gD3.5 Scalability and replicability rules

Scaling up and replication rules of the GRID4EU demonstrations as inferred from the SRA studies

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Executive summary

The present document constitutes deliverable gD3.5 and presents the final results of the scalability and replicability analysis (SRA) of the use cases of the GRID4EU project. The aim of GRID4EU SRA is to learn from the smart grid solutions tested in the Demonstrators and evaluate the implications of their implementation at a larger scale or in a different context. The SRA carried out has identified the most favourable conditions and potential barriers and has assessed the effect of the boundary conditions for the implementation of GRID4EU use cases. These boundary conditions comprise technical, economic, regulatory and stakeholder-related issues.

The work presented herein builds on the methodological developments presented in previous deliverables, namely gD3.1 and gD3.2/gD3.3 and the simulation-based technical SRA described in detail in deliverable gD3.4. This report presents the major results obtained from the technical SRA as well as the generalization SRA rules that can be derived from these results, placing a strong emphasis on comparisons across use cases with similar goals. SRA rules may allow DSOs to perform a preliminary assessment of the expected results of the adoption of a specific smart grid solution or allow decision-makers to make better informed decisions on roll-out plans. Additionally, the lessons learnt when developing and applying a SRA methodology can help future researchers when performing similar analyses.

The SRA comprises two main stages, namely, a technical analysis and a general analysis focused on the non-technical boundary conditions, which include regulation and the perspectives of the different stakeholders involved.

Technical SRA relies on simulation using representative[1] networks to compute the Key Performance Indicators (KPIs). According to the pursued objectives, use cases were grouped into three categories: (i) use cases aimed at improving continuity of supply through the implementation of automation, (ii) use cases that aim to achieve a more efficient integration of DER, and (iii) use cases to enable islanded operation of a section of the distribution network.

In addition to the technical results, on a more qualitative level, the influence of non-technical boundary conditions related to regulation and stakeholders' perspectives is evaluated in this report. Thus, this document discusses the drivers and barriers that these boundary conditions may pose to DSOs for the implementation of GRID4EU use cases.

[1] The selected networks are relevant and complementary for the tested use cases, but do not constitute a fully exhaustive set and no representativity rates are assigned to each network within each DSO or demo country.

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1 Introduction and scope of the document

1.1 Scope of the Document

The present document, numbered as gD3.5, presents the final results of the SRA carried out within the GRID4EU project. The work presented herein builds on previous deliverables, namely gD3.1 and gD3.2/gD3.3, which presented the general SRA methodology and the more specific technical SRA methodology applicable to each type of use case respectively.

As described in the aforementioned deliverables, the proposed methodological approach is focused on the expected impact of the implementation of different smart grid solutions on relevant KPIs rather than on the technological aspects of communications, information systems or measurement devices; which are oftentimes only accessible to developers and manufacturers. Therefore, the results presented could be useful to anyone willing to adopt or assess a similar solution, e.g. MV automation to improve reliability levels, irrespective of the specific hardware installed by the GRID4EU DSOs.

In this approach, a simulation-based technical SRA, which allows quantifying the values of KPIs under different conditions, constitutes the cornerstone of the analyses. Notwithstanding, non-technical boundary conditions can have a great impact on the success of several innovative solutions. On the one hand, the monopolistic nature of power distribution requires that any change in the planning and operational practices of DSOs is accompanied by regulatory mechanisms and incentives consistent with the new environment. Therefore, current regulatory frameworks ought to be evaluated so that potential barriers may be identified and alternatives proposed. On the other hand, active network management frequently requires a more active behaviour of distribution network users and their interaction with DSOs. At the same time, transformation processes always affect a wider range of stakeholders comprising, among others, manufacturers, end-consumers, DSO employees, etc. Thus, the expectation and perspectives may also need to be considered within such a framework.

Considering all of the above, this report presents the major results obtained from the technical SRA as well as the generalization SRA rules that can be derived from these results, placing a strong emphasis on comparisons across use cases with similar goals. Due to confidentiality reasons, technical data is presented in an anonymized way, so that an unequivocal relation, for instance, between a specific representative network and a participating DSO cannot be made. In spite of this shortcoming, this approach allowed the publication of these technical parameters which are essential to understand the technical SRA results. In addition to the technical results, on a more qualitative level, the influence of non-technical boundary conditions related to regulation and stakeholders' perspectives is evaluated in this report. Finally, a recap of SRA rules and lessons learnt is provided.

The final results provided in this deliverable intend to be twofold. On the one hand, SRA rules may allow DSOs to perform a preliminary assessment of the expected results of the adoption of a specific smart grid solution or allow decision-makers to make better informed decisions on roll-out plans. On the other hand, the lessons learnt when developing and applying a SRA methodology can help future researchers when performing similar analyses.

1.2 Structure of the Document

After this introductory section, the remainder of this report is organized as follows. Section 2 provides a brief recapitulation of the approach and methodology developed within the project to perform the SRA. Section 3 presents a summary of the main simulations results obtained for the different use cases tested within the project as well as the technical SRA rules that may be inferred from them. Section 4 addresses the non-technical boundary conditions related to regulation and the perspectives of stakeholders that may act as enablers or barriers to the successful scaling-up and replication of smart grid solutions. Finally, section 5 summarizes the major SRA rules identified that may support prospective adopters of similar smart grid solutions, as well as the lessons learnt from the overall analysis that may guide anyone willing to perform SRA studies.

1.3 Notations, abbreviations and acronyms

ACER	Agency for the Cooperation of Energy Regulators
AD	Active Demand
AMI	Advanced metering Infrastructure
ASIDI	Average System Interruption Duration Index
ASIFI	Average System Interruption Frequency Index
AGR	Automatic Grid Recovery
BESS	Battery Energy Storage System
CAPEX	Capital Expenditures
CBA	Cost-Benefit Analysis
CEER	Council of European Energy Regulators
DER	Distributed Energy Resources
DG	Distributed Generation
DSO	Distribution System Operator
ENS	Energy Non Supplied
EU	European Union
gD	General Deliverable
GWP	General Work Package
HC	Hosting Capacity (for DG)
HV	High Voltage
IED	Intelligent Electronic Device
KPI	Key performance indicator
LV	Low Voltage
MV	Medium Voltage
NEM	Network Energy Manager (Demo 6)
NIEPI	Número de Interrupciones Equivalente de la Potencia Instalada
NPAM	Network Performance Assessment Model

NRA	National Regulatory Authority
OLTC	On-Load Tap Changer
OPEX	Operation Expenditures
PV	Photovoltaics
RAB	Regulatory Asset Base
RNM	Reference Network Model
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SGCG	Smart Grid Coordination Group
SGAM	Smart Grid Architecture Model
SoC	State of Charge (battery)
SRA	Scalability and Replicability Analysis
TIEPI	Tiempo de Interrupción Equivalente de la Potencia Instalada
TOTEX	Total Expenditures
UoS	Use of System (charges)
WACC	Weighted Average Cost of Capital

Table 1: Acronyms

2 SRA methodology and its application to GRID4EU use cases

The proposed SRA methodology intends to evaluate the potential impact of the implementation of a specific smart grid solution under varying boundary conditions and scales, through a combination of quantitative and qualitative analyses. For the sake of generality, specific technological aspects are intentionally neglected. Thus, as far as SRA is concerned in this report and unless stated otherwise, the appropriate functioning of software and hardware solutions involved is taken for granted.

Note that, at the current stage, some technologies may be experimental (prototypes), selected based on subjective reasons (a DSO having further experience with a certain communication technology, or a partnership with a specific supplier) or partially confidential (proprietary protocols, etc.). Therefore, this report will address questions concerning what smart grid solution to implement under what conditions as well as what non-technical barriers may be encountered. However, the answers to technology selection questions may be found in the results of the demonstration activities carried out within GRID4EU.

2.1 SRA methodology

The scalability and replicability potential will be assessed following the methodology displayed in Figure 1. It can be seen that a simulation-based technical analysis plays a key role to quantify the impact of smart grid solutions under different boundary conditions measured through a set of KPIs, specific to each use case. Nonetheless, a qualitiative analysis is required to incorporate additional boundary conditions that can greatly determine the implementation and outcomes of a smart grid use case. Among these, regulatory and stakeholders' perspectives aspects are particularly relevant.

This SRA methodology will be applied to carry out a process in accordance with the different dimensions of scalability and replicability that have been identified, namely:

Scaling-up in density: evaluates the effect within a given network or distribution area of a certain smart grid solution under different degrees of implementation (e.g. level of MV automation, number of DG units responding to DSO commands, amount of controllable demand in the area).

Scaling-up in size: evaluates the effect of implementing a smart grid solution in all the DSO distribution areas or even at country level to establish guidelines regarding its feasibility and advisability. The different types of distribution areas (rural, urban, etc.) need to be considered.

Intra-national replicability: evaluates the effect of implementing a smart grid solution in different types of distribution area within the same country or region. In this case, technical boundary conditions will change significantly whereas the regulatory and stakeholders' boundary conditions are likely to remain the same or very similar.

International replicability: evaluates the effect of implementing a smart grid solution in a different region or country, thus being affected all boundary conditions.

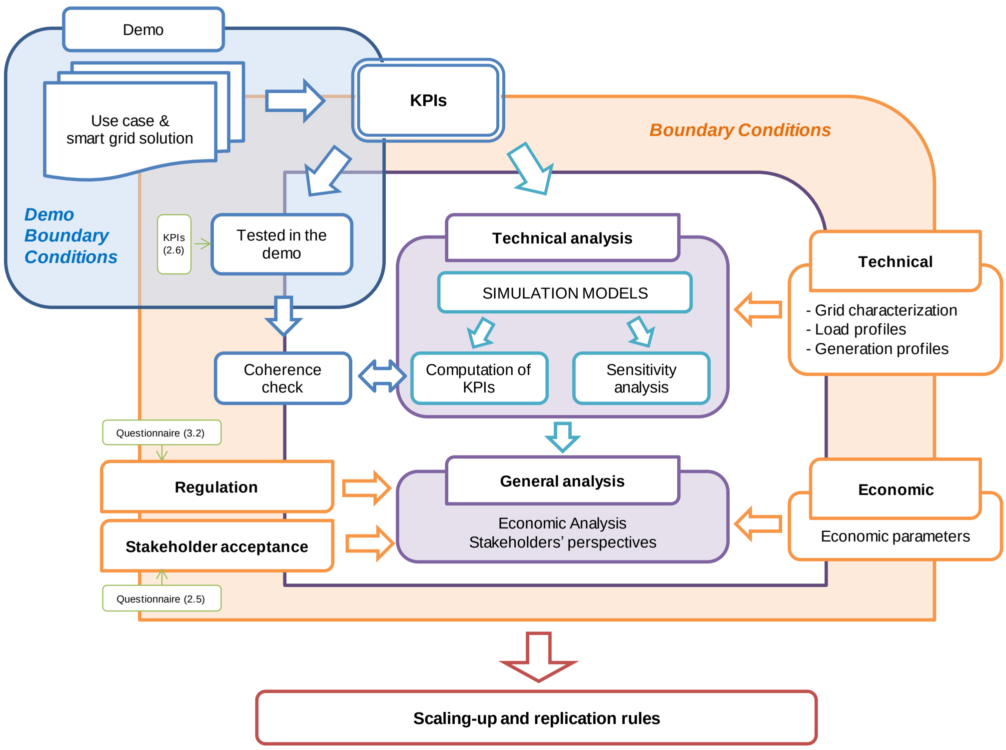

Figure 1: SRA general methodology

The overall approach to perform the technical SRA is shown in Figure 2. Nonetheless, the choice of simulation model, set of KPIs and parameters to which sensitivities have to be performed needs to be adapted for each use case. This selection is mainly driven by the characteristics and goals pursued by the use case being analysed. For instance, power flow studies will be required to evaluate voltage control strategies aimed at increasing network hosting capacity whereas time-domain simulation models will be required to analyse use cases related to the islanded operation of part of the distribution network.

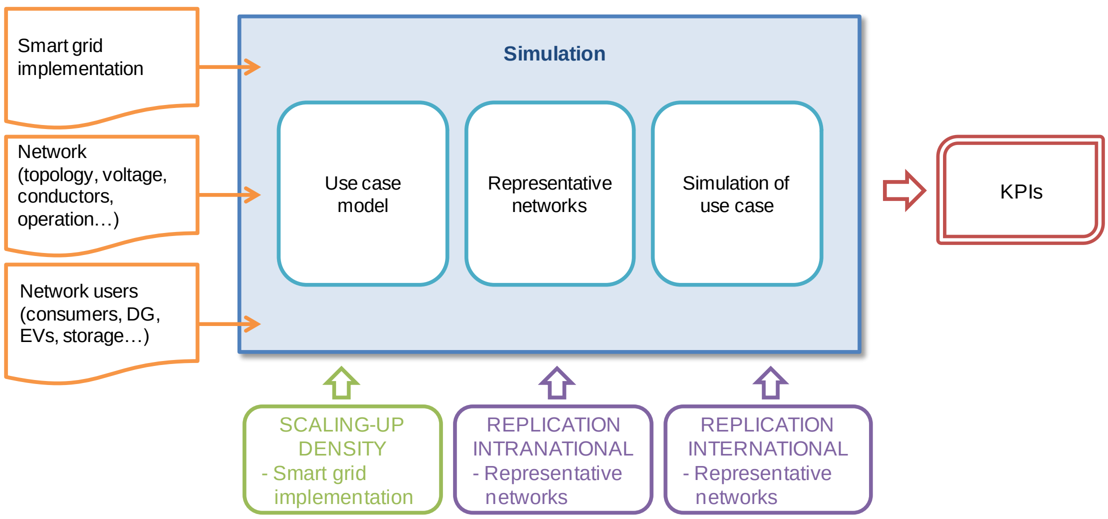

Figure 2: Methodology for technical SRA of smart grid use cases

Performing simulations on the overall distribution network of a DSO or a country would be infeasible due to the huge number of individual network buses and components. Therefore, in most cases[2], a set of representative networks is necessary in order to adequately capture the effect of implementing a use case in different types of distribution areas. Each representative network should reflect the characteristics and conditions of a different type of distribution area. In this regard, it is important to highlight the difference between a test network and a representative network. A test network is intended to serve as an example or case study for a given study and can therefore be constructed on its own. However, a set of representative networks can only be understood as a group where each member complements each other and which ought to be evaluated as a whole. Moreover, representative networks are necessarily linked to a specific set of parameters (load density, degree of undergrounding, configuration, etc.) that differ among each other. Ideally, these representative network could be built by performing clustering analysis from detailed aggregate information on the distribution grids at DSO or country level; see, for instance, (Kawahara et al. 2004; Levi et al. 2005; Schneider et al. 2008). However, data availability regarding distribution grids characteristics and distribution network users (mainly end consumers and DG units) normally hampers such an approach. Consequently, simpler approaches are usually followed at the expense of limited representativity. The approach followed for all technical SRA analysis in GRID4EU, based on different network models built according to data provided by Demo leaders to represent their boundary conditions as much as possible, was presented in gD3.2/gD3.3, and is summarized in the following sub-section.

2.2 Application to GRID4EU use cases

As a preliminary step, the initial list of use cases developed by the participating DSO was reduced in order to consider only those use cases with an immediate effect of measurable KPIs. This was deemed reasonable as several of the use cases defined at the beginning of the project served mainly as enablers for other functionalities. Moreover, these use cases were classified according to their characteristics and goals (similar KPIs) so that SRA was conducted in such a way that similar solutions could be compared among them. This classification is particularly relevant for the technical simulation-based analyses. Note that regulatory and other non-technical barriers may not fit perfectly these groups, thus an alternative approach will be followed in section 4.

The resulting categorization is presented in Table 2. It can be seen that three major groups were identified according to their goals:

Firstly, several use cases aimed to improve reliability levels through enhanced MV monitoring and automation (this solution was implemented at the LV level as well in one case). The most relevant KPIs that allow measuring the impact of these use cases are reliability indices, such as SAIDI and SAIFI, or ASIDI and ASIFI. These indicators will be computed under different scenarios through a Matlab script simulating the fault location and restoration process.

A second set of use cases are oriented towards increasing network hosting capacity for DG by controlling voltages, demand response or grid reconfiguration so as to prevent overloads and overvoltages. In this regard, the central KPI is the increase in network hosting capacity that is achieved, although some other intermediate KPIs such as voltage profiles or load shedding will be quantified. The scenarios will be simulated through power flow calculations.

The last group of use cases are related to the islanded operation of part of the distribution grid,

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[2] Islanding use cases, for instance, do not require a detailed network model since the focus is placed on very short-term balance of active and reactive power. Thus, local load-generation balance and controllers design are the key factors. This will be further discussed in section 3.3.

either intentionally or not. Dynamic simulations have been carried out in Simulink (Matlab) to measure voltage and frequency deviation in the islanded area to determine whether these are within the limits that allow a successful islanded operation or allow preventing an unintentional island formation. Some additional indicators will be measure in some cases such as the volume of load shedding required for a successful islanding.

Group	Use Case
Reliability improvement	Demo 1 - Failure management in MV Demo 3 - Automatic grid recovery (AGR) Demo 5 - Failure management in MV Demo 5 - Failure management in LV
Voltage/load control to increase network hosting capacity	Demo 1 - Decentralized grid operation in MV networks Demo 2 - LV Network Monitoring and Control Demo 4 - Voltage regulation in MV Demo 6 - Maximize PV production in LV
Islanding operation/anti-islanding protection	Demo 4 - Anti-islanding protection Demo 5 - Automated islanded operation Demo 6 - Islanding

Table 2: Categorization of GRID4EU use cases for technical SRA

Once the use cases had been categorized, the relevant KPIs identified and the approach to evaluate the value of these indicators under varying conditions determined; it was necessary to define what parameters were the most relevant for each use case. These parameters are the ones with respect to which sensitivity analyses should be performed in the simulations since they are the ones which explain the variations in the values of the KPIs obtained. A summarized cross list of relevant technical parameters and use cases is shown in Table 3. Therein, it can be seen that technical parameters can be related to the network characteristics themselves, to the distribution network users (mainly DG and consumers) and also to the type of smart grid solution being evaluated and its degree of implementation.

The aforementioned table allows identifying at a glance the differences and similarities across use cases. For instance, all use cases aiming at achieving a reliability improvement require paying attention to exactly the same values and mainly differentiate in the implementation details of the solution (e.g. centralized vs. local control, or degree of automation). However, the use cases whose goal is to increase network hosting capacity may resort to different control variables to achieve the same goal. For instance, in demo 1, the increase in HC is to be attained through network automation and reconfiguration, thus re-distributing the loading level across neighbouring feeders. On the contrary, in demo 4, the same goal is pursued through voltage control with OLTC, network storage or DG power factor control.

			USE CASES										
			Increasing HC through voltage/load control				**Improving reliability through automation**				**Islanded operation**		
			Demo 1 - Load control in MV	Demo 2 - LV Network Monitoring & Control	Demo 4 - Voltage regulation in MV	Demo 6 - Maximize PV production in LV	Demo 1 - Failure management in MV	Demo 3 - Automatic grid recovery (AGR)	Demo 5 - Failure management in MV	Demo 5 - Failure management in LV	Demo 4 - Anti-islanding protection	Demo 5 - Automated islanded operation	Demo 6 - Islanding
Network	Voltage level		x	x	x	x					x	x	x
	Conductors	Overhead/underground, section, material, length	x	x	x	x							
	Architecture	Type of area (urban/rural)	x	x	x	x	x	x	x	x			
	Network topology	Meshing degree, connection of secondary substations	x				x	x	x	x			
	Reliability level	Failure rate, length of feeder, reliability level					x	x	x	x			
Demand	Number of consumers, installed capacity	Distribution of demand	x	x	x	x	x	x	x	x			
	Contracted power/peak demand	Size and type of consumers (residential/industrial/…)	x	x	x	x					x	x	x
	Load scenarios	Period of the year, type of consumers	x	x	x	x					x	x	x
DG	Penetration degree	Distribution of DG (size and location)	x	x	x	x					x	x	x
	Generation scenarios	DG technology, season	x	x	x	x					x	x	x
Use Case Implementation	Automation scenarios	Telecontrol	x				x	x	x	x			
		Monitoring (fault-pass detection)	x	x			x	x	x	x			
		Centralized/local control system	x				x	x	x	x			
		Reconfiguration	x				x	x	x	x			
	Control system	Dynamics of controlling unit (DG/storage)										x	x
		Flexible demand										x	x
		Load-shedding mechanism, protections									x	x	x
	OLTC				x								
	Network storage	Location and size of storage			x	x							
	DG reactive power				x								
	Prosumer	Storage				x							
		Demand response				x							

Table 3: Mapping technical parameters to use cases (x denotes relevance)

Last but not least, as mentioned above, representative networks needed to be built. These networks should describe the behavior of a set or cluster of real distribution feeders. Within the project, a limited set of networks has been considered to represent as much as possible all analyzed countries for the considered use cases due to the lack of publicly available data and confidentiality barriers. The number of representative networks taken into account in each case has been determined in collaboration with the corresponding Demo leader. This number typically varies between two and four networks per country and voltage level; MV and LV grids were developed independently since use cases normally address one of these voltage levels. The main criteria followed was to capture areas with different load density, as regulation usually already defines these areas in order to define area-dependent continuity of supply incentives. Furthermore, the representative networks built do not constitute a fully exhaustive set and no representativity rates are assigned to each network within each DSO or demo country.

Besides representativity, relatively simple networks were deemed desirable in order to enable running a large number of simulation scenarios for sensitivity analysis. Thus, networks comprising between 3 and 5 feeders outgoing of a substation (or several substations in the case of MV grids so as to represent possible transfer of load between substations) were deemed sufficient to capture the complexities of distribution grids for the purpose of technical analysis for the SRA of the impact of the use cases studied, whilst ensuring a manageable amount of data.

Depending on the country, two main approaches have been followed. On the one hand, representative networks may be based on aggregate data for the area operated by the DSO or a specific region comprising load density, average feeder length, characteristics of network components, etc. On the other hand, some DSOs directly suggested a few actual grids to be used as representative of their overall distribution area. Since the degree of representativity of these networks will be inevitably limited, sensitivity analyses to some network characteristics will be used as means to capture a wider range of alternatives. Furthermore, the choice of representative networks for technical analysis has been linked to the tested use cases. The main characteristics of the different representative networks considered for the technical SRA will be provided in the corresponding sections.

Table 4 presents a first set of parameters to characterize distribution in the Demo countries, according to the information monitored and published by the CEER. Some other parameters are more specific and may vary for different areas within countries, especially in regions operated by different DSOs. Table 5 presents a second set of parameters based on the information provided by the Demos used to build the representative networks for simulation. Due to the confidentiality of the parameters related to the topology and loading of the MV grid, their actual values cannot be shown in Table 5. Instead, it has been necessary to follow a more qualitative approach. For each parameter, the average of the values corresponding to each of the six columns has been computed and used as a reference, so that actual values have been substituted by the labels “below average”, “average” and “above average”. It must be borne in mind however, that the data for each column corresponds to a different scope, according to the first row of Table 5 itself, so that this categorization does not correspond to a comparison among countries. The non-homogeneity of the data must be taken into account when interpreting the different columns corresponding to the different demos.

		DEMO 1 Germany	DEMO 2 Sweden	DEMO 3 Spain	DEMO 4 Italy	DEMO 5 Czech Republic	DEMO 6 France
Voltage levels[3]		10kV	10 / 20kV	11 / 15 / 20 / 30kV	10 / 15 / 20kV	22 / 35kV (6 /10kV past)	10 / 20kV
Voltage limits		±10%	±10%	±7%	±10%	±10%	±5%
Continuity of supply levels	**SAIDI**[4]	15,4	93,9	58,2	45,6	107,8	58,5
	SAIFI[3]	0,3	1,6	1,6	1,7	1,7	0,9
Continuity of supply monitored by regulation		SAIDI (LV), ASIDI (MV), SAIFI	SAIDI, SAIFI	TIEPI, NIEPI (≈ ASIDI, ASIFI)	SAIDI, SAIFI	SAIFI, SAIDI, CAIDI	SAIFI, SAIDI

Table 4: General characteristics of MV distribution networks in Demo countries.

[3] The underlined values correspond to the voltage levels of the MV representative networks for SRA.
[4] Average of annual SAIDI and SAIFI indices due to unplanned interruptions (t>3min), excluding exceptional events, for years 2010, 2011 and 2012. Source: CEER Benchmarking Report [2].

		DEMO 1 Germany	DEMO 2 Sweden	DEMO 3 Spain	DEMO 4 Italy	DEMO 5 Czech Republic	DEMO 6 France
Scope of information provided by DSOs used to characterize MV networks and build set of representative networks for technical SRA		General data based on the North-West region and also for three representative networks (1-2 HV/MV subst and 6-30 feeders each)	Data based on one representative urban network (1 feeder)	Data based on networks in the whole country	Data based on the Forli-Cesena province	Data based on two representative networks (1 feeder each) for the part of the country operated by CEZ Distribuce	Data based on four real networks representative of the tested use cases (2 HV/MV subst and 4-6 feeders each)
Representative networks built for SRA[5]		3 MV networks (U, SU, R)	2 MV networks (U, R) 2 LV networks (R, RI)	3 MV networks (U, SU, R)	3 MV networks (U, SU, R)	2 MV networks (U, R) 2 LV networks (U, R)	4 MV networks (U, SU, RC, RS) 4 LV networks (U, SU, RU, RO)
Feeder length	**Urban**	below average	n/a	average	average	above average	above average
	Rural	below average	average	above average	average	above average	average
Density of load (number of subst/feeder)	**Urban**	average	n/a	average	average	above average	below average
	Rural	average	above average	average	below average	above average	below average
Density of load (number of cons/subst)	**Urban**	below average	n/a	average	below average	above average	below average
	Rural	below average	above average	average	below average	above average	below average
Density of load (inst capacity/feeder)	**Urban**	average	n/a	above average	below average	above average	below average
	Rural	average	below average	above average	below average	above average	below average
Meshing and interconnection degree	**Urban**	above average	n/a	average	average	average	average
	Rural	average	above average	below average	average	above average	above average
Automation degree	**Urban**	average	n/a	average	above average		
	Rural	average	above average	below average	above average		
Undergrounding level	**Urban**	average	average	average	below average	average	average
	Rural	above average	average	above average	below average	below average	below average

Table 5: Specific characteristics of MV distribution networks and set of representative networks for technical SRA.

[5] U: Urban, SU: Sub-urban, R: Rural, RC: Rural Concentrated, RS: Rural Scattered, RU: Rural Underground, RC: Rural Overhead

3 Technical SRA: Simulation based rules

3.1 Improving reliability through network automation

3.1.1 Technical analysis for SRA

These automation use cases implement smart grid solutions based for fault detection and remote control of switching elements, which help improve the process of failure management and service restoration. The objective is to improve continuity of supply, reducing both the amount of consumers affected by supply interruptions and the duration of these interruptions. Therefore, the main KPIs to measure the impact of these use cases are indices of continuity of supply, such as SAIDI and SAIFI.

Comparative of use cases

The functionalities of these four use cases are very similar. Failure management in MV (Demo 1), Automatic grid recovery (AGR) (Demo 3), and Failure management in MV (Demo 5) are focused on the implementation of failure management systems (the ASS system, the AGR system and a system based on automated disconnection points, respectively) in the MV network. The use case of Failure management in LV (Demo 5) is focused on a system that uses weak bonds and automated cabinets in the LV network.

The main difference between the outcomes expected from these use cases is related to the response time of the control system in place. This response time depends on whether the control is local or centralized, and whether the control system is autonomous, or must be supervised. Table 6 displays the main features of the different smart grid solutions implemented in the use cases for continuity of supply.

	Failure management in MV (Demo 1)	**Automatic grid recovery (AGR) (Demo 3)**	**Failure management in MV (Demo 5)**	**Failure management in LV (Demo 5)**
Architecture: centralized vs local	Local control	Centralized control	Local control	Local control
Supervision: supervised vs. autonomous	Autonomous (supervised at a first implementation stage)	Supervised (requires confirmation of an operator at the control centre)	Supervised (local control reports to central control and confirmation of an operator is required)	Supervised (local control reports to central control and confirmation of an operator is required)
Elements	Some MV/LV subst: • Measuring modules (remote	Some MV/LV subst: • Automated substations: remote control,	Some MV/LV subst: • Disconnection points: remote control, IEDs	Interconnection of LV feeders: • Automated cabinets: remote

	monitoring, including detection of fault-pass and short-circuits) • Switching modules (remote control, monitoring, switching)	monitoring, fault-pass detection, open circuits in normal and fault conditions	monitoring, fault-pass detection, open circuits in normal and fault conditions • Non-disconnection points with monitoring	control, monitoring, fault-pass detection, allows LV reconfiguration

Table 6: Comparative of smart grid solutions implemented in use cases for improvement of continuity of supply

Simulation for technical SRA

The technical SRA for this group of use cases consists in computing the indices of continuity of supply through simulations to compare the situation before and after the implementation of the smart grid use case. For this purpose, a simulation tool has been designed. This tool emulates the actual process of fault location, isolation, service restoration and repair performed by DSOs and computes the interruption time suffered by each consumer for each possible fault in the MV system, according to the flow chart in Figure 3.

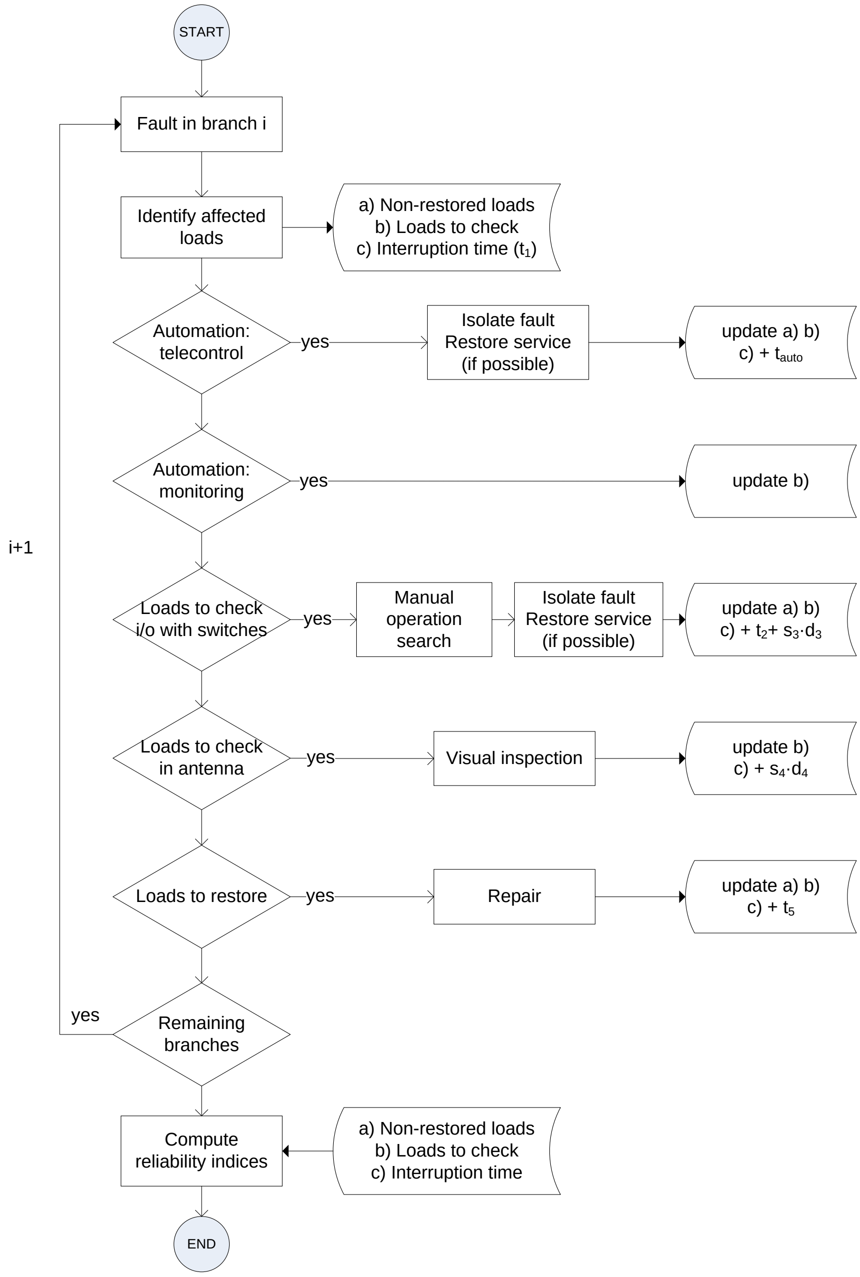

Figure 3: Flow chart for the simulation for reliability analysis of automation use cases.

Ten representative networks have been used for simulation, which have been specifically built based on data provided by Demo leaders to represent distribution networks in their countries for different types of distribution zones (urban, sub-urban and rural) and voltage levels (MV, LV). Special attention is paid to the grid architecture, meshing of the network, protection schemes, registered indices of continuity of supply and level of existing automation.

A wide range of scenarios is simulated in order to assess the effect of the different boundary conditions that may be involved in the scaling-up and replication of these use cases, including network length, network failure rate, type of automation solution, and implementation degree of monitoring and telecontrol, as listed in Table 7.

Characterization of simulation scenarios	
Representative networks	8 MV networks & 2 LV networks Urban, sub-urban and rural
Network length	7 values for each network
Failure rate	7 values for each network
Use cases: smart grid solution	Automation control system: local vs. centralized & autonomous vs. supervised
Automation scenarios: implementation degree	% secondary substations with monitoring and/or full automation (20-40 combinations)

Table 7: Scenarios analysed for technical SRA of use cases for improvement of continuity of supply.

3.1.2 Lessons learned and SRA rules

Automation of secondary substations may include monitoring and telecontrol of switchgear or just monitoring. Monitoring features fault-pass detection and helps locate the fault within a section of the grid. Therefore the duration of interruptions is reduced because the search of the fault must be carried out for a smaller portion of the feeder. SAIDI is reduced, and SAIFI is not modified. Telecontrol enables the remote operation of load break switches, and can only be implemented in the case of secondary substations that are connected to the MV grid in an input-output configuration through load break switches. Thanks to telecontrol faults can be very quickly located and reconfiguration of the network may be performed to isolate the fault and restore supply in healthy sections, so not only the time for fault location is dramatically reduced, but also non-affected sections of the grid experience a decrease in the number of interruptions. Thus, both SAIDI and SAIFI are reduced, and the reduction of SAIDI is much deeper than in the case of only monitoring.

The remainder of this section describes the main conclusions extracted from the simulations.

Impact of automation: implementation degree of automation, monitoring and telecontrol

The **effect of increasing** the amount of secondary substations with **telecontrol** is not linear, there is a **saturation effect around an automation degree of around 20-40%.** Fault location and service restoration is based on a dichotomic search, where the network is split into two halves, and thus the initial steps affect a much larger number of consumers and the distances to cover are much longer than in subsequent steps.

The saturation effect can be observed in the graphs of Figure 4 where the SAIFI and SAIDI indices are displayed for increasing shares of telecontrolled secondary substations for urban and sub-urban networks.

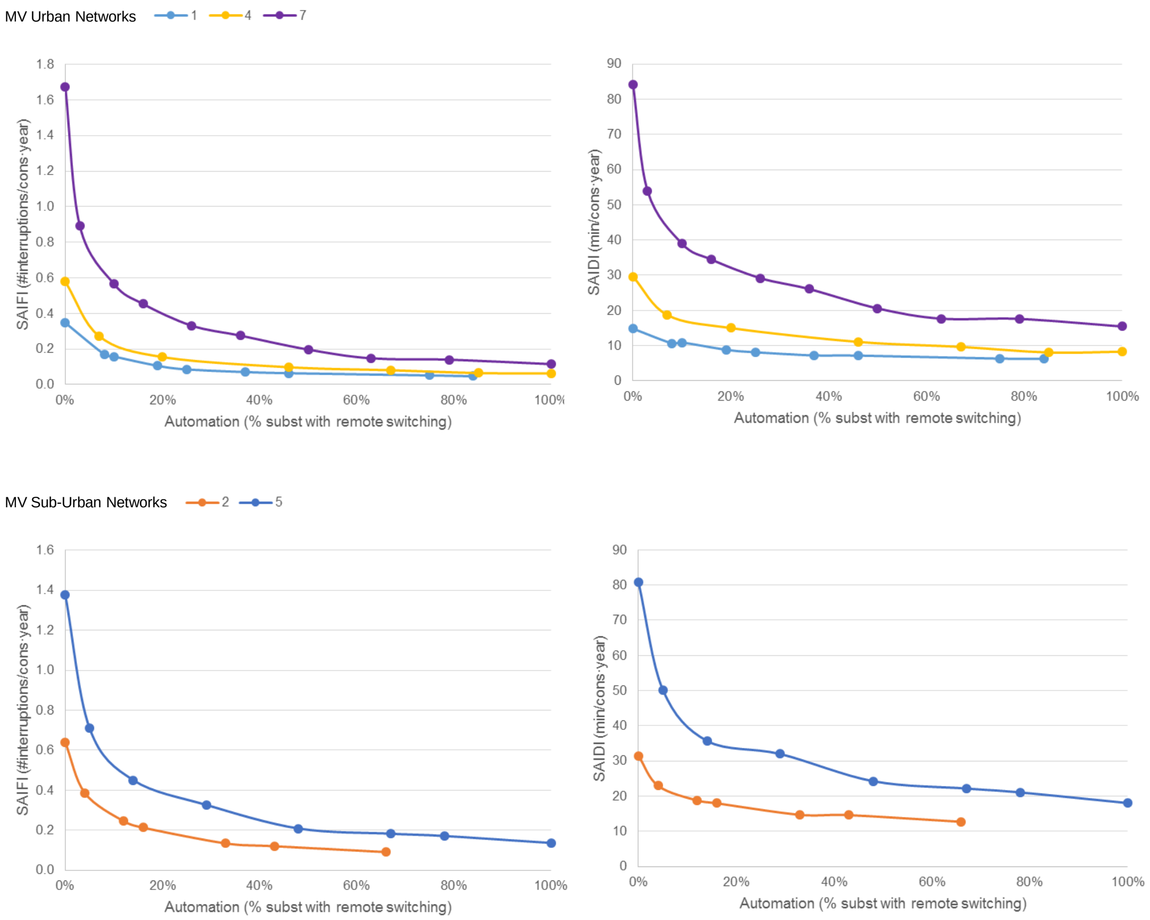

Figure 4: SAIFI (left) and SAIDI (right) values for different shares of telecontrol in 5 MV networks split per type of area (urban at the top, sub-urban at bottom).

The impact of implementing a certain degree of automation is **much higher for networks with lower reliability** (higher values of continuity of supply indices). Given the same architecture and type of network, poorer reliability can be linked to higher fault rates, length, times for operation, etc. The higher the number of interruptions, the higher number of interruptions avoided; the longer the distance to cover, the time per operation or the number of secondary substations to operate, the deeper the impact of automation on reducing interruption durations and the number of affected consumers if restoration can be achieved within the regulatory threshold. However, it must be highlighted that if the cause of low reliability is the lack of maintenance, priority should be given to proper maintenance. Smart solutions improve reliability in well-maintained networks.

The results depicted in Figure 4 clearly illustrate this effect. For instance, the case of urban networks #1 and #7 can be considered. These networks have a SAIFI value of 0.35 and 1.67 interruptions/consumer·year, respectively. The implementation of telecontrol in 10% of the secondary substations achieves a reduction of 1.11 interruptions/consumer·year (a reduction of SAIFI by 66% of its initial value) in urban network #7 and a reduction of 0.19 interruptions/consumer·year (55% of its initial value) in urban network #1.

Telecontrol of load break switches has a **very significant impact on both the frequency and duration of supply interruptions** suffered by consumers. By contrast, **monitoring** has a **much**

milder impact on the duration of supply interruptions. Figure 5 shows the results achieved when implementing full automation (monitoring and telecontrol) or just monitoring in urban MV networks. It is clear that the impact on SAIDI is dramatically different

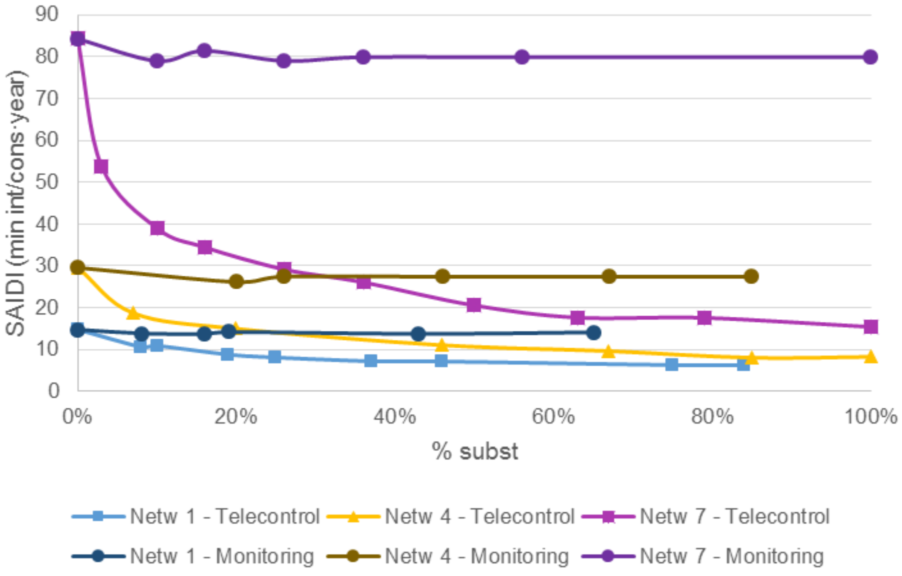

Figure 5: SAIDI values achieved with telecontrol or only monitoring for urban MV networks #1, #4 and #7.

<u>**SRA rules:**</u>

- Telecontrol of load break switches has a very significant impact on both the frequency and duration of supply interruptions suffered by consumers. By contrast, monitoring has a much milder impact on the duration of supply interruptions.
- The impact of telecontrol when increasing amount of automated substations is very deep for automation degrees up until 20-40%. Adding more automation further improves reliability but to a much lesser extent.
- The impact of implementing a certain degree of automation is much higher for networks with lower reliability (for properly maintained networks).

Most important technical boundary conditions: network structure (type of area, meshing and protection elements)

The structure of distribution networks, in terms of **switching elements** (whether there are switches that can segment the feeders) **and meshing capabilities** (whether feeders can be connected to other feeders to allow reconfiguration), is the **most important and influential parameter** that defines the process for fault management and modifies the impact of automation on reliability.

- The presence of load break switches in the input and output of secondary substations or any other **switches** in the MV line allows the **segmentation** of this network. Thus, faults can be isolated in smaller sections, so that a lower number of consumers is affected by a fault and fault location is faster because the maintenance crew must locate the fault within a smaller part of the grid. Moreover, consumers upstream the fault may not be affected at all by the fault.

- Besides, if the network is meshed, and there are **interconnections** to other feeders, **service can be restored** in more cases through reconfiguration, so the duration of interruptions is much shorter because the DSO may be able to re-supply many consumers before repairing the fault. Adding monitoring and telecontrol speeds up segmentation and reconfiguration of the network, so of course the impact on reliability improvement is subject to the possibilities allowed by the structure of the network.

As a result of comparing the different types of distribution networks that are representative for different types of distribution areas, it is clear that the **type of distribution area**, related to the geographical distribution and type of consumers, is the most influential factor in the resulting network architecture and in the impact of automation. Of course, network planning in different distribution companies has also been subject to many other factors, such as regulation, economic context, historical evolution, etc. However, in most regions and countries, the main differences between the different types of distribution zones are generally the following:

- **Urban** areas have **higher meshing capabilities, with interconnected grids** and **secondary substations are connected to the MV grid in an input-output configuration through load break switches**, so reconfiguration is possible. Additionally, urban networks typically have higher degrees of underground cable, so fault rates are much lower.
- **Rural** areas have **longer lines**, with a **lower degree of undergrounding**, and a more **radial structure with ramifications**. Often **secondary substations are connected in antenna**, so it is not possible to operate switches that can isolate a faulty section.
- **Sub-urban** networks have typically **intermediate values** of network length, undergrounding degree, meshing degree and presence of switches or segmenting elements.

If the networks are not meshed, service restoration cannot be achieved for all faults, so the **effect on SAIFI is not as deep**. Monitoring reduces the distances to cover for fault location, so SAIDI is reduced. Distances and time for visual inspection are much longer in more rural networks, so the **effect of monitoring on SAIDI is deeper for rural than for urban networks**.

Ideally, automation should be introduced **gradually** in distribution networks, **prioritizing** the **full automation** (monitoring + telecontrol) of a share of secondary substations (up to **20-30%**) in **urban** networks. To maximize the effect on reliability improvement, the location of automated secondary substation must be designed in accordance with the manual fault management process (dichotomic search), distributing automated secondary substations along the line. In the case of rural networks, monitoring may be the only option available when there are no load break switches, and it can help reduce the duration of service interruption for some consumers. The implementation of shares of monitoring-equipped secondary substations additionally to fully automated substations can be observed as a complementary investment in urban and sub-urban networks with some telecontrol that, if well-coordinated and located, can help reduce outage duration, but only very mildly.

SRA rules:

- Automation has a much deeper impact on reliability in the case of meshed networks with switches in the MV line.
- Generally, distribution networks for different types of distribution areas share common characteristics:
  - Urban areas have more meshed and secondary substations are connected to the MV grid in an input-output configuration through load break switches.
  - Rural areas have longer lines, with a lower degree of undergrounding, and a more radial structure with ramifications. Often secondary substations are connected in antenna.
- Ideally, automation should be introduced gradually in distribution networks, prioritizing the full automation (monitoring + telecontrol) of a share of secondary substations (up to 20-30%) distributed along the MV line in urban networks.
- Monitoring may be the only option available when there are no load break switches, and it can help reduce the duration of service interruption for some consumers.
- Adding monitoring-equipped secondary substations additionally to fully automated substations can help reduce outage duration only very mildly.

Other relevant boundary conditions: architecture of automation control system

The main difference between the smart grid solutions implemented for the different GRID4EU use cases is related to the **control system** or the logic of the automation in real-time operation of the distribution grid. The control system may be **local or centralized**, and **autonomous or supervised**. The architecture of the control system for automation has an impact on the time required by the system to perform reconfiguration.

- **Time response** of the system has an **impact on both SAIDI and SAIFI**. If the system is able to perform FDIR in a shorter time than the regulatory threshold[6], the interruption does not affect consumers in healthy sections of the grid.
- A **local** control system would isolate **directly** the faulty section, whilst a **central** control would perform **switching operations** to **gradually** isolate the faulty section. In the first case, consumers in the healthy sections of the grid would not suffer the interruption of supply. Typically, if communications are fast enough, the difference in time response between the two systems would be negligible.
- **Human supervision** introduces a **longer, more arbitrary response time**, so that the **regulatory threshold may be surpassed**. In that case, no SAIFI reduction would be achieved.
- For **higher automation degrees**, where SAIDI and SAIFI values are already very low and

[6] Regulation sets the threshold of time to consider a supply interruption as a permanent interruption to be included in the SAIFI. This threshold is set at 3 minutes in most European countries.

more switching operations must be carried out by the control system, the effect of the response time of the automation system becomes **more relevant**.

The resulting values of SAIDI and SAIFI implementing telecontrol in three different urban MV networks with different response times for the control system illustrate how SAIDI is slightly affected by higher response times and SAIFI is discontinuously affected (as long as the regulatory threshold is not surpassed, there is no effect on SAIFI, but if this limit is surpassed, a number of consumers is now considered to be affected by an interruption, although a very short one). The results also show how the effect of response time is more relevant as automation degree is higher.

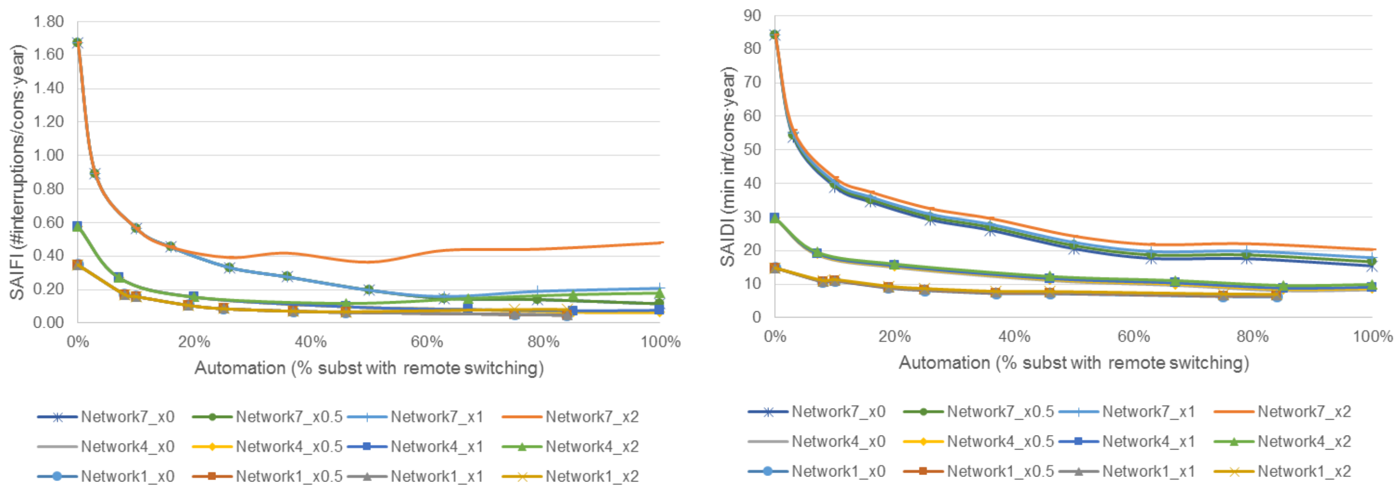

Figure 6: SAIFI and SAIDI values for urban MV networks considering different response times to account for centralized/local, supervised/autonomous control.

SRA rules:

- Time response of the system has an impact on both SAIDI and SAIFI. If regulatory threshold is surpassed, no reduction of SAIFI is achieved.
- Typically, the difference in time response between centralized and local control systems is negligible.
- Human supervision introduces a longer, more arbitrary response time, so that the regulatory threshold may be surpassed.
- The effect of the response time of the automation system becomes more relevant for higher automation degrees.

Other relevant boundary conditions: network length and failure rate

Fault rate and network length are related to the initial reliability level. Networks with higher fault rate (for instance, overhead conductors instead of underground cables, older networks) have higher initial values of SAIFI and SAIDI because of higher occurrence of faults. Longer networks have higher initial values of reliability indices because of higher probability of MV faults and additionally due to longer distances to cover during service restoration process.

Given a certain network architecture and demand, for **lower initial reliability levels** (higher fault rates or longer lines), the **reduction of SAIDI and SAIFI achieved by automation is larger**. The evolution of SAIDI and SAIFI with telecontrol follow similar curves.

The **percentage decrement of SAIFI and SAIDI** achieved **with a certain degree of automation** remains the **same when changing failure rates**. The **percentage decrement of SAIFI** achieved **with a certain degree of automation** remains the **same when changing network length**. The **percentage decrement of SAIDI is slightly higher for longer networks**. This effect is illustrated by the resulting values of SAIDI and SAIFI for an urban network for different values of network length and failure rate, obtained by applying different factors to the values of these parameters for all the branches comprising the network, presented in Table 8.

Scenario factor	Failure rate				Length			
	No automation		25% automation degree		No automation		25% automation degree	
	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI
x0.7	0.24	10.38	0.06 (-75%)	5.69 (-45%)	0.24	10.07	0.06 (-75%)	5.64 (-44%)
x0.8	0.28	11.86	0.07 (-75%)	6.51 (-45%)	0.28	11.63	0.07 (-75%)	6.47 (-44%)
x0.9	0.31	13.34	0.08 (-75%)	7.32 (-45%)	0.31	13.21	0.08 (-75%)	7.30 (-45%)
base case	0.35	14.82	0.09 (-75%)	8.13 (-45%)	0.35	14.82	0.09 (-75%)	8.13 (-45%)
x1.1	0.38	16.31	0.09 (-75%)	8.95 (-45%)	0.38	16.46	0.09 (-75%)	8.97 (-46%)
x1.2	0.42	17.79	0.10 (-75%)	9.76 (-45%)	0.42	18.13	0.10 (-75%)	9.82 (-46%)
x1.3	0.45	19.27	0.11 (-75%)	10.57 (-45%)	0.45	19.83	0.11 (-75%)	10.67 (-46%)

Table 8: Effect of automation when increasing/decreasing failure rate and network length on reliability indices for MV urban network #1.

SRA rules:

- Given a certain network architecture and demand, the reduction of SAIDI and SAIFI achieved by automation is larger for lower initial reliability levels (longer lines and higher fault rates).
- Percentage decrement of SAIFI and SAIDI achieved with a certain degree of automation remains the same when changing failure rates and network length. In the case of SAIDI, the percentage reduction is slightly higher for longer networks.

Other relevant boundary conditions: reliability indices (SAIFI-SAIDI vs. ASIFI-ASIDI)

The use of different **reliability indices** by regulation may encourage DSOs to **prioritize investment in different areas**. Indices based on consumers (**SAIFI, SAIDI**) place an **equal weight on all consumers**, while indices based on load (**ASIFI, ASIDI**) place a higher importance on **consumers with larger demand**.

Networks may have areas of poorer reliability, for instance in ramifications, especially if no interconnections are available for service restoration. In that case, different sets of indices would yield different results, depending on the proportion of number of consumers or the share of rated power located in that part of the grid.

The **measurement of reliability improvement** achieved by automation **will differ slightly** for different sets of indices according to the structure of the demand (in terms of rated power and number of consumers). Typically, in **urban** areas **the differences among the two sets of indices are less visible**, because the reliability of the network is more homogeneous in the network than in the case of more rural networks. This can be observed in Figure 7. The graphs show the resulting SAIFI, ASIFI, SAIDI and ASIDI for two different networks. The two sets of indices differ slightly more in the case of the rural area.

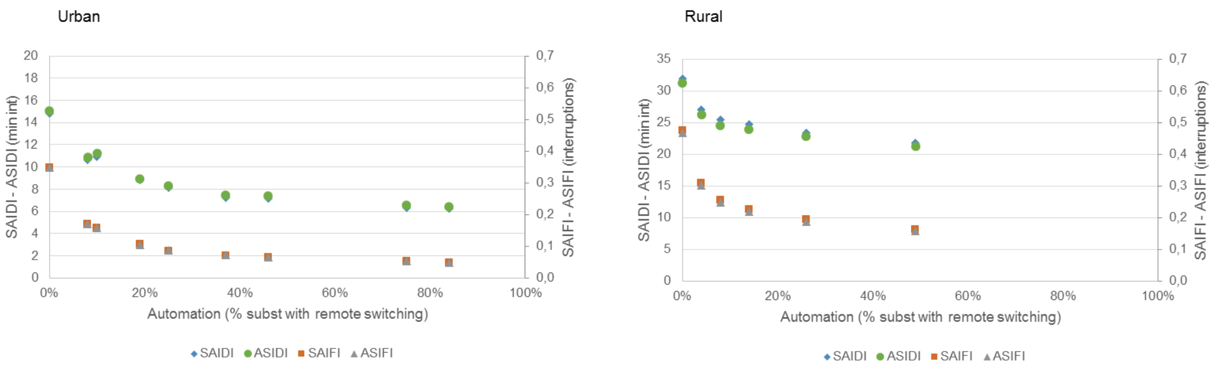

Figure 7: SAIFI, ASIFI, SAIDI and ASIDI values for different shares of fully automated secondary substations for an urban (left) and a rural (right) MV network.

SRA rules:

- The use of different reliability indices to compute reliability improvement achieved by automation leads to slightly different results, depending on the structure of the demand and the reliability throughout the MV network.
- The use of SAIFI, SAIDI will prioritize reliability improvement for areas with higher number of consumers, while ASIFI, ASIDI will prioritize reliability improvement for areas with larger demand.
- Typically, in urban areas the differences among the two sets of indices are less visible.

Other relevant boundary conditions: voltage level (MV vs. LV)

The LV grid is the last step in distribution for LV consumers, and the number of supplied consumers and the volume of supplied power by LV lines are of course much lower than in the case of MV lines. LV lines are usually **not meshed** and have no reconfiguration options. In comparison to MV grids, LV networks are much shorter and fault rates of cables are usually quite similar to that of MV lines, but slightly higher. LV distribution networks for different types of areas (urban, rural, etc.) are much more similar to each other than in the case of MV networks: both LV urban and rural LV lines are typically quite short, with a very high level of undergrounding (higher than in MV lines, and more similar from urban to rural LV networks than when comparing MV urban and MV rural networks).

Automation in the LV network is implemented in the form of LV cabinets, where some LV lines are interconnected, and that include switchgear. This equipment enables fault management in the same way as for MV lines with automated secondary substations, so the **same impact on reliability** is achieved, and the **same factors** affect the results achieved (interconnection of lines and switches available, failure rate, network length and response time of the automated fault management system). It can be concluded that voltage level has no effect on the scalability and replicability of reliability improvement through automation.

However, since reliability improvement in LV networks **affects much fewer consumers** than MV lines, and the infrastructure required to improve reliability for a certain amount of consumers would be much more numerous, it is advisable to prioritize automation on MV.

SRA rules:

- LV networks usually have no interconnections or switches to operate. For more advanced LV networks, there may be a few LV cabinets interconnecting different LV lines and including switchgear.
- Automation of LV cabinets achieves a reduction of SAIFI and SAIDI, in the same way that the automation of secondary substations improves the reliability of the MV grid.
- Automation in LV responds to the same parameters than automation in MV networks: the most determining factor is the structure of the network in terms of interconnection and switches available to segment the network, and other relevant parameters are failure rate, network length and response time of the automated fault management system.
- It is advisable to prioritize the automation of the MV grid rather than the LV grid, since reliability improvement at MV level affects a much higher number of network users.

3.2 Enhancing the network hosting capacity through smart grid solutions

This chapter presents use cases with the main objective of enabling efficient DER integration. The use cases included in this category are Decentralized grid operation in MV networks (Demo 1), LV Network Monitoring and Control (Demo 2), Voltage regulation in MV (Demo 4), Maximize PV production in LV (Demo 6) and Anti-islanding (Demo 4).

These use cases (except for the use case of anti-islanding) are focused on quality of supply improvement, and avoiding overloads and overvoltages in the networks. These use cases implement smart grid solutions based on different elements (demand side management, use of storage, reactive power output of DG units or network reconfiguration), with a direct impact on voltage profiles, power flows and losses. Technical SRA for these use cases is based on steady-state loadflow analysis for different scenarios, monitoring voltage profile, avoided overvoltages, avoided overloads, avoided disconnection of DG units and load shedding to determine network hosting capacity.

The use case of anti-islanding aims to improve protection schemes of DG units to avoid unintentional islanding in the event of supply interruptions. Technical SRA of this use case is based on dynamic analysis to study the response of the system, monitoring voltage and frequency deviation. Therefore, this use case has been grouped together with islanding use cases for simulation, and together with use cases aimed at the increase of network hosting capacity for SRA.

3.2.1 Demo 1: Decentralized grid operation in MV networks

This use case employs automation to optimize the configuration of the network according to the state of the system. Monitoring and telecontrol may be used to detect and avoid overloads and voltage problems, so that network hosting capacity is increased, and reduce energy losses through reconfiguration of the network.

Technical SRA of this use case focuses on the increase of network hosting capacity (ΔNHC) achieved by the implementation of automation. Network hosting capacity has been computed for all possible configurations of the grid enabled by the autonomous switching system (switching and measuring modules), to determine the optimal configuration (the configuration with the highest network hosting capacity). Network hosting capacity will be assessed in terms of the maximum generation that can be accommodated at a single node in the network under the most unfavourable conditions without violating technical constraints. Technical constraints considered include maximum loading of lines and cables, given by the rated current of conductors, and voltage limits, given by regulation. Then, ΔNHC will be computed with respect to the network hosting capacity of the grid for its normal configuration.

Simulations have been carried out for seven MV representative networks of different distribution areas (urban, sub-urban and rural) and voltage levels (10 and 20kV). The selected scenarios for simulation are based on low demand (10% of contracted power or maximum demand of each consumer) and concentrated DG at maximum production. Sensitivity to DG location has been studied, considering DG at the beginning, at the middle and at the end of the main trunk of an MV feeder, and in the end of ramifications when applicable. Additionally, different voltage limits have been considered as a limit for network hosting capacity (3, 5, 7 and 10% of nominal voltage). In line with the so-called scalability in density, different degrees of automation have been contemplated, to assess the effect of having a wider range of possible configurations on the improvement of network hosting capacity.

3.2.1.1 Lessons learned and SRA rules

Network hosting capacity of MV networks: overvoltages and overloading

Even when considering very restrictive voltage limits, the limiting factor for network hosting capacity is most frequently the thermal limits of lines, especially for more urban areas. Meanwhile, voltage problems arise more often in more rural areas, where networks are longer.

The most unfavourable locations for DG, where a higher voltage rise is experienced, are those where the DG is located the farthest from the primary substation, often at the end of feeders, and especially at ramifications at the end of the feeder. In the case of DG connected at nodes closer to the substation, voltage deviations are much more limited, so that overloading of the lines is the limiting factor to DG hosting, overvoltage is hardly a problem.

These effects are illustrated in Table 9, where the permitted volumes of DG are compared for an urban and a rural area, at the beginning and at the end of MV feeders. The limiting factor for each case is marked through shading with a lighter colour for thermal limit of lines (overloading) and a darker shade for voltage restrictions (overvoltage).

Effect of automation for reconfiguration

Reconfiguration can help solve or **mitigate voltage problems caused by concentrated DG**: a) load from another feeder can be transferred to the feeder where the DG is located, so that a higher share of the injection of the DG is consumed locally and therefore the excess of power is decreased; b) DG can be transferred to a feeder with a higher load so that the DG production is consumed; c) DG can be transferred to a different part of the grid so that it is connected closer to the primary substation and therefore the voltage rise is lower.

However, **when the lines are overloaded** due to the power flows originated by the injection of DG, the **effect of reconfiguration is usually more limited**. Again, transferring DG to more loaded sections, or transferring load from other feeder to the section where the DG is connected helps to locally balance generation and demand and thus reduce power flows in the network.

The results presented in Table 9 show for instance an increase of permitted penetration degree of 2% in the case of a rural network with DG at the beginning of the feeder with automation, where overcurrents set the limit for DG injection.

Max DG penetration in % of total installed capacity of demand		URBAN NETWORK			RURAL NETWORK			
		autom=0%	autom=8%	autom=19%	autom=0%	autom=4%	autom=8%	autom=14%
DG at beginning of feeder	Vmax=3%	24%	26%	26%	47%	49%	48%	50%
	Vmax=5%	24%	26%	26%	47%	49%	48%	50%
	Vmax=7%	24%	26%	26%	47%	49%	48%	50%
	Vmax=10%	24%	26%	26%	47%	49%	48%	50%
DG at end of feeder	Vmax=3%	14%	17%	20%	18%	18%	18%	29%
	Vmax=5%	23%	24%	25%	28%	29%	29%	36%
	Vmax=7%	23%	24%	25%	36%	36%	36%	36%
	Vmax=10%	23%	24%	25%	36%	36%	36%	36%

V limit I limit

Table 9: Network hosting capacity (% of total installed capacity of transformers of secondary substations) achieved by reconfiguration for different automation degrees for a scenario of low demand and high generation for DG concentrated at a single node.

SRA rules:

- Network hosting capacity can be increased by reconfiguration. Results have shown increases of up to 65% of initial network hosting capacity for automation degrees below 20%.
- Reconfiguration can bring DG closer to the primary substation, so that voltage rises are mitigated, or locally consume a larger share of the DG production, so that generation and demand are more balanced. The improvement of network hosting capacity achieved by reconfiguration is higher in the case of overvoltages than for overloading of the lines caused by concentrated DG.

Effect of topology of the network (distribution of interconnections, automation, generation and demand)

The **structure of the network**, in terms of meshing, interconnections and available switching elements, is crucial, since it **determines the possible alternative configurations of the network**. The structure of the network is typically linked to the type of distribution area. In general, urban networks are more meshed and interconnected, and most secondary substations are connected in an input-output configuration through load break switches. Therefore, given a certain degree of automation, more meshed networks provide more opportunities for reconfiguration.

The **location of** switching modules, is usually linked to the fault management and service restoration process. The location of the remote-controlled switching elements is also a key factor because these elements **establish the possibilities for reconfiguration**. For this reason, in some cases **increasing the degree of automation may not improve hosting capacity**.

The potential of reconfiguration is also linked to the **distribution of generation and demand with respect to the location of switching modules**. In the case of having regions with higher DG penetration and other regions with higher load, or lower presence of DG, reconfiguration can have a much deeper impact if alternative configurations include transferring part of the DG to feeders with less DG or higher demand.

For instance, in the case of network #2, when the DG is located at the beginning of the feeder, the limiting factor is the loading of the lines. The maximum DG installed capacity that can be accommodated considering the original configuration of the network is 11.2MW. For the first automation scenario (4%), an additional 800kW can be introduced in the network. However, for the second automation scenario (12%), which features a higher number of remote-controlled switches, the best configuration possible cannot accommodate more than 11.6MW, so the improvement of network hosting capacity is lower than for the first automation scenario.

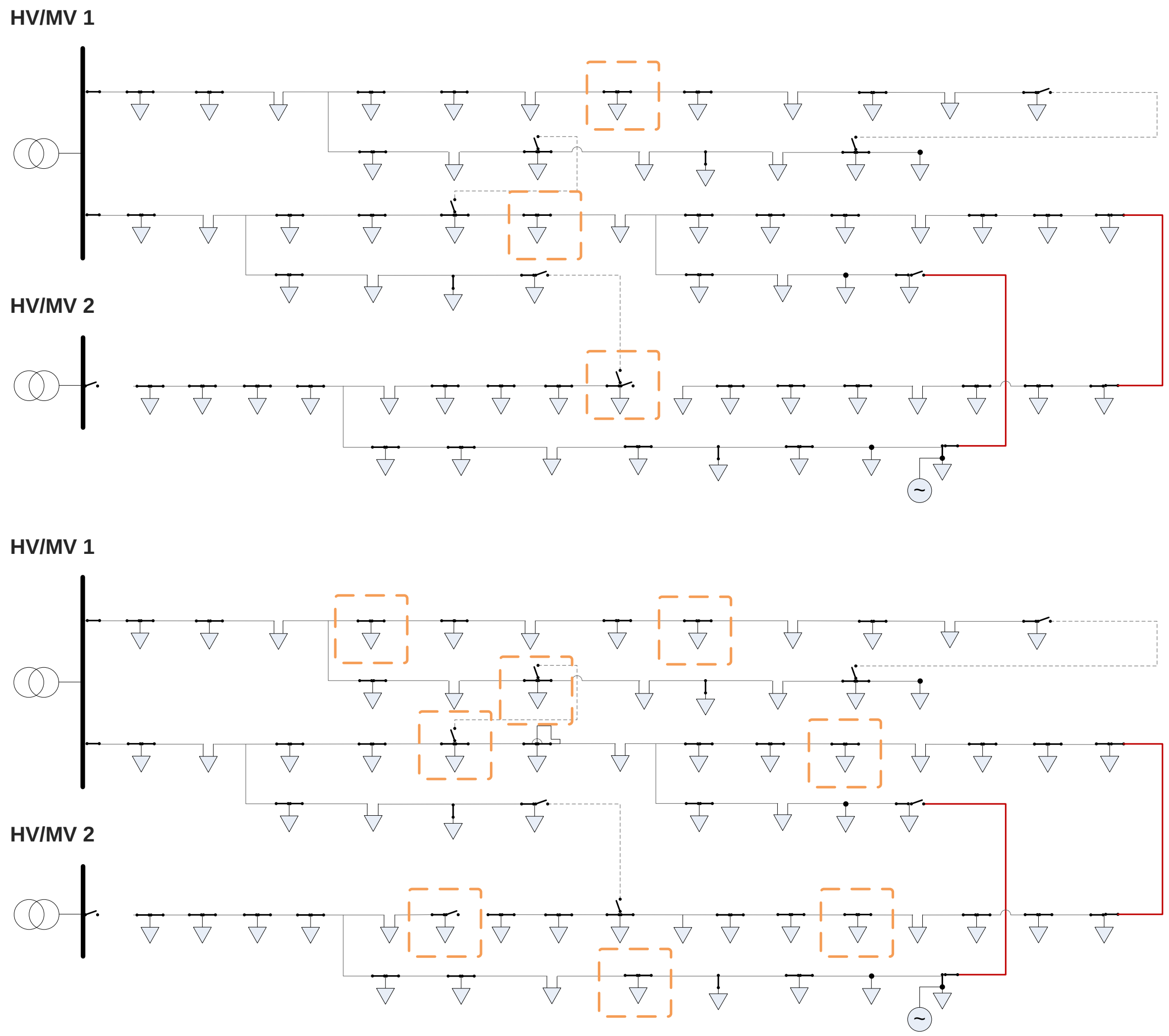

Figure 8: Sub-urban network #2 with DG located at the end of the ramification of the third feeder: a) reconfiguration to maximize network hosting capacity, 4% automation degree (above); b) reconfiguration to maximize network hosting capacity, 12% automation degree (below)

SRA rules:

- Reconfiguration possibilities strongly depend on the structure of the network (meshing and interconnections) and on the location of the remote-controlled switching elements. Replicability of the observed results to other networks is subject to the specific topology and design of the automation implementation.
- Automation is usually designed for the main purpose of fault management, so localization of switching modules may not be optimized to improve network hosting capacity. In addition, existing switching modules could suffer from premature ageing due to more frequent usage.
- Higher degrees of automation may not improve hosting capacity, since configurations allowed may not be aligned with the distribution of load and DG
- In the case of a non-homogeneous distribution, reconfiguration may be able to achieve a deeper impact if regions with higher DG penetration can be connected to regions with higher load to transfer part of the generation or load to one another.

3.2.2 Demo 4: Voltage regulation in MV

This use case incorporates new elements to traditional voltage control strategies to avoid overvoltages caused by DG and thus increase the capability of the distribution network to accommodate further DG production. The voltage control strategies implemented and tested in this use case include the following:

- Regulation of transforming relationship at the primary substation through on-load tap changers (OLTC)
- Active participation of DG, controlling reactive power according to power factor set points sent by the DSO
- Use of storage in the form of a 1MVA-1MWh battery connected to the MV grid and controlled by the DSO

3.2.2.1 Technical analysis for SRA

Technical SRA of this use case is focused on the assessment of the increase of network hosting capacity achieved by storage and power factor control of DG. The increase of network hosting capacity will be measured as the percetage increment with respect to the base case of taking no voltage control action.

Power flow analyses have been carried out to determine voltage profiles in the network and the flows in the lines to check compliance with voltage limits and thermal limits of the conductors. Network hosting capacity is thus determined by gradually increasing DG until technical constraints are reached. Network hosting capacity has been measured with respect to the total installed capacity for demand, i.e., the sum of rated power of the transformers in the secondary substations of the MV grid.

The voltage limits are set by regulation for each country. The maximum voltage deviation in Europe is 10% (CENELEC, 2010), and European countries may establish more restrictive limits. Furthermore, often DSOs set even more restrictive values as operational standards. The limits may be symmetrical or non-symmetrical for over- and under-voltages. The values considered for the present analysis allow a maximum deviation of 3%, 5%, 7% and 10% with respect to the nominal value.

The analysis has been carried out for 6 representative MV networks of different regions and countries, with different voltage level (10 and 15kV) and for three distribution zones (urban, sub-urban and rural).

Network hosting capacity has been assessed under two different scenarios of penetration of DG: (i) homogeneously distributed at all secondary substations of the MV network; and (ii) at the node where the highest voltage deviation is observed, to assess the most unfavourable situation possible. The DG analyzed includes PV and wind.

Different approaches for the use of storage have been evaluated, considering also different sizes and locations of storage. In the case of having concentrated DG at the end of a feeder, storage has been located (i) at the beginning of the feeder where the concentrated DG is located, (ii) at the middle of the feeder where the concentrated DG is located, (iii) together with the concentrated DG, at the end of the feeder, and (iv) at the end of a different feeder supplied by the same primary substation to use in combination with OLTC to avoid under-voltages in the feeder where the storage is located.

3.2.2.2 Lessons learned and SRA rules

In general, European distribution networks have been planned and sized to allow for demand growth over long periods of time, so even for the scenarios of maximum demand, which would correspond to all consumers demanding their maximum consumption at the same time, voltage profiles remain within acceptable limits, with a maximum voltage variation of 4%.

In the presence of DG, demand of the system is partially supplied by the DG units, so the net demand is reduced in the system, and voltage rises in the network. Voltage deviations across the lines are proportional to the impedance of the lines, so in rural networks, which are typically much longer, DG cause higher voltage rises. The farther the DG is located from the primary substation, the higher the voltage deviation.

The interaction between demand and generation in time is a key aspect to the integration of DG. If DG production is injected into the grid at periods of high demand, the energy is consumed locally, and the effect on the operation of the distribution system is very positive. The most problematic situation is having DG production during periods of low demand. This interaction of generation and demand is given by their load and generation profiles. Generation profiles depend mainly on the technology of DG. In the case of PV and wind power, DG production is linked to meteorology. In the case of CHP, the profiles is linked to its use of electricity and heat.

Additionally, the size of DG is also a key element. Small DG units, such as PV rooftop panels, are connected at the LV networks. Larger DG units, such as solar farms or wind turbines, are much bigger and are typically connected to the MV grid. The size and location of DG is typically linked to DG technology, but is also much related to the regulation in place in each country (DG connection rules), incentive mechanisms (eligibility for feed-in tariffs), and historical/social reasons, all of which may vary across regions and countries. The size and use of DG will result in a more disperse DG (such as for instance in the case of a residential area where many consumers may have small PV panels), or more concentrated (for example in the case of a rural area where there are several solar farms connected at MV). The effect of a more distributed DG is smoother, since power flows are locally counteracted by the different network users.

Simulations have been carried to compare the effect of disperse and concentrated DG. Figure 9 shows the voltage profile for a rural network with DG at all nodes, distributed proportionally to demand in the secondary substations (diagram above), and located in a single node at the end of one of the feeders that comprise the representative network (below). Different levels of penetration, indicated as a percentage of the total installed capacity (sum of rated capacity of the transformers of the secondary substations) are represented. The nodes of the representative networks used are enumerated so that each of the four feeders is displayed sequentially, starting from the primary substation.

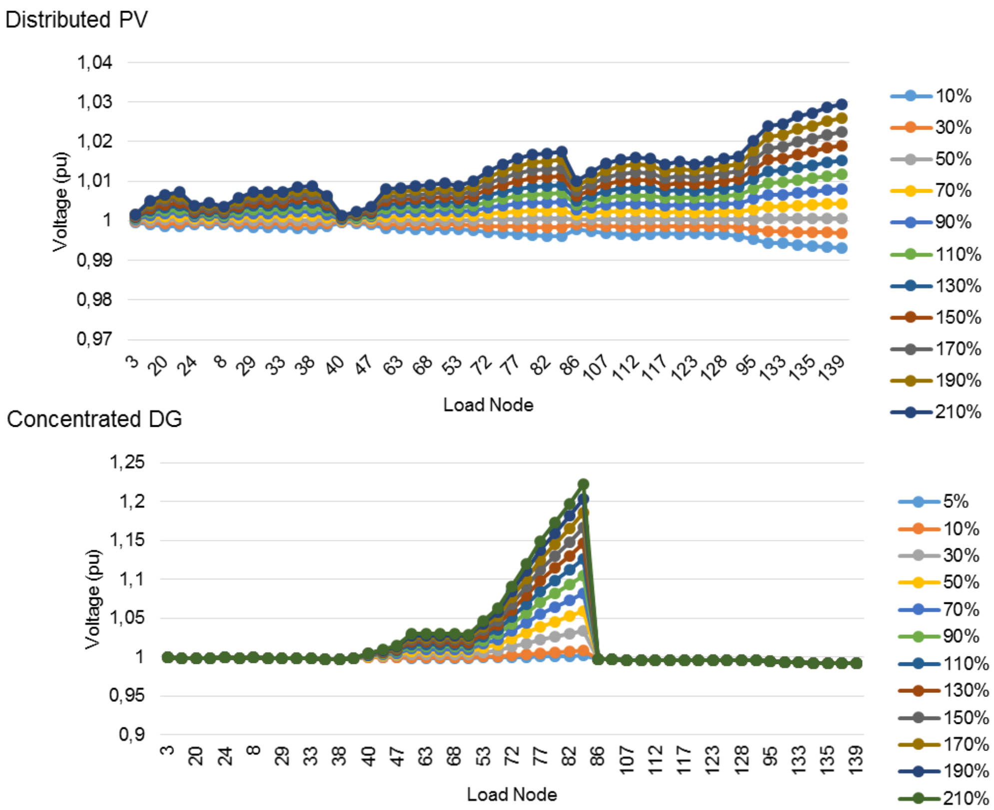

Figure 9: Voltage profile of rural network #6 for a scenario of intermediate demand and maximum PV production for different penetration degree of PV (% over total installed capacity in secondary substations), with PV distributed in all nodes proportionally to demand (top) and located at one node (bottom).

Results show that in the case of distributed DG for rural network #6, voltage rises in the whole network, but no voltage problems arise for a penetration degree below 200% (expressed with respect to the sum of rated capacity in secondary substations of the network) even considering the 3% voltage deviation. In the case of concentrated DG, the local effect on voltage in the feeder where the DG is located is much more extreme, and the 10% voltage deviation limit is already surpassed for values of penetration degree below 100%. Concentrated DG is more problematic, causing local voltage problems, due to the deviation along the network.

SRA rules:

- DG causes higher voltage rises in more rural networks, where lines are generally longer.
- Higher R/X ratios are translated into higher impact of DG on voltage profiles. On the other hand, reactive power has a deeper impact on more inductive lines, so the participation of DG in voltage control is more effective for lines with lower values R/X.
- The size and location of DG are very relevant: the farthest DG is located from the primary substation, the higher the voltage deviation caused. Concentrated DG is more problematic for voltage profiles. Typically, larger DG units may be expected in more rural areas, while smaller DG units may be found connected to the LV network in more residential areas.
- The effect of a more distributed DG is smoother, since power flows are locally counteracted by the demand of consumers in the network. Concentrated DG is more problematic, causing local voltage problems.
- If generation and demand are close, energy must flow through a shorter path, so there are less losses and voltage deviations remain smaller.
- Voltage control strategies should be prioritized for more problematic networks, where voltage problems occur and where the active participation of DG in voltage

Voltage control using OLTC in the primary substation

The tap of the transformer sets the transforming ratio so that the voltage at the head of the feeder can be increased (or decreased). The effect of this measure is the increase (or decrease) of the voltage on all nodes of the network, is a shift of the voltage profile.

Network hosting capacity can be dramatically increased if voltage is the limiting factor. However, overloading of the lines may be more critical in some cases. For instance, Table 10 presents the resulting values of network hosting capacity (as a percentage of the total installed capacity in the secondary substations of the network) for a rural network in a low demand, high PV production scenario with PV concentrated at one single node at the end of a MV feeder. Considering a voltage limit of ±5% of the nominal value, the maximum penetration degree that the network can accommodate is 47%. Lowering voltages by changing the tap of the transformer at the primary substation achieves a maximum penetration degree of 78%, thus increasing network hosting capacity by 66%. However, if a less restrictive voltage limit was considered, for a penetration degree over 90%, power flows become the limiting factor, since thermal limits of the lines are reached at some points of the network. In this case, changing the tap of the transformer of the primary substation would not be able to improve the situation.

Voltage Limits	NHC (base case)	NHC with OLTC	ΔNHC with OLTC
-5%, +3%	31%	59%	**93%**
-5%, +5%	47%	78%	**66%**
-7%, +7%	64%	90%*	**38%**
-10%, +10%	90%*	90%*	**0%**

Table 10: Network hosting capacity (as a percentage of total rated power of secondary substations in the network) for rural network #6 with PV located at the most unfavorable node, considering different voltage limits, and increase of network hosting capacity (ΔNHC) achieved using OLTC. The asterisks denotes that the thermal limits of the lines are the limiting factor.

When there is a problem of generalized overvoltage or under-voltage in the network, this is the most adequate solution. However, in the case of local problems, such as when having concentrated DG in a certain region of the network, it can have a dual effect, solving a problem of overvoltage (or under-voltage) but worsening voltage at other nodes and feeders with high demand and low voltage.

For instance, Figure 10 shows in grey the voltage profile of a network with a large volume of DG connected at the end (node 84) of a feeder (feeder 2, nodes 40-84). When the tap is changed to lower the voltage and mitigate the overvoltage caused by the DG, voltage at the other feeder (feeder 1, nodes 1-39) also decreases and a problem of under-voltage arises for this feeder

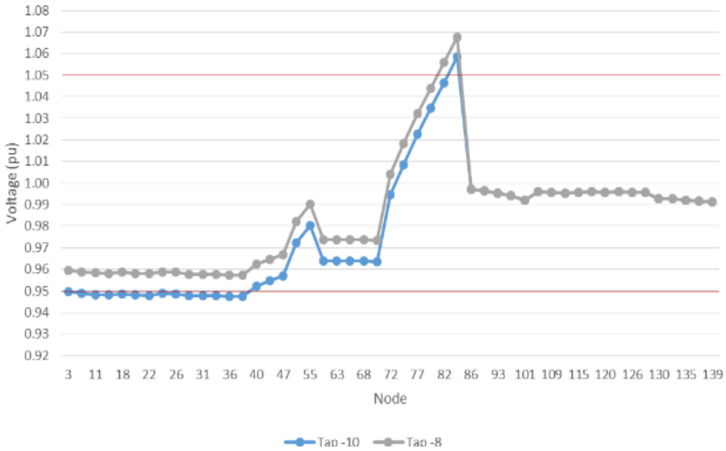

Figure 10: Voltage profile in a MV line with different tap positions at the primary substation.

Participation of DG in voltage control

Distributed generation can participate in voltage control by regulating its reactive power output and thus help mitigate the voltage rise caused by the injection of active power. The most appropriate power factor must be determined according to the state of the grid.

Simulation has been carried out testing different power factor set points for DG for the representative networks and scenarios previously described. Taking again the example of rural network #6, the resulting voltage profiles are shown in Figure 11 and Figure 12 for disperse PV and concentrated PV, respectively.

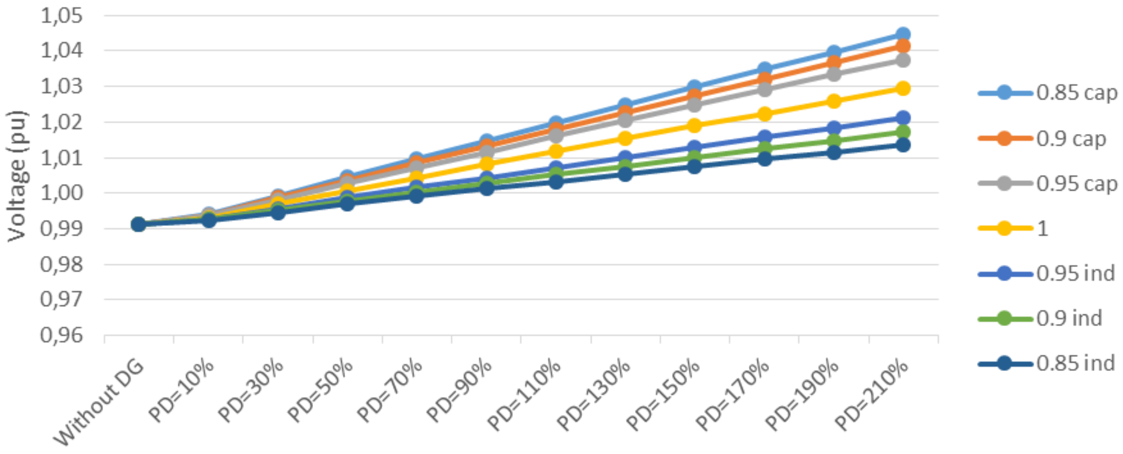

Figure 11: Voltage at the most unfavorable node in rural representative network #6 for a scenario with distributed DG with different power factors.

Initially, for an intermediate demand and no DG injection, voltage at the end of the feeder is around 0.99pu. As PV generation is introduced (considering maximum production P=0.661Pn) in all load nodes, proportionally to demand, voltage rises. When generation exceeds demand, the power flow changes direction, from the load nodes to the primary substation and the voltage profile of the network changes, so that voltage is higher at the end of feeders.

Most PV units are connected to the grid through inverters, so that it is possible to set a certain power factor. If PV units exchange reactive power to maintain an inductive power factor, voltage decreases. In particular, at the end of the feeder, where the maximum voltage rise is experienced, for a penetration degree of 100%, if PV sets a 0.85 inductive power factor, voltage decreases from 1.011 to 1.001pu. For higher penetration degree of PV, voltage rises higher, and the impact of reactive power control from DG is deeper.

In the case of concentrated PV, voltage variation is more extreme and is experienced only in the feeder where PV is located. For a penetration degree of 100%, if PV sets a 0.85 inductive power factor, voltage decreases from 1.10 to 1.05pu.

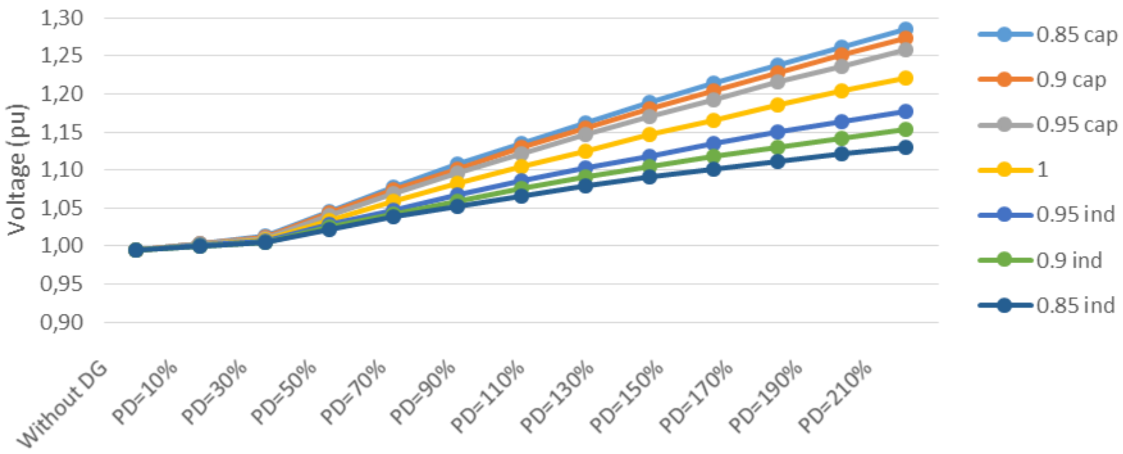

Figure 12: Voltage at the most unfavourable node in rural representative network #6 for a scenario with concentrated DG with different power factors.

Network hosting capacity for the case of concentrated PV is presented in Table 11. If DG maintains a controllable power factor (0.85 inductive), considering a voltage limitation of ±5%, a maximum penetration degree of 73%, compared to a penetration degree of 47% when no voltage control strategy is applied.

Voltage Limits	NHC (base case)	NHC with PF control for DG	ΔNHC with PF control for DG
-5%, +3%	31%	46%	**52%**
-5%, +5%	47%	73%	**56%**
-7%, +7%	64%	79%*	**24%**
-10%, +10%	90%*	90%*	**0%**

Table 11: Network hosting capacity (as a percentage of total rated power of secondary substations in the network) for rural network #6 with PV located at the most unfavorable node, considering different voltage limits, and increase of network hosting capacity (ΔNHC) achieved controlling the power factor of the DG. The asterisks denotes that the thermal limits of the lines are the limiting factor.

Reactive power from DG is an effective voltage control strategy and, as it is provided by the same element that causes the overvoltage, compensation is provided in the best possible location. However, the effect of reactive power output from DG on voltage variation is quite limited in comparison to OLTC. Moreover, DG units exchanging reactive power may increase power flow and, in that case, the thermal limits of the lines can become the limiting factor for a lower DG penetration degree than in the case of OLTC.

Use of storage

Demo 4 has tested the use of energy storage in the form of a 1MVA-1MWh battery connected to the MV grid at an intermediate substation. Two main uses of storage have been identified for voltage control:

a) Charge of the battery: Storage located near DG can help mitigate the voltage rise caused by DG by absorbing the excess of energy (the energy injected into the grid by the DG that is not consumed locally).

b) Discharge of the battery: the presence of DG causes high voltages along the feeder, which can be solved setting the tap of the transformer at the primary substation to a lower voltage. The voltage would decrease in all outgoing MV lines. In the case of a feeder with lower DG production and higher demand with already low voltages, this would deteriorate the voltage profile. Storage located in that feeder could be used to inject energy and increase voltages in that feeder, so that the combination of tap changing and storage would be able to improve the situation for the whole system.

Simulation has been carried out for all representative networks to assess the impact on the voltage profile for both disperse and concentrated DG. Both uses of storage have been analyzed.

However, simulation results obtained so far cannot illustrate the use of storage described in b), since the representative networks used for simulation only have a low number of outgoing feeders from the primary substations and the situation of demand and DG is quite homogenous. The injection of active power in the grid would be useful in the case of having feeders with a rising voltage profile, i.e., with more generation than demand, and feeders with a decreasing voltage profile along the MV line. Although less frequent, this situation has been identified as an actual problem and the use of storage in such way has been discussed in dD4.3. It could happen for instance during noon when PV production is at its maximum, in a region with a residential area with a large volume of PV (rooftops) and an industrial area with a high demand during working hours supplied by different MV lines coming from the same primary substation.

Three different locations have been studied for the battery used to absorb excess of generation: at the beginning, at the middle and at the end of the feeder, where the DG is located. Considering the use of storage to counteract DG, charging a 1MVA-1MWh battery located near the DG, network hosting capacity is improved as stated in Table 12.

Voltage Limits	NHC (base case)	NHC with storage		
		Start of feeder	Mid-feeder	End of feeder
-5%, +3%	31%	31%	38%	53%
-5%, +5%	48%	47%	54%	69%
-7%, +7%	64%	64%	71%	86%
-10%, +10%	90%*	90%*	90%*	113%

Table 12: Network hosting capacity for rural network #6 with PV located at the most unfavorable node and 1MW battery located at different nodes of the feeder. The asterisks denotes that the thermal limits of the lines are the limiting factor.

Results evidence that the closer the storage is located to the DG, the deeper the effect of storage, since power injection from the DG is compensated and flows along the network are reduced.

Regarding the size of the storage, simulations have been carried out and the results obtained for rural network #6 are presented in Figure 13. Logically, the effect of having storage beside the DG to absorb excess of generation is proportional to the size of the storage.

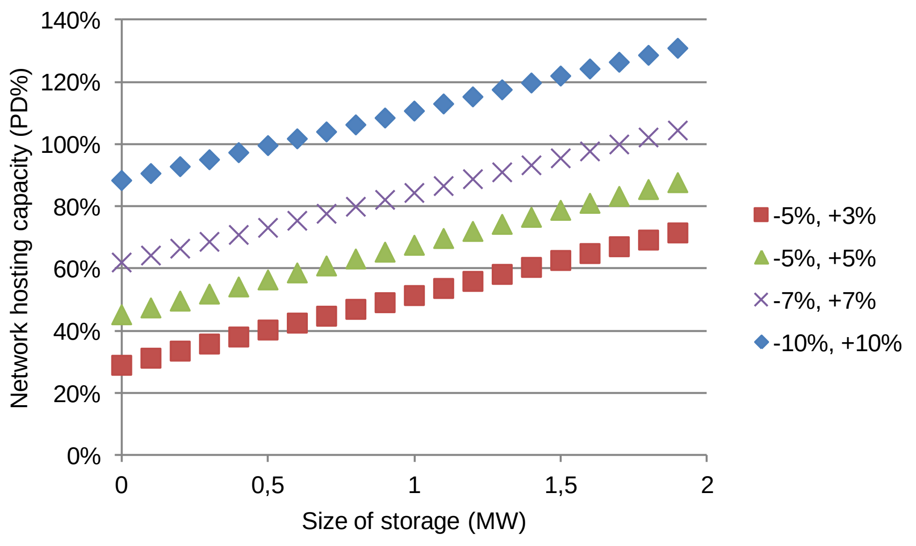

Figure 13: Network hosting capacity for rural network #6 with PV located at the most unfavorable node and different volumes of storage located together with the DG.

Combination of voltage control strategies

In order to achieve the most efficient integration of DG and other DER, the three voltage control strategies should be used and combined depending on the state of the network, in terms of demand and generation. These strategies may be regarded as alternatives to network reinforcement. The traditional fit and forget approach was to integrate as much DG as needed by reinforcing the network when problems aroused. The implementation of these solutions enables postponing investment in network reinforcement by making a more efficient use of the existing infrastructure.

Table 13 displays the increase of network hosting capacity achieved for rural network #6 with PV located at the most unfavourable node with the different voltage control strategies separately, and applying various strategies at the same time. Using the three resources available, better results can be achieved. The optimal tap position, power factor set point for DG and use of storage is determined for each combination.

Voltage Limits	OLTC	PF	Storage	OLTC & PF	OLTC & Storage	PF & Storage	OLTC, PF & Storage
-5%, +3%	93%	52%	74%	149%	178%	166%	228%
-5%, +5%	66%	56%	48%	75%	117%	103%	117%
-7%, +7%	38%	24%	36%	38%	73%	62%	73%
-10%, +10%	0%	0%	25%	0%	25%	25%	25%

Table 13: Increase of network hosting capacity (ΔNHC) for rural network #6 with PV located at the most unfavorable node, considering different voltage limits, and applying OLTC, control of DG PF, and/or using 1MW battery located together with the DG.

Network hosting capacity may be limited by voltage restrictions, set by regulation, or by the thermal limits of the conductors of lines and cables. The limiting factor for each case is very relevant when comparing different strategies to increase network hosting capacity.

In cases where voltage is the limiting factor, more frequent in the case of rural feeders and concentrated DG for restrictive voltage limitations, better results are achieved when using the combination of all strategies considered to obtain the highest increases of network hosting capacity. OLTC is the most effective resource to decrease voltage. However, it is important not to lose sight of the possible negative impact of using OLTC in other feeders with low or null DG injection and high demands, already discussed in 0.

However, when the lines are overloaded and current is the limiting factor, network hosting capacity can only be increased applying voltage control strategies that decrease active and reactive power flowing through the lines. Voltage control provided by DG is based on the injection of reactive power, which increases the loading of the lines resulting in an earlier thermal limit constraint violation. In these cases, the most effective solution is the use of storage close to the DG injections.

In cases where thermal limits of the lines and overvoltages take place (e.g. for a voltage limit of ±7%, in Table 13), most effective strategies are OLTC and storage. Finally, in the scenarios that consider more moderate voltage limitations (e.g. for a voltage limit of ±10%, in Table 13), typically thermal limits of the lines are the limiting factor. In these situations, the only effective strategy is the use of storage close to the DG injections, and combinations with other strategies lead to no improvement.

Table 14 displays the increase of network hosting capacity achieved for suburban network #2 with wind production located at the most unfavourable node with the different voltage control strategies separately, and applying various strategies at the same time. It is relevant to highlight that the network here considered is a suburban network and has shorter lines and lower impedance of the conductors with respect to the rural representative network #6. Thus, same amount of DG has a lower impact on voltage. Due to this fact, thermal limits of the lines would also be the limiting factor for lower voltage limits (i.e. ±7% in addition to ±10% in network #2, while only ±10% in network #6). Taking this fact into consideration, results presented in Table 14 reveal the same conclusions above mentioned.

Voltage Limits	OLTC	PF	Storage	OLTC & PF	OLTC & Storage	PF & Storage	OLTC, PF & Storage
-5%, +3%	97%	76%	38%	97%	135%	118%	135%
-5%, +5%	29%	21%	25%	29%	54%	42%	54%
-7%, +7%	0%	0%	19%	0%	19%	19%	19%
-10%, +10%	0%	0%	19%	0%	22%	19%	22%

Table 14: Increase of network hosting capacity (ΔNHC) for suburban network #2 with wind production located at the most unfavorable node, considering different voltage limits, and applying OLTC, control of DG PF, and/or using 1MW battery located together with the DG.

<u>SRA rules:</u>

- Network hosting capacity can be clearly be increased making use of the voltage strategies considered in this analysis (OLTC, DG reactive power control and the use of storage) and the combination of these strategies, especially for those cases where overvoltages are the limiting factor to the integration of DG.
- In the cases where thermal limits of the conductors are the limiting factor, the effect of voltage control strategies is much more limited. The most suitable strategy is to locate storage as close as possible to the DG to mitigate the excess of power injected by DG.
- The use of OLTC in the primary substation has the deepest impact on voltage profiles, shifting up or down the voltage in all the nodes of the feeders supplied by the primary substation. It is the most effective voltage control strategy. However, it may not be adequate to solve more local problems, since the impact could be negative for other regions of the network in a different situation (for instance in the case of having feeders with overvoltages caused by concentrated DG and feeders with high demand and thus lower voltages).
- The participation of DG in voltage control by modifying its power factor is positive although voltage is only slightly modified. It has the main advantage of having a very local effect right where the DG causing overvoltage is located.
- Storage can be used to modify active power flows, so the effect on voltage control is much deeper than regulation of reactive power of DG. The location is key: in the case of storage close to the DG, storage increases network hosting capacity in the region of the network accordingly to its size. By contrast, if the storage is located close to the primary substation, the effect on the voltage profile of the network is very weak.

Sensitivity analysis to R/X parameter. Influence on voltage strategies.

Different conductors for overhead lines and underground cables have different technical characteristics. Typically, conductors of larger section are more inductive, while conductors of smaller section are more resistive. The difference is more relevant across different voltage levels, so that MV lines are more resistive than high voltage lines, but more inductive than LV lines.

The behavior of the lines depends on several factors: (i) whether the network is overhead or underground, (ii) rated voltage and (iii) loading of the network. Underground cables have typically lower R/X ratios and thus absorb more reactive power. Moreover, the lines consume more reactive power for higher voltage levels.

Simulations have been carried out to analyze the impact of the ratio R/X of the conductors, and the results obtained for rural network #6 are presented in below.

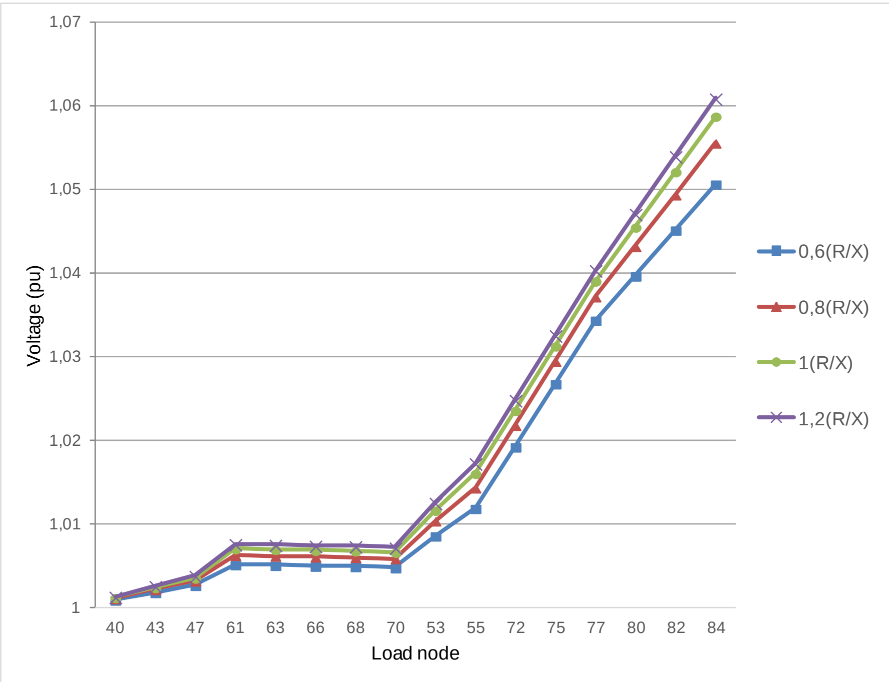

Figure 14: Voltage profile of feeder 2 of the rural network #6 for a scenario of intermediate demand and maximum PV production for different (R/X) ratio of the lines, with PV located in the most unfavorable node (84), considering a 50% of DG penetration degree (over the total installed capacity of the secondary substations of network #6) and without considering voltage strategies.

As it can be observed in Figure 14, the higher the (R/X), this is, the more resistive the lines are, the higher the impact of the active power injection of DG. This is the reason why lower voltage rises are observed when the (R/X) ratio is lower, i.e. when the lines are more inductive. Table 15 presents the network hosting capacity for the different values of R/X.

Voltage Limits	0,6(R/X)	0,8(R/X)	(R/X)	1,2(R/X)
-5%, +3%	35%	32%	30%	29%
-5%, +5%	54%	49%	47%	45%

-7%, +7%	74%	67%	64%	62%
-10%, +10%	89%*	90%*	90%	87%

Table 15: Network hosting capacity (NHC) for rural network #6 with PV located at the most unfavorable node, considering different voltage limits, and varying (R/X) ratio of the lines. The asterisks denote that the thermal limits of the lines are the limiting factor.

Additionally, more simulations have been carried out with the aim of analyzing the impact of (R/X) ratio on different voltage strategies. Table 16 and Table 17 show the impact of this ratio variation on the improvements of NHC provided by DG power factor control and storage strategies respectively.

Voltage Limits	0,6(R/X)	0,8(R/X)	(R/X)	1,2(R/X)
-5%, +3%	104%	74%	52%	41%
-5%, +5%	42%	52%	56%	43%
-7%, +7%	11%*	23%*	24%*	28%*
-10%, +10%	0%*	0%*	0%*	0%*

Table 16: Increase of network hosting capacity (ΔNHC) for rural network #6 with PV located at the most unfavorable node, with DG power factor control, considering different voltage limits, and varying (R/X) ratio of the lines. The asterisks denote that the thermal limits of the lines are the limiting factor.

As it can be observed in the results provided in Table 16, whenever the limiting factor is the voltage limit (e.g. for a voltage limit of (-5%,+3%), in Table 16), a lower (R/X) ratio of the lines, i.e. lines with higher inductive behavior, enables higher improvements of NHC with DG power factor control, as controlling reactive power through the lines enables a higher decrease of voltages.

Voltage Limits	0,6(R/X)	0,8(R/X)	(R/X)	1,2(R/X)
-5%, +3%	64%	70%	74%	76%
-5%, +5%	41%	45%	48%	49%
-7%, +7%	30%	33%	35%	36%
-10%, +10%	25%*	25%*	25%*	26%*

Table 17: Increase of network hosting capacity (ΔNHC) for rural network #6 with PV located at the most unfavorable node, considering storage and different voltage limits, and varying (R/X) ratio of the lines. The asterisks denote that the thermal limits of the lines are the limiting factor.

By contrast, in the cases where voltage is the limiting factor when considering the storage strategy (e.g. for a voltage limit of (-5%,+3%), in Table 17), higher (R/X) ratios would enable higher NCH improvements, as the effect of active power on the voltage profiles is higher. If thermal limits of the lines are the limiting factor (e.g. for a voltage limit of ±10%, in Table 17), as (R/X) variations have been performed keeping the total impedance of the lines constant, these variations will not affect

<u>SRA rules:</u>

- Higher R/X ratios are translated into higher impact of DG on voltage profiles. On the other hand, reactive power has a deeper impact on more inductive lines, so the participation of DG in voltage control is more effective for lines with lower values R/X.
- Voltage control strategies should be prioritized for more problematic networks, where voltage problems occur and where the active participation of DG in voltage control and the use of storage can help increase network hosting capacity.

the storage strategy improvement.

3.2.3 Demo 2: LV network monitoring and control

The use case of LV network monitoring and control is based on the implementation of AMI for fault detection and with a long-term perspective to pave the way for the connection of DER. mainly solar PV and EVs.

Technical SRA has focused on the assessment hosting capacity of LV networks with the aim to determine the conditions and EV and DG penetration degrees that could cause operational problems and would therefore require monitoring. Since EV charging points and PV units are most frequently connected to the LV grid as single-phase conections, phase unbalances are bound to increase.

In order to determine network hosting capacity capturing the effect of unbalances, a three-phase unbalanced power flow analysis has been carried out to determine voltage and loading profiles in order to detect overloads and voltage problems for different scenarios. Additionally, energy losses have been assessed.

Phase unbalance

Voltage and current unbalance can be a relevant problem in LV distribution networks, often neglected by DSOs due to the current lack of LV monitoring. The European Standard EN 50160 on “Voltage Characteristics of Public Distribution Systems” states that voltage must not exceed an unbalance of 2%, or up to 3% for some specific locations, during 95% of the time of the week. However, this standard is not enforced since voltage unbalances are hardly ever measured in practice.

In higher voltage levels both generation and demand are typically three-phase and balanced. However, LV loads and DER are generally connected to a single-phase, only distributed initially at the time of connection. Unbalanced currents in the LV grids are filtered by the Delta-Y connection of MV/LV transformers, but in the LV networks it can be quite high, as shown in Figure 15.

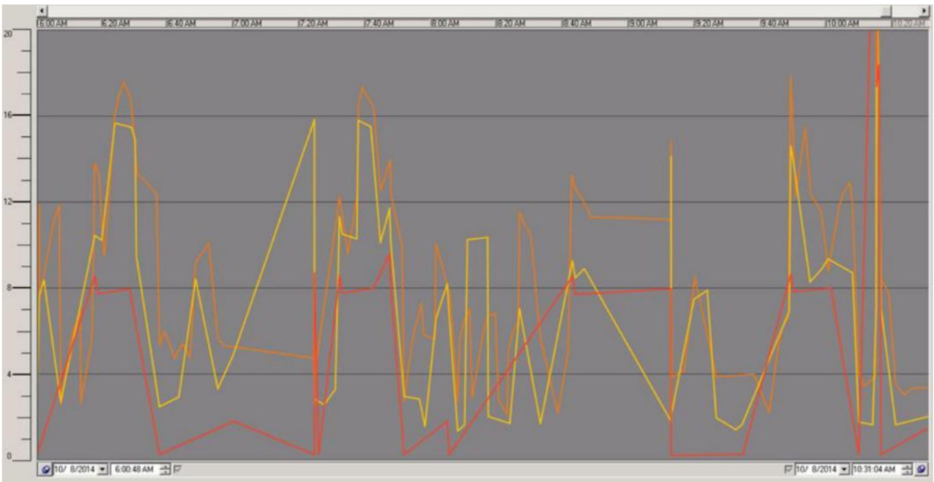

Figure 15: Unbalanced three-phase current in an outgoing feeder of a secondary substation in demo site. Source dD2.3

One of the main impacts of unbalanced systems on the network is an increase the energy losses. For example, in a four wire three-phase system the maximum current unbalance presents 3.5 higher energy losses (losses factor) as compared to a balanced situation, considering that same load, separated a distance L is supplied by a conductor with a resistance R (see Figure 16). Additionally, the voltage drop in the phase with the highest current may require the installation of voltage compensation equipment, such as capacitor banks or voltage regulators. This may ultimately require to upgrade the conductors in order to increase the ampacity of a single phase or to reduce the voltage drop.

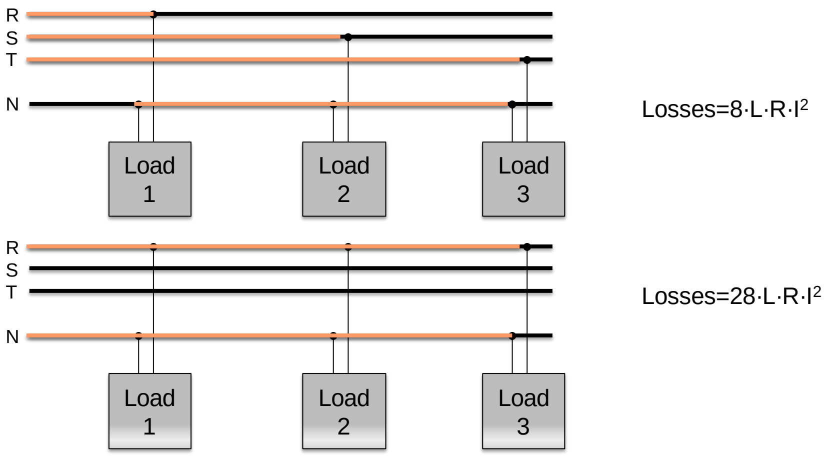

Figure 16: Effect of current unbalance on energy losses in a 4-wire network

A second effect of voltage unbalances is the potential damaging of electric equipment connected to the network such as transformers, electronic devices, generators and induction motors. In all these devices, voltage unbalance results in an internal current unbalance causing higher losses and increased heating. The most troublesome case is that of induction motors as they typically work at rated capacity and, consequently, unbalances result in overcurrents and overheating. These effects accelerate the degradation of the insulation material, and reduce the useful life of the equipment.

3.2.3.1 Technical analysis for SRA

Three-phase power flow calculations have been made for five rural LV networks and two semi-rural LV networks. The power flow has been computed using the forward/backward sweep or ladder algorithm, which is a simple, efficient and robust three-phase power flow algorithm for radial distribution networks that uses forward and backward propagation to calculate branch currents and bus voltages (Thukaram et al. 1999).

The analysis has been made on an hourly basis covering a full day, representative of an average working day, where the average power consumption for each of the 24 hours are considered. All end consumers have been assumed to be residential, following the same consumption pattern. Based on this demand profile, four different scenarios have been defined for different loading levels.

Additionally, the effect of the degrees of unbalance has been studied, considering 21 situations ranging from a fully-balanced system up to a system where all of the current circulates through only one of the phases. The degree of unbalance is defined for this analysis as the maximum voltage deviation of each phase voltage with respect to the mean.

Gradual penetration of PV and EV have been separately addressed through various scenarios of penetration of PV and slow charging of EVs.

3.2.3.2 Lessons learned and SRA rules

Effect of phase unbalance

These results includes the energy losses, the share of consumers who experience under-voltages and the share of consumers who experience over-voltages. Energy losses are sometimes measured through a loss factor. The losses factor for a certain scenario represents the increase in losses in a fully unbalanced system, as compared to the same scenarios without unbalances (see Figure 16).

Firstly, the effect of phase unbalance on LV networks under different loading levels has been analysed. The impact of these parameters on the losses factor for all the LV grids considered is presented in Table 18. It can be observed that for any network the increase in phase unbalance results in higher energy losses. This effect has an exponential behaviour and ranges, showing losses factor values ranging from 1.3 up to 3.9 times the losses for a balanced network.

	Load	R1	R2	SR1	SR2	R3	R4	R5
Losses factor	**25%**	3,19	2,75	2,38	2,74	2,16	1,31	1,79
	50%	3,52	3,55	3,46	3,69	3,23	1,97	2,85
	75%	3,25	3,56	3,78	3,87	3,54	2,62	3,31
	100%	2,92	3,38	3,83	3,82	3,51	3,1	3,36

Table 18: Effect of different loading levels in unbalanced LV networks (loss factors)

Moreover, as depicted in Figure 17, the higher the loading level the higher the energy losses in all cases. This figure clearly illustrates that, since energy losses increase with the square of the current, energy losses for a scenario with the maximum load (factor 1) losses increase much more than in a scenario where consumption is at 25% of contracted/maximum capacity (factor 0.25). Therefore, the impact of unbalances on losses is particularly relevant in networks which are more heavily loaded. It can be seen that for shorter and less loaded grids (e.g. R4 and R5), lower values of the losses factor have been generally obtained, whereas the opposite effect is observed for the semi-rural networks, which tend to be more heavily loaded.

Moreover, this effect is exponential with the level of unbalance. Therefore, the problem of increasing energy losses may not be very relevant for moderate levels of unbalances (typically below 25-30%). Nonetheless, in case unbalances exceed this threshold a significant increase in LV energy losses is to be expected and DSOs should implement measures to mitigate it.

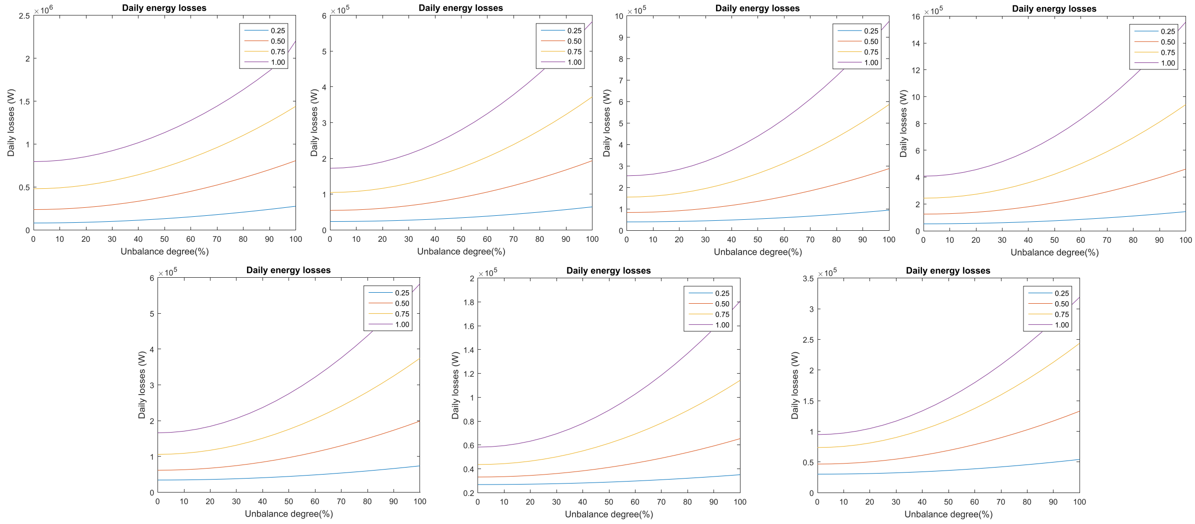

Figure 17: Daily energy losses under different loading levels and degree of unbalance in the LV networks. From left to right and top to bottom: R1, R2, SR1, SR2, R3, R4, R5

The degree of phase unbalance not only affects energy losses but also bus voltages and, consequently, the network HC. From Figure 18, it is clear that in the higher the unbalance, the more noticeable the effect of loading levels on bus voltages, measured as the number of consumption points below the limits (90% of rated voltage according to EU standards). No over-voltages were observed for any degree unbalance or level of loading in any of the LV networks analyzed since the original grids were adequately designed to supply the local load.

Another relevant observation is that the impact of phase unbalances on bus voltages varies among networks much more significantly than in the case of energy losses discussed above. For example, it can be seen in Figure 18 that in the case of network R2, an unbalance of 5% will already result in some consumers with voltages below 90% in a maximum demand scenario. In the same case, a fully unbalanced system would see 12% of the network buses with under-voltages. On the contrary, no voltage constraints occurred for network R4 in any case. This is mainly due to the physical characteristics of the LV networks.

In Figure 18, it can be easily seen that voltage drop is mainly a problem in long overhead feeders such has R1, R2 and R3; where voltage constraints violations are observed for relatively moderate degrees of unbalance. Whilst significant under-voltage are observed beyond a threshold of 25-30% in networks R2 and R3, network R1 would be an extreme case in which network may need reinforcing, as under-voltage are observed even with very low degrees of phase unbalance. The effect of unbalances on under-voltages in the other networks, generally much shorter and largely underground (SR1, SR2 and R4), is limited to situations with a very high load and very highly unbalanced grids. Another relevant parameter clearly setting apart these two groups of network is the share of network buses experiencing voltage problems, which is almost negligible in the latter group (even for very extreme situations). The network R5 could be seen as an intermediate situation between both groups.

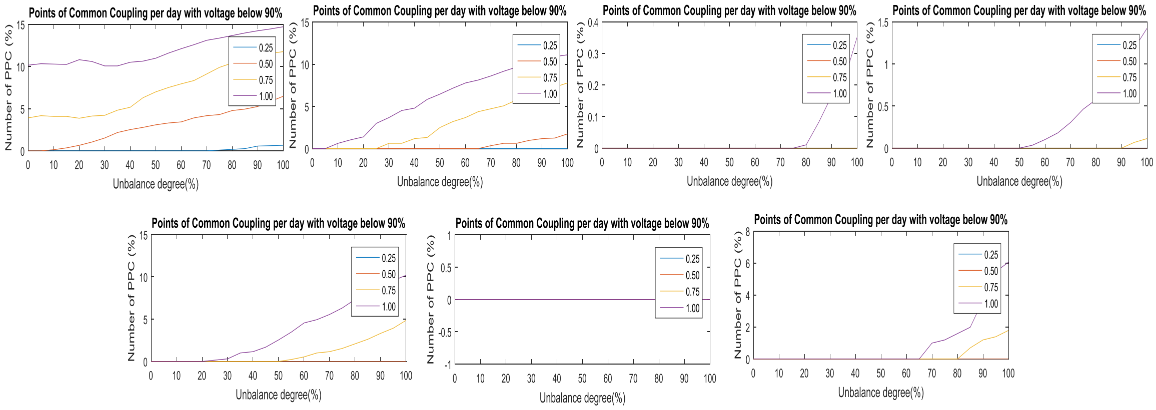

Figure 18: Share of buses experiencing over-voltages under different loading levels and degree of unbalance in the LV networks. From left to right and top to bottom: R1, R2, SR1, SR2, R3, R4, R5

<u>SRA rules:</u>

- The increase in phase unbalance results in exponentially higher energy losses (increase of 130% to 390% with respect to the losses experienced in fully-balanced networks). The impact of unbalances on losses is particularly relevant in networks which are more heavily loaded.
- The degree of phase unbalance also affects voltages and, consequently, the network HC. Voltage constraints violations may occur especially in long overhead feeders. The higher the unbalance, the more noticeable the effect of loading levels on bus voltages.

Electric vehicles

The effect of the penetration of electric vehicles slow charging in unbalanced networks on the loss factors is shown in Table 19. We observe a similar impact on the energy losses as in the case above. For high degrees of phase unbalance, energy losses increase exponentially, reaching values of 2 to 3.8 times the losses in a fully balanced system.

	EVs	R1	R2	SR1	SR2	R3	R4	R5
Losses factor	5%	3,52	3,55	3,47	3,7	3,25	1,99	2,87
	10%	3,52	3,56	3,49	3,71	3,26	2,01	2,89
	15%	3,51	3,56	3,5	3,72	3,28	2,02	2,90
	20%	3,51	3,57	3,51	3,73	3,29	2,04	2,92

Table 19: Effect of EV penetration in unbalanced LV networks (loss factors)

As charging increases the load in valley hours (mainly during the night) and the EV penetration levels considered are deemed moderate but realistic nonetheless, the total effect on losses for different penetration levels is low, as shown in Figure 19. The same exponential behaviour discussed above is observed. Thus, unbalance degrees beyond 25-30% drive a fast increase in LV distribution losses in all EV penetration scenarios. Notwithstanding, reaching higher values of unbalance degree becomes more likely under larger penetration levels of EVs as they constitute a relatively large single-phase load that increases the heterogeneity in load profiles of individual consumers, i.e. consumers with EVs will show a much different load profile as compared to those without an EV.

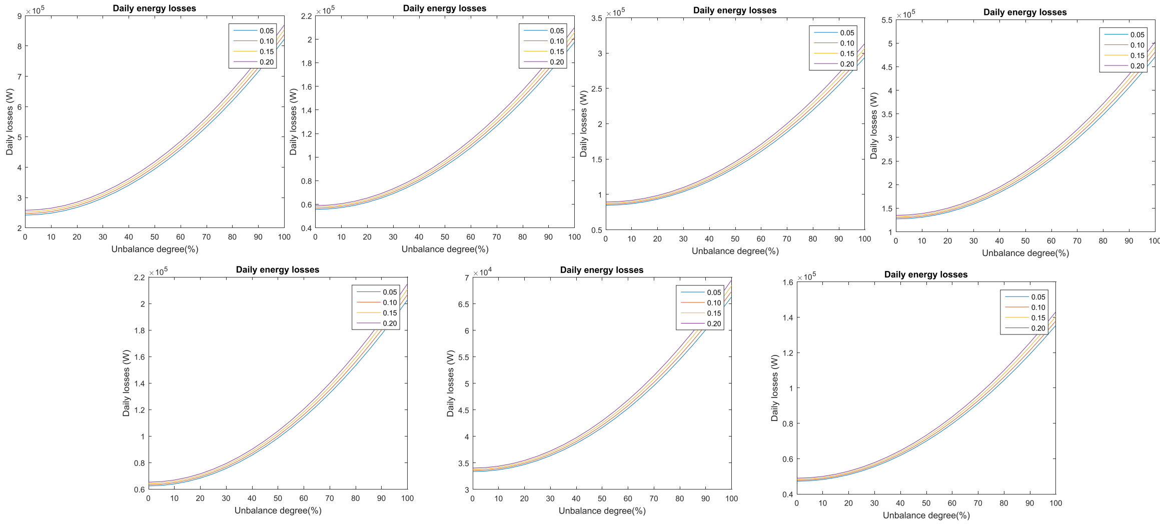

Figure 19: Daily energy losses under different EV penetration levels and degree of unbalance in the LV networks. From left to right and top to bottom: R1, R2, SR1, SR2, R3, R4, R5

The behaviour of bus voltage profiles follows a similar pattern to the case with only load previously analyzed too. Under-voltages were only observed in three of the networks analyzed, namely R1, R2 and R3. Again, this is due to the physical characteristics of these networks which present long overhead feeders. Note that other more aggressive charging strategies may result in different impact on the system. For instance, if EV charging took place during working hours, the overall network load would grow, pushing energy losses upwards and presumably causing a higher number of buses to experience voltage levels below the minimum threshold. Furthermore, if fast charging stations were used[7], these would presumably be connected as a three-phase load. Therefore, in spite of rising network loading and losses, system unbalance would not be affected.

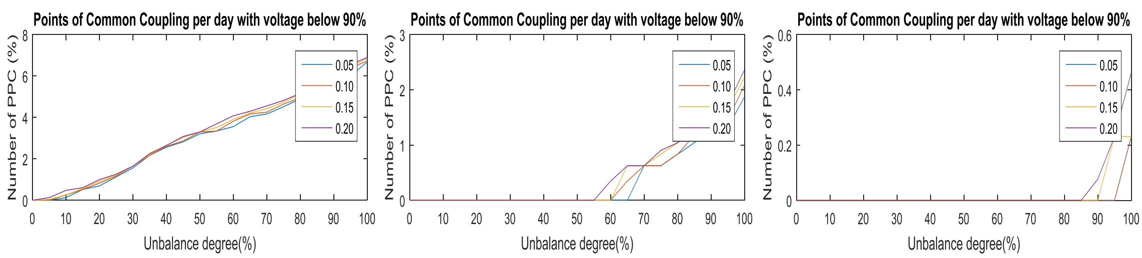

Figure 20: Share of buses experiencing over-voltages under different EV penetration levels and degree of unbalance in the LV networks. From left to right: R1, R2, R3

[7] Note that fast charging stations will be most probably directly connected to the MV network given the charging capacity needed. Hence, this discussion in mainly hypothetical.

SRA rules:

- Under the presence of electric vehicles slow charging, the loading of the lines increase, and the implications of phase unbalance remain the same: energy losses increase exponentially with unbalance (up to 200-380% with respect to a fully-balanced system).
- Charging strategies and interaction with demand are key parameters. Since EV charging is expected mainly in the load in valley hours (during the night), no under-voltage problems are expected. If EV charging took place during peak demand, energy losses would increase much more and voltage problems could arise.
- The penetration of EV may increase unbalance of distribution networks, as EVs are relatively large single-phase loads.
- In the case of fast charging, charging stations are typically three-phase loads, so system unbalance would have no effect.

Distributed generation: PV

Table 20 shows the impact of increasing the penetration of PV in the system on the losses factor. The generation curve will reduce consumption in the mid-day hours, hence slightly reducing losses; this effect is observed in Table 20, where initially losses factors are reduced for 50% of PV penetration but then increase again for 75% or 100% penetration.

	PVs	R1	R2	SR1	SR2	R3	R4	R5
Losses factor	**25%**	3,43	3,34	3,18	3,47	2,92	1,71	2,51
	50%	3,38	3,27	3,09	3,39	2,82	1,67	2,41
	75%	4,55	3,92	3,43	3,75	3,35	1,83	2,72
	100%	7,72	5,44	4,06	4,45	4,49	2,16	3,27

Table 20: Effect of PV penetration in unbalanced LV networks (loss factors)

Figure 21 allows analysing the effect that PV penetration has on energy losses under different degrees of phase unbalance in the system. Comparing these results with those previously obtained in the scenarios without generation, it can be observed that moderate penetration levels (of up to 75% of the local contracted/maximum capacity) actually mitigate the increase in losses driven by system unbalances. The steep increase in daily losses that previously occurred beyond a threshold of 25-30% degree of unbalance, now takes place for unbalance degrees beyond a threshold of 50-60%. On the contrary, higher PV penetration levels (100% PV scenario) the exact opposite happens. In these scenarios, the slope of the exponential curves starts increasing sharply for lower levels of unbalance degrees, generally around a value of 20%, in all the LV networks analyzed.

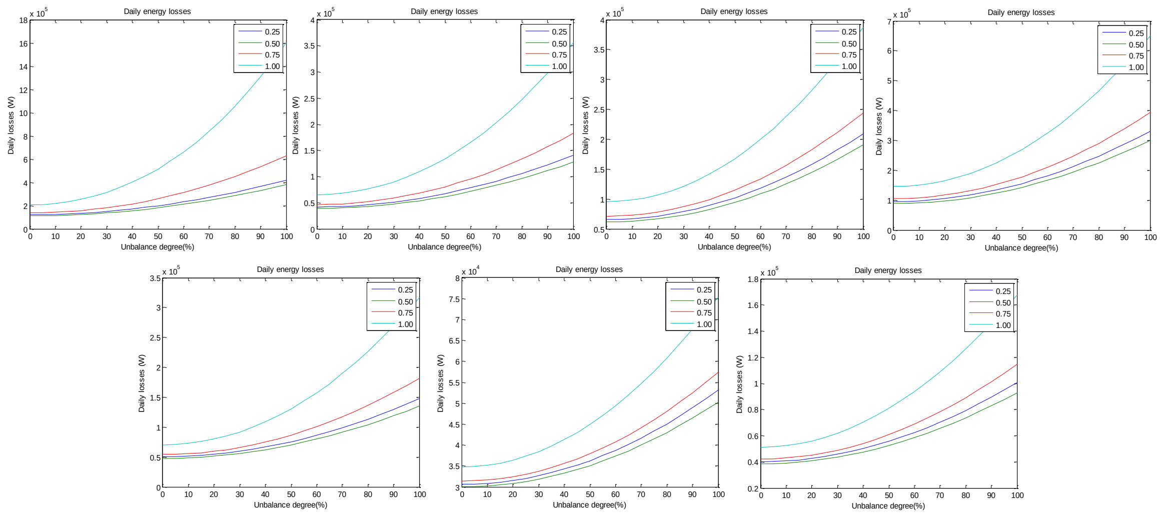

Figure 21: Daily energy losses under different EV penetration levels and degree of unbalance in the LV networks. From left to right and top to bottom: R1, R2, SR1, SR2, R3, R4, R5

The impact of PV penetration and system unbalance significantly differs from the scenarios where only loads were connected to the LV grid, as it can be seen in Figure 22. On the one hand, the problem of under-voltages is generally mitigated thanks to the penetration of solar PV. The networks for which this was previously a major problem (R1 and R2), a much lower number of buses would experience under-voltages. Furthermore, this problem is virtually non-existent for the remaining grids in the PV scenarios analyzed. Note that they may happen in other periods of the year with very high load and little PV production, as in the case of residential consumers with electric heating during winter periods. During these hours, the effect of unbalances to be expected would be closer to the situation depicted in Figure 18.

On the other hand, the progressive penetration of PV may cause over-voltages in those hours with higher local production in those buses with a larger installed capacity. For instance, in network R1 this already happens even in the absence of phase unbalance for high PV penetration levels. Notwithstanding, the degree of unbalance clearly causes a higher number of voltage violations due to excessively high bus voltages. Note that the connection of PV units at the LV level is bound to increase the likelihood of high degrees of unbalanced for the same reasons mentioned about EVs. Figure 22 also shows that over-voltages are to be expected particularly in long overhead LV feeders (e.g. R1, R2 and R3). In the remaining networks, over-voltages only arise for very large PV penetration levels in very specific buses.

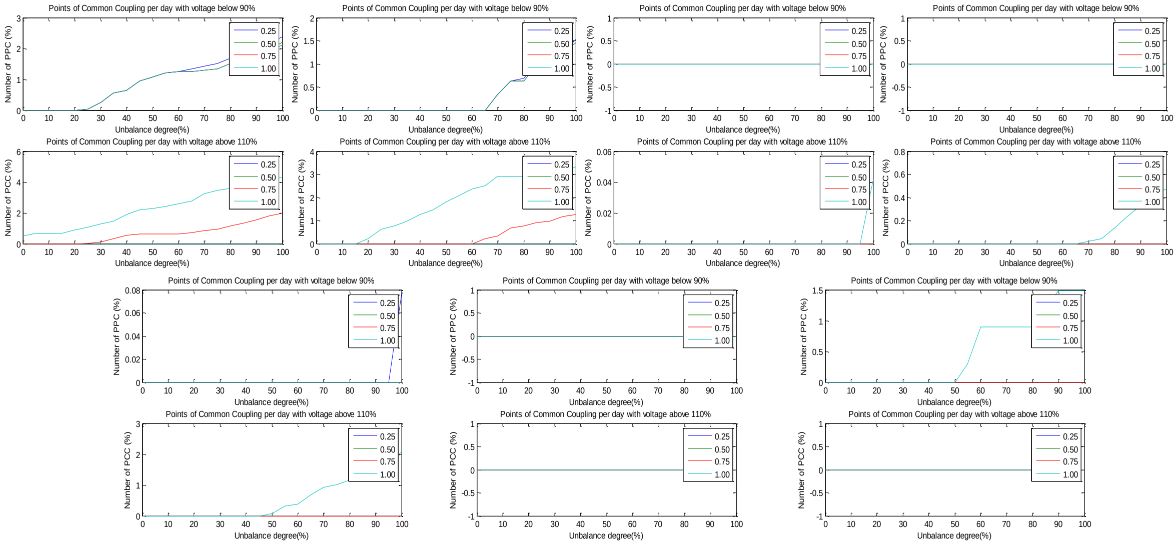

Figure 22: Share of buses experiencing over-voltages and under-voltages under different PV penetrations and degree of unbalance in the LV grids. From left to right and top to bottom: R1, R2, SR1, SR2, R3, R4, R5

It is important to highlight that this over-voltage problem will limit the hosting capacity of PV in these networks. For most of the networks studied there is a limit for PV hosting to 75% or 100% contract power in the consumer facilities when the system presents a high phase unbalances. Moreover, in some networks this limit is reached even for low unbalance (0-20%). It can also be observed that the higher the unbalance the lower the hosting capacity for PV. Lastly, the selected scenarios assumed that for fully unbalanced systems current flows in one single phase, but there may exist other unbalanced scenarios where loading current flows in one phase and PV injections in another phase. These extreme scenarios will result in even more limited PV hosting capacity.

SRA rules:

- PV penetration slightly reduces the losses in the system for low penetration degrees. For higher shares of PV, if PV production exceeds demand, losses are increased.
- Moderate penetration levels of PV (up to 75% of maximum capacity) mitigate the increase in losses driven by system unbalances (the sharp increase for an unbalance degree of 25-30% is shifted to 50-60%). Higher PV penetration degrees (100%) produce the opposite effect (the drastic increase of losses is shifted to an unbalance degree of 20%).
- For higher shares of PV, when PV production exceeds the demand, over-voltage problems may arise and limit network hosting capacity, especially in the case of longer lines.
- Unbalance reduces network hosting capacity, so that most of the networks studied can accommodate a volume of PV of around 75% to 100% of the total contracted power of consumer for high degrees of phase unbalance.
- The penetration of PV may increase the unbalance in the system, as it is typically connected on a single phase.

3.2.4 Demo 6: Maximize PV production in LV

This use case aims to improve efficient integration of PV in the LV network, avoiding overloads and overvoltages in the networks that can lead to curtailment of PV production. For this purpose, the so-called Network Energy Manager (NEM) has been implemented, market-based system where aggregators can offer available flexibility through DER management to the DSO. On a day-ahead basis, historical data and meteorological predictions are used to forecast generation and demand. Loadflow analysis is run to identify congestions and determine the increase (or reduction) of load that would be required to avoid generation (or demand) curtailment. Aggregators can provide flexibility by managing the charge and discharge of different storage batteries and flexible demand from consumers with electric water heaters that can shift demand to different hours. The technical analysis carried out for this use case, as will be explained, is focused exclusively in the overloading of transformers and how demand flexibility and storage can help avoid it.

3.2.4.1 Technical analysis for SRA

The integration of DG in distribution network may be limited by different technical constraints, namely loading of the lines, loading of the transformers and voltage problems. The technical analysis carried out for this use case is focused exclusively in the overloading of transformers and how demand flexibility and storage can help avoid it.

Voltage control has been studied in section 3.2.2 for the use case of voltage regulation in MV and how the use of storage and OLTC can mitigate overvoltages caused by PV in MV networks. Voltage problems are most frequent for long, overhead lines, so voltage problems are much less frequent in LV networks, where lines are much shorter. Section 3.2.3 presented the technical SRA for the use case of LV Network Monitoring and Control, dealing with the integration of PV and EVs in LV networks. Technical SRA consisted in three-phase unbalanced power flow analyses to monitor the voltage profile along the LV network as a limiting factor to the increase of penetration of DER. A strong focus was put on the effect of the phase unbalance of load and DER on network hosting capacity.

In distribution planning, LV networks are sized so that the capacity of the conductors can accommodate future demand. Actually, the marginal cost of increasing the capacity of LV lines, i.e. choosing a conductor with a wider section over another one with lower capacity, is relatively low at the moment of the construction, in comparison to the total cost of building the LV line (digging a trench, laying the conductor, etc.). Therefore, LV lines are usually sized with extra capacity and thus normal operation is usually quite far from maximum loading. By contrast, the cost of transformers compared to the cost of re-sizing capacity (i.e. substituting a transformer with another of higher capacity) is much higher and, most importantly, transformers of higher capacity have much higher no-load losses. Hence, transformers are usually more tightly sized, to avoid operation under a too low loading degree. In the presence of high penetration of PV, the total injection of PV could exceed the nominal power of the transformer in periods of low demand. PV production (or demand) that causes overloading of the transformer would have to be curtailed.

The use case of PV maximization is based on the use of batteries and demand flexibility to reduce the net power flow through the transformer and thus avoid curtailment. The system implemented in the Demo, the NEM, is based on a market where aggregators offer the flexibility of a certain number of consumers and other DER owners.

The technical SRA for the use case of Maximize PV production in LV is focused on the loading of the transformer. In line with the NEM, technical SRA of this use case has considered the secondary substations as the reference to consider a minimum area to manage the provision of flexibility, grouping all the consumers and DER connected to the LV lines fed by one secondary substation.

The technical SRA presented in this section evaluates the power flow through the transformer in the secondary substation for a full day, for different generation and demand scenarios. The net power flow is obtained as the sum of the demand of all consumers, subtracting the injection of all PV for every hour. The analysis quantifies the corresponding amount of energy that overloads the transformer to determine the size of storage and /or demand flexibility that would be required to avoid curtailment. Therefore, network hosting capacity has been computed as the maximum installed capacity that can be accommodated for each scenario so that transformer rated capacity is not surpassed, without taking the voltage at the LV nodes into account (even though this type of constraints is likely to be the most restrictive / to happen the first).

Representative networks

The technical analysis has considered a set of LV networks of 13 different distribution areas and countries relevant for the tested use cases. The technical SRA for this use case is focused on the loading of the transformer, and therefore, the relevant network parameters are the size of the transformer of the secondary substation and the degree of loading of the system. These two parameters are linked to the type of network so that typically, the density of load is much higher in urban networks than in more rural areas. Generally, transformers of higher capacity are used for urban areas.

Demand

Several load profiles have been considered for consumers of different type (residential/commercial), demand (high/medium/low contracted power, with/without electric heating) and flexibility (with/without water heaters, with/without time discrimination in electricity tariff); as well as for different periods, in terms of day of the week (weekdays/weekends) and season of the year (winter/summer). Only consumers connected to the LV grid have been analysed, so that industrial consumers and commercial consumers of big size (such as for instance shopping malls), which would be connected to the MV grid, are necessarily left out of the analysis. The types of consumers are listed in Table 21.

	Type of consumer	Tariff	Electric heating	Demand flexibility	Contracted power
ResS	Res: residential	S: tariff with no time discrimination	no electric heating		
ResS+h	Res:residential	S: tariff with no time discrimination	h: with electric heating		h: smaller size
ResS+H	Res:residential	S: tariff with no time discrimination	H: with electric heating		H: larger size
ComS-S	Com: commercial	S: tariff with no time discrimination			S: smaller size
ComS-L	Com: commercial	S: tariff with no time discrimination			L: larger size
ResT	Res:residential	T: time-of-use tariff	no electric heating		
ResT+h	Res:residential	T: time-of-use tariff	h: with electric heating	with electric water heater	h: smaller size
ResT+H	Res:residential	T: time-of-use tariff	H: with electric heating	with electric water heater	H: larger size

Table 21: Consumers considered for demand scenarios for technical SRA of use case maximization of PV production in LV

PV generation

Different PV production curves have been considered to account for different geographical locations, in representation of Northern/Mid/Southern Europe, and for different times of the year considering a typical day of winter/summer[8]. The PV profiles are displayed in Figure 23.

[8] Source: Photovoltaic Geographical Information System by the Joint Research Centre. Available at: http://re.jrc.ec.europa.eu/pvgis/apps4/pvest.php#

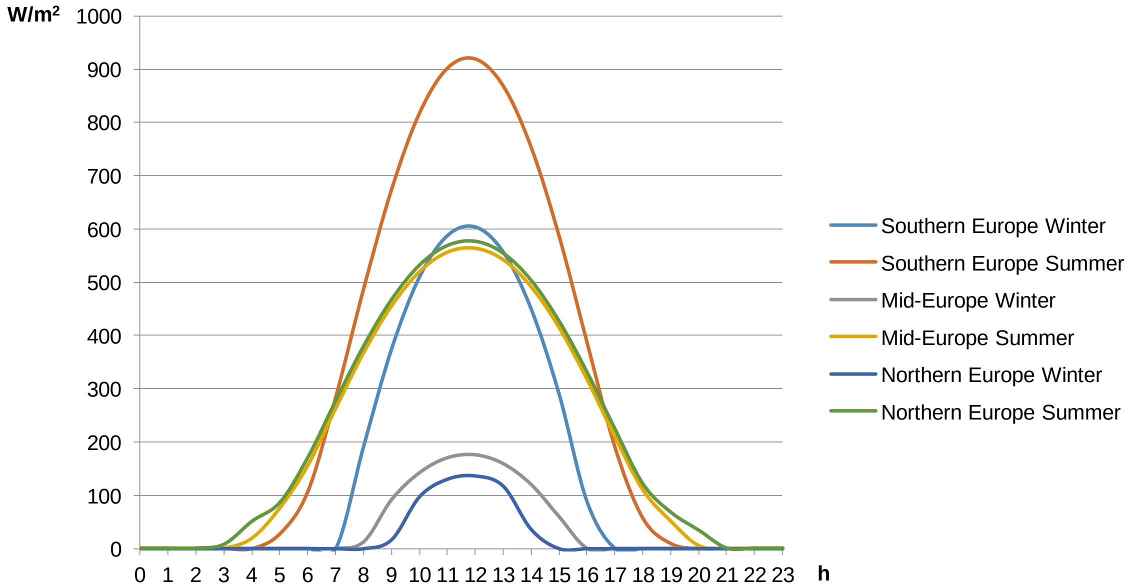

Figure 23: PV production profiles considered for technical SRA of use case maximization of PV production in LV

3.2.4.2 Lessons learned and SRA rules

The technical SRA of the use case of Maximize PV production in LV networks has focused in the overloading of transformers of secondary substation as a limit to network hosting capacity, forcing PV production to be curtailed during the day. Simulations have been carried out to evaluate the power flow through the transformer in the secondary substation for a full day, for different generation and demand scenarios. The analyses carried out quantified the corresponding power and amount of energy that overloads the transformer to determine the size of storage and /or demand flexibility that would be required to avoid curtailment. The main conclusions extracted from these simulations are summarized in this sub-section.

For each case, it is assumed that all consumers are of the same type, and the number of consumers is such so that the maximum consumption in the year amounts to 50% of the rated capacity of the transformer (so that the maximum total consumption is 200kW). The penetration degree of PV is measured with respect to the rated capacity of the transformer. The results are displayed in colour maps that show the number of hours of transformer overload and the volume of exceeding power and energy through the transformer for the different types of consumer considered and for an increasing penetration degree of PV, ranging from 0% to 200% (with respect to rated capacity of the transformer).

Looking at the exceeding energy and power, storage could increase network hosting capacity. For instance, according to Figure 24, a LV network of residential consumers of type ResS, in a weekday in winter, can accommodate a PV penetration degree of 120%, and would require a storage of 600kWh of capacity and charge rate of 210kW in order to integrate a PV penetration degree of 200% without PV curtailment during winter weekdays. Storage of 100kW would increase network hosting capacity by 21%, from 560KW (penetration degree of 140%) to 680kW (penetration degree of 170%), and it would be used for 3 hours in an average winter weekday.

The use of electricity varies across the different types of consumers. In general, residential consumers have their peak consumption during the evening and a smaller peak early in the morning. The lowest demand is registered during the night. PV generation injects power during the day, so that in case of high penetration of PV, excessive generation may cause overloading of the secondary substation at mid-day. Consumers with electric heating have an additional load during winter that is quite flat and large in size, so that the demand curves during winter follow similar trends to those of summer, only shifted upwards to a higher demand. The colour maps show that overloading is caused at a higher penetration degree, that is, the capacity of the network for hosting PV is higher, since the generation produced by PV during the day is consumed by the electric heating.

In the case of commercial consumers, the number of consumers is lower and contracted power is typically higher. The diversity of electricity uses and schedules is much wider. Smaller shops or offices may close during lunchtime, while restaurants and cafés would not close during the day and even have maximum demand at noon. In the first case, the effect of PV is much more problematic, since PV would inject power at its maximum when demand is very low. In the latter, PV production would be able to feed the peak demand, so overloading would only be caused at much higher PV penetration degrees. This can be observed in the diagrams, where consumers of type ComS-S can host a PV penetration of 120%, while ComS-L can host up to 170% penetration degree of PV. Consumers with tariffs with time discrimination lead to demand curves with higher consumption during the night, so the network can host a lower degree of PV, as seen in the colour maps. In order to avoid PV curtailment, storage or demand flexibilities would have to absorb power from the grid during noon. For all consumers, the ratio between power and energy to be absorbed is quite similar.

In Europe, different electricity tariffs with time discrimination are already in place for residential and commercial consumers. The most simple type of time-of-use (ToU) tariffs are those with on-peak and off-peak electricity prices. Typically, consumers who opt for this type of tariff are those with electric water heaters that are automatically turned on during the night, enabling consumers to have hot water throughout the day and benefit from reduced prices. For both residential and commercial consumers, the resulting demand profiles have a high share of demand during the night, but follow a similar pattern during the day, when compared to residential and commercial consumers, respectively, with simple tariffs with no time discrimination. Simulations carried out for technical SRA have considered residential consumers with this ToU tariffs and results show that the decrease in the demand during the day results in a lower capacity for hosting PV of the network. For instance, comparing residential consumers ResS+H to ResT+H, the network hosting capacity in the former is 140% PV penetration, while for the latter is 130%. In the presence of a high penetration degree of PV, the storage required to avoid PV curtailment would be larger in the case of consumers with ToU tariffs. Taking again the previous example, in order to accommodate a penetration degree of 200% of PV, 200kW/500kWh of storage would be needed for consumers of type ResS+H, and 230kW/800kWh would be required in the case of consumers of type ResT+H. Clearly, the design of this ToU tariff is aimed at peak shaving to reduce demand during the day, so demand is shifted to the night. This potential could be used to increase network hosting capacity by designing ToU tariffs with low prices during PV production periods, which is precisely the aim of this use case. Overloading would be avoided by using the excess of PV power and energy to heat the water in water heaters.

Figure 24 shows the corresponding colour maps for the same LV network (400kVA transformer, located in the centre of Europe) during four different average days: a weekday in winter, a weekend day in winter, a weekday in summer and a weekend day in summer. Comparing workdays to weekends, it is clear that working days are more problematic in residential areas, since the demand is very low when PV production is at its maximum, when people are out of home, working. At weekends, people are home during the day and the load is more in line with PV production, so network hosting capacity increases up to 150% for ResS and 160% for ResS+H (instead of 140% during the week for both cases). Furthermore, overloading happens for shorter time, and with a lower excess of power and energy, so that PV integration would require less storage capacity (or less demand shifting). In the case of small commercial consumers, corresponding to shops that close during the weekend, there is almost no demand during the weekend and therefore, PV generation would have to be curtailed for much lower penetration degrees.

In summer, PV production is much higher both in power and in the number of hours of production. At the same time, demand is much lower. During summer, the effect of electric heating is no longer observable, naturally, so network hosting capacity is very similar for residential consumers with and without electric heating. For all types of consumers, the network can host up to a penetration degree of 120%. Overloading situations become less punctual, so that flexibility requirements would be difficult to fulfil through load shifting, since the number of hours of activation would be quite high. In order to increase network hosting capacity, storage would have to be used. The energy and power to be stored is much higher (note that in the figure, the meaning of the different shades of colour differ from one diagram to another).

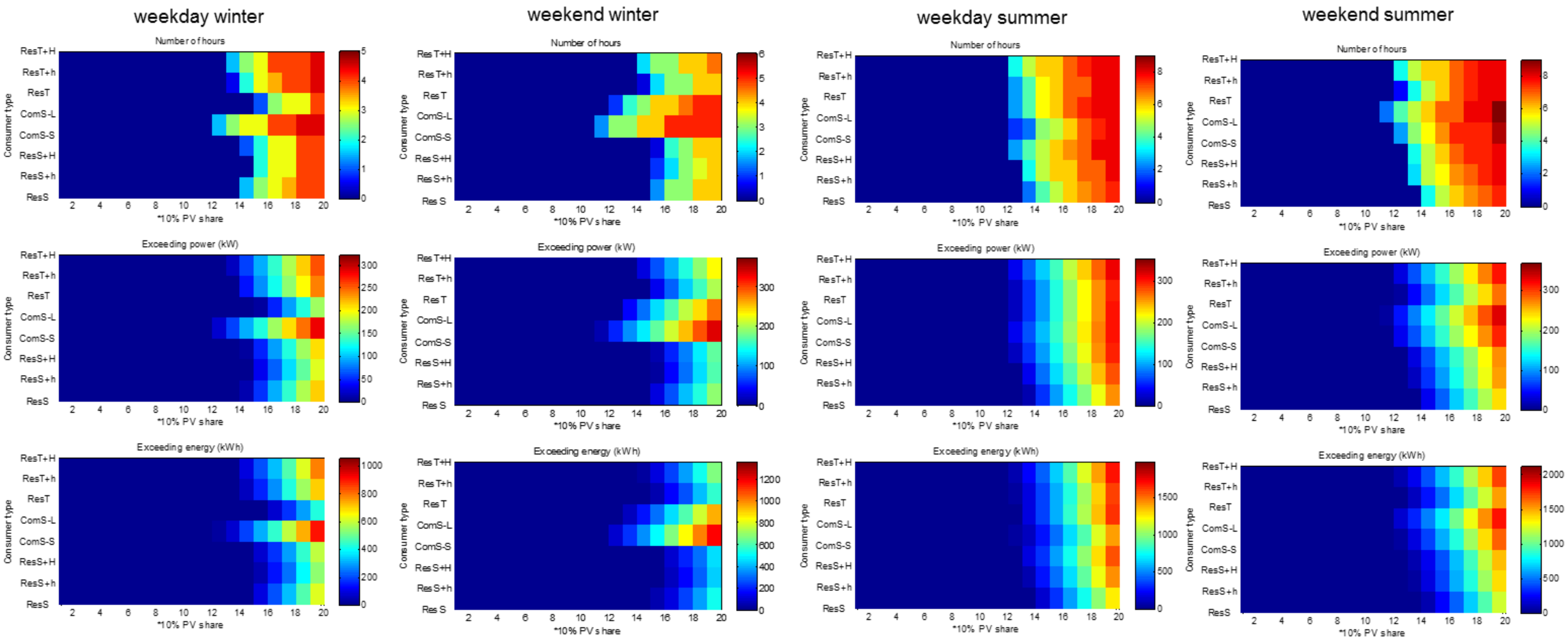

Figure 24: Number of hours of transformer overload and volume of exceeding power and energy through the transformer during an average weekday/weekend day in winter/summer in the centre of Europe for different types of consumer and an increasing penetration degree of PV, ranging from 0% to 200% (with respect to rated capacity of the transformer)

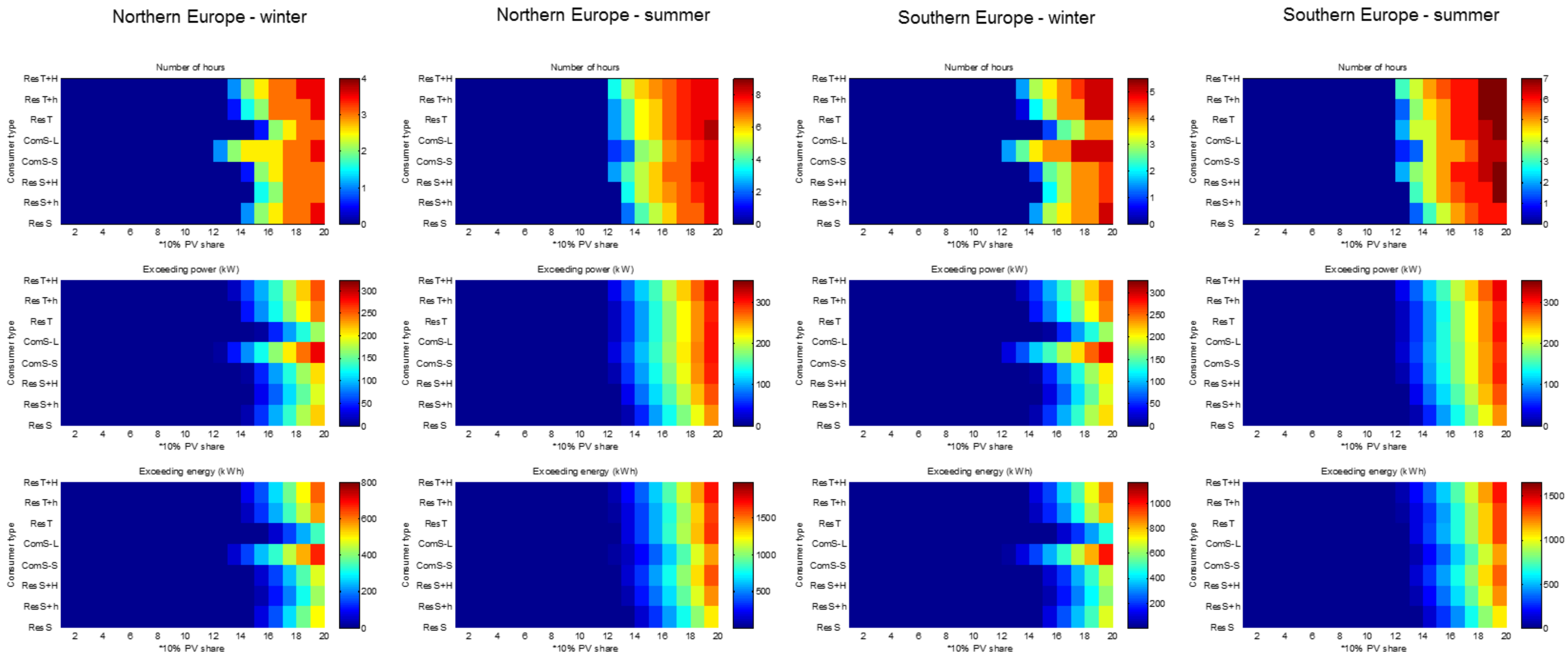

Figure 25: Number of hours of transformer overload and volume of exceeding power and energy through the transformer during an average weekday in winter/summer in the North/South of Europe for different types of consumer and an increasing penetration degree of PV, ranging from 0% to 200% (with respect to rated capacity of the transformer)

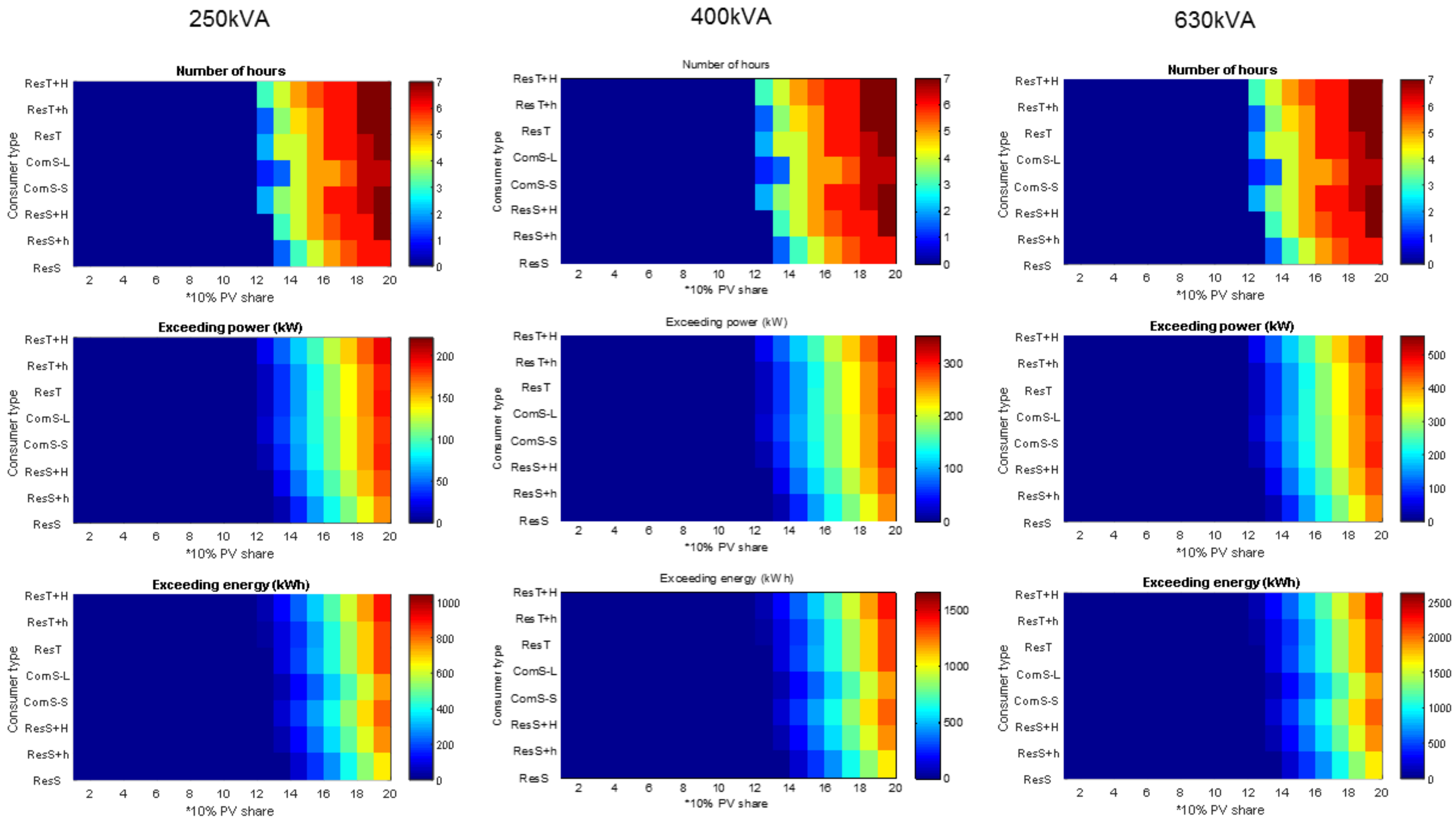

Figure 26: Number of hours of transformer overload and volume of exceeding power and energy through the secondary substation with a transformer of 250/400/630kVA during an average weekday in summer in the South of Europe for different types of consumer and an increasing penetration degree of PV, ranging from 0% to 200% (with respect to rated capacity of the transformer)

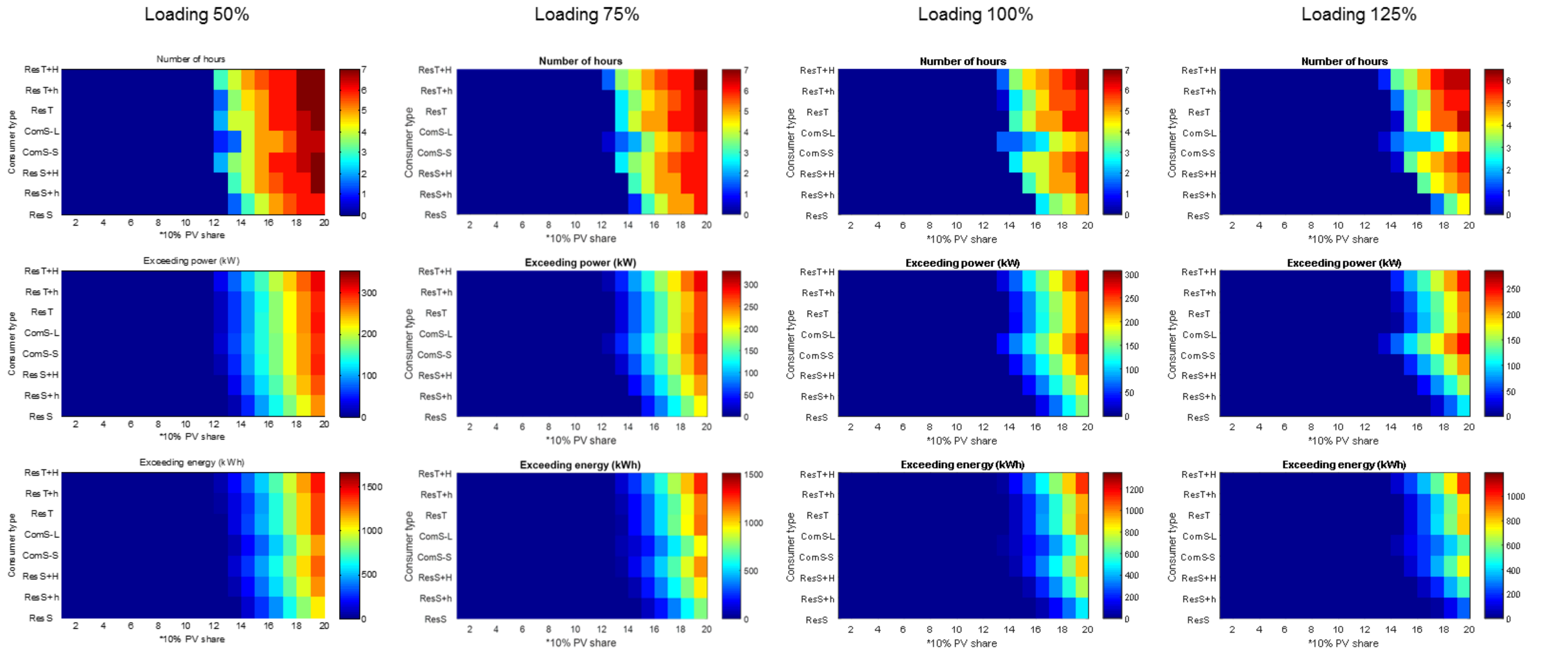

Figure 27: Number of hours of transformer overload and volume of exceeding power and energy through the secondary substation during an average weekday in summer in the South of Europe for different volumes of demand (maximum demand of 50%/75%/100%/125%, sized with respect to the rated capacity of the transformer) and different types of consumer and an increasing penetration degree of PV, ranging from 0% to 200% (with respect to rated capacity of the transformer)

The PV production profile varies for different geographical locations. Locations closer to the equator have a more homogenous PV production profile throughout the year, while locations closer to the poles have very few hours of solar production in winter, and a very high number of hours of solar production during summer. The effect of the location on PV network hosting capacity can be observed in the colour maps in Figure 25, which correspond to a winter and a summer weekday at the North, the middle and the South of Europe. The results show that the network hosting capacity is very similar: both in the Northern and in the Southern locations a maximum of 120% penetration degree of PV can be hosted (except for consumers of type Res-S and ResS+h, with a network hosting capacity of 130%). The exceeding energy during winter is much higher in the Southern location, and vice versa, the exceeding energy during summer is much higher in the case of the Northern location. The differences between Northern and Southern locations are not very relevant for PV penetration slightly over network hosting capacity, and become more remarkable for higher degrees of PV penetration: for instance, for residential demand (consumers of type ResS) a 150% penetration degree a battery of 100kW/400kWh would be required in the North and 120kW/450kWh for the Southern location, while for a 200% PV penetration, storage requirements would be 230kW/1250kWh for the former and 270kW/1100kWh for the latter.

Simulation has been carried out considering the standard capacity of transformers. Figure 26 shows the results obtained for 250 kVA, 400kVA and 630 kVA of capacity. Considering the same degree of loading, and expressing penetration degree of PV as a percentage of the rated capacity of transformers, results show no difference. Naturally, the actual volume of PV that can be connected to the LV network increases proportionally to the size of the transformer, and so does the required storage or flexibility to increase network hosting capacity. For instance, in order to accommodate a PV penetration degree of 200%, a LV network supplied by a 250kVA transformer would require 160kW/620kWh of storage to connect a PV installed capacity of 500kW, while a LV network supplied by a 630kVA transformer would need 400kW/1600kWh of storage to reach a 200% penetration degree, which means the connection of 1260kW of PV.

Regarding the volume of demand, different loading degrees have been compared in Figure 27. If PV production can supply local demand, the effect of power injection in the network is very beneficial, reducing the power flows in the lines and thus reducing losses in the network, and decreasing power exchange between the MV and the LV network. If the demand during the hours of PV production is higher, there is a wider margin for PV integration. The results shown in the colour maps illustrate this effect. For instance, in the case of residential consumers with electric heating, network hosting capacity increases from 130% to 170% for a demand increase from 50% to 125%. In order to integrate a PV penetration degree of 200% of rated capacity of the transformer, the storage required would change from 270kW/1300kWh to 150kW/420kWh. In the case of commercial consumers, for ComS, network hosting capacity increases from 120% to a 130% penetration degree when the maximum total demand accounts for a 125% of the rated capacity of the transformer. In order to host 800kW of PV (penetration degree of 200%), storage requirements vary from 300kW/1350kWh to 220kW/900kWh. If the increase of demand takes place at mid-day, during the hours of maximum PV production, power requirements of the storage to host any given PV installed capacity decrease significantly. Regarding storage energy requirements, the decrease is proportional to the decrease of demand. Networks where consumers have a flatter demand profile, such as for instance those with time-of-use tariffs or electric heating, will experience a lower reduction of power storage requirements than networks where consumers have a more irregular demand curve.

Distribution networks are designed according to the concentration and size of demand. The most basic categories of networks generally used to classify distribution zones and distribution networks are urban and rural, with different intermediate categories (sub-urban, rural with concentrated or scattered population, etc.). Urban networks feed a much higher density of consumers, and these consumers have typically smaller contracted power and lower demand, with a lower probability of living in individual houses. In more rural areas, consumers are more related to agriculture, residential consumers live in bigger houses, etc. These factors result in urban networks typically having a higher loading degree and transformers with larger rated capacity, while rural areas have transformers of lower capacity. Regarding network hosting capacity in urban and rural areas, simulation results show that the most relevant factors are the loading of the networks and more importantly, how this demand coincides with PV production. Demand flexibility and storage would be required to avoid PV curtailment when the demand does not match PV production.

3.2.5 Demo 4: Anti-islanding protection

The use case of anti-islanding aims to avoid the problem of unintentional islanding when the grid is disconnected due to maintenance or faults but the protections of PV units are not able to detect

SRA rules:

- The most relevant factor is the interaction between demand and PV generation profiles. In general, PV production and domestic demand are not very coincident: heating and lighting represents a high share of demand, and this demand is higher when the sun is not shining, when it is colder and there is no light.
- Energy storage in batteries and flexible demand can consume the excess of power injected by PV when demand is low, so that network hosting capacity is increased. Consumers with electric water heaters can easily provide flexibility by shifting their demand.
- In general, the demand of residential consumers during the day is higher in the weekends, when people are home. Therefore, workdays are more critical for the integration of PV production.
- In the case of commercial consumers, the use of electricity is more diverse. Small shops may close during lunch time and in the weekends, so this would be a critical period. By contrast, restaurants and shops open during mid-day, PV generation is much more aligned with the demand, and so the network is able to host a higher share of PV.
- Regarding the season of the year, summer is more problematic because solar production is much higher and demand tends to be lower.
- Typical Time-of-Use tariffs already existing for consumers with electric water heaters discriminate on- and off- peak periods, defined according to typical demand profiles. Therefore, demand is shifted from daytime to the night. However, as PV is introduced in the LV network, the excess of PV production may cause overloading of the transformer of the secondary substation.
- The geographical location determines the PV production curve. In countries in Southern-Europe, the number of annual hours of sun and therefore the annual PV production is much higher than in Northern European countries. The number of daily hours of PV production varies across the seasons of the year, and the variation is much higher for Northern countries, where there are very little hours of sun during winter and many hours of sun during summer. This results in very different needs for storage and demand flexibility to avoid PV curtailment.
- Urban areas are more densely populated than more rural areas. Therefore, urban networks are usually supplied by secondary substations with higher rated capacity of the transformers. Moreover, the degree of loading is usually higher. For this reason, in general overloading of transformers caused by PV generation is less frequent and would require a higher penetration degree of PV. At the same time, for larger transformers, a certain penetration degree means a higher installed capacity of PV, so storage requirements to increase network hosting capacity are higher both in power and energy.

this situation and power is injected into the grid. Undesired and islanding may cause:

- Low grid power quality
- Mal-operation of protection devices
- Personnel safety hazards
- Auto-reclosing failures
- Damage to the electrical equipment, e.g., electrical loads and grid-connected ac/dc inverters

The use case of anti-islanding is grouped together with the islanding use cases for simulation, because the technical analysis is focused on the dynamic response of the system, and the main KPIs are voltage and frequency deviation. However, the main objective of this use case is to enable the safe integration of DG in the distribution network, and therefore the discussion of main lessons learned from the analysis and SRA rules of this use case is included in section 3.2 together with use cases related to reconfiguration and voltage control to increase network hosting capacity.

Anti-islanding protection schemes can be generally divided into local detection and remote method. Generally, while local detection methods are basically applied inside the grid-connected ac/dc inverter system of the PV units, the remote methods send control / tripping signals to the DER units, e.g., PV units, mainly using the measurement systems and communications. In GRID4EU Italian demo, the anti-islanding schemes that have been implemented and tested are remote methods based on communications and local passive methods based on the OUV and OUF techniques.

In the following subsections, the technical analysis for the use case of anti-islanding is addressed to briefly describe the modelling and simulations carried out. Then, the main conclusions drawn from the results are discussed and the developed SRA rules are highlighted.

Simulation model of anti-islanding

A generic three-phase system has been modelled in two configurations: grid-connected and islanded, shown in Figure 28 and Figure 29, respectively. The model comprises the grid, the load and PV units:

- The N inverter-based PV units connected to the PCC through an inductive filter and the RLC load is connected in parallel. The PCC is connected to the grid through an impedance and circuit breaker.
- The PV units are composed of the following parts: 1) roof-top solar cell modules, 2) DC / DC boost converter, and 3) AC / DC converter. For the islanding analysis, since the islanding detection time is relatively very short, the solar cell modules and DC / DC boost converters are modelled as constant DC voltage source in the islanding detection simulations (X. Chen and Li 2015).
- According to IEEE std. 929 and IEEE std. 1547, it was recommended to model the loads for the islanding detection analysis as a parallel resonant RLC load, as shown in Figure 28 and Figure 29.
- In order to model the upstream MV Italian grid connection, a three-phase four-wire balance system is realized using three voltage-sources in star. These sources are connected to the LV distribution system through an impedance ($R + jX$).

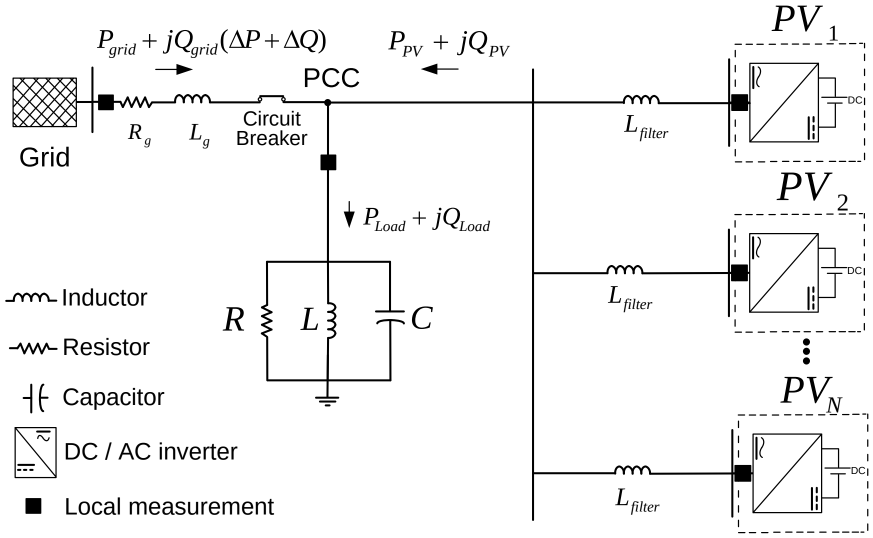

Figure 28. Generic three-phase system configuration during the grid-connected operating mode.

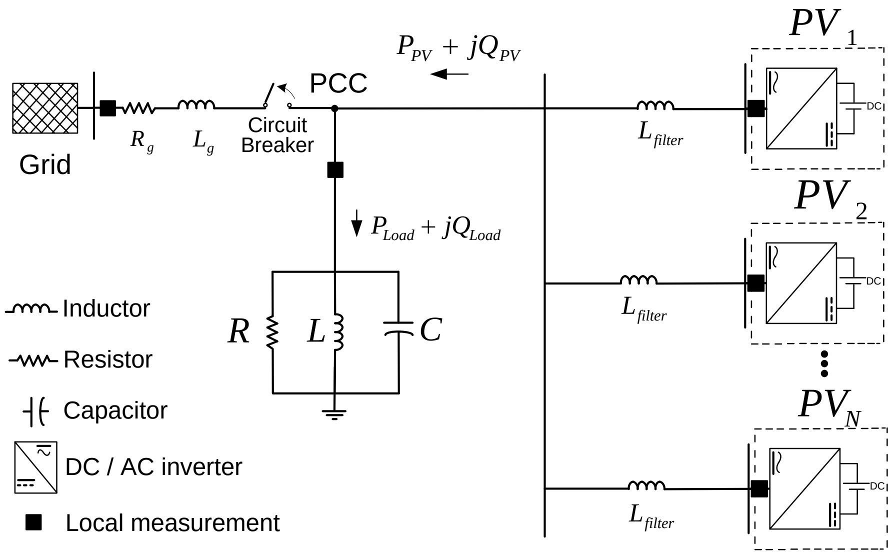

Figure 29. Generic three-phase system configuration during the islanded operating mode.

The islanding phenomena is analysed and formulated through a set of linear algebraic equations. When islanding condition occurs, the grid active power before the disturbance (ΔP) results in the voltage deviation (ΔV) at the PCC. Similarly, the grid reactive power before the disturbance (ΔQ) results in the frequency deviation (Δf) at the PCC. According to IEEE std. 929 and IEEE std. 1547, the voltage thresholds are typically set at 88% and 110% for under- and over- voltage problems, respectively and the frequency thresholds are typically set at 49.3 Hz and 50.9 Hz for under- and over frequency thresholds, respectively (X. Chen and Li 2015).

Case studies and simulation scenarios

Several case studies have been simulated to assess the performance of the anti-islanding OUV and OUF mechanisms and to analyse (i) the impact of different volumes of PV production and demand causing different power mismatches in the moment of disconnection of the grid; (ii) the relationship between grid active power mismatch and voltage deviation; (iii) the relationship between grid reactive power mismatch and the frequency deviation; and (iv) the decoupling of the two previous effects.

Characterization of simulation scenarios	
PV power production	3 scenarios with high, medium and low PV power production (20-60-120MW) with zero grid power (no mismatch)
Active power mismatch	5 scenarios with medium PV production and different active power mismatch (+20, +10, 0, -10, -20 MW) 3 scenarios with medium active power mismatch and high, medium and low PV power production (20-60-120MW)
Reactive power mismatch	6 scenarios with medium PV production, different reactive power mismatch (+5.25, -4.4 Mvar) with the same load quality factor and different load resonant frequency 3 scenarios with medium reactive power mismatch and high, medium and low PV power production (20-60-120MW) 5 scenarios with medium PV production, different reactive power mismatch (0.6, 2.7, 5.25, 10.4, 20Mvar) and load quality factor for a given load resonant frequency
Active and reactive power mismatch	3 scenarios with medium PV production, different active and reactive power mismatch (10MW, 5 Mvar, and 10MW 5Mvar)

Table 22: Scenarios analysed for technical SRA of use cases for the use case of anti-islanding.

3.2.5.1 Discussion on SRA rules including selected simulation results

The islanding performance within the Italian project framework was evaluated and studied through simulations using Matlab Simulink for different grid operating conditions such as various values of resistance, inductance and capacitance of RLC load, and grid active and reactive power mismatch. Accordingly, the summary of main conclusions in terms of anti-islanding protection modelling as well as concluded SRA rules for passive anti-islanding methods is shown in Table 23. Generally, as it was shown in the simulations, the islanding results had an excellent agreement with the islanding mathematical formulation previously presented in this document. Accordingly, it was shown that if the OUV and OUF thresholds as well as the parallel equivalent RLC resonant load are known for the grid operator, then the conditions, under which the islanding cannot be detected within the non-detection zone, can be carefully defined and obtained as follows[9]:

- The grid active power mismatch during the islanding is mainly defined the amount of

[9] In fact, since the islanding could be occurred and carried out at any time of the day (or night), where the total parallel RLC resonant load, share of the dynamic and static loads and PV units production in the islanded area could remarkably vary along the day, these sensitivity analyses parameters were carefully defined and addressed to assess the islanding performance.

voltage deviation during the islanding. This effect is illustrated in Figure 30 (a), where voltage at the PCC is shown for scenarios with different power mismatch, the voltage deviation mainly depends on the grid active power mismatch. Note that in all the figures presented below, the grid is disconnected at t=0.5 s, in other words the islanding mode starts at that time. On the one hand for the over voltage problems, for instance scenarios A.1.4 and A.1.5, if the amount of active power mismatch was below +0.18 pu (exporting active power to main grid), then the islanding could not be detected (voltage remains below 1.1 pu voltage threshold). On the other hand, for the under voltage problem, for instance scenarios A.1.1 and A.1.2, if the amount of active power mismatch was above -0.3 pu (importing active power from main grid), then the islanding was not detectable by PV units (the voltage remains above the voltage threshold 0.88 pu). Note that is it is assumed that the PV units do not provide reactive power to the grid, then the conversion base power for per units is the total PV units' power production.

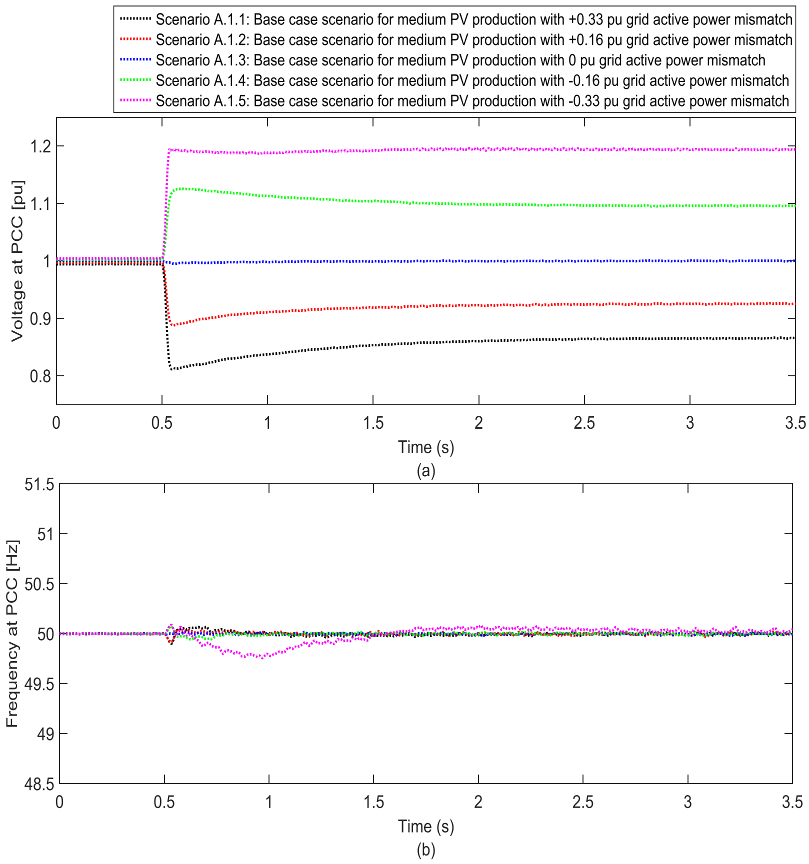

Figure 30. Scenario A1 from grid-connected to islanding operating mode at t=0.5 s; (a) voltage at PCC; (b) frequency at PCC (conversion base voltage 20 kV).

- The grid reactive power mismatch during the islanding mainly defined the amount of frequency deviation during the islanding, as shown in Figure 31. (b). As our sensitivity analysis validated, both load quality factor as well as the resonant parallel RLC load frequency are determinant factors for islanding detection when the reactive power mismatch is applied. While the resonant frequency typically set the steady-state value of frequency during the islanding (taking into account Figure 31, see scenarios B.1.1 to B.1.6 in Figure 31. (b) for various load resonant factors), the load quality factor defines the frequency response time of the islanded area (taking into account Figure 31 see scenarios B.3.1 to B.3.5 in Figure 32.(b) for various load quality factors). Therefore, if the resonant frequency of the equivalent RLC model of the system could be obtained by the grid operators, then they could compare it with the allowable frequency thresholds, 49.3-50.9 Hz. If the frequency remains within the thresholds, then the islanding might not be detected by the PV units. Moreover, it was shown that for the loads with very poor quality factors, for instance scenario B.3.2 in Figure 32.(b), the frequency of the islanded area might reach its steady state values with a considerable delay, therefore the islanding condition might not be detected and removed in due time with the expected clearing time.

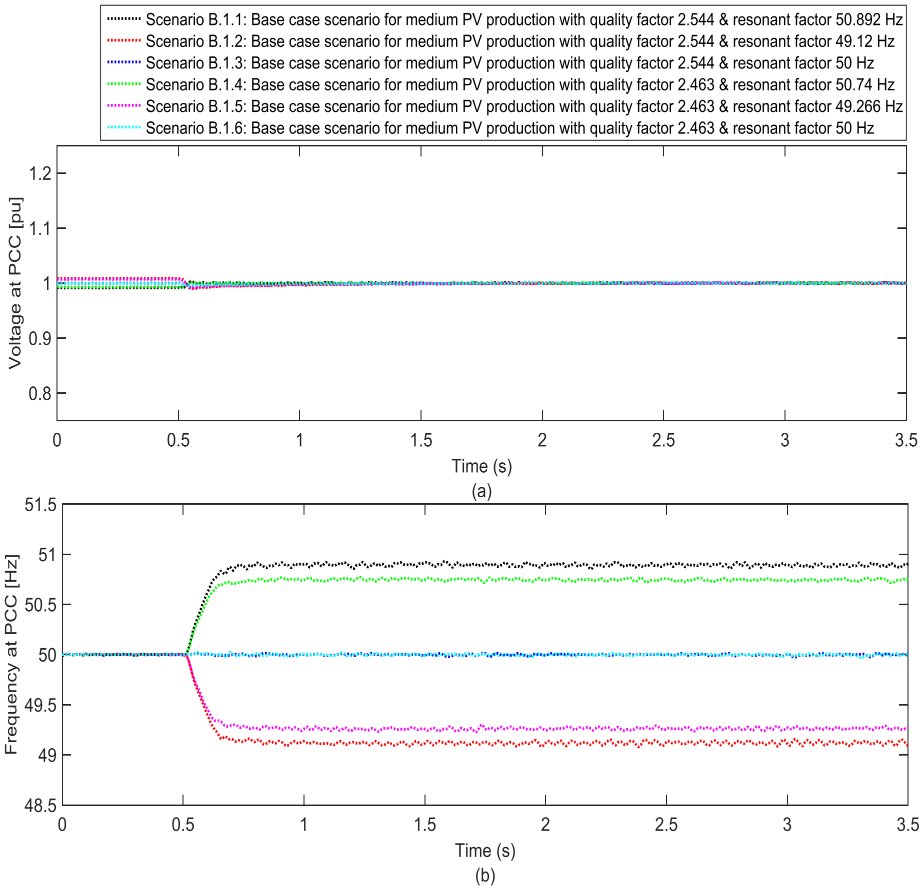

Figure 31. Scenario B1 from grid-connected to islanding operating mode at t=0.5 s; (a) voltage at PCC; (b) frequency at PCC (conversion base voltage 20 kV).

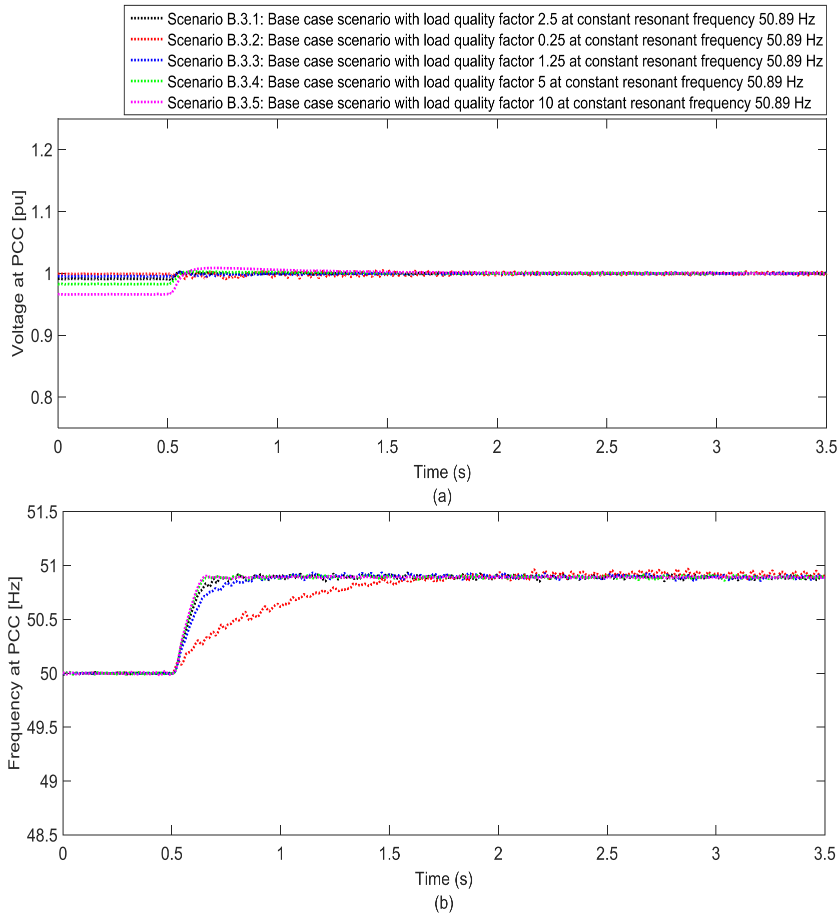

Figure 32. Scenario B3 for constant resonant frequency 50.89 Hz from grid-connected to islanding operating mode at t=0.5 s; (a) voltage at PCC; (b) frequency at PCC (conversion base voltage 20 kV).

- Our simulation results confirmed that the reactive power versus frequency is totally decoupled from the active power versus voltage. In other words, with respect to the here-presented mathematical formulation, the grid active power mismatch negligibly impacts on the frequency deviation (taking into account Figure 33 see scenarios C.2 and C.3 in Figure 33.(b)), whereas the grid reactive power mismatch negligibly affects the voltage deviation during the islanding condition (see scenarios C.1 and C.3 in Figure 33. (a)).

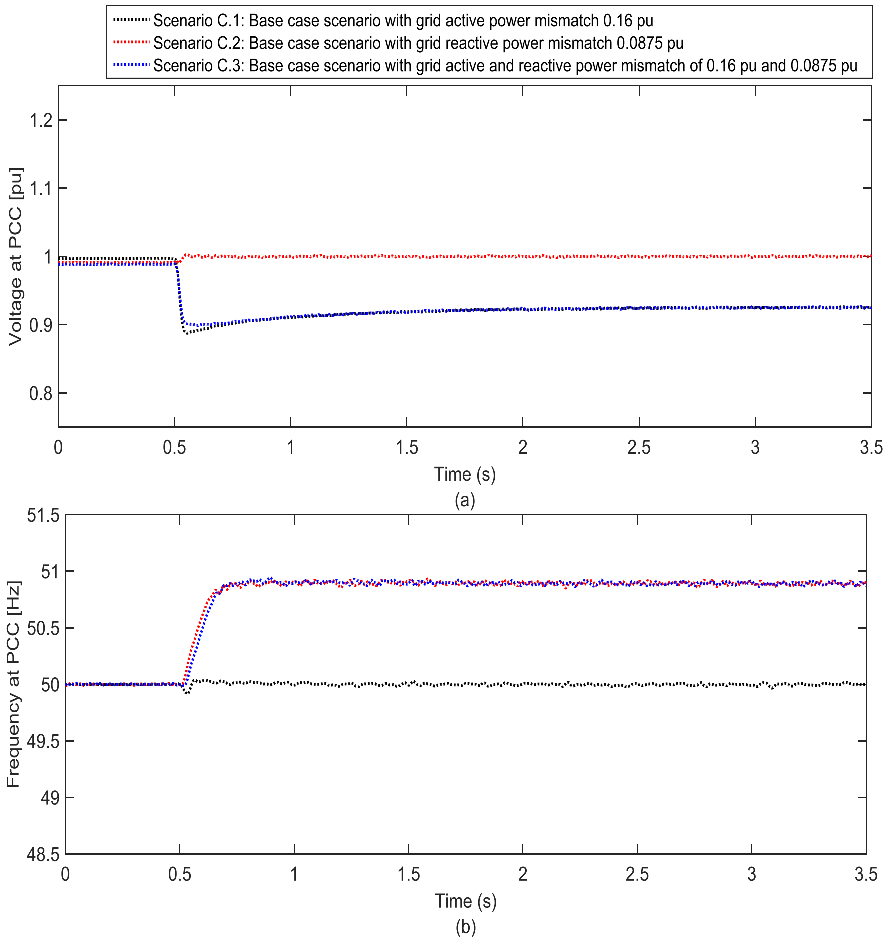

Figure 33. Scenario C from grid-connected to islanding operating mode at t=0.5 s; (a) voltage at PCC; (b) frequency at PCC (conversion base voltage 20 kV).

- In terms of scalability, it was shown that the here presented analysis for islanding process can be easily extended and scaled for different power systems with various sizes, network types, and voltage levels, if the parallel resonant RLC values of the equivalent load could be properly calculated and obtained by the grid operator in their system under study.
- In terms of replicability, since for the anti-islanding analysis, the reactive power versus the frequency as well as the active power versus the voltage are approximately linear around their nominal values, therefore the results could be separately and accurately obtained for OUV and OUF methods, replicating in various power systems with different network types and voltage levels.

Summary of main conclusions
Anti-islanding protection modelling considerations
• Modelling the loads by **parallel resonant RLC impedance** is a reasonable approach and provides scalable and replicable results (dynamic loads like induction machines were neglected) • Thanks to the **fast power control of PV units**, their active and reactive power remains almost constant during islanding • Grid connection consists in **simple resistances and inductances** • In most cases, **the distribution lines impedances** can be neglected compared to the RLC load impedance in order to study the dynamic response of the system

SRA rules for passive anti-islanding protection schemes		
General rules	**OUV method boundaries**	**OUF method boundaries**
• The active power-voltage and reactive power-frequency relationships are **totally decoupled** during islanding. • The analysis is quite **scalable and replicable** in different power systems with various sizes, network types, and voltage levels	• **Voltage deviation** mainly depends on the amount of the **grid active power mismatch** • For the base case study considered and under the assumptions made for this technical SRA analysis, if the **injected** grid active power is below **0.18 pu**, islanding is not detected by PV units • For the base case study considered and under the assumptions made for this technical SRA analysis, if the **consumed** grid active power is below **0.3 pu**, the islanding is not detected by PV units	• Both **load quality factor and resonant frequency** must be obtained and taken into account • LC load resonant frequency defines the **steady-state frequency** during islanding • For the base case study considered and under the assumptions made for this technical SRA analysis, if load resonant frequency is within **49.3 and 50.9 Hz**, the islanding is not detected by PV units • Poor load quality factors might provide a **delay on clearing time** of islanding

Table 23. Summary of main conclusions on the anti-islanding modelling as well as the technical SRA rules.

- It is worth mentioning that dynamic loads such as induction machines were not modelled in the simulations, following the recommendations made by IEEE std. 929 and IEEE std. 1547. Therefore in order to evaluate the islanding performance of the residential, commercial, and industrial areas with difference share of dynamic and static loads, it might be suggested that the share of dynamic loads could be obtained for each area, and later on it is incorporated into the inductance L of the equivalent parallel resonant RLC load model.

- Since the total MV lines impedance was relatively much lower than the RLC load impedance, the effect of the various lines, e.g., overhead power lines or underground cables, on our results were not evaluated.

Finally, it should be mentioned that since only the anti-islanding passive local methods have been implemented in the Italian demo, we did not study and apply the active anti-islanding local methods in this work, and our main focus was to obtain proper scalability and replicability rules and boundaries for the anti-islanding passive local methods, i.e., OUV and OUF methods.

3.3 Islanded operation in sections of the distribution grid

Thanks to the presence of DG and DER in distribution networks, it is possible to supply demand locally and islanded operation of distribution networks becomes a possibility in the case of scheduled maintenances or faults that cause the disconnection of the upstream network. The main objective of islanding is to improve reliability for network users in these cases.

This section presents the main conclusions and lessons learned from the technical analysis carried out for the SRA of GRID4EU islanding use cases. The use case of Automated islanding of Demo 5 has tested automatic islanded operation of a MV distribution network including CHP unit, while the use case of Islanding of Demo 6 has demonstrated the islanded operation of a LV distribution network including storage (BESS).

Simulation has been carried out to assess different scenarios of operation for the islanding and sustaining of the island. To this end, the islanded systems have been modelled with Matlab-Simulink and the dynamic response of the system has been studied, monitoring voltage and frequency during the different stages of islanding.

3.3.1 Demo 5: Automatic islanded operation

This section briefly describes the simulation carried out for technical analysis of this use case and discusses the main conclusions extracted from the results obtained to derive SRA rules. This use case is based on the use of a CHP unit as the main provider of the voltage and frequency regulation during the transition from grid-connected mode to the islanded mode. It must be noted that technical SRA simulation has been designed in accordance to the implementation of Demo5, but because of island operation complexity, it does not reflect the exact and complete technical solutions and boundary conditions of Demo 5.

3.3.1.1 Technical analysis for SRA

Simulation model

The dynamic model of the islanded distribution zone comprises the CHP unit, fast controlled loads, and residential loads (Kundur 1994) and is shown in Figure 34.

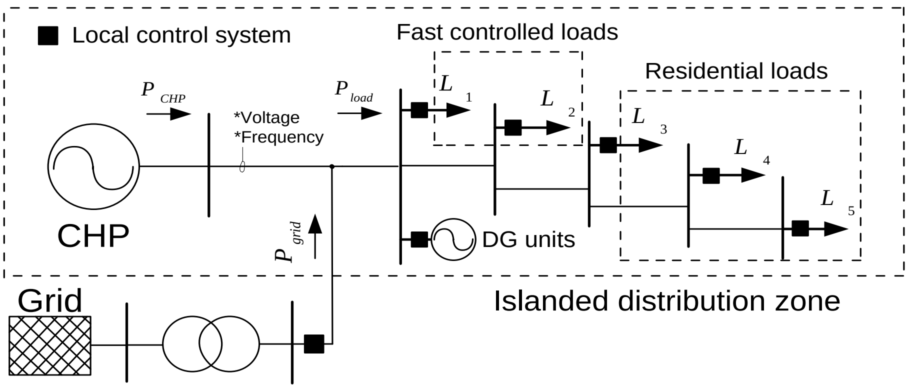

Figure 34. Distribution zone configuration including the CHP unit, fast controlled loads, and residential loads.

The CHP unit is modelled as a thermal engine generator, consisting of an engine, which is connected through a rotating shaft to a synchronous generator (Idlbi 2012). The voltage and speed of the connected synchronous generator to the electric grid are controlled by the rotor exciter and the governor, respectively. Besides, active power oscillations in the islanded system are reduced using power system stabilizer (PSS).

Regarding the demand, residential consumption has been modelled as three blocks of constant impedance load. There is a water heating load, which is a fast-controllable load used to provide flexibility to the system during islanded operation. This load has been modelled as a two-block resistance.

Additionally, dynamic loads considered as three-phase squirrel cage induction machines have been included in the model to account for industrial demand.

The upstream MV grid connection is modelled as a three-phase four-wire balance system using three voltage-sources in star connected to the MV distribution system through an impedance $(R + jX)$.

Islanding process

The islanding comprises four different stages, as shown in Figure 35 through frequency response:

- Grid connected mode (start and final points in Figure 35): Initially, the CHP unit power production is set according to the required heat and electricity in the zone. If the production exceeds the demand in the area, power flows from the distribution zone to the grid upstream, and vice versa.
- Transition from grid connected mode to the islanded mode (points 1, 2 and 3 in Figure 35): At a certain point, the grid is temporarily disconnected from the distribution zone, and the islanded operation must start. During the transition from the grid connected to the islanded operation, voltage and frequency must be controlled within the allowable range to avoid collapse and disconnection of all loads and DG. The control system (CS) stabilizes the system balancing generation and demand controlling the CHP unit and the fast-controllable thermostatic load. If the imbalance is too high, the system may not be able to maintain frequency and voltage within the permitted range and the system must be shut down. In the case of overfrequency, there is a load-shedding mechanism to gradually disconnect load and be able to maintain supply for the rest.
- Islanded mode (point 4 in Figure 35): If stable operation is achieved, it can be sustained in time indefinitely, since the CHP unit can in principle provide the required energy.
- Reconnection to the grid (points 5, 6 and 7 in Figure 35): Transition from islanded mode to the grid connected mode is carried out using a synchrotact.

Simulation is focused on the transition to islanding, since this is the critical step that determines the success of islanding or supply interruption of the system. The distribution network is initialized at t=0 s (start point in Figure 35). Due to the fault in the grid, the grid is disconnected from the distribution zone at t=2 s (points 1 and 2 in Figure 35), at which the islanded operation mode gets started. At t= 5 s (point 5 in Figure 35), the grid is reconnected to the islanded system. Afterwards, the loads connection status and CHP production will be again set to the pre-fault situation at t=7 s (point 6 in Figure 35) and t=9 s (point 7 in Figure 35), respectively.

The main variables monitored are voltage and frequency.

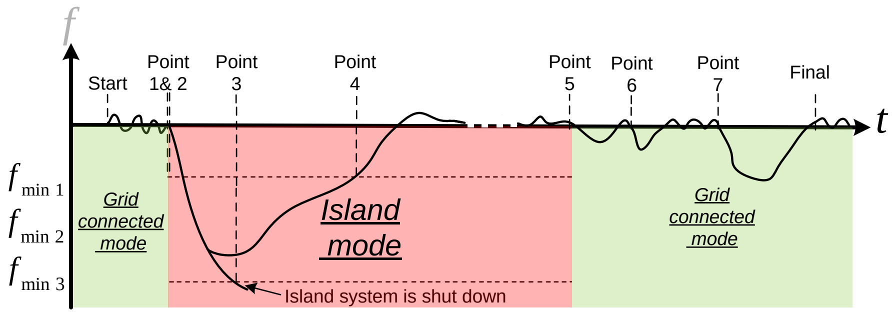

Figure 35. Frequency response during the process of islanding for the use case of islanding in MV.

Case studies and simulation scenarios

Several scenarios have been analysed to assess the effect of different parameters and situations, as presented in Table 24.

Boundary condition analysed	Simulation scenarios
Fast load control system	2 scenarios with and without fast-load control system 3 scenarios with different size of fast controlled thermostatic loads (10, 100, 200kW)
Power disturbance (CHP production and demand)	6 scenarios with different values of CHP production (0.2, 0.5, 0.8pu) and residential consumption (0.4MW, 1.6MW)
Level of CHP production and demand	3 scenarios with the same power disturbance but different CHP production and load consumption (gen:0.2 pu load:0.78 pu, gen:0.3 pu load:0.88 pu, gen:0.4 pu load:0.98 pu
Size of DG	2 scenarios with different CHP installed capacity
Passive DG	small-hydro, biogas and PV panels of different size
Effect of intermittent DG generation	3 scenarios with variation of PV power generation at different rates (200 kW/s, 100 kW/s, and 50 kW/s)
Structure of load for UFLS	2 scenarios where load is divided into different number of blocks for the under-frequency load shedding mechanism
Voltage level	3 scenarios with different voltage level (10, 20, 35kV)
Demand	3 scenarios for different types of demand (residential, commercial and industrial)

Table 24: Scenarios analysed for technical SRA of the use case of islanding in MV.

3.3.1.2 Discussion on SRA rules including some selected simulation results

The summary of main modelling conclusions and technical SRA rules is presented in Table 23. While during the grid connected mode, the grid predominantly stabilized the frequency and voltage of the distribution zone, during the islanded mode, the CHP unit and the load control system controlled and maintained the islanded area. Generally, it was shown that the CHP unit was technically and practically able to operate and maintain the islanded area by quickly controlling the voltage and frequency. However several points must be taken into account when the technical feasibility of successful islanding operation of the CHP unit is assessed as follows[10]:

Summary of main conclusions	
CHP unit islanding modelling considerations	
• **Type of loads** including dynamic or static loads affected considerably the islanding performance • CHP unit including both **governor and excitations systems** could quickly control the frequency and voltage • **The PSS** helped dampen the low-frequency active power oscillations during islanding • Grid connection consists in **simple resistances and inductances**	
SRA rules for CHP unit islanding performance at MV level	
General rules	• The CHP unit islanding analysis is **quite scalable and replicable** for various power systems with different voltage levels, network types, grid power mismatch, however **the SRA analysis boundaries** must be carefully defined
Grid power imbalance	High grid power mismatch might result in an **unsuccessful islanding** as follows: • For instance, grid power mismatch of **0.72 pu for under frequency case** • Or, grid power mismatch of **-0.58 pu for over frequency case**
Fast-controlled thermostatic loads	Fast controlled loads significantly **helped suppress** voltage and frequency deviations during the islanding: • For instance, for the range of fast-controlled loads from **0.01 up to 0.166 pu**
Under-frequency load shedding scheme	• UFLS is **very effective scheme** to maintain frequency for under frequency cases • To improve the islanding performance, **UFLS levels** should be carefully defined • The **larger** the number of UFLS levels & load blocks, the **better** the islanding performance
Different levels of CHP unit production and total load consumption with the same grid power imbalance	• The same grid power imbalance **does not necessarily lead** to the same islanding performance • The CHP unit performance during islanding could depend on **its power production level**
Further rules learnt by simulations	The following parameters had a negligible impact on the islanding performance of the CHP unit: • **Conductor types** (e.g., overhead lines or underground cables) • **Load or DG power variation** (e.g., cloud effect of PV units) • **Various MV voltage levels**

Table 25. Summary of main conclusions on the CHP unit islanding modelling as well as the technical SRA rules.

[10] In fact, since the upstream grid disconnection due to the faults can occur at any time of the day (or night), the total load consumption, share of the dynamic and static loads, CHP unit operating point, and DG units production in the islanded area could remarkably vary along the day. This is why, a broad range of sensitivity analyses on a large number of input parameters are carefully defined and addressed to assess the CHP performance during the islanding mode.

1. **Grid power imbalance during islanding mode:** Since the grid power exchanged at the time of grid disconnection defines the size of the disturbance, which should be compensated by the CHP unit during islanding mode, the successful islanding process highly depends on the grid power imbalance. While the under-frequency problem occurs when the grid injects active power to the islanded area (see Figure 36.(b) at t=2 s), the over-frequency problem typically occurs when the grid consumes active power from the islanded area (see Figure 37.(b) at t=2 s). For very high (e.g., the base case study in Figure 36.(b) for grid power imbalance of 0.72 pu for the under-frequency problem) or low (e.g., scenario 2.8 in Figure 37.(b) for grid power imbalance -0.58 pu for the over-frequency problem) values of the grid power imbalance, the frequency might reach its maximum or minimum limits respectively, and consequently the CHP unit might be disconnected from the islanded area. Note that since for the under frequency case, various under frequency load shedding mechanisms is applied, the islanding performance was generally better compared to the over frequency problem, where no load-adding mechanism was implemented in the distribution area. To support this statement, in scenario 2.1 in Figure 36 for instance the under frequency load shedding has resulted even in the over frequency problem at t=2.5 s.

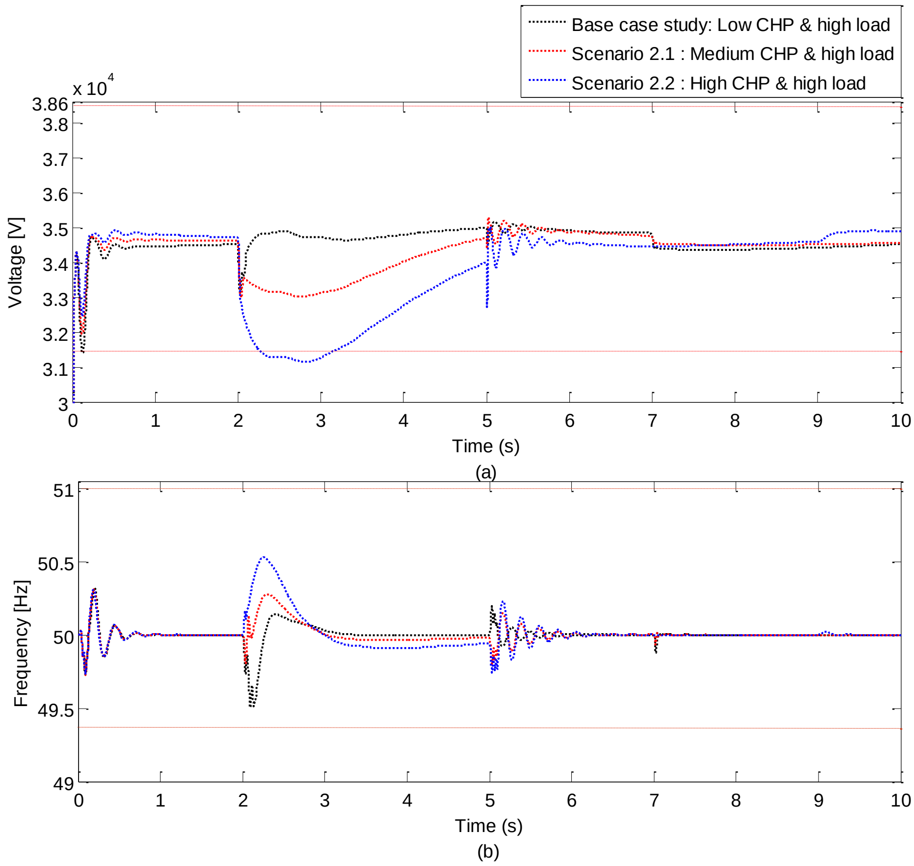

Figure 36. Voltage magnitude and frequency for scenario 2, (a) voltage magnitude, (b) system frequency.

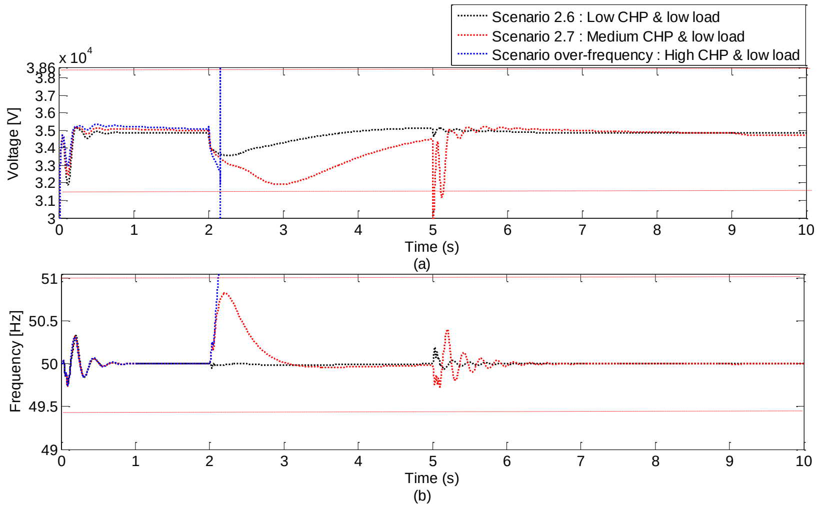

Figure 37. Voltage magnitude and frequency for scenario 2, (a) voltage magnitude, (b) system frequency.

2. **Fast thermostatic load control:** As shown in the simulation, the fast control of thermostatic loads within hundreds of milliseconds after the grid disconnection could considerably improve the frequency response during islanding. In Figure 38.(b), when the fast load control is not activated in scenario 1.1, the maximum frequency deviation reaches the allowable limits and consequently the islanding process is unsuccessful. While for the base case study using the fast load control, the islanding process was successful. Besides, in Figure 39.(b), if the size of the fast-controlled thermostatic loads was increased from scenario 3.1 to 3.2, for instance from 0.01 pu to 0.166 pu, then this not only resulted into a successful islanding process, but also helped improve the system frequency response compared to the pre-defined base case.

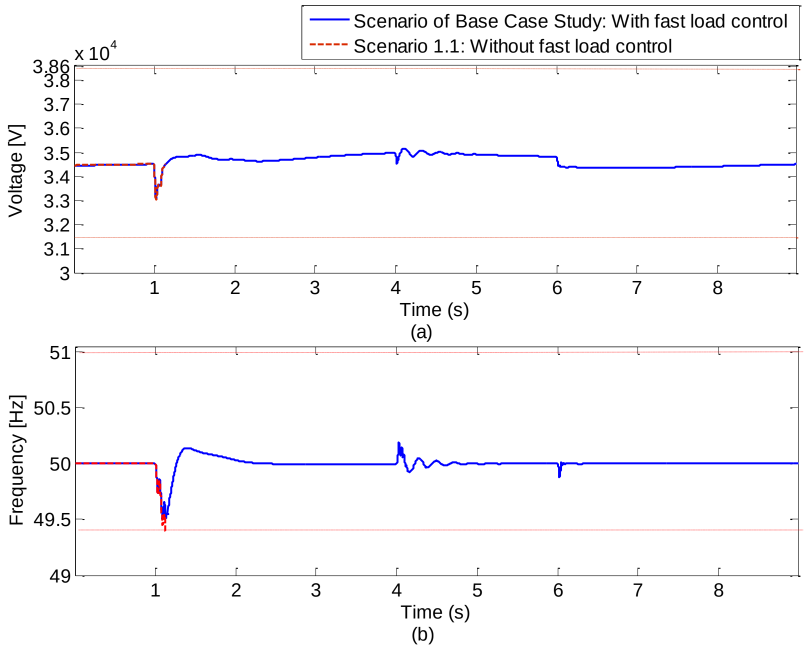

Figure 38. Voltage magnitude and frequency for scenario 1, (a) voltage magnitude, (b) system frequency.

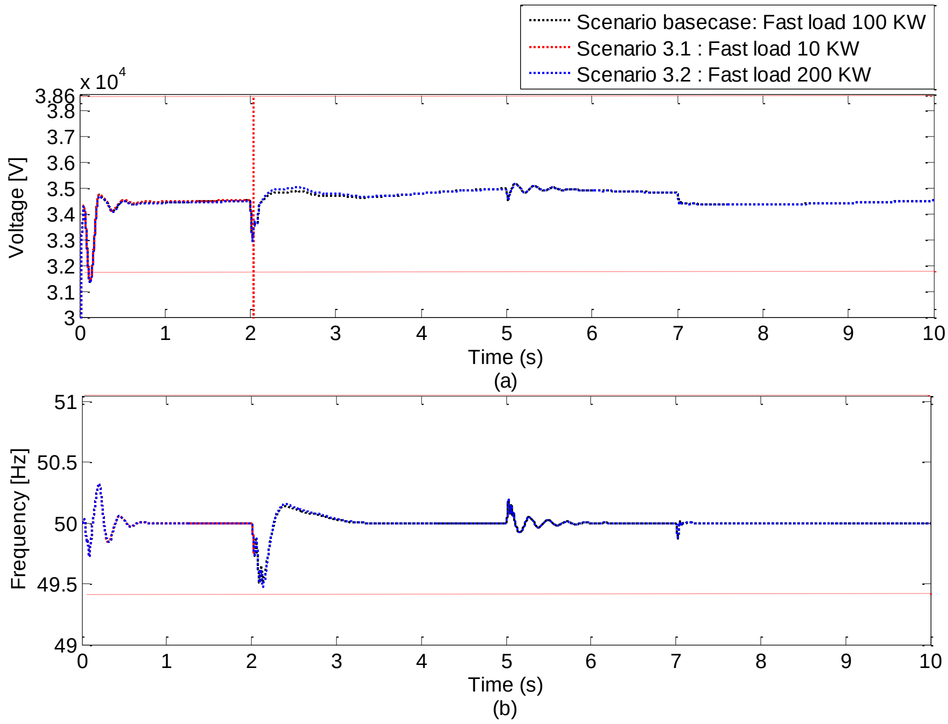

Figure 39. Voltage magnitude and frequency for scenario 3, (a) voltage magnitude, (b) system frequency.

3. **Under-frequency load shedding scheme:** For the case of under-frequency problems, the UFLS could remarkably improve the frequency response during islanding, as shown in Figure 36. Additionally, it notably improved the frequency response such that the frequency did not reach the minimum limits, and consequently the islanding process was successful. Moreover, it was observed that if a higher number of the UFLS levels (e.g., from 3 to 6 load blocks in scenario 8.1 in Figure 40) was implemented in the area, then not only the frequency response was remarkably improved (minimum frequency from 49.51 Hz to 49.62 Hz) by avoiding the probable over-frequency problems, but also a smaller number of load blocks was shed during the islanding process.

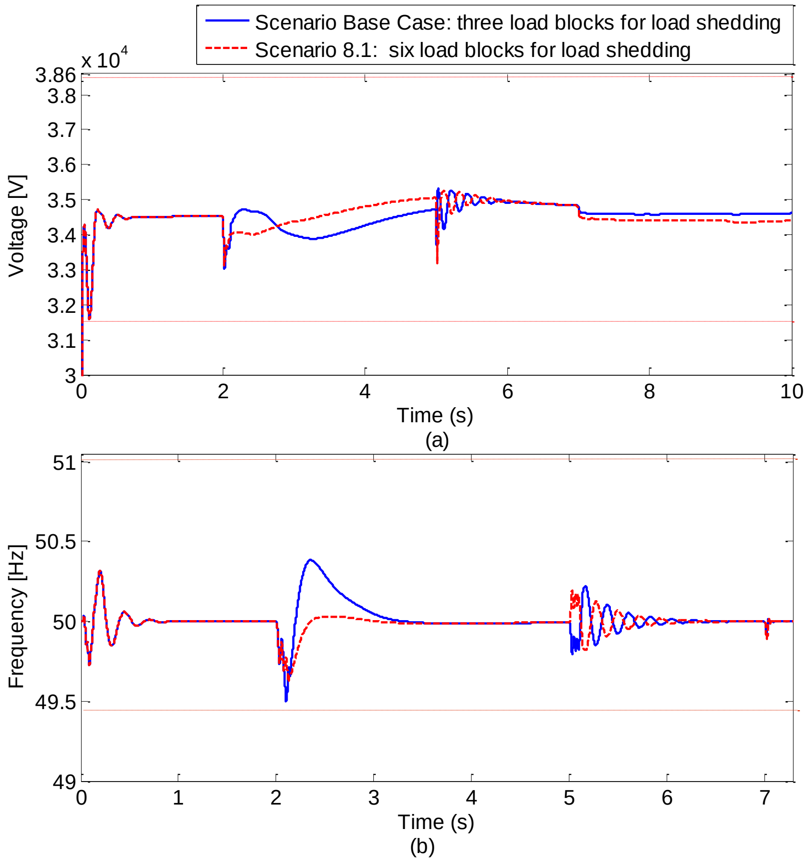

Figure 40. Voltage magnitude and frequency for scenario 8, (a) voltage magnitude, (b) system frequency.

4. **Different levels of CHP unit production and total load consumption with the same grid power imbalance:** It was observed that for the same amount of grid power disturbance (e.g., 0.58 pu in scenarios 7.1 and 7.2 in Figure 41) with different levels of CHP production and load consumption, the CHP unit performance during the islanding process was not necessarily the same. As seen for example, the UFLS scheme was operated at different load levels during the islanding, and consequently the frequency deviation remarkably varied from under-frequency (e.g., minimum of -0.51 Hz in the base case scenario in Figure 41) to over-frequency problem (e.g., maximum of 0.52 Hz in scenario 7.2 in Figure 41). Moreover, the CHP dynamic performance during islanding mode may considerably depend on the power reference set points of the unit as well as the loads. For instance, if the CHP unit has a low value of upward or downward power reserve compared to the grid power following the disturbance, then the islanding could be unsuccessful unless some loads are shed or connected to the grid.

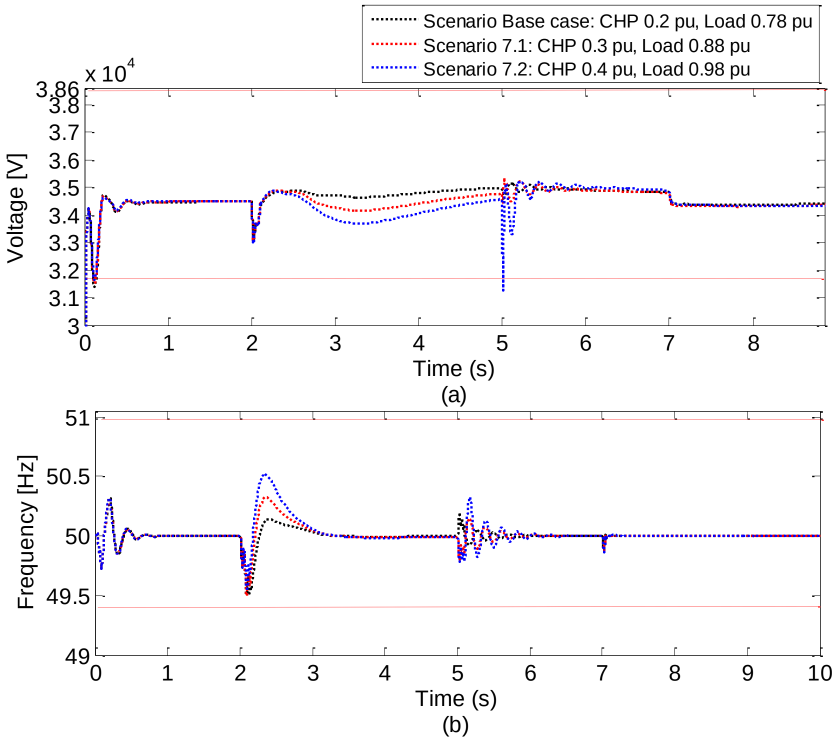

Figure 41. Voltage magnitude and frequency for scenario 7, (a) voltage magnitude, (b) system frequency.

5. **Type of loads, i.e., dynamic or static load models:** As shown in the simulations in Figure 42, the islanding process not only may depend on the CHP unit model, but also on the load model. In order to assess the replicability of our results for different distribution networks with various shares of dynamic or static loads, several scenarios for residential, industrial and commercial networks were defined and simulated (see the base case, scenario 11.1 and 11.2 in Figure 42). Then, the effect of both dynamic and static loads on the islanding process was evaluated. Generally, it was shown that the dynamic response of the induction machines could highly affect the frequency (see Figure 42.(c) and (d)) and voltage profiles (see Figure 42.(a) and (b)) during the islanding.

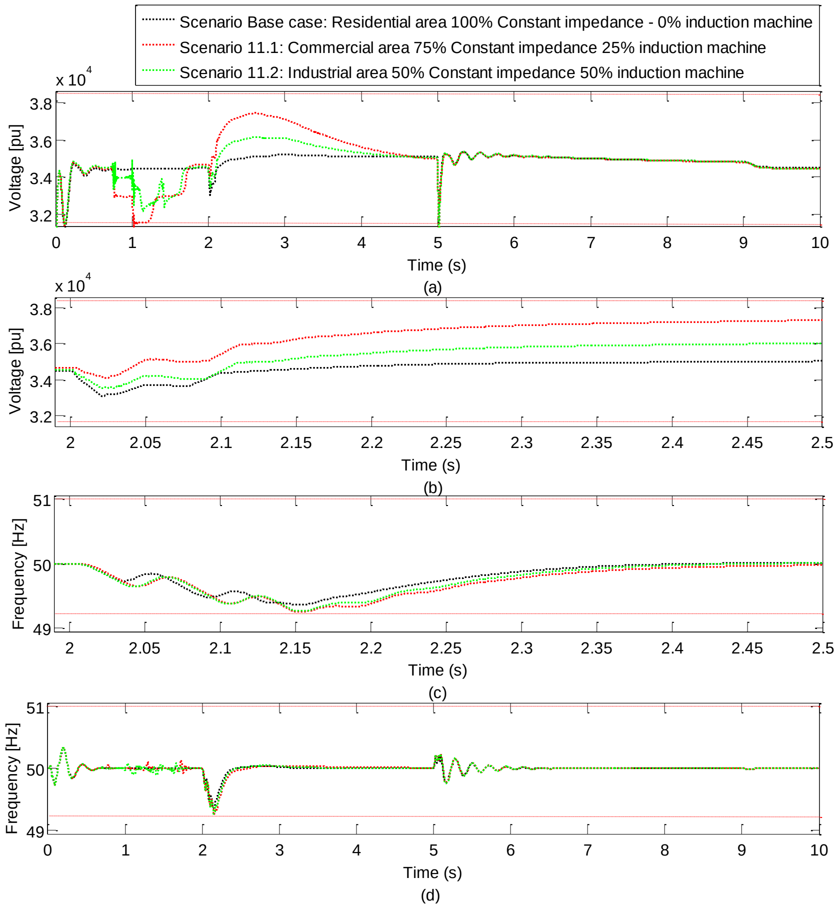

Figure 42. Voltage magnitude and frequency for scenario 11, (a) voltage magnitude, (b) system frequency.

Finally in order to present our further lessons learnt from these simulations, it is worth mentioning that the grid MV levels as well as the conductor types (e.g., overhead lines or underground cables) had negligible impact on the islanding process. Moreover, it was shown that the load or DG power variation (e.g., cloud effect of PV units) during islanding mode within several minutes had very negligible impact on the frequency and voltage profiles even for relatively high values (e.g., 100 kW/s or 0.062 pu/s). In other words, the CHP unit during the islanding mode can successfully cope up with both active and reactive power variations for about several minutes provided by the DG units or loads.

3.3.2 Demo 6: Islanding

This section briefly describes the simulation carried out for technical analysis of this use case and discusses the main conclusions extracted from the results obtained to derive SRA rules. This use case is based on the use of a BESS unit to control frequency and voltage for the islanded operation of a LV line supplied by a secondary substation. The disconnection from the grid and activation of islanded operation of a section of the distribution network may be planned and performed by the DSO or may also occur due to a fault. The following islanding modes will be considered for the technical SRA of LV islanding:

- "Programmed", "Intentional", "Scheduled" or "Foreseen" islanding: the grid is initially connected to the network and at a specific time, the island is disconnected from the upstream MV grid is disconnected under controlled and monitored conditions. The grid power, which is the amount of power flowing from the secondary substation to the LV grid at the moment of disconnection from the upstream grid, is equal to zero. Immediately afterwards, the BESS unit becomes the main responsible to provide the frequency and voltage support within the islanded distribution area. The transition to islanding mode is smooth.

- "Unexpected", or "Unforeseen" islanding mode: an unexpected failure in the MV upstream grid causes the islanded distribution area to be disconnected from the grid. In this case, two approaches could be followed: a) shutting down the system and using the BESS unit to carry out a black start of the island, or b) using the BESS unit to make a transition from grid-connected to islanded operation. The use case tested in Demo 6 has adopted the first approach, so that black start is attempted. The present SRA technical analysis has studied both options.
    - Transition from grid-connected to islanded operation: In this case, the grid power is not equal to zero. The BEES unit must be able to sustain islanded operation so that supply in the area is not interrupted. The transition to islanding mode may not be so smooth, depending on the power flowing through the secondary substation at the moment of disconnection from the grid. The success of islanding means that frequency and voltage deviations do not exceed the admissible limits and safe operation is sustained.
    - Black start: when the disturbance, i.e., grid power, or power flowing through the secondary substation at the moment of disconnection from the grid, is large and frequency or voltage exceed allowed limits, the islanded distribution area is shut down. Then, the BEES unit must be able to restore service from scratch.

3.3.2.1 Technical analysis for SRA

Simulation model

The use case of islanding in Demo 6 consists in the isolated (or islanded) operation of the LV network supplied by a secondary substation. The LV distribution system comprises residential consumers and DG in the form of PV. For islanding, the DSO has a battery energy storage system (BESS) and a flexible load (or dummy load).

The model developed for the LV island is shown in Figure 43. The distribution network model has the following elements: a battery energy storage system (BESS) modelled following (S. Izadkhast, Garcia-Gonzalez, and Frias 2015; Seyedmahdi Izadkhast et al. 2015), three photovoltaic (PV) solar cells, a dummy resistive load, three residential loads and the connection to the MV grid.

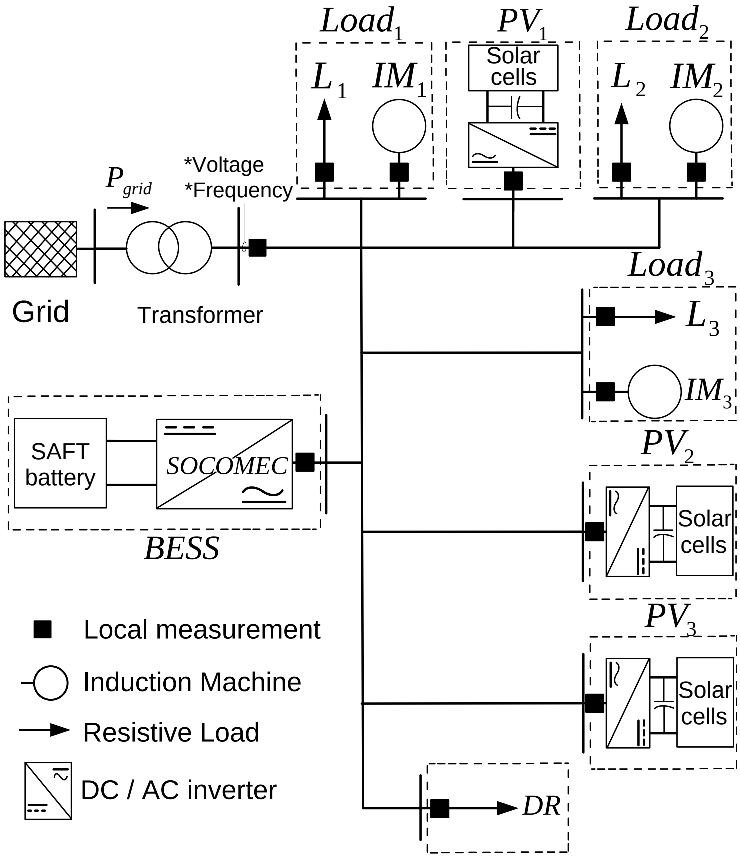

Figure 43. Distribution network configuration including PV, dummy resistive load, induction loads, grid connection, and battery energy storage system.

The BESS consists of a li-ion battery, modelled by an electrical model that is a combination of thevenin-based and runtime-based models (M. Chen and Rincon-Mora 2006), and an AC/DC power conversion system model composed by (i) modulation and PWM IGBT based inverter, (ii) voltage, current, frequency, and phase measurements using phase-locked loop (PLL), and active and reactive power calculation, and (iii) primary and secondary controllers (Shafiee, Guerrero, and Vasquez 2014).

The PV units are composed of roof-top solar cell modules, a DC/DC boost converter and an AC/DC converter. The solar cell modules and DC/DC boost converter is modelled as constant DC voltage source. In this analysis, PV units do not provide any voltage or frequency regulation either in grid-connected or islanding modes.

The load of the system corresponds to residential and industrial consumers. Additionally, the use case contemplated the use of a flexible load controlled by the DSO to help release excess of PV production if needed during islanding. The technical analysis for SRA has considered a dummy load that is able to quickly connect or disconnect from the grid within milliseconds to absorb excess of generation and also to help control frequency and voltage deviations during the transient from grid-connected to islanding mode by reducing the size of disturbance, i.e., grid power at the moment of disconnection from the grid.

The load has been modelled as constant impedance load for static, mainly resistive loads. Dynamic loads (e.g., heating systems and induction motors) are considered as three-phase squirrel cage induction machines.

In addition, the fast controlled dummy load is modelled by a resistance. The dummy load control objective is to minimize the size of disturbance ($P_{g0} \pm a \cdot P_L$), where P_{g0} is the grid power before the disturbance; and a and P_L are the dummy load connection status (0 or 1) and the total load consumption, respectively.

In order to model the upstream MV grid connection, a three-phase four-wire balance system is realized using three voltage-sources in star. These sources are connected to the LV distribution system through an impedance ($R + jX$).

Islanding process

The process for islanding is described in chronological order through frequency response in Figure 44. At point 1, the grid is disconnected from the islanded area and consequently, the frequency starts to deviate from the nominal value. At point 2, the fast load control dummy load can be connected or disconnected in order to help reduce the frequency deviation. If frequency or voltage deviations exceed allowed limits, the BESS unit is shut down and islanding is not successful. If the BESS is able to achieve successful islanding, it can be sustained for as long as there is energy stored in the BESS to provide the energy consumed by the loads.

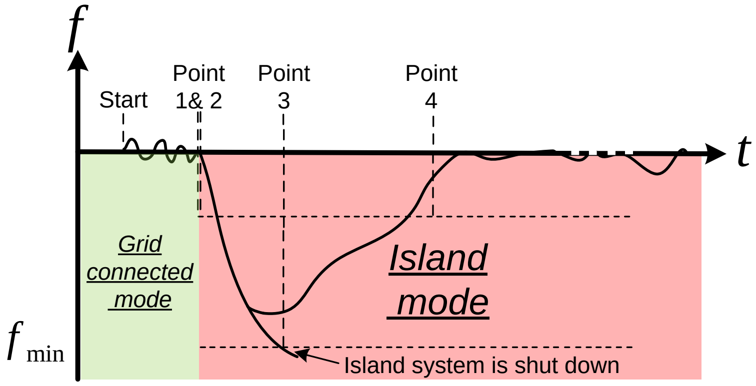

Figure 44. Frequency response during the process of islanding for the use case of islanding in LV.

Simulation has been carried out according to the three islanding modes studied:

The following islanding modes are addressed and studied for technical SRA of this use case:

A.1) “Programmed” islanding mode: the BESS unit transitions from grid connected to islanded mode, and this transition is scheduled so that grid power, which is the amount of power flowing from the secondary substation to the LV grid at the moment of disconnection form the grid, is equal to zero.

A.2) “Unforeseen with transition to islanding” islanding mode: the BESS unit transitions from grid connected to islanded mode, but this transition is not planned, so there may be a certain amount of power disturbance.

B) “Unforeseen with black start” islanding mode: the area goes through a black-out and the BEES unit must be able to pick up different loads and generation units to restore service from scratch in the islanded system, according to the sequence depicted in Figure 45.

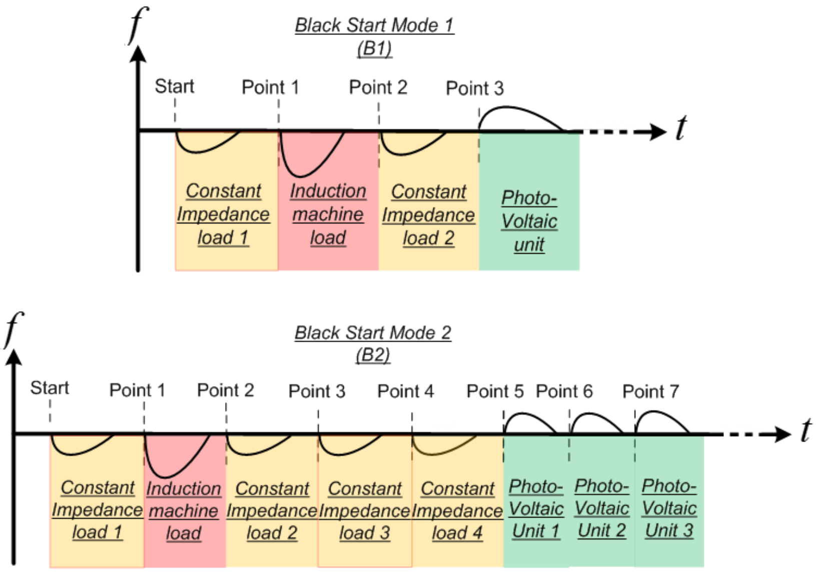

Figure 45. Simulation of events for "Unforeseen with black start" islanding mode in chronological order.

The two first cases have been grouped together to analyze the transition from grid connected operation to islanded operation. Black start has been addressed separately.

Case studies and simulation scenarios

Several scenarios have been analysed to assess the effect of different parameters and situations, as presented in Table 26.

Boundary condition analysed	Simulation scenarios
"Programmed" and "Unforeseen with transition to islanding" islanding modes	
Grid disturbance power (P_{grid})	5 scenarios of different power disturbance (0, 100, 200, -100, -200kW[11])
Battery state of charge (SOC)	3 scenarios with different initial set point of BESS (-80%, 0%, 80%)
Size of storage	3 scenarios with different values of storage capacity (185, 264, 396kW)
Type of demand	3 scenarios with different load structure (share of constant impedance vs induction machines 70%-30%, 85%-15%, 40%-60%)
Flexible demand	scenarios with and without fast-controllable dummy load
Controller	4 scenarios with different values of secondary PI controller gain

[11] In the case of programmed islanding, the power disturbance is equal to zero.

	K_{gain}
Unbalanced load	sensitivity to load unbalance in the LV grid
Unforeseen with black start islanding mode	
Flexible demand	scenarios with and without fast-controllable dummy load
Size of load to pick-up	10 scenarios with different values of pick-up load ($P_{Initial}$ 5, 50, 100, 200kW) (P_{Pickup} 10, 20, 40, 60, 80, 100kW)

Table 26: Scenarios analysed for technical SRA of the use case of islanding in LV.

3.3.2.2 Discussion on SRA rules

As a result from the simulation carried out, it has been observed that several points must be taken into account when the technical feasibility of successful islanding operation of the BESS unit is assessed as follows:

- During the **"Programmed" and** the **"Unforeseen with transition to islanding" islanding**, the BESS unit's performance highly depended on the following parameters:
    1. **Grid power disturbance:** As observed in the simulations, the BESS units was able to control the island for high values of grid power disturbance, which is the power flowing through the secondary substation to the LV network at the moment of disconnection from the grid, e.g., scenario A.1.3 in Figure 46 for the grid power mismatch of 0.4 pu. However for the very large values of grid power disturbance, e.g., scenarios A.1.2 and A.1.4 in Figure 46 for the grid power mismatch of 0.8 pu, the BESS unit was not able to control the island. In addition, the BESS power variation was not necessarily the same for the provision of upward or downward reserves.

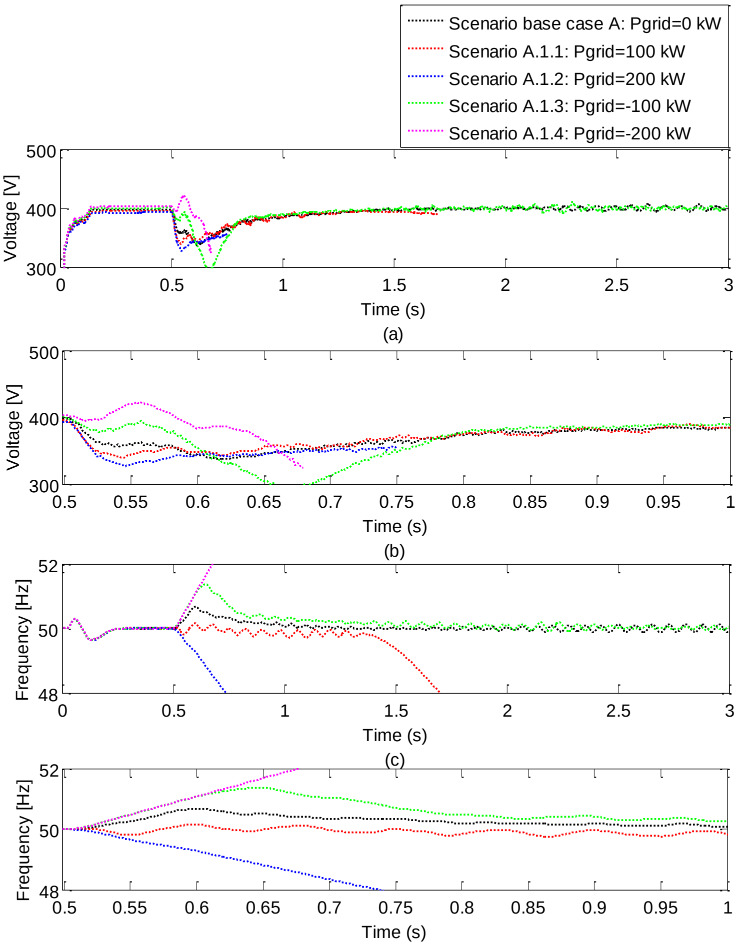

Figure 46. Island voltage and frequency for scenarios A1.

2. **Share of dynamic loads, e.g., induction machines:** It was shown that dynamic load such as induction machines could highly increase the inertial response of the islanded area, and as a consequence the BESS performance was considerably improved when the induction machine's share increased in the area (see Figure 47.(c) and (d) from scenario A.3.1 to A.3.2 where the share of induction machines increases from 15% to 60%, respectively). However it was also indicated that the newly installed induction machines are typically connected through a power-electronically interface to the grid that remarkably deteriorate their inertial contribution to the grid. A very high share of induction machines would result in high currents when switching between grid-connected and islanded mode.

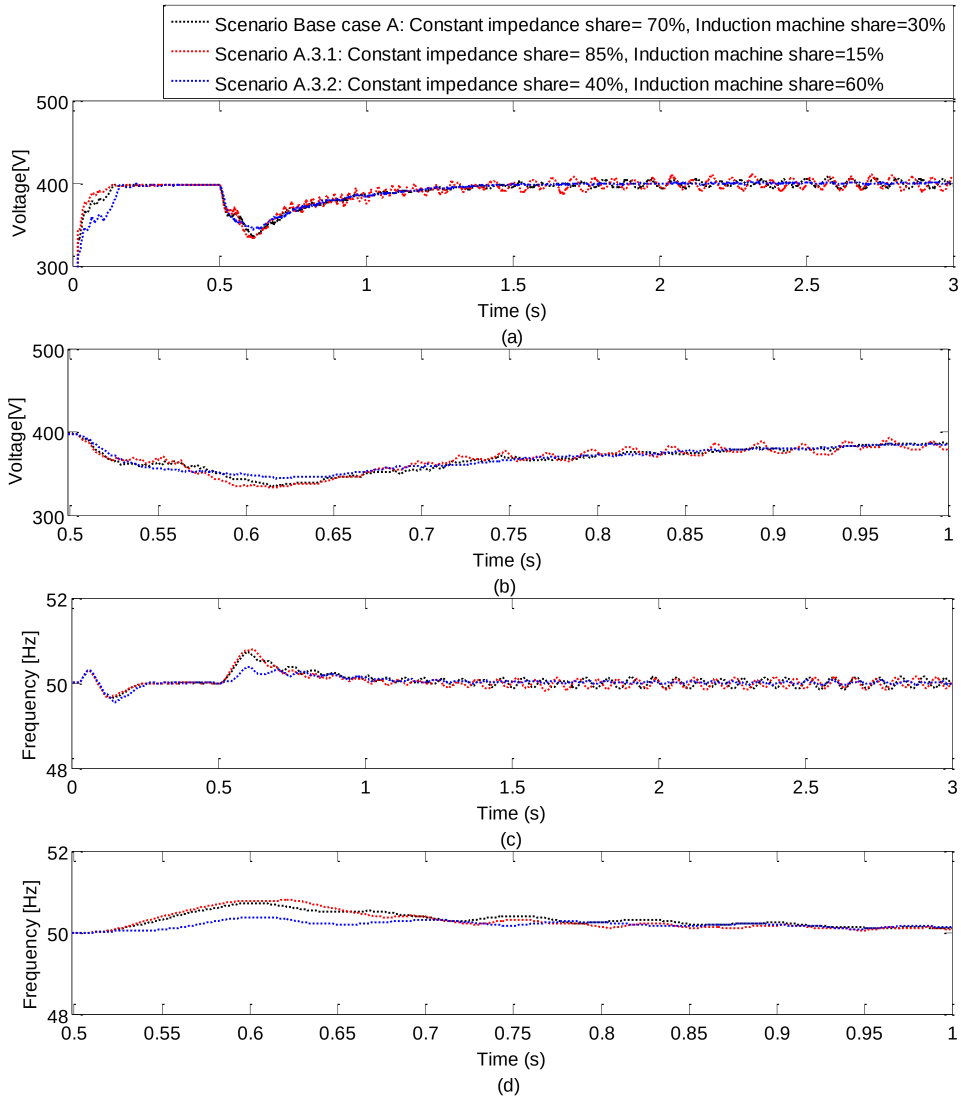

Figure 47. Island voltage and frequency for scenario A3.

3. **Secondary controller gain:** Secondary controller gain had undoubtedly significant impact on the performance of the BESS unit. While very low controller gains (see scenario A.4.1 in Figure 48) could lead to poor performance of the BESS unit, very high controller gains (see scenario A.4.3 in Figure 48) could also cause steady-state high-amplitude high-frequency voltage and frequency oscillations in the area. Since both high and low values could tend the islanded area to instability, the secondary controller gains must be carefully tuned and adjusted for the islanding operation.

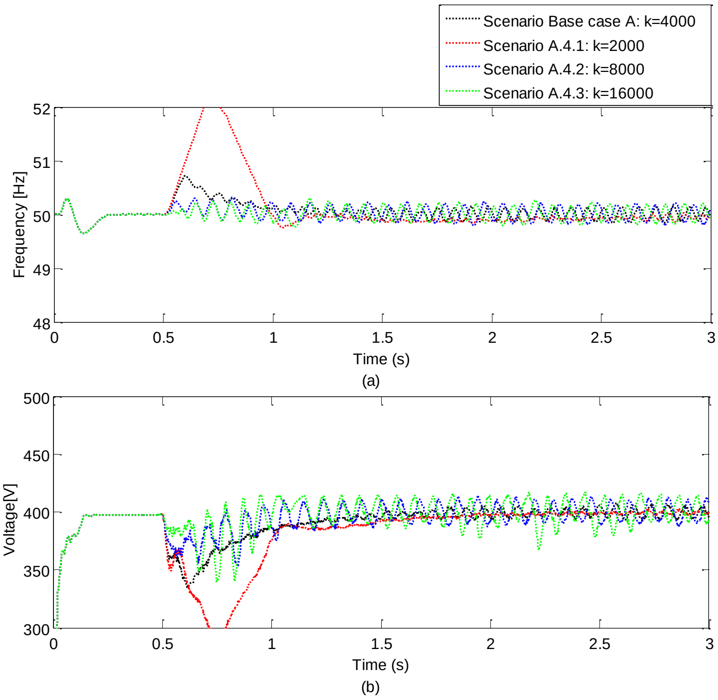

Figure 48. Island voltage and frequency for scenario A4.

4. **BESS unit initial set points before islanding:** If the BESS unit set points before the islanding was close to its maximum or minimum power limits (for instance, see scenario A.5.2 in Figure 49.(a) and (b)), then the BESS performance could be highly reduced close to these limits, and the islanded area could be shut down. Thus, it is highly recommended that the initial BESS set points are carefully adjusted so that the BESS unit has enough upward or downward power reserves during the islanding operation.

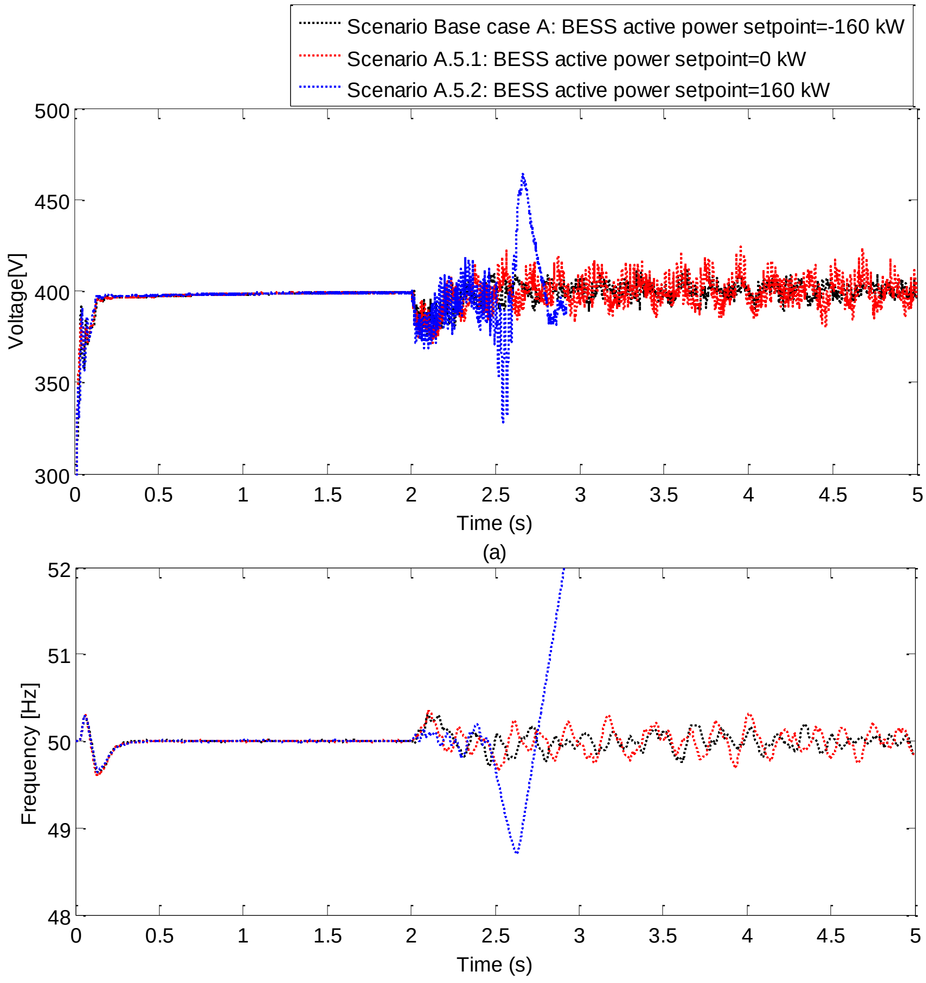

Figure 49. Island voltage and frequency for scenario A5.

5. **BESS capacity:** With respect to the previous point, i.e., point 4, if the BESS unit capacity also was very low, then the BESS unit had limited capabilities to control the voltage and frequency with allowable limits (for instance, this occurred for the BESS capacity of 0.7 pu in scenario A.6.2 in Figure 50). Thus, it is also recommended that the BESS unit size is carefully selected and defined with respect to the grid power disturbance, total load consumption and PV production in the area.

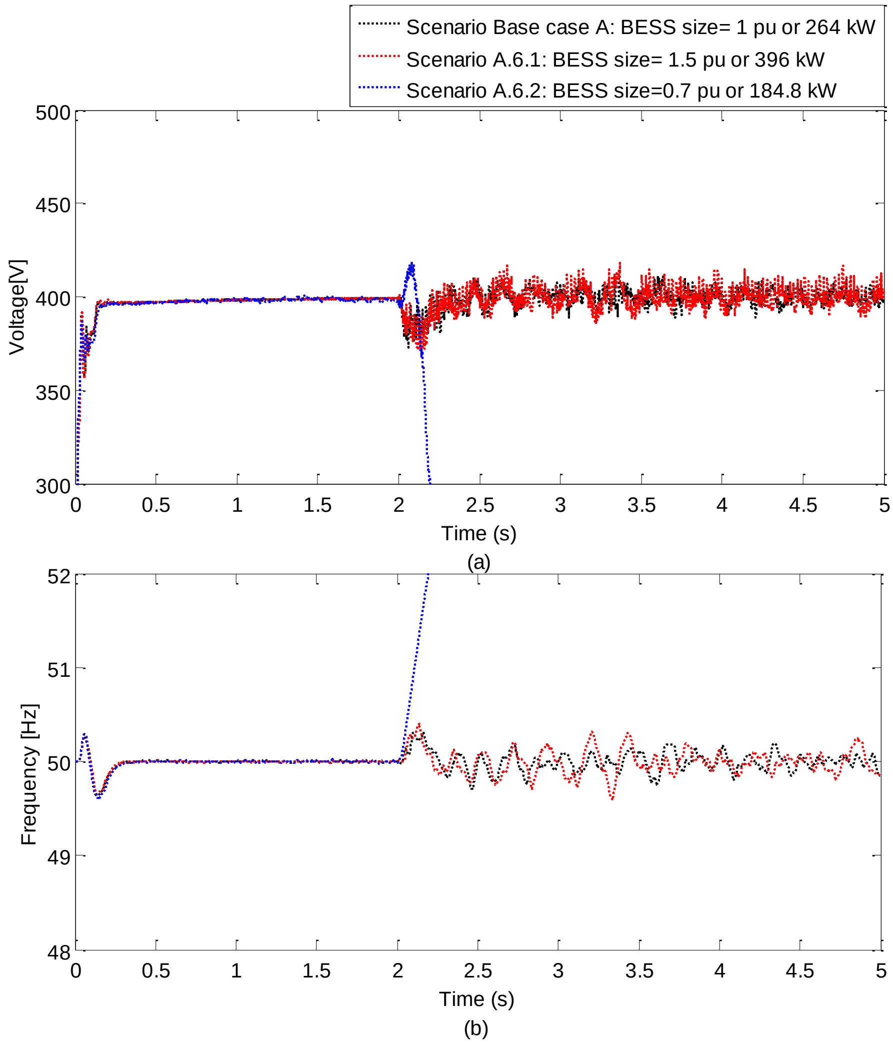

Figure 50. Island voltage and frequency for scenario A6.

6. **Demand response, e.g., fast load control, in the islanded area:** Fast controlled dummy load could significantly help the BESS unit successfully stabilize the islanded area, whereas without fast dummy load control, the islanded area was shut down (for instance, see scenario A.7.1 in Figure 51).

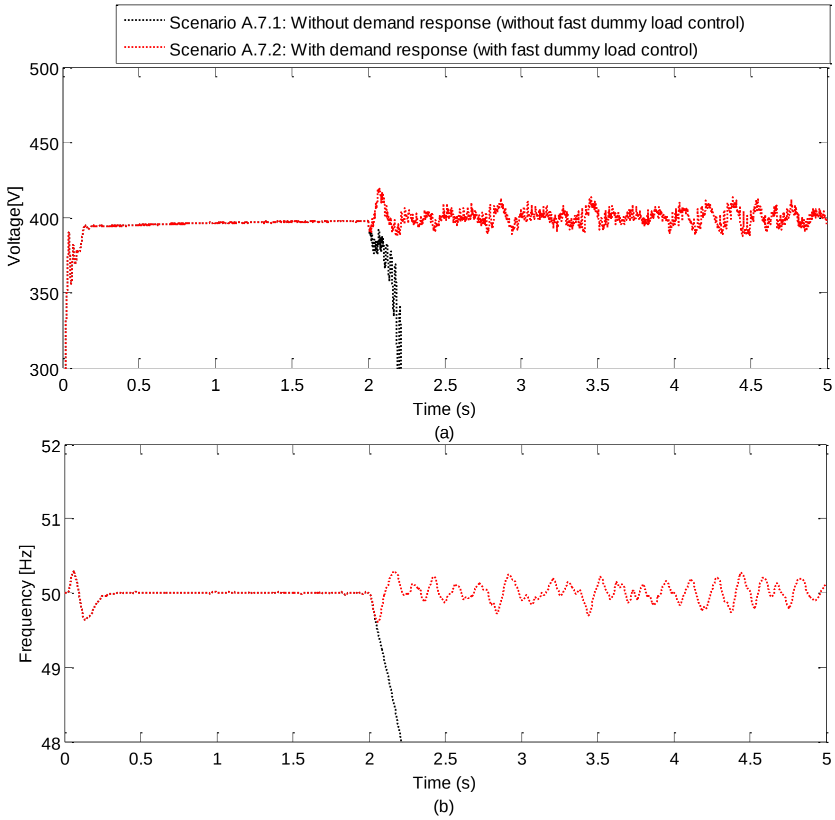

Figure 51. Island voltage and frequency for scenario A7.

- During the **"Unforeseen with black start" islanding,** the BESS performance highly depends on the following parameters[12]:

    1. **Type of the load connected:** As it was shown in the simulations, the dynamic loads such as induction machines could have very high in-rush current which remarkably decrease both voltage and frequency during "Unforeseen with black start" mode. However with the same size of the load consumption, the BESS had better performance for constant impedance loads compared to the induction machine loads. For instance in Figure 52, the connection of 40 kW dynamic load at t=2 sec caused 1.55 Hz frequency deviation, however the connection of constant impedance load 40 kW at t=12 s only led to 1Hz frequency deviation. Last but not least important point, it was mentioned that the newly installed induction machines are typically connected through a power-electronically interface to the grid that helps avoid high amplitude in-rush currents following their connection to the islanded area. In such cases, the induction machines with power-electronically interface can be modelled as constant power loads rather than dynamic loads.

[12] In fact, since the "Unforeseen with black start" mode could be started and carried out at any time of the day (or night), where the size of the load in the islanded area could be remarkably different, these sensitivity analyses parameters were defined to assess the BESS performance during "Unforeseen with black start" mode at any time with different types and size of the loads.

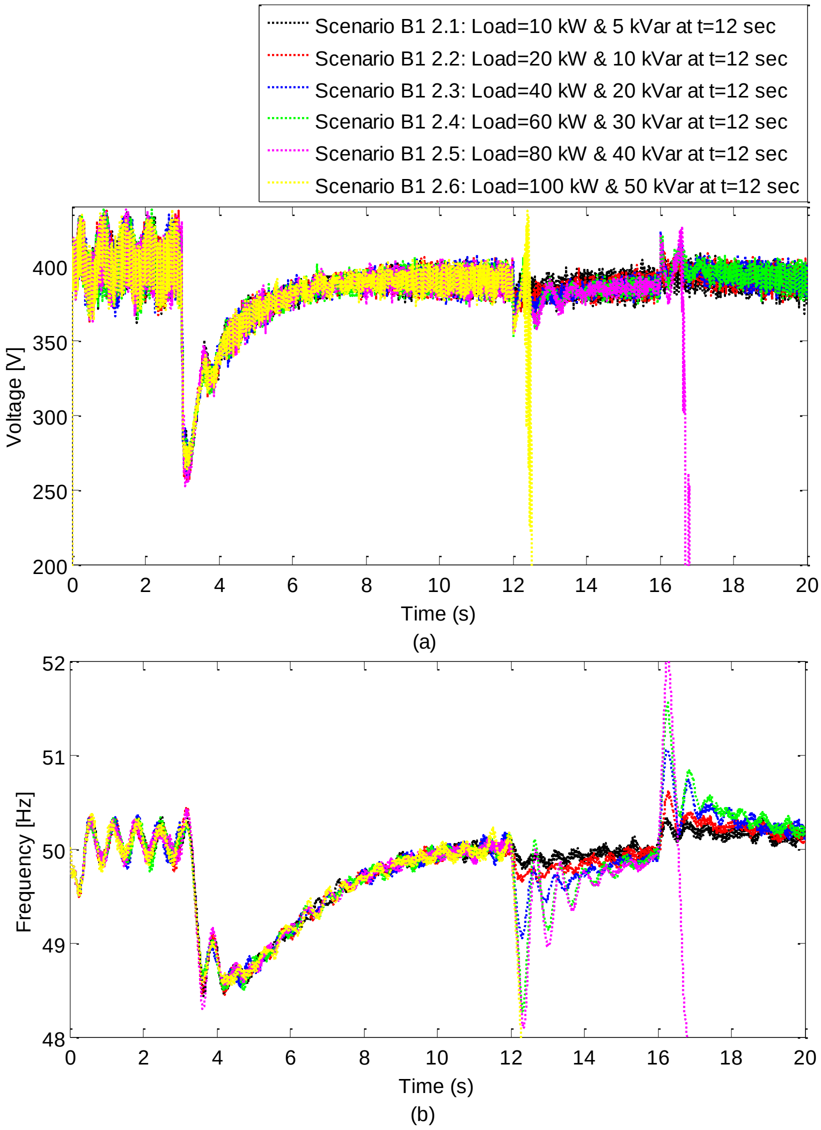

Figure 52. Voltage and frequency for scenario B1.2.

2. **Size of the load connected:** Obviously, the feasibility of successful "Unforeseen with black start" mode mainly depends on the size of the load connected to the area (for instance, the black start was unsuccessful for scenario B1 1.4 in Figure 53 for the load pick up of 200 kW or equivalently 0.8 pu). Generally, the BESS unit had high capability to pick up high values of load, e.g., for scenario B1 1.3 in Figure 53 for the load pick up of 0.38 pu.

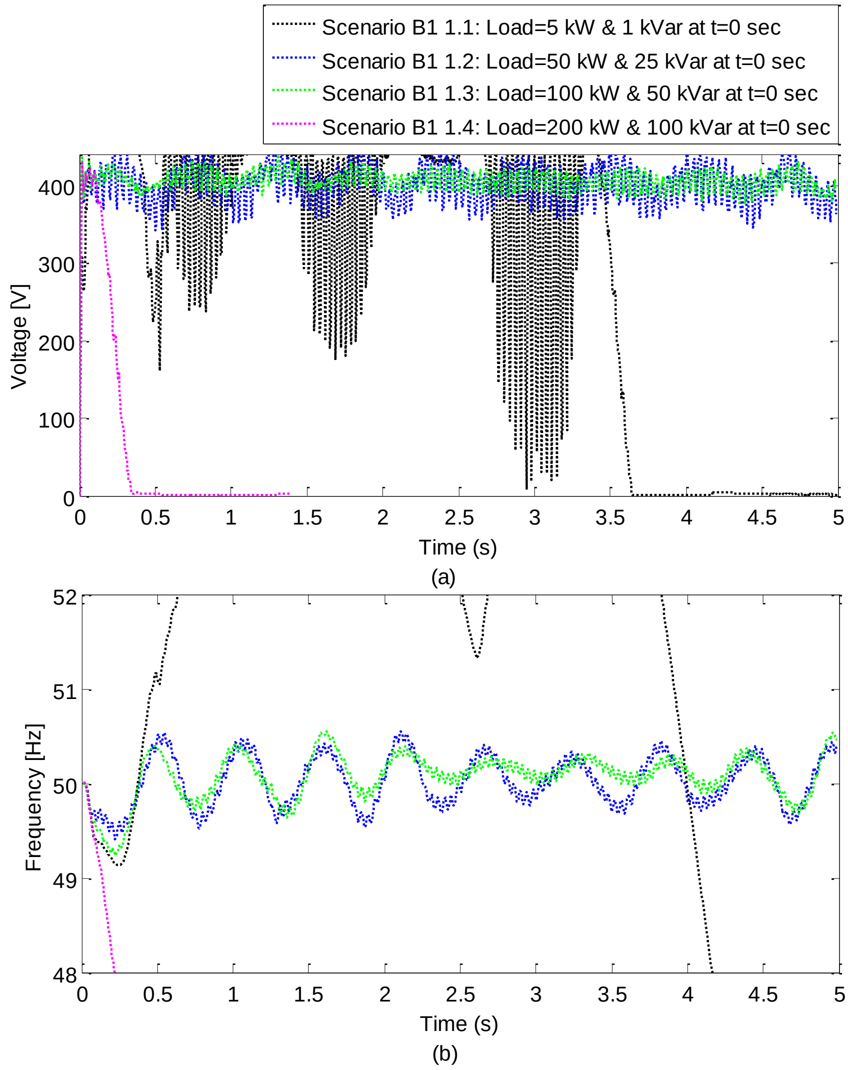

Figure 53. Voltage and frequency for scenario B1.1.

3. **Size of the PV units:** Although in practice PV units are gradually connected to the islanded area with very slow rate under monitored and controlled conditions, the BESS unit performance was very acceptable even for the sudden connection of PV units with 0.08 pu to the area (see Figure 54 at t= 25, 30, 35, and 40 s)

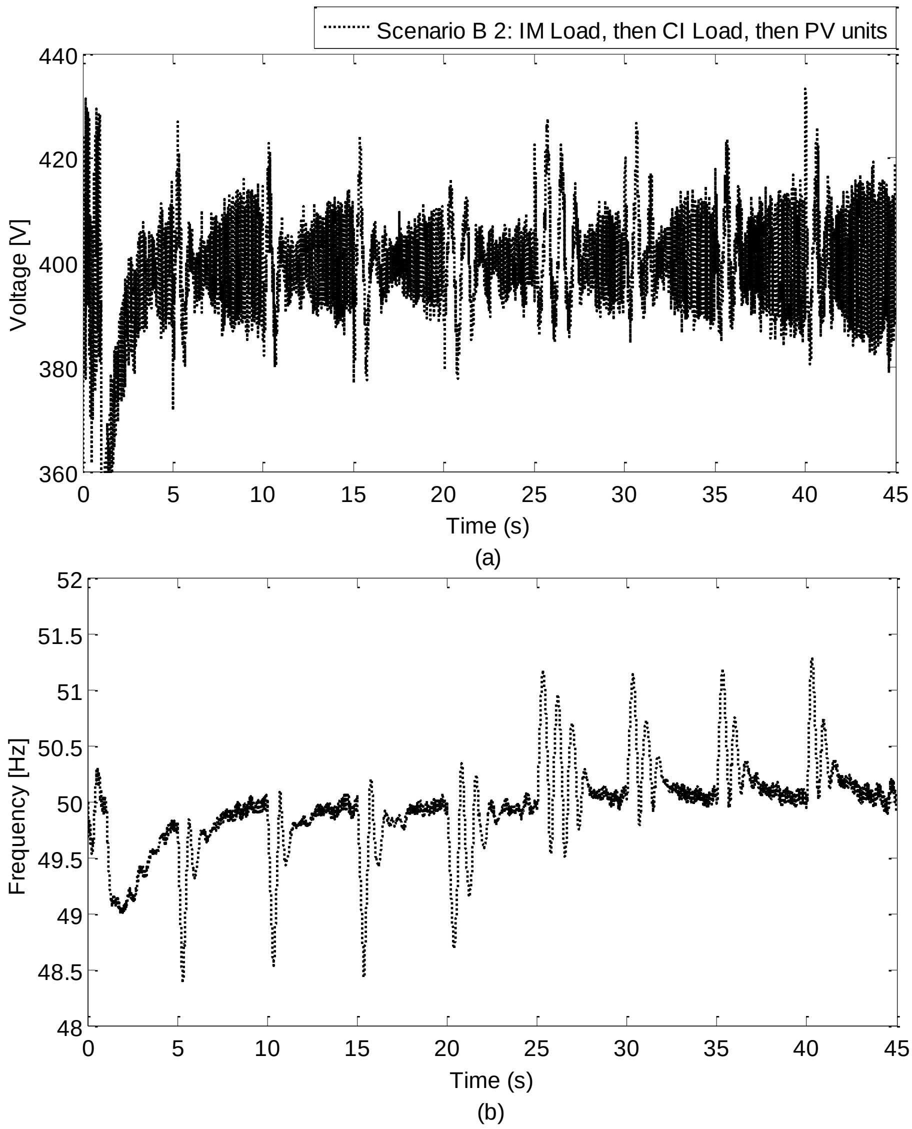

Figure 54. Voltage and frequency during "Unforeseen with black start" mode.

4. **Type of secondary controller:** In addition to the conventionally PI controllers used for the secondary controller, we had to add derivative (D) controllers to the secondary controllers in order to significantly improve the BESS capability for the "Unforeseen with black start" mode. In fact, since the total inertial response of the islanded area is comparatively low during this mode, **D controllers** can effectively emulate and increase the inertial response of the island and consequently help suppress large frequency and voltage deviations during the load pick up process.

Finally in order to present our further lessons learnt from these simulations, it is worth mentioning that the level of battery SOC as well as unbalanced load flows had negligible impact on the "Programmed" islanding mode. However if the high unbalanced load flows are not properly controlled by the BESS unit during islanding mode, then the single-phase load or PV unit connected to the area could be damaged due to the high single-phase current, and furthermore it could activate the over-current relay or fuse protection of that specific load or PV unit. As a result, in case of highly unbalanced networks, the performance of the BESS unit should not only evaluated by the frequency and three-phase voltages amplitudes, but also the current variation of each single phase during islanding mode should be additionally controlled and monitored.

4 Non-technical boundary conditions

The previous section has presented the technical impacts that may be expected from the implementation of the smart grid solution tested within GRID4EU, as well as the technical SRA rules derived from such analysis. However, actual results depend not only on the technical characteristics of the distribution grid, smart grid solution or network users, but also they can be deeply affected by non-technical aspects related to regulation or the involvement of relevant stakeholders. This section discusses the drivers and barriers that these boundary conditions may pose to DSOs.

4.1 Regulatory drivers and barriers

Electricity distribution is widely considered to be a natural monopoly as it presents its typical characteristics: cost subadditivity, information asymmetries, economies of scale, entry-exit barriers, etc. (Joskow 2008; Gómez 2013a). Hence, DSOs are subject to some form of economic regulation in terms of revenues, quality of service, access to the service, etc. As a consequence, the incentives perceived by DSOs to implement the aforementioned use cases greatly depend on the regulatory framework under which they operate. Moreover, several use cases rely on the active participation of distribution network users or distributed energy resources (DER) (active consumers, DG, distributed storage) to support grid operation. However, the regulatory mechanisms allowing and encouraging distribution network users to provide these services are scarcely developed yet. These mechanisms should be designed ensuring efficient and transparent outcomes, especially in those countries where unbundling is not fully implemented (CEER 2013; CEER 2014a).

In conclusion, without an extensive revision of conventional regulatory arrangements, the widespread adoption of more active operation and planning practices will not take place. Nonetheless, the smart grid solutions tested within GRID4EU are very diverse. Thus, the relevance of each specific regulatory aspect will not be the same for all of them. In order to perform a more focused assessment, a first step taken when performing this regulatory analysis consisting in mapping the relevant use cases identified onto the list of regulatory topics so as to highlight the most relevant topics for each use case. The results of this task is shown in Table 27.

Following this categorization, a detailed regulatory questionnaire was prepared and submitted to the 6 GRID4EU participating DSOs. Ad-hoc meeting were organized with members of the regulatory departments of some companies when deemed necessary and additional documentation, either from national regulatory authorities (NRA) or from supra-national organization such as ACER or CEER, was collected[13]. This process concluded in a detailed review of the current situation in all 6 demo countries that is presented in gD3.2b. Hence, this chapter focuses on the identified barriers for scalability and replication of smart grid solutions building on the comprehensive information on the regulatory framework in the specific member states that is presented in gD3.2b.

On the ensuing, the regulatory topics previously identified will be described in further detail. Firstly, an explanation on the kind of barriers and drivers DSOs may face, and under what conditions, will be provided. Moreover, the current situation in the 6 countries involved in the GRID4EU project will

[13] Note that difficulties were faced due to frequently changing regulation and language barriers.

be presented so as to illustrate how regulatory frameworks may differ across Europe. Lastly, a set of barriers and drivers for the scalability and replicability of smart grid solution will be provided with the aim of achieving a rapid and efficient transition towards smarter distribution grids.

		Demo 1 Germany: Load control in MV	Demo 1 Germany: Failure management in MV	Demo 2 Sweden: Outage detection in the LV grid	Demo 3 Spain: Automatic grid recovery	Demo 3 Spain: Customer engagement	Demo 4 Italy: Anti-islanding protection	Demo 4 Italy: Voltage regulation in MV	Demo 5 Czech Republic: Failure management in MV	Demo 5 Czech Republic: Failure management in LV	Demo 5 Czech Republic: Automated islanded operation	Demo 6 France: Maximize PV production in LV	Demo 6 France: Islanding
DER participation in network services: storage, DG or active demand	DER voltage control	-	-	-	-	-	-	X	-	-	-	X	-
	DER congestion management - curtailment	-	-	-	-	-	-	X	-	-	-	X	-
	DSO visibility over DER	-	-	-	-	-	X	X	-	-	X	X	X
	Contracts DSO-DER	-	-	-	-	-	X	X	-	-	X	X	X
Business models for DER	DSO ownership DG or storage	-	-	-	-	-	-	X	-	-	X	X	X
	Energy resale (storage)	-	-	-	-	-	-	X	-	-	-	X	X
	Aggregation allowed	-	-	-	-	-	-	-	-	-	-	X	X
Network charges for DER	Type of connection charges	X	-	-	-	-	-	X	-	-	-	X	-
	Design of connection charges	X	-	-	-	-	-	X	-	-	-	X	-
	UoS charges for DG	X	-	-	-	-	-	X	-	-	-	X	-
	Design of uso charges for DG	X	-	-	-	-	-	X	-	-	-	X	-
DSO revenue regulation	General regulatory framework	X	X	X	X	-	-	X	X	X	-	X	-
	Cost benchmarking approach	X	X	X	X	-	-	X	X	X	-	X	-
	Treatment of DER-driven network investments	X	-	-	-	-	-	X	-	-	-	X	-
DSO incentives to reduce losses	Implemented or not	X	-	-	-	-	-	X	-	-	-	X	-
	Type of scheme	X	-	-	-	-	-	X	-	-	-	X	-
	Impact of DER considered?	X	-	-	-	-	-	X	-	-	-	X	-
DSO reliability incentives	Implemented or not	-	X	X	X	-	-	-	X	X	X	-	X
	Type of scheme	-	X	X	X	-	-	-	X	X	X	-	X
	Potential contribution of DER considered?	-	X	X	X	-	-	-	X	X	X	-	X
Islanding operation	Permitted?	-	-	-	-	-	-	-	-	-	X	-	X
	Role of DSOs	-	-	-	-	-	-	-	-	-	X	-	X
Active demand and smart metering	Existing AD mechanisms	-	-	-	-	X	-	X	-	-	X	X	X
	Role of DSO in AD schemes	-	-	-	-	X	-	X	-	-	X	X	X
	Plans for smart metering roll-out	-	-	X	-	X	-	-	-	-	-	X	-
	Functionalities of smart meters	-	-	X	-	X	-	-	-	-	-	X	-
	Ownership/access to smart meter data	-	-	X	-	X	-	-	-	-	-	X	-
DSO incentives for innovation	Specific incentives implemented?	X	X	X	X	X	X	X	X	X	X	X	X
	Design of incentives	X	X	X	X	X	X	X	X	X	X	X	X

Table 27: Mapping use cases onto regulatory topics (X indicates strong relevance)

4.1.1 DSO revenue regulation and smart grid solutions

As discussed above, DSOs are regulated companies under the supervision of the corresponding NRA. Therefore, as shown in Table 27, DSO revenue regulation will be key for the replicability and scalability of any smart grid solution where DSO costs and investments are required or affected in any way. For instance, several uses cases require DSOs to invest in network supervision and automation technologies. The corresponding costs, beyond the scope of a demonstration project, would have to be recovered through the regulated revenues in some way. Additionally, resorting to automation or voltage control to increase HC could be also seen as a means to defer or avoid grid reinforcements driven by the connection of DG. Thus, the treatment of DG-driven investments and the incentives to substitute CAPEX by OPEX solutions is a key consideration when assessing scalability and replicability barriers.

Over the last years, incentive-based regulation, and more specifically revenue cap regulation, has become particularly popular across EU countries (Eurelectric 2011). Despite the fact that revenue-cap regulation is becoming widespread, important differences exist in the implementation aspects, especially concerning the treatment of investment allowances. Hence, in order to carry out a meaningful regulatory assessment, attention must be paid to a number of aspects that can greatly determine the incentives perceived by DSOs and final outcomes. These comprise: RAB calculation method, selection of benchmarking techniques and application of results, determination of the cost of capital, regulatory depreciation method, treatment of new investments and DSO investment plans, length of regulatory periods, combination of ex-ante and ex-post interventions, etc. (OFGEM 2010; Cossent 2013; CEER 2015).

Incentive-based regulation was originally designed as a mechanism to encourage cost reductions in an environment characterized by slow innovation and technology change. However, an efficient transition towards smarter distribution grids does not seem possible under a regulatory framework that is focused on short-term cost reductions (ERGEG 2010; Cossent 2013; Lo Schiavo et al. 2013; THINK Project 2013). Moreover, regulatory stability is also perceived as an essential aspect to attract investments, particularly under technology uncertainty (Eurelectric 2011). Therefore, the main challenge for regulators is to develop predictable yet flexible regulation that encourages DSOs to invest and innovate.

Since the goal of this report of to identify the drivers and barriers for scalability and replicability of GRID4EU use cases, a comprehensive in-depth review and assessments of each and every of the issues previously mentioned will not be made herein. General SRA rules to perform a high-level assessment of any regulatory framework will be developed. Notwithstanding, these should not be interpreted as detailed implementation guidelines for any specific country.

Some of the features that have been identified in the literature as suitable for the changing environment for DSOs are to retain incentive-based regulatory schemes whilst shifting the focus towards an output-oriented approach, performing forward-looking cost assessments, lengthening the duration of the regulatory periods or incorporating flexibility mechanisms into remuneration frameworks (reopeners, profit-sharing schemes, menu regulation). All these issues are considered effective to promote innovation and long-term efficiency. However, oftentimes, they cannot be directly related to specific GRID4EU use cases. Therefore, on the ensuing, the focus will be placed on those aspects of DSO revenue regulation that more specifically affect to smart grid investments.

Power distribution is a capital intensive activity. Hence, one of the major steps in every regulatory review (also known as rate case or price control review) is to determine the regulatory asset base

(RAB) or rate base and how new investments are added to it. This is the economic worth of net assets considered by the regulator to calculate the return on assets included in the DSO allowed revenues. Traditionally, long-lived distribution lines and substations account for the majority of the RAB, whilst ICTs and information systems represented a minor share of it. Moreover, load growth and substitution of depreciated assets were the major drivers for network reinforcement and expansion. However, growing levels of DG and smarter grids are bound to challenge this paradigm.

The concentration of DG in specific areas may trigger investments due to the lack of hosting capacity, especially in the absence of a more active network management. Hence, peak demand may not be the only suitable indicator to determine investment needs any more. On the other hand, smart grid solutions can be used as alternatives to grid reinforcements. The net result can be a substitution of additional assets by OPEX-based solutions. Furthermore, investment assessments and regulatory approaches have conventionally focused on “copper and iron assets”, whereas new types of distribution assets, with shorter useful lives and more rapid technological development, may become increasingly needed. Lastly, the combined influence of technology uncertainty and a more unpredictable behaviour of DG as compared to conventional passive loads, make it harder to estimate future investment needs.

Owing to the influence of all the aforementioned consequences of a transition towards smarter distribution systems hosting large shares of DG, future regulatory schemes should ideally present the following properties:

a. Remuneration schemes provide DSOs with incentives to attain a long-term efficiency, neutral to the relative shares of CAPEX or OPEX over the total expenditures.

b. Smart grid investments should be eligible to be included in the RAB and reflected in the DSO remuneration.

c. The impact of DG on investments needs should be reflected in the allowed revenues so that the connection of DG cannot be hampered due to lack of HC.

d. Remuneration schemes should be flexible in order to react to uncertainties in terms of network users’ connection and technology needs.

However, a review of existing approaches to the DSO revenue regulation in the GRID4EU countries, which can be considered representative of the situation at European level, reveals that deviations with respect to the previous may exist nowadays[14]. Some form of incentive-based regulation has been introduced in all the countries. However, important differences exist among the countries, particularly in relation to the treatment of CAPEX and new investments. Based mostly on the information collected in gD3.2 and the questionnaires filled-in by GRID4EU participating DSOs (other references are indicated where applicable), the following conclusions can be drawn:

- A separate treatment of OPEX and CAPEX is frequently applied. Whilst OPEX are subject to a pure revenue cap scheme, CAPEX tend to be subject to a more input oriented approach, i.e. CAPEX are at least partially excluded from efficiency gain requirements. As a result, DSOs generally perceive strong incentives to reduce OPEX, whilst almost no incentive at all to reduce the asset base. This can be an important barrier for the implementation of solutions

[14] Note that comparing different regulatory frameworks among them is not straightforward since regulation is in constant evolution and “the devil” is usually in details which are hard to assess. Hence, these comparisons do not intend to be a comprehensive review of the adaptations required in each country but to identify general trends and potential barriers to the deployment of smart grid solutions.

aiming to increase the network HC, which reduce the asset base at the expense of increasing OPEX. In fact, the Italian regulator has announced plans to modify their regulation in this line (AEEGSI 2015).

- On the other hand, an input-based approach for CAPEX can be an enabler for other smart grid solutions (and reinforce the grid to connect DG) that do increase the asset base without significantly reducing OPEX, as it is the case of use cases related to grid automation or islanded operation. However, the determination of the RAB needs to incorporate specific asset categories with differentiated asset lives for smart assets, as it is the case of Sweden or Italy. What is more, Italy applied an additional mark-up on the WACC applied to some smart grid investments pre-approved by the regulator for a period of 12 years. Nonetheless, this approach violates the principle of technology-neutrality. Hence, whilst this may be an enabler for those types of smart grid solution deemed eligible by the regulator, it may act as a barriers for other types of solutions for which cost recovery would be uncertain.
- A TOTEX approach, i.e. equalizing the incentives to reduce OPEX and CAPEX, has been mentioned as a desirable approach to encourage certain smart grid solutions. However, even when this is done, as in Germany, important barriers may be encountered. The determination of allowed TOTEX usually relies on conventional benchmarking approaches which build efficiency estimates on the basis of historical information and cross-comparisons among DSOs. However, the penetration of DG and smart grid investments needs may widely differ across DSOs (e.g. a certain distribution area may be very favourable for the connection of DG due to resource availability). Moreover, these effects may be hardly reflected in historical information. Therefore, cost assessment methodologies adopting a more forward looking standpoint are required so as to consider the future investment needs in smart grids and DG.
- Nonetheless, cost assessment approaches tend to be quite limited with respect to the estimation of smart grid investments or DG-driven ones. Engineering models such as the NPAM previously applied in Sweden (Jamasb and Pollitt 2008) or the RNM applied in Spain (Mateo Domingo et al. 2011) may capture the impact of DG-driven network investments. However, these models are still largely incapable of incorporating smart grid solutions into their decisions. In order to overcome these limitations, ex-ante DSO investment plans should play a central role. Countries such as France or Spain (according to regulation in RD1048/2013) already require DSOs to submit standardised plans in terms of format and content-wise. Regulators ought to encourage DSOs to justify the decisions made these business plans applying cost-benefit analyses considering smart grid solutions and several probabilistic-based load and DG scenarios.
- Flexibility mechanisms are not given a priority, presumably due to the input-oriented regulation implemented in most cases. These schemes are limited to the use of standard investment costs in combination with actual costs to determine RAB additions in Sweden and Spain[15], or to a profit-sharing mechanism for OPEX in Italy. Nonetheless, incorporating CAPEX into these flexible remuneration schemes becomes more relevant as regulation becomes more output-oriented so as to mitigate uncertainties, or regulatory periods are lengthen. Moreover, resorting to DSO investment plans adds to this need so as to mitigate the incentive DSOs may see to provide the regulator with inflated investment prognoses. Flexible remuneration systems, such

[15] The use of standard investment costs, instead of or in combination with actual costs, encourages DSOs to reduce per unit costs. However, it does not promote reduction in the “amount” of physical assets, since DSO returns will increase with the RAB (as long as actual costs can fall below standard values).

as profit-sharing schemes or menu regulation, usually involve increasing ex-post interventions. Being this the case, pre-defined rules should be set so as to mitigate regulatory uncertainty.

4.1.2 DSO innovation incentives

As stated in section 4.1.1, conventional incentive regulation schemes are not deemed suitable to promote innovation and taking technology risks. Therefore, several NRAs decided to adopt specific incentives to implement innovative technologies or solutions with the goal of testing potentially beneficial and workable ones. These schemes are generally implemented as input-oriented ones in the form of investment incentives. Nonetheless, as technology maturity is achieved and experience is progressively gathered, they tend to evolve towards output-oriented ones, based on performance indicators. The most active countries in this regard at European level are presumably the UK and Italy (CEER 2011; OFGEM 2013; AEEGSI 2015).

The remainder of this section will focus mostly on input-oriented or investment incentives since they are the ones more directly related to the promotion of smart distribution grids. Despite the fact that performance indicators may indeed encourage the adoption of proven innovative solutions, they may be seen as an integral part of the overall revenue regulation rather than innovation incentives per se. In fact, some form of output incentive related to the improvement of continuity of supply and energy losses levels are common nowadays. The topic of enhanced use by regulators of output performance incentives, in addition to the existing ones, will be treated in section 4.1.3.

DSOs in all GRID4EU countries may request funding for smart grid projects either from EU or national funding programs for research and demonstration. In several cases, regulators may additionally allow DSOs to pass-through demonstration costs on to revenue allowances without subjecting them to efficiency gains, as in the case of Germany or France. Likewise, the Italian regulator allowed DSOs to earn an extra 2% incremental points on WACC over a period of 12 years for those pilot projects pre-approved by the regulator, with a particular emphasis on DG integration. In order to be eligible for such support, smart grid projects had to comply with a set of technical requirements and information disclosure obligations[16].

Existing experiences show that input-oriented schemes are suitable to promote experimentation and demonstration projects as they encourage DSOs to test without an excessive exposure to technology risks. However, the large-scale deployment of smart grid technologies, i.e. the scalability and replicability of tested solutions, may be conditioned by the design of these investment incentives. Moreover, since this is a transversal issue, all smart grid use cases would be equally affected.

Firstly, input oriented mechanisms may focus on specific technologies or solutions. Consequently, only those under the regulatory radar would tend to be tested. Therefore, despite the fact that a certain solution may have proved to be successful in a different country, it may not be replicated elsewhere because regulatory incentives exclude a key technology. This may be the case, for instance, of energy storage whose deployment and operation by DSOs may collide with unbundling provisions (more on this topic in section 4.1.6). This may hamper the replicability of solutions tested by DSOs in other countries.

Moreover, demonstration projects within these incentive schemes are generally limited in size, so their scalability is subject to how these investment are treated within the overall remuneration

[16] Further information on the pilot projects carried out under this scheme can be found at: http://www.autorita.energia.it/it/operatori/smartgrid.htm

scheme (see section 4.1.1). Lastly, input incentives normally require an extensive regulatory oversight to pre-approve and monitor demonstration activities. However, the regulatory burden could be unsustainable should this approach be applied to a large-scale deployment. Therefore, the following conclusions or rules may be drawn:

- Input incentives require the regulator to define the technologies and projects eligible for support, either before or after the application for funding by the DSO. Therefore, the implementation of functionalities tested in a different context may be hampered by the regulator's decision, thus acting as a barrier to international replication.
- Demonstration projects driven by investment incentives are normally limited in size according to the corresponding eligibility criteria. Therefore, alternative approaches are necessary for the large-scale roll-out of proven technologies.
- Knowledge-sharing obligations related to input incentives facilitate the replicability by other DSOs. This obligation may include lessons learnt (both positive and negative) and additional analyses, e.g. CBA.
- The degree of regulatory supervision required in the project approval and monitoring make it impractical to rely solely on input regulation for a large scale roll-out. Alternatively, regulators may opt for output regulation to ensure DSOs select the technologies and the deployment strategy more suitable to achieve those outputs.

4.1.3 DSO regulatory incentives: continuity of supply and energy losses

4.1.3.1 Continuity of supply

One of the major duties of DSOs is to provide network users with adequate levels of quality of service. However, a degradation in quality of service levels is a potential drawback of the cost reduction incentives DSOs may perceived after the introduction of incentive-based regulation. This is particularly relevant for continuity of supply[17] as it is the component of quality of service at distribution level that is more deeply connected to network investment and maintenance (Gómez 2013b). This concern is proved by the fact that all European countries monitor continuity of supply at distribution level and most of them have implemented are have planned to do it some type of incentive scheme for network operators (CEER 2012).

Conventionally, reliability levels could be improved by enhancing network redundancy (investments in copper and iron) and through improved maintenance strategies to minimize the number of faults, or through the work of in-field maintenance crews once a fault had already occurred. However, network monitoring and automation favoured by ICTs has become a powerful tool for DSOs to keep improving reliability levels whilst reducing conventional network investments, which besides costly can present important lead times and face administrative barriers. Within the GRID4EU project, up to four demonstrations apply this type of solutions to improve continuity of supply caused by faults in the MV grid (demo 1, demo 3 and demo 5) and in the LV grid (demo 2 and demo 5). Additionally, the presence of active DER in the distribution network enables the islanded operation of a section of the grid in case of an upstream fault, should the appropriate protection and control equipment be in place. This is tested in demo 5 and demo 6.

[17] Continuity of supply measures the frequency and duration of supply interruptions. Other quality of service components are power quality and commercial quality.

Consequently, the regulation of continuity of supply is determinant to the scalability and replicability potential of the aforementioned use cases. More specifically, the measurement of continuity of supply level[18] and the type of regulatory approach adopted will be reviewed in this section.

Firstly, it is important to evaluate how continuity of supply (or the lack of it) is measured. Reliability indices normally reflect only the so-called long interruptions, i.e. those going beyond transitory voltage dips of very short interruptions caused, for example, by switching operations. Across Europe, there has been a convergence towards the 3min threshold for an interruption to be considered as a long one (CEER 2012). This is in fact the case in all GRID4EU countries. This time buffer allows DSOs to reduce the number of interruptions considered in the indices measured through network automation as these systems only start operating after a fault has been detected. The tighter this threshold is, the harder it will be for DSOs to reduce the number of recorded long interruptions. Being this the case, faster solutions could be sought, e.g. choosing local control as opposed to centralized operations. However, beyond a certain point, network automation may be unable to reduce this number.

Another relevant aspect of continuity of supply measurement is whether planned interruptions are excluded from the indicators used in regulation as well as the criteria to be met for interruptions to be considered as such. In principle, most European countries, being the six GRID4EU countries among these, exclude at least partially planned interruptions from the indices used to calculate incentives and/or penalties. Since smart grid solutions mainly address unplanned interruptions that require a fast response from the DSO[19], this aspect should not be relevant for SRA purposes. However, the conditions to be fulfilled by DSOs vary significantly across countries, namely the minimum notice time for consumers (varies between 15 days and 24h), the communication for (written, mass media, other) and the administrative permissions. Consequently, in countries with more stringent criteria for planned interruptions it is more likely that interruptions known in advance by the DSO represent a significant share of the faults embedded in the reliability indices measured. Therefore, network automation will be able to reduce the values reliability indices in a proportionally lower amount.

According to CEER's 5th benchmarking report, all countries but a few exceptions monitor interruptions occurring in all distribution voltage levels. Thus, in principle, DSOs in all these countries should present similar regulatory incentives to implement LV monitoring to detect outages as soon as possible. However, a closer look at the mechanisms used to identify and log faults in the LV grid shows that this may not be the case in practice. Whilst faults in the MV and HV levels are generally identified through different information systems (although the impact on LV consumers is usually estimated following heterogeneous criteria), LV faults and the customers affected by them are estimated through less precise methods. Oftentimes, these has to be identified through call centres and customer claims.

The use of LV monitoring and AMI to identify faults in the LV grid presents clear benefits for consumers. In spite of this, DSOs may not be encouraged to implement such solutions under conventional reliability calculation methods (without automatic identification and logging). In fact, it could even happen that reliability indices worsen due to the implementation of more accurate recording methods that capture faults or interrupted consumers that were not considered before,

[18] DSOs would see no economic incentive to improve reliability levels unless specific regulatory mechanisms are in place. Therefore, the discussion on measuring continuity of supply indicators would be mainly relevant when these indicators are used for such purposes.

[19] Switching operations can also help DSOs minimize the impact of planned interruptions. However, since these are known in advance, manual operations could be used instead in these cases.

e.g. because not all consumers affected by a fault complained. In conclusion, this type of functionality is desirable for consumers and thus should be encouraged by regulators (presumably subject to a CBA analysis). However, a transitional period may be required to prevent jeopardizing DSOs and hampering replicability and scalability.

The last relevant aspect of continuity of supply measurement, is related to the indices recorded and how interruptions are weighted to compute them. The most common approach is to weight interruptions according to the number of consumers affected by them. Thus, SAIDI and SAIFI are the most widespread indicators. Notwithstanding, some countries apply alternative weighting methods such as the amount of power affected (Spain or Germany through the TIEPI/NIEPI or ASIDI indices) or the estimated ENS during the interruptions (France). The use of one or another reliability index would not affect the incentives for DSOs to implement these smart grid solutions. Nonetheless, it would indeed affect the scalability and replicability strategies adopted by DSOs, i.e. the areas to prioritize the implementation of the solution. These could either be those affecting a larger number of consumers (SAIDI/SAIFI), those affecting a larger amount of capacity (ASIDI/ASIFI) or those affecting consumers with larger energy consumptions (ENS).

As mentioned at the beginning of this section, the design of continuity of supply regulation is a key enabler for the scalability and replicability of some use cases. These mechanisms commonly consist in a bonus-malus scheme according to which DSO revenues increase if actual levels of continuity of supply at system level are better than a certain reference value defined by the regulator and decrease otherwise. This is actually the type of mechanism applied to DSOs in all six GRID4EU countries. From a theoretical standpoint, the power of the incentives do not depend on the reference value but on the unit incentive[20] (how DSO revenues increase or decrease per a deviation in one unit between actual and reference values of the relevant indicator) (Cossent 2013).

However, actual remuneration frameworks sometimes deviate from a theoretical linear and symmetrical scheme. Deadbands around the reference value or asymmetric incentives (e.g. penalties only) introduce discontinuities that can distort the effectiveness of these incentives, thus affecting the scalability and replicability potential of the smart grid solutions affected. DSOs whose reliability levels are within the deadband, especially when far from its limits, or above the threshold to be penalized would perceive weak incentives to improve continuity of supply through automation at least until the reference values are updated. However, since reference values are usually defined based on past performance, this may imply a permanent stagnation of reliability levels.

Another discontinuity introduced in these mechanisms are caps and floors to mitigate the exposure of DSOs and rate payers. For example, the value of the total incentive/penalty is set to 3% of the annual remuneration in Sweden, Spain or Czech Republic. If the upper limitations would be reached systematically, this could be a barrier for scalability and replicability (no further benefit is received from an improvement in performance). Nonetheless, being this the case, regulators would presumably opt for updating the reference values accordingly.

A key element in the design of continuity of supply regulation is the definition of the unit incentive, which can be seen as the price of quality of the cost for consumers of the lack of quality. Broadly speaking, the higher this unit incentive, the stronger the incentives to improve continuity of supply but at a higher cost for rate payers. Conventionally, this value has been estimated by quantifying

[20] This means that the DSO would be equally motivated to reduce the losses as to increase the gain as long as the marginal cost of improving quality is lower than the marginal increase in the economic incentive or decrease in the penalty.

the cost of interruptions for consumers through a variety of methods (CEER 2010). However, due to the different formulas and reliability measurement approaches that can be found across countries, it is virtually impossible to set comparisons or to determine whether current approaches are sufficient to encourage the implementation of smart grid solutions. Such an evaluation would require an economic assessment of the marginal cost of improving reliability through these solutions[21] to be compared against regulatory incentives in each country.

Some countries monitor reliability per type of area (depending on load density) or on a regional basis and set up differentiated reference values accordingly. This is the case of Spain, Italy and France. This approach acknowledges that the costs of providing a certain level of continuity of supply depends on the characteristics of the distribution area and prevents penalizing DSOs from providing poorer quality in more costly areas[22]. However, this will not affect scalability and replicability strategies adopted by DSOs as long as the unit incentives remain the same for all areas (see footnote 20).

The last item related to this piece of regulation that will be addressed are the direct economic compensations[23] to individual consumers due to excessively poor levels of quality. This feature is used to prevent the existence of specific users experiencing very poor levels of grid reliability despite the fact that average levels may be fine. All GRID4EU countries but Germany apply some form of compensation related either to the duration of single events or the number/duration of total yearly values. Moreover, (CEER 2012) shows that this is not the exception across the EU. These compensations can represent an added driver for DSOs to implement reliability improvement strategies, especially those based on network monitoring which can reduce significantly the times required to identify a fault occurrence. In fact, LV outage detection as in demo 2 is mainly addressing fault location in isolated rural areas with long overhead lines that can remain unsupplied for long times after a meteorological event. Moreover, they can influence the areas to be prioritized when determining a roll-out strategy.

- The inexistence of regulatory incentives to improve reliability levels will deeply hamper the implementation of network automation or islanding except in very specific areas with very poor reliability levels so as to prevent high individual compensations.
- Excluding planned interruptions from regulatory incentives strengthens the incentives for DSOs to implement network monitoring and automation, as the relatively gain in reliability levels becomes larger.
- Measuring reliability more accurately at LV, e.g. by forcing DSOs to use smart metering data, is a key driver for the use cases related to LV monitoring and automation. However, transition periods may be required to prevent jeopardizing DSOs as a result of a change in measurement approaches.
- Reducing the threshold for long interruptions, e.g. from 3 min to 1 min, will tend to favour solutions based on local intelligence. However, there is threshold beyond which automation will only help you reduce time of interruptions but not the number. If smart grid solutions are not able to resupply the load interrupted before this time elapses, the incentives perceived to

[21] The technical analyses presented in section 3.1 could serve as a basis for this, in case implementation costs were used in the horizontal axis instead of automation/monitoring degree.
[22] This is the economically efficient outcome provided that all consumers, regardless of where they are located, present the same willingness to pay for quality.
[23] These are translated in a direct payment/deduction to the involved consumers instead of affecting DSO revenues which are socialized among rate payers

implement these solutions will be only related to the reduction of the duration of the interruptions, thus being significantly diluted (unless incentive mechanisms are redesigned). In case regulatory incentives are independent of the number of interruptions, focusing exclusively on their duration, the aforementioned threshold would be less relevant. Moreover, this threshold seems to be more relevant for MV automation than for islanding solutions, since the latter allow resupplying the loads in a very short time span.

- The type of reliability indices measured, either weighted in terms of power or in terms of number of users, does not affect the incentives seen by DSOs to improve network reliability. Nonetheless, it could direct their priorities to the areas where these indices improve the most. Hence, in case SAIDI/SAIFI are used, DSOs would tend to maximize the number of consumers who see an improved continuity of supply. On the contrary, is ASIDI/ASIFI are used, DSOs would try to maximize the amount of power affected by the smart grid solutions.
- Different design elements of reliability incentives can deeply affect the extent to which DSOs are promoted to implement smart grid solutions for continuity of supply improvement. Discontinuities such as deadbands or caps may act as barriers for further reliability improvements. Likewise, low values for the unit incentive may not be enough to compensate DSOs for the additional costs (unless all or part of these costs are included in the RAB). General rules cannot be applicable, since the most suitable option would depend on many factors, most notably pre-existing levels of reliability as well as consumers' willing to pay for further improvements. Hence, regulators should evaluate on a case by case basis whether further reduction in interruption levels are desired and, in case of an affirmative answer, whether existing regulatory incentives would be enough to achieve them.
- Individual compensations can act as a driver for some solutions whose benefits are ripped by a low number of consumers and that otherwise could be largely neglected, e.g. LV monitoring in rural areas. Moreover, individual compensations can affect the replicability of these use cases by modifying the priorities of DSOs when deploying these solutions.

4.1.3.2 Energy losses

Energy losses represent the difference between the amount of electricity injected into the distribution grid and the energy metered in consumption points. This deviation may correspond to the so-called commercial losses (theft, meter tampering, billing errors, etc.) or to the technical losses that inevitably occur when electricity flows through network components. GRID4EU use cases where energy losses are deemed a relevant KPI, focus on the effect of advanced grid solutions on technical energy losses. Therefore, on the ensuing, the focus will be mainly placed on technical losses[24].

In a context where distribution companies are pure network operators, i.e. they do not produce or sell to end users any electricity, energy losses do not constitute a direct cost for them in most countries[25]. However, DSOs may indeed be able to affect the volume of losses through their investment and operation decisions. Therefore, performance incentives to encourage DSOs to reduce energy losses are frequently implemented as a complement to revenue regulation (ERGEG 2008; ERGEG 2009).

Conventionally, DSOs could reduce losses through operational decisions such as elevating the

[24] Notwithstanding, some smart grid solutions such as smart metering and LV supervision may indeed support DSOs in the reduction of commercial losses when relevant.
[25] This is not the case of France, where the DSO must buy energy losses, so it is incentivized to reduce them.

operating voltage with OLTCs or reducing reactive power flows through capacitor banks. Over the long-term, some investment decisions could be made so as to reduce losses such as installing thicker conductors, low-loss transformers or upgrading rated voltages. Smart grid solutions open new possibilities for DSOs to reduce energy losses in their grids by, for instance, reconfiguring their grids to redistribute power flows through the different feeders, as in Demo 1, or by interacting with distribution network users to control power flows or bus voltages, as in Demo 4 or Demo 6.

It is precisely in these use cases that, according to the KPI definition presented in gD2.2, energy losses are deemed relevant[26]. Notwithstanding, energy losses are not considered a major driver for the implementation of smart solutions, whose main objective is usually to increase in DG network HC. In these cases, energy losses are considered as an added benefit or secondary objective that may contribute to tipping the scales towards a positive business case.

Nonetheless, in spite of these solutions, distribution losses largely depend on the location and operation of network users, i.e. end consumers and DG units. Therefore, DSOs may only control energy losses to a limited extent. This lack of controllability and predictability presumably increases as the power system moves towards a largely decentralized model where intermittent generation is widely connected to the distribution grid. Therefore, the risk exposure of DSOs should be born in mind when designing regulatory incentives for losses. Moreover, reference values for losses ought to incorporate the impact of DER on network losses in order to expose DSOs to the associated risks (which may benefit or jeopardize them depending on the evolution of losses). However, this may not be the case when reference values are solely based on historical information.

The design of regulatory incentive schemes for losses reduction share many features with the ones described above for reliability indicators. For instance, the discussion on deadbands (e.g. the loss incentive in Spain is capped at +1% and -2%) and cap/floor mechanisms are directly applicable in this case too. On the ensuing, the focus will be placed on the particular aspects strictly related to the regulation of energy losses.

The value of losses, or unit incentive, is usually related in some way to the wholesale electricity prices. Thus, the determination of unit incentive values is more transparent and objective than in the case of continuity of supply, where approximate methods were required. When this value is set in advance by the regulator, this provides higher certainty to DSOs when internalizing the cost of losses into their operation and investment decisions. However, in practice, a pre-defined value of losses may significantly deviate from the actual cost of energy generation at each moment. Therefore, these values are sometimes determined ex-post on the basis of realized market prices. For example, in Spain, RD 1048/2013 sets the unit incentive as 1.5 time the average wholesale spot price (only known ex-post). On the contrary, in Germany, the prices are calculated by using reference values from the futures market (known between 8-6 months in advance) with a fixed mixture of base and peak periods.

A consequence of linking the value of losses to wholesale prices is that the incentives for DSOs to reduce losses depend to a great extent on system conditions. Therefore, ceteris paribus, countries with higher electricity prices would provide stronger incentives for DSOs for loss reduction than otherwise[27]. Moreover, the progressive penetration of RES in European markets is modifying price patterns, creating many hours with very low (or even negative prices) and some hours with peaking

[26] In demo 6, the use case related to the maximization of PV integration in LV assesses battery losses suffered by end consumers rather than on the distribution network losses.

[27] This does not mean the unit incentives should be raised artificially, as they would not reflect the actual value of losses. However, it may indeed affect the replicability of solutions aiming to reduce energy losses.

or scarcity prices (the trend, either upwards or downwards, in average prices may change on a country basis). Therefore, the incentives seen by DSOs would also greatly depend on whether the unit incentives are defined as an average value or with a time-differentiation.

In the former case, DSOs would be equally encouraged to reduce losses at all times, particularly during peak conditions in their distribution areas (which do not necessarily coincide with system peaks). On the contrary, introducing a time-differentiation would encourage DSOs to focus efforts on reducing losses in periods with high energy prices. For instance, reconfiguring the grid to balance the production of PV units across neighbouring feeders, assuming local PV production follows the same pattern as system wide production, may yield lower benefits for DSOs when unit incentives show a time discrimination since solar production could push prices down.

- The inexistence of regulatory incentives to reduce energy losses decreases the benefit for DSOs of implementing load management or voltage control strategies which, in addition to increasing the network hosting capacity, may reduce network losses.
- Since unit incentives are usually related to wholesale electricity prices, the system price patterns can affect the incentives seen by DSOs and the replicability and scalability of smart grid use cases. Broadly speaking, higher electricity prices would result in stronger incentives for DSOs, and higher benefits from loss reductions.
- Fixing unit incentives in advance, e.g. through forward prices of forecasts, provides DSOs with stronger certainty on the benefits of losses reduction when internalizing the cost of losses into their operation and investment decisions, thus facilitating scalability and replicability.
- When a fixed unit incentives for losses reduction is used, e.g. in relation to average prices, DSOs would be equally encouraged to reduce losses at all times, particularly during peak conditions in their distribution areas (which do not necessarily coincide with system peaks).
- On the contrary, unit incentives showing a time discrimination encourage DSOs to focus efforts on reducing losses in periods with high energy prices which may not be the periods with the highest distribution losses.
- Discontinuities such as deadbands or caps may act as barriers for further reductions in losses. Regulators should evaluate on a case by case basis whether further reduction in losses is desired and, in case of an affirmative answer, whether existing regulatory incentives would be enough to achieve them

4.1.3.3 Other incentives mechanisms

As mentioned in sections 4.1.1 and 4.1.2, some regulators have identified the need to move towards a more output oriented regulation so as to encourage an efficient deployment of smart grid technologies (CEER 2011; OFGEM 2013; CEER 2014b; AEEGSI 2015). However, output regulation has conventionally been mostly limited to the aforementioned incentives to improve continuity of supply and reduce energy losses. Some countries additionally set penalties on DSOs for exceeding a certain time when connecting a new grid user or in relation to power quality indicators.

CEER has identified several other indicators, of which the following, applicable to distribution networks, were evaluated in further detail: network hosting capacity, energy not withdrawn from renewables and satisfaction of grid users (CEER 2011; CEER 2014b). The UK is probably the EU country with a stronger application of output incentives in distribution regulation. The implementation of UK's RIIO regulation for the first time in the electricity distribution activity has resulted in an enhanced use of output indicators and regulatory incentives (comprising customer satisfaction, swift grid connection or environmental impact) as summarized in (OFGEM 2013).

Within GRID4EU countries, some examples on the application of additional output performance indicators can be found. For instance, RD 1048/2013 introduced a new regulatory incentives for DSOs to detect fraud and electricity theft. According to this mechanism, DSOs may receive as an additional income 20% of the network charges collected as a result of the fraud detection. This incentive is capped at 1.5% of total remuneration. Such an incentive may encourage DSOs to implement LV supervision and AMI solutions. Another example is that of Italy, where the selection of pilot projects eligible for regulatory support was carried out on the basis of, among other scores, an output indicator measuring the increase in network hosting capacity, referred to as P_{smart} (Lo Schiavo et al. 2013). Naturally, this promoted demonstration projects on the area of DG integration.

This example shows that output indicators do not necessarily have to be directly applied as revenue drivers as it has been conventionally done with losses or reliability. Alternative approaches may equally encourage DSOs to deploy innovative solutions whilst mitigating the typical problems of incentives based on performance indicator, i.e. lack of observability (easily and objectively measured and quantified) and non-controllability by DSOs. Some additional examples of alternatives regulatory applications of output indicators include faster approval of investment plans with a lower degree of regulatory scrutiny, similar to the fast-tracking process carried out by OFGEM, or in combination with menu regulation, as suggested by the New York authorities through the so-called scorecard performance as described in (New York DPS 2015).

In conclusion, the increased use of output indicators for the regulation of DSOs can be seen a driver for the deployment of those smart grid solutions which target precisely those performance criteria. To the extent possible, the output indicators should correspond to a final benefit for network users or the society as a whole, be accurately and objectively measurable and quantifiable, be controllable by the DSO and be technology neutral (CEER 2011).

4.1.4 DER active participation and islanded operation

The smart grid solutions analysed in this report sometimes depend on the active participation of different types of DER to support grid operation. For example, in Demo 4, the voltage rise problem caused by the connection of large shares of DG to the MV grid is solved by an active control over the DG units' reactive power injection (power factor control) and a BESS active and reactive power injection. Moreover, DG active power curtailment or demand response were originally considered as additional control variables but ultimately discarded for demonstration purposes due to difficulties in the engagement process. Furthermore, in Demo 6, LV network constraints are solved by means of a local market for flexibility, referred to as NEM, where demand and battery aggregators can offer their services.

Additionally, Demo 5 and Demo 6 have tested and demonstrated the islanded operation of part of the distribution grid thanks to the presence of an active resource connected to the DSO system. It is important to make a distinction between this approach and what is normally referred to as microgrids. In both cases, there exists a cluster of loads, storage and generation which are locally controlled and can operate in isolation from the main grid. However, microgrids normally are located downstream of a single meter or point of common coupling, thus being a single network user from the DSO perspective. On the contrary, in the use cases under evaluation the different resources are connected among them through the DSO or utility network. The former is sometimes referred to as a “consumer microgrid” or “true microgrid”, whereas the latter is referred to as a “utility microgrid” or “miligrid” (Marnay et al. 2011). This difference, in spite of the similarities from a technical perspective, has important regulatory implications.

Distribution network users have conventionally behaved passively with respect to network conditions. Additionally, DSOs oftentimes had no visibility over DER. This was possible because networks were designed according to a fit & forget approach ensuring that no problems could arise at the operation stage. However, the growing presence of DER, particularly DG, is bound to change this paradigm. Nonetheless, the major barrier DSOs may face when trying to scale-up or replicate the solutions tested within the project, lies in the fact that the regulatory mechanisms enabling the active DER participation are normally not in place. Due to the regulated nature of DSOs, regulatory supervision in the provision of these services is necessary to ensure efficient and transparent results. Several alternatives can be found for the provision of network services by DER. These can be broadly categorized as follows:

- Mandatory requirements: these are the conditions that DER must comply with in order to be granted permission for grid connection which are usually set through grid codes. This is the simplest approach in terms of implementation and transaction costs as well as effective (DER have no alternative but to provide the service or disconnect). Furthermore, in principle, it would be applicable in all contexts and services.

  Mandatory requirements for DG units are quite frequent and similar conditions would be directly applicable to network storage when it is not owned by the DSO (see section 4.1.6 for a deeper discussion on storage ownership). Regarding active demand, some countries already have some connection requirements on consumers, e.g. the obligation to maintain a certain power factor. However, this is usually limited to large HV and MV consumers and its extension to LV consumers and more complex services would be rather limited.

  Mandatory requirements are suitable for very technical requirements without which network safety can be jeopardized (protections, fixed power factor). However, they may not be perfectly fit when they imply incurring in additional costs for DER promoters which are not compensated economically by the DSO. This is particularly relevant, when recurring costs are created for DER (e.g. DG active power curtailment) or in retrofitting processes of existing units after the introduction of new requirements.

- Incentive schemes: these are an evolution from mandatory requirements that addresses the last limitation mentioned above. In combination with mandatory requirements for a minimum performance, incentive schemes provide DER units with an additional remuneration in case they perform better than the minimum threshold. Once again, incentive schemes are set out in grid codes or similar regulation. Despite compensating DER for network services provision, this type of mechanism may not be suitable to engage demand response and, being a centralized scheme, to provide the flexibility needed to address the specific problems that each distribution area may be facing in each moment.

- Local markets: the most evolved mechanisms to draw DER participation in network services is to set up local DSO-run markets for the provision of distribution services such as the NEM previously mentioned. Local market can indeed overcome most of the difficulties enumerated above (lack of remuneration, not addressing local needs). However, the main problems local markets present are related to the potentially low level of competition given the very local nature of these services, the need to define a relevant area for the service provision and high transaction costs.

- Bilateral agreements between DER and DSO: due to the strong location-dependence of the network services required by DSOs, it could often be the case that only a few DER could potentially provide them within a certain area. Therefore, a market approach such as the ones discussed above may not lead to an efficient outcome. In these cases, DSOs may directly contract the service from DER. However, these contracts ought to be standardized in terms of product definition, remuneration, technical conditions, etc. Note that since a distribution company may operate hundreds or thousands of areas where network problems may arise every day, ex-post regulatory supervision is virtually impossible.

At the moment, the degree of implementation of such mechanisms enabling the contribution of DER to distribution network services is rather limited across European countries. An exception to this is the setting of limits on the reactive power injection from DG units connected to the distribution grid (mandatory requirement approach, in some cases with associated incentives and penalties). However, these provisions seem to be mainly addressed at preventing any potential negative impact from DG, by imposing a power factor close to unity, rather than a true voltage control service attending to the specific circumstances of each distribution area.

Nonetheless, a few more advanced schemes enabling DER participation can be found in some of the GRID4EU countries. As it will be discussed in section 4.1.5, DSO-driven demand response may be found in Germany, Sweden or Czech Republic. However, this is usually limited to the curtailment of specific loads under emergency conditions rather than as an additional operation resource. Lastly, German DSOs are entitled to limit the active power injection of PV units based on some pre-defined rules under emergency conditions[28]. Once again, the provision of all these services is based on mandatory requirements set in grid codes, on in equivalent pieces of legislation, rather than on commercial terms.

A similar situation can be found concerning the implementation of islanded operation. Nowadays, DG units are normally mandated to disconnect from the grid in case of a fault for safety reasons. Furthermore, except within pilot projects such as GRID4EU, islanded operation may only happen under two situations: i) consumer microgrids (see above) and ii) in case of a fault, DSOs resort to diesel generators to reduce the time of interruptions suffered by end consumers. Thus, in these cases, DER are not in fact providing a service to the DSO, as it is the focus on the GRID4EU islanding use cases in demo 5 and demo 6.

Overall, it can be seen that despite the great potential contribution of DER to distribution network services, the appropriate regulatory provisions are not usually in place nowadays. Moreover, in the few situations where DSOs may actually interact with DER, this is normally based on centralized mandatory requirements that oftentimes do not allow taking into account the specific local network conditions. Moreover, regulation enabling the islanded operation of part of the distribution grid with the contribution of external DER, i.e. those not owned or operated by the DSO, is still inexistent.

In order to enable the implementation of the aforementioned use cases, regulators should identify the services DER could provide and select for each one of them the most suitable regulatory alternative from the ones described above. An evolution from purely mandatory technical requirements to more market-based approaches is to be expected in this regard. Note that even ion the case of very technical services, such as islanded operation, market-based approaches (auctions) can be used to allocate the provision of the service. Last but not least, due to the fact that ex-post regulatory supervision of these services would be excessively burdensome, an

[28] In the long-run, DSOs are still expected to reinforce the grid so as to prevent any curtailment.

appropriate definition of the services, remuneration schemes and technical requirements ought to be pre-defined by regulators.

4.1.5 Smart metering and active demand

Directive 2009/72/EC mandates a roll-out of smart-meters by 2020 that ought to reach at least 80% of end consumers (European Communities 2009). The goal is to unlock the demand response potential and stimulate the retail market, particularly at the residential commercial and level. In fact, some GRID4EU use cases rely on the existence of smart metering to test different functionalities. This is the case of the consumer engagement use case in demo 3, whose goal is to provide end consumers with real-time information about their consumption and tariff options, and the LV maximization in LV in demo 6, which applies demand response at residential level to increase the network HC. In both cases, a supplier or aggregator is the main responsible in the relationship with the end consumers.

However, not all Member States opted for a full smart metering roll-out. The aforementioned mandate was conditional upon a positive CBA to be carried out by Member States. According to the survey in (European Commission 2014), only 16 Member States have plans to proceed to a large-scale roll-out before 2020[29]. Out of the six countries within the scope of GRID4EU, two countries have already carried out a full deployment of smart meters (Italy and Sweden), two countries are within this process (France and Spain), one is undergoing a partial roll-out for some categories of consumers (Germany) and another one will not proceed to a large-scale roll-out due to a negative CBA result (Czech Republic).

Nonetheless, the previous use cases are not the only ones which require smart metering and AMI. Despite the fact that the European mandate for its deployment was mainly driven to promote demand response and competitive retail markets, some DSOs saw this as an opportunity to enhance network monitoring. In fact, the use case “outage detection in the LV grid” of demo 2 falls within this realm of smart grid solutions. However, the list of functionalities to be incorporated into smart metering systems is not standardized across the EU. The EC recommendation 2012/148/EU enumerates a list of minimum functionalities (European Commission 2012), among which power quality monitoring (including power outages) is not included. Therefore, the replicability of demo 2 use case will be dependent on whether national regulation imposed additional the functionalities or the DSOs by themselves decided to implement such functionalities. In the latter case, individual DSO decisions would also affect the scalability at national level[30].

The possibility of using of AMI for LV network supervision and outage detection additional depends on the model for meter ownership and data management. Conventionally, data storage and access models, see (Smart Grids Task Force 2013) for a detailed discussion on the different models, revolve around consumption data used for billing, tariff design and, at most, network planning applications. In most Member States where smart metering has been or is being deployed, the DSO are in charge of deploying and owning the meters. Within GRID4EU countries, Germany is the only exception where consumers are free to choose independent metering point operators, who will also act as data manager. Additionally, despite the fact that the Czech Republic has not opted for a large-scale roll-out, the data management model will presumably not be DSO-centric (European Commission 2014). Regardless, of the potentially competitive advantages these

[29] Spain mandated a full roll-out for consumers below 10kW without carrying out a CBA.
[30] The smart meters benchmarking report (COM 2014 356 final) states that most Member States leave at the discretion of roll-out responsible parties (most frequently DSOs) the inclusion of alternative functionalities.

alternative data management models may have for the liberalized retail market, this may constitute a barrier for distribution operation applications of smart metering data due to lack of standardized functionalities and data access barriers for DSOs.

Potentially limited smart meters functionalities and barriers for accessing the data may also constitute a replicability and scalability barrier for the use cases where consumption data is provided to end consumers so that they may change their behaviour, such as the ones mentioned at the beginning of this section for demo 3 and demo 6. Consumer access to their own data as well as home automation functionalities embedded within the meter are not widespread. Out of the six demo countries, only Czech Republic and France incorporate in-home displays and/or home automation functionalities. Thus, an additional interface (and potentially hardware) needs to be developed, increasing complexities and costs. The Enel smart info® program[31] is an example of this. Moreover, (European Commission 2014) states that roll-out plans oftentimes do not foresee to provide consumers and entitled third-parties with frequent enough consumption data, thus creating barriers.

In addition to adequate meter functionalities and consumers' data access, several use cases require the access of DSO to active demand flexibilities. For instance, demo 4 initially intended to use MV demand response to control voltage profiles or demo 6 relies on demand flexibilities to eliminate network constraints. Similarly, islanding use cases in demos 5 and 6 could potentially use demand resources to stabilize the islanded area. Important progress has been made across Europe concerning demand side participation in capacity mechanisms, balancing services or energy markets, as well as the diffusion of different forms of ToU pricing.

However, DSO access to demand flexibilities is not the rule nowadays. Those few countries were some form of DSO-driven demand response is in place, this is usually limited to specific loads such as electric heaters or water boilers that can be switched off in case of emergency. This is the case in Germany (temperature dependent load profiles), Czech Republic (through a ripple control system) or in Sweden. However, at least in the case of Germany and Czech Republic, these mechanisms have been "inherited" from the pre-liberalization times; hence showing the difficulties from a regulatory perspective in implementing such schemes in an unbundled environment. Moreover, the small penetration of thermal heating or electric boilers in other countries (e.g. southern European countries such as Spain or Italy) may hinder replicability. Therefore, in view of the replicability and scalability of smart grid solutions, attention must be paid to the mechanisms discussed in section 4.1.4 and the enabling business models discussed in section 4.1.6.

Summing up, the following premises summarize the impact on scalability and replicability that regulatory frameworks concerning smart metering and demand response:

- Residential demand response as implemented in demo 3 and demo 6 will not take place without smart metering deployment. Likewise, LV monitoring is largely enabled by the deployment of smart metering. In other words, the lack of a (limited) smart metering deployment is a barrier to the implementation of these types of use cases.
- Outage detection in the LV grid is facilitated when the DSO is responsible for smart meter deployment and data management. However, being this the case, transparency and data accessibility for retail market functioning must be ensured.
- The smart meters functionalities can greatly determine whether use cases are replicable in

[31] http://www.enel.com/en-GB/sustainability/stakeholders/stakeholder_customers/projects/smart_info.aspx

other countries. The lack of standardized functionalities hampers this possibilities and may require software and hardware adaptations. Further standardization is to be sought when the second generation of smart metering deployment is to take place.

- Resorting to AMI for network supervision only seems possible when the DSO is in charge of metering data management. Otherwise, billing information and historical consumption may be suitable for planning applications and network studies, but not for operation. Similarly, the scalability and replicability of such solutions may be hampered if this deployment does not reach a significant share of end consumers.
- The absence of regulatory mechanisms enhancing DSOs to access to active demand flexibilities in transparent and competitive conditions is a key barrier for those use cases where load control could contribute to increasing the network HC (demo 4 and demo 6), as described in section 4.1.4.

4.1.6 Business models: aggregation, unbundling and self-consumption

As discussed in section 4.1.4, some smart grid solutions require an active participation from DER. Therein, the regulatory mechanisms to enable this participation were discussed. Nonetheless, some additional regulatory consideration need to be taken with regard to these use cases. Firstly, unlocking the end-user flexibility to provide grid support would require the intermediation of aggregators, as it is the case in the NEM tested in demo 6. Moreover, the application of storage systems directly connected to the distribution networks to provide grid support services, as tested in demos 4 and 6, should be done observing the unbundling rules set in the EU Directive 2009/72/EC (European Communities 2009). Lastly, the installation of DG and storage units on the consumers' premises, as in the case of demo 6, may be encouraged through self-consumption policies, thus enhancing the flexibility of demand response. Therefore, these three topics will be addressed below.

4.1.6.1 Demand aggregation for flexibility services

Demand aggregation to provide services at distribution level is virtually non-existent nowadays. As discussed in section 4.1.5, the mechanisms allowing DSOs to access demand flexibilities are mostly based on a direct DSO control of certain loads. However, the scalability and replicability of certain use cases, especially the local market or NEM implemented in demo 6, may be hampered by the inexistence of demand (and/or battery) aggregators. At the moment, those few countries were aggregators are in commercially operation, these are limited to providing services to TSOs or for market participation. This is the case, for instance, of some GRID4EU countries such as France or Germany as well as other EU countries such as Belgium or the UK (SEDC 2015).

However, their participation in distribution network services is still limited to pilot projects. Since this activity is to be performed under competition, the role of regulation in spurring the development of aggregators is more limited than in the case of DSOs. What regulators may indeed act on is creating the need for aggregation services by encouraging DSOs to rely on alternative solutions to network reinforcements when this is more cost-efficient (section 4.1.1) as well as defining the mechanisms necessary to enable this service provision (section 4.1.4).

4.1.6.2 Storage ownership and unbundling rules

Concerning the ownership of storage systems, it is necessary to differentiate between the systems installed at the premises of end users from those directly connected to the distribution grid. It is in the latter case that the issue of DSOs ownership and unbundling rules becomes relevant. This is due to the fact that, in addition to distribution grid support, distributed storage systems may provide other system services such as balancing or price arbitrage (Eurelectric 2012; THINK Project 2012). Furthermore, the effect of storage on the distribution network greatly depend on its location. Therefore, the main question is whether to allow DSOs to own storage under certain circumstances and, in case this is not allowed, how to ensure that storage units are connected where it is needed to provide grid support.

Within the boundaries of GRID4EU demonstration activities, DSOs are directly operating network storage systems. However, this is allowed by a regulatory exemption, which is not a viable model to allow for the scalability and replicability of the aforementioned use cases. Thus, the absence of clear regulatory guidelines concerning storage ownership, as it is the case nowadays[32], may be an important barrier. Two main alternatives may be found:

- Regulators may allow DSOs to own storage for grid support, preventing them from participating in other services delivered under competition. A potential barrier for this approach it may result in underutilized systems since network constraints in a specific network area may only be active for a few hours per year. The recent proposals published by the Italian regulator broadly follow this approach, as shown in Figure 55. Should these provisions be finally implemented, DSO ownership would be limited to non-competitive activities or to small-scale applications. In all cases, DSOs should demonstrate a positive cost-benefit analysis.

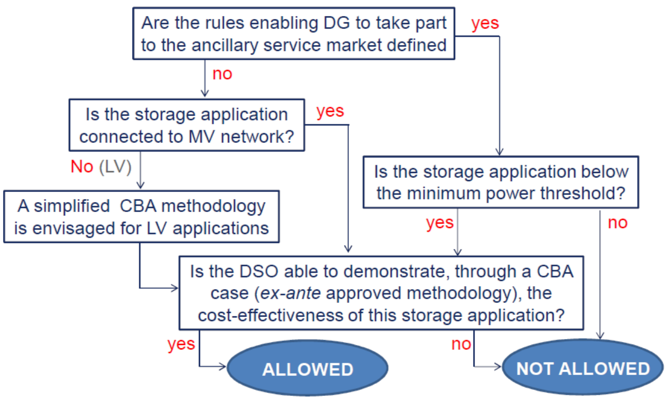

Figure 55: proposed flowchart setting the conditions for DSO ownership of storage assets in Italy (Lo Schiavo 2015)

- Alternatively, auction mechanisms may be implemented that achieve storage units are located where needed from a network perspective whilst avoiding DSO-ownership. At each tendering period, the DSO would specify the location and services required, whereas the bidders would obtain a long-term agreement with the DSO granting additional revenues that may be considered within their business cases. A similar approach may be found in California where

[32] Strictly speaking, DSO ownership may not be explicitly forbidden by regulation. However, its potential consideration as generation assets and the associated regulatory uncertainty may be enough to deter DSOs from investing in storage assets until clear rules are established.

the regulator has set binding targets on utilities to deploy storage assets (CPUC 2013)[33]. In order to achieve these goals, utilities have to carry out competitive tenders. Despite the fact that DSO unbundling rules are not applicable in California, certain features of this approach may be replicable in the EU since Californian utilities may own no more than 50% of the storage capacity, thus being forced to contract with third parties a significant share of the storage capacity.

4.1.6.3 Self-consumption schemes

The regulatory analysis presented so far has addressed different topics in relation to DG and storage units directly connected to the distribution grids. Nevertheless, the deployment of generation at the consumer premises is seen as a powerful means to sustain the growth in RES installation rates under falling support payments. This can be promoted through self-consumption policies which allow consumers to reduce their amount of energy billed thanks to the self-generated electricity.

This self-consumed electricity can bring about benefits both for consumers, in the form of cheaper bills, and the power system as a whole, in the form of reduce peak demand or more efficient consumption decisions. Furthermore, when combined with an efficient tariff design, self-consumption can be a major driver for the diffusion of demand response and consumer-owned storage, especially at commercial and residential level (European Commission 2015). Therefore, solutions such as the one tested in demo 6 aiming at the maximization of PV integration in the LV could be facilitated through this type of policy mechanism.

Among GRID4EU countries, some form of self-consumption is already permitted in Italy, Germany and, more recently, Spain (EPIA 2014). Nonetheless, the design of self-consumption policies deserves a closer look, particularly regarding the remuneration of the energy that is not instantly locally self-consumed and that is therefore injected back into the grid. A frequent approach is to grant some form of credit to consumers in such a way that the excess production injected into the grid can be used to offset a consumption in a period where there is no such production, i.e. implicitly valuing excess production at the retail energy tariff. Thus, net-metering is oftentimes characterized as allowed prosumers to use the main grid as storage.

Net-metering constitutes a strong economic incentive for the deployment of DG at the consumers' premises, especially with long netting periods. However, since the main grid is being used to balance the imbalances between local generation and demand, this approach dilutes the incentives seen by prosumer for the installation of storage units and respond to price signals. Moreover, net-metering may jeopardize the recovery of fixed system costs when retail tariffs are largely volumetric, i.e. when a large share of the system fixed costs (networks, system operation, RES support costs) are to be recovered via an energy component (European Commission 2015). This problem may lead to a vicious circle where regulators are forced to raise tariffs to ensure fixed cost recovery, which at the same time strengthens the incentives to self-consume and ultimately disconnect from the main grid. This process is known as grid defection or utility death spiral (RMI 2014).

In order to prevent this problem, regulators have implemented alternative ways to remunerate the excess production such as specific FITs, using the (average) market price as a reference or even do not remunerate excess production at all (European Commission 2015). Nonetheless, the most

[33] Note that the storage applications are not limited to distribution grid support, but also for transmission services and customer storage. Separate targets are defined for each of these segments.

effective alternative to promote prosumer flexibility, including storage and demand response, would be to implement short netting periods and advanced cost-reflective tariff designs with appropriate time discrimination. Note that a truly cost-reflective tariff structure may imply a larger capacity or fixed tariff component. This may be seen as a barrier to energy efficiency and demand response in the short-term. However, when this change in the tariff structure responds to the underlying cost structure of the system, the long-term sustainability of the system is ensured, providing a stronger stability to self-consumption policies.

Lastly, it should be born in mind that smart-metering is a pre-condition for an efficient self-consumption implementation promoting demand response and customer-owned storage. Without smart metering, it would not be possible to measure bi-directional power flows with the required time granularity, e.g. hourly. Note that conventional electromechanical meters would only allow netting intervals equal to the reading period, which typically ranges between one and two months, and would not support advanced tariff schemes. Hence, in the absence of smart metering, self-consumption is bound to hamper fixed system cost recovery.

- Self-consumption encourages demand response and consumer-owned storage, therefore it can be a driver for smart grid solutions relying on demand response and customer-owned storage, especially at the LV grid.
- Moving away from net-metering schemes towards shorter netting periods or hourly self-consumption provides stronger incentives for prosumer flexibility.
- Largely volumetric tariffs, which intend to recoup a large share of fixed costs through an energy term can be a driver for demand response and customer-owned storage in the short-term. However, this may not be sustainable over the long-term due to the missing money problem, thus potentially turning into a barrier in the long-term.
- Smart metering technologies capable of recording consumption with an adequate time discrimination are a pre-condition for the most advance self-consumption schemes, thus being an additional driver for demand response and customer-owned storage.

4.1.7 Network charges for DG

Distribution costs are recovered through the network charges that are paid by distribution network users. These network charges comprise both connection charges, a one-off payment made at the time of grid connection, and use-of-system (UoS) charges, which are periodic payments to defray network costs normally included in the overall tariffs.

Conventionally, only consumers have paid UoS distribution charges. However, as DG penetration rates increase, DG is increasingly seen as a network user that should contribute to defraying network costs. Within GRID4EU countries[34], only generators in Sweden (units above 1.5MW) and Spain (all generation units regardless of their size, technology or voltage level, pay a uniform charge of 0.5 €/MWh) pay UoS network charges. A review presented in (Eurelectric 2013) shows that, whilst most countries still have not implemented UoS charges for DG, these are may not be considered as an exception anymore.

Despite the fact that UoS charges may potentially affect operational decisions of DG units, this effect will presumably be minor due to the fact that DG is largely based on non-controllable

[34] The administrative charges for measurement and billing that DG units may pay in some countries are not being considered here as a network charge.

technologies and the network price signals will presumably be much weaker than the selling price of the DG production. Therefore, it is connection charges that may affect the scalability and replicability of some smart grid use cases; more specifically, those smart grid solutions aiming to increase DG HC of the existing network and defer network reinforcements. Thus, the GRID4EU use cases potentially affected by connection charges design include the load control in MV of demo 1, voltage control of demo 4 and PV maximization in the LV network of demo 6.

Connection charges may cover only the direct costs of connection to the nearby distribution grid (shallow connection charges) or also the full cost of reinforcing the grid to accommodate the additional DG capacity (deep connection charges). Intermediate approaches, usually referred to as shallowish connection charges, consist in including only part of the upstream reinforcement costs (e.g. a pre-defined share or only those costs within the same voltage level) in the connection charge. When determining the most suitable approach, regulators ought to meet a trade-off between sending efficient locational signals to generators (deep charges) or facilitating the connection of DG-RES (shallow charges).

Given that the location of DG units is usually driven by land and resource availability rather than connection charges themselves, and that deep connection charges may constitute an important economic barrier for small projects, shallow connection charges facilitate DG development. In fact, Article 16 of Directive 2009/72/EC states that, where appropriate, Member States may require DSOs to bear, in full or in part, the grid connection and reinforcement costs. A review of regulation in GRID4EU countries shows that most countries apply either shallow or shallowish connection charges. Moreover, exemptions are frequently implemented for small-sized generators, which allow them to pay lower connection charges. This is the case, for instance, of generators connected to MV (up to 1MV) and LV of (up to 100kW) levels in Spain, micro-generators in Sweden or generators below 30kW in Germany.

Furthermore, rule-based calculations, which provide higher transparency and simplicity to the computation process, are applied in Italy, Sweden (for micro-generators), Czech Republic, France and Germany. According to these rules the resulting connection charges are calculated as a summation of lump sums that depend on parameters like capacity requested, distance to the grid or voltage level at the point of connection.

In these aforementioned smart grid solutions, if DG units have to pay deep connection charges, i.e. the full costs of connection plus any upstream reinforcement needed, DSOs would see virtually no benefit from avoiding grid reinforcements (albeit generators may benefit from lower connection charges). An exception to this may arise in those cases where DSOs are obliged to attend every connection request or they are penalized for failing to meet a predefined deadline, and grid reinforcements are hampered by administrative or technical reasons. Being this the case, smart grid solutions may indeed allow DSOs to achieve a faster grid connection and comply with their obligations.

- The existence of deep connection charges may reduce the incentives seen by DSOs to connect DG cost-efficiently by deferring grid reinforcements, usually at the expense of OPEX, since generators would be paying for the additional network capacity anyway.
- Even in the presence of deep connection charges, DSOs may be interested in achieving a swift grid connection process through smart grid solutions when grid reinforcements may be delayed due to administrative or technical reasons, e.g. in order to meet deadlines for grid connection.
- On the contrary, shallow connection costs, together with a revenue regulation that does not

promote CAPEX solutions over OPEX solutions (see section 4.1), constitute a driver for the scalability and replicability of these use cases.

4.2 Stakeholders' acceptance

DSOs would naturally play a central actor in the scalability and replicability of smart grid solutions. However, this process may also be deeply affected by the expectations and behaviour of other stakeholders, including regulators, end consumers, DG operators, equipment manufacturers, TSOs or aggregators. The perspectives of stakeholders were already discussed in gD2.6, which presented the results of an on-line survey assessing the drivers and barriers to smart grid developments as seen by relevant stakeholders. In this section, this section builds on the outcomes of this report, as well as additional sources of information, so as to identify how stakeholders' acceptance may facilitate or hamper the diffusion of GRID4EU solutions.

Despite the fact that gD2.6 has not been the only attempt at identifying stakeholders' perspectives through survey-based methods, these surveys present answers in an aggregate manner or address a single stakeholder group, thus not allowing to draw conclusions broken down per type of stakeholder. The reader is referred to, for instance, the studies presented in (Pacific Crest Mosaic 2009; Arronte 2010; DEFG 2010; Ecoalign 2011; Xenias et al. 2015). Therefore, a mostly deductive approach has been followed to infer the potential stakeholder-related barriers and drivers for the scalability and replicability of GRID4EU use cases.

Firstly the most relevant stakeholder groups have been identified, based on the work in GWP2, and mapped against the smart grid use cases being tested by the demos. This is shown in Table 28, which identifies the stakeholders that are more closely affected by the scalability and replicability of each smart grid solution. This mapping is particularly relevant for agents active in the power supply chain (distribution network users, supplier/aggregators and TSOs). In the case of other stakeholders (regulators, manufacturers or ICT/software providers), a clear differentiation per use case was not possible because these groups play rather cross-cutting roles.

		Demo 1 Germany		Demo 2 Sweden	Demo 3 Spain		Demo 4 Italy		Demo 5 Czech Republic			Demo 6 France	
		Load control in MV	Failure management in MV	Outage detection in the LV grid	Automatic grid recovery	Customer engagement	Anti-islanding protection	Voltage regulation in MV	Failure management in MV	Failure management in LV	Automated islanded operation	NEM: PV integration and demand reduction	Islanding
Consumers	Directly					X		X[1]			X[2]	X	X[2]
	Indirectly		X	X	X		X		X	X	X		X
DG/storage	Directly						X	X			X	X	X
	Indirectly	X	X	X	X				X	X			
TSOs												X	
Suppliers/aggregators						X		X[3]			X[3]	X	X[3]
Regulators		X	X	X	X	X	X	X	X	X	X	X	X
Manufacturers, software/ICT providers, etc.		X	X	X	X	X	X	X	X	X	X	X	X

1 In case demand response is used for voltage control
2 In case demand response is used to support islanded operation
3 Suppliers/aggregators may act as intermediaries between consumers and DSOs when using demand response to support islanded operation or for voltage control

Table 28: Mapping use cases with stakeholder groups, where an X indicates a direct relation between the use case and the stakeholder group

Subsequently, each stakeholder group has been analysed separately so as to identify what possible drivers and barriers may be caused by their perspective with respect to smart grids in general, and GRID4EU cases in particular. Overall, consumers are the target group that has been most extensively researched as compared to other stakeholder groups. Therefore, it has been possible to make a more comprehensive analysis of this group. Nonetheless, significant research is still needed to fully understand consumers' attitudes and perspectives towards smart grids. The main challenges arise due to the heterogeneity existing among different consumers in terms of type of consumer (industrial/commercial/residential, size, etc.), socio-economic aspects (income, education, age, etc.) and local conditions (climate, trust in power companies, social cohesion, etc.).

End consumers

Electricity consumers are presumably the most widely mentioned stakeholder group in relation to smart grids. See, for instance, the detailed review of studies evaluating the roles and perspectives of consumers and communities in the smart grid development presented in (JRC 2013), or the review of real experiences and best-practice identification carried out within the EU-funded SC3[35]. Within GRID4EU demos, consumers are differently affected among use cases.

First and foremost, a direct consumer participation is required in the consumer awareness use case of demo 3, or in those where they may act as flexibility providers as in the NEM of demo 6 or, potentially[36], for voltage control or islanded operation support in demo 4 and demos 5 and 6 respectively. Conventionally, the focus on customer engagement has been mostly placed on technological issues and economic incentives, leaving aside other subjective factors and consumer perceptions (JRC 2013). However, the latter oftentimes critically affect the success of demonstration activities, and determine the scalability and replicability of the tested solutions.

Large industrial and commercial consumers may be more prone to respond to price signals given their already high awareness with respect to their energy use, especially when electricity represents a significant input to their activity. Nevertheless, the probability of achieving a change in consumption behaviour through economic incentives alone is rather low otherwise, especially in the case of residential consumers for whom subjective perceptions are comparatively more relevant. These subjective factors comprise motivational issues (e.g. degree of environmental concern, enhanced information on billing and consumption, comfort) and level of trust in agents. As a consequence, consumers cannot be treated as a homogeneous group, thus requiring a segmentation with respect to engagement activities.

The main barriers for an active demand side participation identified in gD2.6 are those related to the retail market functioning and low economic incentives for consumers. At a second level of importance, respondents identified the reluctance of consumers to modify their behaviour as well as home automation systems, which may tackle this reluctance. It was noteworthy that data privacy issues were not seen as a major barrier. However, end consumers were poorly represented in the sample, which was rather tilted towards experts from consultancy, research, manufacturers and power companies. Likewise, customer disengagement or resistance is mentioned as one of the main barriers for smart grids in an expert survey carried out for the UK (Xenias et al. 2015). This study did not show as a relevant item the lack of confidence of customer in suppliers, although authors considered this was due to the fact that respondents did not include consumer representatives.

When consumers are specifically addressed, their expectations with respect to smart grids are

[35] http://s3c-project.org/

[36] Demand response was not tested as a resource for voltage control or islanded operation control in demonstration activities, albeit it may be used as an additional resource in future implementations.

indeed mainly related to bill reductions or enhanced information. Nonetheless, the risks perceived comprise several more subjective aspects such as the fear of tariff increases, privacy concerns or opposition to remote load control by DSOs or aggregators (Ecoalign 2011; UKERC 2014). Moreover, concerns about the increased inequalities that derive from the fact that only wealthy people could afford smart appliances and home automation have been expressed in (UKERC 2014). Lastly, the lack of trust in power companies can also act as a barrier for smart grid deployment (Wolsink 2012; UKERC 2014).

This factor is intimately related to the perceived satisfaction of end consumers with the electricity services they receive. As shown by a large-scale survey carried out by the European Commission (European Commission 2013a; European Commission 2013b), the degree of satisfaction with the electricity services is generally among the lowest ranked service markets in Europe, being ranked the 28th out of the 31 markets monitored. Nonetheless, this situation can greatly vary among countries. According to this survey, the GRID4EU countries showing the highest level of satisfaction are Germany and France, situated well above the EU average in terms of satisfaction. Sweden and Czech Republic would be in an intermediate position, with satisfaction levels slightly above the EU average. Lastly, satisfaction levels in Italy and Spain are among the lowest ranked across the EU. In fact, only in three of these countries (Germany, France and Sweden), the degree of satisfaction with electricity services is above the average for all services markets monitored.

There are some practical examples of how these perceptions may hamper customer participation, most saliently the opposition to the installation of smart meters. For instance, in the Netherlands, authorities had to introduce an opt-out and an administrative-off[37] alternatives as a result of data privacy and security concerns from consumers (European Commission 2014a). Smart metering has faced important opposition in California due not only to privacy concerns, but also to health issues caused by wireless communications[38]. Consequently, utilities have been mandated to allow their customers to opt out from smart meter installation.

Hence, barriers and drivers to the scalability and replicability of tested solutions should consider not only technical and economic issues, but also behavioural and subjective aspects. Additionally, demand response demonstrations oftentimes put in place ad-hoc incentives for end users, require the involvement of local authorities or carry out targeted recruitment campaigns in order to ensure a successful pilot project, i.e. these may be drivers for replicability. However, such an approach may not be feasible or economic at a larger scale, thus hindering scalability of the solution.

In this line, (SC3 2014) identifies several features that may hamper the scalability and replicability of demand response pilot projects. Firstly, given that most pilot projects rely on voluntary participation, the final sample may not representative of the overall population as only the more knowledgeable or interested take part. Therefore, authors suggest to use random samples or representative samples, together with opt-out strategies rather than opt-in. Moreover, they highlight the fact that the impact of local culture of local behaviours can greatly affect the project outcomes and therefore, it will always be hard to extrapolate the results. Additionally, several projects characteristics were highlighted as barriers for scalability: high degree of involvement required from end-consumers (i.e. how easy it is for them to participate), high costs of engaging each consumer (high economic incentives or discounts, giving away free devices such as in-home displays), high cost of consumer technologies (e.g. fridge magnets or web-based information platforms are more

[37] Under an administrative off option, consumption data is only available to the consumer, not being shared with DSOs or suppliers.
[38] http://www.cpuc.ca.gov/PUC/energy/Demand+Response/ami.htm

scalable than individual in-home displays), and lack of modularity and standardization of technologies.

An additional factor that may act as barrier or driver is the level of maturity of the retail sector and how used end consumers are to dealing with different suppliers and tariff alternatives. Increased consumer awareness and flexibility may be perceived to be excessively complex for consumers who may not understand all the different tariff options and services. Therefore, retail market maturity is a key driver. Nonetheless, this is very country-specific aspect, thus making it difficult to draw general conclusions. Lastly, practical experiences suggest that consumers are motivated by what others around them are doing. Therefore peer comparisons with other consumers and gamification can act as drivers for a successful replicability and scalability. Nonetheless, the extent to which this effect may dilute over time ought to be evaluated.

Up to now, the focus has been placed on those use cases that require a direct involvement of end consumers. Notwithstanding, those use cases aimed at improving continuity of supply (automation or islanding in demos 1, 2, 3, 5 and 6) or preventing unintentional islanding[39] (anti-islanding in demo 4) additionally yield benefits for consumers. As beneficiaries, end consumers may indirectly determine the promotion of these smart grid solutions. Regulators frequently determine the quality of service incentives for DSOs on the basis of the estimated valuation consumers make of reliability and voltage problems (CEER 2010). Thus, if consumers demand more and more quality levels, this can be a driver for these use cases scalability and replicability.

DG and storage operators

Similarly to the case of consumers, DG and storage may actively contribute to grid operation in several of the use cases evaluated. Herein, energy storage has been treated jointly with DG because the operators of both types of assets would show very similar perspectives when they correspond to third-parties, i.e. the subsequent discussion would not be applicable to DSO-owned[40] or consumer-owned storage.

DG and storage operators are relevant stakeholders in those use cases where they directly provide services to DSOs through local flexibility markets (demo 6), voltage control (demo 4) or controlling the islanding operation (demos 5 and 6). Moreover, DG units are central agents in the anti-islanding protection use case (demo 4). Nonetheless, the perspective may be different from the previous cases since, given its implications in terms of personnel safety, such solution would presumably be implemented through a mandatory connection requirement rather than on voluntary basis.

In all these use cases, the associated costs of implementing the solution, the lack of technical capabilities for providing the service or the risk of damaging the equipment may be a barrier perceived by these stakeholders. Smaller units would be especially sensitive to this barrier since not only their technical capabilities may be more limited, but also their financial resources may be scarcer. This can be particularly relevant when significant required adaptations in the operator's installation are required, which imply added costs and lost production during the retrofitting process, as in the islanding use cases. In these cases, DSOs may evaluate tendering schemes for new units as discussed in section 4.1.6 to overcome this particular barrier and ensure a suitable location of DG/storage units.

[39] In addition to safety risks, unintentional islanding may cause power quality problems at the consumers' premises. Therefore, the anti-islanding would result in improved power quality for end consumers.
[40] See section 4.1.6 for a discussion on the ownership of distributed storage.

Notwithstanding, gD2.6 showed that the most important issues hampering the active participation of DG, according to the survey, are related to insufficient economic signals and the absence of appropriate regulatory mechanisms. For instance, production-based support mechanisms, such as feed-in tariffs or feed-in premiums, would not give them incentives to participate in these services when they imply a reduction in active power injection is required, as it may happen in demo 6 or when using active power curtailment for voltage control. Furthermore, the revenue streams obtained from these services may not be enough to compensate them for the required change in behaviour (e.g. in the case of CHP units and the coupling with thermal demand) or the aforementioned costs.

In a more indirect way, DG and storage would be positively affected by the reduction in interruptions achieved by network automation (demos 1, 3 and 6), in the form of increased production, or by the increase in network hosting capacity (demos 4 and 6), in the form of faster or less costly grid connections. Therefore, the growing presence of DG and storage units in distribution networks may encourage the implementation of these use cases. Nonetheless, this may require revisiting how reliability is measured in distribution grids.

TSOs

The direct involvement of TSOs in GRID4EU use cases is rather limited, as it can be observed in Table 28, being demo 6 an exception. In this case, a demand reduction on the distribution side achieved through the NEM platform could help the TSO alleviate transmission constraints. Thus, the TSO would be purchasing flexibility services to distribution-connected users. However, this does not mean that TSOs are not relevant stakeholders for smart grids and DER integration. The main reason for the apparently limited role of TSOs is that GRID4EU is a DSO-driven demonstration project focused on the lower voltage levels of the system.

Notwithstanding, the large-scale deployment of DER will lead to an increasingly decentralized system where the flexibilities connected to the distribution network may no longer be neglected with respect to system operation. Therefore, a stronger cooperation between TSOs and DSOs will be increasingly necessary, as it has been acknowledged and advocated for by several institutions (EU Network Operators 2015); (ISGAN 2014; CEER 2015b). Besides clear regulatory guidelines and allocation of responsibilities, the lack of a well-functioning coordination and cooperation between DSOs and TSOs would be the main barrier for the scalability and replicability of similar solutions.

Suppliers/aggregators

Suppliers and aggregators are key stakeholders in several of the use cases tested. More specifically, these agents may act as intermediaries in those which rely on the active participation of consumers. In demo 3, due to unbundling provisions between distribution and retail, the supplier is the agent in charge of customer engagement and interaction. In demo 6, suppliers/aggregators[41] are essential participants in the local market or NEM in order to unlock the flexibilities both from the demand and the storage units. In demo 4, demand response was initially conceived as an additional source of flexibility to control network voltages and increase the network HC. Lastly, the islanded operation tested in demos 5 and 6 could rely on an automated load control service provided by end consumers through an aggregator.

[41] Note that both functions (retail services and aggregation) could be performed by the same agent or by separate entities depending on the business model adopted.

The type of barriers for upscaling and replication can be classified in two main groups. On the one hand, the customer engagement use case in demo 3 could be mainly affected by the functioning of the retail market and the level of trust of end consumers on their suppliers. Despite the fact that both a stagnated retail market and the mistrust of consumers represent important barriers for customer engagement, different types of suppliers may be affected in very different ways. Incumbents may benefit from a poorly developed retail market since they would have a significant competitive advantage against new entrants. However, such a scenario may hamper the deployment of more innovative solutions for consumers allowing them to manage their consumption. On the contrary, in countries where consumers do not trust their power suppliers, this may be seen as an opportunity for new entrants by offering end consumers innovative services.

On the other hand, the active contribution of suppliers/aggregators may be hampered for several reasons. Once aggregators have acquired a portfolio of customers, they will try to provide their available flexibility in those services or markets where they would obtain higher and more stable revenues. Thus, a kind of competition for flexibility may arise between DSOs and TSO. In those cases where the opportunity cost seen by aggregators may be higher in TSO services, the scalability and replicability of the smart distribution grid solutions could be hampered. The solutions mostly affected by this barrier would be the NEM of demo 6 or voltage control in demo 4 (especially concerning storage or demand response). Additionally, the fact that the regulatory mechanisms enabling the provision of services at distribution level are not developed (see section 4.1.4), would make it easier for aggregators to access more traditional services such as balancing services.

Lastly, the location-specific nature of distribution services, especially in the cases of voltage control and islanded operation, may be an added barrier for regulators. Since only a reduced set of their customers may provide these services, they would have more difficulties complying with the requirements set by the DSO due to the lower amount of flexibilities available and the reduction in the portfolio effect increasing the uncertainties.

Regulators

As it can easily inferred from section 4.1, adapting regulation is an essential step affecting scalability and replicability of smart grid use cases. Consequently, NRAs are key stakeholders to be considered in this regard. The most relevant barriers for upscaling and replication may arise as a result of what may be called resource-bounded regulators (Glachant et al. 2012).

This means that regulators may not have the necessary resources (human resources, budget or training) specifically devoted to the power sector or face important limitations in terms of their ability to change regulation and oversee the behaviour of companies. This problem is worsened by the fact that removing the barriers identified in section 4.1, involves a significant regulatory burden. Therefore, an adequate regulatory endowment, an effective regulatory independence and appropriate legal powers of NRAs are key enablers for a diffusion of smart grid solutions.

Additionally, in certain cases, it may be necessary to overcome NRA inertias and internal cultures which constitute barriers to changes in regulation. These problems can be tackled by enhancing the exchange of lessons learnt and best practices among neighbouring regulators. Thus, this cooperation is indeed a driver to facilitate the replicability of smart grid solutions.

Manufacturers, software providers, ICT service providers

Standardization, interoperability and technology maturity and affordability are key enablers for a faster scalability and replicability of smart grid solutions, as shown by the responses given by

DSOs in the survey presented in gD2.5. Consequently, all those stakeholders involved in technology development and provisions are central stakeholders in the development of smart distribution grids. These comprise equipment manufacturers, software developers, system integration firms and ICT services providers. Given that any of the use cases tested in the demonstrations rely on some form of innovative equipment, software and/or ICT solution, the perspectives of this stakeholder group is transversally relevant to all use cases.

These stakeholders could tend to oppose developing or implementing fully interoperable and standardized solutions owing to commercial and strategic reasons: to retain or gain in market share, to keep their margins or create a captive demand. Their motivation to adopt such position is due to the uncertainties with respect to the size of the market for innovative technologies/solutions as well as the number of suppliers competing for this market volume. Broadly speaking, reduced market sizes and a large degree of competition, enabled by standardization, would force manufacturers and suppliers to reduce their margins, raising concerns about insufficient returns from the innovation. All these may effectively act as barriers for scalability and replicability, especially in the case of services or devices where the market size is potentially more limited. These potential strategies are counteracted through the existing standardization bodies and progressive implementation efforts, as discussed in gD4.1&gD4.2.

Alternative strategies could be more beneficial for them in certain cases. For instance, enhanced standardization may enlarge their potential customer base as DSOs may be reluctant to rely on a single supplier for a specific solution. Moreover, a successful collaboration for the development of a certain device or solution may be used by these stakeholders in their marketing campaigns or as a cover letter for potential customers. This raises the topic of the type of commercial relationship these stakeholders establish with DSOs as their suppliers. This is relevant since important barriers for scalability and replicability may exist when this stakeholder group does not share the same views of DSOs with respect to specifications and functionalities.

The aforementioned barriers are presumably more likely to appear under a conventional transaction-based (with frequent price negotiations) relationship model between DSOs and their suppliers. However, different forms of collaborative more stable relationships and information-sharing may be adopted to overcome these barriers, at least during the development stages. These may take place, for instance, in the framework of specific R&D projects which provides both DSOs and manufacturers some hedging against technology risks and reduce development costs. Note that engaging competing companies within the same project or consortium may not be advisable since these could be reluctant to share data and experiences. Nonetheless, engaging providers of systems that should interact among them may facilitate system integration, where oftentimes important challenges arise when the involved providers are engaged separately.

Whilst this type of cooperation ensures that DSO interests are aligned with technology developments, it does not ensure the standardization and interoperability of the solutions since these are developed ad-hoc. Being this the case, this may facilitate the scalability within the same DSO, but hamper the replicability by other DSOs. Thus, alternatively, the development of common standards and interoperability could be deemed as a high priority when it is necessary to create a large market for products that show a scarce differentiation and are more commodity-like, e.g. smart meters. Such an approach may be pursued through the joint technology development with participation from a wide range of stakeholders, as in the case of the Prime Alliance[42] which comprises DSOs, manufacturers, research institutions and ICT service providers. This process

[42] http://www.prime-alliance.org

could benefit both manufacturers and service providers, by increasing their sales, and DSOs, by the reduction in unit prices.

5 Summary and lessons learnt

This report has provided a comprehensive summary of the main contributions and final results obtained within the GRID4EU SRA, with an emphasis on the work developed within the fourth and final year of the project. Firstly, a theoretical framework and a practical methodological approach had to be developed before proceeding to the analysis itself. The core of this methodology corresponds to a simulation-based technical analysis which required classifying the different smart grid solutions attending to their specific goals. Furthermore, this report has presented an extensive discussion on how non-technical boundary conditions, i.e. regulation and stakeholders' perspectives, may affect the replication and upscaling of the GRID4EU smart grid use cases. Lastly, this section introduces some additional concluding remarks in order to highlight the future work that may help expand the analyses presented herein as well as the main barriers encountered whilst developing this work.

Conceptual framework and general methodology

A general understanding of the concepts of scalability and replicability is relatively easy to grasp intuitively. However, in order to be able to define a realistic methodological framework, it was necessary to narrow the scope of the analysis. The scope adopted in this case was focused on the technical impacts on distribution networks of smart grid solutions, as well as the effect of regulatory and stakeholder-related aspects on such a technical impact. This means that technological aspects such as software/hardware performance, modularity or standardization have not been factored in. As a result, in spite of its limitations, this approach yields conclusions that could be applicable to smart grid projects testing similar goals by using different technological solutions and devices.

In this context, the aforementioned impacts of smart grid use cases is measured through a set of metrics or KPIs. Thus, the SRA assesses the extent to which the KPI values are affected by technical, regulatory or stakeholder boundary conditions. Furthermore, several dimensions of scalability and replicability have been identified.

- Scalability analysis may focus on the effect of enlarging the scope of the smart grid solution in a given area, e.g. engaging more DER flexibilities or increasing network automation (**scalability in density**). On the other hand, this analysis may focus on the effect of implementing the smart grid solution over a larger geographical area, e.g. at regional or DSO level (**scalability in size**).
- Replicability may be assessed by considering different distribution areas within the same country (**intranational replication**), or by considering distribution areas in different countries (**international replication**). The major differences consist of whether regulatory and stakeholder boundary conditions may be considered to remain unchanged.

In line with the previously described scope, a two-step SRA methodology was defined. Firstly, a detailed quantitative simulation-based technical analysis aims to compute the KPI values under different boundary conditions, both with and without the smart grid solution. This involves changing the values of different input parameters so as to quantify their effect on the relevant KPIs through sensitivity analyses. As discussed below, different simulation tools and KPIs may need to be considered for each use case. The second stage consists in a qualitative evaluation of the regulatory aspects, as well as the perspectives of the relevant stakeholders. The objective of this second stage is to identify barriers, enablers and drivers for the scalability and replicability of the solution posed by these boundary conditions.

Technical scalability and replicability analysis: methodology

As mentioned above, the most important part of the proposed SRA methodology corresponds to a simulation-based technical analysis. Given the wide range of existing smart grid solutions, this requires developing specific analytical frameworks for each type of use case according to their goals and characteristics. Therefore, it was necessary to carry out a preliminary categorization of use cases, which resulted in the identification of three major groups.

- Reliability improvement: solutions aiming to improve grid reliability through network automation. The impact is measured by several reliability indices that are computed by simulating the fault location and restoration process.
- Increase of DG hosting capacity: use cases seeking to increase the HC for DG by means of voltage control, demand response or grid reconfiguration. The central KPI is the increase in HC, although additional KPIs may be measured, such as losses of RES curtailment. Simulations mainly correspond to power flow calculations under different scenarios.
- Islanding operation/anti-islanding protection: use cases aiming to achieve or, when unintentional, to prevent the islanded operation of part of the distribution network. Dynamic time-domain simulations have been used to monitor voltage and frequency behaviour during the islanding.

The analytical framework required defining, for each use case, the parameters with respect to which sensitivity analyses should be performed so as to infer the SRA rules. These technical parameters can be related to the network characteristics (e.g. voltage levels, topology, feeder length), to the distribution network users (e.g. DG technologies, load profiles) or the implementation of the smart grid solution (e.g. voltage control variables, degree of automation).

Finally, since performing simulations on the overall distribution network of a DSO or a country would be infeasible due to the size of the problem, the technical SRA methodology relies on the concept of representative networks. A representative network should describe the behaviour of a cluster of real distribution feeders with similar technical characteristics such as voltage level, load density, undergrounding, topology, etc. Meeting the trade-off between representative and simplicity, networks comprising between 3 and 5 feeders outgoing of a substation, or several substations in the case of MV grids, were deemed sufficient to capture the complexities of distribution grids whilst ensuring a manageable amount of data.

Technical scalability and replicability analysis: results and lessons learnt

Most of this report is focused on presenting the results of the technical analysis and the development of technical SRA rules. These rules are qualitative premises which summarize the impacts to be expected from implementing the same or a similar functionality in a different area, i.e. replication, or at a larger scale, i.e. upscaling. The results have been presented attending to the goals pursued by the different use cases.

As mentioned above, one of the main groups of use cases identified comprise those solutions aiming to improve distribution reliability through network monitoring and automation. The technical analyses carried out show that MV automation can have a very significant impact on both the frequency and duration of supply interruptions. Nonetheless, this effect tends to dilute for automation levels beyond 20-40%. The reliability improvement achieved is much more relevant for networks with initially low levels of reliability, as well as in meshed grids with high load densities. Solutions based on human supervision present a more arbitrary response time, particularly for higher automation degrees, although results yielded small differences between autonomous and supervised systems.

Lastly, the selection of different reliability indicators, e.g. weighting the number of consumers affected or the volume of load, may affect the replicability of the tested solutions by shifting DSO priorities. This difference is less noticeable in urban areas where consumers tend to be more homogeneous, however it can be very relevant otherwise. Note that the previous analysis was carried out for LV networks as well. However, since these are typically less meshed than MV networks and affect a much lower number of consumers, MV automation may be prioritized.

The second category of uses cases comprises those resorting to different control actions to increase the network hosting capacity for DG. These control actions comprise network reconfiguration, voltage control, grid supervision, demand response or network storage; both at the MV and LV levels. Despite the fact that these solutions are quite heterogeneous with respect to the smart grid solution implemented, significant points in common were found. The impact of these solutions on network hosting capacity greatly depends on the characteristics of the distribution network were it is applied (feeder length, R/X ratio or topology) as well as the characteristics and location of the DG units connected. This implies that the replicability and upscaling of these use cases should be made attending to these parameters so as to focus on those potentially problematic areas and those where the penetration of DG is expected to be greater.

The islanded operation of part of the distribution grid has been analyzed for two very different approaches: MV islanding supported by a CHP unit and LV islanding supported by an energy storage system. In both cases, the size of the disturbance faced by the islanding controller was one of the main factors affecting the performance of the system and the presence of fast controllable loads significantly improved this performance. Moreover, the system performance in both cases could be jeopardized when the CHP or storage unit had to work close to their operational limits, denoting the importance of properly sizing these units with respect to the area to be controlled. One of the major differences observed is that battery systems, connected through a power electronics interface, showed a faster response as compared to the CHP unit. Nonetheless, this response was not symmetric, generally responding faster when discharging.

Regarding anti-islanding protection, the analysis intended to identify the conditions under which an unintentional MV islanding may occur due to lack of protection sensitivity. It was observed that the voltage deviation during islanding depends almost exclusively on the active power mismatch, whereas the frequency deviation does so on the reactive power mismatch. In fact, both effects are quite linear. Hence, the results could be easily replicated in various distribution areas. Nevertheless, this would be subject to an accurate estimation of the local load model since the characteristics of the load to be supplied greatly determines the frequency response of the system.

The previous SRA rules represent the result of significant amount of work and complex analyses. Nonetheless, these results are not without their limitations, which ought to be acknowledged. The main shortcoming of this study is related to potential insufficient representativity, given that a reduced number of distribution networks were considered in the simulations. The consequences are twofold. On the one hand, there may be some technical conditions relevant for the KPI quantification that have not been captured, thus limiting the replicability of the smart grid solutions for the areas matching these conditions. On the other hand, performing a truly comprehensive assessment of the scalability in size was not possible precisely because of the insufficient data.

Obtaining a comprehensive set of fully representative networks for several EU countries exceeded the scope of the GRID4EU project. It is important to highlight that representative networks are different from test or benchmark networks, as their selection criteria and number should precisely seek this representativity and not just provide a possible example of a distribution grid. Hence, further efforts on the creation of a European-wide repository of distribution grid data are recommended so as to facilitate future analyses by reducing the costs of data collection and processing. Noteworthy, some initiatives of this sort may already be found addressing Italy (Atlantide project), UK (generic distribution systems) or the EU as a whole (JRC's DSO Observatory).

Another lesson learnt whilst developing this work is that, despite the fact that DSO size or ownership may vary greatly across Europe, the characteristics of distribution networks and operational approaches are relatively homogeneous across European countries. This ensures that the previous technical results could be broadly applicable on a wider European context. Nevertheless, their direct application to contexts outside the EU where the grid characteristics may be significantly different could be more arguable. Hence, in order to evaluate the extent to which the technical SRA rules presented in this report would be applicable to other contexts as well as the adaptations that may be necessary, a new task was added to the GRID4EU project. The results of this task are presented in the report gD3.8.

Non-technical boundary conditions: regulation

Conventionally, the main discussions about distribution regulation focused on how to balance the need to ensure investment adequacy and the incentives for DSOs to cut inefficient costs. Thus, regulatory frameworks have usually been based on cost of service regulation, RPI-X regulation, or a combination of both. However, growing volumes of DG-RES, the increasing consumer awareness and the development of the so-called smart grid technologies are driving a change in paradigm. Nowadays, the major regulatory dilemma is how to move away from short-term cost reduction incentives so as to encourage DSOs to innovate and integrate DER efficiently over the long-term. In this context, smart grid solutions are seen as essential components of future distribution networks.

Hence, pilot project and demonstration activities are being promoted by regulators and policy-makers through input incentives and grants. Nonetheless, the long-term adaptation of DSO regulation seems to be a pending issue yet. Therefore, it is important to identify the drivers and barriers for the deployment of smart grid solutions that may exist so as to guide future regulatory developments. This report in particular has analyzed the potential barriers for the scalability and replicability of the GRID4EU use cases previously mentioned. These use cases mainly aim either to improve continuity of supply or to increase the network hosting capacity, enabling DSOs to defer or avoid reinforcing the grid or achieve a swifter connection of DG. Consequently, the regulatory barriers and drivers identified are in accordance with these goals.

The solutions aiming to increase in network HC can be hindered by regulatory designs that promote conventional grid reinforcements over advanced solutions. These comprise input-based approaches to remunerate network CAPEX or mandating DG operators to pay deep connection charges. On the contrary, equalizing the incentives for DSOs to cut OPEX and CAPEX and shallow connection charges would promote these solutions. Moreover, in order to mitigate the increasing uncertainties faced by DSOs under this environment, regulators could incorporate flexibility mechanisms in remuneration formulas and set ex-ante revenues that account for the forecasted future investment needs on the basis of DSO-submitted detailed investment plans, thus avoiding a

CAPEX time-shift problem.

In addition to the overall revenue regulation, use cases whose ultimate goal is to improve reliability are of course heavily influenced by the existence and design of continuity of supply incentives for DSOs. The absence of such incentives or an inappropriate design, e.g. scarcely demanding reference values, wide deadbands or tight caps/floors, may act as barriers for the replicability and scalability of these smart grid solutions.

The previous use cases oftentimes depend on the active participation of distribution network users such as DG, storage or demand response. However, the regulatory mechanisms to enable such interaction are not commonly in place. The scarce occasions in which this may happen, these schemes are usually limited to mandatory requirements on DER to address emergency situations, rather than contract-based or market-based transactions where DER are remunerated on the basis of the value of the service they are providing and where DSOs may truly rely on network users as an alternative to network reinforcements. Additionally, the potential contribution of energy storage systems still depends on the definition of an ownership model for such assets, which ought to be compatible with existing unbundling rules for DSOs.

Similarly to the case of energy storage, the lack of a clear regulatory framework governing the role and data management of smart metering may constitute an important barrier for scalability and replicability of solutions relying on this technology, i.e. demand response and LV supervision enabled by AMI. Likewise, these smart grid solutions may be hindered by limited meter functionalities and restricted DSO access to data generated by the meters, including consumption data, power quality data, etc.

This regulatory analysis has strictly focused on the economic regulation of DSOs and their interaction with the different types of distribution network users. The main reasons for this is that GRID4EU is a DSO-centred project, where the solutions tested do not have a significant involvement of the upstream segments of the power supply chain. However, smart grid deployment and the progressive decentralization of the power system being witnessed in Europe may call for a stronger interaction between DSOs and the upstream power sector actors, particularly TSOs. The TSO-DSO interaction for an efficient integration of DER in the overall power supply chain is a line of future research and relevant item in the European regulatory agenda.

Non-technical boundary conditions: stakeholders' perspectives

The regulatory analysis summarized above has clearly shown the need of DSOs to actively interact with a wider range of stakeholders such as network users or TSOs. Therefore, incorporating the perspectives of stakeholders is key to understand the replicability and scalability potential drivers and barriers for smart grid solutions. This report has discussed about the expectations and behaviour of stakeholder groups comprising regulators, end consumers, DG operators, equipment manufacturers, ICT service providers, TSOs and suppliers/aggregators. Some of these groups can be related to specific use cases, mainly those that are part of the power supply chain (DER, supplier/aggregators or TSOs); whereas other stakeholders, such as regulators, manufacturers or ICT/software providers, play rather cross-cutting roles.

- Consumers are presumably the most extensively analyzed group, although the focus has been commonly placed on enabling technologies and economic incentives, neglecting critical subjective factors such as motivational (environmental concern or comfort), trust in suppliers or privacy issues. Hence, consumers are not homogeneous with respect to engagement activities. Moreover, the outcomes of particular experiences may not be generalized as these perspectives show a very strong local or even community-related dependency. Successful engagement in pilot projects may not be easily scalable since these usually rely on voluntary participation, resulting in non-representative samples, or ad-hoc incentives and information campaigns, which would be too costly at a large scale. Therefore, low degree of consumer involvement and engagement costs are key drivers for scalability. An additional factor that may act as barrier or driver is the level of maturity of the retail sector and how used end consumers are to dealing with different suppliers and tariff alternatives.

- DG and storage (when owned by third-parties) may also provide grid services to DSOs in several of the use cases evaluated. In this case, subjective aspects may presumably be less relevant as compared to implementation costs, technical requirements or suitable economic signals.
- Despite the fact that the direct involvement of TSOs in GRID4EU is rather limited, this does not mean that TSOs are not relevant stakeholders. Due to the increasing decentralization of the power system, DER flexibilities may no longer be neglected in system operation. Therefore, a stronger cooperation and trust between TSOs and DSOs will be necessary, for which clear regulatory guidelines are necessary to remove barriers for scalability and replicability.
- Suppliers and aggregators may act as intermediaries for consumers. However, inappropriate functioning of retail markets and the lack of trust of end consumers can hamper this possibility. Moreover, even if aggregators succeed in customer engagement, they may see a higher value in non-DSO services, hampering the scalability and replicability of distribution solutions.
- The need to adapt regulation places regulators as key stakeholders for upscaling and replication of smart grid solutions. Nevertheless, limitations in their resource or legal capabilities can represent significant hurdles. Therefore, an adequate regulatory endowment, an effective regulatory independence and appropriate legal powers of NRAs are key enablers. Additionally, enhancing the exchange of lessons learnt and best practices among regulators is advisable.
- Agents involved in technology development and provision are central stakeholders, including manufacturers, software developers, system integrators or ICT service providers. Interoperable, modular and standardized products are desirable for scalability and replicability. However, these stakeholders may not be willing to follow that path for strategic reasons in case the expected market size is insufficient to ensure adequate returns for the innovation efforts. In order to overcome this barriers, their conventional relationship with DSOs could shift, seeking enhanced stability and information-sharing so as to reduce development costs. This model could co-exist with another based on common standards and interoperability requirements for commodity-like products presenting low differentiation and high market size.

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