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 7 – Regulatory recommendations

Regulatory barriers in target countries and recommendations to overcome them

D7.2

Topic	Demonstration of smart grid, storage and system integration technologies with increasing share of renewables: distribution system
Call	LCE 02 - 2016 - SGS
Grant Agreement Number	731218
Project Acronym	InteGrid
Document	D7.2 Regulatory barriers in target countries and recommendations to overcome them
Type (Distribution Level)	☒ Public ☐ Confidential
Due Delivery Date	30.06.2020
Date of Delivery	15.07.2020
Status and Version	V3.1
Number of Pages	184
WP Responsible	Comillas
Deliverable Responsible	Comillas
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File Name	Integrid_D7.2_Regulatory Recommendations_V3.1_15072020.Docx

Document History

Version	Issue Date	Content and Changes
0.1	30/10/2019	First draft
0.2	01/03/2020	Regulatory barriers and country analysis
1.0	30/05/2020	Draft for internal review (without recommendations)
2.0	10/06/2020	Full draft for internal review
3.1	14/07/2020	Fully revised version

Acknowledgements

The following people are hereby duly acknowledged for their considerable contributions, which have served as a basis for this deliverable:

Name	Partner
Werner Friedl	AIT
Olle Hansson	Ellevio
Leif Boström	Ellevio
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Miguel Pereira Morgado	DNV-GL
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Executive Summary

This deliverable D7.2 concludes the regulatory analysis carried out throughout the Integrid project. This report was preceded by deliverables D1.3 and D7.1. While the former made a first assessment of regulation in the Integrid countries, the latter already provided an assessment of the main regulatory barriers for the solutions proposed and tested in the project. Therefore, the present deliverable builds on top of the previous work to provide a twofold analysis. Firstly, this deliverable makes a detailed assessment of what were the regulatory barriers in the five Integrid target countries - Austria, Portugal, Slovenia, Sweden and Spain – for the successful implementation of the solutions proposed and demonstrated by the project. Secondly, it provides recommendations on how to overcome these regulatory barriers.

The identification of barriers and assessment of the current situation in the five Integrid target countries was also complemented by an analysis of prospective changes due to occur in the coming years. The regulation regarding the topics addressed in Integrid is changing at a fast pace. Firstly, because the objectives of project are in line with the European views of a fully-integrated internal energy market, and a digitalized power sector that puts the consumer in the centre. Secondly, because the solutions tested in Integrid can also contribute to the national decarbonization targets. In this context, besides analysing the current national regulatory frameworks exclusively, this report also takes into account the provisions brought by the Clean Energy Package for all Europeans (CEP), as well as the expectations of policy makers in the five countries, expressed in the National Climate and Energy Plans.

Relevant topics for the Integrid project in the CEP

Actor	Topic	Sub-Topic	Main Legal Act(s)
DSO	Core activities of DSOs	Network Planning	Electricity Directive
		Network Operation: Use of Flexibility	Electricity Directive
		TSO-DSO Coordination	Electricity Directive, Electricity Regulation
	Innovative Roles of DSOs	EV charging stations	Electricity Directive
		Storage facilities	Electricity Directive
		Data management	Electricity Directive
Consumer / Flexibility Providers	Consumers	Self-consumption (Active consumer consuming self-generated electricity)	Electricity Directive
		Energy/Flexibility provision (Active consumer injecting electricity upstream the meter)	Electricity Directive, Renewables Directive
		Smart metering system	Electricity Directive
		Data access	Electricity Directive
		Dynamic pricing	Electricity Directive, Electricity Regulation
	New agents	Aggregators	Electricity Directive
		Balancing market rules	Electricity Regulation

Based on the solutions proposed and demonstrated in the Integrid project, a list of regulatory barriers for their successful implementation was identified. In order to organize the guide, the discussion, this deliverable D7.2 uses the concept of Business Models (BM), used throughout the work conduct in WP7. The

Integrid BMs are an extrapolation of the High-Level Use Cases (HLUC) used in other work packages of the project. Five main BMs were identified, as listed below:

BM1 – DSO procures flexibility: The DSO is the main agent. In this Business Model, the DSO generates economic benefit by procuring flexibility from resources connected at the distribution level. By doing so, costs for the DSO are expected to be reduced and investments to be deferred.

BM2 - DSO improves quality of service. The DSO is the main agent. The economic benefit is generated for the DSO in the form of cost reduction by reducing interruptions through improved fault location and improving asset management.

BM3 – Data Services: In this BM, the Data Service Provider is the main actor. This BM encompasses businesses enabled by the implementation of the grid and market hub (gm-hub). Two sub-business models have been identified. On the one hand, data service providers will be able to exploit the data in gm-hub for the benefit of consumers, DSOs, TSOs, and aggregators. On the other hand, the operator/owner of the gm-hub operator may benefit from providing access to this platform; several different revenue models may be found for these services.

BM4 – Consumer reduces electricity bill: The Consumer is the main agent of this BM. The economic benefit to be generated in this BM is the reduction of the electricity bill for the final consumers through load automation. Two sub-business models are identified, one for industrial consumers (BM4.1) and another for residential ones (BM4.2).

BM5 – Creating value through aggregation: In this Business Model, the Retailers/Aggregators are the main agents. They will be able to create value for end-users by reducing the electricity bill through aggregation and fostering the use of demand flexibility. This business model explores the potential of aggregation for retailers (BM5.1), the potential of behavioural demand response (BM5.2) as a means of fostering demand response, and finally the potential of the Virtual Power Plant concept (BM5.3, for the tVPP, and BM5.4 for the cVPP)

It can be seen that BM1 and BM2 are mostly dependent on the economic regulation of DSO, which is normal as the DSO is the main actor in both BMs. Since BM1 also requires the provision of flexibility services by grid users, other topics such as local flexibility mechanisms, tariffs, or network access regulation are also relevant to this BM. On the other hand, BM3 mostly depends on the topics related to smart metering deployment and data management, as well as the existence of local flexibility mechanisms (the gm-hub acts both as a platform to exchange metering data and flexibilities information).

In turn, BM4, where the main actor is the final consumer who wishes to reduce the energy costs, mostly depends on the regulation concerning tariffs and metering. Moreover, self-generation or the provision of flexibility services may be additional strategies to achieve the same goal. Lastly, the most relevant topics to BM5, whose main actor is the BRP or the aggregator, comprise the local flexibility mechanisms, balancing markets, including aggregation rules, as well as tariffs and metering issues which may affect the participation of demand in these services.

Relevance of regulatory topics per BM. (3 – key regulatory topic; 2 – direct effect on the BM, but not the most relevant one; 1 – Indirect or implementation-dependent impact)

Topic	Sub-Topic	BM1 (HLUC1 and 2)	BM2 (HLUC3 and 4)	BM3 (HLUC6)	BM4 (HLUC8 and 9)	BM5 (HLUC10-12)
DSO Economic regulation	Revenue Regulation	3	2	-	-	2
	Other output based incentives	1	3	-	-	-
Other roles of DSOs	Network access and connection	2	-	-	2	1
	Ownership of storage	1	-	-	-	-
Service Provision	Mechanism to provide local flexibility	3	-	3	1	2
	Balancing services and aggregation rules	-	-	-	1	3
Tariffs and self-generation	Tariff structure and regulated charges	1	-	-	3	2
	Self-generation regulation	-	-	-	2	-
	Metering deployment and functionalities	2	-	3	3	2
Data Management	Data Management	-	-	3	-	-

For each topic and subtopic, specific barriers are identified. In total, 31 potential regulatory barriers are identified barriers, and so national regulatory frameworks are reviewed in order to assess the presence of each barrier in each country. To help this analysis, **key questions** were prepared, as well as a scoring criteria. This approach aims at providing not only a more specific guideline assessment of the barriers, but also to seek some comparability among the different countries. A "maturity level" rank was created based on how well adapted current regulation is to enable and promote the implementation of each one of the BMs.

The maturity assessment in the five Integrid target countries shows which regulatory barriers are more evident. The lack of local flexibility procurement mechanisms is the barrier that scored the lowest, considering the average of all countries, showing that DSOs and consumers still do not count on mechanisms to trade flexibility, impacting BM1 and BM5, for instance. On the other hand, regulation on self-generation, metering and data management provide a more favourable environment for BM3 and BM4, for example, although certain barriers still exist. Other topics present a mixed level of maturity, also among the five countries.

Overall assessment of barriers in the five countries

Topic	Sub-Topic	Overall assessment in the five countries
DSO Economic regulation	Revenue Regulation	
	Other output-based incentives	
Other roles of DSOs	Network access and connection	
	Ownership of storage	
Local flexibility markets/services	Mechanism to provide local flexibility	
Balancing Markets	Balancing services rules for DR and aggregation	
Tariffs and self-generation	Retail tariff design	
	Self-generation and metering	
Data Management	Data Management	

Legend:

 Regulation does not allow solutions proposed by the Integrid project. Several important barriers exist.

 Regulation acknowledges or allows solutions but does not provide a framework for their implementation.

 Regulation allows and enables solutions. **However, some barriers may still exist.**

Following the assessment of regulatory barriers in the five Integrid countries, recommendations are provided. These recommendations have been developed taking into account the need to be aligned with the CEP dispositions as well as the key lessons learnt in the Integrid SRA and CBA. Additionally, key papers and reports from academia and leading institutions (e.g. ACER, CEER, ENTSO-E, DSO Associations) are also taken into account.

Below, the full list of recommendations is provided. In order to interpret the recommendations provided herein, it is relevant to bear in mind that the **different regulatory topics** addressed in this report, in practice, **are highly interrelated**. For instance, DSO revenue regulation needs to be well coordinated with the design of local flexibility mechanisms or the grid connection regulation. Likewise, some tariff designs and self-generation regulations require having the appropriate metering functionalities in place. Because of this, this section discusses the interactions between different regulatory topics. Furthermore, the individual **recommendations may not be considered in isolation**, but as a combined package.

DSO Economic Regulation

Revenue Regulation

- The new additions to the RAB of DSOs should be decoupled from their actual investment in order to equalize the incentives for reducing CAPEX and OPEX. This can be done by applying a pre-defined capitalisation rate on the DSO allowed TOTEX. A progressive implementation needs to be made to prevent abrupt changes in the remuneration.

- Regulators should introduce ad-hoc mechanisms to encourage DSOs to keep assets in operation after the end of their regulatory life, especially when revenue regulation presents a strong CAPEX bias.
- DSO remuneration formulas should incorporate flexibility mechanisms, such as profit-sharing or trigger schemes, which mitigate the impact of regulatory forecasting errors in a context with growing uncertainties.
- DSOs should submit investment plans as part of the price review process. These plans should reflect fairly the use of flexibility as an alternative to grid reinforcements and make it clear how the different expenditures are related to the outputs that want to be attained. The level of detail or granularity may be lower for the LV grid due to the high extension of these systems. Regulation should clarify how the consultation process is to be conducted.
- It is recommended that investment plans are used as part of the revenue determination process. Thus, their elaboration should be coordinated with price reviews. NRAs should have the necessary tools and resources to assess the DSO network development plans by using forward-looking cost assessment methods.
- DSOs should be explicitly allowed to implement pilots to test innovative smart grid functionalities and technologies. Regulatory supervision either as an –ante approval, an ex-post evaluation, or both. Such evaluation should be made based on a set of KPIs and/or CBA where the benefits for network users are clearly shown.

Other output-based incentives

- The reference values for losses considered in the incentives schemes should reflect the impact of DER on network losses in each DSO area.
- Implement incentive/penalty mechanisms for the DSOs to improve network reliability. These mechanisms should incorporate reliability indicators measuring both the number and the duration of interruptions.
- Regulators should ensure that the incentive mechanisms parameters send adequate incentives for DSOs to improve quality of service by avoiding wide deadbands, tight cap and floors. Moreover, reference values and marginal incentive rates should be assessed, and not be based exclusively on historical values, in order to reflect appropriately both the marginal cost of improving reliability (including smart grid solutions) and the cost of interruptions for consumers in their country.
- Incentive schemes should encourage DSOs to replace unplanned interruptions with scheduled interruptions, as the latter have less impact on grid users.
- A regulatory sandbox can be used to extend research activities towards market demonstration in a protected environment. Design recommendations are given in section 7.7.2

Other roles of DSOs

Network access and connection

- Regulation should enhance the transparency in grid connection by setting minimum information disclosure requirements to DSOs, especially when connection charges are determined by the DSO:
  - For small users and/or those connected to the LV grid, information about the expected amount of the connection charges ought to be published.

- For larger units connected to the MV and HV levels, information disclosure may apply to the available hosting capacity in different points of the grid.

- Shallow or shallowish charging approaches for small DER units should be implemented to avoid barriers to the connection of small units to the grid. Regulation may stablish differences by requested capacity and/or by voltage levels. Large DER may be subject to deep connection charges in order to provide them with efficient locational signals. However, this should be implemented together with flexible network access and information disclosure about available grid capacity.
- Flexible network access should be enabled in order to ensure an efficient network development, especially in MV and HV distribution networks. When with deep connection charges are in place, new grid users could be offered several options with different combinations of connection charges and level of firmness (curtailment probability) in their connection.

Ownership of storage

- Regulators should seek to establish competitiveness wherever possible. This is the case for new roles as well as for the amendment of existing roles.

Local flexibility markets/services

Mechanism to provide local flexibility

- DSOs should be explicitly allowed to procure flexibility services from grid users or intermediaries managing a portfolio of flexible DER.
- In the early stages, DSOs and third-parties should be allowed to test different local flexibility market configurations, under regulatory sandboxes if necessary. Over time, flexibility markets and products may be standardize if deemed required.
- Long-term procurement, years-ahead and with a contract duration of several years (e.g. an entire regulatory period or the period between investment plans), should be encouraged to enable incorporating it in the DSO investment plans.
- The activation price of flexibility sources that are contracted under a long-term framework should be determined in the short-term under a market-based mechanism competing against all available sources of flexibility (including those without a long-term contract and flexible connection agreements). Long-term contracts may include a cap on the activation price to protect DSOs against opportunistic behaviours from flexibility providers (market power abuse).
- Enhanced TSO-DSO coordination is necessary to ensure seamless participation of aggregators in both local and centralized markets. Enhanced coordination is necessary both in the operational planning and real-time operation timeframes. Coordinate market models and activation procedures can reduce the risk upon flexibility providers and increase overall economic efficiency.

Balancing Markets

Demand Response participation in balancing services

- The participation of DR in balancing market is likely to follow an incremental approach. Large consumers are likely to be more willing to participate in balancing markets than residential consumers. Therefore, when adapting balancing markets for demand response participation, large consumers may be included in the first stage.

- Balancing capacity services (for aFRR, mFRR and RR) should be open to the participation of all agents, including DR, under transparent, market-based procurement conditions.
- Minimum bid sizes should allow for DR participation while maintaining the capability of the TSO to efficiently manage the system's balance. Additionally, independent upward and downward bidding should be allowed.
- Settlement prices for capacity and energy balancing markets should not be regulated. In capacity balancing markets, pay-as-clear can offer better conditions from a DR integration standpoint, although such design choice can not consider this element in isolation. Energy balancing markets should adopt pay-as-clear settlement method.
- Prequalification could be done in a pooled fashion to allow for easier aggregated DR participation, and also to allow for higher capability and reliability of a pooled BSP. Prequalification should also be coordinated with DSOs, considering that they will also procure DR flexibility. From the DR's perspective, to the extent possible, a "one-stop shop" is the most suitable option.
- A clear baseline methodology is necessary for the participation of DR in balancing markets. They provide TSOs with the means to verify flexibility activation and DR providers with a transparent and predictable rule for expected profits.
- Aggregators should be allowed to participate in multiple markets with the same portfolio, provided the prequalification requirements are met to all of them.
- Aggregation of different types of DER in the different markets should be allowed, provided that prequalification requirements are met.
- A framework to settle imbalances in the supplier's portfolio originated by flexibility activation and to adjust financial positions is necessary to insure harmony between the independent aggregator and the supplier's activities. An example of such a framework is the Transfer of Energy, already adopted in Belgium.

Tariffs and self-generation

Retail tariff design (regulated charges)

- Purely volumetric distribution network tariffs should be avoided. Capacity charges and/or fixed charges should be introduced to recover the fixed network costs, provided metering technologies allow to do so.
- "Locational and time differentiation should be introduced in the network tariffs, so that grid users can make decisions on the adoption of new technologies under predictable conditions.
- LV ToU tariffs may present a small number of time periods for LV consumers, whereas a higher number may be applied in higher voltage levels.
- Large network areas with consistent utilization rates could be selected to set different network tariffs. Local flexibility mechanisms can be used to address network constraints inside these areas or in countries where geographical discrimination is not allowed."
- If dynamic tariffs are implemented, unpredictability problems ought to be mitigated. Moreover, the design of dynamic tariffs, e.g. geographical granularity, should be coordinated with local flexibility mechanisms. The former could be more suitable to solve system-wide critical periods, whereas the latter seem more suitable for more localized network constraints.

Self-generation and metering

- All consumers with a smart meter should be entitled to a dynamic pricing option. This could be introduced as the default regulated tariff (last resource tariff) and/or mandating suppliers to include this alternative in their offers.
- When introducing dynamic price contracts, retailers should be required to publish clear and transparent information about this alternative, including the potential risks, and make it easily available to consumers. Dynamic prices may be linked to day-ahead markets, instead of intraday markets, to mitigate the uncertainties for consumers, particularly for residential consumers. Additionally, particularly when market price caps are high, regulators should assess the introduction of safety nets for consumers in the dynamic price contracts.
- To the extent possible, all the costs not related to the electricity supply should be removed from the regulated charges included in the electricity tariff. When some of these costs remain in the electricity tariff, they should be allocated in the least distortive way possible, particularly avoiding artificially high volumetric charges.
- Regulation should allow end-consumers to self-generate and store their own electricity without undue barriers as set in Directive (EU) 2018/2001. In the case of self-generation, allocation rules of renewable production should ensure the appropriate regulated charges are paid for.
- Abandon net-metering schemes in favour of net-billing schemes or market participation of self-producers. Under net-billing, active consumers should receive a compensation for the energy injected into the grid that reflects the market value of that electricity. Consumers with self-generation facilities may be requested to have a smart meter installed to ensure they can be exposed to cost-reflective tariffs.
- Regulatory barriers to the development of renewable PPAs should be removed.
- The deployment of Smart Meters should consider the needs of different stakeholders and ensure interoperability in order to allow new business models (e.g. consider observability requirements from TSOs in order to allow for DR balancing provision).
- DSOs should facilitate on-demand deployment to the extent possible. This allows not only consumers to feel more encouraged to adopt Smart Meters, but also new business models to foster the use of the new meters.
- The choices in terms of Smart Meter capabilities should aim at a “future-proof” deployment. Non forward-looking approaches lead to additional costs, as Smart Metes will have to be updated more often to meet the ever evolving needs of the industry, and to delays in the adoption of new business models.

Data Management

- The definition of national regulation on data management model can make use of guiding principles and recommendations provided by CEER. The implementation of a data hub (gm-hub) in a centralised model provides possibilities for the development of new businesses. Implementation of the data service provider in the decentralised model environment is possible. In this case, the means to obtain consumer consent need to be taken into consideration.

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Abbreviations and Acronyms

ACER	Agency for the Cooperation of Energy Regulators
aFRR	Automatic Frequency Restoration Reserve
AMI	Advanced Metering Infrastructure
AS	Ancillary Services
BDR	Behavioural Demand Response
BM	Business Model
BRP	Balancing Responsibility Party
BSP	Balancing Service Provider
CAIDI	Customer Average Interruption Duration Index
CAPEX	Capital Expenditures
CBA	Cost-Benefit Analysis
CDS	Closed Distribution System
CEC	Citizen Energy Communities
CEER	Council of European Energy Regulators
CEP	Clean Energy Package
CPP	Critical Peak Pricing
cVPP	Commercial Virtual Power Plant
DAM	Day-ahead Market
DEA	Data Envelopment Analysis
DER	Consortium Agreement
DG	Distributed Generation
DoA	Description of Action
DR	Demand Response
DSO	Distribution System Operator
EBGL	Electricity Balancing Guideline
EDC	Electricity Distribution Companies
EHV	Extra High Voltage
ENS	Energy Non-Served
ENTSO-e	European Network of Transmission System Operators for Electricity
EPEX	European Power Exchange
ESCO	Energy Services Company
ETIP-SNET	European Technology and Innovation Platform - Smart Networks for Energy Transition
EV	Electric Vehicle
EXAA	Energy Exchange Austria
FCR	Frequency Containment Reserve
FiT	Feed-in Tariff
FRR	Frequency Restoration Reserve

GDPR	General Data Protection Regulation
Gm-hub	Grid-market hub
HEMS	Home Energy Management System
HLUC	High-Level Use Case
HV	High Voltage
ISGAN	International Smart Grid Action Network
ISO	Independent System Operator
KPI	Key Performance Indicator
LV	Low Voltage
MARI	Manually Activated Reserves Initiative
mFRR	Manual Frequency Restoration Reserves
MOLS	Modified Ordinary Least Squares
MS	Member State
MV	Medium Voltage
NCEP	National Energy and Climate Plans
NEMO	Nominated Electricity Market Operator
NRA	National Regulatory Agency
OLTC	On-Load Tap Changer
OPEX	Operational Expenditures
OTC	Over The Counter
O&M	Operation and Maintenance
P2P	Peer-to-Peer
PCR	Price Coupling of Regions
PICASSO	Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation
PPA	Power Purchase Agreement
PV	Photovoltaic
RAB	Regulatory Asset Base
REC	Renewable Energy Communities
RES	Renewable Energy Sources
RNM	Reference Network Model
RPI-X	Retail Price Index minus “X” (efficiency factor)
RR	Replacement Reserve
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SIDC	Single Intraday Coupling
SOGL	System Operation Guideline (ENTSO-e)
SRA	Scalability and Replicability Analysis
TERRE	Trans European Replacement Reserves Exchange
TLS	Traffic-Light System
ToE	Transfer of Energy

TOTEX	Total Expenditures
ToU	Time-of-Use
TSO	Transmission System Operator
tVPP	Technical Virtual Power Plant
UoS	Use-of-System Charge
VPP	Virtual Power Plant
WACC	Weighted Average Cost of Capital
WP	Work Package
WTA	Willingness To Accept
WTP	Willingness To Pay
XBID	Cross-Border Intraday Market

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. Moreover, several pilot projects have been carried out by different Distribution System Operators (DSO) 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 DER 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 five countries where InteGrid partners are located, the impact of such frameworks, and recommendations for future regulation.

1.2. Work Package 7 and the regulatory analysis

The overall objectives of Work Package 7 (WP) are to understand the potential business models enabled by the InteGrid solutions, carry a cost-benefit analysis of these solutions, and research the regulatory layer underlying their implementation in a set of focus countries.

Since the identification of disruptive business models (BM) is one of the core objectives of the InteGrid project, WP7 was structured having the BMs in at the centre of the discussion as shown in Figure 1. The successful development and implementation of these business models strongly depend on i) appropriate regulatory conditions, ii) their economic feasibility, and iii) the direct or indirect involvement of several stakeholders. Therefore, the work in this WP includes: a characterization of the BMs (D7.5), a regulatory analysis and recommendations (D7.2), a cost-benefit analysis (CBA) (D7.4), and a consultation among key stakeholders about their views on the BMs proposed (D7.6).

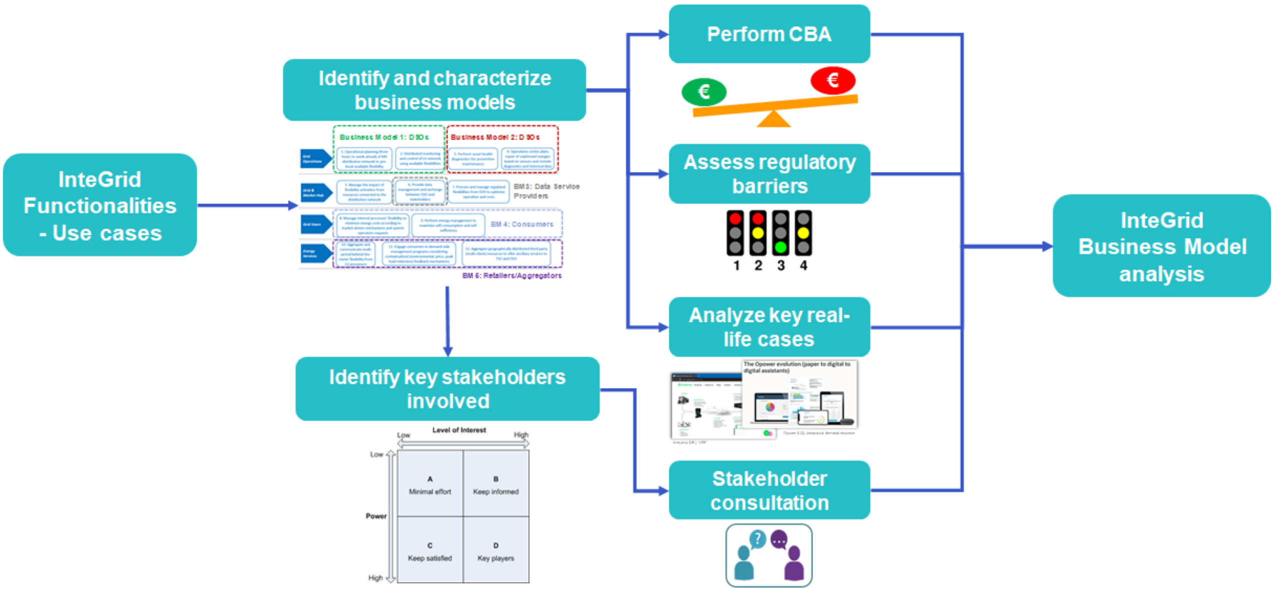

Figure 1: Flowchart of the business model analysis in Integrid

This deliverable specifically aims at presenting the regulatory analysis performed in Integrid. Note that, as already done in deliverable D7.1, we focus on InteGrid BMs instead of the High-Level Use Cases (HLUCs) to guide this discussion. Aiming the discussion towards BMs has the benefit of harmonizing the work done in other tasks of WP7 and possibly making the discussion and conclusions more accessible to the reader not so familiar with the technical aspects of the HLUCs. The Business Models, as well as their correspondence with HLUCs, are explained in detail in Section 2.

This approach does not mean that the conclusions here presented are dissociated from the use case architecture of the project. There is a clear correspondence between BMs and respective HLUCs. Therefore, the regulatory implications for the individual HLUCs are easily identifiable. Moreover, we believe the BMs can be a more accessible approach for the external public, facilitating the dissemination of the regulatory discussion. Figure 1 presents a schematic overview of the use of the identified business models with the work carried out in WP7.

This analysis will be focused on the selected target countries. These countries correspond to the three demo countries as well as two additional countries where research members of the consortium were based: Portugal, Slovenia, Sweden, Spain and Austria. Nonetheless, the discussions and recommendations may also be applicable for similar EU contexts. In order to maximize the EU-wide applicability, this report places a particular emphasis on how these recommendations fit within and contribute to the achievement of the EU energy policy goals and their compliance with the latest European regulatory developments in the Clean Energy Package (CEP), as discussed in section 3.1.

The regulatory analysis within the InteGrid project has taken place in different stages. In the first one, a preliminary assessment of regulatory frameworks was carried within WP 1, under Task 1.3. The result of this analysis was presented in Deliverable D1.3. Within WP7, two additional deliverables assess the barriers for the implementation of InteGrid solutions and provide recommendation on how to overcome them. Firstly, deliverable D7.1 provided an update on the national regulatory frameworks in the five target countries and carried out a first assessment of the regulatory barriers for the different business models. The present deliverable D7.2 goes one step further and aims at providing a comprehensive assessment of the regulatory barriers for the implementation of InteGrid solutions, as well as at providing recommendation on how to overcome them.

This deliverable will present the results of subtask 7.1.2. The goal of this subtask is to identify existing regulatory barriers to the implementation of successful smart grid solutions - leveraging on demonstration activities, the Cost and Benefit Analysis (CBA) and the Scalability and Replicability Analysis (SRA) - tested within the project and provide recommendations to overcome them.

1.3. Document Structure and Methodology

The aim of this deliverable is to be able to provide sound regulatory recommendation to overcome possible regulatory barriers that InteGrid BMs may face. For that reason, Chapter 2 provides an overview of the BMs considered in the regulatory analysis and their correspondence with the HLUCs, mostly used in the other tasks. Moreover, this section provides a brief overview of the different regulatory aspects that are relevant to each BM.

After that, the remainder of the document is a two-part analysis. Firstly, it comprises of a comprehensive identification of regulatory drivers and barriers in the different target countries. Secondly, it provides recommendations to overcome the specific barriers that were identified.

The processes of identification of regulatory drivers and barriers in the target countries is composed of several steps. Considering the lessons learned from other tasks in the InteGrid project that covered the regulation in the different countries (e.g. D1.3, D7.1, D8.2), it is safe to say that regulatory frameworks cannot be considered as a static body of already-published national legal acts. This fact is even more important in the context of the InteGrid project. The solutions proposed by the project are in line with both European views for the electricity sector, as well as with national decarbonization target. Therefore, the identification of barriers (and further recommendations) and drivers should also take into account the forthcoming changes in regulation. For this reason, a review of two important sources of changes is proposed, namely the CEP and the National Energy and Climate Plans (NECP).

The CEP is the most recent and important European package of regulatory measures for the energy sector. In the documents of the CEP, important changes are set to take place in the coming years, changes that are related with the solutions proposed by InteGrid. In this context, Section 3.1 conducts an analysis of the relevant topics in the CEP for InteGrid. This work is not only an identification of upcoming changes, but also an effort to understand what is already defined in the CEP and what is left for Member States to regulate. This is especially important for the recommendations that will be issued, considering that many important topics in the CEP are presented as guidelines, but final definitions are to be made by the Member States in the transposition process.

The second set of high-level documents analysed is the NECP of each target country. In these documents, national policy makers set their country decarbonization targets for 2030 and express their views on the strategies to achieve them. Although the scope of these documents is much broader than the scope of the InteGrid project, the NECPs are still relevant as a source of expected upcoming changes and they may address topics relevant for the BMs discussed in this deliverable. This is especially relevant considering that an underlying common theme of the strategies to achieve the decarbonization targets consists in the electrification of energy uses and the decarbonization of the electricity production. This is bound to result in growing shares of DER that need to be integrated into the electricity system is the most efficient manner. For this reason, Section 3.2 presents an overview of the NECPs from the InteGrid solutions perspective.

Having considered the expectations contained in the CEP and the NECP, this report proceeds to the review the current national regulatory frameworks in the five target countries. For that, first a list of potential regulatory barriers is identified and presented in Section 4. Following this identification, Chapter 5 provides the actual country assessment. For each regulatory barrier, the situation in each country is presented and assessed, aiming at understanding how relevant the different barriers are in the different countries. For this assessment, the main documents reviewed are the published regulatory documents (e.g. acts from regulators, laws, decrees, etc.) and eventually secondary sources (e.g. reports from EU institutions such as CEER, ACER, ENTSO-E, etc.).

Once barriers are identified, Chapter 6 develops and provides the regulatory recommendations to overcome possible barriers for the implementation of InteGrid BMs. This chapter brings together the assessment of regulatory barriers, the expectations of the CEP and the NECP, as well as the academic discuss relevant for each regulatory topic to provide sound recommendation for each InteGrid target country.

Finally, Chapter 0 concludes this report.

1.4. Concepts and Definitions

The analysis presented in this report uses several concepts that may be confusing if not properly defined. Thus, this section aims to clarify the nomenclature that will be used throughout the report. The reason is two-fold. On one hand, concepts like “demand-response” or “flexibility” are often used in many different sources with slightly different definitions that may lead the reader to understand them according to hers/his previous reading, possibly not matching completely to the understanding of this report. On the other hand, the different sources analysed may use overlapping concepts, which may create confusion. Therefore, this short section, composed of a single table, aims at providing a quick reference to the reader of the concepts and definitions used throughout the deliverable, and how they relate to each other.

Table 1: Concepts and Definitions

Concept	Definition	Notes
DER	Distributed energy resources are understood as all resources connected at the distribution grid that can provide flexibility. This includes DG, DR, EV and storage systems	
Flexibility	Is the capacity of a DER to change its consumption or production pattern (active power) for a certain period given a certain input (implicit or explicit).	In power systems, flexibility can be understood in a broader sense, but in this report we understand flexibility as the one provide by DER only
Implicit Flexibility	The change of output by a certain DER as a reaction to some signal (e.g. price signal, environmental or social signal).	
Explicit Flexibility	The change of output of output by a certain DER as a part of a market commitment by the direct activation from another agent (e.g. DSO, TSO, aggregator)	
DG	Distributed generators are generation units connected at the distribution grids, in the premises of a consumer or not.	
DR	Demand response is defined as consumers that can provide flexibility, be that explicit flexibility or implicit flexibility	
Active customer	Means a final customer, or a group of jointly acting final customers, who consumes or stores electricity generated within its premises located within confined boundaries or, where permitted by a Member State, within other premises, or who sells self-generated electricity or participates in flexibility or energy efficiency schemes, provided that those activities do not constitute its primary commercial or professional activity.	This concept comes directly from the CEP. In this deliverable, it can be considered interchangeably with the concept of "prosumer".
Net-metering	An electricity billing mechanism for prosumers in which the electricity injected into the grid offsets the electricity consumed from the grid in a certain period (e.g. month, year).	
Aggregation	Means a function performed by a natural or legal person who combines multiple customer loads or generated electricity for sale, purchase or auction in any electricity market	Concept from the CEP. Used in this deliverable as defined in the CEP.
Independent aggregator	Means a market participant engaged in aggregation who is not affiliated to the customer's supplier	Concept from the CEP. Used in this deliverable as defined in the CEP.
Self-generation	Generation made by an active customer. In other words, the generation from DG associated with a consumer. Alternatively, the generation of a "prosumer".	Concept largely used in the CEP.
Self-consumption	The part of the self-generation used for internal consumption of the active customer. The self-generation not used for self-consumption is the energy fed into to grid.	Concept used in the CEP to describe the production-consumption behind the meter.

2. InteGrid Business Models and power system regulation

In this report, a business model is understood as a set of strategies chosen by a certain agent in order to generate economic benefits, i.e. additional revenues and/or cost reductions. These business strategies can combine multiple instruments, and several sources of economic benefits.

The instruments necessary to implement a business strategy vary and may include the provision of services, the selling of a product, adopting a new technology or the implementation of a new internal process. These business strategies are then combined into an actionable framework, meaning that the main agent has a common final goal for all business strategies.

Following the above-mentioned definition, a set of BMs have been identified based on a classification of the project's HLUCs. For each business model, a set of parameters has been identified, namely main actor, involved actors (partners, custumers, etc.), economic benefits for the main actor, cost structure, etc. Figure 2 presents the five Business Models identified in InteGrid. Note that within these five BM categories, additional subcategorizations have been made as discussed below.

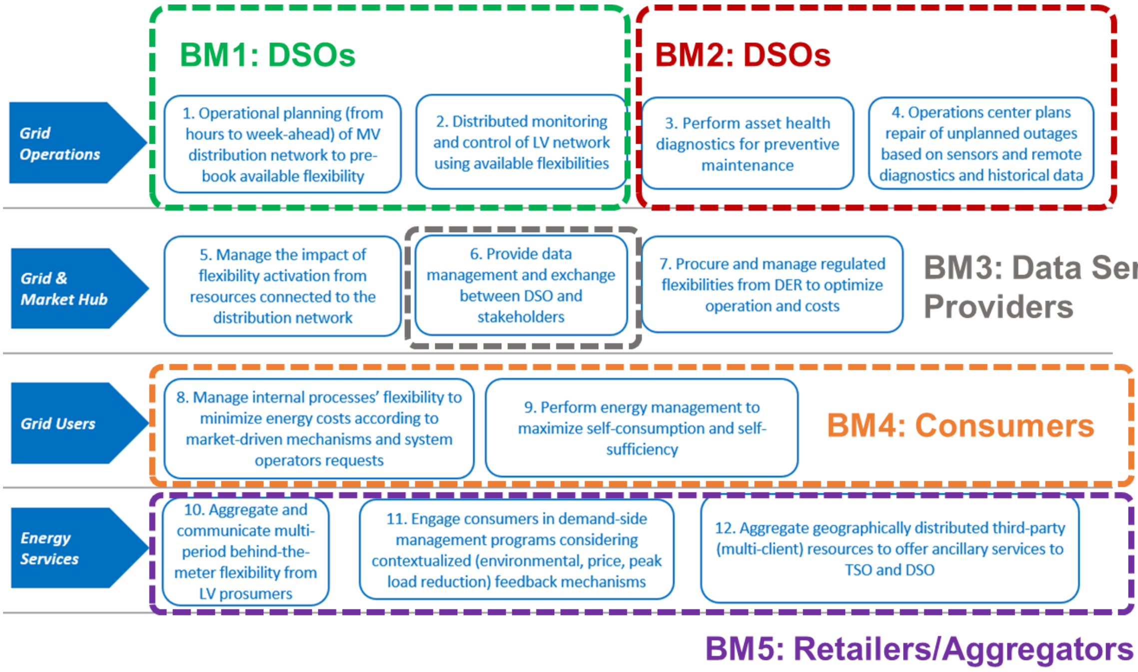

Figure 2: Business Models Mapping

Below, the main features of the five BMs are briefly described:

BM1 – DSO procures flexibility: The DSO is the main agent. In this Business Model, the DSO generates economic benefit by procuring flexibility from resources connected at the distribution level. By doing so, costs for the DSO are expected to be reduced and investments to be deferred.

BM2 - DSO improves quality of service. The DSO is the main agent. The economic benefit is generated for the DSO in the form of cost reduction by reducing interruptions through improved fault location and improving asset management. The increase in quality of service may lead the DSO to higher incomes, depending on how regulation incentivizes it, and the improved asset management may reduce overall maintenance cost.

BM3 – Data Services: In this BM, the Data Service Provider is the main actor. This BM encompasses businesses enabled by the implementation of the grid and market hub (gm-hub). Two sub-business models have been identified. On the one hand, data service providers will be able to exploit the data in gm-hub for the benefit of consumers, DSOs, Transmission System Operators (TSO), and aggregators. These agents may pay Data Service Providers for providing analyses that may decrease the energy bill (in the case of consumers), reduce costs (in case of system operators), or increase revenues (for aggregators). On the other hand, the operator/owner of the gm-hub operator may benefit from providing access to this platform; several different revenue models may be found for these services.

BM4 – Consumer reduces electricity bill: The Consumer is the main agent of this BM. The economic benefit to be generated in this BM is the reduction of the electricity bill for the final consumers through load automation. Two sub-business models are identified, one for industrial consumers (BM4.1) and another for residential ones (BM4.2).

BM5 – Creating value through aggregation: In this Business Model, the Retailers/Aggregators are the main agents. They will be able to create value for end-users by reducing the electricity bill through aggregation and fostering the use of demand flexibility. This BM is divided into four sub-business models. The first one (BM5.1), centered in the retailer (or the BRP) that uses flexibility of commercial buildings to provide balancing services[1]. In the second business model (BM5.2), a platform will foster demand-side management by the residential consumers through tips and gamification (behavioural demand response). The third business model (BM5.3), in which the aggregator is the main actor, explores the idea of aggregation through the Commercial VPP concept (cVPP) profiting from providing ancillary services to the TSO. In the fourth business model (BM5.4), the aggregator explores the Technical VPP concept (tVPP), in which local services are provided to the DSO by the aggregated flexibility.

[1] Alternatively, retailers may use the flexibility within their portfolio to minimize their own imbalance.

Box 1: Technical and Commercial VPPs

Customers and distributed third-party energy resources that have the ability of changing their consumption or generation for short time could be aggregated, and their flexibility could be offered as ancillary service to TSO or to be used for DSO grid purposes.

In case of the technical VPP, whenever the DSO detects some congestions or voltage problems, he orders activation of distributed flexibility resources like loads, renewables and storage on MV/LV grid that are aggregated within the relevant grid sections by the flexibility operator

In case of the commercial VPP, when the TSO triggers an activation of mFRR, the flexibility operator executes TSO's requested activation schedule by means of the VPP system. The VPP activates distributed flexibility resources like loads, renewables and storage for a predefined maximum period and controls the fulfilment of the activation schedule.

The implementation of the previous BMs will be affected by the existing regulatory framework in the electricity system, including balancing market rules, network regulation or tariff design. Since the BMs pursue distinct objectives and affect different types of stakeholders, each one of them requires considering different aspects of regulation. A detailed mapping and discussion about the regulatory topics affecting each BM was presented in D7.1[2]. A simplified version is presented in Table 2 below to be used as a reference hereafter. Based on that mapping, the relevance of each regulatory barrier identified for each BM is analysed in section 4.

It can be seen that BM1 and BM2 are mostly dependent on the economic regulation of DSO, which is normal as the DSO, a regulated natural monopoly, is the main actor in both BMs. Since BM1 also requires the provision of flexibility services by grid users, other topics such as local flexibility mechanisms, tariffs, or network access regulation are also relevant to this BM[3]. On the other hand, BM3 mostly depends on the topics related to smart metering deployment and data management, as well as the existence of local flexibility mechanisms (the gm-hub acts both as a platform to exchange metering data and flexibilities information).

In turn, BM4, where the main actor is the final consumer who wishes to reduce the energy costs, mostly depends on the regulation concerning tariffs and metering. Moreover, self-generation or the provision of flexibility services may be additional strategies to achieve the same goal. Lastly, the most relevant topics to BM5, whose main actor is the BRP or the aggregator, comprise the local flexibility mechanisms, balancing markets, including aggregation rules, as well as tariffs and metering issues which may affect the participation of demand in these services.

[2] Note that the numbering of BM1 and BM2 has been exchanged with respect to D7.1. This needs to be taken into account when comparing both documents.

[3] Apart from these regulatory aspects, others such as GdPR and ePricavacy regulation are also relevant to a lesser extent. Given that the importance of these topics is more evident in other BMs (such as BM3), they are mainly discussed in the context of those other BMs.

Table 2: Relevance of regulatory topics per BM. (3 – key regulatory topic; 2 – direct effect on the BM, but not the most relevant one; 1 – Indirect or implementation-dependent impact)

Topic	Sub-Topic	BM1 (HLUC1 and 2)	BM2 (HLUC3 and 4)	BM3 (HLUC6)	BM4 (HLUC8 and 9)	BM5 (HLUC10-12)
DSO Economic regulation	Revenue Regulation	3	2	-	-	2
	Other output based incentives	1	3	-	-	-
Other roles of DSOs	Network access and connection	2	-	-	2	1
	Ownership of storage	1	-	-	-	-
Service Provision	Mechanism to provide local flexibility	3	-	3	1	2
	Balancing services and aggregation rules	-	-	-	1	3
Tariffs and self-generation	Tariff structure and regulated charges	1	-	-	3	2
	Self-generation regulation	-	-	-	2	-
	Metering deployment and functionalities	2	-	3	3	2
Data Management	Data Management	-	-	3	-	-

3. An assessment of the EU policy and regulatory context and implications for Integrid BMs

3.1. The Clean Energy Package vs. national regulation

The Clean Energy for all Europeans package (hereafter referred to as Clean Energy Package, or simply CEP), finally published in the Official Journal of the European Union between June 2018 and June 2019, is the most recent and significative piece of European regulation concerning the energy sector. Together with the adoption of the Network Codes and Guidelines, these two packages are expected to have an important influence on the national regulations.

Several regulatory topics covered by the CEP are also relevant for the development of the solutions proposed by InteGrid. Therefore, an analysis of regulatory barriers and regulatory recommendations should also take into consideration the forthcoming changes contained in the new European regulations.

This section presents an assessment of the regulatory topics included in the CEP that are relevant for that deployment of InteGrid BMs. The objective of this assessment is twofold. Firstly, it aims at identifying the relevant topics regarding the solutions proposed in the project. Secondly, it is important to understand how clear or specific the CEP is in each of the regulatory topics.

The following analysis shows that the level of precision is not harmonized across regulatory topics. For some topics, the CEP is precise in its orientations, and clearly states the measures Member States should adopt. For other, the general directions are provided, but the implementation is not completely defined. This can happen either because the CEP does not advocate for one single solution or because the topic is still not fully mature or depends on the country context.

3.1.1. CEP Mapping – Relevant documents and topics

The CEP is a major European regulatory package on energy that will guide energy regulation in Europe for the following decades. In legal terms, this package is distributed across nine different legal acts. Most of these documents are amendments or recasts from previous legal acts, already introduced by previous important regulatory packages (e.g. the Third Package). As shown in Table 3, the most relevant documents in the context of the InteGrid project are Electricity Directive, the Electricity Regulation, and the Renewable Energy Directive.

Table 3: CEP legal acts and their relevance in the context of InteGrid

Legal Act	Official Journal Publication	Relevance in the context of InteGrid
Energy Performance in Buildings Directive	Directive (EU) 2018/844	Very low
Renewable Energy Directive (RES-Directive)	Directive (EU) 2018/2001	Medium
Energy Efficiency Directive	Directive (EU) 2018/2002	Low
Governance of the Energy Union Regulation	Regulation (EU) 2018/1999	Low
Electricity Regulation (E-Regulation)	Regulation (EU) 2019/943	High
Electricity Directive (E-Directive)	Directive (EU) 2019/944	High
Risk Preparedness Regulation	Regulation (EU) 2019/941	Very low
ACER Regulation	Regulation (EU) 2019/942	Very low

After an analysis of the above-mentioned legal acts, several topics were identified as being critical for the solutions proposed in the InteGrid project. These topics can be divided according to the main actor they are addressed to. In this context, DSOs are at the centre of many regulatory definitions in the CEP. Consumers, prosumers and other flexibility providers are also addressed in the CEP.

The topics covering DSO regulation can be divided into two groups for the purpose of this analysis. Firstly, some topics address core activities of the DSO today, as network planning, operation, and the interaction TSO-DSO. Secondly, the CEP also identifies and regulates the new roles of DSOs. These new roles include the definitions on the ownership and operation of Electric Vehicle (EV) charging stations and storage facilities, as well as the data access and data management roles.

On the consumer/flexibility provider's side, several topics are of relevance for the InteGrid BMs. Starting with self-consumption definitions, that will mainly have an impact on BM4, in which the consumer minimizes energy costs, by, among other measures, installing distributed generation. The concept of flexibility provision by consumers and prosumers is also a very relevant covered by the CEP. It will impact both BM4 and BM5, on the flexibility provider's side, as well as BM1, in which the DSO procures this flexibility. The deployment of smart meters is also addressed in CEP, and it is a topic that underlies almost all BMs, except for BM2. Moreover, this report also looks at the importance of the dynamic pricing for consumers, and definitions on metered data access, essential for BM3.

Finally, it is worth mentioning aggregation, and especially the concept of independent aggregation is also treated by the CEP and are very relevant in BM5.

Table 4 summarizes the main relevant topics covered by the CEP that are relevant for the InteGrid project, as well as a reference of the most important legal acts for each topic. The remainder of this subsection will discuss each of the regulatory topics, the main ideas brought by the CEP, and how they impact each BM.

Table 4: Relevant topics addressed in the CEP for the InteGrid project

Actor	Topic	Sub-Topic	Main Legal Act(s)	Relevant BMs
DSO	Core activities of DSOs	Network Planning	Electricity Directive	BM1
		Network Operation: Use of Flexibility	Electricity Directive	BM1, BM4, BM5
		TSO-DSO Coordination	Electricity Directive, Electricity Regulation	BM1, BM4, BM5
	Innovative Roles of DSOs	EV charging stations	Electricity Directive	BM1 (minor impact)
		Storage facilities	Electricity Directive	BM1 (minor impact)
		Data management	Electricity Directive	BM3
Consumer / Flexibility Providers	Consumers	Self-consumption (Active consumer consuming self-generated electricity)	Electricity Directive	BM4
		Energy/Flexibility provision (Active consumer injecting electricity upstream the meter)	Electricity Directive, Renewables Directive	BM4, BM5, BM1
		Smart metering system	Electricity Directive	BM1, BM3, BM4, BM5
		Data access	Electricity Directive	BM3
		Dynamic pricing	Electricity Directive, Electricity Regulation	BM4
	New agents	Aggregators	Electricity Directive	BM5
		Balancing market rules	Electricity Regulation	BM5

3.1.2. DSO regulation

3.1.2.1. Core activities of the DSO: grid planning and operation

The CEP brings several definitions for DSOs that are relevant for the InteGrid project. One of the topics discussed in detail by the CEP is network planning by DSOs. The Electricity Directive establishes that DSOs should produce development plans that go through public consultation, are approved by NRAs and are made public so grid users have the necessary information to decide on new grid connections. The Energy Directive, in its recital 61, also recognizes that this still missing in most Member States:

> "*Member States should also introduce network development plans for distribution systems in order to support the integration of installations generating electricity from renewable energy sources, facilitate the development of energy storage facilities and the electrification of the transport sector, and <u>provide to system users adequate information regarding the anticipated expansions or upgrades of the network</u>, as currently such procedures do not exist in the majority of Member States*."

In Article 32, the Electricity Directive complements the objective of the publication of network plans by saying that they "shall provide transparency on the medium and long-term flexibility services needed". Moreover, the network plans should also take into account the "use of demand response, energy efficiency, energy storage facilities or other resources that the distribution system operator is to use as an alternative to system expansion."

These are important definitions that are in line with the solutions proposed in BM1 of InteGrid, namely the procurement of local flexibility by DSOs, possibly leading to investment deferral. Therefore, Article 32 highlight two important aspects of network plans in this context. Firstly, that potential flexibility providers should have **access to network information,** so they can install DER where it will be mostly needed. Secondly, **DSOs should actively consider potential investment deferrals** at the network expansion planning.

The CEP clearly states when and how the network expansion plans should be published. DSOs shall publish them at least every two years, following a public consultation process and approval of the national regulatory authorities. The expansion plans "shall set out the planned investments for the next five-to-ten years, with particular emphasis on the main distribution infrastructure which is required in order to connect new generation capacity and new loads, including recharging points for electric vehicles."

The Article 32 of the Electricity Directive sets the requirement for network expansion planning considering the flexibility potential as an important mechanism to incentivise DSOs to use local flexibility for grid management purposes. This requirements on network expansion planning can be consider **fairly clear**, giving a ready to implement regulatory mechanism to Member States. However, the CEP is not so clear when dealing with other incentive mechanisms that might be necessary for DSOs to act as active system operators.

In the first item of Article 32, the E-Directive defines that "*Member States shall provide the necessary regulatory framework to allow and provide incentives to distribution system operators to procure flexibility services, including congestion management in their areas, in order to improve efficiencies in the operation and development of the distribution system.*" The E-Directive highlights that this procurement should allow for DER participation, and that it should be done "*with transparent, non-discriminatory and market-based procedures unless the regulatory authorities have established that the procurement of such services is not economically efficient or that such procurement would lead to severe market distortions or to higher congestion.*"

This Article 32, the only one clearly defining incentives for DSOs to procure local flexibility, highlights two important characteristics of the CEP is this topic. Firstly, that the CEP **does not provide clear incentive mechanism options,** but rather states the need for incentives to be defined by Member States. The second important message is that **the procurement of local flexibility should be done only when and where it proves to be more efficient** than the business as usual operation.

On the definitions for local flexibility procurement mechanisms, the CEP states that **flexibility services** should be specified by DSOs. This specification process, however, should also consider the opinions of stakeholders and should be approved by the NRAs. The CEP also says that, where appropriate, market products should be standardized at least at national level. In this context, DSOs will have a central role in the definition of products and services.

From the revenue regulation perspective, the CEP clearly states that:

> "*Distribution system operators shall be adequately remunerated for the procurement of such services to allow them to recover at least their reasonable corresponding costs, including the necessary information and communication technology expenses and infrastructure costs."*

In summary, the DSOs should consider flexibility procurement in their network expansion planning, should have the appropriate incentives to operate networks including the procurement of local flexibility, when efficient, and should have the means to recover the cost of the flexibility activate.

Finally, on the traditional roles of DSOs, it is worth mentioning that the CEP calls for an enhanced TSO-DSO coordination. This may be seen as an expansion in the scope of DSO activities in order to account for the decentralization of the power system and the growing role of flexibility usage (instead of basing system operation on the robustness of the grid with high security margins). This necessity arises from the fact that, once DSOs become active system operators, a closer coordination will be necessary to avoid conflicts in the operation of the grids.

The E-Directive highlight the need for "*optimal utilisation of resources, to ensure the secure and efficient operation of the system and to facilitate market development*". The E-Regulation also emphasises the need for enhanced TSO-DSO coordination In Article 57, dedicated to the topic. It states that DSOs and TSOs shall "achieve coordinated access to resources such as distributed generation, energy storage or demand response that may support particular needs of both the DSO and the TSO". Therefore, in defining services and products, DSOs should also take into account the need for coordinated access to resources.

3.1.2.2. New roles for DSOs

The CEP also defines conditions for the new roles of DSOs. The relevant new roles in the context of the InteGrid project are three, namely the ownership and operation of EV charging stations, the ownership and operation of storage facilities and data management responsibilities.

The ownership and operation of EV charging station is not so central in the context of InteGrid. Nevertheless, it is worth mentioning that according to the E-Directive, DSOs should not own, develop, manage or operate EV charging station[4], in principle. An exception to this rule is when other investors or other parties do not show interest in deploying the charging stations. This condition must be reassessed periodically (at least every five years).

[4] Except when these are used for the DSO private recharging exclusively (e.g. office workers, maintenance crews, etc.).

The energy storage systems should not, in principle, be owned or operated by DSOs. The Recital 62 of the E-Directive argues that energy storage services should be market-based and competitive, and for that reason DSOs should not operate these assets. However, exceptions exist, as defined in the Article 36 of the E-Directive. Regulators can authorize DSOs to own/operate storage systems “where they are fully integrated network components”, or when public tenders are not successful in attracting investments and storage systems are necessary. If the second case applies, the regulator should monitor market conditions every 5 year, for eventually transferring the ownership and operation of storage system to independent investors.

The most relevant “new role” for InteGrid is perhaps the data management and data access. The possible roles for DSOs in these topics are relevant especially for BM3, in close connection with the grid and market-hub concept developed in InteGrid. When defining the rules for **data management,** the CEP does not impose or advocate for a specific model, and states that the data management rules and model definitions are a responsibility of the Member States.

> *Member States shall organise the management of data in order to ensure efficient and secure data access and exchange, as well as data protection and data security.*
>
> ***Independently of the data management model applied in each Member State****, the parties responsible for data management shall provide access to the data of the final customer to any eligible party, in accordance with paragraph 1.*

Therefore, we observe that the CEP leaves the data management model definition to the Member States exclusively. What the CEP does provide are guidelines on **data access.** The definitions of data access are discussed in the following subsections of this chapter, as they are equally important for the development of BM3.

3.1.3. Consumer / Flexibility Providers

The CEP is designed as a consumer-centric package, as Article 3 of the E-Directive calls for Competitive, consumer-centred, flexible and non-discriminatory electricity markets. Therefore, several are the provisions with regards to new roles and opportunities for consumers and related stakeholders. It is important to notice that the concept of consumer includes not only the final consumer, who purchases electricity for own use, but also the “active consumer”, in the terms of the CEP, which is

> *“a final customer, or a group of jointly acting final customers, who consumes or stores electricity generated within its premises located within confined boundaries or, where permitted by a Member State, within other premises, or who sells self-generated electricity or participates in flexibility or energy efficiency schemes, provided that those activities do not constitute its primary commercial or professional activity” (E-Directive, Article 2, Item 8).*

In the context of InteGrid, the active consumer is a Distribute Generation (DG) owner or a Demand Response (DR) provider, or a storage system owner/operator, or simply referred as DER.

We divide the consumer-related topics in two groups. Firstly, we analyse the topics directly related to consumers and DER. These topics include self-consumption, flexibility provision, smart metering, data access and dynamic pricing. Secondly, we look at definitions for the aggregator, with special attention to the independent aggregator, a new agent that will act as an enabler for flexibility provision, as well as how balancing market rules may be adapted.

Self-consumption: Active consumer using electricity behind the meter

An important distinction must be made between the concepts of self-generation and self-consumption. Self-generation is understood as the generation made a DG owner for the purpose of self-consumption or for selling as flexibility. Therefore, self-consumption can be defined as the part of self-consumption dedicated to internal consumption, behind the meter.

The CEP addresses mainly self-generation as a whole. Nevertheless, it also recognizes the importance of self-consumption, and acknowledges that "legal and commercial barriers exist, including, for example, disproportionate fees for internally consumed electricity, obligations to feed self-generated electricity to the energy system", and that "*such obstacles, which prevent consumers from self-generating electricity and from consuming, storing or selling self-generated electricity to the market, should be removed while it should be ensured that such consumers contribute adequately to system costs*" (E-Directive, Recital 42). In this context, the E-Directive, in its Article 49(1z), states that it is a duty of regulators to "*monitoring the removal of unjustified obstacles to and restrictions on the development of consumption of self-generated electricity*". With regard to network tariffs for self-consumption, the E-Regulation, in Article 18(2), states that "network charges shall not discriminate either positively or negatively against energy storage or aggregation and shall not create disincentives for self-generation, self-consumption or for participation in demand response."

Finally, one last aspect about self-consumption should be mentioned. The CEP makes a distinction between the "self-consumption" and the "renewables self- consumption", established in the RES-Directive. For the latter, in addition to the general objectives set by the CEP in terms of fostering DER, one aspect should be taken into account. The RES-Directive also defines the concept of the "jointly acting renewables self-consumers", meaning consumers of the same residential building that jointly own/operate DG. For this consumers, the RES-Directive states that "*Member States should therefore generally not apply charges to electricity produced and consumed within the same premises by renewables self-consumers*". However, exceptions exist. In case the renewable self-consumers benefit from support schemes, charges over self-consumption could be charged, under a series of conditions.

Energy/Flexibility provision: Active consumer injecting electricity upstream the meter

Enabling self-generators and demand response to participate in energy markets is in the centre of the CEP. The Recital 49 of the E-Directive clearly states that "all customer groups (industrial, commercial and households) should have access to the electricity markets to trade their flexibility and self-generated electricity." Moreover, it concludes by saying that "products should be defined on all electricity markets, including ancillary services and capacity markets, so as to encourage the participation of demand response". Therefore, fostering self-generation and demand response, or in other words, fostering DER flexibility provision is at the core of the CEP.

The Article 15 of the E-Directive lists a series of rights and requirements for DERs. On the rights side, DER should be able to participate in energy markets, directly or through aggregation, benefit from flexibility or energy efficiency schemes, and delegate their energy management. As requirements, they should be subject to cost-reflective, transparent and non-discriminatory network charges, and should be financially responsible for their imbalances. The same article also states that DER should not be "subject to disproportionate or discriminatory technical requirements, administrative requirements, procedures and charges, and to network charges that are not cost-reflective".

Although the CEP aims at securing important rights for DER, at least one regulatory challenge can be identified, when it is stated that DER should be "*financially responsible for the imbalances they cause in the electricity system; to that extent they shall be balance responsible parties or shall delegate their balancing responsibility*". It is not clear, however, how self-generator or demand response can be responsible for imbalances, as most of the DER units do not have individual scheduling. This problem, also known in the literature as the baseline problem, is not clearly addressed by the CEP.

One topic on self-generation, conversely, is clearly defined by the CEP, namely the phase out of net-metering schemes. After 2024, no schemes that do not account separately for the electricity fed into the grid and the electricity consumed from the grid should be granted, and consumer under net-metering should be able to change scheme. This is an important definition that affect InteGrid target countries, as discussed in the following sections.

Smart metering

The deployment of smart metering systems is an important enabler of consumer engagement in energy management and possibly in flexibility provision. As exposed in the previous deliverables D1.3 and D7.1, Member States should have a smart meter deployment strategy to cover all consumers, following a CBA for such deployment. In case of a positive CBA, massive deployment should take place, while in case of a negative CBA, Member States should re-evaluate the analysis every five years. The CEP also states that in the case of negative CBA, the consumer should be able to opt for the installation of a smart meter, provided that the consumer bears the costs.

The Article 20 of the E-Directive also mentions the important of "introducing smart metering systems that are interoperable, in particular with consumer energy management systems and with smart grids". On one hand, this is particularly relevant for the Home Energy Management System (HEMS) developed in the InteGrid project, key for the deployment of several BMs (e.g. BM1 (LV), BM4). On the other hand, interoperability is also important for innovative BMs, such as the implementation of behavioural demand response programs (BM5.2).

Data access

Article 20 of the E-Directive clearly states that consumers should have access to their metering data, clearly accounting for the energy withdrawn from the grid and the energy injected, in case of active consumers. Moreover, final consumers should be entitled to "*retrieve their metering data or transmit them to another party at no additional cost*".

Data access is a requirement not only for consumers, that will need access to their metering data for energy management purpose, but also for third parties, that may have access to metering data to offer services to consumers and other stakeholders, always provided that privacy regulation is respected. In the CEP, "*data shall be understood to include metering and consumption data as well as data required for customer switching, demand response and other services*" (E-Directive, Article 23(1)).

In this context, the CEP is also clear in saying that Member States shall ensure "*efficient and secure data access and exchange, as well as data protection and data security*" (E-Directive, Article 23(2)). Additionally, the CEP also states that data access should be provided not only to the final consumer, but also to "eligible parties". Article 23(2) states also that "*eligible parties shall have the requested data at their disposal in a non-discriminatory manner and simultaneously. Access to data shall be easy and the relevant procedures for obtaining access to data shall be made publicly available*."

It is not clear in the CEP how eligible parties will be constituted, apart from the fact that "processing of personal data within the framework of this Directive shall be carried out in accordance with Regulation (EU) 2016/679"[5] (E-Directive, Article 23(3)). Therefore, it is clear that eligible parties should be able to non-discriminatory access, and that procedures to obtaining data access should be public, but further definitions are still needed. The CEP also mentions that "*Member States shall be responsible for setting the relevant charges for access to data by eligible parties*" (E-Directive, Article 23(5)). This is relevant in the context of BM3, in which the data service provider (an eligible party, according to the CEP nomenclature) accesses metering data in order to provide services to consumers and other stakeholders. The definition of charges is also relevant for the business model of platform owners and operators (e.g. the grid and market-hub).

Tariff Design

According to the CEP, consumers should be able to opt for dynamic pricing in the case they already have smart meters installed. At least one supplier should offer dynamic pricing, and every supplier with more 200 000 final consumers should offer dynamic pricing contracts. Member States should monitor the development of these contracts and the impact they have over consumers' bills (E-Directive, Article 11). The CEP does not mention specifically dynamic pricing contracts in the case of last resort suppliers.

The E-Regulation also states the need for cost-reflective distribution tariffs. It states that:

> *Distribution tariffs may contain* ***network connection capacity*** *elements and* ***may be differentiated based on system users' consumption or generation profiles****. Where Member States have implemented the deployment of smart metering systems, regulatory authorities shall consider time-differentiated network tariffs when fixing or approving transmission tariffs and distribution tariffs or their methodologies in accordance with Article 59 of (EU) 2019/944 and,* ***where appropriate, time-differentiated network tariffs may be introduced to reflect the use of the network****, in a transparent, cost efficient and foreseeable way for the final customer.*

Therefore, the CEP acknowledges that network tariffs can be composed of a capacity term plus an energy term. The former can be differentiated according to the user, while the later, can, where appropriate, be time-differentiated to account for network use.

Finally, regarding tariff design, it is also worth mentioning that the CEP also calls for reducing the share of fixed components in electricity bill ("*where such potential exists*"). Recital 38 of the E-Regulation is clear and worth observing:

> *In order to maximise the benefits and effectiveness of dynamic electricity pricing, Member States should assess the potential for making more dynamic or* ***reducing the share of fixed components in electricity bills****, and where such potential exists, should take appropriate action.*

Aggregation

Aggregation is defined in the CEP as the "*multiple customer loads or generated electricity for sale, purchase or auction in any electricity market*" (E-Directive, Recital 18). The E-Directive also defines the concept of the

[5] Regulation (EU) 2016/679 is the General Data Protection Regulation – GDPR – in the European Union.

"independent aggregator" as the "*market participant engaged in aggregation who is not affiliated to the customer's supplier*" (E-Directive, Recital 18). Therefore, aggregation can be seen from two different perspectives. Firstly, from the retailer, that explores the flexibility of its own customers, and secondly, from the independent aggregator, a company not linked to the consumer's supplier. Both concepts are relevant in the InteGrid project, as BM5.1 refers to the aggregation carried out by the retailer, while in BM5.3 and BM5.4, it is possible that independent aggregator will be the main actor.

Demand response through aggregation is one of the topics addressed by the CEP. The E-Directive states that TSOs and DSOs should "*market participants engaged in the aggregation of demand response in a non-discriminatory manner alongside producers on the basis of their technical capabilities*" when procuring ancillary services (Article 17).

An important definition for independent aggregators is that Member States should ensure the "*right for each market participant engaged in aggregation, including independent aggregators, to enter electricity markets without the consent of other market participants*" (E-Directive, Article 17(3)). This means that independent aggregator will be able to contract DER's flexibility without entering it a contract with the DER's supplier or corresponding BRP. At the same time that this is an important definition that simplifies the operation of the independent aggregation, it also poses questions, especially because aggregators should also be responsible for imbalances they cause to the system (E-Directive, Article 17(3d)). In this context it is important to define how BRPs (e.g. suppliers) will interact and settle imbalances, without having to enter into individual agreements. For that matter, the E-Directive already mandates the creation of "*a conflict resolution mechanism between market participants engaged in aggregation and other market participants, including responsibility for imbalances*" (E-Directive, Article 17(3f)).

How this conflict resolution process will work is not completely clear. However, a few guidelines are provided by the CEP. When a BRP or supplier faces imbalance costs due to the activation of flexibility by aggregation activities, a compensation mechanism can be created. The compensation shall be limited to the imbalances created and should not create a barrier to aggregation or flexibility. The methodology for such compensation, however, is left to the Member States and NRAs.

An additional topic related to the previous one is, already mentioned briefly above, that of defining the baseline of the demand aggregator, i.e. the position with respect to which imbalances will be settled. This is particularly challenging for independent aggregators, as these may manage DER resources corresponding to more than one BRP. However, the CEP does not provide detailed guidelines in this regard.

Balancing market rules

Article 6 of the E-Regulation sets some conditions about the organization of balancing markets. Many of these changes aims at facilitating the participation of all potential flexibility providers on a level playing field and the harmonization of balancing products and market rules across Europe. Some of the most relevant conditions for the organization of balancing markets set in the E-Regulation are:

> *ensure effective non-discrimination between market participants* ***taking account of the different technical needs of the electricity system and the different technical capabilities of generation sources, energy storage and demand response****;*
>
> *ensure that services are defined in a transparent and* ***technologically neutral manner*** *and are procured in a transparent, market-based manner;*

ensure non-discriminatory access to all market participants, ***individually or through aggregation****, including for electricity generated from variable renewable energy sources, demand response and energy storage;*

It can be seen that the CEP asks Member States to ensure aggregators and demand response can participate in balancing markets in transparent and non-discriminatory. An issue that can be challenging to achieve is how to ensure that balancing products both i) take into account the needs of the system and those of flexibility providers, and ii) are technology neutral. In practice, the needs of some flexibility providers (e.g. long-term procurement, or large bidding blocks) may not fit within the system needs, or the technical capabilities of different flexibility providers may clash among them.

In relation to this, the E-Regulation provides some further details on how balancing market rules should evolve. These include the condition that the "*price for balancing energy price shall not be pre-determined in contracts for balancing capacity*" and that "*the procurement of upward balancing capacity and downward balancing capacity shall be carried out separately.* Nonetheless, NRAs may decide not comply with these conditions, if an alternative is proven more efficient based on an evaluation by the TSO. Additionally, the E-Regulation states that the procurement of balancing capacity no longer than on a day-ahead basis and the contracting period should not be longer than one day. In the latter case, even if the National Regulatory Authority (NRA) decides to derogate this condition, the E-regulation sets upper bounds for the amount of contracting capacity that may be procured in the long-term or with contracting periods longer than one day.

3.1.4. Impact to InteGrid BMs and Implementation challenges

The abovementioned topics will all have an impact to InteGrid BMs, as already identified in Table 4. However, the impact of such topics varies. Some are more relevant than other for certain BMs and for the project as a whole. Also, the level of clarity on the way these regulatory topics will be implemented are not homogeneous either. The implementation of certain regulatory topics is clearly defined in the CEP, while for other it is left for further definitions, often to be done at the national level. Therefore, in the context of the regulatory recommendation provided in this report, addressed in the following chapters, it is important to understand where the CEP already provide ready-to-implement regulatory solutions, and where national regulator will have to develop their own frameworks.

Table 5 summarizes the main discussions on the CEP, as well as the level of relevance for the different BMs. It also shows the level of readiness for implementation of the different regulatory topics.

Table 5: CEP assessment

Actor	Topic	Sub-Topic	What does the CEP say?	BMs Affected	How clear is its implementation?
DSO	Core activities of DSOs	Network Planning	- DSOs should produce development plans that go through public consultation, are approved by NRAs and are made public so grid users have the necessary information to decide on new grid connections. - DSOs should demonstrate the expected usage of flexibility and the respective deferred investment. - DSOs should have the proper economic incentives to procure flexibility.	BM1: Medium impact - Although the BM1 (HLUC01 and 02) does not consider planning, it will be affected if previous actions are not taken, such as having the proper incentives and accounting for the flexibility to be used in the short-term.	Not completely clear: The CEP is precise on the requirements for planning consultation and publication. However, it doesn't provide important details on how the NRA evaluates and approves the development plan, for instance.
		Network Operation: Use of Flexibility	- DSOs should have the means to procure flexibility (incentives and cost recovery) - DSOs should design non-discriminatory, transparent, and market-based mechanisms for flexibility procurement. The flexibility products ought to be standardized at national level.	BM1: High impact - It is the core of the BM. BM4.1: Medium impact - Impacts industrial consumers that may offer flexibility to DSO. BM5: Medium impact - Impacts the Technical VPP concept.	Unclear: The CEP does not clarify which could be the market-based mechanisms that could be used or how flexibility products could be standardized.
		TSO-DSO Coordination	- TSO-DSO coordination and data exchange must be enhanced in order to allow both TSOs and DSOs to procure flexibility resources at the distribution grid without causing congestions	BM1: Medium Impact - Flexibility usage by the DSO is impacted by TSO-DSO coordination BM4: Medium Impact - Active consumers providing flexibility are also impacted by TSO-DSO coordination BM5: High Impact - TSO-DSO is fundamental for the operation of tVPP and cVPP	Unclear: The CEP only defines that TSO-DSO coordination and information exchange must be enhanced, but not how.
	Innovative Roles of DSOs	EV charging stations	- DSOs should not be allowed to own and operate EV charging stations (with exceptions)	Not directly impacting InteGrid BMs.	Room for interpretation: The CEP is clear in its general direction, but the exceptions could give room for interpretation.
		Storage facilities	- DSOs should not be allowed to own and operate storage systems (with exceptions)	Not directly impacting InteGrid BMs.	Room for interpretation: The CEP is clear in its general direction, but the exceptions could give room for interpretation.
		Data management	- The CEP does not define a preferred data-management model. - Independently of the data management model, data access should be granted to consumers and eligible parties, provided that privacy regulation is complied with.	BM3: High impact - How data is management and accessed is in the core of BM3	Unclear: The CEP is absent in defining a data management model. This can lead to important differences for BM3.

Consumer/ Flexibility Providers	Consumers	Self-consumption (Active consumer using electricity behind the meter)	- Active consumers should be able to store and consume self-generated electricity without barriers. - Nevertheless, charges can applicable in the case of renewable self-consumption that benefits from support schemes.	BM4.2: High impact - Especially relevant for the residential consumer trying to reduce the electricity bill by deploying DG for self-consumption.	Clear instructions: Active consumers should be able to store and consumer self-generated electricity without disproportionate fees and should not be obliged to feed self-generated electricity to the grid
		Energy/Flexibility provision (Active consumer injecting electricity upstream the meter)	- Active consumers, demand response, and aggregated active consumers should be able to participate in all electricity markets, including ancillary services and capacity markets.	BM4.2: Medium impact BM5: High impact - The ability of active consumers to participate in electricity markets is key for both the VPP and for the retailer's imbalance minimization. BM2: High impact - DSOs depend on active consumers to provide flexibility.	Unclear: It is unclear how to adapt products and services in order to enable the integration of active consumers. Although the CEP is unclear, some answers may come from the Network Codes. E.g.: balancing capacity should be procured separately (upward and downward). This enables demand response participation.
		Smart metering system	- DSOs should deploy smart meters in case of a positive CBA. - In case of a negative CBA, MSs should review calculations periodically. - Even in case of a negative CBA, consumers are entitled to request a smart meter.	Smart meters are essential to most BMs BM4: High Impact BM5: Medium/high impact BM3: High impact BM1: Medium impact	Clear instructions: The CEP is clear in its smart metering view. Nevertheless, a challenge still exists in the case of negative CBA (Portugal). Maybe pilots could help countries with negative CBA to reach a deployment policy.
		Data access	- Metering and consumption data should be accessible by consumers and eligible parties in a non-discriminatory way. - MSs should define the charge applied to eligible parties for data access.	BM3: High impact - Same as for data management, data access is key for BM3	Not so clear: It is not clear how third parties can have access to public data while complying with privacy regulation.
		Dynamic pricing	- Consumers should be able to opt for dynamic electricity prices. - Network charges should be designed in a time-of-use fashion, and where appropriate, should reflect the use of the network. - MSs should reduce the fixed part of the electricity bill.	BM4: High/medium impact	Clear for retail electricity prices. Not so clear for network tariffs: defining network tariffs that reflect the usage of the network is not straightforward.
	New agents	Aggregators	- Aggregators should be able to participate in electricity markets without the consent of other market participants. Moreover, consumers should also be able to sign contracts with aggregators without the supplier's consent. - Compensation mechanisms may be put in place to settle imbalances caused by one agent to another (e.g. an aggregator that causes an imbalance to a supplier)	BM5: Medium impact* * In the case a tVPP or cVPP is operated by an independent aggregator.	Unclear: Important questions have yet to be answered regarding the BRP/Ind.Aggregator settlement.

		Balancing market rules	- non-discrimination between market participants taking account technical system needs and the technical capabilities of all providers; - services defined in a transparent and technologically neutral manner - non-discriminatory access to all market participants, individually or through aggregation - Price for balancing energy price not pre-determined in contracts for balancing capacity - Procure separately upward and downward balancing capacity - Procure balancing capacity no longer than on a day-ahead basis with contracting periods no longer than one day.	BM5: High impact	Clear instructions about the pricing and procurement rules addressed in the E-Regulation Not so clear on how to completely remove all barriers to the participation of all flexibility service providers or how to ensure that balancing products are completely technology-neutral.

3.2. Alignment with National Energy and Climate Plans

The National Energy and Climate Plans are 10-year integrated elaborated by each Member State setting the strategies for achieving the EU's energy and climate target for 2030. These high-level documents are important also for regulatory recommendations provided by this deliverable. The analysis of the NECPs shows the countries' intentions in different topics that may be relevant for InteGrid BMs. However, it is worth mentioning that these documents are high-level proposals that do not necessarily aim at addressing the topics directly connected to distribution-side stakeholders. Some NECP do cover some topics relevant for the InteGrid project specifically, while others are more focused to other types of energy and climate policy, outside the scope of this project.

This subsection presents an overview of the main relevant topics for InteGrid BMs addressed in the draft of the NECPs[6].

Austria

One of the priorities mentioned in the Austrian NECP is the alignment of grid planning and renewables investments. This is mostly relevant at transmission level but could be translated to distribution grid.

> *Synchronise grid development with the development of renewable energy*
>
> *The investments made by grid operators make them key enablers for investments in renewable energy. **Grid development and the development of renewable energies must take place systemically**. Synchronicity and overall planning will bring about security of supply and planning security, as well as saving costs.*

This is especially relevant for BM2, and in line with the provisions on the CEP regarding network expansion planning and the consideration of flexibility usage.

The Austrian NECP also states the need for eliminating barriers to distributed resources, including storage. This is relevant for almost all BMs.

> *Facilitate local networks and storage facility operators*
>
> *In order to strengthen the market, regulatory barriers to local initiatives in the production, distribution and storage of electricity and heat should be gradually eliminated.*

The need for less distorted price signals is also acknowledged. This topic is especially relevant for BM4, in order to foster consumer side energy management and flexibility provision.

> *Successful transformation of the energy system depends on support for price incentives, energy efficiency and use of renewable energy sources. Competitive pricing mechanisms that take account of tax, duty*

[6] At the writing of this section, not all final versions were published yet, and some were only available in the Member States' official language. Therefore, this section discusses the drafts, available at the time of writing. All drafts can be found in https://ec.europa.eu/energy/topics/energy-strategy/national-energy-climate-plans_en

and incentives will be used to minimise market distortions. Households, commerce and industry will be able to participate actively in the energy market and to react to price signals.

If the electricity supply is to be based on renewable energy sources by 2030, functioning, cross-border, liquid wholesale markets and common price zones are needed in order to generate the necessary price signals. The required investments will need to be financed primarily via the market. Market-distorting incentives that conflict with the decarbonisation pathway must be minimised, and undistorted, competitive pricing mechanisms must be (re-)established.

Finally, another statement worth mentioning is the updated plans of smart metering deployment, important for all BMs.

In Austria, in December 2017, the 2012 Ordinance on the introduction of smart meters (Intelligente Messgeräte-Einführungsverordnung, IME-VO) was amended. The objective is to provide smart meters to at least 80 % of Austrian electricity customers by the end of 2020 and, where technically feasible, to at least 95 % by the end of 2022.

Spain

The Spanish NECP addresses several relevant topics for InteGrid's BMs. Starting with the acknowledgement of the importance of demand response, the NECP identifies the need for measures to foster aggregation and local energy communities. It also recognizes the importance of the industrial consumers for demand response.

The Integrated National Energy and Climate Plan 2021-2030 proposes instruments and measures to facilitate and reinforce the role of local energy communities and the emergence of new players in the energy transition, as well as guaranteeing the right of access to energy.

Demand management enables both greater variability in electricity generation to be accommodated and alternative mechanisms to be provided for the stability of a system with an ever-lower degree of inertia as a result of the departure of thermal power station. The industrial sector plays a significant role in this respect, given that it is a major energy consumer.

At the same time, the new figure of the demand aggregator will enable participation of the tertiary and residential sectors in providing services to the system, participation in providing services to the system via remuneration aggregators, and therefore the possibility of new

On the practical side, Measure 1.3 of the NECP proposes the facilitation of delegating energy management to third-parties.

Under this model, specialised companies invest in self-consumption facilities and maintain them, selling the energy produced to the consumers under favourable terms. This avoids the consumer company, family or administration having to make an investment in or take charge of an activity of which they have no experience.

Industrial consumers are also included in the measures foreseen by the NECP. Support for industries to adopt renewable energies are proposed.

Aid programmes to incorporate renewable energies into industrial processes.

Aid lines for industries or the heating networks that supply them, depending on the potential, cost and characteristics of the technology and the potential improvement in their carbon footprint.

Finally, Measure 1.12 specifically addresses the need for data access and sharing with eligible parties. It is a very relevant proposal from the Spanish NECP for the development of BM3, as it also recognizes the need for data access for the "development of new services to facilitate decarbonization".

Access to information on consumption

Giving the public and the productive sectors easy and instant access to their energy consumption data, as well as the opportunity to share this information with third parties, is necessary in order to harness the potential of energy management, the drive for self-consumption and the development of new services to facilitate decarbonisation.

Portugal

The draft of the Portuguese NECP is not so comprehensive in terms of topics that concern InteGrid BMs. In fact, on the section of the NECP dedicated to the describe actions related to fostering demand response and aggregation, the Portuguese NECP simply states "Nothing to note at this stage of development in the NECP."

Where applicable, national objectives related to the non-discriminatory participation of renewable energy, demand response and storage, including via aggregation, in all energy markets, including a timeframe for when the objectives are to be met

Nothing to note at this stage of development in the NECP.

Nevertheless, the NECP mentions the pilot program for demand-side participation in the tertiary regulation market.

In February 2018, ERSE approved the rules for implementing, as of 1 June 2018, two pilot-projects, including the introduction of dynamic tariffs for access network access in mainland Portugal.

Participation in the pilot-projects, intended only for industrial consumers, is voluntary and will cover 100 consumers per pilot-project, over 12 months. Based on the results of the pilot-projects, ERSE will conduct a cost-benefit analysis to assess the merits for the electricity system and the possible setting of specific targets for installing smart meters.

Slovenia

The Slovenian NECP is also limited in relevance for specific InteGrid topics. There is however an acknowledgement on the importance of smart grids and storage in order to enable high shares of DG.

At the same time, the development of intelligent networks will enable active role of consumers and increased utilization of RES at the local level. Since energy produced from RES is volatile within a given time-frame and is not responsive to the needs of consumers, the mass utilization of such energy in the coming period will require infrastructure that is sufficiently efficient and advanced managed, and high capacity converters for energy surpluses produced to be converted into other useful forms of energy or energy products, the storage of which in high quantities will be cheaper.

Transition to a low-carbon society will be supported also by inclusion of innovative, even cleaner energy sources as soon as the solutions are considered technologically mature (ReEKS Motion, paragraph 52).

Sweden

The Swedish NECP mentions support schemes for DG as measures being taken to contribute the 2030 renewable target of the EU. Among the mechanisms, the tax reduction for DG, and tax reduction for self-generation are mentioned. The NECP also mentions an exception from network charges for self- generation fed into to grid.

Exceptions from the network charge

Electricity prosumers feeding in less electricity into the grid than what they purchase on a yearly basis are exempted from the network charge for the electricity they feed in. Examples of electricity users covered by the exemption are farms with small wind turbines and buildings with solar power systems on the roof.

Moreover, the Swedish NECP states the measures being taken for the integration of demand response in energy markets.

The Swedish Energy Markets Inspectorate has developed an action plan in which a number of measures to achieve increased demand response are identified. The measures consist of proposals for new or amended regulations, knowledge-enhancing efforts, government assignments and cooperation between authorities and other stakeholders to create long-term conditions and rules. The measures focus primarily on household customers as they have a high potential for demand response that is not taken advantage of today.

Svenska kraftnät also works with these issues mainly through European and Nordic cooperation projects. Among these the following can be mentioned: - Adapting the mFRR market to better fit consumption flexibility (e.g. in terms of bid size). - Active cooperation with Nordic TSOs to review the price signals that the regulatory framework for the balancing market and imbalance fees give to market participants.

Summary of the NECPs

Table 6 presents an overview of the NECP in the five target countries and the relevant topics for the different BMs.

Table 6: Summary of NECPs

Country	Topic	BMs affected
	Mention on the alignment of grid planning and renewables. Mostly at transmission level, but could be translated to distribution	BM1
	Mentions the need to eliminate barriers to distributed resources	BM1, BM4, BM5
	Mentions the need for non-distorted price signals	BM4
	Mentions the amendment of the smart meter rollout plan, with an expected deployment of 95% by the end of 2022	BM1, BM3, BM4, BM5
	Mentions the need to foster demand response and aggregation	BM1, BM4, BM5
	Proposes management by third parties or the energy services model	BM4, BM5
	Proposes an aid programmes to incorporate renewable energies into industrial processes	BM4
	Proposes access to information on consumption	BM3, BM4, BM5
	Highlights the pilot project on industrial demand-response participation in balancing markets	BM4
	Mentions the need to develop intelligent networks to enable the active role of consumers and increased utilization of RES at the local level	BM1, BM2, BM4
	Mentions tax relieves for micro-DG	BM4
	Mentions tax exemption for micro-production of renewable electricity consumed at the place of production	BM4
	Mentions exceptions from the network charge	BM4
	Proposes a plan to increase demand response	BM1, BM4, BM5

4. Regulatory barriers for InteGrid BMs

In this section, the main regulatory barriers for the development of InteGrid BMs in the target countries are identified. These barriers are organized in different topics and sub-topics. For each sub-topic, a list of barriers is identified, and rated according to relevance for each BM.

The first group of barriers is related to the economic regulation of DSOs. This group of composed on topics regarding revenue regulation and specific output-based incentives. The former is especially relevant for BM1, and eventually BM2. For BM1, DSOs will have to (i) be able to recover the costs of flexibility procurement and (ii) have economic incentives to procure flexibility and therefore defer investments. For BM2, revenue regulation is also important, as it may incentivize (or not) the extension of network assets life. DSO revenue regulation is also indirectly relevant to BM4 and, especially, BM5, since end users and flexibility providers may not provide services to DSOs if these are not willing to procure them.

Output based incentives may also provide important incentives for DSOs to use flexibility (BM1) and to deploy fault locator and adopt predictive maintenance (BM2). For instance, incentives for the reduction of energy losses may promote or hamper the use of flexibility by DSOs depending on their design. On the other hand, output-based incentives for continuity of supply will play an important role in promoting BM2, given that this is one of the key goals pursued by this BM.

The incentives for innovation have been included within this category of output-based incentives. For the sake of simplicity, both the regulatory incentives for DSOs to implement pilot projects that are embedded in network regulation, and the possibility to request regulatory sandboxes, which do not involve necessarily only the DSO, have been included in this barrier. Thus, those BMs that are not permitted under current regulation are given a high relevance, i.e. the procurement of flexibility by DSOs (BM1), or the participation of demand in balancing markets (BM3). In terms of relevance, the next BMs would be those that, even if not directly prohibited by regulation, are seriously limited or hampered unless sandboxes were a possibility, e.g. the possibility to exchange data from a sample of consumers to test innovative platforms or data services (BM3), or the chance to test innovative tariff schemes on a small group of consumers (BM4). Lastly, BM2 may require some DSOs to carry out pilots (no sandbox required) in order to test some innovative grid management solutions.

The DSOs roles other than network planning and operation are also relevant in the context of InteGrid. In particular, the rules for network access and connection can have an impact on the viability of BMs based on the adoption of certain DER technologies. Broadly speaking, transparent, efficient and predictable network access rules are necessary to enable DER adoption by end users (BM4) or to ensure a swift and economic integration of DG-RES into the grid. Moreover, the incentives for DSOs to reduce network costs by using flexibility can also depend on the approach followed to compute the connection charges or how grid access is granted (BM1), i.e. on a firm basis or if some flexible access is possible. For example, deep connection charges, i.e. the new user pays for the direct cost of connection plus all the additional adaptations and/or reinforcements in the upstream grid, would eliminate any incentive for DSOs to defer grid investments as this would be paid by grid users.

Moreover, under the “other roles of DSOs” category is the ownership and operation of storage by DSOs. This topic, although not central to InteGrid BMs, could be relevant for BM1 and BM2, as these assets may help the DSO to replace conventional investments. As discussed in section 3.1.2, NRAs may allow DSOs to own and operate storage systems, presumably as part of their regulatory asset base (RAB). This possibility would facilitate the access to flexibility by DSOs, but would probably lead to underutilized storage assets as grid support may be required for a limited amount of time (especially if stationary systems are installed). Additionally, DSO storage ownership may reduce the liquidity in local flexibility markets.

A central regulatory topic for InteGrid though is the existence of local flexibility mechanisms in which DSOs are able to procure the flexibility they need for BM1, and aggregators and customers are able to offer and trade flexibility (BM4 and BM5). Moreover, the existence and design of these mechanisms is also relevant to BM3, where local flexibility platforms are included (in addition to data services and data exchange platforms, as discussed below).

Within InteGrid, aggregators and customers do not only offer flexibility to DSOs, through the concept of the tVPP, but also to TSOs, through the cVPP. Moreover, BM5 also addresses the possibility of a retailer aggregating the demand flexibility of commercial buildings to provide balancing services to the TSO. Nonetheless, balancing markets today may not be open to demand-side bidding and, even if they were, their rules and requirements are generally poorly adapted for the technical characteristics of demand response. This effectively hampers the development of BM5 (and to a lesser extend BM4) and ultimately hampers competition and efficiency in balancing markets. Moreover, the lack of clear rules to perform the aggregation activity (e.g. types of resources aggregated, balancing responsibility allocation, baseline determination, etc.), particularly as an independent aggregator, may block some aspects of BM5.

From the perspective of the consumers, more specifically the residential consumers, topics on tariff design and rules on self-consumption may have an important impact over their ability and incentives to adopt the solutions proposed by BM4. Tariff design (e.g. flat vs dynamic, local or time granularity, etc.) and the weight of regulated charges may jeopardize potential gains they may have from adopting energy management solutions (e.g. adopting the HEMS). The design of the tariff system can also affect BM5, particularly where asymmetric charges between generation and demand, or between resources connected at transmission and distribution level, can affect the competition among resources when providing flexibility services. Additionally, certain rules on self-consumption may limit the incentives for DG installation, and therefore limits the flexibility potential as well.

Another essential topic not only for BM4, but for almost all BMs is the deployment of smart meters and the functionalities they provide. In the absence of smart meters, many Integrid solutions would simply not be possible. These range from the use of demand response to support LV grid operation (BM1), enable end-user cost reductions through advanced tariff schemes and energy management systems (BM4), or the exchange of data through transparent and non-discriminatory platform-based system to provide data services to different stakeholders (BM3).

Finally, the last group of regulatory topics identified for this analysis is on data management. The definition of the data management model, as well as the rules on data access are crucial for the functioning of BM3.

Table 7 presents a complete picture of this barrier assessment and a mapping between regulatory barriers and Integrid BMs (as defined in section 2), where a rating “1” means a low importance of the barrier for the development of the BM, and “3” means a high relevance for that BM.

Table 7: Regulatory barriers for InteGrid's BMs (0 no relevance, 1 small relevance, 2 relevant, 3 very relevant)

Topic	Sub-Topic	Identified Barrier	BM1	BM2	BM3	BM4	BM5
DSO Economic regulation	Revenue Regulation	Lack of incentives for DER flexibility procurement due to asymmetries between the treatment of CAPEX and OPEX which favour the former over the latter	3	0		1	2
		Lack of incentives to extend the useful life of network assets beyond their regulatory lives		3			
		DSO revenue regulation does not remunerate the cost of new "distribution services" i.e. management of the grid using flexibility	3			1	1
		Allowed revenues based in past investment/costs only, without taking into account future investment needs, including DER	2				
		DSO are not required to submit long-term investment plans and/or it is not clear how these are reflected into their allowed revenues	3	2			1
		New smart grid technologies, beyond pilot projects, are not considered in the remuneration of DSOs	3	3			
	Other output based incentives	Incentives for the reduction of energy losses are not in place or provide weak incentives (low-powered incentive, deadbands, non-symmetric designs, cap and floors)	2				
		Output-based incentives for continuity of supply are not in place or provide weak incentives (low-powered incentive, deadbands, non-symmetric designs, cap and floors)		3			
		Energy losses incentives do not consider the impact of DER and smart grid technologies	2				
		Reference values for reliability indices based exclusively on historical values, cost-benefit analyses that allow continuous improvements are not being carried out		3			
		Equal treatment of planned and unplanned interruptions or stringent requirements to qualify as planned interruption		3			
		Lack of incentives for innovation and experimentation, including the possibility of requesting regulatory sandboxes	3	1	2	2	3
Other roles of DSOs	Network access and connection	System users do not have appropriate information regarding expected expansions or upgrades due to new connections (degree of detail of the expansion plans). Lack of transparency on available grid capacity for new DER				1	2
		Deep connection charges are a barrier for the connection of DG, particularly small units.	2			2	1
		Lack of transparency in the calculation of grid connection charges	2			2	1

	Ownership of storage	Unclear regulation on the ownership of storage systems by DSOs	1				
Local flexibility markets/services	Mechanism to provide local flexibility	Mechanisms for local flexibility procurement and provision (local markets, non-firm access, agreements DSO-DER) are not implemented	3		3	1	2
		Lack of regulation for the coordination between TSO and DSO for the provision of ancillary services by DER	2		2	1	2
Balancing Markets	Balancing services	Balancing markets not open to demand, included the one connected at distribution level, or balancing products not suited for demand-side resources				1	3
		Balancing market access and product definition not suited for DER (minimum sizes, design of deviation penalties, upwards and downwards allocated together, dual imbalance pricing)				1	3
		Barriers to the development of the aggregation activity					3
		Barrier for the aggregation of different DER types					3
		Barriers to independent aggregation (e.g. balancing responsibility)					3
Tariffs and self-consumption	Retail tariff design (regulated charges)	Regulated charges show no or little time discrimination; structure inappropriate to promote flexibility	1			3	2
		Tariff design: high share of taxes and other regulated costs may kill other price signals	1			3	2
	Self-consumption and metering	Self-consumption not permitted or facing relevant barriers (administrative, economic, technical)				2	
		Inefficient incentives for self-consumption that hamper flexibility: net-metering permitted, large share of regulated costs charged through a volumetric component				2	
		Insufficient smart meter capabilities	2		3	3	2
		Lack of a clear framework for the deployment of smart meters (technical requirements, accessibility)	2		3	3	2
Data Management	Data Management	Lack of definition on the data-management model			3		
		Barriers to grant access to metering data to third-parties, whilst complying with GDPR requirements			3		

5. Country Assessment

In this section, a country assessment of the regulatory barrier identified in section 4 is made. This country assessment follows the same methodologic approach proposed in the deliverable D8.2. Considering the identified barriers, national regulatory frameworks are reviewed in order to assess the presence of each barrier in each country. To help this analysis, **key questions** were prepared, as well as a scoring criteria. This approach aims at providing not only a more specific guideline assessment of the barriers, but also to seek comparability among the different countries.

A "maturity level" rank was created based on how well adapted current regulation is to enable and promote the implementation of each one of the BMs. This definition is shown in Table 8. Next, for each of the regulatory barriers, the maturity level of existing regulation was assessed based on the key regulatory questions.

Table 8: Definition of regulatory maturity levels considered for country assessment

Maturity level	Description
0	Current regulation prohibits or prevents implementation
1	Current regulation does not explicitly prohibit/prevent implementation, but fails to promote it effectively
2	Current regulation enables implementation, but regulation is still immature
3	Current regulation enables implementation and some advanced regulation in place, but still not fully developed
4	Regulation enables and promotes implementation

Part of the regulatory barriers identified in the section 4 was already made in deliverable D8.3, within the regulatory replicability analysis. Therefore, the main focus of this section is to discuss the barriers that were not discussed in that report.

The sources used for this assessment are mainly three. Firstly, the work presented in deliverables D1.3 and D7.1 are the starting point for this analysis. They offer a comprehensive overview for the five InteGrid target countries, in addition to the internal questionnaires circulated in which these deliverables are based on. Secondly, reports and surveys elaborated by recognized European institutions are also used, such as ACER or CEER. Thirdly, and the most import source, the regulations in the different countries published by NRAs, laws, public consultations, and documentation on national pilots.

The discussion on the regulatory barriers follows a question and answer approach. Having as a starting point the questions elaborated for each regulatory barrier, this sections aims at assessing them in the five target countries, in order to inform the regulatory recommendations in section 6.

5.1. DSO revenue regulation

Revenue regulation for DSOs is a topic that can impact all BMs to some extent. However, it is noticeably more relevant in the context of BM1 and BM2. Especially for the former, revenue regulation can play an important role in enabling the flexibility procurement at the exchange of deferred investments. In order for that to happen, however, an adaptation of the traditional CAPEX[7]-oriented remuneration formulas may be necessary. In this subsection, we analyse how DSO revenue regulation are set in the five target countries and what are the impacts for the adoption of the different BMs.

Considering that this topic was extensively discussed and evaluated in the Deliverable 8.2, the country assessment carried out for that deliverable is presented below.

Portugal

The Portuguese regulatory framework in the last regulatory period for HV and MV distribution is based on a rate of return regulation for CAPEX and a price cap regulation for OPEX[8], i.e. cost reduction targets are set on OPEX whilst a cost of service approach is retained for CAPEX. The path of allowed OPEX is set every three years, being the efficiency requirements determined through a DEA benchmarking and complemented with the Malmquist Index. On the contrary, CAPEX is updated annually according to actual investments. In the case of the LV grid, a TOTEX approach is followed, by which all costs (except concession rents and workforce restructuring plans) are subject to an efficiency target.

Regarding the inclusion of new investments in the RAB, in addition to the values sent by the companies each year, the NRA also takes into account the Development and Investment Plan prepared by the DSO, which is focused on the HV/MV distribution networks. The DSO must submit a 5-year HV and MV investment plan, every two years, to DGEG (technical regulatory body dependent on the government) and ERSE for evaluation and subsequent approval by the Portuguese parliament and the Portuguese government. In the case of the LV grid, the DSO submits a LV plan every year to the regulator.

The impact of DER penetration on grid costs is taken into account when investment plans are made. Additionally, the Portuguese regulation includes an incentive for the DSO to deploy innovation projects. In case these projects are approved by the regulator, the DSO would receive 50% of their annual benefits up to 1.5% of their investment, for 6 years. This type of incentive is enabled when CAPEX is regulated under a cost of service regulation.

It is important to notice that in Portugal the Law 8/2012 forbids utilities from applying consumers any charge related to meters. This is an important barrier to the definition and stabilization of a clear incentive mechanism to the deployment of smart metering in Portugal.

Slovenia

A revenue cap methodology is allegedly in force for OPEX and CAPEX. However, both cost components are calculated and regulated separately. A benchmarking analysis is used to determine DSOs eligible costs.

[7] Capital expenditure
[8] Operational expenditure

CAPEX allowances are based on the investment plans submitted by DSOs. For every year, the deviations between approved investment plans and actual investments must be explained, including the causes for these deviations e.g. insufficient financial resources, long procedures for the preparation and collection of the investment documentation, etc. The Ministry of Infrastructure is the institution that accepts and confirms the plans.

The Slovenian regulation includes financial incentives for the deployment of smart grid solutions, provided the corresponding projects comply with a set of criteria defined in the regulation. Eligible projects include investment projects that aim to promote an efficient development of networks whose total investment value exceeds 200.000 €, as well as pilot addressing the integration of new technologies and services in the area of smart grids and related market mechanisms. A project that is included under this scheme is credited with a one-off incentive of 3% of the carrying amount of the asset as at 31 December of the year in which the asset entered in operation. The sum of the incentives is capped to 10% of the reported net benefits of the whole project.

Sweden

The regulatory model of Sweden is structured on the different cost items. First, a separate assessment of CAPEX and OPEX is made, being in turn the latter divided into controllable and non-controllable cost. An efficiency target, computed through a DEA (Data Envelopment Analysis) benchmarking study, reduces the controllable cost year by year. This efficiency gain is at least 1% per year during each 4-year regulatory period. In the next regulatory period, a new benchmarking study is performed based on actual OPEX the previous 4 year period.

This requirement on higher productivity is not applied for the non-controllable cost. The RAB is computed as the replacement value of existing assets. The allowed revenue is adjusted after the 4-year regulation period due to deviations between prognoses and realized values for investments, disposal and non-controllable costs. The regulatory rate of return is determined as the WACC[9].

DSOs periodically submit investment plans to the regulator. However, these are just indicative as the RAB is updated based on actual investments and depreciation after each 4-year regulatory period by the regulator.

The Swedish regulation does not include specific incentives for the deployment of smart grid solutions, although ICT-related CAPEX is handled as any other cost with a depreciation time of 12 years. Related OPEX can be recovered in the next regulatory period, although efficiency requirements would apply to these.

Spain

DSOs in Spain are under a revenue cap regulation with six-year periods, being the current one 2020-2025[10]. CAPEX and OPEX remuneration are calculated separately considering the information reported by DSOs and a set of tables of standard costs for different asset categories. Deviations between standard and actual costs

[9] In the regulatory period starting in 2020, CAPEX remuneration is expected to decline significantly due to the introduction of longer depreciation times and a lower regulatory WACC.

[10] A set of amendments to the DSO revenue regulation was approved at the end of 2019 (Circular 1/2019) and it will be applied for the first time in the period 2020-2025. Despite the fact that the overall revenue regulation model was not changed, this piece of regulation modified several aspects of DSO regulation that are relevant to InteGrid.

are capped and these must be justified if they exceed a certain threshold. The remuneration is therefore largely proportional to the volume of investments made by the DSO. New distribution investments are included into the RAB and start to be remunerated with a delay of two years, i.e. assets put into service in year n-2 start are included in the remuneration of year n. The rate of return is determined following the WACC approach.

DSOs must submit every year an investment plan for the next 4 years, which are reviewed and eventually approved by the NRA and other authorities. A cap on the overall volume of investments is set according to the finally approved investment plan; upwards deviations may result in a lower CAPEX remuneration for the investment costs that exceed the allowed investment cap. This reduced remuneration applies throughout the whole useful life of the assets. Compliance with the investment plans and the corresponding investment limits is checked every three years, i.e. twice during each regulatory period.

The recently passed regulation introduces two mechanisms to promote smart grid solutions. Firstly, the regulation defines the category of “type 2” investments, which correspond to investments in network automation and digitalization required to support the energy transition. These investments are added to the RAB at their actual cost provided that they fall within one of the smart grid asset categories defined by the regulator. Additionally, DSOs are entitled to passed-through to their allowed revenues the cost of pilot projects, both CAPEX and OPEX, subject to the submission of a CBA and the approval of the regulator. The cost of these pilot projects will not be considered within the abovementioned investment limits.

In Spain utilities can apply consumers monthly rents on the meters during the lifetime of such equipment. Spanish utilities were offered an incentive for them to ensure the roll-out of smart metering until the end of 2018. Such incentive consisted in an increased value of such monthly rent applied to the meters.

Austria

Austrian DSOs are subject to an incentive regulation scheme for OPEX and a hybrid scheme for CAPEX. Allowed OPEX in the base year, i.e. the one considered for the price review, are adjusted according to a cost path determined taking into account both general and individual benchmarking-based productivity targets, as well as inflation. Regarding CAPEX, investments within a regulatory period are added to the RAB with a two-year delay, without any assessments about cost efficiency or usefulness. However, investments will be part of the TOTEX cost base considered in the benchmarking studies performed in the subsequent price review. The results of this analysis will affect the individual productivity factor and the opening RAB of the next regulatory period. Thus, this may be considered a hybrid regulatory scheme between cost of service and incentive regulation.

DSOs do not submit investment plans. Excessive investments are prevented through the continuous TOTEX benchmarking process described above.

The Austria regulation does not present any specific incentives for the deployment of smart grids. Nonetheless, investments are not distinguished between innovative or conventional solutions; thus, DSOs, in principle, could include them in their declared costs to the regulator.

Summary

Considering the conditions described in each of the countries, Table 9 summarizes the importance of each barrier related to DSO revenue regulation.

Table 9: Country assessment of DSO revenue regulation

Identified Barrier	Guiding Question	AT	ES	PT	SE	SI
Lack of incentives for DER flexibility procurement due to asymmetries between the treatment of CAPEX and OPEX which favour the former over the latter	Would DSOs benefit from using flexibility to defer or avoid grid investments?	3	1	3	1	1
DSO revenue regulation does not remunerate the cost of new "distribution services" i.e. management of the grid using flexibility	Would DSOs recover the costs associated with the use of flexibility?	2	3	2	1	2
Allowed revenues based in past investment/costs only, without taking into account future investment needs, including DER	Do regulators use forward-looking tools/scenarios to assess investment needs and/or allowed revenues?	1	3	2	1	2
DSO are not required to submit long-term investment plans and/or it is not clear how these are reflected into their allowed revenues	Do DSOs and regulators adopt a long-term vision for grid development/regulation, including the use of flexibilities?	1	2	1	1	2
New smart grid technologies, beyond pilot projects, are not considered in the remuneration of DSOs	Would DSOs recover the costs associated with smart grid technologies deployment beyond pilot projects?	2	3	2	3	3

5.2. Energy losses incentives

The use of flexibility to support MV or LV grid operation mainly aims at solving potential or detected grid constraints and, in the long-term, defer or avoid new grid reinforcements. However, these functionalities will also affect technical network losses as a result of changes in the active and reactive power flows through the network. The financial exposure of DSOs to changes in network losses depends on the regulatory framework. DSO regulation, particularly after the implementation of incentive-based regulation schemes, frequently presents ad-hoc incentive mechanisms to encourage DSOs to reduce network losses.

Thus, it is relevant to assess whether adequate economic incentives to reduce network losses are in place in each country and whether these incentives are strong enough. Additionally, it is important to assess whether losses incentives already consider the effect of DER flexibility or not. The situation in the InteGrid target countries is as follows:

Portugal

A symmetric bonus-malus scheme with a deadband around the reference value is in place. The value of this incentive is also subject to a cap and floor values. The regulator sets for every year within a regulatory period the economic value of losses, the reference level and the cap/floor values. In the period 2018-2020, the value of losses was set to a third of the annual average price in the day-ahead market.

The reference level of losses is set by the regulator, supposedly based on the national climate change mitigation plan. In practice, the reference percentage value for losses has remained constant in the last ten years (ERSE, 2019c).

Slovenia

The DSO has to compensate actual network losses by purchasing the corresponding amount of electricity. However, DSO allowed revenues only recover a certain amount of pre-defined allowed losses, expressed as a share of the energy distributed annually. Thus, DSOs see an incentive to reduce network losses, under which these are valued at market prices.

The allowed level of losses is determined every three-year regulatory period by the NRA based on the actual losses in the previous year and the expected reduction over the next period.

Sweden

DSOs have to purchase the energy necessary to cover actual losses. The cost of this energy is added to the allowed revenue. In addition to this, there are incentives to reduce losses through norm costs determined by comparison with other electricity grid companies depending on customer density.

Reference levels of losses are calculated individually for each DSO in such a way that they are encouraged to progressively decrease the losses compared to historical values. However, these norm losses are calculated by the regulator considering the density of customers of each DSO.

Spain

Spanish DSOs are encouraged to reduce network losses by an incentive scheme that is added on top of their base allowed revenues. The design of this mechanism has been recently modified as described in Article 24 of Circular 6/2019 from the regulator. According to this scheme, DSOs whose level of losses are above standard loss factors, set in the regulation and common to all DSOs, would have to pay a penalty, whereas those DSOs performing better than this standard value would receive an incentive. The amount paid or perceived by each DSO would depend on their own historical evolution; being the incentive (penalty) larger for those DSOs whose own losses decrease (increase) over time and vice versa. The incentive is designed in such a way that the amount of money paid by all the DSOs that are penalized is generally equal to the amount paid to all the DSOs that receive an incentive. The total value of the individual incentive or penalty is capped by the NRA to ±5% of the base allowed revenues of each DSO.

Actual losses of each DSO are compared against an industry wide standard, defined as a share of network losses different for each time period and voltage level as well as its own historical performance. Therefore, this approach does not consider differential aspects of the distribution area, although the energy injection in each DSO area is considered in the energy balance to compute grid losses.

Austria

The cost of energy losses is part of the TOTEX used in regulatory benchmarking in which they are compared to other DSOs in the country. Hence, DSOs have an incentive to reduce losses, as their benchmarking score will otherwise be distorted. Losses are bought via the electricity TSO for all electricity DSOs in a competitive manner on power exchanges or OTC markets.

Under this approach, there is no specific reference level of losses. Grid losses are indirectly compared among DSOs.

Summary

Incentives for the reduction of losses are present in all the target countries. Nevertheless, their strength is limited in some countries due to the existence of caps, dead bands, or low economic value on losses. For example, in Portugal, the maximum amount of the incentives or penalties is capped and a deadband is in place. Moreover, the economic value of losses is below the market price. Likewise, in Spain, the incentive is capped and the individual incentive depends on the performance of other DSOs as it is designed as a "zero-sum game". Therefore, it may not be enough to properly drive loss reduction efforts. The remaining countries make grid operators purchase energy to cover their network losses, thus DSOs have an incentive to reduce them as either allowed revenues only include a pre-defined share of losses (Slovenia and Sweden), or the corresponding cost is included in a TOTEX benchmarking analysis (Austria).

Reference levels of losses generally do not consider the impact of DER and/or the specific characteristics of each DSO area on grid losses. These reference levels are usually determined simply as an improvement with respect to past performance or based on emission reduction targets. In some cases, some differentiation per DSO area is made, but this usually consists in setting different loss factors or reference levels by load-density areas, regardless of DER penetrations seen by individual DSOs.

Considering the conditions described in each of the countries, Table 10 summarizes the importance of each barrier related to the lack of incentives to reduce energy losses, taking into account DER penetration, in the five countries.

Table 10: Country assessment of incentives to reduce energy losses with DER

Identified Barrier	Guiding Question	AT	ES	PT	SE	SI
Incentives for the reduction of energy losses are not in place or provide weak incentives (low-powered incentive, deadbands, non-symmetric designs, cap and floors)	Do DSOs receive (strong) economic incentives to reduce energy losses?	3	2	2	4	4
Energy losses incentives do not consider the impact of DER and smart grid technologies	Is the impact of DER and smart grid solutions considered when setting baseline/target levels for losses?	1	2	1	2	2

5.3. Continuity of supply incentives

Continuity of supply incentives are important mainly in the context of BM2. DSOs that have strong incentives to improve continuity of supply maybe be more inclined to the adoption of solutions proposed in BM2, e.g. predictive maintenance and advanced fault location tools.

Portugal

- Do DSOs receive (strong) economic incentives to improve reliability?

The incentive is symmetric, with a dead band and two components: one of focus on the ENS (or END, in the Portuguese acronym), while the other focuses on the 5% worst served MV delivery points and uses the indicator SAIDI[11]. The first component is a linear incentive related to the END, with a cap and floor and a deadline. The parameters are set by the energy regulator at the beginning of each regulatory period.

[11] Average cumulated duration of interruptions per customer per year

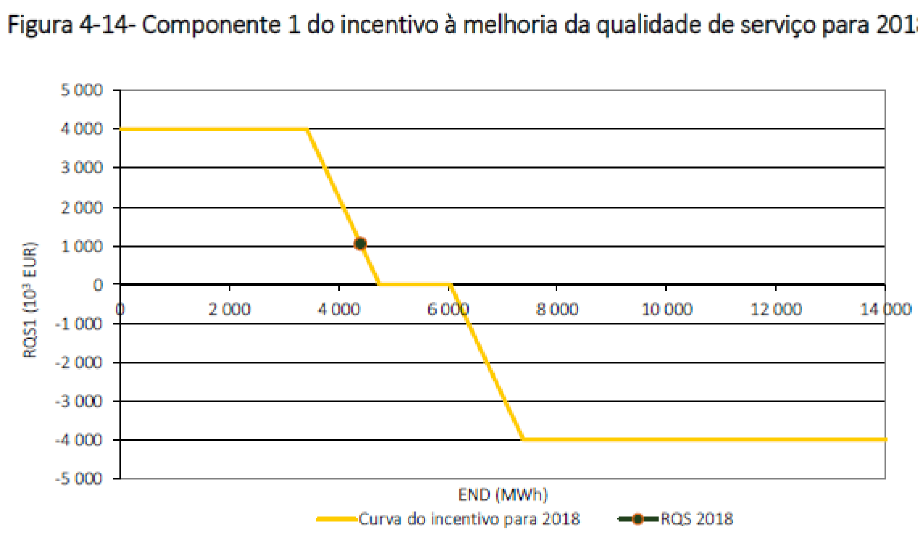

Figure 3: Component 1 of the Portuguese Continuity of Supply Incentive for 2018. Source: ERSE, 2019c.

The second component is related to the three-year average of MV SAIDI in the 5% worst-served secondary substations. Similarly to component 1, the second component is designed in a bonus-malus scheme, with a dead band, as shown in Figure 3.

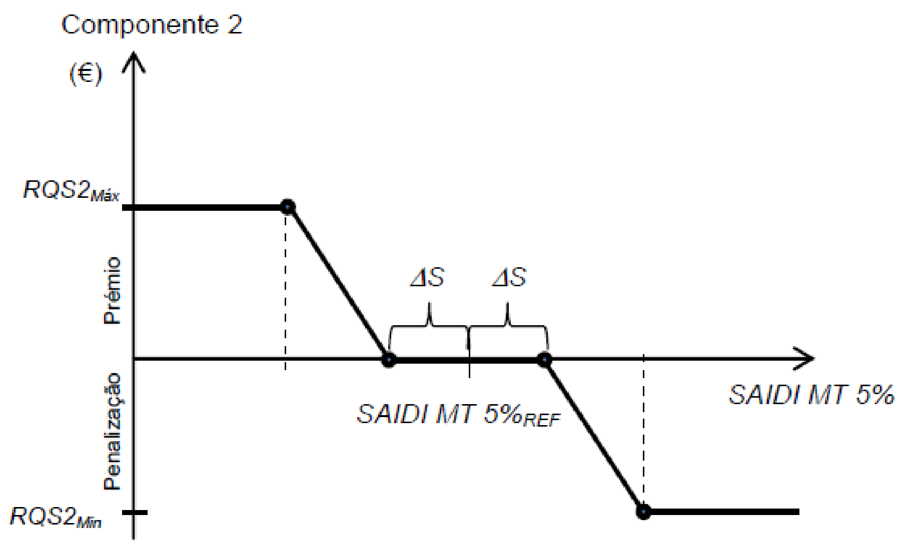

Figure 4: Component 2 of the Portuguese continuity of supply incentive. Source: ERSE, 2019c.

Total allowed revenues of the DSO over the last two years, including HV/MV and LV, amounted to approximately 1000M€, as shown in Figure 5. Therefore, the maximum value of the incentive/penalty faced by the Portuguese DSO is around 0.5% of its base revenues.

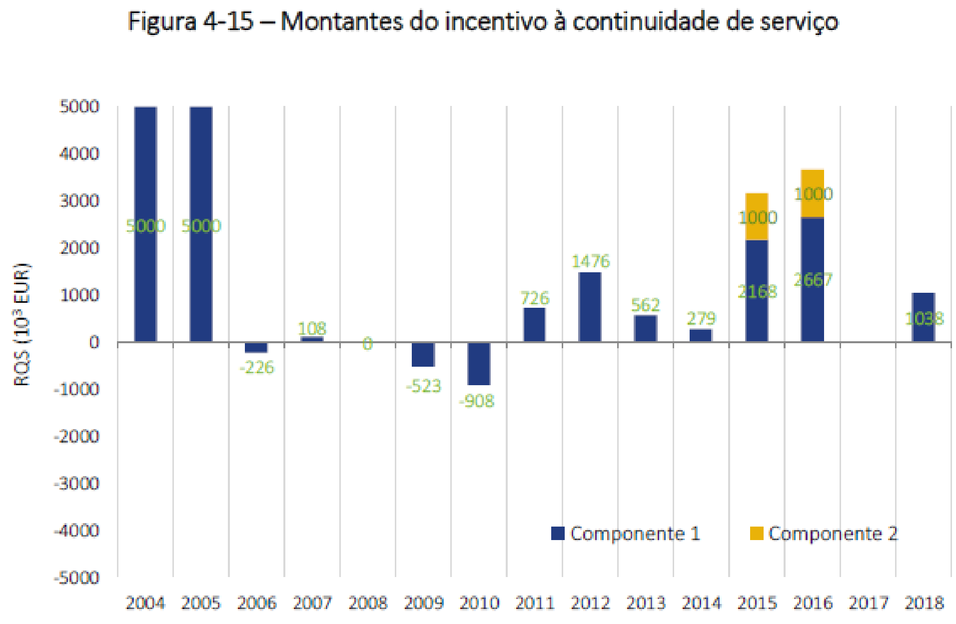

Figure 5: Total incentive/penalty related to continuity of supply in Portugal per year. Source: ERSE, 2019c.

- Is the design of incentive schemes, i.e. incentive rates and reference values, based on up to date cost-benefit analyses?

It is unclear how they are defined. The Diretiva n.º 2/2018 published the last reference values for the parameter on continuity of supply, including 0.00134% of energy distributed, the deadband being plus/less 12% of the reference indicator, and the incentive rate as 3€/kWh (which is in line with common values for ENS). Nevertheless, there is not clear indication that the definition of the parameters is based on up to date CBA.

- Do incentive schemes provide a fair, distinct treatment of planned and unplanned interruptions?

Planned interruptions are interruption with notice in accordance with the Commercial Relations Code, published by ERSE.

- Interruptions for reasons of public interest: the entity responsible for the network must inform, whenever possible, and with a minimum prior notice of 36 hours, the customers which may be affected by the interruption.
- Interruptions for service reasons: DSOs can agree with customers the best moment for the interruption. If an agreement is not possible, the interruptions must occur, preferentially, on Sundays, between 05:00 hours and 15:00 hours, with a maximum duration of 8 hours per interruption and 5 Sundays per year, per costumer affected. DSO must inform a customer with a minimum prior notice of 36 hours.
- Interruptions due to costumer responsibility: The supply interruption may only take place following a prior notice of interruption, with a minimum advance warning of 8 days relative to the date when it will occur. If the costumer installation emits perturbations to the network, the operator establishes, in accordance with the costumer, a time period for solving the problem.

The reliability indicators considered in the incentive mechanisms exclude those driven by security reasons, interruptions caused by faults in the transmission system, and those classified as exceptional events.

Therefore, regulation defines the two types of interruptions clearly, but the incentives do not differentiate between them, leaving no incentive for the DSO to replace unplanned with planned besides reputational.

Slovenia

- Do DSOs receive (strong) economic incentives to improve reliability?

On the basis of the SAIDI and SAIFI relating to individual distribution company, the Energy Agency calculates the aggregate value of SAIDI and SAIFI indicators on the basis of the number of all consumers in Slovenia. The monitoring of SAIDI and SAIFI in the observed period indicates gradual improvement of quality of supply.

For the current regulatory period, the indicators considered are SAIDI and SAIFI values, which are separated for rural and urban. The NRA performed 2 surveys to assess customer interruption costs (2007 and 2010). However, the utilization of both studies in terms of design of the incentive scheme was limited. Furthermore, the NRA is currently working on the estimation of an optimal continuity level to update the incentive scheme for the next regulatory period. Within the scheme, there is a long-term reference (target) value for SAIDI and SAIFI in each regulatory period set. In addition, it is defined and applied separately for each distribution area in a particular area type (rural, urban). It is defined using the reference standards calculated each year applying the requested improvement on the initial (starting) level of continuity of supply using SAIDI and SAIFI. A minimum improvement of the continuity level is demanded according to the initial starting level: if the long term reference level has already been reached, there is no consequence; if it has not been reached, then an improvement is demanded on a yearly basis. The current scheme uses a dead band to avoid strong effects on the tariff (optimizing the administrative costs) caused by non-structural changes in level of continuity of supply (i.e. stochastic variations around the reference). The Slovenian incentive structure is partly linear and partly constant in the sense that a certain constant band (constant economic effect) is applied for each quality class and a linear function is defined in the range between the quality classes. This is introduced for the same reason as in case of so-called dead-band: to avoid the effect on the tariff. Rewards and penalties are capped and also floored (to the certain percentage of controlled costs for O&M). Capping is applied since the NRA has not yet completely verified/validated the customer information on the marginal valuation of quality. The continuity scheme is linked to the regulatory formula, which corresponds to a mix of revenue and price-cap regulation and is funded by all customers via regulated tariffs.

- Is the design of incentive schemes, i.e. incentive rates and reference values, based on up to date cost-benefit analyses?

As mentioned in the previous question, the NRA is currently working on the estimation of an optimal continuity level to update the incentive scheme for the next regulatory period. It is not expected to use a CBA, however.

- Do incentive schemes provide a fair, distinct treatment of planned and unplanned interruptions?

In case of planned outage, each customer that will be affected must be informed, using written form or any other suitable form, in a timely manner. If the interruption will affect a greater number of customers, the customers must be informed by public notification (by announcement on the local radio, publication on the

DSO website, notification by using messaging services (SMS, MMS) etc.) at least 48 hours before the start of the interruption.

However, although the regulation clearly identifies the two types of interruption, there is no clear separation in the way incentives are set.

Sweden

- Do DSOs receive (strong) economic incentives to improve reliability?

Sweden uses a combination of rewards and penalties for the TSO as well as for the DSO level. Since the beginning of the last regulatory period in 2020, Sweden uses AIT and AIF, i.e. normed ENS and PNS, both for DSOs and the TSO. The NRA conducted a cost estimation survey to set an incentive rate for the continuity of supply (CoS) indicators. By setting an incentive rate based on data from customer surveys ("bottom up"), the quality regulation aims to give incentives for a socioeconomic level of CoS. An explicit Q-element is calculated using the mentioned CoS-indicators, whereby the target for DSOs (there is no target and no minimum improvement determined for TSOs) is set using a benchmarking method where DSOs with similar customer density are exposed to a similar target. The target is not an "optimal" level but the mean value of the relevant CoS indicators, i.e. it is calculated based on the mean value of all DSO CoS-indicators (per customer group) as a function of customer density.

That target is predefined during the regulatory period and has to be reached within 4 years. Afterwards it is updated for the next period. The scheme does not involve the use of a dead band. Incentives are calculated as follows:

$$Q_{DSO} = \left(AIT_{target} - AIT_{result}\right) * P_{mean} * cost$$

Where,

$AIT = ENS/P_{mean}$

For both TSOs and DSOs, the scheme is linked to the overall revenue-cap model while quality incentives are capped to 1/3 of the regulatory return on the capital base. The scheme is funded only by costumers of areas/companies which are entitled to incentives.

- Is the design of incentive schemes, i.e. incentive rates and reference values, based on up to date cost-benefit analyses?

No. The national regulation provides the same incentives for the country as whole. Rural areas with less dense population are allowed to have longer outages usually. There is not differentiation based on voltage level but the ENS is the base for incentives.

Although the regulation does not follow a CBA specifically to set incentives for reliability, a comprehensive socio-economical survey is conducted to define the incentives.

- Do incentive schemes provide a fair, distinct treatment of planned and unplanned interruptions?

The interruptions costs are computed considering SAIDI, SAIFI and ENS. LV faults included in the calculation. Both planned and unplanned interruptions are considered, but a different economic value, determined based on the WTP per customer category, is considered for planned and unplanned interruptions, as shown in Table 11. Therefore, there is an incentive to replace one type with the other; this incentive is particular strong for non-residential customer categories.

Table 11: Cost for planned and unplanned outages in Sweden

Price level 2017, adjust with yearly price increase	Unplanned outages, >3 min		Planned outages, >3 min	
	ENS SEK/kWh 1)	Power not served SEK/kW 2)	ENS SEK/kWh 1)	Power not served SEK/kW 2)
Industry	159,96	70,75	76,00	20,71
Services	175,06	17,78	79,31	5,94
Farming	34,35	9,78	14,10	1,72
Public service	96,97	7,65	43,70	0,92
Households	5,84	1,95	4,98	1,85
DSO-areas	96,01	22,18	45,16	7,08

Spain

- Do DSOs receive (strong) economic incentives to improve reliability?

Spanish DSOs are encouraged to improve reliability by an incentive scheme that is added on top of their base allowed revenues. Two indicators are monitored, i.e. NIEPI and TIEPI, which measure the average number of interruptions and average time each kW of demand has been interrupted in a year within a certain area.

The design of this mechanism has been recently modified as described in Chapter VI of Circular 6/2019 from the regulator. According to this scheme, DSOs whose reliability levels are worse than the national average would be penalized, whereas those DSOs performing better than this average would be rewarded. The incentive is designed in such a way that the amount of money paid by all the DSOs that are penalized is generally equal to the amount paid to all the DSOs that receive an incentive. The total value of the individual incentive or penalty is capped by the NRA to ±2% of the base allowed revenues of each DSO

In this regard, the incentive can still be considered weak.

- Is the design of incentive schemes, i.e. incentive rates and reference values, based on up to date cost-benefit analysis?

The reference value for both TIEPI and NIEPI is the national average for the last three years. A different reference value is considered for each type of area based on density of consumers (urban, rural, concentrated rural, dispersed rural).

The incentive rate is the result of discretionary parameters set by the regulator which look aimed at controlling the magnitude of overall incentives rather than on a proper incentive to improve reliability.

- Do incentive schemes provide a fair, distinct treatment of planned and unplanned interruptions?

Regulation defines them clearly, but the incentives do not differentiate between them. Therefore, we can conclude that incentives do not provide a fair distinct treatment between planned and unplanned interruptions.

According to the Spanish regulation, and unplanned interruptions is an interruption of continuity of supply declared by the DSO previously (72 hours) to the Regional Government, and authorized by this institution.

Planned interruptions must be announced to affected customers, giving them a minimum of 24 hours in advance notice by the following means: a) Individualized notification using a method whereby there is a record of it having been sent to consumers shows supplies are carried out at voltages higher than 1 kV and to those establishments rendering services that are declared to be essential services, b) Advertising posters in visible spots with regard to all other consumers and by means of 2 of the most widely circulated printed media in the region.

Unplanned interruptions are considered in the incentive scheme together with planned ones (excluding force majeure and third-party interruptions).

Austria

- Do DSOs receive (strong) economic incentives to improve reliability?

In Austria, the indicators are published and maximum amounts for indicators are set within a decree on network services. The maximum amounts do not vary between regions or voltage levels and the impact of DER is not considered.

According to (CEER, 2016c), Austria was considering the implementation of an incentive mechanism, but had not yet done so.

- Do incentive schemes provide a fair, distinct treatment of planned and unplanned interruptions?

The DSO has to inform the affected grid users about the start and duration at least 5 days before the planned interruption. In case of individual mutual agreements, the notification can be shorter.

In conclusion, regulation defines them clearly, but gives no incentives besides reputational.

Summary

Considering the conditions described in each of the countries, Table 12 summarizes the importance of each barrier related to continuity of supply regulation in the five countries.

Table 12: Country assessment of continuity of supply barriers

Identified Barrier	Guiding Question	AT	ES	PT	SE	SI
Output-based incentives for continuity of supply are not in place or provide weak incentives (low-powered incentive, deadbands, non-symmetric designs, cap and floors)	Do DSOs receive (strong) economic incentives to improve reliability?	1	2	2	3	2
Reference values for reliability indices based exclusively on historical values, cost-benefit analyses that allow continuous improvements are not being carried out	Is the design of incentive schemes, i.e. incentive rates and reference values, based on up to date cost-benefit analyses?	NA	2	2	3	2
Equal treatment of planned and unplanned interruptions or stringent requirements to qualify as planned interruption	Do incentive schemes provide a fair, distinct treatment of planned and unplanned interruptions?	1	2	2	4	2

5.4. Incentives for innovation and sandboxes

As discussed in the following section of this deliverable, large-scale pilots and sandboxes provide an opportunity for regulatory authorities to experiment different regulatory alternatives for a given problem. This is beneficial when regulators face the need for completely new regulatory instruments or have to carry out comprehensive changes in the existing regulation. Sandboxes are also very relevant when national contexts differ considerably, not allowing for a straightforward replication of other regulations or recommendations.

In the context of InteGrid, sandboxes may be particularly relevant for the development of BM1, BM2 and BM3. The BM1 may be the most affected one, as this business model may require important changes in DSO economic regulation. The following Table 13 presents the criteria for the evaluation of this barrier.

Table 13: Criteria for the assessment of the sandboxes frameworks

Maturity level	Criteria
0	Clear barrier for the implementation of pilots
1	Pilots may be allowed, but only a part of the cost can be recovered
2	There is some incentive for pilots.
3	Possibility of sandbox but not clearly stated
4	Clear rules for sandboxes

Portugal

- Does regulation leave room for pilot projects, even if they do not fit within the regulation in place?

The Portuguese regulation includes an incentive for the DSO to deploy innovation projects. In case these projects are approved by the regulator, the DSO would receive 50% of their annual benefits up to 1,5% of their investment, for 6 years.

Additionally, the fact that there is one pilot project for the participation of demand in balancing market is a precedent of a sandbox. Similarly, previous projects have enabled the DSO to directly operate storage.

Slovenia

- Does regulation leave room for pilot projects, even if they do not fit within the regulation in place?

The Slovenian regulation includes financial incentives for the deployment of smart grid solutions, provided the corresponding projects comply with a set of criteria defined in the regulation. Eligible projects include investment projects that aim to promote an efficient development of networks whose total investment value exceeds 200.000 €, as well as pilot addressing the integration of new technologies and services in the area of smart grids and related market mechanisms. A project that is included under this scheme is credited with a one-off incentive of 3% of the carrying amount of the asset as at 31 December of the year in which the asset entered in operation. The sum of the incentives is capped to 10% of the reported net benefits of the whole project.

There is no structured sandbox program as of today.

Sweden

- Does regulation leave room for pilot projects, even if they do not fit within the regulation in place?

The Swedish regulation does not include specific incentives for the deployment of smart grid solutions, although ICT-related CAPEX is handled as any other cost with a depreciation time of 12 years. Related OPEX costs can be recovered in the next regulatory period, although efficiency requirements would apply to these.

Sweden is designing and proposing a sandbox program.

Spain

- Does regulation leave room for pilot projects, even if they do not fit within the regulation in place?

The art. 16 of Circular 6/2019 included a new mechanism to support pilot projects specifically for DSOs, in case these bring benefits for the overall system. These must be approved by the regulator and informed by a DG from the Ministry. For these costs to be passed-through to the tariffs, DSOs must file a technical report and a CBA.

It is unclear whether pilots may go around existing regulation (sandbox), but some DSOs are starting to submit applications including this possibility.

Austria

- Does regulation leave room for pilot projects, even if they do not fit within the regulation in place?

The DSOs could claim the costs in principle, but no specific mechanism. Austria is currently designing and proposing a sandbox program.

Summary

Considering the conditions described in each of the countries, Table 14 summarizes the importance of each barrier related to sandboxes regulation in the five countries.

Table 14: Country assessment of Pilots/Sandboxes Barriers

Identified Barrier	Guiding Question	AT	ES	PT	SE	SI
Lack of incentives for innovation and experimentation, including the possibility of requesting regulatory sandboxes	Does regulation leave room for pilot projects, even if they do not fit within the regulation in place?	3	3	3	3	2

5.5. Incentives for Smart Grid technologies

Smart grid technologies are the backbone of BM1 and BM2. Regulation can give more or less incentives for DSOs to deploy smart grid technologies, such as AMI, fault locators and other sensors. In the following paragraphs we comment on how DSOs in the different countries recover the costs associated with smart grid technologies.

Table 15: Criteria for the assessment of Smart Grid cost recovery by DSOs

Maturity level	Criteria
0	DSOs cannot recover any cost associated with smart grid technologies
1	DSOs can only recover the cost of smart grid technologies within a project
2	They could claim the costs beyond projects in principle, but no specific or explicit mechanism
3	Costs can be recovered, but the need to comply with the regulator categories
4	Costs beyond the scope of projects can be recovered and mechanisms for recovery are clear

Portugal

The recently published *Regulamento 610/2019*, a new regulation on smart grids in Portugal, introduces specific incentives for integration of LV units in smart grids. By that, the regulation means not only the deployment of smart meters, but also all communication systems and other system should be in place so that the smart meters can perform all the applicable services.

This incentive is composed of an additional remuneration to the DSO based on the number of units integrated to the smart grid.

There are also some incentives to deploy innovation projects and smart metering systems in the LV.

Slovenia

The Slovenian regulation includes financial incentives for the deployment of smart grid solutions or innovation projects, provided the corresponding projects comply with a set of criteria defined in the regulation. Eligible projects include investment projects that aim to promote an efficient development of networks whose total investment value exceeds 200.000 €[12].

Sweden

ICT-related CAPEX is handled as any other cost with a depreciation time of 12 years. Related OPEX costs can be recovered in the next regulatory period, although efficiency requirements would apply to these.

[12] This does not apply to projects already financed by other programs such as EC's H2020.

Spain

The recently passed regulation on Smart Grids (Circular 6/2019) introduces two mechanisms to promote smart grid solutions. Firstly, the regulation defines the category of "type 2" investments, which correspond to investments in network automation and digitalization required to support the energy transition. These investments are added to the RAB at their actual cost provided that they fall within one of the smart grid asset categories defined by the regulator. Secondly, DSOs are entitled to recover the costs associated with pilot projects through the tariffs, subject to the pre-approval of the regulator, according to Article 16 of the same Circular 6/2019. DSOs have to file a request with an economic and technical analyses.

Austria

They could claim the costs in principle, but no specific or explicit mechanism.

Summary

Considering the conditions described in each of the countries, Table 16 summarizes the importance of each barrier related to Smart Grid cost recovery barriers in the five countries.

Table 16: Country assessment of Smart Grid cost recovery barriers

Identified Barrier	Guiding Question	AT	ES	PT	SE	SI
New smart grid technologies, beyond pilot projects, are not considered in the remuneration of DSOs	Would DSOs recover the costs associated with smart grid technologies deployment beyond pilot projects?	2	3	3	3	3

5.6. Incentives to extend useful life of assets

Giving the possibility for DSOs to extend the useful life of assets is a way to promote BM2. Traditional regulation usually remunerates assets according to a fixed depreciation period, commonly defined for accounting purposes in the first place. The BM2 gives the opportunity for DSOs to have an improved asset management and maintenance processes, possibly allowing for the extension of the useful life of many assets. However, if DSOs do not receive any incentive for this extension, they may simply opt for not investing in solutions like the ones proposed in BM2, as well as being incentivized to replace good assets to be remunerated for the new equipment.

Table 17: Criteria for the assessment of incentives to extend the useful life of assets

Maturity level	Criteria
0	DSOs do not have any incentives. On the contrary, they are worst off by extending the life of assets
1	DSOs have no incentives but are not worst off. Regulation provides a neutral condition
2	There are only implicit incentives
3	Explicit incentives exist, but they depend on the context
4	Significant and clear benefit

Portugal

This type of incentive exists for transmission grids, but not for distribution.

Being CAPEX in MV/HV subject to CoS regulation, there is no benefit for the extension in asset life, i.e. asset remuneration will cease at the end of the regulatory lifetime. In the LV, due to the TOTEX regulation, **DSOs can have an incentive to avoid asset replacement** (CAPEX) by increase maintenance expenditures (OPEX).

The TOTEX remuneration for LV is a result of the sum of four components: i) Variable component of the revenue of the electrical energy distribution activity (€/remuneration); ii) Variable component of the revenue of the electrical energy distribution activity (€/MVA); iii) Variable component of the revenue of the electrical energy distribution activity (€/km); iv) Variable component of the revenue of the electrical energy distribution activity (€/client). There is no direct relation between these components and depreciation. Therefore, an incentive may exist regarding LV networks.

Slovenia

There is no specific incentive. Moreover, the RAB is based on book values plus investment plans, and therefore there are not benefits.

Sweden

The RAB is computed as the replacement value of existing assets. Moreover, DSOs receive some extra remuneration if assets are still operational after full depreciation.

Spain

The art. 15 of Circular 6/2019 increases the O&M remuneration for assets that exceed their regulatory useful life. The REVU[13] term is the additional remuneration on top of standard O&M costs (COM).

$$REVU_n^i = \mu_{n-2}^i \times COM_{VU,n-2}^i$$

Where:

Period (years X)	μ^i_a
First 5 years	0.3
From 6 to 10 years	0.30 + 0.01·(x−5)
From 11 to 15 years	0.35 + 0.02·(x−10)
Year 16 onwards	0.45 + 0.03·(x−15)

Still, the benefit could be higher if the DSO reinvests. This is also linked to the WACC definition, which was just adjusted in the last regulatory period.

[13] Mention what it is

Austria

There is no specific incentive to increase the operating lifetime of the assets. In fact, the use of a historical cost approach to compute the RAB discourages CAPEX reductions. On the other hand, by doing so, the DSO could obtain a higher efficiency score in the TOTEX benchmarking, which is a slight incentive.

Summary

Considering the conditions described in each of the countries, Table 17 summarizes the importance of each barrier related to the extension of useful life of assets in the five countries.

Table 18: Country assessment of incentives extension of useful life of assets

Identified Barrier	Guiding Question	AT	ES	PT	SE	SI
Lack of incentives to extend the useful life of network assets beyond their regulatory lives	Would DSOs benefit from keeping assets under operation beyond its regulatory useful life?	1	3	1	3	0

5.7. Forward-looking tools/scenarios to assess DSO investment needs and/or allowed revenues

This barrier happens when allowed revenues based in past investment/costs only, without taking into account future investment needs, including DER. This can be a barrier for BM1, for instance, considering that past investments and costs have only considered a scenario without DER.

Table 19: Criteria for the assessment of forward-looking tools/scenarios to assess DSO's investment needs and/or allowed revenues

Maturity level	Criteria
1	No investment plan specifically used
2	Investment plan but backward-looking benchmarking
3	Investment plan and some forward-looking possibility but something not clearly defined
4	both clearly detailed in regulation and applied

Portugal

The efficiency is determined using international benchmarking analysis (Data Envelopment Analysis and Malmquist index), meaning that backward looking is done for OPEX, but investment plan is carried out for CAPEX.

Slovenia

Investment plans are used, but no specific benchmarking model used.

Sweden

Historical OPEX with an efficiency demand calculated by DEA, Swedish DSOs, with a minimum of normally 1%/year in real terms. Ex-post evaluation of costs.

Network CAPEX are analysed based on best practice and norm costs evaluated and decided by the NRA.

Spain

Art. 17 of Circular states that the regulator can use whatever tools she estimates required to fulfil the objectives of regulation.

Past legislation referred to a reference network model (RNM) as a benchmarking tool the regulator may use. However, the precise application of this RNM or other tools is not explained in the regulation. In the past, it has been used to calculate the efficiency factors that would be applied to quantify the value of the investments made in previous regulatory periods.

Austria

A backward looking TOTEX benchmarking is applied using MOLS and DEA.

Allowed OPEX in the base year are adjusted according to a cost path with general and individual productivity targets and inflation. For individual productivity targets benchmarking techniques (DEA and MOLS) are used.

Summary

Considering the conditions described in each of the countries, Table 20 summarizes the importance of each barrier related to forward-looking instruments for the definition of allowed revenues.

Table 20: Country assessment of forward-looking tools/scenarios to assess DSO's investment needs and/or allowed revenues

Identified Barrier	Guiding Question	AT	ES	PT	SE	SI
Allowed revenues based in past investment/costs only, without taking into account future investment needs, including DER	Do regulators use forward-looking tools/scenarios to assess investment needs and/or allowed revenues?	1	3	2	1	2

5.8. Network access and connection

Network access and connection rules are particularly relevant for the development of BM4 and BM5, specially the former. Consumers and prosumers are impacted by the way network connection and access rules are defined, and so is their business model. In this context, this deliverable identifies three main barriers for consumers.

- System users do not have appropriate information regarding expected expansions or upgrades due to new connections (degree of detail of the expansion plans). Lack of transparency on available grid capacity for new DER
- Deep connection charges are a barrier for the connection of DG, particularly small units.
- Lack of transparency in the calculation of grid connection charges

Portugal

- Does new generation have information on available grid hosting capacity before submitting an application?

Only in HV and MV by primary substation. Nevertheless, the information available for large connections is very comprehensive. Figure 6 shows an example of the information on hosting capacity per primary substation available online in Portugal.

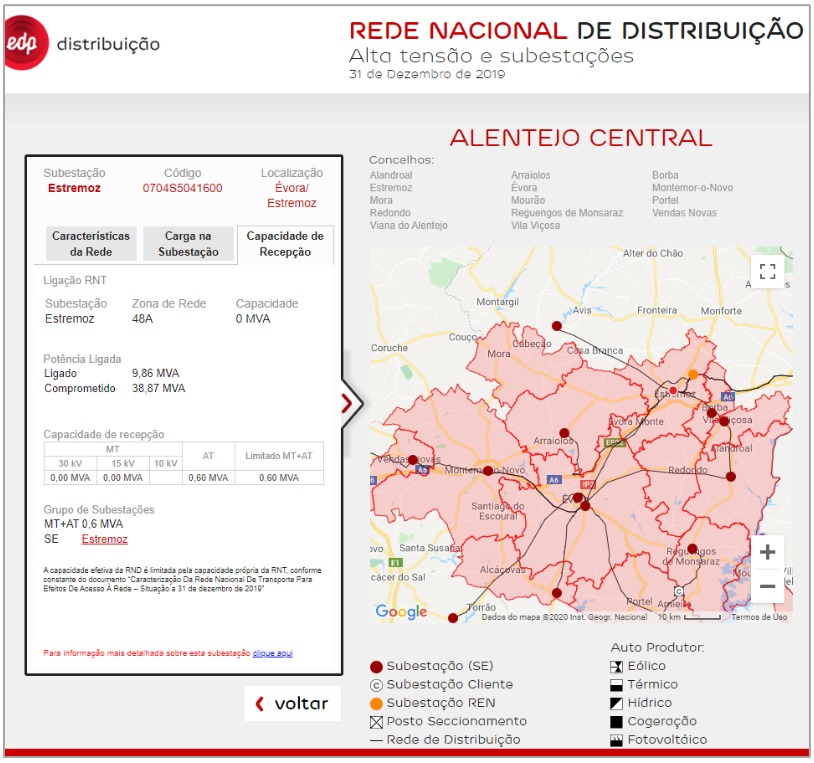

Figure 6: Hosting capacity availability map – Example of a Portuguese primary substation[14]

- Does new generation have to pay deep connection charges? Are there differences by size or voltage level?

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, DG is mostly exposed to deep connection charges.

- Are grid connection charges calculated in a transparent manner and predictable by new users?

[14] https://edp-distribuicao-rede.wntech.com/

These connection conditions are established by the Portuguese legislation. Calculated by the DSO; some components established by the regulator.

There is a simulator for consumer connection costs: distance to grid, installed and firm capacity, overhead or underground connection.

In conclusion, there is a simulator for LV and MV, and an online hosting capacity map for the HV grid, providing interested parties with comprehensive information.

Slovenia

- Does new generation have information on available grid hosting capacity before submitting an application?

No, each customer application or request regarding the connection to the grid is analysed separately.

- Does new generation have to pay deep connection charges? Are there differences by size or voltage level?

Same as for loads, conventional and renewable production units are obliged to follow the regulation and pay the connection fee, if they would like to be connected to the grid. The DGs are recognized as network users, as well, meaning that a network user must apply for a new connection approval if the basic parameters on which the current connection approval was issued are altered. These are: change to a connected load, change in the technical characteristics of a facility or a device for which the connection approval was issued, change to a group of end users[15].

The connection approval is valid for two years once it has been fully issued by SODO d.o.o.[16]. During that period, the user must meet all the conditions for their facility stated in the connection approval. It is not possible to transfer rights from one connection approval to another location.

- Are grid connection charges calculated in a transparent manner and predictable by new users?

Yes. The DSO publishes a price list which is same for the whole country, same for all EDCs.

For new or even for the existing users who wants to change the level of contracted capacity, the Connection to the Grid procedure and the price list for it are public available on the DSO's website[17].

Sweden

- Does new generation have information on available grid hosting capacity before submitting an application?

No, this information is not available beforehand.

- Does new generation have to pay deep connection charges? Are there differences by size or voltage level?

[15] Grouping is regulated in the Terms and conditions for supply and consumption of electricity from the distribution network. If consumption exceeds the connected load stated in the connection approval, the approval holder will be notified by SODO of the need to acquire a new connection approval or reduce electricity consumption in line with the current connection approval. The decision SODO then issues replaces the previous connection approval.

[16] SODO is a legal entity. It is a short name stands for Official Distribution System Operator, or DSO, in Slovenian.

[17] https://www.sodo.si/za-distributerje/prikljucevanje

Deep connection charges apply. DG pays for the actual specific connection to the existing grid, substation, and if needed the additional increase of capacity.

- Are grid connection charges calculated in a transparent manner and predictable by new users?

They are calculated by the DSO, but the customer has the right to request a review to the National Regulator if the charge is considered unfair.

DSOs can provide customers with an online calculator, estimating the connection charges depending on capacity and distance to the grid.

Prislista för anslutningar (inkl moms)

Servissäkring	Upp till 200 meter	Över 200 meter och upp till 600 meter	Över 600 meter och upp till 1 200 meter	Över 1 200 meter och upp till 1 800 meter
Max 25 A	36 250 kr	36 250 kr + 310 kr/m för den del som överstiger 200 m	160 250 kr + 678 kr/m för den del som överstiger 600 m	566 750 kr + 411 kr/m för den del som överstiger 1 200 m
Max 35 A	48 375 kr	48 375 kr + 310 kr/m för den del som överstiger 200 m		
Max 63 A	61 250 kr	61 250 kr + 310 kr/m för den del som överstiger 200 m		
Max 125 A	92 500 kr	92 500 kr + 310 kr/m för den del som överstiger 200 m		
Max 160 A	130 000 kr	130 000 kr + 310 kr/m för den del som överstiger 200 m		

Prislista gäller från 17 februari 2020

Figure 7: Example of online calculation of estimated connection charge in Sweden[18]

Spain

- Does new generation have information on available grid hosting capacity before submitting an application?

Not for the moment at distribution level. At transmission level, the TSO publishes available grid hosting capacity per substation, differentiating between RES technologies.

In June 2019, the regulator published a new proposal on the regulation of grid access and connection for generation units. This stated that grid operators should publish in their webpages detailed geo-referenced information on the available hosting capacity in all network buses above 1kV. This information ought to be updated monthly.

- Does new generation have to pay deep connection charges? Are there differences by size or voltage level?

DG normally has to pay deep connection charges. The RD 1699/2011 introduced some exceptions to this rule:

[18] https://www.ellevio.se/privat/anslutningar/elnatsanslutning/ny-elnatsanslutning/

- Installations below 100kW connected to LV level (below 1kV) and installations below 1MW connected to the MV grid (from 1kV to 36kV) would only have to pay for network reinforcements within the same voltage level at which they are connected to (shallowish charges).
- Installations below 20kW located near consumption points (located on land for building development) would pay regulated shallow connection charges similarly to LV consumers.

Additionally, RD 244/2019 states that DG installations for self-consumption that have a relay that prevents them from injecting power back to the grid, are exempted from paying the connection charges for DG units. Likewise, self-consumption installation below 15kW in urbanized locations are also exempted.

Installations larger than 15kW must have a three-phase connection.

- Are grid connection charges calculated in a transparent manner and predictable by new users?

Connection charges are calculated by DSOs. Some general rules are provided in RD 1699/2011 to calculate the maximum available hosting capacity:

At LV level, the maximum hosting capacity would be calculated as 50% of the line or transformer capacity less the capacity of DG units already connected to the same area.

At MV level, the maximum hosting capacity is calculated as the maximum capacity that can be connected (including existing generation capacity) considering the minimum expected demand in the area. The minimum simultaneous consumption would be calculated as the minimum load measured in the area or, when there is no information available, 10% of the secondary substation rated capacity.

In case of discrepancies, any party can present a complaint to the corresponding authorities. The regulator (CNMC) publishes the conclusion reports for each of these complaints/enquiries in their web page. It seems that in most cases, the problems derive from different views on the exact amount to be paid as connection charge or how to divide costs when the connection installations are used by more than one installation

Austria

- Does new generation have information on available grid hosting capacity before submitting an application?

No, this information is not available beforehand.

- Does new generation have to pay deep connection charges? Are there differences by size or voltage level?

Deep charges for network provision (power deployment of the DSO) and shallow for network admission (preparation activities for connection). Even small customers have to pay deep connection charges.

- Are grid connection charges calculated in a transparent manner and predictable by new users?

The deep connection charges are set by the regulator, while shallow connection charges are calculated by the network operators. As part of the charges are published by the regulator, this reduces uncertainty for the final user.

Summary

Considering the conditions described in each of the countries, Table 21 summarizes the importance of each barrier related to network access and connection.

Table 21: Country assessment of network access and connection barriers

Identified Barrier	Guiding Question	AT	ES	PT	SE	SI
System users do not have appropriate information regarding expected expansions or upgrades due to new connections (degree of detail of the expansion plans). Lack of transparency on available grid capacity for new DER	Does new generation have information on available grid hosting capacity before submitting an application?	0	1	3	0	0
Deep connection charges are a barrier for the connection of DG, particularly small units.	Does new generation have to pay deep connection charges? Are there differences by size or voltage level?	1	3	2	2	2
Lack of transparency in the calculation of grid connection charges	Are grid connection charges calculated in a transparent manner and predictable by new users?	3	2	3	3	4

5.9. DSO ownership and operation of storage

The ownership and operation of storage by DSOs is a regulatory topic that has seen some debate. On one hand, European regulation (e.g. the CEP) gives clear instruction that DSOs should, in principle, not own or operate storage systems, as those can be active market players. On the other hand, DSOs could benefit from storage system as a means to support network operating, e.g. alleviating congestions[19].

Although this barrier is not so critical in the context of InteGrid, as the usage of batteries is limited, it may still be considered a barrier for BM1 and BM2.

Portugal

Storage systems used to manage the distribution grid have only been tested in pilot projects. In these pilots, the asset is owned by the DSO. However, there are no specific connection requirement established by the Portuguese regulatory framework.

There is an ongoing pilot in Évora with batteries owned by the DSO being tested. European legislation is actually going towards a framework where DSO can only own storage devices when there are no market solutions available.

Slovenia

The DSO is not allowed to own production units. Nevertheless, it is not completely clear if batteries could be used as a grid management device to support power quality.

[19] For a more theoretical discussion on the implications of storage ownership by DSOs, please see Section 5, with the regulatory recommendations.

Sweden

Not foreseen in the regulation, but as of today, DSOs can own storage systems according to regulation if it supports power quality and/or losses in the grid.

Spain

This topic is not regulated. It is generally assumed that DSOs cannot own storage devices for grid support. They could use it under similar conditions as generation units (e.g. temporarily in case of an outage).

Austria

It depends on the size of the utility (following the 2009/72/EC unbundling rules). Utilities with more than 100.000 customers are not allowed to own storage (only if required for grid operation, e.g. for emergency supply or batteries in substations for uninterruptible power supply).

Summary

Considering the conditions described in each of the countries, Table 22 summarizes the importance of each barrier related storage ownership and operation by the DSOs.

Overall, most countries consider storage as generation and therefore, similar rules apply in terms of unbundling (only possible for quality of service or compensation of losses). These countries have not implemented provisions in the Directive to check for market interest in running storage units. All countries given a 2, except Spain where there is nothing explicit.

Table 22: Country assessment of storage ownership and operation by the DSOs

Identified Barrier	Guiding Question	AT	ES	PT	SE	SI
Unclear regulation on the ownership of storage systems by DSOs	Does current regulation clearly state whether DSOs may own/operate storage systems as well as the required conditions for this?	1	2	2	2	2

5.10. Local Flexibility Mechanisms

From a DSO perspective, there are two main regulatory requirements for the deployment of the solutions related to BM1. On the one hand, as discussed previously, DSO revenue regulation should encourage DSOs to use flexibility as an alternative to grid reinforcement. On the other hand, certain regulatory mechanism allowing the DSO to actually access this flexibility are necessary, i.e. whether DSOs are enabled by regulation to procure flexibility from grid users to support grid operation.

Considering that this topic was extensively discussed and evaluated in the Deliverable 8.2, the country assessment carried out for that deliverable is presented below.

Portugal

The DSO may only manage the injection/withdrawal of grid users in case or emergency under grid congestion. The recently approved DL nº 162/2019, which establishes the new regime for self-consumption in Portugal, introduced the possibility to limit the capacity of self-generators connected to the grid or temporarily curtail them under emergency conditions where the operational limits of the grid quality of service indicators may be violated. In any case, affected users would not be entitled to an economic compensation.

Slovenia and **Sweden** reported that these mechanisms are not used at distribution level.

Spain

In principle, DSOs are enabled by regulation to request the RES Control Centre (CECRE) run by TSO to curtail RES generation units larger than 5MW connected to their grids in case grid constraints are foreseen or under emergency conditions. In these cases, the DSO ought to identify the units able to solve this congestion as well as the amount of generation that must be curtailed to solve the congestion, and notify the TSO. The TSO, via the CECRE, would solve the congestion by limiting and, if necessary, redispatching the corresponding RES units in the same way as if the congestion were located in the transmission network. The DG units affected would be paid according to the rules set in the technical constraint management market run by the TSO. However, in practice, due to the lack of well-developed procedures and regulation, DSOs rarely ask the TSO to perform such curtailment actions.

Austria

Distribution-connected generation participates in voltage control services according to existing grid codes. Despite the fact that generators should maintain a unity power factor by default, the grid operator may require a different setting if grid conditions require it. The provision of this service is subject to non-remunerated mandatory requirements that depend on the type (inverter-based or other) and size of the generator as well as the voltage level (MV or LV). The fulfilment of these requirements has priority over the injection of active power. Regarding congestion management services, current regulation does not explicitly prevent it, but it is not done in practice due to the lack of incentives for network operators.

Summary

Considering the conditions described in each of the countries, Table 23 summarizes the importance of each barrier related to local flexibility procurement mechanisms.

Table 23: Country assessment of local flexibility procurement mechanisms

Identified Barrier	Guiding Question	AT	ES	PT	SE	SI
Mechanisms for local flexibility procurement and provision (local markets, non-firm access, agreements DSO-DER) are not implemented	Are DSOs enabled by regulation to procure flexibility from grid users to support grid operation?	2	0	1	0	0

5.11. Balancing Services

In the context of the InteGrid project, demonstrations are mainly testing the use of flexibility by DSOs for grid management purpose, as discussed above for BM1. Nevertheless, the participation of demand-side response and other types of DER in balancing markets is also being researched in the InteGrid project, mostly from the DER and aggregators’ perspective. These solutions correspond to BM4 and BM5.

The participation of demand response in balancing markets may face several barriers as of today. In order to check if these barriers exit in the analysed countries, the abovementioned barriers can be translated into different research questions, organized into three main blocks, namely balancing market design, aggregation and TSO-DSO coordination.

Firstly, the design of balancing markets is important in enabling the participation of demand response, both by explicitly allowing this participation, and by setting appropriate products and market rules for this kind of distributed energy resource. Secondly, aggregation is analysed, as it is also at the core of BM5.

Table 24 presents the guiding questions under each category.

Table 24: Key regulatory question for demand participation in balancing markets

Key regulatory questions for demand participation in balancing markets	
Balancing Market Design	Are balancing markets open for demand-response participation?
	Are products and conditions suitable for demand/DER participation?
Aggregation	Are there barriers for the aggregation of resources in balancing markets?
	Is the independent aggregation allowed? Is it viable?
	Is different type of DER aggregation (VPP concept) possible?
TSO-DSO coordination	Is TSO-DSO coordination mature enough for DER to provide balancing services?

Considering that this topic was extensively discussed and evaluated in the Deliverable 8.2, the country assessment carried out for that deliverable is presented below.

Portugal

Balancing markets are not yet open for demand-response participation (Smart Energy Europe, 2018). As of today, FCR[20] is a mandatory and non-remunerated product, and must be provided by agents connected at the transmission network only (ERSE, 2019). For the aFRR, the market is, in principle, open to all prequalified agents. Nevertheless, the prequalification process involves the testing of generation capabilities. Even more importantly, participating units have to provide both upwards and downwards bids. These bids do not have to be exactly the same, but they have to respect a certain ratio established by the system operator. These conditions make the participation of demand-response, in practice, not possible. Regarding the tertiary regulation, or the mFRR in the terms of the EBGL, the Portuguese regulation also impose restrictions to the participation of the distributed-connected resources. Among the requirements for an agent to provide tertiary regulation, two are especially restrictive namely the necessity for being a generator and being connected to the transmission grid (ERSE, 2019).

Despite the lack of an already open balancing market for the participation of demand response, important initiatives are ongoing in Portugal that may enable the participation of distributed resources in the near future. The first and more predictable is the implementation of the EBGL. But besides that, the Portuguese regulator started in 2019 a pilot project for the participation of large demand response in the tertiary reserve market (Diretiva n.º 4/2019. Aprovação Das Regras Do Projeto-Piloto de Participação Do Consumo

[20] In Portugal, the current framework still treats the balancing services as primary, secondary and reserve regulation. For the sake of simplicity, we assume the primary regulation as equivalent to the EBGL's FCR, the secondary as the aFRR and the reserve regulation as the mFRR.

No Mercado de Reserva de Regulação, 2019). In this Pilot Project, the abovementioned constraints for demand participation are relaxed for the participating agents. The offers are submitted only for downwards reserves, and are non-mandatory (differently than the mandatory bids in the case of generation). This project is still on-going, as it was set to last for one period. By the end of the project, a report stating the results of the project will be published by the regulatory authority ERSE[21].

It is important to notice though, that participants on this pilot project must bid over 1MW, and therefore it is aimed at large consumers. Aggregation is not permitted in this pilot, although it is expected to be allowed in future balancing markets, based on a recently published regulation[22]. Therefore, this pilot project is a step forward towards the implementation of BM5, but it would not allow fully using the cVPP concept.

Slovenia

In principle, load is able to provide balancing services. According to the last survey on ancillary services published by ENTSO-E, Slovenian loads use the same market mechanisms as others participants (ENTSO-E, 2019). Regarding the services that demand resources can provide, the survey mentions that only the mFRR is applicable for this type of agent. FCR is only open to generators, while aFRR is open to generators and pump storage units[23]. In fact, in Slovenia the TSO already procures mFRR bilaterally from industrial consumers (Smart Energy Europe, 2018)[24].

Despite the fact that the Slovenian balancing market is somehow open to the participation of demand-response, the smartEn (2018) report is sceptical about the potential and openness of balancing markets for load participation. On one hand, the Slovenian balancing market is said to be limited for the participation of several types of resources. In fact, the contracted reserves are rather small, summing up +-60MW for aFRR in 2015, and +348 MW and -180 MW for mFRR for the same year [REF D1.3]. DER account for roughly 10% and 6% of these for upward and downward mFRR, respectively. However, these resources are rarely activated (Smart Energy Europe, 2018). On the other hand, the participation of DER is bilaterally contracted, and therefore suffers from lack of transparency. In this context, the Slovenia balancing services seem to be open for demand-side participation and the Slovenian TSO seem to proactively look for the participation of these resources. Nevertheless, questions on the (1) transparency of the mechanism, and (2) the possibility for a business model for demand participation in balancing markets, given the size and concentration of the market, remain open.

Sweden

The Swedish regulatory framework is very much linked with the ones in Norway, Finland, and Denmark, as the Nordic countries share a single market and regulation (despite having different TSOs). In principle, in the Nordics allow the participation of demand response in ancillary service markets. Nevertheless, roles

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[21] Considering the time-line for the end of the project, results will be available before the end of the regulatory analysis in InteGrid. Therefore, results on this pilot project are expected to be discussed in deliverable D7.1.

[22] Decreto-Lei n.º 162/2019

[23] Nevertheless, innovation products are testing the possibility of aFRR provision by aggregated flexibility. The H2020 FutureFlow project is an example. Website: https://www.futureflow.eu/

[24] The reader may notice that the smartEn report mentions that aFRR is procured bilaterally by the TSO from industrial consumers. This information however is divergent from the ENTSO-E survey and also from the field experience in InteGrid. Within the stakeholder consultation, industrial consumers providing balancing to the TSO were interviewed, and they were clearly providing a manually activated reserve.

and responsibilities are not well defined, and retailers (the ones that can aggregate demand response and offer in balancing markets) have to incur relatively high costs in providing balancing (Bertoldi et al., 2016).

Besides the lack of regulatory definition and the high costs for retailers to participate, other practical aspects of the balancing markets in Sweden may create additional barriers for the participation of demand response as of today. In Sweden, most of balancing services are provided by hydro generation, cheap and very flexible resource for this kind of product. This, however, may change in the future in favour of DR balancing opportunities, as more inflexible generation (such as wind) is being installed in Sweden. Additionally, demand response can contribute to alleviate north-to-south congestions. As of today, most of hydro generation is located in the north of the country, while the important urban centres are in the south, creating pricing differences between the four bidding zones in Sweden due to the limited transmission capacity. In this context, distributed-connected resources may become an important tool for balancing the system, as they are connected within, or very close to load centres.

Austria

Demand response and aggregation have progressively been accepted in balancing markets, starting in the year 2013. At the time, demand response was expected to bring balancing prices down. Although Austria had significant over installed capacity, prices in balancing markets were considered high (Bertoldi et al., 2016a). Therefore, in theory, demand response can participate in all balancing markets, as long as they fulfil the prequalification process (Smart Energy Europe, 2018). In practice though, the prequalification process is still complex and imposes several limitations for certain types of demand response participation. Starting with FCR, this product has to be offered in a symmetrical way, and therefore is limited to generation. For aFRR, procured in weekly tenders, the minimum bid size is 1 MW. However, polling is allowed, provided that individual consumers maintain a communication (phone contact) with the TSO. Bertoldi et al. (2016) argues that this requirement alone excludes residential consumers from participation, together with the requirement of 4-hour activation block, in the case of mFRR provision. On the prequalification process, balancing service providers (BSPs) can perform the tests on a centralized way, but they need to measure and store data on individual users/consumers.

Despite the complex prequalification process and limiting conditions on product definition, the Austrian regulation is clearly proactive in trying to include demand-connected resources in balancing services provision. The network charges, for instance, are differentiated in case of balancing provision, being charged at a lower rate by DSOs. Also, consumers are not penalized for changing their consumption profile when providing demand response (Bertoldi et al., 2016a). Moreover, Austria is actively participating in the implementation of the PICASSO and MARI platforms, which may help foster the inclusion of demand response in balancing markets not only in Austria, but also in other Member States.

Summary

Considering the conditions described in each of the countries, Table 25 summarizes the importance of each barrier related to the participation of demand response in balancing services.

Table 25: Country assessment of barrier for the participation of demand response in balancing services

Identified Barrier	Guiding Question	AT	ES	PT	SE	SI
Balancing markets not open to demand, included the one connected at distribution level, or	Are balancing markets open for demand-response participation?	3	2	1	3	3

balancing products not suited for demand-side resources						
Balancing market access and product definition not suited for DER (minimum sizes, design of deviation penalties, upwards and downwards allocated together, dual imbalance pricing)	Are products and conditions suitable for demand/DER participation?	2	1	1	2	2
Barriers to the development of the aggregation activity	Are there barriers for the aggregation of resources in balancing markets?	3	1	1	2	3
Barrier for the aggregation of different DER types	Is different type of DER aggregation (VPP concept) possible?	3	0	1	2	3
Barriers to independent aggregation (e.g. balancing responsibility)	Is independent aggregation allowed? Is it viable?	3	1	1	2	3

5.12. Self-consumption

Self-consumption rules can greatly affect the viability of most BMs. Customers will be affected in case self-consumption is not permitted or incentives are not appropriate (e.g. net-metering, large share of regulated costs). DSOs will also be impacted. If self-consumption is not adopted by customers, less flexibility will be available for the development of BM1, for instance.

Portugal

In Portugal, a new regulation on self-consumption was also published in 2019. The Decree-Law 162/2019 provides a framework for both self-consumption from renewable sources (individual or collective) and for renewable energy communities.

Connection rules for the DG associated to self-consumption are based on the installed capacity. Below 350 W, no controls apply, while for generation up 30 kW, only a communication is necessary. From 30 kW to 1 MW, a registration and certification is necessary. The energy surplus can be sold either in the organized electricity markets (directly or through a third party), or through bilateral PPAs. The legislation also mentions that self-generators are responsible for their imbalances in case of market participation. Nevertheless, balancing responsibility can be transferred to a representative.

Collective self-consumption is also a possibility under the new Decree-Law 162/2019. In this case, consumer have to be in close proximity and define internal rules defining rights and obligations. Moreover, the regulation also defines the concept of energy communities (not to be confused with the previously mentioned “collective self-consumption”). The energy communities are broadly defined as associations of consumers and prosumers that explore and benefit from renewable energy production. The legislation is not exhaustive, and defines that Portuguese authorities will monitor the development of this activity. The text do define however that the generating units of energy communities need a generation licence as the distribution generation for self-consumption.

Tariffs due to self-consumption are not completely defined yet, and are expected to be published before the end of 2020 according to article 18 of the Decree-Law 162/2019.

Slovenia

Slovenia too has recently approved a bylaw providing further definitions on self-consumption from renewable energy sources (*Regulation on Self-Supply of Electricity from Renewable Energy Sources*, 2019). The new regulation provides the rules for individual self-consumption, collective self-consumption (CSC) and RES energy communities. Both individual and collective prosumers are limited to install DG with a capacity up to 0.8 times the contracted power for consumption. In the case of CSC, consumers have to agree on benefit sharing terms.

The new regulation maintains a net-metering scheme for the excess energy injected into the grid. The energy injected cannot be sold in the market. At each "accounting period", the energy consumed and the energy produced is netted. If an excess exists, the contract between supplier and prosumer will determine the compensation value for the excess energy.

Sweden

Self-consumption in Sweden is allowed and prosumers are able to sell excess electricity to suppliers. According to Sweco and Osloeconomics (2019), approximately 50% of retailers in Sweden offer to buy the energy surplus from distributed generation. Besides benefiting from the energy sold, prosumers may also benefit from a support scheme in the form of tax reduction. For small DG connected at the location as the consumption unit, a tax reduction of 60 öre/kWh is given in the income tax. This benefit is valid for both households and small businesses. Additionally, storage can also receive a support to cover up to 60% of the installation cost, if connected to self-production of energy. Other support schemes may also be applicable to self-consumption, such as support on PV installation cost and energy certificates from renewable production (Sweco & Oslo Economics, 2019). Grid tariffs over DG are in general exempt for small units.

Spain

Spain was known to have, until very recently, restriction to self-consumption. Prior to 2018, the so-called "tax on the sun" was seen as an important barrier to the development of self-consumption [REF D1.3]. In 2018, the Royal Decree 15/2018 already eliminated this barrier, in a first step to foster self-consumption in Spain [REF D7.1]. More recently, the Royal Decree 244/2019 introduced a new and comprehensive legislation for self-consumption, taking another step to try to increase the adoption of self-consumption (*Real Decreto 244/2019, de 5 de Abril, Por El Que Se Regulan Las Condiciones Administrativas, Técnicas y Económicas Del Autoconsumo de Energía Eléctrica*, 2019).

The new legislation stablishes the types of self-consumption allowed in Spain, as well as the procedures for their operation. Self-consumption is defined as the installation of distributed generation, limited to 100 kW of installed capacity, at the consumers' premises. This includes shared self-consumption as well, in which several consumers can jointly own a distributed generation facility in close proximity to their consumption points.

With the introduction of the Royal Decree 244/2019, there are basically three types of self-consumption in Spain:

- Self-generation without energy surplus: In this modality, the prosumer is not allowed to inject the self-produced energy into the grid. In this modality, the prosumer is exempt from getting the permission for installation of DG.

- Self-generation with energy surplus and compensation mechanism: In order to participate in this category, the prosumer is required to install renewable DG. The surplus of energy can be injected into the grid, and will be compensated according to a simplified mechanism introduced by the RD 244/2019. Both consumed and produced energy will be valued at the hourly price. This can happen for either prosumers that have a contract with a liberalized retailer, or for prosumers at the last resort tariff. Prosumers in this category are exempt from access tolls related to the energy injected into the grid.
- Self-generation with energy surplus and no compensation mechanism: In this category are the prosumers that do not participate in the compensation mechanism. In this case, the prosumer is treated as a consumer and producer, and is fully entitled to all obligation of both activities.

Austria

In Austria, self-consumption is allowed and net metering applied. In principle, no direct support for self-consumption applies (e.g. no FiT). Self-consumption is mainly profitable due to price difference, as the energy taken from the grid is charged with regulated costs that account for approximately two thirds of the total cost for consumers. Prosumers may be charged with a part of this regulated costs, the so-called "electricity duty", at approximately 1,5 cent/kWh. Nevertheless, this charge is only applicable to prosumers whose consumed and produced electricity are higher than 5 MWh/year or 25 MWh/year in case of renewable energy (E-Control, 2018).

Although this approach may be foster the adoption of DG by consumers, the net-metering approach may be considered not as efficient.

Summary

Considering the conditions described in each of the countries, Table 28 summarizes the importance of each barrier related to self-consumption.

Table 26: Country assessment of barriers for self-consumption

Identified Barrier	Guiding Question	AT	ES	PT	SE	SI
Self-consumption not permitted or facing relevant barriers (administrative, economic, technical)	Does regulation allow self-consumption without unfair barriers?	4	4	3	4	3
Inefficient incentives for self-consumption that hamper flexibility: net-metering permitted, large share of regulated costs charged through a volumetric component	Do the tariff structure and self-consumption regulation promote an efficient behaviour?	2	4	4	3	2

5.13. Smart meters

Smart meters are undoubtedly important for almost all business models[25]. Both their deployment and a comprehensive set of functionalities are necessary.

[25] The exception would be BM2, that is focused on the maintenance of the DSO's assets.

Considering that smart meter roll-out and the set of basic functionalities have been discussed in the Deliverables D1.3 and D7.1, in this section we provide an update of the current status of deployment and a summary of the basic functionalities in each country. Table 27 presents an update status for the five target countries.

Table 27: Roll-out and functionalities of smart meters in target countries

	Roll-out status	Expectation of conclusion	Minimal Functionalities	Responsible for Deployment
	41% in LV (2019)	100% by 2026	Although the rollout has not been defined yet, a new regulation (Reg. 610/2019) just defined the rules for smart grids. Min. Functionalities: - Daily reading - Consumption information for customers - Remote on/off	DSO
	58% (2018)	92% by 2022, and 100% by 2025 (legal obligation)	Remote reading, remote on/off control, and events	DSO
	100% (2009)	Ended in 2009[26]	Remote reading on a monthly basis and if the customers want to have hourly values, the DSO has to supply hourly values. A new generation of smart meters with more functions, higher resolution and a standardized interface for customers to add new services shall be in place in 2025.	DSO
	100% (2019)	100% by 2018	Remote meter reading, automatic disconnection in case of surpassing contracted capacity and remote connection/disconnection due to billing and contracting reasons.	DSOs
	12% (2018)	80% by 2020 and 95% by 2022	A specific regulation sets the functionalities required for the Smart Meters, including readings every 15 minutes, bidirectional communication and remote connection/disconnection	DSO

[26] (Commission, 2014)

Summary

Considering the conditions described in each of the countries, Table 28 summarizes the importance of each barrier related to smart-meter deployment and functionalities.

Table 28: Country assessment of smart-meter deployment and functionalities

Identified Barrier	Guiding Question	AT	ES	PT	SE	SI
Insufficient smart meter capabilities	Do smart meter capabilities enable the required functionalities?	3	3	2	3	3
Lack of a clear framework for the deployment of smart meters (technical requirements, accessibility)	Is there clear regulation promoting the deployment of smart meters?	1	4	2	4	3

5.14. Data management

Data management is at the centre of BM3. The grid and market hub proposes a centralized data hub that also acts as a market facilitator. This will enable not only flexibility procurement, but also other types of services, including data services based on the metering data accessible through the gm-hub. Although a centralized data hub is not essential for the development of BM3.1 (data service provision)[27], clear data access rules, privacy requirements and efficient data management is necessary.

Portugal

According to the new regulation of smart grids, the responsible to collect, store and make consumption data available is the DSO, who can also use this data for grid management purposes. The new regulation describes in its article 11 how the data access should take place. The regulation defines that the consumer is the owner of the data, and that retailers and third parties may access the consumers' data provided that they authorize this access. In this case, the DSO is the responsible for providing the relevant information so the consumer can authorize third party data access.

Slovenia

The DSO have access to all data stored inside of the meter. Industrial meters are programmed to transfer the data from the meter to the database every day. Concentrators do it once a month. The Metering Data Management System is the main data base for the data.

Third parties can access to the data provided by the meter only if they get/ or have the written permission, allowance signed by the end customer. The reason is that the real owner of the metering data is the end customer, actually the owner of the metering-connection place. The access is enabled by the DSO establishing a physical connection between the meter and the third party system.

Sweden

As already reported in the deliverable D7.1, a centralized data hub is being developed and implemented in Sweden. This datahub will be operated by the TSO. According to (Svenska Kraftnät, 2018), the data hub commissioning was expected for 2021, although it will be finally delayed. This datahub is expected to

[27] It is indeed relevant for BM3.2 whose main actor is precisely the operator of the data exchange platform.

operate in somewhat similar way as the gm-hub proposed by InteGrid. According the preliminary planning done by the Swedish regulator (no final decision yet), this datahub will be service based and supplier-centric, as shown in the architecture shown in Figure 8.

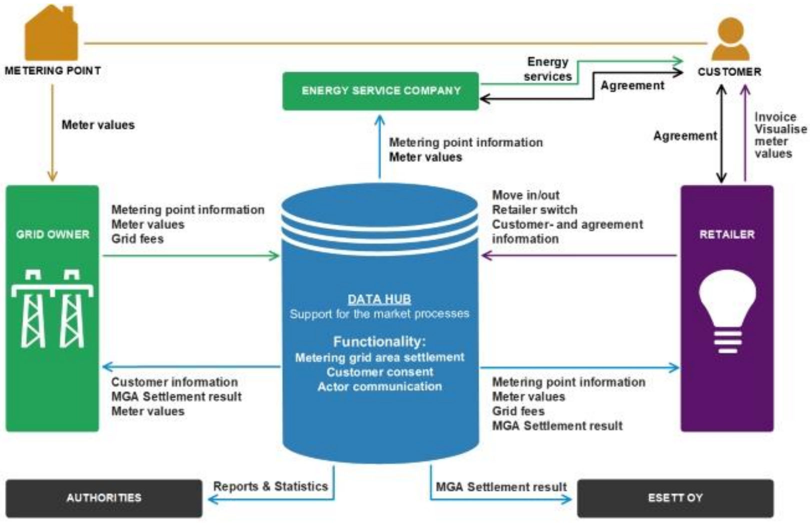

Figure 8: Data-hub in Sweden. Source: Svenska Kraftnät[28]

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 or 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.

Austria

The operation and handling of meter data is a responsibility of the DSO. However, data exchange in Austria is based on a decentralized infrastructure known as EDA (Energy Data Exchange Austria). This was an initiative of the Austria grid operators association (Österreichs Energie). The goal was to base all data exchanges on standard and common formats, interfaces and communication architecture to ensure an easy and unified data access, avoiding the cost of setting up a centralized infrastructure. Accordingly, meters

[28] https://www.svk.se/en/stakeholder-portal/Electricity-market/data-hub/

must have a communication interface with external (flow)meters and external devices present in the customer's system must be ensured.

Another regulation defines the data format and data representation of data (DAVID-VO 2012) for customers. This directive states that end consumer's consumption data shall be made available to the end consumer by the network operator via a customer-friendly website. This means at the same time that it is up to the customer to decide who and which 3rd party will get access to this website and finally to the data.

Summary

Considering the conditions described in each of the countries, Table 29 summarizes the importance of each barrier related to data access and management.

Table 29: Country assessment of barriers regarding data access and management

Identified Barrier	Guiding Question	AT	ES	PT	SE	SI
Lack of definition on the data-management model	Does current regulation clearly state the metering data management model adopted?	4	3	3	4	3
Barriers to grant access to metering data to third-parties, whilst complying with GDPR requirements	Does current regulation enable an easy access to metering data, safeguarding privacy requirements?	4	2	2	4	2

5.15. Summary of the Country Assessment

Table 30 below provides a consolidated view of the assessment of regulatory barriers in the five target countries.

Table 30: Consolidate country assessment of regulatory barriers

Topic	Sub-Topic	Identified Barrier	Guiding Question	AT	ES	PT	SE	SI
DSO Economic regulation	Revenue Regulation	Lack of incentives for DER flexibility procurement due to asymmetries between the treatment of CAPEX and OPEX which favour the former over the latter	Would DSOs benefit from using flexibility to defer or avoid grid investments?	3	1	3	1	1
		Lack of incentives to extend the useful life of network assets beyond their regulatory lives	Would DSOs benefit from keeping assets under operation beyond its regulatory useful life?	1	3	1	3	0
		DSO revenue regulation does not remunerate the cost of new "distribution services" i.e. management of the grid using flexibility	Would DSOs recover the costs associated with the use of flexibility?	2	3	2	1	2
		Allowed revenues based in past investment/costs only, without taking into account future investment needs, including DER	Do regulators use forward-looking tools/scenarios to assess investment needs and/or allowed revenues?	1	3	2	1	2
		DSO are not required to submit long-term investment plans and/or it is not clear how these are reflected into their allowed revenues	Do DSOs and regulators adopt a long-term vision for grid development/regulation, including the use of flexibilities?	1	2	1	1	2
		New smart grid technologies, beyond pilot projects, are not considered in the remuneration of DSOs	Would DSOs recover the costs associated with smart grid technologies deployment beyond pilot projects?	2	3	3	3	3
	Other output based incentives	Incentives for the reduction of energy losses are not in place or provide weak incentives (low-powered incentive, deadbands, non-symmetric designs, cap and floors)	Do DSOs receive (strong) economic incentives to reduce energy losses?	3	2	2	4	4
		Output-based incentives for continuity of supply are not in place or provide weak incentives (low-powered incentive, deadbands, non-symmetric designs, cap and floors)	Do DSOs receive (strong) economic incentives to improve reliability?	1	2	2	3	2
		Energy losses incentives do not consider the impact of DER and smart grid technologies	Is the impact of DER and smart grid solutions considered when setting baseline/target levels for losses?	1	2	1	2	2
		Reference values for reliability indices based exclusively on historical values, cost-benefit analyses that allow continuous improvements are not being carried out	Is the design of incentive schemes, i.e. incentive rates and reference values, based on up to date cost-benefit analyses?	NA	2	2	3	2
		Equal treatment of planned and unplanned interruptions or stringent requirements to qualify as planned interruption	Do incentive schemes provide a fair, distinct treatment of planned and unplanned interruptions?	1	2	2	4	2
		Lack of incentives for innovation and experimentation, including the possibility of requesting regulatory sandboxes	Does regulation leave room for pilot projects, even if they do not fit within the regulation in place?	3	3	3	3	2

Other roles of DSOs	Network access and connection	System users do not have appropriate information regarding expected expansions or upgrades due to new connections (degree of detail of the expansion plans). Lack of transparency on available grid capacity for new DER	Does new generation have information on available grid hosting capacity before submitting an application?	0	1	3	0	0
		Deep connection charges are a barrier for the connection of DG, particularly small units	Does new generation have to pay deep connection charges? Are there differences by size or voltage level?	1	3	2	2	2
		Lack of transparency in the calculation of grid connection charges	Are grid connection charges calculated in a transparent manner and predictable by new users?	3	2	3	3	4
	Ownership of storage	Unclear regulation on the ownership of storage systems by DSOs	Does current regulation clearly state whether DSOs may own/operate storage systems as well as the required conditions for this?	1	2	2	2	2
Local flexibility markets/ services	Mechanism to provide local flexibility	Mechanisms for local flexibility procurement and provision (local markets, non-firm access, agreements DSO-DER) are not implemented	Are DSOs enabled by regulation to procure flexibility from grid users to support grid operation?	2	0	1	0	0
		Lack of regulation for the coordination between TSO and DSO for the provision of ancillary services by DER	Is TSO-DSO coordination mature enough for DER to provide flexibility?	1	1	1	1	1
Balancing Markets	Balancing services	Balancing markets not open to demand, included the one connected at distribution level, or balancing products not suited for demand-side resources	Are balancing markets open for demand-response participation?	3	2	1	3	3
		Balancing market access and product definition not suited for DER (minimum sizes, design of deviation penalties, upwards and downwards allocated together, dual imbalance pricing)	Are products and conditions suitable for demand/DER participation?	2	1	1	2	2
		Barriers to the development of the aggregation activity	Are there barriers for the aggregation of resources in balancing markets?	3	1	1	2	3
		Barrier for the aggregation of different DER types	Is different type of DER aggregation (VPP concept) possible?	3	0	1	2	3
		Barriers to independent aggregation (e.g. balancing responsibility)	Is the independent aggregation allowed? Is it viable?	3	1	1	2	3
Tariffs and self-consumption	Retail tariff design (regulated charges)	Regulated charges show no or little time discrimination; structure inappropriate to promote flexibility	Are taxes and/or other regulated charges distorting flexibility incentives embedded in the tariffs?	2	2	1	2	3
		Tariff design: high share of taxes and other regulated costs may kill other price signals						

	Self-consumption and metering	Self-consumption not permitted or facing relevant barriers (administrative, economic, technical)	Does regulation allow self-consumption without unfair barriers?	3	3	2	3	3
		Inefficient incentives for self-consumption that hamper flexibility: net-metering permitted, large share of regulated costs charged through a volumetric component	Do the tariff structure and self-consumption regulation promote an efficient behaviour?	1	4	1	4	3
		Insufficient smart meter capabilities	Do smart meter capabilities enable the required functionalities?	3	3	2	3	3
		Lack of a clear framework for the deployment of smart meters (technical requirements, accessibility)	Is there clear regulation promoting the deployment of smart meters?	1	4	2	4	3
Data Management	Data Management	Lack of definition on the data-management model	Does current regulation clearly state the metering data management model adopted?	4	3	3	4	3
		Barriers to grant access to metering data to third-parties, whilst complying with GDPR requirements	Does current regulation enable an easy access to metering data, safeguarding privacy requirements?	4	2	2	4	2

6. Key inputs from Integrid SRA and CBA

Integrid has carried out quantitative analysis assessing the technical and economic implications of the implementation of the tested functionalities. These are the scalability and replicability analysis (SRA) in WP8 and the cost-benefit analysis (CBA) carried out in Task 7.2. This section discusses the regulatory implications of these analyses in order to support the recommendations provided in section 7.

6.1. SRA

The scalability and replicability analysis aimed at assessing the implications, impact and potential bottlenecks of deploying the Integrid solutions at a larger scale or in contexts different from the demo areas. This analysis requires a multi-faceted approach. Therefore, it was organized into four types of complementary analyses: functional, ICT, regulatory and economic SRA. For the purposes of this report, the most relevant outcomes are those of the economic, which was also based on the quantitative results of the functional SRA, and the regulatory SRA. Moreover, D8.2 made an analysis of the interactions between the economic and the regulatory SRA.

It is relevant to note that, whilst this regulatory analysis is organized by BMs, the work of the SRA was structured by clusters. Four different clusters were defined, each one of them comprising the functionalities of several HLUCs. The relation between the SRA clusters, the HLUCs and the BMs considered in this report is shown in Table 31. Therein, it can be seen that the SRA focused the work on the provision of flexibility services to the DSO both to support MV grid operation (cluster 1) and LV grid operation (cluster 2), and balancing services to the TSO. The latter may be provided either by a VPP aggregating both DG and DR (cluster 3), or a retailer/aggregator exploiting the flexibility potential from commercial buildings (cluster 4).

Table 31: Correspondence between the clusters considered in the SRA, the HLUCs and the BMs

Cluster #	Cluster Description	HLUCs included	Main BM related	Enabling BMs
1	Flexibility Management for Optimized MV Network Operation	HLUC01, HLUC06, HLUC12	BM1	BM3.2, BM5.4
2	Flexibility Management for Optimized LV Network Operation	HLUC02, HLUC06, HLUC09	BM1	BM3.2, BM4.2
3	Large customer cVPP	HLUC05, HLUC06, HLUC08, HLUC12	BM5.3	BM3.2, DM4.1
4	Office Buildings Aggregation	HLUC06, HLUC10	BM5.1	BM3.2

Therefore, from a regulatory perspective, the four clusters can be split in two groups: i) use flexibilities to support grid operation (clusters 1 and 2) and ii) aggregation of demand to provide balancing services (clusters 3 and 4). The regulatory SRA followed a similar approach as the steps presented in sections 2-5 of this this report. This analysis builds on the previous one by covering a wider range of topics, thus going deeper in the country analysis, and finalizes by providing a set of recommendations. Since several conclusions from the regulatory SRA may overlap with the previous sections, only a brief summary is provided below:

- Clusters 1 and 2 are hampered by current regulation in most countries, mostly due to the lack of local flexibility mechanisms and, specially, a network regulation that favours grid reinforcement over flexibility services.
- Clusters 3 and 4 require not only balancing markets that are nominally open to demand-side participation, but also that the balancing product definitions ensure a level playing field for all flexibility providers. Generally, mFRR (cluster 3) is more open to demand than aFRR (cluster 4). Markets for aFRR are closed to DR participation in many of the analysed countries, and conditions for participation are stricter. Concerning aggregation, broadly speaking, when balancing markets are open to demand response, they tend to be also open to aggregation. Nevertheless, it does not necessarily mean that products and aggregation rules pose no barrier at all. In case of an independent aggregator (cluster 3), two additional aspects need to be considered, i.e. the possibility of aggregating different types of DER and the rules on independent aggregators.

An interesting input to support the regulatory recommendations may be found in the economic SRA, which identified the most relevant benefits for each cluster and the parameters that affect the value of these benefits. Regarding the use of **flexibility to support grid operation (clusters 1 and 2, and BM1)**, the **key lessons learnt** may be summarized as follows:

- In most of the scenarios analysed, the overall economic result was negative. In fact, neither the DSO nor the flexibility providers break even in most cases. This is due to the fact that either the grid did not present constraints, or because DSO-owned resources (e.g. OLTCs, capacitor banks, reconfiguration), whose activation is generally less costly, were enough to solve most voltage issues.
- This implies that a VPP providing services exclusively to the DSO, especially if network problems arise sporadically and depending on meteorological conditions, may not recover its costs.
- In the few scenarios where the overall economic result is positive, the most relevant benefits were labelled as “societal”, i.e. not directly or clearly attributed to a specific stakeholder. These include the reduced voltage deviations, which could be seen as a proxy for avoided reinforcements, and the increased RES production injected into the grid, which reduced CO_2 emissions and fuel costs.
- The business case tends to be better when the distribution grid is stressed, e.g. high DER penetration. If the grid does not face technical constraints, the benefits (essentially lower losses) are very low. Thus, the reduction of network losses is not a main driver for these solutions.
- DSOs may use flexibility services and its own controlled resources to solve grid constraints. Due to their lower operational costs, the latter are usually prioritized (once installed). However, results indicate that the most suitable approach varies case by case depending and DER and grid characteristics. For instance, OLTCs may solve voltage issues in network dominated by demand, but be ineffective to address over voltages driven by DG.

On the other hand, the results of the economic SRA yielded the following **key lessons** learnt related to the **provision of balancing services to the TSO through aggregation**:

- The composition of the VPP/aggregator portfolio, both in terms of the number of DER aggregated and their average available flexibility, plays a central role in the economic profitability. Generally, DR aggregation requires large portfolio sizes and very flexible individuals to show profitability. This is due to the costs require to communicate with and control each DER unit. However, regulation may impose barriers to enlarging the size of the portfolio (e.g. forbidding to bundle different technologies).
- When providing mFRR, results denote that the procurement scheme greatly determines the benefits for the VPP/aggregator. In countries where capacity is procured, remuneration can be much higher than in countries where only activated energy is paid.
- The economic prospects of providing aFRR are generally better since aFRR products are also paid based on capacity, which represented around 45% of the total revenues in the conditions simulated. The results also showed that once contracted to provide regulation band (capacity), the probability of being activated is also larger, which reduces the uncertainties for the VPP/aggregator.
- Nevertheless, it must be noted that some of the current technical requirements common in aFRR markets have been neglected. These include the requirement to submit symmetric bids or having mandatory bidding ratios between upwards and downwards capacity, which can be hard to comply with by a demand aggregator[29]. Other issues not considered, such as prequalification procedures and monitoring requirements, can also jeopardize the profitability of this cluster.

6.2. CBA

As compared to the SRA discussed above, the CBA carried out mostly differs in terms of the scope of the analyses. In this case, the CBA focused on the demo areas, for which a detailed analysis of all relevant HLUCs, i.e. all but those that mostly act as enablers of other functionalities, was performed. This included several HLUCs that were not included in the SRA clusters described in section 6.1, such as HLUC11 (BM5.2), HLUC03 and HLUC04 (BM2). Therefore, in this case, the analysis was organized by demo country and HLUC.

[29] It is generally easier for demand to provide upwards reserve, i.e. a reduction in demand, that to provide downwards regulation.

Table 32: HLUCs analysed in the Integrid CBA per demo country and correspondence with BMs

Demo country	HLUCs analyzed in the CBA	Beneficiaries	Main BM related
Portugal	HLUC01	DSO	BM1
	HLUC02	DSO	BM1
	HLUC08	Industrial consumer	BM4.1
	HLUC09	Residential consumer	BM4.2
	HLUC10	Retailer	BM5.1
Slovenia	HLUC01	DSO	BM1
	HLUC12	VPP operator	BM5.3, BM5.4
Sweden	HLUC03	DSO	BM2
	HLUC04	DSO	BM2
	HLUC09	Residential consumer	BM4.2
	HLUC11	Residential consumer	BM5.2

Moreover, the CBA performed a deeper assessment of some benefits that were only indirectly considered in the SRA due to the difficulties of quantifying them for a large number of scenarios. For example, the distribution grid investments avoided through HLUC01 and HLUC02, which in the SRA were indirectly assessed as reduced voltage deviations or avoided RES curtailment, were, in this case, quantified with the support of DSOs' planning departments. Likewise, the benefits for different types of residential consumers from using the HEMS were evaluated in more detail. Lastly, since the CBA was finalized at a later stage than the economic SRA, the CBA calculations are based, in some cases, on the KPIs and results as measured in the actual demonstrations.

Portuguese demo:

The Portuguese demo is the complex and extensive; thus, the CBA had to cover a number of HLUCs, where the main actors included the DSO, a retailer, industrial consumers and residential consumers. The most relevant lessons learnt for this demo are the following:

- **HLUC01 and HLUC02:** these HLUCs address the procurement of DER flexibility by the DSO to avoid network reinforcements in the MV (HLUC01), and reduce PV or EV curtailment in the LV (HLUC02). The CBA for these functionalities is greatly affected by two parameters largely based on assumptions. Firstly, several of the software tools required to enable these solutions are essentially experimental and, therefore, do not have a clear commercial cost. In these cases, an estimation of the development costs has been considered. Secondly, since the analysis is performed from the viewpoint of the DSO, it is necessary to estimate the compensations/payments that the DSO would make to the flexibility providers.

  Therefore, for the purposes of this report, it is more relevant to analyse the factors that determine whether or not the use of DER flexibility may actually yield relevant benefits. More specifically, the main benefits are derived from solving grid constraints, i.e. grid loss reduction is not a major driver for these solutions. Results show that voltage or congestion constraints can be caused either by demand or by generation and that the location and time when the flexibilities are required by the DSO would be different. If both happen in the same network, but at different times and different elements of the grid, this would significantly increase the costs, as a higher number of flexibility providers would need to be equipped with communications and control devices.

Moreover, the available flexibility should be enough to completely remove the network constraints, or reinforcements/curtailment would be needed anyway. This latter issue is more relevant when grid reinforcements is the solution by default since, whilst it is possible to curtail as many kW of generation or demand as needed, network investments are non-continuous.

- **HLUC08:** the CBA for this HLUC focused on the case of a water utility optimizing the energy use in several water treatment plants and pumping stations to reduce its energy costs and, additionally, provide mFRR to the TSO. The analysis shows most benefits (approximately 85%) come from the optimization of internal processes rather than the provision of mFRR. Under current market rules at least, this HLUC shows more potential in the reduction of energy costs than in the provision of mFRR.
- **HLUC09:** in this HLUC, residential consumers would purchase smart appliances controlled by a HEMS to reduce their energy costs. The results show that end consumers can indeed reduce their energy costs significantly, especially those consumers with a higher electricity consumption and equipped with more smart appliances. However, these savings may not be enough to compensate for the costs of the aforementioned technologies, particularly when the full purchase cost of these appliances are included in the calculations, i.e. assuming the replacement is driven for home automation purposes exclusively. Nonetheless, this functionality could yield a better CBA outcome if consumers had to procure new appliances anyway, and only the cost difference between a regular and a smart appliance were considered. Likewise, the CBA allowed estimating the market price that the HEMS, which is not a commercial product, should reach in order to be attractive for end-users.

  The electricity price (variable component of the tariff) is another key parameter in this case. The CBA considered a dynamic electricity price reflecting the variations in production costs, so that end-user flexibility can result in a gain both for the user and the system.

  Lastly, it is relevant to highlight that the consumers with self-generation installations showed the worst CBA result. This may seem counter-intuitive as the consumer could use home automation to increase its self-consumption ratio and reduce energy costs accordingly. However, the results show that this consumer would have already achieved significant savings through self-consumption alone, i.e. no home automation, and therefore the incremental gains from using the HEMS are lower than for those consumers with no on-site generation.
- **HLUC10:** under this HLUC, the retailer would control the HVAC systems of commercial buildings to provide aFRR to the TSO. As in the case of the economic SRA, some assumptions were made in order to do the calculations. Otherwise, it would not have been possible to do any calculations, since the balancing market rules forbid demand from participating in this market in Portugal. The NPV of the CBA[30] tends to be positive as long as the probability of being activated is above a certain level of approximately 30% (measured as the ratio over the available flexibility potential). The reason is twofold. On the one hand, costs are lower since only AC systems are controlled. On the other hand, revenues from providing aFRR in Portugal are expected to be much higher than mFRR (provided the retailer or demand aggregator could comply with the prequalification and participation requirements).

[30] Considering a 12-year period and a 15% discount rate.

Slovenian demo:

As shown in Table 31, the CBA for the Slovenian demo addressed the procurement of flexibility by the DSO to support MV grid operation (HLUC01) and the provision of both local flexibility and balancing services by the VPP operator through aggregation (HLUC12). The main conclusions obtained for each HLUC can be summarized as follows:

- **HLUC01:** The use of flexibility for the DSO in this demo area shows a positive CBA as the network is facing some voltage constraints. However, comparing the three future scenarios envisioned by the DSO, it was observed that the net benefits for the DSO greatly depend on the level of grid congestions since avoided investments is the main benefit expected from this HLUC.

  Those results indicate that the best alternative to be implemented by the DSO, i.e. the use of flexibility or grid reinforcement, greatly depend on the local conditions, as already discussed above. Moreover, the results also show that when faced with such decisions at the planning stage, the DSO could face significant uncertainties about the future evolution of demand or DER penetration. Risk aversion may lead the DSO to favour grid investments over flexibilities in these situations.

- **HLUC12:** the CBA for this HLUC shows that the cVPP faces a more favourable environment than the tVPP. The first reason is that the cVPP resources, with similar costs to the tVPP, would be contracted/activated more often because grid constraints happen sporadically. This would not be an issue if the resources used to provide balancing services were the same ones activated to provide services to the DSO. However, the best resources to provide balancing services, e.g. those with higher individual flexibility potential, are not necessarily located in the areas where they can solve network constraints. Thus, even if the software platform is common to both services, the need to deploy communication and control infrastructure to a higher number of resources significantly increases the costs for the VPP operator.

  These results are also affected by the particular design and conditions of the mFRR market in Slovenia, where both reservation and activation of resources are remunerated. Alternative market rules, e.g. no reservation payments, would diminish the profitability of the cVPP. This is also behind the low profitability of the tVPP, which was assumed to be remunerated only after an activation by the DSO. Thus, the structure and amount of the payments made from the DSO to the tVPP are key to ensure the tVPP breaks even too.

Swedish demo:

Lastly, in the case of the Swedish demo, the CBA analysed two use cases focused on the DSO implementing advanced grid monitoring functionalities for predictive maintenance and advanced fault location (HLUC03 and HLUC04 respectively), and two other use cases aiming at promoting an efficient electricity use by residential consumers through price signals and behavioural DR (HLUC09 and HLUC11 respectively). On the ensuing, the main takeaways from the Swedish CBA are presented:

- **HLUC03**: the implementation of predictive maintenance requires deploying sensors in every single transformer included in the functionality as well as a central software system that, based on the previous information, determines the asset conditions and supports decision-making regarding asset maintenance. The former cost category is linear with the number of transformers monitored, whereas the latter is mostly a fixed cost. The results show generally a positive CBA result for this HLUC. However, it is relevant to break down the results by type of transformer. Broadly speaking, deploying this solution should be prioritized on those transformers whose failure affects a higher number of consumers or in those transformers that supply critical consumers whose value of non-served energy is very high.

Nonetheless, the incentives for DSOs to do so greatly depends on the existence and design of incentives to improve reliability. In the case of Sweden, this incentive mechanism is based on the cost of interruptions for consumers, estimated through their willingness to pay (WTP). This cost is computed with different values for different customer categories (see Table 11). Therefore, the DSO sees an incentive to prioritize predictive maintenance of some transformers as mentioned above. In other countries where the incentive schemes are based on average cost of interruptions for consumers, this efficiency signal may be lost.

This HLUC may have an added benefit that could not be quantified in this CBA. This is the increase in the operating lifetime of the assets, probably at the expense of increasing maintenance expenditures. However, as discussed in section 5, some regulatory frameworks implicitly encourage DSOs to remove assets from operation after the end of their regulatory lifetime.

- **HLUC04**: as in the previous case, an advanced fault location yielded a positive CBA result for the demo area. Nonetheless, when interpreting these results it should be considered that they are affected by the baseline scenario with respect to which the benefits are assessed. In the years preceding, the demo area had experienced very high levels of ENS, thus the advanced fault location showed very significant benefits. This has some regulatory implications. Firstly, regulators face high uncertainties when setting reference values for reliability levels and assessing whether reductions in SAIDI/SAIFI are genuinely the result of the efforts made by the DSO. Additionally, fault location may not have to be deployed all over the grid, but only in those areas where the improvements expected justify the expenditures (e.g. high fault levels).
- **HLUC09 and HLUC11:** these two HLUCs share the same primary goal, which is to foster energy bill savings for residential consumers. However, they follow very different strategies to achieve this objective. Whilst HLUC09 uses price signals and home automation technologies, HLUC11 is based on behavioural strategies (e.g. peer comparisons or target-setting) to promote an efficient energy use. The CBA shows that the more conventional residential DR in HLUC09 achieves, on average, almost three times higher energy savings than BDR. However, it is also significantly more costly for the consumers. It must be considered that these results can be very different in different contexts, as they depend on end-user acceptance and engagement as well as electricity tariffs.

7. Regulatory recommendations

Building on the work presented in the previous section, this section provides a set of regulatory recommendations to overcome the regulatory barriers presented in section 4, considering the current situation in the five target countries (section 5). These recommendations have been developed taking into account the need to be aligned with the CEP dispositions (section 3) as well as the key lessons learnt in the Integrid SRA and CBA (section 6).

In order to interpret the recommendations provided herein, it is relevant to bear in mind that the **different regulatory topics** addressed in this report, in practice, **are highly interrelated**. For instance, DSO revenue regulation needs to be well coordinated with the design of local flexibility mechanisms or the grid connection regulation. Likewise, some tariff designs and self-generation regulations require having the appropriate metering functionalities in place. Because of this, this section discusses the interactions between different regulatory topics. Furthermore, the individual **recommendations may not be considered in isolation**, but as a combined package.

7.1. Enabling and promoting DSOs to use flexibility

The procurement of DER flexibility by the DSO as a means to support distribution grid operation and, eventually, defer or avoid grid reinforcements is at the core of the Integrid concept. However, whilst it may be straightforward to legally enable DSOs to procure services from network users, it can be much more challenging to ensure that regulatory conditions truly provide DSOs with the incentives to do so. Such conditions require the combination of several mechanisms as displayed in Figure 9. The four main regulatory topics addressed in this section are summarized below:

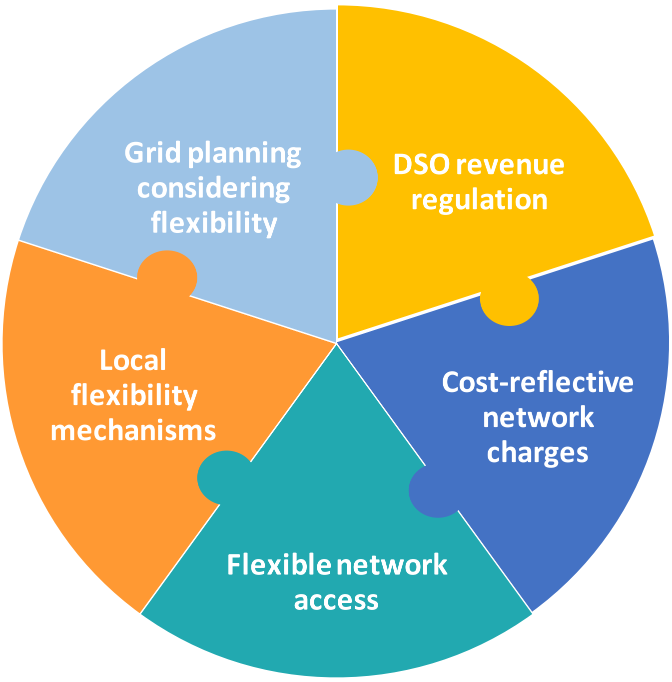

Figure 9: Regulatory aspects related to the use of flexibilities

i. DSO revenue regulation: DSOs should be encouraged to use flexibility when this is the least costly alternative. This requires revisiting DSO revenue regulation to remove the existing bias favouring CAPEX-based solutions, i.e. reinforcement the grid, over OPEX, i.e. flexibility procurement.

ii. Cost-reflective network charges: distribution network charges, in addition to a cost recovery function, can serve to promote an efficient grid utilization if properly design. In the long-term, this can serve to avoid costly reinforcements.

iii. Flexible network access: granting all new grid users with firm network access may be excessively costly and delay the connection of new DER to the grid. If all potential network problems need to be solved at the connection stage, this would render useless the future use of flexibility in many cases. Flexible network access should be enabled so that grid users and DSOs can benefit from lower grid investment needs. Flexible connections agreements can be used together or in coordination with market-based flexibility procurement.

iv. Local flexibility mechanisms: schemes enabling DSOs to procure the flexibility from DER, whenever possible based on market mechanisms, ought to be in place. An effective and efficient design of these mechanisms could combine a long-term procurement, so that DSOs may consider them for the development of the grid, and short-term dispatch to promote an efficient pricing.

v. Network planning: distribution investment plans that consider the use of flexibilities as part of the DSO toolbox shall become an integral part of price reviews. This would also require NRAs to adopt forward-looking cost assessment methods capable to evaluate future investment needs in each DSO area.

7.1.1. DSO revenue regulation

Power distribution, being considered a natural monopoly, is a regulated activity whose revenues are determined by the corresponding NRA. Nowadays, most countries allegedly apply some form of incentive regulation for electricity distribution, most commonly a revenue cap approach (CEER, 2020a). However, a deeper analysis clearly shows that **efficiency incentives are not evenly placed on CAPEX and OPEX**. Whilst annual efficiency requirements (cost reductions) are generally imposed on OPEX, new DSO investments are roughly included in the RAB as declared (subject to auditing) and passed-through to the network charges.

European regulators acknowledge this is a generalized situation in network regulation across Europe, as stated in (CEER, 2020a):

> *"The survey revealed that a majority of the regulators in electricity and gas focus on cost saving on the OPEX side. On the CAPEX side, nearly 20% of respondents have efficiency requirements applied. This result is independent of the energy (gas/electricity) and the market layer (TSO/DSO). In some cases, an efficiency requirement is applied to TOTEX (CAPEX+OPEX)."*

This is a clear barrier for reducing grid reinforcements through the procurement, and activation when needed, of flexibility by DSOs. Doing so would imply a reduction in CAPEX at the expense of increasing OPEX to remunerate flexibility providers. Current regulation would be myopic to this CAPEX reduction, whereas, the increase in OPEX may be seen as inefficient. As a result, the **DSO could actually be penalized even if opting for a flexibility-based solution can be less costly** overall.

The review of existing regulation in the target countries revealed that this barrier is active in all five countries in different degrees. Regulators in all these countries update the RAB somehow based on the actual investments carried out by DSOs. The two main differences are:

a) When the new investments are added to the RAB: annually as in Portugal (MV and MV) and Slovenia, annually but with a two-year lag as in Spain and Austria, or at the end of the regulatory period as in Sweden.

b) How new RAB additions are valued: at the actual costs as in Portugal, Slovenia or Austria (book values), or as a replacement value based on standard or norm costs as in Spain or Sweden.

This does not mean regulators in these countries are unaware of this problem. This so-called "CAPEX bias" in existing revenue regulation was highlighted by all the regulators interviewed during the stakeholder consultation presented in D7.6, which comprised NRA representatives from all target countries but Austria. Several of them pointed out that the solution could be to **shift towards a TOTEX-based regulation**. However, they were **not sure how to implement this approach** in practice.

Within the target countries, two of them already have some form of partial TOTEX regulation in place. In Portugal, LV networks are regulated under a TOTEX framework under which all costs, except some non-controllable ones, are subject to an efficiency target[31]. In Austria, despite the fact that actual investments are added to the RAB, an ex-post TOTEX benchmarking study is made at the beginning of the next regulatory

[31] Note that LV networks in continental Portugal are owned by the municipalities and operated by the DSO under concession contracts. These contracts expire in the next few years and the regulator plans to organize tendering procedures to check if new entrants could be interested in taking over the concessions under the rules laid out in Lei nº 31/2017.

period. The efficiency rates obtained in this analysis is used to determine the productivity factor of each DSO for the next few years. Thus, DSOs have an implicit incentive not to overinvest to be granted a good efficiency rate.

However, the previous approaches do not fully remove the aforementioned CAPEX bias and a major part, if not all, of the RAB is still dependent on the actual investment carried out by DSOs. Therefore, solutions for this problem are required if DSOs are to be encouraged to use flexibilities when this is more efficient. It is important to take into account that regulators could hardly know in every single case what the less costly solution, i.e. CAPEX-oriented or flexibility-oriented, is less costly in each case. As shown by the SRA and CBA analysis, determining the most suitable solution requires a case-by-case analysis considering: investments required and planning criteria, DSO-owned resources in the concerned area, available flexibility and capability to alleviate the constraints, corresponding costs, etc.

One potential approach is to require NRAs to analyse all this information and make a decision at the time of approving the investment plans. However, this would require very significant resources, face hurdles imposed by information asymmetries, and it could be seen as an attempt to micromanagement that would face resistance from DSOs. Instead, distribution regulation should set general revenue requirements and remuneration formulas that provide the right incentives for DSOs to be efficient. These efficiency incentives should be neutral to CAPEX and OPEX reductions so as to allow the DSOs to exploit the potential trade-offs between both types of expenditures.

Therefore, the first recommendation to shift towards a TOTEX-based regulation by decoupling new RAB additions from actual investments. In practice, this requires decoupling RAB updates from actual DSO investments. Following (OFGEM, 2017), this can be done by considering **a fixed capitalization rate**, as opposed to the real CAPEX/OPEX ratio, when updating the RAB. This capitalization rate represents the share of total allowed expenditures, including flexibility-related costs, that is considered as equivalent to investment costs and added to the RAB. The remaining share would be treated as an OPEX. The general revenue setting when adopting this approach is shown in Figure 10.

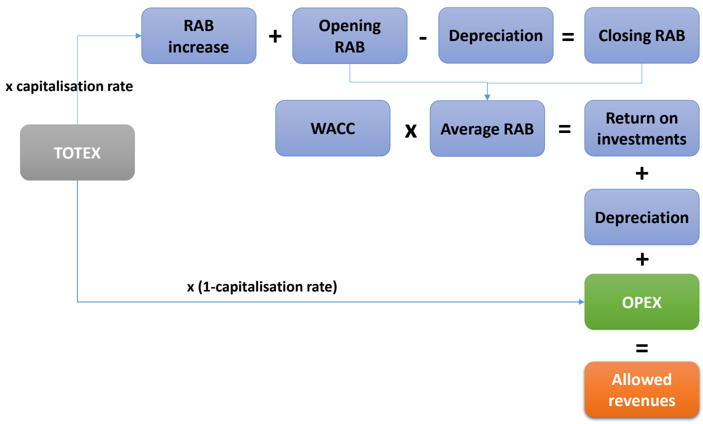

Figure 10: Revenue setting using a fixed capitalisation rate (TOTEX regulation). Based on (OFGEM, 2017)

It is relevant to note that this approach can lead to deviations between the actual asset structure of DSOs and the RAB. In order to avoid abrupt changes in the remuneration, a **progressive implementation over several regulatory periods** may be necessary. Some options that regulators could explore include applying the fixed capitalisation rate only to certain asset categories (by asset type or by voltage level), or start applying values close to the actual CAPEX/TOTEX ratio of DSOs and adapt them over time.

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The new additions to the RAB of DSOs should be decoupled from their actual investment in order to equalize the incentives for reducing CAPEX and OPEX.

This can be done by applying a pre-defined capitalisation rate on the DSO allowed TOTEX. A progressive implementation needs to be made to prevent abrupt changes in the remuneration.

Another relevant regulatory implication of this change in paradigm is that DSOs and regulators face a more uncertain context. Future investment needs are no longer driven exclusively by increases in a peak demand[32] that is relatively easy to forecast. More and more, investment needs will be driven by the connection of RES units in the HV and MV distribution grids, or the connection of EV charging points or self-consumption installations. The adoption rates and location of these DER is uncertain as they depend to some extent on end-user preferences, policy and regulatory decisions, economic conditions, etc. Therefore, a purely ex-ante allowed revenue determination might enlarge the impact of regulatory forecasting errors made at the price reviews.

In order to mitigate these uncertainties, a second recommendation consists in **introducing some flexibility mechanisms in remuneration formulas**. This consists in combining an ex-ante revenue determination with some ex-post corrections, mid-period or at the end of the regulatory period. These ex-post corrections would aim to reflect deviations with respect to ex-ante forecasts and they should be made based on some pre-defined rules (to prevent regulatory uncertainties). The main existing schemes comprise profit-sharing mechanisms or event-triggered reopeners:

- **Reopeners**: this instrument consists in reopening the revenue determination when a large deviation with respect to the conditions expected at the price review happens. The type of events that can trigger a reopening may include large demand forecast errors, high increase in DG connection, or sudden technology changes. This reopening may take place at the request of the DSO at any moment during the regulatory period, or at pre-defined time windows (OFGEM, 2013a).
- **Profit-sharing**: a profit-sharing regulatory contract can be seen as a hybrid between a cost-of-service and a revenue cap approach (Joskow, 2008). Whereas under a pure revenue cap regulation DSOs are exposed to 100% of the deviations between the ex-ante allowances and the actual expenditures (*E*), under a profit-sharing regulation, DSOs would only be exposed to a pre-defined share of these deviations, known as the sharing factor (*SF*). This sharing factor can be either symmetric, i.e. it takes the same value regardless of the direction of the deviation, or asymmetric, i.e. it takes a different value depending on the direction of the deviation.

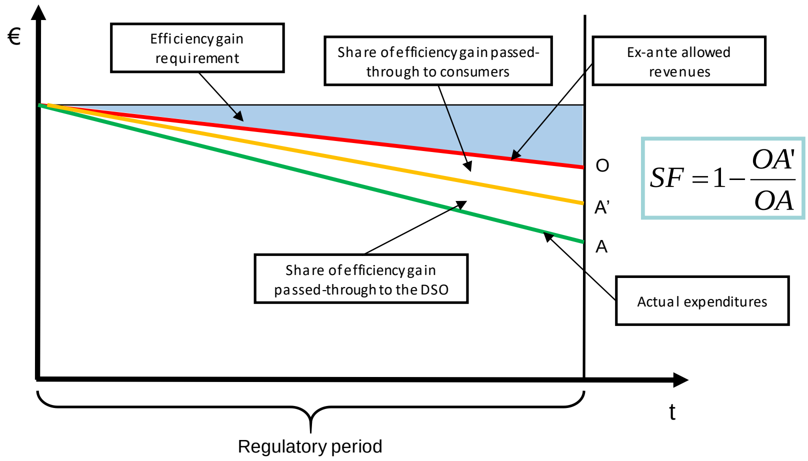
Figure 11 illustrates the functioning of this mechanism (assuming a symmetric sharing factor). The formula at the top of the figure would be the DSO remuneration formula. The annual ex-post allowed revenues (R_n) would be computed as the sum of the conventional revenue cap formula (in this case represented through the conventional RPI-X approach) times the sharing factor (*SF*) plus a second term that is obtained as the

[32] For the sake of simplicity, only load-related investments are considered in this discussion. Investment may also be driven by other factors, including asset replacement, reliability, etc.

product of the actual expenditures declared by the DSO (ex-post) times the complementary of the sharing factor. This remuneration formula has the following characteristics:

- If the sharing factor is equal to 1, the formula is a pure revenue cap.
- If the sharing factor is zero, the formula corresponds to a pure cost of service regulation.
- For values of the sharing factor between o and 1, the formula is a hybrid approach. The higher the value of SF, the closest the regulation would be to a revenue cap and vice versa.

$$R_n = R_{n-1} \cdot (1 + RPI - X) \cdot SF + E_n \cdot (1 - SF)$$



$$SF = 1 - \frac{OA'}{OA}$$

Figure 11: Illustration of a profit-sharing mechanism combined with a revenue cap

Profit-sharing regulation is a well-known concept in economic theory. In fact, several European regulators apply it in the regulation of gas TSOs (ECA, 2018). However, it has not been extensively applied to the regulation of electricity DSOs. Only in the UK and Italy, NRAs have applied a combination of profit-sharing contracts with menu regulation (OFGEM, 2013a) (ARERA, 2016) to the regulation of electricity DSOs. The main idea of this regulatory approach is that regulator offer DSOs the possibility to choose between different profit-sharing contracts with different combinations of ex-ante allowed revenues and sharing factors. By doing so, regulators can also encourage DSOs to submit accurate investment forecasts. Additional details on the design and implementation of profit-sharing contracts with menu regulation to regulate electricity DSOs can be found in (Crouch, 2006) and (Cossent and Gómez, 2013).

DSO revenue regulation - Recommendation No. 2

DSO remuneration formulas should incorporate flexibility mechanisms, such as profit-sharing or trigger schemes, which mitigate the impact of regulatory forecasting errors in a context with growing uncertainties.

7.1.2. Network tariffs

This section will focus specifically on the use-of-system (UoS) charges, i.e. the part of the regulated charges paid periodically by grid users to recover the allowed revenues of DSOs. One-off connection charges are discussed in section 7.1.3, whereas other aspects related to the design of other regulated components of the tariffs and the retail market will be addressed in section 7.5.1.

The goal of distribution UoS charges is, at least ideally, twofold: i) recover the DSO allowed revenues and ii) promote an efficient grid utilization. However, traditionally tariff structures have essentially prioritized the first of them, neglecting the second. However, under increasing shares of DER, network tariff design is essential to ensure an efficient DER integration.

Distribution tariffs have conventionally been largely allocated through flat, i.e. time independent, volumetric charge (€/kWh), especially for household consumers (DG-Ener, 2015). This is a simple approach that works well with unidirectional power flows and very homogeneous grid users. However, the growing penetration of DER significantly changes this paradigm as many different types of grid users, with different levels of capacity utilization, can be found. What is more, purely volumetric tariffs can create perverse incentives for grid users and over promote of deter certain end-user technologies. It is important to highlight that network costs are largely fixed and, once incurred, they are independent on the volume of electricity consumed.

The deployment of smart meters allows the implementation of more advanced tariff schemes that send users better signals for utilizing the grid more efficiently (CEER, 2020b). This includes the use of capacity or fixed charges. In fact, Article 18 of the CEP electricity Regulation states that "*Distribution tariffs may contain network connection capacity elements and may be differentiated based on system users' consumption or generation profiles*".

Thus, the first recommendation would be to **abandon purely volumetric network tariffs** and analyse the introduction of capacity-based or fixed charges to allocated fixed network costs.

Network tariffs - Recommendation No. 1
Purely volumetric distribution network tariffs should be avoided. Capacity charges and/or fixed charges should be introduced to recover the fixed network costs, provided metering technologies allow to do so.

In addition to the different terms that make up the distribution UoS charges, a second relevant topic is that of the **time and locational discrimination**. Thus, grid tariffs are higher in those periods and/or areas where the network elements are closer to their rated capacity.

In a first-best scenario, each network user would be charged according to its contribution to the peak flow of each network element. However, this method is impractical as it would result in differentiated network tariffs for each node of the system and time period. Such a system could not be practically managed in practice. Moreover, current legislation may not allow for it in some countries. Therefore, a **trade-off must be met** regarding the time and location granularity embedded in the network tariffs.

In any case, smart metering does allow to progressively introduce more granular and cost-reflective network tariffs. Pre-defined static ToU tariffs would allow grid users to modify their behaviour and make robust investment decisions in different technologies (smart appliances, solar PV, storage EVs). Static ToU network tariffs may not present many time blocks; possibly 2-3 periods for LV consumers could be enough (e.g. to promote night EV charging), whereas a higher number of periods could be implemented for higher voltage levels.

Likewise, geographical differentiation in distribution tariffs is scarce. In some countries, national tariffs only change by voltage levels, e.g. in Spain, whereas others present distinct network tariffs by DSO area, e.g.

Sweden. However, grid utilization may indeed change significantly below those levels. The existing trade-off can be met by selecting large enough network areas where the level of utilization may be consistent and calculate the tariffs for those areas (including ToU segmentation). Note that these tariffs differentiated per large areas can be complemented with local flexibility mechanisms specifically designed to deal with constraints happening inside these areas (Gómez, et al., 2020). Furthermore, flexibility mechanisms can be implemented to introduce a geographical discrimination in countries where legislation prohibits doing so in the network tariffs (e.g. Spain).

The second recommendation is therefore to **introduce locational and time differentiation** in the network tariffs reaching a **trade-off between complexity and efficiency**, so that grid users can make decisions on the adoption of new technologies under predictable conditions. This could be met with a limited number of time periods for LV consumers, and a higher time discrimination for larger consumers or higher voltage levels. In terms of locational discrimination, large network areas with consistent utilization rates could be selected to set different network tariffs. Local flexibility mechanisms can be used to address network constraints inside these areas.

Network tariffs - Recommendation No. 2

Locational and time differentiation should be introduced in the network tariffs, so that grid users can make decisions on the adoption of new technologies under predictable conditions.

LV ToU tariffs may present a small number of time periods for LV consumers, whereas a higher number may be applied in higher voltage levels.

Large network areas with consistent utilization rates could be selected to set different network tariffs. Local flexibility mechanisms can be used to address network constraints inside these areas or in countries where geographical discrimination is not allowed.

The discussion above essentially refers to static tariffs that are set months ahead. However, tariff discrimination may also be introduced in the short-term through the so-called **dynamic network tariffs**. Dynamic tariffs aim at preventing grid constraints foreseen in the short-term. Flexible consumers capable to react to these tariffs could manage their loads and be compensated for that.

Dynamic network tariffs are not implemented in any of the target countries[33]. Nonetheless, a pilot project based on the use of dynamic network charges for MV, HV and EHV industrial consumers has taken place over a period of one year (June 2018-June 2019). The rules for the design and implementation of this pilot are defined in (ERSE, 2018d). The dynamic charging approach was designed as a form of critical peak pricing (CPP) built on top of a ToU network charging structure. Therefore, in the absence of critical conditions, consumers would be exposed to ToU network charges with four time blocks: (non-critical) peak, plateau, valley and super-valley. The exact scheduling of these periods changes by region, seasons and day of the week. When critical conditions are detected, a critical period is called (peak periods would be transformed

[33] Dynamic network tariffs, which aim to price network constraints, should not be mistaken by dynamic retail pricing, which reflect the value of energy production in each moment. As discussed in section 7.5.1, residential consumers in Spain and Sweden can opt for a dynamic pricing contract nowadays.

into critical peak periods) and the capacity charge (€/kW) would be increased for those hours. End consumers must be notified 48h (weekdays) or 24h (weekends and holidays) in advance.

The ToU charging would send long-term signals to adapt to general system conditions, whereas the CPP component would intend to solve problems caused by critical system conditions detected in the short-term. The dynamic charging pilot was run along another pilot with advanced ToU network charges (which included a geographical differentiation in the definition of the periods) and, each one of these, would have 100 participants and a control group to allow for an evaluation of the results.

The implementation of dynamic network tariffs present additional challenges related to the time **granularity and tariff predictability**. Fully dynamic network tariffs can change on daily basis to reflect the changing periods of maximum grid utilization, which can introduce significant uncertainties for grid users. In practice, implementing dynamic network tariffs could require a combination of pre-defining critical periods together with a short-term notification for those events not easily anticipated, as shown in the Portuguese example.

Moreover, dynamic network tariffs should be **coordinated with local flexibility mechanisms** as both address similar issues (CEER, 2020b). The most suitable alternative in each case may depend on the extension of the area where flexibility is needed. For instance, system wide reactions, e.g. due to a heat wave, could be addressed with day-ahead dynamic tariffs, whereas more localized constraints can be addressed more effectively through local flexibility markets (Gómez et. Al, 2020). For instance, in the Portuguese pilot with dynamic tariffs, the whole country was divided into 6 large regions, which is not enough to tackle congestions in a smaller distribution area.

Network tariffs - Recommendation No. 3

If dynamic tariffs are implemented, unpredictability problems ought to be mitigated. Moreover, the design of dynamic tariffs, e.g. geographical granularity, should be coordinated with local flexibility mechanisms. The former could be more suitable to solve system-wide critical periods, whereas the latter seem more suitable for more localized network constraints.

7.1.3. Grid connection and access

Over the next few years, provided that the decarbonization targets set in the NECPs are to be fulfilled, distribution networks are expected to experience the connection of large volumes of DER. Therefore, the technical and economic criteria followed to grant access to the grid to these new resources are essential to ensure the targets are achieved efficiently and in time.

In this regard, three main topics will be addressed. First, the regulation concerning connection charges, i.e. the one-off payments that new network users have to make to cover for the costs of connection, will be discussed. The second topic addressed is the possibility to implement flexible network access rights to new grid users as a means to achieve a faster and less costly grid connection thanks to a more active grid operation. Lastly, information disclosure obligations for DSOs, on available grid hosting capacity or level of connection charges, are discussed.

Connection charges

There are two main approaches to determine the level of the connection charges that new grid users must pay to be granted network access: deep charges include the direct cost of connection as well as the cost of reinforcing the upstream network to accommodate the new capacity, whilst shallow charges only comprise the direct connection costs. In the latter case, any additional cost of connecting the new users would be socialized and recovered through the network charges paid by all users. None of these approaches is necessarily better than the other as both approaches have their advantages and disadvantages:

- **Deep connection charges**: they provide new users with efficient locational signals, i.e. they are encouraged to connect to the areas with more available hosting capacity. However, deep connection charges can represent an important barrier for the connection of small-sized DER, for which connection charges can represent a significant part of the capital costs. Moreover, when the calculation of the deep connection charges is deemed non-transparent by the users, this can result in litigations and important delays in the connection process.
- **Shallow connection charges**: the main advantage of shallow connection charges is that they lower the costs for new DER to connect to the grid. Moreover, they avoid litigations over the calculation of connection charges in case of lack of transparency. Likewise, this approach prevents problems derived from the allocation of the responsibility of reinforcements when several applications for connection are received for the same area either at the same time, or in a short time span (IRENA, 2017)[34]. However, shallow charges fail to provide efficient location signals, which can lead to significant cost increases, especially in higher voltage levels.

Additionally, intermediate approaches between deep and shallow charging may be found. These are generally referred to as shallowish connection charges. For instance, new grid users may be requested to pay for the direct costs of connection plus a certain share (not fully) of the upstream reinforcement costs or only the reinforcement costs within the same voltage level at the point of connection (reinforcements in upstream voltage levels would be socialized).

The review of the current regulation in the target countries showed that Portugal, Sweden and Austria apply deep connection charges mostly calculated by the DSO (the regulator may set the cost of some components). Note that small LV consumers are normally subject to more standard connection charging approaches, e.g. based on look-up tables using parameters such as size, distance to the grid, etc. In Slovenia, new users pay a pre-defined grid connection fee; this may be considered as a form of shallow/shallowish charging approach. Lastly, in Spain there is a combination of approaches depending on the size of the user. Generally, new users who wish to connect to the distribution grid have to pay deep connection charges determined by the DSO. However, exceptions apply for small users, e.g. consumers connecting to the LV grid in populated areas pay pre-defined shallow charges. In the case of generators, exceptions apply per size and voltage level:

- Units below 20kW located near consumption points pay regulated shallow connection charges.

[34] As connection requests are usually processed on a first-come/first-served basis, the first applicants could use the existing grid capacity at a low cost. If subsequent requests for connection trigger the need to reinforce the grid, these new users may be forced to fully defray these cost despite the fact that recent connections could also be considered responsible for these connections. This problem can be worsen due to the scale economies in network components.

- Units below 100kW connected to the LV or units below 1MW connected to the MV grid pay shallowish connection charges.

In order to remove barriers to the connection of small DER units whilst providing efficient locational signals to large projects that could otherwise cause significant cost increases, it is recommended to **combine shallow/shallowish charging approaches for small-sized DER with deep connection charges for larger units**. The differentiation may be introduced by requested capacity and/or voltage levels. Additionally, it is important to highlight that the deep charging approach should be combined with flexible network access and information disclosure to enable new grid users to make efficient decisions (see Grid connection and access recommendation No. 2 and No. 3).

> Grid connection and access - Recommendation No. 1
>
> Shallow or shallowish charging approaches for small DER units should be implemented to avoid barriers to the connection of small units to the grid. Regulation may stablish differences by requested capacity and/or by voltage levels.
>
> Large DER may be subject to deep connection charges in order to provide them with efficient locational signals. However, this should be implemented together with flexible network access and information disclosure about available grid capacity.

Firm vs. flexible network access

Access rights are generally granted on a firm basis, i.e. grid users are free to inject or withdraw as much energy to and from the grid as they want as long as they do not surpass the capacity allocated. As discussed in section 5.10, DSOs in the target country are not generally allowed to modify the injection/consumption of grid users except under emergency conditions.

This approach is simple to implement as does not require an active grid operation. However, it requires adopting conservative technical criteria to ensure no problems arise during real-time operation under no circumstance. Therefore, some network components may only be used at their rated values on rare occasions if ever. Additionally, the need to provide new users with firm network access can result in long connection delays or the rejection of the request. This can be an important barrier for the connection of new DER.

Non-firm or flexible network access could be used to facilitate network access and avoid unnecessary grid reinforcements. Flexible grid connection schemes would allow DSOs to curtail the consumption or generation of network users to prevent grid constraints under the conditions agreed. Thus, DSOs could relax some of the aforementioned technical criteria as they now have the possibility to manage the end user's feed-in/consumption during grid operation. In turn, network users could be offered a remuneration as a service, lower connection charges (especially if deep connection charges apply), or a faster grid connection. As discussed in section 7.1.4, the activation of non-firm access agreements may be coordinated together with other flexibilities procured by DSOs through any local flexibility mechanism/market.

Due to its potential to reduce reinforcement costs, increase the number of flexibility sources available to DSOs and allow new DER to avoid the payment of costly deep connection charges, it is recommended to implement flexible network access. Moreover, DER, particularly those connecting to the MV or HV grids could be offered a menu of options with different combinations of connection costs and probability of curtailment due to the local grid conditions. Thus, each new grid users could select the connection agreement best suited to its risk profile or preferences. The implementation of some form of non-firm access, including the possibility to offer alternatives to new users are being considered in some countries such as Spain or the UK (OFGEM, 2019) (CNMC, 2020).

Grid connection and access - Recommendation No. 2

Flexible network access should be enabled in order to ensure an efficient network development, especially in MV and HV distribution networks. When with deep connection charges are in place, new grid users could be offered several options with different combinations of connection charges and level of firmness (curtailment probability) in their connection.

Information disclosure

The disclosure of information by DSOs can facilitate the connection of new grid users by enhancing the transparency related to the calculation of connection charges and the available network hosting capacity. Additionally, this helps reduce complaints and litigations in access conflicts that may arise as large volumes of DER request a grid connection. Regulators may mandate DSOs to disclose information about:

- Grid connection charges: DSOs may provide potential new users with information regarding the **amount they may have to pay to connect** to the grid based on its characteristics (size, location, distance to the grid, voltage level, etc.). This can be done, for instance, through on-line calculators or look-up tables. This is mostly applicable for small connections, usually in the LV, since connection costs are relatively easy to compute in a standard manner. However, for larger connections to the MV and HV, large cost variations may be observed between individual cases.
- **Available grid hosting capacity**: would allow DG promoters to estimate in advance whether their application will be successful or what location would result in lower connection charges. This would, in turn, encourage generators to request their connection at the point where network conditions are most favourable and prevent the submission of several connection requests, either subsequently or simultaneous. The latter will also reduce the workload of DSOs who need to evaluate each connection request individually. The determination of this available hosting capacity can be made as part of the network development plans discussed in section 7.1.2.

The review made for the five target countries revealed that most countries already have in place some of these mechanisms. Portugal (MV and LV), Slovenia, Sweden (LV), and Austria (only partly) already publish publicly available information about the connection charges that will be paid by end users. On the other hand, only the Portuguese DSO publishes information about the available hosting capacity. This information is provided for each primary HV/MV substations. Moreover, the Spanish regulator plans to mandate DSOs to publish this kind of information for MV and HV grids.

In those countries where there are several DSOs, regulation should set some common requirements in order to ensure good practices are extended and avoid differences across DSOs, which could result in discriminatory treatments among end users depending on their location.

Grid connection and access - Recommendation No. 3

Regulation should enhance the transparency in grid connection by setting minimum information disclosure requirements to DSOs, especially when connection charges are determined by the DSO:

- For small users and/or those connected to the LV grid, information about the expected amount of the connection charges ought to be published.
- For larger units connected to the MV and HV levels, information disclosure may apply to the available hosting capacity in different points of the grid.

7.1.4. Local flexibility services

Some form of mechanism is necessary to enable DSO to access flexibility services. (CEER, 2018a) mentions four different schemes enabling DSOs to unlock flexibility: i) mandatory requirements, ii) network tariffs, iii) connection agreements, and iv) market-based procurement. Network tariffs and connection agreements were already discussed in sections 7.1.2 and 7.1.3 respectively. Thus, herein the remaining two schemes will be discussed.

Whilst an obligation system would be possible, the Electricity Directive clearly advocate for the use of market-based mechanisms whenever possible. In addition to this lack of market compatibility, mandatory requirements, when set on a general level, can force some DER to incur in additional costs when their flexibility is not needed because the local grid is not congested or may not send the right signal to DER to could provide additional flexibility beyond the mandated requirements in a congested area, but does not see the right signals to do so. Therefore, mandatory requirements should only be used to set minimum technical requirements to ensure the system security (e.g. protection systems). Flexibility procurement to manage grid constraints at local level should, to the extent possible, **take place through market-based schemes**.

The description of the current situation in the target countries shows that these mechanisms are non-existent (only emergency curtailment is foreseen in some countries). Even if not explicitly prohibited, DSOs are not procuring flexibility services both due to the lack of incentives for DSOs (see section 7.1.1) and the lack of clearly defined procurement mechanisms. Therefore, the first step would be for national regulation to explicitly acknowledge the need for DSOs to procure DER flexibility to manage their grids. However, there are **many open issues** regarding the most suitable design for these schemes (USEF, 2018), including: how many platforms can there be, who operates these platforms? How are flexibility products defined? Are these products standardized?

Because of this, in the early stages of implementing the CEP dispositions, the main sources of flexibility for DSOs could be based on advanced network tariffs and flexible connection agreements. In parallel regulators may enable DSOs to **test alternative local flexibility market configurations**, or enable third-party initiatives as the ones discussed in D7.5, under regulatory sandboxes when needed, following the recommendations presented in section 7.7.2. As more knowledge is gathered, regulation may try to standardize flexibility markets and products if deemed necessary.

In fact, in Spain there is an ongoing initiative to test different forms of local market configurations. This is the IREMEL[35] project, which is promoted by the Spanish market operator OMIE and the governmental agency named IDAE[36] together with different utilities and research institutions. At the moment, several different local market designs have been identified and a public consultation carried out. The next steps include performing some pilots to test the previous alternative designs (OMIE, 2019).

Local flexibility services - Recommendation No. 1
DSOs should be explicitly allowed to procure flexibility services from grid users or intermediaries managing a portfolio of flexible DER. In the early stages, DSOs and third-parties should be allowed to test different local flexibility market configurations, under regulatory sandboxes if necessary. Over time, flexibility markets and products may be standardized if deemed required.

The review of existing local market mechanisms in Europe presented in D7.5 showed that many different designs are possible. One of the key aspects is how to coordinate flexibilities procured in the long-term and the short-term. Note that other important aspects such as TSO-DSO coordination of granting access to aggregators are discussed in section 7.6.

On the one hand, **long-term procurement of flexibility is essential** to ensure that DSOs can incorporate this possibility in their network development plans. Otherwise, DSOs would face important risks in relying on the availability of flexibility providers as an alternative to grid investments, which cannot be commissioned at short notice. Therefore, DSOs should be entitled to procure flexibility in the long-term, e.g. through tenders. Flexibility providers may receive a reservation payment for this long-term availability. This is also in line with the SRA and CBA results, which showed that the risks for the tVPP can be mitigated if both flexibility availability and activation are remunerated as opposed to only paying after an activation. In addition to investment deferral, DSOs could also rely on these mechanisms when reinforcing the grid in time is not possible in certain areas, e.g. naturally protected areas, historical city centres.

Local flexibility services - Recommendation No. 2
Long-term procurement, years-ahead and with a contract duration of several years (e.g. an entire regulatory period or the period between investment plans), should be encouraged to enable incorporating it in the DSO investment plans.

On the other hand, actual flexibility needs and value can be more accurately estimated in the short-term. Moreover, some flexibility providers may not be willing to engage in a long-term commitment but may have some flexibility available in the short-term. Therefore, both approaches could be combined and coordinated in the following manner:

[35] Integration of energy resources through local electricity markets.

[36] Institute for Energy Diversification and Energy Efficiency (acronym in Spanish).

- DSOs **procure long-term flexibility** so that it can be considered for the network development plans. These agreements would set the price for the flexibility reservation, but not the activation.
- The **activation price can be set in the short-term** through competitive mechanisms together with all flexibility providers, including those who did not sign any long-term agreement. Those users who have a long-term agreement are obliged to participate in the short-term activation markets, but participation is voluntary for the rest. Note that flexible connection agreements may be included in this short-term activation framework.
- Long-term agreements may include a price cap to prevent opportunistic behaviours from flexibility providers who could have market power in the short-term in case no additional sources of flexibility were available.

Note that this framework is somehow reminiscent of the way balancing services are procured in some countries, as well as the model laid out in Regulation (EU) 2019/943 for the pricing of balancing capacity and balancing energy.

Local flexibility services - Recommendation No. 3

The activation price of flexibility sources that are contracted under a long-term framework should be determined in the short-term under a market-based mechanism competing against all available sources of flexibility (including those without a long-term contract and flexible connection agreements).

Long-term contracts may include a cap on the activation price to protect DSOs against opportunistic behaviours from flexibility providers (market power abuse).

7.1.5. Assessing DSO investment needs

Article 32 of Directive (EU) 2019/944 places a high importance on the use of distribution network development plans both to enhance transparency and as part of the regulatory process. It clearly states that DSOs shall develop an investment plan at least every two years with a horizon between 5 and 10 years. These network development plans should clearly reflect how DER flexibilities have been considered as an alternative to grid reinforcements/expansion. Moreover, these plans ought to be consulted with all “relevant” system users and TSOs. The results of this consultation should be published and submitted to the NRA, who may request modifications.

In three of the target countries (Portugal, Spain and Slovenia), DSOs submit investment plans to the corresponding NRAs. Regulators monitor deviations with respect to the investment plans. If these deviations go beyond certain thresholds, DSOs ought to be provide justifications. In Sweden, DSOs do submit investment plans but they are just indicative, whereas in Austria, DSOs submit no investment plan to the NRA. Thus, it can be seen that investment plans are indeed submitted by DSOs in most target countries. However, these plans presumably do not explicitly consider the use of flexibility, which in most cases it is only seen as an emergency resource (see section 7.1.4).

In order to comply with the CEP dispositions, regulators should mandate DSOs to **elaborate investment plans and carry out the corresponding consultation process**. The Directive fails to clarify who the relevant system users that shall be consulted are[37]. Likewise, it is not clear whether this consultation should be public or restricted. Therefore, national regulation should clarify these points. Lastly, NRAs should define together with DSOs the **format and level of detail** of these plans. This level of detail may differ across voltage levels to prevent an excessive burden and high uncertainties. For instance, the plan may present detailed analysis for HV and MV grids, whereas the LV grid is analysed at a higher level.

As mentioned in the Directive, investment plans need to consider the use of flexibility as part of the DSO toolbox. It must be noted that these flexibilities may correspond to flexible connection agreements, services procured in local markets, or the expected response of grid users to network tariffs. In order to ensure a fair and comprehensive evaluation of all the alternatives, development plans should explicitly reflect the following:

- The costs considered for the flexibility-based alternatives should include both the compensations to flexibility providers and the infrastructure/ICT costs required to enable such solutions.
- Investment plans should incorporate an **analysis of the different risks** entailed by flexibility services as compared to grid investments (uncertainty, reliability, duration of the period the solution is active, etc.). The most suitable solution may change over time depending on these parameters. For instance, in areas where the probability of having constraints is relatively low and the development of the grid is costly or time-consuming, flexibility-based solutions may be prioritized since a wait-and-see approach may yield future benefits in the form of avoided investments. On the other hand, if the grid constraints are bound to happen and a long-term solution is needed, copper and iron solutions could be preferable.

Assessing DSO investment needs - Recommendation No. 1

DSOs should submit investment plans as part of the price review process. These plans should reflect fairly the use of flexibility as an alternative to grid reinforcements and make it clear how the different expenditures are related to the outputs that want to be attained. The level of detail or granularity may be lower for the LV grid due to the high extension of these systems.

Regulation should clarify how the consultation process is to be conducted.

As mentioned above, the electricity Directive states that DSOs should submit the development plans and the results of the stakeholder consultation to the NRA. However, it is unclear as to how or whether these plans are to be used in the framework of DSO revenue regulation. It does state that NRAs may request changes to these investment plans; thus, it seems natural that regulators **consider these investment plans as an input to set the DSO allowed revenues**. In order to do this, the timing for preparing and submitting investment plans should be coordinated with prices reviews.

Furthermore, regulators should have the **appropriate resources to evaluate these network development plans**. However, as of today, regulators in the target countries do not seem to be using specific methodologies to evaluate investment plans. The most common benchmarking method is DEA, which is

[37] Article 2 of Directive (EU) 2019/944 only defines system user as *a natural or legal person who supplies to, or is supplied by, a transmission system or a distribution system.*

applied in Portugal and Sweden to assess the efficiency of OPEX and, together with the parametric method MOLS, in Austria to perform a TOTEX benchmarking. However, all these methods are based on past information and peer comparisons. Thus, they may not be the appropriate tools to assess future investment needs in a context with rapidly changing conditions both in technologies and network uses (past information is not suitable to forecast the future) and with potentially growing heterogeneity among DSOs in a country, i.e. not all DSOs will experience the same impact of DER.

Among the target countries, only Spain has reported the use of a RNM that can be used as a forward-looking cost assessment tool. However, its actual application within the regulatory process is not clearly defined. Therefore, regulators should not rely exclusively on backward-looking benchmarking methods to assess future needs.

Assessing DSO investment needs - Recommendation No. 2

It is recommended that investment plans are used as part of the revenue determination process. Thus, their elaboration should be coordinated with price reviews.

NRAs should have the necessary tools and resources to assess the DSO network development plans by using forward-looking cost assessment methods.

7.1.6. Other topics related to the use of flexibilities

This section discusses some additional regulatory topics that, in spite of not being as relevant as the ones discussed above, can also have an impact of the incentives for DSO to procure flexibilities.

Regulatory incentives for the reduction of energy losses:

The use of flexibilities to prevent or solve grid constraints also has an impact on the level of network losses, both in the short-term and, specially, in the long-term. In the short-term, the economic SRA presented in D8.2 showed that the reduction of losses could be an added benefit of the tVPP (but not the main one). Nonetheless, in the long-term, a more active grid operation that succeeds in avoiding some grid reinforcements would eventually result in a higher utilization rate of some network components and, consequently, higher network losses.

Therefore, DSOs may be actually penalized from using flexibilities due to the existence of incentives and penalties linked to the level of losses. As discussed in section 5.2, two elements are relevant in this regard: i) the power of the incentive and ii) the determination of the reference value of losses. Ideally, DSOs should be exposed to the real value of losses (high-powered incentives) where references values appropriately reflect the impact of DER on losses in each DSO area. However, if the reference value does not consider the impact of DER, DSOs may be rewarded or penalized for changes in losses that are unrelated to their performance.

The review of the target countries showed that all of them have in place some sort of loss reduction incentive for DSOs. The mechanisms with the highest incentive strength were found in Sweden and Slovenia, whereas in the remaining countries, some aspects weakened their strength (dead bands, tight caps, etc.). However, the main driver to set the reference values for losses still seems to be progressive reductions over historical values and, in some cases, comparisons across DSOs. Over time, **regulators**

should consider the impact that DER can have on network losses in each DSO area when setting the reference values.

> Incentives to reduce energy losses - Recommendation No. 1
>
> The reference values for losses considered in the incentives schemes should reflect the impact of DER on network losses in each DSO area.

Other incentive mechanisms:

Some countries can introduce additional output-based incentives that may have an effect on the DSO perspective about the use of flexibility. For instance, the Swedish regulator recently introduced a new incentive mechanism (only positive values are possible) to encourage DSOs to increase the load factor in their grids, i.e. the ratio of peak demand over average demand (Wallerström et al., 2019a). Since the use of flexibility will in the long-term lead to a more levelized asset utilization, the Swedish scheme can serve as an additional push for the DSO.

7.2. Fostering advanced operation and maintenance practices to enhance reliability

As presented in section 2, Integrid BM2 addresses the adoption by the DSO of innovative approaches for the operation and management of the distribution network. Moreover specifically, the functionalities considered are the automatic fault location thanks to the deployment of sensors throughout the grid, and the predictive maintenance of distribution transformers based on their operating conditions.

The main benefits expected are the improvement of **grid reliability**, a reduction in maintenance costs and an **increase in the operating lifetime** of transformers. Thus, this section will analyse the aspects of DSO regulation that have an impact on whether the DSOs would benefit from these and, therefore, whether DSOs would be encouraged to adopt these solutions.

7.2.1. DSO incentives to keep assets in operation after the end of their regulatory life

The use of predictive asset maintenance has several implications for the cost structure of a DSO. The DSO can attain a reduction in maintenance costs (OPEX) by avoiding unnecessary maintenance actions on transformers that are in good condition[38]. On the other hand, predictive maintenance can also help the DSO to lengthen the useful life of assets by avoiding major failures performing maintenance actions before the former happen. In the first case, i.e. OPEX decrease, any form of incentive regulation would already

[38] In other assets, the DSO may reduce interruption times by increasing O&M expenditures. This will be covered in section 7.2.2, when discussing the incentives to increase continuity of supply.

promote such cost reductions. However, current regulation may not be sending the right signals to DSOs to keep depreciated assets under operation.

As discussed in section 7.1.1, current DSO efficiency incentives are generally placed on OPEX reductions, whilst CAPEX are mostly treated as a pass-through cost. Regulation in the target countries generally conforms to this paradigm. Therefore, DSOs are implicitly encouraged to replace network assets right after the end of their regulatory lifetime, when these would be written-off the RAB and the corresponding CAPEX remuneration stopped. In addition to that, if an increase in O&M costs is required to achieve the life of assets, then DSOs could actually be penalized for increasing OPEX.

A possible solution would be, as recommended in section 7.1.1 (*DSO revenue regulation - Recommendation No. 1*), to decouple the new RAB additions from the actual investment costs of DSOs (**TOTEX regulation**). By doing this, DSOs would see an incentive to defer asset replacement solutions. This is present in Portugal for LV networks and, to a limited extent, in Austria thanks to the use of TOTEX benchmarking. In Sweden, the RAB value is decoupled from actual unit investment costs (but not from asset volumes) thanks to the use of a replacement cost approach to determine the RAB. Thus, DSOs in Sweden may still be remunerated for assets beyond their regulatory life.

Shifting away from a CAPEX-oriented regulation will presumably not happen overnight in order to prevent high short-term variations in DSO allowed revenues and network charges. Hence, regulators may **implement alternative incentive mechanisms** to promote the use of predictive maintenance even if DSO revenue regulation still presents a CAPEX bias. For instance, Spanish DSOs perceive a higher O&M remuneration for those assets that remain in operation after the end of their lifetime (see section 5.6). Another alternative consists in developing specific output indicators and subject these to a performance-based regulation. For instance, UK DNOs have to measure asset health (or health and criticality combined) and can be penalized (or rewarded) if these indicators fall below (or above) certain thresholds (OFGEM, 2013b).

Incentives to keep depreciated assets in operation - Recommendation No. 1

Regulators should introduce ad-hoc mechanisms to encourage DSOs to keep assets in operation after the end of their regulatory life, especially when revenue regulation presents a strong CAPEX bias.

7.2.2. Continuity of supply incentives

Since one of the main benefits derived from the two functionalities covered under BM2 is to improve continuity of supply, the existence and design of reliability incentives for DSOs is a key regulatory topic for this BM. This type of incentive schemes is generally widespread across European countries (CEER, 2016c). As discussed in section 5.3, all target countries but Austria have already implemented some form of incentive mechanisms. In fact, the Austrian regulator allegedly planned on introducing such scheme.

Nonetheless, the existence of these incentives per se is not enough by itself to promote such functionalities. The incentive design and is strength is also very relevant. A first aspect to consider is whether the incentive schemes is tied to **both the duration and the number of interruptions**. Among the target countries, only Slovenia and Spain consider both the duration and number of interruptions. In Sweden and Portugal, the economic incentives exclusively on indices measuring the duration of interruptions, which can dilute the incentives seen by DSOs to implement advanced fault detection. Advanced fault location, if combined with telecontrolled grid reconfiguration in meshed networks, can reduce both the measured duration and number of interruptions if consumers can be reconnected in less than a few minutes after an interruption. This is because long interruptions are considered to be those that last more than a pre-defined number of minutes, typically 3 min (CEER, 2016c).

Incentives to improve continuity of supply - Recommendation No. 1 Implement incentive/penalty mechanisms for the DSOs to improve network reliability. These mechanisms should incorporate reliability indicators measuring both the number and the duration of interruptions.

Another aspect to consider is how **planned and unplanned interruptions are treated** in the regulation, i.e. whether the incentive strength is different for both types of interruptions, and how easy it is for DSOs to qualify an incident as a planned interruption. This is particularly relevant concerning the implementation of predictive maintenance strategies. By monitoring the condition of transformers, a potential unplanned interruption caused by an equipment failure can be prevented by a maintenance action that may also require taking the transformer out of service, thus causing a scheduled interruption. Despite the fact that in both cases consumers would be interrupted, this allows the DSO both to notify grid users in advance and schedule the maintenance works at a time that disturbs grid users the least. Therefore, this should be encouraged.

Nonetheless, the current regulation in target countries does not seem to promote this in most cases. In Portugal, Slovenia and Spain, both types of events are clearly defined, but incentive schemes do not differentiate between them. Likewise, scheduled and non-scheduled interruptions are also defined in Austria, but no incentive is in place. In Sweden, however, the differentiation is clear and DSOs have strong incentives to replace one type of interruption with the other, specially for non-residential consumers, since the cost of ENS is difference for each type of event.

Incentives to improve continuity of supply - Recommendation No. 2 Incentive schemes should encourage DSOs to replace unplanned interruptions with scheduled interruptions, as the latter have less impact on grid users.

Lastly, even if incentive mechanisms are in place, and these appropriately discriminate between planned and unplanned interruptions, DSOs may still not implement the advanced O&M approaches in BM2 if the gain they perceive from improving reliability is very low. There are two key parameters that determine this: the **reference reliability levels and the marginal incentive rate**[39]. Moreover, **discontinuities** in the incentive mechanisms may be introduced in the form of deadbands around the reference values or upper/lower bounds on the value of the incentive/penalty, i.e. caps and floors. In fact, these features are present in all

[39] The reference value is the threshold beyond which the DSO revenues increase if actual levels of continuity of supply exceed it and vice versa. The incentive rate determined how much is the marginal reward or penalty the DSO gets for a marginal decrease or increase in the value of the continuity of supply indicators.

the four target countries who have an incentive mechanisms in place. In Portugal and Slovenia there are both cap/floor and deadbands, whereas Spain and Sweden only have a cap/floor system.

Such discontinuities are used in order to mitigate the risk of excessively high rewards or penalties due to errors in the regulator's estimates when designing the incentive or to unforeseen events. However, if they are not correctly set and periodically revised, they can significantly weaken the power of the incentive. For instance, if a DSO presents reliability levels that are within the dead-band or above/below the cap/floor, the incentives obtained from improving reliability may be negligible. This "incentive trap" can be avoided updating the reference values. However, since these are oftentimes defined based on historical information, as it is the case in the Slovenia or Spain, this may result in a permanent stagnation of reliability levels. Sweden is the only target country in which reference values are based on the results of a benchmarking analysis among DSOs, attending to the customer density in each DSO area.

Lastly, the marginal incentive rate is usually determined based on consumer surveys that estimate the cost of interruptions for consumers (CEER, 2016c). For instance, the Swedish and Slovenian regulators do carry out such surveys. On the contrary, the calculation of this parameter in Portugal and Spain is not transparent and no details are provided about its calculation. It is important that this parameter appropriately reflects the true value of quality of service for network users as well as the new opportunities DSOs have to improve reliability. Therefore, regulatory practices should be reviewed to account for these. Additionally, transparency is required to provide DSOs with certainty before investing in these new functionalities.

Incentives to improve continuity of supply - Recommendation No. 3

Regulators should ensure that the incentive mechanisms parameters send adequate incentives for DSOs to improve quality of service by avoiding wide deadbands, tight cap and floors.

Moreover, reference values and marginal incentive rates should be assessed, and not be based exclusively on historical values, in order to reflect appropriately both the marginal cost of improving reliability (including smart grid solutions) and the cost of interruptions for consumers in their country .

7.2.3. DSO incentives to test new smart grid functionalities

The adoption of new grid operation solutions and technologies will presumably require DSOs to test them at a limited scale before deploying them at a larger scale. This will allow them to test and compare alternative technology solutions, work together with developers and manufacturers, and prevent mistakes and dead-ends when performing the deployment. Since DSOs face some **technology risks** in this process, the existence of **mechanisms that allow DSOs to mitigate** this these risks would facilitate the adoption of innovative solutions such as the ones in Integrid BM2, i.e. advanced fault location and predictive transformer maintenance. This can be achieved through ad-hoc economic incentives that allow DSOs to recover, at least partly, the corresponding costs outside the regulator allowed revenues[40].

[40] Note that this section refers to pilot projects that can be implemented by the DSO on its own and do not require exemptions from certain regulatory rules. The topic of regulatory sandboxes is addressed in section 7.7.2.

Regulatory supervision of such expenditures is necessary to ensure that the solutions really required this risk mitigation mechanism, i.e. immature solutions with a high technological risk, and DSOs are not trying to exempt mature technologies from efficiency requirements. The latter solutions should not be covered in these explicit innovation incentives; instead, they ought to be included in the general framework for DSO allowed revenues (CEER, 2018b). This NRA supervision may take the form of an ex-ante approval of the corresponding expenditures, an ex-post evaluation of the outputs achieved measured through the appropriate KPIs, or both. In any case, the evaluation should be based on the potential benefits for network users, avoiding technology-specific approaches (CEER, 2018b).

The innovation projects funded through the revenue allowances should be well **coordinated with other innovation funds** received by DSOs, e.g. from national public budgets or European research programmes, to ensure the funds are spent efficiently.

The review of the situation in the target countries in sections 5.4 and 5.5 showed that several target countries have some form of incentive in place, although not all the conditions above are met in all cases. Austria and Sweden have no explicit mechanism. Despite the fact that DSOs may recover (partly) these costs, if they do so, they could be penalized in the benchmarking analyses performed by the corresponding NRAs. In Portugal and Slovenia, DSOs can implement innovation projects subject to the prior approval of the NRA. DSOs are entitled to recover part of the costs involved, subject to a cap. Lastly, in Spain DSOs can carry out pilot projects and the corresponding costs will be passed-through to the network tariffs. Nonetheless, the NRA must approve the projects ex-ante and the DSO must submit a technical report and a CBA to recover the aforementioned costs.

Incentives to test new smart grid functionalities - Recommendation No. 1

DSOs should be explicitly allowed to implement pilots to test innovative smart grid functionalities and technologies.

Regulatory supervision either as an ex–ante approval, an ex-post evaluation, or both. Such evaluation should be made based on a set of KPIs and/or CBA where the benefits for network users are clearly shown.

7.3. Setting the conditions for the provision of data services

The provision of data services is at the core of BM3, considering both the perspectives of the DSP (BM3.1) and the data platform manager (BM3.2). However, the deployment of smart metering system and the definition of a clear data management model by regulation are key preconditions for the development of this BM[41]. This section addresses the regulation concerning these two topics.

[41] The provision of data-based services is indeed possible either by using proprietary data of certain stakeholders, e.g. the DSO, or by using alternative data sources, e.g. deploying a parallel metering infrastructure. However, Integrid envisions an open, but secure, access to the data so that this BM can be more open to all potential data service providers and transactions costs are reduced.

7.3.1. Smart metering deployment

It is safe to say that smart meters are a central piece for almost all BMs explored in the InteGrid project. Without smart meters, time-differentiated consumption cannot be accounted for, and therefore, most of the solutions proposed in InteGrid may become inviable. Moreover, smart meter deployment is one of the most important steps towards the digitalization of the distribution grid to allow optimization of the network operations (Tractebel, 2019).

Section 5.13 showed that the level of deployment in the InteGrid countries varies. While Spain and Sweden have completed the deployment, Slovenia, Portugal and Austria are still in very different stages of deployment. Moreover, only looking at the percentage of deployment may not be enough to understand if the deployment being made will be enough for solutions such as the ones in InteGrid to be adopted. Functionalities between smart meters vary, and therefore certain equipment could require upgrade or substitution before it can cope with new applications. This is the case for Sweden, for example, that concluded the deployment in 2009, but now is going through a second wave to substitute the old smart meters (Ei, 2019).

Regardless of the pace the InteGrid countries are following, an important step is the fact that all five countries have already an implementation strategy in place for the deployment of Smart Meters (Tractebel, 2019), even though not all CBAs were positive. In Spain, for instance, a CBA was not conducted, but the country adopted a national deployment plan and finished the deployment in 2018 (CNMC, 2019). In Austria, a first CBA resulted positive, while a revised analysis was negative. In spite of the negative result, the country keeps its commitment to the deployment of the Smart Meters. Therefore, the first and most important step for Smart Metering deployment is already being observed by Member States, namely having a national deployment plan.

Nevertheless, the deployment pace varies among countries, and as such, it can slow down the possibilities of new business models. Therefore, DSOs[42] should facilitate, to the extent possible, the early adoption of Smart Meters by interested consumers. Even though on-demand deployment is already a requirement according to the CEP[43], DSOs can adopt a proactive approach in makeing consumers and stakeholders aware of the possibility of installing Smart Meters, as well as the costs and benefits associated to it. This way, not only consumers may feel motivated to adopt the technology, but other stakeholders use the early adoption as part of their strategy. For example, an aggregator can pay the cost of the Smart Meter as part of the flexibility provision contract.

Smart Meter Deployment - Recommendation No. 1
DSOs should facilitate on-demand deployment to the extent possible. This allows not only consumers to feel more encouraged to adopt Smart Meters, but also new business models to foster the use of the new meters.

[42] In all five countries, the DSO is the responsible for the deployment of Smart Meters.
[43] Article 21 of the E-Directive

Beyond the need of Smart Meter deployment itself, there is the need to ensure that Smart Meters actually deliver what is necessary for new business models and enhanced grid management. Requirements for Smart Meters are now determined by the CEP[44], stablishing a high-level set of functionalities. However, these functionalities are (i) limited in scope, and do not cover all possibilities of uses of Smart Meters, and (ii), they are not fully specified, meaning that Member States can end up with different implementations of such requirements. For instance, the CEP does not mention the need for interoperability, what could lead to barriers for third-parties trying to exploit the potential of Smart Meters.

According to Tractebel (2019), one of the main obstacles to the digitalisation of the European grid, taken as a whole, is probably the limitation in the functionalities imposed by MS. As mentioned above, Smart Meters are the backbone infrastructure for several new business models, and therefore functionalities should also consider the needs from other stakeholders. Naturally, a balance must be achieved in terms of functionalities, costs, cybersecurity protection and overall benefits to be achieved. Nevertheless, a deployment that considers the needs of stakeholders and ensures interoperability is likely to increase the benefits of this infrastructure. This can be achieved by the consultation of stakeholders in e.g. terms of need from this infrastructure, the standardization of communication protocols, cyber-security, privacy and a forward-looking approach regarding the functionalities to be included. In order to accommodate the increased costs incurred due to new functionalities, a more comprehensive cost allocation could take place, including other stakeholders.

Smart Meter Deployment - Recommendation No. 2
The deployment of Smart Meters should consider the needs of different stakeholders and ensure interoperability in order to allow new business models (e.g. consider observability requirements from TSOs in order to allow for DR balancing provision).

Finally, a successful deployment should also be a “future-proof” deployment to the extent possible. Smart Meters and ICT technologies have a much shorter asset life than usual power system assets. Therefore, it is important to adopt actions to mitigate as much as possible the costs incurred in the eventual update of infrastructures, as well as its frequency.

For many countries ongoing the deployment of Smart Meters or that have already concluded it, the set of functionalities included in their deployed equipment is not up to date with the ones specified in the CEP. One example is the need for smart meters enable final customers to be metered and settled at the same time resolution as the imbalance settlement period (ISP) in the national market. According to the EB GL (Art. 53), TSOs should harmonize the ISP and apply a 15 minutes period by 2021[45]. In this case, the smart meters already deployed may remain in service until 2031, according to the CEP[46]. On one hand, this means that smart meters will have to be substituted before its expected lifetime (if they were planned for more than 12 years). On the other hand, it also means that certain business models will be delayed, as smart meters with the new functionality will be only deployed in 2031. The ISP requirement is a clear example in the context of BM4 and BM5. Once the ISP is set to 15 min, and consequently balancing products are also

[44] Article 20 of the E-Directive

[45] Art. 53 of the EB GL says that by three years after the entry into force (therefore 2021), all TSOs shall apply the imbalance settlement period of 15 minutes. However, exemptions could be granted by NRAs (Schittekatte et al., 2019).

[46] Art. 19(6) of the E-Directive.

adapted to 15 min delivery periods, some deployed smart meters will not be capable of providing the necessary readings for balancing provision and settlement (e.g. mFRR). In this case, either additional infrastructure has to be deployed, or alternative methodologies used for DR participation. In InteGrid project, the VPP uses separate RTUs to achieve the necessary observability. Otherwise, the aggregator cannot access the metering data in real-time[47].

> Smart Meter Deployment - Recommendation No. 3
>
> The choices in terms of Smart Meter capabilities should aim at a "future-proof" deployment. Non forward-looking approaches lead to additional costs, as Smart Metes will have to be updated more often to meet the ever-evolving needs of the industry, and to delays in the adoption of new business models.

7.3.2. Metering data management

Metering data management has high impact on the business model for data service providers (InteGrid BM3). As outlined in Chapter 3.1, the CEP does not define a preferred data management model. Member States use different approaches. The implementation design of the business model therefore needs to consider the respective national framework.

The business model is based on the provision of data services through the gm-hub. Its implementation can face regulatory barriers depending on the national framework. The two identified regulatory barriers in data management are

- Lack of definition on the data-management model and
- Barriers to grant access to metering data to third-parties, whilst complying with GDPR requirements

According to the country assessment in Chapter 5.14 different relevance for the deployment of the business model, depending on the country. Sweden is implementing a centralised model with a hub similar to the one proposed by InteGrid, and that could easily be integrated with gm-hub proposed in Integrid[48]. The deployment of the business model should therefore not face a major barrier. The implementation in Spain, Portugal, Austria and Slovenia can face barriers in data access. *In these countries, DSO collects the data, but the end-consumer decides if data access is granted to third parties.*

Guiding principles

The lack of definition on data-management model as a barrier has also been identified by CEER in its 'Review of Current and Future Data Management Models'. CEER acknowledges the importance of the data management for the functioning of retail energy markets and explains provisions in its deployment. The report concludes that an appropriate data management model should [CEER 2016b: 7]:

[47] The economic SRA and CBA showed that this is a major reason why the portfolio of the VPP is critical for profitability, ideally few consumers with a large flexibility potential, considering that the VPP has to borne the CAPEX associated to the additional RTUs.
[48] Although the Swedish data hub and the Integrid gm-hub share similarities, it is also important to highlight their differences. While the Swedish hub collects and stores data centrally, the gm-hub acts as a "virtual hub" and is capable of offering services directly. In this context, it is also safe to assume that Integrid's gm-hub concept could be implemented on top of the Swedish hub, by accessing its data and providing services.

-

- enable the efficient, safe and secure exchange of customer and metering data to facilitate retail market competition and ensure adequate customer protection;

- make data available for competitive market actors in a standardised format, enabling them to easily perform market operations, such as commencing a supply contract, billing etc. and

- provide consumers with full ownership over their data and control over who has access to it.

CEER developed an approach for the assessment of existing data management models.[49] This approach can also be used for the development of new models. It consists of 5 guiding principles with 7 recommendations, summarised as follows [CEER 2015b: 31]:

- Privacy and security principle
    1. Appropriate security and privacy measures need to be in place. Customers should control access to their data, with the exception of data required to fulfil regulated duties and within the national market model. The principle should be that the party shall state what information they will collect, with what frequency and for how long.
- Transparency principle
    2. Relevant bodies should provide general information to customers on data management.
    3. Active steps to build customer confidence in sharing customer meter data should be made by responsible parties.
    4. Member States are recommended to standardize data format and exchange on regional and/or European level.
- Accuracy principle
    5. Any inaccuracies need to be communicated to the customer.
- Accessibility principle
    6. The customer should have easy access to the data.
- Non-discrimination principle
    7. Equal access to stakeholders should be granted in the competitive market.

Approaches used on national level

The difference in the approaches used on national level can be identified by the level of centralisation. The level of centralisation can be determined by investigating the nature of key aspects of data management models (i.e. sourcing, validating, storing, protecting, processing and distributing or providing access to data). Following models are possible [CEER 2016b: 13]:

- Centralised data management model – all key aspects related to data management are centralised; e.g. data hub, where all data is retrieved, validated, stored, protected, processed, distributed and accessed;

- Partially centralised model - centralisation of one of the key aspects; e.g. communications hub that provides a common access point for data that could be stored in several databases;

- Decentralised model – key aspects of data management are decentralised and responsibility of the DSO.

[49] The approach has been applied in the review of data management models in [CEER 2016b].

In all three cases the data storage as such can stay decentralised (in different databases). The difference is the extent of centralisation of data handling aspects, not the data itself. Countries with centralised data management models provide ideal conditions for the implementation of a business model for the provision of data services through the gm-hub. Also, the partially centralised data model can form an essential environment for the new role of a data service provider as long as its scope and the consideration of key aspects ensure a single point of access to the data. This possibility can avoid the barrier of difficult data access.

The European Commission has identified different data formats used in national data management models as a market entry barrier, referring also to CEER's studies in this regard. A full harmonization (one data management model in the EU) is not seen as the ideal solution since this option is expected to induce high costs for actors in charge of data management (usually DSOs and TSOs) to adapt their existing models. The Commission proposes to introduce data management rules that can be applied independently of the national data management model. [EC 2016]

Recommendations

Data management model differs from country to country. The different frameworks represent a challenge in the adaptation of business models to local conditions. A lacking definition of data management models in the national regulation is seen as one of the major regulatory barriers for the implementation. **The definition of national regulation on data management model can make use of guiding principles and recommendations provided by CEER**.

Many European countries are currently implementing a decentralised data management model. Only certain countries (e.g. Sweden, Denmark) are implementing a centralised model with a data hub already. However, national approaches are also subject to development and **in many European countries the future trend goes towards increasing centralisation in the data management**. [CEER 2016b: 23] The implementation of a data hub (such as the gm-hub) in a centralised model provides possibilities for the development of new businesses (i.e. data service providers and/or data hub operators). The DSO plays a core role in most of the models. The extent of key activities performed by DSO can vary. It is larger in decentralised data management models. Implementation of the role of a data service provider in the decentralised model environment is possible. In any case, **the means to obtain consumer consent need to be taken into consideration**.

The establishment of data platforms with standardized format and open access to other parties enables the non-discriminatory entry of new actors. In this regard, additional costs for the adaptation of national data management models to comply with these rules are expected. Actors in charge of data management (in most cases DSOs or TSOs) will most likely pass these costs through to end consumers. On the other side, network operators will benefit from the entry of aggregators and other energy service companies who can facilitate network flexibility. [EC 2016] CEER recommends Member States in this regard to **perform a cost-benefit analysis of harmonizing data management standards at regional or European level**. [CEER 2016b: 28]

7.4. New DSO roles

The deployment of InteGrid business models can have a significant benefit from the development of DSOs' roles. The integration of more decentralised generation and of prosumers requires DSOs to move from the traditional role of grid operation and maintenance to a more (pro-)active grid development, management and operation. (van den Oosterkamp et al., 2014) This development can provide benefit to business models having the DSO as the core actor (in InteGrid the business model BM1) or as an enabler (technical VPP, in InteGrid BM5.4).

Proactive grid development and operation should be organised in a way consistent with liberalised market rules. Competitive market situation should be established whenever possible. Within the EU, a DSO is seen as a monopolist that requires an independent role. The independence of DSOs in the EU has been established with the liberalisation of the European energy market. The current version of the Electricity Market Directive (Directive (EU) 2019/944) defines the role of the DSO in the market[50] (Article 2 §6, Article 25) and sets requirements for its independence (Directive (EU) 2019/944, Article 35 §1)[51]. These provisions ensure market activities are separated from regulated activities related to the infrastructure operation, which enables the entry of new enterprises into market areas where competition is seen as essential for the market operation. Business models in InteGrid have been developed in the framework of liberalised competitive market. DSO plays a core role in most of the new business models as market enabler.

Yet, situations can occur, where competitive market is desired but not developed. For a DSO, this can represent a challenging situation in case grid stability requires flexibility (e.g. storage facility) that cannot be procured in the market due to lack of flexibility providers. A possibility is the operation by DSO. The operation of storage is, however, seen as competitive activity that must not be performed by a DSO. Solutions for non-developed markets are therefore needed as well. Missing regulation has been identified as one of the regulatory barriers in this regard. Approach in the case of lack of regulation for new DSO activities on national level can be determined from:

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[50] Electricity Market Directive provides a definition of DSO (Directive (EU) 2019/944, Article 2 §29):

'distribution system operator' means a natural or legal person responsible for operating, ensuring the maintenance of and, if necessary, developing the distribution system in a given area and, where applicable, its interconnections with other systems and for ensuring the long-term ability of the system to meet reasonable demands for the distribution of electricity;

whereas §28 of the same article specifies the term distribution as follows:

'distribution' means the transport of electricity on high-voltage, medium-voltage and low-voltage distribution systems with a view to its delivery to customers, but does not include supply.

[51] In cases, where DSOs are part of a vertically integrated undertakings, provisions need to be taken to ensure their independence. The unbundling of distribution system operators is regulated in the Electricity Market Directive (Directive (EU) 2019/944, Article 35 §1):

Where the distribution system operator is part of a vertically integrated undertaking, it shall be independent at least in terms of its legal form, organisation and decision making from other activities not relating to distribution.

- CEER principles for regulation of DSOs and approach to determine a competitiveness of a DSO activity;
- Exemptions which can be granted by Member States under the current Electricity Market Directive (Directive (EU) 2019/944)

Determination of competitiveness

In general, new DSOs' activities must not interfere with activities underlying competitive market. Under certain circumstances, it is not always easy to determine under which category a certain activity would fall or where the exact boundaries are (CEER, 2019). CEER recommends four principles for the regulation of DSOs (CEER, 2015a):

1. DSOs must run their businesses in a way which reflects the reasonable expectations (e.g. firm security, high quality of supply, easy and non-discriminatory access to network, quick response to increases in demand, and transparent access to information – all efficiently) of network users and other stakeholders, including new entrants and new business models, now and in the future
2. DSOs must act as neutral market facilitators in undertaking core functions
3. DSOs must act in the public interest, taking account of the costs and benefits of different activities
4. Consumers own their data and that this should be safeguarded by DSOs when handling data

To determine whether an activity is competitive, CEER also provided a scheme (see Figure 12) helping to determine whether an activity can be seen as competitive, regulated or allowed under certain conditions.

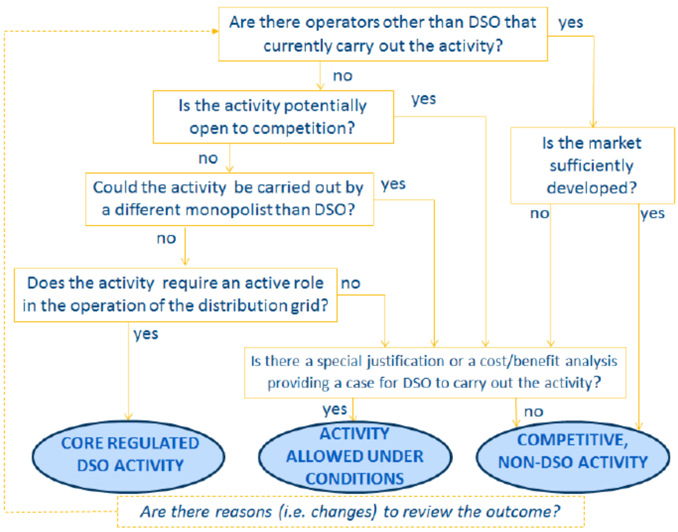

Figure 12 Scheme for the determination of DSO activities (CEER, 2019a)

Examples of new DSO roles

The CEER Conclusions Paper on New Services and DSO Involvement discusses several activities that arise and go (at least partly) beyond the traditional role of a DSO. These can be concluded as follows [CEER 2019]:

- Data management: Although the collection of data can be seen as a core activity of DSO, services related to further data processing, such as data analysis services or provision of enriched data to third parties, can be established as competitive activities. A discussion of possible models is provided in Chapter 5.14.

- Energy advice: In the past, DSOs have developed or participated in energy efficiency campaigns. The determination of the competitiveness of such activity depends on whether it is a charged service to the customer or a general campaign. While there are no issues with the latter, the former is a competitive activity (e.g. an energy audit) and should not be performed by DSO.

- Provision of flexibility services, esp. the operation of storage: In general, the operation of storage is seen as competitive activity that should not be owned or operated by a DSO. There are, however, exemptions. These are discussed below.

- Operation of electric vehicle charging infrastructure: The infrastructure development and operation can be built in a competitive environment and is thus not a core DSO activity. Examples of DSO operation can be found in countries with early EV infrastructure deployment or within pilot projects. This is the case in Luxembourg, where a model with charging service suppliers has been established. In Ireland, the DSO ESB is in charge of the provision of conventionally positioned charging points (ESB, 2020).

- Telecommunication services: CEER provides this as an example for DSO activities outside the energy sector. Reason to expand to this area can be the availability of communication infrastructure or the use of synergies (e.g. utility pole used as a cell tower).

Regulatory exemptions

The Electricity Market Directive enables the operation of storage by DSO (Directive (EU) 2019/944, Article 36):

- In case of fully integrated network components (§2),
- In case there is a lack of competitors (§2),

These exemptions can be granted for new storage facilities for a limited time frame and need to be reassessed regularly.

National regulation can exempt DSOs, which serve less than 100.000 connected customers, from the unbundling obligation (Directive (EU) 2019/944, Article 35, §4). As stated in Section 4.1.7 of this report, this is currently allowed in Austria. Spain, Portugal, Sweden and Slovenia do not have according regulations, which implies the operation is not possible except for special cases (e.g. emergency situations, power quality support). CEER collected case studies explaining factors that are taken into consideration by national governments in the process of granting DSOs a possibility to operate storage (CEER, 2019: 18-19):

- Alternative to grid investments (Italy, Norway);
- Avoided RES curtailment (Italy);
- Energy losses reduction (Italy);
- Security of supply (Italy);
- Reduction of reactive power exchange at the TSO/DSO interface (Italy);
- Voltage dip mitigation (Italy);
- Improvement of voltage regulation capabilities (Italy);
- Island mode and remote areas (UK, Norway).

These exemptions can be granted for certain circumstances in line with the Electricity Market Directive for a limited timeframe (with regular checks) if needed for grid stability in undeveloped markets or within a regulatory sandbox programme.

Exemptions for the operation of EV charging infrastructure by the DSO are provided in Article 33 of the Electricity Market Directive (Directive (EU) 2019/944):

- §2 allows the operation of DSO-owned EV-fleet,
- §3 allows the operation in case there are no competitors for a limited time (§4).

Recommendations

The relevant framework for new roles of DSO is the Electricity Market Directive (Directive (EU) 2019/944). The extent of the application of the directive by Member States can differ. Also, the market conditions can be very different. This leads to a heterogenous situation among the Member States. In the **case of lacking regulation** or room for interpretation, **the Electricity Market Directive and the methodology from the CEER guidelines** (as stated above) are suitable as a decision support.

DSOs play a major role in the efficient functioning of electricity markets and act as an entry gate to retail markets in most countries. DSOs have an important influence on competition level. (CEER, 2016a) On the other side, DSOs are regulated monopolists that act in the public interest. Therefore, their changed roles and activities must not interfere with (new) competitive market activities. In the changing environment, DSOs have to focus on their role as a market facilitator and make the maximum use of flexibilities to avoid grid investments.

Regulators should seek to **establish competitiveness wherever possible**. This is the case for new roles as well as for the amendment of existing roles. **Exemptions can be granted where no competitive alternative exists**, e.g. storage is needed for grid operation but there are no actors apart of DSO willing to provide it. These exemptions should be limited in time and regularly checked (e.g. call for interest, tendering procedure, competitiveness check using the cost-benefit analysis).

The provision of grid services by utilising storage can be implemented by using different **ownership and operation models involving third parties**. These new actors can take over the ownership and/or operation the storage facility for DSO. Their revenues can be generated from the market operation of the storage facility and additionally used for grid purposes (Poplavskaya & Friedl, 2016: 39-41).

7.5. Retail tariffs and self-consumption

Distribution network UoS charges were addressed in section 7.1.2. However, the price signal seen by end consumers is the retail tariff, which is freely negotiated with the supplier (except in the case of default regulated tariffs) and includes all the regulated charges, plus the energy and retailing costs. Therefore, retail tariffs are a very relevant topic for BM4, and especially for BM 4.2 since small residential consumers tend to bear the highest share of regulated costs. Moreover, self-generation was one of the key strategies considered within BM4.2 for cost reduction. In fact, the CBA for HLUC09 in Portugal specifically analysed the case of a consumer with a self-generation unit. These two topics are highly interrelated as the implicit economic value of the energy self-consumed is precisely the volumetric component of the retail tariff.

Therefore, this section addresses these two regulatory issues and proposes a set of recommendations to ensure self-generation is developed in an efficient manner and consumers receive appropriate signals for flexibility, whilst ensuring a well-functioning retail market.

7.5.1. Retail tariffs and regulated charges

The CBA and SRA analyses showed that, as would otherwise be expected, extracting the full value of HEMS requires retail electricity tariffs that adequately promote end-user flexibility. This would allow consumers to benefit from energy savings which, at the same time, could bring about peak load reductions and long-term system savings. Retail tariffs comprise the **energy costs** (and retail fees) on the one hand, and the **regulated charges** on the other. The scope of regulation is different for each of these components.

Concerning energy prices, dynamic prices that follow hourly energy prices are, in principle, the most suitable to promote flexibility and drive the adoption of HEMS. However, in liberalized retail markets, regulation cannot determine the structure of energy prices seen by end consumers as these are freely negotiated between them (in practice, small consumers essentially choose from the commercial offerings of different retailers). Nonetheless, regulation may still favour this pricing scheme as follows:

- Using **dynamic pricing as the default tariff** (if it exists[52]) offered by suppliers of last resort.
- **Mandating retailers to include a dynamic pricing option** in their commercial offer. In fact, as discussed in section 3.1, Article 11 of the recast EU Electricity Directive (Directive 2019/944) states that final customers who have a smart meter should have the right to sign a *"dynamic electricity price contract with at least one supplier and with every supplier that has more than 200 000 final customers"*.

Retail tariffs and regulated charges - Recommendation No. 1
All consumers with a smart meter should be entitled to a dynamic pricing option. This could be introduced as the default regulated tariff (last resource tariff) and/or mandating suppliers to include this alternative in their offers.

The first of these options can be found in Spain. The Spanish default tariff, called voluntary price for the small consumer or PVPC[53], is computed (volumetric component) as the day-ahead spot market prices plus the regulated charges. This tariff option is only open to LV consumers with a contracted capacity below 10kW and reference suppliers are obliged to provide this tariff scheme to any consumer who complies with the previous criteria and asks for it.

Another target country where household consumers can opt for a dynamic price contract is Sweden. In this country, regulator states that consumers with a fuse of no more than 63 amperes (approximately 14kW in the case of a LV single-phase connection) and a smart meter with hourly metering installed can choose an hourly pricing contract without any additional cost. Nonetheless, an evaluation made by the Swedish energy regulator in 2013 concluded that end-users showed little interest in this type of contract and less than half

[52] According to (ACER/CEER, 2019a), 27 out of 29 countries in EU-28 and Norway have suppliers of last resort.

[53] https://www.ree.es/en/activities/operation-of-the-electricity-systemvoluntary-price-small-consumer-pvpc

of the suppliers offered hourly contracts. Moreover, suppliers do not generally make it easy for consumers to be aware of such an option as many suppliers do not publicize it in their web sites. Thus, consumers have to contact the customer services in case they were interested (Ei, 2013). Nonetheless, the information about these contracts has been included in the NRA's price comparison tool (CEER, 2019b).

In both of the previous cases, the dynamic prices presented an hourly granularity and were tied to the day-ahead market prices. Nonetheless, dynamic price contracts can have a higher time granularity and be tied to intraday wholesale markets. The problem with linking dynamic prices with intraday markets is that the uncertainty for end users can be higher as they would not know their prices 24 hours in advance. Moreover, the more complex design of intraday markets and, oftentimes, higher market price caps can increase the risk for consumers (CEER, 2020c). In this regard, a trade-off between cost-reflectivity and simplicity should be met. Therefore, dynamic price contracts **linked to the day-ahead spot prices** seem preferable for residential consumers. Moreover, these should be **duly informed of the potential risks**, particularly the possibility of peak periods and price volatility. In case national markets have very high price caps, regulators may explore the possibility of setting safety nets for consumers in the regulation.

Retail tariffs and regulated charges - Recommendation No. 2
When introducing dynamic price contracts, retailers should be required to publish clear and transparent information about this alternative, including the potential risks, and make it easily available to consumers. Dynamic prices may be linked to day-ahead markets, instead of intraday markets, to mitigate the uncertainties for consumers, particularly for residential consumers. Additionally, particularly when market price caps are high, regulators should assess the introduction of safety nets for consumers in the dynamic price contracts.

The second component of retail tariffs corresponds to the regulated charges. These include not only the costs corresponding to the transmission and distribution activities, but also many other concepts such as extra RES costs and other policy costs (nuclear phase-out, tariff deficit financial costs, coal phase-out, etc.). The nature and amount of these costs can vary greatly on a country basis, as shown in Figure 13. This figure shows that the price of energy itself accounts for less than half of the overall electricity price in all the target countries, with a maximum of 44% in Spain and a minimum of 30% for Portugal. Therefore, the way these costs are allocated to the different tariff terms is key to the flexibility signals seen by end consumers.

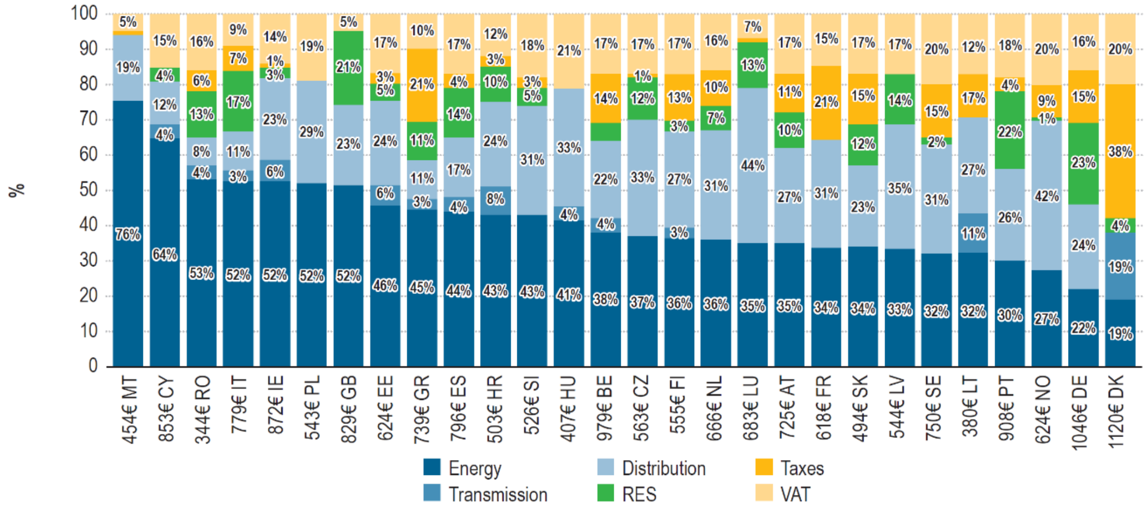

Figure 13: Breakdown of residential electricity prices in November/December 2018. Source: (ACER/CEER, 2019b)

Broadly speaking, regulated charges, in particular those associated with policy costs, should avoid distorting the efficient response of end consumers to locational/time differentiated energy prices (see above in this section) and/or network charges (see section 7.1.2). The discussion will mostly focus on RES-related costs as this the most common policy cost in European countries. This topic is very relevant because extra remuneration for RES may not completely disappear over the next years, in spite of the decline in RES technology costs. As shown in (Gerres et al., 2019), in a system with a very high RES penetration, the captured price of intermittent RES could drop, especially if large-scale electricity storage is limited. Hence, even if RES costs fall, they may still require some remuneration over the market price.

A first option is to remove these costs from the electricity tariffs. In fact, some countries already recover these costs, at least partly, through state budgets or green taxes (CEER, 2018). However, this may not be always easy for several reasons. Hence, to the extent that policy costs are defrayed through the electricity tariff, these should be **allocated in the least distortive manner possible**, especially avoiding allocating them to the volumetric term of the retail tariff. This would significantly distort the incentives seen by end users to adopt technologies such as storage, self-generation, etc. Note that, whilst in principle artificially high volumetric tariffs may promote some of these technologies, this is not an efficient way to do so. Two main problems may arise:

- Since the volumetric component does not reflect the real value of electricity, end users may tend to over invest in some technologies (e.g. energy efficiency, self-generation), whilst hampering the adoption of electrification technologies necessary to achieve the long-term decarbonization goals (e.g. heat pumps or EVs).
- Those end-users who decide to invest in the over-promoted technologies, such as self-generation units, may be incur in an economic loss if changes are made to the tariff after they have made their investment decisions.

Retail tariffs and regulated charges - Recommendation No. 3

To the extent possible, all the costs not related to the electricity supply should be removed from the regulated charges included in the electricity tariff.

When some of these costs remain in the electricity tariff, they should be allocated in the least distortive way possible, particularly avoiding artificially high volumetric charges.

7.5.2. Self-generation and self-consumption

As discussed in section 3.1, the CEP recognizes the value of self-generation to support the penetration of RES and enhance end-user involvement[54]. Therefore, **regulation should enable self-generation, including collective self-generation[55]**, to develop without undue barriers such as excessive administrative requirements, e.g. similar to those of conventional generators, or charges to the electricity self-consumed. Directive (EU) 2018/2001 provides detailed instructions for Member States to remove barriers to renewable self-generation (notification-only procedures for small units, network charges, network access, etc.).

Section 5.12 showed that all the target countries allow self-generation. In fact, several of these countries have recently passed new legislation that go along the dispositions of the RES Directive. These are Portugal, Slovenia, and Spain. These three countries are also the ones that allow some form of collective self-generation.

Self-generation and self-consumption - Recommendation No. 1

Regulation should allow end-consumers to self-generate and store their own electricity without undue barriers as set in Directive (EU) 2018/2001.

In the case of self-generation, allocation rules of renewable production should ensure the appropriate regulated charges are paid for.

However, it must be ensured that the development of self-generation takes place without causing unfair discriminations between network users. In this regard, the proper allocation of regulated charges discussed in the previous section is a key topic, as the volumetric component of the tariff can be seen as the opportunity cost of the electricity self-consumed. Hence, the need to have properly designed tariffs, that avoid cross-subsidization and potential cost recovery problems (Eid et al., 2014). These problems exacerbate when large volumetric tariffs are combined with net-metering schemes. An additional drawback of net-metering is that it effectively eliminates any incentive for flexibility, including HEMS or storage technologies[56]. Therefore, **net-metering schemes should be phased out** where they exist. As stated by (CEER, 2016d):

> *"Net metering should be avoided as it implies that system storage capacity is available for free. It reduces consumers' time-value sensitivity to volatile energy prices and hence undermines*

[54] Even if not always stated explicitly, this section specifically addresses renewable self-generation.

[55] Collective self-generation is usually restricted to consumers located in the same apartment building or similar proximity limitations. These schemes do not require to constitution of a new legal entity, as opposed to RECs or CECs (CEER, 2019c). The latter will be discussed in more detail in section 7.7.1.

[56] In fact, under a net-metering scheme, the grid becomes a "free battery" for the prosumer.

> *efforts to enhance flexibility and to develop a wider demand-side response with consumers playing a more active market role."*

However, among the target countries, Austria and Slovenia still follow a net-metering approach to value the excess production injected into the grid.

The challenge is that replacing net-metering with other approaches, such as **net-billing[57] or selling the excess self-generated electricity to the market or through P2P schemes**, and achieve a sustainable development of active consumers, requires two things: i) cost-reflective design of retail tariffs (see section 7.5.1), and ii) the roll-out of advanced metering technologies. Thus, in those countries where a large-scale deployment of smart meters has not taken place, prosumers may be required to install one at their premises.

> Self-generation and self-consumption - Recommendation No. 2
>
> Abandon net-metering schemes in favour of net-billing schemes or market participation of self-producers. Under net-billing, active consumers should receive a compensation for the energy injected into the grid that reflects the market value of that electricity
>
> Consumers with self-generation facilities may be requested to have a smart meter installed to ensure they can be exposed to cost-reflective tariffs.

A possible alternative to net-billing methods, particularly for large self-generation installations, is to sell their excess production to large consumers or suppliers through a PPA. This possibility should be enabled by regulation as it could bring several benefits: i) limit the exposure of RES, including self-generation, to low market prices, ii) reduce the impact of RES subsidies on system costs, and iii) help industrial consumers to reduce their electricity costs and/or price exposure. Therefore, regulators should **remove barriers for the development of RES PPAs** as stated in Article 15 and 21 of Directive (EU) 2018/2001.

The situation in the target countries about the treatment of excess production may be classified into three groups. As mentioned above, in Austria and Slovenia net-metering is the only alternative for renewable self-producers. In Sweden, self-producers can sell their production to suppliers (but not at the market). In Portugal and Spain, self-generators can be directly compensated for the energy injected to the grid (net-billing) or sell their excess production in the market (including PPAs) directly or through a representative third-party. In the latter case, additional requirements may be set (registration, imbalance responsibility, etc.).

> Retail tariffs and regulated charges - Recommendation No. 3
>
> Regulatory barriers to the development of renewable PPAs should be removed.

[57] Under net-billing, the economic value of the excess electricity injected back into the grid is decoupled from the volumetric component of the retail tariff. Instead, the economic compensation for this electricity, if any, is set in relation to the wholesale market price or as a FiT set administratively.

7.6. Creating a level playing field for all flexibility providers

The Integrid concept, particularly everything related to the BM5, strongly relies on the role of flexibility providers that aggregate the flexibility of all types of DER to provide services to TSOs and DSOs. However, in practice, these stakeholders face important regulatory barriers to develop their full potential, particularly in relation to the aggregation of demand-side resources or when acting as independent aggregators. This section addresses these barriers and provides recommendations to overcome them.

7.6.1. Balancing market design and access rules

Access of DER to balancing markets, especially demand-side response, is at the centre of BM5. In this business model, different types of demand response participate in different balancing markets, through the aggregation of different agents. In BM5.1, the supplier acts as a BSP using the flexibility from its customers to participate in balancing markets, namely the secondary and tertiary reserve markets. In this context of InteGrid specifically, the demand-side units considered were commercial buildings, and flexibility provision in both the aFRR and the mFRR markets was considered. In BM5.2 the aggregated resources are industrial consumers, that participate in the mFRR through the cVPP. In this business model, both the type of demand-side unit and the aggregator are different. Industrial consumers present different characteristics compared to commercial consumers in terms of flexibility potential (e.g. potential duration/capacity of activation, price elasticity etc). Moreover, the cVPP is also a different type of aggregation compared to a retailer. It is safe to expect that the cVPP will mostly be an independent aggregator. As one of the main potentials of the VPP concept is to aggregate different types of DER, unless the VPP is limited to DR and DG for self-generation (connected to a consumer, and therefore in the portfolio of a retailer), this agent will have to build a portfolio independent from the portfolio of a retailer.

As shown in section 5.11, the five InteGrid target countries are at different stages with regard to the opening of balancing markets to the participation of DR. While some countries such as Austria, Sweden and Slovenia already allow explicitly the DR participation, all five countries have certain design aspects that, in practice, are a limiting factor for the integration of DR in balancing services in its full potential.

Considering the solutions tested in InteGrid, in BM5.1 and BM5.2, this section drafts recommendations for demand-side participation in balancing markets. In this section specifically, the recommendations for demand-side participation itself are explored. In the following section, specific recommendations for aggregated participation in balancing markets are made.

Ensuring that all resources can participate in electricity and service markets under level-playing field rules is one of the priorities set in both the Network Codes and Guidelines and the CEP. This also includes demand-side participation in balancing markets. This participation, according to the CEP, can be directly or through other market agents. The CEP also does not make a distinction about residential, commercial or industrial demand response.

The potential for demand-side response participation in balancing markets is not equal among different types of consumer. The ease of integration of these different units is not equal either. CEER (2014), for instance, argue that residential and industrial consumers differ both in terms of capital cost and operational costs. While the former will face a much higher CAPEX before being able to provide flexibility in markets, the OPEX is expected to be low, as the opportunity cost of the traded flexibility is also low for this type of consumers (e.g. reduction in household comfort). On the other side of the spectrum, the industrial consumer will have reduced CAPEX costs, but high OPEX cost, as the cost of opportunity is much higher (e.g. changes in production process).

Beyond differences in CAPEX and OPEX mentioned by CEER, it is also important to mention social aspects of DR participation. Large consumers (industrial or commercial) are likely to be more willing to participate in flexibility provision at first, considering that this type of consumer already has internal expertise in energy management. Conversely, residential consumers not only lack the resources for energy management, but may also face more difficulties in understanding and trusting energy markets, as also shown in the stakeholder consultation of InteGrid [REF D7.6].

A few other aspects may corroborate the conclusion that large consumers may have a higher willingness to participate in balancing markets. Firstly, some industries can provide flexibility while facing a reduced operational cost. That is the case for water treatment companies, for example, that due to the inertia in their process can offer a flexibility without hampering internal processes. Secondly, as discussed in the following paragraphs, DR benefits more from the participation in capacity markets, than in energy markets. Therefore, for industrial consumers, the participation in capacity markets with reduced likelihood of activation can be economically viable, as the operation expenditure is low. Finally, it is also relevant for DR participation that some industries may be able to explore different types of flexibility other than the simple reduction of consumption. Many industries have a backup generator in their premises that could be used (although activation costs would be high) or even batteries (e.g. in cell phone towers), are able to install CHP units to benefit from the heat generated by industrial processes, and due to inertia in their process may also be able to offer downward regulation bids, as well as upward[58].

Therefore, the participation of DR in balancing market is likely to follow an incremental approach, in which at first, large consumers, especially industrial, will perceive more value providing flexibility in these markets.

> Balancing Market Design - Recommendation No. 1
>
> The participation of DR in balancing market is likely to follow an incremental approach. Large consumers are likely to be more willing to participate in balancing markets than residential consumers. Therefore, when adapting balancing markets for demand response participation, large consumers may be included in the first stage.

The participation of DR in balancing markets is highly affected by how products are defined and procured. Firstly, and most straightforward, are the definitions on minimum bid size and symmetry of bid. The former can be adjusted to levels that are more suitable to demand response participation, that are usually smaller in installed capacity. This adjustment, however, can be more difficult to reach the kW level, as the complexity of managing very small bids and deliveries increases considerably for TSOs. It seems that a

[58] Upward regulation bid means an offer to increase generation. The need for increasing generation can be substitute for decrease in consumption. Therefore, DR will offer mainly upward regulation bids. On the other hand, downward regulation bid is an offer to decrease generation, or possibly increase consumption.

reasonable minimum size bid for tertiary reserve markets is of 1MW. This value is also proposed as a minimum bid size for the MARI platform, the cross-border exchange platform for mFRR being developed as part of the Electricity Balancing Guideline. According to the consultation document, the 1MW minimum bid size is a “consensus between TSOs, who want the minimum quantity to be large enough to carry out their work in good conditions, and BSPs, who want the minimum quantity to be small enough to facilitate their participation” (ENTSO-E, 2018).

The bid symmetry is the obligation of a BSP to offer the same capacity on both directions, upward or downward. This is characteristic is clearly a barrier for DR participation, that can mainly offer upward regulation. Alternatively, some balancing markets require a certain ratio between upward and downward bids, still requiring that agents bid in both directions. Although this design is not so rigid as the symmetrical bids and could be accessible by VPPs, for instance, it is still a barrier for overall participation of demand response.

Balancing Market Design - Recommendation No. 2

Minimum bid sizes should allow for DR participation while maintaining the capability of the TSO to efficiently manage the system’s balance. Additionally, independent upward and downward bidding should be allowed.

Balancing markets are usually designed in a way that TSOs remunerate either energy only (the activated energy to balance the system), or they remunerate capacity (a band that provides the TSO the security that balancing capacity will be available) plus the activated energy for each balancing product. According to ENTSO-E’s guidelines, TSOs should procure a minimum reserve capacity for each product, usually to cope with the maximum generation loss of a N-1 situation. However, a common practice in several balancing markets is to oblige all available generators to provide all available capacity. This capacity though is not remunerated. Only the eventual energy activated. This method makes for a “cheap” reserve capacity procurement for TSOs, as this service is not remunerated. At the same time, it is an important barrier for the participation of DR, considering that in non-remunerated reserve capacity markets, capacity provision is mandatory to all generators, but also limited to those agents.

The InteGrid’s economic SRA showed that balancing capacity is the main source of value for DR in balancing markets [REF D8.2]. The reservation of capacity for balancing purposes[59] is a service needed by TSOs, as they provide a short-term “hedge” against sudden changes in the demand-generation balance. For several reasons, this hedge is not remunerated for certain services in certain markets (e.g. mFRR in Spain and Portugal). This can be due to the fact that capacity is also available in the scope of these services, due to high amount of idle installed capacity, for instance, or just because this is a legacy market design from the moment that balancing services could only be provided by centralized generation. In the context of future power grids, with high shares of DER and a higher intermittency caused by RES, the value of this capacity in

[59] Balancing capacity here should not be confused with reserve capacity markets. Balancing capacity procurement is a short-term product (usually procured in the day-ahead) used to cope with sudden changes in the systems’ demand-generation balance. In other words, it is a product to **ensure system security.** Reserve capacity markets are long term capacity procurements aiming at providing the adequate level of generation at any given time, also known as **system adequacy**. In this section we focus on the first one, although DR could also benefit from the participation in capacity mechanisms.

balancing markets may become more evident, and proper pricing of this service can bring benefits to the whole system. As mentioned above, mandatory provision of balancing capacity also excludes the participation of DR and possibly other DER. Therefore, capacity is being procured “cheaply”, but bids for activated energy are limited to those units able to participate, excluding potential efficiency gains from the participation of DR. This is also limiting the economic incentive for the DR engagement in electricity markets.

Another possible barrier created by mandatory provision of mFRR capacity is the high share of upward regulation offered into the market, considering that all generators are obliged to provide their capacity. The economic SRA showed that, at least for Portugal, this market design promotes a higher availability of upward regulation compared with downward. Considering that demand response will mostly offer upward regulation, a situation in which all generators have to offer their capacity may create a distorted market environment, not in line with the “level playing field” spirit promoted by the EU Target Model. From a society’s perspective, promoting a level playing field may also be beneficial. The participation of DER as proposed in BM5, means that other agents are entering balancing markets, and therefore more competition and lower balancing costs can be expected.

Balancing Market Design - Recommendation No. 3

Balancing capacity services (for aFRR, mFRR and RR) should be open to the participation of all agents, including DR, under transparent, market-based procurement conditions.

The third market design aspect to be considered is on how the market is cleared. Two main options are usually used in energy clearing markets, namely “pay-as-bid” and “pay-as-clear” (also known as uniform or marginal pricing). In the former, the accepted bid is paid the amount they bid in the market, while in the latter, agents are paid the bid of the last unit accepts, the marginal price of that market session. Continuous markets, such as most of the intraday markets in Europe, are necessarily cleared using pay-as-bid, while auctions can be cleared with both methods. Participants in the market are expected to behave differently under the two clearing options. In energy markets under uniform pricing, agents have a strong incentive to bid their marginal cost, while under “pay-as-bid”, agents will try to predict the outcome of the market and bid accordingly. Both settlement options have positive and negative sides. In the case of uniform pricing, the methodology is simpler to participants, revels the variable costs of participants, while the pay-as-bid could be an overall cheaper procurement mechanism. On the negative side, uniform pricing can promote distortions due to market power, while pay-as-bid increases the complexity for participants and may lead to more volatile prices.

The definition of the settlement mechanism for balancing capacity and balancing energy markets does not find consensus in the literature (Schittekatte et al., 2019). Also, the Electricity Balancing Guideline does not impose one over the other either, and most EU markets seem to adopt pay-as-bid for balancing capacity markets. One could argue that this could lead to lower capacity procurement costs. In addition to that, a marginal cost for the capacity provision is not as straightforward as it is for energy. Nevertheless, from the DR participation standpoint, pay-as-clear could lead to less complexity and a higher incentive for participation, as the potential gains of investing in new equipment to enable DR would be higher (NordREG, 2016). In addition to that, once more resources are integrated in balancing markets, competition tends to be higher and market power problems lower.

Still regarding the settlement of the balancing capacity, it is important to mention that some countries still have regulated prices for capacity of certain FRR and RR products. Regulated prices are not allowed anymore by the EB GL (Art. 32(2)) (Schittekatte et al., 2019).

Regarding the settlement of balancing energy, different than for balancing capacity, the EB GL clearly states that balancing energy clearing should be based on pay-as-clear, unless TSOs identify inefficiencies in this settlement type.

> Balancing Market Design - Recommendation No. 4
>
> Settlement prices for capacity and energy balancing markets should not be regulated. In capacity balancing markets, pay-as-clear can offer better conditions from a DR integration standpoint, although such design choice can not consider this element in isolation. Energy balancing markets should adopt pay-as-clear settlement method.

A key aspect of balancing market participation is the necessity of a prequalification procedure. This is necessary so TSOs can ensure that the participants in the balancing markets are capable to deliver products with the required reliability and observability needed by the system. It is worth remembering that balancing services are necessary to recover the system from an unexpected situation, and that this service is very critical for the security of the system. Therefore, TSOs need to be sure that balancing offers can be activated properly when needed.

Prequalification procedures can follow two approaches. It can either prequalify a whole BSP's portfolio, in case it aggregates resources (portfolio-based), or it obliges the prequalification of each unity separately (unit-based) (Poplavskaya & de Vries, 2019). From the perspective of DR participation, a portfolio-based prequalification tends to be an easier approach, not only from the administrative point of view, but also because a pool of resources will be able to ensure a higher reliability for the provision of balancing services.

Additionally, it is important to consider that BSPs often must go through different prequalification processes for the different balancing products. In the future, with DSOs also procuring flexibility from DER, prequalification processes could be harmonized, creating a simpler environment for BSPs. Of course, the level of harmonization of prequalification processes will depend on the needs associated to the products being procured by TSOs and DSOs, and it is likely that a single prequalification process will not be possible. Nevertheless, at least the processes can be coordinated, and flexibility providers can be offered with a "one-stop shop" in which prequalification procedures are coordinated and combined whenever possible.

> Balancing Market Design - Recommendation No. 5
>
> Prequalification could be done in a pooled fashion to allow for easier aggregated DR participation, and also to allow for higher capability and reliability of a pooled BSP. Prequalification should also be coordinated with DSOs, considering that they will also procure DR flexibility. From the DR's perspective, to the extent possible, a "one-stop shop" is the most suitable option.

Finally, one last element is necessary for the proper integration of DR in balancing markets, namely a baseline methodology. Differently from generating units, most consumers do not have their consumption individually scheduled and are free to change consumption patterns. From the TSOs' perspective, however, it is important to verify if a certain activation instruction is executed or not. Therefore, a methodology is needed in order to establish what would be the energy consumed in the absence of the signal to reduce (baseline). Figure 14 illustrates this concept.

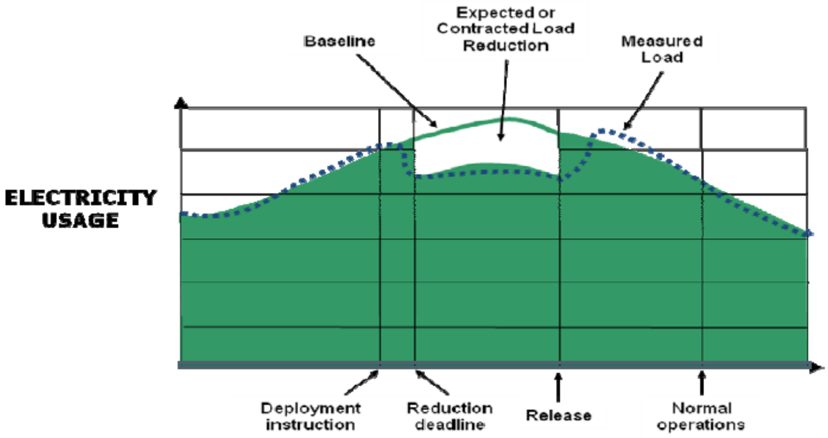

Figure 14: Baseline example. Source: (AEIC, 2009)

Several methodologies for establishing a baseline were already proposed in the literature and adopted by different countries. These methodologies can be grouped into three main categories, according to the to the time before the demand response event upon which they are calculated, as proposed by Ramos (2019) and summarized below:

- Regression approach with adjustments: calculated using statistical methodologies on historical data of a long timeframe, from months up to a year.
- X of Y approaches: either the highest days or an average of X days in a period of Y days is used to calculate a baseline. The methodologies are called 'high X of Y' or 'Last Y days' accordingly.
- Meter before/Meter after DR: This methodology considers the very close to real-time timeframe. It uses the load immediately before and immediately after the event to calculate the amount of demand response dispatched

Ramos (2019) concludes that these three approaches for the baseline calculation present trade-offs among them. Ease of validation, accuracy, data intensiveness and gaming potential are attributes in which different baseline methodologies show different performance levels, as shown in Figure 15.

Method/ Features	Statistical approach	X of Y approach	Meter before/ meter after
Ease of validation	Low	Medium	High
Accuracy	High	Medium	Low
Data Intensiveness	High	Medium	Low
Gaming potential	Low	Low	High

Figure 15: Comparison of baseline approaches. Source: (Ramos, 2019)

Balancing Market Design - Recommendation No. 6

A clear baseline methodology is necessary for the participation of DR in balancing markets. They provide TSOs with the means to verify flexibility activation and DR providers with a transparent and predictable rule for expected profits.

7.6.2. Aggregation and DER

Aggregation will play a fundamental role in enabling the participation of DR not only in balancing markets, but in providing flexibility in all energy and service markets. For several reasons, the participation of individual demand-side response providers is expected to be limited. Some large industries may be able to manage such participation internally. However, for most DR agents the costs of developing internal expertise and dedicating own personal to this activity will outweigh the benefits. In this context, the aggregator will be able to develop tools, gather market expertise and unlock economies of scale that will make the participation of DR in various markets possible.

In the context of the InteGrid project, aggregation is a key concept in several BMs. Starting with BM1, the tVPP is the responsible to aggregate resources that will later be used by the DSO. In BM5, on the other hand, the cVPP aggregates resources, mainly industrial consumers, and bids into tertiary reserve markets. Still in the context of BM5, another type of aggregation is also researched, namely the one made by the supplier directly. This type of aggregation of flexibility could lead to two use cases. Firstly, the supplier could try to minimize imbalances, should they arise in the real-time, and secondly, the supplier could also act as a balance service provider (BSP). For the latter case, the InteGrid project looked into the possibility of aggregating the flexibility of commercial buildings for the participation in the aFRR and mFRR markets [REF D8.2]. Therefore, both the supplier-lead aggregation and independent aggregation are studied withing the project.

The aggregation of resources will take several different forms according to the agents involved and on how their portfolios overlap. There are three key agents for this discussion, namely the aggregator, the supplier and the BRP. In the simplest of the cases, the three are the same entity. In this case, no conflicts will arise, as the portfolios are the same. Conflicts start to happen when these three agents are in fact different entities, but they share the same portfolio to some extent. In that case, the actions of one entity could impact on the activities of the others.

An independent aggregator could, for instance, aggregate resources from customers from two different suppliers, as exemplified in Figure 16. For the sake of simplicity, we consider that supplier is a BRP as well, and the same applies for the independent aggregator.

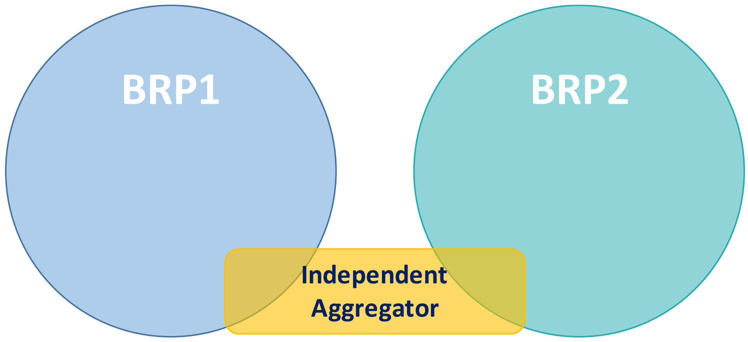

Figure 16: Representation of an independent aggregator managing resources from more than one BRP

In the case represented above, it is easy to realise that when the independent aggregator is active, and a certain DER has to provide flexibility, the supplier will be impacted in two ways. Firstly, it will be imbalanced, as the supplier committed to a certain level of consumption on behalf of its customers, but this consumption was reduced/increased due to the flexibility traded by the independent aggregator. Secondly, the supplier is also financially impacted as they procured energy for the fulfilment of the whole expected consumption of their customer. The consumption difference between the expected consumption and the reduced consumption due to flexibility provision has to be borne by the supplier. Therefore, without a robust framework on independent aggregation, situations like the one described above can hamper the business models of retailers. In order to build such a framework, two main aspects must be defined. Firstly, the baseline methodology, as mentioned previously. Secondly, the methodology to settle imbalances and financial differences caused by flexibility activation.

One of the main methodologies for settling imbalances and financial positions is called Transfer of Energy (ToE), as the one implemented by the Belgium TSO Elia, for instance (Elia, 2019). In the case of Elia, the ToE network allows for the neutralisation of the impact of the activation on the calculation of the imbalance of the supplier and provides the necessary data so that aggregator and supplier can adjust their financial position accordingly. The way it works is when an activation takes place, the capacity related to that activation is 'transferred' from the supplier's balancing responsibility to the independent aggregator. In other words, the independent aggregator become balance responsible for the portion of its customer capacity devoted to flexibility provision. The supplier is exempt from the amount, therefore. Also, the ToE, operated by the TSO, calculates the necessary financial adjustments necessaries so the supplier is compensated by the resulting long position created by the flexibility activation. The ToE is regularly audited to ensure the neutrality of the TSO, and agents can also opt-out from the framework and enter into bilateral agreements.

Aggregation - Recommendation No. 1 A framework to settle imbalances in the supplier's portfolio originated by flexibility activation and to adjust financial positions is necessary to insure harmony between the independent aggregator and the supplier's activities. An example of such a framework is the Transfer of Energy, already adopted in Belgium.

Aggregators will most probably participate in both TSOs and DSOs flexibility markets. It is possible that one single aggregator operates as both tVPP and cVPP. However, for this type of operation to take place, enhanced coordination between TSOs and DSOs in the procurement and activation of resources is needed. In case this coordination is not in place, the aggregator may face the situation of being activated by one system operator, but not being able to deliver the flexibility for conditions in the other grid. To avoid such situations, enhanced TSO-DSO coordination schemes are necessary, such as the one proposed in InteGrid, namely the Traffic Light System.

The enhancement of TSO-DSO coordination is necessary and should take place in three different stages, namely the network planning, the operational planning and real-time management of the grid. The enhanced TSO-DSO coordination for network planning concerns more BM1, for instance, as the DSO will defer investments. In the context of BM5, the most relevant areas of cooperation are the **operational planning** and **real-time grid operation**. In the former, aggregator will benefit if TSOs and DSOs cooperate in the way they **procure flexibility**, while in the latter the benefit comes from the coordination in the way they **activate the necessary flexibility**. For both situations, enhanced information exchange between the two SOs is also necessary.

A recent report jointly published by CEDEC, EDSO, ENTSO-E, Eurelectric, and GEODE[60] explores the possible ways forward in the field of TSO-DSO coordination (CEDEC et al., 2019). Regarding the crucial points for aggregators and DR, the report explores the possible balancing and congestion management market configurations that could lead to a more efficient procurement. In this case, not only the TSO procures resources for balancing and congestion management, but also the DSO procures flexibility for local congestion management. Therefore, having a coordination in this procurement reduces the risk incurred by the aggregator, besides possibly simplifying procedures.

Three main market models are identified. Firstly, the simplest and possibly less coordinated one, is the market model in which all markets are operated independently. In this case, aggregators would have to participate in each market independently. In the second market model, certain markets could be operated jointly (e.g. local congestion management and centralized congestion management), reducing the number of marketplaces for flexibility providers. Additionally, markets could exchange bids. For instance, bids not used in balancing markets could be sent to congestion markets. For this type of exchange to happen, a higher harmonization in products would be necessary[61]. Finally, a third type of market model is when both balancing and congestion management markets are jointly operated. Figure 17 illustrates the three market models proposed by CEDEC et al. (2019).

[60] CEDEC, EDSO, Eurelectric, and GEODE are DSOs associations in Europe, while ENTSO-E is the association of TSOs.

[61] One example are balancing bids, that often do not have a location information associated to it. For congestion management purposes, that information is necessary.

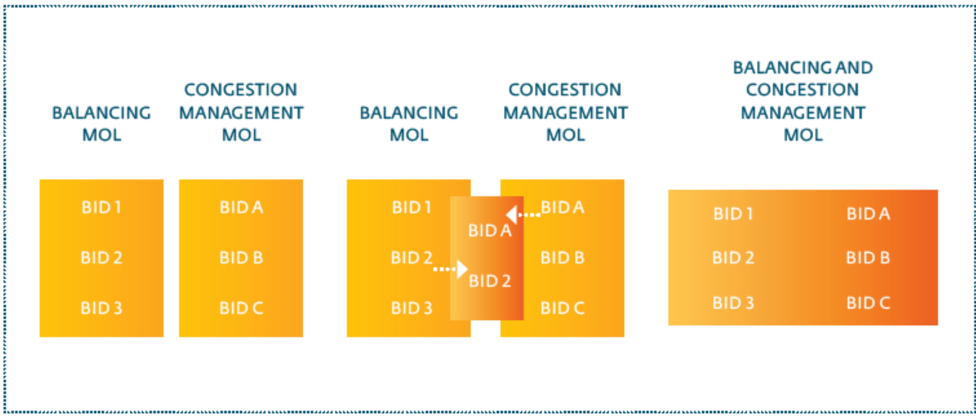

Figure 17: Main options for market models. Source: (CEDEC et al., 2019)

The enhancement of TSO-DSO coordination is a topic that goes beyond the scope of the InteGrid project. In this context, it suffices to say that for the aggregation activity, enhanced coordination in the procurement and activation of resources is necessary. For that to take place, enhanced information exchange is also necessary. Nevertheless, sound recommendation on the topic itself can be found in CEDEC et al. (2019). Also, several different H2020 projects explored or are exploring solutions within this topic, namely the SmartNet[62], CoordiNet[63] and Interrface[64] projects, that are exclusively devoted to the research of TSO-DSO coordination.

Aggregation - Recommendation No. 2 Enhanced TSO-DSO coordination is necessary to ensure seamless participation of aggregators in both local and centralized markets. Enhanced coordination is necessary both in the operational planning and real-time operation timeframes. Coordinated market models and activation procedures can reduce the risk upon flexibility providers and increase overall economic efficiency.

The economic SRA also showed the importance of allowing aggregator to participate in different markets in a seamless way becomes important. The barriers identified by the economic SRA on the limitation of small pools or pools of resources with reduced flexibility can be partially mitigated by allowing aggregators to participate in multiple markets. These may include other balancing markets such as the aFRR, DSO service provision and other markets, such as congestions management, voltage control, black start etc. Such participation of aggregators in different markets is still very incipient in most countries, considering that most of the abovementioned services are not traded in organized markets yet.

Aggregation - Recommendation No. 3 Aggregators should be allowed to participate in multiple markets with the same portfolio, provided the prequalification requirements are met to all of them.

[62] http://smartnet-project.eu/
[63] https://coordinet-project.eu/
[64] http://www.interrface.eu/

Finally, it is also important to highlight that VPP will most probably aggregate different types of DER under a same portfolio. This is key for the full exploitation of the VPP potential. Having a portfolio with several types of DER will ensure that the VPP can behave as similarly to a large generator as possible. If only one type of DER is used, the VPP will be limited to the characteristics of that type of DER (e.g. limits to provide one or the other direction).

This advantage of having several types of DER aggregated under the VPP was also confirmed by the SRA. Aggregating different types of resources can allow the tVPP, for instance, to solve grid constraints which can be caused either by peak demand or peak generation conditions, or to gain in size, which was detected as a major economic barrier for the VPP [REF D8.2].

Therefore, the aggregation of different types of DER in the different markets should be allowed, provided that prequalification requirements are met.

Aggregation - Recommendation No. 4 Aggregation of different types of DER in the different markets should be allowed, provided that prequalification requirements are met.

7.7. Additional regulatory topics that could affect the BM implementation

This section addresses some regulatory topics that, in spite of not being directly related to the implementation of the BMs, could be also relevant to their future development. In subsection 7.7.1, two types of end-user associations will be discussed: the **closed distribution systems (CDS) and the Citizen Energy Communities (CECs).** These two entities defined in the European legislation could be used as a form to maximize the benefits from pursuing some of the Integrid BMs, particularly BM4 and BM5. Nonetheless, an inappropriate regulatory design may lead to opportunistic behaviours that ought to be avoided.

Lastly, subsection 7.7.2 discusses the possibility of enabling **regulatory sandboxes** as a means to support upcoming regulatory amendments. This can be particularly relevant to clarify some of the unclear dispositions in the CEP discussed in section 3 before their transposition, or to allow regulators gather more experience before implementing a regulatory change that may have unintended consequences. Herein, a review of existing international experiences with regulatory sandboxes will be performed in order to draw key lessons learnt and provide recommendations for the design of these sandboxes.

7.7.1 Citizen energy communities and closed distribution systems

Article 38 of Directive (EU) 2019/944 enables EU Member States to allow for the existence of closed distribution systems (CDS). A CDS is a distribution system which supplies electricity within a specific geographical area where all points of supply, usually large industrial or commercial consumers, have a direct relationship with the owner/operator of the system or share some services. The CDS operator would bill these consumers for the use of the grid and, if exempted from unbundling, act as their supplier. For example, CDS can be found in places such as industrial sites (usually chemical sites), seaports or airports. According to the Directive, CDS may not supply electricity to residential consumers, except for those who are employees of the CDS operator or have a similar relation.

The operators of CDS are legally considered as DSOs. Nonetheless, they can be exempted from several obligations related to the tariffs approval, procurement of flexibility, procurement of energy losses or ancillary services. Moreover, they are entitled to own EV charging infrastructure or energy storage system. Moreover, since they usually supply less than 100,000 points of supply they are usually exempted from unbundling obligations[65]. Thus, they usually act as a vertically integrated company.

Concerning electricity consumption, constituting a CDS can have **several benefits for the operator and the consumers connected to them**. Becoming a CDS gives the operator the possibility to offer services that make it more attractive for potential customers to locate at their premises, e.g. EV charging infrastructure for corporate fleets, or lower electricity costs. For instance, the developer of an industrial site can be interested in bringing new industries to its site because of local employment benefits, the possibility to reduce operational costs by sharing services or using by-products of some industrial processes as an input to others (saving transportation costs).

On the other hand, the consumers connected to the CDS can lower their electricity costs thanks to the benefits derived from the possibility of bundling the consumption of several supply points, as well as sharing on-site generation or storage resources. The complementarities between the consumption profiles of different supply points and the use of local generation/storage can help them reduce the payments in network charges based on capacity (€/kW) or reduce network connection costs, as compared to the situation in which each of these supply points had to request a connection to the existing DSO grid. This is because the simultaneity between different consumers is lower than one. Thus, the sum of the peak demands of the individual consumers is always lower than the maximum of the aggregated consumption of all consumers in the CDS. Since tariff periods over which network capacity is billed or contracted are usually discrete, this can lead to economic savings.

Figure 18 illustrates this last situation with a simple example. Initially, there would be only one industrial consumer (Industry 1) connected to the DSO grid through the substations depicted in the figure using its own dedicated line. Then, a new industry (Industry 2) wishes to locate close to the existing industry and requests a connection to the DSO, who would require building a new feeder and substation switch bay for this connection (dashed line in Figure 18). These costs, depending on regulation, could be borne by the new industrial consumers or socialized among ratepayers. However, if the new industrial consumer were allowed to connect directly downstream of Industry 1, significant network costs could be avoided.

[65] Some countries set a lower threshold for unbundling exemptions

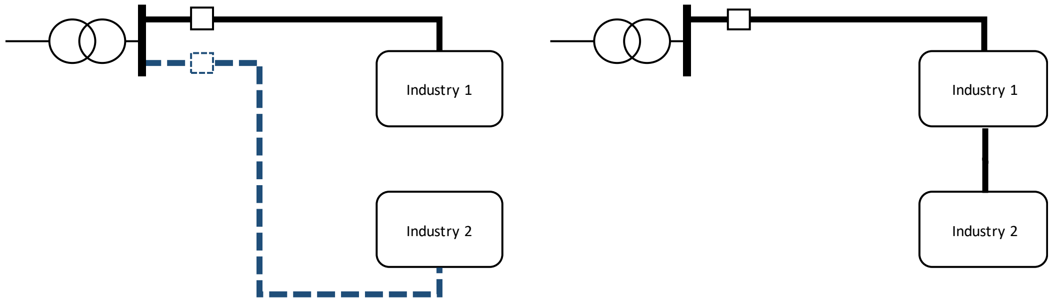

Figure 18: Connection to the DSO grid (left) as compared to the connection in a CDS (right)

Note that the existing line connecting Industry 1 to the DSO grid may actually need no reinforcements despite the fact that it is now supplying two different industrial consumers under several circumstances (note that these are not mutually exclusive, as they could be compounded):

i. The existing line has significant spare capacity due to the scale economics of network components.

ii. The simultaneity in the consumption profile of both industries increases the utilization rate of the line, nut not the maximum power flow through it.

iii. Industry 2 is not really a new plant. Both industries used to be part of a pre-existing industrial installation that belonged the same company and had a single grid connection. However, after a set of corporate sales Industry 1 and Industry 2 now belong to two different companies. In the absence of the figure of CDS, Industry 2 could be required by law to request a new connect point to the DSO grid and bear the corresponding cost.

Citizen Energy Communities (CECs), enabled through Article 16 of Directive 944/2019, is a new type of entity created by the CEP which can extend some of the benefits of sharing energy services to a broader range of consumers, including residential ones. According to this Directive, the CEC may provide all sorts of electricity services to the members that freely decide to join (including distribution, if national regulation allows for it). A key difference with respect to the CDS is that the benefits pursued are not exclusively financial, as they may include social or environmental benefits too.

Regulatory challenges:

The discussion above addresses some of the genuine benefits that CDS may bring to both the CDS operator and its users. However, CDS may also open the gate to **exploiting opportunistic benefits** that may not be socially desirable. These are essentially based on inefficiencies or discontinuities in the tariff structure that allow a group of bundled points of supply to avoid the payment of certain regulated charges. The effects of bundling points of supply is illustrated in Figure 19: Comparison of individual users connected to the DSO grid (left) against the effect of bundling points of supply under a CDS (right). This figure compares two situations. The image on the left shows a set of consumers who have their individual points of connection to the MV grid. On the other hand, the image on the right depicts a situation in which the same consumers are connected to a CDS, which has the point of connection to the DSO or the TSO grid at the substation, i.e. either at HV or MV level.

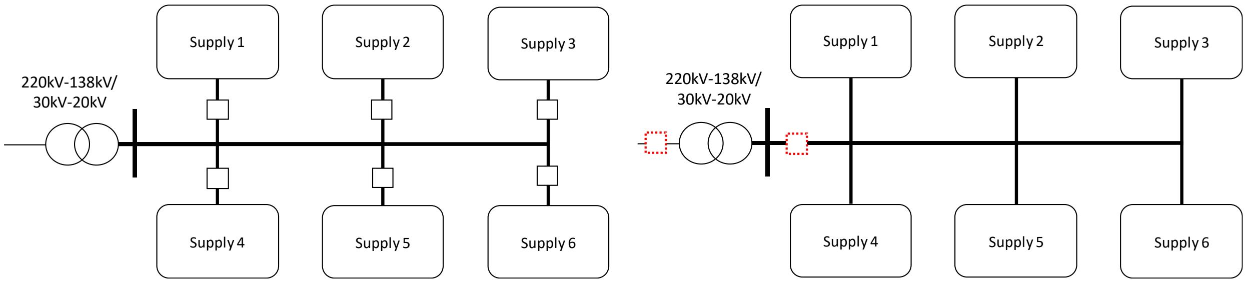

Figure 19: Comparison of individual users connected to the DSO grid (left) against the effect of bundling points of supply under a CDS (right)

The bundling of points of supply shown above may lead to some cost savings for the consumers connected to the CDS when the tariff structure presents the following characteristics:

- **Fixed charges**: fixed charges (€/month-user) can be used to allocate some of the fixed system costs to end users. Therefore, aggregating points of supply into a CDS as shown above could allow these consumers to reduce their regulated payments. This has no benefit for the system as a whole and may pose a threat to the recovery of the system fixed costs.

- **Tariff differences by voltage level**: regulated charges in many countries present a differentiation by voltage level. Most commonly, consumers connected to the lower voltage levels tend to pay a higher share of regulated charges, both network costs and other regulated charges (e.g. RES extra costs). Therefore, consumers connected to a CDS could significantly reduce their energy costs by stablishing their point of connection to the DSO/TSO grid upstream of the nearest transformer (see Figure 19: Comparison of individual users connected to the DSO grid (left) against the effect of bundling points of supply under a CDS (right)). Once again, this does save any costs for the system whilst it hampers cost recovery.

The aforementioned challenges posed by CDS are not new. In fact, Directive 2009/72/EC from the Third Energy Package had a very similar regulation concerning CDS. Nonetheless, Member States usually limited this possibility to very specific circumstances (limits in number of users or voltage levels, or requirements for the CDS operator). Now, Directive 2019/944 from the CEP has opened the possibility for CECs to own and operate the local distribution network if member states decide to allow it. In that case, the CEP states that they should become a DSO or a CDS operator. Therefore, this disposition may increase the opportunities for exploiting opportunistic benefits if the number of CDS operators increases, thus threating the recovery of fixed system costs.

Notwithstanding, it is true that the CEP mitigates this risk by imposing that, when allowed to own and operate distribution systems, the CECs should become a DSO (with the same third-party access or unbundling obligations) or a CDS operator (who may not supply residential consumers and is limited to a certain geographical area).

Opportunities of CDS or CECs for Integrid BMs

CDS can offer opportunities for the development of BM4.1 (industrial consumers reducing energy costs) as a similar energy management system could be used to control loads from the whole CDS users instead of a single industrial consumer. This would allow gaining from scale economies. In fact, the CBA results for HLUC08 already showed that a main reason for the negative CBA result was the limited cost reduction obtained by a single user did not compensate the fixed costs of the system (i.e. those that do not depend on the number of resources controlled).

A similar strategy could be pursued by a CEC. For instance, by controlling the loads of its members the CEC could maximize the ratio of self-consumed electricity and reduce energy procurement costs (BM4.2), or provide EV charging services using locally produced electricity. This control may be based on individual HEMS systems or some form of community energy management system.

Going one step further, the CDS operator or the CEC, leveraging on the internal energy control capabilities, could become a VPP operator (BM5.3 and BM5.4) and additionally provide services to the DSO or TSO. In fact, providing tVPP services to the DSO could be easier for a CDS or a CEC than for an independent VPP operator, provided the DSO grid upstream of the CDS or CEC is constrained. One of the key challenges observed in the SRA and CBA analysis was that the resources in the VPP portfolio needed to be located precisely where the flexibility was required by the DSO, and an independent VPP may not be successful engaging consumers connected to those areas. Since the CDS or CEC users are already located within a specific area, this would not be a major challenge.

On the contrary, CDS or CECs may face additional barriers when providing services to the TSO. Firstly, the CDS or CECs will be necessarily limited in size, so they may not be able to reach the adequate portfolio size to break even when providing balancing services to the TSO. Secondly, if the upstream distribution grid is congested, which is positive from the tVPP point of view, may hamper the viability of the cVPP if these constraints prevent the CDS or CEC to provide the balancing services. In order to bring the best of both alternatives, CDS or CECs could enter into partnerships with experienced VPP companies. The former would be granted access to an advanced energy management system and advice from the VPP operator, whereas the latter could swiftly enlarge its portfolio, especially in those areas where the tVPP presents a higher value.

Regulatory recommendations:

National regulation should **allow CDS and CECs** in order to unlock their potential benefits and as a means to promote the flexible behaviour of different types of DER. However, it is relevant to note that Directive (EU) 2019/944 provides different levels of legal obligation on Member States. Whilst it states in Article 16 that Member States “shall” enable CECs, Article 38 states that Member States “may” enable CDS. This may create some legal gaps if CECs are allowed to own and operate distribution networks and CDS are not transposed into national legislation.

However, regulation should prevent these entities from exploiting possible opportunistic benefits derived from the tariff structure as these may jeopardize system cost recovery or force to increase tariffs for consumers not part of a CDS or CEC. In order to achieve these, regulation should:

i) To the extent possible, **remove large discontinuities in the tariff structure** that provide strong incentives to bundle metering points or change the voltage level at the point of connection.

ii) If the tariff structure cannot be adequately modified to remove perverse incentives, regulation should **set conditions to be granted the status of CDS or CECs** so that opportunistic rents are avoided. This may include limits in the number of metering points inside the CDS/CEC or in the voltage levels that can be included in the same CDS/CEC. **NRAs should have the power to supervise** that these conditions are fulfilled.

7.7.2 Enabling the transition through regulatory sandboxes

The existence of regulatory barriers calls for the adaptation of the existing regulatory framework that would allow for the implementation of novel business models. A major challenge for such adaptation is the uncertainty of the impact of the changes on the actors in the market. On the other side, experiences from the real-world environment are essential for the understanding of the rollout of novel business models and their coexistence with the traditional business. This is why experimental spaces are being created to test how novel business models can be operated under real market conditions and how does the change of regulatory rules impact the conditions for the actors in the market. Several countries have already launched experimental spaces or are in preparations to do so. In some of these experiments, the idea is taken from the financial technology industry's regulatory sandbox instrument. (ISGAN, 2019) In this sector, regulatory sandboxes are used to reduce the time-to-market and allow for the deployment of innovations that would otherwise not be deployed. (FCA, 2015) For the deployment of InteGrid business models, regulatory sandboxes can be used as a comprehensive solution to address several regulatory barriers that currently hinder the implementation in real-time market.

The application of regulatory sandboxes can be relevant to almost all InteGrid business models to address barriers. In particular it can be used for business models including services to procure flexibility from DER and consumers – BM2, BM4.1 and 4.2, BM5.1, 5.3 and 5.4.

The design of a bespoke framework can be derived from experiences in countries that already have launched an experimental space. A detailed description of the different regulatory sandboxes is provided by the publication of IEA International Smart Grids Action Network (ISGAN, 2019) describing the background of these initiatives and explaining the different approaches country by country. The following summary explains the core aspects that have been identified in the country review. For further information, the above-mentioned publication can be recommended.

(ISGAN, 2019) lists the following services as within the scope of the regulatory sandbox:

- development of flexibility services for grid stability,
- reduction in environmental impacts
- sector coupling
- energy storage integration in the power sector
- management of local energy communities
- performance-based method for tariffs

Table 33 provides a list of regulatory sandboxes implemented in the energy sector that have been analysed for the purposes of this section.

Table 33: Outline of considered sandboxes in the energy sector

Country (Initiative)	Regulatory body	Implementation stage (time frame)	Combination with funding
Australia	AER	Ongoing (2019-2025)	Unknown
Austria (Energie.Frei.Raum)	e-control	Planned (2019-2025)	Yes, approx. €4,4 mln.
Germany (SINTEG)	BNetzA	Ongoing (2017-2020)	Yes, SINTEG-programme of BMWi with €230mln.
Italy (Regulatory experiments to promote innovation in the power system in Italy)	ARERA	Closed (2010-2019)	no
The Netherlands (Experiment article)	ACM	Ongoing (2017-present)	no
United Kingdom (Innovation Link)	OFGEM	Ongoing (2017-2019, ongoing)	No, but available funding schemes can be used

The following sections summarise the main aspects and properties of the design of already implemented sandboxes or those which are in deployment.

Motivation

The main motivation for governments to launch a regulatory sandbox is to enable innovation in the energy sector without disturbing the existing regulatory framework that ensures an essential delivery of services. It provides a space where barriers that would usually occur for innovative business and services are removed. The regulatory sandboxes are seen as a part of a comprehensive set of measures that allow for innovation. They enhance technological innovation projects providing an extended testing environment.

In the UK, OFGEM sees the regulatory sandbox as a service to help innovators that want to offer novel service or launch new business and face regulatory barriers. (OFGEM, 2020) Stakeholder consultations in Australia performed by AEMC showed that the stakeholders see barriers in conducting proof-of-concept trials pointing out concerns regarding the flexibility of the regulatory framework, absence of defined and well understood regulatory process for conducting trials and complexity of the framework. Regulatory sandboxes addressing these issues can facilitate proof-of-concept trials and promote innovation. (AEMC 2019: 8)

The motivation for the Dutch regulatory sandboxes is to gain insights from practical situations that can be translated into new policies, if necessary. This way, the knowledge is built on real-time situations and can help in the upscaling to other areas. New businesses are possible and more chances for sustainable local communities can be provided. The main goal is to see if the current regulation has to be made fit for future solutions for the energy transition. (ISGAN, 2019: 47-49) Austria puts system integration aspects into the focus. The assessment and adaptation of the regulatory framework is seen as an integral part of technology support programs that usually address technological innovation only. The Austrian government aims with this program to reduce barriers for testing and implementing energy innovations and the corresponding technologies to enable their deployment. (FFG, 2020)

Scope of services

The scope of the services is quite large. This also influences the scope of the regulatory exemption granted. An exemption waiver might be granted to projects facing a particular barrier. On the other side, major update of the regulation or new regulation (if not existing) can be necessary if the deviation from the current regulation is significant. In some cases, the program is flexible so both large-scale projects and smaller exemptions can be granted. Programs with some maturity, i.e. OFGEM's innovation link, include also feedback systems as an alternative for projects that need rather advice then an exemption to go ahead. Topics are of different kind including peer-to-peer trading, demand response programs, flexibility markets, enabling the provision of ancillary services by small consumers and generators or time-of-use tariffs.

The Australian proposal is based on a study of already performed sandboxes, such as the OFGEM-programme in the UK. According to (ISGAN, 2019), Australia plans different levels of trials depending on their deviation from the current regulatory framework. This can range from trials facing a specific regulatory barrier, e.g. trial of a new technology that does not meet current requirements to be granted an AER waiver or exemptions power to trials with a significant deviation from the existing framework undergoing a trial rule making process, e.g. in-market trials of demand response or trials proposed by market bodies.

The British sandbox initiative is open to proposals, which are individually evaluated and if seen as essential, also granted an exemption. So far, these have been provided to peer-to-peer local energy trading platforms that enables residents to trade energy with their neighbours, enabling grid balancing capacities by trialling tariffs supported by smart home technology, central data platform with time-of-use tariff selection, balancing community energy, battery and grid, cloud-based marketplace for small-scale domestic generation (OFGEM, 2019).

Italy provides regulatory sandbox programmes for the following topics (ISGAN, 2019):

1. Improved automation and control of network components,
2. Utility-scale energy storage systems and dynamic thermal rating for transmission lines,
3. Integrated approaches for e-mobility,
4. Behind-the-meter solutions for communication between in-home devices and smart meters,
5. Opening of ancillary services market to the participation of RES and demand units

Germany follows a different approach. The regulatory sandboxes are implemented through five showcase regions which can be compared to complex research and demonstration programmes comprising of different topics (including management of flexibilities, trading platforms, sector-coupling, provision of ancillary services by prosumers) organised as an integrated comprehensive solution (BMWi, 2020).

In the Netherlands, two kinds of projects are eligible for exemption (ISGAN, 2019: 48):

1. Large experiments – the waiver holder in consultation with a regional DSO carries out the experiment with a maximum of 10,000 customers. The holder can combine renewable electricity production or CHP, supply to the consumers and set own tariffs. By matching supply and demand they can try to reduce the necessary grid capacity.

2. Project Network – up to 500 customers with only one connection to the grid of DSO. The waver holder may combine production, supply and management of the local electricity grid.

Duration

Limited duration is common for all launched regulatory sandboxes. The typical duration ranges from 2 to 4 years. In Italy, the length of regulatory experiments is variable according to the complexity of each initiative. Usually it is limited to 2 to 4 years (ISGAN, 2019: 34). In Germany, the five showcase regions have a duration of four years. (BMWi, 2016) The underlying ordinance is valid two years longer (BMVJ, 2017). In the Netherlands, the duration of the experiment is subject to an approval. The maximum duration of an experiment is limited with 10 years. (ISGAN, 2019: 51) In the UK, the trials launched so far must be completed within two years of the approval (OFGEM 2018: 1).

Type of stakeholders involved

The type of stakeholders is also dependent on the scope and size of the proposition. The representation in the German large-scale sandboxes is similar to the energy system value-chain (PtJ, 2020). The participation of research organisation is for the design, planning and accompanying the implementation essential. In the Italian case, research projects are seen as prerequisite for performing demonstration under real conditions. [ISGAN 2019: 32] Since the implementation of a regulatory sandbox is a complex issue that has to consider various aspects and addresses several fields, the governments combine it with open stakeholder consultations involving different market and non-market actors. The following groups of stakeholders are usually part of a regulatory sandbox programme in their respective role:

- All sandbox programmes have (public) **coordinating bodies**: The planning and the implementation of regulatory sandboxes is usually managed and coordinated by a selected organisation. The scope of their work and their role can differ from country to country. The responsibility can be combined with competences of other organisations (such as ministries or governmental departments). The role can be taken by regulators (Italian Regulatory Authority, OFGEM in the UK), programme management organisations (Projektträger Jülich in Germany, Austrian Research Promotion Agency FFG), advisory bodies (AEMC in Australia) or agencies (Netherlands Enterprise Agency) (ISGAN, 2019).

- Major part of the sandbox programme is performed by **energy market actors** – TSOs, DSOs, providers of flexibility, retailers, final customers with active demand, aggregators. These can represent the whole value chain, a part of it or fragments of different value chain depending on the objective.

- Public and/or private **research organisations** usually accompany the implementation process. In some cases (Austria, Italy) the sandbox programme is seen as the final phase of a research project (techno-regulatory innovation process) representing the demo phase with focus on the adaptation of the national regulatory framework.

- **Consumer associations** or consumer protection authorities – This is the case in Australia, where the consumer organisation ECA is involved in the consultations (AEMC, 2019). In the Netherlands the Dutch Authority for Consumers & Markets (ACM) is involved in the programme (ISGAN, 2019: 49) The involvement of consumer protection organisations is key to consider provision for the protection of consumers beforehand as well as during the experiment (e.g. by monitoring the impact on consumers and rules to reverse the test should this impact turn out to be negative).

- **Public bodies** with respective competences (ministries, governmental departments, market regulators, market operators) are usually involved in the advice of the programme.

- **Further stakeholders** can be involved depending on the extent of the sandbox programme, e.g. technology providers, metering infrastructure operators or smart meter gateway operators, project developers, supporting service providers housing associations.

Public support and supervision

The exemptions are being performed as amendments to exiting energy rulebook. Changes can be granted for electricity markets, gas markets or complex projects including sector-coupling. Exemptions can be used to compensate financial disadvantages occurred through the implementation of the experiment to involved stakeholders, to remove a particular barrier, to change legislation or establish new rules where none exist. Two models are evident: centrally managed process (published during a window or call for proposals), where an open procedure is used to determine the most suitable consortium to perform the experiment or open framework responding to requests as they come in without fixed dates. The latter is usually combined with a feedback system. In some cases, the regulations are not published or are issued along with a disclaimer to avoid interpreting the exemptions as the expected position of the regulator or interpretation of possible future rules.

The supervision is performed in most cases by a ministry or its advisory body. Austria developed for the preparation of a sandbox a specific and open research call. The administration and coordination can be transferred to another organisation or advisory board (e.g. in Australia, Austria, Germany, the Netherlands). The regulator can also take the role over (i.e. UK, Italy, Australia in the implementation) or be actively involved in the design process (i.e. Austria).

The granted normative exemptions and the role of the supervisory committee differ in each country:

- Australia: The design of the sandbox program is being developed by AEMC the Australian Energy Market Commission who reports to the Council of Australian Governments. AEMC conducts independent reviews of the national electricity, gas and energy retail rules for the COAG Energy Council. AEMC proposed three new tools for conducting the regulatory sandbox approach [AEMC 2019: 10]:
    1. An innovation inquiry service to provide guidance and feedback
    2. Australian Energy Regulator trial waiver power, which can temporarily exempt trials from the existing rules representing a particular regulatory barrier
    3. AEMC trial rule change process: a new rule change process to provide temporary trial rules that allow a trial to be performed (temporarily change existing rules or introduce a new rule), where it is in the long-term interest of consumers.

The implementation of the proposed regulatory sandbox toolkit would require amendments of the current legislation: the National Electricity Law, National Energy Retail Law and the National Gas Law (AEMC, 2019: i)

- Austria: A currently performed study will be used to assess the necessity and extent of a possible regulatory exemption. Austria follows an approach of a techno-regulatory innovation zone co-optimising technological changes with regulatory changes, both with equal priority. The adjustment of the regulatory framework with an experimentation clause is seen just as one of the possible options of the result (ISGAN, 2019: 21&23). Accompanying policy measures in the Austrian programme include stakeholder involvement, provision of funding resources, EU-level coordination, monitoring procedure and the treatment of possible regulatory barriers (ISGAN, 2019: 26).
- Germany: The Federal Ministry for Economic Affairs and Energy is providing up to €230 million in funding for five showcase model regions expecting that each euro of funding will have a considerable leverage of approx. €1.6 in additional private sector investment (BMWi, 2016). The showcases are designed as funding programs. The participating organisations receive funding and need in return to publish and disseminate findings of their projects. The executing organisation is Projektträger Jülich. A fixed-term ordinance for conducting experiments, the so-called SINTEG-Verordnung, has been issued to test new technologies, procedures and business models in practice without facing financial disadvantages. The rules set out under the ordinance do not prejudge any future regulation but make it possible to learn from practical tests so that the existing legal framework can be updated. German public bodies and associations had been consulted prior to its issuing (BMWi, 2020).

- Italy: The regulatory authority can autonomously proceed to set up regulatory experiments, following the due public procedures. The regulator commissions a research project to a research organisation, identifies the most important characteristics and problems along with critical parameters and indicators to be asked for in each initiative. The demonstration phase is designed around a competitive process to select a demonstration process benefiting from the incentive. The regulator then derives lessons learned in public consultation documents. The authority directly issues provisions for the regulatory measures to be put in place after the end of the experiment. Regulatory experiments in Italy have mostly been funded through network tariffs (i.e. through levies on the electricity bills for research on smart networks). In return, the outcomes of the projects have to be made public to enable external evaluation and dissemination of best practices. Market players make their own investments and are partly remunerated (ISGAN, 2019: 29&32-33)

- The Netherlands: The general administrative regulation is performed by the Ministry of Economic Development and Climate Change. The Ministry performed a stakeholder consultation prior to the program. The regulatory sandbox program is managed by Netherlands Enterprise Agency who checks the applications, controls projects and organizes the program. After four years, the government will evaluate the outcome to judge whether a legislation change is needed. The projects can ask for exemption of specific articles within the electricity legislation for the following areas: supply, production and distribution in local communities, smart electricity grid, sector coupling, storage, new flexibility services for grid stability in a house or a residential area. No funding is provided, only exemptions within the electricity law (ISGAN, 2019: 47-49)

- UK: Innovators were able to submit expressions of interest to OFGEM during two application rounds. Not successful applicants were not only provided with a justification why a sandbox was not suitable but also with feedback on how to go ahead (OFGEM, 2018). After these two application windows, the service has been adapted. The service is now accessible upon request. Reason for the change of approach seemed necessary since many applicants needed rather feedback in advance to or instead of a sandbox support. Therefore, OFGEM offers 'Fast Frank Feedback' in the first place providing a one-stop-shop service to innovators. This way it is possible to provide the most appropriate instrument (feedback, guidance or sandbox) and ensure that applicants for sandboxes have the required maturity (OFGEM, 2020). Each innovator receives a so-called sandbox letter. The letter sets out OFGEM's understanding of the proposed trial, expected operation within the regulatory framework and required protection for consumers participating in trials. These letters are restricted to trial participants and not being published. Reason for this arrangement is to avoid the interpretation of the conditions outlined in these letters as OFGEM's position on the change of rules (OFGEM, 2018).

Recommendations

A regulatory sandbox can be used to extend research activities towards market demonstration in a protected environment. Sandboxes are increasingly used by governments to perform trials preceding a market rule adaptation. An **advantage** of this approach is the **possibility to test the conditions** especially for customers with the possibility to **reverse the trial in case it is not successful** or if customers are facing negative impact. The main **disadvantage** is the **complexity** in the setup and the number of stakeholders involved in the preparation and execution of the sandbox.

Sandboxes can **address several regulatory** (market rules prohibiting certain aspects of novel business models) **or legislative barriers** (lack of regulation for new business models) while the risk of unknown negative impacts is minimised through the limitation of their duration and scope. In some countries these regulatory exemptions are combined with research activities in a **techno-regulatory innovation approach** to check the necessity or extent of an existing market rule's amendment . Such sandboxes are then equipped with funding and require knowledge sharing so that all results are publicly available also to other innovators. Another model is used in the United Kingdom or currently being prepared in Australia, where each proposal is evaluated and the necessity for regulatory sandbox assessed. Moreover, in the UK innovators are provided with fast frank feedback during the first enquiry in a one-stop-shop for innovation. In any case, once set up, a sandbox programme should be clearly connected to regulatory amendment and development process or even form its core.

The **duration** of the exemption must be limited. Regulatory sandboxes are usually given a duration from 2 to 4 years. Longer duration can be reasonable since monitoring and evaluation of the results are essential parts of an experiment/demonstration.

The **extent of the stakeholder involvement** depends on the size of the undertaking. While the participation of a limited number of consumers / prosumers along with the initiating organisation (aggregator, retailer, DSO) is sufficient for **exemption waivers** facing a particular barrier, the involvement can get complex in the case of **larger market trials**. In the latter case, a mock-up of the underlying value chain in the demonstration or at least during the consultation phase might be essential for the design.

The **involvement of customer protection organisations** is recommended in sandboxes affecting or involving end-users. **Public bodies** with competences entirely or partly covering the energy market regulation (ministries, governmental departments, regulators, market operators) should be involved in the **consultation process** preceding and/or accompanying a regulatory sandbox.

The **coordination and management of a sandbox programme** should be performed by a selected organisation. This does not necessarily need to be the national regulator. In some countries this role is given to a programme management organisation or an agency. However, in such case the regulator should be involved in another way, i.e. via a consultation process.

7.8. Summary of key recommendations

In this section, a summary of the recommendations drafted in Chapter 7 is provided. The structure of this summary is the same as the one of the regulatory barriers of Chapter 4, and for each barrier previously identified, the recommendations drafted are matched.

7.8.1. DSO Economic Regulation

Revenue Regulation

Identified Barriers	Recommendations
Lack of incentives for DER flexibility procurement due to asymmetries between the treatment of CAPEX and OPEX which favour the former over the latter	The new additions to the RAB of DSOs should be decoupled from their actual investment in order to equalize the incentives for reducing CAPEX and OPEX. This can be done by applying a pre-defined capitalisation rate on the DSO allowed TOTEX. A progressive implementation needs to be made to prevent abrupt changes in the remuneration.
Lack of incentives to extend the useful life of network assets beyond their regulatory lives	Regulators should introduce ad-hoc mechanisms to encourage DSOs to keep assets in operation after the end of their regulatory life, especially when revenue regulation presents a strong CAPEX bias.
DSO revenue regulation does not remunerate the cost of new "distribution services" i.e. management of the grid using flexibility	DSO remuneration formulas should incorporate flexibility mechanisms, such as profit-sharing or trigger schemes, which mitigate the impact of regulatory forecasting errors in a context with growing uncertainties.
DSO are not required to submit long-term investment plans and/or it is not clear how these are reflected into their allowed revenues	DSOs should submit investment plans as part of the price review process. These plans should reflect fairly the use of flexibility as an alternative to grid reinforcements and make it clear how the different expenditures are related to the outputs that want to be attained. The level of detail or granularity may be lower for the LV grid due to the high extension of these systems. Regulation should clarify how the consultation process is to be conducted.
Allowed revenues based in past investment/costs only, without taking into account future investment needs, including DER	It is recommended that investment plans are used as part of the revenue determination process. Thus, their elaboration should be coordinated with price reviews. NRAs should have the necessary tools and resources to assess the DSO network development plans by using forward-looking cost assessment methods.

New smart grid technologies, beyond pilot projects, are not considered in the remuneration of DSOs	DSOs should be explicitly allowed to implement pilots to test innovative smart grid functionalities and technologies. Regulatory supervision either as an ex–ante approval, an ex-post evaluation, or both. Such evaluation should be made based on a set of KPIs and/or CBA where the benefits for network users are clearly shown.

Other output-based incentives

Identified Barriers	Recommendations
Incentives for the reduction of energy losses are not in place or provide weak incentives (low-powered incentive, deadbands, non-symmetric designs, cap and floors)	The reference values for losses considered in the incentive schemes should reflect the impact of DER on network losses in each DSO area.
Energy losses incentives do not consider the impact of DER and smart grid technologies	
Output-based incentives for continuity of supply are not in place or provide weak incentives (low-powered incentive, deadbands, non-symmetric designs, cap and floors)	Implement incentive/penalty mechanisms for the DSOs to improve network reliability. These mechanisms should incorporate reliability indicators measuring both the number and the duration of interruptions.
Reference values for reliability indices based exclusively on historical values, cost-benefit analyses that allow continuous improvements are not being carried out	Regulators should ensure that the incentive mechanisms parameters send adequate incentives for DSOs to improve quality of service by avoiding wide deadbands, tight cap and floors. Moreover, reference values and marginal incentive rates should be assessed, and not be based exclusively on historical values, in order to reflect appropriately both the marginal cost of improving reliability (including smart grid solutions) and the cost of interruptions for consumers in their country.
Equal treatment of planned and unplanned interruptions or stringent requirements to qualify as planned interruption	Incentive schemes should encourage DSOs to replace unplanned interruptions with scheduled interruptions, as the latter have less impact on grid users.
Lack of incentives for innovation and experimentation, including the possibility of requesting regulatory sandboxes	A regulatory sandbox can be used to extend research activities towards market demonstration in a protected environment. Design recommendations are given in section 7.7.2

7.8.2. Other roles of DSOs

Network access and connection

Identified Barriers	Recommendations
System users do not have appropriate information regarding expected expansions or upgrades due to new connections (degree of detail of the expansion plans). Lack of transparency on available grid capacity for new DER	Regulation should enhance the transparency in grid connection by setting minimum information disclosure requirements to DSOs, especially when connection charges are determined by the DSO: For small users and/or those connected to the LV grid, information about the expected amount of the connection charges ought to be published. For larger units connected to the MV and HV levels, information disclosure may apply to the available hosting capacity in different points of the grid.
Lack of transparency in the calculation of grid connection charges	

Deep connection charges are a barrier for the connection of DG, particularly small units.	Shallow or shallowish charging approaches for small DER units should be implemented to avoid barriers to the connection of small units to the grid. Regulation may stablish differences by requested capacity and/or by voltage levels. Large DER may be subject to deep connection charges in order to provide them with efficient locational signals. However, this should be implemented together with flexible network access and information disclosure about available grid capacity.
	Flexible network access should be enabled in order to ensure an efficient network development, especially in MV and HV distribution networks. When, with deep connection charges in place, new grid users could be offered several options with different combinations of connection charges and level of firmness (curtailment probability) in their connection.

Ownership of storage

Identified Barriers	Recommendations
Unclear regulation on the ownership of storage systems by DSOs	Regulators should seek to establish competitiveness wherever possible. This is the case for new roles as well as for the amendment of existing roles.

7.8.3. Local flexibility markets/services

Mechanism to provide local flexibility

Identified Barriers	Recommendations
Mechanisms for local flexibility procurement and provision (local markets, non-firm access, agreements DSO-DER) are not implemented	DSOs should be explicitly allowed to procure flexibility services from grid users or intermediaries managing a portfolio of flexible DER. In the early stages, DSOs and third-parties should be allowed to test different local flexibility market configurations, under regulatory sandboxes if necessary. Over time, flexibility markets and products may be standardized if deemed required.
	Long-term procurement, years-ahead and with a contract duration of several years (e.g. an entire regulatory period or the period between investment plans), should be encouraged to enable incorporating it in the DSO investment plans.
	The activation price of flexibility sources that are contracted under a long-term framework should be determined in the short-term under a market-based mechanism competing against all available sources of flexibility (including those without a long-term contract and flexible connection agreements). Long-term contracts may include a cap on the activation price to protect DSOs against opportunistic behaviours from flexibility providers (market power abuse).
Lack of regulation for the coordination between TSO and DSO for the provision of ancillary services by DER	Enhanced TSO-DSO coordination is necessary to ensure seamless participation of aggregators in both local and centralized markets. Enhanced coordination is necessary both in the operational planning and real-time operation timeframes. Coordinated market models and activation procedures can reduce the risk upon flexibility providers and increase overall economic efficiency.

7.8.4. Balancing Markets

Demand Response participation in balancing services

Identified Barriers	Recommendations
Balancing markets are not open to demand, included the one connected at distribution level, or balancing products not suited for demand-side resources	The participation of DR in balancing market is likely to follow an incremental approach. Large consumers are likely to be more willing to participate in balancing markets than residential consumers. Therefore, when adapting balancing markets for demand response participation, large consumers may be included in the first stage.
	Balancing capacity services (for aFRR, mFRR and RR) should be open to the participation of all agents, including DR, under transparent, market-based procurement conditions.
Balancing market access and product definition not suited for DER (minimum sizes, design of deviation penalties, upwards and downwards allocated together, dual imbalance pricing)	Minimum bid sizes should allow for DR participation while maintaining the capability of the TSO to efficiently manage the system's balance. Additionally, independent upward and downward bidding should be allowed.
	Settlement prices for capacity and energy balancing markets should not be regulated. In capacity balancing markets, pay-as-clear can offer better conditions from a DR integration standpoint, although such design choice can not consider this element in isolation. Energy balancing markets should adopt pay-as-clear settlement method.
	Prequalification could be done in a pooled fashion to allow for easier aggregated DR participation, and also to allow for higher capability and reliability of a pooled BSP. Prequalification should also be coordinated with DSOs, considering that they will also procure DR flexibility. From the DR's perspective, to the extent possible, a "one-stop shop" is the most suitable option.
	A clear baseline methodology is necessary for the participation of DR in balancing markets. They provide TSOs with the means to verify flexibility activation and DR providers with a transparent and predictable rule for expected profits.
Barriers to the development of the aggregation activity	Aggregators should be allowed to participate in multiple markets with the same portfolio, provided the prequalification requirements are met to all of them.
Barrier for the aggregation of different DER types	Aggregation of different types of DER in the different markets should be allowed, provided that prequalification requirements are met.
Barriers to independent aggregation (e.g. balancing responsibility)	A framework to settle imbalances in the supplier's portfolio originated by flexibility activation and to adjust financial positions is necessary to insure harmony between the independent aggregator and the supplier's activities. An example of such a framework is the Transfer of Energy, already adopted in Belgium.

7.8.5. Tariffs and self-generation

Retail tariff design (regulated charges)

Identified Barriers	Recommendations
Regulated charges show no or little time discrimination; structure inappropriate to promote flexibility	Purely volumetric distribution network tariffs should be avoided. Capacity charges and/or fixed charges should be introduced to recover the fixed network costs, provided metering technologies allow to do so.

Tariff design: high share of taxes and other regulated costs may kill other price signals	Locational and time differentiation should be introduced in the network tariffs, so that grid users can make decisions on the adoption of new technologies under predictable conditions. LV ToU tariffs may present a small number of time periods for LV consumers, whereas a higher number may be applied in higher voltage levels. Large network areas with consistent utilization rates could be selected to set different network tariffs. Local flexibility mechanisms can be used to address network constraints inside these areas or in countries where geographical discrimination is not allowed.
	If dynamic tariffs are implemented, unpredictability problems ought to be mitigated. Moreover, the design of dynamic tariffs, e.g. geographical granularity, should be coordinated with local flexibility mechanisms. The former could be more suitable to solve system-wide critical periods, whereas the latter seem more suitable for more localized network constraints.

Self-generation and metering

Identified Barriers	Recommendations
Self-generation not permitted or facing relevant barriers (administrative, economic, technical)	All consumers with a smart meter should be entitled to a dynamic pricing option. This could be introduced as the default regulated tariff (last resource tariff) and/or mandating suppliers to include this alternative in their offers.
	When introducing dynamic price contracts, retailers should be required to publish clear and transparent information about this alternative, including the potential risks, and make it easily available to consumers. Dynamic prices may be linked to day-ahead markets, instead of intraday markets, to mitigate the uncertainties for consumers, particularly for residential consumers. Additionally, particularly when market price caps are high, regulators should assess the introduction of safety nets for consumers in the dynamic price contracts.
	To the extent possible, all the costs not related to the electricity supply should be removed from the regulated charges included in the electricity tariff. When some of these costs remain in the electricity tariff, they should be allocated in the least distortive way possible, particularly avoiding artificially high volumetric charges.
Inefficient incentives for self-generation that hamper flexibility: net-metering permitted, large share of regulated costs charged through a volumetric component	Regulation should allow end-consumers to self-generate and store their own electricity without undue barriers as set in Directive (EU) 2018/2001. In the case of self-generation, allocation rules of renewable production should ensure the appropriate regulated charges are paid for.
	Abandon net-metering schemes in favour of net-billing schemes or market participation of self-producers. Under net-billing, active consumers should receive a compensation for the energy injected into the grid that reflects the market value of that electricity Consumers with self-generation facilities may be requested to have a smart meter installed to ensure they can be exposed to cost-reflective tariffs.
	Regulatory barriers to the development of renewable PPAs should be removed.
Insufficient smart meter capabilities	The deployment of Smart Meters should consider the needs of different stakeholders and ensure interoperability in order to allow new business models (e.g. consider observability requirements from TSOs in order to allow for DR balancing provision).
Lack of a clear framework for the deployment of smart meters (technical requirements, accessibility)	DSOs should facilitate on-demand deployment to the extent possible. This allows not only consumers to feel more encouraged to adopt Smart Meters, but also new business models to foster the use of the new meters.
	The choices in terms of Smart Meter capabilities should aim at a “future-proof” deployment. Non forward-looking approaches lead to additional costs, as Smart Metes will have to be updated more often to meet the ever evolving needs of the industry, and to delays in the adoption of new business models.

7.8.6. Data Management

Identified Barriers	Recommendations
Lack of definition on the data-management model	The definition of national regulation on data management model can make use of guiding principles and recommendations provided by CEER. The implementation of a data hub (gm-hub) in a centralised model provides possibilities for the development of new businesses. Implementation of the data service provider in the decentralised model environment is possible. In this case, the means to obtain consumer consent need to be taken into consideration.
Barriers to grant access to metering data to third-parties, whilst complying with GDPR requirements	

8. Conclusions

This deliverable D7.2 concludes the regulatory analysis carried out throughout the Integrid project. This report was preceded by deliverables D1.3 and D7.1. While the former made a first assessment of regulation in the Integrid countries, the latter already provided an assessment of the main regulatory barriers for the solutions proposed and tested in the project. Therefore, the present deliverable built on top of the previous work to provide the reader a twofold analysis. Firstly, this deliverable made a detailed assessment of what were the regulatory barriers in the five Integrid target countries, namely Austria, Portugal, Slovenia, Sweden and Spain. Secondly, it took on the challenge of providing recommendations on how to overcome these regulatory barriers.

Both the assessment of barriers and the crafting of recommendations was a challenging work, considering the broad range of regulatory topics that are relevant for the Integrid project. In fact, the Integrid project researched and/or demonstrated solutions that reached a significant number of relevant distribution-connected stakeholders, including DSOs, customers (including different types of DER), suppliers, aggregators and technology companies that may foster new services based on the use and management of data. In this context, the regulatory analysis in this project covered topics ranging from DSO economic regulation to rules and frameworks for independent aggregators.

In order to reach the final recommendations, this work also considered the inputs from several other analyses other than the current national regulatory frameworks. Firstly, the provisions brought by the Clean Energy Package for all Europeans (CEP) were considered. Secondly, the National Climate and Energy Plans were also consulted in order to verify the foreseen action by policy makers that could be relevant. And lastly, the results from the SRA and CBA also served as important inputs for recommendations provided.

The remainder of these conclusions provide a discussion on what we believe are the most important recommendations in key regulatory topics for successful implementation of Integrid's functionalities and solutions in the five Integrid countries.

8.1. Use of flexibility at distribution level, mainly for distribution investment deferral

The procurement of DER flexibility by the DSO to support distribution grid operation and, eventually, defer or avoid network reinforcements is at the core of Integrid. However, ensuring that regulatory conditions truly encourage DSOs to do so is very challenging, which requires addressing several regulatory aspects in a coordinated and comprehensive manner. These aspects can be seen as pieces of the overall puzzle.

Remove the CAPEX bias in DSO revenue regulation:

Current DSO regulation fails to encourage DSOs to use flexibility because efficiency incentives are not evenly placed on CAPEX and OPEX. What is more, DSOs may be actually penalized when reducing investments happens at the expense of increasing OPEX to remunerate flexibility providers, even if opting for a flexibility-based solution is less costly in the long-term.

Current situation in the InteGrid countries[66]:

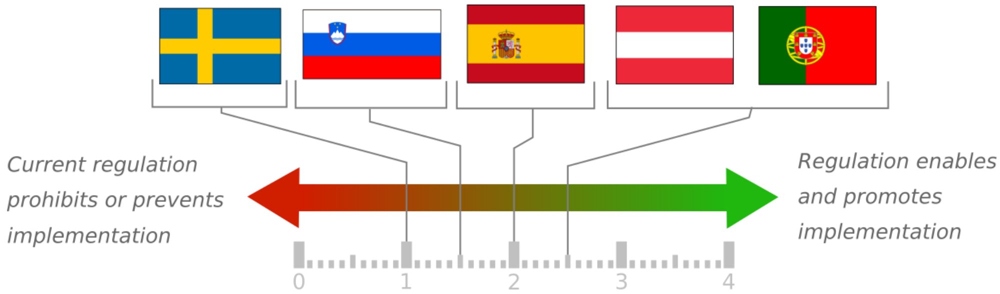

Figure 20: Possibility for DSOs to benefit from using flexibility to defer or avoid grid investments

The CAPEX bias embedded into DSO regulation should be removed. This can be achieved by decoupling new additions to the regulatory asset base (RAB) from the actual investments carried out by DSOs. A pre-defined capitalisation rate can be used to split annual allowed revenues into a share considered equivalent to investment costs, and added to the RAB to be recovered over several years or decades, whereas the remaining share would be treated as OPEX, and recovered in the same year. A progressive implementation of this approach is advised to prevent abrupt changes in the remuneration.

Design cost-reflective network charges:

Distribution network charges have traditionally been used mostly as a tool to recover DSO allowed revenues through the payments made by passive and largely passive electricity consumers. Therefore, simple tariff structures such as flat, time-independent, volumetric charges (€/kWh) are commonly applied, especially for household consumers. However, the growing penetration of DER deeply changes this paradigm. Network costs are largely fixed and largely driven by the periods of maximum grid utilization. Moreover, once incurred, they are independent on the volume of electricity consumed. DER introduces a high heterogeneity among distribution network users, with distinct and bi-directional capacity utilization levels. Therefore, it is necessary to revisit existing tariff structures to ensure that grid users receive the right signals to use the network more efficiently and avoid reinforcements in the long-term.

Leveraging on the deployment of smart meters, more advanced tariff schemes should be implemented. Purely volumetric network charges should be abandoned in favour of a more extensive use of capacity or fixed charges. Additionally, locational and time differentiation should be introduced in the network tariffs to account for the periods of maximum grid utilization. In order not to have excessively complex tariff structures, different network tariffs could be set for large network areas with consistent utilization rates.

Moreover, dynamic network tariffs can be used on top of static ToU tariffs to prevent short-term grid constraints. Static ToU chares would send long-term signals to adapt to general system conditions, whereas the dynamic component would address specific critical conditions. Nonetheless, dynamic network tariffs can create significant uncertainties for grid users. In practice, dynamic network tariffs could be introduced

[66] Average of scorings for the assessment on "Would DSOs benefit from using flexibility to defer or avoid grid investments?" and "Would DSOs recover the costs associated with the use of flexibility?" from Section 5.

by pre-defining the critical periods together with a short-term notification for those events not easily anticipated. Moreover, dynamic network tariffs should be coordinated with local flexibility mechanisms. System wide reactions, e.g. due to a heat wave, could be addressed with day-ahead dynamic tariffs set by large network areas, whereas localized constraints within these areas can be addressed more effectively through local flexibility markets.

Flexible and transparent network access:

Conventionally, network access rights have been granted on a firm basis, i.e. grid users are free to use the grid as they want as long as they do not surpass the capacity allocated. However, granting all new grid users with firm network access may be excessively costly and delay the connection of DER. Hence, flexible network access should be enabled so that grid users and DSOs can benefit from lower grid investment needs. These agreements enable the DSO to manage the consumption/ generation to prevent or solve grid constraints whereas network users can be remunerated or benefit from lower connection charges or a faster grid connection.

Current situation in the InteGrid countries[67]:

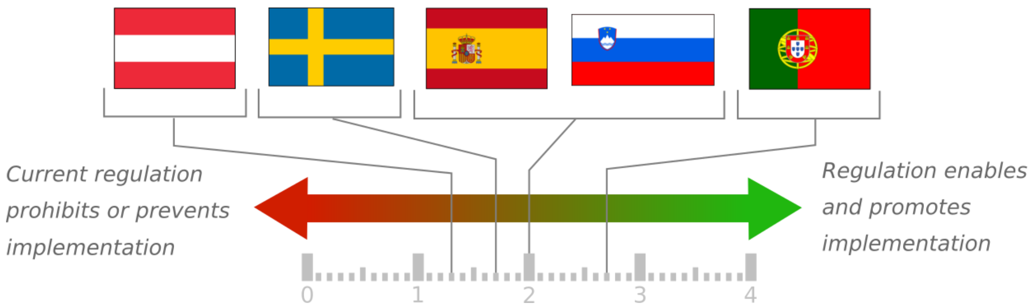

Figure 21: Level of how flexible and transparent the network access is

Moreover, DER, particularly those connecting to the MV or HV grids could be offered a menu of options with different combinations of connection costs and probability of curtailment due to the local grid conditions. Thus, each new grid user could select the connection agreement best suited to its risk profile or preferences. As discussed below, the activation of non-firm access agreements may be coordinated with other flexibilities procured by DSOs through local flexibility mechanisms.

Lastly, regulation should enhance the transparency in grid connection processes to reduce access conflicts that may arise as large volumes of DER request a grid connection. This can be done by setting information disclosure requirements on DSOs. For small users and/or those connected to the LV grid, whose costs are relatively easy to compute in a standard manner, information about the expected amount of the connection charges ought to be published. For larger units connected to the MV and HV levels, which can show large cost variations between individual cases, DSOs may publish information about the available hosting capacity in different parts of the grid. This would, encourage DER to request their connection at those points with higher available capacity and prevent the submission of several connection requests, also reducing the workload of DSOs. The available hosting capacity can be computed as part of the network development plans discussed below.

[67] Scoring for the assessment on "Flexible and transparent network access?"

Local flexibility mechanisms

Local flexibility mechanisms are needed to enable DSOs to procure the flexibility from DER. Thus, regulation should explicitly allow DSOs to procure flexibility services from grid users or third-parties managing a portfolio of flexible DER. As many implementation aspects remain unsolved, in the early stages, DSOs should be allowed to test different local flexibility market configurations, under regulatory sandboxes if necessary. Over time, flexibility markets and products may be standardized if deemed required.

Current situation in the InteGrid countries[68]:

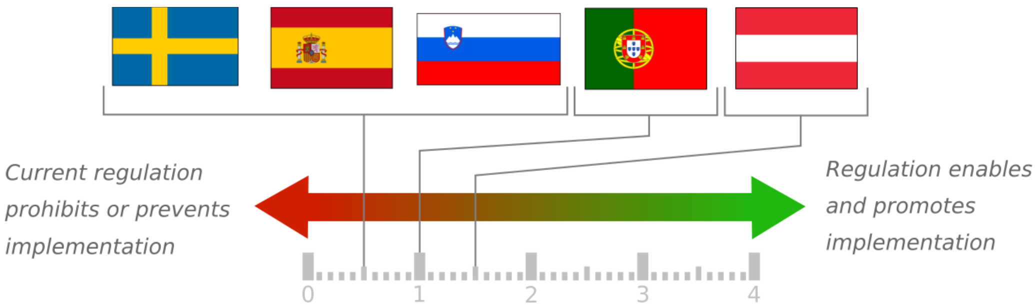

Figure 22: Overall existence of local flexibility mechanism and TSO-DSO coordination

The long-term procurement of flexibility, e.g. year-ahead, and with duration of several years (e.g. an entire regulatory period or the period between investment plans), should be encouraged to ensure DSOs can incorporate this possibility in their network development plans with a low risk. Flexibility providers may receive a reservation payment for this long-term availability. Nonetheless, the activation price of flexibility sources that are contracted under a long-term framework should be determined in the short-term through market-based mechanisms where competition is established among all available sources of flexibility, including those procured in the short-term and flexible connection agreements. Long-term contracts may include a cap on the activation price to protect DSOs against opportunistic behaviours from flexibility providers (market power abuse).

Distribution planning considering flexibility

Distribution investment plans that consider the use of flexibilities as part of the DSO toolbox shall become a central tool to enhance transparency and support price review processes. The flexibilities considered may correspond to flexible connection agreements, services procured in local markets, or the expected response of grid users to network tariffs. A fair and comprehensive evaluation of all the alternatives, requires i) factoring into the network development plans the full cost of flexibility-based solutions, including payments to flexibility providers and the associated infrastructure/ICT costs, and ii) incorporate a risk analysis of using flexibility services as compared to grid investments (uncertainty, reliability, duration of the period the solution is active, etc.). The level of detail or granularity required by NRAs may be differentiated between areas or voltage levels due to the high extension of these systems.

[68] Average of the scoring of the assessment on “Are DSOs enabled by regulation to procure flexibility?” and “Is there enough TSO-DSO coordination?”

Current situation in the InteGrid countries[69]:

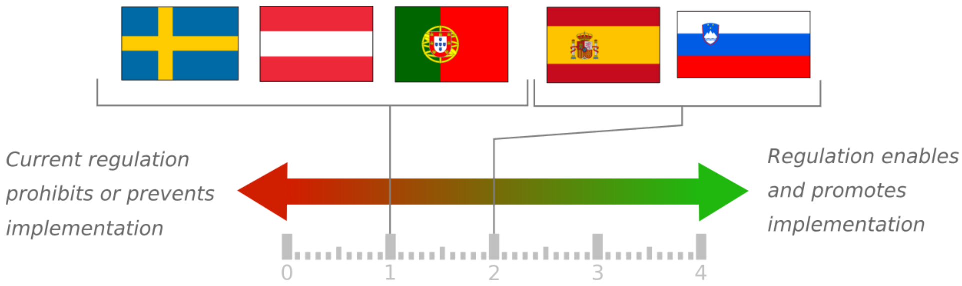

Figure 23: Grid development/planning and the consideration of the use of flexibilities

Regulators should use these investment plans as an input to set the DSO allowed revenues. Thus, the timing for preparing and submitting investment plans should be coordinated with prices reviews. Furthermore, regulators should have adequate resources to evaluate these network development plans using forward-looking cost assessment methods.

8.2. Fostering advanced operation and maintenance practices to enhance reliability

Integrid BM2 addresses the adoption by the DSO of innovative approaches for the operation and management of the distribution network. Moreover specifically, the functionalities considered are the automatic fault location thanks to the deployment of sensors throughout the grid, and the predictive maintenance of distribution transformers based on their operating conditions. The main benefits expected are the improvement of grid reliability, a reduction in maintenance costs and an increase in the operating lifetime of transformers.

DSO incentives to keep assets in operation after the end of their regulatory life

Integrid tested the potential benefits of the use of predictive asset maintenance. By doing so, the DSO can attain a reduction in maintenance costs (OPEX) by avoiding unnecessary maintenance actions on transformers that are in good condition, also allowing the DSO to extend the useful life of assets. However, regulation often fails to incentivize DSOs to keep depreciated, but well-functioning assets under operation. This is particularly true for revenue regulation with a strong CAPEX bias.

[69] Scoring of the assessment on "Do DSOs and regulators adopt a long-term vision for grid development/regulation, including the use of flexibilities?"

Current situation in the InteGrid countries[70]:

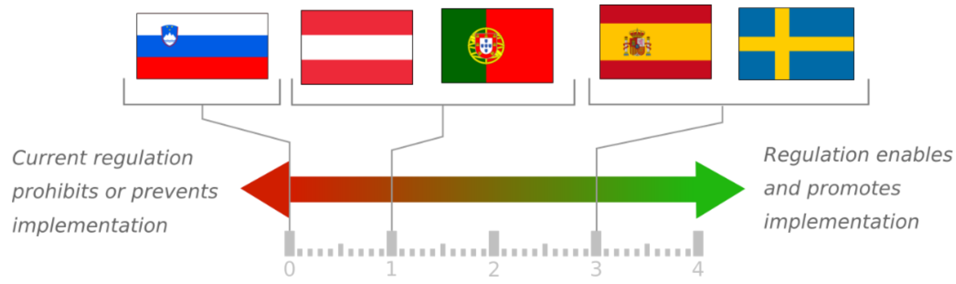

Figure 24: Incentives for keeping assets beyond regulatory life

Regulators could decouple the new RAB additions from the actual investment costs of DSOs (TOTEX regulation). By doing this, DSOs would see an incentive to defer asset replacement solutions. Alternatively, regulators may implement alternative incentive mechanisms to promote the use of predictive maintenance even if DSO revenue regulation still presents a CAPEX bias. A higher O&M remuneration or performance-based regulation based on specific output indicators are examples of tools already in use by some countries to encourage DSOs to keep assets after the end of their regulatory life.

Continuity of supply incentives

Both predictive asset management and fault location functionalities tested in Integrid may contribute to the improvement in continuity of supply. Incentive schemes for continuity of supply are generally widespread across European countries. Nonetheless, the existence of these incentives per se is not enough by itself to promote such functionalities. The incentive design and is strength is also very relevant.

Current situation in the InteGrid countries[71]:

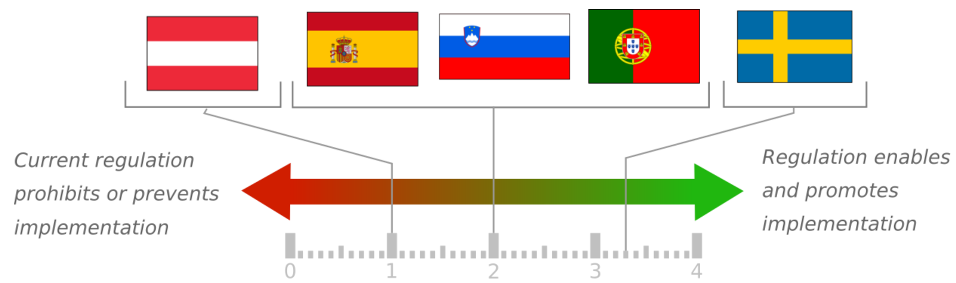

Figure 25: Presence of adequate continuity of supply incentives

Incentive schemes should consider both the duration and the number of interruptions. Advanced fault location, if combined with telecontrolled grid reconfiguration in meshed networks, can reduce both the measured duration and number of interruptions if consumers can be reconnected in less than a few minutes after an interruption. This is because long interruptions are considered to be those that last more than a pre-defined number of minutes, typically 3 min

[70] Scoring of assessment on "'Would DSOs benefit from keeping assets under operation beyond its regulatory useful life?"

[71] Average of questions "Do DSOs receive (strong) economic incentives to improve reliability?"; "Is the design of incentive schemes, i.e. incentive rates and reference values, based on up to date cost-benefit analyses?" and "Do incentive schemes provide a fair, distinct treatment of planned and unplanned interruptions?"

Regulation should also differentiate planned and unplanned interruptions. Incentive schemes should encourage DSOs to replace unplanned interruptions with scheduled interruptions, as the latter have less impact on grid users.

Lastly, regulators should ensure that the incentive mechanisms parameters send adequate incentives for DSOs to improve quality of service by avoiding wide deadbands, tight cap and floors. Moreover, reference values and marginal incentive rates should be assessed, and not be based exclusively on historical values, in order to reflect appropriately both the marginal cost of improving reliability (including smart grid solutions) and the cost of interruptions for consumers in their country.

DSO incentives to test new smart grid functionalities

The adoption of new grid operation solutions and technologies will presumably require DSOs to test them at a limited scale before deploying them at a larger scale. This will allow them to test and compare alternative technology solutions, work together with developers and manufacturers, and prevent mistakes and dead-ends when performing the deployment. Since DSOs face some technology risks in this process, the existence of mechanisms that allow DSOs to mitigate this these risks would facilitate the adoption of innovative solutions.

Current situation in the InteGrid countries[72]:

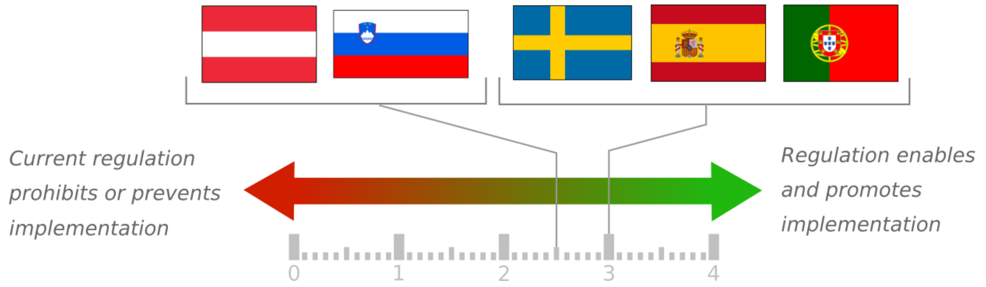

Figure 26: Incentives to test new smart grid functionalities

DSOs should be explicitly allowed to implement pilots to test innovative smart grid functionalities and technologies. The innovation projects funded through the revenue allowances should be well coordinated with other innovation funds received by DSOs.

Regulatory supervision of such expenditures is necessary to ensure that the solutions really required this risk mitigation mechanism. It can be either as an ex–ante approval, an ex-post evaluation, or both. Such evaluation should be made based on a set of KPIs and/or CBA where the benefits for network users are clearly shown.

[72] Average of the assessment on “Would DSOs recover the costs associated with smart grid technologies deployment beyond pilot projects?” and “Does regulation leave room for pilot projects, even if they do not fit within the regulation in place?”

8.3. Demand aggregation and participation in balancing markets

Flexibility operators that aggregate the flexibility of all types of DER to provide services to TSOs and DSOs are another central element of the Integrid concept. However, these stakeholders face important regulatory barriers to develop their full potential, particularly in relation to the aggregation of demand-side resources or when acting as independent aggregators.

Revisit balancing market rules to create a level playing field for all flexibility providers

First, demand-side participation in balancing markets is not allowed in many countries yet. Therefore, the first step would be to open these markets to all source of flexibility. Nonetheless, the participation of demand in balancing markets is likely to follow an incremental approach. Large industrial consumers are likely to be more capable and willing to participate in balancing markets than residential consumers. Therefore, when adapting balancing markets for demand response participation, large consumers may be included in the first stage.

However, this does not automatically mean that all resources can participate in electricity and service markets under a level-playing field. Market rules, originally designed for large generators, should be reviewed to remove any possible technology bias. Firstly, minimum bid sizes should be adjusted to levels that are more suitable to demand response participation, while maintaining the capability of the TSO to efficiently manage the system balance. Likewise, independent upwards and downwards bidding should be allowed, since demand side flexibility can mainly offer upwards regulation.

Current situation in the InteGrid countries[73]:

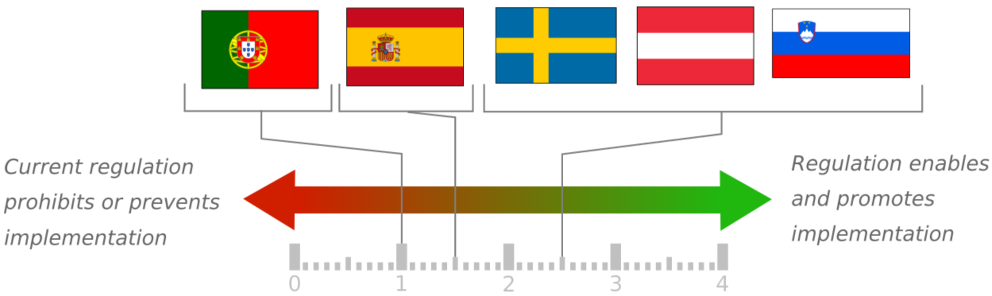

Figure 27: Openness and suitability of balancing markets for demand response participation

The third market design aspect to be considered is on how the balancing market prices are determined. First, those countries that still have regulated prices for balancing capacity in products should shift towards a market-based price setting. In order to do this, two main methods can be found, namely “pay-as-bid” and “pay-as-clear”. Whilst both of them present advantages and disadvantages, pay-as-clear for balancing capacity pricing would facilitate the participation of demand-side providers. On the other hand, as stated in the European regulation, balancing energy should be priced separately from balancing capacity following a pay-as-clear approach.

[73] Average of the scoring of the assessment on “Are balancing markets open for demand-response participation?” and “Are products and conditions suitable for demand/DER participation?”

Turning to market access requirements, it is necessary to address the design of prequalification procedures which aim to ensure that market participants are capable to comply with the system needs. In order to facilitate the participation of aggregated demand resources, portfolio-based prequalification is recommended as opposed to a prequalification unit-by-unit. Prequalification should also be coordinated with DSOs, considering that they will also procure demand side flexibility.

Finally, a last element necessary for the integration of DR in balancing markets is a methodology to define the baseline against which deviations will be measured. Contrary to large generators, DER do not have an individual schedule. In fact, most consumers are free to change their consumption patterns as they wish. However, the TSO must verify if a certain activation instruction is executed or not. Hence, regulation should define a transparent baseline methodology to enable the participation of demand in balancing markets. The specific approach should be selected considering criteria related to ease of validation, accuracy, data intensiveness and gaming potential.

Facilitating the development of aggregators

Aggregation will play a fundamental role in enabling DER participation in all flexibility services. The tasks of aggregators are key to develop the required software tools, gather market expertise and exploit economies of scale. There are three key roles to consider in this discussion: the aggregator, the supplier and the balancing responsible party (BRP). Conventionally, the supplier performed the three roles together. However, the Clean Energy Package opens the possibility to allocate these roles to distinct actors, most prominently the possibility to have independent aggregators, i.e. independent from the supplier who would retain the BRP. Therefore, conflicts may arise when these two different entities manage the same resources. What is more, such an independent aggregator could also aggregate resources from the portfolio of several different suppliers.

In such a situation, the supplier would be impacted by the actions of the independent aggregator as these can leave suppliers with energy imbalances and over or under procurement in energy markets. In order to avoid these problems, regulation should define a methodology to settle imbalances and adjust financial positions among aggregators and BRPs/suppliers caused by flexibility activations.

Current situation in the InteGrid countries[74]:

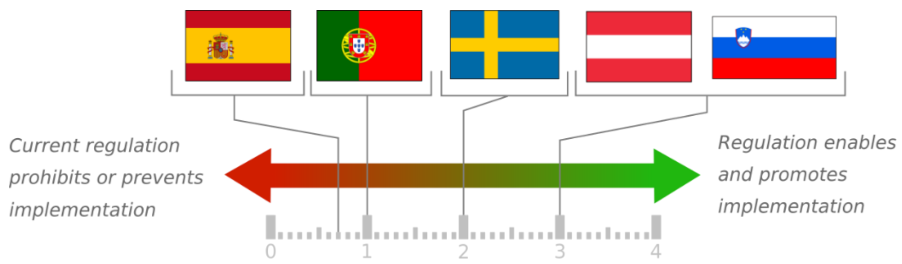

Figure 28: Overall regulatory landscape for aggregation, independent aggregation and the VPP concept

DER aggregation may serve to provide services both to TSOs and DSOs, as demonstrated by the VPP in Integrid. In fact, the project has shown the importance for the aggregator to be able to stack the revenues from participating in different markets in order to ensure profitability, especially when small flexibility portfolios are managed. This requires the coordination between both grid operators, to mitigate the risk

[74] Average of "Are there barriers for the aggregation?", "Is different type of DER aggregation (VPP concept) possible?" and "Is the independent aggregation allowed? Is it viable?"

for the aggregator of being activated by one operator and be unable to comply with its commitment due to limitations set by the other grid operator. Therefore, an enhanced TSO-DSO coordination is necessary to avoid these situations and ensure a seamless participation of aggregators in both local and centralized markets. This is necessary both in the operational planning and real-time operation timeframes.

An additional recommendation to facilitate the VPP operator to benefit from scale economies is to allow the VPP to aggregate different types of DER under a same portfolio, particularly when the unit seizes are medium/small. This would also make it easier for the aggregator to comply with the prequalification criteria set by the TSO leveraging on the different flexibility potential of different types of DER.

8.4. Providing value to consumers through energy and data services

The CEP calls to place energy consumers at the centre of the energy transition. In fact, the functionalities previously discussed in this chapter already intend to benefit end consumers from a more efficient grid and system operation. However, Integrid has also addressed the end consumer directly who would be able to reduce its energy bill thanks to energy management systems and self-consumption, or to receive data-based services from different stakeholders.

A key regulatory topic concerning the perspective of electricity consumers is naturally the design of the retail electricity tariff and how the regulated system charges are allocated to the consumers. Cost-reflective tariffs are key to promote an efficient end user behaviour. Likewise, the CEP wishes MS to remove barriers to (renewable) self-generation as a means to empower and activate consumers. Nonetheless, some regulatory barriers need to be removed to ensure its effective and efficient development. These two topics are highly interrelated as the implicit economic value of the energy self-consumed is precisely the volumetric component of the retail tariff. On the other hand, concerning the provision of data services, two main aspects should be addressed by regulation: i) the deployment of smart metering systems, an enabler for most of the Integrid solutions, and ii) the definition of a clear data management model by regulation.

Setting electricity tariffs that promote an efficient end-user response

Extracting the value of demand response requires electricity tariffs that promote end-user flexibility. Retail tariffs comprise the energy costs (and retail fees) on the one hand, and the regulated charges on the other. The scope of regulation is different for each of these components.

Current situation in the InteGrid countries[75]:

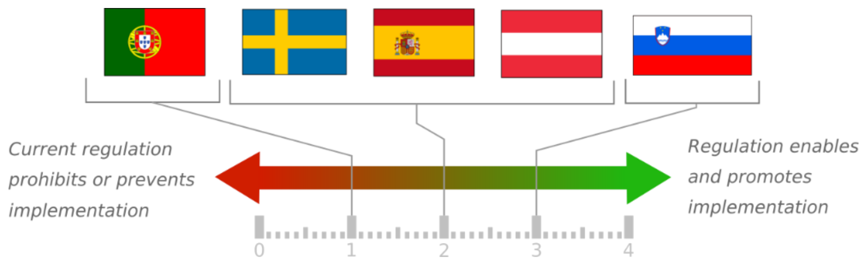

Figure 29: Distortions created by taxes and regulated charges

Concerning energy prices, dynamic prices that follow hourly, or even more granular, market prices are the most suitable approach to promote end-user flexibility. In liberalized retail markets, the structure of energy prices are freely negotiated between consumers and suppliers. In fact, consumers have the right not to engage in dynamic price contacts if they do not wish to do so. Nonetheless, regulation may still ensure that, as stated in the Electricity Directive, consumers have the possibility to opt for this pricing scheme. This could be introduced as the default regulated tariff, where last resource tariffs exist, and/or mandating certain suppliers to include this alternative in their offers.

When introducing dynamic price contracts, retailers should be required to publish clear and transparent information about this alternative, including the potential risks, and make it easily available to consumers. Linking dynamic prices to day-ahead markets, instead of intraday markets, is preferable to mitigate the uncertainties for consumers, particularly for residential consumers. Additionally, particularly when market price caps are high, safety nets for consumers may be introduced.

The second component of the retail tariff corresponds to the regulated charges, which comprise transmission and distribution costs, as well as other policy costs such RES-related costs. These costs can represent a significant share of the total; therefore, their allocation to the different tariff terms has a great influence on the price signals seen by end consumers. As discussed above, network charges ought to send efficient signals for the utilization of the grid. On the contrary, the remaining policy-related items should not distort the efficient response of end consumers to locational/time differentiated energy prices and/or network charges. Ideally, to the extent possible, all the costs not related to the electricity supply should be removed from the regulated charges included in the electricity tariff. However, this is not always possible due to economic, political or acceptance reasons. Thus, when some of these costs remain in the electricity tariff, they should be allocated in the least distortive way possible, particularly avoiding artificially high volumetric charges.

Enabling and promoting efficient renewable self-generation and self-consumption

Renewable self-generation can create value for consumers and the system, support the growth of RES and enhance end-user involvement. Therefore, regulation should enable self-generation, including collective self-generation, to develop without undue barriers such as excessive administrative requirements, as set in Directive (EU) 2018/2001. Nonetheless, regulation must also ensure that self-generation is developed without causing unfair discriminations between network users.

[75] Scoring of the assessment on "Are taxes and/or other regulated charges distorting flexibility incentives embedded in the tariffs?"

Current situation in the InteGrid countries[76]:

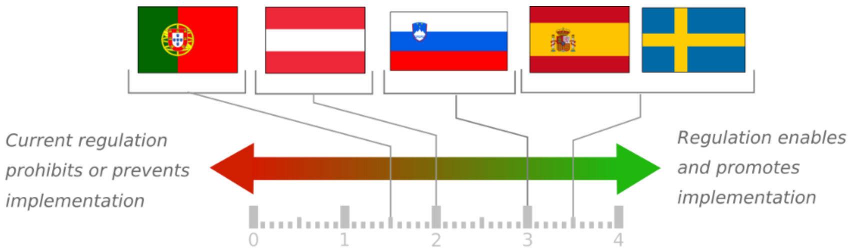

Figure 30: Regulation on self-consumption and self-generation

In this regard, the proper allocation of regulated charges discussed in the previous section is a key topic, as the volumetric component of the tariff can be seen as the opportunity cost of the electricity self-consumed. Hence, the need to have properly designed tariffs, that avoid cross-subsidization and potential cost recovery problems. These problems exacerbate when large volumetric tariffs are combined with net-metering schemes. An additional drawback of net-metering is that it effectively eliminates any incentive for flexibility, including energy management or storage technologies. Therefore, net-metering schemes should be phased out where they exist.

Instead, net-billing schemes or market participation of self-producers, including through renewable power purchase agreements, should be used to compensate active consumers for the energy injected into the grid in such a way that this remuneration reflects the market value of that electricity. Consumers with self-generation facilities may be requested to have a smart meter installed to ensure they can be exposed to cost-reflective tariffs.

The role of data access and data management

The access to data is a fundamental requirement not only for consumer engagement, but also for other business models such as aggregation, behavioural demand response and data services. Therefore, an efficient data access framework is necessary. Such a data access framework may well be impacted by the data management model adopted by countries.

Current situation in the InteGrid countries[77]:

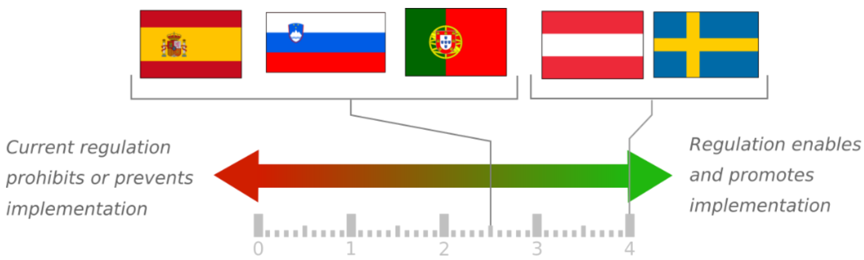

Figure 31: Existence of a data management framework and efficient data access

[76] Average of questions “Does regulation allow self-generation without unfair barriers?” and “Do the tariff structure and self-generation regulation promote an efficient behaviour?”

[77] Average of questions “Does current regulation clearly state the metering data management model adopted?” and “Does current regulation enable an easy access to metering data, safeguarding privacy requirements?”

Many European countries are currently implementing a decentralised data management model. In this cases, especial attention must be paid to ensure a seamless data access by consumers and authorized third parties. On the other hand, the establishment of data platforms with standardized format and open access to other parties enables the non-discriminatory entry of new actors.

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[REF D6.5] Prototype of the Market Hub, central platform and services

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[REF D7.5] Business models to support the developed concepts

[REF D7.6] Stakeholder consultation

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[REF D8.2] Economic and regulatory scalability and replicability of the InteGrid smart grid functionalities

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