 8 hours-20 days)	€20 (range: €1.45-€100)
IV.2 Time from the notice to pay until disconnection	AT, EE, RO	HU, LU, PL	BA, BE, EL, ES, FI, KS*, LT, LV, NL, NO, RS, SE, UA	Median: 15 days (range: 5 working days-2 months)	€15[166]
IV.3 Time for restoration of power supply following disconnection due to non-payment or other non-compliance	AT, RO	BA, EL, ES, GE, HR, HU, LU, MD, ME, PT, SI, SK, UA	LT, LV, NL, RS	Median: 1 day (range: 0.25-5 days)	€20 (range: €1.45-€100)

The indicator 'time for meter inspection in case of meter failure' (IV.1) is used in 19 responding countries. The aim of notifying a customer about an interruption in advance is to give the end-user the possibility to implement proper measures to reduce the negative consequences of interruption. The median compensation is €20, but this can be as much as €100 in some countries. The inspection itself usually takes between eight hours (Lithuania) and 20 days (Ukraine) after the meter failure. Georgia, Latvia, Slovenia and Ukraine provided their average performance time, and their values are below the median of the responding countries.

Time limits for the 'time from the notice to pay until disconnection' (IV.2) typically vary between five working days and two months, with a median of 15 days. This standard is mainly regulated by ORs (13 countries for OR, compared to three countries each for GI and OI). Furthermore, there are several examples where NRAs apply country-specific considerations. In Austria, in the case of separate bills, the DSO must send at least two payment reminders with a two-week deadline for each. This means a minimum four-week deadline before the customer is disconnected and this is not allowed on Fridays or on days before public holidays. For this standard, the minimum time is observed in Ukraine and the maximum time is observed in Belgium and Spain. Compensation payments associated with non-compliance have a European median value of €15.

'Time for restoration of power supply following disconnection due to non-payment or other non-compliance' (IV.3) is the third and most used indicator of this group. Of 19 countries that implement it, 13 use a GI for this standard. The median duration for this restoration is one day (with the minimum in Montenegro and the maximum in Latvia and Ukraine), while the median compensation is €20. In Poland, there is no indicator, but the energy company is obliged to restore the power supply immediately. In Austria, the DSO has to reconnect the customer during the next working day.

4.4.6 Customer compensation

Table 4-9 shows that there is a variety of payment methods in cases of compensation to customers when GIs are not fulfilled. Indicators can be classified by the type of payment.

TABLE 4-9: Compensations due if CQ guaranteed indicators are not fulfilled

Country	Compensation payment method		
	Automatic	Upon claim	Other
Albania		×	×
Belgium		×	
Croatia		×	
Cyprus		×	
Estonia	×		
Georgia	×		
Hungary	×		
Ireland	×	×	
Kosovo*		×	
Latvia			×
Luxembourg			×
Moldova	×	×	
Montenegro		×	
Netherlands, The	×		
Poland		×	
Portugal	×		
Romania	×		
Slovakia	×		
Slovenia		×	
Spain	×		
Ukraine	×		

166 Range is not provided here since only data from Latvia was obtained.

Automatic compensation is preferable to guarantee effective customer protection. The amount can vary in each country, either by the customer sector (residential, non-residential), or by the voltage level (LV, MV and HV) or depending on the delay in executing the transaction beyond the standard. Estonia, Georgia, Hungary, Ireland, Moldova, the Netherlands, Portugal, Romania, Slovakia, Spain and Ukraine all use this type of compensation in some CQ indicators.

Compensation upon customer claim is used in Albania, Belgium, Croatia, Cyprus, Ireland, Kosovo*, Moldova, Montenegro, Poland and Slovenia. This means that Ireland and Moldova have both automatic compensation and compensation on customer request, depending on the indicator.

Albania (in addition to their compensation upon customer claim), Latvia and Luxembourg have declared the use of other types of mechanisms for compensating customers in cases of non-compliance with GIs, but the procedure has not been explained.

In general, it can be concluded that automatic payments to customers are used more frequently than other types of compensation, but each country can decide which commercial indicators deserve automatic compensation.

4.5 PERFORMANCE LEVELS OF COMMERCIAL QUALITY INDICATORS

This section provides an overview of the performance levels of the countries that submitted data. For each of the four Groups, the median of provided reference values and the median of provided average performance times were calculated. The median of provided reference values contains the median value of the time requirements of CQ indicators for those countries that provided values. The performance was unfortunately obtained from a low number of participants.

4.5.1 Connection

The overall average performance time for response to customer claim for network connection was 13.7 days in 2018. Some countries made noticeable progress in the past few years.

With respect to the first indicator in this Group ('time for response to customer claim for network connection'), Malta made the most noticeable progress in the analysed period by managing to reduce the average performance time from 21.3 days in 2014 to 9.6 days in 2018. The average performance time of Ukraine decreased from five days in 2014 to 4.27 days in 2018. Bosnia and Herzegovina achieved a good and relatively stable performance since 2014: 13 days in 2014 and 11 days for three years in a row (2016, 2017 and 2018). The average performance time for Hungary increased from 4.62 days in 2014 to 6.5 days in 2018 but is still below the overall average performance time of 13.7 days. During the analysed period, the value in Serbia varies from seven days in 2014 to the maximum of ten days in 2016 but decreased again to 6.34 in 2018. That same year, five countries (Bosnia and Herzegovina, Hungary, Malta, Serbia, and Ukraine) were below the average performance time of 13.7 days, while six countries (Georgia, Kosovo*, Latvia, Portugal, Romania and Slovenia) were above the average.

For the second performance indicator of the Group, 'time for cost estimation for simple works', data were submitted by only two countries (Greece and Slovenia), despite it being monitored in a total of 13 countries. The overall average performance time for providing a cost estimation for simple works was 4.8 days in 2018. The average time for Slovenia decreased from 3.41 days in 2014 to 2.91 days in 2018, while in Greece, it increased from 4.89 days in 2014 to 6.82 days in 2018.

TABLE 4-10: Average performance time of indicators in Group I (Connection)

Quality indicators (Group I)	European median of reference values 2018	Average performance time (median of provided values) 2018
I.1 Time for response to customer claim for network connection	30 days	13.7 days
I.2 Time for cost estimation for simple works	14 days	4.8 days
I.3 Time duration of connecting customers to the network	20 days	16 days
I.4 Time for disconnection upon customer's request	5 days	3.7 days
I.5 Time to switch supplier on customer request	15 days	4 days

For the third indicator of this Group, 'time duration of connecting customers to the network', the overall average performance of 16 days includes the values of Bosnia and Herzegovina, Georgia, Greece, Hungary, Kosovo*, Latvia, Malta, Portugal, Slovenia, and Ukraine. In 2018, four countries (Hungary, Malta, Slovenia, and Ukraine) were below the average of 16 days (shorter duration), five countries (Bosnia and Herzegovina, Georgia, Greece, Kosovo* and Latvia) were above the average (longer duration), while Portugal did not submit data for 2018. Correspondingly to the first indicator in this Group, Malta made the most noticeable progress decreasing their average performance time from 21.3 days in 2014 to 9.6 days in 2018. Although the average performance time of Latvia is above 16 days, significant progress can be reported since the time was reduced from 54 days in 2014 to 38 days in 2018. Countries such as Hungary and Slovenia have performance times lower than the European average, but their values have increased over the years.

For 'time for disconnection upon customer's request', data were submitted by only three countries: Georgia, Latvia and Serbia. Latvia's average performance time is below the overall average time of 3.7 days (shorter), Serbia's is equal to the average, while Georgia's is above (longer).

The last indicator from this Group is 'time to switch supplier on customer request'. Data were submitted by only two countries: Kosovo* and Portugal. Kosovo* submitted data for just one year and Portugal for three, so there are no sufficiently reliable data available for this indicator to be analysed.

4.5.2 Customer care

Akin to indicators for Connection (Group I), the reported performance time indicators related to Customer care (Group II) are also relatively low and homogeneous during the 2014-2018 period. This Group is the largest, consisting of nine indicators, with performance levels submitted for all except the first indicator, for which no country provided data.

TABLE 4-11: Average performance time of indicators in Group II (Customer care)

Quality indicators (Group II)	European median of reference values 2018	Average performance time (median of provided values) 2018
II.1 Punctuality of appointments with customers	5 hours	-
II.2 Time for response to customer complaints	15 days	12 days
II.3 Time for response to customer enquiry	15 days	7.1 days
II.4 Time for response to customer voltage and/or current complaint	30 days	13 days
II.5 Time for response to customer interruption complaint	30 days	4.6 days
II.6 Time for response to questions in relation with costs and payments (excluding connection)	30 days	3.3 days
II.7 Time limit for waiting in call centres (telephone contact)	60 sec	35.8 sec
II.8 Time limit for waiting in call centres specifically regarding emergency and/or failure calls	60 sec	29.3 sec
II.9 Time limit for waiting in customer centres	20 minutes	7 minutes

The most monitored customer care indicator is the 'time for response to customer complaints. The overall average performance time was 12 days in 2018. Out of six countries that submitted data for that year, Georgia, Ireland and Portugal were below the average performance time of 12 days (meaning faster response), while Kosovo*, the Netherlands and North Macedonia were above (meaning slower response).

Four countries (Georgia, Hungary, Portugal, and Ukraine) submitted performance levels for the third indicator ('time for response to customer enquiry'). Three of them submitted data for the entire period (2014-2018), while Georgia submitted only for the last two years. The average performance time of Hungary is below (shorter than) the overall average performance time of 7.1 days, while Portugal and Ukraine have a performance time that is above (longer than) the average.

The fourth indicator in this Group ('time for response to customer voltage and/or current complaint') is monitored by five countries (Georgia, Kosovo*, Latvia, Portugal, and Slovenia). As with the previous indicator, Georgia submitted data only for the last two years of the analysed period. Portugal provided data only for the last observed year (2018). The average performance time of Georgia and Portugal in 2018 was below the overall average performance time of 13 days. In Kosovo* and Slovenia, it was above the average performance time, while the performance time of Latvia was equal to the average.

For the fifth indicator from this Group ('time for response to customer interruption complaint'), there are no sufficiently reliable data available for analysis. According to submitted answers, data from only two countries are available (Latvia and Serbia). The average performance time of these two countries is 4.6 days.

The average performance of the sixth indicator of the Group, 'time for response to questions in relation to costs and payments (excluding connection)', is 3.3 days, according to data offered by Latvia, Serbia, Slovenia, and Ukraine. The performance time of Serbia and Slovenia in 2018 was slightly lower (shorter) than the average, while Latvia's and Ukraine's were higher (longer).

'Time limit for waiting in call centres (telephone contact)' is monitored in Hungary, Latvia, and Portugal. According to available data, the average performance time for these three countries is 35.8 seconds. Only in Portugal is the average performance time higher than the average.

Data for 'time limit for waiting in call centres specifically regarding emergency and/or failure calls' were also provided by only Hungary, Latvia and Portugal. The average time for emergency and/or failure calls in 2018 for these three countries was 29.3 seconds.

For the ninth and final indicator of the customer care group ('time limit for waiting in customer centres'), data were obtained from only two countries: Hungary and Portugal. The average performance time of these two countries is seven minutes.

4.5.3 Technical service

The Technical service group (Group III) consists of four different indicators: 'resolution of VQ problems', 'time until the start of restoration of supply following failure of DSO's fuse', 'time for giving information in advance of a planned interruption' and 'time until the restoration of supply in case of unplanned interruption'. They are the least monitored electricity CQ indicators. The low number of obtained performance levels makes it impossible to analyse and compare indicators from this Group. Values for the first and third indicator were submitted by Latvia only, for the second indicator by Portugal and Slovenia and for the fourth indicator by Georgia and Latvia. The average performance time of each indicator is presented in table below.

TABLE 4-12: Average performance time of indicators in Group III (Technical service)

Quality indicators (Group III)	European median of reference values 2018	Average performance time (median of provided values) 2018
III.1 Resolution of VQ problems	90 days	
III.2 Time until the start of restoration of supply following failure of DSO's fuse	9 hours	38.695 hours
III.3 Time for giving information in advance of a planned interruption	2 days	
III.4 Time until the restoration of supply in case of unplanned interruption	12 hours	28.265 hours

4.5.4 Metering and billing

Nine countries provided their metering and billing indicators performance. This Group consists of only three indicators: 'time for meter inspection in case of meter failure', 'time from the notice to pay until disconnection' and 'time for restoration of power supply following disconnection due to non-payment or other non-compliance'. A fourth indicator was included in the questionnaire but was omitted from the analysis in this Report due to different understandings of the question by countries.

TABLE 4-13: Average performance time of indicators in Group IV (Metering and billing)

Quality indicators (Group IV)	European median of reference values 2018	Average performance time (median of provided values) 2018
IV.1 Time for meter inspection in case of meter failure	7.5 days	5.5 days
IV.2 Time from the notice to pay until disconnection	15 days	21.94 days[167]
IV.3 Time for restoration of power supply following disconnection due to non-payment or other non-compliance	1 day	1.73 days

All indicators in this Group are monitored by around the same number of countries. For the first indicator, the average performance time for 2018 was 5.5 days according to data provided by Georgia, Latvia, Slovenia and Ukraine. Only Latvia had a performance time below the mean (shorter time), while the other three countries were above the median (longer time). Georgia only contributed performance values for two years, showing that it managed to decrease its customers' wait for meter inspection from 12 days in 2017 to six days in 2018.

It was not possible to calculate the median of the performance time for the second indicator as the value was only provided by Latvia. For the third indicator, the average performances were obtained from Georgia, Ireland, Latvia, Serbia, Slovenia and Ukraine. Georgia managed to decrease its restoration time from 41.24 hours (1.72 days) in 2017 to 4.16 hours (0.17 days) in 2018 and is the country with the best declared performance for this indicator. Performance time in Georgia, Latvia and Ukraine is below (shorter than) the average performance time of 1.73 days, while in other countries, the average performance time is above (longer than) the average.

4.6 SUMMARY OF BENCHMARKING RESULTS

In Group I, 'time for response to customer claim for network connection' (I.1) and 'time for connecting customers to the network' (I.3) are the most used indicators. The average number of indicators per activity is 19.6 ('standards/activity', that is (24+14+27+12+21)/5). This figure is the highest among all Groups, meaning that connection to network in the surveyed countries is of primary importance. The customer care group (Group II) has an average value of 11.1 indicators/activity.

Technical service (Group III) (with an average value of 17.5 indicators/activity) and metering and billing (Group IV) (with an average value of 19 indicators/activity) also have a high degree of monitoring. Of note is that much attention is paid to the quickest possible restoration of supply, irrespective of whether the loss of supply was caused by faults or missing payments. This confirms the energy regulation priority to ensure the availability of supply.

There are considerable differences in the average number of indicators per indicator type. GIs are the most frequently used

167 Latvia only.

indicator type for regulation of connection, customer care and technical service, and they share the most used indicator type with OR for billing and metering issues. In some cases, GIs, OIs and ORs are used in parallel by countries. OIs are rarely used as technical service indicators. Table 4-14 shows the indicators applied per group and per type.

TABLE 4-14: Electricity CQ indicators applied per group and type of indicator

Country	I. Connection			II. Customer care			III. Technical service			IV. Metering and billing		
	OI	GI	OR	OI	GI	OR	OI	GI	OR	OI	GI	OR
Albania			✓			✓						
Austria		✓	✓		✓			✓	✓		✓	
Bosnia and Herzegovina	✓		✓			✓	✓		✓	✓		✓
Belgium			✓			✓			✓			✓
Cyprus												✓
Croatia	✓		✓	✓			✓		✓	✓		
Estonia		✓				✓	✓	✓			✓	
Finland			✓			✓			✓			✓
France		✓	✓	✓	✓	✓			✓			
Greece		✓	✓		✓			✓			✓	✓
Georgia		✓		✓	✓			✓			✓	
Hungary	✓	✓	✓	✓	✓		✓			✓	✓	
Ireland	✓			✓	✓		✓					
Kosovo*	✓			✓		✓			✓			✓
Latvia			✓			✓			✓			✓
Lithuania			✓			✓			✓			✓
Luxembourg	✓				✓					✓		
Malta												✓
Moldova	✓					✓	✓	✓	✓	✓		
Montenegro	✓			✓			✓			✓		
Netherlands, The		✓	✓			✓	✓		✓			✓
North Macedonia	✓	✓		✓			✓					
Norway			✓									✓
Poland		✓			✓			✓			✓	
Portugal		✓		✓	✓			✓	✓	✓	✓	
Romania	✓			✓	✓		✓		✓		✓	
Serbia			✓			✓			✓			✓
Spain	✓		✓	✓	✓			✓		✓		✓
Slovakia	✓			✓			✓			✓		
Slovenia	✓	✓		✓	✓		✓			✓		
Sweden	✓	✓	✓			✓						✓
Ukraine	✓		✓	✓	✓		✓		✓	✓		✓

4.7 FINDINGS AND RECOMMENDATIONS ON COMMERCIAL QUALITY OF ELECTRICITY

It is important to recall that the results on CQ should be interpreted with caution as some elements can be measured in different ways and data is not yet available in every country. This may reflect differences in measurement. For example, some indicators do not differentiate between simple and complex work. Furthermore, the performances of the operators are not comparable across countries since each country has its own regulatory system (with specific time limits, standards, compensation levels, penalty amounts, etc.).

FINDING #1:
There is an increased focus by NRAs on the quality of the services provided to customers.

The first finding, in line with the conclusions from CEER's past Benchmarking Reports, is that European NRAs devote significant attention to the CQ of the services provided. A total of 34 responding countries reported 325 national CQ indicators between them, all referring to 21 indicator types.

FINDING #2:
A broad but increasingly harmonised range of CQ indicators is monitored.

There are significant differences concerning the nature and the number of indicators monitored across countries. Although the set of activities and the expected goals of the regulation are similar, in some countries the regulations are not clearly defined or are less enforced than specific quality indicators (e.g. 'within reasonable time', 'in reasonable terms'). The regulation of a given service can be achieved in many ways such as time limits, standards, compensation levels, penalty levels etc.

NRAs should set the CQ regulations while taking into account their national, political, cultural and economic specificities. At the same time, progress in harmonisation has been achieved compared with the previous Benchmarking Reports. At the time of the 3rd Benchmarking Report (in 2005), the CQ parameters were rarely regulated in the same way across CEER MS, whilst the 7th Benchmarking Report reveals that the number of identical or partially identical regulations concerning these indicators has grown considerably.

FINDING #3:
Requirements and compensations vary greatly depending on the customer type.

CQ concerns different types of customers; the difference in the volume of consumption is also important from a regulation point of view. Their classification (location, voltage levels) varies from country to country and from network operator to network operator. In a given country, requirements may vary greatly depending on whether the customer concerned is connected to LV or HV, for example. In general, CQ is mainly focused on residential customers with a connection to the LV network because they represent the largest group and because small domestic customers often need more protection.

FINDING #4: the move towards more GIs (with compensation) is again confirmed.

The analysis of the results confirms that there is a general trend over time to move away from OIs toward GIs. This trend was already identified by the 4th, 5th and 6th Benchmarking Reports. This 7th Benchmarking Report reveals 157 GIs compared to 49 OIs currently being applied.

This trend can be confirmed with certainty by comparing the situation in the countries that participated both in this Report and in the main body of the 6th Benchmarking Report (Austria, Belgium, Croatia, Estonia, Finland, France, Greece, Hungary, Ireland, Latvia, Lithuania, Luxembourg, Malta, the Netherlands, Norway, Poland, Portugal, Slovenia and Sweden). The total number of GIs declared in the 7th Benchmarking Report amounts to 84 indicators across these countries, which is much higher than the 44 GIs declared for the same countries in the 6th Benchmarking Report.

FINDING #5:
CQ is still mainly focused on the DSO's relationship with customers.

In countries where competition works well, the NRAs are focused more on monitoring the DSOs' CQ obligations (rather than those of the suppliers) as the distribution activities are closely linked to customers (connection to the grids, activations, etc.). Among all responding countries, indicators apply to DSOs in 272 cases and to USPs in 60 cases.

FINDING #6:
Network connection and customer care remain as key considerations.

From a consumer perspective, connection, activation, and maintenance are very relevant processes, as, in some cases, they represent the consumer's first interaction with the energy market. If these processes are well designed and function efficiently, they will help to improve consumers' perception of the energy market. The survey stresses that priority is given to the standards for connection of customers to the network and customer care, such as the response time to complaints. In fact, out of a total of 325 indicators among all countries, 98 cases deal with network connection and 100 with customer care services.

FINDING #7:
Smart meters impact the CQ regulation.

Having accurate billing based on the actual, measured consumption is becoming more and more important both for customers and system operators. All parties expect a more detailed picture of consumption habits (profiles), based on which they would be able to plan network maintenance, energy purchase or eventual change in daily consumption practices. Recognising this need, many countries aim to collect monthly (or even more frequent) meter data via meter readings through the roll-out of smart meter programmes. Smart meters facilitate a more accurate picture of electricity consumption, of grid status and can ease and shorten both the procedure of supplier switching and the process of deactivation and reactivation due to unpaid bills.

FINDING #8:
The focus needs to be wider than DSOs' written responses to consumers.

In addition to a customer's expectation to be connected or reconnected as quickly as possible, there is a noticeable need for a substantive response from the DSO/supplier to any customer request within a reasonable limit of time. The data reveals that the current emphasis is placed on DSOs' performance regarding written forms of communication. This results in an incomplete picture of the quality of responses to customer requests for two different reasons: (1) non-written forms of communication like telephone (landline and mobile) and internet (website) have developed significantly and are widespread; (2) in some countries, the more traditional approach of visiting local customer centres continues. There are countries where oral claims are still not considered, and only written complaints are counted.

RECOMMENDATION 1

PERFORM REGULAR REVIEWS OF NATIONAL REGULATIONS.

It is important for CEER and ECRB (and NRAs) to regularly review the CQ indicators, taking into account the development of national conditions (e.g. the development of smart grids) and customer expectations. Monitoring the actual level of CQ (average values of the indicators and percentages of fulfilment) has an important role in such reviews. The most important factor in this process is the availability of wide and realistic data. Therefore, it is necessary to examine in detail (including questioning stakeholders about) the CQ regulations in place to know if additional indicators or requirements are monitored, or to understand the specificities of each country surveyed.

RECOMMENDATION 2

PURSUE THE HARMONISATION OF CQ INDICATOR DEFINITIONS.

Harmonising the definitions[168] facilitates significant results from European countries and a more consistent and understandable database. Comparisons between countries are difficult to make, as the regulation of a given activity can be achieved in different ways, depending on the country. A clear framework and harmonised parameters can improve the analysis of the results and the identification of further improvements and recommendations.

168 Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2013, ACER/CEER, October 2014.

RECOMMENDATION 3

ENSURE GREATER PROTECTION THROUGH GIs WITH AUTOMATIC COMPENSATION FOR CUSTOMERS.

It is recommended that NRAs should apply GIs with automatic compensation, or OIs or ORs associated with the option of sanctioning. For the most important indicators (e.g. for connection activities), a combination of OIs with economic sanctions (like penalties) and GIs is recommended to both improve the average performance and to protect customers from the worst service conditions. This recommendation is targeted mainly at DSOs given their important relationship with consumers. In addition, automatic compensation, which is increasingly applied, should be extended to every country.

RECOMMENDATION 4

NRAs SHOULD MONITOR INDICATORS IN ALL FORMS OF COMMUNICATION FOR MORE ACCURATE PERFORMANCE LEVELS.

Most of the indicators consider only written forms of communication, which provides an incomplete picture of the CQ. Non-written forms of communication like telephone (landline and mobile) and internet (website) should also be considered. For example, not all countries monitor oral and written complaints. CEER and ECRB recommend that NRAs also regulate the performance of the service level provided to consumers through communications such as phone, e-mail and online (e.g. website/apps), and visits to customer centres. In particular, the performances of DSOs and USPs in the increasingly important field of phone contacts should be monitored. Attention should be paid not only to rapid responses but also to thorough and useful responses. All types of responses should be taken into account in the CQ regulation: oral, internet-based and written complaints.

RECOMMENDATION 5

ENSURE THE AVAILABILITY OF SERVICES, PARTICULARLY REGARDING CONNECTION AND CUSTOMER CARE.

CEER and ECRB recommend that countries and their NRAs evaluate customer priorities before creating new regulatory frameworks.

RECOMMENDATION 6

FURTHER DEVELOP THE REGULATION OF CUSTOMER RELATIONS.

To further develop CQ regulation, satisfaction surveys (although costly) could be implemented to have qualitative elements (in addition to quantitative elements the CEER-ECRB questionnaire provides), since they could help assess how customers actually perceive the service achieved by the operator.

RECOMMENDATION 7

UPDATE CQ INDICATORS TO REFLECT MODERN PRACTICES.

Extensive introduction of commercial IT platforms and new functionalities in interaction with consumers has not yet been translated into rights for consumers and new CQ standards. Redefining, harmonising and updating European CQ standards to modern, state-of-the-art practices should be considered by NRAs.

4.8 CASE STUDY – ELECTRICITY AND NATURAL GAS SERVICE QUALITY RULES AND MONITORING IN GEORGIA

4.8.1 'Quality of Service Rules'

The Georgian National Energy and Water Supply Regulatory Commission (GNERC) approved the 'Quality of Service Rules' on 28 December, 2018 and subsequently replaced them with a new resolution on 28 June, 2021 [40]. These Rules apply to the utilities performing electricity and natural gas distribution activities and/or supplying natural gas to retail consumers, as well as to those consumers who receive (or request) from the above-mentioned utilities the services related to the activities regulated by these Rules. They set uniform requirements for the following issues:

1. Quality standards of service;
2. Requirements and criteria for service quality;
3. Target indices of service quality standards;
4. Financial mechanisms of compensating and incentivising-sanctioning, in the cases if the service provided is not in compliance with the target indices of the standards established by these Rules;
5. Recordings and analyses of the data on the quality of service provided by the utility to the customer; and
6. Submitting to GNERC the information on the quality of service provided to the customer.

SERVICE QUALITY STANDARDS

Service quality standards are divided into supply reliability standards and commercial service quality standards. Service quality standards may be **overall** or **guaranteed** with definitions as they are used in CQ chapters of this Benchmarking Report.

Table 4-15 shows the service quality standards, their definition and the financial mechanism that are in place in Georgia:

TABLE 4-15: Service quality standards, their definition and the financial mechanism in Georgia

Nº	Standard Name	Standard Type	Sector	Standard Target	Financial Mechanism	Quality standards of service
1	System Average Interruption Duration Index (SAIDI)	Overall	Electricity	SAIDI targets are set for each region, by separate resolution of the Commision. Targets are applied only to outages caused by internal reason in electricity sector	In the case of improvement or worsening the targets by the Utility allowed revenue of a DSO will be increased or reduced to the Q factor	supply reliability
2	System Average Interruption Frequency Index (SAIFI)		Natural Gas	SAIFI targets are set for each region, by separate resolution of the Commision	The regulated cost base of the Utility shall be increased/ reduced respectively by 0.01% of the regulated cost base for each 1% improved/worsened annual standard target	
3	The time required for responding to calls by the call center operators		Electricity Natural Gas	80% of incoming calls shall be answered within 80 seconds		commercial service quality
4	Providing information to the customers about the date and duration outages		Electricity Natural Gas	90% of customers shall be informed		
5	Restoration of supply to the customers who have been switched off, as a result of unscheduled outages		Electricity Natural Gas	80% of customers shall be restored in time		
6	Restoration of supply to the customers who have been disconnected due to unpaid bills	Guaranteed	Electricity Natural Gas	If repayment took place until 16:00 during working days (as for high-mountain areas and during weekends - until 14:00) utility shall restore supply within 5 hours from repayment of bills. Otherwise, supply should be restored until 12:00 of the next day	For household customers - 5 GEL, for non-household customers - 10 GEL	
7	Reacting to the written/electronic queries made by the customers		Electricity Natural Gas	10 working days	For household customers - 5 GEL, for non-household customers - 10 GEL	
8	Registering as a subscriber and ensuring supply under requested conditions		Electricity Natural Gas	5 working days		
9	Onsite inspection of metering tools, based on customer's application		Electricity Natural Gas	10 working days		
10	Onsite inspection of technical quality of the supply, based on customer's application		Electricity Natural Gas	5 working days		
11	Technical supervision of construction, installation of the metering node and network in-cut		Electricity Natural Gas	Commission defines price and time for fulfilment of these standards according to requested capacity (packages)	For each exceeding of the deadline defined by the relevant package, compensation in the amount of 50% of the cost shall be deposited to the customer for each exceeding.	
12	Connecting new customers/ increasing the capacity		Electricity Natural Gas			
13	Connection of Micro Power Plant to the Grid		Electricity			
14	Issuance of technical conditions for connecting new customers		Electricity Natural Gas	10 working days	No compensation	

SUPPLY RELIABILITY

Supply reliability standards are standards which concern the quality of supply by the DSO, including timely remedying and reduction of interruptions. These standards are:

1. SAIDI
   Standard type: overall
   Standard target: SAIDI targets are set for each region by separate resolution of the NRA. Targets are applied only to outages caused by internal reason in electricity sector.

Financial mechanism: in case of improvement or worsening of SAIDI by the DSO, the NRA is authorised, during calculation of the DSO's tariff, to increase or decrease the regulated cost base according to the Q factor. The Q factor is calculated based on the rate of incentivising/sanctioning for ENS (in GEL/min) which is defined by the multiplication of the VoLL and the average annual load of the customers. The Q Factor for each region equals the total customer number times the rate of incentivising/sanctioning for ENS multiplied by the difference between the target value of SAIDI and the actual value of SAIDI.
Criteria: SAIDI defines the average duration of long (longer than five minutes) electricity outages within a one-year period, per customer of a DSO in the specific region. Regional SAIDI is calculated as follows: each interruption duration multiplied by the corresponding number of affected customers is summed up and divided by the total number of customers in the region.

2. SAIFI
Standard type: overall
Standard target: SAIFI targets are set for each region by separate resolution of the NRA. Targets are applied only to outages caused by internal reasons.
Financial mechanism: the regulated cost base of a DSO is increased/decreased by 0.01% of the regulated cost base for each 1% of improved/worsened annual standard target only in the natural gas sector.
Criteria: SAIFI defines the average frequency of outages within a one-year period, per customer of a DSO in the specific region. Regional SAIFI is calculated as follows: sum of the number of affected customers during each interruption divided by the total number of customers in the region.

COMMERCIAL SERVICE QUALITY STANDARDS

Commercial service quality standards are standards that concern the DSO informing customers about supply interruptions or reacting to applications submitted by customers. These standards are:

1. The time required for responding to calls by the call centre operators
Standard type: overall
Standard target: 80% of incoming calls should be answered within 80 seconds.
Financial mechanism: the regulated cost base of a DSO is increased/decreased by 0.01% of the regulated cost base for each 1% of improved/worsened annual standard target.
Criteria: the time period for responding to calls by call-centre operators is calculated in standard situations from the moment when the incoming call takes place until the moment the operator responds. Standard targets do not apply to force majeure. Force majeure is implied in such cases when supply has been interrupted simultaneously to more than 15,000 customers or to more than 30% of customers within the self-governing unit, due to a scheduled/unscheduled outage. The DSO is obligated to record force majeure separately and submit it to the NRA if requested.

2. Providing information to customers about the date and duration of outages
Standard type: overall
Standard target: 90% of customers should be informed. This is the minimum percentage to be reached in a year and is calculated by dividing the number of informed customers by the total number of customers who should have been informed throughout the year (those who have submitted their contact information for such communication).
Financial mechanism: the regulated cost base of a DSO is increased/decreased by 0.01% of the regulated cost base for each 1% of improved/worsened annual standard target.
Criteria:
a. Information about a scheduled outage is considered delivered if information about the repair works scheduled in the relevant area has been sent to all customers within the respective area who have submitted their contact data to the DSO via means selected by the customer (e-mail or text message). Customers should be informed in advance, no more than five and no less than one calendar day before the commencement of works. In the case of unscheduled outages, the DSO should notify all customers within the respective area who have submitted their contact data to the DSO via means selected by the customer (e-mail or text message), immediately, but no later than three hours as of the start of the outage, about the exact cause of the outage and estimated time of restoration of supply;
b. Deviation from the time of the start, end and duration of the outage, indicated in the notification, should not exceed two hours (in high-mountain settlements three hours); and
c. If more than 3,000 customers are affected in urban areas and/or more than 500 in rural areas, the DSO shall also disseminate relevant information via the media.

3. Restoration of supply to the customers who have been switched off as a result of unscheduled outages
Standard type: overall
Standard target: 80% of customers should be restored on time. Target is applied only to internal unscheduled outages. This is the minimum percentage to be reached in a year and is calculated by dividing the number of customers whose supply was restored within 12 hours by the total number of affected customers whose supply should have been restored within 12 hours.
Financial mechanism: the regulated cost base of a DSO is increased/decreased by 0.01% of the regulated cost base for each 1% of improved/worsened annual standard target.
Criteria: the DSO should restore the power supply in the case of internal unscheduled outages within 12 hours.

4. Restoration of supply to customers who have been disconnected due to unpaid bills
Standard type: guaranteed
Standard target: if repayment took place by 16:00 during working days (in high mountain areas and during weekends by 14:00), a DSO should restore the supply within five hours of the bill repayment. Otherwise, supply should be restored by 12:00 the following day.

Compensation amount: for household customers: 5 GEL (approx. €1.7[169]), for non-household customers: 10 GEL (approx. €3.3). The compensation should be deposited to the customer's subscriber card as credit for further financial settlement.
Compensation deadline: within 15 working days of the breach of the guaranteed service standard.
Criteria: the time period necessary for restoring supply to customers who have been disconnected due to non-payment of debts is calculated as the time from the moment when the payment has been received the moment when the customer has submitted the receipt confirming this payment, or the moment when the contract for payment in instalments (for customers who are not able to pay their entire outstanding bill at once) is processed, until the moment of the actual restoration of supply.

5. Providing substantiated answers/sending text messages and/or reacting to the written/electronic queries made by customers
Standard type: guaranteed
Standard target: ten working days.
Compensation amount: for household customers: 5 GEL (approx. €1.7), for non-household customers: 10 GEL (approx. €3.3). The compensation should be deposited to the customer's subscriber card as credit for further financial settlement.
Compensation deadline: within 15 working days of the breach of the guaranteed service standard.
Criteria: the DSO is obligated to send a written response if the customer request is being rejected. Otherwise, they can inform the customer about fulfilment of the request by e-mail, SMS, or letter.

6. Registering as a subscriber and ensuring supply under requested conditions
Standard type: guaranteed
Standard target: five working days.
Compensation amount: for household customers: 5 GEL (approx. €1.7), for non-household customers: 10 GEL (approx. €3.3). The compensation should be deposited to the customer's subscriber card as credit for further financial settlement.
Compensation deadline: within 15 working days of the breach of the guaranteed service standard.
Criteria: the DSO is obligated to send a written response if the customer request is being rejected. Otherwise, they can inform the customer about fulfilment of the request by e-mail, SMS, or letter.

7. On-site inspection of metering tools based on customer's application
Standard type: guaranteed
Standard target: ten working days.
Compensation amount: for household customers: 5 GEL (approx. €1.7), for non-household customers: 10 GEL (approx. €3.3). The compensation should be deposited to the customer's subscriber card as credit for further financial settlement.
Compensation deadline: within 15 working days of the breach of the guaranteed service standard.
Criteria: the DSO is obligated to send a written response if the customer request is being rejected. Otherwise, they can inform the customer about fulfilment of the request by e-mail, SMS, or letter.

8. On-site inspection of technical quality of the supply, based on customer's application
Standard type: guaranteed
Standard target: five working days.
Compensation amount: for household customers: 5 GEL (approx. €1.7), for non-household customers: 10 GEL (approx. €3.3). The compensation should be deposited to the customer's subscriber card as credit for further financial settlement.
Compensation Deadline: within 15 working days of the breach of the guaranteed service standard.
Criteria: the DSO is obligated to send a written response if the customer request is being rejected. Otherwise, they can inform the customer about fulfilment of the request by e-mail, SMS, or letter.

9. Technical supervision of construction, installation of the metering node and network in-cut
Standard type: guaranteed
Standard target: the NRA defines the time necessary to fulfil a customer request and connection price according to requested capacity (packages). The time necessary for construction work can vary from ten to 30 working days, while the price can vary from 100 to 25,000 GEL (approx. €33 to €8,333), depending on the chosen connection package.
Compensation amount: the deadline for installation of the metering node and network in-cut (access point to network) is defined for each package and established by the Electricity (Capacity) Supply and Consumption Rules [76]. In cases where works are still not completed by the second deadline, the customer is not obligated to make any payments. In cases where works are not completed by the third, and every subsequent, deadline, the network operator is obligated to compensate the customer in the amount of the cost reduced due to exceeding the first deadline.
Criteria: the DSO is obligated to send a written response if the customer request is being rejected. Otherwise, they can inform the customer about fulfilment of the request by e-mail, SMS, or letter. The deadline for rejection of an application is ten working days.

169 Chapters on CQ also include the monetary amounts for countries that do not use euro as currency. In some cases, the amount in original currency is shown (as provided by the responding country), followed by an approximate amount in euros in parentheses. In this case study, the exchange rate used is from late 2020 which differs from exchange rates used in the rest of the chapter due to prolonged preparation of this Benchmarking Report.

10. Connecting new customers/increasing the capacity
Standard type: guaranteed
Standard target: in Georgia, connection to the distribution network may be regulated or negotiated. Regulated connection is where the object to be connected is located within 800 meters from the network for 0.4 kV voltage level consumers, whereas a 6 km radius applies to consumers on the 6/10 kV voltage level. For the gas distribution network, the distance should be no more than 300 metres. In this case, the price and duration of the connection is set by the NRA, in accordance with the capacity requested. The time necessary for construction works can vary from ten to 120 working days, while the price can vary from 100 to 750,000 GEL (approx. €33 to €250,000), depending on the chosen connection package and the location (urban or rural areas).
Compensation amount: if the new connection, or increasing the capacity, is completed within the defined deadline, the customer pays the whole new connection package price. In case of delay, the customer pays only half of the set price. In case of a second delay, the customer pays nothing and is connected free of charge. In case there are three or more delays to connect a customer, the DSO is obligated to pay 50% of the defined package price as compensation for each delay.
Criteria: the DSO is obligated to send a written response if the customer request is being rejected. Otherwise, they can inform the customer about fulfilment of the request by e-mail, SMS, or letter. The deadline for rejection of an application is ten working days.

11. Connection of micro power plant[170] to the grid
Standard type: guaranteed
Standard target: the NRA defines the time necessary to fulfil the customer's request and the connection price according to the requested capacity (packages). The time necessary for construction works can vary from ten to 25 working days, while the price can vary from 200 to 2,000 GEL (approx. €66.7 to €667), depending on the chosen connection package.
Compensation amount: a deadline for installation of the metering node and network in-cut (access point to network) is defined for each package and established by the Electricity (Capacity) Supply and Consumption Rules. In cases where works are still not completed by the second deadline, the customer is not obligated to make any payments. In cases where works are not completed by the third, and every subsequent, deadline, the network operator is obligated to compensate the customer in the amount of the cost reduced due to exceeding the first deadline.
Criteria: the DSO is obligated to send a written response if the customer request is being rejected. Otherwise, they can inform the customer about fulfilment of the request by e-mail, SMS, or letter. The deadline for rejection of an application is ten working days.

12. Issuance of technical conditions for connecting new customers
Standard type: guaranteed
Standard target: in case of a negotiated connection, the DSO issues a technical condition within ten business days from the date of a customer's request, where the customer is responsible for construction of the necessary network. After finalisation of works, the DSO will install a meter for a fee and during the term fixed by the NRA in accordance with the 'technical supervision of construction, installation of the metering node and network in-cut' standard.
Compensation amount: no compensation.
Criteria: the DSO is obligated to send a written response if the customer request is being rejected. Otherwise, they can inform the customer about fulfilment of the request by e-mail, SMS, or letter.

4.8.2 Electronic Journal

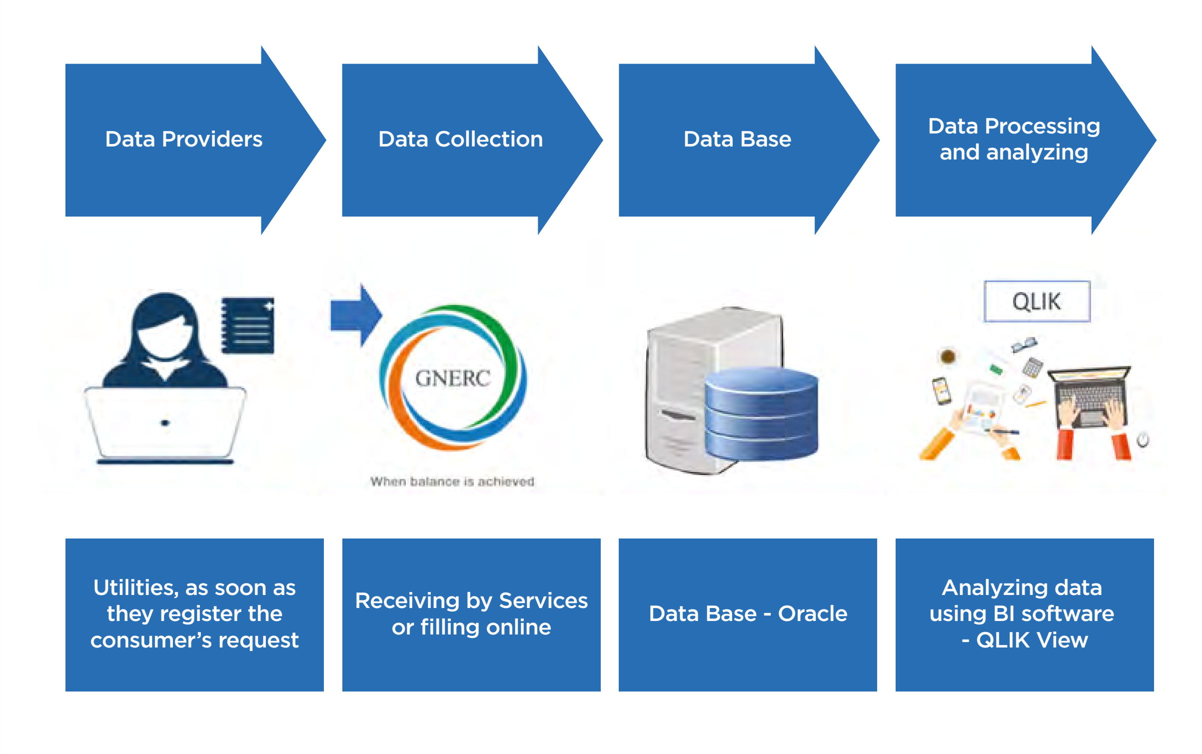
While having a certain type of regulation in place is one thing, the ability to monitor it is a different matter. For this reason, GNERC has made an exceptional case of access to information by introducing the Quality of Service Monitoring Programme's so-called 'Electronic Journal' in 2016. Notably, the Electronic Journal is an innovative instrument that significantly differs from the previous practices and methods recognised worldwide. Hence, instead of the processed statistics received from companies, GNERC has immediate access to all written consumer applications submitted to companies and all interruption data through direct access to this programme.

More specifically, when a customer submits a request/application to the service provider or when an interruption takes place, the provider is required to immediately upload the application/information regarding interruption to the programme, as well as the actions undertaken by the service provider. The Electronic Journal assigns a unique code to it and defines a deadline for carrying out an action or providing a response based on the type of requested service. After reacting to the request, the DSO provides a written response to the consumer regarding the outcome that is automatically reflected in the Electronic Journal. In case of belated reaction to the registered application, the DSO is obligated to pay compensation to the customer. The amount of compensation and the deadline for payment are defined by the Electronic Journal. The timely issuance of compensation is also controlled by the Electronic Journal. As a result, customers obtain services according to the quality standards.

Data in the Electronic Journal is received via a digital interface between the databases of a DSO and GNERC, called 'services' or is filled in online. The collected data is stored in an Oracle database that is connected to business intelligence and visualisation software (QlikView) for further analysis. This process is shown in Figure 4-2:

170 A renewable energy plant with installed capacity not exceeding 500 kW.

FIGURE 4-2: The Electronic Journal



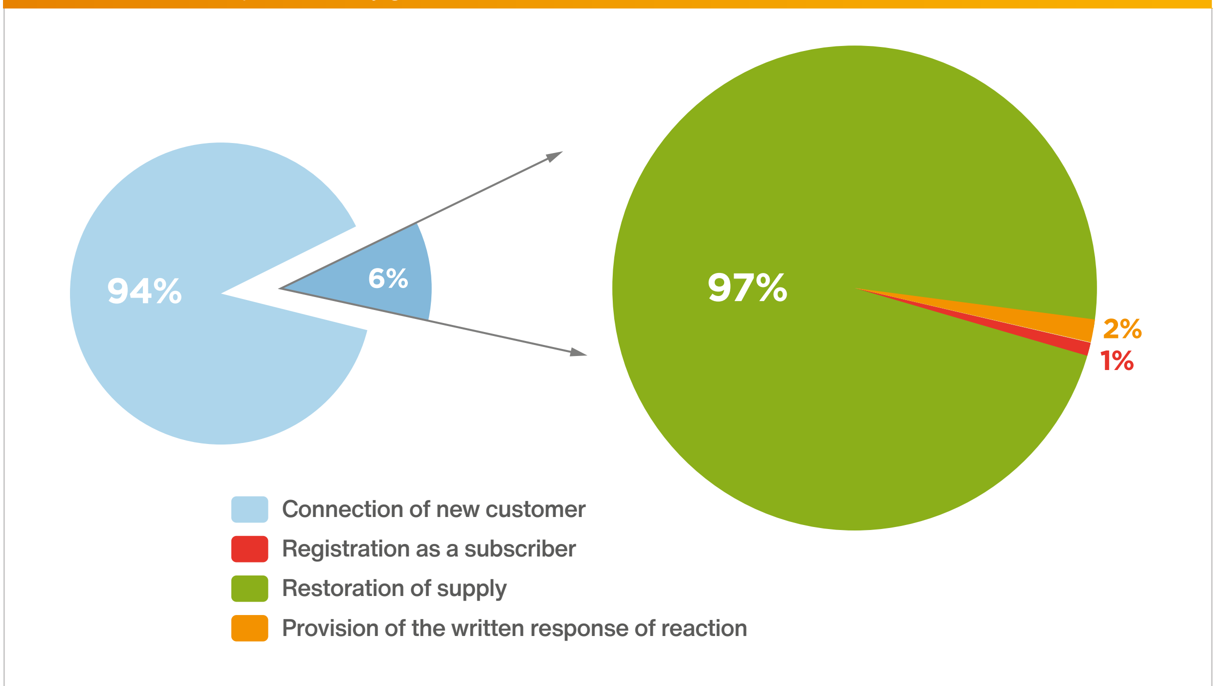
The Electronic journal was fully implemented on 1 January 2017 and nearly 5 million records have been made between 1 January 2017 and 31 December 2019 in electricity and natural gas sectors.

Compensation paid because of overdue performance amounts to nearly 3 million GEL (approx. 1 million euros) during this period and the percentage for each sector is as follows:

- Electricity - 38%; and
- Natural gas - 62%.

As for compensation paid according to the standards above, 94% of the total amount was paid related to the connection of new consumers, while 6% was paid for non-compliance with the standards, as shown in Figure 4-3:

FIGURE 4-3: Paid compensations by guaranteed standards



4.9 CASE STUDY – CALL CENTRE REQUIREMENTS IN UKRAINE

The mandatory functioning of call centres for regional electricity companies (bundled companies – distributors and regulated suppliers) in Ukraine was introduced by the Ukrainian NRA, NEURC, in 2014. An obligation to organise and ensure the functioning of the call centres with the minimum organisational and technical requirements was set by NEURC's decree for companies with more than 100,000 customers.

The following requirements for call centres were established:

- 24/7 telephone service, free of charge;
- Using the Interactive Voice Response;
- Incoming call distribution; and
- Audio recording of calls and retaining of those recordings for two years.

Call centres are required to provide information on electricity supply interruptions and time of restoration, execute meter readings and take customers' complaints and enquires. They are also obliged to maintain an electronic database with the following information for each call:

- The date and time of the connection with a call centre of an operator;
- Contact information of a customer (name, address, telephone number);
- The reason for the call;
- Short summary of the call; and
- The point of customer's connection to the electrical grid (line or transformer).

Due to lack of automatic registration tools, the NRA performs audits by using an electronic database to verify the correctness of the registration of a starting time of an interruption of supply, in particular for 0.4 - 10 kV voltage levels. The starting time of an interruption registered by the DSO is compared to the time of the first call by customers who reported an interruption.

In accordance with the unbundling requirements, NEURC set the requirements for the unbundling of DSOs' and suppliers' call centres in 2019. The NRA monitors the following call centres' indicators:

- Service level 30/60 seconds;
- Call abandon rate;
- Average speed of answering a call;
- Average handling time;
- Average number of calls answered by a call centre operator; and
- The number of calls by the main topic: connection, metering, prices/tariffs, contract, quality of supply, billing etc.

NEURC also introduced overall quality standards for two of the above-mentioned indicators for the call centres:

- Service level 30 seconds – not less than 75%; and
- Call abandon rate – less than 10%.

The standards stipulate that at least 75% of calls must be answered within 30 seconds and that the percentage of lost calls must be less than 10%. The DSOs and suppliers not complying with these standards are penalised.

In 2014, 27 call centres of (bundled) regional electricity companies (consisting of suppliers and DSOs) were set up. Nowadays, as a result of unbundling, 27 DSO call centres and 25 supplier call centres operate in accordance with the regulator's requirements. The total number of calls has increased from 4.6 million in 2014 to 18.9 million calls in 2021. The three leading subjects of calls are metering (44.9%), the quality of supply (22.7%) and billing (13.2%).[171]

171 Data for 2021.

05

GAS – TECHNICAL OPERATIONAL QUALITY

5 GAS – TECHNICAL OPERATIONAL QUALITY

5.1 INTRODUCTION

Chapters on the quality of gas were included in the 6th Benchmarking Report [6] for the first time. In general, the quality of supply regulation of gas networks does not differ from the approaches used in electricity networks, although the underlying objective is entirely different. Since gas is a natural resource, its quality and composition are of particular importance, especially in an international context. Moreover, technical safety is of much higher importance than in electricity since an interruption of gas delivery may give rise to physical danger and, in the worst case, fatalities. This is why an extensive set of gas technical standards and rules have been established for gas internationally. In addition, the ability of gas to be stored leads to a very high quality of supply concerning gas continuity.

In the following chapters, the dimensions 'technical operational quality', 'natural gas quality' and 'commercial quality' are covered. Each of these chapters contains a brief description of relevant quality factors, initial benchmarking of current quality levels, and standards introduced by NRAs.

5.2 STRUCTURE OF THE CHAPTER ON TECHNICAL OPERATIONAL QUALITY

This chapter gives a brief overview on the structure of gas networks and CoS indicators used and regulation that is applied in CEER and ECRB countries. Firstly, this chapter gives an overview of the structure of the gas networks. Secondly, CoS indicators provided by these countries are presented. Finally, this is followed by an overview of the regulation in force dealing with CoS and safety.

This chapter is based on input from 30 participating countries: Austria, Belgium, Bosnia and Herzegovina[172], Bulgaria, Croatia, the Czech Republic, Estonia, Finland, France, Georgia, Germany, Great Britain, Greece, Hungary, Ireland, Latvia, Lithuania, Luxembourg, Malta, the Netherlands, North Macedonia, Poland, Portugal, Romania, Serbia, Slovakia, Slovenia, Spain, Sweden and Ukraine.

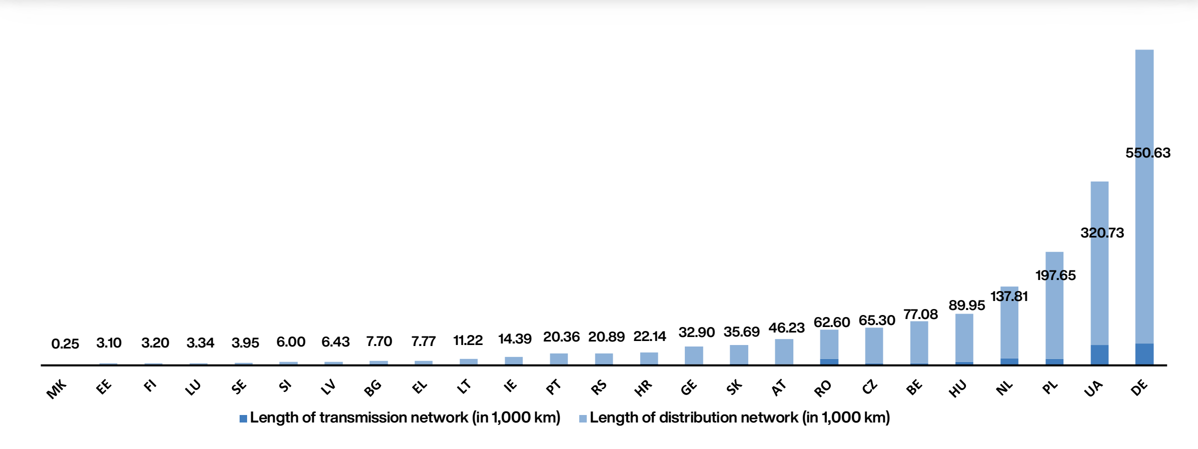
It should be noted that the overall availability of data and information differs noticeably from question to question, which does not always allow for a consistent comparison of the answers to all questions.

5.3 STRUCTURE OF GAS NETWORKS

Before providing more detail, it is helpful to have an overview of the technical structure of gas networks across the reporting countries. Therefore, the definition of pressure levels and the length of the gas networks are outlined below.

5.3.1 Network length

FIGURE 5-1: Length of the gas network (per 1,000 km) in 2018



5.3.2 Gas pressure regulating stations

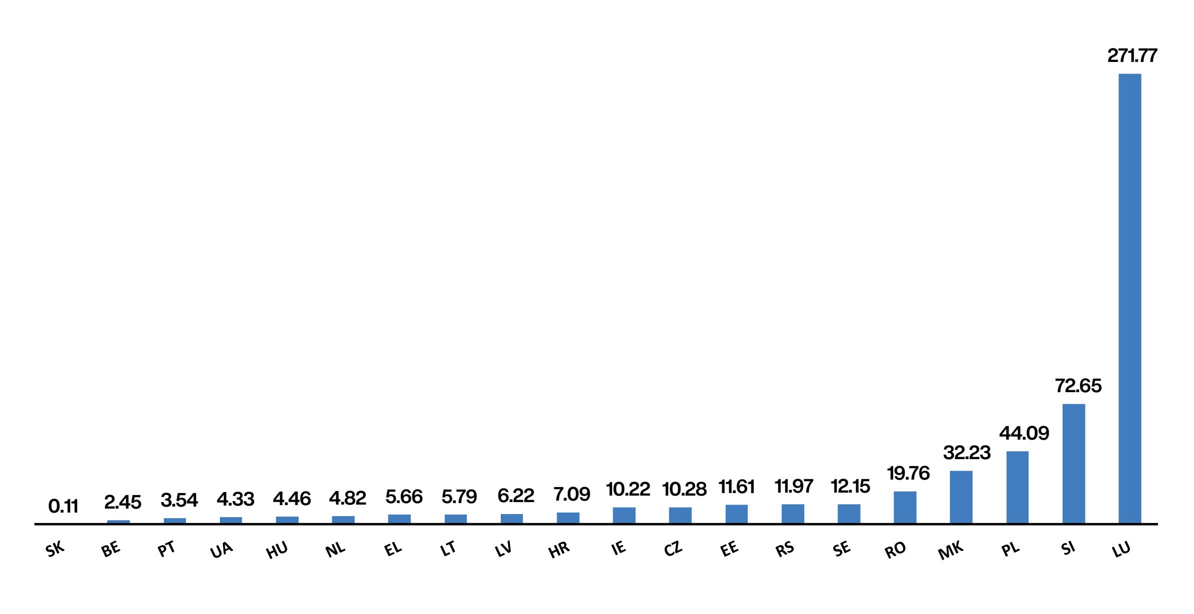
In electricity, transformers are used to increase or decrease the voltage of the network. In gas, there are pressure regulators that have a similar purpose – to convert the pressure of gas to a different level. Table 5-1 lists the number of these stations in each responding country.

172 The entity of Republika Srpska only.

TABLE 5-1: Number of gas pressure regulating stations

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
BE						191	192		189
CZ					686	683	678	671	671
EE					36	36	36	36	36
EL	35	36	38	38	39	41	41	44	44
FI			463	477	456	453			
FR					21,803				
HR								157	157
HU					399	399	400	400	400
IE					151	151	148	146	147
LT	65	65	65	66	66	66	67	66	65
LU					835	833	856	872	908
LV								40	40
MK				8	8	8	8	8	8
NL							669	665	665
PL					6,847	7,340	7,591	8,437	8,714
PT	68	69	71	71	71	71	71	72	72
RO								1,233	1,237
RS					267	269	244	245	250
SE					48	48	48	48	48
SI		350	359	378	388	387	384	392	436
SK			4	4	4	4	4	4	4
UA					1,456	1,390	1,392	1,389	1,390

FIGURE 5-2: Number of gas pressure regulating stations per length of the gas network (per 1,000 km) in 2018



5.3.3 Number of served customers

The following table shows the total number of served customers for the reporting countries in recent years. For a more disaggregated representation of these values with regard to pressure levels, see Table A 89 in the annex.

TABLE 5-2: Number of served customers

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
AT								1,249,963	1,247,767
BE	416,916	419,115	1,083,230	1,098,535	3,113,687	3,126,835	3,234,315	3,285,452	3,342,019
CZ					2,849,162	2,844,334	2,840,473	2,844,257	2,840,619
DE	13,503,145	13,419,509	13,698,780	13,979,337	13,837,257	14,124,144	14,487,346	14,240,557	14,441,600
EE					51,176	51,013	52,185	52,342	51,864
EL								412,894	458,447
ES	7,180,332	7,278,501	7,366,468	7,448,827	7,548,654	7,585,830	7,672,662	7,797,233	7,870,899
FI			38,111	38,086	38,049	28,373	28,542	28,130	27,893
GE									1,239,000
HR								665,283	671,715
HU					3,442,833	3,447,267	3,452,051	3,451,818	3,461,780
IE					673,160	673,858	680,155	688,283	697,458
LT				561,972	565,267	569,261	573,004	582,482	594,950
LU					85,907	87,021	88,629	89,130	89,939
LV								412,583	409,255
MK				100	120	261	323	365	433
MT								2	2
NL					7,226,855	7,261,540	7,300,259	7,355,067	7,379,079
PL					6,824,590	6,823,946	6,827,315	6,973,348	7,045,453
PT				1,320,052	1,355,122	1,395,741	1,424,259	1,452,094	1,542,009
RS					261,263	262,591	267,158	270,689	276,581
SE			37,704	37,393	37,023	36,564	36,525	35,164	34,047
SI	128,914	130,293	131,652	133,073	133,364	133,444	133,439	133,630	134,642
SK								1,514,282	1,518,200
UA					13,641,851	12,393,808	12,270,759	12,396,866	12,435,678

The very small number of only two customers in Malta originates from the supply of natural gas to two power stations (owned by D3 Power Generation Ltd and ElectroGas Malta Ltd) located in the vicinity of the liquefied natural gas (LNG) terminal in Delimara since 2017. Besides that, there is no operating transmission or distribution gas network in Malta.

5.3.4 Measurement Points

TABLE 5-3: Number of measurement points

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
AT	1,351,888	1,350,842	1,350,310	1,350,423	1,348,867	1,346,339	1,346,537	1,347,685	1,344,868
CZ					8,108	3,747	3,694	3,649	3,663
DE	13,503,145	13,419,509	13,698,780	13,979,337	13,837,257	14,124,144	14,487,346	14,240,557	14,441,600
EE					3	3	3	3	3
FR					174,874				
GE									1,239,000
HU					636	640	644	646	651
IE					175	178	178	178	178
LT			3	3	3	3	3	3	3
LU					85,907	87,021	88,629	89,130	89,939
LV								412,583	409,255
MK				100	120	261	323	365	433
PL					6,851,750	6,437,723	6,932,009	7,111,151	7,357,808
PT	12	12	12	12	12	12	12	12	12
RS				261,015	261,263	262,591	267,158	270,689	276,581
SE					48	48	48	48	48
SI		419	444	452	451	447	444	454	499
SK			1,508,309	1,502,898	1,506,260	1,514,656	1,518,131	1,514,282	1,518,200
UA					2,647	2,657	2,677	2,996	3,031

5.3.5 Pressure levels

Pressure levels play an important role in the transport of gas through the network. The choice of pressure level has an impact on the choice of almost all components of the gas network. However, the answers to the questionnaire show that there is no single definition of different pressure levels in use. In fact, the definitions vary widely throughout the reporting countries which is analogous to definitions of voltage levels used across Europe.

The most commonly used pressure levels are low, medium and high pressure (LP, MP, HP).

Moreover, in some countries, variations in pressure are accepted, which might be due to the physical nature of gas as a natural resource. The different definitions of pressure levels and the accepted variances are shown in the following table.

TABLE 5-4: Pressure levels in use

Country	High-pressure	Definition	Medium-pressure	Definition	Low-pressure	Definition	Other
AT	Yes	All transmission pipeline systems are listed in Annex 2 of Natural Gas Act 2011	Yes	Higher than 6 bar	Yes	Lower than 6 bar	
BA	Yes	> 16 bar	Yes	6 bar ≤ P < 16 bar	Yes	Lower than 6 bar	
BE	Yes	> 16 bar	Yes	100 mbar ≤ pressure ≤ 16 bar Flanders: maximum operating pressure (MOP) 98.07 mbar-14.71 bar	Yes	< 100 mbar Flanders: MOP ≤ 98.07 mbar	
BG	Yes		Yes		Yes		
CZ	Yes	Between 1.6 Mpa and 3.9 MPa	Yes	Between 5 kPa and 0.4 Mpa	Yes	up to 5 kPa	
DE	Yes	> 1 bar	Yes	Between 100 mbar and 1 bar	Yes	≤ 100 mbar	
EE	Yes	> 16 bar	Yes	< 16 bar	Yes	≤ 5 bar	
EL	Yes	≤ 70 bar g[173]	Yes	≤ 19 bar g	Yes	≤ 4 bar g (25 mbar g)[174]	
ES	Yes	> 60 bar	Yes	Between 4 and 60 bar	Yes	< 4 bar	
FI	No		No		No		

173 Gauge pressure.
174 In Athens centre.

TABLE 5-4: Pressure levels in use

Country	High-pressure	Definition	Medium-pressure	Definition	Low-pressure	Definition	Other
FR	Yes	Between 40 bar and 70 bar	Yes	3 types: MP-C: between 4 bar and 25 bar MP-B: between 0.4 bar and 4 bar MP-A: between 0.05 bar and 0.4 bar	Yes	Up to 50 mbar	
GB	Yes	≥ 7 bar	Yes	< 2 bar, ≥ 75 mbar	Yes	< 75 mbar	
GE	Yes	3 to 12 bar (> 12 bar for TSO)	Yes	0.05 to 3 bar	Yes	< 0.05 bar	
HR	Yes	75 bar, 50 bar	Yes	From 0.1 bar up to 5 bar	Yes	< 0.1 bar	
HU	Yes	MOP > 25 bar	Yes	100 mbar < MOP ≤ 4 bar	Yes	MOP ≤ 100 mbar	High-Medium 4 bar < MOP ≤ 25 bar
IE	Yes	MOP: 85 bar	Yes	MOP: 40 bar	Yes	MOP: 19 bar	Distribution system (MOP 16 bar g-millibar) Subsea Transmission System MOP =148 bar g[175] Southwest Scotland Onshore System MOP = 85 bar g
LT	Yes	DSO: 5 to 16 bar TSO: above 16 bar	Yes	Category I: 2 to 5 bar Category II: 0.1 to 2 bar	Yes	Below 0.1 bar	
LU	Yes	Above 1 bar	Yes	Between 100 mbar and 1 bar	Yes	Below 100 mbar	
LV	Yes	TSO: >2.5 MPa DSO: I: from 0.4 MPa up to 0.6 MPa II: above 0.6 MPa up to 1.2 MPa III: from 1.2 MPa up to 1.6 MPa	Yes	I: from 0.005 MPa up to 0.01 MPa II: from 0.01 MPa up to 0.4 MPa	Yes	Up to 0.005 MPa	
MK	Yes	MOP: 54 bar (currently around 40 bar)	Yes	In cities between 8 and 12 bar	Yes	In cities between 2 and 4 bar	
MT	No		No		No		
NL	Yes	From 40 bar to 80 bar. Levels: 40 bar 67 bar	Yes	P > 200 mbar (HP DSO) Levels: 1 bar 2 bar 4 bar 8 bar	Yes	P ≤ 200 mbar	
PL	Yes	Above 1.6 MPa	Yes	More than 10 kPa up to 0.5 MPa (included)	Yes	Up to and including 10.0 kPa	Increased MP: above 0.5 MPa up to 1.6 MPa (included)
PT	Yes	> 20 bar	Yes	Between 4 and 20 bar	Yes	< 4 bar	
RO	Yes	HP > 6 bar	Yes	2 bar < MP ≤ 6 bar	Yes	LP ≤ 0.05 bar	Reduced pressure (RP): 0.05 bar < RP ≤ 2 bar
RS	Yes	> 16 bar	No		Yes	≤16 bar	
SE	Yes	80 bar	Yes	4 bar	Yes	0.03 bar	
SI	Yes	> 1 bar	Yes	Between 0.1 bar and 1 bar	Yes	≤ 0.1 bar	Currently, there is no clear definition to divide gas network in different pressure levels.
SK	Yes	Three levels: PN63: gas pressure up to 6.3 MPa PN40: gas pressure level up to 4.0 MPa PN25: gas pressure level up to 2.5 MPa (Minimum operating level is 1.2 MPa).	Yes	Two levels: STL1: gas pressure up to 100 kPa STL2: gas pressure level up to 400 kPa (Minimum operating level is 50 kPa).	Yes	NTL: up to 5 kPa (Minimum operating level is 1.6 kPa).	
UA	Yes	Transmission: above 1.2 MPa Distribution: I: 0.6 MPa - 1.2 MPa II: 0.3 MPa - 0.6 MPa	Yes	0.005 MPa - 0.300 MPa	Yes	up to 0.005 MPa	7

175 'Bar(a)' and 'bara' are sometimes used to indicate absolute pressures and 'bar(g)' and 'barg' for gauge pressures.

In Bulgaria, HP, MP and LP levels are defined and used, but no definitions for them were provided. As for other countries, the HP level can vary between 0.3 for the minimum and 85 bar for the maximum operating pressure. The MP level is defined to be between 0.05 and 40 bar and the highest LP level was listed as 19 bar. Some respondents provided their pressure levels in bar while others used kilopascal (kPa) and megapascal (MPa).

TABLE 5-5: Allowed variations in pressure of gas networks

Country	Allowed pressure variations
AT	1.022 bar to 91 bar (also depending on the pipeline)
BE	Federal: from a regulatory point of view, there is no under limit allowed Flanders: 16-25 mbar at gas meter exit for high calorific gas (16-30 for low calorific gas) Wallonia: See SPF[176]: depends on pressure variations at the inlet of gas appliances
BG	From 0.3 MPa to 50 MPa[177]
CZ	Within the above-mentioned pressure ranges for HP, MP, and LP
ES	For transmission pipelines, the minimum pressure allowed is 40 bar For distribution pipeline, the minimum pressure allowed depends on the supply pressure: 16 bar if the customer is connected to a 16-bar pipeline; 3 bar[178] if the customer is connected to a pipeline between 16 and 4 bar; 0.4 bar if the customer is connected to a pipeline between 4 and 0.4 bar; 50 mbar if the customer is connected to a pipeline between 0.4 and 0.05 bar; and 18 mbar if the customer is connected to a pipeline below 0.05 bar.
FI	Defined in terms of use between consumer and network operator.
FR	If the maximum incidental pressure (MIP) ≥ 10 % on the network: see EN 12186 § 9 [77] and Gesip guide N° 2007/09 [78]: The pressure control system shall maintain the pressure in the downstream system within the required limits and shall ensure that this pressure does not exceed the permitted level.
HR	In transmission system allowed pressure variations are 70-75 bar and 45-50 bar, with respect to working pressure.
HU	In case of HP pipeline system, the allowed variation is between 25 bar and 75 bar
IE	8 bar off the 19 bar system 19 bar off the 70 bar system 50 bar of the SUB/SEA offtake
RS	For transmission system MIP not to exceed 15% of MOP. MIP on distribution level in line with SRPS EN 12007-1 and SRPS EN 12007-5[179].
SE	There are no regulations on gas quality in Sweden.
SI	Transmission system: 30 to 70 bar (depending on customer demand and also depending on the pipeline). Distribution system: 0.022 bar to 4 bar (98.5%), > 4 bar to 16 bar (1.5%).
SK	The company is operating the distribution network to secure the reliable and continuous distribution for all customers on all pressure levels. The control of the network is performed to not exceed the maximum pressure levels, and to provide guaranteed pressure levels for customers with pressure requirements.

Of note is a special situation in the Netherlands, where the Groningen gas field produces gas with a relatively high nitrogen concentration, resulting in a lower caloric value of the gas. Thus, most Dutch consumers use low caloric gas and therefore most of the gas infrastructure transports low caloric gas. High caloric gas is consumed by some industrial consumers and separate infrastructure is present for transporting high caloric gas.

There is a significant domestic production of natural gas in Hungary. Domestic producers may connect to the TSO's network, but as a general rule, their activities are not regulated by the NRA.

176 Federal Public Service Economy, a Federal Public Service of Belgium.
177 Refers to LP, as there are only a few LP pipelines in use.
178 The minimum guaranteed pressure is 3 bar.
179 SRPS EN 12007-1 and SRPS EN 12007-5 are the Serbia-specific versions of EN 12007-1 and 12007-5.

5.4 GAS STORAGE INFRASTRUCTURE

The following table shows the capacity and type of gas storage infrastructure for the reporting countries. Some reporting countries (Bosnia and Herzegovina, Estonia, Finland, Georgia, Greece, Ireland, Lithuania, Luxembourg, Malta, North Macedonia and Slovenia) do not have any gas storage facilities.

TABLE 5-6: Gas storage infrastructure and capacities in 2018

Country	Gas storage Infrastructure	Depleted fields capacity (Million m^3)	Salt caverns capacity (Million m^3)	Aquifer capacity (Million m^3)	Other
AT	Yes	8,122			
BE	Yes			The maximum underground storage capacity is 1,400 m^3, of which just over half is useful gas (761,700 m^3)	
BG	Yes	550			
CZ	Yes	3,005	75	177	
DE	Yes	8,753	15,183	362	
ES	Yes	2,429		1,050	
FR	Yes[180]				
GB	Yes	410	1,300		
HR	Yes	553			
HU	Yes	6,330			
LV	Yes	2,330			Layer of porous sandstone, which has good storage properties and which is coated with gas-tight rock layers
NL	Yes	12,100	308		
PL	Yes	2,475	735.35		
PT	Yes		335		
RO	Yes	3,100			
RS	Yes	450			
SE	Yes				The NRA has no data on the storage point. Sweden has one facility.
SK	Yes	4,010			
UA	Yes	29,140		1,810	

TABLE 5-7: Regulation of gas storage infrastructure

Country	Regulation of Gas Infrastructure	How?	Indicators used for regulation
BG	Yes	Price	
ES	Yes	Access is regulated, capacity is booked via auctions	
HR	Yes	Law: Gas Market Act [79], bylaw: Gas Storage Code [80]	Revenue cap
HU	Yes	Regulated third-party access (TPA), with regulated prices	
LV	Yes	NRA sets tariffs and gas storage terms of use of the facility	Maximum storage capacity, information on injection capacity, withdrawal capacity and so on
NL	Yes	Directive 2009/73/EC is implemented in Dutch law [81]	
PL	Yes	Gas storing in underground formations concession, storage licence, tariffs	Regulated access (tariffs, storage code)
RO	Yes	The NRA ANRE decides the annual minimal quantity of natural gas to be stored and the regulated storage tariffs	Quantity of natural gas (in MWh) and the storage tariffs
SK	Yes	Non-tariff regulation	Gas quality, invoicing, interruption of operation, publishing information on free storage capacity
UA	Yes	Access is regulated	There is one storage system operator (SSO) in Ukraine, no competition

180 There are 16 underground gas storage sites in France – one depleted field, four salt caverns, and 11 aquifers. Three of the facilities have been taken out of service (two aquifers and one depleted field). Salt caverns account for 10% of working gas volume and 32% of withdrawal capacity in France.

Regulation of the storage infrastructure could apply to the maximum storage, injection or withdrawal capacity, tariffs, or the minimal quantity of gas to be stored. Croatia uses a revenue-cap system, while Hungary implemented a hybrid revenue-cap/price-cap regulatory regime, with cost and asset reviews undertaken every four years. It builds the basis of the tariffs applicable for the next four-year regulatory period. During the regulatory period tariffs are adjusted (for inflation, volumes, etc.) annually.

5.5 LNG INFRASTRUCTURE

An alternative to the common gas supply through (cross-border) gas pipelines is its import in the form of LNG by sea. Since the EU energy policy aims at providing its consumers with safe, balanced and competitive energy at affordable prices, LNG plays an important role in this policy, especially in guaranteeing the security of supply as well as raising the integration and competitiveness of the gas market. This section describes the existence and the use of LNG infrastructure across the participating countries.

TABLE 5-8: LNG infrastructure

	Yes	No	Yes (countries)	No (countries)
Existence of LNG infrastructure	12	17	BE, EL, ES, FI, GB, HR, LT, MT, NL, PL, PT, SE	AT, BA, BG, CZ, DE, EE, GE, HU, IE, LU, LV, MK, RO, RS, SI, SK, UA
Regulation of LNG infrastructure	9		BE, EL, ES, FI, HR, LT, MT, NL, PL, PT	

As seen in Table 5-8, LNG infrastructure is used in 12 countries and regulated in ten.

In **Belgium,** the LNG buffer storage consists of four tanks with a total capacity of 380,000 m^3 of LNG. Three tanks have a useful volume of 80,000 m^3 of LNG each, while the fourth can hold 140,000 m^3 of LNG. A fifth tank is under construction.

Greece uses one LNG terminal located on the island of Revythousa and it constitutes one of the three entry points to the National Natural Gas Transmission System. The terminal is fully regulated with total storage capacity up to 225,000 m^3 LNG (two underground tanks of 65,000 m^3 LNG and one of 95,000 m^3), gasification rate up to 1,400 m^3/h and a high efficiency cogeneration unit.

- Regulation: the operator provides to users of LNG services access to the LNG facility located on the Island of Revithoussa at the gulf of Megara, without discrimination among users and user categories. These services include:
  - The LNG cargo unloading, including the mooring of an LNG vessel, the discharge of LNG cargo and the detachment of the LNG vessel;
  - The provision, to the LNG user, of storage space in the LNG facility for the interim storage of the LNG cargo (temporary LNG storage);
  - The regasification of the LNG cargo and its subsequent discharge into the transmission system via the LNG entry point; and
  - The execution of the necessary measurements as well as any action necessary for the effective, secure and cost-effective operation of the LNG facility, in the framework of the provision of the services stated above.
- For the provision of the LNG services, users shall enter into an LNG agreement with the operator. Those LNG agreements are based on the standard LNG agreement, where the contracting procedure, the contents, as well as the terms for accessing and use the Revythoussa LNG facility, are specified. The LNG agreement is made between the operator and entities registered in the national natural gas system users' registry. The contract period consists of integral multiples of one day, and at least for the time period between the maximum commencement date of an LNG agreement and the minimum expiry date of an LNG agreement, both of which are included therein, as long as:
  - They have (the LNG users) booked transmission capacity at the LNG entry point of the transmission system, as transmission users; and
  - They serve other transmission users that have booked transmission capacity at the LNG entry point of the transmission system.
- To enter into an LNG agreement, the users submit to the operator an application for the provision of the basic LNG service, 45 days before the beginning of the month in which applicant's first LNG cargo is scheduled for unloading, at the latest, as per the provisions of the standard LNG agreement. The application is followed by the documents and data defined as per the provisions of the standard LNG agreement.
- According to the approval of the national natural gas system usage tariffs for the year 2020.
- Indicators used for regulation: the level of LNG plant's utilisation is measured, both in terms of send out and storage capacity.
- Send out capacity (% yearly) = total send out gas (kWh/year) / technical capacity (kWh/year)
- Use of Storage Capacity (% yearly) = storage capacity use (kWh/year) / total storage LNG capacity (kWh/year)

Currently there are three LNG terminals in use in **Finland** (in Tornio, Pori and Hamina); two are operational and one under construction. The one under construction (in Hamina) will be connected to the distribution network. The NRA, the Energy Authority, confirms tariffs and terms of use.

Lithuania uses a 170,000 m^3 floating storage and regasification unit in Klaipėda. There is a price regulation for regasification and LNG unloading effective.

The LNG infrastructure in **Malta** consists of a floating LNG storage and onshore regasification plant on the Delimara site. The floating storage and regasification unit has an LNG storage capacity of 125,000 m^3 and the regasification plant has a maximum natural gas output rate of 89,000 Nm^3/hour of natural gas. Regulation of the infrastructure is implemented through the subsidiary legislation 545.12 'Natural Gas Market Regulation' [82].

In **the Netherlands** one LNG gate terminal in the port of Rotterdam is used for the import of LNG. The gate terminal has storage capability, expands the LNG to natural gas and feeds into the national gas transportation grid. Across the country, LNG can be tanked at several locations which are supplied by LNG transporting trucks. Regulation is implemented in Dutch law by Directive 2009/73/EC [81].

Poland uses one LNG Terminal in Świnoujście, the usage of which is regulated by regasification licenses and dedicated tariffs.

In **Portugal**, the following LNG terminal operating capacities are available:

- Annual natural gas regasification capacity of eight billion cubic metres;
- Storage capacity of 390,000 m^3 (2.5 terawatt-hours (TWh));
- Mooring adapted for methane tankers with capacities ranging from 40,000 to 216,000 m^3;
- Maximum output to the National Natural Gas Transportation Network of 1,350,000 m^3(n)/h; and
- Tanker loading capacity: 36 tankers/day.

Regulation of this infrastructure uses the following continuity of service indicators:

- Average effective discharge time for methane vessels (hours): ratio of the sum of the effective discharge times and the total number of discharges;
- Average load rate (m^3/h): ratio of the sum of the loaded volumes and the sum of the load times;
- Average methane vessel unloading delay time (hours): ratio of the sum of unloading delay times and the number of delayed discharges;
- Effective average tanker filling time (hours): ratio of the sum of the filling times and the total number of fillers; and
- Average tanker filling delay time (hours): ratio of the sum of the filling delay times and the number of delayed fillers.

In **Spain**, seven LNG regasification plants exist, six of them in operation. Access to the LNG facility is regulated by booking the capacity via a first-come first-served mechanism. This regulation is currently under revision.

5.6 CONTINUITY OF SUPPLY OF GAS NETWORKS

As for electricity, CoS concerns interruptions in gas supply and focuses on the events during which there is no gas at the supply terminals of a network user, or the pressure drops below a specific level. Various aspects are used to describe CoS, the most commonly used ones are the number of interruptions per year, or the unavailability measured by interrupted minutes per year.

The justification for the use of such indicators is the idea that network users expect a high CoS level at an affordable price. The fewer the interruptions and the shorter these interruptions are, the better the continuity is from the viewpoint of the network user. Therefore, one of the roles of network operators is to optimise the continuity performance of their distribution and/or transmission network in a cost-effective manner.

CoS indicators are traditionally important tools for making decisions on the management of distribution and transmission networks. However, in the case of gas networks, safety is of much greater importance than in the electricity branch since unavailability or interruption of supply in many cases may correspond to some level of danger.

Most of the indicators used to describe CoS are adapted from the electricity sector. However, some gas-specifics have to be considered in its application and interpretation. Since there is the possibility of storage in the grid and because of the very high technical requirements, CoS is not the main scope for decisions for the network operator. Nevertheless, the typically used interruption-indicators are good candidates to describe and compare CoS internationally.

5.6.1 Terminology of incidents, leaks, interruptions and emergency

Within the gas sector, the quality of supply is not only expressed by continuity indicators but also through incidents that could precede an interruption, like incidents or leaks.

As mentioned before, technical safety of gas networks plays an important role when analysing CoS. In contrast to the electricity sector, different types of events exist in gas grids. These events have different consequences for network users and network operators and therefore need to be handled differently when analysing technical and operational gas quality.

An **incident** can and does happen in every running system, but the existence of incidents is not necessarily an indicator for an interruption since that is dependent on other factors. Incidents may lead to interruptions, but in many cases, an incident can be fixed without any effect on the supply of customers. In some cases, there may be interruptions without any incident at all, for example due to maintenance of the grid.

Leaks are a direct indicator for the technical quality of the infrastructure. It means that gas unwantedly leaves the closed system due to corrosion, a burst pipe, or some security leaks.

The consequences with respect to CoS can differ, since not every leak inevitably entails an interruption for the customer. Leaks may be repaired in due time when they are observed close to buildings but there is some room for action for the network operator if the leak is observed far from buildings or populated areas. An accident (damage) is the worst of all incidents, where gas is ignited and physical damage occurs.

It should be noted that incidents are likely to increase the risk of leaks, interruptions or damages, but may not necessarily cause them. Moreover, there is some room for action for the network operators especially with respect to failure management.

The following tables give an overview of the usage and classification of gas leaks across the reporting countries.

TABLE 5-9: Is there a definition of gas leak?

	Yes	No	Yes (countries)	No (countries)
Definition of gas leak	8	17	BE, CZ, DE, FR, HU, IE, NL, RO	BA, BG, EE, EL, FI, GE, HR, LT, LU, LV, MK, MT, RS, SE, SI, SK, UA

TABLE 5-10: Definitions of gas leak in use

Country	Definition of a gas leak	Applies to
BE	Definition set by SPF[176]	Distribution & Transmission
CZ	Gas leak is an uncontrolled release of the gas (technical rules for gas TPG 913 01).	Distribution & Transmission
DE	Unwanted gas release.	Distribution & Transmission
FR	Accidental release of gas, 3 different leak sizes puncture (diameter ≤ 12 mm), hole (12 mm < diameter ≤ 70 mm) and rupture (diameter > 70 mm).	Distribution & Transmission
HU	There is a general definition in the Gas Act [83] for disruption of service, which includes all abnormal events resulting in the interruption of service for one or more consumers and the disruption or endangerment of gas supply. The events in the definition are not classified any further in the Gas Act.	Distribution & Transmission
IE	Leaks are defined as loss of product from a stable defect in the 'Gas Networks Ireland Transmission Safety Case' [84].	Distribution & Transmission
NL	Unintended outflow of gas, caused by a failure of a component of the gas distribution network[181].	Distribution
RO	Unintended loss of gas from a pipeline. Leaks can be caused by the existence of orifices or cracks, loss of contact or tightening between the sealing elements, disconnection of the pipeline elements or degradation of the joints/conjunctions between them.	Transmission

TABLE 5-11: Classification of gas leaks

Classification of gas leaks	Yes	No	Yes (countries)	No (countries)
Technical classification based on a degree of dangerousness	8	8	CZ, IE, LT, LV[182], NL, RO[183], SE, SI	BA, BG, EE, FI, HU, MK, MT, RS
Localised after planned inspections	9	8	BE[183], CZ, IE, LV[182], MK[183], NL[182], RO, SE, SI	BA, BG, EE, FI, HU, LT, MT, RS
Reported by third parties (e.g. via prompt intervention telephone number)	10	7	BE[183], CZ, IE, LV[182], MK[183], NL, RO, RS, SE, SI	BA, BG, EE, FI, HU, LT, MT
Gas leaks per km of network	3	13	BE[183], NL, SI[182]	BA, BG, EE, FI, HU, IE, LT, LV, MK, MT, RO, RS, SE
Gas leaks per number of final customers	2	13	LV[182], NL	BA, BG, EE, FI, HU, IE, LT, MK, MT, RO, RS, SE, SI
Others	1	11	SI[182]	BA, BE, BG, EE, FI, HU, IE, LT, MT, RO, RS

181 The Royal Netherlands Standardisation Institute: NEN 7244-9; Gas supply systems - Pipelines for maximum operating pressure up to and including 16 bar - Part 9: Specific functional requirements for processing of reported gas leaks and gas leak survey.
182 Only for distribution.
183 Only for transmission.

North Macedonia does not have an official definition of gas leaks in bylaws, but it is expected to be implemented in the future. The TSO uses a definition on operational level.

In Slovenia, a different kind of classification of gas leaks is in use, which focuses on the type of pipeline, where the gas leak occurs (e.g. gas pipeline, connection pipeline, house gas pipeline).

For more information on the monitoring of incidents, emergencies, and their classification, please refer to the 6th Benchmarking Report [6].

5.6.2 Continuity of supply indicators

As is the case with electricity, CoS indicators can also be used for gas. Some respondents use indicators for both frequency and duration, and some distinguish between planned and unplanned interruptions. Most countries that monitor CoS use SAIDI, ASIDI, SAIFI, and CAIDI as indicators. The use of more than just one indicator to quantify CoS, results in more information being available and more possibilities to compare the results among different countries.

SAIDI and SAIFI are the basic indicators, reported in almost all responding countries, albeit under different names and with different methods for weighting the interruptions. As mentioned previously, the method of weighting affects the results and can lead to different biases towards different types of network users. When weighting focuses on the number of network users, each user has the same weight, independent of its size and independent of their consumption levels. Whereas when weighting is based on interrupted or contracted power, an interruption gets a higher weighting when the total interrupted power is higher.

Again, it should be highlighted, that one single interruption in gas can lead to a high risk of danger and therefore the efforts of network operators to almost avoid such an interruption completely might be greater than in electricity. In general, this may be one reason for having considerably fewer interruptions than in electricity. Another reason for fewer interruptions is that most of the pipelines are below ground level and therefore are less vulnerable than overhead power lines. However, once an interruption occurs, in many cases it lasts much longer compared to electricity.

TABLE 5-12: What reliability indicators are available as far as gas networks are concerned?

Country	SAIDI		ASIDI		SAIFI		CAIDI		Other	Applies to
	Unplanned	Planned	Unplanned	Planned	Unplanned	Planned	Unplanned	Planned		
AT	Yes	No	No	No	Yes	No	Yes	No		Distribution
BA	No	No	No	No	Yes	Yes	Yes	No		Distribution & Transmission
BE	Yes	Yes	No	No	No	No	No	No		Distribution
BG	Yes	Yes	No	No	Yes	Yes	Yes	Yes		NA
DE	Yes[184]	Yes[185]	Yes	Yes	Yes	NA	NA	NA		Distribution & Transmission
FI	Yes	Yes	No	No	Yes	Yes	No	No		Distribution & Transmission
FR	NA	NA	Yes	Yes	Yes	NA	Yes	NA		NA
GE	Yes	Yes	No	No	Yes	NA	NA	NA		Distribution
LT	Yes	Yes	No	No	Yes	Yes	No	No		Distribution
LV	Yes	Yes	No	No	Yes	Yes	Yes	No		Distribution
NL	Yes	Yes	No	No	Yes	Yes	Yes	Yes		Distribution
PT	Yes	Yes	No	No	Yes	Yes	No	No	AIT[186]	NA
RS	Yes	Yes	NA	NA	Yes	Yes	NA	NA		Distribution
SI	Yes	Yes	No	No	Yes	Yes	No	No		Distribution & Transmission
SK	Yes	No	No	No	Yes	No	No	No		Distribution
CZ, EE, EL, HR[187], HU, IE, LU, MT, RO[188], SE, UA	No	No	No	No	No	No	No	No		

184 Only calculated for pressures below 100 mbar; without exceptional events and planned events.
185 Only planned events.
186 Portugal uses AIT as an additional indicator, measured as minute per interruption, which is the ratio of the overall duration of interruptions at the exit points and the total number of interruptions at the exit points over the period considered.
187 Croatia only uses the duration of all interruptions of gas supply in relation to the number of all end customers to which gas supply has been interrupted.
188 In Romania, the only indicators related to interruptions in the gas networks that have to be reported to the NRA are the following: notification sent to the affected customers regarding planned and unplanned limitations and/or interruptions in the supply of gas. They are calculated as: the number of notified customers divided by the total number of affected customers, thus, if all affected customers were notified, the value of the indicator would be 100%. This applies to both distribution and transmission and has to be reported by all DSOs and the TSO.

TABLE 5-13: Definitions of reliability indicators in use

Country	SAIDI		ASIDI		SAIFI		CAIDI	
	Unplanned	Planned	Unplanned	Planned	Unplanned	Planned	Unplanned	Planned
AT[189]	SAIDI = (sum of all customer interruption durations) / (total number of customers served)				SAIFI = (total number of customer interruptions) / (total number of customers served)		CAIDI = (sum of all customer interruption durations) / (total number of customer interruptions) = SAIDI / SAIFI	
BG	The average outage duration for each customer served.				The average number of interruptions that a customer would experience.		The ratio of total interruptions to the total number of disconnected users on the network.	
DE	SAIDI = $\Sigma(N_i \times r_i) / N_t$ N_i - number of customers interrupted by each incident, N_t - total number of customers in the system for which the index is calculated, r_i - restoration time for each incident		ASIDI = $\Sigma(L_i \times r_i) / L_t$ L_i - contracted power interrupted by each incident, L_t - total contracted power in the system for which the index is calculated, r_i - restoration time for each incident		SAIFI = $\Sigma(N_i) / N_t$ N_i - number of customers interrupted by each incident, N_t - total number of customers in the system for which the index is calculated		CAIDI = $\Sigma(N_i \times r_i) / N_i$ N_i - number of customers interrupted by each incident, r_i - restoration time for each incident	
FI[190]	SAIDI = $\Sigma(N_i \times r_i) / N_t$ N_i: number of customers interrupted by each incident, N_t: total number of customers in the system for which the index is calculated, r_i: restoration time for each incident				SAIFI = $\Sigma(N_i) / N_t$ N_i: number of customers interrupted by each incident, N_t: total number of customers in the system for which the index is calculated			
LT	It is average disruption duration for one customer, calculated as: Sum of all customers who encountered unplanned interruption times the length of duration (minutes) in the numerator and total number of customers in the denominator.				It is average number of interruptions for one customer, calculated as: Sum of all customers for who encountered unplanned gas distribution interruption in the numerator and total number of customers in the denominator.			
NL	Yearly loss of service due to unforeseen circumstances, in minutes per consumer per year				The number of unforeseen interruptions of service per year per connection.		Average interruption duration due to unforeseen maintenance in minutes per interruption	
PT	Average duration of interruptions per exit point: the ratio of the overall duration of unplanned interruptions at the exit points over a specific period and the total number of exit points at the end of the period considered.				Average number of interruptions per exit point: the ratio of the total number of unplanned interruptions at the exit points over a specific period and the total number of exit points at the end of the period considered.			
RS	Ratio of total supply interruption duration on all delivery points and total number of delivery points for unplanned interruptions.				Ratio of total number of supply interruptions and total number of delivery points for unplanned interruptions.			
SI	SAIDI = $\Sigma(N_i \times r_i) / N_t$ [min/customer] N_i: number of customers interrupted by each unplanned interruption, N_t: total number of customers in the system for which the index is calculated, r_i: time of interruption for each unplanned interruption				SAIFI = $\Sigma N_i / N_t$ [number of interruptions per customer] N_i: number of customers interrupted by each unplanned interruption, N_t: total number of customers in the system for which the index is calculated			
SK	Average duration of interruptions in the distribution system, calculated by the formula: $\text{SAIDI} = \frac{\sum_{i-1}^{n} Z_i \times t_i}{N}$ Z_i: number of affected supply points in the interruption of gas distribution, N: total number of supply points of the DSO, t_i: duration of the i-th interruption of gas distribution in hours				Average number of interruptions in the distribution system calculated by the formula: $\text{SAIDI} = \frac{\sum_{i-1}^{n} N_i}{N}$ N_i: number of affected supply points in the interruption of gas distribution, N: total number of supply points of the DSO			

189 Taken from the 6th Benchmarking Report.
190 SAIDI and SAIFI figures in earlier years only available as sum of combined unplanned and planned.

5.7 REGULATION OF CONTINUITY OF SUPPLY AND SAFETY ISSUES

Technical quality of gas networks is mainly a result of operating and maintaining the gas networks by the network operator. In this area, network operators have to follow technical rules and standards with the aim of guaranteeing a mostly uninterrupted distribution of gas in sufficient quantity and quality and the required pressure.

This section focuses on an overview of odorisation of gas and if there are obligations for market participants to be International Organization for Standardization (ISO) certified. Even though ISO develops international standards, it is not involved in their certification. This is performed by external certification bodies. For more information on other aspects of safety issues, such as the handling of planned interruptions, rules and incentives for safety, whether or not there are rules in force for the restoration of networks in case of an unplanned interruption please refer to the 6th Benchmarking Report.

5.7.1 Obligations for odorising natural gas

The primary objective of gas odorisation is safety. Since natural gas, as delivered to pipelines, has practically no odor, the addition of an odorant allows natural gas in air to be detected before it reaches combustible levels and hence acts as a warning. Odorisation is thus part of the risk management for natural gas pipelines and is required by most regulations. The addition of odorants to liquid petroleum gas and natural gas gives an improved level of safety. Odorisation is generally provided by adding trace amounts of some organic sulphur compounds to gas before it reaches the consumer. The aim is that leaks can be detected before a fire or explosion.

TABLE 5-14: Obligation to odorise natural gas (1)

Country	Obligation for odorisation	Level	Not mandatory for
AT	Yes	Distribution	
BA	Yes	Transmission	
BE	Yes	Distribution	Consumers directly connected to the transmission network (industrial and gas fired power plant).
BG	Yes	Distribution	
CZ[191]	Yes	Distribution	
DE	Yes	Distribution	
EE	Yes	Distribution & Transmission	
EL	Yes	Transmission	Odorisation is mandatory for distribution networks at city gates.
ES	Yes	Distribution & Transmission	
FI	Yes	Distribution	
FR	Yes	Distribution & Transmission	
GB	Yes	Distribution	
GE	Yes	Distribution	Generation and chemical industry
HR	Yes	Distribution	
HU	Yes	Distribution	Natural gas is odorised at the domestic exit points of the TSO's system (city gates), with the exception of exit points to storage and to blending circuits.
IE	Yes	Distribution & Transmission	
LT	Yes	Transmission	
LU	Yes	Transmission	
LV	Yes	Distribution	
MT[192]			
NL	Yes	Distribution & Transmission	
PL	Yes	Distribution (up to 0.5 MPa)	Distribution system with pressure higher than 0.5 MPa and transmission system.
PT	Yes	Distribution	
RO	Yes	Distribution & Transmission	Consumers who request unodorised gas in order to use it in technological processes.
RS	Yes	Distribution	For consumers connected to steel distribution pipelines, odorisation is not mandatory.
SE	Yes	Distribution & Transmission	Rules are set by a government authority different from the NRA.
SI	Yes	Distribution	There are exceptions for natural gas for further processing or special kind of use.
SK	Yes	Distribution	Customers who use gas for the technological purposes.
UA[193]	Yes	Distribution & Transmission	

191 Odorising natural gas is not obligatory for innogy GasNet, since they use on its grid system combined central and local odorising. They use a mixture of Tertiary Butyl Mercaptan (TBM) and Diethylsulfide (DMS). Customers directly connected to TSO use natural gas without odorisation.
192 Natural gas is used only for power generation and is not transferred to final customers through distribution networks. Thus, odorisation is not mandatory.
193 Exceptions for the obligation to odorise natural gas are defined by contracts between consumers and the TSO (if a consumer is connected to the transmission system) and by contracts between TSO, DSO and consumers (if a consumer is connected to the distribution system).

In 28 responding countries, DSOs have some obligations concerning gas odorisation. This could, for example, be monitoring the degree of gas odorisation in specific locations of the distribution network and in particular periods of the year.

TABLE 5-15: Obligation to odorise natural gas (2)

Country	Requirement	Monitored	Type	Company involved	Applies to year	Pressure levels
BE	Flanders: only general responsibility but no specific obligations. Wallonia and Brussels: Article 6 of the Royal Decree of 28 June 1971 [85] determines the safety measures to be met. See text for more information.			DSO		
CZ	TPG 918 01 Technical rule on odorisation [86].	Yes	OR	DSO		MP, LP, HP up to 40 bar
DE	Requirement not specified					
EE	ISO/TR 16922 standard is used ("ISO/TR 16922 Natural gas – Odorization" [87]). Gas odorisation takes place in gas distribution stations. The level of gas in the distribution networks should be measured at least once a year.					
ES	DSO is also responsible for the gas odorisation					
FI	Finnish Safety and Chemicals Agency (Tukes) handles technical safety aspects.	No	OR	DSO		
HR	DSO is obliged to odorise gas and to monitor the effectiveness of odorisation.	Yes	OI	DSO	Each year	MP, LP
HU	DSOs monitor the compliance with odorisation requirement continuously with chromatographs.	Yes	OR	DSO	2019	All
IE	Odorisation is monitored at distribution level.	Yes	OR	DSO	2019	
LV	According to Standard LVS 445-2:2011, Operation and Maintenance of natural gas distribution and Consumer supply systems with max operation pressure 1.6 MPa (16 bar). Part 2: Maintenance terms, kinds of work and the execution organisation [88].	Yes	OR	DSO	2019	MP, LP
NL	Degree of gas odorisation	Yes	OR	DSO		MP, LP
PL	Degree of gas odorisation (different for high methane and low methane gases)	Yes (at least once in 14 days)	OR	DSO	2019	Up to 0.5 MPa
RO	A DSO is required to ensure the gas odorisation, based on the service contract agreements concluded with the operator located upstream, as well as the additional odorisation of gas in distribution network, if necessary.	No				
RS	DSO is obliged to assure adequate level of odorant at the very end points of distribution system.	No				
SE	Odorisation THT	Yes	OR	DSO, SP	Each year	MP, LP
SI	Rules on the technical conditions for the construction, operation and maintenance of gas pipelines with a maximum working pressure up to and including 16 bar, DVGW (G 280-1 odorisation of gas)	Yes				
SK	TPP 918 01 (Technical norm)	Yes	OR	DSO	10+ years	All
AT, BA, BG, EL, FR, LT, LU	No requirements					
DE, GE	Requirement not specified					

In **Belgium** (Flanders region), there is only a general responsibility but no specific obligation to odorise. DSOs follow a common recommendation for odorisation. In Wallonia and Brussels, Article 6 of the Royal Decree of 28 June 1971 [85] determining the safety measures to be taken during the establishment and operation of gas distribution installations by pipelines stipulates that the gas distributed must be odorised in a way strong enough to immediately detect gas leaks through smell. This smell must disappear during the combustion of the gas. Article 41 stipulates that the gas distributor controls the odorisation of gas. The gas distributor is therefore responsible for the odorisation of gas and for its control.

In the **Czech Republic** a standard value of 1 mg/m³ is defined as a standard with odorisation controls performed every six months.

In **Finland**, the Finnish Safety and Chemicals Agency (Tukes) handles technical safety aspects. "The Government Decree on Safety in the Handling of Natural Gas" includes the following: odorisation needs to be enough at the end of a network. This must be inspected yearly. If the area of distribution has a substantial number of household consumers, inspections must be carried out routinely [89].

In **Croatia**, the DSO is obliged to odorise gas and to monitor the effectiveness of odorisation in accordance with the provisions of special laws, regulations, standards, codes of practice and internal technical acts of the DSO regulating the technical conditions of the odorisation. Also, a number of measurements in each semi-annual period on specific points in the distribution system defined by the DSO, have to be performed.

In **Hungary**, the standard level for odorisation is the same as in the general case and measurement has to be performed continuously.

Odorisation is monitored at distribution level in **Ireland**. This is in line with Gas Networks Ireland's (GNI) distribution safety case and its odour intensity monitoring and control procedures. The odour intensity must be within the sales scale range of 1.7 to 2.2 100% of the time.

In **Poland**, the odorisation level in the distribution system (up to 0.5 MPa) is measured at least once in 14 days. The smell should be clearly perceptible if the concentration of natural gas in the air is 1% for high methane gas, and from 1.2% to 1.5% for low methane natural gases.

In **Slovakia**, the odorant concentration is measured in mg/Nm³. Quality is assessed by one of three levels with a standard value of one and a warning level of two.

In **Sweden**, the requirement is set from a safety perspective. Regular check-ups are performed to monitor odorisation.

5.7.2 Obligation of ISO-certification

TABLE 5-16: Obligation for network operators to be ISO-certified

Country	Requirement of ISO-certification	Number of certifications	Type	Company involved	Applies to year
AT	Yes	21	GI	DSO	2019
BA	Yes		GI		
LV	Yes	2	OR	DSO	2019
BG, EL, SE	Yes	No specific information			
BE, CZ, EE, FI, HR, HU, IE, LT, LU, MK, MT, NL, RS, SI, SK, UA	No				

For all aspects of safety and operations in **Austria**, the Austrian Association for Gas and Water's (ÖVGW) guidelines are binding. The same is true for **Germany** for the German Association of Energy and Water Industries' (BDEW) guidelines.

In **Belgium**, safety measures are detailed in technical codes approved by official authorities.

In **Finland**, the Finnish Safety and Chemicals Agency (Tukes) handles technical safety aspects.

In **Hungary**, several of the processes and systems of the grid operators have to be ISO-certified for the company to be licensed (such as ISO 9001:2008 – Quality management systems, ISO 14001:2004 - Environmental management systems, ISO 50001 – Energy management, etc.), but there is no specific ISO standard applied for the whole of the network operation activity.

Safety requirements in **Serbia** are included in technical regulation, for which monitoring is performed by relevant inspections.

In **Sweden**, a standardisation organisation, SIS, has a standard for how the transmission grid should be designed.

5.7.3 Network losses

In general, losses are defined as the absolute difference between the volume of gas entering the system (metered or estimated at the point of entry) and the customer related amount of gas exiting the system (metered or estimated at the point of exit). The specific definition of network losses varies across countries.

In the CEER Reports on Power Losses [90], [91] only losses in electricity networks have been considered so far. To be able to compare losses across countries in the future, the adoption of a common standard for the expression of losses might be worth considering for gas systems as well.

In the meantime, the existing definitions of power losses in gas networks can be found in the 6th Benchmarking Report [6].

5.8 FINDINGS AND RECOMMENDATIONS ON GAS TECHNICAL OPERATIONAL QUALITY

FINDING #1:
In addition to electricity, CoS is also monitored in gas grids.

CoS indicators can also be used for gas. Some respondents use indicators for both frequency and duration, and some distinguish between planned and unplanned interruptions. Most countries that monitor CoS use SAIDI, ASIDI, SAIFI, and CAIDI as indicators. The use of more than just one indicator to quantify CoS results in more information being available and more possibilities to compare the results among different countries.

FINDING #2:
There are vast differences in indicators used for CoS and technical safety across Europe.

Interruptions in gas, while much less common than those in electricity, can lead to a high risk of danger, resulting in greater efforts to avoid an interruption than in electricity. Although gas interruptions are less frequent, they usually last longer than those in electricity. Although there is general availability of information on CoS indicators, the level of detail varies markedly across the reporting countries.

Technical safety plays a very important role in the gas sector with indicators, such as leaks, used to describe the technical quality of the infrastructure. The effect of leaks on CoS can differ, since not every leak inevitably entails an interruption for the customer.

FINDING #3:
Odorisation of gas improves safety and is required in most European countries.

In 28 responding countries, DSOs have some obligations regarding gas odorisation, which gives an improved level of safety. Odorisation is part of risk management and is required to detect the presence of gas before it can reach combustible levels and cause fires or explosions.

FINDING #4:
Gas storage infrastructure is regulated in only about half of the countries that use storage.

Gas storage facilities are used in 19 responding countries and regulated in ten. Regulation of the storage infrastructure could apply to the maximum storage, injection or withdrawal capacity, to tariffs, or to the minimal quantity of gas to be stored.

FINDING #5:
LNG infrastructure is used in 12 responding countries and regulated in ten.

LNG, which can be imported by sea, offers an alternative to common gas supply which typically uses (cross-border) gas pipelines. Since the EU energy policy aims at providing its consumers with safe, balanced and competitive energy at affordable prices, LNG plays an important role in this policy, especially in guaranteeing the security of supply as well as raising the integration and competitiveness of the gas market.

RECOMMENDATION 1

EXPAND THE COVERAGE OF MONITORING OF CoS INDICATORS AND SAFETY INDICATORS.

As in the previous edition of the Benchmarking Report, it is recommended to extend the reported indicators across Europe so that comparisons are possible across more countries in the future. Consequently, the definition of a basic set of indicators might be useful.

RECOMMENDATION 2

PURSUING THE HARMONISATION OF THE CoS INDICATORS WOULD ENABLE EASIER BENCHMARKING.

As explained in the chapter on electricity, indicators used for gas can also widely differ among countries. A move towards harmonisation of parameters such as weighting methods would make comparability of values more reliable.

RECOMMENDATION 3

EXPAND ODORISATION TO ALL COUNTRIES.

Odorisation of gas is part of risk management and is required to detect the presence of gas before it can reach combustible levels and cause fires or explosions. Since it gives an improved level of safety, odorisation should be extended to all countries with gas pipelines and infrastructure.

RECOMMENDATION 4

EXPAND THE REGULATION OF GAS STORAGE.

Gas storage is regulated in around only half of the countries where this infrastructure is available. It is recommended to implement this regulation in more countries as setting the minimal quantity of gas to be stored can improve availability of gas.

RECOMMENDATION 5

FURTHER DEVELOP THE LNG INFRASTRUCTURE.

LNG, which can be imported by sea, offers an alternative to common gas supply by pipelines. Since the EU energy policy aims at providing its consumers with safe, balanced and competitive energy at affordable prices, LNG plays an important role in this policy, especially in guaranteeing the security of supply as well as raising the integration and competitiveness of the gas market

06

GAS – NATURAL GAS QUALITY

6 GAS – NATURAL GAS QUALITY

6.1 INTRODUCTION

Depending on its origin, the composition of natural gas can differ. Gas can be supplied to a country from different sources such as indigenous production, imports from neighbouring countries at interconnection points, or LNG imports through LNG terminals. As a result of the varying supply mixes and the different structure of networks, each country has developed its own gas quality standards. This chapter compares the different standards across the European countries.

This benchmarking analysis is also relevant since European regulations such as the Interoperability Network Code (INT NC) [92] had to be implemented from May 2016 with the aim of facilitating efficient gas trading and transmission across gas systems within the European Union, and thereby moving towards greater internal market integration. Furthermore, work is being carried out by the European Committee for Standardization (CEN), European Network of Transmission System Operators for Gas (ENTSOG) and other stakeholders to examine the impact of harmonising gas quality across Europe.

6.2 STRUCTURE OF THE CHAPTER ON NATURAL GAS QUALITY

In this chapter, a list of technical parameters is presented followed by an overview of definitions and applications in the reporting countries. Deviating from the 6th Benchmarking Report [6], this chapter only describes the application of the parameters and no other topics, such as responsibilities of the involved parties.

The content of this chapter is based on answers provided by 28 countries: Austria, Belgium, Bosnia and Herzegovina[194], Bulgaria, Croatia, the Czech Republic, Estonia, Finland, France, Georgia, Germany, Greece, Hungary, Ireland, Latvia, Lithuania, Luxembourg, the Netherlands, North Macedonia, Poland, Portugal, Romania, Serbia, Slovakia, Slovenia, Spain, Sweden and Ukraine. Among these countries, Austria and Germany did not provide technical data given that parameters are defined by technical associations for gas (OVGW for Austria and DVGW for Germany) which set binding guidelines and technical rules according to their national legislation. This means that in Austria and Germany quality requirements for injecting and transporting gas that are set in the general terms and conditions for the distribution and transmission networks, shall comply with OVGW or DVGW regulation, respectively. Therefore, the requested parameters are not monitored by their NRAs but by the associations and network operators.

6.3 ANALYSIS OF TECHNICAL PARAMETERS MONITORED BY COUNTRIES

6.3.1 Overview of technical parameters

In the natural gas quality part of the questionnaire, NRAs were asked to provide data on several parameters. Some of them represent the chemical composition of natural gas (methane, sulphur, carbon dioxide, etc.). Other parameters such as Wobbe Index (WI), Relative Density or Water/Hydrocarbon Dew Point, etc. are considered important quality parameters, are sometimes stipulated in contractual specifications and enforced throughout the natural gas supply chain, from producers through processing, transmission and distribution companies to end-users.

Table 6-1 and Table 6-2 present an overview of the technical parameters monitored by each country. The definitions and characteristics of the main parameters are given in Section 6.3.2.

194 The entity of Republika Srpska only.

TABLE 6-1: Overview of the parameters monitored by each country (1)

Parameter	Yes	No	Yes (countries)	No (countries)
Wobbe Index	22	6	BA, BE, BG, CZ, EE, EL, ES, FR, GE, HR, HU, IE, LT, LV, MK, NL, PL, PT, RS, SI, SK, UA	AT, DE, FI, LU, RO, SE
Gross Calorific Value (Real Gross Dry)	24	4	BA, BE, BG, CZ, EE, EL, ES, FI, FR, GE, HR, HU, IE, LT, LU, LV, MK, PL, PT, RO, SE, SI, SK, UA	AT, DE, NL, RS
Relative Density	18	9	BA, BE, EE, EL, ES, FR, GE, HR, HU, IE, LT, LV, MK, PL, PT, SE, SI, SK	AT, BG, CZ, DE, FI, NL, RO, RS, UA
Methane (CH_4) Content	20	4	BA, BE, BG, CZ, EL, ES, GE, HR, HU, IE, LT, LV, MK, NL, PT, RS, SE, SI, SK, UA	AT, DE, FI, RO
Ethane Content	15	9	BA, BE, BG, CZ, EE, EL, HR, HU, IE, MK, RS, SE, SI, SK, UA	AT, DE, ES, FI, LT, LV, NL, PT, RO
Propane Content	14	10	BA, BE, BG, CZ, EE, EL, HR, HU, IE, MK, SE, SI, SK, UA	AT, DE, ES, FI, LT, LV, NL, PT, RO, RS
Sum of Butanes Content	13	11	BA, BE, BG, CZ, EE, EL, HU, IE, MK, SE, SI, SK, UA	AT, DE, ES, FI, HR, LT, LV, NL, PT, RO, RS
Oxygen (O_2) Content	16	8	BE, CZ, EE, EL, ES, GE, HR, HU, IE, LT, LV, NL, PT, SI, SK, UA	AT, BA, BG, DE, FI, MK, RS, SE
Nitrogen (N_2) Content	18	7	BA, BE, BG, CZ, EE, EL, ES, GE, HR, HU, IE, LT, LV, RS, SE, SI, SK, UA	AT, DE, FI, MK, NL, PT, RO
Hydrogen (H_2) Content	7	15	BG, ES, IE, LT, LV, NL, UA	AT, BA, BE, CZ, DE, EL, FI, HR, HU, MK, PT, RS, SE, SI, SK
Carbon monoxide (CO) Content	3	19	ES, NL, SE	AT, BA, BE, BG, CZ, DE, EL, FI, HR, HU, IE, LT, LV, MK, PT, RS, SI, SK, UA
Carbon dioxide (CO_2) Content	19	6	BA, BE, CZ, EE, EL, ES, GE, HR, HU, IE, LT, LV, MK, NL, PT, RS, SI, SK, UA	AT, BG, DE, FI, RO, SE
Hydrogen sulphide (H_2S) Content	21	6	BA, BE, BG, CZ, EE, EL, ES, FR, GE, HR, HU, IE, LT, LV, NL, PL, PT, RS, SI, SK, UA	AT, DE, FI, MK, RO, SE
Total Sulphur Content	19	7	BA, BE, CZ, EE, EL, ES, FR, HR, HU, IE, LT, LV, NL, PL, PT, RO, RS, SI, SK	AT, BG, DE, FI, MK, SE, UA
Mercaptan Sulphur Content	18	8	BA, BG, CZ, EE, EL, ES, FR, GE, HR, IE, LT, LV, PL, PT, RS, SI, SK, UA	AT, BE, DE, FI, MK, NL, RO, SE
Sum of Pentanes and higher Hydrocarbons	9	13	BE, CZ, EL, HU, IE, MK, RS, SI, UA	AT, BA, BG, DE, ES, FI, HR, LT, LV, NL, PT, SE, SK
Dust Particles	7	16	EE, ES, HU, LT, LV, NL, UA	AT, BA, BE, BG, CZ, DE, EL, FI, HR, IE, MK, PT, RS, SE, SI, SK
Water/Hydro Dew Point	22	5	BA, BE, BG, CZ, EE, EL, ES, FR, GE, HR, HU, IE, LT, LV, MK, NL, PL, PT, RS, SI, SK, UA	AT, DE, FI, RO, SE
Water (H_2O) Content	2	21	HU, IE	AT, BA, BE, BG, CZ, DE, EE, EL, ES, FI, HR, LT, LV, MK, NL, PT, RS, SE, SI, SK, UA
Odorant Content	10	13	BE, ES, FR, GE, HU, IE, LV, NL, PL, UA	AT, BA, BG, CZ, DE, EE, FI, HR, MK, PT, RO, RS, SE
Contaminants & Odour	2	18	HU, UA	AT, BA, BE, BG, CZ, DE, EE, EL, ES, FI, HR, IE, LV, MK, PT, RS, SE, SI
Incomplete Combustion Factor	3	19	IE, SI, SK	AT, BA, BE, BG, CZ, DE, EE, EL, ES, FI, HR, HU, LV, MK, NL, PT, RS, SE, UA
Delivery Temperature	9	14	BA, BE, EE, EL, HU, IE, MK, NL, SI	AT, BG, CZ, DE, ES, FI, HR, LV, PT, RO, RS, SE, SK, UA
Soot Index	2	19	IE, SI	AT, BA, BE, BG, CZ, DE, EE, EL, ES, FI, HR, HU, LV, MK, NL, PT, RS, SE, UA
Organo Halides	1	20	IE	AT, BA, BE, BG, CZ, DE, EE, EL, ES, FI, HR, HU, LV, MK, NL, PT, RS, SI, SE, UA
Radioactivity	1	20	IE	AT, BA, BE, BG, CZ, DE, EE, EL, ES, FI, HR, HU, LV, MK, NL, PT, RS, SI, SE, UA

TABLE 6-2: Overview of the parameters monitored by each country (2)

	BA	BE	BG	CZ	EE	EL	ES	FI	FR	GE	HR	HU	IE	LT	LU	LV	MK	NL	PL	PT	RO	RS	SE	SI	SK	UA	Total
Wobbe Index	×	×	×	×	×	×	×	-	×	×	×	×	×	×	-	×	×	×	×	×	-	×	-	×	×	×	22
Gross Calorific Value	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	-	×	×	×	-	×	×	×	×	24
Relative Density	×	×	-	-	×	×	×	-	×	×	×	×	×	×	-	×	×	-	×	×	-	-	×	×	×	-	18
Methane Content	×	×	×	×	-	×	×	-	-	×	×	×	×	×	-	×	×	×	-	×	-	×	×	×	×	×	20
Ethane Content	×	×	×	×	×	×	-	-	-	-	×	×	×	-	-	-	×	-	-	-	-	×	×	×	×	×	15
Propane Content	×	×	×	×	×	×	-	-	-	-	×	×	×	-	-	-	×	-	-	-	-	-	×	×	×	×	14
Sum of Butanes Content	×	×	×	×	×	×	-	-	-	-	-	×	×	-	-	-	×	-	-	-	-	-	×	×	×	×	13
Oxygen (O_2) Content	-	×	-	×	×	×	×	-	-	×	×	×	×	×	-	×	-	×	-	×	-	-	-	×	×	×	16
Nitrogen Content	×	×	×	×	×	×	×	-	-	×	×	×	×	×	-	×	-	-	-	-	-	×	×	×	×	×	18
Hydrogen Content	-	-	×	-	-	-	×	-	-	-	-	-	×	×	-	×	-	×	-	-	-	-	-	-	-	×	7
Carbon Monoxide (CO) Content	-	-	-	-	-	-	×	-	-	-	-	-	-	-	-	-	-	×	-	-	-	-	×	-	-	-	3
Carbon Dioxide (CO_2) Content	×	×	-	×	×	×	×	-	-	×	×	×	×	×	-	×	×	×	-	×	-	×	-	×	×	×	19
Hydrogen Sulphide (H_2S) Content	×	×	×	×	×	×	×	-	×	×	×	×	×	×	-	×	-	×	×	×	-	×	-	×	×	×	21
Total Sulphur Content	×	×	-	×	×	×	×	-	×	-	×	×	×	×	-	×	-	×	×	×	×	×	-	×	×	-	19
Mercaptan Sulphur Content	×	-	×	×	×	×	×	-	×	×	×	-	×	×	-	×	-	-	×	×	-	×	-	×	×	×	18
Sum of Pentanes and higher Hydrocarbons	-	×	-	×	-	×	-	-	-	-	-	×	×	-	-	-	×	-	-	-	-	×	-	×	-	×	9
Dust Particles	-	-	-	-	×	-	×	-	-	-	-	×	-	×	-	×	-	×	-	-	-	-	-	-	-	×	7
Water/Hydro Dew Point	×	×	×	×	×	×	×	-	×	×	×	×	×	×	-	×	×	×	×	×	-	×	-	×	×	×	22
Water (H_2O) Content	-	-	-	-	-	-	-	-	-	-	-	×	×	-	-	-	-	-	-	-	-	-	-	-	-	-	2
Odorant Content	-	×	-	-	-	-	×	-	×	×	-	×	×	-	-	×	-	×	×	-	-	-	-	-	-	×	10
Contaminants & Odour	-	-	-	-	-	-	-	-	-	-	-	×	-	-	-	-	-	-	-	-	-	-	-	-	-	×	2
Incomplete Combustion Factor	-	-	-	-	-	-	-	-	-	-	-	-	×	-	-	-	-	-	-	-	-	-	-	×	×	-	3
Delivery Temperature	×	×	-	-	×	×	-	-	-	-	-	×	×	-	-	-	×	×	-	-	-	-	-	×	-	-	9
Soot Index	-	-	-	-	-	-	-	-	-	-	-	-	×	-	-	-	-	-	-	-	-	-	-	×	-	-	2
Organo Halides	-	-	-	-	-	-	-	-	-	-	-	-	×	-	-	-	-	-	-	-	-	-	-	-	-	-	1
Radioactivity	-	-	-	-	-	-	-	-	-	-	-	-	×	-	-	-	-	-	-	-	-	-	-	-	-	-	1
	14	16	11	14	15	16	15	1	8	11	13	19	23	13	1	14	11	12	8	10	2	10	8	18	15	17	

Most countries monitor more than ten parameters related to gas quality, while Ireland, Hungary and Slovenia monitor at least 18 (in the case of Ireland, 23), which demonstrates that countries are attentive to gas quality. However, some countries consider that some parameters are more important than others.

In the remainder of this chapter, results for the parameters considered relevant by countries are presented while other results are available in Annex E.

6.3.2 Definitions and characteristics of the main parameters

This section describes the main indicators and attempts to give readers an understanding of the links between them and their main characteristics.

Gross Calorific Value: the amount of heat evolved by the complete combustion of a unit certain volume of gas with air [93]

Relative Density: the density of gas in relation to the density of air, when both are at the same reference conditions [93]

Wobbe Index: the Wobbe Index is the main indicator of the interchangeability of fuel gases and is frequently defined in the specifications of gas supply and transport utilities. The WI is used to compare the combustion energy output with different composition of fuel gases. If two fuels have identical WIs at a given pressure and valve setting, then the energy output will be identical. WI is a critical factor in minimising the impact of fluctuations in fuel gas supply and can therefore be used to increase the efficiency of burner or gas turbine applications [93]. WI is defined as:

$$\text{Wobbe Index} = \frac{\text{Gross Calorific Value}}{\sqrt{\text{Relative density}}}$$

Water and Hydrocarbon Dew Point: Hydrocarbon Dew Point is the temperature (at a given pressure) at which the hydrocarbon components of any hydrocarbon-rich gas mixture, such as natural gas, will begin to condense out of the gaseous phase. The Hydrocarbon Dew Point is a function of the gas composition as well as the pressure and is a different concept from that of Water Dew Point, the latter being the temperature (at a given pressure) at which water vapour present in a gas mixture will condense from the gas [94].

Hydrogen Sulphide and Mercaptan Sulphur: they are composed of sulphur which, when present in sufficient volumes, can lead to serious problems such as increased corrosion rates. Odorants added for safety reasons often also contain sulphur which may explain why sulphur content can be very different if a country has odorised its gas on the transmission network.

6.3.3 CEN gas quality standards

CEN has established standards in EN 16726 [95] that specify gas quality characteristics, parameters and their limits for gases classified as group H (high calorific gas) that are to be transmitted, injected into and withdrawn from storage, distributed and utilised. These standards are shown in Table 6-3:

TABLE 6-3: Gas quality standards according to CEN

Parameter	Unit	Min	Max
Relative density	No unit	0.555	0.700
Total sulphur without odorant	mg/m^3	No limit	20 (30[195])
H_2S & COS	mg/m^3	No limit	5
Mercaptan sulphur	mg/m^3	No limit	6
Oxygen	mol/mol	No limit	10 ppm to 1%[196]
CO_2	mol/mol	No limit	2.5% to 4%[196]
Hydrocarbon dew point	°C (up to 70 bar)	No limit	-2
Water dew point	°C (at 70 bar)	No limit	-8
Methane number	No unit	65	No limit

The CEN standard was approved in September 2015 and had to be adopted as the national standard by CEN members no later than June 2016. Responsibility and liability issues are subject to European or national regulations. Therefore, as long as the standard is not referred to in regulation, its application is voluntary.

As mentioned earlier, in Austria and Germany these standards are defined by technical associations for gas (OVGW for Austria and DVGW for Germany) which set the binding guidelines and technical rules according to their national legislations.

195 The limit refers to gas at HP networks and on interconnection points. For those transmission systems where the gas is odorised, a limit of 30 mg/m^3 applies.
196 At network entry points and interconnection points, the mole fraction of oxygen shall be no more than 10 ppm, the one of carbon dioxide shall be no more than 2.5%. However, where the gas can be demonstrated not to flow to installations sensitive to higher levels of oxygen (carbon dioxide), e.g. underground storage systems, a higher limit of up to 1% (4%) applies.

6.3.4 Wobbe Index, Gross Calorific Value and Relative Density

WI is intrinsically linked to Gross Calorific Value and Relative Density, which means that all are considered significant by countries. The tables below present the standards usually used by countries, the frequency of measurement and the publication of these values at the entry point of a transmission network. It should be kept in mind that different countries provided answers in different units and that 1 kWh is equal to 3.6 megajoules (MJ).

TABLE 6-4: Wobbe Index range and monitoring frequency

Wobbe Index	Min	Max	Unit	Measurement frequency	Publication frequency
BA	42	46	MJ/m³	Daily	System operator's responsibility
BE	13.65	15.78	kWh/m³ [197]	Continuously	Daily/Yearly [198]
BG	45	55	MJ/m³	Hourly	Hourly
CZ	12.07	14.05	kWh/m³ [199]	Continuously	Daily (by TSO)
EE	13.06	14.44	kWh/m³	5 minutes	Monthly
EL	13.066	16.328	kWh/m³	5 minutes	Daily
ES	13.403	16.058	kWh/m³	Daily	Daily
FR	13.4	15.7	kWh/m³	5 minutes	Not published
GE	41.2	54.5	MJ/m³	Daily	NA
HR	12.75	15.81	kWh/m³ [200]	Twice per month	Twice per month
HU	12.68	15.21	kWh/m³	4 minutes	Daily
IE	47.2	51.41	MJ/m³	Continuously	Monthly
LT	14.05	15.51	kWh/m³	Daily	Daily
LV	13.06	14.44	kWh/m³	Continuously	Daily
MK	45.049	45.136	MJ/bm³	4 minutes	Not published
NL	47	55.7	MJ/m³	Continuously	Yearly
PL	45	56.9	MJ/m³	Hourly	TSO: daily and monthly DSO: monthly
PT	13.38	16.02	kWh/m³	Hourly	Monthly
RO	41.69	57.79	MJ/m³	Daily/every 10 days/monthly[201]	No obligation
RS	42	46	MJ/m³	Daily	NA
SI	14.815	14.82	kWh/m³	4 minutes	Hourly & Daily[202]
SK	13.41	14.25	kWh/m³	NA	Monthly
UA	41.2	54.5	MJ/m³ [203]	Daily/Weekly [204]	Monthly

Due to the different gas supply portfolios and gas system configurations, some countries are used to a relatively narrow WI bandwidth below 1 kWh/m³, while in other regions the actual distributed gases have a relatively wide WI bandwidth above 10 kWh/m³.

In Germany, two different types of natural gas are used. L-gas (low calorific gas), which is extracted in the Netherlands and Germany, has a lower methane content and therefore a lower calorific value or energy content than H-gas (high calorific gas). Due to their different calorific values, the two types of gas must be transported in separate gas networks. As the production of L-gas is declining, it will be completely discontinued by 2030.

Among countries that monitor this parameter, the measurement frequency varies from continuous measurement to a weekly and, rarely, monthly measurement. If countries publish WI values, this is done at least monthly – with two exceptions: Belgium and The Netherlands publish these values only yearly.

Although the CEN standard has proposed the harmonisation of several parameters relating to natural gas quality, a common WI range could not be defined because of different regulations in CEN MS and limited knowledge of the influence of broadening WI range on integrity, efficiency and safe use of appliances in some countries. Table 6-5 and Table 6-6 present Gross Calorific Value and Relative Density standards used by countries and their monitoring frequency.

197 Based on normal reference condition 25°C/0°C.
198 For connected companies, authorities and shippers / for others.
199 Based on standard reference condition 15°C/15°C.
200 Based on standard reference condition 15°C/15°C.
201 Depending on the yearly energy consumption.
202 Average of the hourly values.
203 Based on normal reference condition 20°C/25°C.
204 Depending on the flow rate.

TABLE 6-5: Gross Calorific Value range and monitoring frequency

Gross Calorific Value	Min	Max	Unit	Measurement frequency	Publication frequency
BA	31,088.35	≥35,588.35	kJ/m^3	Daily	NA
BE	9.61	12.79	kWh/m^3 [205]	Continuously	Hourly
BG	10	12.7	kWh/m^3	Hourly	Hourly
CZ	9.04	11.08	kWh/m^3 [206]	Continuously	Daily (by TSO)
EE	9.69	NA	kWh/m^3	Continuously	Monthly
EL	10.174	13.674	kWh/m^3	5 minutes	Daily
ES	10.26	13.26	kWh/m^3	Daily	Daily
FI	No limit	No limit	MJ/m^3	Yearly	Yearly
FR	10.7	12.8	kWh/m^3	5 minutes	Daily
GE	35	NA	MJ/m^3	Daily	Daily
HR	10.28	12.75	kWh/m^3	Twice per month	Twice per month
HU	8.61	12.58	kWh/m^3	4 minutes	Daily
IE	36.9	42.3	MJ/m^3	Continuously	Hourly
LT	10.41	NA	kWh/m^3	Daily	Daily
LV	≥9.69	≥8.83	kWh/m^3	Continuously	Daily
MK	34,357	34,693	kJ/m^3	4 minutes	Not published
PL	34.00	No limit	MJ/m^3	Hourly	TSO: daily and monthly DSO: monthly
PT	No limit	No limit	kWh/m^3	Hourly	Monthly
RO	32.8	52.15	MJ/m^3	Daily/every 10 days/ monthly [207]	Daily
SE	10.911 [208]	12.211 [208]	kWh/m^3		Hourly
SI	11.3	11.36	kWh/m^3	4 minutes	Hourly/Daily/Monthly
SK	9.3	NA	kWh/m^3	NA	NA
UA	36.2	38.3	MJ/m^3 [209]	Daily/Weekly [210]	Monthly

TABLE 6-6: Relative Density range and monitoring frequency

Relative Density	Min	Max	Measurement frequency	Publication frequency
BA	0.55	0.75	Daily	System operator's responsibility
BE	NA	NA	Continuously	Daily/Yearly [211]
CZ	0.56	0.70	Continuously	Monthly
EE	0.55	0.75	5 minutes	Monthly
EL	0.56	0.71	5 minutes	Daily
ES	0.555	0.7	Daily	Daily
FR	0.555	0.7	5 minutes	Not published
GE	0.56	0.71	Daily	Daily
HR	0.56	0.7	Twice per month	Twice per month
HU	No limit	No limit	4 minutes	Not published
IE			Continuously	Monthly
LT	0.55	0.7	NA	NA
LV	0.55	0.7	Continuously	Daily
MK	0.699	0.708	4 minutes	Not published
PL	0.5	0.7	Daily	Monthly
PT	0.5549	0.7001	Hourly	Monthly
RO	NA	NA	Daily/every 10 days/monthly [212]	No obligation
SI	0.5818	0.5878	4 minutes	Not published
SK	0.555	0.7	NA	NA

205 Based on normal reference condition 25°C/0°C.
206 Based on normal reference condition 15°C/15°C.
207 Depending on the yearly energy consumption.
208 https://www.swedegas.com/Our_services/services/heat_values
209 Based on normal reference condition 20°C/25°C.
210 Depending on the flow rate.
211 For connected companies, authorities and shippers / for others.
212 Depending on the yearly energy consumption.

Since the relative density range is almost the same in all countries and nearly in line with the values 0.555 to 0.7 advocated by the CEN standard, a similar spread for Gross Calorific Value to that of the WI might be observed. This is because the Gross Calorific Value is equal to the WI multiplied by the square root of the relative density (see definition of WI in Section 6.3.2). Interestingly, Slovenia has a very narrow bandwidth of minimum and maximum values of only 0.06 kWh/m³ for Gross Calorific Value and 0.006 points for Relative Density. North Macedonia also reported a very narrow range of Relative Density of 0.009 points.

6.3.5 Water and Hydrocarbon Dew Point

In the compressed air industry, dew point is always a measurement of water content. However, in the natural gas industry, dew point often refers to Hydrocarbon Dew Point. Table 6-7 presents the maximum limit of Water Dew Point for each country.

TABLE 6-7: Water/Hydro Dew Point range and monitoring frequency

Water Dew Point	Max	Unit	Measurement frequency	Publication frequency
BA	-5	°C	Daily	System operator's responsibility
BE	-8 / -2 [213]	°C	Continuously	Not published
BG	-8	°C	Daily	Daily
CZ	-7	°C [214]	Continuously	Monthly
EE	-8	°C	Continuously	Monthly
EL	5	°C [215]	5 minutes	Daily
ES	2	°C [216]	Daily	NA
FR	-5	°C	NA	NA
GE	-5	°C	NA	NA
HR	-8	°C	Twice per month	Twice per month
HU	4	°C	NA	NA
IE	-2	°C [217]	Continuously	Monthly
LT	-10	°C [218]	NA	NA
LV	-10	°C	Continuously	On request
MK	-17 [219]	°C	4 minutes	Not published
NL	-8	°C [220]	5 minutes	Yearly
PL[221]	-5.0/+3.7	°C	Daily	Monthly
RO	-15 (Water) 0 (Hydrocarbon)	°C	Daily/every 10 days/monthly[222]	No obligation
RS	-5	°C [223]	NA	NA
SI	NA [224]	°C [225]	10 minutes	Not published
SK	-8	°C [226]	NA	NA
UA	-8	°C [227]	Daily/Weekly[228]	Monthly

Multiple countries that delivered answers to this question have reported a maximum limit that is higher than the CEN standards recommendation for this parameter, which is -8°C for water and -2°C for hydrocarbon, with three of them (EL, ES, HU) having a positive maximum limit for this parameter, which appears to be far from the CEN standards recommendations. Poland was not included in the three countries with a positive maximum limit since its limit is negative between 1 October and 31 March.

The results are somewhat difficult to compare, as the maximum allowable temperature may vary according to pressure as stated by the Czech Republic, Greece, Ireland, Spain and other countries (see footnotes in Table 6-7).

6.3.6 Chemical content

Gas usually contains a small amount of sulphur as a result of decaying organic substances. This can be as hydrogen

213 At a pressure of 69 bar g / up to a pressure of 69 bar g.
214 At a pressure of 40 bar.
215 At a reference pressure of 80 bar g.
216 At a pressure of 70 bar.
217 Up to 85 bar g.
218 At a reference pressure of 4 MPa.
219 Minimum value of -19°C.
220 At a reference pressure of 70 bar.
221 At a reference pressure of 5.5 MPa. The maximum from 1 April to 30 September is +3.7, the maximum from 1 October to 31 March is -5.0.
222 Depending on the yearly energy consumption.
223 At a reference pressure of 40 bar.
224 Minimum value of -24°C.
225 At a reference pressure of 50 bar g.
226 At a reference pressure of 4 MPa.
227 At a reference pressure of 3.92 MPa.
228 Depending on the flow rate.

sulphide, carbonyl sulphide, mercaptans, and/or other kind of sulphides, depending on the origin of the gas and its treatment.

Furthermore, the majority of artificial odorants contain strong sulphur organic compounds. These odorants are added to nearly all distribution grids and also to some transmission grids to give gas a smell for the purpose of leak detection.

In some gas storage facilities, higher sulphur contents can lead to serious problems such as increased corrosion rates, degradation of glycol, disposal of produced water and higher sulphur dioxide content in exhaust gases.

Table 6-8 presents the maximum acceptable sulphur content for each country.

TABLE 6-8: Total Sulphur range and monitoring frequency

Total Sulphur	Max	Unit	Measurement frequency	Publication frequency
BA	20	mg/m^3	Daily	System operator's responsibility
BE	30	mg/m^3 [229]	Continuously	Daily/Yearly [230]
CZ	30	mg/m^3	Continuously	Monthly
EE	0.03	g/m^3	NA	Monthly
EL	80	mg/Nm^3	5 minutes	Daily
ES	50	mg/m^3	Daily	NA
FR	150	mg/m^3	5 minutes	Daily
HR	30	mg/m^3	Twice per month	Twice per month
HU	100	mg/m^3	4 minutes	Daily
IE	50	mg/m^3	Monthly	Monthly
LT	0.03	g/m^3	NA	NA
LV	0.03	g/m^3	Continuously	On request
NL	30	mg/Nm^3	Sporadic sample	Yearly
PL	40	mg/Nm^3	Daily	Monthly
PT	50	mg/m^3	Hourly	Monthly
RO	100	mg/m^3	Daily/every 10 days/monthly [231]	No obligation
RS	20	mg/m^3	Daily	NA
SI	1.2 [232]	mg/Nm^3	3 minutes	Not published
SK	30	Mol-%	NA	NA

As recommended by the CEN standard, the maximum acceptable sulphur content for conveyance should be 20 mg/m^3 in HP networks non-odorised gas. However, with respect to transmission of odorised gas between HP networks, a higher sulphur content value up to 30 mg/m^3 may be accepted.

For some countries, the maximum amount of sulphur exceeds the CEN standard of 20 mg/m^3. In past editions of this Report, few countries indicated that the gas was odorised at the transmission level, which was an explanation for some very high sulphur values. For countries that do add odorant to the gas (either on distribution or transmission level), the amount is provided in Table 6-9 below.

229 Based on normal reference condition 25°C/0°C.
230 For connected companies, authorities and shippers / for others.
231 Depending on the yearly energy consumption.
232 With a minimum value of 0.05.

TABLE 6-9: Odorant range and monitoring frequency

Odorant	Min	Max	Unit	Measurement frequency	Publication frequency
BE	NA	NA	NA	2 to 4 times a year [233]	Not published
ES	18	22	mg/m^3	Daily	NA
FR	15	40	mg/m^3	NA	NA
GE	16	NA	mg/m^3	NA	NA
HU	11.97 / 14.4 [234]	14.63 / 17.6 [234]	$mg/1000m^3$	Twice per year	Not published
IE	1.7	2.2	Olfactory degree [235]	Monthly	Monthly
LV	3	NA	mg/m^3	Continuously	On request
NL	10	40	mg/m^3	Every three weeks [236]	Yearly
RO	8	24	mg/m^3	Continuously	No obligation
SI	10	40	mg/m^3	Twice per month / monthly / twice per year [237]	Not published
UA	5	16	$g/1000m^3$	Continuously	Not published

Hungary is the only country that requires different values during winter and summer.

As stated in the previous chapter, the odorisation level in Poland (in distribution systems up to 0.5 MPa) is measured at least once in 14 days.

Table 6-10 and Table 6-11 present the maximum Hydrogen Sulphide and Mercaptan Sulphur values applied by countries. The CEN standards are 5.0 mg/m^3 for the former and 6.0 mg/m^3 for the latter.

TABLE 6-10: Hydrogen Sulphide (H_2S) maximum value and monitoring frequency

Hydrogen sulphide (H_2S)	Max	Unit	Measurement frequency	Publication frequency
BA	5	mg/m^3	Daily	System operator's responsibility
BE	5	mg/m^3 [238]	Continuously	Daily/Yearly [239]
BG	NA	%	Daily	Daily
CZ	6	mg/m^3	Continuously	Monthly
EE	0.007	g/m^3	NA	Monthly
EL	5.4	mg/Nm^3	5 minutes	Daily
ES	15	mg/m^3	Daily	NA
FR	5	mg/m^3	5 minutes	Daily
GE	20	mg/m^3	Daily	NA
HR	5	mg/m^3	Twice per month	Twice per month
HU	20	mg/m^3	4 minutes	Daily
IE	5	mg/m^3	Monthly	Monthly
LT	0.007	g/m^3	NA	NA
LV	0.007	g/m^3	Continuously	On request
NL	5	mg/Nm^3	5 minutes	Yearly
PL	7	mg/Nm^3	Daily	Monthly
PT	5	mg/m^3	Hourly	Monthly
RO	6.8	mg/m^3	Daily/every 10 days/ monthly [240]	No obligation
RS	5	mg/m^3	Daily	NA
SI	0.18	mg/Nm^3	3 minutes	Not published
SK	2	% mol	NA	NA
UA	0.006	g/m^3	Daily/Weekly [241]	Monthly

233 Measure done by Gas.be laboratory on behalf of DSOs
234 Winter / Summer
235 Unit of measure of the odour intensity which is proportional to the logarithm of the odorant concentration. Various scales have been proposed for expressing the odour intensity of substances. The gas industry refers frequently to the scale proposed by Sales which refers to trained persons. (see: https://www.iso.org/obp/ui/#iso:std:iso:tr:16922:ed-1:v1:en)
236 At every odorisation location.
237 Depending on DSO.
238 Based on normal reference condition 25°C/0°C.
239 For connected companies, authorities and shippers / for others.
240 Depending on the yearly energy consumption.
241 Depending on the flow rate.

TABLE 6-11: Mercaptan Sulphur maximum value and monitoring frequency

Mercaptan Sulphur	Max	Unit	Measurement frequency	Publication frequency
BA	5.6	mg/m^3	Daily	System operator's responsibility
BG	NA	%	Daily	Daily
CZ	5	mg/m^3	Continuously	Monthly
EE	0.016	g/m^3	NA	Monthly
ES	17	mg/m^3	Daily	NA
FR	6	mg/m^3	5 minutes	Daily
GE	36	mg/m^3	Daily	NA
HR	6	mg/m^3	Twice per month	Twice per month
HU	No limit		4 minutes	NA
IE	No limit	mg/m^3	Monthly	Monthly
LT	0.016	g/m^3	NA	NA
LV	0.016	g/m^3	Continuously	On request
PL	16	mg/m^3	Daily	Monthly
PT	No limit	mg/m^3	Hourly	Monthly
RO	24 [242]	mg/m^3	Continuously	No obligation
RS	5.6	mg/m^3	Daily	NA
SI	0.8 [243]	mg/Nm^3	3 minutes	Not published
SK	5	% mol	NA	NA
UA	0.02	g/m^3	Daily/Weekly [244]	Monthly

There are countries where the CEN standards are considerably exceeded, but, as stated before, high values in some reporting countries may be due to gas odorisation at the transmission level.

6.4 CONCLUSIONS

As the 6th Benchmarking Report was published in 2016, the European Commission had signalled its intent to amend the INT NC [92] by including CEN standards EN 16726 [95]. By that time (December 2015), the European Commission invited ENTSOG to carry out a detailed analysis of the CEN standard and the consistency with the provisions of the INT NC, covering the whole gas value chain in relevant EU MS and based on the result, submit to the Agency for the Cooperation of Energy Regulators (ACER) an amendment proposal.

As requested, ENTSOG concluded a detailed impact analysis of EN 16726. The analysis has shown that a whole EU chain implementation of the EN 16726, despite providing certainty on the rules and removing any contracting difficulties, would face significant legal barriers and produce widespread negative impacts across segments of the gas supply chain and MS.

In an associated consultation process, the stakeholder community expressed concerns that security of supply could be compromised by reduced access to existing or new sources. They argued that it could lead to a situation where supply routes with currently accepted gas qualities could be rejected if the standard were to be applied. Stakeholders saw the additional risk that competitiveness could be impaired by less efficient cross-border trade and reduced available gas sources and market liquidity. It should be noted, that neither in that process nor in the monitoring of the INT NC, evidence of cross-border trade restrictions has been revealed.

Additionally, the consultation process has shown that a revision of the values in the standard would not substantially increase its acceptance. Furthermore, as the consultations have confirmed the lack of support for binding provisions, a voluntary adoption scenario may not be risk-free.

Moreover, it became clear that an uncertain future of a legal framework would add uncertainty in the complementary efforts by CEN to find a European agreement on WI, as a consistent definition of this parameter would be key for safety and necessary for a complete gas quality standard.

242 Lower limit of 8.
243 Lower limit of 0.05.
244 Depending on the flow rate.

After all, ENTSOG has recommended not to amend the INT NC. The analysis has shown that a reference to CEN standards is not needed as it would bring little added value and perhaps limit the possibility to adapt the standard to future needs.

In October 2016, the European Commission announced at the Madrid Forum its intention not to pursue legally binding provisions for the standards.

Regarding WI, the stakeholder community welcomed an examination of current practices and a vision of future supplies. The European Commission declared to reconsider harmonisation, if an agreement for WI which may include regional differences is reached.

Nevertheless, even without a legally binding standard, this chapter shows that many countries already rely on the CEN standards, which – in the long term – might contribute to reducing restrictions in cross-border gas flows and increasing commercial market efficiency.

07

GAS – COMMERCIAL QUALITY

7 GAS – COMMERCIAL QUALITY

7.1 WHAT IS COMMERCIAL QUALITY AND WHY IS IT IMPORTANT TO REGULATE IT?

In a liberalised natural gas market, a customer has either a single contract with a supplier or separate contracts with a supplier and a DSO, depending on the national regulations. In both cases, CQ is an important issue.

CQ is directly associated with transactions between gas companies (either DSOs or suppliers, or both) and customers. CQ covers not only the supply and sale of gas, but also various forms of contacts established between gas companies and customers. New connections, disconnection upon customers' request, meter reading and verification, repairs and elimination of pressure problems and claims processing are all services that involve some CQ aspect. The most frequent CQ aspect is the timeliness of services requested by customers.

Where it concerns the need for CQ indicators, a distinction should be made between the deregulated market of natural gas energy and the regulated market of network operation. An energy NRA does not generally intervene in the deregulated market, as competition between retailers is expected to result in the sufficient quality. However, in some cases, a certain level of customer protection is needed. The need for such protection differs among different types of customers.

Network operators (i.e. the regulated market) are natural monopolies, free or almost free from competition. CQ indicators help ensure a sufficient level of quality of service by network companies. In some countries, a regulatory framework based on financial incentives (e.g. a bonus/penalty system) has been set: if the operator's performance reaches the quality level expected, it can be awarded a bonus, and if not, it will have to pay a penalty and/or compensation to the affected customer. Numerous CQ aspects (e.g. times for connections) in the deregulated market of natural gas energy are also related to distribution networks and therefore, given their monopolistic nature, should still be regulated.

EU legislation provides a framework for CQ measures. Directive 2009/72/EC and Directive 2009/73/EC [96], [75] require that MS take appropriate measures to protect final customers, to ensure that they:

- Have a right to a contract with their gas service provider that specifies: the services provided, the service quality levels offered, as well as the time needed for the initial connection; any compensation and the refund arrangements which apply if contracted service quality levels are not met, including inaccurate and delayed billing; and information relating to customer rights, including on complaint handling and all of the information referred to in this point, clearly communicated through billing or website; and
- Benefit from transparent, simple and inexpensive procedures for dealing with their complaints. In particular, all customers shall have the right to a good standard of service and complaint handling by their electricity/natural gas service provider.

Based on these Directives, the national authorities have a duty to monitor the time taken by TSOs and DSOs to make connections and repairs. While these requirements concern the regulated part of energy markets, their functioning is essential for retail markets as a whole. Therefore, it is important to monitor these key services and their timely provision by the system operators so as to provide a full picture of market functioning from a customer perspective.

7.2 STRUCTURE OF THE CHAPTER ON GAS COMMERCIAL QUALITY

The 6th Benchmarking Report [6] was the first CEER Benchmarking Report that included chapters focusing on the quality of gas supply. For that Report, 17 CEER countries provided data for gas CQ indicators. This 7th Benchmarking Report adopts a similar structure regarding CQ by presenting a list of indicators followed by illustrating approaches to regulating gas CQ. In comparison with the 6th Benchmarking Report, the list of indicators is now shorter since the results of the previous Report revealed that many indicators are not monitored in some responding countries. Consequently, the 7th Benchmarking Report includes only the most frequently used indicators and categorises them into five groups.

The contents of this chapter are based on answers provided by 29 countries: Austria, Belgium, Bosnia and Herzegovina[245], Bulgaria, Croatia, the Czech Republic, Estonia, Finland, France, Georgia, Germany, Great Britain, Greece, Hungary, Ireland, Latvia, Lithuania, Luxembourg, the Netherlands, North Macedonia, Poland, Portugal, Romania, Serbia, Slovakia, Slovenia, Spain, Sweden and Ukraine. A summary of indicators and compensations is presented in Section 7.4, organised by main groups of CQ aspects. The results of benchmarking are provided in Section 7.5.

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7.3 MAIN ASPECTS OF GAS COMMERCIAL QUALITY

As in electricity, commercial transactions between gas companies and customers are traditionally classified as follows:

- Pre-contract transactions, such as information on connection to the network and prices associated with the supply of gas. These actions occur before the supply contract comes into force and incorporate actions by both the DSO and the supplier. Generally, customer rights with regard to such actions are set out in codes (such as connection agreements and the general conditions of supply contracts) and are approved by the NRA or other governmental authorities; and
- Transactions during the contract period, such as billing, payment arrangements and responses to customers' complaints. These transactions occur regularly (billing and meter readings, for instance) or occasionally (when a customer contacts a company with a query or a complaint).

The quality of service during these transactions can be measured by the time the company needs to provide a proper reply. These transactions could relate to the DSO, the supplier/universal supplier or to the MO and could be regulated according to the regulatory framework of a particular country. This chapter focuses on all types of gas customers with connections to LP, MP or HP networks.

7.3.1 Main groups of gas commercial quality indicators

To simplify the approach to such a complex matter as CQ, indicators relating to gas CQ have been classified into five main groups:

- Customer care (Group I);
- Grid access (Group II);
- Activation, deactivation, and reactivation of supply (Group III);
- Metering (Group IV); and
- Invoices (Group V).

7.3.2 Commercial quality indicators and their definitions

The CQ of gas was first evaluated in the 6th Benchmarking Report [6]. In this 7th Benchmarking Report, 'standard' once again refers to the minimum levels of service quality, as defined by the NRAs, that a company is expected to deliver to its customers. Indicators are defined as a way to measure dimensions of service quality. NRAs can define standards for indicators, or they can define indicators without standards and simply publish the indicator values of the companies. Therefore, 'overall' or 'guaranteed' describes the indicators, not the standards, because 'overall' and 'guaranteed' refers to the nature of the indicator. A standard is a limit, a value (e.g. a percentage). As is the case with electricity, three types of indicators are used for gas CQ: GIs, OIs and ORs.

For example, as illustrated in Figure 7-1 below, for the OI 'time to respond to a customer request for a new grid connection', the time taken to respond to a household customer request for a connection to the grid should not exceed two working days in a specific country. The response should inform the customer of the process, the estimated schedule and requests for information required from the customer, including contact details. For the standard in the example below, the time taken to respond to a customer request for a connection to the grid should not exceed two working days in 90% of the cases.

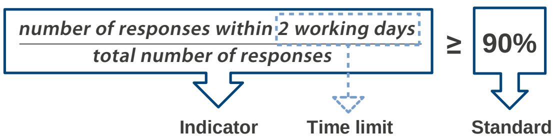

FIGURE 7-1: Example of a CQ indicator and standard (gas)

Table 7-1 shows the gas CQ indicators included in the survey and their definitions for the purpose of this 7th Benchmarking Report.

TABLE 7-1: CQ indicators surveyed (gas)

Group	Indicator	Definition
I. Customer care	I.1 Time for response to customer request and/or complaint	Time period between the receipt of customer's request or complaint and the response to it.
	I.2 Punctuality of appointments with customers	The personnel appear at the customer site within the time range (period of hours) previously agreed with the customer.
	I.3 Time limit for waiting in customer centres	Time period between the arrival of a customer and the answer given by the customer centre employee.
	I.4 Time limit for waiting in call centres (telephone contact)	Time period between the receipt of customer's call and the answer given by the call centre operator (telephone contact).
	I.5 Obligation for DSO regarding response time in emergency situations	Punctuality of appointments with customers regarding time limit between the receipt of emergency call and DSO's response.
II.Grid access	II.1 Time duration of connecting customers to the network	Time period between the receipt of customer's claim for connection and the date the customer is connected to network.
III. Activation, deactivation, reactivation of supply	III.1 Time for activation of supply following a request	Time period between the receipt of customer's request for activation and the activation of supply.
	III.2 Time for deactivation of supply following a request	Time period between the receipt of customer's request for deactivation and the deactivation of supply
	III.3 Time for reactivation of supply after payment (for bad payers previously disconnected)	Time period between the receipt of customer's payment for reactivation (for bad payers previously disconnected) and the reactivation of supply
IV. Metering	IV.1 The percentage of gas meters not installed in due time	Number of gas meters not installed in due time with respect to the total number of meters installed as a result of customers' requests.
	IV.2 Time for meter verification	Time period between customer's notification about a meter problem and the inspection of the meter.
	IV.3 Minimum frequency of meter readings per year	-
V. Invoices	V.1 Percentage of invoices submitted in due time	Number of invoices submitted in due time with respect to the total number of invoices.
	V.2 Time to switch supplier on customer request	Time period between the receipt of customer's written request to switch their supplier and the date the switch takes effect.

7.3.3 How to regulate commercial quality

For this 7th Benchmarking Report, there are three types of requirements for CQ:

- **Guaranteed Indicators (GIs)** refer to service quality levels which must be met in each individual case. If the company fails to provide the level of service required by the GI for a specific service, the customer affected must receive **compensation**. Usually, a GI includes the following features:
  - A performance standard, which sets the expected level of service for each case (e.g. five working days); and
  - Economic compensation to be paid to the customer in the case of failure to comply with the requirements (e.g. €20).
- **Overall Indicators (OIs)** refer to a given set of cases (e.g. all customer requests in a given region for a specific service) and are used as a metric with respect to the whole population in that set. In some cases, a **penalty** has to be paid whenever companies' performances are not up to a standard set for a given indicator. OIs usually include the following features:
  - A time limit that sets a reasonable period for the completion of a specific service (e.g. 20 working days); and
  - A performance standard (commonly a given percentage of cases), which has to be met for a whole set of customers (e.g. 90% of new customers have to be connected to the distribution network within 20 working days).
- **Other Requirements (ORs).** In addition to GIs and OIs, NRAs (and/or other competent parties) can issue requirements to achieve a certain quality level of service that are not easily classified as either GI or OI. These quality levels can be set as the NRA wishes, e.g. a minimum set of information that must be given to customers when they are connected. If the requirements set by the NRAs are not met, the NRA could impose sanctions (e.g. financial penalties) in most cases.

7.4 MAIN RESULTS OF BENCHMARKING COMMERCIAL QUALITY INDICATORS

7.4.1 Commercial quality indicators applied

This chapter on CQ illustrates, among other findings, financial rewards and/or penalties applied across Europe. For the countries that do not use euro as currency, the amount in original currency was used, followed by the approximate (but not exact) amount in euros in parentheses. The only exception is Poland which provided answers in euros even though a different currency is used in that country. Moreover, when providing a range of monetary amounts, euros (without the original currency) were always used in this chapter as the only way to compare responses. With the exception of Table 7-2, Finland is absent from tables in this chapter since its target levels are not specifically set by the NRA or are vague. Most of them are in legislation without specific levels or are set out in a contract between an operator and a consumer. The Finnish Safety and Chemicals Agency (Tukes) handles specific technical and safety aspects of the gas networks. For this reason, specific answers for this chapter could not be provided by Finland.

It is also important to state that the results of the 6th [6] and 7th Benchmarking Reports are difficult to compare as they relate to different sets of countries and the questionnaires were different.

Table 7-2 shows whether a country monitors or applies a requirement (GI, OI or OR) for the different CQ aspects. In the last column, the total number of countries where a specific indicator is in use is shown. Note that countries using multiple types of indicators are counted multiple times when calculating the total number (e.g. Portugal for indicator I.1).

The most common groups of indicators among the NRAs are the ones concerning customer care (Group I) and activation, deactivation, reactivation of supply (Group III) issues. The most common indicators monitored are the 'time for response to customer request and/or complaint' (indicator I.1, 26 instances with 24 different NRAs) and 'time duration of connecting customers to the network' (indicator II.1, 23 instances with 22 NRAs). In addition, four other indicators are in use in more than half the responding countries. These are 'time for activation of supply following a request' (indicator III.1), 'time for reactivation of supply after payment' (indicator III.3), 'minimum frequency of meter readings per year' (indicator IV.3) and 'time to switch supplier on customer request' (indicator V.2).

Three times as many countries use an indicator for the time customers spend waiting in call centres (in other words, on the phone) than for the time customers spend physically waiting in customer centres. Since there is no information on what type of requirements countries use for their frequency of meter readings (indicator IV.3), the table simply points out the countries where such a requirement exists and marks them with an 'x'. This explains why the sum of indicators in Table 7-2 (a total of 168) is higher than in Table 7-4, Table 7-18 and Table 7-19 (a total of 150), as those tables do not include the minimum frequency of meter readings.

TABLE 7-2: Summary of countries that employ CQ indicators (gas)

Group	Indicator	AT	BA	BE	BG	CZ	DE	EE	EL	ES	FI	FR	GB	GE	HR	HU	IE	LT	LU	LV	MK	NL	PL	PT	RO	RS	SE	SI	SK	UA	Total
I. Customer care	I.1 Time for response to customer request and/or complaint	OI		OR	OR	GI		OR	OR	OR		OI	GI	GI	OI	GI	OR	OI	GI	OR	OR	OR	GI	GI OI OR	GI	OR		GI		GI	**26**
	I.2 Punctuality of appointments with customers	OI										GI			GI	GI	GI							GI							**6**
	I.3 Time limit for waiting in customer centres															OI								OI							**2**
	I.4 Time limit for waiting in call centres (telephone contact)											OI		OI		OI	OR							OI	OI						**6**
	I.5 Obligation for DSO regarding response time in emergency situations	OR	OR	OR					OR				OI		OI		OI	OR	GI					OI							**10**
II. Grid access	II.1 Time duration of connecting customers to the network	OI	OR	OR		OR			OR	OR		OI	GI	GI	GI	GI		OR	OI		OR	OR		GI	OR	OR	OR	OI	GI OI	GI	**23**
III. Activation, deactivation, reactivation of supply	III.1 Time for activation of supply following a request	OI	OR	OR		GI			OR	OR		OI		GI						OR	OR			GI		OR		GI	GI OI	GI	**16**
	III.2 Time for deactivation of supply following a request		OR	OR	OR	OR			OR			OI		GI	GI				OI		OR			GI		OR				GI	**13**
	III.3 Time for reactivation of supply after payment (for bad payers previously disconnected)	OI	OR		OR	GI			OR	OR				GI	GI	GI			OI	OR	OR			GI		OR		GI	GI OI	GI	**18**
IV. Metering	IV.1 The percentage of gas meters not installed in due time	OI				GI								GI																	**3**
	IV.2 Time for meter verification					GI								GI	OR	GI								GI		OR			GI OI	GI	**9**
	IV.3 Minimum frequency of meter readings per year	x	x	x	x	x	x			x	x	x			x	x	x		x			x			x	x		x	x		**18**
V. Invoices	V.1 Percentage of invoices submitted in due time	OI	OR													OR															**3**
	V.2 Time to switch supplier on customer request		OR	OR	OR	GI		OR		OR		OI			OR			OR					OR	OR	OR		OR	OR		OR	**15**
Total number of indicators per country		**9**	**8**	**7**	**5**	**9**	**1**	**2**	**6**	**6**	**1**	**8**	**3**	**8**	**9**	**9**	**5**	**4**	**6**	**3**	**5**	**3**	**2**	**13**	**5**	**7**	**2**	**6**	**9**	**7**	**168**

In Table 7-3, the number of various CQ indicators is shown together with the type of company they refer to (DSO, SP, USP and MO). The highest number of indicators is used for DSOs, followed by suppliers/universal suppliers and TSOs. Responses to the questionnaire revealed that there are very few indicators used for MOs.

TABLE 7-3: Number of CQ indicators (GI, OI, OR) per group and per company type (gas)

Group	Indicator	DSO	SP/ USP	MO	TSO	Total
I. Customer care	I.1 Time for response to customer request and/or complaint	23	14	1	12	**50**
	I.2 Punctuality of appointments with customers	6	1	1		**8**
	I.3 Time limit for waiting in customer centres	2	2			**4**
	I.4 Time limit for waiting in call centres (telephone contact)	6	4	1	1	**12**
	I.5 Obligation for DSO regarding response time in emergency situations	10	1		3	**14**
II. Grid access	II.1 Time duration of connecting customers to the network	21			8	**29**
III. Activation, deactivation, reactivation of supply	III.1 Time for activation of supply following a request	14	4		4	**22**
	III.2 Time for deactivation of supply following a request	12	5		2	**19**
	III.3 Time for reactivation of supply after payment (for bad payers previously disconnected)	15	7		3	**25**
IV. Metering	IV.1 The percentage of gas meters not installed in due time	3				**3**
	IV.2 Time for meter verification	8			4	**12**
V. Invoices	V.1 Percentage of invoices submitted in due time	2	2		1	**5**
	V.2 Time to switch supplier on customer request	11	11		4	**26**
Total		**133**	**51**	**3**	**42**	**229**

Table 7-4 shows the number of CQ indicators per country, distinguishing between GIs, OIs and ORs. The results show that NRAs make more use of ORs and GIs. From the customer protection point of view, the most efficient regulation is based on GIs, or OIs with minimum requirements set by the NRA where sanctions can be issued. Croatia, Hungary, Ireland, Portugal, Romania and Slovenia are the countries where all three indicator types are used. In addition, seven other countries apply two types of indicators as presented in the table below.

TABLE 7-4: Number of CQ indicators surveyed (gas)

Country	GI	OI	OR	Total
Austria		7	1	**8**
Belgium			6	**6**
Bosnia and Herzegovina			7	**7**
Bulgaria			4	**4**
Croatia	4	2	2	**8**
Czech Republic	6		2	**8**
Estonia			2	**2**
France	1	6		**7**
Georgia	7	1		**8**
Great Britain	2	1		**3**
Greece			6	**6**
Hungary	5	2	1	**8**
Ireland	1	1	2	**4**
Latvia			3	**3**
Lithuania		1	3	**4**
Luxembourg	2	3		**5**
Netherlands, The			2	**2**
North Macedonia			5	**5**
Poland	1		1	**2**
Portugal	7	4	2	**13**
Romania	1	1	2	**4**
Serbia			6	**6**
Slovakia	4	4		**8**
Slovenia	3	1	1	**5**
Spain			5	**5**
Sweden			2	**2**
Ukraine	6		1	**7**
Total	**50**	**34**	**66**	**150**

7.4.2 Group I: Customer care

This Group concerns CQ indicators that are related to customer care, especially contacts with customers, which can be in written form through letters, appointments with customers, or through customer centres, call centres etc. As shown in Table 7-5, many countries apply indicators (GI, OI or OR) for this quality aspect.

TABLE 7-5: Types of indicators used in Group I (gas)

Indicator		Countries grouped by types of indicators in 2018			Time limit	Compensation (median value and range)	Company involved
		GI	OI	OR	2018	2018	
I.1	Time for response to customer request and/or complaint	CZ, GB, GE, HU, LU, PL, PT, RO, SI, UA	AT, FR, LT, HR, PT	BE, BG, EE, EL, ES, IE, LV, MK, NL, PT, RS	Median: 15 days Range: 1 working day -30 days	€20[246] (range: €1.7-€308)	DSO, USP/SP, MO, TSO
I.2	Punctuality of appointments with customers	HR, HU, IE, FR, PT	AT		Median: 2.2 hours Range: 2-4 hours		DSO, USP/SP, MO

The most common indicator applied by the majority of countries (24 countries with 26 different instances of this indicator) relates to response time to customer requests and/or complaints. Complaints and requests are an important tool to take into account customers' expectations. A claim is a written or oral expression of discontentment from a network user. The analysis of the customers' complaints (cause, frequency, volume, etc.) or requests can allow the apprehension and improvement of the quality of services perceived by the customer. The time to treat a complaint/request and the quality of response are major issues in CQ.

Most of the responding countries monitor the response time for both complaints and requests. Several countries monitor the response time only for complaints (Czech Republic, Ireland, Luxembourg, Spain) or requests (Belgium). In France, 100% of complaints must be answered within 30 days and there are only financial penalties, but no compensation involved. The penalty for each complaint or request that is not answered within 30 days is 25 euros. The total penalty regarding this indicator cannot exceed 18,000 euros per year.

Concerning the time for response to a customer request and/or complaint, the time limits vary from one working day to 30 calendar days, with a median value of 15 days. In most countries, these time limits are applied for customers on all pressure levels (LP, MP, HP).

Ten reporting countries use compensation for non-compliance with the prescribed time limits (see Table 7-7). The level of the compensation payments for this quality aspect varies from €1.7[246] (Georgia) to €308 (Czech Republic) and in some countries depends on customer type or type of request/claim, as is the case in the Czech Republic, Romania and Hungary. In case of non-payment or late payment of compensation, the company is penalized (Georgia, Poland) or the level of the compensation is significantly increased (Czech Republic, Slovenia, Ukraine). In the Czech Republic, for instance, the penalty doubles each day up to a maximum of 158,000 CZK (approx. €6,161)[247].

In Portugal, a combination of different types of requirements (GI, OI, OR) is used, depending on the type of claim (request or complaint) or the companies involved. There is an OI (average time of response) for TSOs, storage system operators and LNG operators regarding response to requests, and another indicator regarding response to complaints. There are no standards to be fulfilled for these entities. For the DSO, USP and SP, there is an OI regarding written requests (which must be answered within 15 working days), with a standard of 90%. For the DSO, USP and SP, there is a GI regarding complaints. For the DSO and USP, complaints must be answered within 15 working days. For suppliers, the time limit is set in the contract and cannot be longer than 15 working days. Compensation is €20 for DSOs and USPs. For SPs, it is set in the contract and cannot be less than €5.

For 'punctuality of appointments with customers' (I.2), five reporting countries (Croatia, Hungary, Ireland, France, Portugal) use GIs while Austria uses an OI (see Table 7-8 for more information on criteria and obligations). Time limits vary from two hours (in Austria and Croatia) to four hours (in Hungary), with a median value of two hours.

The compensation for non-compliance for indicator 'punctuality of appointments with customers' is €16-€94 in Hungary (depending on the type of meter a customer has). In Ireland, the compensation for failing to attend an appointment at the agreed time or failing to notify the customer of cancellation, at least by the working day before the appointment day, is €50.

246 The median values and ranges of compensation also include countries that do not use euro as currency. Throughout this chapter, the exchange rates used are from mid-2020 which might differ from exchange rates used in other chapters due to prolonged preparation of this Benchmarking Report.
247 Chapters on CQ also include the monetary amounts for countries that do not use euro as currency. In some cases, the amount in original currency is shown (as provided by the responding country), followed by an approximate amount in euros in parentheses. In this chapter, the exchange rates used are from mid-2020 which might differ from exchange rates used in other chapters due to prolonged preparation of this Benchmarking Report.

TABLE 7-6: Examples of criteria and obligations by which the response to customer request and/or complaint is monitored

Country	Limit	Company involved	Standard that must be met	Number of cases for which the limit was fulfilled (2018)	Value of the indicator (2018)	Pressure levels	Request / complaint
Austria	5 working days	DSO	95%	301,547	98.9%	LP, MP	Requests & complaints
Belgium	5 working days (for TSO) 10 working days (Flanders for DSO) 10 working days (Wallonia for DSO and SP) 20 working days (Brussels for DSO)	TSO, DSO, SP	100%			LP, HP	Requests (DSOs in Wallonia and TSO, on federal level) Complaints (Flanders, Brussels)
Bulgaria	20 days (requests), 30 days (complaints)	TSO, DSO, USP/SP				LP, MP, HP	Requests & complaints
Croatia	10 working days	SP, DSO supplier	90% for DSO supplier 80% for SP			LP, MP, HP	Requests & complaints
Czech Republic	15 days	DSO	100%	27,619	100%	LP, MP, HP	Complaints
Estonia	30 days	TSO, DSO, SP				LP, MP, HP	Requests & complaints
Great Britain	10 working days (standard), 20 working days[248] (if visit is required)	DSO	100%			LP	Complaints
Greece	30 working days	DSO				LP, MP	Requests & complaints
France	30 calendar days	DSO	100%		96.6%	LP, MP	Complaints
Georgia	5 or 10 working days	DSO		50,824	96%	LP, MP	Requests & complaints
Hungary	15 days	TSO, DSO, USP/SP	100%	63,885	99.8%	LP, MP	Requests & complaints
Ireland	1 or 4 working days for responding, 10 or 30 days for resolving	DSO/MO	100%	1,884	96.5%	LP, MP	Complaints
Latvia	15-30 days	TSO, DSO, USP/SP		326		LP, MP, HP	Requests & complaints
Lithuania	30 days	TSO, DSO, SP	Is set for every company separately			LP, MP, HP	Requests & complaints
Luxembourg	5 working days	TSO, DSO	100%	123 requests 44 complaints	71% complaints	LP, MP, HP	Complaints
Netherlands, The	10 working days	DSO	100%	5,536 complaints	93%	LP, MP	Requests & complaints
North Macedonia	14 days	USP/SP, TSO, DSO				LP, MP	
Poland	14 days	TSO, DSO, SP, SSO, LNG terminal operator				LP, MP, HP	Requests & complaints
Portugal	15 working days	TSO, DSO, USP/SP, SSO, LNG terminal operator	90% - requests 100% - complaints	258,969 requests 73,961 complaints	98.85% - requests 76.97% - complaints	LP, MP	Requests & complaints
Romania	30 days	TSO, DSO, USP/SP	80 - 95%, depending on the request type			LP, MP, HP	Requests & complaints
Serbia	several different time limits for different type of requests & complaints	TSO, DSO, SP				LP, HP	Requests & complaints
Slovenia	8 working days	TSO, DSO				LP, MP, HP	Requests & complaints
Spain	1 month	DSO, SP				LP, MP, HP	Complaints
Ukraine	1 month	DSO, USP/SP		60,490 requests 8,011 complaints		LP, MP, HP	Requests & complaints

248 Starting in 2021, the time limits were changed from 10 (standard)/20 (if visit required) working days to 5 (standard)/10 (if visit required) working days.

TABLE 7-7: Examples of compensations paid to customers for non-compliance with standard related to the response to customer request and/or complaint

Country	Compensation for non-compliance	Penalty or other consequences	Total compensation value (2018)	Total number of affected customers who received compensation
Czech Republic	750-7,900 CZK/day (€29.2-€308/day) depending on customer type	Doubles each day to maximum of 158,000 CZK (€6,161)		
Georgia	5 or 10 GEL (€1.7 or €3.3)	Company will be penalized 5,000 GEL (€1,672) for non-payment	80 GEL (€26.7)	14
Great Britain	£20 (€22.6) for each succeeding period of 5 working days thereafter, up to a maximum of £100 (€113)			832
Hungary	5,000 – 30,000 HUF (€16-94) depending on the type of meter		645,120 HUF (€2,016)	127
Poland	€115	Up to 15% of annual licence activity income		
Portugal	€20 (only for complaints DSO and USP) Set in contract with SP (but not less than €5)		€415,540	20,777
Romania	10-100 RON (€2.1-€21.5) depending on request type		273 RON (€58.7)	2
Slovenia	€20	Compensation must be paid within a month of customer's request. If not, the amount doubles and must be paid within 8 days of customer's request. In case the compensation has again not been paid, the amount triples and must be paid within further 3 days of customer's request		
Ukraine	100 UAH (€3.1)	Compensation must be paid in the next billing period. If not, the amount is doubled and should be taken into account in the calculations in the nearest billing period		

In France, as part of the incentive regulation scheme, appointments that the DSO has not met are monitored (in number, not in percentage). It includes planned appointments that require the customer's presence but where the intervention was not performed because of the DSO. For each case, a penalty of €29 (excluding tax) is charged to the supplier. DSOs faced a total penalty of approximately €400,000 in 2018 because of 14,348 missed appointments. The detection of missed appointments has been automatically processed by the grid operator since July 2013 (before this date, it was the supplier or the customer).

TABLE 7-8: Examples of criteria and obligations by which the punctuality of market participants regarding appointments with customers is monitored

Country	Limit	Company involved	Standard that must be met	Number of cases for which the limit was fulfilled (2018)	Value of the indicator (2018)	Pressure levels	Compensation for non-compliance	Total compensation value (2018)	Total number of affected customers who received compensation
Austria	2-hour time window	DSO	95%	281,871	99.7%	LP			
Croatia	2 hours	DSO				LP, MP, HP			
France		DSO	100%	14,348		LP, MP	€29		
Hungary	4 hours	DSO	100%	120,563	99.9%	LP, MP	5,000 – 30,000 HUF (€16-94) depending on the type of meter	755,200 HUF (€2,360)	141
Ireland	At the agreed time (cancellation at least by the working day before the appointment)	DSO/MO		82,126	98.1%	LP, MP	€50		
Portugal	2.5-hour time window	DSO, USP/SP	100%	329,789	99.69%	LP, MP, HP	€20	€15,820	791

Table 7-9 shows some examples of requirements for waiting time for customer centres in the case of a personal visit, and call centre service level. A low number of countries apply indicators for time limits for customer and call centres.

TABLE 7-9: Examples of regulation of customer contacts other than in writing

Country	Call centre service level	Waiting time for customer centres in case of personal visit
Georgia	OI for DSOs and suppliers. Requirement: 80% of calls must be answered within 80 seconds[249]. Actual value in 2018 is 81.8% (607,273 calls).	
Hungary	OI for DSOs and USPs. Requirement: 75/85% (for DSOs) and 80% (for USPs) of calls must be answered within 30 seconds. Actual value in 2018 is 95.1% (138,177 calls) If company has not met OI it will be penalised 50 million HUF (€160,000) or 100 million HUF (€320,000) depending on the level of the non-fulfilment.	OI for DSOs and USPs. Requirement: 90% of customers visiting the customer centres should wait less than 20 minutes. Actual value in 2018 is 93.3% (136,964 customers). If company has not met OI it will be penalised 50 million HUF (€160,000) or 100 million HUF (€320,000) depending on the level of the non-fulfilment
Ireland	OR for DSOs and MOs. Percentage of calls answered within 20 seconds. Actual value in 2018 is 94.4% (273,137 calls)	
Portugal	OI for DSO, USP/SP Requirement: 85% of calls must be answered within 60 seconds. Actual value in 2018 is 74.32% (5,025,039 calls)	OI for DSO, USP/SP Requirement: waiting time for customers centres should be less than 20 minutes. Actual value in 2018 is 89.11% (1,148,926 customers).
Romania	OI for DSOs, SP/USPs. Requirement: 98% of calls must be answered within 60 seconds. Actual value in 2018 is 97.7% (218,607 calls)	

A high number of countries set obligations for DSOs on response times in emergency situations (I.5). Time limits vary from one hour (Great Britain (uncontrolled emergency), Ireland, Lithuania) to two hours (Belgium, Great Britain (controlled emergency), Greece, Luxembourg) and two days in Bosnia and Herzegovina. In Austria, in case of repairs, maintenance works or meter readings, appointments must be agreed between DSOs and customers specifying a two-hour window that DSOs would need to adhere to. In emergency cases, DSOs need to react immediately upon receipt of a customer complaint, enquiry or notification.

Instead of obligations, Spain has established recommendations on response time for incidents related to DSOs' facilities, depending on the type of emergency. These recommendations are:

- In case of an incident with warnings from official bodies (police, fire department, civil protection etc.) related to the gas odour in enclosed spaces, homes, or buildings, and whose origin cannot be determined, or the DSO cannot isolate the leak, the DSO has to attend to such an incident within two hours;
- In case of an incident where the alleged gas odour is in a ventilated place, on the street or inside residential areas, and where the odour could be eliminated by closing a key installation or ventilating the premises, the DSO has to attend to such an incident within six hours; and
- In case of an incident related to the lack of gas supply or service problems that do not compromise the safety of persons or property, the DSO has to attend to such an incident within a day.

Great Britain, Ireland, Croatia and Portugal set standards for OIs regarding response times for emergency situations: in Ireland, 97% of cases must be responded to within one hour (actual value in 2018 was 99.3% for 16,761 notifications); in Croatia, 90% within 90 minutes and in Portugal, 85% within 60 minutes (actual value in 2018 was 96.54% for 14,105 notifications). In Great Britain, the value of the OI is 97%.

7.4.3 Group II: Grid access

Connection to the gas network is one of the most important CQ issues as customers expect the time limit to be connected to the network to be respected. Time limits for execution of connection are applied by most countries. Table 7-10 contains aggregated data for the time limit for connecting customers to the network by the type of applied indicators, values of time limits and companies involved. Please note that using two types of indicators at the same time is possible in some countries.

249 This is the minimum percentage to be reached in a year.

TABLE 7-10: Monitoring of indicator II.1 'Time duration of connecting customers to the network'

Indicator	Countries grouped by types of indicators in 2014			Time limit (range)	Company involved
	GI	OI	OR	2018	
II.1 Time duration of connecting customers to the network	GB, GE, HR, HU, PT, SK, UA	AT, FR, LU, SI, SK	BA, BE, CZ, EL, ES, LT, MK, NL, RO, RS, SE	5 days – 24 months	DSO, TSO

TABLE 7-11: Examples of criteria and obligations by which the time limit for connecting customers to the network is monitored

Country	Limit	Company involved	Standard that must be met	Number of cases for which the limit was fulfilled (2018)	Value of the indicator (2018)	Pressure levels
Austria	14 working days (for simple works)	DSO	95%	8,390	99.8%	LP
Belgium	For simple works: Flanders: 15 working days Wallonia: 30 working days (without network extension); 60 working days (network extension is necessary) Brussels: 20 working days For complex works: specified in the contract with customer	DSO	100%			LP, MP
Bosnia and Herzegovina	45 days	TSO, DSO				LP, MP, HP
Croatia	30 working days For HP - specified in the contract with customer	DSO				LP, MP, HP
Czech Republic	30 days	DSO				LP, MP, HP
France	Time that both parties agreed on	TSO, DSO	89%			LP, MP
Georgia	40, 45 or 60 working days	DSO		68,680	92.6%	LP, MP
Great Britain	24 months (for TSO) Time that both parties agreed on (for DSO)	TSO, DSO				LP, MP, HP
Greece	60 days	DSO				LP, MP
Hungary	8 working days	DSO	100%	23,289	99.91%	LP, MP
Lithuania	5 working days	DSO			99.44%	LP, MP, HP
Luxembourg	30 working days	DSO	100%	787	100%	LP
Netherlands, The	18 weeks	DSO	100%			LP, MP
North Macedonia	14 days or the period stipulated in contract	TSO, DSO				LP, MP, HP
Portugal	45 days	TSO, DSO	100%			LP, MP, HP
Romania	Specified in the contract with customer	DSO				LP, MP, HP
Slovakia	5 days	TSO, DSO	TSO -94.25%, DSO 94.40%	14,220		LP, MP, HP
Slovenia	30 working days	TSO, DSO	95%			LP, MP, HP
Spain	12 working days (for simple works) 18 working days (for HP customers)	DSO				LP, MP, HP
Ukraine	3 months (for simple works) specified in the contract with customer (for complex works)	DSO		9,544		LP, MP, HP

The 'time duration of connecting customers to the network' (II.1) varies considerably in different countries: from five days (Slovakia for all pressure levels) to 24 months in Great Britain for HP customers (see Table 7-11). In some countries, time limits (either for all types of works or only for complex works or certain types of customers) are set in contracts between the system operator and customer (Belgium (Brussels), Croatia, France, Great Britain, Romania, Ukraine). Such a broad range of time limits is explained by the intricate structure of connection activity that depends on the complexity of the work to be done, and national differences in legislative requirements for system operators in the connection process. In some countries, the responsibility for construction lies with customers and DSOs are responsible only for installation of gas meters, while in others, system operators are liable for all connection processes including the construction of gas pipelines.

In Spain, the DSO has a maximum time limit of six workings days to check the connection request, answer the customer and supplier (accepting or denying the request for connection) and set-up an appointment with the customer to make the connection within the next six working days. This equates to a total maximum time for connection of 12 working days. This obligation applies only to simple works (checking or installing a gas meter and a security check of a gas installation). For HP levels (>60 bar), the maximum time to connect is increased by an additional six days, with the DSO having 12 working days (instead of six) to check the request, answer it and set-up an appointment. It also has an additional six days to connect a customer, bringing the total maximum time for connection to 18 working days.

In Portugal, the DSO and TSO have a time limit of 45 days to connect a customer. In some circumstances, construction works can be done by customers, in which case companies must provide the necessary technical specifications regarding the connection within 30 working days (this limit applies to household customers).

In Sweden, the operators of a natural gas pipeline should:

- When a new connection is being requested within a reasonable time, provide written information about the fee and other conditions for the connection; and
- Provide, upon request, without delay, written information on the conditions applicable to the quality, odour or pressure of the natural gas in the connection point.

In Serbia, the time to respond to a customer request for connection is monitored, but there is no indicator for the whole process from the connection request to execution of the connection.

TABLE 7-12: Examples of compensation paid to customers for non-compliance with standard related to the time duration of connecting customers to the network

Country	Compensation for non-compliance	Penalty or other consequences	Total compensation value (2018)	Total number of affected customers who received compensation (2018)
Belgium	For simple works: €28.57/working day of delay For complex works: from €57.14 to €114.29/working day of delay			
Georgia	Half of the cost of connection		369,000 GEL (approx. €123,358)	1,198
Great Britain	Prescribed sum in respect of the initial failure and each additional working day during which the failure continues			
Hungary	5,000 – 30,000 HUF (€16-94) depending on the type of meter		110,080 HUF (€344)	22
Portugal	€20			
Slovakia	€5/day of delay, max. €500		€20	1
Ukraine	200 UAH (€6.2)	Compensation must be paid in the next billing period. If not, the amount is doubled and should be taken into account in the calculations in the nearest billing period		

Six reporting countries set compensation for non-compliance with time limits for execution of connections (see Table 7-12). The amount of compensation can be defined as a fixed value (Hungary, Portugal, Ukraine), or a fixed value per day of delay (Belgium, Slovakia), or it can depend on the cost of connection (Georgia).

In France, a reward/penalty scheme for execution of connection to the network has been introduced with a rule that 89% of all connections must be executed within the time agreed by both parties (DSO and customer). Each year, the actual number of connections executed within the agreed time is compared to this standard. The amount of reward is +€50,000 for each 0.1% above 89%, while the amount of penalty is -€50,000 for each 0.1% under 89%. The previously used tolerance band was abolished in 2015.

7.4.4 Group III: Activation, deactivation and reactivation of supply

In this section, the analysis focuses on three indicators: the 'time for activation of supply following a request' (III.1), the 'time for deactivation of supply following a request' (III.2) and the 'time for reactivation of supply after payment (for bad payers previously disconnected)' (III.3). These indicators are mostly monitored as GIs and ORs, as seen in Table 7-13. As with the time for connecting customers to the network, there are cases of countries using two types of indicators at the same time in this Group as well.

TABLE 7-13: Types of indicators used in Group III (gas)

Indicator	Countries grouped by types of indicators in 2014			Time limit	Compensation (range)	Company involved
	GI	OI	OR	2018	2018	
III.1 Time for activation of supply following a request	CZ, GE, PT, SI, SK, UA	AT, FR, SK	BA, BE, EL, ES, LV, MK, RS	Median: 7.5 days Range: 1 – 21 working days	€1.7-€20	DSO, SP/USP, TSO
III.2 Time for deactivation of supply following a request	GE, HR, PT, UA	FR, LU	BA, BE, BG, CZ, EL, MK, RS	Median: 10 working days Range: 3 days – 3 months	€1.7-€20	DSO, SP/USP, TSO
III.3 Time for reactivation of supply after payment (for bad payers previously disconnected)	CZ, GE, HR, HU, PT, SI, SK, UA	AT, LU, SK	BA, BG, EL, ES, LV, MK, RS	Median: 1 working day Range: 4 hours – 20 working days	€1.7-€20	DSO, SP/USP TSO

TABLE 7-14: Examples of criteria and obligations by which indicators used in Group III are monitored

Country	Limit	Company involved	Standard that must be met	Number of cases for which the limit was fulfilled (2018)	Value of the indicator (2018)	Pressure levels
III.1 Time for activation of supply following a request						
Austria	14 working days	DSO	95%	34,090	100%	LP
Belgium	2 working days	DSO	100%			
Bosnia and Herzegovina	3 days	TSO, DSO, SP				LP, MP, HP
Czech Republic	2 working days	DSO		34,051	100%	LP, MP, HP
France	Within time requested by customer	DSO	93%			LP, MP
Georgia	10 working days	DSO, SP		297	99.61%	LP, MP
Greece	21 working days	DSO				
Latvia	5 days	DSO				LP, MP, HP
North Macedonia	1 working day	DSO, SP				LP, MP, HP
Portugal	3 working days	DSO	100%	119,931	82.5%	for households
Serbia	15 days	TSO, DSO				LP, MP, HP
Slovakia	5 days for DSO 10 days for supplier According to contract with customer for TSO	TSO, DSO, SP	TSO – 94.25%, DSO – 94.40%, SP – 95.9%	2,652		LP, MP, HP
Slovenia	10 working days	TSO, DSO	100%			LP, MP, HP
Spain	12 working days	DSO				LP, MP, HP
Ukraine	5 days in urban area 10 days in rural area	DSO		4,353		LP, MP, HP
III.2 Time for deactivation of supply following a request						
Belgium	35 working days	DSO, SP	100%			
Bosnia and Herzegovina	3 days	TSO, DSO, SP				LP, MP, HP
Bulgaria	10 days	DSO, SP/USP				LP, MP, HP
Croatia	15 working days	DSO				LP, MP, HP
Czech Republic	3 working days for industrial customers 10 working days for commercial customers and households	DSO		31,350	100%	LP, MP, HP
France	Within time requested by customer	DSO	95.5%			LP, MP
Georgia	10 working days	DSO, SP		297	99.61%[250]	LP, MP
Greece	10 working days	DSO				
Luxembourg	10 working days	DSO	100%	86	82.46%	LP, MP, HP
North Macedonia	1 working day	DSO, SP				LP, MP, HP
Portugal	3 working days	DSO	100%	119,931	82.5%	for households
Serbia	Request should be performed as soon as possible without any delay	TSO, DSO				LP, HP
Ukraine	3 days	DSO		62,324		LP, MP, HP
III.3 Time for reactivation of supply after payment (for bad payers previously disconnected)						
Austria	No later than the next working day	DSO	95%	1,562	99.9%	LP
Bosnia and Herzegovina	24 hours	TSO, DSO, SP				LP, MP, HP

250 In Georgia, indicators for activation and reactivation are registered in one category and not differentiated. That is why values for indicators III.1 and III.2 are the same.

TABLE 7-14: Examples of criteria and obligations by which indicators used in Group III are monitored

Country	Limit	Company involved	Standard that must be met	Number of cases for which the limit was fulfilled (2018)	Value of the indicator (2018)	Pressure levels
Bulgaria	1 working day	DSO, SP/USP				LP, MP, HP
Croatia	2 working days for DSO 1 working day for SP	DSO, SP				LP, MP, HP
Czech Republic	5 working days	DSO	100%	1,084	100%	LP, MP, HP
Georgia	5 hours	DSO, SP		73,887	95.17	LP, MP
Greece	20 working days	DSO				
Hungary	24 hours	DSO, USP		23,220	99.84	
Latvia	5 working days	DSO				
Luxembourg	3 working days	DSO	100%	95	83%	LP, MP, HP
North Macedonia	1 working day	DSO, SP				LP, MP, HP
Portugal	4 hours for urgent requests 12 hours for households 8 hours for other customers	DSO	100%	40,787	93.51%	LP, MP, HP
Serbia	24 hours	TSO, DSO				LP, HP
Slovakia	1 working day	SP	95.9%	92,889		
Slovenia	3 working days	TSO, DSO				
Spain	48 hours	DSO				LP, MP, HP
Ukraine	2 working days in urban area 5 working days in rural area	DSO		50,023		LP, MP, HP

The time for activation of supply following a request (III.1) varies from one working day (Lithuania) to 21 working days (Greece); and for deactivation of supply following a request (III.2), from three days (Bosnia and Herzegovina, Ukraine) to 35 working days (Belgium). In France, the time for activation/deactivation of supply following a request is set as time requested by customer. The time for reactivation of supply after payment (for bad payers previously disconnected) (III.3) vary from four hours (in Portugal for some cases) to 20 working days (Greece). The rules in Portugal are that SPs and USPs have 30 minutes after customer payment of debt to send a request for reactivation of supply to the DSO. The time a DSO would have for reactivation depends on the type of customer and urgency of the request: four hours for urgent customer requests, 12 hours for households and 8 hours for other customers.

TABLE 7-15: Examples of compensation paid to customers for non-compliance with standards related to activation, deactivation and reactivation of supply

Country	Indicator	Compensation for non-compliance	Penalty or other consequences	Total compensation value (2018)	Total number of affected customers who received compensation
Croatia	III.2	From 5 to 70,000 HRK (€0.7 to €9,436) / day / measurement point depending on tariff model			
Czech Republic	III.3	375 – 2,200 CZK/day (€14.6-€85.8) depending on whether it is for households or commercial customers	Double per day to max 3,750 - 44,000 CZK (€146-€1,716)		
Georgia	III.1 III.2	5 or 10 GEL (€1.7 or €3.3)		15 GEL (€5)	3
	III.3			45,420 GEL (€15,184)	8,777
Hungary	III.3	5,000 – 30,000 HUF (€16-94) depending on the type of meter		190,080 HUF (€594)	37
Portugal	III.1	€20		-	-
	III.2			-	-
	III.3			€2,300	115
Slovakia	III.1	€10/day, max. €400		€40	1
	III.3	€5/day for households (max. €50) €20/day for non-households (max. €400)		€10,552.2	558
Slovenia	III.1	€20	Compensation must be paid within a month of customer's request. If not, the compensation doubles and must be paid within 8 days of customer's request. In case the compensation has again not been paid, the amount triples and must be paid within further 3 days of customer's request		
	III.3				
Ukraine	III.1	100 UAH (€3.1)	Compensation must be paid in the next billing period. If not, the amount is doubled and should be taken into account in the calculations in the nearest billing period		
	III.2				
	III.3				

Many countries provide compensation for non-compliance with time limits for indicators in Group III (see Table 7-15). The amount of compensation is defined as a fixed value (Georgia, Hungary, Portugal, Slovenia, Ukraine) that varies from €1.7 (Georgia) to €20 (Portugal, Slovenia), or a fixed value per day of delay (Croatia, Czech Republic, Slovakia).

In France, a reward/penalty scheme for activation/deactivation of supply following a request has been introduced and sets the target values for activation/deactivation of supply following a request in time agreed by both parties. If the actual rate is lower/higher than the target value (93% for activation and 95.5% for deactivation) than a penalty/reward of +/-€20,000 is applied for each 0.1% below/above the standard. For more details, see the French case study in the 'commercial quality gas' chapter of the 6th Benchmarking Report [6].

7.4.5 Group IV: Metering

Metering is another important CQ issue with requirements for meter verification and reading being particularly important. Indicators in Group IV refer exclusively to TSOs and DSOs.

Austria sets an OI for 'the percentage of gas meters not installed in due time' (IV.I): DSOs must install 95% of meters within five working days. In 2018, 99.5% of meters were installed in due time.

The Czech Republic and Georgia provide compensation for non-compliance with GIs for the time needed for meter installation. If a limit of five working days is not respected in the Czech Republic, compensation amounts to 1,500-10,500 CZK (€58.5-€409.4), depending on the customer type. In Georgia, the time limit is between ten and 20 working days and the amount of compensation for non-compliance amounts to half of the cost of meter installation.

The time for meter verification after customer notification of a problem is monitored as a GI in the Czech Republic, Hungary, Portugal, Slovakia and Ukraine and as an OR in Croatia and Serbia (see Table 7-16). The time limit varies from two calendar days (Serbia) to 90 calendar days (Czech Republic).

Many countries set requirements for the frequency of meter verification: Latvia (every 18 years), Serbia (every five years), Croatia (every eight years) and Portugal (between six months and ten years depending on the pressure and type of meter for non-households and every 20 years for households)..

TABLE 7-16: Examples of criteria and obligations by which the time limit for meter verification after customer notification of a problem is monitored

Country	Limit	Company involved	Number of cases for which the limit was fulfilled (2018)	Value of the indicator (2018)	Pressure levels	Compensation for non-compliance	Total compensation value (2018)	Total number of affected customers who received compensation (2018)
Croatia	3 working days	DSO			LP, MP, HP			
Czech Republic	90 days	DSO	40,614	100%	LP, MP, HP	750 – 7,900 CZK (€29-€308) depending on customer type		
Hungary	15 days	DSO	412	98.1%	LP, MP	5,000 – 30,000 HUF (€16-94) depending on the type of meter	400,000 HUF (€1,250)	8
Portugal	15 working days	DSO			LP, MP, HP	€20		
Serbia	2 calendar days	DSO, TSO			LP, HP			
Slovakia	15 days	TSO, DSO	74		LP, MP, HP	TSO: €100/day, max. €1,000, DSO: €10/day, max. €500	€480	1
Ukraine	10 working days	DSO	14,242		LP, MP, HP	100 UAH (€6.2)		

Almost all reporting countries set requirements for minimum frequency of meter reading (IV.3). Such frequency varies widely and often depends on the type of customer or meter. It can be:

- Hourly, – for some type of smart meters in Germany and Spain;
- Daily – Slovenia (for customers with a yearly consumption higher than 800,000 kWh), Ireland (for industrial and commercial customers) and Luxembourg[251];
- Bi-monthly – Spain (for households);
- Monthly – Bosnia and Herzegovina, Belgium (automated meter reading in Flanders), Spain (for commercial customers), North Macedonia, Romania (in case of self-reading) and Serbia;
- Four times per year – Finland;
- Every three months – Romania;
- Every six months – France, Croatia;
- Yearly – Belgium (Brussels and non-automated meter reading in Flanders), Bulgaria, Czech Republic, Germany, Hungary, Poland, Slovakia (for households) and Slovenia (for customers with a yearly consumption less than 800,000 kWh);
- Every two years – Belgium (Wallonia) or
- Every three years – Austria, the Netherlands.

In Austria, DSOs must attempt to read the meter once a year and establish a record of an actual reading every three years themselves. DSOs must announce a meter reading at least two weeks in advance in case the customer requires to be present to access the meter. In cases where the customer's presence is not needed, DSOs must inform customers immediately upon the reading of their meters. Depending on the type of meter, DSOs are obligated to activate existing meters within a specific time period. In Portugal, the time between meter readings must not exceed 64 days in 98% of cases.

7.4.6 Group V: Invoices

Some requirements must be respected for invoices, such as the lead time for the network operator to issue invoices. The analysis in this section focuses on the following indicators: the 'percentage of invoices submitted in due time' (V.1) and the 'time to switch supplier on customer request' (V.2).

TABLE 7-17: Types of indicators used in Group V (gas)

Indicator	Countries grouped by types of indicators in 2014			Time limit	Company involved
	GI	OI	OR	2018	
V.1 Percentage of invoices submitted in due time		AT	BA, HU	1 month – 6 weeks	DSO, USP, TSO
V.2 Time to switch supplier on customer request	CZ, PL	FR, LT	BA, BE, BG, EE, ES, HR, PT, RO, SE, SI, UA	Median: 21 days Range: 4 working days - 21 days	DSO, SP/USP, TSO

The percentage of invoices submitted in due time (V.1) is monitored in only three responding countries: as an OI in Austria and as an OR in Bosnia and Herzegovina and Hungary.

In Austria, DSOs are required to issue bills directly to a customer within six weeks of a reading or supplier switching. In cases where the (former) supplier issues a joint bill, DSOs must submit their bills to the supplier within three weeks. In 2018, 97.2% of

251 In Luxembourg, a full smart meter rollout was completed by the end of 2021 and hourly meter readings are currently being enabled at a large scale.

invoices were submitted in due time (the standard is 95%) for 1,732,370 cases for which the limit was respected. In Hungary, invoices must be submitted eight days before the payment time.

The time to switch supplier on customer request (V.2) is monitored in many reporting countries, mostly as OR, and varies from four working days (in Croatia) to 21 days (in majority of countries).

7.5 SUMMARY OF BENCHMARKING RESULTS

Table 7-18 and Table 7-19 below synthesise the results of the indicators (see also Section 7.4.1). Indicators for DSOs form the largest part of the total (see Table 7-3).

TABLE 7-18: Total of applied indicators per type

Indicator	GI	OI	OR	TOTAL
I. CUSTOMER CARE				
I.1 Time for response to customer request and/or complaint	10	5	11	**26**
I.2 Punctuality of appointments with customers	5	1		**6**
I.3 Time limit for waiting in customer centres		2		**2**
I.4 Time limit for waiting in call centres (telephone contact)		5	1	**6**
I.5 Obligation for DSO regarding response time in emergency situations	1	4	5	**10**
TOTAL FOR CUSTOMER CARE INDICATORS	**16**	**17**	**17**	**50**
II. GRID ACCESS				
II.1 Time duration of connecting customers to the network	7	5	11	**23**
TOTAL FOR GRID ACCESS INDICATORS	**7**	**5**	**11**	**23**
III. ACTIVATION, DEACTIVATION, REACTIVATION OF SUPPLY				
III.1 Time for activation of supply following a request	6	3	7	**16**
III.2 Time for deactivation of supply following a request	4	2	7	**13**
III.3 Time for reactivation of supply after payment (for bad payers previously disconnected)	8	3	7	**18**
TOTAL FOR ACTIVATION, DEACTIVATION, REACTIVATION INDICATORS	**18**	**8**	**21**	**47**
IV. METERING				
IV.1 The percentage of gas meters not installed in due time	2	1		**3**
IV.2 Time for meter verification	6	1	2	**9**
TOTAL FOR METERING INDICATORS	**8**	**2**	**2**	**12**
V. INVOICES				
V.1 Percentage of invoices submitted in due time		1	2	**3**
V.2 Time to switch supplier on customer request	1	1	13	**15**
TOTAL FOR INVOICES INDICATORS	**1**	**2**	**15**	**18**

The most monitored indicator is the time for response to customer requests and/or complaints (I.1) in the customer care group (Group I), with the total number of GI, OI and OR being 26. This number is the highest for a single indicator, meaning that customer care and the time to respond to requests and complaints in the CEER-ECRB countries is of primary importance. The other four indicators in the customer care group have an average number of six indicators per activity ((6+2+6+10)/4). The second most monitored indicator is the time limit for connecting customers to the network (II.1) in the grid access group (Group II) with the total number of indicators being 23.

The other widely monitored group of indicators is activation, deactivation and reactivation of supply (Group III) with an average value of approximately 16 indicators per activity. Metering (Group IV) and invoices (Group V) have an average value of approximately six and nine indicators per activity respectively. The most monitored indicator in Group IV is the time for meter verification and in Group V, the time to change supplier on customer request.

Looking at the average number of indicator types per activity group, there is a considerable difference between them. OIs are the most frequently applied indicators for regulation of customer care issues. GIs are frequently applied for activation, deactivation and reactivation of supply and customer care activities. ORs are widely applied in almost every group of indicators. Table 7-19 shows the indicators applied in responding countries, per Group and per type.

TABLE 7-19: Gas CQ indicators applied per group and type of indicator

Country	I. Customer care			II. Grid access			III. Activations, deactivations, reactivations			IV. Metering			V. Invoices		
	GI	OI	OR	GI	OI	OR	GI	OI	OR	GI	OI	OR	GI	OI	OR
Austria		2	1		1			2			1			1	
Belgium			2			1			2						1
Bosnia and Herzegovina			1			1			3						2
Bulgaria			1						2						1
Croatia	1	2		1			2					1			1
Czech Republic	1					1	2		1	2			1		
Estonia			1												1
France	1	2			1			2						1	
Georgia	1	1		1			3			2					
Great Britain	1	1		1											
Greece			2			1			3						
Hungary	2	2		1			1			1					1
Ireland	1	1	2												
Latvia			1						2						
Lithuania		1	1			1									1
Luxembourg	2				1			2							
Netherlands, The			1			1									
North Macedonia			1			1			3						
Poland	1														1
Portugal	2	4	1	1			3			1					1
Romania	1	1				1									1
Serbia			1			1			3			1			
Slovakia				1	1		2	2		1	1				
Slovenia	1				1		2								1
Spain			1			1			2						1
Sweden						1									1
Ukraine	1			1			3			1					1
TOTAL	**16**	**17**	**17**	**7**	**5**	**11**	**18**	**8**	**21**	**8**	**2**	**2**	**1**	**2**	**15**

7.6 FINDINGS AND RECOMMENDATIONS ON COMMERCIAL QUALITY OF GAS

It is important to recall that the results on CQ should be interpreted with caution as national legislation on CQ in CEER-ECRB countries have their own differences and data are not yet available in every country. Some elements can be measured in different ways (for example, starting point to measure time limits) or indicators can have different complexity (for example, components of grid connection work that DSOs are obligated to execute). The performances of the operators are not comparable across countries since each country has its own regulatory system (with specific time limits, standards, compensation systems, penalty amounts, etc.). Furthermore, each country has its own mix of CQ indicators which may not be covered in its entirety by this Benchmarking Report.

FINDING #1:
There is an increased focus by NRAs on the quality of the services provided to customers.

In line with the conclusions from CEER's past Benchmarking Reports, the NRAs devote significant attention to the CQ of the services provided. A total of 29 responding countries reported a combined sum of 168 national CQ indicators referring to 14 indicator types.

FINDING #2:
A broad but increasingly harmonised range of CQ indicators is monitored.

There are significant differences concerning the nature and the number of indicators monitored across countries. The regulation of a given service can be achieved in many different ways such as time limits, standards, compensation levels and penalty levels. NRAs set the CQ regulations, taking into account their national, political, cultural and economic specificities. It is worth noting that NRAs apply identical or similar regulations concerning CQ indicators.

FINDING #3:
CQ requirements vary greatly depending on the customer type or on the company involved.

CQ requirements in different countries depend significantly on the customer type; the NRAs set indicators by the pressure level and location. Some NRAs focus only on LP or domestic customers as those with the least capacity to protect themselves in cases of non-performance of companies' duties. Furthermore, many countries set different requirements depending on the type of company involved (TSO, DSO, USP/SP), especially different time limits and even different types of indicators for some categories.

FINDING #4:
A significant number of OIs and GIs is monitored in the regulation of gas CQ.

The data collected show that CQ indicators can be used by NRAs in three ways:

- To define OIs, either without any economic consequence upon non-compliance by a DSO or a supplier, or with economic sanctions. NRAs are entitled to impose sanctions such as penalties;
- To set GIs by which customers receive direct compensation if standards are not met; or
- To apply OR, and in the case of non-compliance, sanctions could be imposed by the NRA.

This benchmarking exercise reports 50 instances of GIs and 34 instances of OIs being applied among the responding countries, out of a total number of 150 indicators in all countries combined. This total of 150 indicators does not include the minimum frequency of meter readings (used in 18 countries) since there is no information on the type of requirements (GI, OI or OR) the responding countries use for this indicator. This explains the difference between the total mentioned here (150) and the combined sum of 168 national gas CQ indicators from Finding #1.

FINDING #5:
Regulations in respect of compensations have different variations.

The amount of compensation is determined in many ways: as a fixed value, as a fixed value per day/a period of delay, depending on the amount on a customer's bill or on the amount of payment for a service (for example, connection). The amount of compensation can increase in case of delayed payment or non-payment. Regulations regarding compensation vary in the way compensations are paid: automatically or by customer request, as the amount being subtracted from the bill or as a direct payment to the customer. In some countries, a maximum yearly amount that a customer can receive for non-compliance with a GI has been introduced.

FINDING #6:
CQ is mainly focused on the DSO's relationship with customers.

The CEER-ECRB countries are focused more on the DSOs' CQ obligations rather than those of the suppliers' (133 indicators relate to DSOs out of 229 total indicators between all company types) as the distribution activities are closely linked to customers (connection to the grids, activations, etc.).

FINDING #7:
Customer care, activations and connections to the network are key considerations.

From a customer perspective, contacts with companies, connections, activations and deactivations are important processes. Effective functioning of these processes forms an overall customer assessment of the functioning of the energy market. Survey results demonstrate that priority is given to the indicators for customer care, activation/deactivation and connections. The NRAs implement GIs and OIs more often than ORs for these groups of indicators.

FINDING #8:
The focus needs to be wider than written responses to customers.

There is a noticeable need for a substantive response from a DSO/supplier to any customer request within a reasonable limit of time. The data reveal that the current emphasis is placed on performance with respect to written forms of communication. This results in an incomplete picture of the quality of responses to customer requests for two different reasons: (1) non-written forms of communication like telephone (fixed and mobile) and internet (website) have been developed significantly and are widespread; (2) in some countries, the more traditional approach of visiting local customer centres continues. A limited number of countries introduced indicators related to call centres and customer centre services.

RECOMMENDATION 1

PERFORM REGULAR REVIEWS OF NATIONAL REGULATIONS.

It is important to regularly review the CQ indicators, taking into account the development of national conditions and the expectations of customers. Monitoring the actual level of CQ (average values of indicators, percentages of fulfilment and data regarding the amount of paid compensations) has an important role in such reviews. The most important factor in this process is the availability of wide and reliable data. Therefore, it is necessary to examine in detail (including questioning stakeholders) the CQ regulations that are in place to know if additional indicators or requirements (that are not included in this chapter) are monitored, or to understand the specificities of each country surveyed.

RECOMMENDATION 2

PURSUE THE HARMONISATION OF CQ INDICATOR DEFINITIONS.

Harmonising the definitions would facilitate significant results from CEER-ECRB countries and a more consistent and understandable database. Comparisons are sometimes difficult to make as the regulation of a given activity can be achieved in many ways, depending on the country. A clear framework and harmonised parameters, definitions and principles of indicator measurement can help the analysis of the results and thus the identification of further possible improvements and recommendations.

RECOMMENDATION 3

ENSURE GREATER PROTECTION THROUGH GIs WITH AUTOMATIC COMPENSATION FOR CUSTOMERS.

It is recommended that NRAs should apply GIs with automatic compensation or OIs or ORs associated with the option of sanctioning. For the most important indicators (e.g. for connection activities), a combination of OI with economic sanctions (like penalties) and GIs is recommended to both improve the average performance and protect customers from bad service. This recommendation is targeted mainly at DSOs given their important relationship with customers. In addition, automatic compensation payments, which are increasingly applied, should be extended to every country. OIs should be applied for indicators where some quality levels are achieved in general but not in each individual case (e.g. for call centres indicators).

RECOMMENDATION 4

NRAs SHOULD MONITOR INDICATORS IN ALL FORMS OF COMMUNICATION FOR MORE ACCURATE PERFORMANCE LEVELS.

It is recommended for NRAs, to, in addition to written forms of communication, regulate the performance of the service level provided to customers through communications such as phone, e-mail and online (e.g. website/apps) and through visits to customer centres. The increasingly important field of phone contacts should be monitored, especially in the performances of DSOs and USPs. Attention should be paid not only to the speed but also to thoroughness and usefulness of a response. Another important aspect for customers in case of phone contact is the rate of abandoned calls. All types of responses should be taken into account in the CQ regulation.

RECOMMENDATION 5

ENSURE THE AVAILABILITY OF THE SERVICES, IN PARTICULAR REGARDING CONNECTION AND CUSTOMER CARE.

CEER and ECRB recommend that countries and their NRAs evaluate customer priorities before creating new regulatory frameworks.

RECOMMENDATION 6

FURTHER DEVELOP THE REGULATION OF CUSTOMER RELATIONS.

Quality perception is not sufficiently evaluated in the countries surveyed in this Report. To further develop the CQ regulation, satisfaction surveys, although costly, could be implemented to have qualitative elements (in addition to the quantitative elements the CEER-ECRB questionnaire provides). These surveys could help assess how customers actually perceive the service achieved by the operator and improve regulations (setting targets, compensation levels etc).

ANNEX A

ANNEX A – MEDREG FACT SHEETS

A.1 JORDAN

General information

	Electricity	Gas
Number of DSOs	3	
Number of TSOs	1	
Network length		
Distribution	59 km[252]	
Transmission	4,800 km[253]	
Year	2020	

Voltage levels in use		Min	Max
Extra High Voltage	Yes	400 kV	400 kV
High Voltage	Yes	132 kV	220 kV
Medium Voltage	Yes	3.30 kV	33 kV
Low Voltage	Yes	0.23 kV	1 kV

Regulatory Framework

	Electricity	Gas
Regulation of networks?	Yes	Yes
Type of Regulation	Revenue cap / Price cap	
Regulatory Framework	Licensing persons working in generation, transport, supply, distribution and operation of the transport system: • determine the electric tariff, subscription fees, service and cost allowance, security and the cost of delivery services in transmission and distribution systems; • ensure the provision of safe, stable, durable and high-quality services in the field of generation, transmission, distribution and supply of electricity and operation of the transmission system; • ensure that projects operating in the sector comply with environmental standards and public safety conditions applicable in Jordan under the legislation in force; • ensure the provision of electricity service licensees to consumers adequately.	
Main Elements of Regulation	WACC	
Legal Framework	Electricity Law N° 64 of 2002, and renewable energy and energy conservation law N°13 of 2012. National regulatory authority sets the codes, rules and the instructions based on these laws.	
Effective since	2002	
Regulatory Period	4 years	
Ownership	Transmission network is owned by a public company. Distribution network is private.	
Historical development of regulation	The electricity network has been regulated since 2001 by the Electricity Regulatory Commission (ERC) and since 2014, Energy and Minerals Regulatory Commission (EMRC) is a governmental body that possess a legal personality with financial and administrative independence and is considered the legal successor of the Electricity Regulatory Commission (ERC).	

252 Value for 2015.
253 Value for 2018.

Continuity of Supply – Electricity

Is continuity of supply monitored in your country?	Yes
Are any continuity of supply indicators used?	Yes
If yes, which ones	SAIDI, SAIFI, MAIFI, AFIK, TTIK, EENS.
Values (Year)	
SAIDI	3 hours per consumer (2020)
SAIFI	3 times per consumer (2020)
Scheme to reduce the number or duration of interruptions	After the DSOs complete their SCADA system, indicators SAIDI, SAIFI and EENS will be assessed and new values for these indicators will be decided in order to allow the DSOs to improve their networks. Note: as of the writing of this report, there were no penalties if an indicator value exceeds the limit.

Voltage Quality – Electricity

Are voltage quality indicators monitored?	Yes
If yes, which ones	Supply voltage variation, flicker, harmonic voltage and current
At which network points are these indicators monitored?	At certain voltage levels

Commercial Quality – Electricity

Are commercial quality indicators monitored?	Yes
If yes, which ones	1. Time to connect new customers 2. Response to customer complaints 3. Time required for the DSO to reconnect the customer (in case the customer was disconnected for non-payment of bills)

Continuity of Supply – Gas

Is continuity of supply monitored in your country?	No
Are any continuity of supply indicators used?	No

Natural Gas Quality

Is natural gas quality monitored?	NA
If yes, which parameter is used?	

Commercial Quality – Gas

Are commercial quality indicators monitored?	NA
If yes, which ones	

A.2 LEBANON

General information

	Electricity	Gas
Number of DSOs	3	
Number of TSOs	1	
Network length		
Distribution		
Transmission	2,198 km	
Year	2019	

Voltage levels in use		Min	Max
Extra High Voltage	Yes	400 kV	400 kV
High Voltage	Yes	33 kV	220 kV
Medium Voltage	Yes	5.50 kV	20 kV
Low Voltage	Yes	NA	NA

Regulatory Framework

	Electricity	Gas
Regulation of networks?	No	No
Type of Regulation		
Main Elements of Regulation		
Legal Framework	Law 462 issued in 2002, but not implemented yet	
Effective since	2002	
Regulatory Period		
Ownership	Public	
Historical development of regulation		

Continuity of Supply – Electricity

Is continuity of supply monitored in your country?	Yes
Are any continuity of supply indicators used?	No
If yes, which ones	
Values (Year)	
SAIDI	
SAIFI	
Scheme to reduce the number or duration of interruptions	No

Voltage Quality – Electricity

Are voltage quality indicators monitored?	Yes
If yes, which ones	Voltage variation
At which network points are these indicators monitored?	Substations via the national control center

Commercial Quality – Electricity

Are commercial quality indicators monitored?	N/A
If yes, which ones	

Continuity of Supply – Gas

Is continuity of supply monitored in your country?	N/A
Are any continuity of supply indicators used?	N/A

Natural Gas Quality

Is natural gas quality monitored?	N/A
If yes, which parameter is used?	

Commercial Quality – Gas

Are commercial quality indicators monitored?	N/A
If yes, which ones	

A.3 TURKEY

General information

	Electricity	Gas
Number of DSOs	21	72
Number of TSOs	1	1
Network length		
Distribution	1,164,170 km[254]	16,500 km
Transmission	68,204 km[255]	146,500 km
Year	2020	2020

Voltage levels in use		Min	Max
Extra High Voltage	No		
High Voltage	Yes	36 kV	380 kV
Medium Voltage	Yes	1 kV	36 kV
Low Voltage	Yes	0.23 kV	1 kV

254 Value for 2018.
255 Value for 2015.

Regulatory Framework

The NRA Energy Market Regulatory Authority (EMRA) has a very broad authority to regulate the market, including:

- establishing a legislative framework to ensure reliable, high-quality, stable and low-cost electricity services;
- granting, amending or cancelling licences; approving and amending tariffs;
- establishing and enforcing standards and rules for relations among affiliates to promote competition; and
- imposing administrative fines and sanctions for non-compliance with the applicable legislation and the terms and conditions set out in the licence or the decisions of EMRA.

Electricity

In March 2013, a new Electricity Market Law was enacted. The Law introduced a number of new features to the electricity market including:

- Preliminary licences;
- Supply licences for retail and wholesale activities;
- Incorporation of a new market operator for the operation of wholesale markets.

Following the law, the Electricity Market Licensing Regulation was issued on 2 November 2013. In addition, there is a lot of secondary legislation regulating activities in the electricity market including:

- Generation, transmission, distribution, wholesale, retail and other electricity services; and
- Import and export of electricity. The rights and responsibilities of individuals receiving electricity services.

Renewable energy is also specifically controlled in the Turkish regulatory framework. In 2005, the Renewable Energy Law (Law Nº 5346) was enacted to introduce certain advantages such as floor prices and priority dispatch. The regulatory framework for renewable energy was strengthened in January 2011 with amendments to the Renewable Energy Law. Feed-in tariffs have been introduced for each type of power generation and were followed by the law on renewable energy zones. Turkey's main regulatory authorities include:

- The Ministry of Energy and Natural Resources, which broadly determines Turkish energy policy;
- The Energy Market Regulatory Authority (Enerji Piyasası Düzenleme Kurumu) (EMRA); which is the market regulator. It is an autonomous, public legal entity with administrative and financial authority established to regulate and monitor electricity, natural gas, petroleum and liquid petroleum gas markets. EMRA is governed by the Energy Markets Regulatory Board. EMRA can create and approve tariff levels, issue licences, establish quality service standards and address other matters such as management and consumer complaints arising from lack of quality or interruptions in the power supply.

Gas

Foundations of the liberal Turkish natural gas market were laid by the enactment of the Natural Gas Market Law Nº 4646 (the NGML) in 2001. The NGML, in line with the EU Directives in force, established a legal framework for all market activities such as transmission, distribution, import, sales, and storage of gas and set out the bases for licensing regulations and usage codes.

In 2004, the network code of the TSO and the transmission tariffs based on Entry/Exit System were prepared and published by EMRA, granting third party access (TPA) to the system for all market participants. As a result of these steps, TPA to the gas infrastructure has been granted in a non-discriminatory and transparent manner.

As a result of the gas release tenders in 2005, gas supply by private importers started in 2007, from Russia via Malkoclar entry point. Following the gas release tenders, wholesale prices including LNG sales were liberalised at the beginning of 2008 by a Board Decision, in line with the relevant article of the NGML that dictates that the wholesale tariffs should be set freely between the parties.

The amendments of the NGML made in July 2008 set the legal basis for spot LNG imports to the country and lifted the limitations regarding the source countries for LNG imports. Following the amendment in May 2009, 'By-law on Establishing Basic Usage Procedures and Principles of Liquefied Natural Gas Storage Facilities' was put into effect, and in 2010, two separate 'Basic Usage Procedures and Principles' that regulate non-discriminatory TPA to the two active LNG terminals were published by EMRA.

In 2011, as a result of increasing shares of the private importers, trading at the Turkish National Balancing Point started. In 2012, EMRA published a Board Decision declaring that residential customers who have an annual consumption above 75,000 Sm^3 are eligible customers, as well as all non-household customers. In March 2016, EMRA Board issued a decision on the licensing regime of floating storage and regasification units (FSRUs), introducing the FSRUs to the Turkish gas market. Basic Usage Procedures and Principles of the first FSRU was approved by the EMRA Board and published in November 2016.

The by-law on Organised Natural Gas Wholesale Market enacted in 2017 established the basis for the foundation of the Turkish Continuous Trade Platform (TCTP). The market operations on TCTP started on September 1, 2018. The new organised market also lets the TSO balance the system as the 'Residual Balancer', fully in line with EU regulations. By the amendment of the Market Operation Code in January 2020, Balance of Week, Weekends and Working Days Next Week contracts were introduced to the organised market.

	Electricity	Gas
Regulation of networks?	Yes	Yes
Type of Regulation	A hybrid regulation model for electricity distribution tariffs is used. For CAPEX, rate of return regulation is in use, for OPEX, revenue cap regulation is used.	
Main Elements of Regulation	OPEX (length of lines, number of customers, distributed energy, number of transformers)	
Legal Framework	Electricity Market Law N° 6446, many ordinances, codes, principles and Procedures and Board Decisions.	
Effective since	2001	
Regulatory Period	5 years (DSO) / 3 years (TSO)	
Ownership	Distribution: 21 private companies Transmission: 1 state-owned company	Distribution: 71 private and 1 municipality-owned company Transmission: 1 state-owned company
Historical development of regulation	In 1970, the vertically integrated Turkish Electricity Authority (TEK) was established. In 1984, Turkey first opened its energy sector to the private sector. TEK was responsible for generation, transmission and rural electrification. Law N°3096 ended TEK's role as a generation monopoly and allowed the private sector by introducing private generation investment models. This law in effect ended TEK's monopoly in generation by introducing private generation investment models such as build-operate-transfer (BOT), transfer of operational rights (TOOR), and autoproduction. Due to the uncertainties and unsatisfactory progress of the BOT model, a specific law for BOT implementation (Law N° 3996) was issued in 1994. This law included not only the energy sector but other sectors like transportation and construction. Later, the build-own-operate (BOO) model was introduced in 1997 to enhance private generation investments in thermal power plants. In 1993, TEK was restructured with the decision of the Council of Ministers and two state-owned companies were established: TEAŞ (the Turkish Electricity Generation and Transmission Company) and TEDAŞ (the Turkish Electricity Distribution Company). This was an important step toward unbundling. In 2001, Electricity Market Law was enacted and Energy Market Regulatory Authority was established. This law (N° 4628) set the legal framework for the sector, defined the institutional structure and related market activities and also defined the roles and responsibilities of market players. With Electricity Market Law, market activities were split into two groups such as Regulated Market Activities and Competitive Market Activities. Regulated market activities are transmission, distribution and sales to non-eligible consumers and wholesale, while generation, wholesale and sales to eligible consumers were competitive activities. In 2001, by the Council of Minister's Decision TEAŞ was further divided into three companies, which were responsible for transmission, generation and wholesale. In 2013, New Electricity Market Law was enacted. This is the current law and is still in effect. In 2005, The Use Of Renewable Energy Sources For Electricity Generation Law was enacted and feed-in-tariff rates for renewables were changed in 2011. In order to clarify the rules and procedures described in these laws, many by-laws and communiques were also published. Transmission is a monopoly belonging to the Turkish Electricity Transmission Company (TEİAŞ). TEİAŞ was initially responsible for market and system operation, under the Electricity Market Law in 2013, an additional licence was granted to Energy Exchange Istanbul (EPİAŞ). TEİAŞ continues to operate the balancing power market and the ancillary services market while EPİAŞ is responsible for operating the day-ahead market and the intraday market. Regarding distribution, before 2001, TEDAŞ and regional affiliates were responsible for distribution and retail and they were a vertically integrated structure. Between 2001 and 2013, after the first Electricity Market Law, the distribution privatisation process was ongoing with TEDAŞ affiliates and private companies dealing with both distribution and retail sales (within the same company) and there was only account unbundling. With the new Electricity Market Law enacted in 2013, there are now 21 private companies responsible for distribution and 21 incumbent supplier companies with the same ownership but there is a legal unbundling between them.	

Continuity of Supply – Electricity

Is continuity of supply monitored in your country?	Yes
Are any continuity of supply indicators used?	Yes
If yes, which ones	SAIDI, SAIFI
Values (Year)	
SAIDI	1,841.94 (2018)[256]

256 Without force majeure.

SAIFI	19.576 (2018)[256]
Scheme to reduce the number or duration of interruptions	There are many schemes/incentives to reduce the number of interruptions. DSOs have to pay compensation to network users if the duration of an interruption exceeds 12 hours in a day. Moreover, DSOs need to pay compensation to network users if the threshold period and/or the number specified in the according Service Quality Regulation is exceeded. In addition, there is a Quality Factor incentive in distribution tariff. If DSOs can reduce their SAIDI, they can increase their revenue cap up to a certain level, determined in each tariff period. This has been in effect since December 2017. Distribution companies who can reduce their SAIDI levels can get an increase in revenue by 0.7%. In order to get this increase, they have to develop a supply continuity monitoring system in advance. With this system, they can record the interruption duration and frequency correctly via supply continuity remote monitoring systems like SCADA or AMR systems.

Voltage Quality – Electricity

Are voltage quality indicators monitored?	Yes
If yes, which ones	Effective voltage value, voltage variation, voltage dips, total harmonic distortion, harmonic voltages, flicker.
At which network points are these indicators monitored?	In both low and medium voltages, DSOs place technical quality measuring devices. EMRA informs DSOs every year before 15 March about the points where to place the devices. According to Service Quality Regulation, DSOs must install technical quality measuring devices in the grid and must measure the quality parameters for one year and submit the results to EMRA. Every year, EMRA changes the location of the devices to be installed. Measurements take place in both residential and industrial areas, in substations and/or in other relevant points in the grid. The number of devices is calculated according to a formula in the Service Quality Regulation, which takes the number of customers and transformers in the region into account.

Commercial Quality – Electricity

Are commercial quality indicators monitored?	Yes
If yes, which ones	Time to connect new customers to network, time for switching of a supplier, response to customers' complaints. Both distribution companies and incumbent supplier companies must submit the results of their commercial quality indicators to EMRA by periods specified in Service Quality Regulation.

Continuity of Supply – Gas

Is continuity of supply monitored in your country?	Yes
Are any continuity of supply indicators used?	No

Natural Gas Quality

Is natural gas quality monitored?	Yes
If yes, which parameter is used?	Gross calorific value

Commercial Quality – Gas

Are commercial quality indicators monitored?	Yes
If yes, which ones	Time to connect new customers to network and response to customers' complaints are monitored according to the by-law on Customer Relations.

ANNEX B

ANNEX B – ANNEX TO CHAPTER "ELECTRICITY – CONTINUITY OF SUPPLY"

B.1 COMMON INDICATORS

TABLE A 1: Planned interruptions, SAIDI (minutes per customer per year)

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
Austria	17.26	16.38	14.87	14.35	16.36	15.13	13.69	14.04	12.89
Bosnia and Herzegovina					474.27	557.93	469.44	451.29	395.55
Croatia	293.43	308.50	295.45	253.49	250.15	251.43	222.85	213.12	180.06
Cyprus					50.00	48.00	51.00	52.00	55.00
Czech Republic	159.40	154.74	147.59	159.68	162.33	171.18	159.91	141.63	140.63
Denmark	5.37	4.94	4.74	4.70	5.05	4.65	4.24	4.31	3.46
Estonia					66.00	69.00	74.00	74.00	84.00
Finland	15.15	15.22	14.10	15.45	12.89	11.51	12.64	14.63	10.41
France	23.95	18.88	15.79	15.86	15.75	16.26	17.85	14.74	13.09
Georgia									26.28
Germany	9.66	10.12	11.83	7.23	7.56	7.03	10.29	7.23	7.51
Great Britain	6.72	6.69	6.70	5.68	5.72	5.72	5.02	3.91	4.25
Greece	202.00	166.60	149.00	156.00	136.00	105.00	112.00	100.92	88.47
Hungary	180.00	157.00	153.00	123.00	131.70	161.20	157.20	135.00	137.90
Ireland				42.12	49.77	72.70	63.56	60.66	52.41
Italy	55.71	61.85	65.97	55.28	59.60	66.62	78.85	65.78	62.99
Kosovo*						1,411.20	5,143.53	3,305.40	2,807.40
Latvia	219.00	236.00	265.00	280.00	256.00	206.00	156.00	143.00	123.00
Lithuania					217.45	194.18	173.04	154.75	127.96
Luxembourg								4.40	4.30
Malta				61.04	207.00	54.60	62.80	64.80	44.06
Montenegro									784.63
Netherlands, The			5.16	6.02	5.89	4.76	6.28	7.32	7.02
Norway	36.67	40.73	40.95	37.64	43.05	44.05	41.15	45.01	41.00
Poland	129.70	153.05	147.32	139.12	119.40	95.86	80.17	62.62	56.23
Portugal	1.57	2.05	1.68	1.46	2.59	2.44	1.91	0.36	0.23
Romania					229.24	211.27	183.50	193.10	183.58
Serbia	441.18	433.32	344.86	322.83	436.44	562.86	227.05	338.36	369.84
Slovenia	105.55	126.33	116.61	115.09	119.28	128.61	120.10	111.49	118.03
Spain	8.82	9.00	10.62	9.18	10.50	13.38	12.54	9.72	8.70
Sweden			16.93	18.87	18.17	16.66	18.80	18.11	16.17
Switzerland	14.00	13.00	12.00	10.00	9.00	10.00	10.00	10.00	9.00
Ukraine	599.25	681.82	681.12	736.55	565.58	568.98	521.78	485.16	449.45

TABLE A 2: Unplanned interruptions, all events, SAIDI (minutes per customer per year)

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
Austria	36.50	28.48	34.64	38.68	51.57	32.50	27.48	53.22	31.47
Belgium					26.17	25.19	25.63	28.64	26.48
Croatia	306.97	250.59	372.49	306.03	411.57	264.89	189.39	259.46	188.17
Cyprus					37.00	33.00	37.00	34.00	39.00
Czech Republic	135.88	114.08	125.06	195.08	120.89	144.89	98.38	289.82	115.42
Denmark	15.05	17.04	14.75	15.86	11.59	15.86	15.14	16.61	17.34
Estonia					117.10	168.50	148.50	96.40	129.73
Finland	128.34	327.61	73.07	170.94	66.84	157.62	67.82	55.29	49.22
Georgia									33.26
Germany	19.27	16.68	17.37	32.71	13.50	15.16	13.26	21.00	16.48
Great Britain	75.69	81.42	70.01	68.05	61.02	92.51	50.71	46.53	42.87
Greece	162.94	166.31	150.00	133.00	122.00	143.00	132.00	131.41	172.61
Hungary	133.00	85.00	77.00	139.00	86.19	89.48	75.16	126.61	79.33
Ireland				134.31	431.48	105.63	86.99	440.29	211.51
Italy	88.84	107.96	132.73	105.40	93.80	129.03	64.89	102.77	100.51
Latvia	1,073.00	708.00	371.00	341.00	210.00	144.00	130.00	117.00	105.00
Lithuania					144.04	106.53	172.92	137.57	81.63
Luxembourg									23.80
Malta				360.04	570.60	172.80	101.02	417.60	69.32
Moldova					200.00	342.00	348.00	1,040.00	505.00
Montenegro									1,911.53
Netherlands, The			26.34	23.40	20.00	32.90	21.00	24.40	27.30
Norway	63.79	220.11	65.81	143.77	118.07	128.77	87.68	65.86	125.76
Poland	386.18	325.76	263.19	281.82	205.41	267.46	191.83	370.62	142.79
Portugal	276.04	131.43	94.15	259.80	94.75	75.03	75.74	143.30	200.63
Romania					479.89	370.78	371.14	623.76	463.43
Serbia	906.67	557.43	590.83	400.90	852.04	534.60	416.30	578.14	441.03
Slovenia	80.57	76.06	169.43	109.32	907.91	71.34	71.82	175.29	77.90
Spain	140.76	58.20	58.56	99.18	52.68	55.68	54.78	72.42	59.40
Sweden			88.18	151.94	83.73	118.15	75.62	62.89	126.50
Switzerland	14.00	16.00	22.00	15.00	13.00	11.00	9.00	10.00	18.00
Ukraine	804.93	649.45	734.91	702.86	2,408.12	1,173.41	938.66	1,060.94	1,054.25

TABLE A 3: Unplanned interruptions excluding exceptional events, SAIDI (minutes per customer per year)

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
Austria	35.92	28.32	32.90	33.01	33.26	27.18	24.22	31.88	25.21
Bosnia and Herzegovina					400.16	316.65	311.29	368.16	293.82
Croatia	188.94	151.95	196.84	176.12	166.34	152.99	102.40	125.71	100.46
Cyprus					35.00	32.00	34.00	33.00	36.00
Czech Republic	106.24	107.09	109.77	98.01	84.38	82.14	73.09	96.32	77.67
Denmark	15.00	16.10	14.70	11.20	11.60	14.90	15.10	16.50	17.30
France	61.32	51.44	57.93	65.96	48.27	44.82	46.25	50.36	50.78
Georgia									21.40
Germany	14.90	15.31	15.91	15.32	12.28	12.70	12.80	15.14	13.91
Great Britain	70.02	67.94	55.43	54.71	53.22	44.86	38.39	39.06	39.64
Greece	121.07	101.32	101.00	96.00	92.00	94.00	96.00	97.46	118.77
Hungary	102.00	76.00	76.00	67.00	74.33	66.63	59.14	68.54	60.07
Ireland				86.73	97.63	82.99	79.05	90.34	97.43
Italy	47.77	43.59	45.45	42.27	41.32	45.40	37.11	43.87	50.30
Kosovo*						4,982.40	3,017.34	3,033.00	3,939.60
Latvia			255.00	192.00	153.00	126.00	104.00	100.00	102.00
Lithuania					49.43	44.58	47.94	49.27	42.12
Luxembourg				21.60	18.50	22.80	16.60	21.30	23.80
Moldova					162.00	218.00	172.00	217.00	217.00
Montenegro									1,646.75
Poland	316.26	309.10	254.00	254.85	191.77	244.18	180.19	286.82	138.67
Portugal	172.98	97.25	78.48	88.70	74.89	66.76	64.08	102.00	80.98
Romania					361.05	307.75	289.93	283.92	224.14
Serbia					510.82	421.01	318.04	456.05	357.77
Slovenia	50.58	63.87	74.55	60.04	70.51	52.25	45.35	61.08	53.24
Spain	79.20	58.20	52.62	88.14	54.00	55.68	54.78	72.42	59.40
Sweden			88.18	151.94	83.73	118.15	75.62	62.89	126.50
Switzerland	14.00	16.00	22.00	15.00	13.00	11.00	9.00	10.00	14.00
Ukraine	579.05	518.86	511.86	527.06	534.38	617.36	690.47	727.62	692.87

TABLE A 4: Unplanned interruptions excluding exceptional events, SAIDI, EHV (minutes per customer per year)

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
Great Britain	1.38	1.87	1.27	0.90	3.24	1.16	0.93	0.94	0.92
Netherlands, The						12.20	0.00	0.00	0.00
Norway					3.85	2.34	0.58	0.25	0.08
Portugal	0.57	0.17	0.00	0.20	0.10	0.14	0.11	0.12	0.13
Switzerland									1.00

TABLE A 5: Unplanned interruptions excluding exceptional events, SAIDI, HV (minutes per customer per year)

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
Bosnia and Herzegovina					277.15	76.00	68.61	48.55	53.31
Denmark	2.17	1.86	1.41	0.70	0.62	1.89	1.10	1.60	0.86
Great Britain	33.89	31.55	24.87	24.39	24.05	20.43	18.05	17.61	18.22
Hungary	0.21	0.33	0.55	0.41	0.32	0.16	0.18	0.20	0.31
Ireland				10.09	5.80	6.01	6.97	6.03	5.52
Italy	2.85	2.34	1.33	1.93	2.88	1.59	1.16	1.35	1.05
Kosovo*						78.00	58.14	22.20	25.80
Lithuania					1.78	0.00	0.27	0.20	1.00
Netherlands, The				0.80	0.90	2.20	3.20	8.40	6.70
Norway					14.65	18.21	7.78	6.84	9.71
Portugal					18.18	12.83	13.71	2.73	28.80
Romania					8.60	1.79	96.94	2.13	4.27
Sweden			14.07	27.80	26.66	16.85	44.50	32.21	365.43
Switzerland	4.00	2.00	6.00	1.00	2.00	1.00	1.00	1.00	2.00
Ukraine	4.22	4.45	6.93	5.19	6.54	7.35	11.02	15.58	9.17

TABLE A 6: Unplanned interruptions excluding exceptional events, SAIDI, MV (minutes per customer per year)

Country[257]	2010	2011	2012	2013	2014	2015	2016	2017	2018
Cyprus					25.00	23.00	31.00	27.00	32.00
Denmark	12.49	12.15	11.27	8.79	9.12	10.84	12.01	12.50	14.26
France	44.34	34.28	39.73		31.01	30.92	29.44	33.06	34.36
Germany	12.10	12.68	13.35	12.80	10.09	10.45	10.69	12.92	11.57
Greece	116.26	96.92	96.00	91.00	88.00	89.00	92.00	93.06	114.10
Hungary	74.25	52.78	55.03	48.34	49.54	45.53	40.02	44.71	42.97
Ireland				71.36	85.47	71.37	67.32	78.88	85.55
Italy	28.46	26.12	27.31	25.36	24.49	27.58	22.21	27.56	28.68
Latvia				138.00	113.00	86.00	78.00	75.00	72.00
Lithuania					37.75	35.79	37.96	41.83	35.49
Moldova					162.00	218.00	172.00	217.00	217.00
Montenegro									1,557.25
Netherlands, The				15.90	12.80	12.60	11.70	10.20	14.10
Norway					98.86	103.84	76.09	56.15	110.70
Portugal	130.23	82.53	65.39	76.66	87.30	74.30	71.20	71.38	84.95
Romania					326.31	293.82	301.44	253.27	204.82
Sweden			69.32	122.32	102.15	92.97	80.82	75.75	103.12
Switzerland	7.00	12.00	14.00	12.00	10.00	8.00	6.00	7.00	9.00
Ukraine	475.17	428.10	429.29	435.71	435.93	507.06	574.28	600.37	580.46

257 Great Britain does not define MV, but provided values for the 132 kV level instead. Since that voltage level is not easily comparable with MV, GB is not included in this table, but the values are provided in this footnote. 2010: 0.36. 2011: 0.80. 2012: 0.41. 2013: 0.16. 2014: 0.52. 2015: 0.24. 2016: 0.30. 2017: 0.20. 2018: 0.15.

TABLE A 7: Unplanned interruptions excluding exceptional events, SAIDI, LV (minutes per customer per year)

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
Cyprus					12.00	10.00	6.00	7.00	7.00
Denmark	2.03	2.09	2.07	1.76	1.81	2.15	1.97	2.40	2.15
France	31.32	51.44	57.93	65.96	48.27	44.82	46.25	50.36	50.78
Germany	2.80	2.63	2.57	2.50	2.19	2.25	2.10	2.22	2.34
Great Britain	20.65	20.24	15.21	17.46	13.60	12.23	11.17	11.53	12.15
Greece	4.81	4.40	5.00	5.00	4.00	5.00	4.00	4.40	4.67
Hungary	28.08	22.40	20.73	18.47	24.47	20.94	18.95	23.63	16.78
Ireland				5.28	6.37	5.61	4.76	5.44	6.35
Italy	16.15	14.86	16.26	14.51	13.59	15.14	13.55	14.61	20.36
Kosovo*		5,928.6	6,576.6	5,133.0	4,818.6	4,904.4	2,959.2	3,010.8	3,913.8
Latvia				49.00	40.00	40.00	26.00	25.00	30.00
Lithuania					9.90	8.79	9.71	7.24	5.60
Montenegro									1,675.16
Netherlands, The				6.70	6.30	5.90	6.00	5.80	6.60
Norway					2.54	4.95	3.36	2.54	4.79
Portugal	172.98	97.25	78.48	88.70	74.89	66.76	64.08	66.57	80.98
Romania					367.44	310.41	289.91	284.00	224.20
Sweden			88.22	151.99	83.70	118.19	75.61	62.87	126.52
Switzerland	2.00	2.00	2.00	2.00	1.00	2.00	2.00	2.00	2.00
Ukraine	99.66	86.32	75.64	86.16	91.91	102.95	105.16	111.67	102.94

TABLE A 8: Planned interruptions, SAIFI (interruptions per customer per year)

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
Austria	0.16	0.15	0.13	0.13	0.14	0.13	0.13	0.12	0.13
Bosnia and Herzegovina					4.41	4.74	4.05	4.17	4.36
Croatia					1.63	1.66	1.51	1.45	1.18
Cyprus					0.12	0.11	0.11	0.11	0.13
Czech Republic	0.59	0.54	0.50	0.52	0.51	0.54	0.50	0.45	0.45
Denmark	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.03
Estonia					0.48	0.47	0.47	0.48	0.55
Finland	0.20	0.20	0.17	0.19	0.15	0.14	0.15	0.19	0.13
France	0.21	0.14	0.12	0.13	0.13	0.13	0.14	0.13	0.11
Georgia									8.87
Germany	0.09	0.10	0.12	0.08	0.08	0.08	0.08	0.07	0.08
Great Britain	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02
Greece	1.00	0.85	0.70	0.90	0.70	0.60	0.60	0.55	0.48
Hungary	0.61	0.55	0.54	0.43	0.45	0.53	0.53	0.44	0.46
Ireland				0.17	0.18	0.25	0.23	0.22	0.19
Italy	0.38	0.37	0.41	0.37	0.36	0.37	0.41	0.34	0.31
Kosovo*						11.98	45.47	34.17	13.73
Latvia	0.85	0.85	0.94	0.96	0.99	0.83	0.68	0.64	0.55
Lithuania					0.56	0.65	0.58	0.55	0.53
Luxembourg								0.03	0.03
Malta				0.63	0.76	0.63	0.61	4.69	0.54
Montenegro									6.05
Netherlands, The			0.03	0.03	0.03	0.03	0.03	0.04	0.04
Norway	0.26	0.28	0.27	0.26	0.29	0.30	0.30	0.32	0.29
Poland	0.68	0.82	0.70	0.62	0.56	0.50	0.46	0.36	0.34
Portugal	0.01	0.01	0.01	0.01	0.01	0.02	0.01	0.00	0.00[258]
Romania					0.80	0.77	0.65	0.66	0.61
Serbia	2.41	2.86	2.42	2.34	2.40	2.47	1.55	1.97	1.99
Slovenia	0.86	0.98	0.88	0.89	0.86	0.89	0.87	0.82	0.83
Spain			0.48	0.06	0.07	0.10	0.09		
Sweden			0.14	0.15	0.16	0.14	0.16	0.15	0.14
Switzerland	0.12	0.12	0.11	0.09	0.08	0.09	0.10	0.11	0.10
Ukraine	2.93	3.41	3.40	3.58	2.74	2.62	2.35	2.18	2.02

258 Since only two decimal points are used, the Portuguese values for 2017 (0.0024) and 2018 (0.0015) appear to be zero.

TABLE A 9: Unplanned interruptions, SAIFI, all events (interruptions per customer per year)

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
Austria	0.76	0.56	0.67	0.66	0.81	0.67	0.60	0.93	0.66
Belgium					0.59	0.56	0.58	0.67	0.63
Croatia					2.71	2.49	2.00	2.32	2.33
Cyprus					0.23	0.23	0.21	0.21	0.25
Czech Republic	1.78	1.82	1.89	2.13	1.86	2.11	1.71	2.31	1.79
Denmark	0.39	0.40	0.40	0.37	0.31	0.38	0.38	0.37	0.44
Estonia					0.65	1.26	1.49	1.26	1.37
Finland	1.81	2.58	1.77	2.16	1.60	2.37	1.43	1.38	1.52
Georgia									19.61
Germany	0.30	0.32	0.29	0.50	0.37	0.83	0.51	0.47	0.27
Great Britain	0.72	0.69	0.65	0.61	0.72	0.56	0.53	0.51	0.51
Greece	2.73	2.90	2.60	2.30	2.10	2.30	2.20	1.95	2.33
Hungary	1.63	1.26	1.17	1.15	1.13	1.10	0.99	1.21	0.99
Ireland				1.39	1.81	1.18	1.12	1.73	1.71
Italy	2.27	2.08	2.33	2.20	1.99	2.43	1.76	2.05	2.14
Latvia	4.15	4.74	3.84	3.52	2.78	2.35	2.45	2.14	1.93
Lithuania					1.29	1.06	1.25	1.31	1.10
Luxembourg									0.35
Malta				4.13	4.59	2.49	1.99	0.59	1.87
Moldova					2.48	4.50	4.80	6.70	5.40
Montenegro									28.88
Netherlands, The			0.29	0.30	0.28	0.44	0.29	0.28	0.41
Norway	1.31	2.44	1.36	1.96	2.15	1.87	1.59	1.37	1.97
Poland	3.77	4.22	3.44	3.32	2.96	3.61	3.00	3.72	2.58
Portugal	4.32	2.41	1.88	3.09	1.89	1.53	1.64	1.98	1.90
Romania					5.06	4.72	4.35	4.70	4.32
Serbia	9.11	7.59	7.37	6.45	7.98	6.55	5.29	6.42	6.00
Slovenia	1.81	1.81	2.99	2.20	4.31	1.77	1.62	2.73	1.74
Spain	1.96	1.42	6.89	1.04	1.13	1.21	1.11	1.34	1.26
Sweden			1.33	1.33	1.30	1.22	1.17	1.08	1.49
Switzerland	0.28	0.28	0.34	0.28	0.22	0.23	0.20	0.22	0.30
Ukraine	4.70	4.86	5.32	5.56	13.56	6.63	8.02	8.14	8.25

TABLE A 10: Unplanned interruptions excluding exceptional events, SAIFI (interruptions per customer per year)

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
Austria	0.75	0.55	0.65	0.63	0.62	0.57	0.59	0.72	0.61
Bosnia and Herzegovina					5.61	5.38	5.20	6.00	4.96
Croatia					1.83	1.94	1.44	1.52	1.63
Cyprus					0.23	0.22	0.21	0.20	0.25
Czech Republic	1.64	1.65	1.81	1.69	1.60	1.55	1.45	1.53	1.47
Denmark	0.39	0.40	0.40	0.32	0.31	0.37	0.38	0.37	0.43
France	0.87	0.77	0.82	0.80	0.68	0.69	0.63	0.68	0.69
Georgia									14.04

TABLE A 10: Unplanned interruptions excluding exceptional events, SAIFI (interruptions per customer per year)

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
Germany	0.26	0.31	0.27	0.48	0.34	0.63	0.50	0.44	0.25
Great Britain	0.69	0.68	0.60	0.59	0.60	0.54	0.48	0.48	0.47
Greece	2.10	1.94	1.73	1.60	1.70	1.50	1.47	1.51	1.62
Hungary	1.45	1.21	1.16	1.04	1.07	1.01	0.90	0.94	0.91
Ireland				1.14	1.24	1.03	1.04	1.21	1.23
Italy	1.80	1.67	1.74	1.63	1.65	1.75	1.50	1.68	1.76
Kosovo*						52.21	28.36	26.91	55.31
Latvia			3.40	2.90	2.38	2.14	2.20	1.99	1.89
Lithuania					0.67	0.60	0.62	0.67	0.68
Luxembourg				0.32	0.29	0.36	0.23	0.26	0.35
Moldova					2.09	3.11	2.81	2.97	3.36
Montenegro									26.00
Poland	3.74	4.14	3.42	3.02	2.95	3.60	2.99	3.69	2.58
Portugal	3.14	1.94	1.62	1.75	1.56	1.44	1.45	1.47	1.55
Romania					4.35	4.19	3.83	3.54	3.20
Serbia					6.78	6.41	4.96	5.48	5.03
Slovenia	1.40	1.63	2.16	1.59	1.89	1.45	1.21	1.54	1.34
Spain	1.82	1.42	4.05	1.28	1.13	1.21	1.11	1.34	1.26
Sweden			1.33	1.33	1.30	1.22	1.17	1.08	1.49
Switzerland	0.28	0.28	0.34	0.28	0.22	0.23	0.20	0.21	0.27
Ukraine	3.68	4.05	4.34	4.59	4.73	5.50	6.93	6.88	6.83

TABLE A 11: Unplanned interruptions excluding exceptional events, SAIFI, EHV (interruptions per customer per year)

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
Great Britain	0.05	0.06	0.05	0.04	0.06	0.05	0.04	0.04	0.04
Netherlands, The						0.12			
Norway					0.13	0.06	0.05	0.01	0.01
Portugal	0.04	0.03		0.04	0.03	0.01	0.03	0.04	0.02
Switzerland				0.02			0.01		0.02

TABLE A 12: Unplanned interruptions excluding exceptional events, SAIFI, HV (interruptions per customer per year)

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
Bosnia and Herzegovina					0.80	0.90	0.97	0.81	0.69
Denmark	0.07	0.11	0.08	0.07	0.06	0.09	0.09	0.08	0.10
France	0.06	0.06	0.08	0.10	0.07	0.09	0.08	0.07	0.08
Great Britain	0.46	0.45	0.40	0.39	0.38	0.35	0.31	0.31	0.31
Hungary	0.01	0.05	0.02	0.03	0.03	0.02	0.02	0.02	0.02
Ireland				0.19	0.16	0.13	0.18	0.16	0.13
Italy	0.12	0.09	0.11	0.12	0.16	0.12	0.09	0.10	0.09
Kosovo*						1.51	1.04	0.46	1.20
Lithuania					0.02	0.00	0.01	0.01	0.01
Netherlands, The				0.05	0.04	0.09	0.07	0.10	0.16
Norway					0.45	0.32	0.25	0.24	0.24
Portugal					0.23	0.22	0.21	0.18	0.21
Romania					0.17	0.11	0.09	0.05	0.15
Sweden			0.24	0.42	0.53	0.37	0.50	0.29	0.54
Switzerland	0.08	0.07	0.10	0.06	0.06	0.05	0.04	0.04	0.04
Ukraine	0.07	0.12	0.14	0.11	0.12	0.14	0.16	0.17	0.17

TABLE A 13: Unplanned interruptions excluding exceptional events, SAIFI, MV (interruptions per customer per year)

Country[259]	2010	2011	2012	2013	2014	2015	2016	2017	2018
Cyprus					0.18	0.19	0.19	0.20	0.18
Denmark	0.30	0.27	0.30	0.24	0.23	0.26	0.27	0.27	0.32
France	0.88	0.78	0.82	0.80	0.70	0.68	0.63	0.70	0.70
Germany	0.24	0.29	0.25	0.46	0.33	0.61	0.49	0.42	0.23
Greece	2.03	1.88	1.65	1.50	1.60	1.44	1.42	1.45	1.57
Hungary	1.24	1.00	0.99	0.86	0.89	0.86	0.77	0.78	0.77
Ireland				0.93	1.06	0.87	0.83	1.02	1.07
Italy	1.47	1.37	1.38	1.28	1.27	1.41	1.20	1.37	1.42
Latvia				2.45	2.12	1.88	2.00	1.81	1.70
Lithuania					0.52	0.48	0.51	0.58	0.58
Moldova					2.09	3.11	2.81	2.97	3.36
Montenegro									25.25
Netherlands, The				0.20	0.20	0.18	0.17	0.14	0.21
Norway					1.60	1.43	1.27	1.10	1.69
Portugal	3.02	1.88	1.57	1.70	1.84	1.64	1.68	1.55	1.77
Romania					4.80	5.16	6.11	3.60	3.22
Sweden			0.94	1.07	1.03	0.92	0.99	0.89	1.28
Switzerland	0.17	0.20	0.22	0.19	0.14	0.17	0.12	0.15	0.18
Ukraine	3.04	3.41	3.68	3.83	3.94	4.62	5.97	5.92	5.93

259 Great Britain does not define MV, but provided values for the 132 kV level instead. Since that voltage level is not easily comparable with MV, GB is not included in this table, but the values are provided in this footnote. 2010: 0.02. 2011: 0.02. 2012: 0.01. 2013: 0.01. 2014: 0.02. 2015: 0.01. 2016: 0.02. 2017: 0.01. 2018: 0.01.

TABLE A 14: Unplanned interruptions excluding exceptional events, SAIFI, LV (interruptions per customer per year)

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
Cyprus					0.05	0.04	0.02	0.01	0.07
Denmark	0.02	0.02	0.02	0.01	0.02	0.02	0.02	0.02	0.02
France	0.87	0.77	0.82	0.80	0.68	0.69	0.63	0.68	0.69
Germany	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Great Britain	0.10	0.10	0.08	0.09	0.07	0.08	0.07	0.07	0.07
Greece	0.07	0.06	0.08	0.10	0.10	0.06	0.05	0.06	0.05
Hungary	0.20	0.16	0.16	0.15	0.14	0.13	0.12	0.13	0.11
Ireland				0.03	0.03	0.02	0.02	0.03	0.03
Italy	0.21	0.19	0.23	0.21	0.20	0.21	0.20	0.20	0.23
Kosovo*		49.74	56.91	43.27	29.57	50.70	27.23	26.45	54.11
Latvia				0.29	0.26	0.26	0.20	0.18	0.20
Lithuania					0.12	0.12	0.10	0.09	0.08
Montenegro									26.16
Netherlands, The				0.04	0.04	0.04	0.04	0.04	0.04
Norway					0.02	0.02	0.02	0.02	0.02
Portugal	3.14	1.94	1.62	1.75	1.56	1.44	1.45	1.40	1.55
Romania					4.49	4.30	3.83	3.54	3.20
Sweden			1.33	1.33	1.30	1.22	1.17	1.08	1.49
Switzerland	0.02	0.02	0.02	0.02	0.01	0.01	0.02	0.02	0.03
Ukraine	0.57	0.52	0.52	0.64	0.66	0.74	0.80	0.79	0.72

TABLE A 15: Unplanned interruptions, MAIFI (short interruptions per customer per year)

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
Belgium		0.08	0.07	0.07	0.06	0.06	0.06	0.06	0.05
Bosnia and Herzegovina[260]					9.42	7.67	8.96	11.61	14.27
Finland	5.53	7.06	4.58	5.38	5.25	3.98	3.50	2.95	2.91
France	2.01	1.66	1.76	1.96	1.84	1.68	1.64	1.67	1.59
Great Britain	0.78	0.71	0.85	0.79	1.01	0.85	0.87	0.84	0.96
Hungary	2.85	2.39	2.16	2.40	2.42	2.44	2.26	3.53	2.70
Latvia				3.52	3.25	3.27	3.19	2.61	2.85
Lithuania					0.54	0.85	0.88	0.87	0.56
Norway	1.45	2.40	1.57	1.92	2.15	1.87	1.67	1.50	2.09
Poland	3.67	3.41	3.52	3.25	3.72	5.05	6.08	6.56	5.80
Portugal					13.25	10.36	10.59	11.49	12.36
Romania									4.58
Slovenia		4.31	6.37	5.70	9.41	5.20	6.30	8.98	7.18
Sweden			0.85	0.86	1.09	0.81	0.82	0.68	0.85
Ukraine	0.16	0.40	0.61	0.67	0.70	0.77	1.16	1.21	1.27

260 MAIFI is recorded in Republika Srpska.

TABLE A 16: Unplanned interruptions, MAIFI-E (short interruptions per customer per year)

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
Hungary	6.91	6.31	4.60	4.36	5.70	4.94	4.74	5.57	5.33
Italy	2.79	2.34	2.33	2.24	2.11	2.23	1.87	1.93	2.17
Norway	1.45	2.40	1.57	1.92	2.15	1.87	1.67	1.50	2.09
Portugal					0.04	0.09	0.04	0.05	0.05
Slovenia						3.34	4.77	6.38	5.31

TABLE A 17: Unplanned AIT (minutes per year)

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
Belgium		1.71	2.18	1.76	3.45	1.25	1.90	2.13	0.84
Bosnia and Herzegovina					19.12	21.02	28.70	33.39	33.52
Croatia									3,370.00
Cyprus					120.83	38.99	44.10	26.06	18.84
Czech Republic	5.00	15.40	4.00	18.38	15.83	17.50	16.00	7.70	32.00
Estonia					410.30	552.00	1,404.70	905.00	1,745.00
Finland			0.34	0.88	2.90	1.05	0.75	2.56	346.84
France	2.90	1.70	2.30	3.00	2.80	5.73	2.90	1.45	3.00
Greece			13.61	23.78	19.65	30.61	20.93	18.96	19.64
Hungary	0.13	0.09	0.06	0.00	0.04	0.03	0.03	0.01	0.03
Italy	3.41	4.88	6.17	4.65	2.68	5.29	2.69	6.68	2.59
Latvia					0.50	0.70	0.68	0.83	0.74
Lithuania					0.25	0.22	0.04	0.06	0.04
Moldova			26.70	21.99	25.40	10.10	33.70	38.80	27.10
Montenegro									86.56
Norway					11.38	6.93	1.77	0.78	0.32
Poland	0.00	21.14	0.00	10.00	0.00	0.15	0.00	20.72	0.00
Portugal	1.16	0.28	0.00	0.09	0.02	0.00	0.12	0.09	0.03
Romania					0.82	0.36	2.11	2.76	1.13
Serbia					14.03	17.86	18.40	21.38	11.46
Slovakia							11.09	2.19	0.32
Slovenia		2.17	4.92	4.79	2,250.13	2.80	1.36	2.37	1.46
Spain			0.24	2.40	0.44	0.11	0.14	0.30	0.71
Sweden			0.03	0.00	0.05	0.04	0.01	0.01	1.26
Ukraine								5.93	9.00

TABLE A 18: Unplanned ENS (MWh)

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
Belgium		235.47	293.81	237.48	453.79	161.09	242.33	270.81	105.40
Bosnia and Herzegovina					420.75	467.22	528.46	1,362.35	1,181.83
Croatia									292.29
Cyprus					992.00	335.00	407.00	248.00	180.00
Czech Republic	7.00	161.30	4.50	167.50	231.00	64.00	16.00	22.00	27.00
Estonia					27.56	11.93	67.54	44.22	18.53
Finland			60.00	150.00	490.00	170.00	139.67	432.92	59,139.51
France	2,300.00	1,600.00	3,600.00	2,750.00	2,170.00	5,540.00	2,320.00	1,148.00	2,328.00
Greece			1,275.00	2,050.63	1,672.13	2,645.03	1,806.75	1,666.66	1,701.00
Hungary	10.43	7.40	4.53	0.00	3.21	2.45	2.73	0.46	2.50
Italy	2,175.00	3,131.00	3,886.00	2,839.00	1,593.00	3,209.00	1,623.00	4,104.00	1,595.00
Kosovo*						1,150.00	1,150.00	489.00	378.00
Latvia					1,316.00	1,241.00	1,318.80	1,231.00	64.20
Lithuania					5.36	4.54	1.03	1.68	0.95
Moldova			214.70	219.67	260.68	78.03	255.50	297.90	215.75
Montenegro									536.96
Norway					1,006.37	531.98	131.18	613.76	30.67
Poland	0.00	95.01	0.00	42.66	0.00	0.67	0.00	125.22	0.00
Portugal	116.20	27.00	0.00	8.60	1.80	0.40	11.00	9.10	2.50
Romania					82.51	38.36	224.69	289.46	118.81
Serbia					873.38	1,149.91	1,177.32	1,382.88	734.46
Slovenia		52.06	116.49	114.10	52,340.37	67.77	32.90	70.84	36.69
Spain			344.00	1,278.00	365.00	232.00	524.30	140.00	350.00
Sweden			6.90	0.20	10.60	9.30	1.10	1.30	290.10
Ukraine								1,278.54	1,948.80

B.2 SYSTEM DATA

TABLE A 19: Circuit length, EHV (km)

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
Austria	6,421.11	6,513.69	6,504.38	6,504.83	6,729.41	6,728.00	6,764.67	6,763.17	6,763.06
Belgium	1,753.00	1,768.00	1,759.00	1,758.00	1,751.00		1,862.00	1,954.00	1,975.00
Croatia			2,457.00	2,511.00	2,460.00	2,460.00	2,458.00	2,460.00	2,493.00
Denmark	2,821.00	2,827.00	46.00	46.00	46.00	46.00	0.00	0.00	0.00
Estonia					1,940.00	1,940.00	1,940.00	1,943.00	1,943.00
Finland	6,968.00	7,154.00	7,165.00	7,376.40	7,378.40	7,245.40	6,977.00	6,990.00	7,039.00
Germany	34,749.00	34,797.00	35,270.00	34,979.00	34,737.00	35,970.00	35,970.00	37,267.00	36,700.00
Great Britain		53,588.00	53,676.00	52,730.00	53,051.00	53,796.00	54,133.00	54,846.00	55,006.00
Greece	4,407.20		4,560.30	4,698.28	4,698.50	4,699.05	4,920.55	4,920.55	4,736.00
Hungary									4,645.00
Italy	21,997.00	20,581.00	21,960.00	21,895.00	21,931.00	22,080.00	22,254.00	22,078.00	22,319.00
Luxembourg						300.00	341.00	341.00	345.00
Malta						117.70	117.70	117.70	117.70
Netherlands, The			2,872.10	2,973.50	2,973.70	2,968.80	2,986.90	3,016.62	3,022.79
Norway				11,167.00	11,773.00	11,735.00	12,477.00	12,595.00	12,608.00
Poland	13,506.00	13,472.00	13,529.00	13,725.00	13,688.00	14,281.00	14,334.00	14,403.00	14,888.00
Portugal	8,049.00	8,371.00	8,534.00	8,733.00	8,629.00	8,805.00	8,863.00	8,907.00	8,907.00
Romania					8,735.00	8,735.00	8,794.00	8,794.00	8,850.00
Slovakia									6,880.00
Slovenia	836.00	836.00	836.00	997.00	997.00	997.00	997.00	997.00	997.00
Spain					20,661.69	20,944.83	20,966.42	21,077.42	21,079.07
Sweden			15,170.00	15,197.00	15,272.00	14,794.00	14,838.90	14,870.90	14,903.00
Switzerland	6,750.00	6,750.00	6,750.00	6,750.00	6,750.00	6,750.00	6,629.00	6,590.00	6,652.00
Ukraine	22,295.86	22,255.46	22,252.32	22,252.32	22,332.52	22,332.52	21,038.76	19,345.38	19,933.03

TABLE A 20: Circuit length, HV (km)

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
Albania									3,388.10
Austria	11,166.26	11,119.81	11,169.88	11,180.59	11,276.92	11,381.09	11,435.30	11,478.23	11,507.45
Belgium	9,540.00	9,521.00	9,537.00	9,550.00	9,604.00		9,605.00	9,484.00	9,400.00
Bosnia and Herzegovina					6,309.94	6332.66	6320.94	6371.11	6402.09
Croatia			4,917.00	4,939.00	5,188.00	5,108.00	5,096.00	5,223.00	5,298.00
Cyprus					1,360.29	1,360.82	1,330.74	1,325.33	1,356.67
Denmark	8,857.00	8,850.00	8,412.00	8,392.00	8,479.00	8,343.00	8,438.00	8,310.00	8,190.00
Estonia					3,564.00	3,565.00	3,565.00	3,568.00	3,568.00
Finland	15,925.00	15,776.00	15,791.10	16,024.20	16,171.00	16,268.15	16,495.08	16,262.72	16,341.25
Germany	95,154.00	95,022.00	95,425.00	96,308.00	96,373.00	96,658.00	96,749.00	94,480.00	94,600.00
Great Britain		324,947	326,224	325,900	326,702	327,972	328,872	329,902	330,882
Greece	12,660.80		12,772.60	12,832.70	12,733.99	13,209.18	13,369.26	13,426.66	12,945.00
Hungary									8,465.00
Ireland					7,266.00	13,794.00	13,993.00	14,214.00	14,390.00
Italy	45,758.00	45,649.00	46,102.00	46,300.00	46,575.00	48,894.00	48,832.00	48,801.00	48,766.00
Kosovo*					1,233.00	1,324.00	1,353.00	1,353.10	1,377.00
Latvia					5,359.14	5,337.43	5,324.57	5,329.04	5,338.92
Lithuania					6,792.00	7,029.00	7,080.00	7,048.00	7,143.90
Luxembourg						818.00	803.70	820.00	821.40
Malta				48.00	61.00	67.00	86.70	86.70	90.80
Moldova					5,739.24	5,732.24	5,732.24	5,732.24	5,732.24
Montenegro	1,356.70	1,356.70	1,358.20	1,346.80	1,345.80	1,345.80	1,355.40	1,350.80	1,351.30
Netherlands, The			9,798.85	9,651.73	9,710.98	9,773.35	9,731.37	9,735.67	9,759.36
North Macedonia					2,202.83	2,450.00	2,458.00	2,450.00	2,447.00
Norway				19,253.00	19,295.00	18,829.00	18.848.00	18,950.00	19,138.00
Poland	32,712.00	32,739.00	34,380.00	32,936.00	33,082.00	33,224.00	33,454.00	33,665.00	33,769.00
Portugal	8,981.00	9,114.00	9,140.00	9,303.00	9,375.00	9,427.00	9,516.00	9,516.00	9,516.00
Romania					22,312.00	19,592.00	22,206.42	22,222.00	22,245.00
Serbia					9,639.57	9,712.15	9,745.41	9,884.41	9,979.94
Slovakia									33,649.00
Slovenia	2,589.00	2,614.00	2,723.00	2,802.00	2,798.00	2,732.00	2,770.00	2,786.00	2,823.00
Spain					115,426.16	115,518.24	116,408.61	116.637,48	117,547.17
Sweden			30,272.00	30,515.00	30,750.00	30,825.00	31,034.00	31,141.00	31,057.00
Switzerland	8,950.00	8,852.00	8,898.00	9,035.00	9,189.00	8,815.00	8,662.00	8,783.00	8,683.00
Ukraine	41,345.49	40,959.24	41,091.52	41,317.11	41,323.22	38,278.13	37,140.89	38,105.37	35,983.97

TABLE A 21: Circuit length, MV (km)

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
Albania									16,350.00
Austria	67,105.53	67,681.55	68,067.78	68,336.99	68,693.24	68,906.37	69,061.74	67,410.02	67,863.52
Belgium					75,817.00	75,865.00	76,029.00	76,324.00	76,787.00
Bosnia and Herzegovina					26,942.00	27,083.00	27,201.00	27,401.00	27,572.00
Croatia			41,467.00	40,478.00	40,599.00	40,971.00	41,253.00	41,645.00	41,731.00
Cyprus					9,576.52	9,645.94	9,667.83	9,759.19	9,880.59
Denmark	63,128.00	63,387.00	63,629.00	63,562.00	63,809.00	63,275.00	63,243.00	61,012.00	60,729.00
Estonia					31,609.50	29,662.50	29,432.50	29,401.50	29,309.50
Finland	137,697.00	138,153.00	139,013.50	140,212.80	141,289.50	143,111.42	145,818.81	148,509.38	151,782.82
France		613,123.35	617,642.00	622,155.99	626,835.01	631,414.86	635,613.89	640,688.36	644,900.77
Germany	497,044.00	532,894.00	507,953.00	509,866.00	511,591.00	511,164.00	520,326.00	520,010.00	519,200.00
Greece	106,204.00	107,519.00	108,746.00	109,686.00	110,750.00	111,139.00	111,559.00	111,865.00	112,295.00
Hungary								67,081.09	67,201.99
Ireland					92,326.00	92,619.00	92,859.00	93,161.00	93,705.00
Italy	377,365.00	383,076.00	385,662.00	387,730.00	388,762.00	390,336.00	391,594.00	393,022.00	394,584.00
Kosovo*					7,709.50	7,467.00	7,314.00	7,435.00	7,637.00
Latvia					35,648.00	35,380.00	35,469.00	35,550.00	35,541.00
Lithuania						55 182,81	55 274,35	55 235,12	55,166.42
Luxembourg						3,778.00	3,916.00	4,014.00	4,087.00
Malta				1,399.70	1,394.20	1,398.1	1,496.4	1,537.30	1,594.60
Moldova					22,059.20	22,014.84	21,988.34	21,911.70	21,828.64
Montenegro	5,950.00	5,992.40	5,861.70	5,919.20	5,893.70	6,017.30	6,061.30	6,072.30	6,223.70
Netherlands, The			104,022.42	104,534.34	105,131.22	105,753.58	106,305.48	106,731.66	106,463.13
North Macedonia					11,340.00	11,427.00	11,555.80	11,637.80	11,657.00
Norway				100,481.00	101,085.00	101,844.00	102,499.00	103,214.00	103,758.00
Poland	289,029.00	290,736.00	313,192.00	294,028.00	294,756.00	296,921.00	296,132.00	298,055.00	300,066.00
Portugal	73,472.00	74,142.00	74,179.00	74,319.00	72,319.00	72,749.00	73,042.00	73,042.00	73,042.00
Romania					119,017.00	106,396.00	119,306.00	119,723.00	120,313.00
Serbia					51,194.17	51,541.69	52,023.74	52,407.99	53,537.32
Slovenia	17,516.00	17,571.00	17,696.00	17,422.00	17,425.00	17,600.00	17,798.00	17,880.00	18,009.00
Spain					276,868.41	278,551.60	277,951.68	276,662.74	278,195.99
Sweden			193,960.00	196,991.00	199,091.00	202,602.00	201,376.00	202,983.00	202,723.00
Switzerland	42,839.00	43,258.00	43,744.00	43,984.00	44,458.00	44,460.00	44,105.00	44,459.00	44,765.00
Ukraine	411,437.59	414,015.03	423,420.61	422,235.34	418,321.36	396,375.22	382,999.40	382,606.18	372,057.06

TABLE A 22: Circuit length, LV (km)

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
Albania									24,973.00
Austria	165,305.52	166,065.85	167,412.49	169,174.89	170,501.27	171,892.00	173,370.42	172,619.55	173,570.04
Belgium					125,524.00	126,155.00	126,926.00	127,637.00	128,758.00
Bosnia and Herzegovina					66,706.00	68,188.00	69,816.00	70,732.00	70,952.00
Croatia			95,271.00	95,420.00	95,173.00	95,837.00	100,092.00	98,790.00	97,058.00
Cyprus					15,606.48	15,816.10	15,959.67	16,203.16	16,482.18
Denmark	95,370.00	95,797.00	94,856.00	94,132.00	93,482.00	92,944.00	92,905.00	89,429.00	89,123.00
Estonia					37,192.90	35,814.80	35,770.80	35,726.80	35,744.90
Finland	235,943.00	237,966.00	239,283.30	238,111.40	239,959.10	241,988.86	242,791.58	246,119.90	249,183.05
France		691,964.59	697,151.21	701,796.65	706,106.44	709,481.38	713,262.12	717,090.23	721,000.29
Germany	1,123,898.0	1,134,668.0	1,149,973.0	1,156,785.0	1,164,311.0	1,173,065.0	1,190,704.0	1,193,628.0	1,200,500.0
Great Britain		394,064.00	395,804.00	391,488.00	389,634.00	390,926.00	391,629.00	391,758.00	392,789.00
Greece	119,916.00	121,409.00	122,470.00	123,352.00	124,575.00	125,164.00	125,798.00	126,377.00	126,941.00
Hungary								87,672.65	87,999.06
Ireland					70,460.00	71,033.00	71,607.00	72,285.00	72,552.00
Italy	828,737.00	830,444.00	839,832.00	852,835.00	857,977.00	861,390.00	865,536.00	869,236.00	873,393.00
Kosovo*					11,665.00	18,615.00	19,147.00	19,211.00	20,088.20
Latvia					58,961.00	58,740.00	58,345.00	58,010.00	57,634.00
Lithuania						70,645.00	70,378.00	69,920.00	69,910.00
Luxembourg						6,360.00	6,453.00	6,694.00	6,777.00
Malta				2,847.00	3,028.20	3,118.00	3,429.30	3,286.70	3,376.00
Moldova					33,593.95	33,538.35	33,388.95	33,285.25	33,163.15
Montenegro	12,890.00	12,897.30	13,066.70	13,155.70	13,216.50	13,256.70	13,349.40	13,351.80	13,293.80
Netherlands, The			145,251.40	145,213.90	145,610.50	146,137.30	146,787.00	147,622.44	148,376.06
North Macedonia					15,452.00	15,739.00	16,000.00	16,221.00	16,406.00
Norway				199,074.00	207,258.00	204,716.00	206,767.00	211,280.00	212,319.00
Poland	424,803.00	430,477.00	498,113.00	468,979.00	469,979.00	471,586.00	464,638.00	468,868.00	474,032.00
Portugal	137,864.00	139,371.00	140,415.00	141,324.00	141,829.00	142,325.00	142,834.00	142,834.00	142,834.00
Romania					181,766.00	165,941.00	182,903.00	183,628.00	183,723.00
Serbia					113,136.75	114,057.84	114,719.95	115,379.22	115,639.29
Slovakia									55,083.00
Slovenia	45,499.00	45,656.00	45,778.00	45,808.00	45,534.00	45,814.00	45,808.00	45,258.00	45,009.00
Spain					444,353.82	453,648.60	457,747.40	451,898.63	456,479.85
Sweden			305,673.00	311,283.00	314,372.00	316,179.00	317,520.00	319,372.00	319,373.00
Switzerland	130,336.00	130,062.00	132,174.00	136,326.00	138,599.00	142,174.00	143,872.00	142,430.00	144,783.00
Ukraine	483,787.91	479,245.30	479,695.40	464,448.28	468,363.35	453,935.50	435,612.92	434,045.85	422,468.65

TABLE A 23: Underground cable length, EHV (km)

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
Austria	59.10	59.30	59.30	59.30	59.30	62.99	62.99	61.49	61.94
Belgium						5.00	5.00	25.00	54.00
Denmark	596.00	599.00							
Finland				233.40	233.40	233.40	271.00	271.00	271.00
Germany								118.20	329.00
Great Britain		21,267.00	21,601.00	20,859.00	21,258.00	22,107.00	22,579.00	23,342.00	23,576.00
Greece			4.70	30.58	30.80	31.35	31.35	31.35	31.35
Luxembourg						27.00	37.00	37.00	41.00
Malta						18.99	18.99	18.99	18.99
Netherlands, The			45.86	63.59	62.66	59.36	61.28	67.40	69.49
Norway				59.00	75.00	93.00	125.00	125.00	108.00
Poland	1.00	1.00	1.00	125.00	128.00	129.00	129.00	129.00	129.00
Spain					59.13	62.82	60.12	60.91	60.80
Sweden			102.00	103.00	116.00	121.00	155.00	177.00	209.00

TABLE A 24: Underground cable length, HV (km)

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
Austria	621.56	649.97	659.94	724.50	765.29	773.06	773.54	758.93	784.47
Belgium						2,869.00	2,927.00	2,892.00	2,888.00
Bosnia and Herzegovina					33.15	33.15	33.15	33.15	33.15
Croatia									86.00
Cyprus					212.08	212.08	222.23	227.93	227.93
Denmark	3,026.00	3,037.00	2,938.00	2,991.00	3,132.00	2,987.00	3,094.00	3,061.00	3,031.00
Estonia					63.00	64.00	64.00	72.00	72.00
Finland	204.96	205.28	226.79	231.10	236.59	248.11	306.32	324.99	335.61
Germany								6,436.66	6,544.11
Great Britain		155,563	156,804	157,393	158,566	160,149	161,917	163,321	164,605
Greece	282.90		292.70	312.40	341.57	396.85	388.19	403.49	382.70
Hungary									146.00
Ireland					1,144.00	1,438.00	1,459.00	1,648.00	1,764.00
Latvia					86.50	86.50	86.76	89.07	95.25
Lithuania					64.50	98.40	102.90	105.00	106.20
Luxembourg						89.00	97.00	135.00	137.00
Malta				48.00	61.00	67.00	86.70	86.70	90.80
Montenegro				3.60	3.60	3.60	7.30	7.30	7.30
Netherlands, The			4,211.12	4,122.99	4,147.51	4,230.90	4,276.18	4,278.80	4,252.99
Norway				1,278.00	1,228.00	1,205.00	1,200.00	1,214.00	1,360.00
Poland	136.00	157.00	182.00	205.00	240.00	259.00	295.00	392.00	408.00
Romania					366.00	394.00	400.00	405.00	429.00
Serbia					33.64	33.64	36.40	42.38	42.38
Slovenia					28.00	32.00	36.00	40.00	44.00
Spain					11,030.31	11,106.73	11,455.96	11,624.16	11,800.51
Sweden			1,011.00	1,231.00	1,557.00	1,550.00	1,761.00	1,783.00	1,697.00
Switzerland	1,893.00	1,917.00	1,980.00	1,976.00	2,031.00	1,911.00	1,924.00	1,992.00	1,906.00
Ukraine	73.14	80.17	94.69	115.34	122.37	128.51	126.30	131.21	139.39

TABLE A 25: Underground cable length, MV (km)

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
Austria	36,523.90	37,800.38	39,321.01	40,185.67	41,164.83	42,121.07	42,939.60	42,192.90	43,085.77
Belgium					70,000.00	70,205.00	70,655.00	71,102.00	71,736.00
Bosnia and Herzegovina					4,998.00	5,088.00	5,325.00	5,495.00	5,595.00
Croatia									17,872.00
Cyprus					3,760.24	3,785.39	3,812.05	3,864.97	3,939.53
Denmark	59,824.00	60,666.00	61,576.00	62,023.00	62,450.00	62,112.00	62,314.00	60,405.00	60,266.00
Estonia					9,007.50	8,546.50	8,693.50	8,860.50	9,011.60
Finland	15,925.00	17,000.00	18,376.00	20,406.00	23,163.16	27,144.24	32,779.10	40,445.26	48,138.72
France		261,456.76	270,473.30	279,270.87	288,207.95	296,344.74	303,992.41	312,580.71	319,781.74
Germany	377,660.00	382,009.00	394,538.00	398,232.00		407,286.00	414,145.00	422,416.64	424,404.32
Greece	9,481.00	9,913.00	10,132.00	10,315.00	10,609.00	10,727.00	10,818.00	10,892.00	11,030.00
Hungary								13,461.83	13,616.20
Ireland					9,526.00	9,602.00	9,705.00	9,825.00	10,027.00
Italy	161,756.00	167,415.00	170,175.00	172,277.00	173,660.00	175,428.00	176,965.00	178,615.00	180,450.00
Kosovo*					1,165.90	1,331.00	1,233.00	1,326.00	1,452.00
Latvia					6,456.00	6,831.00	7,186.00	7,531.00	7,876.00
Lithuania						12,296.00	12,828.00	13,628.00	15,051.00
Luxembourg						2,712.00	2,870.00	3,001.00	3,099.00
Malta				1,290.40	1,295.50	1,315.90	1,415.30	1,442.10	1,505.00
Montenegro	1,310.00	1,332.60	1,344.50	1,381.10	1,422.60	1,512.70	1,540.40	1,548.90	1,711.10
Netherlands, The			104,022.40	104,534.32	105,131.20	105,753.56	106,305.46	106,731.64	106,463.13
North Macedonia					2,677.00	2,769.00	2,909.00	3,002.00	3,047.00
Norway				39,106.00	39,949.00	41,113.00	42,136.00	43,141.00	43,983.00
Poland	63,540.00	65,212.00	67,313.00	69,109.00	70,931.00	72,923.00	74,335.00	76,980.00	79,838.00
Portugal	15,527.00	16,009.00	16,027.00	16,044.00	14,135.00	14,316.00	14,436.00	14,436.00	14,436.00
Romania					28,682.00	26,291.00	29,139.00	29,499.00	30,137.00
Serbia					13,118.03	13,346.81	13,690.66	13,953.14	14,197.12
Slovenia	4,921.00	5,133.00	5,312.00	5,316.00	5,482.00	5,737.00	5,967.00	6,178.00	6,440.00
Spain					84,758.92	84,831.98	85,169.56	86,161.54	87,363.10
Sweden			107,018.00	111,894.00	116,112.00	121,376.00	123,263.00	127,440.00	132,267.00
Switzerland	30,607.00	31,370.00	32,174.00	32,833.00	33,544.00	33,870.00	34,044.00	34,675.00	35,307.00
Ukraine	47,351.86	48,696.59	50,545.27	50,964.80	51,054.98	47,107.34	44,381.10	43,854.61	42,754.66

TABLE A 26: Underground cable length, LV (km)

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
Albania									1,835.00
Austria	125,587.20	127,517.80	130,324.85	133,056.52	135,192.24	137,528.45	139,754.28	140,662.82	142,583.50
Belgium					76,780.00	77,944.00	78,917.00	79,962.00	81,195.00
Bosnia and Herzegovina					4,827.00	5,238.00	5,794.00	6,018.00	6,147.00
Croatia									30,119.00
Cyprus					5,848.49	5,844.32	6,038.26	6,198.34	6,411.44
Denmark	91,517.00	92,431.00	92,014.00	92,540.00	92,659.00	92,646.00	92,708.00	89,358.00	89,069.00
Estonia					10,918.90	10,409.80	10,619.80	10,797.80	11,033.90
Finland	85,823.00	89,208.00	92,340.00	92,843.00	97,807.33	102,746.44	107,978.10	115,319.73	122,353.57
France		276,870.56	285,978.78	294,373.27	302,556.36	309,450.28	316,201.81	323,129.57	330,015.05
Germany	1,123,898.0	1,241,361.0	1,149,973.0	1,156,785.0	1,164,311.0	1,053,014.0	1,065,691.0	1,079,430.1	1,088,820.6
Great Britain		329,189.00	331,376.00	327,574.00	328,829.00	330,509.00	331,350.00	331,782.00	333,055.00
Greece	13,071.00	13,570.00	13,891.00	14,160.00	14,427.00	14,636.00	14,789.00	14,907.00	15,045.00
Hungary								22,930.78	23,163.11
Ireland					12,362.00	12,472.00	12,611.00	12,782.00	13,255.00
Italy	296,249.00	302,386.00	309,119.00	316,993.00	320,578.00	323,628.00	326,462.00	329,219.00	332,572.00
Kosovo*					423.00	2,017.00	2,277.00	2,345.00	2,534.00
Latvia					21,483.00	23,191.00	23,601.00	24,460.00	25,360.00
Lithuania						17,365.00	18,627.00	20,807.00	22,625.37
Luxembourg						6,023.00	6,123.00	6,367.00	6,450.00
Malta				799.00	951.20	1,036.00	1,345.80	1,198.90	1,275.00
Montenegro	1,549.00	1,510.40	1,657.70	1,666.80	1,686.40	1,721.30	1,725.80	1,727.10	2,072.50
Netherlands, The			145,163.50	145,157.50	145,553.40	146,077.70	146,730.10	147,566.14	148,314.92
North Macedonia					3,647.00	3,765.00	3,896.00	4,032.00	4,145.00
Norway				105,682.00	112,937.00	112,516.00	115,736.00	121,140.00	124,118.00
Poland	134,777.00	138,754.00	148,058.00	147,518.00	151,876.00	154,757.00	153,419.00	157,651.00	161,442.00
Portugal	32,113.00	32,627.00	32,899.00	33,127.00	33,243.00	33,389.00	33,543.00	33,543.00	33,543.00
Romania					49,910.00	46,328.00	50,359.00	50,871.00	50,820.00
Serbia					15,456.30	15,995.92	16,362.64	16,521.85	16,637.62
Slovenia	20,171.00	20,959.00	21,556.00	22,228.00	22,169.00	22,740.00	23,290.00	24,413.00	24,734.00
Spain					189,597.13	192,951.78	194,896.59	192,782.41	195,528.54
Sweden			237,612.00	244,766.00	249,630.00	253,498.00	257,115.00	261,397.00	265,039.00
Switzerland	118,778.00	118,945.00	121,339.00	126,099.00	128,880.00	131,521.00	132,251.00	134,280.00	137,120.00
Ukraine	35,939.52	37,278.82	36,385.96	40,486.85	40,176.65	38,329.36	35,739.72	35,625.92	34,843.86

TABLE A 27: Overhead lines length, EHV (km)

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
Austria	6,362.01	6,454.39	6,445.08	6,445.53	6,670.11	6,665.01	6,701.68	6,701.68	6,701.12
Belgium							1,857.00	1,929.00	1,879.00
Croatia									2,492.00
Denmark	2,121.00	2,119.00	46.00	46.00	46.00	46.00			
Estonia					1,940.00	1,940.00	1,940.00	1,943.00	1,943.00
Finland	6,968.00	7,154.00	7,165.00	7,143.00	7,145.00	7,012.00	6,706.00	6,719.00	6,768.00
Germany								34,666.40	34,478.40
Great Britain		31,917.00	31,672.00	31,466.00	31,374.00	31,268.00	31,180.00	31,130.00	31,060.00
Greece	4,407.20		4,555.60	4,667.70	4,667.70	4,667.70	4,889.20	4,889.20	4,704.4
Hungary									4,645.00
Luxembourg						274.00	304.00	304.00	304.00
Netherlands, The			2,826.26	2,909.24	2,911.13	2,909.39	2,925.62	2,949.22	2,953.30
Norway				10,809.00	11,314.00	11,250.00	11,378.00	11,493.00	11,557.00
Poland	11,140.00	11,071.00	11,068.00	11,140.00	11,097.00	11,457.00	11,549.00	11,420.00	11,661.00
Romania					8,735.00	8,735.00	8,794.00	8,794.00	8,850.00
Slovenia					997.00	997.00	997.00	997.00	997.00
Spain					20,602.55	20,882.01	20,906.30	21,016.51	21,018.27
Sweden			15,060.00	15,086.00	15,148.00	14,665.00	14,669.00	14,679.00	14,679.00
Switzerland	6,750.00	6,750.00	6,750.00	6,750.00	6,750.00	6,750.00	6,629.00	6,590.00	6,652.00
Ukraine	22,295.86	22,255.46	22,252.32	22,252.32	22,332.52	22,332.52	21,038.76	19,345.38	19,933.03

TABLE A 28: Overhead lines length, HV (km)

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
Albania									3,388.10
Austria	10,544.71	10,469.83	10,509.94	10,456.09	10,511.62	10,608.03	10,661.76	10,719.30	10,722.98
Belgium							6,678.00	6,592.00	6,512.00
Bosnia and Herzegovina					6,276.79	6,299.51	6,287.79	6,337.96	6,368.94
Cyprus					1,148.21	1,148.74	1,108.51	1,097.40	1,128.74
Croatia									5,139.00
Denmark	5,525.00	5,499.00	5,366.00	5,284.00	5,231.00	5,222.00	5,214.00	5,128.00	4,988.00
Estonia					3,501.00	3,501.00	3,501.00	3,496.00	3,496.00
Finland	15,720.04	15,570.72	15,564.31	15,793.10	15,871.36	15,910.41	16,106.51	15,937.73	16,005.63
France									105,857.0
Germany								87,976.48	88,039.64
Great Britain		169,180.0	169,213.0	168,300.0	167,907.0	167,590.0	166,665.0	166,299.0	166,040.0
Greece	12,177.90		12,324.90	12,365.30	12,234.42	12,620.10	12,738.50	12,780.60	12,107.60
Hungary									8,319.00
Ireland					6,122.00	12,356.00	12,534.00	12,567.00	12,625.00
Kosovo*					1,223.00	1,324.00	1,353.10	1,353.10	1,377.00
Latvia					5,272.64	5,250.93	5,237.81	5,239.97	5,243.67
Lithuania					6,727.70	6,847.80	6,843.30	6,809.60	7,005.90
Luxembourg						729.00	707.00	685.00	685.00
Montenegro	1,356.70	1,356.70	1,358.20	1,343.20	1,342.20	1,342.20	1,348.10	1,343.50	1,344.00
Netherlands, The			5,587.73	5,528.74	5,563.47	5,542.45	5,455.19	5,456.87	5,506.37
North Macedonia					2,302.83	2,450.00	2,458.00	2,450.00	2,447.00
Norway				17,551.00	17,729.00	17,310.00	17,324.00	17,420.00	17,460.00
Poland	27,812.00	27,847.00	29,184.00	27,945.00	27,926.00	28,080.00	28,245.00	28,184.00	28,199.00
Romania					21,945.00	19,198.00	21,806.42	21,817.00	21,816.00
Serbia					9,605.43	9,678.51	9,709.02	9,842.04	9,937.56
Slovenia					2,676.00	2,700.00	2,734.00	2,746.00	2,779.00
Spain					104,395.85	104,411.51	104,952.64	105,013.32	105,746.66
Sweden			29,261.00	29,284.00	29,193.00	29,275.00	29,273.00	29,358.00	29,360.00
Switzerland	7,057.00	6,935.00	6,918.00	7,059.00	7,158.00	6,904.00	6,738.00	6,791.00	6,777.00
Ukraine	41,272.35	40,879.07	40,996.83	41,201.77	41,200.85	38,149.62	37,014.59	37,974.16	35,844.57

TABLE A 29: Overhead lines length, MV (km)

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
Austria	30,581.62	29,881.17	28,746.77	28,151.33	27,528.41	26,785.31	26,122.14	25,217.12	24,777.74
Belgium					5,817.00	5,660.00	5,374.00	5,222.00	5,051.00
Bosnia and Herzegovina					21,944.00	21,995.00	21,877.00	21,942.00	21,977.00
Croatia									23,471.00
Cyprus					5,816.28	5,860.55	5,855.78	5,894.22	5,941.06
Denmark	3,304.00	2,722.00	1,876.00	1,330.00	1,156.00	939.00	730.00	394.00	331.00
Estonia					22,602.00	21,116.00	20,739.00	20,541.00	20,295.00
Finland	121,772.00	121,153.00	120,643.50	119,806.80	118,126.34	115,967.19	113,033.20	108,064.11	103,644.10
France		351,666.59	347,168.70	342,885.12	338,627.06	335,070.12	331,621.48	328,107.65	325,119.03
Germany						103,878.00	106,181.00	97,593.71	94,806.52
Greece	95,740.00	96,622.00	97,612.00	98,370.00	99,139.00	99,410.00	99,739.00	99,973.00	100,264.00
Hungary								53,619.26	53,585.79
Ireland					82,800.00	83,107.00	83,154.00	83,336.00	83,678.00
Italy	215,609.00	215,661.00	215,487.00	215,453.00	215,102.00	214,908.00	214,629.00	214,407.00	214,134.00
Kosovo*					6,543.60	6,137.00	6,082.00	6,108.00	6,184.00
Latvia					29,192.00	28,549.00	28,283.00	28,019.00	27,665.00
Lithuania						42,887.00	42,447.00	41,607.00	40,115.28
Luxembourg						1,066.00	1,046.00	1,013.00	988.00
Malta				95.50	84.90	82.20	81.10	80.70	75.10
Montenegro	4,640.00	4,659.80	4,517.20	4,538.10	4,471.10	4,504.60	4,520.90	4,523.50	4,512.70
Netherlands, The			0.02	0.02	0.02	0.02	0.02	0.02	0
North Macedonia					8,660.00	8,632.00	8,546.80	8,635.80	8,610.00
Norway				59,622.00	59,353.00	58,909.00	58,422.00	58,114.00	57,756.00
Poland	224,454.00	224,465.00	244,983.00	223,804.00	222,629.00	222,803.00	220,595.00	219,971.00	219,034.00
Portugal	57,945.00	58,133.00	58,152.00	58,275.00	58,184.00	58,433.00	58,606.00	58,606.00	58,606.00
Romania					90,335.00	80,104.00	90,167.00	90,224.00	90,176.00
Serbia					38,076.14	38,194.88	38,333.08	38,454.86	39,340.20
Slovenia					11,943.00	11,863.00	11,830.00	11,702.00	11,569.00
Spain					192,109.49	193,719.62	192,782.12	190,501.20	190,832.89
Sweden			86,942.00	85,097.00	82,979.00	81,226.00	78,113.00	75,543.00	70,456.00
Switzerland	12,232.00	11,888.00	11,570.00	11,151.00	10,914.00	10,590.00	10,061.00	9,784.00	9,458.00
Ukraine	364,085.73	365,318.44	372,875.34	371,270.55	367,266.38	349,267.88	338,618.29	338,751.57	329,302.40

TABLE A 30: Overhead lines length, LV (km)

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
Albania									23,138.00
Austria	39,718.32	38,548.05	37,087.65	36,118.37	35,309.02	34,363.55	33,616.14	31,956.73	30,986.54
Belgium					48,744.00	48,211.00	48,009.00	47,675.00	47,563.00
Bosnia and Herzegovina					61,879.00	62,950.00	64,023.00	64,709.00	64,804.00
Croatia									66,938.00
Cyprus					9,757.99	9,971.78	9,921.41	10,004.82	10,070.74
Denmark	3,853.00	3,366.00	2,842.00	1,592.00	823.00	298.00	197.00	71.00	54.00
Estonia					26,275.00	25,405.00	25,151.00	24,929.00	24,711.00
Finland	150,120.00	148,758.00	146,943.30	145,268.40	142,151.77	139,242.42	134,813.50	130,800.16	126,829.48
France		415,094.03	411,172.43	407,423.38	403,550.08	400,031.10	397,060.31	393,960.66	390,985.24
Germany						120,051.00	125,013.00	114,197.50	111,686.04
Great Britain		64,875.00	64,428.00	63,914.00	60,805.00	60,417.00	60,279.00	59,979.00	59,735.00
Greece	106,843.00	107,837.00	108,576.00	109,190.00	110,145.00	110,526.00	111,007.00	111,467.00	111,894.00
Hungary								64,741.89	64,835.95
Ireland					58,098.00	58,561.00	58,996.00	59,503.00	59,297.00
Italy	532,488.00	528,058.00	530,713.00	535,842.00	537,399.00	537,762.00	539,074.00	540,017.00	540,821.00
Kosovo*					11,242.00	16,598.00	16,870.00	16,867.00	17,555.00
Latvia					37,478.00	35,549.00	34,744.00	33,550.00	32,274.00
Lithuania						53,280.00	51,751.00	49,113.00	47,285.06
Luxembourg						337.00	330.00	327.00	327.00
Malta				2,048.00	2,077.00	2,082.00	2,083.50	2,087.80	2,101.00
Montenegro	11,341.00	11,386.90	11,409.00	11,488.90	11,530.10	11,535.40	11,623.60	11,624.70	11,221.30
Netherlands, The			87.89	56.36	57.05	59.61	56.87	56.29	61.14
North Macedonia					11,805.00	11,974.00	12,054.00	12,189.00	12,261.00
Norway				93,044.00	93,959.00	91,843.00	90,660.00	89,753.00	87,787.00
Poland	285,685.00	287,220.00	345,670.00	316,666.00	312,891.00	312,171.00	306,529.00	306,546.00	307,765.00
Portugal	105,751.00	106,744.00	107,516.00	108,197.00	108,586.00	108,936.00	109,291.00	109,291.00	109,291.00
Romania					131,856.00	119,614.00	132,545.00	132,756.00	132,905.00
Serbia					97,680.45	98,061.92	98,357.61	98,857.37	99,001.67
Slovenia					23,881.00	23,076.00	22,517.00	20,845.00	20,275.00
Spain					254,756.70	260.696.82	262,850.82	259,116.22	260,951.32
Sweden			68,061.00	66,517.00	64,742.00	62,681.00	60,405.00	57,975.00	54,334.00
Switzerland	11,558.00	11,117.00	10,835.00	10,227.00	9,719.00	10,653.00	11,621.00	8,150.00	7,663.00
Ukraine	447,848.40	441,966.48	443,309.44	423,961.44	428,186.70	415,606.14	399,873.20	398,419.93	387,624.79

TABLE A 31: Transformers EHV/HV (number of transformers)

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
Belgium					92	92	97	103	108
Bosnia and Herzegovina					28	28	28	28	27
Croatia					35	35	36	36	36
Estonia					21	21	21	21	21
Finland					71	73	71	74	73
Great Britain		9,966	9,977	10,081	10,122	10,190	10,587	10,675	10,731
Greece	50		54	54	58	58	58	59	59
Ireland				9	9	9	9	65	65
Lithuania					27	27	27	27	27
Luxembourg	14	14	14	14	14	14	13	15	13
Malta						2	2	2	2
Netherlands, The				107	111	112	114	97	98
North Macedonia					5	5	6	6	6
Norway					434	447	301	301	327
Poland	185	187	197	195	191	202	211	215	214
Romania					221	222	216	218	215
Slovenia					21	21	21	21	22
Spain					496	498	500	499	546
Switzerland	150	158	154	155	152	146	148	151	145
Ukraine	367	376	372	367	369	371	345	345	279

TABLE A 32: Transformers EHV/MV (number of transformers)

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
Belgium					7	8	8	8	8
Croatia					1	1	1	1	1
Estonia					3	3	3	3	3
Finland							1	1	1
Luxembourg	2	2	2	2	2	2	2	2	2
Netherlands, The				8	8	8	8	8	8
Spain[261]					727	751	757	766	787

261 In addition to EHV/HV and EHV/MV, Spain also has an EHV/LV transformer. The number provided was one in every year from 2014 to 2018.

TABLE A 33: Transformers HV/MV (number of transformers)

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
Albania									302
Austria	1,051	1,065	1,077	1,092	1,093	1,101	1,115	1,116	1,121
Belgium					842	857	868	886	896
Bosnia and Herzegovina					222	227	237	248	248
Croatia					262	273	253	287	288
Cyprus					131	133	134	135	132
Estonia					225	225	225	225	221
Finland					1,113	1,125	1,145	1,156	1,172
Greece	487	488	488	495	497	493	503	503	520
Hungary					495	495	497	501	506
Kosovo*					62	67	66	68	68
Latvia					271	270	271	271	274
Luxembourg	85	86	92	91	90	95	89	92	94
Malta					9	9	9	9	12
Moldova					679	679	679	679	679
Montenegro	44	44	46	46	46	46	51	51	53
Netherlands, The				1,167	1,152	1,137	1,128	1,122	1,120
North Macedonia					62	75	73	70	69
Norway					1,990	2,013	1,993	1,999	2,057
Poland	2,534	2,556	2,642	2,620	2,665	2,695	2,733	2,754	2,766
Portugal						692	705	705	705
Romania					953	869	870	870	871
Slovenia					200	196	205	201	200
Spain					4,111	4,062	4,093	4,104	5,399
Switzerland	1,117	1,140	1,147	1,144	1,145	1,143	1,142	1,150	1,143
Ukraine	2,931	3,154	3,149	3,158	3,129	3,055	2,850	2,813	2,693

TABLE A 34: Transformers MV/MV (number of transformers)

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
Belgium					14	15	15	15	16
Bosnia and Herzegovina					150	150	150	150	150
Croatia					679	685	751	767	767
Cyprus					4	6	6	8	8
Estonia					16	16	16	16	16
Finland					112	113	119	101	99
Greece	126	122	130	126	128	122	122	122	122
Hungary					88	84	82	82	82
Ireland			403	413	419	373	373	375	367
Kosovo*					95	101	114	114	117
Luxembourg	4	2	2	13	14	10	8	8	8
Malta					35	35	35	43	47
Montenegro	85	91	92	94	95	96	97	97	99
North Macedonia					75	76	76	76	76
Poland	153	153	130	136	142	138	139	132	138
Serbia					1,237	1,235	1,217	1,205	1,218
Slovenia					49	49	44	34	29
Spain					2,187	2,262	2,722	2,710	5,148

TABLE A 35: Transformers MV/LV (number of transformers)

Country[262]	2010	2011	2012	2013	2014	2015	2016	2017	2018
Albania									25,849
Austria	76,730	77,092	76,001	76,520	77,546	78,048	78,536	78,955	79,469
Belgium								71,137	71,355
Bosnia and Herzegovina					20,312	20,434	20,669	20,856	21,020
Croatia					26,723	28,215	28,929	26,777	26,973
Cyprus					16,295	16,490	16,577	16,741	16,974
Estonia					2,290	2,305	2,316	2,359	2,371
Finland					135,444	135,931	137,894	139,942	140,214
France		750,849	757,778	763,812	769,494	774,517	778,774	783,262	787,492
Greece	153,596	156,061	158,832	160,975	161,729	162,322	163,063	163,751	164,342
Hungary					60,454	60,801	61,325	61,674	62,212
Ireland			252,187	253,512	254,738	255,735	258,155	259,962	263,102
Kosovo*					7,881	8,030	8,396	8,788	9,160
Latvia					29,711	29,883	29,899	29,967	30,316
Luxembourg	3,466	2,747	2,798	2,844	2,889	2,916	2,956	2,994	3,027
Malta					1,520	1,542	1,586	1,626	1,656
Moldova					14,975	14,902	14,766	14,660	14,642
Montenegro	4,518	4,524	4,665	4,729	4,789	4,841	4,883	4,891	4,571
Netherlands, The				131,540	132,182	132,062	132,403	117,391	116,182
North Macedonia					7,061	7,142	7,202	7,260	7,305
Norway					134,636	135,552	135,716	136,150	137,337
Poland	240,723	243,416	268,302	247,712	249,174	251,799	253,949	256,018	257,389
Romania					70,969	62,915	72,024	72,798	73,587
Serbia					45,747	46,025	46,790	47,126	47,541
Slovenia					19,209	19,345	19,432	19,677	19,853
Spain					334,907	336,765	336,225	335,158	337,658
Switzerland	55,272	55,340	56,816	57,693	58,110	59,153	58,426	58,601	58,995
Ukraine				221,108	207,192	213,874	207,192	225,397	217,988

262 Great Britain does not define MV, but it provided the number of HV/LV transformers. Its HV is comparable to other countries' MV. The numbers are: 2011: 584,709. 2012: 586,806. 2013: 590,099. 2014: 591,183. 2015: 592,642. 2016: 591,999. 2017: 593,279. 2018: 594,576.

TABLE A 36: Installed capacity EHV/HV (MVA)

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
Bosnia and Herzegovina					7,000.00	7,000.00	7,000.00	7,000.00	6,850.00
Croatia[263]					7,700.00	7,700.00	7,950.00	7,950.00	7,950.00
Estonia[264]					4,143.00	4,143.00	4,218.00	4,218.00	4,218.00
Finland					21,520.00	21,920.00			
Great Britain		38,700.00	38,700.00	39,100.00	39,100.00	39,400.00	40,800.00	41,200.00	41,400.00
Greece	13,540.00		14,640.00	14,670.00	15,790.00	15,790.00	15,790.00	16,070.00	16,070.00
Ireland				2,250.00	2,250.00	2,250.00	2,250.00	2,500.00	2,500.00
Lithuania					4,200.00	5,168.00	5,168.00	5,168.00	5,168.00
Malta						500.00	500.00	500.00	500.00
Netherlands, The				35,360.00	36,670.00	36,750.00	37,250.00	40,246.00	40,536.00
Norway					4,367.14	4,643.34	4,248.32	4,300.28	4,729.09
Poland	42,302.00	42,577.00	46,485.00	46,245.00	46,315.00	50,610.00	56,470.00	57,905.00	58,360.00
Romania					39,794.00	40,119.00	38,058.00	38,289.00	36,959.00
Slovenia					5,650.00	5,650.00	5,650.00	5,650.00	5,950.00
Spain[265]					69,048.50	69,947.50	70,970.90	71,140.90	73,174.44
Switzerland	23,045.00	24,569.00	24,438.00	25,237.00	24,325.00	24,133.00	24,858.00	25,576.00	24,602.00
Ukraine	75,891.50	75,276.50	75,676.50	76,076.50	75,956.50	62,470.00	60,685.00	61,757.00	61,757.00

263 In addition to EHV/HV, Croatia also provided the capacity of their EHV/MV transformers. From 2014 to 2018, it was 20 MVA.
264 In addition to EHV/HV, Estonia also provided the capacity of their EHV/MV transformers. From 2014 to 2018, it was 219 MVA.
265 In addition to EHV/HV, Spain also provided the capacity of their EHV/MV transformers. 2014: 32,010.69 MVA. 2015: 33,247.69 MVA. 2016: 33,629.19 MVA. 2017: 34,028.79 MVA. 2018: 34,877.00 MVA.

TABLE A 37: Installed capacity HV/MV (MVA)

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
Austria	63,205.00	64,854.00	66,321.00	69,103.00	69,781.00	71,063.00	72,779.00	73,813.00	75,216.00
Bosnia and Herzegovina					5,376.00	5,387.00	5,636.00	6,022.00	6,053.00
Croatia					8,116.00	8,451.00	8,788.00	8,971.00	9,190.00
Cyprus					3,855.00	3,929.50	3,940.50	3,964.00	3,923.00
Estonia					4,240.70	4,240.70	4,240.70	4,176.70	4,176.70
Finland					25,810.70	26,221.70	26,549.50	26,780.50	27,135.00
Greece	22,500.00	22,550.00	22,575.00	22,885.00	22,794.00	22,628.00	23,228.00	23,253.00	24,105.00
Hungary					15,930.00	15,954.00	15,995.00	16,125.00	16,310.00
Ireland				6,457.00	6,595.00	6,595.00	6,650.00	6,738.00	
Kosovo*					2,429.00	2,632.00	2,609.00	2,649.00	2,649.00
Latvia					8,899.80	8,926.80	8,949.80	8,963.00	9,165.00
Lithuania					92.60	92.60	152.60	152.60	
Malta					650.00	650.00	650.00	650.00	880.00
Moldova					4,768.00	4,768.00	4,768.00	4,768.00	4,768.00
Montenegro	3,349.50	3,287.50	3,350.50	3,359.00	3,359.00	3,413.50	3,526.50	3,526.50	3,846.50
Netherlands, The				47,809.00	48,307.00	51,583.00	51,808.00	51,958.00	52,217.00
Norway					39,520.26	41,142.67	40,398.97	41,092.14	42,455.78
Poland	49,408.00	50,419.00	52,289.00	52,669.00	53,873.00	55,621.00	57,276.00	58,552.00	59,509.00
Portugal						17,364.00	17,452.20	17,534.00	17,494.50
Romania					35,379.00	30,149.00	35,456.00	35,712.00	36,132.00
Serbia					10,855.00	11,082.00	11,551.00	11,099.00	11,130.50
Slovenia					5,774.00	5,694.00	5,940.00	5,732.00	5,724.00
Spain					213,623.47	137,921.78	168,526.65	94,086.46	96,534.28
Switzerland	27,528.00	28,070.00	29,388.00	29,555.00	29,352.00	29,956.00	30,546.00	30,967.00	31,392.00

TABLE A 38: Installed capacity HV/LV (MVA)

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
Great Britain		5,243.00	5,262.00	5,291.00	5,301.00	5,314.00	5,309.00	5,320.00	5,332.00
Moldova					4,478.50	4,500.10	4,552.00	4,597.14	4,605.50
Spain					56.96	55.80	21.36	36.99	49.99

TABLE A 39: Installed capacity MV/MV (MVA)

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
Croatia					4,444.00	4,444.00	4,810.00	5,069.00	5,203.00
Cyprus					29.00	38.00	38.00	78.00	78.00
Estonia					111.50	111.50	111.50	111.50	111.50
Greece	1,011.00	975.00	1,020.00	996.00	999.00	951.00	951.00	951.00	951.00
Hungary					770.00	744.00	734.00	734.00	744.00
Kosovo*					626.00	686.00	765.00	765.00	774.00
Malta					752.10	752.10	752.10	972.10	1,062.10
Montenegro	797.00	787.00	820.30	852.80	857.90	869.50	893.50	897.50	902.60
North Macedonia									740.00
Poland	760.00	744.00	636.00	670.00	714.00	731.00	793.00	715.00	792.00
Romania					23,034.00	19,916.00	23,283.00	23,432.00	24,296.00
Serbia					6,827.32	6,805.98	6,822.32	6,760.73	6,878.74
Slovenia					311.00	311.00	415.00	205.00	173.00
Spain					5,254.80	5,331.92	40,971.04	5,488.43	5,941.86

TABLE A 40: Installed capacity MV/LV (MVA)

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
Albania									5,785.00
Austria	29,387.00	29,845.00	29,533.00	29,901.00	30,462.00	30,775.00	31,287.00	31,695.00	32,395.00
Belgium								12,625.51	12,752.24
Bosnia and Herzegovina					5,835.00	5,858.00	6,033.00	6,081.00	6,238.00
Croatia					8,348.00	9,350.00	9,482.00	8,816.00	8,954.00
Cyprus					4,443.37	4,454.68	4,483.10	4,515.72	4,596.33
Estonia					682.20	689.40	695.70	699.83	703.43
Finland					24,515.53	24,875.44	24,330.19	24,856.75	25,152.59
Greece	26,908.31	27,514.66	28,073.91	28,452.83	28,708.45	28,892.55	29,082.33	29,265.07	29,386.60
Hungary					18,551.31	18,634.14	18,780.31	18,879.30	19,012.43
Kosovo*					2,610.00	3,014.00	3,576.00	3,745.00	3,919.00
Latvia					5,869.00	5,881.00	5,892.00	5,913.00	5,930.00
Malta					1,340.60	1,372.10	1,410.60	1,457.10	1,492.01
Montenegro	1,715.00	1,766.00	1,881.60	1,944.50	1,994.60	2,044.30	2,076.90	2,081.60	1,765.30
Netherlands, The				56,036.94	59,717.26	58,693.44	60,104.46	51,873.31	51,850.31
Norway					43,178.59	44,567.29	44,930.25	45,689.70	47,299.48
Poland	43,056.00	43,863.00	50,026.00	45,496.00	45,935.00	47,182.00	48,297.00	48,990.00	49,767.00
Serbia					18,295.85	18,432.33	18,939.51	19,177.17	19,306.98
Slovenia					6,002.00	6,079.00	6,161.00	6,242.00	6,376.00
Spain					126,995.93	127,690.39	128,066.85	127,528.61	128,101.58
Switzerland	27,189.00	27,270.00	29,189.00	29,002.00	29,648.00	30,000.00	30,209.00	30,552.00	30,594.00

B.3 ENERGY DATA

TABLE A 41: Transmitted/distributed energy (TWh) – all customers

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
Albania						7.67	8.27	7.42	9.61
Austria	55.01	55.06	55.70	56.85	56.47	57.40	58.20	58.89	59.27
Belgium	86.50	83.30	81.70	80.50	77.20	77.20	77.30	77.40	76.70
Bosnia and Herzegovina					12.20	12.58	12.79	13.08	13.14
Croatia	15.72	15.60	15.35	15.19	14.93	15.49	15.57	16.16	16.41
Cyprus	5.03	4.82	4.56	4.09	4.11	4.29	4.64	4.75	4.79
Denmark	33.30	32.30	33.00	32.70	32.20	32.30	32.30	34.30	34.60
Estonia					7.42	7.44	7.66	7.87	7.98
Finland	75.88	71.30	72.61	63.54	58.56	58.00	60.40	60.99	62.99
France	513.00	478.20	489.50	495.00	465.30	475.40	483.00	482.00	478.00
Germany	490.50	506.10	501.70	499.00	496.20	488.00	488.10	560.60	553.20
Greece	50.86	50.58	49.24	45.33	44.73	45.42	45.38	46.19	45.52
Hungary				35.10	35.63	36.74	36.99	38.22	38.87
Ireland				46.92	46.34	46.79	48.38	48.59	49.95
Italy	335.00	337.00	331.00	321.00	313.00	319.00	317.00	323.00	324.00
Kosovo*					5.40	5.57	5.30	5.69	5.67
Latvia					9.05	9.48	9.85	10.17	10.54
Lithuania					9.80	10.00	10.50	10.70	11.20
Luxembourg					6.33	6.37	6.52	6.55	6.55
Malta					2.13	2.24	2.27	2.44	2.49
Moldova						4.10	4.03	4.03	4.10
Montenegro	3.35	3.57	3.24	2.84	2.73	2.88	2.79	2.95	2.99
North Macedonia					6.96	6.85	6.45	6.38	6.36
Norway					114.44	116.06	117.68	116.61	120.99
Poland	103.00	105.00	125.00	136.00	137.00	140.00	144.00	149.00	152.00
Portugal	52.20	50.50	49.06	49.15	48.82	48.96	49.27		
Romania					41.04	41.17	41.31	41.46	42.01
Serbia	28.05	28.61	27.98	28.00	27.66	28.53	28.82	29.32	29.23
Slovakia								31.98	28.62
Slovenia	12.16	12.68	12.63	12.82	12.72	13.04	13.30	13.67	13.74
Spain			235.59	228.63	226.41	230.52	232.36	229.50	230.50
Sweden			131.90	129.19	125.04	126.80	130.10	130.46	132.00
Switzerland		58.60	59.00	59.30	57.50	58.20	58.20	58.50	57.60
Ukraine	146.40	147.90	148.30	144.70	133.90	117.10	116.90	117.50	120.80

TABLE A 42: Distributed energy (TWh) – MV and LV customers only

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
Albania						6.11	5.90	6.15	5.96
Austria	43.06	42.77	43.16	43.41	42.41	43.01	41.20	41.80	41.95
Bosnia and Herzegovina					9.48	9.85	9.99	10.18	10.14
Croatia	14.72	14.75	14.61	14.32	14.06	14.61	14.79	15.21	15.32
Finland	50.04	47.67	48.95	47.41	46.91	45.98	48.02	47.88	48.36
France						345.60	351.90	349.70	348.10
Great Britain		302.00	298.00	302.00	295.00	290.00	287.00	285.00	284.00
Greece	47.28	45.78	45.68	44.14	42.60	43.24	42.97	43.92	43.19
Hungary				27.94	27.99	28.85	29.50	30.40	30.98
Ireland				21.21	20.86	21.11	21.33	21.47	21.98
Italy	240.00	241.00	237.00	230.00	224.00	229.00	226.00	229.00	230.00
Kosovo*					4.56	4.56	4.80	4.99	5.12
Latvia					6.42	6.39	6.47	6.46	6.60
Lithuania					8.40	8.60	9.00	9.30	9.60
Luxembourg						3.66	3.46	3.50	3.58
Moldova						3.30	2.60	2.60	3.70
Montenegro	2.00	2.06	2.06	2.05	2.02	2.16	2.18	2.27	2.29
Netherlands, The			85.05	84.35	83.11	82.57	81.61	81.55	80.54
North Macedonia					4.97	5.18	5.13	5.25	5.21
Norway					80.56	80.47	81.69	81.95	84.02
Poland					43.00	45.00	49.00	51.00	53.00
Portugal	39.83	38.27	36.27	39.18	38.60	35.43	35.78		
Romania					33.79	33.96	34.13	34.31	34.98
Serbia	25.50	25.86	26.67	25.58	25.11	25.86	26.15	26.43	26.40
Slovakia								19.76	19.97
Slovenia	10.52	10.57	10.39	10.42	10.32	10.62	10.82	11.17	11.37
Spain			185.72	180.38	204.08	183.51	185.11	187.08	188.83
Sweden			93.85	94.53	90.51	91.96	94.14	94.12	95.53
Switzerland		51.30	50.80	52.40	51.40	51.30	51.50	51.00	51.00
Ukraine	107.07	89.60	92.10	92.10	88.80	77.90	77.40	87.80	82.90

B.4 SYSTEM STRUCTURE

TABLE A 43: Number of MV connection points

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
Albania									6,783
Austria	1,676,246	1,667,616	1,661,022	1,657,577	1,652,039	1,669,613	1,090,377	1,109,043	1,102,046
Belgium					37,864	36,588	38,209	37,306	39,024
Bosnia and Herzegovina					1,992	2,106	2,214	2,330	2,464
Croatia	2,078	2,096	2,115	2,126	2,113	2,136	2,165	2,218	2,288
Cyprus					631	626	637	639	656
Denmark	3,230,806	3,299,965	3,366,461	3,365,731	3,380,292	3,385,398	3,396,110	3,355,376	3,414,663
Estonia					2,262	2,277	2,323	2,334	2,325
Finland	3,742	3,759	3,815	3,913	3,971	4,075	4,102	4,094	4,204
France					93,047	92,234	91,611	91,311	91,243
Greece	9,961	10,147	10,422	11,207	11,418	11,444	11,487	11,536	11,660
Hungary				6,124	5,569	4,858	4,539	4,621	4,928
Ireland				1,523	1,538	1,567	1,609	1,656	1,697
Italy	97,071	93,381	105,607	110,411	110,274	108,425	108,546	108,298	108,451
Kosovo*					236	294	335	366	396
Latvia								1,494	1,501
Lithuania					1,587	2,197	2,263	2,244	2,227
Luxembourg					8,130	8,272	9,801	9,571	8,429
Malta					20	20	22	25	28
Moldova					6,327	6,441	6,626	6,818	7,055
Montenegro	430	509	524	537	546	553	549	554	581
Netherlands, The				32,982	34,121	34,742	28,789	34,055	28,929
North Macedonia								1,054	1,099
Norway					6,230	8,628	3,118	11,925	3,360
Portugal	23,218	23,400	23,520	23,538	23,993	23,646	23,819	24,557	24,606
Romania					22,149	22,425	22,265	22,289	23,066
Serbia					4,348	4,303	4,378	4,547	4,822
Slovenia	1,461	1,508	1,535	1,526	1,566	1,551	1,563	1,597	1,703
Spain			121,601	120,892	118,943	118,172	117,529	115,976	115,456
Sweden			7,945	8,203	7,838	7,869	8,472	8,492	8,456
Switzerland	8,300	8,500	8,300	8,400	8,500	8,500	8,900	9,500	9,400
Ukraine	107,615	104,389	110,529	92,485	89,631	89,013	86,977	85,437	84,083

TABLE A 44: Number of LV connection points

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
Albania									1,228,494
Austria	4,164,192	4,208,469	4,266,177	4,308,600	4,356,097	4,368,836	4,954,927	4,980,460	5,033,744
Belgium					5,717,457	5,773,395	5,762,646	5,881,075	5,935,989
Bosnia and Herzegovina					1,502,131	1,510,764	1,534,443	1,544,361	1,562,570
Croatia	2,312,959	2,325,522	2,350,881	2,349,240	2,357,635	2,380,334	2,385,194	2,388,069	2,409,239
Cyprus					553,938	559,069	564,915	567,857	575,563
Denmark	3,220,488	3,256,161	3,363,102	3,386,371	3,382,133	3,373,974	3,378,083	3,316,574	3,358,125
Estonia					355,913	357,964	360,708	362,877	367,311
Finland	1,731,719	1,754,133	1,705,318	1,715,436	1,720,766	1,723,057	1,721,033	1,726,258	1,731,946
France					35,258,688	35,528,606	35,844,017	36,167,282	36,473,378
Germany	49,025,432	49,236,444	48,769,681	49,935,441	50,088,370	49,900,000	50,300,000	50,500,000	50,700,000
Greece	7,564,777	7,493,118	7,355,122	7,381,515	7,413,826	7,427,011	7,454,041	7,474,603	7,531,447
Hungary				7,224,293	7,205,366	7,249,423	7,272,789	7,308,669	7,341,826
Ireland				2,231,695	2,234,605	2,240,579	2,252,025	2,282,791	2,355,389
Italy	36,313,508	36,526,794	36,691,237	36,834,312	37,193,352	37,246,576	37,305,249	37,273,997	36,644,403
Kosovo*					488,555	514,513	536,058	561,443	579,567
Latvia								1,109,209	1,105,238
Lithuania					1,683,600	1,705,392	1,726,183	1,748,266	1,771,741
Luxembourg					278,339	287,542	289,400	297,543	313,914
Malta				277,586	283,801	290,471	295,945	303,726	308,595
Moldova					1,328,702	1,340,818	1,352,804	1,372,131	1,381,897
Montenegro	358,038	362,635	369,428	377,528	384,184	373,552	367,331	376,173	386,375
Netherlands, The				8,119,161	8,221,175	8,336,508	8,393,541	8,539,213	8,645,817
North Macedonia								722,454	740,924
Norway					2,906,076	2,933,014	2,990,536	3,040,221	3,105,165
Portugal	6,110,889	6,119,634	6,092,584	6,106,168	6,128,791	6,111,540	6,096,692	6,065,720	6,068,857
Romania					9,112,456	9,164,477	9,237,788	9,309,885	9,425,413
Serbia					3,601,052	4,005,327	3,620,194	3,635,036	3,646,293
Slovenia	919,440	923,765	928,699	931,505	935,306	939,232	943,871	948,650	954,213
Spain			28,493,626	29,179,543	29,397,213	29,430,463	29,782,610	29,821,750	29,839,537
Sweden			5,321,531	5,378,681	5,390,919	5,424,839	5,447,052	5,487,510	5,524,504
Switzerland	5,070,800	5,167,300	5,233,800	5,304,400	5,379,500	5,543,400	5,502,200	5,566,300	5,716,600
Ukraine	20,152,977	19,979,235	20,355,057	20,431,020	19,477,738	17,850,446	17,967,559	18,002,612	18,067,424

TABLE A 45: Number of system operators (TSOs and DSOs) in 2018

Country	TSO	DSO
Albania	1	1
Austria	2	122
Belgium	1	16
Bosnia and Herzegovina	1	8
Croatia	1	1
Cyprus	1	1
Denmark	1	44
Estonia	1	34
Finland	1	77
France	1	161
Georgia	1	2
Germany	4	890
Great Britain	3	14
Greece	1	1
Hungary	1	6
Ireland	1	1
Italy	1	130
Kosovo*	1	1
Latvia	1	11
Lithuania	1	6
Luxembourg	1	5
Malta	0[266]	1
Moldova	1	2
Montenegro	1	1
Netherlands, The	1	7
North Macedonia	1	2
Norway	1	111
Poland	1	5
Portugal	1	11
Romania	1	8
Serbia	1	1
Slovakia	1	139
Slovenia	1	1
Spain	1	333
Sweden	1	166
Switzerland	1	630
Ukraine	1	39

266 No transmission grid in Malta.

TABLE A 46: Number of customers connected to distribution grid

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
Albania									1,235,277
Austria							4,573,536	4,603,345	4,685,242
Belgium					5,755,321	5,809,983	5,800,855	5,918,381	5,975,013
Bosnia and Herzegovina					1,499,949	1,511,881	1,528,329	1,538,267	1,552,612
Croatia	2,315,037	2,327,618	2,352,996	2,351,366	2,359,748	2,382,470	2,387,359	2,390,287	2,411,526
Cyprus					554,569	559,695	565,552	568,496	576,219
Estonia					560,715	563,046	565,253	670,577	668,270
Finland	3,309,146	3,348,179	3,383,845	3,421,969	3,454,366	3,485,018	3,525,626	3,563,297	3,614,889
France									38,800,000
Germany					50,087,805	48,597,340	49,961,844	50,467,419	51,405,860
Great Britain		29,219,288	29,387,690	29,561,569	29,651,565	29,811,869	30,027,420	30,172,996	30,405,683
Greece	7,574,738	7,503,265	7,365,544	7,392,722	7,425,244	7,438,455	7,465,528	7,486,139	7,543,107
Hungary				7,341,826	7,211,056	7,254,396	7,277,445	7,313,408	7,346,891
Ireland				2,233,316	2,236,247	2,242,253	2,253,749	2,268,468	2,357,214
Kosovo*					490,542	511,817	536,390	561,806	579,960
Latvia					846,933	840,003	834,686	825,325	817,859
Lithuania					1,685,162	1,707,589	1,728,466	1,750,510	1,773,968
Luxembourg			280,914	286,276	286,504	295,849	299,236	307,154	315,102
Malta				277,592	283,807	290,477	295,951	303,732	308,601
Moldova					1,335,029	1,352,804	1,359,430	1,378,949	1,388,952
Montenegro	358,468	363,144	369,952	378,065	384,730	374,105	367,880	376,727	386,956
Netherlands, The				8,152,143	8,255,296	8,371,250	8,422,330	8,573,268	8,674,746
North Macedonia					695,351	698,590	716,383	728,729	741,926
Norway					2,912,462	2,941,782	2,993,806	3,052,293	3,108,672
Poland	12,935,743	13,074,464	15,551,358	16,792,316	16,933,277	17,063,387	17,235,079	17,405,142	17,712,347
Romania					9,134,949	9,187,239	9,260,396	9,332,511	9,448,823
Serbia					3,605,402	4,009,632	3,624,574	3,639,585	3,651,117
Slovakia									2,562,811
Slovenia	920,903	925,275	930,236	933,033	936,874	940,785	945,438	950,251	955,920
Spain			28,617,487	29,302,523	29,517,350	29,576,524	29,902,214	29,939,782	29,957,059
Sweden			5,241,239	5,343,272	5,391,305	5,421,239	5,453,547	5,493,504	5,524,755
Switzerland			4,675,000	4,768,800	4,963,800	5,141,300	5,118,200	5,158,400	5,134,300
Ukraine					18,896,261	17,068,426	17,282,174	17,398,592	17,475,739

TABLE A 47: Number of customers served by the country's largest DSO

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
Albania									1,235,277
Belgium					1,273,441	1,286,850	1,300,544	1,313,023	1,337,921
Bosnia and Herzegovina					733,605	740,918	750,497	756,596	764,774
Croatia	2,315,037	2,327,618	2,352,996	2,351,366	2,359,748	2,382,470	2,387,359	2,390,287	2,411,526
Cyprus					554,569	559,695	565,552	568,496	576,219
Estonia					497,270	499,361	501,189	607,265	605,866
Finland	441,491	445,425	449,630	453,738	456,616	459,068	463,377	466,588	470,532
France	34,100,000	34,600,000	35,000,000	35,400,000	35,700,000	36,000,000	36,300,000	36,600,000	36,900,000
Great Britain		3,516,859	3,537,357	3,556,281	3,565,115	3,581,606	3,599,594	3,614,431	3,627,858
Greece	7,574,738	7,503,265	7,365,544	7,392,722	7,425,244	7,438,455	7,465,528	7,486,139	7,543,107
Hungary				1,777,509	1,776,168	1,787,897	1,793,354	1,804,404	1,815,717
Kosovo*					490,545	511,820	536,393	561,809	579,963
Latvia					840,433	833,503	828,186	818,570	811,359
Lithuania					1,685,039	1,707,452	1,728,318	1,750,374	1,773,828
Luxembourg			250,111	255,301	256,304	265,428	267,956	275,186	283,151
Malta				277,592	283,807	290,477	295,951	303,732	308,601
Moldova					856,421	867,142	878,402	888,989	897,973
Montenegro	358,468	363,144	369,952	378,065	384,730	374,105	367,880	376,727	386,956
Netherlands, The				2,946,331	3,021,008	3,042,888	3,120,738	3,200,728	3,213,671
North Macedonia					695,279	698,518	716,311	728,670	741,867
Norway					575,689	689,401	698,580	709,018	718,493
Poland	1,705,802	1,717,433	4,185,068	5,334,122	5,377,469	5,417,569	5,473,941	5,532,579	5,597,420
Romania					1,431,200	1,441,303	1,450,243	1,455,630	1,469,771
Serbia					937,643	4,009,632	3,624,574	3,639,585	3,651,117
Slovakia									1,149,618
Slovenia	920,903	925,275	930,236	933,033	936,874	940,785	945,438	950,251	955,920
Spain	12,125,276	12,189,368	12,230,291	12,208,728	12,263,594	12,254,831	12,268,183	12,308,961	12,325,529
Sweden			1,007,432	1,009,625	1,009,822	1,015,373	1,019,493	1,025,292	1,031,639
Switzerland				356,600	360,800	366,200	370,800	375,400	381,100
Ukraine					1,506,644	1,508,264	1,509,769	1,508,918	1,511,060

TABLE A 48: Number of customers served by the country's three largest DSOs

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
Albania									1,235,277
Belgium					2,484,278	2,524,467	2,495,162	2,572,029	2,609,579
Bosnia and Herzegovina					1,174,213	1,184,077	1,195,993	1,204,695	1,216,118
Croatia	2,315,037	2,327,618	2,352,996	2,351,366	2,359,748	2,382,470	2,387,359	2,390,287	2,411,526
Cyprus					554,569	559,695	565,552	568,496	576,219
Estonia					555,531	557,388	559,424	662,821	661,422
Finland	1,186,556	1,198,001	1,207,766	1,231,067	1,239,678	1,249,951	1,262,753	1,274,273	1,290,162
Georgia				1,600,382	1,641,012	1,640,153	1,678,832	1,753,615	1,767,551
Germany	8,254,673	8,279,248	8,315,114	9,873,436	9,511,788	9,410,913	8,707,729	8,686,074	8,812,474
Great Britain		9,157,512	9,200,562	9,229,584	9,237,235	9,278,026	9,320,620	9,278,214	9,324,841
Greece	7,574,738	7,503,265	7,365,544	7,392,722	7,425,244	7,438,455	7,465,528	7,486,139	7,543,107
Hungary				4,204,398	4,208,613	4,230,117	4,246,828	4,272,199	4,299,933
Kosovo*					490,545	511,820	536,393	561,809	579,963
Latvia					845,602	838,710	833,366	824,647	817,177
Lithuania					1,685,114	1,707,540	1,728,404	1,750,466	1,773,921
Luxembourg			273,788	279,043	279,060	286,452	291,550	299,225	307,026
Malta				277,592	283,807	290,477	295,951	303,732	308,601
Moldova					1,335,029	1,352,804	1,359,430	1,378,949	1,388,952
Montenegro	358,468	363,144	369,952	378,065	384,730	374,105	367,880	376,727	386,956
Netherlands, The				7,686,247	7,788,691	7,900,454	7,950,460	8,211,362	8,309,474
Norway					958,830	1,062,755	1,085,513	1,110,809	1,143,391
Poland	9,656,693	9,736,925	12,199,287	13,409,913	13,511,646	13,598,705	13,736,791	13,873,883	14,085,840
Portugal								6,079,107	6,079,107
Romania					4,057,987	4,132,812	4,166,703	4,177,746	4,214,082
Serbia					2,731,264	4,009,632	3,624,574	3,639,585	3,651,117
Slovakia									2,546,484
Spain	26,878,916	27,081,384	27,158,683	27,236,338	26,982,291	26,970,711	27,304,340	27,328,733	27,338,699
Sweden			2,765,090	2,775,202	2,787,024	2,801,480	2,836,860	2,855,465	2,882,273
Switzerland				932,900	951,600	964,400	995,000	1,001,900	1,019,100
Ukraine					3,825,541	3,873,001	3,898,122	3,923,274	4,037,756

ANNEX C

ANNEX C – ANNEX TO CHAPTER "ELECTRICITY – VOLTAGE QUALITY"

C.1 VOLTAGE DIPS

In Austria, yearly values of the VQ parameters are available per grid area (this ensures system operator anonymity) as well as for the entire country. The data from 10% of MV substations were used from 2014 to 2015, 50% of MV substations from 2016 to 2019 and 100% of MV substations starting with 2020. Data on voltage dips include a ten-minute aggregation.

In Belgium, VQ parameters are measured on the country level for the network from 36 kV up to 380 kV.

The TSO of Cyprus monitors, collectively and continuously, data from quality meters at two points of connection on HV and four points of connection on MV level, but no statistical data are collected or reported. In case of discrepancies, the user is informed about the need to comply with the terms of agreement and the measures to be taken.

Hungary measures VQ on low and medium voltage levels. On LV, every DSO is measured. This involves 1,036 portable devices that monitor 6,381 network points, with average duration of measurement of 11.62 days and a total duration of 1,269,933 hours. On MV, only four of the six DSOs are measured. This involves 325 fixed devices that monitor 325 network points, with average duration of measurement of 11.7 months and a total duration of 2,738,142 hours. Data on voltage dips in Hungary are presented in this annex only for distribution but separately for low and medium voltage levels. Classification of residual voltage and duration is slightly different than in other countries. Hungary uses 40 > u ≥ 10 and 10 > u for residual voltage percentage, rather than the standard 40 > u ≥ 5 and 5 > u. Moreover, the shortest duration is 20 < t ≤ 200 ms rather than the standard 10 < t ≤ 200 ms.

Slovenia indicated that the VQ measurements are performed on a yearly basis.

TABLE A 49: Number of voltage dips per number of monitored points in distribution in Austria in 2018

Residual voltage u (%)	Duration t (ms)				
	10 < t ≤ 200	200 < t ≤ 500	500 < t ≤ 1,000	1,000 < t ≤ 5,000	5,000 < t ≤ 60,000
90 > u ≥ 80	8.689	1.1	0.271	0.244	0.244
80 > u ≥ 70	1.826	0.191	0.324	0.087	0.01
70 > u ≥ 40	1.375	0.288	0.324	0.087	0.054
40 > u ≥ 5	0.458	0.124	0.114	0.037	0
5 > u	0.007	0	0.003	0.017	0.117

TABLE A 50: Number of voltage dips per number of monitored points in distribution in Austria in 2017

Residual voltage u (%)	Duration t (ms)				
	10 < t ≤ 200	200 < t ≤ 500	500 < t ≤ 1,000	1,000 < t ≤ 5,000	5,000 < t ≤ 60,000
90 > u ≥ 80	8.872	0.404	0.224	0.196	0.012
80 > u ≥ 70	2.604	0.368	0.364	0.128	0.012
70 > u ≥ 40	1.952	0.512	0.356	0.28	0.504
40 > u ≥ 5	0.436	0.16	0.108	0.024	0.008
5 > u	0.036	0.124	0.328	0.144	0.056

TABLE A 51: Number of voltage dips per number of monitored points in distribution in Austria in 2016

Residual voltage u (%)	Duration t (ms)				
	10 < t ≤ 200	200 < t ≤ 500	500 < t ≤ 1,000	1,000 < t ≤ 5,000	5,000 < t ≤ 60,000
90 > u ≥ 80	9.137	0.412	0.206	0.198	0.011
80 > u ≥ 70	2.408	0.229	0.191	0.111	0.004
70 > u ≥ 40	1.244	0.454	0.344	0.092	0
40 > u ≥ 5	0.405	0.156	0.065	0.046	0.011
5 > u	0.008	0.073	0.137	0.053	0.08

TABLE A 52: Number of voltage dips per number of monitored points in distribution in Austria in 2015

Residual voltage u (%)	Duration t (ms)				
	10 < t ≤ 200	200 < t ≤ 500	500 < t ≤ 1,000	1,000 < t ≤ 5,000	5,000 < t ≤ 60,000
90 > u ≥ 80	7.949	0.519	0.253	0.215	1.354
80 > u ≥ 70	2.81	0.494	0.367	0.063	0
70 > u ≥ 40	1.646	0.506	0.443	0.203	0
40 > u ≥ 5	0.747	0.177	0.089	0	0
5 > u	0.038	0.329	0.582	0.228	0.051

TABLE A 53: Number of voltage dips per number of monitored points in transmission in Belgium in 2018

Residual voltage u (%)	Duration t (ms)				
	10 < t ≤ 200	200 < t ≤ 500	500 < t ≤ 1,000	1,000 < t ≤ 5,000	5,000 < t ≤ 60,000
90 > u ≥ 80	19.5	3	35	1	0
80 > u ≥ 70	5	1	0	0	0
70 > u ≥ 40	4	0	0	0	0
40 > u ≥ 5	1	0	0	0	0
5 > u	0	0	0	0	0

TABLE A 54: Number of voltage dips per number of monitored points in transmission in Belgium in 2017

Residual voltage u (%)	Duration t (ms)				
	10 < t ≤ 200	200 < t ≤ 500	500 < t ≤ 1,000	1,000 < t ≤ 5,000	5,000 < t ≤ 60,000
90 > u ≥ 80	36	4.7	3	1	0
80 > u ≥ 70	6.7	0	1	0	0
70 > u ≥ 40	3.7	0	0	0	0
40 > u ≥ 5	1	0	0	0	0
5 > u	0	0	0	0	0

TABLE A 55: Number of voltage dips per number of monitored points in transmission in Belgium in 2016

Residual voltage u (%)	Duration t (ms)				
	10 < t ≤ 200	200 < t ≤ 500	500 < t ≤ 1,000	1,000 < t ≤ 5,000	5,000 < t ≤ 60,000
90 > u ≥ 80	20	3	2	1	0
80 > u ≥ 70	7	1	1	0.2	0
70 > u ≥ 40	5.2	1	0	0	0
40 > u ≥ 5	3	0	0	0	0
5 > u	0	0	0	0	0

TABLE A 56: Number of voltage dips per number of monitored points in transmission in Belgium in 2015

Residual voltage u (%)	Duration t (ms)				
	10 < t ≤ 200	200 < t ≤ 500	500 < t ≤ 1,000	1,000 < t ≤ 5,000	5,000 < t ≤ 60,000
90 > u ≥ 80	19.1	2	2	0	0
80 > u ≥ 70	5	1	0	0	0
70 > u ≥ 40	2	1	0	0	0
40 > u ≥ 5	1	0	0	0	0
5 > u	0	0	0	0	0

TABLE A 57: Number of voltage dips per number of monitored points in MV in Hungary in 2018

Residual voltage u (%)	Duration t (ms)				
	20 < t ≤ 200	200 < t ≤ 500	500 < t ≤ 1,000	1,000 < t ≤ 5,000	5,000 < t ≤ 60,000
90 > u ≥ 80	25,956	2,234	1,353	776	47
80 > u ≥ 70	6,950	805	290	201	0
70 > u ≥ 40	6,712	575	184	57	16
40 > u ≥ 10	1,464	261	71	18	2
10 > u	128	23	2	4	1

TABLE A 58: Number of voltage dips per number of monitored points in MV in Hungary in 2017

Residual voltage u (%)	Duration t (ms)				
	20 < t ≤ 200	200 < t ≤ 500	500 < t ≤ 1,000	1,000 < t ≤ 5,000	5,000 < t ≤ 60,000
90 > u ≥ 80	26,841	2,315	1,836	917	34
80 > u ≥ 70	7,922	1,037	525	253	0
70 > u ≥ 40	8,098	697	288	159	2
40 > u ≥ 10	1,941	282	100	42	4
10 > u	98	33	12	2	0

TABLE A 59: Number of voltage dips per number of monitored points in MV in Hungary in 2016

Residual voltage u (%)	Duration t (ms)				
	20 < t ≤ 200	200 < t ≤ 500	500 < t ≤ 1,000	1,000 < t ≤ 5,000	5,000 < t ≤ 60,000
90 > u ≥ 80	25,250	1,520	1,123	723	34
80 > u ≥ 70	6,622	730	226	130	1
70 > u ≥ 40	5,328	516	148	36	5
40 > u ≥ 10	1,064	170	44	9	1
10 > u	39	10	1	1	0

TABLE A 60: Number of voltage dips per number of monitored points in MV in Hungary in 2015

Residual voltage u (%)	Duration t (ms)				
	20 < t ≤ 200	200 < t ≤ 500	500 < t ≤ 1,000	1,000 < t ≤ 5,000	5,000 < t ≤ 60,000
90 > u ≥ 80	23,242	1,353	942	777	52
80 > u ≥ 70	6,199	607	293	189	1
70 > u ≥ 40	4,851	580	193	45	12
40 > u ≥ 10	1,138	235	36	15	0
10 > u	0	0	0	0	0

TABLE A 61: Number of voltage dips per number of monitored points in LV in Hungary in 2018

Residual voltage u (%)	Duration t (ms)				
	20 < t ≤ 200	200 < t ≤ 500	500 < t ≤ 1,000	1,000 < t ≤ 5,000	5,000 < t ≤ 60,000
90 > u ≥ 80	58,765	52,963	21,363	20,405	25,562
80 > u ≥ 70	5,815	3,531	2,447	2,100	1,686
70 > u ≥ 40	2,735	589	187	245	37
40 > u ≥ 10	1,398	343	56	217	29
10 > u	479	171	469	1,392	500

TABLE A 62: Number of voltage dips per number of monitored points in LV in Hungary in 2017

Residual voltage u (%)	Duration t (ms)				
	20 < t ≤ 200	200 < t ≤ 500	500 < t ≤ 1,000	1,000 < t ≤ 5,000	5,000 < t ≤ 60,000
90 > u ≥ 80	49,219	30,265	12,250	12,601	16,417
80 > u ≥ 70	6,223	2,541	1,456	1,046	588
70 > u ≥ 40	2,831	580	368	223	63
40 > u ≥ 10	1,497	316	126	295	42
10 > u	660	204	500	2,000	602

TABLE A 63: Number of voltage dips per number of monitored points in LV in Hungary in 2016

Residual voltage u (%)	Duration t (ms)				
	20 < t ≤ 200	200 < t ≤ 500	500 < t ≤ 1,000	1,000 < t ≤ 5,000	5,000 < t ≤ 60,000
90 > u ≥ 80	67,703	46,245	12,852	15,098	18,641
80 > u ≥ 70	8,667	4,920	2,460	754	1,009
70 > u ≥ 40	3,065	747	694	741	63
40 > u ≥ 10	1,980	2,051	456	1,155	38
10 > u	2,558	1,172	1,656	3,604	768

TABLE A 64: Number of voltage dips per number of monitored points in LV in Hungary in 2015

Residual voltage u (%)	Duration t (ms)				
	20 < t ≤ 200	200 < t ≤ 500	500 < t ≤ 1,000	1,000 < t ≤ 5,000	5,000 < t ≤ 60,000
90 > u ≥ 80	59,340	44,501	15,853	19,902	28,055
80 > u ≥ 70	6,413	5,212	3,981	3,272	6,085
70 > u ≥ 40	2,839	1,218	2,954	2,858	458
40 > u ≥ 10	1,735	354	72	3,441	11
10 > u	889	361	1,253	9,066	438

TABLE A 65: Number of voltage dips per number of monitored points in transmission in Ireland in 2018

Residual voltage u (%)	Duration t (ms)				
	10 < t ≤ 200	200 < t ≤ 500	500 < t ≤ 1,000	1,000 < t ≤ 5,000	5,000 < t ≤ 60,000
90 > u ≥ 80	35	3			

TABLE A 66: Number of voltage dips per number of monitored points in transmission in Ireland in 2017

Residual voltage u (%)	Duration t (ms)				
	10 < t ≤ 200	200 < t ≤ 500	500 < t ≤ 1,000	1,000 < t ≤ 5,000	5,000 < t ≤ 60,000
90 > u ≥ 80	55				

TABLE A 67: Number of voltage dips per number of monitored points in transmission in Ireland in 2016

Residual voltage u (%)	Duration t (ms)				
	10 < t ≤ 200	200 < t ≤ 500	500 < t ≤ 1,000	1,000 < t ≤ 5,000	5,000 < t ≤ 60,000
90 > u ≥ 80	31	3		1	

TABLE A 68: Number of voltage dips per number of monitored points in transmission in Ireland in 2015

Residual voltage u (%)	Duration t (ms)				
	10 < t ≤ 200	200 < t ≤ 500	500 < t ≤ 1,000	1,000 < t ≤ 5,000	5,000 < t ≤ 60,000
90 > u ≥ 80	35	3			

TABLE A 69: Number of voltage dips per number of monitored points in transmission in Kosovo* in 2018

Residual voltage u (%)	Duration t (ms)				
	10 < t ≤ 200	200 < t ≤ 500	500 < t ≤ 1,000	1,000 < t ≤ 5,000	5,000 < t ≤ 60,000
90 > u ≥ 80	2	0	0	0	0
80 > u ≥ 70	1	0	0	0	0
70 > u ≥ 40		0	0	0	0
40 > u ≥ 5	0	0	0	0	0
5 > u	0	0	0	0	0

Kosovo* reported 0 in all other years.

TABLE A 70: Number of voltage dips per number of monitored points in distribution (MV network) in Portugal in 2018

Residual voltage u (%)	Duration t (ms)				
	10 < t ≤ 200	200 < t ≤ 500	500 < t ≤ 1,000	1,000 < t ≤ 5,000	5,000 < t ≤ 60,000
90 > u ≥ 80	51.3	5.8	5.1	0.5	0
80 > u ≥ 70	14.4	2.3	1.8	0.1	0
70 > u ≥ 40	14.9	3.2	1.9	0.2	0
40 > u ≥ 5	4.1	1.3	0.5	0.1	0
5 > u	0.1	0	0	0	0

TABLE A 71: Number of voltage dips per number of monitored points in distribution (MV network) in Portugal in 2017

Residual voltage u (%)	Duration t (ms)				
	10 < t ≤ 200	200 < t ≤ 500	500 < t ≤ 1,000	1,000 < t ≤ 5,000	5,000 < t ≤ 60,000
90 > u ≥ 80	64.8	4.3	3.6	0.4	0
80 > u ≥ 70	19.8	1.5	1.4	0.2	0
70 > u ≥ 40	16.3	1.6	1.8	0.1	0
40 > u ≥ 5	3.8	1	0.5	0	0
5 > u	0	0	0	0	0

TABLE A 72: Number of voltage dips per number of monitored points in distribution (MV network) in Portugal in 2016

Residual voltage u (%)	Duration t (ms)				
	10 < t ≤ 200	200 < t ≤ 500	500 < t ≤ 1,000	1,000 < t ≤ 5,000	5,000 < t ≤ 60,000
90 > u ≥ 80	49.41	3.34	3.91	0.41	0
80 > u ≥ 70	15.63	1.34	1.54	0.11	0
70 > u ≥ 40	13.91	2.86	1.61	0.21	0
40 > u ≥ 5	2.96	1.52	0.48	0.06	0
5 > u	0	0	0	0	0

TABLE A 73: Number of voltage dips per number of monitored points in distribution (MV network) in Portugal in 2015

Residual voltage u (%)	Duration t (ms)				
	10 < t ≤ 200	200 < t ≤ 500	500 < t ≤ 1,000	1,000 < t ≤ 5,000	5,000 < t ≤ 60,000
90 > u ≥ 80	39.3	5	4	0.5	0
80 > u ≥ 70	10.9	1.1	1.8	0.3	0
70 > u ≥ 40	10.2	2.5	2.1	0.1	0
40 > u ≥ 5	2.9	1.7	0.5	0.1	0
5 > u	0	0	0	0	0

TABLE A 74: Number of voltage dips per number of monitored points in transmission in Portugal in 2018

Residual voltage u (%)	Duration t (ms)				
	10 < t ≤ 200	200 < t ≤ 500	500 < t ≤ 1,000	1,000 < t ≤ 5,000	5,000 < t ≤ 60,000
90 > u ≥ 80	44.19	1.71	1.05	0.42	0
80 > u ≥ 70	15.52	0.2	0.24	0.11	0
70 > u ≥ 40	16.4	0.36	0.1	0.1	0.05
40 > u ≥ 5	2.2	0.11	0.01	0.05	0
5 > u	0.14	0	0.05	0.02	0

TABLE A 75: Number of voltage dips per number of monitored points in transmission in Portugal in 2017

Residual voltage u (%)	Duration t (ms)				
	10 < t ≤ 200	200 < t ≤ 500	500 < t ≤ 1,000	1,000 < t ≤ 5,000	5,000 < t ≤ 60,000
90 > u ≥ 80	65.47	1.31	0.88	0.25	0.03
80 > u ≥ 70	18.68	0.33	0.16	0.11	0
70 > u ≥ 40	21.95	0.35	0.13	0.05	0
40 > u ≥ 5	2.68	0.04	0.03	0.03	0.01
5 > u	0.15	0	0.08	0	0

TABLE A 76: Number of voltage dips per number of monitored points in transmission in Portugal in 2016

Residual voltage u (%)	Duration t (ms)				
	10 < t ≤ 200	200 < t ≤ 500	500 < t ≤ 1,000	1,000 < t ≤ 5,000	5,000 < t ≤ 60,000
90 > u ≥ 80	35.4	1.95	1.18	0.33	0.04
80 > u ≥ 70	12.42	0.4	0.11	0.13	0
70 > u ≥ 40	13.42	0.13	0.13	0.05	0.02
40 > u ≥ 5	1.56	0.07	0.05	0.04	0
5 > u	0.04	0	0.05	0	0

TABLE A 77: Number of voltage dips per number of monitored points in transmission in Portugal in 2015

Residual voltage u (%)	Duration t (ms)				
	10 < t ≤ 200	200 < t ≤ 500	500 < t ≤ 1,000	1,000 < t ≤ 5,000	5,000 < t ≤ 60,000
90 > u ≥ 80	25.67	1.42	0.14	0.28	0
80 > u ≥ 70	6.14	0.17	0.08	0.17	0
70 > u ≥ 40	6.92	0.19	0.11	0.03	0
40 > u ≥ 5	1.5	0	0	0.03	0
5 > u	0.06	0.03	0	0	0

TABLE A 78: Number of voltage dips per number of monitored points in distribution in Slovenia in 2018

Residual voltage u (%)	Duration t (ms)				
	10 < t ≤ 200	200 < t ≤ 500	500 < t ≤ 1,000	1,000 < t ≤ 5,000	5,000 < t ≤ 60,000
90 > u ≥ 80	14,744	738	198	252	7
80 > u ≥ 70	4,716	453	100	163	0
70 > u ≥ 40	4,424	866	146	118	7
40 > u ≥ 5	2,167	1,163	160	48	3
5 > u	260	547	232	46	205

TABLE A 79: Number of voltage dips per number of monitored points in distribution in Slovenia in 2017

Residual voltage u (%)	Duration t (ms)				
	10 < t ≤ 200	200 < t ≤ 500	500 < t ≤ 1,000	1,000 < t ≤ 5,000	5,000 < t ≤ 60,000
90 > u ≥ 80	21,055	1,300	669	416	83
80 > u ≥ 70	7,037	490	410	292	12
70 > u ≥ 40	6,032	475	464	190	13
40 > u ≥ 5	2,548	784	246	97	5
5 > u	526	828	293	104	2,240

TABLE A 80: Number of voltage dips per number of monitored points in distribution in Slovenia in 2016

Residual voltage u (%)	Duration t (ms)				
	10 < t ≤ 200	200 < t ≤ 500	500 < t ≤ 1,000	1,000 < t ≤ 5,000	5,000 < t ≤ 60,000
90 > u ≥ 80	11,521	1,092	428	349	57
80 > u ≥ 70	3,582	492	150	169	2
70 > u ≥ 40	3,620	774	174	112	15
40 > u ≥ 5	1,977	1,034	156	51	3
5 > u	293	653	216	50	282

TABLE A 81: Number of voltage dips per number of monitored points in distribution in Slovenia in 2015

Residual voltage u (%)	Duration t (ms)				
	10 < t ≤ 200	200 < t ≤ 500	500 < t ≤ 1,000	1,000 < t ≤ 5,000	5,000 < t ≤ 60,000
90 > u ≥ 80	15,062	967	445	603	532
80 > u ≥ 70	4,462	172	144	105	2
70 > u ≥ 40	4,414	375	154	112	8
40 > u ≥ 5	2,806	997	123	58	0
5 > u	328	798	230	45	213

TABLE A 82: Number of voltage dips per number of monitored points in transmission in Slovenia in 2018

Residual voltage u (%)	Duration t (ms)				
	10 < t ≤ 200	200 < t ≤ 500	500 < t ≤ 1,000	1,000 < t ≤ 5,000	5,000 < t ≤ 60,000
90 > u ≥ 80	4,396	66	10	0	0
80 > u ≥ 70	1,557	11	13	0	0
70 > u ≥ 40	1,922	33	23	0	0
40 > u ≥ 5	450	4	31	5	0
5 > u	4	0	17	3	0

TABLE A 83: Number of voltage dips per number of monitored points in transmission in Slovenia in 2017

Residual voltage u (%)	Duration t (ms)				
	10 < t ≤ 200	200 < t ≤ 500	500 < t ≤ 1,000	1,000 < t ≤ 5,000	5,000 < t ≤ 60,000
90 > u ≥ 80	5,218	183	29	0	0
80 > u ≥ 70	2,143	43	22	0	0
70 > u ≥ 40	1,989	14	17	10	0
40 > u ≥ 5	791	54	15	13	5
5 > u	205	15	23	11	43

TABLE A 84: Number of voltage dips per number of monitored points in transmission in Slovenia in 2016

Residual voltage u (%)	Duration t (ms)				
	10 < t ≤ 200	200 < t ≤ 500	500 < t ≤ 1,000	1,000 < t ≤ 5,000	5,000 < t ≤ 60,000
90 > u ≥ 80	4,946	96	16	0	0
80 > u ≥ 70	2,235	16	3	1	1
70 > u ≥ 40	1,796	28	5	0	0
40 > u ≥ 5	687	79	17	1	9
5 > u	189	15	15	12	44

TABLE A 85: Number of voltage dips per number of monitored points in transmission in Slovenia in 2015

Residual voltage u (%)	Duration t (ms)				
	10 < t ≤ 200	200 < t ≤ 500	500 < t ≤ 1,000	1,000 < t ≤ 5,000	5,000 < t ≤ 60,000
90 > u ≥ 80	4,992	75	9	11	10
80 > u ≥ 70	2,182	7	2	0	1
70 > u ≥ 40	1,567	14	24	13	0
40 > u ≥ 5	810	58	25	1	5
5 > u	225	16	12	7	27

ANNEX D

ANNEX D – ANNEX TO CHAPTER "GAS – TECHNICAL OPERATIONAL QUALITY"

TABLE A 86: Transmission network length (km)

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
AT	1,961.30	1,962.10	1,973.90	2,025.00	2,023.90	2,025.90	2,025.90	2,027.10	2,050.50
BE	3,599.00	3,630.00	3,603.00	3,600.00	3,577.00	3,613.00	3,632.00	3,633.00	3,620.00
BG				2,645.00	2,645.00	2,765.00	2,765.00	2,765.00	2,788.00
CZ					3,821.00	3,821.00	3,821.00	3,822.00	3,822.00
DE	46,428.00	39,496.00	37,695.00	37,880.00	37,580.00	37,809.00	38,759.00	38,798.00	38,501.00
EE					885.00	885.00	885.00	885.00	885.00
EL	1,218.00	1,218.00	1,291.00	1,291.00	1,459.00	1,459.00	1,463.58	1,463.58	1,465.20
ES	11,665.00	11,731.00	12,815.00	13,492.00	13,716.00				
FI			1,314.89	1,287.00	1,287.00	1,287.00	1,293.98	1,197.39	1,193.90
GE									1,900.00
HR								2,693.00	2,693.00
HU					5,873.00	5,873.00	5,873.00	5,873.00	5,873.00
IE					2,412.00	2,433.00	2,427.00	2,427.00	2,477.00
LT	1,865.00	1,865.00	1,904.00	2,007.00	2,007.00	2,113.00	2,115.00	2,115.00	2,114.00
LU					280.00	280.00	282.00	282.00	283.00
LV							944.70	1,189.00	1,188.00
MK				186.10	193.10	194.50	197.10	199.50	201.00
NL						12,600.6	12,631.4	12,592.3	12,483.9
PL					11,008.27	11,681.26	11,673.63	11,743.82	11,427.80
PT	1,267.00	1,296.00	1,298.00	1,375.00	1,375.00	1,375.00	1,375.00	1,375.00	1,375.00
RO								11,562.00	11,586.00
RS	2,258.00	2,321.00	2,391.00	2,398.00	2,423.00	2,423.00	2,423.00	2,459.00	2,464.00
SE					601.00	601.00	601.00	601.00	601.00
SI		1,053.60	1,093.97	1,121.22	1,155.52	1,155.37	1,155.54	1,158.60	1,173.90
SK			2,270.00	2,270.00	2,270.00	2,283.00	2,283.00	2,332.00	2,332.00
UA					35,540.00	35,540.00	35,540.00	35,540.00	35,540.00

TABLE A 87: Distribution network length (km)

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
AT	37,894.47	38,425.17	38,954.05	39,550.62	39,904.15	40,274.10	40,802.80	43,924.34	44,182.49
BE[267]	15,407.00	15,675.60	15,880.50	16,048.80	71,219.13	71,957.60	72,513.84	72,804.00	73,460.00
BG				4,035.00	4,224.00	4,334.00	4,444.00	4,724.00	4,916.00
CZ					61,415.00	61,374.00	61,344.00	61,453.00	61,475.00
DE	448,964.00	471,213.00	470,433.00	485,413.00	481,103.00	481,103.00	497,429.00	498,081.00	512,128.00
EE					2,120.00	2,126.00	2,162.00	2,170.00	2,217.00
EL								6,067.00	6,305.00
ES	62,535.00	64,672.00	67,282.00	67,696.00	68,090.00				
FI			1,963.44	1,973.59	1,985.57	1,990.91	2,079.84	2,023.39	2,008.68
GE									31,000.00
HR								19,318.00	19,448.00
HU					83,530.00	83,618.00	83,732.00	83,862.00	84.079,00
IE					11,288.00	11,339.00	11,527.00	11,745.00	11,913.00
LT	8,120.00	8,255.00	8,357.00	8,465.00	8,559.00	8,663.00	8,772.00	8,914.00	9,106.00
LU					2,878.30	2,932.00	2,977.00	3,029.00	3,058.00
LV							4,108.70	5,211.00	5,243.00
MK				29.33	30.73	37.59	40.09	44.72	47.22
NL					124,626.50	124,513.04	125,150.78	125,123.62	125,325.80
PL					172,718.90	175,962.51	180,071.31	183,021.80	186,225.12
PT	14,840.00	15,433.00	15,878.00	16,291.00	17,374.00	17,759.00	18,245.00	18,565.00	18,987.00
RO								49,444.00	51,015.00
RS			15,348.00	15,839.00	16,363.00	16,532.00	16,653.00	16,961.00	18,422.00
SE					2,882.00	3,513.00	3,546.00	3,347.00	3,348.00
SI		4,319.00	4,342.00	4,450.00	4,531.00	4,632.00	4,672.00	4,733.50	4,827.10
SK			33,079.00	33,182.00	33,257.00	33,301.00	33,270.00	33,273.00	33,358.00
UA					296,884.00	277,000.00	274,000.00	291,779.00	285,191.00

267 Values of the years 2010 to 2013 without data from the Flemish regulatory authority VREG.

TABLE A 88: Transmission and distribution network length (km)

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
AT	39,855.77	40,387.27	40,927.95	41,575.62	41,928.05	42,300.00	42,828.70	45,951.44	46,232.99
BE[267]	19,006.00	19,305.60	19,483.50	19,648.80	74,796.13	75,570.60	76,145.84	76,437.00	77,080.00
BG				6,680.00	6,869.00	7,099.00	7,209.00	7,489.00	7,704.00
CZ					65,236.00	65,195.00	65,165.00	65,275.00	65,297.00
DE	495,392.00	510,709.00	508,128.00	523,293.00	518,683.00	518,912.00	536,188.00	536,879.00	550,629.00
EE					3,005.00	3,011.00	3,047.00	3,055.00	3,102.00
EL								7,530.58	7,770.20
ES	74,200.00	76,403.00	80,097.00	81,188.00	81,806.00				
FI			3,278.33	3,260.59	3,272.57	3,277.91	3,373.82	3,220.78	3,202.58
GE									32,900.00
HR								22,011.00	22,141.00
HU					89,403.00	89,491.00	89,605.00	89,735.00	89.952.00
IE					13,700.00	13,772.00	13,954.00	14,172.00	14,390.00
LT	9,985.00	10,120.00	10,261.00	10,472.00	10,566.00	10,776.00	10,887.00	11,029.00	11,220.00
LU					3,158.30	3,212.00	3,259.00	3,311.00	3,341.00
LV							5,053.40	6,400.00	6,431.00
MK				215.43	223.83	232.09	237.19	244.22	248.22
NL						137,113.64	137,782.18	137,715.92	137,809.70
PL					183,727.17	187,643.77	191,744.94	194,765.62	197,652.92
PT	16,107.00	16,729.00	17,176.00	17,666.00	18,749.00	19,134.00	19,620.00	19,940.00	20,362.00
RO								61,006.00	62,601.00
RS			17,739.00	18,237.00	18,786.00	18,955.00	19,076.00	19,420.00	20,886.00
SE			3,474.00	3,458.00	3,483.00	4,114.00	4,147.00	3,948.00	3,949.00
SI		5,372.60	5,435.97	5,571.22	5,686.52	5,787.37	5,827.54	5,892.10	6,001.00
SK			35,349.00	35,452.00	35,527.00	35,584.00	35,553.00	35,605.00	35,690.00
UA					332,424.00	312,540.00	309,540.00	327,319.00	320,731.00

TABLE A 89: Number of served customers (Total, HP, MP, LP, other)

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
AT (total)								1,249,963	1,247,767
BE (total)	416,916	419,115	1,083,230	1,098,535	3,113,687	3,126,835	3,234,315	3,285,452	3,342,019
CZ (total)					2,849,162	2,844,334	2,840,473	2,844,257	2,840,619
HP					1,599	1,606	1,618	1,703	1,692
MP					6,841	6,814	6,823	6,817	6,817
LP					197,824	199,725	199,995	203,138	205,693
Other[268]					2,642,898	2,636,189	2,632,037	2,632,599	2,626,417
DE (total)	13,503,145	13,419,509	13,698,780	13,979,337	13,837,257	14,124,144	14,487,346	14,240,557	14,441,600
Other[269]	11,730,000	11,890,000	12,420,000	12,453,223	12,511,854	12,387,301	12,416,171	12,467,713	12,840,000
EE (total)					51,176	51,013	52,185	52,342	51,864
HP					10	10	10	9	9
Other[270]					51,166	51,003	52,175	52,333	51,855
EL (total)								412,894	458,447
HP								44	44
LP								412,850	458,403
ES (total)	7,180,332	7,278,501	7,366,468	7,448,827	7,548,654	7,585,830	7,672,662	7,797,233	7,870,899
HP	110	108	111	111	114	114	114	128	129
MP	4,841	4,496	4,320	4,535	3,942	3,855	3,819	3,763	3,890
LP	7,175,381	7,273,897	7,362,037	7,444,181	7,544,598	7,581,861	7,668,729	7,793,342	7,866,880
FI (total)			38,111	38,086	38,049	28,373	28,542	28,130	27,893
GE (total)									1,239,000
HR (total)								665,283	671,715
HU (total)					3,442,833	3,447,267	3,452,051	3,451,818	3,461,780
HP					41	36	37	34	35
Other[271]					3,442,792	3,447,231	3,452,014	3,451,784	3,461,745
IE (total)					673,160	673,858	680,155	688,283	697,458
HP					48	50	48	51	45
MP					213	215	221	232	245
LP					672,899	673,593	679,886	688,000	697,168
LT (total)				561,927	565,267	569,261	573,004	582,482	594,950
LU (total)					85,907	87,021	88,629	89,130	89,939
LV (total)								412,583	409,255

268 Households.
269 Household customers.
270 MP and LP customers.
271 Aggregated data for DSO customers, regardless of their pressure level (mostly LP).

TABLE A 89: Number of served customers (Total, HP, MP, LP, other)

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
MK (total)				100	120	261	323	365	433
HP				1	1	1	1	1	1
MP				45	48	53	55	56	56
LP				54	71	207	267	308	376
MT (total)								2	2
Other[272]								2	2
NL (total)					7,226,855	7,261,187	7,299,902	7,354,730	7,379,014
HP (or MP)					9,798	9,977	9,977	11,544	10,680
LP					7,217,057	7,251,210	7,289,925	7,343,186	7,368,065
Other[273]					0	353	357	337	334
PL (total)					6,824,590	6,823,946	6,827,315	6,973,348	7,045,453
HP					238	241	230	983	934
MP					6,824,352	6,823,705	6,827,085	6,972,365	7,044,519
PT (total)				1,320,052	1,355,122	1,395,741	1,424,259	1,452,094	1,542,009
HP				22	22	22	19	19	19
MP				393	399	353	317	318	341
LP				1,319,637	1,354,701	1,395,366	1,423,923	1,451,757	1,541,649
RS (total)					261,263	262,591	267,158	270,689	276,581
HP					60	85	52	63	63
LP					261,203	262,506	267,106	270,626	276,518
SE (total)			37,704	37,393	37,023	36,564	36,525	35,164	34,047
SI (total)	128,914	130,293	131,652	133,073	133,364	133,444	133,439	133,630	134,642
HP	145	141	137	134	134	132	132	135	139
SK (total)								1,514,282	1,518,200
HP								830	832
MP								1,291,213	1,294,554
LP								222,239	222,814
UA (total)					13,641,851	12,393,808	12,270,759	12,396,866	12,435,678

272 Natural gas used to supply two power stations (owned by D3 Power Generation Ltd and ElectroGas Malta Ltd) located in the vicinity of the LNG terminal in Delimara. No gas transmission or distribution networks.
273 Direct connections to the transmission network.

TABLE A 90: Number of measurement points

Country[274]	2010	2011	2012	2013	2014	2015	2016	2017	2018
AT	1,351,888	1,350,842	1,350,310	1,350,423	1,348,867	1,346,339	1,346,537	1,347,685	1,344,868
CZ					8,108	3,747	3,694	3,659	3,663
With RC					2,009	2,009	2,014	2,051	2,000
Without RC					6,099	1,738	1,680	1,608	663275
With CM					8,098	3,693	3,640	3,605	3,609
DE	13,503,145	13,419,509	13,698,780	13,979,337	13,837,257	14,124,144	14,487,346	14,240,557	14,441,600
EE					3	3	3	3	3
With RC					3	3	3	3	3
ES	7,180,332	7,278,501	7,366,468	7,448,855	7,548,654	7,585,830	7,672,662	7,797,233	7,870,899
FR					174,874				
With RC					174,874				
GE									1,239,000
With CM									1,239,000
HU					636	640	644	646	651
With RC					636	640	644	646	651
With CM					636	640	644	646	651
IE					175	178	178	178	178
With RC					6	6	6	6	6
Without RC					169	172	172	172	172
LT			3	3	3	3	3	3	3
LU					85,907	87,021	88,629	89,130	89,939
LV								412,583	409,255
With RC								567	819
Without RC								412,016	408,436
MK				100	120	261	323	365	433
With RC				1	1	1	8	10	10
Without RC				99	119	260	315	355	423
PL					6,851,750	6,437,723	6,932,009	7,111,151	7,357,808
PT	12	12	12	12	12	12	12	12	12
With RC	12	12	12	12	12	12	12	12	12
With CM	12	12	12	12	12	12	12	12	12
RS				261,015	261,263	262,591	267,158	270,689	276,581
SE					48	48	48	48	48
With CM					48	48	48	48	48
SI		419	444	452	451	447	444	454	499
With CM		419	444	452	451	447	444	454	499
SK			1,508,309	1,502,898	1,506,260	1,514,656	1,518,131	1,514,282	1,518,200
UA					2,647	2,657	2,677	2,996	3,031
With RC					2,438	2,453	2,488	2,752	2,898
Without RC					209	204	189	244	133
With CM					1,834	1,839	1,844	1,872	1,897

274 Measurement points with compliant measurements to technical standards (CM) are included in measurement points with remote control (RC).
275 Some measurement points were changed from 'without RC' to 'with RC'.

TABLE A 91: Unplanned SAIDI (minutes per customer per year)

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
AT				1.83	1.68	1.80	1.59	1.27	2.80
BE					Flanders: 0.2	Flanders: 0.77	Flanders: 1.1	Flanders: 0.31	Flanders: 0.58
DE	1.26	1.96	2.09	0.66	16.82	1.91	1.07	1.78	0.49
FI							0.00	0.00	0.07
GE								545.68	322.77
LT	0.94	0.66	1.44	1.53	2.12	1.03	0.53		
LV								1.39	0.49
NL	0.48	0.72	1.03	1.01	3.25	2.16	0.98	1.03	1.06
PT					1.68	0.90	0.50	0.91	1.66
RS							10.26	10.92	10.54
SI								16.10	9.21

TABLE A 92: Planned SAIDI (minutes per customer per year)

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
BE					Flanders: 5.04	Flanders: 3.3	Flanders: 3.41	Flanders: 2.34	Flanders: 1.62
DE	11.36	136.68	45.25	9.10	38.20	8.52	19.70	48.97	8.40
FI							0.01	0.24	0.00
GE								642.18	359.13
LT	31.13	34.85	27.43	26.97	40.22	43.28	23.39		
LV								30.00	41.00
NL	2.58	4.29	4.57	5.10	4.06	4.16	3.27	3.44	3.93
PT					0.22	0.19	0.37	0.33	0.54
RS							106.67	44.49	46.11
SI								6.49	2.96

TABLE A 93: Unplanned and planned ASIDI (minutes per customer per year)

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
DE (unplanned)	0.32	0.59	1.31	0.09	0.36	0.89	0.22	0.81	0.03
DE (planned)	1.34	1.98	36.45	5.60	7.18	1.01	8.68	14.35	5.98

TABLE A 94: Unplanned SAIFI (interruptions per customer per year)

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
AT				0.01	0.01	0.00	0.00	0.00	0.00
DE	0.03	0.19	0.08	0.01	0.14	0.14	0.02	0.05	0.00
FI									0.03
GE								0.55	0.56
LT	0.01	0.01	0.01	0.00	0.01	0.01	0.01		
LV								0.00	0.00
NL	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
PT					0.04	0.00	0.00	0.00	0.01
RS							0.06	0.06	0.07
SI								0.02	0.04

TABLE A 95: Planned SAIFI (interruptions per customer per year)

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
DE	0.10	0.40	0.79	0.11	0.21	0.04	0.16	0.34	0.13
FI								0.08	0.07
GE								0.74	0.72
LT	0.26	0.25	0.23	0.26	0.25	0.27	0.18		
LV								0.29	0.38
NL	0.02	0.03	0.03	0.03	0.02	0.04	0.04	0.05	0.06
PT					0.00	0.00	0.00	0.00	0.00
RS							0.12	0.11	0.11
SI								0.02	0.01

TABLE A 96: Unplanned CAIDI (minutes per interruption)

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
AT				323.00	335.00	431.00	460.00	350.00	617.00
DE	212.98	58.66	885.91	190.55	1,282.13	82.62	162.16	318.62	203.02
LV								384.00	330.00
NL	97.90	141.20	154.30	122.50	523.50	349.40	113.00	163.30	132.90

TABLE A 97: Planned CAIDI (minutes per interruption)

Country	2010	2011	2012	2013	2014	2015	2016	2017	2018
DE	312.70	417.25	731.49	678.59	530.73	420.25	565.35	947.02	449.99
NL	144.03	167.42	154.23	195.64	208.72	126.69	138.18	121.85	147.80

ANNEX E

ANNEX E – ANNEX TO CHAPTER "GAS – NATURAL GAS QUALITY"

TABLE A 98: Methane (CH_4) content, minimum value and monitoring frequency

Methane (CH_4)	Min	Unit	Measurement frequency	Publication frequency
BA	90	% mol	Daily	System operator's responsibility
BE	NA	NA	Continuously	Not published
BG	70	% mol	Daily	Daily
CZ	85	% mol	Continuously	Monthly
EE	65	NA	NA	Monthly
EL	75	% mol	5 minutes	Daily
ES	90	% mol	Daily	NA
GE	75	% mol	Daily	Daily
HR	85	% mol	Twice per month	Twice per month
HU	No limit	% mol	4 minutes	Yearly
IE	NA	% mol	Continuously	Monthly
LT	90	% mol	NA	NA
LV	90	% mol	Continuously	On request
MK	94.882 [276]	% mol	4 minutes	Not published
NL	65 [277]	% mol	5 minutes	Yearly
PT	No limit	% mol	Hourly	Monthly
RO	70	% mol	Daily/every 10 days/monthly [278]	No obligation
RS	90	% mol	Daily	NA
SI	94.985 [279]	% mol	4 minutes	Not published
SK	92	% mol	NA	NA
UA	90	% mol	Daily/Weekly [280]	Monthly

TABLE A 99: Ethane (C_2H_6) content, maximum value and monitoring frequency

Ethane (C_2H_6)	Max	Unit	Measurement frequency	Publication frequency
BA	4	% mol	Daily	System operator's responsibility
BE	NA	NA	Continuously	Not published
BG	NA	% mol	Daily	Daily
CZ	7	% mol	Continuously	Monthly
EL	No limit	% mol	5 minutes	Daily
HR	7	% mol	Twice per month	Twice per month
HU	No limit	% mol	4 minutes	Yearly
IE	12	% mol	Continuously	Monthly
MK	2.931 [281]	% mol	4 minutes	Not published
RO	10	% mol	Daily/every 10 days/monthly [282]	No obligation
RS	4	% mol	Daily	NA
SI	2.726 [283]	% mol	4 minutes	Not published
SK	4	% mol	NA	NA
UA	7	% mol	Daily/Weekly [284]	Monthly

276 Maximum value of 95.845.
277 Maximum value of 96.
278 Depending on the yearly energy consumption.
279 Maximum value of 96.103.
280 Depending on the flow rate.
281 Minimum value of 2.293.
282 Depending on the yearly energy consumption.
283 Minimum value of 2.167.
284 Depending on the flow rate.

TABLE A 100: Propane (C_3H_8) content, maximum value and monitoring frequency

Propane (C_3H_8)	Max	Unit	Measurement frequency	Publication frequency
BA	2	% mol	Daily	System operator's responsibility
BE	NA	NA	Continuously	Not published
BG	NA	%	Daily	Daily
CZ	3	% mol	Continuously	Monthly
EL	No limit	% mol	5 minutes	Daily
HR	6	% mol	Twice per month	Twice per month
HU	No limit	% mol	4 minutes	Yearly
IE	NA	% mol	Continuously	Monthly
MK	0.978 [285]	% mol	4 minutes	Not published
RO	3.5	% mol	Daily/every 10 days/monthly [286]	No obligation
SI	0.77 [287]	% mol	4 minutes	Not published
SK	2	% mol	NA	NA
UA	4	% mol	Daily/Weekly [288]	Monthly

TABLE A 101: Sum of Butanes content, maximum value and monitoring frequency

Sum of Butanes	Max	Unit	Measurement frequency	Publication frequency
BA	2	% mol	Daily	System operator's responsibility
BE	NA	NA	Continuously	Not published
BG	NA	%	Daily	Daily
CZ	2	% mol	Continuously	Monthly
EL	No limit	% mol	5 minutes	Daily
HU	No limit	% mol	4 minutes	Yearly
IE	NA	% mol	Continuously	Monthly
MK	0.139 [289]	% mol	4 minutes	Not published
RO	1.5	% mol	Daily/every 10 days/monthly [290]	No obligation
SI	0.106 [291]	% mol	4 minutes	Not published
SK	2	% mol	NA	NA
UA	2	% mol	Daily/Weekly [292]	Monthly

285 Minimum value of 0.745.
286 Depending on the yearly energy consumption.
287 Minimum value of 0.55.
288 Depending on the flow rate.
289 Minimum value of 0.109.
290 Depending on the yearly energy consumption.
291 Minimum value of 0.082.
292 Depending on the flow rate.

TABLE A 102: Oxygen (O_2) content, maximum value and monitoring frequency

Oxygen (O_2)	Max	Unit	Measurement frequency	Publication frequency
BE	1,000	ppm	Continuously	Daily/Yearly [293]
CZ	0.02	% mol	Continuously	Monthly
EE	2.5	% mol	NA	Monthly
EL	0.2	% mol	5 minutes	Daily
ES	0.01	% mol	Daily	NA
GE	0.0005	% mol	NA	NA
HR	0.001	% mol	Twice per month	Twice per month
HU	0.2	% V/V[294]	Occasionally	Occasionally
IE	0.2	% mol	Monthly	Monthly
LT	0.5	% mol	NA	NA
LV	1	% mol	Continuously	On request
NL	0.5	% mol	5 minutes	Yearly
PT	No limit	% mol	Hourly	Monthly
RO	0.02	% mol	Daily/every 10 days/monthly [295]	No obligation
SI	0.02 [296]	% mol	Daily	Not published
SK	0.01	% mol	NA	NA
UA	0.02	% mol	Daily/Weekly [297]	Monthly

TABLE A 103: Nitrogen (N_2) content, maximum value and monitoring frequency

Nitrogen (N_2)	Max	Unit	Measurement frequency	Publication frequency
BA	5	% mol	Daily	System operator's responsibility
BE	NA	NA	Continuously	Not published
BG	10	%	Daily	Daily
CZ	5	% mol	Continuously	Monthly
EE	3	% mol	NA	Monthly
EL	6	% mol	5 minutes	Daily
ES	No limit	% mol	Daily	Daily
GE	6	% mol	Daily	Daily
HR	7	% mol	Twice per month	Twice per month
HU	No limit	% mol	4 minutes	Yearly
IE	5	% mol	Monthly	Monthly
LT	3	% mol	NA	NA
LV	3	% mol	Continuously	On request
RO	10	% mol	Daily/every 10 days/monthly [298]	No obligation
RS	5 [299]	% mol	Daily	NA
SI	0.862 [300]	% mol	4 minutes	Not published
SK	3	% mol	NA	NA
UA	5	% mol	Daily/Weekly [301]	Monthly

293 For connected companies, authorities and shippers / for others.
294 Annex 11 of Governmental Decree 19/2009 (I.30) on the Implementation of the Gas Act specifies the allowed maximum of oxygen content as 0.2 V/V%.
295 Depending on the yearly energy consumption.
296 Minimum value of 0.01.
297 Depending on the flow rate.
298 Depending on the yearly energy consumption.
299 Including CO_2.
300 Minimum value of 0.629.
301 Depending on the flow rate.

TABLE A 104: Hydrogen (H_2) content maximum value and monitoring frequency

Hydrogen (H_2)	Max	Unit	Measurement frequency	Publication frequency
BG	NA	%	Daily	Daily
EE	0.1	% mol	NA	Monthly
ES	5	% mol	Daily	NA
IE	0.1	% mol	Monthly	Monthly
LT	2	% mol	NA	NA
LV	0.1	% mol	Continuously	On request
NL	0.02	% mol	NA	Yearly
UA	NA	% mol	Daily/Weekly [302]	Monthly

TABLE A 105: Carbon Monoxide (CO) content, maximum value and monitoring frequency

Carbon Monoxide (CO)	Max	Unit	Measurement frequency	Publication frequency
ES	2	% mol	Daily	NA
NL	2,900	mg/m³	NA	NA

TABLE A 106: Carbon Dioxide (CO_2) content, maximum value and monitoring frequency

Carbon Dioxide (CO_2)	Max	Unit	Measurement frequency	Publication frequency
BA	5	% mol	Daily	System operator's responsibility
BE	2.5	% mol	Continuously	Daily/yearly [303]
CZ	3	% mol	Continuously	Monthly
EE	2.5	% mol	NA	Monthly
EL	3	% mol	5 minutes	Daily
ES	2.5	% mol	Daily	Daily
GE	2.5	% mol	Daily	Daily
HR	2.5	% mol	Twice per month	Twice per month
HU	No limit	% mol	4 minutes	Yearly
IE	2.5	% mol	Continuously	Monthly
LT	2.5	% mol	NA	NA
LV	1	% mol	Continuously	On request
MK	0.258 [304]	% mol	4 minutes	Not published
NL	2.5	% mol	5 minutes	Yearly
PT	No limit	% mol	Hourly	Monthly
RO	8	% mol	Daily/every 10 days/monthly [305]	No obligation
RS	5 [306]	% mol	Daily	NA
SI	0.45 [307]	% mol	4 minutes	Not published
SK	2	% mol	NA	NA
UA	2	% mol	Daily/Weekly [308]	Monthly

302 Depending on the flow rate.
303 For connected companies, authorities and shippers/for others.
304 Minimum value of 0.193.
305 Depending on the yearly energy consumption.
306 Including N_2.
307 Minimum value of 0.208.
308 Depending on the flow rate.

TABLE A 107: Sum of Pentanes and Higher Hydrocarbons content, maximum value and monitoring frequency

Sum of Pentanes and Higher Hydrocarbons	Max	Unit	Measurement frequency	Publication frequency
BE	NA	NA	Continuously	Not published
CZ	0.5	% mol	Continuously	Monthly
HU[309]	No limit	% mol	4 minutes	Yearly
IE	NA	NA	Monthly	Not published
MK	0.024 [310]	% mol	4 minutes	Not published
RS	2	% mol	Daily	NA
SI	0.024 [311]	% mol	4 minutes	Not published
UA	1	% mol	Daily/Weekly [312]	Monthly

TABLE A 108: Dust Particles content, maximum value and monitoring frequency

Dust Particles	Max	Unit	Measurement frequency	Publication frequency
EE	0.001	g/m^3	NA	Monthly
ES	0	NA	Daily	NA
HU	5	mg/m^3	Occasionally	Occasionally
LT	0.001	g/m^3	NA	NA
LV	0.001	g/m^3	Continuously	On request
NL	100	mg/m^3	NA	Yearly
UA	0	g/m^3	Monthly	Monthly

TABLE A 109: Water (H_2O) content, maximum value and monitoring frequency

Water (H_2O)	Max	Unit	Measurement frequency	Publication frequency
HU	0.17	g/m^3	10 minutes	Yearly
IE	50	mg/m^3	Continuously [313]	Monthly

TABLE A 110: Incomplete Combustion Factor maximum value and monitoring frequency

Incomplete Combustion Factor	Max	Unit	Measurement frequency	Publication frequency
IE	0.48	No unit	Monthly	Monthly
SI	1.6	NA	Weekly	Not published
SK	NA[314]	kWh/Nm^3	NA	NA

309 The Values for pentanes and higher hydrocarbons (C_6-C_8) are published not as an aggregated sum, but separately.
310 Minimum value of 0.018.
311 Minimum value of 0.015.
312 Depending on the flow rate.
313 At two out of three entry points.
314 Only minimum limit (9.96).

TABLE A 111: Delivery Temperature range and monitoring frequency

Delivery Temperature	Min	Max	Unit	Measurement frequency	Publication frequency
BA	5	15	°C	Daily	Not required
BE	2	38	°C	Continuously	Daily/Yearly [315]
EE	0	40	°C	Real time	NA
EL	-5	50	°C	5 minutes	Daily
HU	0	NA	°C	Real time	Not published
IE	1	38	°C	Continuously	Not published
MK	2	20	°C	NA	Not published
NL	0	35	°C	5 minutes	Yearly
RO	-10	50	°C	NA	No obligation
SI	-6	28	°C	Every minute	Not published

TABLE A 112: Soot Index maximum value and monitoring frequency

Soot Index	Max	Unit	Measurement frequency	Publication frequency
IE	0.6	No unit	Hourly	Monthly
SI	0.6	NA	Weekly	Not published

315 For connected companies, authorities and shippers / for others.

LIST OF ABBREVIATIONS

Term	Definition
ACER	Agency for the Cooperation of Energy Regulators
AFIK	Frequency of Unscheduled Interruptions Index
AIF	Average Interruption Frequency
AIT	Average Interruption Time
AMI	Advanced Metering Infrastructure
AMR	Automatic Meter Reading
ANRE	The National Agency for Energy Regulation (National Regulatory Authority of Moldova)
ASIDI	Average System Interruption Duration Index
ASIFI	Average System Interruption Frequency Index
bar g	Bar Gauge
BEUC	*Bureau Européen des Unions de Consommateurs* / The European Consumer Organisation
BNetzA	*Bundesnetzagentur* (National Regulatory Authority of Germany)
BOO	Build-own-operate
BOT	Build-operate-transfer
C°	Degree Celsius
CAIDI	Customer Average Interruption Duration Index
CAIFI	Customer Average Interruption Frequency Index
CAPEX	Capital expenditure
CEER	Council of European Energy Regulators
CEI	*Comitato Elettrotecnico* Italiano (Italian standardisation body for electricity)
CEMI	Customer Experiencing Multiple Interruptions
CEN	European Committee for Standardization
CENELEC	European Committee for Electrotechnical Standardization
CI	Customer Interruptions
CIGRE	*Conseil International des Grands Réseaux Électriques* (International Council on Large Electric Systems)
CIRED	*Congrès International des Réseaux Électriques de Distribution* (International Conference on Electricity Distribution)
CM	Compliant Measurements to Technical Standards
CML	Customer Minutes Lost
CNMC	*Comisión Nacional de los Mercados y la Competencia* (National Regulatory Authority of Spain)
CoS	Continuity of supply
CQ	Commercial quality
CRU	Commission for Regulation of Utilities (National Regulatory Authority of Ireland)
CTAIDI	Customer Total Average Interruption Duration Index
CZK	Czech Koruna (currency)
DIN	*Deutsches Institut für Normung* (German Institute for Standardisation)
DNO	Distribution Network Operator
DSO	Distribution System Operator
DVGW	*Deutscher Verein des Gas- und Wasserfaches* (German Technical and Scientific Association for Gas and Water)
EC	European Commission
ECRB	Energy Community Regulatory Board
EENS	Expected Energy Not Supplied
EHV	Extra high voltage
EMC	Electromagnetic Compatibility
EMRA	Energy Market Regulatory Authority (National Regulatory Authority of Turkey)
EMRC	Energy and Mineral Regulatory Commission (National Regulatory Authority of Jordan)

LIST OF ABBREVIATIONS

Term	Definition
EnC CP	Energy Community Contracting Parties
END	Energy Not Distributed
ENS	Energy Not Supplied
ENTSOG	European Network of Transmission System Operators for Gas
EPİAŞ	Energy Exchange Istanbul
EQS WS	Energy Quality of Supply Work Stream
ERC	Energy and Water Services Regulatory Commission of the Republic of North Macedonia (National Regulatory Authority of North Macedonia)
ERE	*Enti Rregullator I Energjisë* (National Regulatory Authority of Albania)
ERSE	*Entidade Reguladora dos Serviços Energéticos* / Energy Services Regulatory Authority (National Regulatory Authority of Portugal)
ES	Energy Supplied
FERK	Regulatory Commission for Energy in Federation of Bosnia and Herzegovina (Regulatory Authority of the Federation of Bosnia and Herzegovina entity in Bosnia and Herzegovina)
FSR	Florence School of Regulation
FSRU	Floating storage and regasification unit
GEL	Georgian Lari (currency)
GI	Guaranteed Indicator(s)
GGP	Guidelines of Good Practice
h	Hour
HERA	*Hrvatska Energetska Regulatorna Agencija* / Croatian Energy Regulatory Agency (National Regulatory Authority of Croatia)
HP	High-pressure
HRK	Croatian Kuna (currency)
HUF	Hungarian Forint (currency)
HV	High voltage
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
INT NC	Interoperability Network Code
IPS/UPS	Integrated Power System/Unified Power System
ISO	International Organization for Standardization
ISS	Indicator for supply standards
kJ	Kilojoule
km	Kilometre
kPa	Kilopascal
kV	Kilovolt
kVA	Kilovolt-ampere
kW	Kilowatt
kWh	Kilowatt-hour
LNG	Liquefied Natural Gas
LP	Low-pressure
LV	Low voltage
m^3	Cubic metre
MAIFI	Momentary Average Interruption Frequency Index
MAIFI-E	Momentary Average Interruption Event Frequency Index
MEDREG	Association of Mediterranean Regulators
mg	Milligram
min	Minute

LIST OF ABBREVIATIONS

Term	Definition
MIP	Maximum Incidental Pressure
MJ	Megajoule
MO	Meter operator
Mol-%	Mole percent
MOP	Maximum Operating Pressure
MP	Medium-pressure
MPa	Megapascal
MS	Member State(s)
ms	Millisecond
MV	Medium voltage
MVA	Megavolt-ampere
MW	Megawatt
MWh	Megawatt-hour
NA	Not available/not applicable
NEURC	National Energy and Utilities Regulatory Commission (National Regulatory Authority of Ukraine)
NGML	Natural Gas Market Law
NIEPI	Equivalent Number of Interruptions Related to the Installed Capacity
Nm^3	Normal cubic metre
NRA	National Regulatory Authority
NVE-RME	The Norwegian Energy Regulatory Authority
OI	Overall Indicator(s)
OPEX	Operational expenditure
OR	Other Requirement(s)
OVGW	*Österreichische Vereinigung für das Gas- und Wasserfach* (Austrian Association for Gas and Water)
P_{lt}	Long-term Flicker Severity
PNS	Power Not Supplied
ppm	Parts per million
PSPP	Pumped-storage Power Plant
P_{st}	Short-term Flicker Severity
RC	Remote control
RERS	Regulatory Commission for Energy in Republika Srpska (Regulatory Authority of the Republika Srpska entity in Bosnia and Herzegovina)
r.m.s.	Root mean square
RON	Romanian Leu (currency)
RoRE	Return on regulatory equity
RP	Reduced pressure
RTDE	*Règlement Technique pour la gestion des réseaux de Distribution d'Électricité* (technical regulations for the management of electricity distribution networks in the Belgian region of Wallonia)
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SARI	System Average Restoration Index
SCADA	Supervisory Control and Data Acquisition
Sec	Second
SEK	Swedish Krona (currency)
SERC	State Electricity Regulatory Commission of Bosnia and Herzegovina (Regulatory Authority for Transmission of Electricity in Bosnia and Herzegovina)[316]

316 SERC is responsible for electricity transmission, international trading and the Brčko district in Bosnia and Herzegovina.

LIST OF ABBREVIATIONS

Term	Definition
Sm^3	Standard Cubic metre
SMS	Short Message Service
SP	Supplier
SSO	Storage System Operator
TCTP	Turkish Continuous Trade Platform
TDR	Transmission and Distribution Rules
TEAŞ	Turkish Electricity Generation and Transmission Company
TEDAŞ	Turkish Electricity Distribution Company
TEİAŞ	Turkish Electricity Transmission Company
TEK	Turkish Electricity Authority
THD	Total Harmonic Distortion
TIEPI	Equivalent Interruption Time Related to the Installed Capacity
TIM	*Tiempo de interrupción medio* (average interruption time)
TOOR	Transfer of Operational Rights
TPA	Third party access
TRDE	*Technisch Reglement Distributie Elektriciteit* (technical regulations for the management of electricity distribution networks in the Belgian region of Flanders)
TSO	Transmission System Operator
TTIK	Total Time of Unscheduled Interruptions Index
TWh	Terawatt-hour
UAH	Ukrainian Hryvnia (currency)
U_n	Nominal Voltage
UNIPEDE	*Union Internationale des Producteurs et Distributeurs d'Énergie Électrique* (International Union of Producers and Distributors of Electrical Energy)
USP	Universal Supplier
VAT	Value-added Tax
VDE	*Verband der Elektrotechnik, Elektronik und Informationstechnik* (Association for Electrical, Electronic & Information Technologies)
VoLL	Value of lost load
VQ	Voltage quality
VQM	Voltage quality monitoring
V_{un}	Supply Voltage Unbalance
V/V	Volume by Volume (the Volume Fraction)
WACC	Weighted Average Cost of Capital
WI	Wobbe Index
WSC	Worst-Served Customer

LIST OF COUNTRY ABBREVIATIONS

Term	Definition
AL	Albania
AT	Austria
BA	Bosnia and Herzegovina
BE	Belgium
BG	Bulgaria
CH	Switzerland
CY	Cyprus
CZ	Czech Republic
DE	Germany
DK	Denmark
EE	Estonia
EL	Greece
ES	Spain
FI	Finland
FR	France
GE	Georgia
GB	Great Britain (England, Scotland and Wales)
HR	Croatia
HU	Hungary
IE	Ireland
IT	Italy
KS*	Kosovo*
LT	Lithuania
LU	Luxembourg
LV	Latvia
MD	Moldova
ME	Montenegro
MK	North Macedonia
MT	Malta
NL	The Netherlands
NO	Norway
PL	Poland
PT	Portugal
RO	Romania
RS	Serbia
SE	Sweden
SI	Slovenia
SK	Slovakia
UA	Ukraine

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The Council of European Energy Regulators (CEER) is the voice of Europe's national energy regulators. CEER's members and observers comprise 39 national energy regulatory authorities (NRAs) from across Europe.

CEER is legally established as a not-for-profit association under Belgian law, with a small Secretariat based in Brussels to assist the organisation.

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CEER

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Energy **Regulators**

ECRB

Council of European Energy Regulators (CEER)
Cours Saint-Michel 30a, box F
1040 Brussels
Belgium
Tel: + 32 2 788 73 30
Fax: + 32 2 788 73 50

www.ceer.eu
brussels@ceer.eu
twitter.com/CEERenergy
www.linkedin.com/company/
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Energy Community Regulatory Board (ECRB)
Energy Community Secretariat
Am Hof 4, Level 5-6
1010 Vienna
Austria
Tel: + 431 535 2222
Fax: + 431 535 2222 11

www.energy-community.org/aboutus/institutions/ECRB.html
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