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IElectrix

Regulatory Recommendations

Deliverable D4.5
Version 1.0

31/10/2022

Short description

This document corresponds to Deliverable D4.5 titled “Regulatory Recommendations”, which presents the results of Task 4.2, “Regulatory recommendations”. The main goal of this deliverable is to provide specific regulatory recommendations considering both the EU and national level in order to foster the deployment of the cost-efficient and scalable innovations demonstrated in the project. In order to achieve this, this report brings together results from WP3 on CBA and business models and from WP4 on SRA, particularly the qualitative assessment of replicability and scalability barriers.

Starting from the characterization of European and national regulation and the regulatory barriers previously presented in D4.4, this report provides a set of recommendations to overcome these barriers. In order to do this, the report considers the outcomes of the qualitative SRA and CBA presented in deliverables D4.3 and D3.3 respectively and brings together best practices and recommendations from external sources.

Associated document(s) & annexe(s)

- NA

Revision History

Version	Date	Nature	Author/Company
V0.1	21/07/2022	ToC	Comillas
V0.2	26/09/2022	First Draft for DSO consultation	Comillas, MERIT
V0.3	24/10/2022	Complete draft after DSO consultation	Comillas, MERIT
V0.4	28/10/2022	Deliverable draft review	E.ON EED
V1.0	31/10/2022	Final Version	Comillas

Accessibility

☒ Public ☐ Consortium + European Commission

Responsibility

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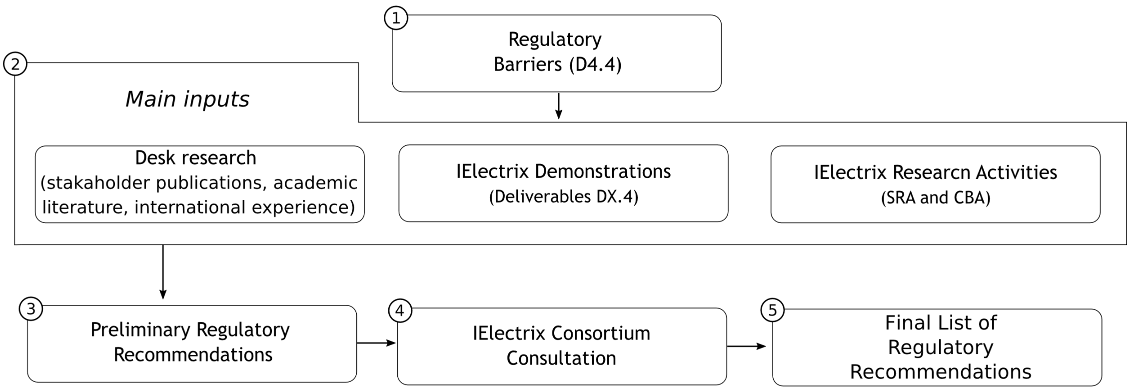
EXECUTIVE SUMMARY

This deliverable presents the final results of Task 4.2 “Regulatory recommendations”. The main aim of this deliverable is to provide recommendations to help overcome the main regulatory barriers to the deployment of the project solutions for local communities. The report builds on the analysis of current existing regulation in the demo countries (Austria, Germany, Hungary and India) as well as the replication countries (France, Sweden and Greece), collectively referred to as target countries, as well as the barriers identified in deliverable D4.4.

The regulatory recommendations presented in this report are intended to be overarching, highlighting best regulatory practices, rather than being country-specific, specially considering the heterogeneity among IElectrix countries.

In order to build the regulatory recommendations, several inputs are used from both the IElectrix project and external sources. The starting point is the list of barriers identified in the IElectrix deliverable D4.4, as this report aims at providing recommendations that can bridge those barriers. For each of them, a list of sources is identified and reviewed. These sources include stakeholder reports (e.g. CEER, ACER, DSO associations), academic literature and international regulatory practice outside the IElectrix country list.

Another important source of inputs is internal to the IElectrix project. Throughout the project, the demonstrations have designed and implemented technical solutions, which enabled them to gain experience in the regulatory barriers they faced, also identifying possible solutions to overcome them. Therefore, the demo results deliverables are consulted and regulatory recommendations from those activities are brought to the present analysis. Other research activities in the IElectrix project also produced important inputs for the regulatory analysis, namely the Scalability and Replicability Analysis (SRA), business model analysis and the Cost and Benefit Analysis (CBA).



D4.5 Methodology

The IElectrix Deliverable D4.4 had previously identified thirteen regulatory barriers for the large-scale deployment of the HLUCs proposed and demonstrated in the project. These regulatory barriers were identified following the assessment of the current regulatory framework in the four demonstration countries plus the three replication countries in IElectrix.

Having these thirteen barriers as a starting point, the present deliverable explored and stated possible recommendations to national regulators and policy makers on how to overcome them. In total, 22 regulatory recommendations were issued.

Summary of Regulatory Recommendations

Regulatory topic	Recommendation
DSO Economic Regulation	*Recommendation No. 1: Mitigate the CAPEX bias from DSO remuneration schemes*
	Recommendation No. 2: Distribution NDPs should consider flexibility as part of the toolbox
	Recommendation No. 3: NDPs should be an integral part of the DSO revenue determination process
New Roles for DSOs	*Recommendation No. 4: Clearly define the conditions for storage assets to be considered FINCs*
	Recommendation No. 5: Develop the necessary regulation for developing the tendering framework for testing commercial interest in the deployment of distributed storage systems
	Recommendation No. 6: Enable a transitory period to enable local flexibility markets to mature and coexist with bilateral agreements
	Recommendation No. 7: Promote long-term flexibility procurement for grid planning
Incentives for Innovation	*Recommendation No. 8: Develop a framework for innovation to inform new regulation*
	Recommendation No. 9: Explicitly allow DSOs to implement pilots and participate in sandboxes
Smart Metering	*Recommendation No. 10: If large-scale smart meter roll-out is not in place, facilitate on-demand deployment*
	Recommendation No. 11: Smart meter deployment should consider the needs of different stakeholders and ensure interoperability
	Recommendation No. 12: Smart meter capabilities should be "future-proof"
Network access and connection	*Recommendation No. 13: DER grid access should be facilitated with a mix of shallower connection charges and information disclosure obligations*
	Recommendation No. 14: Regulation should enhance transparency in grid connection information
	Recommendation No. 15: Flexible grid connection offers should be normalized
Self-generation rules	*Recommendation No. 16: Net-metering schemes should be avoided*
Retail markets and prices for end-customers	*Recommendation No. 17: Dynamic pricing options should be offered to all users*
	Recommendation No. 18: Regulated electricity charges should be devoid of costs unrelated to the electricity supply to the extent possible
Energy Communities	*Recommendation No. 19: National regulation should clearly and comprehensively define RECs and CECs*
	Recommendation No. 20: LEC regulatory frameworks should be consistent with the roles of existing agents
	Recommendation No. 21: Enable collective self-consumption as a step towards LEC development
	Recommendation No. 22: Enable LEC participants to define clear and retail market-compatible rules for energy sharing and entry/exit

The 22 recommendations issued, however, may not have equal relevance in all seven countries analysed. For example, the lack of deployment of smart meters may be an issue in India, Hungary, Austria and Greece, but not in Germany, France and Sweden (as per the information in D4.4). Therefore, barriers 10, 11, and 12 would not be as relevant for the 3 latter countries. Moreover, within countries that face the same barrier, different recommendations may have a lower or higher priority.

In order to shed light on the priority of recommendations, a consultation with the DSOs of the IElectrix consortium was conducted. First, the participants were asked on how important the barrier was, in their view, for the successful large-scale implementation of the IElectrix project solutions as a whole. Second, they were asked how relevant the 22 recommendations issued are.

In total, six DSOs participated in the consultation. The three most important barriers identified are barrier **no 6** (limited smart meter deployment), barrier **no 8** (inexistence of flexible network options) and barrier **no 9** (existence of net-metering schemes). In addition, barriers **no 1, 2, 5, 10** (CAPEX-Bias in incentive regulation; no binding investment plans approved or published; lack of sandbox regulation and experience with large innovation programmes; not developed liberalized retail markets and high presence of regulated tariffs) stand approximately on the same ranking (score 7-8 out of 10) and thus, all were deemed quite relevant. Moreover, the consultation also revealed that the evaluation of some barriers and recommendations was not homogeneous. For barriers **no 4** and **no 7** (lack of local flexibility procurement mechanisms; deep connection charges are a barrier for small DG) there has been a sharp division of opinions regarding their relevance, given the different state of regulation in each country.

Based on the answers obtained (see Chapter 6), a prioritization of recommendations is obtained. The average of "barrier importance" is multiplied by the "effectiveness of each recommendation", resulting on the priority score. Recommendations are then ranked according to this index. It is important to note that only DSOs were consulted; therefore, some barriers and/or recommendations rated with low relevance could be of higher importance to other stakeholders more directly affected by the regulatory barrier in question (e.g. collective self-consumption).

Regulatory Prioritization from DSO consultation, from highest to lowest score

Recommendations	Priority Score
Recommendation No. 15: Flexible grid connection offers should be normalized	Very high
Recommendation No. 10: If large-scale smart meter roll-out is not in place, facilitate on-demand deployment	Very high
Recommendation No. 17: Dynamic pricing options should be offered to all users	Very high
Recommendation No. 16: Net-metering schemes should be avoided	High
Recommendation No. 11: Smart meter deployment should consider the needs of different stakeholders and ensure interoperability	High
Recommendation No. 8: Develop a framework for innovation to inform new regulation	Medium-High
Recommendation No. 9: Explicitly allow DSOs to implement pilots and participate in sandboxes	Medium-High
Recommendation No. 12: Smart meter capabilities should be "future-proof"	Medium-High
Recommendation No. 7: Promote long-term flexibility procurement for grid planning	Medium
Recommendation No. 2: NDPs should consider flexibility as part of the toolbox	Medium
Recommendation No. 14: Regulation should enhance transparency in grid connection information	Medium
Recommendation No. 4: Clearly define the conditions for storage assets to be considered FINCs	Medium-Low
Recommendation No. 20: LEC regulatory frameworks should be consistent with the roles of existing agents	Medium-Low
Recommendation No. 6: Enable a transitory period to enable local flexibility markets to mature and coexist with bilateral agreements	Medium-Low
Recommendation No. 19: National regulation should clearly and comprehensively define RECs and CECs	Medium-Low
Recommendation No. 1: Mitigate the CAPEX bias from DSO remuneration schemes.	Low
Recommendation No. 13: DER grid access should be facilitated with a mix of shallower connection charges and information disclosure obligation	Low
Recommendation No. 5: Develop the necessary regulation for developing the tendering framework for testing commercial interest in the deployment of distributed storage systems	Low
Recommendation No. 3: NDPs should be an integral part of the DSO revenue determination process	Very low
Recommendation No. 18: Regulated electricity charges should be devoid of costs unrelated to the electricity supply to the extent possible	Very low
Recommendation No. 21: Enable collective self-consumption as a step towards LEC.	Very low
Recommendation No. 22: Enable LEC participants to define rules for energy sharing and entry/exit.	Very low

TABLE OF CONTENT

LIST OF FIGURES

LIST OF TABLES

1. Introduction and Project background

1.1. Context of the IElectrix project

Electrix started in response to the growing need for creating innovative technical solutions and business models that facilitate the implementation of Local Energy Communities (LEC) and the integration of distributed Renewable Energy Sources (RES).

IElectrix contributes to the European ambition by adopting a consumer-centred approach and increasing its involvement, particularly through LEC. This project is also a way to accelerate the integration of RES into the distribution networks and the decarbonisation of the energy system. In this context, Distribution System Operators play an important role by ensuring the connection of RES within the grid and facilitating the energy transition.

To reach such goals, IElectrix project brings forward innovative technical solutions:

- Mobile storage systems and smart substations
- Implementation of demand-side management schemes
- Low voltage grid digitalization

The project brings together 15 European partners and 1 Indian partner in order to experiment, through 5 demonstrators, the technical and economical relevance of LEC in different regulatory and ecosystem contexts.

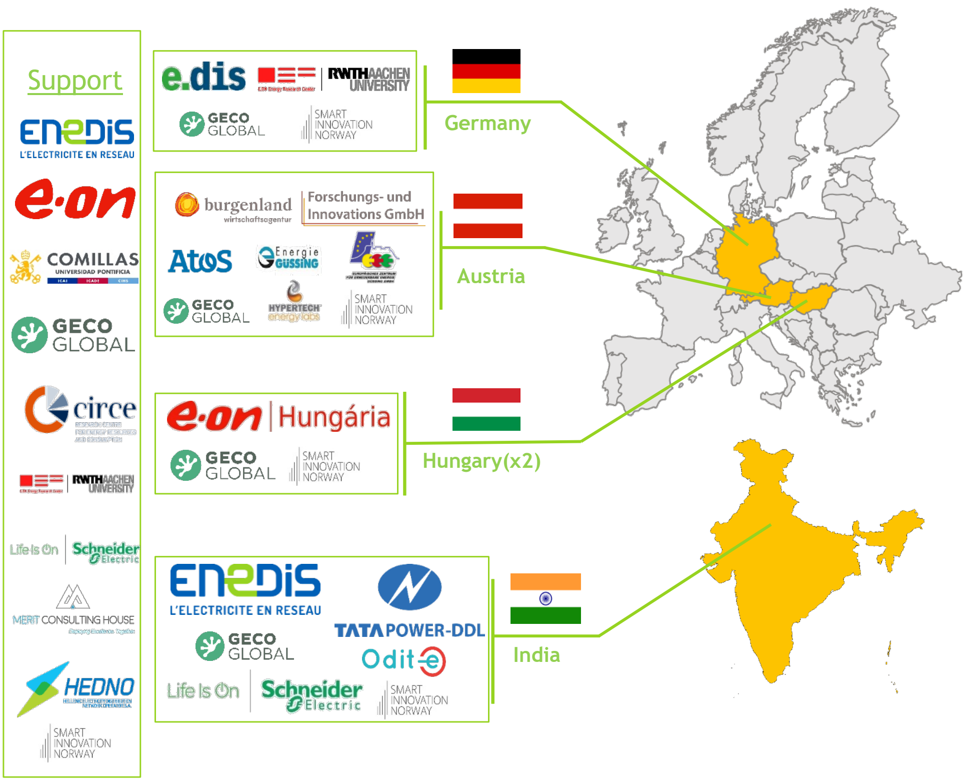


Figure 1: IElectrix Demo map

As shown in Figure 1, two demonstrators are located in Hungary, one in Austria, one in Germany and one in India:

- The Austrian demonstration pilot is currently creating a new energy community in the Güssing District where RES investments have already been made.
- The German demonstration pilot is carried out in a region with a high amount of RES already integrated in the grid. Within the demonstration, a mobile storage system is used in order to postpone costly network reinforcements and vice versa to integrate more DER in a faster way.

- The Hungarian demonstration pilots address issues that are located at an early stage of renewable deployment in two distinct regions.
- The Indian demonstration pilot anticipates the large number of photovoltaic panels (PV) which will be connected at low voltage level in the coming years following recent governmental plans.

1.2. Scope and objectives of the document

This deliverable presents the final results of Task 4.2 “Regulatory recommendations”. The main aim of this deliverable is to provide recommendations to help overcome the main regulatory barriers to the deployment of the project solutions for local communities. The report builds on the analysis of current existing regulation in the demo countries (Austria, Germany, Hungary and India) as well as the replication countries (France, Sweden and Greece), collectively referred to as target countries, as well as the barriers identified in deliverable D4.4.

Moreover, the report draws inputs from the SRA and CBA studies presented in previous project deliverables as well as the KPI values measured during the demonstrations and the regulatory assessment provided by GWP2. The regulatory recommendations address on-going EU regulatory developments (e.g. Clean Energy Package) as well as national regulations.

1.3. Methodology

The regulatory recommendations presented in this report are intended to be overarching, highlighting best regulatory practices, rather than being country-specific, specially considering the heterogeneity among IElectrix countries.

In order to build the regulatory recommendations, several inputs are used from both the IElectrix project and external sources. The starting point is the list of barriers identified in the IElectrix deliverable D4.4, as this report aims at providing recommendations that can bridge those barriers. For each of them, a list of sources is identified and reviewed. These sources include stakeholder reports (e.g. CEER, ACER, DSO associations), academic literature and international regulatory practice outside the IElectrix country list.

Another important source of inputs is internal to the IElectrix project. Throughout the project, the demonstrations have designed and implemented technical solutions, which enabled them to gain experience in the regulatory barriers they faced, also identifying possible solutions to overcome them. Therefore, the demo results deliverables are consulted and regulatory recommendations from those activities are brought to the present analysis. Other research activities in the IElectrix project also produced important inputs for the regulatory analysis, namely the Scalability and Replicability Analysis (SRA), business model analysis and the Cost and Benefit Analysis (CBA).

Considering all the sources mentioned, preliminary regulatory recommendations are drafted by the authors of the report. However, in order to ensure that recommendations are sound, a consultation with the IElectrix consortium is organized and recommendations evaluated. Following that, the final list of recommendations was produced.

Figure 2 illustrates the methodology adopted for the preparation of this report.

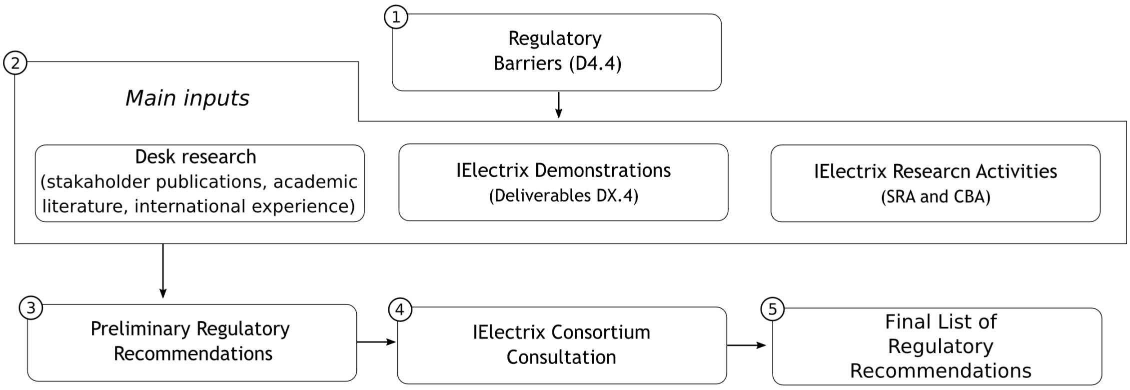


Figure 2: D4.5 Methodology

1.4. Structure of the report

After this introductory chapter, the remainder of this report is structured as follow. Sections 2 and 3 presents some of the key results obtained in preliminary phases of this task (presented in D4.4) by summarizing the relevant regulatory topics and the status in the seven target countries listed above as well as the main regulatory barriers identified for the different BUCs. Section 4 describes the most relevant inputs from other WPs of IELECTRIX. Section 5 then presents and described the regulatory recommendations provided. Section 6 described the approach and results obtained from the consultation among DSOs about the preliminary recommendations proposed. Lastly, section 7provides some concluding remarks.

1.5. Notations, abbreviations, and acronyms

The table below provides an overview of the notations, abbreviations, and acronyms used in the document.

Acronym	Meaning
AMI	Advanced Metering Infrastructure
BESS	Battery Energy Storage System
BM	Business Model
BRP	Balancing Responsible Party
BUC	Business Use Case
CACM	Capacity Allocation and Congestion Management
CAPEX	Capital Expenditures
CBA	Cost-Benefit Analysis
CEC	Citizen Energy Community
CoS	Cost of Service
CSC	Collective Self-Consumption
CVM	Congestion Voltage Management
DER	Distributed Energy Resource
DG	Distributed Generation
DISCOM	Distribution Company
DLC	Direct Load Control

DoA	Description of the Action
DR	Demand Response
DSO	Distribution System Operator
EC	European Commission
EU	European Union
EV	Electric Vehicle
FINC	Fully Integrated Network Component
FiT	Feed-in Tariff
FSP	Flexibility Service Provider
HLUC	High-Level Use Case
HV	High Voltage
KPI	Key Performance Indicator
LEC	Local Energy Communities
LV	Low Voltage
MS	Member State
MV	Medium Voltage
NDP	Network Development Plan
NRA	National Regulatory Authority
OPEX	Operational Expenditures
PPA	Power Purchase Agreement
PV	Photovoltaic
R&I	Research and Innovation
RAB	Regulatory Asset Base
REC	Renewable Energy Community
RES	Renewable Energy Source
SO	System Operator
SRA	Scalability and Replicability Analysis
TOTEX	Total Expenditures
ToU	Time of Use
TSO	Transmission System Operator

Table 1: List of acronyms

1.6. References

IElectrix documents

- IElectrix Project Deliverable D2.13. "Feasibility study on the technical adaptions needed to implement the new generic high-level use cases into the 5 IElectrix demonstrations." September 2022.
- IElectrix Project Deliverable D3.1. "Modelling the commercial exchanges demonstrated experimentally during the use case." April 2022.
- IElectrix Project Deliverable D3.2. "CBA calculation methodologies definition." December 2021.
- IElectrix Project Deliverable D3.3. "Cost/benefit appraisals of the demonstrated use cases." July 2022.
- IElectrix Project Deliverable D4.2. "Scalability and replicability analysis (SRA): technical/functional SRA of the IELECTRIX use cases and solutions." June 2022.
- IElectrix Project Deliverable D4.3. "Scalability and replicability analysis (SRA): qualitative SRA of the IELECTRIX use cases and solutions." June 2022.
- IElectrix Project Deliverable D4.4. "Current regulation in target countries and regulatory barriers identified for the implementation of the use case." April 2021.
- IElectrix Project Deliverable D7.4. "Demonstration activities results: contains all demonstration measurement results, demonstration data and KPIs evaluation, proposals for legal, regulatory and grid code updates and definition of viable business models - German demonstration." June 2022.
- IElectrix Project Deliverable D8.4. "Demonstration activities results: contains all demonstration measurement results, demonstration data and KPIs evaluation, proposals for legal, regulatory and grid code updates and definition of viable business models - Hungarian demonstration." July 2022.
- IElectrix Description of the Action (DoA), Annex 1 to the Grant Agreement.

External documents

[1] Lind L, Cossent R, Herding L, Correa M, Gómez T, Chaves JP. IElectrix D4.4 - Current regulation in target countries and regulatory barriers identified for the implementation of the use case. 2021.

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2. Summary of relevant regulatory topics and current regulation

This section provides an overview of the most relevant regulatory topics for the implementation of the IElectrix solutions. The details on each regulatory topic can be found in the deliverable D4.4 [1]. The mapping of regulatory topics in D4.4 identified eight main topics that have a greater impact to the HLUCs in the project. The level of impact of each regulatory topic to the different HLUCs is not the same though. Nevertheless, each regulatory topic has an impact on at least four out of the eight HLUCs analysed or more.

- DSO Economic Regulation

The DSO revenue regulation is expected to impact nearly all HLUCs, as it sets the incentives for DSOs in relation to operational expenditures (OPEX) and capital expenditures (CAPEX), as well as the remuneration of DSOs. The regulatory incentives on expenditures will determine if DSOs have the incentive to use local flexibility from DERs or LECs as a means to reduce network reinforcement at the expense of increasing OPEX. On top of the incentives on OPEX and CAPEX, it is common for regulation to set specific incentives for the improvement of continuity of supply and the reduction of losses. In the case of the former, the main HLUC affected would be IN-3, as the islanding capability of microgrids are used specifically for increased resilience. In the case of the latter, several HLUCs are influenced, namely AT-1, HU-1 and 2, and IN-1 and 2. In this use cases, the optimization of local generation-consumption is expected to reduce losses in the distribution grid, as the use of the grid is minimized. Moreover, additional incentives may exist for additional purposes other than losses and continuity of supply. Such incentives, if they exist, will be analysed in a case-by-case basis. Finally, the existence of network expansion investment plans is also important, as they may allow for DSOs and regulators to find opportunities to consider the use of local flexibility instead of reinforcing the grid, as proposed in DE-1.

- Incentives for innovation

The deployment of innovative solutions is often associated to economic risks and concepts that do not comply entirely with the regulatory framework in place. Therefore, DSOs (and other actors) should have appropriate incentives for innovation. This can be translated in economic incentives for the development of pilot project, and for the recognition of costs associated to pilot projects. Additionally, DSOs could be granted an exception to certain regulatory conditions, limited both temporally and geographically, allowing the DSOs to test technical and market-based solutions that are currently not allowed by regulation. These exceptions are commonly known as “regulatory sandboxes”. Given the innovative solutions proposed in IElectrix, it is safe to say that this regulatory topic impacts all HLUCs in all countries.

- New roles of DSOs

With the deployment of smart grids, new roles are expected to be performed by DSOs in relation to data management, system operation, and market facilitation. In the context of IElectrix, two of the new roles of DSOs are selected to be analysed, namely the **use of flexibility from DER** and **storage operations and ownership** by DSOs. With regards to the use of use of flexibility from DER for grid management purposes, all HLUCs are impacted by this regulatory topic. The rules on storage ownership will define in which cases the DSO is allowed to own and operated storage systems such as batteries. This definition is important as batteries can play an important role in the management of the grid, but owned by market participants can also provide different services Therefore, this definition should be relevant for all HLUCs that make use of BESS in IElectrix, namely AT-1, DE-1, HU-1 and IN-1.

Network access and connection

Not only DSOs are impacted by the regulatory framework in place, but also consumers, prosumers, and LECs. The rules on access and connection to the grid will have an effect on all HLUCs to a greater or lesser extent. The regulation on connection charges, allocation of grid capacity, connection requirements and firmness of access will give important signals for potential RES deployments, making them more or less economically viable. Considering that nearly all HULCs consider the use and integration of DER, it is important to verify if barriers for their deployment exist.

Smart metering

The deployment of smart meters enables several benefits to the system, such as a higher observability of the grid by the DSOs, the reduction of operation costs (e.g. remote switching) and the availability of important data for consumers. Moreover, smart meters are almost a requirement for the design of effective demand response programs, as the provision of the necessary granularity of consumption/generation data. Therefore, the solutions proposed by HLUCs testing demand response programs, such as AT-2, HU-2 and IN-2 are impacted by the level of deployment, as well as the functionalities of smart meters. In addition, it is also important to consider how the data gathered by smart meters is managed and accessed by consumers and authorized third-parties.

Retail tariff regulation

The design of retail tariffs, together with network connection and access cost, is also relevant in incentivizing consumers and DER owners to participate in DR programs or to provide flexibility in organized markets. In countries in which the retail activity is liberalized, it is important to evaluate which costs other than energy and network-related costs are borne by consumers. If such costs are too high, they could potentially dilute eventual incentives from DR programs, weakening the economic incentive. Also, the way these components are charged also matter (e.g. charges in energy terms or fixed payments). In the case of countries without a liberalized retail, or countries that have an “opt-out” default tariff, it is necessary to analyse if the design of such tariffs is compatible with the solutions proposed in the IElectrix project.

Self-generation and self-consumption

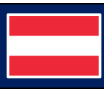
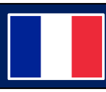
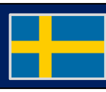
The capacity to install RES, to use it for self-consumption or to inject the remaining energy into the grid is central for the development of LEC. Therefore, it is important for self-generation not only to be authorised, but also to be foster by appropriate regulatory signals, as the existence of self-generation taxes or limitations to grid access may hinder the deployment of local RES. The analysis on barriers for self-generation should consider both individual self-generation as well as collective self-generation, as the latter is an important step towards the formation of LECs.

Local Energy Communities (CECs, RECs)

The last regulatory topic considered is on the rules for LEC. As the development of LEC is still in progress, the legal definitions and implementation in the different countries have to be considered, also in light of the European definitions of Renewable Energy Communities (REC) and Citizen Energy Communities (CEC) defined by the Clean Energy Package. The scope of the LEC activities, as well as the permitting process and requirements will determine if barriers for an eventual deployment of IElectrix solutions exist, specifically for HLUCs AT-1, AT-2, DE-1, IN-1 and IN-2, where LEC will play a central role.

Table 2 provides a summary of the regulatory conditions in the seven analysed countries. Details on each country and topic can be found in the deliverable D4.4. It is important to notice that this summary presents a snapshot at the time of writing D4.4 (April 2021). Upcoming changes might not be reflected.

Table 2: Summary of regulatory conditions

Main Actor	Regulatory Topic							
DSOs	*DSO Economic Regulation*	Incentive regulation with separate treatment of OPEX/CAPEX. A bonus-malus incentive exists for continuity of supply and the DSO has to procure losses. Investment plans are not required yet.	Incentive regulation with TOTEX approach. A bonus-malus incentive exists for both continuity of supply and losses. Investment plans are requested by the NRA on demand.	Incentive regulation with separate treatment of OPEX/CAPEX. A bonus-malus incentive exists for both continuity of supply and losses. Investment plans are not required yet.	Transitioning from a cost-of-service to incentives regulation with separate OPEX/CAPEX treatment. No incentives for losses nor continuity of supply for the first regulatory period. Investment plans are required and approved by the NRA.	Incentive regulation with separate treatment of OPEX/CAPEX. A bonus-malus incentive exists for continuity of supply and penalties for losses. DSO grid development plans are also required since 2021.	Incentive regulation with separate treatment of OPEX/CAPEX. A bonus-malus incentive exists for continuity of supply and the DSO has to procure losses. Investment plans are submitted but not binding.	Cost-of-service regulation with CAPEX subject to NRA approval. DSOs have to buy losses and penalties may apply to continuity of supply. Investment plans are required and approved by the NRA.
	New roles of DSOs	No specific mechanism in place.	No specific mechanism in place. Several pilots are testing concepts	The legislation already allows for flexibility tendering. Process for concluding the tendering process is ongoing	No specific mechanism in place.	Regulation entitles DSOs to procure flexibility services, rules of tendering are already in place.	DSO are allowed to have bilateral contracts with DER. This modality of procurement is already used due to "subscription limits" between SOs.	No specific mechanism in place.ok
	Storage ownership and operation by DSOs	No specific regulation. In principle DSOs should not own/operate BESS	No specific regulation. In principle DSOs should not own/operate BESS	No specific regulation. DSOs should not own/operate BESS, except in case of lack of commercial interest	Only in case of lack of commercial interest	DSOs can own/operate BESS for grid optimization as fully integrated network components under CEP.	In principle DSOs could own/operate BESS for supporting power quality and or losses. The matter is not comprehensively regulated.	Currently, there is no regulatory framework for BESS in India
	Incentives for Innovation	No specific regulatory sandbox regulation, but other incentives for DSO innovation.	No specific regulatory sandbox regulation, but other incentives for DSO innovation.	A specific regulatory sandbox regulation exists, as well as other incentives for DSO innovation.	No specific regulatory sandbox regulation, but other incentives for DSO innovation.	Regulatory sandbox framework regulation already adopted. DSO innovation economically incentivised as well.	No specific regulatory sandbox regulation, but other incentives for DSO innovation.	No specific regulatory sandbox regulation, but other incentives for DSO innovation.
End-users	*Network access and connection*	Deep connection charges and RES priority for connection.	Shallow connection charges and RES priority for connection.	Deep, Shallow for DG < 5 MW. First-come-first-served connection.	Deep connection charges.	Deep, shallow and shallowish (depending on unit). First-come-first-served for HH PVs, otherwise free capacity tenders in every 6 month	Deep connection charges. First-come-first-served connection.	First-come-first-served connection.
	Smart metering	15.4% by 2018	Limited rollout. Large rollout (80%) expected between 2026 and 2030.	80% currently. Completion expected by 2022.	Limited rollout (3.2% currently). Large rollout expected by 2026.	Limited rollout (for 5000+ kWh/year consumption, 3*32A+ capacity, PV) until end of 2024.	First rollout completed by 2009, but with limited functionality. Completion of second rollout expected by 2024.	Limited rollout. However, an ambitious national plan was already developed for a large rollout in the 3 coming years.

	Retail market conditions and tariff regulation	Well-functioning retail market	Well-functioning retail market	Presence of regulated tariffs in the French market is still high	Retail is liberalized, but barriers such as complexity and advantages to incumbents exit	Regulated tariffs and household retail prices	Well-functioning retail market	Regulated for households
Self-producers and energy communities	*Self-generation*	Individual self-generation is allowed with net metering.	Individual self-generation is allowed without net metering. A fixed FiT applies.	Individual self-generation is allowed without net metering. A fixed FiT applies.	Individual self-generation is allowed with net metering.	Individual self-generation is allowed with net metering for HH PVs, but from 2023 changes expected. Incentives for self-generation in connection procedures.	Individual self-generation is allowed without net metering. Surplus is sold to retailer.	Individual self-generation is allowed with net metering.
	Local Energy Communities (CECs, RECs)[1]	*(Updated)* REC and CEC concepts transposed, but no additional details with respect to the CEP [2].	Collective self-generation is allowed but limited. No LEC regulation in place.	*(Updated)* LEC regulation published in 2021 [2].	Collective self-generation is allowed. A LEC regulation is already in place.	*(Updated)* A transposition of REC and CEC was made in 2021, so the regulatory framework is given.	Collective self-generation is allowed but limited. No LEC regulation in place. *(Updated)* A proposal from the Swedish NRA was published [2].	Collective self-generation is not allowed. No LEC regulation in place.

[1] Since the publication of the IElectrix deliverable D4.4, many countries have transposed the LECs concepts from the CEP. For this reason, this row was updated according to the most up-to-date information. Whenever an information was updated, the "(updated)" mark was added with the respective source. If the information was not updated, this means that the information in D4.4 is still up-to-date (Germany and Greece), or no new information was found (India).

3. Identified regulatory barriers

Considering the regulatory conditions in the seven analysed countries and the impact of each regulatory topic for the different HLUCs, a list of drivers and barriers was identified. Drivers are understood as regulatory provisions already in place that fosters the implementation of the HLUCs, while barriers are regulatory provisions (or the lack of) that forbid or prevent the development of the HLUCs. In total, 13 barriers and 2 drivers were identified, as summarized in Table 3.

Table 3: Summary of regulatory drivers and barriers

Regulatory topic	Regulatory Driver or Barrier	Short rationale
DSO Economic Regulation	*Barrier No. 1: CAPEX-Bias in incentive regulation*	CAPEX-bias in incentive regulation scheme weakens the incentive for DSOs to look for more efficient alternatives to grid reinforcements, such as the use of local flexibility resources.
	Barrier No. 2: No binding investment plans approved or published	Network investment plans could be an important tool for potential flexibility providers in order to verify where flexibility is most needed. Moreover, DSOs and regulators may benefit from using investment plans to identify which network reinforcements could be deferred considering the use of local flexibility.
	Driver No. 1: Incentives for loss reduction and improvement of continuity of supply	Specific incentives for reduction of losses and improvement of continuity of supply are beneficial for the exploitation of IElectrix solutions, as several HLUCs contributed to improvement of these aspects.
New Roles for DSOs	*Barrier No. 3: Limitations to use of BESS by DSOs*	Recent EU regulation limits the possibilities for DSOs to own and operate BESS. By way of derogation, Member States and regulators may allow DSOs to own and operate storage systems if considered fully integrated network components, or when no commercial interest exists in their deployment. Regulators should monitor the commercial interest every five years.
	Barrier No. 4: Lack of local flexibility procurement mechanisms	The lack of regulatory definition on the possibilities for the procurement of local services by DSOs reduces the possibilities for both DSOs procuring local services and for flexibility providers to offer them.
Incentives for Innovation	*Barrier No. 5: Lack of sandbox regulation and experience with large innovation programmes*	The CEP is not exhaustive for every topic, especially in the case of the e-Directive. Several definitions are left to be defined at the MS level. In such cases, large R&I programmes, including sandboxes, could serve to inform regulators and policymakers on the different regulatory alternatives, providing results that consider the local context.
	Driver No. 2: Financial incentives for innovation	Financial incentives for DSOs to invest in innovative solutions are important as they reduce the risk for the DSO, inherent of this type of investment.
Smart Metering	*Barrier No. 6: Limited smart meter deployment*	Smart meters are the backbone of the several innovations and business models at the distribution grid. For several use cases, they are a necessary equipment (e.g. enabling dynamic tariffs). For other use cases, they may be not essential, but are an important facilitator when put in place (e.g. fostering DG).
Network access and connection	*Barrier No. 7: Deep connection charges are a barrier for small DG*	Active consumers, especially the ones installing small-sized DG, may be disincentivized by deep connection charges.
	Barrier No. 8: Inexistence of flexible network options	Inexistence of flexible network options may lead to expansive reinforcement needs. Moreover, DG installation may be delayed by the need of prior reinforcements.

Self-generation rules	*Barrier No. 9: Existence of net-metering schemes*	Net-metering schemes may be an effective solution to foster the deployment of certain types of DG. However, they reach this result at the expense of under remunerated network costs by active consumers and the disincentive to other types of DER, in particular the BESS.
Retail markets and prices for end-customers	*Barrier No. 10: Not developed liberalized retail markets and high presence of regulated tariffs*	Liberalized retail offers may help to foster consumer awareness and DER deployment, that can later translate in the formation of LEC.
	Barrier No. 11: High share of regulated costs in the electricity bill	High shares of regulated costs (e.g. RES support schemes and taxes) reduce potential incentives for demand response and DER installation as price signals are weakened.
Energy Communities	*Barrier No. 12: Uncertainty on LEC definitions, especially on topics that are left open to MSs by the CEP*	The definition of the LEC concept is still incipient. The CEP only provides broad definitions that should be finetuned by Member States. However, no timeline exists for this definition of the concept, and a risk exists that LEC are allowed in the MSs, but lack the additional necessary conditions. This could lead to a long period in which LEC are not possible *de facto*.
	Barrier No. 13: Collective self-generation is still incipient	Collective self-generation can play an important role in LECs. Allowing collective self-generation is an important step toward fostering the formation of LECs. However, the schemes in place are still limited.

Finally, an assessment is made on how the different barriers impact the different HLUCs. This analysis is part of the regulatory SRA presented in the IElectrix deliverable D4.3. Table 4 presents the result of this assessment. Additionally, the regulatory SRA reviewed the identified barriers and added another two, namely “forbidden or underdeveloped regulation for DSO islanding” and “weak incentives to improve continuity of supply”.

Table 4: Identified regulatory barriers for the different BUCs. Colours denote the relevance level of the corresponding regulatory topic (red = high, orange = medium, yellow = low). Source: *[1]* (with minor adjustments in case recent regulatory changes were reported by demos).

Main actor	Regulatory topics		Barriers	Business Use Cases							
				AT-1	AT-2	DE-1	HU-1	HU-2	IN-1	IN-2	IN-3
DSO	DSO Economic Regulation	DSO remuneration and investments	CAPEX-Bias in incentive regulation	🔴	🟠	🔴	🔴	🔴	🔴	🟠	
			No binding investment plans approved or published	🔴	🟠	🔴	🔴	🔴	🔴	🟠	
		Incentives to improve CoS	Absence of, or weak incentives to improve continuity of supply								🔴
	New roles of DSOs	Storage ownership	Limitations to use of BESS by DSOs	🟠		🔴	🟡		🔴		
	DSO procurement of grid services	Flexibility procurement by DSOs	Lack of local flexibility procurement mechanisms	🔴	🟠	🔴	🔴	🔴	🔴	🟠	🔴
		Islanded operation	Forbidden or underdeveloped regulation for DSO islanding								🔴
	Innovation and pilots	DSO incentives for pilots/innovation Regulatory sandboxes	Lack of sandbox regulation and experience with large innovation programmes	🟡	🟡	🟡	🟡	🟡	🟡	🟡	🟡
End-users	Network access and connection	Connection charges	Deep connection charges favour grid reinforcement	🔴	🟠	🔴	🟠	🟡	🔴	🟠	
		Firmness of access capacity	Inexistence of flexible network options	🟠	🟡	🟠	🟠		🟠	🟠	
	Smart metering	Smart meter deployment	Limited smart meter deployment		🔴			🔴		🔴	
	Retail tariff regulation	Design of regulated charges	High share of regulated costs in the electricity bill		🟠	🟡	🟡	🟠	🟡	🟠	
		Default/last resource tariffs	Not developed liberalized retail markets and presence of regulated tariffs		🟡			🟡		🟡	
Self-producers and LECs	Self-generation	Individual self-generation	Existence of net-metering schemes	🟠	🟠	🟠			🟠	🟠	
		Collective/shared self-generation	Collective self-generation is still incipient	🟠	🟠	🟠			🟠	🟠	
	LECs	CEC and REC regulation	Uncertainty on LEC definition and open issues in the CEP	🔴	🔴	🔴			🔴	🔴	

4. Key inputs from CBA/SRA, and KPI values measured in the demonstrations

4.1. Inputs from WP3: CBA and Business Models

In the IElectrix Work Package 3, an identification of business models (IElectrix D3.1) and a cost-benefit analysis (IElectrix D3.3) are conducted.

The identification and evaluation of business model sheds light into how the different roles and actors of the value chain prosed by the IElectrix HLUCs. The deliverable D3.1 explores the specificities of business models for different HLUCs/countries. Additionally, it also proposes the "IElectrix generic value network", illustrated in Figure 3. The value network allows for a view of all actors and transactions taking place after the implementation of IElectrix solutions. Despite being a stylized representation, it is possible to observe that several actors are involved in multiple independent transactions. It is also worth noticing that several actors are incumbents (e.g. retailers, DSOs, active users), while others are new actors developing new business models (e.g. LEC, BESS operators). In this context, regulation enabling the new business models will also need to protect the existing transactions without creating distortions for the actors involved.

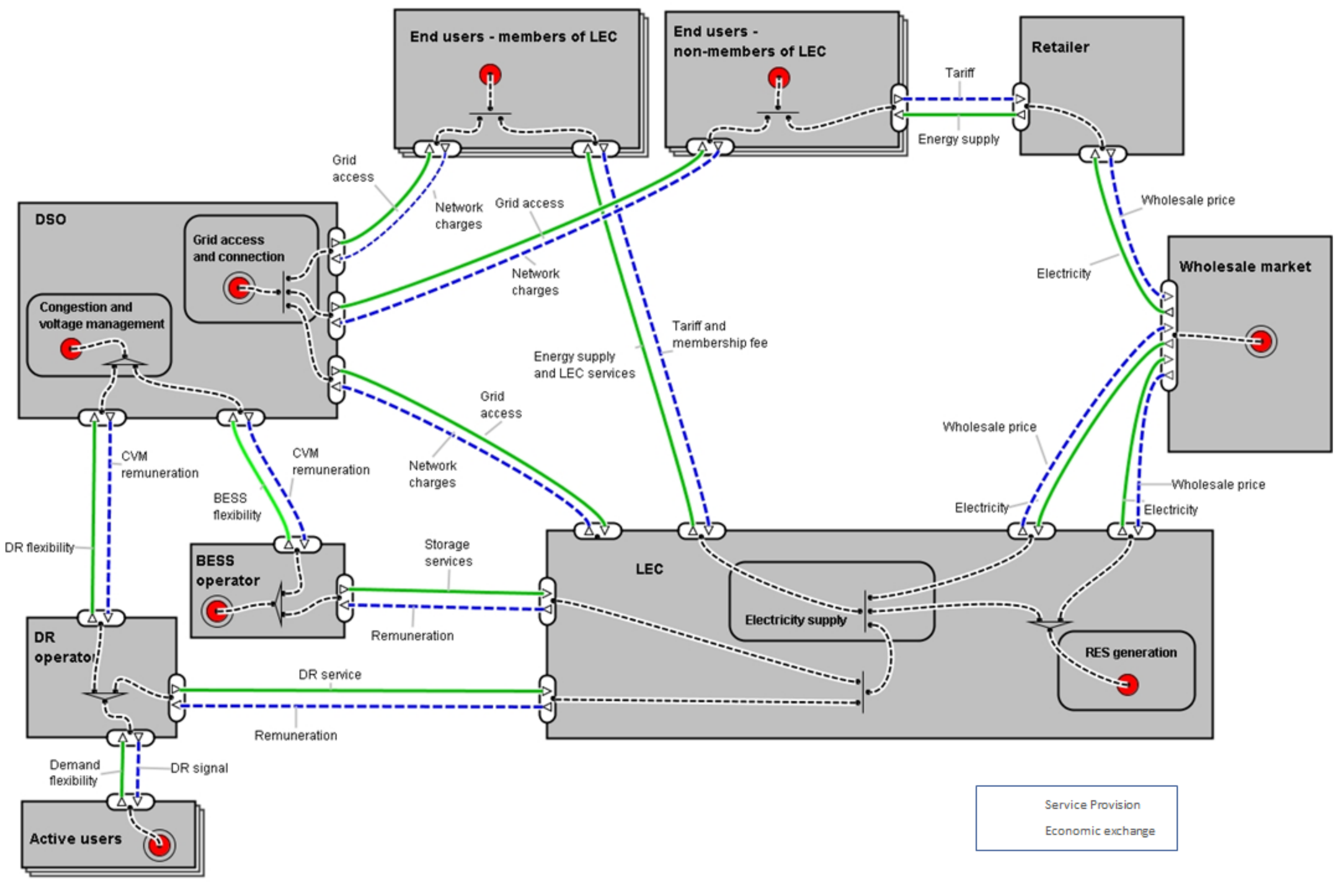


Figure 3: IElectrix generic value network. Source: IElectrix D3.1.

A Cost-Benefit Analysis (CBA) was also conducted for the HLUCs of IElectrix. In the IElectrix Deliverable D3.2, the methodology for the CBA is explained, while in the IElectrix D3.3, the results for the CBA are presented and discussed.

The CBA consisted of identifying the boundary conditions (e.g. discount rate, time horizon, macroeconomic factors), calculating the CBA for the demo scenario in comparison to the non-IElectrix scenario and conducting a sensitivity analysis on key parameters of the CBA calculation, in order to reveal future or scale-up results that could go beyond the demo scenario. This monetary CBA is calculated for the majority of HLUCs[2]. However, it is worth mentioning that the monetary CBA includes only the monetizable benefits. Other possible benefits of the HLUCs are either non-monetizable (e.g. increase of self-consumption, reduction of congestion issues) or non-measurable (e.g. improvement of the perception of the society to the DSO). The CBA is calculated from the perspective of the DSO.

For most of the HLUCs, the monetizable CBA result presented a negative Net Present Value (NPV) for the demo scenario. The negative results persist even under scale-up parameters, such as increasing the RES penetration by factors of 2 to 5 or reducing the CAPEX and OPEX by 10% to 30%. These results can be attributed to the high CAPEX of the BESS solutions (for HLUCs considering BESS installation), and the characteristics of the demo grids.

The only HLUC with a positive NPV was the IN2, which considered the use of demand response from LEC. In this HLUC, the CAPEX for the DSO was very low, and the reduction of imported energy proved to be beneficial. In this use-case, the end-consumer receives an alert in order to reduce consumption at a certain period of the next day. This allows to reduce grid peak load and therefore to reduce overloads and blackouts. The CBA from this HLUC shows that demand response can be beneficial to DSOs, and consequently to customers as well. In the case of India, these benefits are eventually shared among customers, as distribution companies (DISCOMs) are also regulated retailers responsible for procuring the supplied energy in long-term PPAs (IElectrix D4.4). Therefore, accumulated savings from DR programs should result in lower tariffs to customers in the future. Regulation, however, could be designed in a way that DR participants benefit first and more from the gains obtained by the DR program. The positive results from the DR HLUCs in India could possibly be also replicable to the EU Member States, considering the different regulatory framework and different business models in place. In this case, the gains from the explicit demand response programs could be directly perceived by the participating customers, and to a lower portion to the DSO.

The results from the CBA also shed light on some important aspects with regards to the deployment of BESS as FINC by the DSO. Firstly, it is observed that the deployment of BESS solely for monetary benefits could be not economically viable. In this case, regulation should also consider the non-monetizable and non-measurable benefits when defining the boundaries for BESS deployment as Fully Integrated Network Components (FINCs) (e.g. potential improvement in security of supply).

Secondly, it shows that profitability of the deployment of solution is highly dependable on grid conditions (e.g. RES penetration, topology). Therefore, the FINC conditions should also consider a case-by-case assessment in order to identify where asset deployment is more beneficial, possibly including regulatory KPIs for transparency. On one hand, DSOs should justify such deployments in their investment plans. On the other hand, regulatory sandboxes could be used in the short-term to allow regulators to define guiding criteria for the possibilities and requirements for a BESS to be used as FINC.

Finally, it is also important to notice, that the BESS CBAs were calculated from the perspective of the DSO. In this case, the monetary benefits are limited to the ones within the DSO business model. However, other BESS business models are possible, in which the BESS is operated by a flexibility provider that provides flexibility services to the DSO and other buyers. In this case, the CAPEX of the BESS could be diluted among more monetizable benefits (e.g. provision of balancing services to the TSO). For the DSO, on the other hand, the CAPEX component of the BESS would be drastically reduced, being substituted by an OPEX (flexibility procurement) that could make the HLUC economically viable.

[2] For some HLUCs, the data available is considered insufficient for the calculation of monetary CBA. This was the case for HLUCs AT3 and IN3.

4.2. Qualitative SRA

One year after the initial identifications of barriers in the deliverable D4.4, the qualitative SRA was conducted and published in the IElectrix Deliverable D4.3. In this analysis, the initial barriers were revisited, updated and an assessment was carried out in order to understand how replicable the different HLUCs are to the seven countries analysed. The methodology followed consisted in using a scale from 1 to 5 in the assessment of the maturity of the different regulatory topics with respect to the development of the different HLUCs. This exercise enabled to assess how implementable a HLUC is in a country other than the one in which it is currently being demonstrated.

The results show that national regulation still presents relevant barriers to the upscaling and replication of all the BUCs, with just a few exceptions in some countries. Despite the fact that this may not look like good news, it also highlights the innovative nature of IElectrix. Moreover, the CEP dispositions, once fully transposed and implemented, process in which EU MS are immersed, should modify this situation significantly. Although the original deadline for transposition and implementation was up to two years after the CEP publications, not all countries have completed the process, or at least not with the necessary detailing (including secondary legislation beyond the Directive transposition per se).

The BUCs relying on DR, i.e. AT-2, HU-2, IN-2, appear as the most mature in terms of regulation (not factoring in other potential barriers related to end-user engagement or perceived economic value). On the other hand, BUCs relying on the use of BESS to alleviate grid constraints (AT-1, DE-1, HU-1, IN-1) seem to face stronger replicability barriers largely due to two factors: i) most target countries still have not defined a clear framework for either enabling DSOs to directly own and operate storage assets, or procure grid services from third-party storage systems (Hungary is an exception); and ii) DSO revenue regulation fails to provide adequate incentives for the use of flexibility as a mean to defer or avoid reinforcement.

Islanded operation is the BUC with the lowest regulatory replicability index, albeit it is also the one showing the largest standard deviation among the target countries. The highest value would be obtained for France, where in spite of not having explicit regulation, several pilots have already been tested and presents strong incentives for improving CoS, whereas the lowest value is obtained for Greece where DSOs see no economic incentive to improve reliability indices.

Lastly, the assessment shows that self-generation regulation still shows much room for improvement in most countries. Net-metering schemes with long compensation periods are still the norm, presumably affected by the low smart metering deployment level. Furthermore, collective self-generation, even though permitted in most countries, is in several cases constrained to internal networks of apartment buildings, thus limiting its scalability. Concerning the development of a framework for energy communities, Greece and Hungary (from 2021) are the only country which has actually developed it. As a results, the compatibility index for Greece tends to increase in the BUCs where self-generation is a relevant topic (AT-1, AT-2, IN-1, IN-2, DE-1).

Figure 4 presents the result from the country assessment in the regulatory replicability analysis.

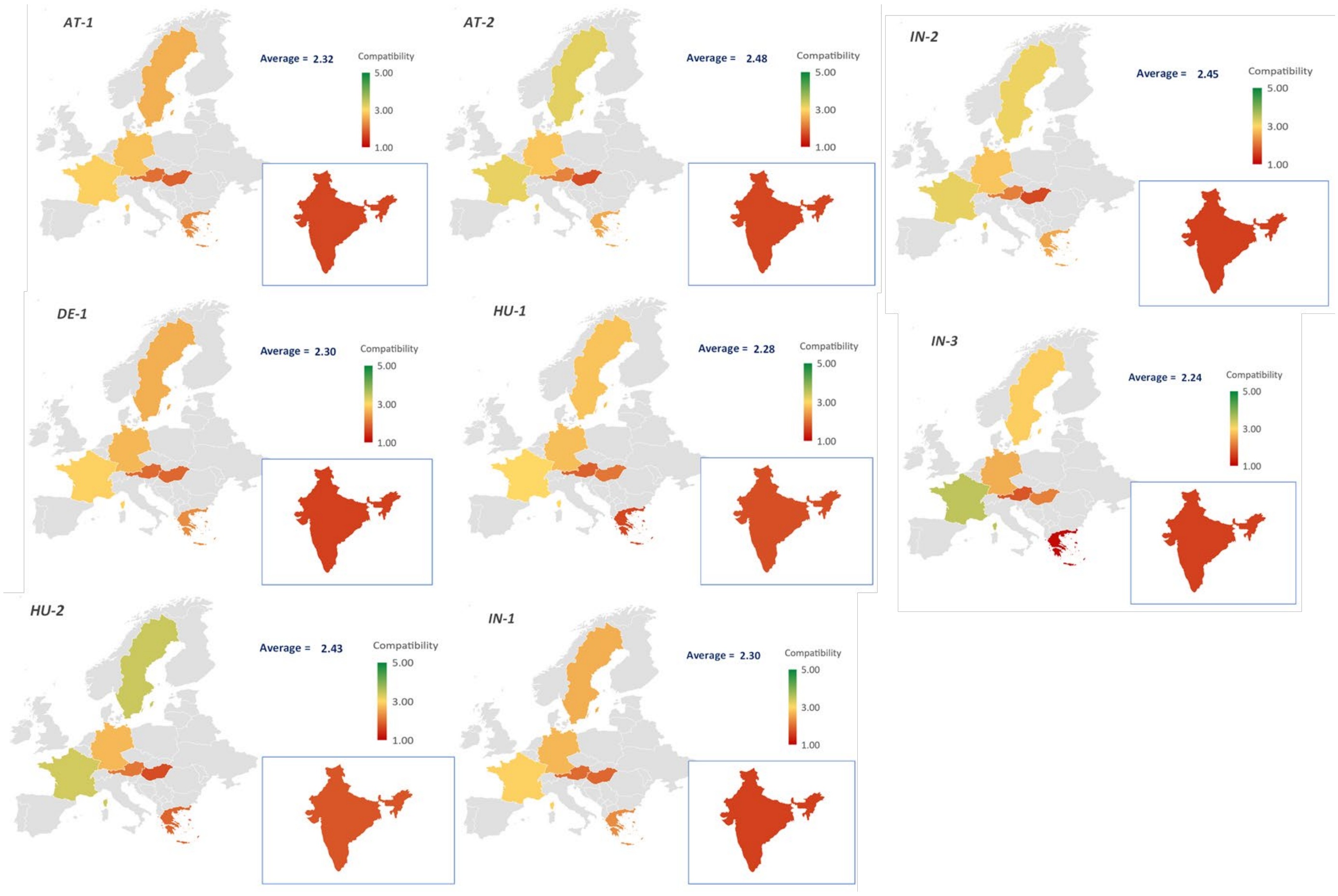


Figure 4: Regulatory compatibility of the different BUCs. 5 (green): high compatibility of the HLUC in the assessed country. 1 (red): low compatibility. Source: IELECTRIX D4.3.

Therefore, the regulatory replicability analysis sheds light on urgency for the different regulatory frameworks in the different countries. Although barriers exist for all HLUCs, their extent is not the same across countries. In this context, the qualitative SRA may help policy makers and stakeholders in setting priorities for the different barriers.

4.3. Demo results

At the time of writing, demonstrations have been already partially or fully implemented, and results started to be collected and reported. In this process, the IElectrix partners have gained important knowledge on the regulatory challenges involved in setting and operating the demonstrators, also allowing them to assess and propose recommendations to their national regulatory frameworks.

The demonstration results for the four demo countries are published under the respective deliverables, as listed below:

- Austrian demonstration: Deliverable D6.4
- German demonstration: Deliverable D7.4
- Hungarian demonstration: Deliverable D8.4
- Indian demonstration: Deliverable D9.4

Both IElectrix deliverables D7.4 and D8.4 were published at the time of writing, allowing for the collection of their inputs on regulation and the KPIs calculated. Whenever the demo result deliverables are not published, information from the IElectrix deliverable D2.13 is used. The D2.13 carried out a feasibility study on the technical adaptions needed to implement generic high-level use cases into the 5 IElectrix demonstrations. Within this work, not only technical aspects were considered, but also regulatory barriers were analysed, providing another important input from the demonstration countries' perspective.

4.2.1 Austrian demo

In the IElectrix deliverable D2.13, four different generic use cases are analysed, namely (i) grid resiliency, (ii) voltage management, (iii) congestion management and (iv) grid booster. From the Austrian perspective, the implementation of these generic use cases would not be limited by important regulatory barriers. In Austria, the BESS is owned an independent BESS operator. Hence, no major barriers exist. This also takes into account the BESS size, that in Austria is of 1 MW. In case of larger batteries (e.g. larger than 5 MW), other requirements could apply, such as the general rule for generators to cover for the costs of primary control reserve in proportion to their annual generated energy (injected, in the case of a battery) and to provide primary control reserve in case the respective tender was unsuccessful.

4.2.2 German demo

The lessons learned from the German demonstration highlighted some of the main barriers and also proposed recommendations and the prioritization of certain barriers. It is worth noticing that Germany already progressed on some regulatory definitions, such as the use of flexibility by DSOs for solving local congestions. However, several aspects are yet to be defined, posing a challenge for BESS investors and for DSOs.

The German demonstration identifies as a barrier the lack of definitions for BESS, especially with regard to the connection agreements, the cost recognition by DSOs, the market mechanisms for flexibility procurement and uncertainties created over the BESS business model. Firstly, it is not clear how connection agreements with BESS should work, and which costs should be paid by the BESS investor, considering that this type of asset has characteristics of both load and generation. It is argued, for instance, that the charge for network reinforcement, which is currently in place, may not make sense for the BESS, as it can in fact help mitigate network congestions. As a recommendation, connection agreements could define how and when a BESS can be operated so that no network constraints are created and grid reinforcement costs are avoided.

Another barrier identified by the German demonstration is the creation of flexibility markets. The German regulation already allows for the DSO to procure and use distributed flexibility for the purpose of congestion management, and such costs are recognized within the revenue regulation of the DSO. However, the procurement mechanism implemented in Germany is cost-based, rather than market-based. The lack of a market-based flexibility created a barrier to investment by BESS owners.

The KPIs calculated by the German demonstration also provide inputs to the regulatory analysis. From a business case perspective, KPIs showed the possible effectiveness of using BESS in supporting the network. Considering that the cost of the BESS is borne by the battery owner, and that the battery owner will have revenues from other markets (e.g. FCR market, wholesale markets), it is possible for the DSOs to incur in lower costs using the battery's flexibility than reinforcing the grid (e.g. additional HV transformer and lines). The final outcome, however, depends on the expected revenues for the BESS operator in these additional markets. It was also verified that the reduction of RES curtailment with the BESS is found to be in the range of 2 – 4 % regarding the energy. Also, voltage deviations are reduced, limited to approximately 1%.

4.2.3 Hungarian demo

The Hungarian demonstration presents an interesting case of DSO-owned BESS and the challenges when defining rules for DSOs to own and operate storage under the Clean Energy Package definitions. In Hungary, DSOs were originally granted the possibility of owning and operating batteries in 2016, under certain conditions (e.g. maximum size of 0.5 MW). This rule was put in place before the entry into force of the CEP. With the publication of the latter, amendments were made so that the concepts and definitions in the CEP are observed by the Hungarian regulation.

As discussed in the following sections, the CEP generally prevents the DSO to own or operate storage. However, an exception exists if the BESS is considered a "fully integrated network asset", meaning an asset used solely for ensuring safe a reliable operation of the grid. Therefore, the Hungarian regulation was adapted in 2020 and 2021 allowing the DSO to own and operate batteries, if approved by the regulator, as fully integrated network assets. However, the CEP also mentions that in such cases, batteries should not be used for the purpose of managing congestions. In this case, the Hungary regulation is not specific, and questions were raised by the Hungary demonstration over the concept of congestion management, initially defined in the 3rd Energy Package as a cross-border trading limitation.

It is not completely clear either how the cost recognition of batteries will take place. DSOs can, in principle, have the cost of BESS recognized, as this type of asset is considered a smart grid device. However, it is not clear how the cost will be recognized (e.g. OPEX, CAPEX, depreciation).

The Hungarian KPIs also give an insight into the economic viability of the solutions tested in IElectrix. Savings due to investment deferral, for instance, could reach up to 29% [Use case 3 (BESS - Dúzs) and Use case 4 (DLC – Dúzs)]. However, the demonstration partner also identifies that both alternatives (grid reinforcement vs. BESS usage) also have their own advantages and disadvantages, and that the savings information should be considered together with other aspects. The traditional reinforcement, for example, has a longer useful life (40 years), while the BESS can go up to 25 years, after refurbishment. On the other hand, the design, permitting, and construction process take much longer for traditional reinforcements when compared to the installation of BESSs.

4.2.4 Indian demo

In principle, no major regulatory barrier or recommendation is identified in the IElectrix deliverable D2.13. The main reason is the fact that DSOs can own and operate BESS in India. It is mentioned though that the use of BESS for tariff purposes is currently allowed but regulations to limit this usage are being developed by the Indian regulator. Although not published yet, the expectation and uncertainty of upcoming regulations can be a barrier in itself, as identified in the IElectrix deliverables D4.4 and D9.1 (Indian demonstration).

5. Regulatory recommendations

This section presents regulatory recommendations for the different barriers identified in the IElectrix project presented in Table 3.

5.1. DSO utilization of flexibility resources

5.1.1. CAPEX-Bias in incentive regulation

Among the seven countries analysed, six[3] have incentive regulation framework for the definition of allowed revenues for DSOs in place. Out of the six incentive regulation frameworks, five treated OPEX and CAPEX separately.

The typical incentive regulation framework places incentive for efficiency gains in the OPEX component of the revenue, while CAPEX is treated either as a pass-through cost component, being declared and possibly audited by the regulator This approach was devised at the beginning of the liberalization process, in which DSOs were being unbundled from public utilities, and gains of efficiency were the main focus. Additionally, the network reinforcement activity of DSOs consisted of forecasting the demand growth and carrying on the necessary investments in a “fit-and-forget” fashion. This framework incentivizes DSOs to reduce OPEX while reinforcing the networks, possibly beyond the minimum standards, as the remuneration is set on the CAPEX. This set of incentives is often referred as “CAPEX-Biased” regulation.

In the context of local flexibility procurement by DSOs for the purpose of deferring or avoiding network reinforcements, it is noticeable that CAPEX-Biased regulation leads to incentives opposite to the idea behind the use of flexibility. By procuring local resources, DSOs will reduce CAPEX (deferral or avoidance of reinforcement) while increasing OPEX (flexibility procurement costs). Under the current regulation, DSOs could be economically penalized if they opt for the procurement of flexibility, even if this is the least-cost option overall. Therefore, an adaptation on the economic regulation of DSOs is necessary.

The “CAPEX-Bias” condition of current regulatory frameworks is already known by regulators and is under discussion in many countries. In the UK, adaptations were already made under the RIIO-2 framework, and in Italy, proposals for modifications were already published [3,4]. One aspect in common of the proposals so far is the focus over the TOTEX, rather than a separate CAPEX/OPEX approach. However, plain TOTEX-based regulation may also fail in removing completely the CAPEX-bias, as the Regulatory Asset Base (RAB) is still dependent on the investments carried out by the DSO.

Regulators could opt for identifying and approving specific flexibility-related trade-offs in a different fashion, so that specific incentives and remunerations could be placed onto these situations. However, this solution seems less viable from a practical perspective, as regulators would require a much higher level of resources to carry out evaluations and asymmetry of information could pose a challenge to the expected efficiency.

Therefore, the first recommendation is 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 [4,5], this can be done by considering a 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 [6]. The general revenue setting when adopting this approach is shown in Figure 5.

[3] At the time of writing D4.4, Greece was in the process of transitioning from a cost-of-service regulation to an incentive regulation.

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 [6].

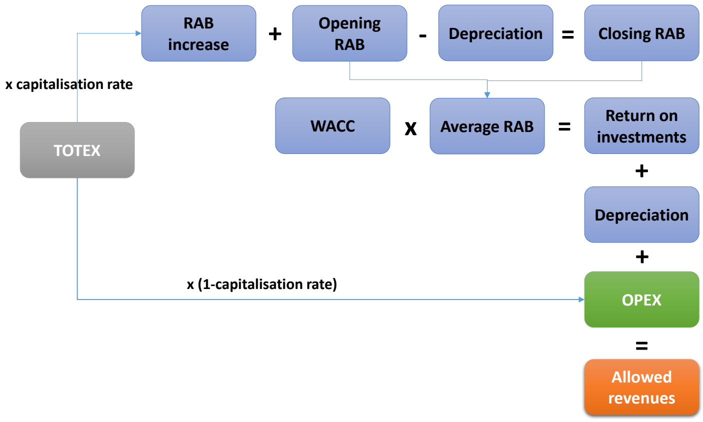


Figure 5: Revenue setting using a fixed capitalisation rate (TOTEX regulation). Source: [6].

Recommendation No. 1: Mitigate the CAPEX bias from DSO remuneration schemes

DSO remuneration should be neutral to the CAPEX/OPEX ratio so that DSOs may decide the least-cost long-term solution to network needs. This means that conventional approaches to determine the RAB should be revisited to equalize the incentives for reducing CAPEX and OPEX. This way, flexibility-related costs could be considered on a level playing field with investments.

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.

5.1.2. No binding investment plans approved or published

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.

However, the CEP is not clear in defining important aspects of the elaboration and approval of the Network Development Plants (NDPs). For instance, it is not clear if the consultation will be public or restricted, or the level of detail in each NDP. Therefore, regulators have the task of defining the methodology and procedure for NDPs.

The first recommendation is, therefore, to establish transparent and effective instruments and procedures for NDPs. CEER advocates for NDPs that (i) are transparent, (ii) properly assess and demonstrates the flexibility-reinforcements costs and benefits, (iii) respects scenarios considered in other national planning documents, and (iv) in which DSOs justify how comments from the consultation process modified the original NDP [7]. A certain level of standardization is also desirable (e.g. use of templates), to ensure transparency and homogeneous information.

Recommendation No. 2: Distribution NDPs should consider flexibility as part of the toolbox

DSO Network Development Plans should (i) be transparent, (ii) properly assess and demonstrates the flexibility-reinforcements costs and benefits, (iii) respects scenarios considered in other national planning documents, and (iv) DSOs should justify how comments from the consultation process modified the original NDP.

Beyond the definition of the methodology, it is also desirable for NDPs to be binding or linked to incentives. In this manner, DSOs have a level of commitment to the NDP. This is important to ensure the quality of the planning elaborated and published. This is especially necessary in the context of flexibility usage. Potential flexibility providers will be able to make better decisions if NDPs are firm. On the other hand, DSOs may benefit from the fact that the NDPs create a more fertile environment for flexibility providers to carry on investment and to make flexibility available when it is needed.

Therefore, the second recommendation is to provide incentives associated with the development of NDPs. For that, first it is advisable to coordinate the elaboration of NDPs with price reviews. Additionally, NDPs can be used as part of the revenue determination process. Both input and output-based incentives can be used to incentivise DSOs to produce adequate NDPs and implement them to the appropriate extent. Similarly to the revenue regulation recommendation, ex-post verification and adaptation mechanisms could allow for corrections due to uncertainty.

Recommendation No. 3: NDPs should be an integral part of the DSO revenue determination process

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

5.1.3. Limitations to the use of BESS by DSOs

The CEP establishes that, in principle, BESS should not be owned or operated by the DSO. However, the E-Directive opens the possibility to grant exemptions to this general rule under two scenarios. These are described below[4].

On the one hand, BESS ownership by DSOs may be allowed if the storage system is a "fully integrated network component" (FINC). In this case, NRAs could assess the suitability of the DSO-owned storage and approve it. By "fully integrated network components", the CEP understands the "network components that are integrated in the transmission or distribution system, including storage facilities, and that are used for the <u>sole purpose of ensuring a secure and reliable operation</u> of the transmission or distribution system, <u>and not for balancing or congestion management</u>" (E-Directive, Article 2(51)).

Therefore, under the NRA's approval, DSOs could own BESS and use to maintain grid security, but not for congestion management or balancing. However, the concept of "congestion management" in the context of DSO-operated BESS is not entirely clear in the European regulation. No definition exists for "congestion management" in the corresponding articles of neither the CEP documents nor the Network Codes. The E-Regulation (2019/943) only defines "congestion" *a situation in which all requests from market participants to <u>trade between network areas</u> cannot be accommodated because they would significantly affect the physical flows on network elements which cannot accommodate those flows*; Therefore, congestions are understood as flow limitations between network areas and as a result of a market clearing.

[4] Another exception applies to storage assets whose final investment decision took place before 4 July 2019 and entered into operation no later than two years after that date, provided they are exclusively used for network restoration after a contingency and are not used for buying or selling electricity in energy or balancing markets. However, this exception would not be applicable to new storage assets used for voltage or congestion management as in most of the projects BUCs.

This corroborates with the “congestion management” definition used in the context of the Guideline on Capacity Allocation and Congestion Management (Regulation 2015/1222, part of the Network Codes) and the Regulation 714/2009 (part of the third package), in which “congestion management” is considered for cross-zonal flows.

The regulation 2015/1222 defines “physical congestion” as any network situation where forecasted or realised power flows violate the thermal limits of the elements of the grid and voltage stability or the angle stability limits of the power system. Therefore, if congestion management is defined as the management of physical congestions, that would go beyond thermal constraints, which is the general focus of congestion management in distribution systems.

For congestion within a bidding zone, other definitions also exist, bringing more ambiguity to the topic. In the CACM Guideline, intra-zonal congestion management is often referred as a “remedial action”. A remedial action is defined in Article 2(13) of CACM Guideline as “any measure applied by a TSO or several TSOs, manually or automatically, in order to maintain operational security.” According to ENTSO-E, remedial actions may include redispatching, countertrading, topology changes, use of reactive power devices (e.g. tap-changers, capacitor banks etc), request (or control if available) additional voltage/reactive support from power plants, among others (ENTSO-E, 2015). This list of possible mechanisms is also in line with the definitions from the System Operation Guideline, Articles 20 to 23 (SO Guideline, 2017). Redispatching is defined as altering the generation, load pattern, or both (including curtailment), in order to change physical flows in the electricity system and relieve a physical congestion or otherwise ensure system security.

Therefore, it seems clear that the EU-level regulation is quite ambiguous regarding the conditions under which DSOs may own BESS as FINC, particularly concerning its use for congestion management. This term is generally used in relation to (transmission) grid congestions that influence the wholesale market clearing; something that is clearly not the case for local congestions happening in the MV and LV distribution grid, as it is the scope of IELECTRIX. This lack of clarity in the definitions could result in a regulatory limbo in which regulators have concerns implementing a regulatory framework compliant with EU regulation, and actors (e.g. DSO) do not invest in BESS due to regulatory uncertainty.

This problem is further exacerbated by the fact that congestion management and (steady-state) voltage control in distribution grids, particularly in the MV and LV levels, are sometimes hard to separate. The reason being that, contrary to transmission systems where series line impedance is dominated by the reactance, in distribution the real (R) component of line impedances is usually comparable in magnitude or even larger than the imaginary (X) component. Thus, both active and reactive power may be used for both purposes. Because of this, even if DSOs are enabled by regulation to own BESS for voltage control but not for congestion management, it may not be entirely clear sometimes whether they comply with the regulation. For example, a BESS injecting active power in the LV grid may help solve voltage problems in the MV whilst, at the same time, alleviate physical congestions (e.g. thermal limits) in the corresponding secondary substation.

Therefore, NRAs should precisely define to which extent ESS usage is considered to be congestion management – solving physical congestions caused by market clearing – and to which extent they can be considered a FINC for the only purpose of ensuring an *efficient, reliable and secure operation of the distribution system*. The definition can include limits to the size of the BESS, the conditions for using it, the voltage levels to which it may be connected to, or prove of economic efficiency. This could also be assessed case-by-case, with regard the purpose end topological conditions of the BESS concerned, provided that definitions give general guidelines and the methodology and procedures are transparent.

Recommendation No. 4: Clearly define the conditions for storage assets to be considered FINCs

NRAs should precisely define to which extent BESS utilization for grid support is considered to be congestion management under EU legislation – solving physical congestions caused by market clearing – and to which extent they can be considered a FINC for the only purpose of performing a reliable, efficient and secure grid operation.

Given that solving congestion and voltage problems in MV and LV grids are oftentimes intertwined and that congestion issues in these voltage levels normally have a negligible impact on wholesale markets, BESS used for these purposes may be deemed FINCs. The regulatory approval can be subject to requirements about the size of ESS in relation to the grid, the conditions for using it, or justification of economic efficiency.

The second possibility to allow DSO BESS ownership would require complying with a list of requirements as follows. First, a tendering procedure, reviewed and approved by the regulator, should show that no other parties are interested or able to provide the same service. Second, DSOs shall prove that the BESS is necessary to fulfil their legal obligations and it is not used to buy or sell electricity in the (wholesale) electricity markets. All this is subject to the supervision and final approval by then NRA. Moreover, the NRA should periodically, at least every five years, carry out public consultations on existing BESS to test whether other non-regulated parties would be willing to own and operate the storage assets. If that were the case, the DSO would have to cease operating it within the next 18 months, with the possibility of compensation for the residual value of the investment.

Implementing this possibility of carrying out tendering procedures could indicate interested parties where storage services would be required by DSOs, thus facilitating the development of distributed storage systems. Among the many open issues to address one may find the following: what conditions should be met by DSOs for the aforementioned tendering procedures to be accepted by regulators? What is the format and procedure for the periodical consultations by the NRA? How can it be unequivocally stablished that a third-party is able to own and operate the existing BESS? In case the consultation carried out by the NRA shows that third-parties are willing to operate the BESS, how would the DSO compensation be determined and included in its remuneration?

Recommendation No. 5: Develop the necessary regulation for developing the tendering framework for testing commercial interest in the deployment of distributed storage systems

Regulation clarifying the framework for implementing the tendering procedures under Art. 36 of the EMD II should be developed. Such rules should include as well how often and in what format NRAs may carry out the periodical consultation about the potential commercial interest in existing storage assets by third-parties, or the calculation of the compensation to DSOs when they are forced to phase out BESS operation activities.

This recommendation would provide more certainty over the rules for BESS ownership, both non-FINC owned by DSOs as well as owned by third-parties, and help develop the market for storage services.

5.1.4. Lack of local flexibility procurement mechanisms

The CEP advocates for DSOs to use local flexibility whenever this is the most efficient option when compared to network reinforcement alternatives. It also defines that this procurement should be market-based preferably. However, on a national level, few countries have already defined local flexibility mechanisms or implemented large scale platforms for their procurement. Flexibility mechanisms are here understood not only as explicit flexibility procurement (e.g. activation of X kWh during a period of time), but also flexible network connections (see section 5.2.2) and network tariffs. However, on this section we focus on the explicit flexibility procurement as the other mechanisms are discussed in other sections.

A list of challenges still exist before DSOs can effectively procure local flexibility. Some have to do with the incentives for DSOs to do so, which are discussed in previous sections. Others, however, have to do with the actual definition of mechanisms, products, and market schemes.

According to the CEP, it is up to the NRAs to define which flexibility mechanisms and services are efficient and to propose services and products, possibly with a national harmonization. For that purpose, innovation projects and sandboxes may be used, as proposed in the recommendations of section 5.1.5. More specifically with regards to flexibility mechanisms, NRAs should consider that flexibility markets are yet to be developed, and possibly will not be as efficient at their infancy as they will be when mature. This maturity curve is not new in power systems and was recently dealt with by regulators when defining support schemes for renewables, for example. In that case, high subsidies were necessary when the technology's CAPEX was high, being progressively reduced to a point in which the RES technologies compete in the wholesale markets without support schemes. A similar process might be necessary when promoting flexibility markets. NRAs might have to consider that flexibility usage might not be economical at first when compared to reinforcements, but that opting for flexibility procurement could develop these markets to a point in which high competition makes this alternative more attractive in the future. In this context, NRAs can establish a period in which flexibility markets can be less cost-effective than reinforcing the grid. During this period, KPIs can be used to monitor the development of flexibility markets. As an alternative, bilateral agreements can be used at early stages of flexibility market development to foster the use of flexibility.

Recommendation No. 6: Ensure a transitory period to enable local flexibility markets to mature and coexist with bilateral agreements

In early stages, NRAs may consider that a maturity curve will exist for the development of flexibility markets. At first, flexibility procurement may be more costly than network reinforcement. However, promoting them may foster market development and decrease in flexibility costs. NRAs can establish a period in which flexibility markets can be less cost-effective than reinforcing the grid. As an alternative, bilateral agreements can be used at early stages of flexibility market development to foster the use of flexibility.

Another important mechanism to foster market development is the existence of some long-term procurement of flexibility. This type of procurement can help not only flexibility providers, but also DSOs as it decreases the long-term risk associated with using local flexibility for avoiding infrastructural developments . These products can be designed as tenders for contracted capacity to be reduced for instance. Or they can be linked to short-term flexibility markets, if those exist (e.g. mandatory participation).

Recommendation No. 7: Promote long-term flexibility procurement for grid planning

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, even when activation prices may be set in the short-term together with other flexibility sources.

5.1.5. Lack of sandbox regulation and experience with large innovation programmes

In the current context in which several regulatory adaptations are expected, NRA can be overwhelmed by the number of changes to be made and the timeline required for these changes. The CEP and the need for flexibility mechanisms call for a large definition of methodologies by NRAs. While international experience and research projects can provide important inputs, local realities may also present challenges that cannot be neglected by NRAs. Therefore, regulatory sandboxes of large innovation programmes can be a valuable tool for NRAs to accelerate the collection of inputs and promote a dialog with stakeholders.

Regulatory sandboxes can be understood as a temporal and locational exception of a set of regulatory conditions aiming at testing alternative and innovative rule and collecting inputs for future regulation. For regulatory sandboxes to be effective, it is important that a well-defined framework of rules is in place.

Firstly, the duration of the exemption must be limited. Regulatory sandboxes are usually given a duration from 2 to 4 years [6]. Longer duration can be reasonable since monitoring and evaluation of the results are essential parts of an experiment/demonstration. Secondly, the application process, the scope and eligible participants should be defined [8]. On one hand, these criteria can be left open to the initiative to the promoters, potentially leading to more innovative approaches but also leading to less harmonized process. Limiting scopes, duration schedule and eligible criteria may allow NRAs to steer sandboxes to their immediate interests and needs. Finally, it is important to consider the funding of the innovation being tested.

Additionally, it is important to notice that regulatory sandboxes are not the only option for NRAs in promoting regulatory experimentation and innovation. CEER lists four types of tools grouped into the "Dynamic Regulation Innovation Toolkit", and recommends the possibility for dynamic use of these tools, such as the sequential use of different tools for the same regulatory objective [9].

Recommendation No. 8: Develop a framework for innovation to inform new regulation

NRAs should promote innovation by exploring the "Regulation Innovation Toolkit", meaning that pilots and a sandbox framework can be used to help inform regulation (e.g. development of flexibility markets). For that, a comprehensive framework is advisable, including transparency on duration, eligibility, scope and evaluation criteria.

DSOs should be allowed to engage in innovation projects and have the necessary cost recognition over these projects. Regulatory supervision either as an ex–ante approval, an ex-post evaluation, could help NRAs to assess the objective and validity of the innovation tested. However, innovative expenditures are risky by nature, and therefore DSOs should not bear a large number of risks if the innovation project is considered appropriate. Such evaluation should be made based on a set of KPIs and/or CBA where the benefits for network users are clearly shown.

Recommendation No. 9: Explicitly allow DSOs to implement pilots and participate in sandboxes

DSOs should be explicitly allowed to implement pilots and participate in sandbox programs to test innovative smart grid functionalities and technologies. Cost recognition can be followed by 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. Nevertheless, regulation should acknowledge the innovative aspect of activities and not place all risk onto DSOs.

5.1.6. **Lack of smart meter deployment**

Smart meters are a necessary feature for the development of customer engagement, flexibility solutions, and the development of new business models. The lack of smart meter deployment may prevent, or at least impose important barriers, to the deployment of many of IElectrix HLUCs.

However, it is understood that countries may observe different realities in which general smart meter deployment may not be beneficial at the moment. Nonetheless, on-demand smart meter deployment can be facilitated by DSOs. The distribution companies should not only make the possibility available to customers, but also advertise this possibility, clearly communicating costs for the customer and benefits. 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.

Recommendation No. 10: If large-scale smart meter roll-out is not in place, facilitate on-demand deployment

Whenever a large-scale deployment is not in place, 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.

Also, one important aspect to be considered is the interoperability of smart meters and other functions and devices, now and in the future. This interoperability is desirable not only among smart meters, but also to other devices placed both in front or behind the meter. Research shows that the lack of homogeneous or standardized functionalities among smart meters prevents more sophisticated ways of flexibility procurement [10].

One option to ensure that could be to determine nationally one type/provider of smart meters for all DSOs. However, such measure could decrease competition, leading to higher deployment costs. An alternative is for MSs to specify the minimum list of functionalities, cost, cybersecurity protection and communication protocols used, for instance. In helping ensure interoperability and consideration of stakeholder needs, public consultations could be used by NRAs and DSOs to collect inputs.

Recommendation No. 11: Smart meter deployment should consider the needs of different stakeholders and ensure interoperability

The deployment of Smart Meters should consider the needs of different stakeholders and ensure interoperability in order to allow new business models.

Finally, adopting a forward-looking strategy is also desirable when defining the smart meter deployment strategy. Some countries in Europe have opted for a first and second-generation of smart meter deployment (e.g. Sweden). This strategy gives the advantage of a fast first deployment, the gain of knowledge on the technology and early engagement of customers. However, the cost of this strategy is also higher for the consumers, especially if benefits are not perceived. Alternatively, a forward-looking strategy may be able to define the necessary requirements from Smart Meters in order to avoid a short-lived deployment. Such forward-looking strategy may involve the consultation of international experience from countries that already completed deployment, consultation with stakeholders and expected changes in regulation. The latter, for example, forces countries that deployed 1 hour-resolution smart meters to redeploy them as the Network Codes called for an imbalance settlement period of 15 min.

Recommendation No. 12: Smart meter capabilities should be "future-proof"

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.

5.2. End-users, tariffs and demand response

5.2.1. Deep connection charges are a barrier for small DG

The initial cost for a new unit to connect to the grid can be split differently among DSO and customer. A deep connection charge is the one in which the customer is responsible for paying all costs derived from their connection. This includes not only the costs of cables from the meter to the connecting point, but also eventual reinforcements in the existing network, triggered by the new connections. On the other hand, a shallow connection charge is the one in which the customer is mostly except for connection costs.

These costs are paid by the DSO and then socialized with all consumers through the tariff. Intermediate approaches between deep and shallow charging may be found. These are generally referred to as shallowish connection charges.

It is important to notice that there is not a better or worse connection charge. Both approaches have advantages and disadvantages. Deep connection charges have the advantage of providing locational signals for new connections. Shallow connection charges incentivise the connection of new DER, especially new ones. It also reduces the risk of delays due to litigations over the calculation of connection charge, if not done transparently.

Therefore, 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.

Recommendation No. 13: DER grid access should be facilitated with a mix of shallower connection charges and information disclosure obligations

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 (see below).

In case of deep connection charges, it is important to disclose minimum network conditions with new DER preferably before the connection request is made. In this way, new DER can better evaluate location signals. Also, DSOs benefit from improving network condition transparency, as DER will make more informed connection requests, reducing the risk of excessive requests to congested nodes, and the consequent need for reinforcement studies by the DSO. The level of information disclosed can be differentiated by size of DER or voltage level.

Recommendation No. 14: Regulation should enhance transparency in grid connection information

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.

5.2.2. Inexistence of flexible network options

Connection agreements are often made on a firm-basis. This means that the DSO provides the customer a contracted capacity (or sometimes not even that) and the customer is able to withdraw or possibly inject that amount at any time. This type of connection agreement is the simplest to implement and easiest to be understood by customers. It is also in line with the “fit-and-forget” approach, in which the DSO sizes the reinforcements need to supply the new customers, executes the improvements in the networks and grants the firm capacity. Although this type of connection might continue the standard for most consumers, especially at LV, considering its simplicity, alternatives may be made available for different DERs that want to opt for those.

DERs can be offered connection options in which contracted capacity can be reduced under certain conditions predefined in the connection agreement. These flexible connections are already being considered in the UK, for instance [11,12]. The advantages for the DER could include a cheaper network charge and a faster connection. With a flexible connection agreement, the DSO may be able to postpone reinforcements that otherwise would be necessary to grant a firm connection. In fact, a flexible network agreement is a flexibility mechanism that achieves exactly a network reinforcement deferral by exploiting DER's flexibility (in terms of maximum capacity, in this case). It can also be seen as a long-term flexibility product, in which conditions mentioned in section 5.1.4. For instance, a flexible connection can be designed in way that the customer has firm capacity but is obliged to participate in certain short-term flexibility market sessions.

Recommendation No. 15: Flexible grid connection offers should be normalized

Flexible network access should be enabled in order to ensure an efficient network development, especially in MV and HV distribution networks. When 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. Also, flexible connection agreements can be designed in combination with other flexibility mechanisms.

5.3. Self-consumption and energy communities

5.3.1. Existence of net-metering schemes

The existence of net-metering schemes is notably harmful to the incentives for adopting certain types of DER, especially batteries, one of the main resources researched in the IElectrix project. A net-metering scheme may provide a "free battery" to other self-generators without storage. When prosumer can inject 1 MWh at a cheap hour (e.g. solar peak production at 14:00) and withdraw at an expensive hour (e.g. consumption at 20:00), this prosumer is achieving the same benefit as a battery, without the investment cost in the storage asset. In fact, the net-metering scheme can be seen as a cross subsidy support scheme for the deployment of DG, in which the other consumers pay for the benefit observed by prosumers. This support scheme was adopted in many countries as a financial incentive to prosumers at early DG development and also as a practical solution when conventional meters (no temporal resolution) were the norm. However, with the availability of smart meters, the maturity of DG in terms of costs, and the negative effects to BESS, net-metering became a counter-productive scheme considering today's goals and conditions in power systems. As a consequence, the CEP, for instance, mandated the abandonment of net-metering schemes.

Possible evolutions to the net-metering can be the net-billing or the direct participation of self-producers in wholesale markets. The former can be achieved by financially settling the energy injected or withdrawn by the hourly prices when they take place. For the mechanism to be implemented, cost-reflective electricity tariffs are necessary, differentiated by the time of use. Also, smart meters that can measure injections and withdraws with a temporal granularity are also necessary. In case a smart meter deployment was not carried out, recommendations from section 5.1.6 may apply.

Recommendation No. 16: Net-metering schemes should be avoided

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.

5.3.2. Not developed liberalized retail markets and high presence of regulated tariffs

For the purpose of incentivizing innovation on the consumers' side (e.g. LEC, flexibility provision) and new business models, it is important for customers to be exposed to cost reflective tariffs. This can be achieved by promoting the liberalized retail market or, in case regulated tariffs exist, amending the latter so that they provide efficient price signalling.

In Europe, the liberalization of retail markets is a goal set in the European regulation. The liberalized retail is expected to promote competition, increase customer's awareness and therefore bring prices down. In the liberalized retail market, customers are free to negotiate different energy prices. However, as retailers are exposed to wholesale market prices, they tend to offer better deal when prices charged to consumers also reflect the wholesale hourly market prices. Flat contracts will be also available, but usually at a premium to the consumer. In this sense, liberalized retailers tend to provide naturally an efficient price signal to consumers. However, if for other market conditions retailers do not offer such tariffs, they could be mandated to offer at least a few options for dynamic contracts in their list of alternatives. 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.

In many countries, however, there are still regulated tariffs. Also known as "last resort tariffs", these tariffs are mainly intended for situations in which the consumer does not have access to liberalized retailers. Nevertheless, many countries allow consumers to freely switch from liberalized retail market to the last resort tariffs, rendering the latter as a regulated tariff that consumers can opt for.

Therefore, in the case of regulated tariffs, these too can be designed to be cost-reflective. A Time-of-Use (ToU) tariff could already be more cost-reflective than the flat alternative. One step further is to implement a dynamic pricing tariff that reflects the cost of energy in the wholesale market. 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. An incentive (or obligation) for retailers to hedge part of their position in forward markets could also help reduce the risk of high volatility.

> **Recommendation No. 17: Dynamic pricing options should be offered to all users**
>
> 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.

5.3.3. High share of regulated costs in the electricity bill

Even if electricity prices are designed in a dynamic and, therefore, cost-reflective way, this alone does not ensure that consumers will have a strong price signal. Often the price signal coming from the electricity price is diluted by a high share of regulated charges and taxes in the electricity bill. The regulated charges are costs that are not related to energy supply or transport directly, but that are necessary for the operation of the power system (e.g. payment of certain ancillary services, costs of a regulated market operator). However, it is not uncommon for policy costs to be included in the regulated charges. The most common example is the RES support scheme costs. Although these costs are related to the power sector, they are also linked to an environmental policy, and therefore it is not clear if the electricity consumer or the taxpayer should be responsible for this charge.

If such policy costs cannot be removed from the electricity tariff, they can be allocated at the least distortive way possible. In this sense, policy costs should not be charged in a volumetric way (e.g. €/MWh consumed). Volumetric policy costs tend to give distorted incentives to consumers. Although they may promote certain types of DER, they do not do it in an efficient way. If volumetric charges are high, consumers will have an incentive to invest in technologies that reduces overall energy consumption (e.g. distributed generation, energy efficiency).

Although this is desirable, high volumetric charges also disincentivize the investment on technologies that exploit price differences in time (storage) and the necessary electrification of transport (e.g. EV) and heating (e.g. heat pumps). Hence, under high volumetric charges, consumers may over-invest in some types of DER and neglect others.

Recommendation No. 18: Regulated electricity charges should be devoid of costs unrelated to the electricity supply to the extent possible

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, since those charges are largely unrelated to consumption.

5.3.4. Uncertainty on LEC definitions, especially on topics that are left open to MSs by the CEP

As described in the IElectrix deliverable D4.4, the CEP has different definitions for the concepts of Citizen Energy Communities (CEC) and Renewable Energy Communities (REC). The concepts of CEC and REC are both defined in EU Directives, and therefore should be translated into national regulation. Therefore, MSs to define the framework for both CEC and REC.

The challenge posed by conflicting concepts in the CEP is a barrier as it puts regulators in a position of less definition from the EU regulation, possibly leading to two risks, namely, (i) delayed or incomplete national definition, and (ii) companies' exploitation of a poor or ambiguous definition in business models that distort the initial purpose of LEC.

Regulators may take more time in implementing the necessary framework or implementing a framework that at first is not complete in providing the necessary definition for the development LEC. In fact, this barrier is already observed in many countries. The concepts of CEC and REC should have already been transposed to national regulation by December 2020 and June of 2021, respectively. However, not all countries have already implemented these frameworks, and those which did, not always implemented it completely [13]. The RESCoop project corroborates with this conclusion by maintaining a tracking platform for the transposition of the CEC/REC definitions. Figure 6 presents the assessment as of August of 2022, showing that more than half of MSs have not completed a satisfactory transposition.

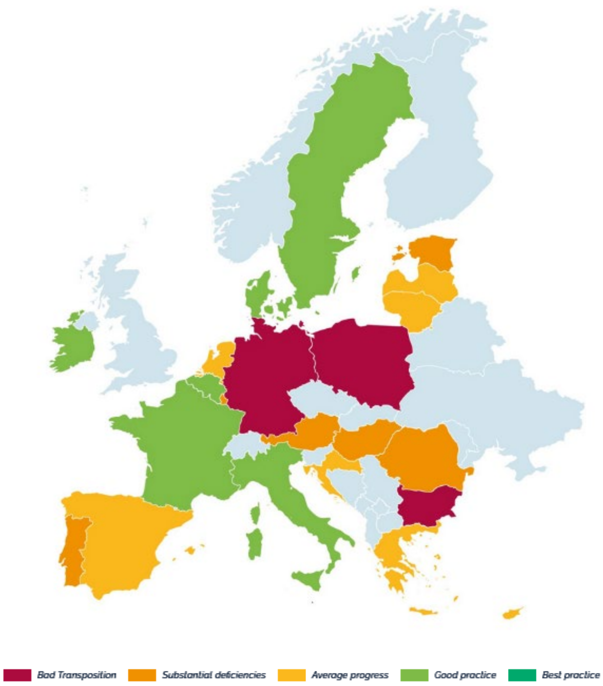


Figure 6: Transposition Tracker [of CEC and REC] by the RESCoop project. Source: [2]

Also, the way countries define and implement the CEC and REC definitions is different. The authors in [13] show that three different approaches exist. Some countries opt for complete separated definitions, others have specific provisions on the interaction between CEC and REC, while others have a hybrid definition without a clear differentiation, as illustrated in Figure 7.

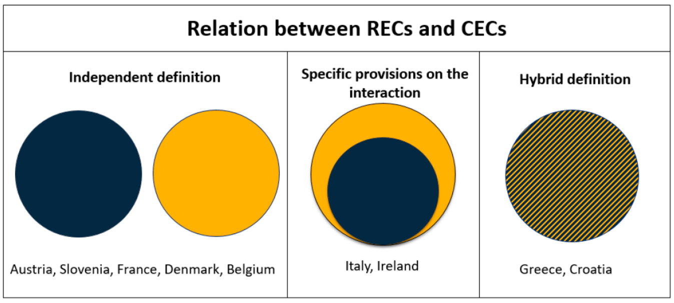


Figure 7: Relationship between RECs and CECs in different national regulatory frameworks. Source: [13]

Independently of which way the definitions are transposed into the national regulation, it is clear that not only the transposition is necessary, but also the development and publication of a comprehensive framework. Countries that successfully implemented the CEC and REC regulation often published additional rules and details that go beyond the CEP. France, for instance, published an Ordinance in 2021. At the time of writing, an Application Decree is about to be published with additional details on effective control and geographic limits [2]. Therefore, the transposition alone might not be enough to promote LECs. Details on proximity requirements, size restrictions, participation, technical requirements and possible tariffs should be included.

Recommendation No. 19: National regulation should clearly and comprehensively define RECs and CECs

When transposing the CEP, NRAs can take the opportunity to eliminate ambiguities and conflicts in the definition of REC and CEC. Also, the transposition alone might not be enough to promote LECs. Details on proximity requirements, size restrictions, participation, technical requirements, and possible tariffs should be included.

Besides the definition of concepts, MSs should also attempt to establish important aspect of LEC that are left open in the CEP. Firstly, LEC may change important role and responsibilities already in place for different stakeholders. For instance, if a LEC acts as a supplier or sell energy in markets, different rearrangement of balancing responsibilities will be necessary between the LEC, the existing suppliers/BRPs that may still provide services to the members of the LEC and the members of the LEC themselves. Also, if LEC act as a grid operator, NRAs should apply the same requirement that are used for DSOs to the LEC in order to ensure that members get the same quality of supply.

Recommendation No. 20: LEC regulatory frameworks should be consistent with the roles of existing agents

The LEC frameworks should ensure that the roles and responsibilities of the new agent are compatible and integrated with the rest of agents (e.g. suppliers, BRPs, aggregators). Also, LEC that operate the local network should comply with the same quality of supply standards as DSOs.

5.3.5. Collective self-consumption is still incipient

Collective self-consumption (CSC) can be seen as a first step towards more complex arrangements such as CEC or the REC. In fact, both the "jointly-acting customer" and the "renewables jointly-acting customer" concepts exist in the E-Directive and RES-Directive, respectively. In addition to the difference that the latter refers to renewable energy, the jointly-acting consumer definition includes the participation in "flexibility or energy efficiency schemes", which is not mentioned for "renewables jointly-acting customer". Moreover, renewable self-consumption should take place "in the same building or multi-apartment block".

The framework for collective self-consumption is simpler to implement and less ambiguous than the LEC. In fact, several countries in Europe started implementing CSC frameworks, some even before the publication of the CEP [14]. Rules for these frameworks vary. Most of them limit CSC to the same building or multi-apartment block. However, some frameworks do allow the use of public grid, under conditions (e.g. Spain).

Recommendation No. 21: Enable collective self-consumption as a step towards LEC development

In the case that a CSC framework is not in place, international experience can be consulted, as several countries have already implemented their CSC frameworks. Also, the CSC framework has the advantage of being simpler, and can potentially serve as a first step towards LEC frameworks.

As for the definitions of LECs, participants in CSC should be protected from restrictive agreements. The participation in a CSC should not limit the capacity to switch retailers or provide flexibility, for instance. Although a CSC may not require a legal entity to be formed, NRAs could provide guidelines on the necessary agreement rules in order to avoid litigations.

Recommendation No. 22: Enable LEC participants to define clear and retail market-compatible rules for energy sharing and entry/exit

Participants should be able to clearly define rules on the energy/profit sharing based on their consumption and participation on DER investments. Also, entry and exit conditions to the LEC should be clearly defined. The existence of CSC should not change the relationship and independence of consumers with respect to their energy retailers, aggregators or any other energy-related activity they may be involved with.

6. Consultation with DSOs

6.1. Survey Structure

To further analyse the above mentioned identified regulatory barriers and suggested recommendations, a survey has been conducted to receive feedback from all the DSOs involved in IElectrix project. The purpose of the survey is to evaluate each barrier's relevance and each measure's efficiency from the DSO perspective. Each question accepts 1 out of 10 responses ranging from "irrelevant/very relevant" and "not effective at all/very effective". The structure of the survey has been based on the structure of the present deliverable as illustrated below:

Barrier No#: Title

Explanation of the identified problem

How relevant/important you consider the identified barrier?

(Scale 0-10); 1: Irrelevant – 10: Very relevant; 0 N/A

> **Recommendation No#: Title**
>
> Explanation of the recommended solution
>
> *Please evaluate how effective you consider the recommended mitigation measure to address the barrier.*
>
> *(Scale 0-10); 1: Not effective at all – 10: Very effective; 0 N/A*
>
> *Other suggestions/comments*

6.2. Evaluation of the survey and results

The approach followed to evaluate the results was to gather all answers (a total of six respondents), sort the score given by each respondent and extract the average score for each barrier and relevant recommendation. For each average score a colour scale has been used to facilitate the interpretation of the results, as illustrated in Table 5.

Barriers with score 1-5

As it can be observed in Table 5, barriers **no. 11** (high share of regulated costs in the electricity bill) and **no. 13** (collective self-generation is still incipient) as well as the respective recommendations to tackle them seem to be - based on the answers - the most irrelevant ones. In particular, one of the participants commented that the recommendation no. 18 (addressing barrier no. 11), does not seem relevant from a DSO perspective.

Barriers **no. 3** (limitations to use of BESS by DSOs), and **no. 12** (uncertainty on LEC definitions, especially on topics that are left open to MSs by the CEP) seem to be neither relevant nor irrelevant rated on an average of 5 out of 10. Nevertheless, despite that the barrier no 12 is not highly relevant, the participants find both recommended solutions (national regulation should clearly and comprehensively define RECs and CECs; LEC regulatory frameworks should be consistent with the roles of existing agents) as very efficient, and it is also added that the incurred cost and the cost coverage is an additional important aspect to define/consider from a DSO point of view.

With respect to the limitations to use BESS by DSOs (barrier no. 3), it has been commented that in Hungary, DSOs have been since 2016 allowed to install and operate energy storage facilities as part of the distribution network, based on the least-cost principle. However, in recent years to fully comply with CEP provisions, the conditions have been revised and defined (e.g. approval of NRA, repeal of maximum size) which enabled the DSO to use energy storage as FINC.

The law stipulates that integrated network storage facilities can only be installed with the approval of the national regulatory authority. In case of the authorized network operators, the Hungarian Energy and Public Utility Regulatory Authority (HEPA) examines specific requirements such as the safe and reliable operation of the network or the implementation of the least-cost principle, so the assessment executed on individual basis, and if the approval is guaranteed, the asset can be implemented. Therefore, it would be recommended that the MS regulator should be given the opportunity to decide what the storage facilities can be used for, also taking into account local specificities. In addition, in India DSOs are allowed to own and operate BESS and, it is likely that the Indian government will soon require DSOs to have a minimum battery energy storage capacity.

To mitigate the mentioned barrier another recommendation would be the implementation of the tendering model under EU law. The introduction of this model on national level could give a further boost to the deployment of storage services, yet further price regulation issues may need to be addressed in the implementation process.

Barriers with score 6-10

For barriers **no. 4** and **no. 7** (lack of local flexibility procurement mechanisms; deep connection charges are a barrier for small DG) there has been a sharp division of opinions regarding the degree of relevance of each barrier. However, it is worth mentioning that between the two recommendations addressing barrier no. 7, only one of them (regulation should enhance transparency in grid connection information) is considered as very relevant, while the other one (DER grid access should be facilitated with a mix of shallower connection charges and information disclosure obligations) is not considered as relevant enough. In detail, in case of Hungary, as the regulation treats LV and MV connections differently this can result in a shift of MV demand to LV. To overcome this, it would make sense to treat uniformly DER below a certain size limit, regardless of the voltage level at which they are connected.

Participants of the survey also commented that the cost should be covered by who incurs it, yet for small renewable installations the connection charges should be fully taken by the DSO to support the development of rooftop PV installation, which it would be pertinent in big cities (as for instance Delhi).

Regarding the lack of local flexibility procurement mechanisms, it has been pointed out that the regulation is defined in principle, yet the concrete processes need to be developed. An additional recommendation to tackle the barrier would be that the long-term flexibility procurements is reviewed periodically depending on market maturity, and cost recognition is also ensured during the period (e.g., the base is an entire regulatory period and the cost incurred in the middle of it, the cost for the last 2-3 years may not be recognised, and it could have a discouraging effect).

All barriers **no. 1, 2, 5, 10** (CAPEX-Bias in incentive regulation; no binding investment plans approved or published; lack of sandbox regulation and experience with large innovation programmes; not developed liberalized retail markets and high presence of regulated tariffs) stand approximately on the same ranking (score 7-8 out of 10) and thus, all are quite relevant based on the DSOs. Nevertheless, proposing tackling the lack of approved/published binding investment plans by integrating NDPs as part of the DSO revenue determination process (recommendation no. 3) seems to be an ineffective recommendation. According to one of the respondents, the DSOs have detailed information about their network, thus direct intervention during the elaboration phase of the NDPs would not be advisable. However, it would be recommended that a dialogue with potential flexibility service providers is established during the preparation of the NDP. By doing so, the local flexibility market players can obtain information on where exactly flexibility is needed from a DSO perspective and thus, ensure that services are provided where they are needed. In addition to the NDPs, for the widespread use of local flexibility additional changes are required. The willingness of distribution system operators to take the risks necessary for the use of flexibility solutions is not favoured by the strict system of quality-of-service indicators (SAIFI, SAIDI) and the strict system of penalties for breaching them. For these solutions to become more widespread in practice, the risk-taking ability of DSOs should be increased by relaxing the rules, at least temporarily.

Last but not least, the three most important barriers based on the consultation with DSOs are barrier **no 6** (limited smart meter deployment), barrier **no 8** (inexistence of flexible network options) and barrier **no 9** (existence of net-metering schemes).

In addition to the limited smart meter deployment (barrier no. 6), respondents also pointed out the lack of data processing and highlighted that the smart metering requirements should be tailored to real market needs to ensure best value for money. Furthermore, the recommendation for “future-proof” smart meter capabilities does seem have certain limitations, given that the energy industry is changing rapidly, and the emerging needs are currently under development. In places, however, where smart metering is not so easy to deploy (e.g., Indian demo site) the chosen technology has to anticipate future requirements.

An alternative recommendation to the inexistence of flexible network options (barrier no. 8) would be offering to a MV renewable energy producer an "alternative connection offer with power modulation", also known as an "Intelligent Connection Offer" (as it is done by Enedis in France). This offer makes it possible to avoid certain connection work in exchange for one-off cuts in renewable electricity production up to a limit of 5% of the energy produced and on condition that the possibility of injecting at least 70% of the requested connection power is always guaranteed.

Table 5. Consultation with DSOs – Results classification

Barriers Recommendations	How relevant/important you consider the identified barrier? (1: Irrelevant - 10: Very Relevant; 0: N/A)	How effective you consider the recommended mitigation measure to address the barrier (1: Not effective at all - 10: Very effective; 0:N/A)
Barrier No. 1: CAPEX-Bias in incentive regulation	**6**	
Recommendation No. 1: Mitigate the CAPEX bias from DSO remuneration schemes.		6,0
Barrier No. 2: No binding investment plans approved or published	**7**	
Recommendation No. 2: NDPs should consider flexibility as part of the toolbox		7,7
Recommendation No. 3: NDPs should be an integral part of the DSO revenue determination process		2,2
Barrier No. 3: Limitations to use of BESS by DSOs	**5**	
Recommendation No. 4: Clearly define the conditions for storage assets to be considered FINCs		9,0
Recommendation No. 5: Develop the necessary regulation for developing the tendering framework for testing commercial interest in the deployment of distributed storage systems		6,2
Barrier No. 4: Lack of local flexibility procurement mechanisms	**6**	
Recommendation No. 6: Enable a transitory period to enable local flexibility markets to mature and coexist with bilateral agreements		6,7
Recommendation No. 7: Promote long-term flexibility procurement for grid planning		9,0
Barrier No. 5: Lack of sandbox regulation and experience with large innovation programmes	**8**	
Recommendation No. 8: Develop a framework for innovation to inform new regulation		8,2
Recommendation No. 9: Explicitly allow DSOs to implement pilots and participate in sandboxes		8,2
Barrier No. 6: Limited smart meter deployment	**9**	
Recommendation No. 10: If large-scale smart meter roll-out is not in place, facilitate on-demand deployment		7,8
Recommendation No. 11: Smart meter deployment should consider the needs of different stakeholders and ensure interoperability		7,3
Recommendation No. 12: Smart meter capabilities should be "future-proof"		7,2

Barrier No. 7: Deep connection charges are a barrier for small DG	**6**	
Recommendation No. 13: DER grid access should be facilitated with a mix of shallower connection charges and information disclosure obligation		5,7
Recommendation No. 14: Regulation should enhance transparency in grid connection information		8,5
Barrier No. 8: Inexistence of flexible network options	**9**	
Recommendation No. 15: Flexible grid connection offers should be normalized		9,3
Barrier No. 9: Existence of net-metering schemes	**9**	
Recommendation No. 16: Net-metering schemes should be avoided		7,5
Barrier No. 10: Not developed liberalized retail markets and high presence of regulated tariffs	**8**	
Recommendation No. 17: Dynamic pricing options should be offered to all users		8,7
Barrier No. 11: High share of regulated costs in the electricity bill	**4**	
Recommendation No. 18: Regulated electricity charges should be devoid of costs unrelated to the electricity supply to the extent possible		3,8
Barrier No. 12: Uncertainty on LCE definitions, especially on topics that are left open to MSs by the CEP	**5**	
Recommendation No. 19: National regulation should clearly and comprehensively define RECs and CECs		7,7
Recommendation No. 20: LEC regulatory frameworks should be consistent with the roles of existing agents		8,3
Barrier No. 13: Collective self-generation is still incipient	**4**	
Recommendation No. 21: Enable collective self-consumption as a step towards LEC development in the case that a CSC framework is not in place, international experience can be consulted, as several countries have already implemented their CSC frameworks.		3,8
Recommendation No. 22: Enable LEC participants to define clear and retail market-compatible rules for energy sharing and entry/exit.		3,2

7. Summary and conclusions

In this IElectrix Deliverable 4.5, regulatory recommendations are developed in order to surpass regulatory barriers identified in previous tasks of IElectrix. More specifically, the IElectrix Deliverable D4.4 had identified thirteen regulatory barriers for the large-scale deployment of the HLUCs proposed and demonstrated in the project. These regulatory barriers were identified following the assessment of the current regulatory framework in the four demonstration countries plus the three replication countries in IElectrix.

Having these thirteen barriers as a starting point, the present deliverable explored and stated possible recommendations to national regulators and policy makers on how to overcome them. The recommendation drafting process involved not only the review and research on the academic and EU stakeholders' literature, but also the developments withing the project. The SRA, the CBA and the demo results (including the KPIs calculated) provided valuable information that informed the drafting of regulatory recommendations.

In total, 22 regulatory recommendations were issued, as shown in Table 6.

Table 6: Summary of Regulatory Recommendations

<table>
<tr><th>Regulatory topic</th><th>Regulatory Driver or Barrier</th><th>Recommendation</th><th>Short Rationale</th></tr>
<tr><td rowspan="3">DSO Economic Regulation</td><td>Barrier No. 1: CAPEX-Bias in incentive regulation</td><td>Recommendation No. 1: Mitigate the CAPEX bias from DSO remuneration schemes</td><td>DSO remuneration should be neutral to the CAPEX/OPEX ratio so that DSOs may decide the least-cost long-term solution to network needs. This means that conventional approaches to determine the RAB should be revisited to equalize the incentives for reducing CAPEX and OPEX. This way, flexibility-related costs could be considered on a level playing field with investments.

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.</td></tr>
<tr><td rowspan="2">Barrier No. 2: No binding investment plans approved or published</td><td>Recommendation No. 2: Distribution NDPs should consider flexibility as part of the toolbox</td><td>DSO Network Development Plans should (i) be transparent, (ii) properly assess and demonstrates the flexibility-reinforcements costs and benefits, (iii) respects scenarios considered in other national planning documents, and (iv) DSOs should justify how comments from the consultation process modified the original NDP.</td></tr>
<tr><td>Recommendation No. 3: NDPs should be an integral part of the DSO revenue determination process</td><td>It is recommended that investment plans are used as part of the revenue determination process. Thus, their elaboration should be coordinated with price reviews.</td></tr>
<tr><td rowspan="2">New Roles for DSOs</td><td rowspan="2">Barrier No. 3: Limitations to use of BESS by DSOs</td><td>Recommendation No. 4: Clearly define the conditions for storage assets to be considered FINCs</td><td>NRAs should precisely define to which extent BESS utilization for grid support is considered to be congestion management under EU legislation – solving physical congestions caused by market clearing – and to which extent they can be considered a FINC for the only purpose of performing a reliable, efficient and secure grid operation.

Given that solving congestion and voltage problems in MV and LV grids are oftentimes intertwined and that congestion issues in these voltage levels normally have a negligible impact on wholesale markets, BESS used for these purposes may be deemed FINCs. The regulatory approval can be subject to requirements about the size of ESS in relation to the grid, the conditions for using it, or justification of economic efficiency.</td></tr>
<tr><td>Recommendation No. 5: Develop the necessary regulation for developing the tendering framework for testing commercial interest in the deployment of distributed storage systems</td><td>Regulation clarifying the framework for implementing the tendering procedures under Art. 36 of the EMD II should be developed. Such rules should include as well how often and in what format NRAs may carry out the periodical consultation about the potential commercial interest in existing storage assets by third-parties, or the calculation of the compensation to DSOs when they are forced to phase out BESS operation activities.

This recommendation would provide more certainty over the rules for BESS ownership, both non-FINC owned by DSOs as well as owned by third-parties, and help develop the market for storage services.</td></tr>
</table>

Regulatory topic	Regulatory Driver or Barrier	Recommendation	Short Rationale
	Barrier No. 4: Lack of local flexibility procurement mechanisms	*Recommendation No. 6: Ensure a transitory period to enable local flexibility markets to mature and coexist with bilateral agreements*	*In early stages, NRAs may consider that a maturity curve will exist for the development of flexibility markets. At first, flexibility procurement may be more costly than network reinforcement. However, promoting them may foster market development and decrease in flexibility costs. NRAs can establish a period in which flexibility markets can be less cost-effective than reinforcing the grid. As an alternative, bilateral agreements can be used at early stages of flexibility market development to foster the use of flexibility.*
		Recommendation No. 7: Promote long-term flexibility procurement for grid planning	*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, even when activation prices may be set in the short-term together with other flexibility sources.*
Incentives for Innovation	*Barrier No. 5: Lack of sandbox regulation and experience with large innovation programmes*	*Recommendation No. 8: Develop a framework for innovation to inform new regulation*	*NRAs should promote innovation by exploring the "Regulation Innovation Toolkit", meaning that pilots and a sandbox framework can be used to help inform regulation (e.g. development of flexibility markets). For that, a comprehensive framework is advisable, including transparency on duration, eligibility, scope and evaluation criteria.*
		Recommendation No. 9: Explicitly allow DSOs to implement pilots and participate in sandboxes	*DSOs should be explicitly allowed to implement pilots and participate in sandbox programs to test innovative smart grid functionalities and technologies. Cost recognition can be followed by 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. Nevertheless, regulation should acknowledge the innovative aspect of activities and not place all risk onto DSOs.*
Smart Metering	*Barrier No. 6: Limited smart meter deployment*	*Recommendation No. 10: If large-scale smart meter roll-out is not in place, facilitate on-demand deployment*	*Whenever a large-scale deployment is not in place, 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.*
		Recommendation No. 11: Smart meter deployment should consider the needs of different stakeholders and ensure interoperability	*The deployment of Smart Meters should consider the needs of different stakeholders and ensure interoperability in order to allow new business models.*
		Recommendation No. 12: Smart meter capabilities should be "future-proof"	*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.*
Network access and connection	*Barrier No. 7: Deep connection charges are a barrier for small DG*	*Recommendation No. 13: DER grid access should be facilitated with a mix of shallower connection charges and information disclosure obligations*	*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 (see below).*
		Recommendation No. 14: Regulation should enhance transparency in grid connection information	*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.*

Regulatory topic	Regulatory Driver or Barrier	Recommendation	Short Rationale
	Barrier No. 8: Inexistence of flexible network options	*Recommendation No. 15: Flexible grid connection offers should be normalized*	*Flexible network access should be enabled in order to ensure an efficient network development, especially in MV and HV distribution networks. When 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. Also, flexible connection agreements can be designed in combination with other flexibility mechanisms.*
Self-generation rules	*Barrier No. 9: Existence of net-metering schemes*	*Recommendation No. 16: Net-metering schemes should be avoided*	*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.*
Retail markets and prices for end-customers	*Barrier No. 10: Not developed liberalized retail markets and high presence of regulated tariffs*	*Recommendation No. 17: Dynamic pricing options should be offered to all users*	*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.*
	Barrier No. 11: High share of regulated costs in the electricity bill	*Recommendation No. 18: Regulated electricity charges should be devoid of costs unrelated to the electricity supply to the extent possible*	*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, since those charges are largely unrelated to consumption.*
Energy Communities	*Barrier No. 12: Uncertainty on LCE definitions, especially on topics that are left open to MSs by the CEP*	*Recommendation No. 19: National regulation should clearly and comprehensively define RECs and CECs*	*When transposing the CEP, NRAs can take the opportunity to eliminate ambiguities and conflicts in the definition of REC and CEC. Also, the transposition alone might not be enough to promote LECs. Details on proximity requirements, size restrictions, participation, technical requirements, and possible tariffs should be included.*
		Recommendation No. 20: LEC regulatory frameworks should be consistent with the roles of existing agents	*The LEC frameworks should ensure that the roles and responsibilities of the new agent are compatible and integrated with the rest of agents (e.g. suppliers, BRPs, aggregators). Also, LEC that operate the local network should comply with the same quality of supply standards as DSOs.*
	Barrier No. 13: Collective self-generation is still incipient	*Recommendation No. 21: Enable collective self-consumption as a step towards LEC development*	*In the case that a CSC framework is not in place, international experience can be consulted, as several countries have already implemented their CSC frameworks. Also, the CSC framework has the advantage of being simpler, and can potentially serve as a first step towards LEC frameworks.*
		Recommendation No. 22: Enable LEC participants to define clear and retail market-compatible rules for energy sharing and entry/exit	*Participants should be able to clearly define rules on the energy/profit sharing based on their consumption and participation on DER investments. Also, entry and exit conditions to the LEC should be clearly defined. The existence of CSC should not change the relationship and independence of consumers with respect to their energy retailers, aggregators or any other energy-related activity they may be involved with.*

The 22 recommendations issued, however, may not have equal relevance in all seven countries analysed. For example, the lack of deployment of smart meters may be an issue in India, Hungary, Austria and Greece, but not in Germany, France and Sweden (as per the information in D4.4). Therefore, barriers 10, 11, and 12 would not be as relevant for the 3 latter countries. Moreover, within countries that face the same barrier, different recommendations may have a lower or higher priority.

In order to shed light on the priority of recommendations, a consultation with the DSOs of the IElectrix consortium was conducted. First, the participants were asked on how important the barrier was, in their view, for the successful large-scale implementation of the IElectrix project solutions as a whole. Second, they were asked how relevant the 22 recommendations issued are.

Based on the answers obtained (detailed in Chapter 6), a prioritization of recommendations is calculated. The average of “barrier importance” is multiplied by the “effectiveness of each recommendation”, resulting on the prioritization index. Recommendations are then ranked according to their priority index, presented in Table 7.

It is worth mentioning that this prioritization is done from the DSO’s perspective, as only this type of stakeholder was consulted. Therefore, some barriers and/or recommendations could have a lower relevance to this type of stakeholder, but a higher importance to other stakeholder that could be directly facing the regulatory barrier in question (e.g. collective self-consumption). For most cases, a correlation can be seen between the rating of the barrier and the rating of the recommendation. In some specific cases though this pattern is not observed. This is the case for the lack of binding investment plan (barrier no. 2; rating 7) and the recommendation that NDPs should be part of the DSO revenue determination process (recommendation no. 3; rating 2.2). In this case, the potential uncertainty perceived within the recommendation may cause a higher aversion, as it can significantly impact the revenue of the DSO depending on its implementation. Conversely, the evaluation that FINC BESS should be clearly defined (recommendation no. 4; rating 9.0) is considerably higher than the barrier that BESS usage is limited to DSOs (barrier no. 3; rating 5). In this case, it is important to consider that some countries may not have clear limitation to the use of BESS by DSOs, but do not have a solid framework either, creating a situation of uncertainty and possibly inaction by the DSO, in which a precise definition would be beneficial.

Despite the abovementioned limitations, most barriers and recommendations do affect the DSOs directly and indirectly. In addition, DSOs consulted are those involved in the demonstrations and therefore they have global view of difficulties faced in the implementation of the HLUCs including those reported by other stakeholders. For these reasons, the consultation conducted can serve as a guideline for the prioritization of regulatory recommendations, particularly those more directly related to network regulation.

Table 7: Prioritization of regulatory recommendations according to DSO consultation

Recommendations	Barrier	Barrier Rating	Recomm. Rating	Prioritization Score
Recommendation No. 15: Flexible grid connection offers should be normalized	Barrier No. 8: Inexistence of flexible network options	9	9.3	83.7
Recommendation No. 10: If large-scale smart meter roll-out is not in place, facilitate on-demand deployment	Barrier No. 6: Limited smart meter deployment	9	7.8	70.2
Recommendation No. 17: Dynamic pricing options should be offered to all users	Barrier No. 10: Not developed liberalized retail markets and high presence of regulated tariffs	8	8.7	69.6
Recommendation No. 16: Net-metering schemes should be avoided	Barrier No. 9: Existence of net-metering schemes	9	7.5	67.5
Recommendation No. 11: Smart meter deployment should consider the needs of different stakeholders and ensure interoperability	Barrier No. 6: Limited smart meter deployment	9	7.3	65.7
Recommendation No. 8: Develop a framework for innovation to inform new regulation	Barrier No. 5: Lack of sandbox regulation and experience with large innovation programmes	8	8.2	65.6
Recommendation No. 9: Explicitly allow DSOs to implement pilots and participate in sandboxes	Barrier No. 5: Lack of sandbox regulation and experience with large innovation programmes	8	8.2	65.6

Recommendation No. 12: Smart meter capabilities should be "future-proof"	Barrier No. 6: Limited smart meter deployment	9	7.2	64.8
Recommendation No. 7: Promote long-term flexibility procurement for grid planning	Barrier No. 4: Lack of local flexibility procurement mechanisms	6	9.0	54.0
Recommendation No. 2: NDPs should consider flexibility as part of the toolbox	Barrier No. 2: No binding investment plans approved or published	7	7.7	53.9
Recommendation No. 14: Regulation should enhance transparency in grid connection information	Barrier No. 7: Deep connection charges are a barrier for small DG	6	8.5	51.0
Recommendation No. 4: Clearly define the conditions for storage assets to be considered FINCs	Barrier No. 3: Limitations to use of BESS by DSOs	5	9.0	45.0
Recommendation No. 20: LEC regulatory frameworks should be consistent with the roles of existing agents	Barrier No. 12: Uncertainty on LEC definitions, especially on topics that are left open to MSs by the CEP	5	8.3	41.5
Recommendation No. 6: Enable a transitory period to enable local flexibility markets to mature and coexist with bilateral agreements	Barrier No. 4: Lack of local flexibility procurement mechanisms	6	6.7	40.2
Recommendation No. 19: National regulation should clearly and comprehensively define RECs and CECs	Barrier No. 12: Uncertainty on LEC definitions, especially on topics that are left open to MSs by the CEP	5	7.7	38.5
Recommendation No. 1: Mitigate the CAPEX bias from DSO remuneration schemes.	Barrier No. 1: CAPEX-Bias in incentive regulation	6	6.0	36.0
Recommendation No. 13: DER grid access should be facilitated with a mix of shallower connection charges and information disclosure obligation	Barrier No. 7: Deep connection charges are a barrier for small DG	6	5.7	34.2
Recommendation No. 5: Develop the necessary regulation for developing the tendering framework for testing commercial interest in the deployment of distributed storage systems	Barrier No. 3: Limitations to use of BESS by DSOs	5	6.2	31.0
Recommendation No. 3: NDPs should be an integral part of the DSO revenue determination process	Barrier No. 2: No binding investment plans approved or published	7	2.2	15.4
Recommendation No. 18: Regulated electricity charges should be devoid of costs unrelated to the electricity supply to the extent possible	Barrier No. 11: High share of regulated costs in the electricity bill	4	3.8	15.2
Recommendation No. 21: Enable collective self-consumption as a step towards LEC.	Barrier No. 13: Collective self-generation is still incipient	4	3.8	15.2
Recommendation No. 22: Enable LEC participants to define rules for energy sharing and entry/exit.	Barrier No. 13: Collective self-generation is still incipient	4	3.2	12.8