Demonstration of **Inte**lligent grid technologies for renewables **Inte**gration and **Inte**ractive consumer participation enabling **Inte**roperable market solutions and **Inte**rconnected stakeholders

WP 1 – Use Cases and System Architecture

Current market and regulatory incentives and Barriers

D1.3

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Executive Summary

This document lies under the scope of "Work Package (WP) 1 – Use Cases and System Architecture" –, as an output of "Task 1.3 - Current market and regulatory incentives and Barriers". The objective of this Deliverable 1.3 is to provide a summary of the characteristics of the main regulatory topics that can have an impact on the demonstration activities and associated use cases. This document also aims at providing directions for future studies to be developed in "WP 7 – CBA, regulatory analysis and business models".

This deliverable identifies the main regulatory topics and organizes them into four macro categories, namely 'DSO Economic Regulation', 'DSOs as a system optimizer and market facilitator´, 'Retail tariffs and metering', 'Aggregation and Market Design'. In order to assess the current status of these regulatory topics, a questionnaire was circulated among the DSOs[1] of the four focus countries of the InteGrid project (Portugal, Slovenia, Spain and Sweden). When needed, external documents were also used.

This preliminary analysis shows that the status of regulatory topics can be summarized into three different situations, namely **harmonized**, **unharmonized** and **incipient**.

In the first situation, the four countries have a similar approach to a certain regulatory topic. An example of this situation is the deep connection charges for DG in the four countries. The fitness of the common approach for the High-Level Use Cases (HLUC) and for the demonstrations will be assessed in WP 7.

In a second situation, countries follow divergent approaches or are in different stages of development. This is the case for the possibility of net-metering, for instance. Recommendations on the approach with the best fitness for HLUCs and demonstrations will be made in WP7.

The last situation is regarding the 'incipient' situation, in which regulatory topics, for the majority of focus countries, lack of a robust provision or are in the early stage of development. Regulation on independent aggregators falls into this situation. In this case, suggestions for future regulation should be done in WP7, based on the international experience, academic literature and expected regulation for the near future (e.g. Clean Energy Package).

[1] In the case of Spain, the questionnaire was answered by Comillas University.

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Abbreviations and Acronyms

AMI	Advanced Metering Infrastructure
AS	Ancillary Services
ASIDI	Average System Interruption Duration Index
ASIFI	Average System Interruption Frequency Index
BRP	Balancing Responsibility Party
CAPEX	Capital Expenditures
CHP	Combined Heat and Power
DER	Distributed Energy Resource
DG	Distributed Generation
DoA	Description of Action
DR	Demand Response
DSO	Distribution System Operator
EDC	Electricity Distribution Companies
ESCO	Energy Services Company
GA	Grant Agreement
HLUC	High-Level Use Case
LV	Low Voltage
mFRR	Manual Frequency Restoration Reserves
MV	Medium Voltage
NHC	Network Hosting Capacity
NIEPI	Número de Interrupciones Equivalente de la Potencia Instalada (≈ASIFI)
NRA	National Regulatory Agency
OPEX	Operational Expenditures
POTP	Electricity Post-Taxes Total Price
RAB	Regulatory Asset Base
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
TIEPI	Tiempo de Interrupción Equivalente de la Potencia Instalada (≈ASIDI)
TOTEX	Total Expenditures
TSO	Transmission System Operator
UoS	Use-of-System Charge
VPP	Virtual Power Plant
WACC	Weighted Average Cost of Capital
WP	Work Package

1. Introduction: goals and scope

1.1. The InteGrid project

The way electricity is produced and consumed is changing fast. Consumers are being empowered with more data, enabling precise management of consumption, and more possibilities to participate in electricity markets. The concept of the producer is also changing. Now it includes not only the traditional large-scale power plant, but also the small generator connected to the distribution grid, storage, and Virtual Power Plants (VPP), through the aggregation of several users at the distribution level.

The creation of these new types of agents and the growing number of Distributed Energy Resources (DER) comes with the need of properly integrating them, both technically and from a regulatory perspective. They have the potential to contribute to the system with services that will enhance its performance and reliability, and potentially reduce operation costs.

A growing number of academic studies and research projects have been dedicated to the integration of a larger share of DER in power systems (GRID4EU, EvolvDSO, and SuSTAINABLE projects, among others). Moreover, several pilot projects have been carried out by different DSOs in order to test the technical and economic viability of such integration. One challenge to be explored yet, however, is how the new agents and technologies can be integrated considering the roles of different stakeholders, and their expectation, while enabling new business models given the current and future regulatory environments.

InteGrid's vision is to bridge the gap between citizens and technology/solution providers such as utilities, aggregators, manufacturers and all other agents providing energy services, hence expanding from DSOs distribution and access services to active market facilitation and system optimization services, while ensuring sustainability, security and quality of supply. The main objectives of the project are:

1. To demonstrate how DSOs may enable the different stakeholders to actively participate in the energy market and to develop and implement new business models, making use of new data management and consumer involvement approaches.
2. To demonstrate scalable and replicable solutions in an integrated environment that enable DSOs to plan and operate the network with a high share of DRE in a stable, secure and economic way, using flexibility inherently offered by specific technologies and by interaction with different stakeholders.

In order achieve the objectives mentioned above, the InteGrid project will carry three different demonstrations in Europe (Portugal, Slovenia and Sweden) to enable the various stakeholders to develop new business models as well as to bring new technologies to the market.

Along with the physical demos, research will be conducted on the several topics surrounding the demonstrations and associated use cases. One of the correlated topics is the analysis of the current regulatory frameworks in the three countries where InteGrid partners are located, the impact of such frameworks, and recommendations for future regulation.

The regulatory analysis within the InteGrid project will take place in different stages. In the first one, a preliminary assessment of regulatory frameworks will be carried within Work Package (WP) 1, under Task 1.3. The result of this analysis is presented in this Deliverable 1.3. On the second stage, WP 7 will study in-depth the issues raised in the WP1, and provide recommendations for future regulation.

1.2. Scope and objectives of this Deliverable

The goal of task 1.3 is to perform a preliminary assessment of regulatory barriers (or drivers) that will serve as a key input to WP7 where specific recommendations to adopt national and European regulation will be delivered. The first step consisted in the identification of the set of regulatory topics that can be relevant to the High-Level Use Cases (HLUCs)[2] considered in the InteGrid project and their mapping against these use cases, i.e. identifying what topics can affect each use case and to what extent.

The next step in this task is to characterize existing regulation in the four target countries defined in the Description of Action (DoA): Spain, Portugal, Sweden, and Slovenia. Regulatory topics are organized into four macro categories, namely 'DSO Economic Regulation', 'DSOs as a system optimizer and market facilitator´, 'Retail tariffs and metering', 'Aggregation and Market Design'. The information for this characterization comes from a comprehensive questionnaire circulated among project partners.

Lastly, a preliminary analysis of the current regulatory framework in the target countries has been carried out. This has enabled the categorization of the current situation into three clusters: harmonized, unharmonized and incipient regulatory topics.

1.3. Document Structure

The remainder of this document is organized as follows. First, section 2 presents a mapping of regulatory topics and HLUCs, which indicates what regulatory issues are relevant to each HLUC. Next, section 3 presents a summary of current regulation and market rules in each of the InteGrid target countries, namely Spain, Portugal, Sweden, and Slovenia. This review and the cross-country comparisons will be updated in WP7 and presented in D7.1. Building on the previous two sections, section 4 provides a preliminary assessment of current regulation and market barriers to the realization of the InteGrid concept. This work will be the basis for further work within WP7, which is to be presented in D7.2.

[2] The 12 HLUCs can be consulted in detail in the Deliverable D1.2, and the Annex A of this Deliverable provides a summary.

2. Mapping use cases with regulatory topics

This section analyses the InteGrid Project architecture and use cases, particularly the HLUCs, in order to identify the key regulatory topics relevant to the goals of InteGrid activities. Furthermore, these topics are mapped against the aforementioned HLUCs, serving as the basis for the subsequent preliminary analysis of current regulation relevant to the realization of the InteGrid goals presented in section 4.

2.1. InteGrid demonstrators and identification of relevant regulatory topics

The InteGrid consortium has identified 12 HLUCs, which are described in further detail in D1.2. These HLUCs have been classified into four different domains, namely: DSO-Grid Operations, DSO-market Hub, Grid Users, and Energy Services. The HLUCs and their corresponding domains are shown in Figure 1.

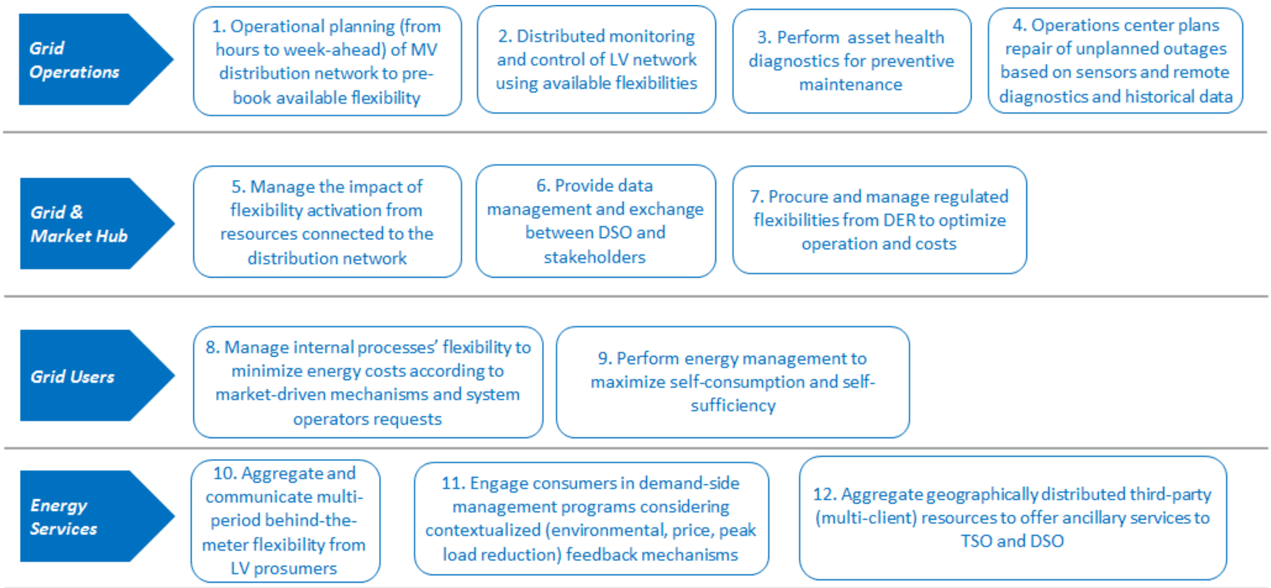

Figure 1: InteGrid HLUCs and corresponding domains

This categorization into four domains will be a key factor in determining the list of relevant regulatory topics and the subsequent cross-mapping. Firstly, some use cases are focused on the internal activities carried out by DSOs in their more **conventional role of network companies**, i.e. grid planning, operation and maintenance. The key innovation in this field lies in how smart grid solutions and the active participation of network users can support and enhance the efficiency of these operations. Consequently, the main regulatory topics for this set of HLUCs that requires analysis are those related to **the economic regulation of DSOs**, i.e. whether their regulation enables and/or encourages the deployment of these advanced solutions.

The second group of use cases constitute a more profound change in the role of DSOs. This is related to the interaction between DSOs and other stakeholders (network users, aggregators, VPPs, or energy services companies) for data exchange as well as the provision of services by DERs, both to the DSO itself (**DSO as a**

system optimizer) and to other stakeholders and markets (**DSO as a market facilitator**). Hence, the key regulatory topics for this second group, besides DSO regulation itself (when it is the DSO who contracts these services), are those related to the deployment of **smart metering infrastructure**, key technology for data acquisition and monitoring the service provision, and the mechanisms enabling and governing the **interactions of DSOs with external stakeholders**.

The third group of use cases shifts the focus from the DSOs to the end-users, specifically industrial and residential prosumers. The two HLUCs identified in this category address the **management of internal end-user flexibilities** to minimize the energy bill (or any other goal important to the end user) and provide system services at different levels, if needed, through the intermediation of an aggregator or retailer. These flexible prosumers will respond based on their **retail tariffs** as well as the **market rules** for the provision of **frequency and non-frequency ancillary services**. Moreover, rules for **aggregation and allocation of balancing responsibility** are very important topics.

Lastly, the fourth set of use cases have as primary actors **stakeholders managing and providing flexibility services** in a competitive environment. These include any agent acting as flexibility operator or energy service provider, such as aggregators, retailers, VPPs, ESCOs, etc. These use cases comprise end-user engagement, flexibility management and service provision. Therefore, the major regulatory topics to take into account are those that determine the **capability and incentives for end-users to respond** (smart-metering, tariff design and market rules), as well as the **capability and incentives of flexibility operators and service providers** to deliver their services (aggregation rules, balancing responsibility allocation, market design, or non-frequency Ancillary Services (AS) provision).

2.2. Mapping use cases with regulatory topics

The previous subsection has described the four domains in which HLUCs have been classified. Additionally, the major general regulatory topics to be considered for each group in this analysis have been identified. This section will go deeper into the regulatory topics that should be analyzed in this report and discuss how these are bound to affect the realization of the InteGrid use cases. The results of this mapping exercise are summarized in Table 1. Therein, it can be seen that the regulatory topics that will be discussed throughout this report can be broadly sorted into four groups: i) DSO economic regulation; ii) DSO as a system optimizer and market facilitator; iii) Retail tariffs and metering; iv) Aggregation and market design.

Power distribution is deemed as a natural monopoly and, therefore, a regulated sector under the supervision of a National Regulatory Authority (NRA). The economic regulation of DSOs is thus of the utmost importance to determine whether DSOs would be willing to adopt many of the InteGrid solutions. In this regard, several of the HLUCs aim to incorporate the flexibility potential of DER into distribution network operation and enhance grid monitoring through smart grid technologies. Some of the main benefits would be the increase of Network Hosting Capacity (NHC), deferring or avoiding network reinforcements, or improving grid reliability. However, DSOs would not be encouraged to do so unless their **remuneration framework** promotes cost reductions and is neutral to CAPEX and OPEX reduction. This is particularly relevant to the HLUCs closer to grid operations and the provision of non-frequency AS (HLUC1, HLUC2, HLUC3, HLUC4, HLUC7). Likewise, the use cases that aim to enhance grid reliability (HLUC3, HLUC4) are dependent on the existence and design of specific **incentive mechanisms to improve continuity of supply**.

Table 1: Mapping relevant regulatory topics to InteGrid HLUCs
(0 - No relation, 1 - Indirect (or implementation-dependent) relation, 2 - Direct relation)

		Functional Domain											
		DSO Domain - Grid Operations				DSO Domain - Market Hub			Grid Users		Energy Services		
		HLUC01	HLUC02	HLUC03	HLUC04	HLUC05	HLUC06	HLUC07	HLUC08	HLUC09	HLUC10	HLUC11	HLUC12
Revenue regulation	Remuneration formula	2	2	2	2	1	0	2	1	1	1	0	1
	CAPEX-OPEX treatment	2	2	2	1	1	0	2	1	1	1	0	1
	DER-driven costs	2	2	0	0	1	0	2	0	0	0	0	0
	Regulatory benchmarking	2	2	1	1	1	0	2	0	0	0	0	0
Output-based incentives	Continuity of supply	0	0	2	2	0	0	0	0	0	0	0	0
	Energy losses	1	1	0	0	0	0	1	0	0	0	0	0
	Others	1	1	1	1	1	1	1	0	0	0	0	0
DSO incentives for innovation	Existence of incentives	2	2	2	2	1	0	2	0	0	0	0	0
	Design of incentives	2	2	2	2	1	0	2	0	0	0	0	0
Network charges for DER	Connection charges for DG	2	2	0	0	1	1	2	1	1	1	0	1
	Use of system charges for DG	1	1	0	0	0	1	1	0	0	0	0	0
Connection schemes	Size limitations per voltage level	2	2	0	0	1	0	2	1	2	2	1	0
	Single-phase/three-phase LV connections	0	2	0	0	1	0	2	0	2	2	0	0
DER provision ancillary services	Distribution non-frequency AS	2	2	0	0	1	0	2	2	1	2	0	2
	DSO-TSO interaction	0	0	0	0	2	0	0	2	1	2	0	2
Business models for DER	DER Aggregation and VPPs	1	1	0	0	2	0	1	1	2	2	0	2
	Storage ownership	1	1	0	0	0	0	1	1	2	0	1	1
	DER Flexibility integration	2	2	1	0	2	0	2	2	1	1	1	1
Smart meters	Functionalities	1	1	2	0	1	2	2	2	2	2	2	1
	Roll-out model	1	1	2	0	1	2	2	1	2	2	2	1
	Metering activity responsibilities	1	2	2	0	2	2	2	1	2	2	2	1
	Metering data management	1	2	2	0	2	2	2	2	2	2	2	1
Design of regulated tariffs	Power system cost break-down	0	0	0	0	0	1	0	2	2	1	2	0
	Regulated tariff structure	0	0	0	0	0	1	0	2	2	2	2	0
	Tariff design responsibilities	0	0	0	0	0	1	0	1	1	0	2	0
Self-generation regulation	Self-generation scheme	0	1	0	0	0	1	0	2	2	2	2	0
	Other limitations or conditions	0	1	0	0	0	1	0	2	2	2	2	0
Aggregation	Aggregation rules	0	0	0	0	1	0	0	1	1	2	0	2
	Balancing responsibility	0	0	0	0	1	0	0	1	1	2	0	2
Balancing/Intrady market design	Market scheduling	0	0	0	0	2	0	0	2	0	2	0	2
	Gate-closure	0	0	0	0	2	0	0	2	0	2	0	2
	Balancing product definition/pricing	0	0	0	0	1	0	0	2	0	2	0	2
	Imbalance settlement	0	0	0	0	1	0	0	2	0	2	0	2
	Market access rules	0	0	0	0	2	0	0	2	0	2	0	2
	Open for demand/storage	0	0	0	0	2	0	0	2	0	2	0	2

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The diffusion of the aforementioned use cases where DSOs are required to adopt innovative grid planning and operational practices (HLUC1, HLUC2, HLUC3, HLUC4, HLUC7) can be facilitated by **innovation incentives**, particularly when these solutions are not yet at a high TRL.

Those use cases where the DSO is resorting to DER flexibilities to tackle grid constraints (HLUC1, HLUC2, HLUC7) are deeply affected by the **connection rules and charges** that need to be paid by these DERs since these affect the possibility to face grid constraints caused by DER. For instance, under deep connection charges and a so-called fit-and-forget approach[3] distributed flexibilities would present a much lower value for DSOs since network constraints are mainly prevented at the time of connection.

Moreover, these use cases, as well as those in which DERs are providing flexibilities to other stakeholders, possibly through a third-party such as an aggregator or a VPP, (HLUC5, HLUC8, HLUC9, HLUC10, HLUC12) greatly depend on the existence of mechanisms enabling these interactions as well as the corresponding access and participation rules. Note that these use cases all refer to the exploitation of distributed flexibilities, albeit from a different perspective depending on who the primary actor is (DSO, end-user or flexibility operator). More specifically, the most relevant regulatory topics would be the mechanisms for the provision of **non-frequency AS at distribution level, DSO-TSO interaction, aggregation rules, balancing responsibility allocation, and balancing/intraday markets** design and rules[4].

The active participation of end-users or advanced monitoring capabilities (HLUC2, HLUC3, HLUC5, HLUC6, HLUC7, HLUC8, HLUC9, HLUC10, HLUC11) requires the deployment of a smart metering infrastructure for the acquisition of the data needed. Therefore, this analysis cannot neglect **all issues related to smart metering deployment** such as rollout model and responsibilities, the capabilities of this devices, or the model for data management.

Lastly, the incentives seen by end-users to adopt new grid-edge technologies, such as small-scale DG or storage systems, and respond to flexibility signals will be ultimately determined by the **structure and level of retail tariffs** they face and the **regulatory framework for self-consumption** Consequently, the influence of both issues must be carefully assessed for those use cases focused on the end-user domain (HLUC8, HLUC9) or on end-user engagement and flexibility quantification (HLUC10, HLUC11).

[3] Fit-and-forget refers to a grid connection approach in which all potential network constraints are solved at the time of connection through grid reinforcements. Alternative, an active network management approach can be used to defer grid reinforcements by resorting to DER flexibilities, thus bringing grid planning and operation closer together.
[4] These are the markets where it is considered that distribution flexibilities can provide more value to the system.

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3. Current regulation and market rules in focus countries

In this chapter, an analysis is made of the existing regulation in the four target countries defined in the DoA: Spain, Portugal, Sweden, and Slovenia[5]. For the completion of this analysis, a questionnaire was circulated among the partner DSOs and universities of the project. Additional sources of information were also used, as results from previous European projects like GRID4EU, evolvDSO, and SuSTAINABLE, as well as reports and publications from NRAs, DSOs, EU institutions and academia.

This chapter is structured according to the four main groups of regulatory topics, as defined in chapter 2, namely: DSO Economic Regulation, DSO as a System Optimizer and Market Facilitator, Retail Tariffs and Metering, and Aggregation and Market Design. In each of them, the corresponding regulatory topics identified in Table 1 are analysed for each country.

3.1. DSO Economic Regulation

Power distribution is a regulated network monopoly within a given geographical area. Therefore, the revenues of DSOs are determined or supervised by NRAs and policy-makers. The economic regulation of electricity distribution companies defines how the allowed components of CAPEX and OPEX are recovered by DSO through the tariffs. In addition to revenue regulation, distribution regulation has increasingly included additional incentive mechanisms related to the performance of DSOs in areas such as energy losses or quality of service. This subsection analyses the topics mentioned above, with an emphasis on how expenditures related to DER and smart grid solutions are treated in the national regulation.

3.1.1. Revenue regulation and cost assessment

As shown in Table 1, the remuneration formula and the CAPEX-OPEX treatment are relevant regulatory topics for all HLUCs except for HLUC06 and HLUC11. The way DSOs are remunerated can provide more or fewer incentives for investments, innovation, and cost reduction. As mentioned above, distribution of electricity is a regulated business and therefore is the task of the regulator to define the mechanisms that will be used to set the remuneration of the DSO. Traditionally, monopoly remuneration mechanisms in the power sector can be divided into two groups, namely cost-plus remuneration and incentive-based remuneration [1].

Cost-plus remuneration (also called cost-of-service regulation, or rate-of-return regulation), was the most traditional mechanism before the liberalization of power sectors. Under this mechanism, the regulatory process is done in two stages. First, the costs and investments of the DSO are identified and, second, the allowed rate-of-return is established. The determination of the allowed costs and investments is usually

[5] Although the focus is on the three countries where demonstrations will take place, namely Portugal, Sweden and Slovenia, we also include Spain in the analysis to provide an additional reference, and considering that Spain is also a partner country of the InteGrid project.

done in short intervals, usually yearly. This regulatory framework has economic properties that make it less risky for the monopolist, offers good incentives for investment but little incentive for cost reduction [2].

Under Incentive-based regulation, companies are subject to longer periods in between price controls. These periods are called regulatory periods and usually range from 3 to 6 years. Once the NRA determines the allowed revenues for the regulated company, this settlement will remain for the rest of the regulatory periods. Also, a specific revenue path is defined to create an incentive for the company to lower costs and thereby increase profits. The most common path mechanism is known as "RPI-X", in which for every year of the regulatory period the company will receive the allowed revenues, plus the yearly inflation minus the efficiency target, also called the "X factor". This factor is a yearly reduction of revenues for the company and therefore pressures the company to be more efficient and reduce costs. The incentive for cost reduction is also an incentive for the company to increase profits, considering that any reduction of costs above the X factor becomes an extra profit for the DSO.

The incentive-based regulation provides a stronger incentive for cost reduction, but can also limit incentives for investments and input more risk to the DSO. For instance, if investments (CAPEX) are also subject to the efficiency targets, the company may hesitate when deciding new investments, considering that all the risk will be borne by the network owner. When these investments are innovative, this may not be the best approach. Therefore, regulators can adjust the level of risk borne by the DSO by setting which types of cost are subject to efficiency targets, and which are not. Regulators can opt for regulating CAPEX and OPEX together, and therefore apply the same efficiency target to both, or separately, applying the efficiency target only to OPEX, for instance. If the regulator opts for the former, the DSO has stronger incentives to reduce costs in the short term, while the latter leaves the DSO in a more "investment friendly" situation.

Incentive regulation is now the standard in European electricity network regulation. Nevertheless, it is implemented in different variations across countries. For instance, the revenue cap can be set in the form of price to be charged from the consumers or as the total revenue to be received by the DSO. The remuneration formula, besides the RPI-X mechanism, can include output incentives (ex-post measurements).

Hereafter, the remuneration frameworks for the four countries is presented, and a comparison follows.

3.1.1.1. Spain

In Spain, distribution companies are under a revenue cap regulation with a six-year regulatory period. The last regulatory period started in 2013 and goes until the end of 2017. During the current regulatory period, the following formula applies:

$$R_n^i = R^i{}_{\underset{Base}{n}} + R^i_{\underset{NI}{n}} + ROTD_n^i + Q_n^i + P_n^i + F_n^i$$

Where:

$R^i{}_{\underset{Base}{n}}$ is the remuneration related to "old investments", made before 2013. These investments are subject to a transitory one-off regulatory regime, which, allegedly, will not be applied in the future.

$R^{i}_{n\,NI}$ is the remuneration over “new investments”, after 2013. For the computation of this term, a sub-formula applies, considering a return over CAPEX for each element of the DSO inventory, an OPEX remuneration and O&M costs subject to an efficiency factor α.

$ROTD_n^i$ are costs not related to grid investment and operation (metering, billing, phone assistance, grid planning, public space occupation fees, and other corporate expenditures).

Q_n^i, P_n^i, and F_n^i correspond to the incentives/penalties associated with continuity of supply, energy losses and fraud detection respectively. These components are described in more detail below.

In Spain, CAPEX and OPEX are remunerated separately, according to different tables of standard costs for different asset categories defined by the regulator. The remuneration is therefore proportional to the volume of investments made by the DSO. Therefore, DSOs have an incentive to reduce their unit costs but not the overall number of individual investments (provided the standard costs defined by the regulator are not too low).

Investments are capped at sectoral level and on a DSO basis, following the expected growth or reduction of the Spanish GDP. Therefore, DSOs should submit investment plans yearly, and these investment plans must be assessed by the regulator and approved by the Secretariat of Energy. Once approved, the execution of investment plans is monitored by the regulation. Deviations are subject to penalties.

The new investments are included in the Regulatory Asset Base (RAB) and their remuneration starts with a delay of two years. The value of the new asset to be included in the RAB is an average of the actual cost paid by the DSO and a reference value computed and published by the regulator. For the most relevant network components such as lines and substations (primary and secondary), the regulatory life is set to 40 years, whereas lower values are in place for mechanical protection and control devices (30 years), electronic protection and control devices (15 years), or control centres and smart grid equipment (12 years).

The last parameter relevant to the remuneration of new investments is the regulatory rate-of-return. This parameter is determined as the average profitability of 10-year state bonds plus a markup defined by the regulator. For the current regulatory period, this markup is set to 200 basis points (2%).

As shown in the remuneration formula, DSOs are also incentivized regarding energy losses, fraud reduction, and continuity of supply. These incentives are detailed below. Regarding innovative incentives and smart meter deployment, no special incentive is in place. Output regulation is not used either.

3.1.1.2. Portugal

The regulatory period in Portugal has a 3-year duration. The current period started in 2018 and will finish at the end of 2020. The distribution company in Portugal (EDP Distribuição) is subject to a price-cap regulation for OPEX and a rate of return regulation for CAPEX for the HV/MV networks, whereas the LV networks are regulated according to a TOTEX regulatory approach. The remuneration formula includes the remuneration over the asset base, the depreciation, non-controllable OPEX, controllable OPEX, loss reduction incentives and continuity of supply incentives.

There are efficiency targets applied to the HV/MV OPEX and to the TOTEX of LV networks. These targets are determined using international benchmarking analysis (Data Envelopment Analysis and Malmquist index).

For the inclusion of new assets, an investment plan must be submitted and approved by the Portuguese government. In the case of HV and MV, investment plans are required every five years. For LV, yearly investment plans must be submitted.

Also, incentives exist for the reduction of losses, improvement of the quality of service, investment in smart grids and the proper execution of the investment plan [3]. These incentives are detailed in section 3.1.2 below.

The implementation of innovative technology is also incentivised in the Portuguese regulation. A minimum between an extra WACC and 50% of the benefits that the project delivers to the Electricity System can be earned by the distribution company. The extra WACC is 1,5% for a period of 6 years. The DSO needs to submit an application to the regulator to have the project accepted as innovative.

No other output based incentives are applied.

3.1.1.3. Slovenia

In Slovenia, the SODO electricity distribution system operator is the concessionaire DSO. The operation of the distribution systems, however, is done by individual electricity distribution companies (EDCs), companies leased for carrying out the tasks of the electricity DSO on behalf of SODO [4]. In total, they are five EDCs.

According to [5], the broad regulatory model is incentive based. The regulatory period is defined by the regulator, and is set to last “one or more years”[6]. The current regulatory period started in 2015 and will last for three years. The scheme of Incentives includes:

- Incurred eligible costs: If the DSO incurs in higher or lower costs compared to the eligible costs (efficient management of TSO, DSO)
- Achieved quality of supply level: Incentives concerning the achieved quality of supply level are determined according to the achieved level of supply continuity from the reference level and are reflected in increased or decreased eligible costs.
- The provision of free ancillary services: If the DSO provides one or more ancillary services[7] without of charge and this service is not the result of legislation, incentives of 10% of savings that equals the amount paid for the ancillary service will be recognized to the system operator.

[6] Set by the “Act on the methodology for determining the regulatory framework and the methodology for charging the network charge for electric operators”.

[7] "ancillary services" are here understood as services necessary for providing the reliable and secure operation of transmission and distribution systems. They are detailed in the Network Code referred to in Article 144 of the

- The acquisition of non-refundable European funds: If the DSO obtains non-refundable European funds, incentives of 5% of the current value of the assets[8] is granted to the DSO.
- Savings in the purchase of smart electricity meters with communications module: If the DSO achieves a lower annual average acquisition price than the price-cap of smart meters in accordance with the methodology, a single incentive of 10% of the realized annual savings is recognized to the system operator.
- Investments in smart grids projects: If the DSO executes an investment in smart grids that meets the requirements set out in the methodology 6, a single incentive is acknowledged amounting to 3% of the current (eligible material costs) value of the asset in the year in which the asset was put into service.
- Realized pilot projects: If the system operator fulfils the conditions and criteria for the projects promoting investments in smart grids in accordance with the methodology, for these projects pilot tariffs can be used.

Investment plans are required and must be approved by the Ministry of Infrastructure. There is no distinction between technical and commercial losses.

3.1.1.4. Sweden

Sweden has a revenue cap with a regulatory period of four years. This regulatory framework was first introduced in 2012, and currently is in the second regulatory period, going from 2016 to 2019. The Swedish revenue cap regulation is illustrated in Figure 2:

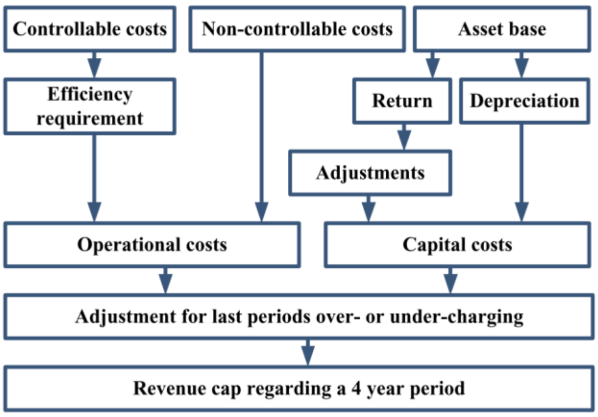

Figure 2: Overview of the Swedish revenue cap regulation. Source [6]

A "building block" approach is used in Sweden, and therefore OPEX and CAPEX are remunerated differently. Controllable costs are subject to an "efficiency requirement". Since the beginning of the second regulatory period, this factor is the sum of a general factor for all DSOs (1%) plus a benchmarking-based specific factor for each DSO (from 0 to 0.82%) [7].

Electricity Act. They include services necessary to control network frequency, voltage and reactive power control, and the engagement of generators without external power supply (black start).

[8] The asset value considers the value at 31 of December of the year the asset was put into service, excluding other non-material costs.

3.1.1.5. Comparison

The four countries considered in this study apply incentive regulation. With the exception of Portugal, countries use revenue cap as a form of price control.

Table 2: Remuneration Characteristics

	Form of price control	Treatment of CAPEX and OPEX	Method used for Calculation of the Rate of Return[9]
	Price Cap	Separately for the High and Medium Voltage concession. TOTEX (equal) approach with price cap for Low Voltage	WACC
	Revenue Cap	Separately	WACC
	Revenue Cap	Separately	No WACC is used. RoR is determined as the 10-year maturity State Bond plus 200 basis points (2%)
	Revenue Cap	Separately	WACC

CAPEX and OPEX are remunerated separately in the four countries, and therefore some form of "building blocks" approach is used. The length of the regulatory periods instead differs from country to country, ranging from 3 to 6 years, as shown in Figure 3.

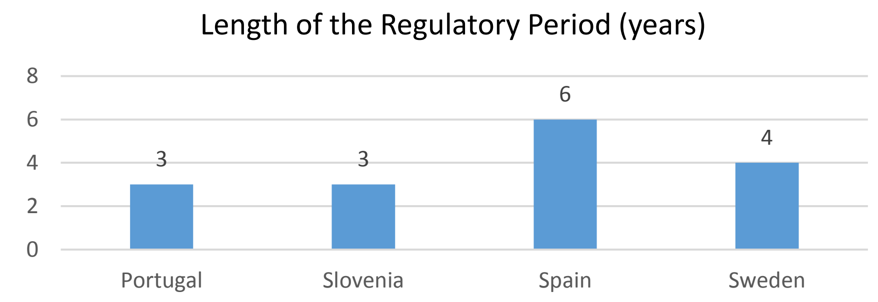

Figure 3: Length of Regulatory Periods

[9] [45]

3.1.2. Regulatory Incentives for DSOs

Regulatory frameworks can foresee particular mechanisms to incentivize specific performance aspects of the DSO. These can be loss reduction, improvement of the continuity of supply, or smart meter deployment, among others.

Reduction of energy losses is subject to special remuneration in Portugal and Spain. In these two countries, a symmetric bonus-malus system is used, meaning that the DSO is rewarded in the case of losses below a pre-established lower limit, or penalized if losses are higher than the higher limit. In between limits, lays a band in which the DSO is neither rewarded nor penalized.

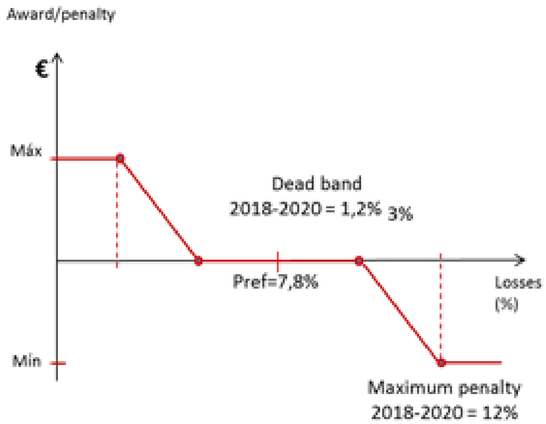

Figure 4 exemplifies the mechanism for the Portuguese regulation. Slovenia and Sweden don´t apply a symmetric bonus-malus system for energy losses. Among the four countries, Spain is the only one that includes an incentive (no penalty possible) to encourage DSOs to detect commercial losses (fraud).

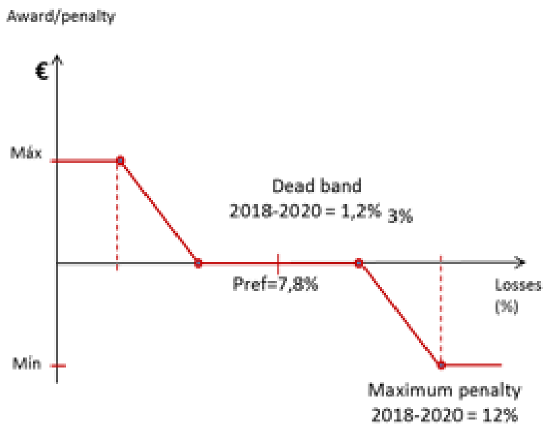

Figure 4: Bonus-malus incentive scheme for losses in Portugal

Continuity of supply can be another component of the incentive regulation scheme as well. The typical metrics to measure continuity of supply are the System Average Interruption Frequency Index (SAIFI) and the System Average Interruption Duration Index (SAIDI), related to the number of consumers affected by shortages, and the Average System Interruption Frequency Index (ASIFI) and the Average System Interruption Duration Index (ASIDI), that account for the load not supplied. Similarly to energy losses, regulation can set a threshold and, based on that, establish penalties, bonus, or a symmetric bonus-malus scheme.

Spain uses TIEPI and NIEPI indexes to measure continuity of supply. These indices are similar to the ASIDI and ASIFI, although instead of using the kVA served, the MV/LV transformation capacity and the power contracted by MV consumers are considered as weighting factors. Based on these indicators, DSOs are incentivized with a symmetric bonus/malus scheme capped to +2%/-3% of the base DSO remuneration.

Portugal uses SAIDI, SAIFI and, TIEPI at different voltage levels. The specific continuity of supply mechanism is based on the MV TIEPI (an overall indicator that calculates the average duration of interruptions, weighted by their installed power). The incentive is symmetric, with a dead band and two components: one of them takes all the MV delivery points into account and uses TIEPI MV, while the other focuses on the 5% worst served MV delivery points and uses SAIDI MV.

Slovenia uses SAIDI and SAIFI indicators to incentivize continuity of supply, separated for rural and urban areas [8]. As for Spain and Portugal, a symmetric bonus-malus scheme is used, capped and floored by the regulator. A dead-band is also used to avoid the effect on the tariff of non-structural changes in the level of continuity of supply [8].

In Sweden, SAIDI, SAIFI and ENS LV faults included and both planned and unplanned for consumers. A symmetric scheme of incentives is also used. The target is set through a benchmarking carried out by the regulator. DSOs with similar customer densities are exposed to the same targets [8].

Table 3: Incentives for continuity of supply

	Metrics Considered	**Incentive Mechanism**	**Do incentives vary by DSO, region, or voltage level?**
	SAIDI, SAIFI, and TIEPI	Symmetric bonus-malus	By region
	SAIDI, SAIFI	Symmetric bonus-malus	By region[10]
	TIEPI, NEIPI	Symmetric bonus-malus	No
	SAIDI, SAIFI and ENS LV	Symmetric bonus-malus	No

Another question analysed for the four countries is the presence of special incentives for the use of innovative solutions and smart meter deployment. Spain and Sweden do not have dedicated incentives for that matter. In Spain however, smart grids are subject to a regulatory life of 12 years, and this accelerated depreciation period can be considered an incentive.

[10] Reporting to the national agency is obligatory for all 5 EDCs, each of them has to report. The Energy Agency then calculates the aggregate values for each of them. The methodology is the uniform for the whole country, but parameters change by region, EDC.

In Portugal, a dedicated scheme gives the DSO the minimum between an extra WACC and 50% of the benefits that the innovative project delivers to the Electricity System. The extra WACC is 1,5% of the investment made and is applied for a period of 6 years. The DSO needs to submit an application to the regulator to have the project accepted as innovative.

In Slovenia, if the system operator realizes the investments in smart grids that meet the requirements set out in the methodology 6, a single incentive is acknowledged amounting to 3% of the current value of the asset in the year in which the asset was put into service [4].

In Sweden, no special incentives are identified. However, it is important to note that the roll-out of smart meters has already finished, as detailed later in this document.

The four countries reported that no output regulation is in place for the current regulatory periods.

Table 4: Incentives for Innovation and Output Regulation

	Type of Incentives for Innovative projects and smart grid deployment	Other output indicators[11]
	Extra remuneration	No
	Extra remuneration	No
	Accelerated depreciation	No
	No incentives	No

3.2. DSOs as a system optimizer and market facilitator

3.2.1. Network charges

Regulation should ensure fair and non-discriminatory network access for DG units whilst allowing DSOs full recovery of efficient connection costs. In this regard, there is a trade-off between providing incentives for the optimal and cost-reflective siting of new generation capacity and facilitating entry for small-sized DG operators. For this purpose, connection charges and Use-of-System (UoS) charges may be designed by the regulator for all agents connected to the distribution network, including DG. Likewise, grid access rules may affect the connection process of new DG units as well as its impact on the distribution grid.

[11] Other than the ones treated before, namely losses, continuity of supply and smart grid deployment.

Connection charges are the onetime payment incurred by the user (load or generation) in order to be connected to the grid. This payment, if existent, can be classified as deep or shallow. In the first type, the user bears the cost of the connection to the grid and any required reinforcement upstream. In the shallow condition, the user pays for the service and grid connection only. An intermediate model is also possible, referred as shallowish costs [1].

In Portugal, all connection costs of DG connections should be supported by the generator. In the case of micro and mini-generation, it is the generator that shall make sure that it has the necessary conditions to connect to the network. Therefore, connections charges are classified as deep [5].

In Spain, connections charges for DG are usually deep, with some exceptions. DG with less than 10 kW10kW used for self-consumption and with a relay preventing power injection into the grid are exempt. Installations below 20 kW20kW close to consumption points would pay shallow connection charges, and installations below 100 kW100kW connected to LV level (below 1 kV1kV), as well as installations below 1 MW1MW connected to the MV grid (from 1 kV1kV to 36 kV36kV) would only have to pay for network reinforcements within the same voltage level at which they are connected to (shallowish charges).

In Sweden, the connection charge for DG is deep [9]. Tariffs are calculated by the DSO, but the user can request a review by the regulator if it is unsatisfied. In Slovenia, DG follows the same rules as consumers, and therefore are subject to connection charges. In Slovenia connection charges for users connected to the distribution network are deep [5].

Therefore, all four countries adopt **deep** connection charges in most cases.

For the calculation of the connection costs, DSO can either apply standardized rules defined in the regulation or calculate the fee on a case-by-case basis. In the Spanish case, connection charges are calculated by the DSO. This procedure is also used in Sweden. In both countries, users can request a revision from the regulator if discrepancies are suspected. In Portugal, conditions are set by the Portuguese legislation. For the generator, costs are calculated case-by-case [5]. In Slovenia, connection charges for DG follow a simple procedure, as users pay an “average connection cost factor” depending on their voltage level.

Apart from connection costs, users may also be subject to the payment of UoS charges. Therefore, UoS charges can be applicable to DG as well. In Spain, all generators, regardless of their size, technology or voltage level, pay a uniform UoS charge of 0.5 €/MWh. In Portugal, no UoS is charged for DG. In Slovenia, UoS are applied in a binomial setting, meaning that the tariff includes both a capacity and an energy component, DG-subsidiary scheme 2012, DG connected to the network are UoS excluded [10]. The NET-metering (micro production units installed behind the meter; the investors are households, max. allowed power of the unit is 11 kW, UoS only for the “power of the connection in kW” is charged; new, upgrade regulation is in the preparation phase).

In Sweden, tariffs are not set by the regulator (Ei), but by each DSO, but they should be set in an objective and non-discriminatory way [11]. Most consumers are charged a fixed fee depending on the size of the fuse and an energy fee. Large consumers are exposed to a fixed fee, a capacity fee and a volume fee. Regarding DG, units with a capacity higher than 1500 kW are subject to UoS. Smaller units are only subject to administrative fees [12].

Table 5: Network charges for DG

	Connection Charge		Use-of-System	
	Type of Connection Charges	**Calculation**	**Applicable for DG?**	**Metric**
	Deep	Case-by-case	No	N/A
	Deep	Standard formula	No[12]	N/A
	Deep	Case-by-case	Yes	Energy
	Deep	Case-by-case	Yes	Energy and Capacity

Grid connection rules may also vary for DG compared to other consumers connected to the distribution grid. Users can encounter specific limitation to connect to the network or respect specific voltage limits.

Regarding the size/capacity of the user for each voltage level, in Spain, there are no explicit rules, but users connected to the LV network may not exceed 100 kW100kW. In other cases, the DSO decides which is the best point of connection. Specifically, about DG connections, the RD 1699/2011 states that DG units above 5 kW5kW must have a balanced three-phase connection to the distribution grid. Smaller units usually have a single-phase connection. Also, DG units have to keep their power factor within a range of 0.98 lagging to 0.98 leading. Otherwise, they have to pay a penalty of 3% of an amount per kWh (set at 8.2954 €/kWh in RD 1565/2010). Moreover, if DG units maintain their power factors above 0.995 (either leading or lagging) they receive an incentive equal to 4% of the previous amount.

In Portugal, LV generators are limited to 100 kVA, either single-phase or three-phase. Above 100 kVA Grid Operators should identify the best adequate voltage level for the connection. Voltage limits are bounded to $\pm$10% on nominal voltage, while frequency limits are bounded to $\pm$1% for both MV and LV, and set between 47,5Hz and 51,5Hz for HV. DG has also to comply with standards of voltage established on the EN 50160 and current nominal capacity.

In Sweden, no limits in size/capacity for new network users is explicitly defined, and DG should be connected as a three-phase connection. Rules regarding voltage limits are based on the IEC50160.

In Slovenia, no restrictions are defined either. The obligation to connect each production unit to the distribution network is the present approach. The distribution company is only obliged to define the connection conditions (e.g. max. power; cable/line, transformer station enhancement). If the DG has to be connected with a single or three-phase connection depends on the size of the user.

3.2.2. Market facilitation

In a highly distributed power system, the role of DSOs will not only be that of network planning and operation. They will increasingly need to interact more closely with the network users both as a means to

[12] DGs connected directly to the grid are exempted of UoS. UoS is payed only for the energy withdrawn from the system, therefore only the consumption of a prosumer is charged.

support their own operations as well as to facilitate the access of DER to upstream markets and services. In fact, the evolving role of the DSO is a key component of the InteGrid vision. Thus, it is important to explore the current situation regarding DSO interactions with DER as system optimizer and market facilitator. In the questionnaire circulated concerning the four countries, DSOs were asked about the participation of DER in voltage control, ownership of DER by the DSOs and visibility of DER profiles for DSOs.

In Spain, the participation of DER in voltage control is limited to the voltage ranges mentioned above, and DER cannot participate in local congestion management. DSOs are not allowed to own grid-connected DG, and only have access to metering data ex-post. It is interesting to note though that the TSO has real-time information on all units above 1 MW1MW but not the DSOs.

Portugal follows a very similar approach. DER is limited to the compliance of voltage and reactive power limits. DER cannot participate in other ancillary services, but in case of congestions, some of them can be remotely managed by the TSO, and in some cases by the DSO, under the terms of the additional power legislation. DSO cannot own DG connected to the grid either[13], and visibility of metering data depends on the voltage level. All DG metering data are available for the DSO (not in real-time). Some MV and HV-connected DER have real-time communications with both the DSO and TSO.

In both Sweden and Slovenia, the participation of DG in voltage control is also limited to the technical requirements. The participation of DER in congestion management or other services is not foreseen in the regulation of the two countries, and ownership of DER is not allowed either. The difference between the two countries is regarding the visibility of DER generation/consumption profiles for grid operation purposes, where in Sweden the DSO has access to this data and in Slovenia not.

Table 6: DSOs are market facilitator

	Participation of DG in Voltage Control	Participation of DG in Congestion Management or Other Ancillary Services	DSOs allowed to own DG	Visibility of DG data for the DSO for grid operation purposes
	Limited to technical requirements	Cannot participate in other services. But DSO and TSO interfere in DG in case of congestion	No	Only DG connected to MV and HV
	Limited to technical requirements	Not foreseen in regulation	No	Not visible for the DSO
	Limited to technical requirements	Cannot participate	No	Only metering data ex-post
	Limited to technical requirements	Not foreseen in regulation	No	DSO has access to DG data

[13] In practice the Portuguese DSO is allowed to have DG for self-consumption with a relay ensuring 0 injection to the grid.

In order to foster the integration of DER, the existence of different agents such agent as aggregators, virtual power plants (VPPs), EV charging managers or other business arrangements that manage DER can play a significant role. In Spain, aggregation of DG can be carried out, although only for wholesale trading purposes or to reduce imbalances. A "charging manager" is also foreseen by the Spanish regulation. These agents are responsible for purchasing and managing the energy necessary to charge the batteries of EVs, and they must be connected to a control centre to follow demand response commands from network operators. In Portugal, the similar EV charging manager also exists, also a regulated agent. Currently, Slovenia has only one operating aggregator- the electricity supplier, trader. This company in its portfolio aggregates DG (diesel generators, micro-hydropower plants) and DR (industry, commercial – loads). This agent offers the service of mFRR to the local TSO, and no services are now offered by the DSO. In Sweden, aggregation is also possible, but currently, there are no active aggregating agents, as shown in section 3.4.1.

Besides being system optimizer, DSOs can also be market facilitators for the integration of DERs. If DERs participate in upstream markets and services (energy markets, balancing, reserves, etc.), the DSO can participate in the process by validating the provision of these services, and not only metering. DSOs can also interact with TSOs for grid planning and operation.

In Spain, these functions are not executed by the DSO yet. Only in case of emergency conditions, the DSO may request the TSO to curtail some RES generation connected to the distribution grid. The interaction TSO-DSO is mainly limited to the metering data exchanges for financial settlements. In Slovenia, the DSO does not intervene in the DER market participation either. The coordination DSO-TSO is mainly done at HV level. Sweden follows a similar approach. DSOs are not involved, and coordination with the TSO is done by means of requirements at the interface. In Portugal, the coordination between TSO and DSO is done regarding investment plans and with respect to the grid operation and energy flows.

3.2.3. Ownership Models of Storage

Ownership models for distributed storage can also impact the roles of the DSO. Below, Table 7 summarizes the approach in the four analysed countries.

Table 7: Storage integration

	Is connection of storage to distr. networks regulated?	Is storage allowed behind the meter?	Can storages provide services to the DSO?	Are DSOs allowed to own and operate storage?
	No	There is no specific regulation regarding storage[14].	Prosumers can inject energy surplus, which could come from storage	Only in pilot projects
	No	Yes, if technical requirements are respected	No regulation on the issue	No legal limitations

[14] It also means that there is no explicit restriction regarding storage behind the meter.

	No	Yes, if technical requirements are respected	No regulation on the issue	No legal limitation, but it is assumed[15] that DSOs cannot own storage
	No	Yes, if technical requirements are respected	Yes	No legal limitations

3.2.4. DER flexibility Integration

A key regulatory aspect for the development of the InteGrid project is the DER flexibility integration in electricity markets. Flexibility is here understood as defined in Ref. [13], as "the possibility of modifying generation and/or consumption patterns in reaction to an external signal (price or activation signals) to contribute to the power system stability in a cost-effective manner". It is usually characterized by the amount of power modulation, the duration, the rate of change, the response time, and the location [13].

The participation of DER in flexibility mechanisms and markets is at the core of InteGrid's objectives. For this reason, this section presents the current possibilities for DER participation in flexibility mechanisms in the four focus countries of this report.

Several are the mechanism option for integrating DER flexibility. The following types of contracts can be considered:

- Bilateral flexibility contracts allocated, whenever possible, through market-based mechanisms (based on activation costs, i.e. merit order): these contracts can be used to contract MV flexibilities or LV flexibilities activated through the home energy management system.
- Non-firm connection contracts for new grid users
- Dynamic network tariffs
- Contracts for load-shedding under emergency conditions for LV flexibilities

In Spain, the main mechanism that provides DER flexibility integration is the use of dynamic tariffs. For the consumers under the regulated tariff (the PVPC, as explained later), it is applied a "Real Time Pricing" tariff. That means that the tariff follows the movements of the day-ahead and intraday markets and it is hourly priced[16]. Moreover, three different options are available for the regulated tariff. Besides the standard tariff that follows the wholesale markets, two-period tariffs are also available. In these types of tariff, the peak hours are more expansive than the standard tariff, while the off-peak hours are cheaper. One of the two-period tariffs is aimed at electric vehicles charging (off-peak hours are even cheaper). Figure 5 exemplifies the dynamic energy tariff mechanism in Spain.

[15] The assumption comes from the expectation of future European regulation on the matter. The Clean Energy Package, for instance, already proposes that "Distribution system operators shall not be allowed to own, develop, manage or operate energy storage facilities."

[16] If the costumer does not have a smart meter installed, a standard load curve is considered.

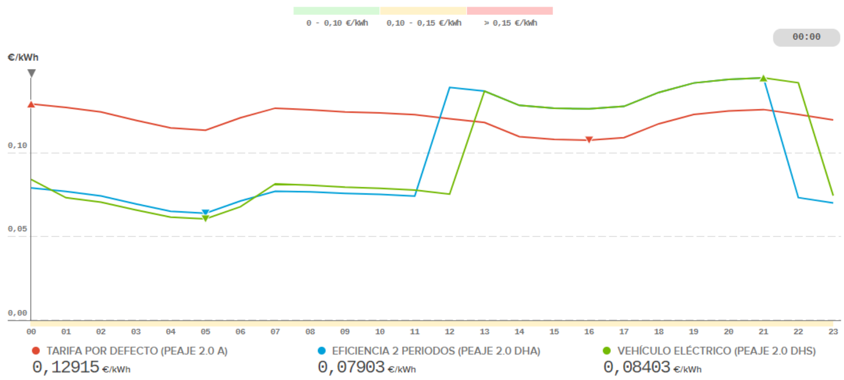

Figure 5: PVPC price in Spain for 1st of February 2018

In Portugal, dynamic tariffs are still being implemented. Several pilot projects are testing the possibility of variable tariff according to the period of the day. These pilot projects include both dynamic access tariffs and dynamic energy tariffs. The differentiation may be among several periods during the day, days of the week, and months of the year [14].

Another form of integrating DER flexibility in Portugal is through curtailment of DER. Portugal recently introduced two pieces of legislation that allow the curtailment of DER in case of violation of technical constraints. The *Decreto-Lei n.º 94/2014* allows the curtailment of repowered wind farms that receive feed-in tariffs, while the *Despacho n.º 8810/2015*, regulates the curtailment of other renewables that also receive feed-in tariffs. Orders for power reduction are centralized in the TSO, but the DSO can request the TSO a power reduction, and in exceptional cases, send power reduction requests directly.

In Sweden, DER flexibility integration is rather limited. A recent survey conducted by the Nordic Council of Ministers [15] shows that, in Sweden, demand side response, for instance, is still limited given technological, regulatory, end-user behaviour and market issues. Technology for demand-side response is considered still limited, price signals for end-users are considered weak, besides low awareness of the demand response concept by the public, and no market options were yet developed.

Other flexibility mechanisms are possible, but their use is also limited. In Sweden, DSOs can offer interruptible-service tariffs[17], but this option is often used. DSOs can also enter into bilateral contracts to purchase capacity from consumers or aggregator, as long as it is justified with grid criteria. Moreover, there are no limitations for the DSO to buy flexibility services from organised markets if the purchases are non-discriminatory.

In Slovenia, there are no provisions for DER flexibility integration specifically. Regulation as of today does not separate resources according to voltage levels. Therefore, DER can participate providing flexibility services such as participating in reserve markets. But this participation is rather limited.

[17] Lower tariffs for customers that are willing to reduce load when the DSO needs.

3.3. Retail tariffs and metering

3.3.1. Retail Tariffs

The price signals seen by consumers are a key variable affecting demand behaviour including their level of engagement, actual flexibility provision, or investment decision in grid-edge technologies (PV, storage, heat pumps). Oftentimes, market prices or network tariffs are seen in isolation from the rest of the cost components that are included in the retail tariff paid by end users. However, this is a myopic view. In order to accurately assess the behaviour of end users, it is necessary to consider the breakdown of costs in the retail tariffs as well as the structure of these tariffs.

Retail tariffs can be broken down into i) regulated charges needed to recover the costs of non-competitive activities (transmission, distribution, system operation), ii) policy costs (capacity mechanisms, regulator costs, RES subsidies, other), iii) the cost of producing the electricity, iv) the cost of supply, and v) taxes.

For Spain, the cost breakdown can be seen in Figure 6 below. Regulated costs accounted for approximately 57% of the total costs in the power sector in Spain. End electricity consumption is subject to an excise tax of 5.11% and the value-added tax of 21%.

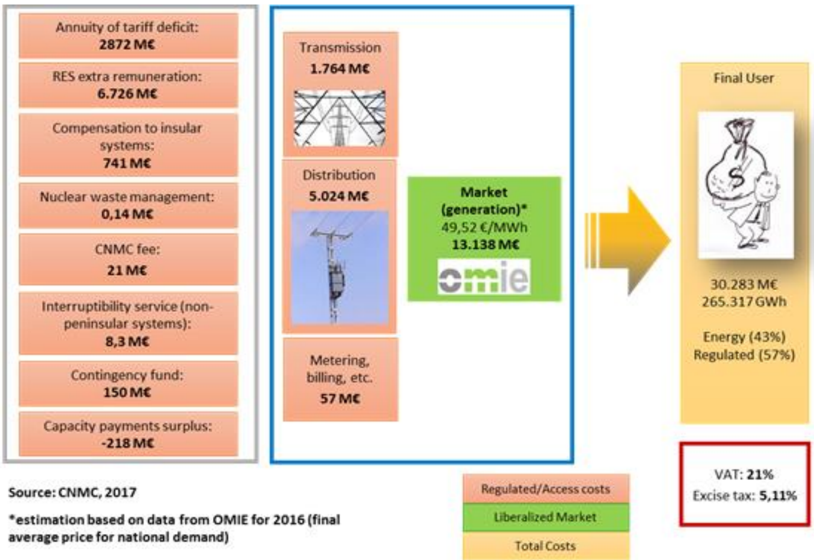

Figure 6: Tariff breakdown for Spain. Data from [16]. [18]

In Slovenia, costs are divided into:

- Market price of electricity,
- Price for the use of the network:
    - Transmission and distribution network charge,
    - Network charge for ancillary services;
- Supplements to the network charge intended to cover:

[18] For the purpose of tariff breakdown, as it is presented in Figure 6, the retail activity is not presented due to the fact this is private information and company-dependent.

- The costs of the operation of the Energy Agency,
- The operation of the market operator, other than costs for carrying out the activities of the Centre for RES/CHP Support;

- Contributions:
  - To support the productions of electricity from RES and CHP,
  - For ensuring the security of supply through the use of domestic sources of primary energy;
  - The excise duties on electricity,
    - The value-added tax.

According to the structure above, energy and the use of the network account for 69% of the tariff. Contributions represent 13%, and the value-added tax is 18%.

In Portugal, tariffs are divided into generation, transmission, distribution, use-of-system (policy costs) and supply charges.

Figure 7 presents a comparison of tariff[19] breakdown for the four countries, based on the information provided by ACER and CEER [17].

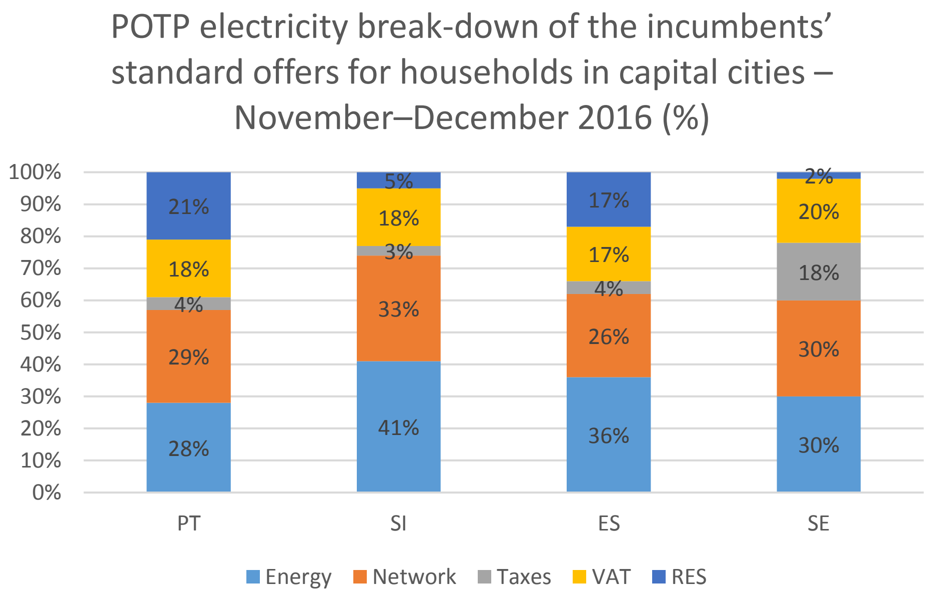

Figure 7: Electricity Post-Taxes Total Price (POTP) breakdown of incumbents' standard offers for households in EU capitals – November– December 2016 (%). Source:[17]**.**

In Spain, the regulated costs are recovered through the regulated charges, referred to access charges, set periodically by the Ministry of Energy. For each tariff category, an energy and a capacity charge are defined. These charges may have a time discrimination of up to 6 periods (the definition of time periods differs among tariff categories). Tariffs categories are defined according to the voltage level at the point of connection and a fixed contracted capacity (Pc).

[19] Breakdown of the EU electricity post-taxes total price (POTP), index calculated by ACER and CEER that reflects the total cost of electricity for the final consumer. More details on [17]

In Portugal, Customers pay contracted power (€/kVA), active energy, and higher voltage levels' customers (HV, MV and larger LV customers) pay for the average load in peak hours and also reactive energy.

In Sweden, the network has official charges that need to be the same in the price area. The area where the DSO has the monopoly by the state to distribute and connect new demands. Network tariffs are generally based on fuse size in LV up to 63 A63A. Above 63 A63A the power tariffs are applied with TOU components. Winter/summer and HL/LL during the day.

Some groups of consumers can still be offered regulated tariffs. That is the case in Spain and Portugal. In Spain, low voltage consumers with a contracted capacity below 10 kW can opt for a regulated tariff known as PVPC (Voluntary Price for the Small Consumer). This tariff can only be offered by specific retailers known as reference suppliers (*comercializadores de referencia*). There are only 8 reference suppliers in Spain, which mainly correspond to the largest power utilities (as compared to the more than 400 conventional retailers). The PVPC consists of charging consumers an hourly price considering the results of the day-ahead market, other regulated costs and the tariff category of each user. These prices are published by the TSO the day before they apply. Additionally, reference suppliers must offer as an alternative to these consumers a fixed energy price for the whole year. Thus, consumers under this tariff option would pay the previous regulated charges plus a fixed, variable term (€/kWh) for the whole year.

In Portugal, from 2013 to 2017, customers switching from the regulated to the market supplier could not return to the regulated supplier. However, the Portuguese Government has recently allowed the possibility of return to the regulated tariffs.

3.3.2. Self-Consumption

Self-consumption is already allowed in the four analyzed countries. In Spain, small prosumers (below 100 kW) face more straightforward requirements and are not remunerated for the energy injected back into the grid. They can be even prevented from injecting energy into the network. For larger prosumers, the regulation sees the user as two, a consumer and a generator, and rules for the two types apply. Prosumers have to request their connection to the DSO and must be registered at the Ministry of Energy. Neither community self-consumption neither net-metering is allowed. Regarding capacity, it has to be always equal or lower than the contracted capacity as consumer. Separate meters are also required.

In Portugal, self-consumption legislation was introduced at the end of 2014. Energy surpluses are remunerated in case the customer wants to and valued at 90% of the energy market price in that hour. There is no net-metering allowed in Portugal. Prosumers are not subject to special requirements regarding connection and limitations on size are to avoid high energy surpluses injected into the grid. Prosumers will start paying policy costs when the installed capacity of self-consumption reaches 1% of the System's installed capacity.

Slovenia allows net-metering for their prosumers. Net metering is available to small consumers, with connection lower than 11 kW. The time scale applied is yearly based. No special procedures (customer is obliged to fill in the application form and to send it to the local DSO that because of installation of power generation the connection approval will change) apply for prosumers, and the capacity of generation is limited by the consumption and main electric power connection capacity, as in Spain. All customers are allowed to self-generate if they follow the technical specifications that are needed for securing safety and power quality. The local EDC does not prove the electric connections behind the metering point.

In Sweden, there is no national net-metering system. A tax reduction scheme is in place to support DG, whereas net metering had been considered incompatible with EU legislation [18]. However, the Swedish Energy Agency highlights that "no national net-metering system exists. However several utilities offer various agreements, including net-metering, for the surplus electricity of a micro-producer" [19].

Table 8: Self-Consumption and Net-metering

	Is Self-Consumption allowed	Is net metering allowed?	On what time scale?	Conditions
	Yes. Surplus is remunerated at 90% of the hourly price	No	NA	NA
	Yes	Yes	Yearly	Small consumers, <11kW
	Yes. No remuneration provided for energy surplus.	No	NA	NA
	Yes	Yes, but it is not a national policy	NA	Depends on the utility offering net-metering

3.3.3. Smart meter roll-out

Smart metering is a crucial enabler for demand flexibility and well-functioning retail electricity markets. Accordingly, it is a central technology within many of the InteGrid functionalities. European directives place a strong emphasis on the need for deploying this infrastructure by 2020 and beyond. However, different countries may opt for different smart metering deployment and data management models. In this section, the status of the roll-out process and the characteristics of the smart meters are explored.

In Spain, DSOs are mandated by regulation to deploy smart meters in 100% of electricity consumers with a contracted capacity below 15 kW15kW by the end of 2018, starting in 2008. Intermediate targets are set in

Order IET 290/2012: 35% by the end of 2014, an additional 35% by the end of 2016 and the remaining 30% by the end of 2018. Moreover, AMR and AMM systems had to be implemented on all existing meters by January 2014. The latest data reported by the regulator (CNMC) in September 2017 [20] indicates that by December 2016, 74% of the meters (21M of 28M) had already been replaced (roughly in line with the plan set above).

In Portugal, the mandatory substitution of meters will be regulated by the Government, that will define when the roll-out of smart meters will take place. Meanwhile, the DSO EDP has decided to start the installation of smart meters within the InovGrid project. Began in 2010, with 30 thousand consumers, it continued in 2012-2013 with 100 thousand more, and another 200 thousand units were expected by 2016. However, the massive rollout to cover the 6 Million homes is yet to be started [21].

Sweden is one of the few countries in Europe that had already completed the roll-out of Smart Meters [22]. In Slovenia, the deployment accounts for 52% (99% for industrials and businesses, and 42% for households).

Table 9: Smart meter deployment

	Status of deployment	Expectation of conclusion	Responsible party - implementation and ownership
	Limited	The target would be 80% by 2020[20]	DSO
	52%	92% by 2022, and 100% by 2025 (legal obligation)	DSO
	74%	100% by 2018	DSO
	100%	Ended in 2009[21]	DSO

3.3.4. Data Management

Data management models adopted by the focus countries will have an important impact on the achievement of InteGrid's objectives, especially the implementation of the market hub concept covered in WP 6. Therefore, in this section, a review of current regulation on data management in the focus countries is presented. The focus of this review is to present the roles of different agents, with special focus on the role of the DSO. For a review of data management models, not only in the focus countries but also for other European countries, we refer to the Deliverable D6.1 [REF 6.1].

[20] [21]
[21] [46]

In Spain, DSOs are in charge of managing metering data. According to RD 1435/2002, all DSOs must have a database accessible for suppliers and the regulator containing the personal and consumption data of their network users. This is known as System of Information of Points of Supply - SIPS.

RD 1074/2015 introduce some changes in the previous legislation by:

- Limiting the access by retailers (other than the one with a contract with the end consumer) and the regulator to data that may allow directly identifying the supply contract holder. The consumer may also request the DSO to deny access to any data to any retailer other than the one they have a contract with.
- Retail companies that are within a process in which they may lose their license will not be entitled to access the database on a temporary basis. Only retail companies with an active contract with the corresponding consumers may access the hourly load profiles of end consumers unless the DSO has the explicit consent of end consumers to provide this information to other suppliers.

In Portugal, also the DSO is responsible for managing the metering data[22]. The DSO is therefore responsible for making available the metering data of final consumers connected to the DSO's network, DG connected to the LV level, and the interface connecting the DSO's network to electric vehicles charging infrastructures.

The data management in Portugal is regulated by a regulatory package called "Guide on Metering, Reading and Data Availability" (GMLDD, from the initials in Portuguese). The GMLDD established precisely the information flows that should occur between the data management party and the several other stakeholders. As an example, the DSO has to provide the retailers with the load curve with a 15 minutes granularity in D+1 for each delivery point, in case the customer has a smart meter installed.

An important aspect regarding the Portuguese data management is the availability of data for energy efficiency programs, demand-side management and remote management. The GMLDD establishes that such data provision may be requested by the consumer or representative, but such service is not mandatory.

In Slovenia, the DSOs[23] are responsible for collecting and managing the data. This obligation is established at the Energy Act, the main document defining the electricity regulation. Article 41 defines the obligation on the delivery of the consumption data. The first paragraph defines the obligation for the suppliers and the second paragraph for the DSOs:

> *Article 41*
>
> *(Access to consumption data)*
>
> *(1) A supplier shall provide free and periodic information to final customers on actual electricity consumption and the characteristics of such consumption with sufficient frequency to enable them to regulate their own electricity consumption.*
>
> *(2) An electricity system operator shall enable customers using the system on which it performs the function of an operator to access their consumption data; this information shall be given within a sufficient time frame which takes account of the capability of customer's metering equipment, the*

[22] The DSO is the responsible for metering data at the LV level, while the TSO for the medium and high-voltage levels.
[23] In order to simplify the understanding, we treat here the EDCs as DSOs. However, as explained in section 3.1.1.3, Slovenia has only one DSO, and different EDCs providing services on behalf of the Slovenia DSO.

electricity product in question and the cost-efficiency of such measures. An electricity system operator shall also enable access to data to other legal or natural persons that enclose with a request for access to data on a customer's consumption the customer's authorisation for each case separately or for all future cases until such authorisation is revoked.

(3) The costs of access referred to in the preceding paragraph shall comply with the direct costs of the operator' service. No additional costs shall be charged to final customers for this service;

(4) The manner of access to consumption data shall be specified in detail by the electricity system operator in the Network Code.

In general, the owner of the metered data is the end customer. The DSOs are only authorized to collect them, to store them and to ensure the quality of the data, as well as providing the date according to what is established in the abovementioned Energy Act.

In Sweden, up to date, the DSO is also the responsible for the data management. However, this is about to change as a central data-hub is to be implemented in Sweden in the coming years. In 2016, the Swedish regulator (Ei) appointed the TSO (Svenska kraftnät) to establish and operate a data-hub for all electricity market data [23]. This initiative follows a regional policy, as other Nordic countries are also implementing centralized data-hubs, namely Denmark, Finland and Norway. The NordREG's[24] vision is to harmonize retail markets in the region [24].

The implementation of the data-hub is still ongoing. A preliminary model is already available, defining the required information in the data hub for the electricity market in Sweden [25]. The document defines already which data should be stored in the data-hub, including actor, metering point, time series (metered information, fee, tariffs) and consumer and contract related information.

The commissioning of the data-hub is currently expected by the end of 2020.

Table 10: Characteristics of smart meters

	Functionalities	Ownership	Meter reading and billing	Responsible for third-party access to data for commercial purposes
	No specific set of functionalities for smart meters because their rollout has not been set by the Government yet.	DSO	The DSO reads the meters, while the supplier bills the customers.	DSO
	Remote reading, remote on/off control, and events	DSO	Reading is done by the EDCs, billing- the suppliers	DSO
	Remote meter reading, automatic disconnection in case of surpassing contracted capacity	DSOs	DSOs	DSOs

[24] NordREG is an organisation for the Nordic energy regulators.

	and remote connection/disconnection due to billing and contracting reasons.			
	Remote reading on a monthly basis and if the customers want to have hourly values, the DSO has to supply hourly values.	DSO	DSO	Data-hub operated by the TSO (being implemented)

3.4. Aggregation and market design

3.4.1. Aggregation

Granting DER access to markets and energy services provision requires in many cases a certain level of aggregation either to comply with market access rules or in order to benefit from portfolio effects. Therefore, intermediaries such as aggregators or VPPs can play a relevant role in a highly decentralized power system. Nonetheless, since this is a relatively new role in many cases, regulation may need to be adapted to remove potential barriers for aggregation whilst ensuring system security and preventing cross-subsidies among agents.

In Spain, aggregation of DG is permitted in spot and reserve markets, on a company basis, and independent aggregators are not allowed. Demand agents are subject to balance responsibility as generators do. In Portugal, there is no specific regulatory framework regarding aggregation, and currently, there are no active aggregators in operation. In Slovenia, aggregation is permitted, and the only active aggregator is presently offering tertiary reserve (mFRR)[25] to the TSO. Aggregators and demand agents are currently exempt from balancing responsibility in order to foster this market. In Sweden, no aggregation agent is currently operating (except in pilot projects). Although the majority of the balancing in Sweden is made by hydro-powerplants, a new regulation on several aspects is expected by 2018, including set requirements on independent aggregators. According to Swedish market rules as of today, an independent aggregator is supposed to be a BRP.

3.4.2. Market Design

Ideally, market design and its rules should create a level playing field so that all potential market participants may compete in equal conditions. However, this is not always the case in practice. Conventionally, market

[25] ENTSOE defines mFRR as reserves that are able to restore the frequency within 15 minutes for continental Europe. As the Slovenian definition of the tertiary reserve product is a reaction time under 15 minutes, which false under this definition of ENTSO-E [10].

rules were designed for a centralized power system where large generators were the primary market participants and demand was mostly inelastic and usually based on forecasts. However, future power systems should aim to integrate all flexibility providers regardless of their locations, size or technology.

3.4.2.1. Spain (part of the Iberian market)

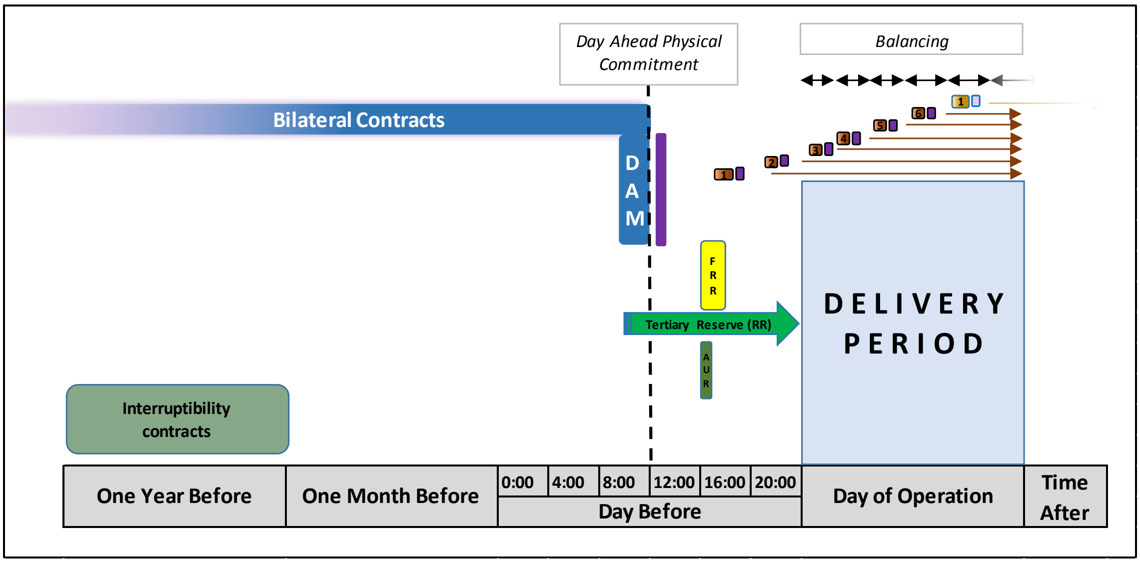

Figure 8: Spanish Electricity Markets

In Spain, most of the energy and balancing services are contracted one day before delivery. 80% of the electricity supplied in Spain and Portugal is traded through OMIE, the market operator. The share of bilateral contracts in the Spanish electricity market, for instance, is significantly less than in the UK or in Belgium [26].

The Spanish day-ahead market opens at 10 a.m. on the day before delivery (although bids can be sent upfront) and closes two hours later at 12 p.m. as shown in Figure 8. In the day-ahead market, the demand side is not allowed to submit complex bids. After the schedule is published, market agents have the possibility to change their commitment through six centralized auctions. These intraday sessions generally are open for 45 minutes (except the first session which is open for 105 minutes) and close a couple of hours before the delivery hour.

As OMIE does not take into account any technical constraints, the SO might find the need to redispatch certain generators. Therefore, the Spanish TSO, Red Electrica, runs a Technical Redispatch market to solve the technical problems. In this market, which is only open for generators, participants are paid pay-as-bid. Moreover, the TSO might find it appropriate to contract additional reserves and run therefore the

Additional Upward Reserve (AUR) market. This market opens at 4 p.m. of the day before when low reserve margins are detected and closes 20 minutes later.

Subsequently the secondary (4 – 5.30 p.m.) and tertiary reserves (up until 1 hour before real time) are contracted. As all the conventional generators with available tertiary reserve are obliged to provide their capacity[26] in this last market, there is only energy contracted in this market.

If the SO predicts an imbalance bigger than 300 MW for a specific hour and there is no more intraday session open for the relevant hour, an additional market can be called. In this deviation management market energy can be offered for the specific hour which will be paid with the marginal market price.

3.4.2.2. Portugal (part of the Iberian market)

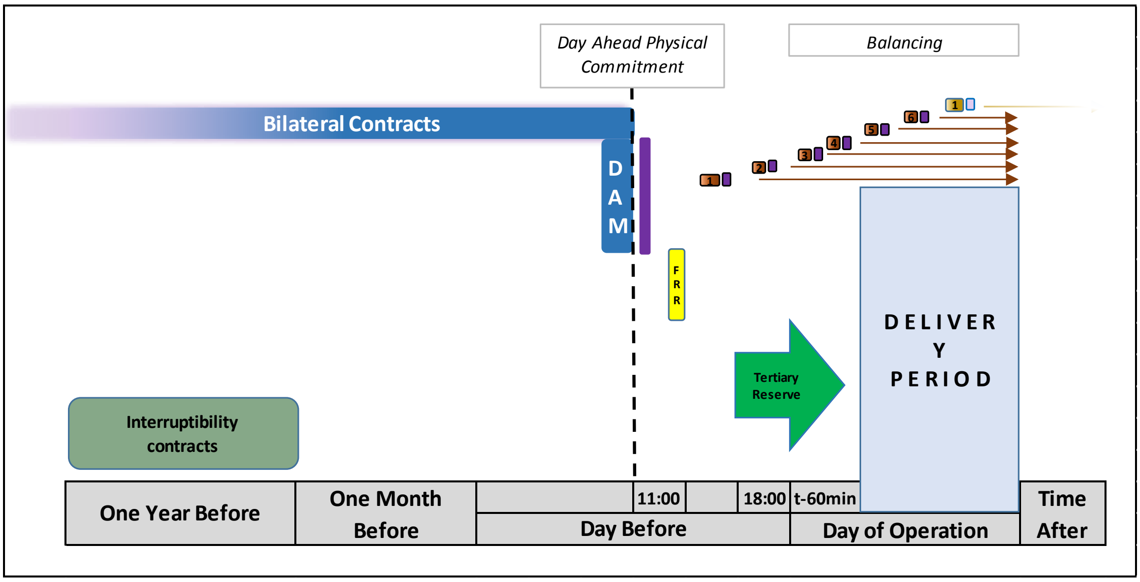

Figure 9: Portuguese Electricity Markets

The Iberian market (Spain and Portugal) is treated as a single market as long as there is no interconnection congestion. This market opens at 9 a.m. on the day before delivery (although bids can be sent upfront) and closes at 11 a.m. (local time) as shown in Figure 9 . In the day-ahead market, the demand side is not allowed to submit complex bids. After the schedule is published, market agents have the possibility to change their commitment through six centralized auctions. These intraday sessions generally are open for 45 minutes (except the first session which is open for 105 minutes) and close a couple of hours before the delivery hour. The principle of six intraday sessions might change in the future as the European policy is to go for a continuous intraday market. However, as no changes are planned yet, we presented here the current market design for the Iberian market. If any congestion on the interconnections is foreseen, the market is split into two separate markets and will be treated separately. In this case, prices in both markets are no longer equal.

[26] Only the available online capacity is considered.

Similarly to Spain, there are some interruptible contracts for some big clients (HV and MV connected) which allow the TSO to curtail the demand in some specific occasions (of high demand). These consumers are rewarded for these contracts, which are typically allocated through a tendering process once a year.

Technical constraints are not taken into account, therefore the SO might find the need to redispatch certain generators. Therefore, the Portuguese TSO, Rede Eléctrica Nacional (REN), runs a Technical Redispatch market to solve the technical problems. In this market, which is only open for generators, participants are paid pay-as-bid.

Subsequently aFRR (before 2.30 p.m.) and the regulation reserve (between 6 p.m. and 9 p.m. with eventual modifications afterwards) are contracted. As all the conventional generators with available tertiary reserve are obliged to provide their reserves in this last market, there is only energy contracted in this market [27].

3.4.2.3. Slovenia

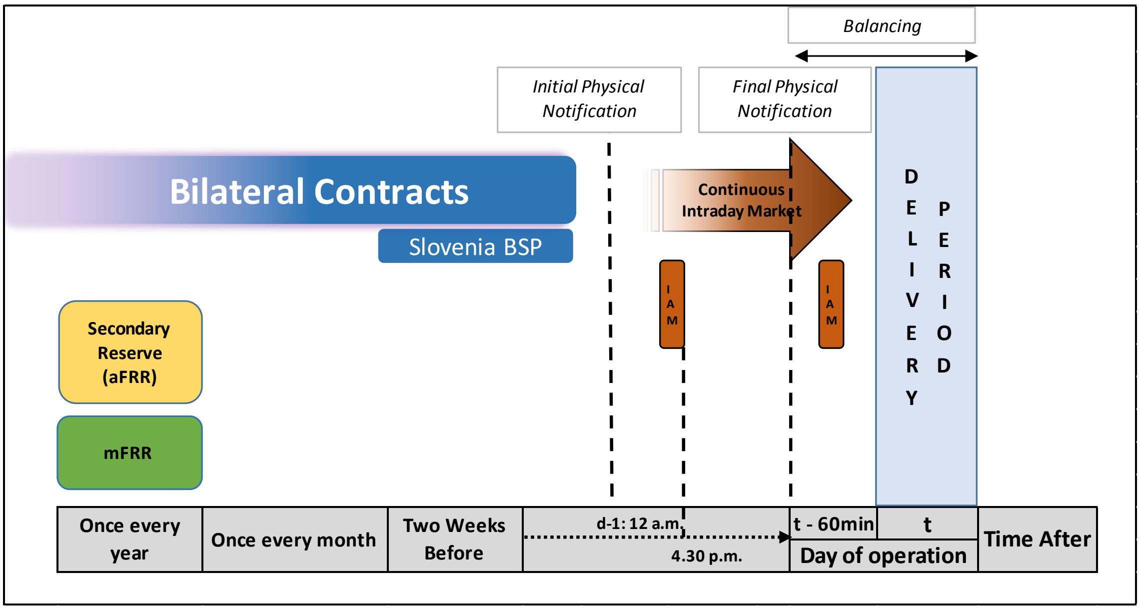

Figure 10: Slovenian Electricity Markets

Similar to other European countries, in Slovenia electricity is traded through an organised spot market (BSP Energy Exchange) and through bilateral contracts. The Power Market Operator BORZEN provides active operation on the organised electricity market for all participants of the organised electricity market. In the day-ahead market, only standardized products (Base, Peak, Hourly and 15-minute products) are traded, while in the intraday market beside standardized products also the user-defined product (buy or sell order defined by the user and constituting of at least two consecutive predefined products of the same delivery day) can be traded.

The gate closure for the day-ahead (auction) market is at 12 p.m. on the day before delivery. After the day-ahead market closes, bids are match and market agents are informed about their commitments. At 3 p.m. the continuous intraday market is opened and closes 60 minutes prior to delivery [28]. In this market both hourly and 15-minute products can be traded, besides base and peak. Apart from the continuous intraday market, energy can also be traded in the intraday auction trading on the Slovenian-Italian border. This market has two sessions: one session on the day before delivery that closes at 4:30 p.m. A second session at 11:15 a.m. on the day of delivery [29].

The balancing market, in which the TSO (ELES) buys and sells electricity for the settlement of imbalances, is added to the continuous intraday market. The only difference between both markets is the gate closure which is set at real-time, as opposed to the 1 hour-before gate closure of the intraday market.

There are two types of ancillary services [30]:

- aFRR (±60 MW in 2015): conventional (hydro, thermal) units participate, contracts for one year, merit order pro rata, activation logic is stepwise, activation cycle is 2 seconds, full activation time ≤ 5 min (no ramping restrictions), minimum bid size 5MW.
- mFRR-Tertiary reserve (+348 MW, –180 MW in 2015): conventional and DR can participate, contracts for one year, auction-bid, activation cycle is 1 minute, full activation time ≤ 15 min, minimum bid size 15MW the reduction of power must be made in the time frame of 15 minutes, the decreasing of power defined in the contract must be reached in 100%, the allowed response time is within 15 minutes after the call.

3.4.2.4. Sweden

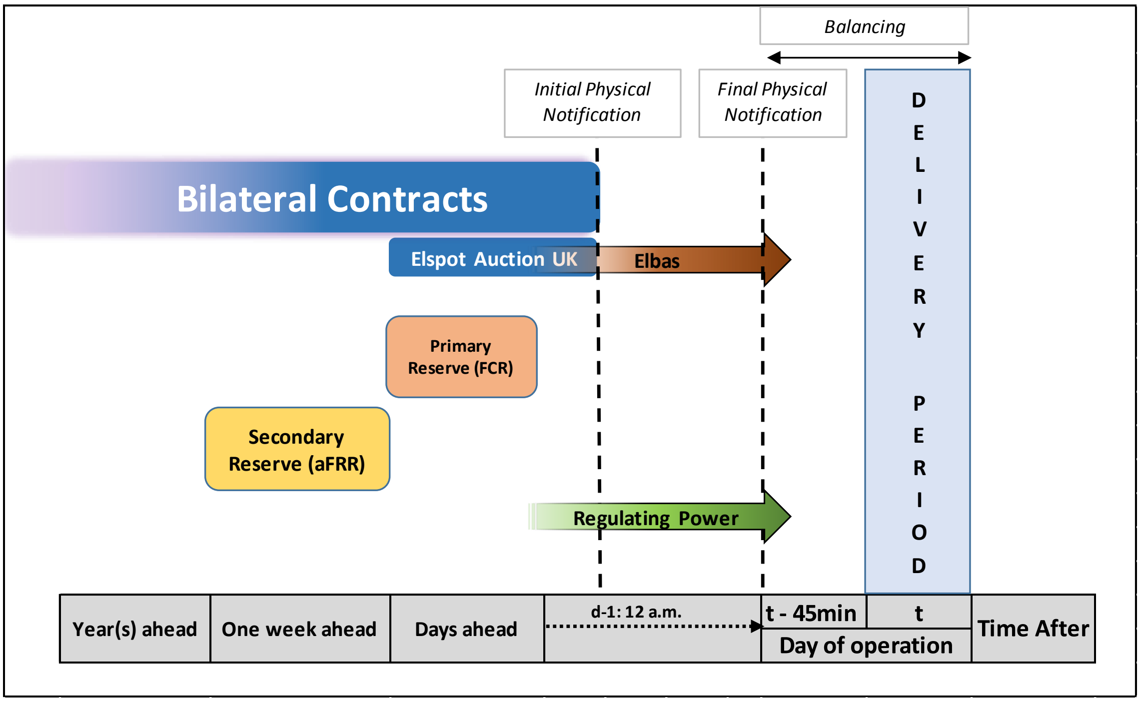

Figure 11: Swedish Electricity Markets

Sweden is part of Nord Pool, the coupled market of Denmark, Sweden, Norway, Finland, Estonia, Latvia, Lithuania and the UK. The gate closure of the spot market (Elspot), and therefore for the Swedish market, is at 12 p.m., similar to the other European countries. Four types of products can be traded in the day-ahead market: single hourly orders, block orders, exclusive groups and flexi orders [31].

The intraday market, Elbas, a continuous market that closes between 30 minutes and 0 minutes before real time, depending on the bidding area[27]. In 2018 a new mechanism will be introduced in which two additional auctions will be organised (at 10 p.m. the day before delivery and at 10 a.m. on the day of delivery) in which energy can be traded.

The minimum volume for all the products in Sweden is 10 MW, while prices asked/bid can vary between €0/MWh and €5000/MWh.

Primary reserves are contracted in two steps. A first tender is held a couple of days before the delivery period and ends at 3 p.m. the day before Elspot closes. After the gate closure of Elspot, a second tender for the primary reserve is run. Secondary reserves are contracted one week ahead which means that they are contracted before primary reserves. Together with Elbas, the intraday market, a market for regulating power is run. This regulating power has the function of tertiary reserve and can be contracted until a couple of minutes before real-time [32].

Sweden has an additional temporary peak load reserve that is designed for situations with an extreme shortage of electricity due to extreme weather conditions [33]. Eventually, these reserves may also be used for other purposes during certain circumstances. The Swedish peak load reserve has been used for congestion management and countertrade [34].

[27] Products traded in this market are: predefined and user-defined block orders, limit orders, iceberg orders and execution constraints. Further information can be found: https://www.nordpoolgroup.com/TAS/intraday-trading/order-types/

4. Preliminary analysis of current regulation and market rules

In this section, a preliminary analysis of the regulatory topics is made. Table 12 presents a summary of the current status of the most relevant regulatory topics in the four focus countries, as well as an indication for future development in Work Package 7.

To structure this summary and analysis, we revisit Table 1 and select the most relevant regulatory topics for the HLUCs (the ones with highest accumulated points), as shown in Table 11 below.

Table 11: Most relevant regulatory topics for the HLUC

		HLUC01	HLUC02	HLUC03	HLUC04	HLUC05	HLUC06	HLUC07	HLUC08	HLUC09	HLUC10	HLUC11	HLUC12	Accumulated relevance
Key regulatory topics	Metering data management	1	2	2	0	2	2	2	2	2	2	2	1	20
	Metering activity responsibilities	1	2	2	0	2	2	2	1	2	2	2	1	19
	Functionalities	1	1	2	0	1	2	2	2	2	2	2	1	18
	Roll-out model	1	1	2	0	1	2	2	1	2	2	2	1	17
	DER Flexibility integration	2	2	1	0	2	0	2	2	1	1	1	1	15
	Remuneration formula	2	2	2	2	1	0	2	1	1	1	0	1	15
	CAPEX-OPEX treatment	2	2	2	1	1	0	2	1	1	1	0	1	14
	Distribution non-frequency AS	2	2	0	0	1	0	2	2	1	2	0	2	14
	Size limitations per voltage level	2	2	0	0	1	0	2	1	2	2	1	0	13
	Connection charges for DG	2	2	0	0	1	1	2	1	1	1	0	1	12
	DER Aggregation and VPPs	1	1	0	0	2	0	1	1	2	2	0	2	12
	Existence of incentives	2	2	2	2	1	0	2	0	0	0	0	0	11
	Design of incentives	2	2	2	2	1	0	2	0	0	0	0	0	11
	Self-generation scheme	0	1	0	0	0	1	0	2	2	2	2	0	10
	Other limitations or conditions	0	1	0	0	0	1	0	2	2	2	2	0	10
	Regulatory benchmarking	2	2	1	1	1	0	2	0	0	0	0	0	9
	Single-phase/three-phase LV connections	0	2	0	0	1	0	2	0	2	2	0	0	9
	DSO-TSO interaction	0	0	0	0	2	0	0	2	1	2	0	2	9
	Regulated tariff structure	0	0	0	0	0	1	0	2	2	2	2	0	9
	Storage ownership	1	1	0	0	0	0	1	1	2	0	1	1	8
	Power system cost break-down	0	0	0	0	0	1	0	2	2	1	2	0	8
	Market scheduling	0	0	0	0	2	0	0	2	0	2	0	2	8
	Gate-closure	0	0	0	0	2	0	0	2	0	2	0	2	8
	Market access rules	0	0	0	0	2	0	0	2	0	2	0	2	8
	Open for demand/storage	0	0	0	0	2	0	0	2	0	2	0	2	8
	DER-driven costs	2	2	0	0	1	0	2	0	0	0	0	0	7
	Others	1	1	1	1	1	1	1	0	0	0	0	0	7
	Aggregation rules	0	0	0	0	1	0	0	1	1	2	0	2	7
	Balancing responsibility	0	0	0	0	1	0	0	1	1	2	0	2	7
	Balancing product definition/pricing	0	0	0	0	1	0	0	2	0	2	0	2	7
	Imbalance settlement	0	0	0	0	1	0	0	2	0	2	0	2	7
	Tariff design responsibilities	0	0	0	0	0	1	0	1	1	0	2	0	5
	Continuity of supply	0	0	2	2	0	0	0	0	0	0	0	0	4
	Use of system charges for DG	1	1	0	0	0	1	1	0	0	0	0	0	4
	Energy losses	1	1	0	0	0	0	1	0	0	0	0	0	3

Status of the most relevant regulatory topics can be summarized into three different situations: **harmonized, unharmonized** and **incipient**.

Some of the regulatory topics are harmonized across the four countries. That is the case for some topics on revenue regulation, for instance. All countries apply incentive regulation to their DSOs, and all regulatory frameworks treat CAPEX and OPEX separately, for instance. All countries also apply deep connection charges, usually calculated and published by the DSO[28]. Functionalities of smart meters are also similar to the four countries. In these cases where regulatory topics are harmonized, one can expect that the implementation of HLUCs will face the same level of difficulties in the four countries from a regulatory perspective.

[28] In the case of Slovenia, the Energy Agency defines the charges.

Even if harmonized, that does not mean that the common regulatory practice is the most effective for the functioning of the HLUCs. For instance, deep connection charges for DGs may limit the possibility of cost reduction for users seeking to optimize electricity costs through self-consumption or providing ancillary service at the distribution level (HLUC 08). The analysis regarding the fitness level of current regulatory choices for the HLUCs will be done on WP7.

On the other hand, many regulatory topics across the countries are unharmonized or at different stages of development. This is the case of the deployment of smart meters. While Sweden completed the deployment in 2009, Portugal has not started massive deployment yet, and Spain and Slovenia are in the process. The approach regarding net-metering is also divergent, as one country allows it, and others do not. Regarding incentives for innovative projects and smart meter deployment, each country has its own approach. For these regulatory topics, WP7 will assess which approaches (if any) have the better fitness for each HLUC.

The third situation in which regulatory topics may fall is the incipient regulation. Some regulatory topics still don´t have a comprehensive regulation in place or are in the early development. TSO-DSO interaction and aggregation fall into this category, for instance. For these regulatory topics, WP7 should provide recommendations, considering the experience of other countries and also the guidelines provided by upcoming regulation (e.g. implementation of the Clean Energy Package).

Finally, it is also important to note that the terms “harmonized” and “unharmonized” are used here to express whether countries follow the same approach on a given regulatory topic or not. It does not mean that one situation is better than the other. Further analysis is required in order to conclude whether each regulatory topic should be harmonized or not for the achievements of the objectives of InteGrid. This analysis will be carried out in WP 7.

Table 12 below provides a summary of the main regulatory topics, their clustering and their implications for HLUCs.

Table 12: Summary and Analysis of Regulatory Topics

			Clustering	Current Situation in Focus Countries	Possible Impact for HLUC
DSO Economic Regulation	Revenue regulation	Remuneration formula	Unharmonized	DSOs in the four focus countries are subject to incentive regulation. The length of regulatory period varies.	Regulatory topics regarding DSO economic regulation will mainly impact the DSO Domain HLUCs (1 to 7), as it sets the economic incentives for the DSO to carry out activities. The separated treatment of OPEX and CAPEX can bring mixed incentives for the DSO. On the one hand, it incentivizes investments as CAPEX as these are usually a pass-through cost. This could incentivize the deployment of smart grids. On the other hand, smart grids are expected to reduce the investment need in network reinforcement, reducing, therefore, the remuneration of DSOs.
		CAPEX-OPEX treatment	Harmonized	The four treat CAPEX and OPEX separately	
		Regulatory benchmarking	Unharmonized	Regulatory benchmarking is used in some of the analysed countries either to establish the efficiency targets (PT) or specific incentive mechanisms (SE, for continuity of supply).	
	DSO incentives for innovation	Existence of incentives	Unharmonized	Countries have some type of incentive for innovative projects and smart grid deployment.	
		Design of incentives	Unharmonized	For smart grids, PT and SI offer extra remuneration and ES a fast depreciation[29].	
DSOs as a system optimizer and market facilitator	Network charges for DER	Connection charges for DG	Harmonized	Connection charges for DG are deep in the four countries. Calculations are not always transparent.	Several aspects of the DSO as a system optimizer are still not fully addressed in the regulation of the demo countries. That can be a barrier for HLUCs on both DSO and Grid Users´ domains. HLUC 07, from the DSO side, and HLUC 08 from the User side are examples in which the lack of specific
	Connection schemes	Size limitations per voltage level	Harmonized	In general, there are no explicit size limitations for connection per voltage level, but rather a decision of the DSO.	

[29] Sweden does not have special incentives for the deployment of smart meters, most probably because the roll out was concluded in 2009.

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		Single-phase/three-phase LV connections	Harmonized	In general, small users connected at the LV level have a single-phase connection, while bigger users have a three-phase connection. In Spain, for instance, this limit is 5kW for DG.	regulation can be detrimental to HLUCs. Some regulatory topics have a special impact on incentivizing end-user flexibility. That is the case for regulated tariff structure. The share of regulated costs is generally quite high. Therefore, energy prices may not be enough to motivate end-user flexibility. The two incipient regulatory topics (distribution non-frequency AS and DSO-TSO interaction) may represent a barrier to the implementation of HLUCs 8 and 12.
	Design of regulated tariffs	Regulated tariff structure	Unharmonized	Regulated charges are borne by users in different ways. In general, they are charged based on contracted power and active energy, but tariffs can also include reactive energy, average load and different time periods.	
	DER provision ancillary services	Distribution non-frequency AS	Incipient	Participation of DG in voltage control is rather limited, usually to the technical requirements and not as an AS.	
		DSO-TSO interaction	Incipient	The DSO-TSO interaction is still limited mostly to metering data exchange, technical requirements at the interface and planning activities. DSOs are not involved if DER participates in upstream markets.	
		DER flexibility integration	Incipient	DER flexibility integration is still restricted to the possibility of curtailment. Dynamic tariffs are also seen in ES and PT (pilots). In SE and SI, some options (or lack of restriction) are available to integrate DER flexibility, the use of such options is rather restricted.	
Retail tariffs and metering	Smart meters	Functionalities	Harmonized	Remote reading and connection/disconnection are the common features.	Approaches regarding metering vary in the focus countries, from the deployment stage of smart meters to the possibility of net-metering. This diversity can impose challenges for some HLUCs in some countries, and not in others. Different approaches have to be analysed. In metering data management, the data hub used
		Roll-out model	Unharmonized	Roll-out status varies considerably among focus countries. On the two extremes, SE completed the roll-out in 2009, while PT has not started massive deployment yet. In between, ES is currently of 74% and SI at 52% of deployment.	
		Metering activity responsibilities	Harmonized	Metering is a DSO activity in the four countries.	

		Metering data management	**Unharmonized**	Also a DSO activity, with the exception of Sweden, that is implementing a data hub operated by the TSO.	in SE can impose a different challenge for HLUC 06. Net-metering, used in SI, can be a challenge for HLUC 07, for instance, as it reduces flexibility and does not incentivize the use of storage.
	Self-consumption regulation	**Self-consumption scheme**	**Unharmonized**	Self-consumption is allowed in the four countries, in different schemes. In ES, small prosumers are not paid for the energy injected. In PT, they are remunerated with 90% of the market price. Net-metering is only allowed in SI.	
		Other limitations or conditions	**Harmonized**	The main condition in the four countries is regarding the generation capacity of the prosumer, set as the consumption capacity of the user.	
Aggregation	**Business models for DER**	**DER Aggregation and VPPs**	**Incipient**	Aggregation is still incipient, and approaches vary. In PT and SE there is still no complete regulation on independent aggregators. In ES, independent aggregators are not allowed, and in SI only one aggregator is currently active.	Aggregation is still under development in the four countries. Especially relevant for HLUC 12.

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[REF D1.2] Use Cases and Requirements

[REF D6.1] Concept of the Market Hub, Central Platform and Services

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Annex A – High Level Use Case Briefs

ID	*Primary actor (Role)*	*Name of use case (Goal to be achieved)*	*Brief description*	*General remarks*
HLUC01	Distribution System Optimiser	*Operational planning (from hours to week-ahead) of MV distribution network to pre-book available flexibility*	The scope of this HLUC is the management of distributed energy resources (DER) connected to the distribution networks considering a multi-period and predictive approach. The DSO will compute for a predefined time horizon (e.g., between hours and week-ahead) a set of optimal automatic and manual control actions for DER (and DSO own resources) to minimize active power losses and solve potential technical problems. Network reconfiguration capabilities should also be considered. The input data are the active and reactive power forecasts for the net-load in each bus and for the renewable energy sources (RES) connected to the MV network, as well as operating points and available flexibilities. As the time goes by, more reliable forecasts along with the current state of the resources will be used to update the plan. The control set points computed for the resources not owned by the DSO will be considered as pre-booked (reserve) flexibility that can be later activated based on real-time information about technical constraints verification (automatic actions propose by the developed tools can be performed on the DSO assets). The interaction with the LV network control capabilities is also included in the predictive management strategy, in articulation with HLUC02. Is intended that the developed tools and load and renewable energy forecast algorithms are integrated into the DSO DMS system to help the decision-making process and to enable real-time operation and supervision. All automatic control actions over DSO assets must only be performed under the supervision and must be previously validated by the operation centres. Relevant LV RES aggregated to the secondary substation level should also be taken into consideration in predictive models (HLUC02).	DSO Domain [Grid Operations]
HLUC02	Distribution System Optimiser	*Distributed monitoring and control of LV network using available flexibilities*	The scope of this HLUC is the operation of LV flexibilities (i.e., small-scale storage, HEMS, EV charging stations, PV voltage regulation) based on predictive management to solve technical problems and real-time monitoring of voltage profiles by exploring real-time smart metering information. In-line power regulators and secondary substation transformers tap changes capabilities for voltage control should also be considered for this HLUC. A set of automatic and manual control actions for DER were determined to solve technical problems for a predefined time horizon (HLUC1). In real-time, the current state of the network is determined and compared with the scenarios used to build the preventive plan and deviations will trigger its update (HLUC1). The control set points that	DSO Domain [Grid Operations]

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			were computed and only used to pre-book (or reserve) flexibility, can be now activated based on real-time information about technical constraints verification. The developed tools should be integrated into the DSO DMS program to help the decision-making process and to enable real-time operation and supervision. All automatic control actions over DSO assets must only be performed under supervision and must be previously validated by the operation centres.	
HLUC03	Distribution System Optimiser	*Perform asset health diagnostics for preventive maintenance*	The goal of this HLUC is to increase the distribution grid reliability, avoid fatal errors, reduce maintenance costs, and postpone unnecessary local maintenance tests by using big data analytics with event-driven maintenance for self-monitored equipment. Vital information for important network assets (e.g., historical oil temperature of transformers, number of short-circuits sustained, number of changes in control) is collected using the advanced metering infrastructure and processed through tools that can diagnose and assess the current technical conditions and trigger probabilistic alarms to schedule maintenance actions.	DSO Domain [Grid Operations].
HLUC04	Distribution System Optimiser	*Operations center plans repair of unplanned outages based on sensors and remote diagnostics and historical data*	The main objective of this HLUC is to schedule the repair actions of unplanned outages based on pre-fault data collected from sensors, on remote equipment diagnostics, and on historical data collected from smart secondary substations. The expected result is a reduction in the outage time and, consequently, an improvement in the SAIDI and CAIDI indexes. Information collected from multiple sensors is used to schedule repair actions supported by intelligent tools and that aim at improving the relationship with consumers (e.g., power quality improvement).	DSO Domain [Grid Operations]
HLUC05	Contributor to Distribution System Security	*Manage the impact of flexibility activation from resources connected to the distribution network*	The objective of this HLUC is to conduct a technical validation of activation programs submitted by the market operator for distributed resources connected to the distribution network (generation, DR) at different timeframes (day-ahead and intraday). The DSO assesses in advance if the requested programs (e.g. flexibility activations) are technically viable or if they create local constraints in the distribution network (e.g. overcurrent, voltage limits). In the latter case DSO assesses if there are control actions in the resources of the DSO (e.g. transformer taps) that can solve the problems identified, and, if not, proposes modifications to the program. This validation service will be provided to the market or other relevant stakeholders (e.g. TSO) in the timeframe compatible with flexibility market. Note: it is important to ensure the effectiveness of these control actions without undermining the TSO's flexibility activations.	DSO Domain [Market Hub]

HLUC06	Data Manager	*Provide data management and exchange between DSO and stakeholders*	The DSO provides anonymized and pre-processed metering data available to external stakeholders in order to promote new data-driven services provided by market entities with benefits for distribution grid users and market actors such as: i) provision of data regarding ToU / dynamic network tariffs to customers, suppliers, aggregators, inducing end use flexibility; ii) provision of information to LV consumers about their peak demand in order to increase threshold if necessary (e.g. based on switch disconnections information or based on peak load before it happen) or the effective use of contracted power to incentivise them to reduce peak demand iii) LV consumers will respond to prices and comfort. Therefore legislation, regulation and market roles must be appropriate for end users engagement (price) and HEMS should be independent of human intervention (comfort). iv) provision of basic efficiency tips based on customer consumption profiles (e.g. comparison to peers average); v) provision of data (e.g. load diagram) to customers or 3rd parties (e.g. suppliers, ESCOs) with explicit consent from customers (acting also as authorization manager); vi) Information regarding new distributed resources connection may also be provided (e.g. inform new DRES facilities in the moment of network connection request about the number of hours per year that may be curtailed)	DSO Domain [Market Hub]
HLUC07	Distribution System Optimizer	*Procure and manage regulated flexibilities from DER to optimize operation and costs*	This HLUC is divided into two parts for different time domains: i) pre-qualify flexibility operators based on technical parameters systems interoperability and activation cost; ii) enable the bidirectional exchange of flexibility data between DSO and external stakeholders (including activation acknowledgement) and manage non-firm connection contracts. The first part consists of defining the terms of new flexibility contracts. The goal is to produce updated information regarding the timeframes in which each flexibility supplier can operate the information regarding the non-functional requirements of ICT (interoperability) as well as the cost of flexibility activation (e.g. curtailment of DRES) It will also be pre-assessed the conditions of each network (e.g. set of networks without any constraint in the case of its resources activation or networks that constantly need it). The second part refers to the operational planning timeframe. The DSO will compute and publish the flexibility needs for the next hours/days in specific network MV and LV network areas and receive the stakeholder's information about their available flexibility for the desired timeframe in order to identify the most efficient decisions regarding the set of activated resources (merit- order). Near to real time and in the case of network eminent risk or network outage's restoration DSO may operate over LV smart meters to a temporary reduction of LV customer's available power (informing customers if possible).	DSO Domain [Market Hub]

			DSO must have updated information regarding all flexibilities (as client and as technical validator).	
HLUC08	Industrial Consumer	*Manage internal processes' flexibility to minimize energy costs according to market-driven mechanisms and system operators' requests*	This HLUC considers the case of an industrial consumer that explores flexibility in its internal processes with two goals: i) to optimise energy consumption taking into account electricity purchasing costs, grid usage cost (specific timeframe) and self-consumption if local generation is available; ii) to offer flexibility to both DSO and TSO. The goals of the HLUC will be achieved by using metering and sub-metering data from different types of sensors to determine the technical feasibility for changes in the industrial process to optimize energy consumption as well as by performing flexibility audits to characterize the degrees of freedom in energy consumption/production. From the flexibility characterization and activation, industrial processes are automatically adjusted to maximize overall profits taking into account energy purchasing costs and flexibility offer profits.	Grid Users
HLUC09	Prosumer	*Perform energy management to maximize self-consumption and self-sufficiency*	The scope of this HLUC is the energy management at the residential consumer premises to maximize self-consumption and self-sufficiency. The possibility of performing load, PV and storage control to maximize internal goals like self-consumption and electricity cost minimization is considered as well as the possibility of making available information about flexibility that can be transmitted to aggregators and/or DSO within HLUC10.	Grid Users
HLUC10	Flexibility Operator	*Aggregate and communicate multi-period behind-the-meter flexibility from LV prosumers*	The goal of this HLUC is to aggregate and communicate behind the meter flexibility calculated in the HEMS (HLUC09) to the market hub. The aggregated flexibility from multiple LV prosumers will be segmented and used in the market by performing bidding optimization in day-ahead, intraday and ancillary services markets. There should be a reference to the possibility of technical validation on the flexibility mechanisms by the DSO before its activation. Segmentation should be done at least reflecting the most important parameters for the DSO activity, namely Contracted Power and Energy Consumption.	Energy Services
HLUC11	Energy Service Provider	*Engage consumers in demand-side management programs considering contextualized (environmental, price, peak load reduction) feedback mechanisms*	This HLUC is centred on providing anonymized and processed data to consumers to promote energy efficiency. The actions are: i) day-ahead hourly dynamic electricity prices targeting demand flexibility and peak load reduction; Note1: Dynamic prices are important especially if they discriminate between the energy component, related to the time-varying marginal costs of energy production and the	Energy Services

			network usage component. This may not be written in the HLUC, but should be a real objective. ii) direct feedback on electricity consumption targeting demand flexibility and peak load reduction. The information is transmitted using secure local social networks on a community level, including non-economic information such as environmental signal's feedback. Note2: It would be important to mention that along with disposal of information on real consumption, the clients should also be offered automation solutions to adjust to economic and non-economic signals without requiring direct user intervention. The user should have the possibility of making initial strategic choices on consumption and then the energy management systems would implement that strategy on a daily basis. Also, the disposal of information through social networks raises many questions on the security and privacy levels.	
HLUC12	Flexibility Operator	*Aggregate geographically distributed third-party (multi-client) resources to offer ancillary services to TSO (frequency) and DSO (non-frequency)*	This HLUC materializes goal of the virtual power plant (VPP) which is to offer bids in flexibility markets by aggregating the flexibility from eligible consumers and distributed energy resources and exploit management functions to support their participation in energy and ancillary services (i.e., frequency services for TSO and non-frequency services for DSO).	Energy Services

Annex B – Characterization of Electricity Generation, demand and electrical system

This annex provides an overview of the electrical systems analysed in this deliverable. Key figures regarding generation, consumption, and market performance are presented, as well as information related to the distribution systems.

Data for the 'General Indicators' and 'Electricity Market Indicator' is gathered from the "Energy datasheet", a report published by the European Commission containing key figures on energy in the 28 member states [5]. Data on distribution systems ('Electricity Distribution Indicators' and 'Distribution Tariffs') are obtained mainly from the "Study on tariff design for distribution systems", a comprehensive report prepared by Refe, Mercados and Indra for the European Commission [35]. Data for the charts on generation mix and load profiles are from ENTSO-E´s database [36]. The chart on installed capacity was prepared using past information from [37] and the projections of the TYNDP 2018 [38].

4.1. Spain

Table 13 shows key figures for Spain, the Spanish electricity market and its distribution system. In Spain, distribution of electricity is dominated by five big companies (Endesa, Iberdrola, Gas Natural Fenosa, E.ON and EDP) that are responsible for supplying more than 95% of the demand. Nevertheless, more than 300 other small distribution companies still operate in Spain, some as small as a few hundred clients.

Table 13: Spain: Key figures

General Indicators (2015)	
Total Population [thousands of people]	46,449.6
GDP-market prices [Mrd EUR at current prices]	1,075.6
Gross Electricity Generation, by Type - TWh	281.0
Final Electricity per Capita - KWh per Capita	4,995.5
Electricity Market Indicators (2015)	
Producers (Representing 95% Total) - Nr	>10
Main Producers (>5% Total) - Nr	4
Cumulative Market Share Generation, Main Entities - %	64.3
Cumulative Market Share Capacity, Main Entities - %	62.3
Retailers to Final Consumers - Nr	267
Main Retailers (Sales >5% Total) - Nr	5
Cumulative Market Share, Main Retailers - %	74.2

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Electricity Distribution Indicators (2014)	
Number of DSOs	342
Number of large DSOs (>100,000 customers)	17
Share of total demand covered by large DSOs	95%
Nr of consumers connected to the distribution network [thousands]	29,500
Distribution Tariffs (2014)	
% Fixed+Capacity Components/% Energy Components	20%/80%
Average network Cost - Household (cent €/kWh)	2.66
Average network Cost - Small Industrial	1.96
Average network Cost - Large Industrial	0.24

The power generation mix in Spain went through a technological and regulatory adaptation during the past few decades. Combined cycle power plants and renewables, especially wind, became a larger share of the generation mix [39]. In 2015, 36% of the total electricity production was already produced by renewables[30].

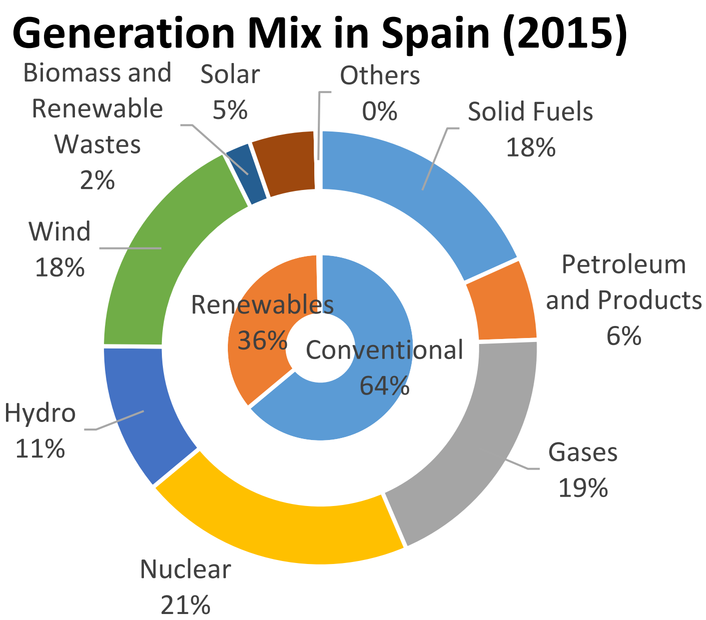

Figure 12: Generation mix in Spain

The installed capacity in Spain incorporated an increasing share of combined cycle power plants and wind power. However, due to recent changes in the support scheme for renewables, wind power capacity should not increase in the coming years. The technology that is expected to take a greater share of the installed capacity mix is solar. Figure 13 shows the installed capacity for the years 2005, 2010 and 2015, as well as the expected installed capacity considered in the TYNDP 2018 scenarios by ENTSO-e. For 2025, the scenario

[30] The concept of renewables used in this report is the one found in the Directive 2009/28/EC, Article 2(a): 'energy from renewable sources' means energy from renewable non-fossil sources, namely wind, solar, aerothermal, geothermal, hydrothermal and ocean energy, hydropower, biomass, landfill gas, sewage treatment plant gas and biogases.

considered is the Best Estimate (BE), and for 2030, we present the scenario 'Distributed Generation 2030', in which ENTSO-e considers a high participation of DG.

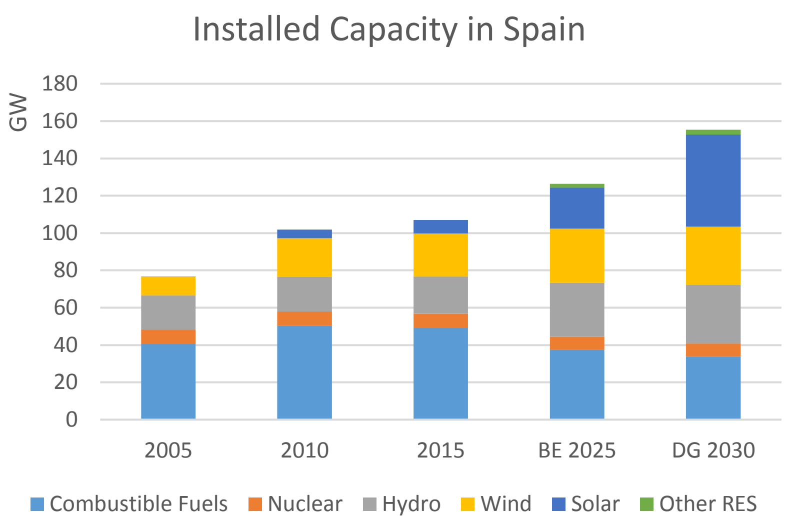

Figure 13: Installed Capacity in Spain

The typical load curve for the Spanish system is presented below in Figure 14. Curves are computed as an average of the working days for summer and winter for the year 2015. The hourly peak demand for that year was 40,300 MW.

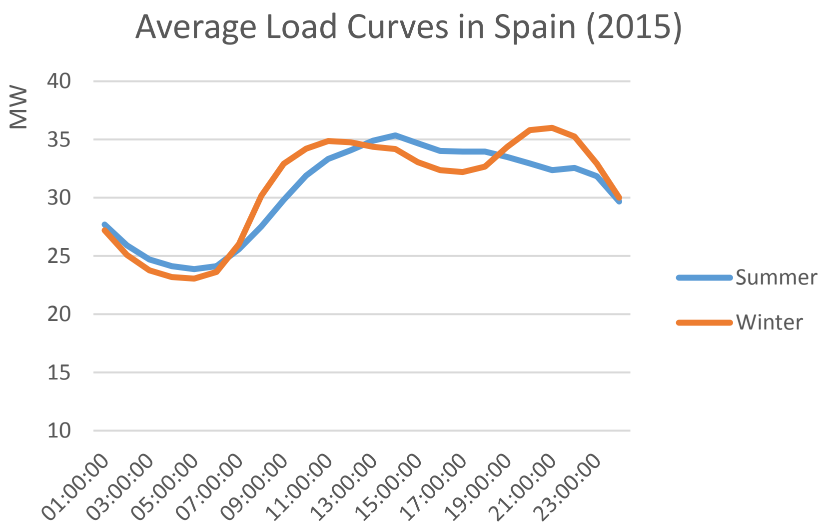

Figure 14: Average Load Curves in Spain

4.2. Portugal

Portugal has 13[31] DSOs supplying over 6 million consumers [40]. However, distribution of electricity in Portugal is mainly done by one company, the EDP Distribuição, responsible for supplying more than 97% of customers [41].

Table 14: Portugal: Key figures

General Indicators (2015)	
Total Population [thousands of people]	10,374.8
GDP-market prices [Mrd EUR at current prices]	179.5
Gross Electricity Generation, by Type - TWh	52.4
Final Electricity per Capita - KWh per Capita	4,415.7
Electricity Market Indicators (2015)	
Producers (Representing 95% Total) - Nr	69
Main Producers (>5% Total) - Nr	4
Cumulative Market Share Generation, Main Entities - %	63.6
Cumulative Market Share Capacity, Main Entities - %	64.9
Retailers to Final Consumers - Nr	19
Main Retailers (Sales >5% Total) - Nr	3
Cumulative Market Share, Main Retailers - %	67.8
Electricity Distribution Indicators (2014)	
Number of DSOs	13
Number of large DSOs (>100,000 customers)	3
Share of total demand covered by large DSOs	99%
Nr of consumers connected to the distribution network [thousands]	6,086
Distribution Tariffs (2014)	
% Fixed+Capacity Components/% Energy Components	5%/95%
Average network Cost - Household (cent €/kWh)	3.11
Average network Cost - Small Industrial	2.39
Average network Cost - Large Industrial	0.52

In 2015, the production of electricity from renewable sources represented 51% of the total generation, as shown in Figure 15. In 2016, this number increased to 57% [42].

[31] 11 in the continental part of Portugal, 1 in the Azores islands and another one in the Madeira islands.

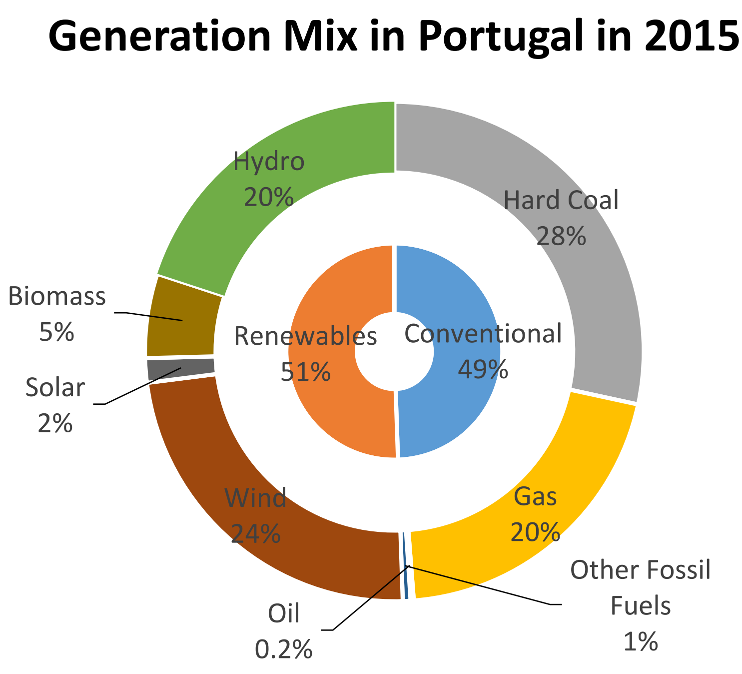

Figure 15: Generation Mix in Portugal

Over the past decade, wind installed capacity grew significantly, while coal, oil and gas-fired contracted [37]. This modification of the Portuguese mix can be seen in Figure 16, along with the expectations for the coming years, according to the scenarios of the TYNDP 2018, made by ENTSO-e [43]. The expectation is for more hydro and solar capacity to incorporate in the Portuguese generation mix. This will lead to even higher shares of renewables, that is already high as of today. In April 2016, for instance, almost all electricity produced in Portugal came from renewable sources [44].

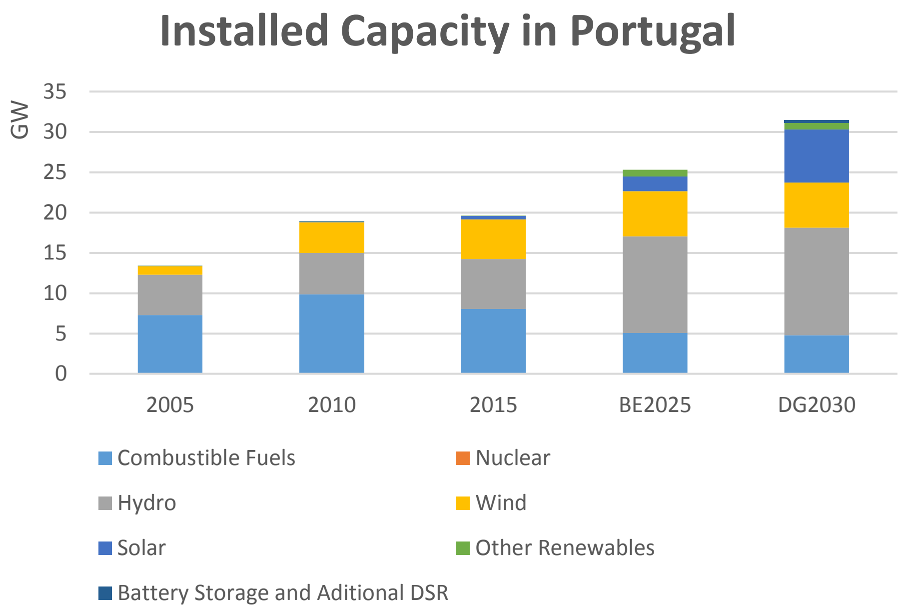

Figure 16: Installed Capacity in Portugal

The typical load curve for the Portuguese system is presented below in Figure 17. Curves are computed as an average of the working days for summer and winter for 2015. The peak power demand in 2015 was 8,620 MW.

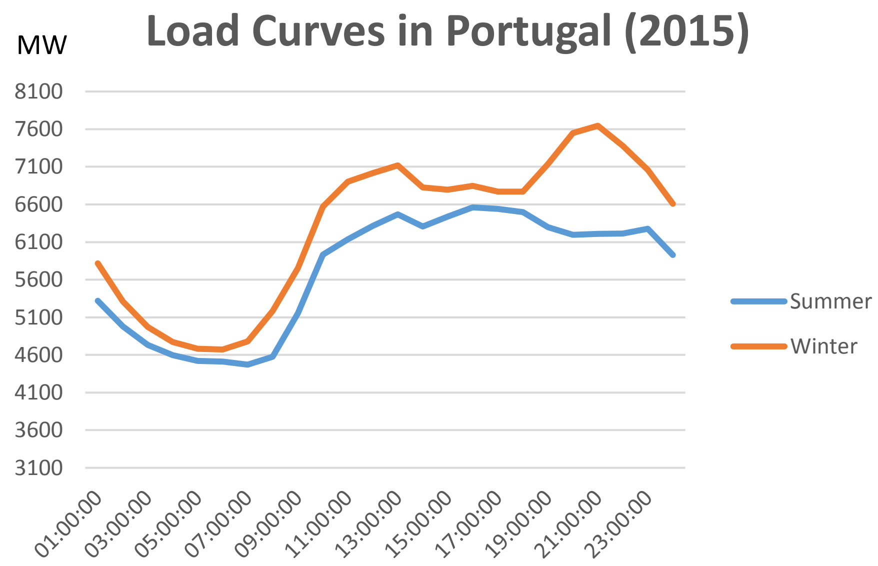

Figure 17: Load Curves in Portugal

4.3. Slovenia

Electricity networks are managed by one TSO (ELES) and one DSO (SODO), which are both state-owned [10].

In 2015 the total electricity generation in Slovenia was 15,1 TWh, growing to 15,2 TWh in 2016 [45]. In the same year, Slovenia had an import dependency of 12%.

Table 15: Slovenia: Key Figures

General Indicators (2015)	
Total Population [thousands of people]	2,062.9
GDP-market prices [Mrd EUR at current prices]	38.6
Gross Electricity Generation, by Type - TWh	15.1
Final Electricity per Capita - KWh per Capita	6,199.1
Electricity Market Indicators (2015)	
Producers (Representing 95% Total) - Nr	3
Main Producers (>5% Total) - Nr	2
Cumulative Market Share Generation, Main Entities - %	92.3
Cumulative Market Share Capacity, Main Entities - %	93.0
Retailers to Final Consumers - Nr	18
Main Retailers (Sales >5% Total) - Nr	5
Cumulative Market Share, Main Retailers - %	84.0
Electricity Distribution Indicators (2014)	
Number of DSOs	1
Number of large DSOs (>100,000 customers)	1
Share of total demand covered by large DSOs	100%
Nr of consumers connected to the distribution network [thousands]	925
Distribution Tariffs (2014)	
% Fixed+Capacity Components/% Energy Components	28%/72%
Average network Cost - Household (cent €/kWh)	5.46
Average network Cost - Small Industrial	5.87
Average network Cost - Large Industrial	1.36

Slovenia generation mix is characterized by the use of nuclear, coal and hydropower plants. Wind and solar are significant, as shown in Figure 18.

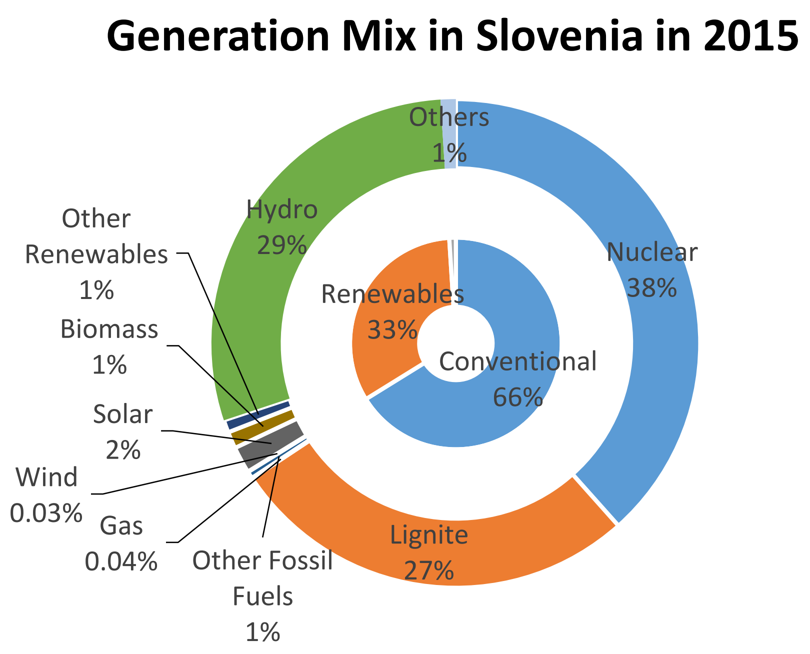

Figure 18: Generation Mix in Slovenia

Expectations for the growth in installed capacity show the higher use of solar generation, as shown in Figure 19 below.

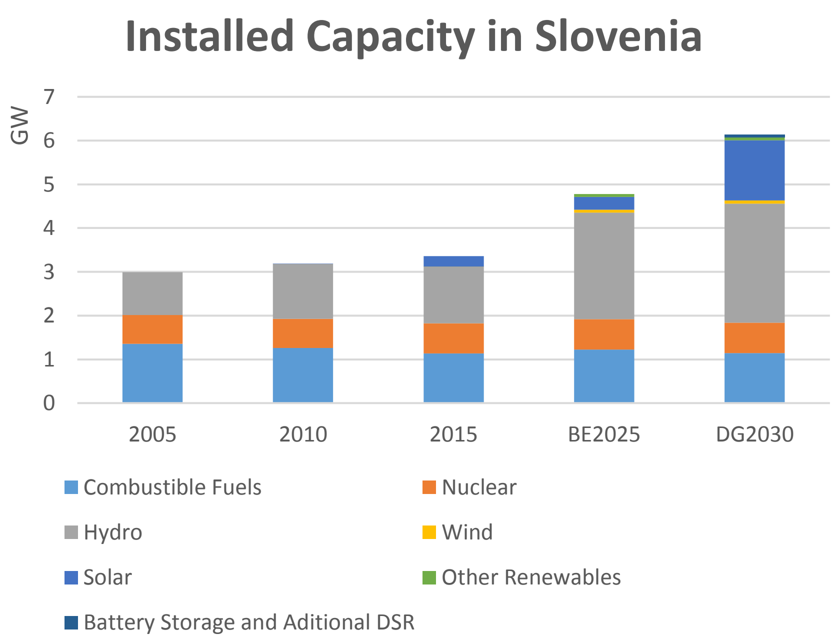

Figure 19: Installed Capacity in Slovenia

The typical load curve for the Slovenian system is presented below in Figure 20. Curves are computed as an average of the working days for summer and winter for 2015. The peak power demand in 2015 was 2,100 MW.

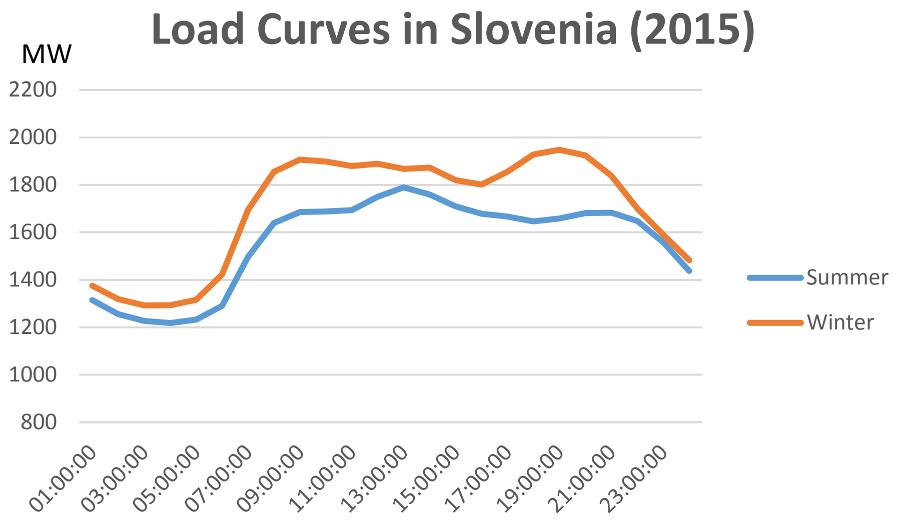

Figure 20: Load Curves in Slovenia

4.4. Sweden

There are 8 main DSOs in Sweden supplying around 5,2 million customers. The large DSOs in Sweden are responsible for around half of the total number of customers.

Table 16: Sweden: Key figures

General Indicators (2015)	
Total Population [thousands of people]	9,747.4
GDP-market prices [Mrd EUR at current prices]	447.0
Gross Electricity Generation, by Type - TWh	162.1
Final Electricity per Capita - KWh per Capita	12,809.5
Electricity Market Indicators (2015)	
Producers (Representing 95% Total) - Nr	33
Main Producers (>5% Total) - Nr	3
Cumulative Market Share Generation, Main Entities - %	73.4
Cumulative Market Share Capacity, Main Entities - %	80.4
Retailers to Final Consumers - Nr	118
Main Retailers (Sales >5% Total) - Nr	7

Cumulative Market Share, Main Retailers - %	
Electricity Distribution Indicators (2014)	
Number of DSOs	161[32]
Number of large DSOs (>100,000 customers)	5
Share of total demand covered by large DSOs	52%
Nr of consumers connected to the distribution network [thousands]	5,200
Distribution Tariffs (2014)	
% Fixed+Capacity Components/% Energy Components	23%/77%
Average network Cost - Household (cent €/kWh)	8.86
Average network Cost - Small Industrial	2.5
Average network Cost - Large Industrial	0.74

Nuclear and hydropower plants account for just over 80% of electricity production in Sweden.

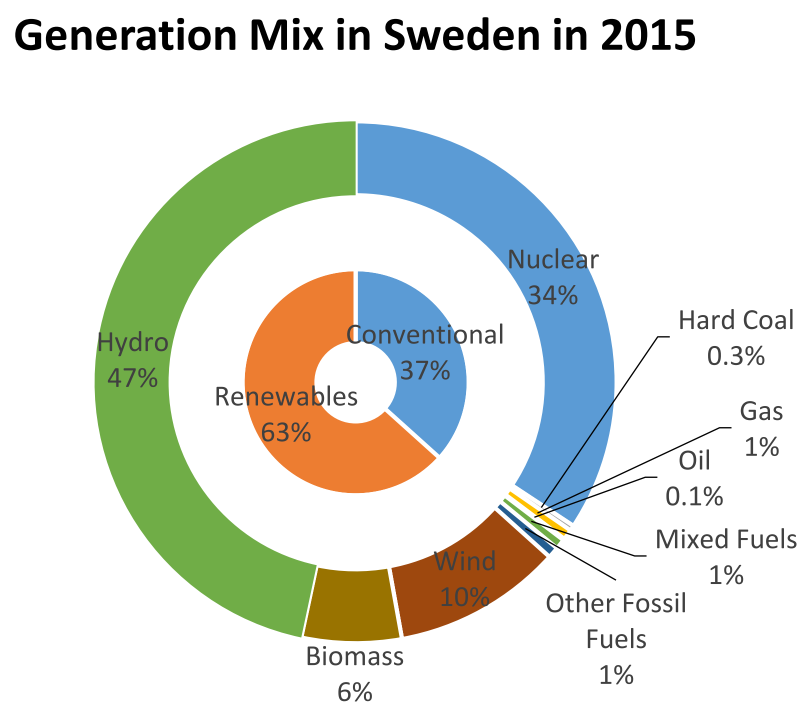

Figure 21: Generation Mix in Sweden

The participation of wind power increased significantly in the past decade. The TYNDP foresees an increase in wind participation and the participation of more solar, other renewables and the decommissioning of combustible fuels, as shown in Figure 22.

[32] [47]

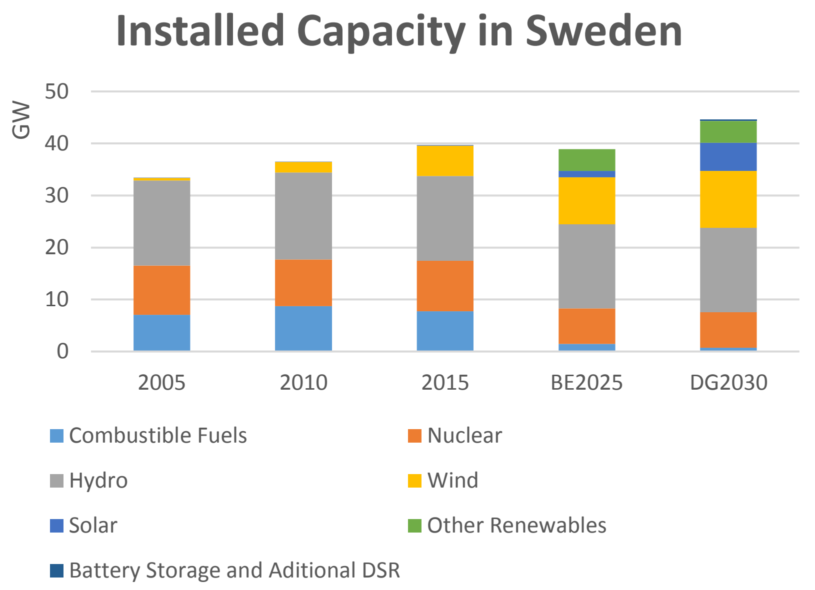

Figure 22: Installed Capacity in Sweden

The typical load curve for the Swedish system is presented below in Figure 23. Curves are computed as an average of the working days for summer and winter for 2015. The peak power demand in 2015 was 23,400 MW.

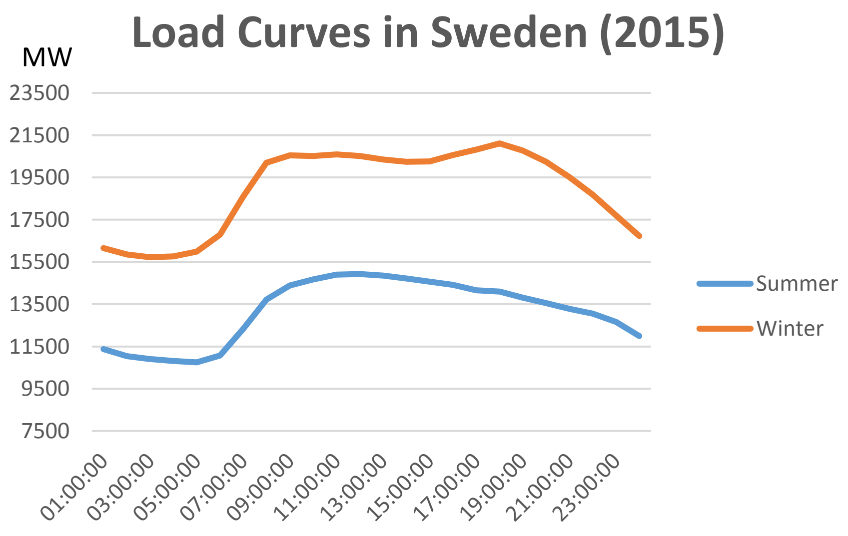

Figure 23: Load Curves in Sweden