UNIVERSIDAD PONTIFICIA COMILLAS DE MADRID
ESCUELA TÉCNICA SUPERIOR DE INGENIERÍA (ICAI)
(Instituto de Investigación Tecnológica)

SCALABILITY AND REPLICABILITY OF THE IMPACT OF SMART GRID SOLUTIONS IN DISTRIBUTION SYSTEMS

Tesis para la obtención del grado de Doctor

Director: Dr. Pablo Frías Marín

Co-Director: Dr. Rafael Cossent Arín

Autor: Ing. Andrea Rodríguez Calvo

Madrid 2017

Resumen

Las soluciones de redes inteligentes o *smart grid* ofrecen un elevado potencial para la integración eficiente de las energías renovables en las redes de distribución. Se están llevando a cabo numerosos proyectos piloto para probar el funcionamiento de las soluciones *smart grid* en condiciones reales. Sin embargo, los resultados obtenidos en dichos proyectos están sujetos a las condiciones específicas del piloto. Por tanto, las conclusiones extraídas pueden no ser directamente aplicables a la implementación de las mismas soluciones en distintos lugares o a mayor escala. Esta tesis propone un marco conceptual y metodológico novedoso para analizar la escalabilidad y la replicabilidad de las soluciones *smart grid* que permite evaluar cómo el contexto en el que se implementan dichas soluciones repercute sobre los resultados de la implantación de la *smart grid*.

Esta tesis propone una metodología para el análisis de escalabilidad y la replicabilidad (SRA, del inglés *scalability and replicability analysis*) que comprende una primera etapa de análisis técnico basado en el uso de simulación para la cuantificación de indicadores clave de rendimiento (KPIs, del inglés *Key Performance Indicators*) que miden el impacto de las soluciones implantadas sobre el sistema; y una segunda etapa de análisis no técnico más cualitativo. El SRA técnico se sustenta en el empleo de redes representativas y escenarios de simulación para abarcar las distintas condiciones de contorno técnicas que pueden encontrarse en las regiones estudiadas. La experiencia reunida en los proyectos piloto se incorpora al SRA técnico comparando los KPI medidos en las demos con los valores obtenidos mediante simulación. El análisis no técnico aborda el contexto regulatorio y la perspectiva de los *stakeholders* relevantes para identificar barreras e impulsores para la implementación de soluciones *smart grid*.

Esta tesis propone una clasificación de las soluciones *smart grid* en tres categorías de casos de uso para SRA basada en los tipos de impactos causados y los objetivos perseguidos: (i) automatización de la red para la mejora de la continuidad de suministro, (ii) control de recursos energéticos distribuidos y control de tensiones para el aumento de la capacidad de integración de la red, y (iii) funcionamiento en isla y micro-redes para la mejora de la continuidad de suministro. La implementación detallada de la metodología de SRA propuesta en esta tesis se ha particularizado para estos tres grupos de soluciones *smart grid*. En esta tesis se han identificado para el SRA de cada grupo de casos de uso de *smart grid* los requisitos para las redes representativas, los enfoques de modelado y simulación adecuados, los KPIs apropiados y los temas regulatorios y *stakeholders* relevantes.

Finalmente, se ilustra la aplicación de la metodología de SRA propuesta mediante el SRA completo para el caso de estudio de automatización de redes de media tensión para la mejora de la continuidad de suministro en España e Italia. Este caso de estudio incluye también un análisis coste-beneficio basado en los resultados del SRA.

Abstract

Smart grid solutions offer a great potential to achieve a more efficient integration of renewable energy in the distribution network. Numerous pilot projects have been launched to test smart grid solutions in real-life systems. However, the results observed are subject to the specific context of the demonstrators. Therefore, conclusions drawn may not be directly applicable to the implementation of the same solutions in different locations or at a larger scale. This PhD thesis proposes a novel framework to assess the scalability and replicability of smart grid solutions to understand the effect of the implementation context and infer the impacts that may be expected from the deployment of the smart grid.

This thesis proposes a SRA methodology comprising a quantitative and detailed technical analysis based on simulation to compute the KPIs that measure the impact of the use case on the system; and a second stage of a more qualitative non-technical analysis. The proposed technical SRA relies on the use of representative networks and scenarios for simulation to account for the different technical boundary conditions that may be encountered in the considered regions. The experience gathered from real-life testing is incorporated in technical SRA comparing the KPIs measured in the demo and those obtained through simulation. The non-technical analysis addresses the relevant regulatory framework and the perspective of stakeholders involved to identify barriers and drivers for the implementation of smart grid solutions.

This thesis proposes to group smart grid use cases into three main categories for SRA, based on the type of impacts caused and objective pursued: (i) network automation to improve continuity of supply, (ii) DER management and voltage control to increase network hosting capacity, and (iii) islanded operation and micro grids to improve continuity of supply. The detailed implementation of the proposed SRA methodology has been particularized for these three groups of smart grid use cases. Accordingly, this thesis has identified the characteristics required for representative networks for the SRA of each group of smart grid use cases, adequate modelling and simulation approaches, appropriate KPIs and the relevant regulatory topics and stakeholders.

Finally, a comprehensive SRA is presented in this thesis to illustrate the application of the proposed SRA methodology to the case study of MV network automation to improve continuity of supply in Spain and Italy. This case study includes a cost-benefit analysis based on the SRA results.

Contents

List of Tables

List of Figures

Nomenclature

Parameters

t_{reg}	regulatory threshold for sustained interruptions (min)
t_{autom}	response time for automation to perform FDIR (min)
t_1	response time of maintenance crew to start fault management(min)
t_2	time for maintenance crew to manually operate load break switches in a secondary substation (min)
v_3	speed of maintenance crew to travel to secondary substation to operate (km/h)
v_4	speed of maintenance crew to perform visual inspection along an overhead line (km/h)
t_5	time for maintenance crew to repair fault (min)

Variables

$\alpha_{i,autom}$	binary variable activated if telecontrol was in place for FDIR
$\alpha_{i,1}$	binary variable activated if a maintenance crew was sent for management of a fault in branch *j* before restoring service in load *i*
$\alpha_{i,k}$	binary variable activated if maintenance crew has operated load break switches in *k* subsequent steps for management of a fault in branch *j* before restoring service in load *i*
k	number of steps of manual operation required for management of a fault in branch *j* before restoring service in load *i*
d_{3k}	distance travelled by maintenance crew at step *k* (km)
$\alpha_{i,4}$	binary variable activated if maintenance crew has performed visual inspection of lines for management of a fault in branch *j* before restoring service in load *i*
d_4	distance covered at visual inspection (km)
$\alpha_{i,5}$	binary variable activated if maintenance crew has repaired the failure of branch *j* before restoring service in load *i*
λ_j	fault rate of conductor *j* (failure/year·km)
L_j	length of branch *j* (km)

$cons_i$	number of consumers supplied by secondary substation i
$int_{i,j}$	binary variable activated if a fault in branch j causes a sustained interruption in load i
$t\_int_{i,j}$	duration of the supply interruption for the consumers of load i caused by a fault in branch j (min)

Acronyms

ACER	Agency for the Cooperation of Energy Regulators
AMI	Advanced Metering Infrastructure
ASIDI	Average System Interruption Duration Index
ASIFI	Average System Interruption Frequency Index
CAIDI	Customer Average Interruption Duration Index
CAPEX	Capital Expenditure
CBA	Cost Benefit Analysis
CEER	Council of European Energy Regulators
CENELEC	European Committee for Electrotechnical Standardization
CHP	Combined Heat and Power
CoS	Continuity of Supply
CS	Control System
DER	Distributed Energy Resources
DG	Distributed Generation
DR	Demand Response
DSM	Demand Side Management
DSO	Distribution System Operator
EC	European Commission
EEGI	European Electric Grid Initiative
ENS	Energy Not Supplied
EU	European Union
EV	Electric Vehicle

FCL	Fast Controllable Load
FDIR	Fault Detection, Isolation and Service Restoration
HP	Heat Pump
HV	High Voltage
ICT	Information and communication technologies
JRC	Joint Research Centre
KPI	Key Performance Indicator
ICER	International Confederation of Energy Regulators (ICER)
ISGAN	International Smart Grid Action Network
LV	Low Voltage
MAIFI	Momentary Average Interruption Frequency Index
MGCC	Microgrid Central Controller
MV	Medium Voltage
NHC	Network Hosting Capacity
NIEPI	"Equivalent number of interruptions related to the installed capacity" (Spain, Portugal)
NRA	National Regulatory Authority
OFGEM	Office of Gas and Electricity Markets (Great Britain energy regulator)
OPEX	Operational Expenditure
PHEV	Plug-in hybrid Electric Vehicle
PV	Photovoltaic
RAB	Regulatory Asset Base
RES	Renewable Energy Sources
R&D	Research and Development
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SET Plan	European Strategic Energy Technology Plan
SGAM	Smart Grid Architecture Model

SRA	Scalability and Replicability Analysis
TIEPI	"Equivalent interruption time related to the installed capacity" (Spain, Portugal)
TOTEX	Total Expenditure
TSO	Transmission System Operator
UFLS	Under Frequency Load Shedding
V2G	Vehicle-to-grid
WACC	Weighted Average Cost of Capital
WTA	Willingness to Accept
WTP	Willingness to Pay

Chapter 1

Introduction

This introductory chapter provides the background that has motivated the work of this PhD thesis and presents the objectives pursued. The evolution towards a smarter distribution grid requires tools to adequately assess the potential of large-scale deployment of available smart grid, taking into account the different technical, economic, social and regulatory context across different countries. The first section of this chapter describes the context and motivation of this work. Secondly, the scope and objectives of the thesis are laid out. Finally, the structure of this document is presented in the last section.

1.1 Introduction and motivation

As our society becomes increasingly concerned about the environment and the serious risks derived from global warming, international organizations have proposed different targets which include CO_2 emissions reduction, such as the Kyoto Protocol (United Nations, 1998) and the Paris Agreement (United Nations, 2015), or the EU Energy Roadmap 2050 (European Commission, 2011). In order to accomplish a low carbon economy, the energy sector plays a key role and a more sustainable and efficient electric power system must be pursued. However, this will require a major structural change, promoting a very strong presence of renewable energy sources (RES), introducing energy efficiency measures and enabling a more active role of demand[1].

1.1.1 General context: smart grids in the distribution system

The technological development and the decrease of required investment costs of smaller-scale renewable generation, together with different support schemes, have boosted the penetration of distributed generation (DG). Many countries have seen a massive deployment of DG mainly in the form of solar PV panels, wind, biomass and micro-cogeneration units connected to distribution networks, so that a significant fraction of deployed RES is distributed[2]. Figure 1.1 displays the installed capacity connected to distribution networks in Spain. Similarly, alternatives for the electrification of transportation have gained prominence in recent years. There has been a very strong increase in the uptake of electric vehicles in the last five years[3] (see Figure 1.2), and a large number of electric vehicles is expected in the near future. Plug-in electric vehicles will connect to distribution networks to charge

---

[1] Actually, with the aspiration for the European Union to lead the clean energy transition, the European Commission has recently issued a package of proposals focusing on putting energy efficiency first, achieving global leadership in renewable energies and providing a fair deal for consumers (European Commission, 2016). The package measures address renewable energy to reach a share of at least 27% of the final energy consumption by 2030, efficiency in the form of a binding target of 30% energy savings by 2030, efficient buildings, eco-design measures, cleaner heating and cooling, decarbonized transport, smart metering and empowered consumers.

[2] In Germany, a total installed capacity of solar PV exceeding 40 GW has been connected to MV and LV networks, and over 85% of the solar energy produced in Germany is injected by units of a capacity below 1 MW (Fraunhofer ISE, 2017). The total installed capacity of solar PV in UK amounted to 9 GW in 2015, from which 5 GW corresponded to PV units of a capacity below 10 MW connected to the distribution network (Castro Legarza & Álvarez Pelegry, 2016). In the United States, around 29% of the solar capacity installed in 2014 was distributed, which accounted for 8% of all US generating capacity additions. In 2015, these values increased so that 41% of the solar capacity installed was distributed, which accounted for 11% of all US generating capacity additions (Massachusetts Institute of Technology, 2016).

[3] The global electric vehicle stock has increased globally from around half a million in 2014 to a million of electric vehicles on the road in 2015. Although this number represents an extremely low share (0.1%) when compared with the total number of cars worldwide, EV market shares reached 23% in Norway and nearly 10% in the Netherlands (International Energy Agency (IEA), 2016).

their batteries at domestic and public charging points. In addition, owners of battery storage, including EVs with so-called vehicle-to-grid capabilities, may be able to both retrieve and inject energy into the grid.

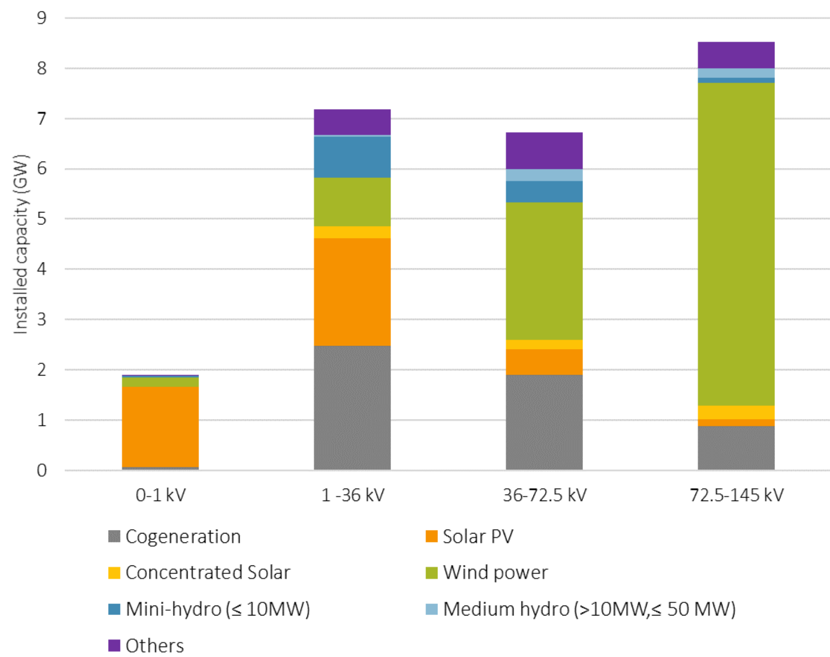


Figure 1.1: Installed capacity of distributed generation in Spain in 2012. Data from CNE.

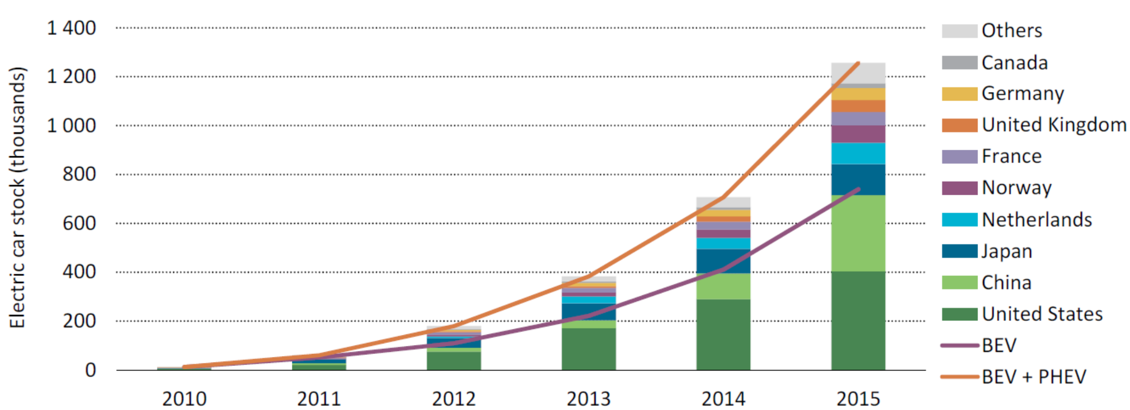


Figure 1.2: Evolution of the global electric car stock, 2010-15. Source: (International Energy Agency (IEA), 2016).

Demand response may unlock a high degree of flexibility for the system and greatly increase energy efficiency. Demand response at domestic level has been enabled by metering and communication technologies, including smart meters and advanced metering infrastructure (AMI), as well as energy boxes and home automation solutions in the domain of the consumers. Actually, most European countries are pursuing a smart meter roll-out and are close to completion (see Figure 1.3)[4]. Consumers may be engaged in demand response motivated by an enhanced awareness of their consumption, environmental concerns and opportunities to reduce their energy costs. Although demand response is a key element of the EU sustainability strategy as reflected in the Energy Efficiency Directive (European Commission, 2012b), the level of actual realization is still quite low in most countries. Demand response is a viable product only in a few countries, as shown in Figure 1.4, mainly due to a lack of a clear commercial and regulatory framework (Smart Energy Demand Coalition (SEDC), 2014).

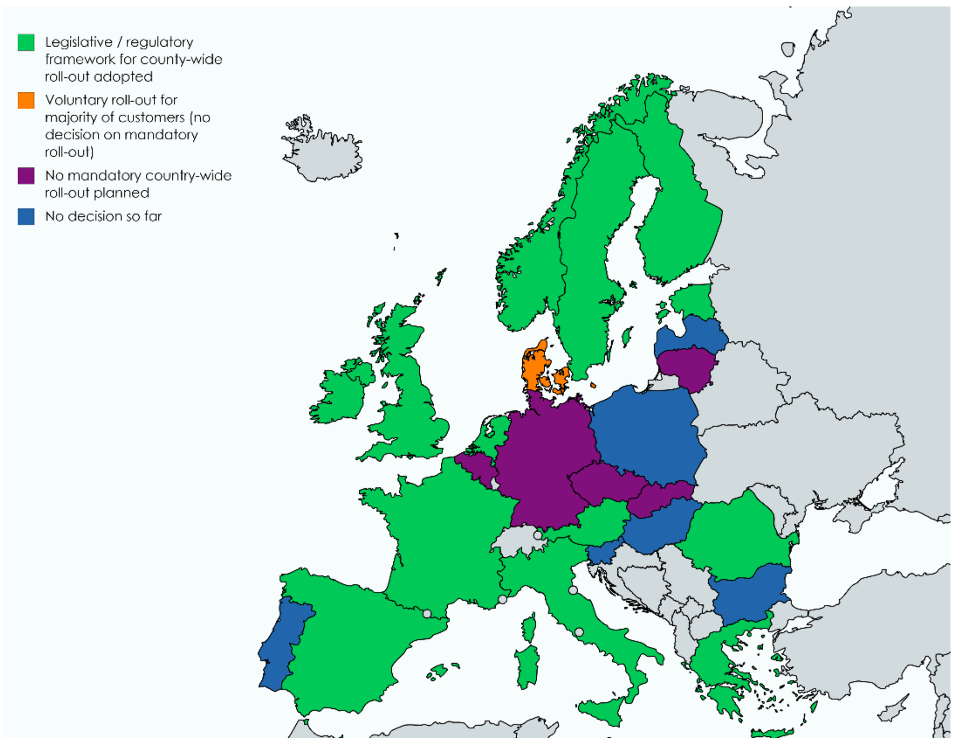


Figure 1.3: Smart meter roll-out in Europe. Source: Adapted from Eurelectric (Eurelectric, 2013).

4 Smart metering has been fully deployed in Italy, Finland and Sweden, and is currently on-going in many other countries (e.g.: Spain, the Netherlands, UK, Ireland). The EC has mandated that at least 80% of all European consumers shall be equipped with intelligent metering systems by 2020, subject to a positive CBA to be carried out by each Member State (European Commission, 2014a).

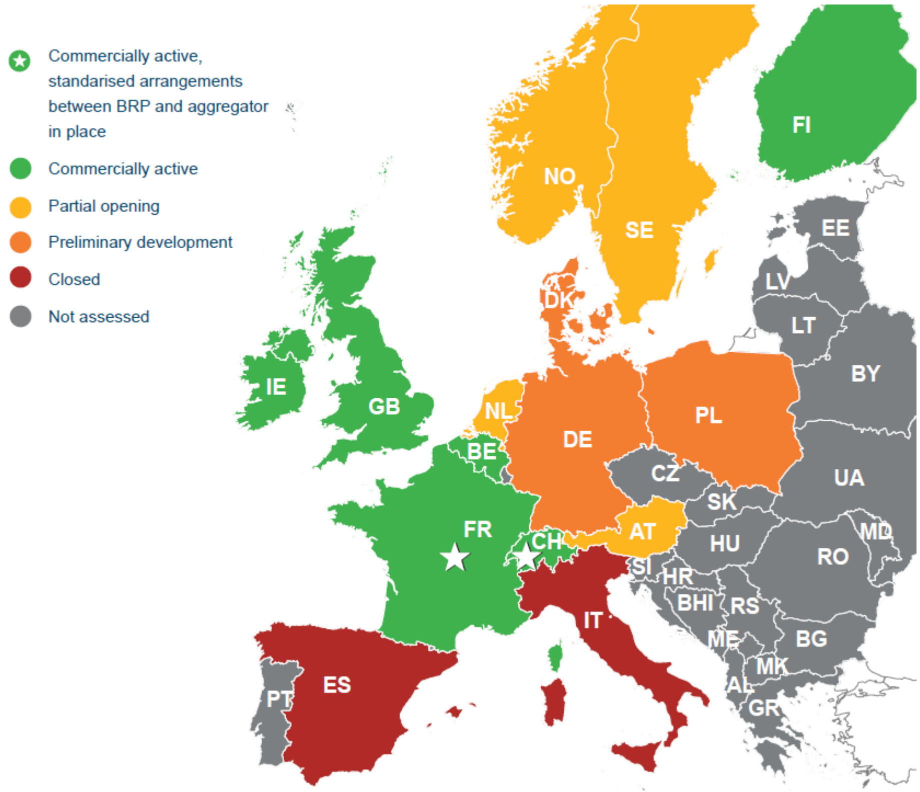


Figure 1.4: Map of explicit demand response development in Europe Today (Smart Energy Demand Coalition (SEDC), 2014)

Electricity networks are hierarchically divided into voltage levels comprising transmission networks and distribution networks, to connect network users to the electric power system. Table 1.1 shows the traditional characteristics of electricity networks of different voltage levels in terms of topology, flexibility and observability for operation, as well as of number of network users and assets. Large-scale generation is directly connected to the transmission network through substation. Distribution networks have been traditionally designed and operated based on unidirectional power flows with no (or very little) generation. As a consequence, and due to the much larger number of assets and connected network users, the degree of monitoring and flexibility in operation has been typically much lower for lower voltage levels.

Network and voltage level		Structure	Typical operation	Number of users	Number of assets	Operation flexibility	Monitoring degree
Transmission (400, 275, 220kV)		Meshed	Meshed	Very few	Few	High	High
Distribution	HV (132, 66, 45kV)	Meshed	Meshed/ Radial	Few	Many	Average	High
	MV (20, 15kV)	Meshed/ Radial	Radial	Many	Many	Poor	Average
	LV (400, 380V)	Meshed/ Radial	Radial	A lot	A lot	Very poor	Low

Table 1.1: Characteristics of traditional electricity networks. Source: (Trebolle, Frías, Maza, & Martínez Ramos, 2012).

The introduction of distributed resources (DER), i.e. distributed generation (DG), demand response (DR), distributed storage and electric vehicles (EVs) is bound to change conventional power flows in the network. Under the increasing presence of distributed energy resources the usual fit-and-forget approach is no longer valid (I. Pérez-Arriaga, Ruester, Schwenen, Batlle, & Glachant, 2013). In order to face the upcoming challenges and successfully allow the integration of renewable energies and active demand response, the distribution system needs to become more flexible.

Furthermore, ageing of the transmission and distribution infrastructure is bringing assets closer to the end of their useful life, so strong investment will be required to upgrade the network. The integration of information and communication technologies (ICTs) into the electric infrastructure will allow a more efficient electric power system to ensure reliability and security of supply (European Distribution System Operators for Smart Grids (EDSO4SG), 2016).

In the light of these changes, the term *smart grid* has been coined to define the new paradigm for the networks of the electric power system. The European Technology Platform for Smart Grids[5] defined the concept of smart grid in 2006 as "*an electricity network that can intelligently integrate the actions of all users connected to it - generators, consumers and those that do both - in order to efficiently deliver sustainable, economic and secure electricity supplies*".

The concept of smart grid has become very relevant over the past years (Eurelectric, 2011; International Energy Agency (IEA), 2011; International Renewable Energy Agency, 2013), covering a wide range of solutions aimed at achieving the necessary upgrade of the distribution grid (Blumsack & Fernandez, 2012; Ipakchi & Albuyeh, 2009; J. Wang, Conejo, Wang, & Yan, 2012). According to the smart-grid taxonomy proposed by GTM Research, the architecture of the electric power system comprises three main layers: (i) a power layer, i.e. physical, electric power infrastructure; (ii) a digital layer, i.e. data and communications; and (iii) a functional layer, i.e. applications and services. As shown

[5] www.smartgrids.eu

in Figure 1.5, the smart grid covers all aspects of the electric power system and comprises the three interconnected layers. Further development of architecture models has resulted in the Smart Grid Architecture Model (CEN/CENELEC/ETSI, 2012) based on five interoperability layers: component, communication, information, function and business layers (see chapter 2).

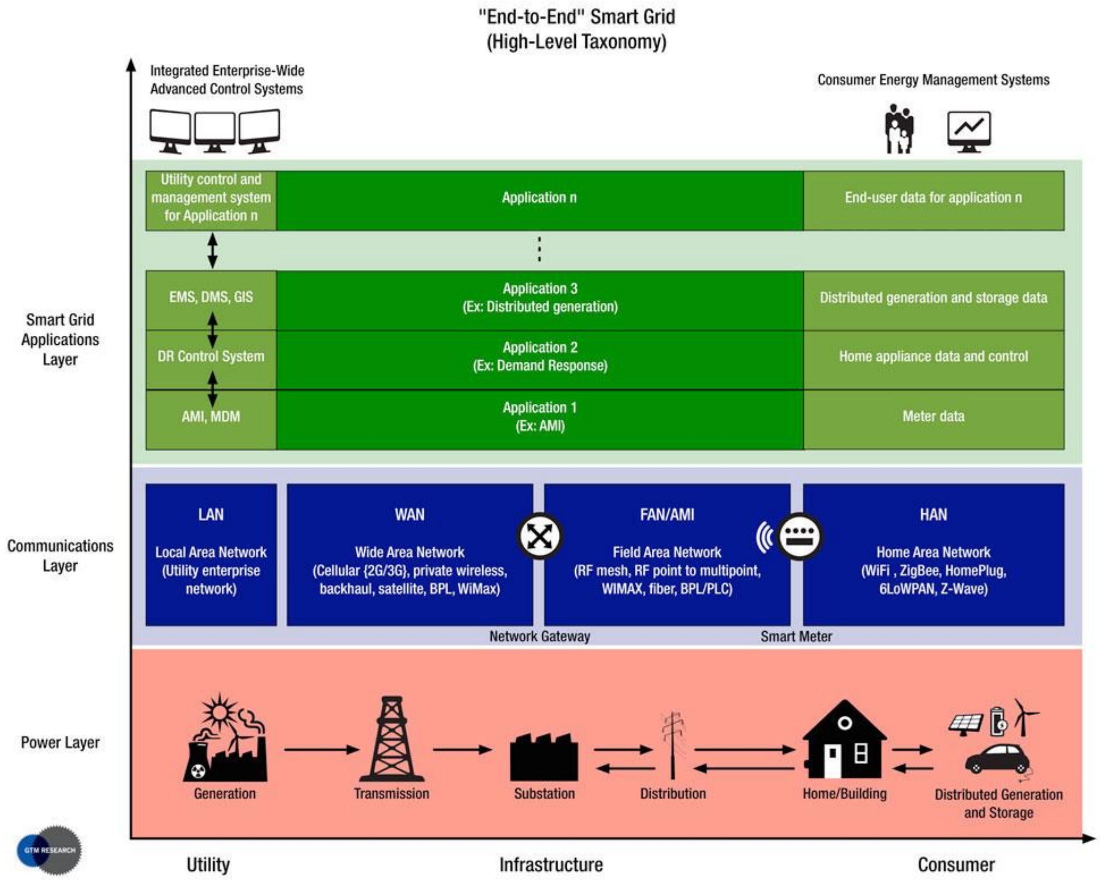


Figure 1.5: "End-to-End" Smart Grid (High-Level) Taxonomy. Source: (GTM Research, 2010).

The academia and industry all around the world have jointly embarked upon smart grid research and development supported both by public and private funding. As smart grid technologies reach maturity, smart grid projects are shifting their focus towards demonstration and deployment (Colak, Fulli, Sagiroglu, Yesilbudak, & Covrig, 2015), as indicated by the graph in Figure 1.6. Indeed, numerous demonstrators and pilot projects have been launched across the world to test different smart grid solutions in real-life systems: up to 2015, over €3.15 billion and $9.7 billion have been invested in the EU and the USA respectively (Covrig et al., 2014; U.S. Department of Energy Electricity Delivery and Energy Reliability, 2012).

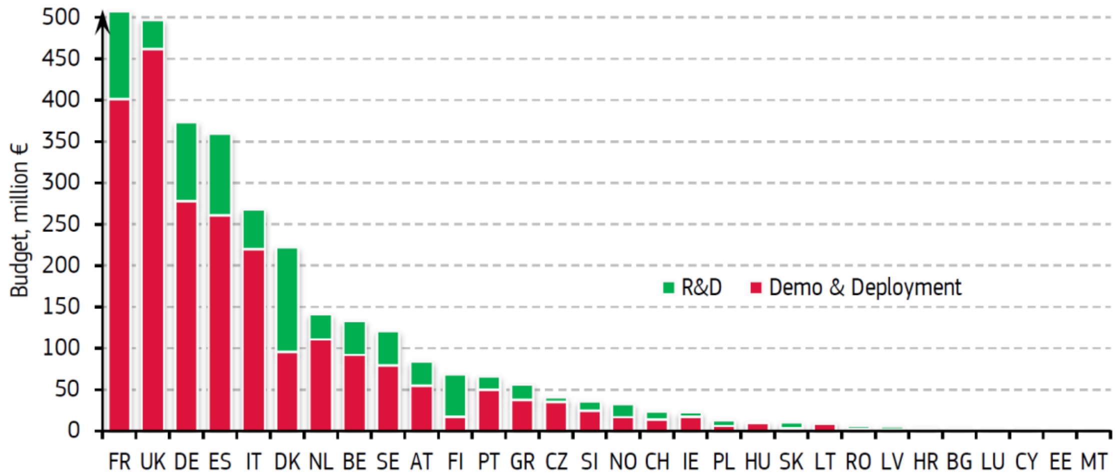


Figure 1.6: Budget of smart grid R&D and D&D projects per country. Source: (Covrig et al., 2014).

Demonstration and pilot projects enable testing new functionalities and their integration with the existing distribution system. Furthermore, new business models may be experienced, engaging intended users in the process to understand their role and interaction with the smart grid. Demonstration projects can also help guide the design of subsequent pilots and identify the need for changes in the regulatory framework to encourage the adoption of the smart grid.

Clearly, a huge volume of investment has already been devoted to smart grid demonstration projects around the world. The deployment and full roll-out of the solutions tested in these demonstration projects require a suitable degree of scalability and replicability to prevent projects from remaining local experimental exercises unable to transfer their knowledge and solutions to real-life industrial-scale applications (Lukas Sigrist et al., 2016).

Public funding institutions like the DOE in USA or the EC in Europe set common requirements for dissemination of project results and outcomes and encourage knowledge sharing among projects. However, there is no systematization of data gathering from pilot projects or common metrics to compare results.

There is a need to bridge the gap between demonstration projects and the large-scale deployment of the smart grid. The adopted smart grid paradigm will not be a one-fits-all model, but rather will comprise different smart grid solutions adapted to the specific local needs and reality of the distribution system across different regions and countries. A systematized, comprehensive analysis is required to identify the most promising solutions and most favorable conditions for their deployment. The assessment of smart grids must be able to tackle the large-scale deployment of smart grid solutions attending to the implications of replication and scaling-up of smart grid implementations.

This PhD thesis aims to contribute to fill this existing gap by developing a methodology for the scalability and replicability analysis (SRA) of smart grid solutions in distribution networks. The proposed methodology will be focused on the assessment of the technical impacts of smart grids on the distribution system, incorporating as well as economic, regulatory and stakeholder-related aspects.

1.1.2 Framing the problem: scaling-up and replication

Much work is currently being carried out to determine the potential impacts, costs and benefits that can be expected from the implementation of smart grid solutions (Electric Power Research Institute, 2011; Giordano & Bossart, 2012; OFGEM, Frontier Economics, & EA Technology, 2012). Cost-benefit analyses (CBA) are well-established for implemented smart grid projects (of a limited size and range). However, CBA aimed at estimating the costs and benefits of the large-scale implementation of the smart grid is much more challenging and implicitly involves scaling-up and replication. Conclusions are drawn from experimental data by extrapolating and performing sensitivity analysis assuming certain hypotheses. Scaling-up and replication have not been yet addressed and performed in an explicit and systematic manner in CBA. Often, observed impacts of smart grids are assumed to be directly applicable for all distribution grids, which implies a linear scaling-up, where the different conditions across the country have not been considered (Electric Power Research Institute, 2011). Thus, SRA must be carried out in order to correctly assess the expected impacts of large-scale implementation of smart grids, accounting for the effect of boundary conditions. Then, the economic valuation of these impacts determines the benefits for the CBA.

There are two main approaches for the assessment of the potential benefits and outcomes of smart grids: the use of analytic models and simulation, and actual implementation of smart grid solutions in pilot projects and demonstrators. Testing smart grid solutions in pilot projects and demonstrators is essential to prove the integration of the deployed technologies and the interaction with the intended users, providing real-life experience. However, testing is costly and the observed results are subject to the specific conditions of the demonstrator. The use of analytic models and simulation allows for assessment of smart grid solutions under different conditions. The results observed in real-life demonstrators may be used to improve analytic models and simulation tools. The proposed scalability and replicability analysis build on the complementarity of these two approaches. Thus, the results observed in real-life in demos may be translated to a larger-scale using simulation to analyze the outcomes expected in other location (replication) or at a larger-scale (upscaling) where the context (i.e. boundary conditions) differs.

As previously mentioned, strong investment has been devoted to smart grid demonstration and pilot projects across the world. These initiatives enable testing the performance of smart grid solutions for real-life conditions. However, the conclusions drawn from testing may not be directly applicable to the implementation of the same solutions at a larger scale or in other regions. The observed results are subject to the technical specificities, the regulatory framework and the environmental and social context of the system itself and the location and time where the implementation is carried out. The assessment of scaling-up and replication requires a thorough analysis of the technical, regulatory and social boundary conditions to identify the relevant factors and evaluate the implications of their variation. This is precisely the main goal of the scalability and replicability analysis (SRA) as proposed in this thesis.

The EU has explicitly stressed the need to assess the scalability and replicability of smart grid solutions and projects in its strategic guidelines (European Electricity Grid Initiative, 2013b). Furthermore, the EU has launched several research projects (e.g.: GRID4EU[6], GRID+[7], iGREENGrid[8], evolvDSO[9], SUSTAINABLE[10]) with specific tasks devoted to (i) analyze the scalability and replicability of tested smart grid solutions, (ii) enable the scaling-up and replication of smart grid demonstration projects and (iii) develop the conceptual and methodological framework to achieve the previous two objectives. The author of this thesis has been involved in several of these projects, and the work of this PhD thesis aims to contribute precisely to these objectives.

In particular, this PhD thesis focuses on functionality-oriented SRA (as opposed to a solution-based SRA aimed at analyzing the scalability and replicability of smart grid technologies) to analyze the impacts of replication and upscaling of smart distribution grids in a European context (assuming that smart grid solutions are scalable and replicable). This thesis proposes a SRA methodology comprising a quantitative and detailed technical analysis based on simulation to compute the metrics (KPIs) that measure the impact of the enabled functionalities on the distribution system; and a second stage of a more qualitative non-technical analysis, to include regulatory aspects and the perspective of the different stakeholders involved. The outcome of SRA is a set of qualitative premises and conclusions, the so-called scaling-up and replication rules, which may be regarded as guidelines to help infer the outcome of implementing smart grid solutions.

The objectives of SRA are very ambitious and the proposed methodology is not exempt of barriers that can result in limitations in the obtained results. The proposed SRA is based on the use of simulation models, representative networks and generation and demand scenarios. Therefore, the validity and robustness of SRA results depends on the representativity and suitability of the representative networks and demand scenarios considered and the fitness of the simulation model(s) to quantify the selected KPIs. In order to ensure the quality of SRA, it is necessary to have enough data available to correctly characterize the distribution system. Furthermore, sensitivity analyses for the technical SRA cannot cover every single variation, parameter and scenario. Moreover, the validation of simulation models with demonstration projects, comparing the values registered for the KPIs to those obtained through simulation under the same conditions, is not straightforward, as demonstrations may not be able to reflect certain impacts.

---

[6] http://www.grid4eu.eu/

[7] http://www.gridplus.eu/

[8] http://www.igreengrid-fp7.eu/

[9] http://www.evolvdso.eu/

[10] http://www.sustainableproject.eu/

In spite of these difficulties, the proposed SRA provides very valuable insights to guide smart grid deployment towards the most promising smart grid solutions and use cases for different contexts and regions. Therefore, SRA is of great interest for policy-makers, to help shape the roadmap for the large-scale smart grid deployment, identifying favorable functionalities and applications for different regions (depending on the prevailing boundary conditions). SRA can also help guide funding of further R&D and demonstration smart grid projects, identifying conditions for testing. Moreover, SRA results can be of assistance for regulators to remove the identified barriers to smart grid implementations, and set adequate regulatory incentives that can facilitate the adoption of smart grid use cases and encourage investment on new solutions.

Furthermore, SRA is extremely relevant for the incumbent industry to guide their investment and shape their strategy for different smart grid solutions. SRA results enables cost-benefit analyses for large-scale smart grid deployment. CBA analyses can be carried out from the perspective of different investors, including DSOs, equipment manufacturers and vendors, software developers, as well as ICT and other service providers. Such analyses can help them understand the business case of investing in the implementation of different smart grid solution in different regions.

1.2 Scope and objectives of the thesis

The previous section has highlighted the importance of understanding the impact and implications of the context for the implementation of smart grid solutions, and the need to address explicitly and systematically the scalability and replicability of smart grid deployment.

The main objective of the proposed PhD thesis is to **develop a methodological framework to assess the scalability and replicability of smart grid use cases in distribution networks** to support policy making. This thesis proposes scalability and replicability analysis (SRA) to **analyze the effect of the technical, economic, regulatory and social conditions on the outcomes of smart grid deployment**.

In order to achieve this central objective, the following sub-objectives have been identified:

- <u>Provide a theoretical framework for scalability and replicability of smart grid solutions.</u>

  The proposed PhD thesis aims to provide a common framework that can serve as the theoretical basis to consider scaling-up and replication of smart grid implementations in an explicit and systematic manner and standardize the use of the language for the field of SRA of smart grid solutions.

- <u>Develop a methodology to perform a comprehensive scalability and replicability analysis (SRA) of the implementation of smart grid solutions in distribution networks</u>

  The methodology designed must be able to assess the effect of the parameters that comprise the boundary conditions of the implementation on the impact of the smart grid solutions under different contexts, i.e. in different locations and at a larger scale, incorporating technical, economic, social and regulatory aspects.

- Map smart grid solutions into smart grid use cases

  Smart grid solutions must be analyzed and classified into groups of smart grid use cases according to the objectives pursued and the types of outcomes of their implementation. The resulting categorization should be comprehensive to cover existing smart grid solutions and flexible to include future solutions in pursue of similar objectives.

- Particularize the designed SRA methodology for the identified smart grid use cases

  The SRA methodology must be able to assess smart grid use cases in detail. Therefore, SRA methodology will be particularized for each type of smart grid use case, identifying the appropriate metrics and simulation tools to measure the impacts of the smart grid, as well as the relevant aspects and boundary conditions.

- Apply the developed SRA methodology

  The SRA methodology developed will be applied step by step to a case study so that the results that can be obtained from scalability and replicability analysis of a smart grid use case are showcased.

1.3 Outline of the document

This document presents the work carried out to accomplish the objectives previously described, structured into seven chapters and an appendix.

Chapter 2 addresses the concept of the smart grid to propose a mapping of smart grid solutions into use cases aimed at specific objectives. This chapter presents an in-depth review of smart grid assessment, including both analytical approaches and pilot and demonstration activities, to understand the complementarity of both, which is the main strength of SRA.

Chapter 3 develops the conceptual and methodological framework for the scalability and replicability analysis of smart grid solutions. This chapter describes the methodology proposed for SRA, which is the main contribution of this PhD thesis. The methodology comprises two main stages, a technical analysis based on simulation, and a non-technical stage aimed at the analysis of regulation and stakeholders.

Chapter 4 presents the particularization of the SRA methodology proposed in chapter 3 for the groups of smart grid use cases identified in chapter 2, namely (i) network automation to improve continuity of supply, (ii) DER management and voltage control to increase network hosting capacity and (iii) islanded operation and microgrids to improve security of supply. The specificities of each group are described, appropriate metrics, scenarios and simulation tools are proposed and the relevant boundary conditions are identified.

Chapter 5 is devoted to representative networks, which constitute a key element in the SRA methodology proposed and developed in chapters 3 and 4. This chapter reviews existing approaches to develop sets of representative networks and defines the requirements for SRA of the three groups of smart grid use cases identified in chapter 4.

Chapter 6 presents the application of the proposed SRA methodology to the use case of MV network automation to improve continuity of supply. This chapter illustrates the step-by-step application of the methodology and showcases SRA results. Furthermore, SRA results are used as the input to conduct a cost-benefit analysis of this smart grid use case, both from a system perspective considering social welfare and from the point of view of the decision-making process of the incumbent investor, the distribution company.

Finally, chapter 7 summarizes the main proposals, conclusions and results obtained in this thesis. This chapter highlights the main contributions of this work and suggests paths for further research.

Appendix A presents a partial application of the proposed technical SRA to analyze the implementation of monitoring and advanced metering infrastructure to detect load unbalance in LV networks. The effect of load unbalance is studied in relation to the network hosting capacity for PV and EVs.

Please note that this document is intended as a comprehensive PhD thesis for its complete reading. However, in order to facilitate its use as a framework to guide SRA of smart grid use cases, the SRA implementation proposed for each of the families of use cases is described independently. Thus, the corresponding sections of chapter 4 (sections 4.2, 4.3 and 4.4) have been designed to support their stand-alone reading. These sections pick up the steps described in the general SRA methodology described in chapter 3, so that common issues are reiterated for the sake of clarity (i.e., the reader interested in a particular group of smart grid use cases would not need to read the general proposal to understand the particularized implementation for the group of interest). Furthermore, the illustration of SRA application for the case study of MV network automation in Spain and Italy in chapter 6 is also self-contained.

Chapter 2

Smart grids in the distribution network

This chapter addresses the concept of the smart grid and smart grid assessment, to understand the subject of the proposed SRA analysis. First, the definition and elements involved in the smart grid paradigm are presented in section 2.1. Then, the chapter focuses on the metrics and approaches for the assessment of smart grid solutions in section 2.2. Section 2.3 reviews pilot and demonstration activities around the world, while section 2.4 addresses smart grid modelling and simulation. Then, smart grid use cases that can be studied for SRA with similar approaches are grouped together for SRA. Section ***¡Error! No se encuentra el origen de la referencia.*** *presents the proposed mapping of smart grid solutions identifying three main categories of use cases according to the type of impacts caused and objectives pursued. Finally, section 2.6 presents the main conclusions of the chapter.*

2.1 The concept of the smart grid

In recent years, the term **smart grid** is being extensively used and there are many definitions available in the literature. Some definitions focus on the functionalities provided, some list the technological features and others are more benefit-oriented, but all of them converge in the idea of upgrading the existing network to efficiently integrate new available resources and users in the network. The concept of the smart grid involves an **evolution** of the electricity transmission and distribution system in all aspects: **upgrade of the infrastructure, addition of a digital layer, a change of paradigm in the business, and a more active participation of the users**.

2.1.1 Definition of the smart grid

In Europe, the European Technology Platform for Smart Grids developed the following definition of smart grid (European Technology Platform for SmartGrids, 2006), which has been adopted by the European Commission (EU Commission Task Force for Smart Grids, 2010), regulators (ERGEG European Regulators Group for Electricity & Gas, 2010) , the industry (Eurelectric, 2011) and standardization organizations (CEN/CENELEC/ETSI, 2011):

> *A **smart grid** is an electricity network that can intelligently integrate the actions of all users connected to it in order to efficiently deliver sustainable, economic and secure electricity supplies.*

In the USA, the National Institute of Standards and Technology (NIST) defines the smart grid as a modernized *grid that enables bidirectional flows of energy and uses two-way communication and control capabilities that will lead to an array of new functionalities and applications* (National Institute of Standards and Technology, 2012). According to the Electric Power Research Institute (EPRI) the term smart grid refers to the *modernization of the electricity delivery system so that it monitors, protects, and automatically optimizes the operation of its interconnected elements—from the central and distributed generator through the high-voltage transmission network and the distribution system, to industrial users and building automation systems, to energy storage installations, and to end-use consumers, and their thermostats, electric vehicles, appliances, and other household devices* (Electric Power Research Institute, 2011).

The smart grid paradigm covers all dimensions of electric power systems: the concept of the smart grid refers to the electric power grid, both the transmission and the distribution network, but smart consumers and smart regulation are key elements in the evolution towards a smarter electric power system (Cossent, 2013; Council of European Energy Regulators (CEER), 2014; I. Pérez-Arriaga et al., 2013). The traditional electric power system based on the unidirectional flow of energy from large generation to electricity consumers involved a *passive* distribution network. Therefore, the degree of visibility and controllability for the network operators has traditionally been much higher in transmission than in the distribution system[11]. The irruption of distributed energy resources with flexible generation and demand profiles has completely changed the picture for the distribution system, and therefore the distribution network needs to become smarter. Thus, although the term smart grid includes both transmission and distribution, this PhD thesis will refer mostly to the **smart distribution grid**.

The architecture of the smart grid is described by the Smart Grid Architecture Model (SGAM) (CEN/CENELEC/ETSI, 2012). The SGAM framework, depicted in Figure 2.1, includes different interoperability layers to represent the different entities and their relationships in the context of smart grid domains. As will be later explained, the scalability and replicability analysis focuses on the functional layer, to analyze the impact of implementing smart grid functionalities in the domain of the distribution system. It also includes the business layer to examine the effect of the regulatory framework, economic aspects and the perspectives of the different stakeholders involved. All of these aspects are interconnected, and the SRA aims to study the relationship among all the parameters.

[11] Automation has been in place in electric power grids for decades, starting at higher voltage levels. Supervision, control and data acquisition systems (SCADA) and substation automation were implemented in transmission networks already since the 70s (Linder, Baumgart, & Brock, 1979). However, due to the much larger number of assets affecting a much lower number of network users, distribution networks have traditionally had a much lower degree of automation, especially at lower voltage levels. Even though distribution automation was discussed already back in the 70s (Working Group on Distribution System Design, 1984), it has not been until recently that the deployment of network automation has become a subject for large-scale deployment at the medium and low voltage level.

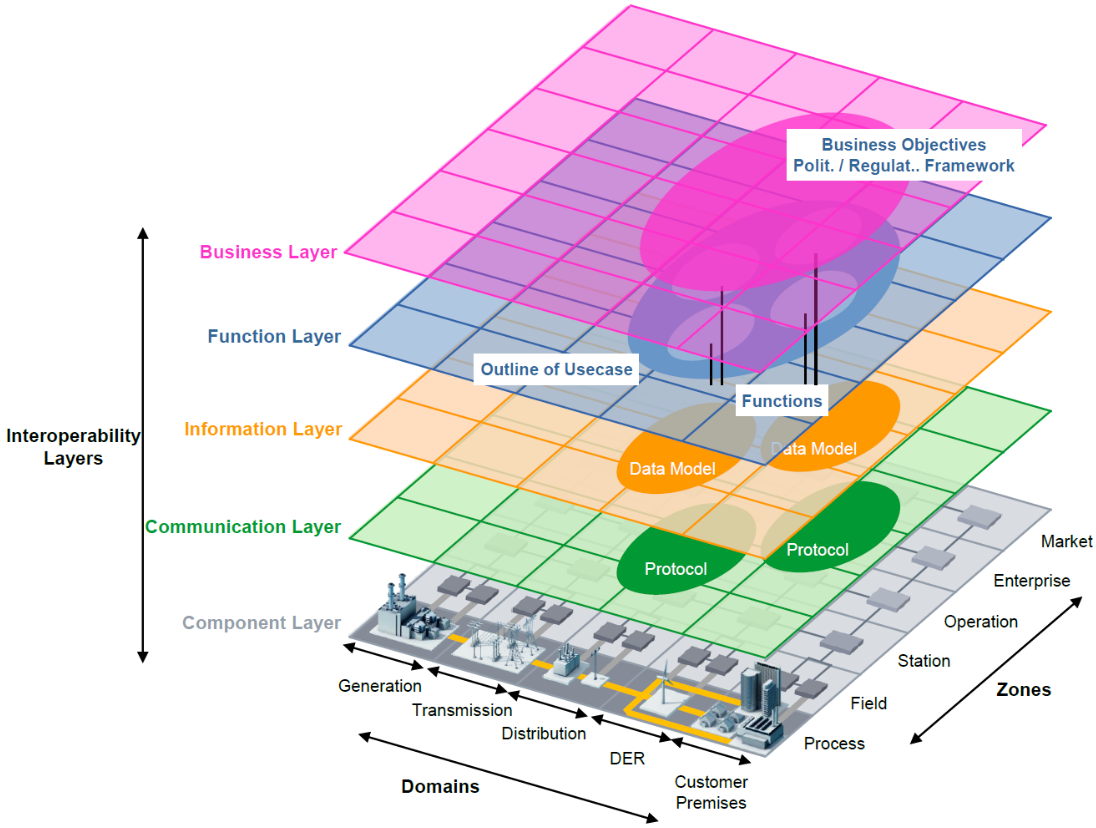


Figure 2.1: SGAM framework (CEN/CENELEC/ETSI, 2012).

The vision of the smart grid has become a very relevant element in the policy, strategy and R&D programs of countries across the world. In the European Union, the European Strategic Energy Technology Plan (SET Plan) has been created to establish an energy technology policy that will accelerate the development and deployment of cost-effective low carbon technologies to achieve the sustainability objectives set for 2020 and 2050 (European Commission, 2011), and smart grids have been identified as one of the technical priorities for these purposes (European Commission, 2007). The instruments provided by the SET Plan include the European Electricity Grid Initiative (EEGI), an industrial initiative that brings together the stakeholders involved in the transition towards smart grids in Europe. The EEGI has defined the technological roadmap and implementation plan (European Electricity Grid Initiative, 2010), updated in (European Electricity Grid Initiative, 2013a, 2013b) to guide European research and innovation (R&I). Additionally, the European Technology Platform for Smart Grids aims to provide strategic guidelines that can serve as an input for the EEGI (European Technology Platform for Smart Grids, 2010; European Technology Platform for SmartGrids, 2007), (European Technology Platform for SmartGrids, 2012).

In the context of smart grid projects, the terms ‘use case’ and ‘functionality’ are frequently used and must be clarified for a correct understanding. Smart grid solutions enable different functionalities to achieve certain objectives.

> *The concept of **functionality** or service refers to a capability added to the network operation thanks to the implementation of the smart grid solution.*

JRC provides a classification of 33 functionalities grouped into six categories (A-F), identifying the outcome, provider and main beneficiaries in the CBA guidelines (Joint Research Centre et al., 2012).

Smart grid demonstration projects consist on the implementation of smart grid solutions organized into use cases. In line with the Unified Modeling Language definition:

> *A **use case** represents a set of functional requirements that must be performed by the smart grid solution in pursue of different objectives.*

For instance, automation systems may increase monitoring of the grid and improve fault management in distribution networks so that continuity of supply is improved - the use case would be MV automation for reliability improvement.

2.1.2 Elements of the smart grid

The concept of the smart grid covers a wide range of technologies, solutions and functionalities. It is not an easy task to create a comprehensive categorization that can accommodate all the different smart grid elements and solutions available, since they are interconnected, so that some functionalities may be achieved by several solutions, some solutions may serve many different purposes, some solutions are complementary while others are alternative, etc. Thus, smart technologies are not independent; a truly smart grid integrates all the deployed solutions and functionalities to maximize the benefits.

Table 2.1 gathers the proposal of the JRC and the GridWise Alliance, two of the main reference organizations in Europe and the U.S. respectively. The JRC classifies smart grid projects into categories attending to the application. However, the criteria applied to determine the proposed categories seem not to be homogenous. For instance, the category 'integration of DER' represents an objective that can be achieved making use of different elements (storage, EVs, demand response, etc.), while the category 'Smart Metering' represents a certain type of smart grid equipment that can enable smart grid solutions such as demand response or network monitoring. Furthermore, some of the proposed categories appear to be overlapping, such as for instance 'integration of DER' and 'Electric Vehicles and Vehicle2Grid applications'. In turn, the GridWise Alliance in the U.S. proposes another categorization of Smart Grid projects, where smart grid elements (e.g.: smart grid transmission apparatus) and general objectives (e.g.: consumer integration into energy markets and grid operations) are mixed.

JRC (Europe)	GridWise (US)
• Smart Network Management • Integration of DER • Integration of large scale RES • Aggregation (Demand Response, VPP) • Smart Customer and Smart Home • Electric Vehicles and Vehicle2Grid applications • Smart Metering • Other (e.g. communication infrastructure, storage)	• Transmission apparatus with Smart Grid capabilities • Transmission monitoring, control, and optimization • Smart Grid Technologies focused on Renewables facilitation • Distribution Systems • Advanced Metering • Micro grids capable of high reliability/resiliency and islanded operation • Integration of Distribution Automation (DA), Feeder Automation (FA) • Consumer integration into energy markets and grid operations

Table 2.1: Categories of smart grid solutions.

Smart grid solutions and elements include smart meters and advanced metering infrastructure (AMI), smart appliances, battery energy storage systems, distributed generation (DG), electric vehicles and network automation. The smartness of these elements relies on their observability and controllability. The smart grid comprises measuring equipment that can acquire data; communications, so that the smart grid elements can exchange information; intelligence for data processing; algorithms that can evaluate different strategies for optimal operation; and telecontrol to remotely operate different elements.

Smart meters and other AMI infrastructure allow consumers to obtain information on their energy consumption. Together with the use of smart appliances, and automatic control systems for electric heating, heat pumps and other potentially flexible loads, these smart elements enable the active participation of consumers in demand response programs and load management through energy service companies and aggregators.

The term distributed energy resources (DER) includes distributed generation (PV, wind, biomass, CHP, mini-hydro, etc.), plug-in electric vehicles and storage systems. DER units can manage their active and reactive power injection into (or absorption from) the grid. The flexibility provided by the ability to manage demand from consumers and the output from DER can be used to optimize the operation of the distribution system, reducing peak demand, improving the voltage profile in the distribution lines to avoid voltage problems, reducing the loading of the lines and transformers to avoid congestions and overloads and reducing energy losses. These objectives are related to higher-level policy goals: achieving a more efficient asset management to improve efficiency; and improving network hosting capacity to facilitate higher shares of RES generation, thus improving sustainability by reducing CO_2 emissions.

Network automation enables remotely controlled fault detection, isolation and service restoration (FDIR) and network reconfiguration, thus further managing power flows in the networks, as previously explained, and enhancing the fault management process to improve continuity of supply. Additionally, DER management enables the possibility of islanded operation of sections of the distribution system as an alternative form of supply in emergency situations.

This thesis proposes a conceptual model or categorization of the items involved in the smart grid paradigm, as represented in Figure 2.2: different **smart grid elements** or components in combination with **smart grid enablers** implement new **functionalities** in the operation of the distribution system[12], which pursue different **objectives** that tackle the major **policy goals** of quality, efficiency and sustainability of the electric power system. The term 'enabler' has been selected to encompass those capabilities that are transversal for different functionalities of the smart grid.

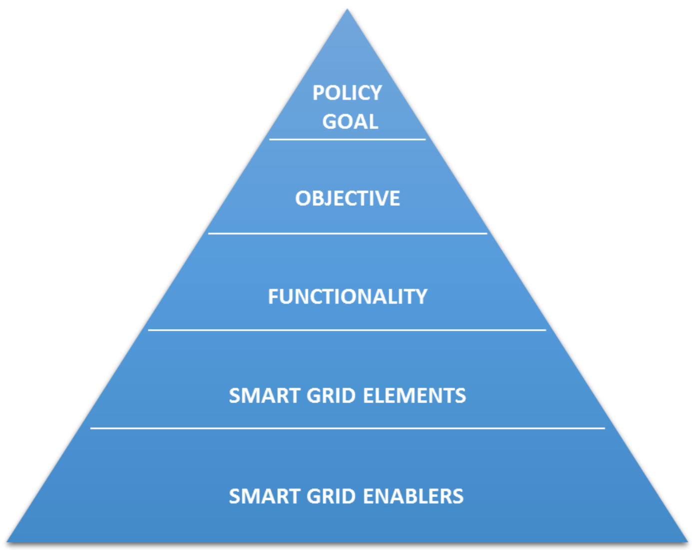


Figure 2.2: Categorization of conceptual items involved in the smart grid paradigm.

Table 2.2 lists the main elements of each smart grid conceptual item. The conceptual model proposed is able to fit all smart grid components and solutions, and will be used throughout this thesis to help understand smart grid projects and initiatives (reviewed in sections 2.3.2 and 2.4) and map them into smart grid use cases (section **¡Error! No se encuentra el origen de la referencia.**).

12 According to this conceptual model, a smart grid solution would be a system comprising different smart grid elements and enablers.

Policy goals	• Improve efficiency and postpone investment • Reduce CO_2 emissions increasing RES generation • Improve quality
Objectives	• Reduce energy losses • Reduce peak demand • Increase network hosting capacity • Improve continuity of supply
Functionalities	• DER management • Voltage control • FDIR • Network reconfiguration • Islanded operation • Smart metering • Demand response
Elements	• Distributed generation • Battery storage • Electric Vehicle • Network automation • Smart meters, AMI • Smart appliances
Enablers	• Communications • Intelligence (data processing, state estimation, forecasting, optimization) • Monitoring • Control

Table 2.2: Conceptual items involved in the smart grid paradigm.

Figure 2.3 presents an example: the smart grid offers the potential to reduce energy losses (objective), which results in a more efficient system (policy goal). Network automation (smart grid element) enables network reconfiguration (smart grid functionality) to reduce energy losses. DER can also be managed (smart grid functionality) to reduce overall network energy losses. Involved DER may include DG, EVs, storage and demand response of smart meter users (smart grid elements). In both cases, the strategy for reduction of losses must be determined by the DSO using information on the state of operation of the system (using data acquired from monitoring systems, applying state estimation algorithms to correct and complete the available information, or even using forecasts to estimate the expected state of the system in advance), and optimization together with information of available options for flexibility (enabling technologies).

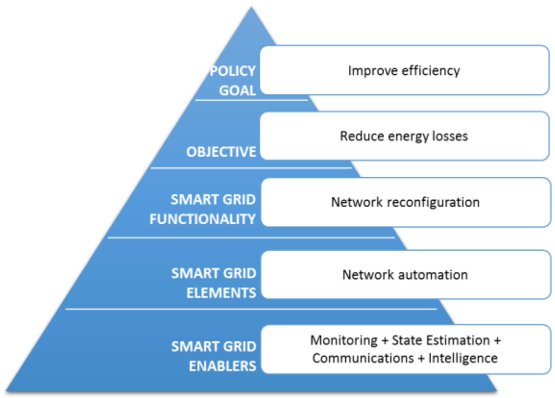


Figure 2.3: Example of smart grid conceptual items for the reduction of energy losses through network reconfiguration (left) and DER management (right).

The proposed PhD thesis is focused on smart grid use cases implemented in the distribution network, to infer the outcomes that may be expected from the implementation of smart grid solutions in relation to the objectives pursued. **Smart grid use cases** involve smart grid elements, and enablers, which are solutions and technologies that directly perform or indirectly enable a certain functionality aimed at a specific objective. Therefore, all the smart grid solutions and technologies involved will be analyzed together as a whole in this thesis and the main focus will be put on functionalities.

2.2 Assessing the impact of smart grids

The results that may be expected from the large-scale implementation of smart grids are still uncertain. Much work has been devoted and is still on-going to assess the impacts and potential benefits of different smart grid solutions and implementations. There are two main approaches for the assessment of the potential benefits and outcomes of smart grids: the use of **analytic models and simulation, and actual implementation of smart grid solutions in pilot projects and demonstrators (demos)**[13].

Testing smart grid solutions in pilot projects and demonstrators is essential to prove the actual functioning[14] and integration of the deployed technologies and provides real-life experience. However, the observed results are limited, since these are subject to the specific conditions of the demonstrator. For instance, pilot projects for demand response typically include consumers that

[13] Additionally, studies aimed at a more qualitative assessment often rely on surveys among experts, to characterize and understand the viewpoints of different stakeholders on specific topics. Such surveys may extract very valuable information from the perceptions or the experience of the respondents.

[14] The development of smart grid solutions involves different stages of testing. Before becoming commercial solutions, prototypes are built and tested first through hardware-in-the-loop and laboratory testing and then in pilot projects.

voluntarily take part into these initiatives, so that the sample is not very representative of the overall population. Furthermore, testing is very costly and is therefore of limited scale.

The use of analytic models and simulation allows for assessment of smart grid solutions under different conditions. The main drawback of simulation is the need for making assumptions and simplifications that may result in limited representativity of the models, inaccuracies and inability to take into account certain elements, producing results that are not fully realistic. Usually, improving the accuracy requires more complex simulation models, that are most costly to produce and to execute.

Actually, both approaches are complementary. The use of models and simulation can define and select the smart grid implementations to test in pilot projects and demonstrators, so that priority may be given to the most promising options. In turn, the results observed in real-life in pilot projects and demonstrators may be used to fine-tune and improve analytic formulae, models and simulation tools. This is precisely the objective of scalability and replicability analysis, so that results observed in real-life may be translated to a larger-scale and for different locations where the context (i.e. boundary conditions) differs.

In order to assess performance and impact of smart grid solutions in distribution networks, a set of metrics or indicators is required, so that results are available for comparison among different cases. The following sub-sections present the concept of Key Performance Indicators, which are commonly used in the context of smart grids, and how these can be used for the SRA of smart grid use cases.

2.2.1 Key Performance Indicators

The concept of Key Performance Indicators (KPIs), commonly used in management science[15], has been widely adopted and is currently in use across European smart grid R&I activities.

Key Performance Indicator (KPI)*: metric to assess the effectiveness of a solution to achieve the aimed objective.*

The work of the GRID+ project and the EEGI (GRID+ Project, 2013a) has set the reference for smart grids KPIs in Europe, providing a set of general KPIs and a methodology to specify KPIs to quantify the contribution of research and innovation (R&I) activities to the objectives of the EEGI roadmap. Actually, KPIs have been identified as a required tool for SRA to compare the impact of smart grids for different implementations and conditions. Two types of KPIs are defined: **Implementation Effectiveness KPIs** to measure the percentage of completion of the objectives and **Expected Impact KPIs** to assess achieved benefits comparing business-as-usual scenarios to R&I implementations. The

[15] The use of the term KPI dates back to the nineties. A first approach was the KPI manual developed by the Australian Government Department AusIndustry in 1995 (Australian Manufacturing Council, 1996). The use of KPIs has been widely adopted by companies and much work has been devoted to this topic (Parmenter, 2007).

latter may be subdivided into **Project KPIs** at project level, **Specific KPIs** at the level of clusters of projects and **Overarching KPIs** at a system level. The overarching and specific KPIs proposed by the EEGI are listed in Table 2.3. Project KPIs would be defined specifically for each project, so the EEGI does not provide a set or list.

EEGI Overarching KPIs
A.1 Increased network capacity at affordable cost.
A.2 Increased system flexibility at affordable cost.
EEGI Specific Objectives
B.1 Increased RES and DER hosting capacity.
B.2 Reduced energy curtailment of RES and DER.
B.3 Power quality and quality of supply.
B.4 Extended asset life time.
B.5 Increased flexibility from energy players.
B.6 Improved competitiveness of the electricity market.
B.7 Increased hosting capacity for electric vehicles (EVs) and other new loads.

Table 2.3: Key Performance Indicators proposed by (GRID+ Project, 2013a).

The EEGI document provides some guidelines to determine the relevant KPIs for different smart grid implementations and how to compute them. The EEGI states that KPIs must be meaningful, understandable and quantifiable. Furthermore, the relevant KPIs for smart grid projects should be established ex-ante, considering the expected outcomes of the project and implemented solutions and functionalities, and specifying baseline values and targets. This way, KPIs can be used to measure the improvement caused by a smart grid solution, comparing the values of certain parameters before the smart grid solution is implemented (baseline values) and after; or to measure the effectiveness of the implementation with respect to the aimed objectives (target values).

In the U.S., the key metrics that the DOE should use to monitor and assess smart grid projects have been defined by the GridWise Alliance in (KEMA for the GridWise Alliance, 2009) based on the objectives established in the American Recovery and Reinvestment Act of 2009. The proposed metrics are listed in Table 2.4. Additionally, the GridWise Alliance proposes to apply the Analytical Hierarchical Process (AHP), using a set of weights for the different metrics that take into account the relative importance perceived by different stakeholders for each objective. The work of (Bossart & Bean, 2011) reviews and summarizes these metrics and maps smart grid functionalities and energy resources to their expected impacts.

Economic Stimulus Effect
• Job creation • Impact on local economy: wages • Stimulation of a Smart Grid business ecosystem • Consumer savings and reduction of regulated electric rates and energy costs • Number or extent of new programs/services being offered • Number of existing smart grid implementations in the state
Energy Independence and Security
• DG: additional capacity for accommodating peak MW & energy from renewables and % of DG that can be sensed and controlled • PHEV: # of PHEV and # PHEV providing V2G services • Demand response management: # customers and peak MW participating, peak reduction in MW and MWh, market price impact and % improvement in losses • System Efficiency: $ and % improvement in costs • Greenhouse gas emissions reduction per MWh and customer • Power System reliability impacts: SAIDI improvement, reduced restoration time, reduction in major outages and improvement in Loss of Load Probability • Amount of distribution and substation automation in project: Increase in IED penetration integrated to SA and control systems and # / % of feeders and stations to be automated
Integration and Interoperability
• Fulfilment of state energy assurance plan • Integration with state/local energy efficiency and conservation programs • Plans for measurement of customer participation and adoption • Interoperability of smart grid technologies • Use of Open Protocols: # of IEDs and controllable apparatus using open protocols and compliance to Security needs
Business Plan Robustness
• Encouragement of direct consumer participation: attractiveness of customer value proposition and open protocols and open business model to 3rd party products / services • Completeness of technology plan and maturity of chosen technologies • Outcome of cost-benefit analysis which includes qualitative factors such as benefits to society • Plans for interim reporting on progress • Implementation plan: assess per FAR, risks - cost, schedule

Table 2.4: List of metrics for the objectives set in the ARRA 2009 (KEMA for the GridWise Alliance, 2009).

The authors of (Dupont, Meeus, & Belmans, 2010) propose a set of KPIs based on the six characteristics of the smart grid determined by the U.S. Department of Energy (DOE) (U.S. Department of Energy Electricity Delivery and Energy Reliability, 2009) and adapted to the European context. These KPIs are quantitative and specific and follow the SMART criteria as proposed by (Shahin & Mahbod,

2007) that states that KPIs must be specific, measurable, attainable, relevant and timely. Table 2.5 contains the proposed KPIs.

Economic Stimulus Effect	
Advanced Meters	1A: Number of advanced meters installed 1B: Percentage of total demand served by advanced meters
Dynamic Pricing	2A: The fraction of customers served by RTP tariffs 2B: The fraction of load served by RTP tariffs
Smart Appliances	3A: Total yearly retail sales volume for purchases of smart appliances [€] 3B: Total load capacity potentially modified through smart appliances [MW]
DSM	4A: Fraction of consumers contributing in DSM [%] 4B: Percentage of consumer load capacity participating in DSM [MW/MW] 4C: Potential for time shift (before start-up and during operation) [h]
Prosumer	5A: Energy locally produced versus energy consumed [MWh/MWh] 5B: Minimal demand from grid (maximal own production) versus maximal demand from the grid (own production is zero) [MW/MW] 5C: Fraction of time prosumer is net producer and consumer [h/h]
Accommodate all generation and storage options	
DG and Storage	6A: Amount of production generated by distributed generation (MW/MW) 6B: Potential for energy storage relative to daily demand [MWh/MWh] 6C: Indirect storage through the use of heat pumps: time shift allowed [h]
PHEVs	7A: Number and % of on-road light-duty vehicles, comprising PHEVs 7B: Percentage of the charging capacity that can be controlled [MW/MW] 7C: Share of stored energy in PHEVs that can be controlled [MWh/MWh] 7D: Number of charging points that are provided to charge the vehicles
DER Interconnection	8A: The percentage of DSOs with standard DER interconnection policies
Sell more than KWhs	
New Energy Services	9A: Number of customers served by ESCO's 9B: Number of additional energy services offered to the consumer9C: Energy savings for the consumer [kWh]
Flexibility	10A: The number of customers offering flexibility to aggregators 10B: The flexibility that aggregators can offer to other market players [MWh] 10C: The time that aggregators can offer a certain flexibility [h] 10D: Ability of storage a DG to provide ancillary services vs total offered [%] 10E: Share of storage and DG that can be modified [MW/MW]
Customer Choice	11A: Number of tariff plans available to end consumers

Support Mechanisms	12A: Smart grid investment that can be recovered by rates/subsidies [%] 12B: The percentage of smart grid investment covered by external financing
Interoperability Maturity Level	13A: The weighted average maturity level of interoperability realized among electricity system stakeholders
Provide power quality for the 21st Century	
Power Quality	14A: Amount of voltage variations in the grid [RMS] 14B: Time of a certain voltage variation [h] 1 4C: Percentage of customer complaints related to power quality problems
Required Power Quality	15A: Range of frequencies [Hz] contracted and range of voltages [V] contracted
Microgrids	16A: The number of microgrids in operation 16B: The capacity of microgrids [MW] 16C: Grid capacity of microgrids versus capacity of the entire grid [MW/MW]
Optimize assets and operate efficiently	
T&D Automation	17A: Percentage of substations applying automation technologies
Dynamic Line Rating	18A: Number of lines operated under dynamic line ratings18B: Transmission circuits operated under dynamic line ratings [km] 18C: Yearly average transmission transfer capacity expansion due to the use of dynamic (versus fixed) line ratings [MW-km]
Capacity Factors	19A: Yearly average and peak generation capacity factor (%)19B: Capacity factor for transmission lines (%-km per km) 19C: Yearly average peak distribution transformer capacity factor (%)
Efficiencies	20A: Generation facilities [energy output (MWh) / energy input (MWh)] 20B: Energy losses in transmission and distribution [MWh/year]
Operate resiliently to disturbances, attacks and natural disasters	
Advanced Sensors	21A: Number (%) of grid elements (substations, switches, …) that can be remotely monitored and controlled in real-time 21B: % of substations possessing advanced measurement technology 21C: Number of applications supported by measurement technologies
Information Exchange	22A: Total SCADA points shared per substation (ratio) 22B: Synchrophasor measurement points shared multilaterally (%) 22C: Performance (bandwidth, response speed, availability, adaptability, …) of the communication channels towards grid elements
T&D Reliability	23A: SAIDI (average duration of customers interrupted each year) [Minutes] 23B: SAIFI (average number of customer interruptions) [Interruptions] 23C: CAIDI (average outage duration per customer) [Minutes] 23D: MAIFI (average number of short interruptions) [Interruptions]

Telecomm. standards	24A: Compliance with European and international telecommunication standards and protocols.

Table 2.5: Key Performance Indicators proposed by (Dupont et al., 2010).

Further work that can be found in the literature includes the proposal of (Arnold, Rui, & Wellssow, 2011) where the importance of establishing clear grid performance targets to measure the "smartness" of solutions is highlighted as a prerequisite for any CBA. The authors postulate that metrics should assess performance considering the perspective of all stakeholders and propose a three-level hierarchical set of metrics. Metrics should be calibrated identifying minimum and maximum values for extreme scenarios. Finally, any given solution would be assessed through a score for the corresponding metrics represented in a spider diagram. Other works in the literature that have explicitly addressed the subject of KPIs for smart grids include (Personal, Guerrero, Garcia, Peña, & Leon, 2014), where KPIs are categorized for different audiences according to the level of technical detail and applied for the Smartcity project in Malaga, the work of (Andrea Bonfiglio, Procopio, Delfino, Invernizzi, & Denegri, 2013) for voltage control in distribution networks and (A. Bonfiglio et al., 2013) to consider distribution, transmission and their interaction.

Although the different proposals reviewed are formulated at different levels and include different KPIs and metrics, all of them include economic considerations (e.g.: economic impact, job creation, affordability, required investment, asset lifetime), integration of RES and DER (e.g.: greenhouse gas emissions reduction, flexibility, DG production maximization), quality of supply (e.g.: continuity of supply, resilience) and competitiveness (e.g.: customer choice, interoperability). Different proposals may include hierarchical levels of KPIs, such as the proposal of the EEGI. KPIs may be technical, economic or social, and quantitative or qualitative (but measurable).

2.2.2 Key Performance Indicators for Scalability and Replicability Analysis

This thesis is focused on the assessment of the potential for the scaling-up and replication of smart grid use cases, to help infer the expected outcomes of deploying smart grid solutions at a large-scale in different locations and conditions. Therefore, measuring the impact of smart grid implementations is of paramount importance, and KPIs are essential for SRA. The SRA of a smart grid use case will require a set of KPIs that can quantify the performance of the smart grid implementation to fulfil the pursued objective, and a set of KPIs to measure different impacts of the implemented functionalities on the operation of the distribution system. Thus, two types of KPIs are defined for SRA, as proposed by the GRID+ project and the EEGI (see section 2.2.1) but under a slightly different approach: **Objective KPIs** and **Intermediate KPIs**.

Objective KPIs will be used to assess fulfilment of the pursued objectives. For instance, islanded operation a section of the distribution network to operate as a microgrid based on the management of DG or storage provides an alternative to maintain electricity supply in the event of supply interruption cause by upstream faults or problems. The use of islanded operation to improve continuity of supply will be measured through objective KPIs such as the volume of non-served energy avoided. **Intermediate KPIs** will be used to evaluate other impacts of the smart grid implementation. Intermediate KPIs will be based on parameters that are relevant to accomplish the objective, but do not directly measure whether the objective is accomplished. Intermediate KPIs are necessary to enable comparing the performance of different implementations under different boundary conditions. Taking the previous example, islanded operation can only successfully supply the demand if stable operation can be sustained after disconnecting from the grid, which requires generation and demand to be balanced maintaining frequency and voltage deviations within allowed limits. Therefore, adequate intermediate KPIs would be voltage and frequency deviations, since these are very important parameters to monitor and compare when assessing the probability of success of different cases of islanded operation.

The appropriate KPIs for the SRA of a smart grid use case are determined based on the objective pursued by the smart grid implementation, considering the type of impacts that may be expected from the implemented functionalities. Different smart grid solutions may pursue the same objective, implementing functionalities that can be analyzed following a similar approach. Therefore, the same KPIs could be used. A mapping that groups smart grid solutions into use cases with the same objectives and types of impacts can facilitate the selection of KPIs. Furthermore, using the same KPIs allows comparing different smart grid solutions for different conditions.

SRA is based on the use of KPIs, and selecting the adequate set of KPIs is an important step of the SRA methodology proposed in this thesis and described in chapter 3. Furthermore, according to the mapping of smart grid use cases developed later in this chapter (section **¡Error! No se encuentra el origen de la referencia.**), the SRA methodology is particularized in chapter 4, and the KPIs proposed for each group of smart grid use cases is discussed. Moreover, the case study presented in chapter 6 illustrates the detailed application of the SRA.

2.3 Practical experience on smart grids: demonstration and pilot projects

Available smart grid technologies and solutions have been tested on the field in pilot projects and demonstration projects to observe their behavior in real-life implementations. This section describes the characteristics of smart grid pilot projects and provides an outlook on the current status of smart grid demonstration.

Smart grid implementations in pilot projects and demos are subject to the technical specificities, the regulatory framework and the environmental and social context of the system itself and the location and time where the implementation is carried out. These aspects are comprised within the so-called **boundary conditions** of the implementation. Thus, the impacts of the smart grid use case and results observed in the demo are linked to the boundary conditions. The scaling-up and replication of the observed results will require an exhaustive analysis of the parameters that constitute the boundary conditions.

2.3.1 Design of pilot projects

Smart grid pilots are vital to provide real-life experience for the performance of the tested solutions and the adoption of implemented innovations by the targeted consumers. Often, on-field implementations and interaction with external elements and agents bring out issues that had not been planned.

The authors of (Faruqui, Hledik, & Sergici, 2009) highlight the importance of piloting innovative solutions with an unclear business case. Their work focuses on pilot projects testing dynamic pricing and response of the demand and list some principles for pilot design. These principles include different baseline and reference elements (control group) to establish comparisons before and after the implemented solution, as well as under different conditions. Furthermore, the authors insist on the size and representativity of the testing, which in the case of dynamic pricing is translated into a sufficient amount and participating consumers, selected accordingly to the envisioned large-scale application (e.g.: random for universal solutions), categorization by their socio-demographic characteristics to extract conclusions, and a long duration of the pilot project in time.

The World Economic Forum launched a Smart Grid project and published a report entitled Accelerating Successful Smart Grid Pilots (World Economic Forum & Accenture, 2010). This work stresses the importance and the need for pilot projects for smart grids and discusses important aspects regarding the design of pilot projects and the lessons that may be extracted from them.

According to this report, pilot projects should be divided into sequential, yet iterative, phases examining technology, operating models and business models. The objectives, test parameters and hypotheses to prove should be clearly specified and documented, both in the design of the pilot and throughout the testing phases.

This work classifies pilot smart grid experiences into grid-centered and consumer-centered solutions, and highlights the additional challenges posed by consumer acceptance and behavioral change. Pilot projects play a critical role to secure the long-term acceptance and engagement of consumers.

Pilot projects give the industry the opportunity to test new business models, identify the needs for training and re-skilling of their personnel and create commercial multidisciplinary consortia. Moreover, observed performance and results of pilot projects can guide the design of the next wave of pilots and can help regulators and policy-makers understand the need for changes in the regulatory frameworks to align incentives and encourage private-sector investment.

Pilots should adopt emerging best practices in relation to interoperability and standards to facilitate the upscaling of tested implementations. As innovative technologies, operating models and business models are tried and tested, pilots are risky exercises and as such should remain flexible, so that they can adapt effectively in response to unexpected challenges, and should also be given, as the World

Economic Forum puts it, "permission to fail". Often, unsuccessful steps provide valuable insights on how to overcome difficulties and barriers, and some solutions are bound to be less promising than others under different circumstances. Regulatory frameworks that impose unrealistic outcomes for funded R&D projects may discourage innovation.

Most importantly, as learning experiences, capturing relevant data, sharing and exchanging knowledge and extracting valuable lessons learned is of paramount importance. However, commercial interests and concerns over intellectual property from participating companies may be in conflict with these objectives. Typically, funding entities (national regulatory authorities, public institutions, etc.) set the obligation of knowledge sharing as a prerequisite for supported pilot projects. The World Economic Forum advocates for the systematization of data gathering from pilot projects around the world into a central clearinghouse using common metrics, normalization and benchmarks to improve knowledge sharing, avoid overlapping of demonstrations and enable comparison and learning from similar pilot projects carried out elsewhere. However, the potential for knowledge-sharing from pilot projects is not fully exploited. There are indeed initiatives to map smart grid demonstration project from funding institutions, such as the EC or NRAs, and other international organizations, as reviewed in the following sub-section. By building the framework for scalability and replicability analysis of smart grid use cases, this thesis aims to contribute so that such systematization, benchmarking and learning from pilot projects can be realized.

2.3.2 Review of demonstration projects

In the last years, a vast amount of research and demonstration projects have been carried out to test different smart grid solutions around the world. There is no single inventory of all smart grid project, but some of the most prominent mapping initiatives around the world are reviewed in the ensuing.

The need to evaluate the outcomes of these projects and share experiences and lessons learned was highlighted in a joint report by the EC JRC and the US DOE (Giordano & Bossart, 2012). This report described the main drivers for smart grid developments in the EU and the US and reviewed smart grid projects carried out in the EU and US.

Europe

JRC has elaborated the most comprehensive database of smart grid demonstrators and pilot projects in Europe. This work is periodically presented in a series of reports that provide a detailed analysis of the status of smart grids in Europe (Covrig et al., 2014; Giordano et al., 2013; Giordano, Gangale, Fulli, & Sánchez-Jiménez, 2011), and in the form of an updated interactive map of the projects[16].

Around 460 smart grid projects are listed and classified according to their maturity, scale, scope, budget and objectives. The JRC monitors the funding sources (private or public funding from the

---

16 http://ses.jrc.ec.europa.eu/smart-grid-projects-europe

European Commission, regulatory, national, etc.) and participants in the projects (country, organization type and role in the project), as well as the main characteristics of the implementation: location, tested applications, targeted consumers and social impact. The diagram of Figure 2.4 summarizes the smart grid projects and related elements listed in the inventory.

Figure 2.4: Summary of smart grid projects in Europe listed in the 2014 JRC inventory. Source: (Covrig et al., 2014).

Smart grid projects are labeled according to their maturity stage as research and development (R&D) projects and demonstration and deployment (D&D) projects. The report points out that at first, sporadic research activity was recorded (2002-05). Then, activities in smart grid projects increased dramatically from 2006 onward and investment has been increasing consistently, as can be observed in Figure 2.5. Over the years, the size of the projects has increased[17], moving towards a higher share of D&D projects, which require larger investment.

[17] The share of projects with budgets over €20 million grew from 27 % in 2006 to 61 % in 2012.

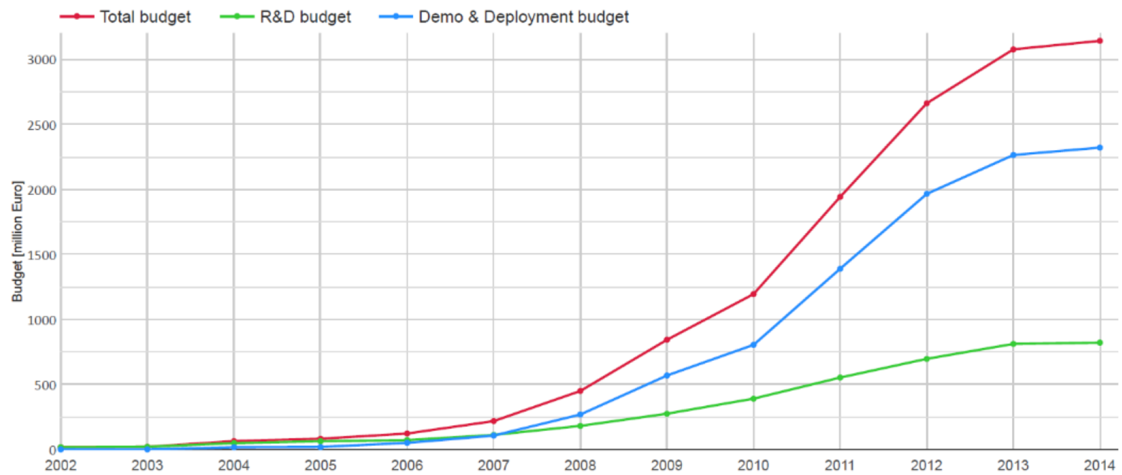


Figure 2.5: Accumulated budget of smart grid R&D and D&D projects per year. Source: JRC[18].

Most projects have received some public funding, around 55% of the total budget for the smart grid projects comes from public funding, mostly from the EC and national research programs, and the remaining 45% from private capital. DSOs are actively participating and leading these projects, together with university, research centers, manufacturers and IT/Telecom companies. TSOs, aggregators, consumers and other associations are also involved, but in a more limited manner. The distribution per countries is illustrated in the map of Figure 1.6.

[18] JRC Smart Electricity Systems and Interoperability http://ses.jrc.ec.europa.eu/european-smart-grid-projects-number-and-budget-evolution (accessed March 2017).

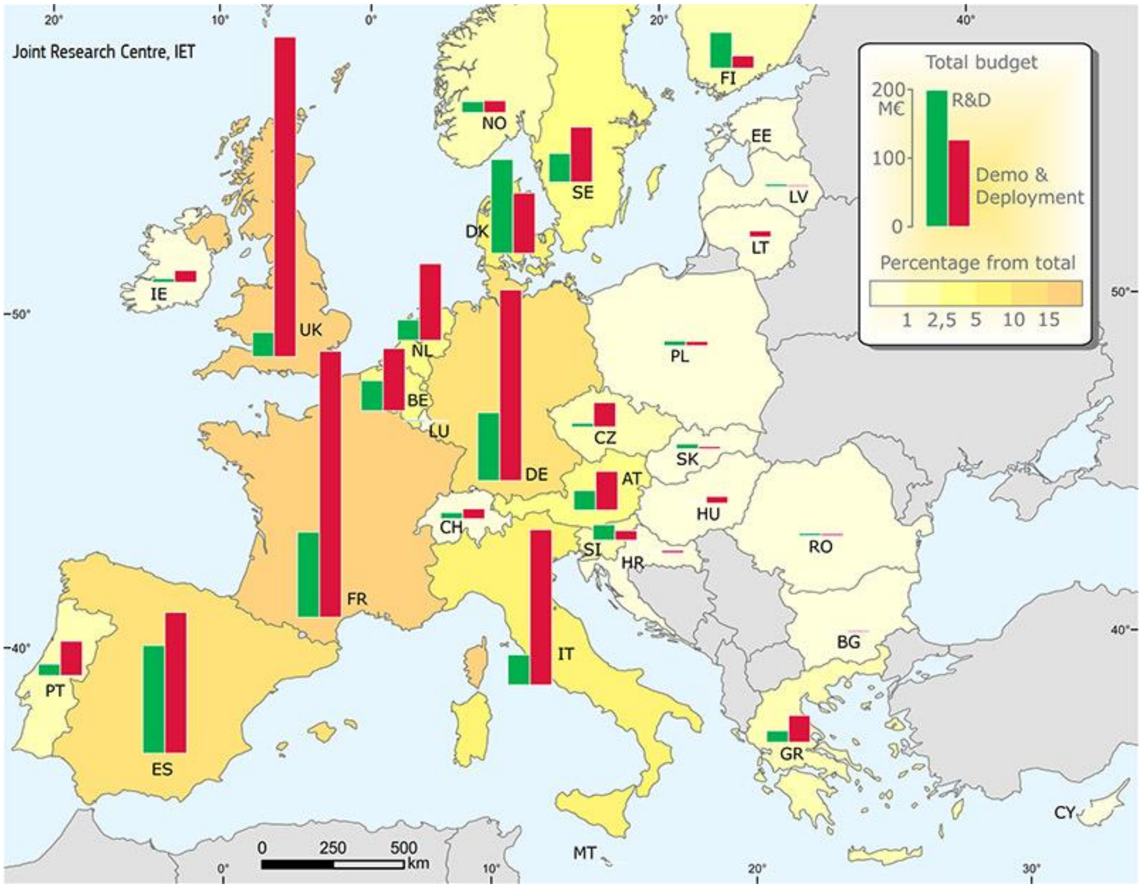


Figure 2.6: Budget of smart grid R&D and D&D projects per country. Source: (Covrig et al., 2014).

The smart grid projects listed in this catalogue include a wide range of smart grid solutions. The authors have established a classification of smart grid applications into the following categories: smart network management, integration of large-scale RES, integration of DER, aggregation, smart customers and smart home, electric vehicles and Vehicle2Grid applications, smart metering and other. Figure 2.7 shows the budget that has been devoted for R&D and D&D projects of each type.

Smart metering, often separately addressed, is already at the implementation stage in most European countries[19]. By 2020, around 200 million smart meters in Europe are expected to be deployed, covering about 72 % of EU customers, with an estimated investment of €35 billion.

[19] 16 Member States (AT, DK, EE, FI, FR, GR, IE, IT, LU, MT, NL, PL, RO, ES, SE and UK) have either planned or already deployed nation-wide smart metering; 3 Member States (DE, LV and SK) are opting for selective smart metering roll-outs. 4 Member States (BE, CZ, LT and PT) decided currently not to proceed with nation-wide smart metering deployment.

Smart network management and smart customer are the most targeted applications. Smart grid solutions aimed at improving the observability and controllability of electricity networks have been grouped together under the first category. Smart network management applications are the most consolidated and widespread and there is a large number of projects focusing on distributed ICT architectures for coordinating distributed resources and providing demand and supply flexibility. Projects incorporating storage are increasing, mostly to provide additional grid flexibility.

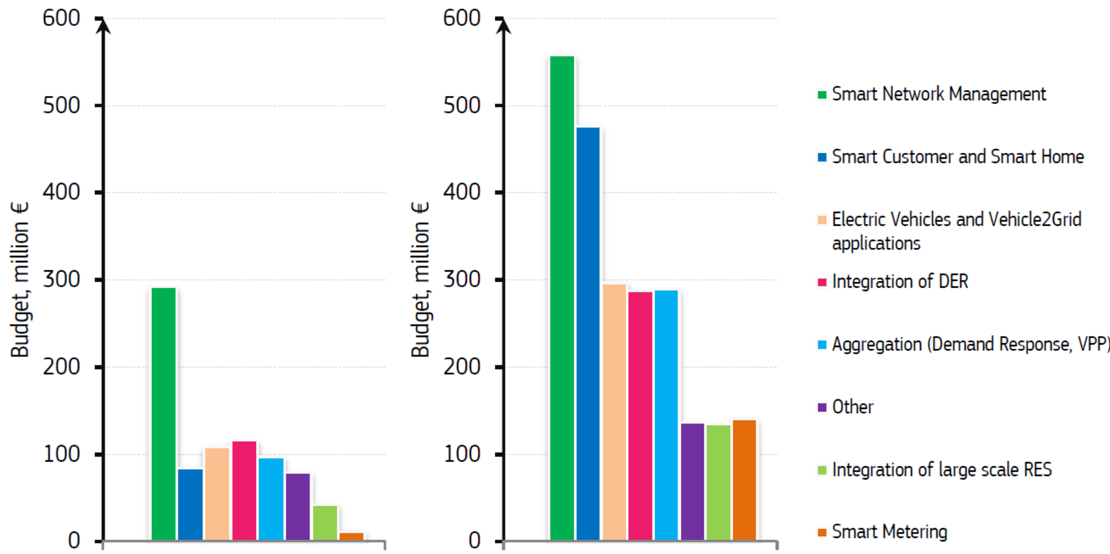


Figure 2.7: Budget of smart grid R&D (left) and D&D (right) projects per type of application. Source: (Covrig et al., 2014).

This exercise of monitoring smart grid projects in Europe has highlighted the need for improving knowledge sharing. Project partners are often reluctant to share negative results and lessons learned and unwilling to reveal data due to confidentiality issues. Furthermore, public information regarding the projects is often fragmented and inconsistent.

In general, smart grid projects have reported that the main obstacles and challenges are mostly at the social and regulatory levels, rather than technical. Consumer participation is quite limited in size (typically up to 2000 customers) and volunteer-based, and therefore not representative of actual consumers.

United States

The US Congress allocated €4.5 billion to the DOE in 2009 through the American Recovery and Reinvestment Act (ARRA) to promote the modernization of the US electricity system through several programs, including the Smart Grid Investment Grant (SGIG) and the Smart Grid Demonstration projects (SGDP).

The Smart Grid Investment Grant (SGIG) is aimed at the deployment of smart grid technologies, tools, and techniques to improve grid performance and provided financial support to 99 projects, categorized into the following groups:

- Customer systems:
  This category includes smart appliances and equipment, energy management systems, distributed energy systems, demand response and load control equipment, energy storage devices, plug-in electric vehicles, and microgrids.
- Electric distribution systems:
  This category includes distribution automation systems; supervisory control and data acquisition (SCADA) systems; distribution monitoring, control, and optimization systems; load control systems for lowering peak demand; and electric distribution applications of distributed generation and energy storage equipment.
- Electric transmission systems:
  Several projects added smart grid functions to equipment in the transmission system mainly based on phasor measurement units, phasor data concentrators, wide area communications networks, and advanced transmission applications to enhance monitoring. Additionally, dynamic line rating systems have also been deployed.
- Advanced metering infrastructure (AMI):
  Several projects deployed AMI systems for residential, commercial, and industrial consumers, and a subset of SGIG projects conducted studies to evaluate customer behavior.
- Equipment manufacturing:
  This category groups projects where equipment, devices, software, or communications and control systems were designed and produced to enable smart grid functions.

With a federal investment of $3.4 billion, the total investment on SGIG projects amounts to $8 billion. The chart in Figure 2.8 displays the number of projects of each category (projects tackling several of these aspects have been labelled cross-cutting projects) and the corresponding total investment.

Figure 2.8: Number of Smart Grid Investment Grant projects and total investment per type. Source: smartgrid.gov[20].

[20] https://www.smartgrid.gov/recovery_act/overview/smart_grid_investment_grant_program.html (accessed in March 2017)

The Smart Grid Demonstration projects (SGDP) comprises Smart Grid Regional Demonstrations, large-scale demonstration projects to verify the viability, quantify the costs and benefits, and validate new business of the smart grid deployment, and Energy Storage Demonstrations to evaluate different storage technologies to provide grid support. In this case, the federal investment added up to $600 million, and the total investment was $1.6 billion. Figure 2.9 shows the share of projects of each category and the corresponding total investment.

Figure 2.9: Number of Smart Grid Demonstration Program projects and total investment per type. Source: smartgrid.gov[21]

India

In India, the main drivers for the SG are reportedly to improve reliability, reduce losses and achieve a 100% electrification (Ministry of Power - Government of India, 2013). The public-private partnership Indian Smart Grid Forum (ISGF) has been established to bring together stakeholders and advise the Ministry of Power on the development of the smart grid in India. The Government has approved the National Smart Grid Mission (NSGM) to support the planning, monitoring and implementation of policies and programs related to Smart Grid activities with a budgetary support of 3.38 billion INR. There are currently 14 smart grid pilot projects under implementation, as shown in the map in Figure 2.10. These projects are mostly focused in the improvement of reliability through outage management and peak load management, as well as on the deployment of advanced metering infrastructure (see Figure 2.11, where the number of smart grid projects addressing each functionality defined by the NSGM is shown). Other tested smart grid functionalities include distributed generation in the form of PV, and a more ambitious project will test the concepts of microgrid, smart city and smart home.

[21] https://www.smartgrid.gov/recovery_act/overview/smart_grid_demonstration_program.html

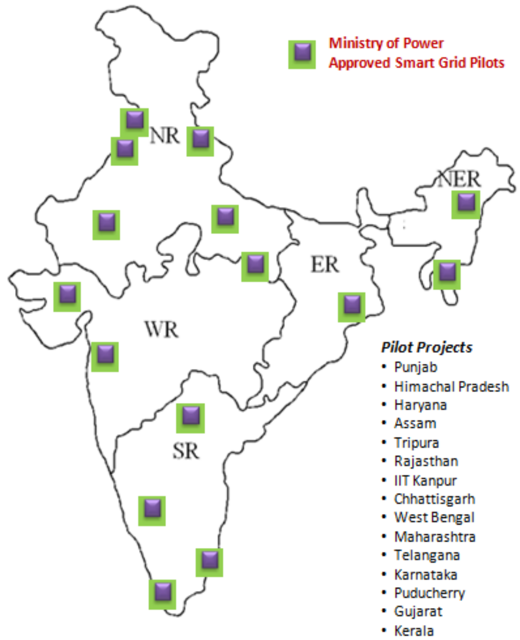


Figure 2.10: Smart grid projects currently under implementation in India. Source: National Smart Grid Mission, Ministry of Power, Government of India[22].

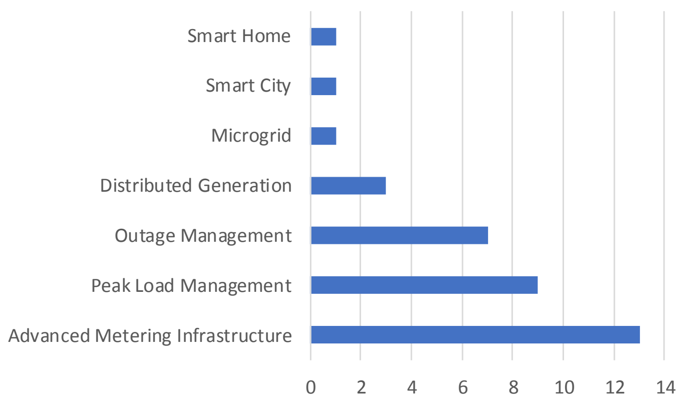


Figure 2.11: Smart grid functionalities addressed in the 14 on-going smart grid projects in India.

Members of ISGAN (several countries)

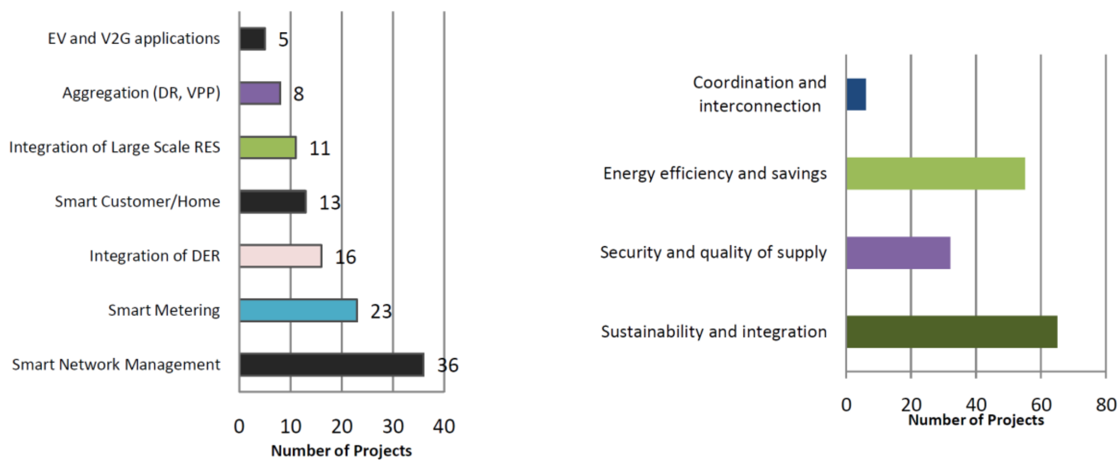
The International Smart Grid Action Network (ISGAN)[23] carried out a survey to identify the main drivers for smart grids in different countries (P. Wang, 2014) and has catalogued 108 smart grid projects

[22] http://www.nsgm.gov.in/content/sg_snapshot.php

[23] The International Smart Grid Action Network (ISGAN) was established in 2011 as the International Energy Agency (IEA) Implementing Agreement for a Co-operative Programme on Smart Grids. ISGAN is currently comprised by 25 countries (Australia, Austria, Belgium, Canada, China, Denmark, European Commission, Finland, France,

according to the main functionality implemented (P. Wang, 2013a) and to their contribution to policy goals (P. Wang, 2013b).

The report (P. Wang, 2014) compared the most relevant drivers and the technologies ranked as most promising to accomplish the main objectives according to the economic development of the responding countries to highlight that developing countries are more interested in improving reliability and achieving in economic savings; while developed countries tend to be more focused on economic efficiency and developing new business opportunities.



a b

Figure 2.12: Smart grid projects catalogued by ISGAN by main application (a) and policy goal heading (b). Source: (P. Wang, 2013a, 2013b)

Summary

Smart grid demonstration projects around the world have focused on testing different solutions to efficiently integrate new DG and EVs in the distribution networks to optimize the flexibility that the DER connected to the network can provide to the system, including DG forecasting, active participation of DG in voltage control, management of storage and EV charging and demand response. Moreover, network management solutions have been tested, increasing monitoring and control capabilities to improve reliability and quality of supply, tackling operation (voltage control) and maintenance (fault management) strategies, and helping the integration of DER as well. Additionally, smart grid solutions have also been tested at the consumer side, including the

Germany, India, Ireland, Italy, Japan, Korea, Mexico, Norway, the Netherlands, Russia, Singapore, Spain, South Africa, Sweden, Switzerland, and the United States).

deployment of smart metering, AMI, and home automation systems, as well as time-of-use tariffs and other economic incentives to empower the consumer and activate demand response.

The mapping efforts of institutions like JRC and ISGAN are very helpful to bring together available information on smart grid projects. Furthermore, public funding institutions like the DOE in USA or the EC in Europe set common requirements for dissemination of project results and outcomes. However, there is no common reference KPIs or metrics and there are limitations in the publication of project data and lessons learned, so demonstration projects are not easily comparable.

Clearly, a huge volume of investment has already been devoted to smart grid demonstration projects around the world. Up to 2015, over €3.15 billion and $9.7 billion have been reportedly invested in smart grid demonstration projects in the European Union (EU) and the USA respectively (Covrig et al., 2014; U.S. Department of Energy Electricity Delivery and Energy Reliability, 2012). The trend is increasing for investment in larger-scale projects and an increased number of tested functionalities at each demonstration site.

Real-life testing and demonstration is a necessary step to ensure that smart grid solutions can actually be implemented in the real world and observe its performance under different conditions. However, pilot projects are very costly and limited to a certain set of conditions. Simulation and scalability and replicability analyses help reduce the required investments. Scalability and replicability analysis of smart grid implementations can maximize the learning potential from demonstration projects, extracting very valuable lessons to identify the most promising solutions and most favorable conditions for deployment of smart grid use cases and help infer the expected outcomes of large-scale deployment. Furthermore, SRA can guide the design of future research investment and further demonstration projects (to decide new demo locations, which solutions to test, etc.) to assess smart grid solutions in different real-life conditions.

2.4 Modeling the impact of smart grids

Much work has been devoted to evaluate the potential and impacts of the integration of smart grid technologies and solutions under different scenarios. Numerous analytical and modelling approaches may be found in the literature, as well as uncountable case studies based on different simulation models and scenarios. As previously introduced, analytic approaches based on modelling and simulation are complementary to pilot and demonstration projects. Furthermore, simulation is essential in order to be able to extrapolate project results for larger-scale deployment (Electric Power Research Institute, 2010) and may be the only way to account for different situations and model critical scenarios (World Economic Forum & Accenture, 2010). Unavoidably, the quality of simulations is driven by the quality of the data available.

Since smart grids cover a wide range of solutions, there are numerous studies and analyses available in the literature where the impacts and benefits of different technologies, systems and solutions are analyzed. The main research lines and references have been reviewed and are presented in this section.

2.4.1 Distributed generation and distributed energy resources

Under the current context of increasing degrees of penetration of DG and other DER, much work has been devoted to analyze the impact of DER in the operation and planning of distribution networks, as well as to propose and assess different strategies for the integration and management of DER. Furthermore, the different elements comprised in the concept of DER are often analyzed separately.

(Alarcon-Rodriguez, Ault, & Galloway, 2010), (Georgilakis & Hatziargyriou, 2013) and (Keane et al., 2013) provide an extensive review of the different approaches proposed in the literature for DER planning. The reviewed references formulate optimization problems for siting and/or sizing of different DER technologies, minimizing losses and/or total cost for different stakeholders, including in some cases environmental benefits or reliability improvement explicitly. The authors state that active management of DER is a key aspect for the optimal integration of DER, however it can be concluded that most references still do not include the possibility of DER management in their analyses. Active management is now becoming the focus of interest for research. For instance, in (Ochoa & Harrison, 2011) the optimization of sitting and operation of DG is carried out for time-varying generation and demand scenarios and a smart voltage control system with active participation of DG is included. Moreover, (Keane et al., 2013) provides some references on operational optimization of DG which explore the provision of ancillary services such as reserve and reactive power by DG.

The impact of DG on distribution has been studied for different scenarios and from many different perspectives, considering diverse aspects of the distribution system, such as energy losses, voltage profiles, operation costs and power quality. The authors of (Cossent, Olmos, Gomez, Mateo, & Frias, 2010) analyze the impact of DG on distribution costs for different management strategies using a reference network model for distribution networks of different countries. A very different approach is presented in the dynamic analysis is carried out in (Srivastava, Kumar, & Schulz, 2012) to assess the effect of DG, with and without storage, on transient stability.

2.4.2 Storage technologies and electric vehicles

Storage technologies offer a great potential, providing flexibility to distribution systems. Therefore, this type of DER has been analyzed for many different uses, isolated and also to enable the integration of other not so flexible DER elements, such as DG. The report prepared by the SANDIA Laboratories (SANDIA National Laboratories et al., 2013) provides an extensive review of available storage technologies and benefits that may be obtained from their connection to distribution and transmission networks for different uses, taking into account the different agents and dimensions of the electric power system. Furthermore, this report provides a framework to analyze the impact of storage based on addressing how storage can help solve different problems. (Beaudin, Zareipour, Schellenberglabe, & Rosehart, 2010) also provides a comprehensive revision of storage systems for different uses and cites batteries as most suitable to maintain power quality and stability in the presence of distributed generation based on renewable sources. (Pudjianto, Aunedi, Djapic, & Strbac, 2014) proposes a whole-system approach to assess system costs using storage connected at different voltage levels as an alternative to network reinforcement. The use of storage located in secondary substations to reduce peak demand and thus reduce network reinforcement requirements has also been studied by (C. Mateo et al., 2015; Carlos Mateo, Sánchez, Frías, Rodriguez-Calvo, & Reneses, 2016) using a reference network model (Mateo Domingo, Gomez San Roman, Sanchez-Miralles, Peco Gonzalez, & Candela Martinez, 2011). (Divya & Østergaard, 2009) discusses energy storage battery systems and methods to assess the technical and economic impact on the system, as well as the role of batteries in EVs, providing yet a different review of references that assess stability, reliability improvement and economic analysis, both from the perspective of utilities and consumers.

Actually, plug-in EVs use batteries, but they are often addressed separately. Their effect on distribution depends on whether only charging is allowed, so that it may be regarded as a flexible load, or vehicle-to-grid applications are also available, so that EVs can be regarded as an additional form of storage. References (Clement-Nyns, Haesen, & Driesen, 2010) and (Sortomme, Hindi, MacPherson, & Venkata, 2011) analyzed the technical impact of EVs, including voltage profiles and losses, to compare different charging strategies for test distribution networks, based on load flow analysis. The authors of (Pieltain Fernandez, Gomez San Roman, Cossent, Mateo Domingo, & Frias, 2011) analyze the impact of EVs on distribution investment costs and energy losses for actual distribution networks based on a technical analysis performed using a reference network model (Mateo Domingo et al., 2011).

2.4.3 Demand response

Finally, under the paradigm of the smart grid, demand takes an active role through demand-side management programs. Active consumers may be regarded as another type of DER that can provide flexibility to the distribution system. The impact of demand shifting and peak shaving on operation and system costs is analyzed in (Dietrich, Latorre, Olmos, & Ramos, 2012) using a unit-commitment model. The authors of (Conejo, Morales, & Baringo, 2010) have developed a model of demand response for a dynamic pricing scheme and the impact on the total energy cost for consumers is analyzed. From the point of view of the distribution system, the work of (Vallés, Reneses, Frías, & Mateo, 2016) quantifies using a reference network model the potential economic savings on network reinforcements achieved through the activation of demand response to decrease peak demand.

2.4.4 Network management and microgrids

Smart grid implementations for network management can improve power quality, and most specifically, continuity of supply. The impact of automated MV/LV transformers on reliability is assessed in (A.S. Bouhouras, Andreou, Labridis, & Bakirtzis, 2010), (Kazemi, Lehtonen, & Fotuhi-Firuzabad, 2012) and (Rodriguez-Calvo, Frias, et al., 2012). The first reference assesses the costs and benefits of implementing this smart grid solution based on the impact of automatic reconfiguration on the number and duration of supply interruptions. The authors of (Rodriguez-Calvo, Frias, et al., 2012) present a similar technical analysis, but includes a sensitivity analysis to the main parameters involved, which would be helpful to analyze the replicability potential of this type of smart grid implementation. (Kazemi et al., 2012) presents the analysis of fault detection schemes on distribution networks based on the use of a simulation model.

Micro grids and islanded operation implementations make use of the same smart grid technologies of the previous two categories, making use of different DER (Hatziargyriou, Asano, Iravani, & Marnay, 2007), (Ravichandran, Malysz, Sirouspour, & Emadi, 2013). In the literature, islanded operation has been regarded as a solution to restore supply in certain areas through reconfiguration during permanent faults affecting supply in larger areas (Brocco, 2013), to supply demand that is isolated from the network in islands or in rural isolated areas as an alternative to network expansion (Palma-Behnke, Reyes, & Jimenez-Estevez, 2012).

The analysis of micro grids that may be found in the literature include DER management and network management within the island or micro grid. (Ahn & Peng, 2013) proposes a voltage control strategy to minimize losses within the micro grid. An economic assessment of smart systems for islanded operation is presented in (L. Sigrist, Lobato, Rouco, Gazzino, & Cantu, 2017), where renewable generation, storage, DSM and EVs are considered in a centralized hourly unit commitment carried out on a weekly basis to minimize system operation costs. The authors of (Conti, Rizzo, El-Saadany, Essam, & Atwa, 2014) assess the effect of islanded operation on reliability making use of tele controlled switches, considering fault rates of automation. Dynamic analysis is the most distinctive aspect of micro grids. (J.-Y. Kim et al., 2010) assesses stability in terms of frequency and voltage with simulation models and presents the results observed on a pilot implementation.

2.4.5 Summary of modeling approaches

While the review carried out in the previous subsections is not completely exhaustive, it aims to provide an overview of the approaches proposed to assess different aspects of smart grids. Table 2.6 summarizes the modelling and simulation approaches adopted in the literature for the technical and economic assessment of smart grid solutions and applications, indicating the evaluated impacts.

A first trend in smart grid research was devoted to the assess the impacts of increasing degrees of DG and EV penetration. Then, an extended body of work has been aimed at the optimal location and sizing of DER connected in distribution networks, considering DG, storage, EVs, devices based on power electronics for voltage control, etc. An alternative large collection of research works focus on quantifying the potential benefits or carry out cost-benefit analyses for smart grid solutions, including managing the flexibility provided by DER (demand response, smart charging of EVs, active participation of DG and storage for different purposes, etc.).

Smart grid solution	Objective of assessment	Approach and tools / techniques	Authors
DG siting and power factor	Minimize energy losses	Multiperiod load flow analysis	(Ochoa & Harrison, 2011)
Storage and DG	Assess transient stability	Dynamic analysis	(Srivastava et al., 2012)
Storage	Reinforcement of distribution and interconnections, use of storage	System model, system cost optimization, representative networks, load flow	(Pudjianto et al., 2014)
EV	Voltage profile and energy losses	Load flow analysis	(Clement-Nyns et al., 2010), (Sortomme et al., 2011)
EV	Energy losses Distribution investment costs	Reference Network Model	(Pieltain Fernandez et al., 2011)
Demand response	Operation costs	Unit commitment model	(Dietrich et al., 2012)
Demand response	Cost for consumers	Dynamic demand profile	(Conejo et al., 2010)
Smart transformer substation	Improvement of continuity of supply	Reliability assessment based on analytic computation	(A.S. Bouhouras et al., 2010) (Rodriguez-Calvo, Frias, et al., 2012)
Fault Diagnosis	Improvement of continuity of supply	Reliability assessment based on simulation of fault management	(Kazemi et al., 2012)
Micro grid	Voltage control, energy losses	Load flow analysis	(Ahn & Peng, 2013)
Micro grid and automation	Reliability	Simulation	(Conti et al., 2014)
Micro grid	Stability	Simulation	(J.-Y. Kim et al., 2010)
Storage, RES, EV, DSM for an islanded system	Operation costs	Unit commitment model	(L. Sigrist et al., 2017)

Table 2.6: Summary of literature review of impact assessment of SG solutions.

Different approaches are proposed, depending on the type of outcome aimed by the analysis. It can be concluded that reliability assessment is the most important analysis to evaluate smart grid solutions focused on islanded operation of the grid, fault management and network diagnosis and automation. Solutions based on demand response, EVs, DG and storage are assessed through different loadflow analyses to determine the investment and operation cost reductions, evaluating losses, reinforcement requirements to accommodate demand and DER, etc. Additionally, stability and dynamic analyses become relevant for microgrids and islanded systems.

2.5 Mapping smart grid solutions for SRA: identification of smart grid use cases

The smart grid demonstration projects reviewed in section 2.3.2 and research work focused on modelling and simulation reviewed in section 2.4 have shown that there is a wide variety of smart grid solutions and many different approaches for their assessment.

Smart grid solutions to perform different functionalities result in different impacts for the planning and operation of the distribution system and for the users of the network. The assessment of the expected impacts must adapt to this reality accordingly. For instance, the evaluation of storage is usually based on loadflow analyses to assess the impact on peak demand and energy losses (Pudjianto et al., 2014) and network planning models to quantify the savings on distribution investment cost due to peak demand reduction (Carlos Mateo et al., 2016). However, these approaches would not be applicable to automation of secondary substations or self-healing systems, which are typically analyzed through simulation focused on reliability assessment (Kazemi et al., 2012; Rodriguez-Calvo, Cossent, & Frías, 2016). By contrast, the effect of demand response on peak shaving and distribution costs can be assessed through a similar approach to the case of storage (Dietrich et al., 2012; Vallés et al., 2016).

As described in section 2.3.2, the JRC grouped smart grid demonstration projects into categories based on the main smart grid components, such as network management solutions, DER, EVs, or smart metering. Meanwhile, the SGIG projects were categorized into groups based on the "side of the system" involved, differentiating customer systems, AMI, distribution systems and transmission systems.

This thesis aims to develop a methodological SRA framework applicable to assess all kinds of smart grid implementations based on KPIs that can quantify the impacts of enabled functionalities for the distribution system. In order to establish guidelines to assess the different types of impacts of smart grid solutions, the SRA methodology must be particularized according to the different types of impacts and objectives of different smart grid solutions.

This PhD thesis proposes to group smart grid solutions into three categories of smart grid use cases for SRA to determine the KPIs to assess their impact on distribution systems: (i) network automation to improve continuity of supply; (ii) DER management and voltage control to increase network hosting capacity; and (iii) islanded operation and microgrids to improve continuity of supply. The smart grid solutions implemented in the reviewed demonstration projects may be mapped into these three groups of use cases according to the pursued objectives, the type of implemented functionalities and the smart grid elements involved.

According to the smart grid conceptual model proposed in section 2.1.2, the policy goals and objectives addressed, as well as the functionalities, smart grid elements and enablers involved in the three types of smart grid use cases are listed in Table 2.7.

	Network automation to improve continuity of supply	**DER management and voltage control to increase network hosting capacity**	**Islanded operation and microgrids to improve continuity of supply**
Policy goals	• Improve quality of service	• Improve efficiency and postpone investment • Reduce CO_2 emissions increasing RES generation	• Improve quality of service
Objectives	• Improve continuity of supply	• Reduce energy losses • Reduce peak demand • Increase network hosting capacity	• Improve continuity of supply
Functionalities	• FDIR • Network reconfiguration	• DER management • Voltage control • Network reconfiguration • Smart metering • Demand response	• DER management • Voltage control • Islanded operation • Demand response
Elements	• Network automation • Smart meters, AMI	• Distributed generation • Battery storage • Electric Vehicle • Network automation • Smart meters, AMI • Smart appliances	• Distributed generation • Battery storage • Network automation • Smart meters, AMI
Enablers	• Communications • Intelligence (data processing, state estimation) • Monitoring • Control	• Communications • Intelligence (data processing, state estimation, forecasting, optimization) • Monitoring • Control	• Communications • Intelligence (data processing, state estimation, forecasting, optimization) • Monitoring • Control

Table 2.7: Mapping of conceptual smart grid items to the identified smart grid use cases

2.5.1 Network automation to improve continuity of supply

The smart grid use cases that aim to improve continuity of supply focusing on the fault management process of fault detection, isolation and service restoration (FDIR) have been grouped in this category. The smart grid solutions involved are generally designated network automation and include: (i) adding monitoring to detect and locate the fault; (ii) remote control of protection elements (switchgear) to enable switching that can help reconfiguration of distribution networks to restore supply in healthy sections of the grid; and (iii) coordination between monitoring and telecontrol of switchgear to remotely operate the network and thus locate faults.

Monitoring of the distribution networks for such use cases is realized through different measuring equipment with communication capabilities, which may include fault-pass detectors and other sensors. The information registered by advanced metering infrastructure (AMI) and smart meters may be used as well to detect supply interruptions and register affected network users.

Furthermore, the available information must be processed and integrated in a control algorithm able to plan the switching and reconfiguration maneuvers required for automatic FDIR. The validity of proposed network configurations for service restoration must be previously assessed by the control algorithm through state estimation to ensure that no technical constraints are violated.

2.5.2 DER management and voltage control to increase network hosting capacity

This category groups together smart grid solutions based on the flexibility of the generation and demand profiles and network reconfiguration to achieve a more efficient operation of the distribution system.

This flexibility may be managed to modify the net demand curve and perform voltage control. This way, voltage problems (undervoltages and overvoltages) and overloading of lines and transformers may be avoided or mitigated. Furthermore, peak demand and network energy losses may be reduced. On the one hand, the distribution network is able to accommodate higher shares of distributed generation, which may result in an increase of energy supplied from renewable energy sources (RES). On the other hand, network reinforcement requirements may be reduced and the corresponding network investment may be deferred in time.

This group of smart grid solutions includes DER management. The term DER includes all network users connected to the distribution networks, so that DG units, plug-in electric vehicles, batteries and active demand response fall under this category.

DG can actively participate in voltage control. Depending on their technical characteristics, DG units may modify the reactive power output to help lower (or raise) the voltage in the network in the case of overvoltages during periods of low demand and high DG generation (or in the case of undervoltages in the opposite situation). Furthermore, the active power output of DG could also be modified in emergency mode to avoid a sustained overload that may trip part of the network.

Electric vehicles may also provide flexibility in their charging profile. The mobility patterns of EV users usually leave room for such flexibility since, typically, EVs are connected to the grid for periods longer than the time required to charge. For instance, EV users may connect their EVs when arriving home after work for the whole night, so that the charging process may be postponed to later hours, when demand is lower, as long as the EV is charged in the morning by the time the user leaves home for work. Similarly, EV users may charge their EVs at work, connecting the vehicle to the grid during a long period, with the requirement of having the EV charged at a certain time. Moreover, EVs may feature the so-called vehicle-to-grid (V2G) capability, which allows these EVs to not only take power from the grid to charge their batteries, but also to inject energy into the grid while connected, allowing even more flexibility.

Energy storage battery systems may be used to absorb (or inject) energy when the network is overloaded due to very high DG production (or to very high demand); to absorb (or inject) active power when overvoltages (or undervoltages) arise; or even modify the reactive power output to support voltage control. Energy storage battery systems may be owned by DG owners to store excess of energy produced, leaving room for flexibility to support distribution operation (e.g.: PV owners). Other users may use batteries to benefit from the different price of energy during peak demand and low demand periods (storing energy when prices are lower and injecting to the grid during peak demand), thus already performing peak shaving, and could therefore further benefit from active participation in voltage control and congestion management. Alternatively, and depending on the regulation, DSOs may own and operate energy storage battery systems precisely to optimize the operation of the system.

Demand response is based on the ability of consumers to shift their demand, for instance in the case of electric heating, heat pumps, air conditioning systems and other heating systems with thermal inertia. Other potentially flexible loads include smart appliances, such as programmable washing machines, dishwashers or dryers.

Network automation enables remote reconfiguration of the network. This smart grid functionality provides the DSO with an additional source of flexibility to manage and optimize operation of the network, by transferring a share of the load (or generation) from one feeder to a less loaded (or more loaded) feeder.

These smart grid use cases must be integrated into the DSO operation strategy. The DSO must analyze the current and expected state of the distribution system to determine the optimal operation strategy, making use of the available resources for voltage control, network reconfiguration and required flexibility from DER. Therefore, monitoring, state estimation, optimal power flow algorithms and forecasting are necessary tools for these use cases. In order to enable the active participation of DER, communications must be established with the DER owners. In the case of consumers engaged in demand response, smart meters will be essential.

Although voltage control specifically targets voltage quality[24], these smart grid use cases are based on the integration and active participation of DER and network reconfiguration in voltage control.

[24] Quality of electricity supply is usually characterized by three properties, namely, continuity of supply, voltage quality and commercial quality (Rivier & Gomez, 2000).

Therefore, rather than improving quality, these use cases are mostly aimed at improving the network hosting capacity to integrate more RES and reducing network losses and reinforcement requirements to improve efficiency.

All of these smart grid use cases have been grouped together because all of them result in the modification of the power flows in the distribution network and can be therefore studied together, using a similar simulation approach based on load flow analysis, as will be later explained.

2.5.3 Islanded operation and microgrids to improve continuity of supply

The disconnection of a section of the distribution grid from the upstream grid and its islanded operation as a so-called microgrid, offers an alternative to ensure supply when there is a fault that impedes electricity supply from upstream (even after fault management and reconfiguration). Therefore, the main objective and addressed policy goal coincides with the previous category grouping network automation use cases.

Islanded operation is enabled by the existence of network users or elements able to provide the energy to supply the demand of the islanded system. Therefore, islanded operation relies on DER management. Generation and demand must be perfectly balanced within the islanded system, which may be facilitated by if different DER elements can provide flexibility to the operation of the network.

Islanded operation use cases involve the same smart grid elements of the two previous categories. On the one hand, the disconnection from and reconnection to the grid of the island (or microgrid) must be controlled and protection and switching elements should be coordinated with the fault management and control system of the upstream network. On the other hand, DER must be managed to enable voltage control. However, these use cases have been grouped into an additional, separate category because in islanded operation, stability becomes a critical issue at the distribution level. Voltage and frequency control become very relevant, and the assessment of these solutions must resort to dynamic analyses monitoring the transient response of the system during disconnection and connection of the microgrid to the upstream grid.

2.5.4 Interaction among the identified groups of use cases

The proposed categorization is aimed for SRA to understand how smart grid implementations can achieve certain objectives under different conditions (in a different location or at a larger scale). The proposed mapping of smart grid solutions into three types of use cases will help develop a particularized SRA methodology in chapter 4, identifying the adequate KPIs and the appropriate modelling and simulation approaches to obtain their values. Furthermore, the particularization of the SRA methodology will help identify the relevant technical, regulatory and stakeholder-related boundary conditions.

It must be noted however, that these three groups of smart grid use cases are not completely independent, there are overlapping solutions and functionalities.

- Different DER management strategies can be performed to facilitate islanded operation. Islanded operation relies on a control system and distributed supplying resources that may be battery storage systems and/or DG. Further DER can be integrated to facilitate successful balance between generation and demand, including other DG, other storage units, demand response lead by the DER owners or a third-party (aggregator, supplier, or other energy service company).
- DER management and islanded operation strategies may be incorporated in the fault management process to improve continuity of supply. During the process of service restoration, demand response and management of distributed storage and EV charging could help reduce the demand in the section to restore and thus facilitate restoring service through an alternative configuration avoiding voltage problems or overloading of sections of the network now assuming the load of the restored section. Besides, the disconnection of sections of the network for islanded operation could be an alternative for service restoration when supply cannot be achieved through reconfiguration (for instance in the case of radial networks with no meshing).
- Network automation solutions enable remote reconfiguration of the network. This functionality may be performed to restore service and thus improve continuity of supply (first group of use cases); or to optimize operation of the network reducing energy losses to improve efficiency or avoiding voltage problems and overloading to improve network hosting capacity (second group of use cases). Furthermore, islanded operation is achieved through the disconnection from the grid, usually enabled by a remote-controlled switch.

2.6 Conclusions

This chapter addresses smart grid implementations in distribution networks to frame the subject of this thesis. As a result, three types of smart grid use cases have been identified to group smart grid solutions according to the pursued objective and type of impacts expected, so that the scalability and replicability analysis proposed in this PhD can be performed to understand how smart grids can achieve the objectives under different conditions (in a different location or at a larger scale).

This chapter has defined the concepts involved in the **smart grid**. The smart grid responds to the need for a passive distribution network and aging infrastructure to adapt to a new situation driven by policy targets for carbon reduction and technological advances that have resulted in the increasing presence of distributed energy resources (distributed generation, electric vehicles, active demand, and distributed storage). The smart grid paradigm involves the upgrade of the infrastructure, addition of a digital layer, a change of paradigm in the business, and a more active participation of the users. Smart grid projects consist on the deployment of smart grid solutions comprising different smart grid **elements** and **enablers** to perform new **functionalities**. These implementations can be organized into **use cases**, i.e. functional requirements performed by the smart grid solution in pursue of different **objectives**.

Smart grid solutions offer a great potential, and much work and strong investment have been devoted to assess the potential outcomes of their deployment based on (i) the use of **analytic models and simulation**, and (ii) the actual implementation of smart grid solutions in **demonstration and pilot projects**. Testing smart grid solutions in pilot projects and demonstrators provides real-life experience, but the results are limited, since it is subject to the specific conditions of the demonstrator. Furthermore, testing is very costly and is therefore of limited scale. The use of analytic models and simulation allows for assessment of smart grid solutions under different conditions. However, the models may be limited by required assumptions and simplifications leading to inaccurate results. The **SRA** proposed in this thesis explores the complementarity of both approaches and maximizes the learning potential from demonstration. The results observed in pilot projects and demonstrators are used to validate simulation results and simulation is used to evaluate the effect of different boundary conditions, so that results observed in real-life may be translated to a larger-scale and for different locations where the context differs. SRA can therefore help reduce the required investments on demonstration projects, guiding the design of future research and demonstration projects to decide the best conditions and solutions to be tested. This thesis proposes to use **objective KPIs** to assess fulfilment of the pursued objectives and **intermediate KPIs** to evaluate other impacts of the smart grid implementation.

As a result from the review of demonstration projects and modelling approaches to assess the impact of different smart grid solutions, this thesis proposes to group smart grid use cases into three main categories for SRA, based on the type of impacts caused and objective pursued: **(i) network automation to improve continuity of supply, (ii) DER management and voltage control to increase network hosting capacity, and (iii) islanded operation and micro grids to improve continuity of supply.** This thesis aims to develop a methodological SRA framework applicable to assess all smart grid implementations. For this purpose, chapter 3 presents a general SRA methodology with common guidelines to assess the different types of impacts of smart grid solutions. Then, the SRA methodology is particularized in chapter 4 for the three groups of smart grid use cases identified so that the analysis can be adapted to the different types of impacts expected and objectives pursued. The adequate KPIs for SRA are defined according to these categories.

Chapter 3

Methodology for scalability and replicability analysis

The main objective of this thesis is to provide the conceptual and methodological framework to analyze the scalability and replicability of the implementation of smart grid solutions in the distribution grid. The analysis must account for all relevant aspects, including technical and economic boundary conditions, regulation, and the behavior and interaction of involved stakeholders.

First, the main concepts related to scalability and replicability are defined and existing and potential approaches to assess scalability and replicability of smart grids are reviewed in section 3.1. Then, the proposal of this thesis is presented: section 3.2 explains the objectives and scope of the proposed SRA, while section 3.3 provides an overview of the proposed SRA methodology. The two main stages of the SRA methodology are subsequently described: section 3.4 portrays the technical SRA while non-technical SRA is addressed by section 3.5. To finalize this chapter, conclusions are presented in section 3.6.

3.1 Scalability and replicability

This section defines the main concepts related to scalability and replicability and reviews the existing approaches to assess the scalability and replicability of smart grids. Thus, this section provides the foundations to build the proposed methodology for the scalability and replicability analysis of smart grid solutions.

3.1.1 Main concepts regarding scalability and replicability

> *The **scalability** of a system may be defined as its ability to increase in size, scope or range, whereas the **replicability** of a system refers to the ability to be duplicated in another location or time.*

As explained in (GRID+ Project, 2012), the ability of a system to be scaled-up and replicated does not necessarily mean that it performs well. A more restrictive definition of scalability and replicability would include the ability of the system to maintain its (relative) performance and properties.

In case of simple systems, the relationship between the dimensions of the physical systems and the outputs can be analytically described through equations. Therefore, the variation of certain parameters can be directly translated into a specific variation of the outcomes, that is, scaling laws exist. However, in complex systems implemented in the real-world, the outcomes depend on many different elements and parameters that are interrelated, as well as on the behavior and interaction of different agents. Therefore, there are no equations that can determine the upscaling of outcomes.

The concepts of scalability and replicability have been addressed in other fields of knowledge, such as environmental governance (Padt, Opdam, Polman, & Termeer, 2014), development (Hartmann, Linn, & Wolfensohn Center for Development, 2008; United Nations Development Programme, 2013) and universal access to energy (United Nations, 2006), or with a more technological scope, for issues such as sensors (Sridhar & Madni, 2009), information and communications technologies (ITCs) (Bondi, 2000) and air transportation (Bonnefoy & Hansman, 2008).

In the context of the smart grid, pilot projects and demonstrations test the real-life implementation of smart grid technologies or solutions (typically experimental solutions, prototypes and non-commercial solutions, at an early stage of development) in a specific location (a small village, a neighborhood in a town or city, the area supplied by a primary substation – HV/MV transformer), usually involving a limited number of consumers and other participants (DER owners, aggregators, etc.).

The scaling-up and replication of the smart grid implementation can then be defined as depicted in Figure 3.1.

- ***Replication***: *Replication of the smart grid implementation means reproducing the implementation elsewhere, i.e. implementing the same smart grid solution in a different location (e.g. a different village, city, or country) or for a different type of stakeholders (e.g. involving a different type of consumers, or using a different type of DG technologies or DER resources, for instance).*
- ***Scaling-up***: *Scaling-up the implementation means widening the region were the smart grid solution is implemented (e.g. extending it to a whole city, a whole province, a whole country), widening the scope of the implementation to reach more consumers and other stakeholders, or increasing the degree of implementation of the solution to include more elements of the networks or larger volumes of produced energy or demand.*

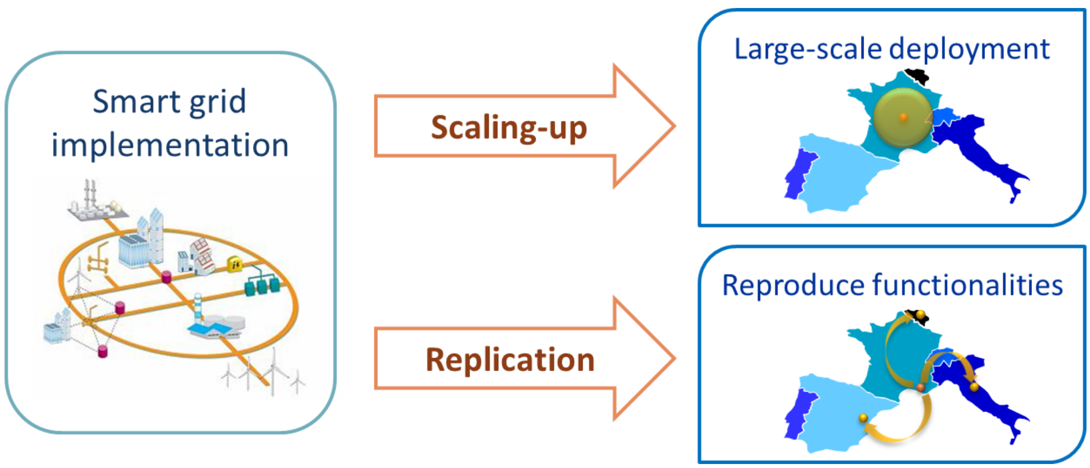


Figure 3.1: Definition of scaling-up and replication of smart grid implementations.

Although often used indistinctively or as synonyms, a distinction must be established between the concepts of **scalability and replicability** and the concepts of **scaling-up and replication**[25]. The first refer to the ability of the system to be deployed at a larger-scale or in a different location, while the second group of concepts refers to the action itself of deploying the solution at a larger-scale or in a different location, and the outcome of this action. Scalability and replicability are the preliminary requisites to perform scaling-up and replication successfully.

Accordingly, the **scalability and replicability analysis (SRA)** of smart grids may be approached from two different perspectives: **solution-based** to assess the scalability and replicability of the solutions; and **functionality-based** to assess the outcome of scaling-up and replication of the implementation

[25] As will be later explained in section 3.2, this PhD thesis is mainly focused on analyzing the scaling-up and replication of smart grid functionalities on distribution systems, so in the ensuing, references to scalability, scaling-up, upscaling, replicability and replication will refer to the impacts and implications of the implementation of smart grid functionalities.

of smart grid solutions. According to these two perspectives for SRA, solution-based and functionality-based, the diagram in Figure 3.2 presents the aspects involved in the implementation of smart grid solutions and how these are addressed by SRA.

- **Solution-based SRA: assessing scalability and replicability.**
  Is it possible to actually implement the same smart grid solution elsewhere or at a larger scale? How could that be accomplished? Would the software, infrastructure, etc. have to be adapted? What would be the limitations or under what conditions would it not be possible to implement the smart grid solution?
  From this perspective, SRA is mainly related to the technological aspects of the smart grid solutions and the context to their implementation.
  The smart grid solutions must be analyzed to assess whether they can cope with an increased volume of information, elements, or a larger radius of action. Furthermore, software and hardware compatibility with existing infrastructure and the evolution of technology must be considered to ensure a correct integration of the smart grid solution in the distribution system. Technological factors that affect the scalability and replicability of smart grid solutions include modularity, interface design, standardization, interoperability, and availability of equipment.
  Additionally, the regulatory framework and the acceptance of stakeholders must be studied to determine whether scaling up or replication of the considered solution would be viable. Pilot projects are not necessarily economically profitable and may be subject to special regulatory treatment. Potential business models and economies of scale should apply in order to ensure profitability of upscaling and replication.
- **Functionality-based SRA: understanding scaling-up and replication.**
  What could be expected if the smart grid use case (in terms of the enabled functionality) were implemented elsewhere or at a larger scale? How could the technical impacts on the distribution system be determined? Under what conditions would it make more sense to implement it? What would be the factors or boundary conditions that could affect the outcomes?
  These questions are related to the impact of the scaling-up and replication of a smart grid use case on the distribution system. The aim is to assess the effectiveness of smart grid solutions to achieve certain objectives, regardless of the actual technologies implemented[26], provided that the solution is scalable and replicable. The outcome of scaling-up and replication is strongly affected by the different boundary conditions of the implementation.

[26] The same functionality can be implemented with different technology solutions. For instance, network reconfiguration may rely on different communication technologies, such as PLC, GPRS, optical fiber, etc. As technology evolves rapidly and is often conditioned by historical reasons (e.g.: existing communications infrastructure already deployed, partnerships between companies, etc.), it is very interesting to be able to extract SRA conclusions that are generally applicable for smart grid use cases.

Under this approach, the technical impact can be quantified through KPIs. Regarding the technical boundary conditions, scaling-up and replication may involve different characteristics of the distribution network, consumers and DER units.

As in the previous case, the economic, regulatory and social context must also be studied to identify whether enablers or barriers may be found to the implementation of the studied use case.

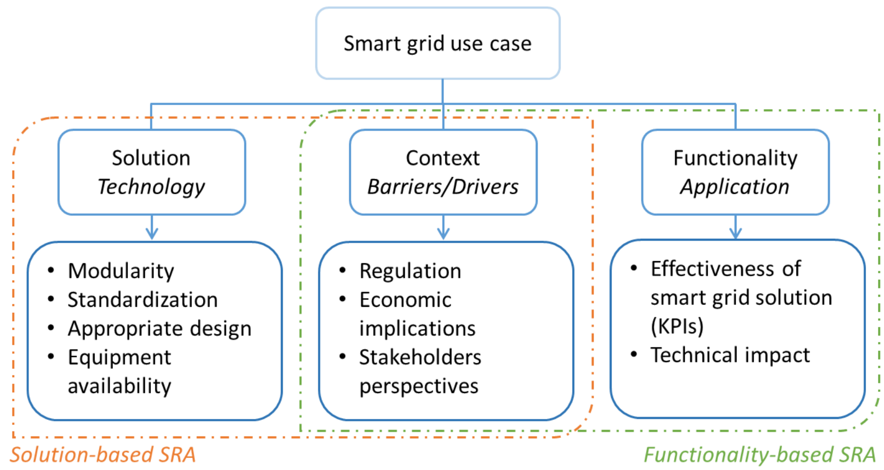


Figure 3.2: Main aspects of smart grid use cases in relation to SRA: smart grid solution, context and functionality.

Scalability and replicability have different **dimensions** that will be considered **for SRA**.

- **Scaling-up in size**: the implementation of the use case is assessed for a larger area, including a larger number of network elements and network users.
- **Scaling-up in density**: the scope of the use case is widened in terms of implementation degree of the smart grid solution (e.g.: larger number of consumers involved, higher volume of participating distributed energy resources (DER), higher number of smart grid elements in the system).
- **Intranational replication**: the implementation of the use case is analyzed for different distribution areas within a country.
- **International replication**: the implementation of the use case is analyzed for different countries.

From the perspective of functionality-based SRA, the different dimensions are addressed focusing on the change of the boundary conditions that may be encountered. Within a country, similar boundary conditions may be expected regarding regulation, perspectives of stakeholders, or technical aspects such as voltage levels. Other technical boundary conditions (network architecture, reliability levels, etc.) may change for different distribution areas with different types of network users (areas of residential consumers, industrial areas, areas with high PV penetration, etc.). For different countries, the boundary conditions may differ more widely, including different regulation schemes, network characteristics, economic conditions or perspectives from stakeholders. Actually, scaling-up in size implies considering a larger region, where boundary conditions may change, so intranational replication implies scaling-up in size and international replication can be regarded as a step further in upscaling. Scaling-up in density refers to the functionality enabled by the smart grid solution. From the point of view of solution-based SRA, scalability in size would be related to the ability of the system to cover wider regions (e.g.: communications covering longer distances), whereas scalability in density would be related to the ability to cover higher of elements (e.g.: higher number of PV units participating in voltage control receiving setpoints from a control system). Replicability is related to the standards and context found in different regions and countries.

3.1.2 Scalability and replicability analysis for smart grids

Scaling-up and replication are always implicitly addressed whenever the potential impact of any solution, technology or policy is assessed for a system, region or country, since conclusions are drawn by extrapolating from experimental data, assuming certain hypotheses, or performing sensitivity analyses. For instance, the work presented in (Working Group III of the Intergovernmental Panel on Climate Change et al., 2011) analyzes the environmental, economic and social impacts of different RES technologies for a wide range of scenarios to include the effect of aspects such as the energy sources displaced by RES or different climate change scenarios or environmental policies and targets. A different example may be found in the smart grid cost-benefit analysis (Electric Power Research Institute, 2011). The impact observed of smart grids is assumed to be directly applicable for all distribution grids in the US, which implies a linear scaling-up, where the different conditions across the country have not been considered.

Cost-benefit analysis of smart grids

Actually, cost-benefit analyses (CBA) and SRA can be considered somehow complementary. The objective of CBA is to assess the economic viability and sustainability of a project by comparing the costs and the expected benefits within a certain time frame, typically related to the expected useful life of the project. The quantification of the benefits involves the monetization of observed or estimated technical impacts of the project, as well as the economic valuation of other qualitative benefits expected for the different stakeholders. SRA aims to determine as precisely as possible what is to be expected when a certain functionality is implemented at a larger scale or in a different context or location, so SRA results would be the input for CBA to quantify some of the benefits. Additionally, regulatory considerations included in the SRA can also contribute to CBA for the evaluation of how to quantify and share benefits and costs among stakeholders in the CBA.

In the U.S., the EPRI (Electric Power Research Institute, 2010) proposed the first methodology for cost-benefit analysis of smart grid projects. Then, this methodology was applied to estimate the costs and benefits of the deployment of smart grids in the U.S. in (Electric Power Research Institute, 2011). The estimated benefits are an update of the values presented in (Report & Electric Power Research Institute, 2004) for two scenarios, i.e. business-as-usual and a more optimistic scenario. The adopted approach assumes that the impact observed of smart grids is directly applicable for all distribution grids in the US, which implies a linear scaling-up. However, it does not consider the effect of the different conditions across the U.S. Actually, the authors already explained the need for further work, potentially using simulation, in order to be able to extrapolate the results observed in individual projects to estimate their broader implications for larger-scale deployment.

Afterwards, the JRC has set the methodological guidelines for CBA of smart grid projects in Europe (Giordano, Onyeji, Fulli, Sánchez Jiménez, & Filiou, 2012) based on the work of EPRI. The proposed CBA methodology considers a large set of functionalities and the economic benefits proposed by the EPRI but also a group of qualitative, non-monetized benefits. The methodology has been applied to the InovGrid project for illustrative purposes. This work is completely oriented to the evaluation of projects, so the replication and upscaling of this project falls out of scope. Additionally, the JRC has developed a specific methodology for the CBA of smart meter deployment in Europe (Joint Research Centre et al., 2012), mapping the benefits to the corresponding functionalities provided by smart metering and describing the corresponding KPIs. This work is more oriented to a wider scope, considering large-scale deployment of smart metering. The authors do not provide a methodology to determine the impacts of the implementation of smart metering, but they do state the need to tailor the analysis to the specific boundary conditions of the considered region and to perform sensitivity analyses for the estimated values. Later on, the JRC has identified and addressed the need for SRA in further work. The CBA of a smart grid project in the city of Rome in (Vitiello et al., 2015) aimed at scaling-up the results of a pilot project mostly based on a linear upscaling of the impacts observed in the pilot project. This work served as a first approach to SRA.

3.1.2.1 Research projects addressing scalability and replicability

Several smart grid research and demonstration projects have addressed scalability and replicability from different perspectives. This section reviews the approaches developed in Europe up until 2016 to the best of the author’s knowledge and is included in (Rodriguez-Calvo, Cossent, & Frias, 2017).

In the EU, the European Electricity Grid Initiative (EEGI) has highlighted the need for scalability and replicability analysis in (European Electricity Grid Initiative, 2013b) and several EU-funded research projects have been launched with tasks and work packages explicitly dealing with scalability and replicability, including GRID+, GRID4EU, IGREENGrid, SINGULAR, SuSTAINABLE and evolvDSO. These projects have been designed and coordinated to adopt complementary perspectives. Additionally, the proposal developed in CLNR, a smart grid project in the UK, is presented as an alternative approach designed outside of the EC funding umbrella, which directly addresses scalability and replicability and carries out SRA, even if under a different name, highlighting the relevance of such analyses in all countries. In the ensuing, these projects are described briefly and then compared to extract conclusions.

Description of projects analyzing scalability and replicability of smart grids

GRID+[27] is a Coordination and Support Action for the development of the EEGI. The project aims to map and monitor smart grid research, development and demonstration activities, foster knowledge sharing and support scaling up and replication activities (GRID+ Project, 2012, 2013b, 2014). Furthermore, the EEGI and GRID+ have created the EEGI Labelling to identify the projects that are in line with the spirit of the EEGI (i.e. knowledge sharing of results, system level innovation, etc.) and address an EEGI functional objective as specified in the EEGI Research and Innovation Roadmap (European Electricity Grid Initiative, 2013b). The EEGI Label provides additional visibility including awarded projects in EEGI and GRID+ communication materials and dissemination activites.

The GRID+ project has studied the prerequisites for smart grid projects to be scalable and replicable. The focus has been put mainly on the technological characteristics of the developed solutions. Thus, the SRA approach followed by this project aims to answer the previously raised question: "is it possible to actually implement the solution?" (functionality-based approach, which is the first approach described in section 3.1.1). The critical factors related to scalability identified include interface design, modularity and evolution of the technology. Meanwhile, the critical factors related to replicability identified include interoperability, plug & play characteristics and standardization. Additionally, aspects of the implementation context have been listed as relevant factors, including regulation, stakeholder acceptance and economic factors such as profitability, business models and economies of scale. The work of the GRID+ project has established the foundation for smart grid scalability and replicability in the literature (May, Vingerhoets, & Sigrist, 2015; Lukas Sigrist et al., 2016).

Moreover, GRID+ carried out a survey among several publicly funded smart grid projects in Europe to evaluate to what extent the proposed scalability and replicability factors were taken into account and whether the results and solutions of the projects were actually deemed apt for scaling-up and replication.

The GRID4EU[28] (Large-Scale Demonstration Project of Advanced Smart Grids Solutions with Wide Replication and Scalability Potential for Europe) project comprises six demonstrators in six European countries (Germany, Sweden, Spain, Italy, Czech Republic and France) where different smart grid solutions have been tested, including active management of demand response, distributed generation (DG) and storage, MV and LV network supervision and automation, and islanded operation.

In this project, there is a scalability and replicability work package[29] to understand what could be expected when replicating and upscaling smart grid use cases, which would correspond to a

---

[27] http://www.gridplus.eu/

[28] http://www.grid4eu.eu/

[29] The Author of this thesis has been involved in the scalability and replicability work package of the GRID4EU project to develop the SRA methodology and conduct SRA for selected use cases of the six GRID4EU Demos.

functionality-based approach (second approach described in section 3.1.1). The GRID4EU has developed a methodology for SRA based on a first stage of technical analysis based on simulation (loadflow analysis, reliability analysis and dynamic analysis) and representative networks, and a second stage to include regulatory and stakeholder-related drivers and barriers to upscaling and replication (GRID4EU project, 2014b, 2015b). Smart grid use cases have been classified into three categories to adapt the required technical analysis, according to the objectives pursued, implemented functionalities and corresponding types of impacts: (i) use cases aimed at efficient and increased integration of DER (voltage control strategies, management of DER), (ii) use cases aimed at improved continuity of supply (network automation), (iii) use cases aimed at autonomous operation (islanded operation). SRA has been carried out for the use cases of the GRID4EU demos to produce a set of scalability and replicability rules (GRID4EU project, 2016d). Then, the application of the GRID4EU SRA studies in the EU-context has been illustrated with the case of Belgium (GRID4EU project, 2015c). Furthermore, the applicability beyond Europe has been addressed for the case of Brazil and the state of California in the US (GRID4EU project, 2016e).

The SuSTAINABLE[30] (Smart Distribution System Operation for Maximizing the Integration of Renewable Generation) project has developed a smart operation paradigm integrating information from smart meters and short-term local forecasting to manage the distribution system and available distributed energy resources. The main objective is to maximize DG hosting capacity and achieve a more efficient and cost-effective integration of variable DG. The developed solution has been tested in a demonstration site in Portugal, and a dedicated Work Package has been devoted to analyze the scalability and replicability potential of the tested smart grid implementation in four target regions (UK, Germany, Greece and Portugal) (SuSTAINABLE project, 2012).

These target regions have been characterized to describe the local implementation conditions, both technical and non-technical. Analyzed technical conditions include population density, orography and types of networks, of a more geographic nature; and generation mix, reliability levels and network configurations, more related to technology. Additionally, the scalability and replicability of the communication solutions has been studied (Gonzalez-Sotres, Mateo, Frias, Rodriguez-Morcillo, & Matanza, 2016)s. Regulation and stakeholder-related issues have also been considered to include operation standards, economic incentives and network access, as well as consumer perception, relationship with TSOs and supplier availability. SRA has been focused on the identification of barriers to scaling-up and replication of the SuSTAINABLE functionalities. The identified technical, economic and regulatory barriers have been mapped against the functionalities, and their impact has been characterized, to determine whether functionalities can still be deployed, and whether the deployment would be delayed, the cost increased or the effectiveness reduced. Moreover, the

[30] http://www.sustainableproject.eu/

prevalence of the identified barriers in each target region has been qualitatively assessed. Finally, mitigation strategies have been proposed for the identified barriers, considering different scenarios.

The IGREENGrid[31] (Integrating Renewables in the European Electricity Grid) project is focused on increasing the hosting capacity for renewable energy sources in distribution grids, using the results from six pilot projects (Spain, Italy, Austria, Germany, France and Greece) testing different solutions. The project includes the assessment of the scalability and replicability at EU level of the solutions identified as most promising to generalize the results obtained by individual projects (IGreenGrid Project, 2016). For this purpose, simulation has been carried out to assess the performance of the solutions in terms of achievable hosting capacity increase, impact on network losses and impact on reactive power balance. A top-down approach was followed comprising three steps: (i) feeder screening based on hosting capacity, (ii) hosting capacity determination to identify critical situations and achievable increase of hosting capacity and (iii) detailed analysis to evaluate further KPIs such as the energy efficiency, voltage quality and reactive power exchange with the upstream network. Additionally, an economic assessment of the different solutions has been performed analyzing the costs related to the solutions and the benefits provided by their large-scale implementation.

The SiNGULAR[32] (Smart and Sustainable Insular Electricity Grids under Large-Scale Renewable Integration) project aims at investigating the effects of large-scale integration of RES and DSM on the planning and operation of insular (non-interconnected) electricity grids, proposing efficient measures, solutions and tools towards the development of a sustainable and smart grid. Different network operation procedures and tools have been developed and tested in different insular systems across Europe (S. Miguel of the Azores Islands in Portugal, Crete Island in Greece, Pantelleria Island in Italy, La Graciosa of the Canary Islands in Spain, and Great Island of Braila in Romania). The results observed in the demonstrations have been studied, implicitly addressing upscaling and replication, to allow the development of generalized guides for smart grid implementation in insular systems.

The EvolvDSO[33] (Development of Methodologies and Tools for New and Evolving DSO Roles for Efficient Distributed Renewable Energy Sources Integration in Distribution Networks) project aims to shape the evolving roles of DSOs and develop the required tools for DSOs to face the future challenges driven by DER integration, technological progress, and different customer acceptance patterns. The EvolvDSO project will produce tools and methods for network planning, forecasting, operational scheduling and grid optimization, operation and maintenance and CBA. The developed tools will be validated and tested, and performance will be evaluated considering the requirements of the key stakeholders. In order to ensure a high replicability potential of the developed tools, an SRA of the tools will be carried out from the point of view of the software developers creating and

[31] http://www.igreengrid-fp7.eu/

[32] http://www.SiNGULAR-fp7.eu/

[33] http://www.evolvdso.eu/

adapting the tools for different implementations, and from the perspective of operators in different DSO using the tools.

The Customer-Led Network Revolution (CLNR)[34] is one of the flagship smart grid projects funded by the Ofgem in the UK designed to test a range of smart grid solutions for a more efficient integration of low carbon technologies (LCT) like solar PV, heat pumps and EVs. The project involved large-scale demonstration of customer-side solutions including innovative tariffs and load control incentives for domestic, commercial, industrial and distributed generation customers and network-side technologies comprising voltage control, real-time thermal rating and storage.

In order to deliver conclusions applicable for the whole country, the project involved large-scale trialing (involving more than 13,000 customers in Northern Powergrid's distribution network) and developed the Validation, Extension, Extrapolation, Enhancement and Generalization (VEEEG) methodology to carry out post-trial analyses. The VEEEG methodology presented in (Lyons et al., 2015) proposes the use of simulation to address scalability and replicability of the technical impacts achieved by the smart grid solutions tested in the project under different LCT scenarios for different network models.

Comparative assessment of proposals and lessons learned

Table 3.1 summarizes the most relevant information regarding the SRA approach of these seven initiatives, describing the geographical scope of application or regions of interest, the subject of the analysis (i.e. the main objective pursued by the proposed SRA), and the main results of SRA.

Naturally, EU-funded projects sustain a EU-scope in their analysis and considerations. However, the main target regions vary depending on the partners involved that can bring their own experience into the analyses and on the locations where demos are implemented. The CLNR is a good example of a national project, focused on the UK. Among the seven initiatives, GRID4EU is the only project where simulation results and SRA rules have actually been used to illustrate the application of scaling-up and replication to a whole country and understand the outcomes that could be expected from the tested use cases (without carrying out further simulations). Furthermore, GRID4EU has also addressed two examples outside of the European context to illustrate the potential of the proposed approach, identifying the aspects that would be excluded from the domain of validity of the SRA results.

It is interesting to observe that the SRA proposed by the initiatives focused on a functionality-based (rather than solution-based) approach relies mainly on technical analyses using simulation and sensitivity analysis. Simulation models are validated with the results observed in real-life testing and sensitivity analyses can account for the variability of boundary conditions in the regions of interest. Regulation and stakeholder-related aspects are mostly included by analyzing the context of the

[34] http://www.networkrevolution.co.uk/

regions of interest to identify how this context can facilitate or hinder the development of the studied solutions, and proposing recommendations to overcome identified barriers.

The GRID+ project aimed to serve as a reference project, monitoring other initiatives to support the work in the field of SRA. Thus, data was gathered on how other R&D projects had tackled the issues of scalability and replicability and providing the first theoretical framework for these concepts.

Noteworthy, interaction is encouraged between EU projects to create a common knowledge base and take advantage of synergies and complementarities. GRID+ and GRID4EU have collaborated closely and adopted complementary approaches. GRID+ has addressed scalability and replicability of the solutions from the point of view of technologies involved, while GRID4EU focuses on the impact of the enabled functionalities. Thus, the main research question is whether it is possible to scale-up and replicate for GRID+, whereas GRID4EU addresses the questions of what to expect if scaled-up and replicated and whether it would make sense. The projects IGREENGrid, SuSTAINABLE and SiNGULAR belong to the family of projects funded under the same call devoted to the integration of variable distributed resources in distribution networks[35]. Therefore, interaction has been established for a close collaboration (IGreenGrid Project, SiNGULAR Project, & SuSTAINABLE Project, 2012). Additionally, GRID4EU, IGREENGrid, and SuSTAINABLE have interacted and collaborated, so their SRA methodological proposals are very much aligned. In the case of the CLNR project, which has been developed separately to the EU projects, the concern for scaling-up and replication of the results observed in demonstration and the proposed studies are remarkably similar.

[35] EC Call "ENERGY.2012.7.1.1. Integration of variable distributed resources in electricity distribution networks".

Project	Date	Scope	SRA objective	SRA results
GRID+	2012-2014	• EU-wide scope	Smart grid demo projects	• EEGI Project Labelling • Critical factors • Survey among projects
CLNR	2011-2014	• Large-scale demo (UK) • National scope	Tested functionalities	• VEEEG based on simulation • Cost-benefit analysis for different scenarios and technologies
SuSTAINABLE	2012-2015	• 2 Demos (PT, GR) • 2 Proof of concept (UK, DE)	Tested functionalities	• Technical, economic and stakeholder-related barriers: impact and prevalence in each target country
IGREENGrid	2013-2015	• 6 Demos (ES, IT, AT, DE, FR, GR)	Tested functionalities	• Simulation & KPIs • Economic assessment: CA&BA
SiNGULAR	2012-2015	• 5 Demos (PT, GR, IT, ES, RO)	Tested functionalities	• Implicit SRA • Simulation & KPIs • Regulatory recommendations
EvolvDSO	2013-2016	• EU-wide scope	Developed tools	• Survey among developers & operators
GRID4EU	2012-2016	• 6 Demos (DE, SE, ES, IT, CZ, FR) • Application to BE • Non-EU application (BR, California) • EU-wide scope	Tested functionalities	• Simulation & KPIs • Regulatory and stakeholder-related drivers & barriers • Stakeholder survey • SRA rules • Application to a country • Application to a non-EU context

Table 3.1: Research and demonstration projects with focus on scalability and replicability.

Most of the projects described comprise demonstrations for real-life implementation and assessment of different smart grid solutions. Table 3.2 lists the main functionalities enabled and technologies implemented in these demos, as well as the monitored KPIs. It can be observed that improving the integration of DER in the distribution grid is the main objective of current smart grid research projects and therefore tested functionalities often include monitoring and control voltage to efficiently integrate and manage PV, EV, storage and other DER. The SiNGULAR project stands out, as these objectives are pursued for islanded systems. Finally, it can be concluded that GRID4EU is the most comprehensive project in terms of the scope of objectives pursued and tested solutions, including automated fault management and islanded operation, in addition to voltage control-related solutions.

Project	Main functionalities	Main technologies	KPIs
CLNR	• Voltage control • Demand response	• Real-time thermal rating • OLTC • Capacitors • Battery energy storage systems • Automatic heat pumps • PV • EV	• Increased allowed penetration of EVs, HPs and PV
SuSTAINABLE	• Monitoring • State estimation • Forecasting of local renewable generation and load • Voltage control • TSO-DSO interaction • Provision of differentiated quality of supply	• OLTC • Capacitors and DFACTS • Battery energy storage systems • DG • Controllable loads	• Deferred Transmission and Distribution Capacity Investment • Reduction of Technical Losses • Allowable maximum DG power without branch overload and voltage limit violations • Share of electrical energy produced by RES • Voltage and Power Quality performance • Reduction of Carbon Emissions • Reduction in RES cut-off due to congestion • Optimized use of Assets • Forecasting Accuracy • State Estimation Quality
IGREENGrid	• Monitoring • State Estimation • Voltage control • Congestion management	• OLTC • STATCOM • Battery energy storage systems • DG • Demand response • EV	• Hosting Capacity • Fulfilment of voltage limits • Variability of voltage amplitude • Duration, number and intensity of voltage violations • Reduction of energy losses • Solution usage time • Reduction of reverse power flow • Forecasting accuracy • Reduction of greenhouse gas emissions
SiNGULAR	• Islanded operation • Forecasting (wind, PV, load, small hydro) • Integration of DER • Storage and DG management	• Battery energy storage systems • Smart meter deployment • Demand response (desalination plant, EV) • DG	• Reduction of CO_2 and GHG emissions • RES hosting capacity: probability of over- and under-voltages • Reduction of RES spillage: stiffness ratio (short-circuit capacity of local generation and network at connection)

			• Reduction of peak demand • Reduction of network losses • Reduction in interruptions per consumer • Waveform quality: harmonics, voltage variations and voltage dips
GRID4EU	• Automated fault detection, isolation and service restoration • Monitoring • Voltage control • Congestion management • Demand response • Losses reduction • Islanded operation	• Monitoring in MV and LV • Automation in secondary substations (MV/LV) • Automation of LV cabinets • Battery energy storage systems in MV and LV • CHP for islanded operation	• Energy losses • Fault awareness, localization and isolation time • Network hosting capacity • Line voltage profiles • Islanded operation metric • Use of standards • Recruitment • Active participation

Table 3.2: Implemented functionalities and technologies in research and demonstration projects.

3.1.2.2 Research on technological aspects for upscaling of solutions

Much work has been devoted to study the scalability of the technologies involved in the smart grid. In order to enable the large-scale deployment, smart grid solutions must be able to cope with increasing volumes of information and interacting agents. Therefore, scalability of solutions is analyzed in terms of capability of information technologies, algorithms, communications and systems to exchange, analyze and store large volumes of data and perform large-scale computations (Birman, 2012). For instance, the work presented in (Vandael, Claessens, Hommelberg, Holvoet, & Deconinck, 2013) and (S.-J. Kim & Giannakis, 2013) aims to overcome the problem of existing demand response approaches that cannot cope with large numbers of electric vehicles (EVs) and consumers, respectively. Yet another example may be found in (Kulkarni, Gormus, Fan, & Ramos, 2012), where a mechanism is proposed to enable scaling up of automatic meter reading.

3.2 Objectives and scope of proposed SRA methodology

The main objective of the SRA proposed in this PhD thesis is to understand **what to expect if the implementation of a smart grid use case is scaled-up and replicated**. Thus, the scalability and replicability analysis (SRA) of a smart grid solution aims to:

- Identify the different technical, regulatory and socioeconomic conditions that may be encountered when the solution is implemented either at a larger scale, or in a different time and location.
- Study the effect of those conditions on the outcomes of the smart grid implementation.
- Identify the most favorable conditions for different smart grid solutions.
- Provide the guidelines to infer the results that may be expected from the implementation of the smart grid.

The scope of the proposed SRA is functionality-oriented. According to the two main perspectives previously identified in section 3.1.1, the smart grid SRA proposed and presented in this PhD thesis aims to answer the second batch of questions. Rather than the technological scalability and replicability of the solutions themselves, the proposed SRA aims to determine what to expect from the implementation of smart grid use cases elsewhere (replication) or at a large scale (upscaling). This SRA is focused mainly on the technical, economic, social and regulatory aspects of the implementation of the smart grid. The proposed SRA aims to identify the conditions to ensure that scaling-up and replication of smart grid use cases make sense and may be more recommendable.

This SRA approach will be more general and open, since conclusions drawn for a certain smart grid implementation will be applicable to other implementations with similar functionalities and objectives but different technologies. This feature is particularly interesting given that the technological solutions implemented may be conditioned by external factors (historical reasons, industrial partnership, etc.), and most importantly, technological development is very fast, so that tested solutions may be experimental or mature, costs decline rapidly and new advances result in profound changes in the constraints for upscaling.

According to the SGAM interoperability layers described in chapter 2, the proposed SRA focuses on the functional layer, to analyze the impact of implementing smart grid functionalities in the domain of the distribution system. It also includes the business layer to examine the effect of the regulatory framework, economic aspects and the perspectives of the different stakeholders involved. SRA, therefore, aims to study the relationship among the interconnected aspects of these layers.

The SRA methodology proposed in this thesis is based on the review of existing approaches for SRA, learning from the different perspectives adopted and focusing on the functionalities enabled by smart grid implementations. More specifically, the developed SRA methodology is very much aligned with the GRID4EU project, as the Author of this thesis has been involved in the scalability and replicability work package of the GRID4EU project to develop the SRA methodology and conduct SRA for selected use cases of the six GRID4EU Demos.

3.3 SRA methodology proposal

As explained, the SRA methodology proposed in this PhD thesis focuses on functionality-oriented SRA (as opposed to a solution-based SRA) and aims to analyze the technical impacts of replication and upscaling of smart grids on the distribution system and how these are affected by the technical and non-technical boundary conditions.

The methodology developed for the SRA of smart grid use cases comprises two main stages: a first step of quantitative and detailed **technical analysis based on the use of representative networks and simulation to compute KPIs** that can assess the performance and impacts of smart grid implementations; and a second stage of a more **qualitative non-technical analysis, to include regulatory aspects and the perspective of the different stakeholders** involved.

The experience gathered from real-life testing in a demonstration project (demos) provides very useful insights to better understand the behavior of the smart grid solution and functionalities implemented. The impacts of smart grid use cases are quantified by KPIs in the demo, and these values are used to validate the results obtained through simulation for the technical SRA of the smart grid use case.

The proposed SRA methodology has been developed mostly based on the context of European distribution systems (i.e. subject to regulated distribution based on unbundling and incentive-based regulation, in a context of high maturity of smart grid solutions and strong investment on demonstration projects of medium-size, etc.). The outcomes of the implementation of a smart grid solution are unavoidably linked to the technical characteristics of the distribution systems and the behavior of the network users. The technical characteristics of the distribution system and the demand and generation profiles of network users are largely influenced by the regulatory framework, the historical evolution of standards and strategies of distribution companies, regulatory requirements and incentives, geographical and climate conditions, maturity and cost of available technologies, etc. Boundary conditions may change from one location to another, from one group of consumers to another, etc. and therefore the analysis of the boundary conditions throughout the whole region of study for smart grid deployment is fundamental. SRA assesses the effect of boundary conditions to identify the most important aspects that must be considered for SRA and scaling-up factors, the drivers and barriers that may be encountered for scaling-up, the validity domain for replication, etc. These results and conclusions are put into the form of general premises, the so-called scaling-up and replication rules.

The outcome of SRA is a set of qualitative premises and conclusions, the so-called scaling-up and replication rules, which may be regarded as guidelines to help infer the outcome of implementing smart grid solutions. Therefore, SRA is of great interest for policy-makers, to help shape the roadmap for the large-scale smart grid deployment, identifying favorable functionalities and applications for different regions (depending on the prevailing boundary conditions). SRA can also help guide funding of further R&D and demonstration smart grid projects, identifying conditions for testing. Moreover, SRA results can be of assistance for regulators to remove the identified barriers to smart grid implementations, and set adequate regulatory incentives that can facilitate the adoption of smart grid use cases and encourage investment on new solutions. Furthermore, SRA is extremely relevant for the incumbent industry to guide their investment and shape their strategy for different smart grid solutions. SRA results enables cost-benefit analyses for large-scale smart grid deployment. CBA analyses can be carried out from the perspective of different investors, including DSOs, equipment manufacturers and vendors, software developers, as well as ICT and other service providers. Such analyses can help them understand the business case of investing in the implementation of different smart grid solution in different regions.

The diagram in Figure 3.3 illustrates the proposed methodology: the stages of technical analysis and non-technical analysis are represented together with the corresponding boundary conditions that constitute the main input for the analyses. The outcome of SRA are the resulting scalability and replicability rules. The diagram also shows the link between SRA and the demonstration project through the observed KPIs.

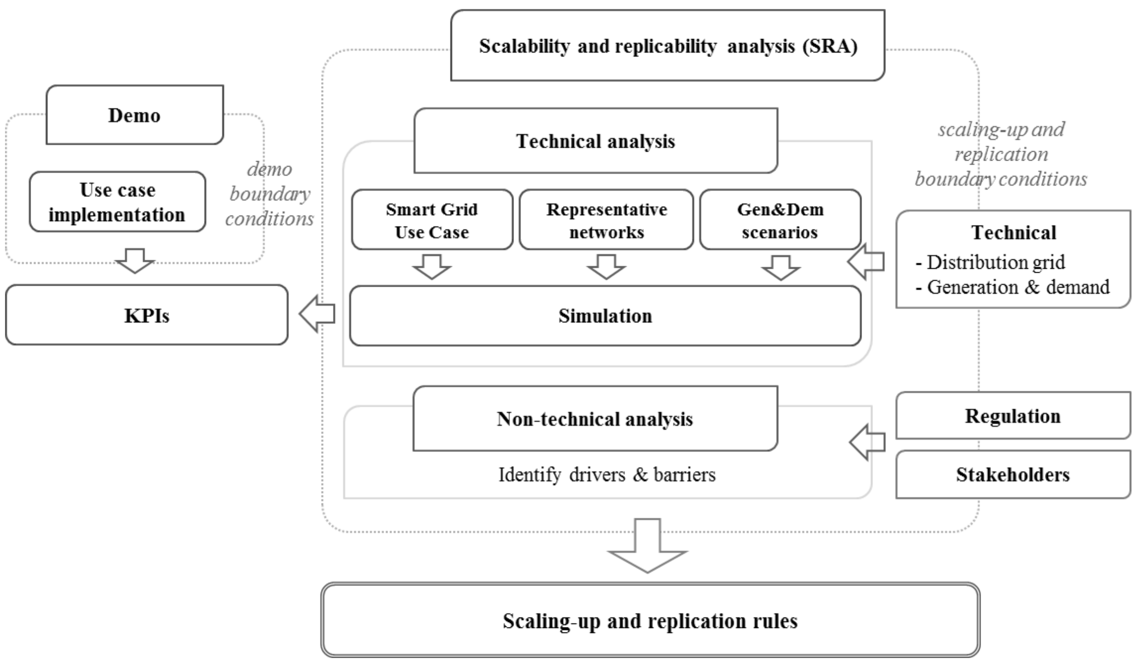


Figure 3.3: Overview of methodology for SRA of a smart grid use case.

The proposed methodology is explained in detail in the following sections. Section 3.4 describes the stage of technical SRA, while section 3.5 is devoted to present the non-technical SRA. The stage of technical SRA is implemented in several steps: (1) identification of relevant KPIs, (2) selection of simulation tool, (3) definition of representative networks, (4) definition of scenarios, (5) simulation for KPI computation, (6) review of demo results, and (7) upscaling of simulation results. The stage of non-technical analysis addresses the regulatory framework and the perspective of stakeholders involved each through three steps of (1) identification of relevant topics, (2) characterization of the boundary conditions, and (3) assessment of the effect of the boundary conditions on the replication and upscaling of the use case. This methodology has been presented in (Rodriguez-Calvo, Cossent, & Frias, 2017).

This thesis aims to provide the methodological framework for the analysis of the scaling-up and replication of any smart grid use case. Thus, the SRA methodology (together with the steps defined for its implementation) is applicable to study the expected impacts from the implementation of any smart grid solutions.

However, as concluded from the review of smart grid solutions implemented in demonstration projects and analyses carried out in research (see chapter 2), depending on the functionalities implemented in the smart grid use case and the objectives pursued, the type of impacts differ. The relevant boundary conditions for SRA differ, and the specific simulation tools and KPIs must be adequately adapted. The mapping of smart grid solutions proposed in chapter 2 has identified three groups of use cases: network automation for the improvement of continuity of supply, DER management and voltage control to increase network hosting capacity and islanded operation and microgrids. The implementation of the proposed SRA methodology is thus particularized for each of these types of smart grid use cases. The particularization of the SRA methodology for each type of smart grid use case is explained in detail in chapter 4, where the appropriate KPIs and simulation models, as well as the relevant technical, regulatory and stakeholder-related boundary conditions, are identified.

3.4 Technical SRA

The technical analysis is the core of the proposed SRA and it comprises several steps to tackle the scalability and replicability dimensions: i.e. scaling-up in density, scaling-up in size, intranational replication and international replication. As indicated in Figure 3.3, technical SRA methodology is based on the simulation of the strategies and processes usually followed by DSOs for the operation of the distribution system in a Business-As-Usual approach and the simulation of the behavior of the smart grid solutions implemented to compute the corresponding KPIs. The distribution system is modelled through a set of representative networks and loading scenarios (see Figure 3.3), so that the boundary conditions that may be encountered in the replication and scaling-up of the smart grid use cases are represented and accounted for. The following sub-sections describe the steps defined for the technical SRA.

3.4.1 Identification of relevant KPIs

Smart grid use cases are designed to achieve a specific objective by enabling a series of new functionalities, such as for instance, to improve continuity of supply (objective) by enabling remote service restoration (functionality), or to increase the amount of DG that can be connected to the distribution network by managing the reactive output of DG to control the voltage profile, etc.

It is important to understand the objectives and determine how to measure the efficiency of the smart grid use case in achieving that objective. The SRA proposed in this PhD thesis is based on the use of Key Performance Indicators (KPIs) to assess the performance of the smart grid solutions and quantify the impacts of the smart grid implementations. As explained in chapter 2, section 2.2.2, **objective KPIs** will be used to assess fulfilment of the pursued objectives and **intermediate KPIs** will be used to evaluate other parameters that are relevant to understand the impacts of the smart grid implementation.

Considering the example of improving continuity of supply, the impact is mainly observed on the impact of faults in the network (in terms of number of affected network users), so the reduction of frequency and duration of supply interruptions measured through SAIFI and SAIDI would be adequate objective KPIs. Taking the example of active participation of PV in voltage control with a controllable inductive power factor to mitigate overvoltage, the achieved increase of network hosting capacity would be an adequate objective KPI, and the voltage profile in the network would be an intermediate KPI to monitor to understand the contribution of DG management to network hosting capacity.

Furthermore, the use of common KPIs enable the comparison of results among different cases of implementation, different contexts, etc. Therefore, a set of KPIs is selected in chapter 4 for each of the three types of smart grid use case identified.

3.4.2 Selection of simulation tool

Naturally, the objectives pursued by different smart grid use cases and implemented functionalities determine the type of impacts to study for SRA. Simulation must be accordingly adapted to integrate all relevant aspects of the system and emulate the performance of the smart grid solution. Technical SRA requires an adequate simulation tool, selecting from available commercial tools, or developing a dedicated software tool. Considering the previous examples, reliability analyses would be required to obtain reliability indices and simulate fault management process with automation, while in the second case simulation must carry out load flow analyses to determine voltage profiles.

3.4.3 Definition of representative networks

SRA aims to assess the effect of implementing smart grid solutions in different contexts. In order to account for the variability of distribution networks in a region or country, this PhD thesis proposes to use representative networks[36]. A set of representative networks consists of a limited number of

[36] As will be later explained in Chapter 5, this PhD thesis proposes the use of representative networks. The use of these reduced network models requires the upscaling of the simulation results in order to extract scaling-up and replication rules for large-scale deployment of smart grids. Alternatively, large-scale reference networks could be used for simulation. These would require adapted simulation tools, able to cope with much larger volumes

network models that can account for the behavior of all the different actual distribution networks that comprise the distribution system of a large area (a region, a country).

The use of representative grids has been common in regulation, serving as a benchmarking tool for regulation of investments for quality of service (Allan & Strbac, 2001) or to estimate distribution costs (Lima, Noronha, Arango, & dos Santos, 2002), and in research to characterize the distribution system (Bracale et al., 2012), or assess the impact of DG (DNV GL, Imperial College, & NERA Economic Consulting, 2014).

Naturally, the importance of a good characterization of the distribution system and the adequacy of the selected representative networks is crucial for scalability and replicability analyses. The definition of representative networks is a very challenging task. Unfortunately, there is generally very little data available to characterize actual distribution networks and users due to confidentiality and data protection issues. Furthermore, distribution infrastructure comprises a vast amount of elements, which complicates the process of characterization.

Chapter 5 has been devoted to describe in detail the process of definition of a set of representative networks and review existing approaches and noteworthy initiatives to provide information and facilitate future analyses, such as for instance the efforts of Atlantide project in Italy (Pilo et al., 2012), the generic distribution systems in the UK (Strbac & McDonald, 2004), Eurelectric (Eurelectric, 2013) or the JRC's DSO Observatory (Prettico, Gangale, Mengolini, Lucas, & Fulli, 2016) for the EU as a whole.

Distribution networks in each country may be classified into a reduced number of categories, according to the type of areas and consumers served (e.g.: industrial, urban, rural). Each category may be represented by a representative network, consisting in a few feeders with the same grid architecture and the same technical characteristics (e.g.: feeder length, rated power of MV/LV substations, undergrounding ratio) as actual networks.

As in the case of simulation tools and KPIs, the set of representative networks for SRA should be adapted to the smart grid use case under study.

For instance, the network models comprising the set of representative networks for the SRA of automated fault management systems must accurately represent the typical architecture, interconnections between feeders and configuration of protections in the evaluated region so that the fault management process can be studied. By contrast, these parameters would not be as relevant for the SRA of smart grid use cases related to DER management to increase network hosting capacity, where the most relevant characteristics would include the impedances of the lines and thermal limits. The level of detail and relevant characteristics required for the technical analyses of the three types of smart grid use case identified are discussed in Chapter 5.

of data and large-scale computation. In this thesis, the author has opted for representative networks to facilitate the understanding of simulation results and the implications of the variation of different parameters.

3.4.4 Definition of scenarios

The variability of distribution networks is modeled through representative networks. Similarly, different generation and demand scenarios will be defined to represent the range of potential conditions of distribution systems and characterize network users. Network users, i.e. consumers and owners of DER, are characterized considering for instance density of demand, types of consumers, or size and technology of DG units and other DER. Reference scenarios have also been proposed in research (Celli, Pilo, Pisano, & Soma, 2014; Vardakas, Zorba, & Verikoukis, 2016). Additionally, different scenarios are designed to assess the effect of different degrees of implementation of the smart grid solution[37] under study.

As discussed for the previous step, adequately characterizing the distribution system is key to obtain good SRA results. Publicly available statistics and aggregated data, such as the Photovoltaic Geographical Information System (PVGIS) (Amillo, Huld, & Müller, 2014), or the statistics provided by the Spanish TSO (Red Eléctrica de España, 2009) can be used to build representative/reference generation and demand profiles.

Furthermore, the aim of SRA is not to predict the exact outcome of smart grid deployment, since the future is uncertain and boundary conditions may change in time. The objective of SRA is to understand the potential outcomes for the possible scenarios in the present and future of the analyzed region (accounting for potential increase of DG, EV penetration, distributed storage, the evolution of demand, the degree of monitoring and control in the network, etc.).

3.4.5 Simulation for KPI computation

Technical SRA is based on simulation to compute the corresponding KPIs that quantify the impact of the use case under different boundary conditions, as explained in section 3.3.

Simulation is carried out using the selected tool, on the representative networks and scenarios defined[38]. First, the baseline values of the parameters monitored by KPIs, i.e. those corresponding to a situation without the corresponding smart grid solution, are computed. Then, the implemented solution is modeled and the new values of the corresponding parameters are computed. The objective KPIs are obtained comparing both sets to determine the achieved improvement.

---

[37] In the case of smart grid use cases based on DER management, scenarios to assess the implementation degree of the smart grid solution and generation and demand scenarios would overlap by considering aspects such as for instance the amount of flexibility offered by consumers engaged in demand response programs.

[38] In some cases, simulations for certain scenarios or reference networks are not required because the implementation of the smart grid solution would not be possible or would not make sense. For instance, a scenario of full automation with telecontrol of the switches in all secondary substations would not be possible for very rural networks where secondary substations are connected to the MV network in a so-called antenna configuration with no input and output switches to enable remote reconfiguration of the network.

The use of representative networks addresses intra- and international replicability. A set of representative networks is developed for the country of the demonstrator, considering the typical types of network that correspond to different types of distribution areas (e.g.: urban, sub-urban, industrial and rural areas). The main parameters that will experiment variations may include network characteristics such as architecture, types of conductors or reliability levels and the characteristics of consumers, DG and other DER owners, such as their size and type of technology. Simulation is carried out to compute the values of the KPIs, performing sensitivity analyses to those parameters that have an effect on the outcomes of the smart grid use case, thus analyzing intranational replication. International replication is addressed by defining the representative networks and generation and demand scenarios for the new country or region, which should account for its specific boundary conditions, such as standard voltage levels or DG technologies installed. Simulation is used to compute the new values of the KPIs and perform sensitivity analyses to the range of parameters where the new country differs from previously analyzed countries.

Then, KPIs are computed for different scenarios of implementation degree of the smart grid use case to analyze scalability in terms of density. At this stage, the parameters subject to variation are those related to the volumes of demand, DER and smart grid solutions, depending on the use case. For instance, number of consumers involved, or volume of shiftable load are considered for demand response use cases, or number of monitoring elements in the case of automation.

3.4.6 Review of demo results

The pilot or demonstration project (i.e. demo) testing the smart grid use cases provides information on the actual performance of the implemented smart grid solution[39]. The results observed in the demo are gathered in the form of measured KPIs.

Comparing the KPIs obtained by simulation to the actual KPIs measured in the demo helps fine-tune and validate the simulation model. For this purpose, the boundary conditions of the demo must be characterized: the distribution networks, the consumers and DER involved (directly and indirectly) in the demo and their demand and generation profiles. The validation of the model could be as detailed as to model the exact conditions of the demo and compute the corresponding KPIs.

However, it must be noted that in some occasions pilot projects may not be able to provide KPIs, such as in the case of an automation demo if no actual faults took place, so that SRA studies based on simulation become more challenging but also more relevant.

---

[39] Demonstration projects provide experience on numerous aspects that are essential to the deployment of smart grid, such as for instance the interaction with consumers and other stakeholders that may actively participate on the smart grid implementation. Many of the conclusions drawn from demos may be incorporated into the SRA under different approaches. This PhD thesis is focused on a functionality-based SRA to assess the technical impacts on the distribution network quantified through KPIs obtained by simulation, so in this case Demos are used to calibrate or validate simulation models.

3.4.7 Upscaling of simulation results

The different dimensions of scalability and replicability are interrelated: scaling-up a use case in size means considering a larger area, which implicitly involves replication too, as the boundary conditions may vary across the region considered.

The use of representative networks enables upscaling of simulation results. The representative networks developed for the analyzed region must be given a representativity rate or scaling-up factor, so that the results previously obtained from simulation for each representative network are weighted to obtain the results for the whole region.

The creation of a set of representative networks involves a classification of all distribution networks in a country or region. Ideally, a list of all distribution networks would be available, and it would be straightforward to identify the share of them represented by each representative network. However, this is often not the case, due to the unavailability of data. Thus, representative networks may be developed according to a high-level categorization, based on aspects such as voltage level and types of distribution areas set by regulation (e.g.: urban, sub-urban and rural). Chapter 5 discusses further the representativity weights and the process of developing representative networks for SRA.

3.5 Non-technical SRA

The economic, social and regulatory context also plays a very important role in the implementation and outcomes of smart grid use cases. Demonstration projects often benefit from specific investment and regulatory support, but the adoption of smart grid use cases may face different challenges. Non-technical aspects may prevent the implementation of a use case (e.g.: prohibition of islanded operation will impede any micro-grid solutions), limit its impact (e.g.: residential demand response solutions have bigger potential where consumers have electric heating), facilitate its adoption (e.g.: mandatory smart meter roll-out may accelerate use cases related to LV monitoring or demand response), or guide it in a certain direction (e.g.: different vendors will promote different solutions to try to sell their equipment to distribution companies).

Including the regulatory framework and the perspectives of all involved stakeholders is of paramount importance to understand the deployment of smart grids. Smart grid research and demonstration projects (as those reviewed in section 2.3.2 and 3.1.2.1) often incorporate regulation in a work package or task devoted to identifying regulatory barriers, or issuing regulatory recommendations. Furthermore, most of these projects are launched and lead by DSOs, usually in collaboration with manufacturers, research institutions and other stakeholders. Acknowledging that more social perspectives have been so far underdeveloped, there is an increasing trend to give more prominence to and incorporate other stakeholders (associations of consumers, aggregators, TSOs, DG owners, etc.).

One of the main contributions of the proposed SRA is to bring technical and non-technical analyses together. Thus, the regulatory and stakeholder-related boundary conditions are incorporated into the proposed SRA methodology to identify barriers and drivers to the implementation of smart grid use cases, as indicated in Figure 3.3.

3.5.1 Regulatory framework

Regulation sets the guidelines and framework for all involved agents in the electric power system[40]. Distribution is a regulated activity, so DSOs must comply with the regulatory framework in place and their activity is remunerated according to the revenues allowed by regulation. Therefore, the deployment of smart grid solutions will be a decision of the DSO strongly linked to regulation. Moreover, many smart grid use cases rely on the active participation of distribution network users or distributed energy resources (DER) (active consumers, DG, distributed storage). However, this requires regulatory mechanisms allowing and encouraging distribution network users to provide these services, which are scarcely developed yet.

The proposed SRA methodology incorporates regulation following three main steps: (1) identification of relevant topics to the implementation of the smart grid use case, (2) characterization of the regulatory boundary conditions in the considered region(s), and (3) assessment of the effect of the boundary conditions on the replication and upscaling of the use case.

3.5.1.1 Identification of relevant regulatory topics

The SRA of a smart grid use case must study the regulation for the topics that have an impact on the implementation and outcome of the smart grid use case. Relevant regulatory topics may be general aspects that have an impact on the adoption of any smart grid solution, such as for instance distribution remuneration and how the cost of innovative smart solutions may be recovered by distribution companies, or specific for some use cases, such as for instance, the treatment of losses, which is relevant for use cases related to DER management and demand response, but not for use cases aimed at reliability improvement. The regulatory topics that are relevant to each type of smart grid use case are identified in Chapter 4.

As a regulated activity, the revenues allowed for DSOs are set by the regulator. Regulation must ensure that distribution is a stable activity with adequate remuneration, and that network users have an adequate service at a reasonable cost. The mechanisms used by the regulator to establish the allowed regulatory asset base and allowed investment costs, as well as the set of revenue drivers and specific

---

[40] The reader is referred to chapters 3-5 of (I. J. Pérez-Arriaga, 2013) for an extensive overview of electricity regulation, regulation of monopolies and electricity distribution. These chapters explain the basic principles underlying regulation, the advantages and drawbacks of the most common approaches for regulatory design and the details of the main regulatory topics.

incentives considered by the regulator are key aspects that greatly influence the strategies adopted by DSOs towards the upscaling and replication of smart grid use cases.

Thus, the treatment of energy losses and continuity of supply, usually subject to economic incentives based on a reward/penalty scheme according to performance with respect to a target may encourage DSOs to invest in smart grid solutions aimed at reducing energy losses and improving continuity of supply, respectively. Furthermore, in a context of uncertainty and technological development, innovation may be promoted through funding of R&D projects and other innovation incentives.

The integration of DG and other DER in the distribution networks is subject to the regulation. Regulation establishes RES-DG and EV promotion policies. It also sets the corresponding network charges and requirements for DSOs to provide network access to DER units, and to DER units regarding visibility (through remote metering) or other technical requirements (e.g.: fixed threshold for power factor).

The active participation of consumers through demand response, DG, storage and EVs for the provision for network services (e.g.: voltage control) requires a regulated mechanism where commercial agreements can be made ensuring a fair remuneration of these services.

3.5.1.2 Characterization of regulatory boundary conditions

Regulation may vary across countries and regions and can change in time, so it is important to have an exhaustive and updated characterization of the regulation in the considered regions for SRA. National regulatory authorities generally make the information available, although language barriers may be encountered in some cases. International organizations such as ICER, CEER and ACER facilitate knowledge sharing among regulators and also provide useful information on different regulatory topics, such as the periodical benchmarking report by CEER on quality of supply (Council of European Energy Regulators (CEER), 2016), investment conditions (Council of European Energy Regulators (CEER), 2017) and smart grid enabling regulation (Council of European Energy Regulators (CEER), 2014).

3.5.1.3 Assessment of the effect of regulatory boundary conditions on the replication and upscaling of the use case

At this step, the regulatory aspects that are relevant to the implementation and performance of the smart grid use case are analyzed to qualitative assess their impact. Thus, regulatory barriers and drivers may be identified. For instance, the existence of economic incentives for innovation mitigate the risk and thus encourage DSOs to invest in smart grid solutions. By contrast, the prohibition of disconnection of network users from the distribution grid impedes the implementation of islanded operation to improve continuity of supply.

It must be noted that the regulatory and technical boundary conditions are not independent, but quite the opposite. Regulation establishes requirements and incentivizes certain levels of investment, reliability, etc. Thus, many technical parameters are determined or very strongly linked to regulation. For instance, the voltage limits set by regulation (typically 10% of nominal value in European countries) limit the hosting capacity of a distribution network. The assessment of these more technical and detailed aspects may require additional simulation scenarios. This way, the application of the steps defined in this thesis for SRA may be carried out in an iterative process, going back to steps 4 and 5 of technical SRA as a part of the regulatory analysis. Taking the previous example, simulation scenarios of different values of allowed voltage could be used to understand how the regulatory limits affect the increase of hosting capacity achieved with smart grids.

3.5.2 Perspective of stakeholders

The potential for replication and scaling-up of smart grid use cases requires the involvement of several stakeholders, besides DSOs. The acceptance of smart grid technologies is necessary for the successful upscaling of smart grids (Broman Toft, Schuitema, & Thøgersen, 2014). Therefore, the expectations and behavior of the relevant stakeholders, and their interactions must also be analyzed.

3.5.2.1 Identification of relevant stakeholders

Some stakeholders, such as regulators, consumers, manufacturers or ICT/software providers, play rather cross-cutting roles, while others such as DER owners, supplier/aggregators or TSOs may be related to specific use cases where their active participation is required.

Consumers

Naturally, consumers are the most important group of stakeholders for the smart grid. The ultimate objective of the electric power system is to deliver a more efficient, sustainable and reliable service for consumers.

Consumers are the main beneficiaries from reliability improvement, and suffer supply interruptions. The costs of supply interruptions for consumers varies depending on the use of electricity of the different consumers at different times and the duration of supply interruptions. Consumers cannot be treated as a homogeneous group. In general, industrial and large consumers are more aware of the cost of supply interruptions. By contrast, it is more difficult for residential to evaluate the monetary loss related to supply interruptions, and to notice improvements of continuity of supply when reliability levels are already high.

Additionally, many use cases are based on a more active role of the demand, providing consumers with an enhanced information about their own consumption, and enabling demand response to improve the operation of the system. Consumers may be reluctant to modify their behavior, especially if they perceive scarce benefits from this. Industrial and commercial consumers are more aware of their energy use and therefore may respond to price signals to a higher extent. In the case of residential consumers, subjective motivations, such as environmental concerns, technology early-adopting attitudes or comfort, are more relevant.

Distribution costs are borne by all network users through the tariff, so consumers tend to expect cost reductions from the implementation of smart grid solutions. Furthermore, the lack of trust of consumers in electric power companies can also act as a barrier for smart grid deployment (Wolsink, 2012).

Distributed generation, distributed storage and electric vehicle owners

Smart grid use cases are motivated by the presence of DER, and at the same time, many smart grid use cases rely on their active participation.

Sustainability and environmental policy goals pursue the decarbonization of the electric power and transportation sectors. Renewable generation and electrification of transportation objectives are translated for the distribution network into the integration of renewable DG and EVs. Additionally, additional distributed resources, such as other DG technologies and distributed storage can help achieve efficiency goals. All in all, international organizations and countries pursue an increasing presence of DER.

In order to encourage investment in DER, different support schemes and incentives have been designed. As technologies become more mature and their adoption is more wide-spread, costs decline and so does the need for additional incentives. However, in order for these mechanisms to be effective, they must be stable, predictable and understandable so that DER owners can perceive them as such. Additionally, network access and network charges add up to the business case for DER owners, as well as interconnection standards and requirements. A positive business case encourages prospective DER owners, thus favoring the context for the upscaling of smart grid implementations.

DER owners could potentially provide several services to network operators and become active participants in smart grid use cases to achieve a more efficient integration of more DER, mitigate voltage and overloading problems, reduce technical losses, enable islanded operation, etc. In order to enable and encourage DER owners to offer their flexibility to the network, appropriate regulatory and economic signals are required. The figure of energy service companies, retailers and aggregators can help bring together small DER owners and thus facilitate a coordinated, more beneficial management.

Additionally, it must be borne in mind that DER owners are network users and as such, benefit from reliability improvements and suffer from the unavailability of the network during supply interruptions. Therefore, as in the case of consumers, smart grid use cases aimed at improving reliability indirectly affect DER owners.

Retailers, suppliers, aggregators

Electricity retail markets are not fully developed yet, particularly for small end consumers. Nonetheless, smart metering and new architectures can potentially be drivers of change in this regard. Thus, suppliers will have to meet the growing needs of consumers offering innovative energy and billing services. These services should have some added value for their customers in economic or environmental terms since this is liberalized activity where competition is promoted. Aggregators are a particular kind of retailer, in the sense that they engage in contracts with end consumers to manage their energy consumption, which specialize in gathering distributed flexibility from network users so as to provide system and network services. Hence, retailers and aggregators will become key agents in smart distribution grid with active demand response.

During the implementation of the demos, retailers may be unable to meet the needs of DSOs at a particular time since these may not coincide with those of aggregators who may find a higher opportunity cost in the delivery of other services. Moreover, given that retailers are the agents that have a more direct relationship with end consumers, they may be unwilling to carry out certain actions which may raise complaints from consumers

Transmission system operators

Distribution networks are connected to the transmission grid, which is operated by a TSO. The increasing presence of DG and other DER connected to distribution networks has significantly altered electricity flows from the transmission to the distribution. Technical requirements imposed on DSOs at the boundary network buses may potentially hamper smart grid solutions based on demand response and DER flexibility management. At the same time, DER could provide flexibility and offer services to the TSO, so that TSOs may even purchase ancillary services from DER to support system operation, use demand response to alleviate network congestions, etc. Therefore, stronger TSO-DSO cooperation and coordination is required (CEDEC, EDSO4SG, ENTSO-E, Eurelectric, & GEODE, 2015; International Smart Grid Association Network (ISGAN), 2014).

TSOs may be reluctant to incorporate distributed resources into their operation strategies, or to hand over a certain degree of control to DSOs. A clear regulatory allocation of responsibilities can help facilitate an efficient cooperation and thus pave the way for the implementation of smart grid solutions.

Manufacturers of smart grid equipment/providers of software and ICT services

This is a heterogeneous group that comprises equipment manufacturers, providers of software services (IS integrators, software developers, etc.) and providers of ICT services. They will be key stakeholders in the development of new smart grid technologies and solutions. Hence, they should cooperate with network companies towards an effective and efficient large-scale deployment. It is desirable that the solutions developed are open and interoperable to facilitate the transition. Innovative technological developments are required in grid components, DG interfaces, demand response, control centers and smart metering solutions and information and management systems.

These stakeholders and DSOs may present divergent views about the specifications and functionalities of devices and solutions. Moreover, in case these are not fully open and interoperable, this could hamper the utilization of devices, ICT systems and software from different agents in the demos.

National regulatory authorities (NRAs)

Regulation clearly plays an essential role for the deployment of the smart grid, defines the framework for all other agents and strongly affects the outcomes of smart grid use cases.

National regulatory authorities must pave the way for a smarter, more efficient and sustainable power system. NRAs must be neutral and ensure that (i) distribution is a stable, sustainable and profitable activity for DSOs and other investing stakeholders, (ii) access to the network and network charges are fair and based on transparent criteria for all agents, (iii) the quality of the service is adequate at a reasonable price for network users.

NRAs may face barriers due to an increased regulatory burden (overseeing new investments to determine efficient costs, etc.) and limited resources (economic constraints, lack of newly required skills, etc.), especially in the face of upcoming challenges and the transition towards smarter grids based on new solutions (Glachant, Khalfallah, Perez, Rious, & Saguan, 2012). Additionally, the activity of NRAs requires an effective regulatory independence and appropriate legal powers. Furthermore, in the smart grid context, it becomes critical to overcome internal culture and inertias and enhance knowledge sharing between regulators, thus tackling scaling-up and replication to learn from existing initiatives and available experience.

3.5.2.2 Characterization of stakeholder-related boundary conditions

The characterization of the relevant stakeholders may be done with the help of questionnaires and surveys in order to learn about their opinions on the functionalities, perceived benefits or drawbacks and components of smart grid solutions. For instance, a survey was carried out in (GRID4EU project, 2014a) to understand the perspective of various stakeholders on smart grids.

3.5.2.3 Assessment of the effect of stakeholder-related drivers and barriers

At this step, the perspectives of the stakeholders identified as relevant to the implementation and performance of the smart grid use case are qualitatively analyzed. The objective is to identify how these stakeholders may oppose or favor the implementation and adoption of the smart grid use case considered, and how their engagement or participation would affect the outcomes of the smart grid implementation.

Naturally, the perspectives of different stakeholders are subject to their own interests and the potential benefits (or setbacks) perceived from the implementation of the smart grid use case. These perspectives are also subject to the information available to the stakeholders and their knowledge in certain subjects. This means that lobbies and information campaigns may have a certain influence on the perspective of stakeholders.

The stakeholder-related boundary conditions are inexorably linked to the regulatory framework, as the behavior of stakeholders is subject to the regulation in place. Regulation must provide stability and economic signals to encourage investment. Furthermore, regulatory standards and requirements, may motivate or hinder the deployment of smart grid solutions.

3.6 Conclusions

Chapter 2 highlighted the need for assessing the scalability and replicability potential of smart grid solutions to learn from demonstration projects, understand the impact of smart grid deployment and guide future investment. This chapter provides the conceptual and methodological framework for the SRA of smart grid use cases in distribution networks. The main concepts, objectives and scope have been defined, and existing approaches have been reviewed.

Scaling-up and replication are implicit to the assessment of the potential impact or cost-benefit analysis of any solution, technology or policy in a region or country, since conclusions are drawn by extrapolating from experimental data, assuming certain hypotheses, or performing sensitivity analyses. However, explicit and systematic SRA for smart grid is still incipient.

This chapter has reviewed the existing approaches for SRA. Based on this review[41], a SRA methodology is proposed. This thesis is focused on a functionality-oriented SRA to determine what to expect from the implementation of smart grid use cases elsewhere (replication) or at a large scale (upscaling). The proposed SRA thus concentrates on the effect of technical, economic, social and regulatory conditions, rather than on the technological scalability and replicability of the solutions themselves.

The proposed SRA methodology comprises a quantitative and detailed technical analysis based on simulation to compute the KPIs that measure the impact of the use case on the system; and a second stage of a more qualitative non-technical analysis, to include regulatory aspects and the perspective of the different stakeholders involved. The SRA methodology incorporates the experience gathered from real-life testing of the smart grid use case in demos, comparing the KPIs measured in the demo and those obtained through simulation. The stage of technical SRA is implemented in several steps: (1) identification of relevant KPIs, (2) selection of simulation tool, (3) definition of representative networks, (4) definition of scenarios, (5) simulation for KPI computation, (6) review of demo results, and (7) upscaling of simulation results. The use of representative networks enables upscaling of simulation results through a representativity rate or scaling-up factor for the whole region considered. Naturally, the adequacy of the selected representative networks is crucial for SRA results. Chapter 5 has been devoted to representative networks, discussing representativity weights and the process of developing representative networks for SRA. The stage of non-technical analysis addresses the regulatory framework and the perspective of stakeholders involved each through three steps of (1)

---

[41] Actually, the proposed SRA is specially aligned with the GRID4EU project, as the Author of this thesis has been strongly involved in this project.

identification of relevant topics, (2) characterization of the boundary conditions, and (3) assessment of the effect of the boundary conditions on the replication and upscaling of the use case.

The proposed SRA methodology is applicable to study the expected impacts from the implementation of any smart grid solution. However, depending on the functionalities implemented in the smart grid use case and the objectives pursued, the type of impacts differ. The relevant boundary conditions for SRA differ, and the specific simulation tools and KPIs must be adequately adapted. Thus, the particularization of the SRA methodology for each type of smart grid use case identified in Chapter 2, namely (i) network automation for the improvement of continuity of supply, (ii) DER management and voltage control to increase network hosting capacity and (iii) islanded operation and microgrids to improve continuity of supply, is presented in Chapter 4. Furthermore, the case study in Chapter 6 illustrates the fully-fledged application of the proposed SRA methodology.

Chapter 4

Implementation of SRA: particularization for smart grid use cases

Building on chapter 3, this chapter further elaborates on the proposed SRA methodology by describing its detailed particularization for the three categories of smart grid use cases identified in chapter 2. Thus, this chapter proposes the detailed implementation of the SRA methodology to analyze smart grid use cases based on (i) network automation to improve continuity of supply; (ii) DER management and voltage control to increase network hosting capacity; and (iii) islanded operation and microgrids to improve continuity of supply.

The SRA implementation proposed for each of the families of use cases is described independently. Sections 4.2, 4.3 and 4.4 have been designed to support their stand-alone reading. Therefore, the steps described in chapter 3 are picked up in this chapter, and common issues to all use cases are reiterated for each group for the sake of clarity.

4.1 Introduction

The proposed SRA methodology comprises a technical analysis based on simulation to quantify a set of KPIs using representative networks and scenarios to account for the different boundary conditions relevant to the scaling-up and replication of the considered smart grid use case. Additionally, a second stage of analysis incorporates the effect of regulation and stakeholder-related boundary conditions as well. The specific KPIs, simulation model, and boundary conditions that are relevant for scaling-up and replication depend on the smart grid functionalities implemented.

Smart grid use cases were mapped in chapter 2 according to the enabled functionalities and pursued objectives into (i) network automation to improve continuity of supply; (ii) DER management and voltage control to increase network hosting capacity; and (iii) islanded operation and microgrids to improve continuity of supply. The scalability and replicability of these three groups of smart grid use cases can be studied together applying the proposed SRA methodology, and the detailed implementation is described in the following sections of this chapter. For each category of smart grid use cases, the steps of the proposed SRA methodology are particularized. Therefore, the adequate KPIs, simulation models and relevant boundary conditions are identified for each category of smart grid use cases.

4.2 Network automation to improve continuity of supply

This category groups use cases that pursue the objective of improving continuity of supply (CoS). Continuity of supply is related to the availability of the network to distribute the electricity for the network users and is usually measured in terms of the number and duration of supply interruptions suffered by the consumers.

Smart grid solutions based on network automation implement remote control of monitoring and protection equipment, thus enabling remote fault detection systems and remote network reconfiguration. These use cases help improve the process of failure management and service restoration[42], so that supply interruptions are reduced in frequency (lower occurrence), impact (each interruption affects less consumers) and duration (each affected consumer suffers an interruption of shorter duration in time).

The main idea behind the SRA is to simulate the implementation of the smart grid use case and assess the outcomes that would result. Therefore, it is important to understand the actual operation of

[42] Smart grid solutions implementing network automation can also help achieve a more efficient operation and maintenance of the distribution grid, thanks to remote switching and network reconfiguration, as discussed in chapter 2.

distribution networks in terms of CoS and fault management. For this purpose, subsections 4.2.1 and 4.2.2 explain in detail the fault management process commonly followed by DSOs and how this process is changed when different automation systems are implemented. Then, sections 4.2.3 and 4.2.4 describe the implementation of the SRA methodology proposed in chapter 3 for the SRA of network automation use cases.

4.2.1 Supply interruptions and fault management in distribution networks

Regulation regarding continuity of supply in distribution networks has historically focused on the MV level. Although the contribution of each voltage level to the reliability for final consumers varies in time and across countries, it can be stated that most supply interruptions are caused by incidents on MV networks[43]. Network reliability and continuity of supply at medium voltage level is mostly related to the occurrence of electric faults caused by the either failure or degradation of electrical equipment or by external elements, such as meteorology, trees and animals for overhead networks and construction works for underground networks[44].

DSOs set operation and maintenance strategies to ensure certain degrees of continuity of supply for the users of their grids. Traditionally, the degree of monitoring of the distribution network has been very low, especially at lower voltage levels. Therefore, an incident in the MV network causing a supply interruption may trigger an alarm at the control center if the protections at the head of the feeder are connected to the control center. Otherwise, and for faults originated at the LV network, DSOs only register the interruption based on notifications from interrupted users. In the occurrence of a fault in the distribution network, this fault must be located and isolated as fast and as much as possible. If possible, service is then restored in healthy sections of the grid. Then, the fault is repaired and service is restored for any users where service is still interrupted and the conditions of operation of the network are brought back to the normal parameters. The process of service restoration depends mainly on the topology of the network: the available switchgear (number, location and type of protection elements), the meshing and structure of the network and whether the line is underground or overhead. Usually, LV networks are not meshed and reconfiguration is not possible.

---

[43] The data reported in (Council of European Energy Regulators (CEER), 2011a) indicated a contribution of around 70% of MV level incidents to both SAIDI and SAIFI for LV users.

[44] Additionally, there is also a concern for cyber-physical security regarding vandalism, hacks and attacks. Physical reliability threats have always been a cause for concern. Actually, distribution companies often claim that distribution infrastructure is exposed to theft and in some cases secondary substations must be protected with video surveillance, etc. Regarding cyber-security, the concern for reliability is stronger at transmission level than for distribution, since the infrastructure is much more critical (of a much higher power and affecting a much larger number of consumers), and telecommunications and automation are already in place. Nevertheless, distribution automation systems, advanced metering infrastructure and smart meters must be protected against cyber-attacks to avoid intentional malicious supply interruptions.

In order to facilitate the understanding, the terms used in this PhD thesis to designate the protection elements in distribution networks are listed and explained below:

- Switch, on-load switch, load-break switch: protection device able to open the circuit only off-load, i.e. in the presence of no current, or under normal operation, i.e. in the presence of normal operation currents, but not in the presence of a fault.
- Breaker, circuit breaker: protection device able to open the circuit in the presence of fault current. In the occurrence of a fault, the closest upstream breaker trips.
- Fault-pass detection: ability to measure normal operation and fault currents to determine whether a fault has gone-through (fault-pass detector), or additionally whether the fault is upstream or downstream the measuring device (directional fault-pass detector).
- Recloser: circuit breaker able to automatically re-connect after a brief interval, used in overhead networks to avoid momentary faults that clear themselves (contact of an external agent, like a tree branch or a bird).

Typically, in distribution networks, all MV feeders have a circuit breaker (with a recloser in the case of overhead networks) in the primary substation, at the head of the feeder. MV/LV transformers may be connected to the MV grid as represented in Figure 4.1: a) in a so-called input-output configuration, in series, through load break switches, which means that the upstream and downstream MV network can be isolated from each other at two different points; or b) in antenna. Distribution networks are radially operated, but MV networks are usually meshed at some points, so that MV feeders are connected to other MV feeders through normally-open switches and alternative configurations are available.

In the European context, distribution systems typically have secondary substations comprising three-phase MV/LV transformers and MV switchgear, supplying three-phase LV outgoing feeders.

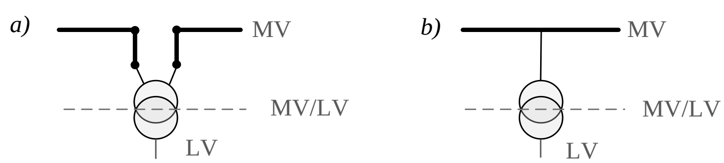


Figure 4.1: Connection of secondary substations to MV grid: a) series with input and output load break switches; and b) antenna.

When a fault occurs in the MV network, the closest upstream breaker (typically, the breaker located at the head of the feeder, in the primary substation) trips and the circuit is open. Thus, service is interrupted for all the downstream section of the network. Reclosers are often placed at the header of the MV feeders of overhead lines too. These devices are able to restore service in the case of transient faults. Transient faults are more frequent in overhead lines where external elements (birds, tree branches, etc.) may contact the MV line. Reclosers are programmed to perform the reconnection of the MV feeder to power supply after the main breaker has tripped, so that in case the fault has been cleared by itself, only a short interruption of supply is caused. If the fault persists, supply remains interrupted and the fault detection, isolation and service restoration (FDIR) must be carried out.

Depending on the configuration of the network and available protection elements, fault location may involve a dichotomic search operating load break switches, the use of information from fault-pass detectors, and visual inspection of the lines.

When a fault occurs in a ramification or derivation from the main trunk protected by a fuse at the point of ramification, this fuse isolates the branch from the main trunk. Therefore, loads in the main trunk and other derivations are not affected, while all loads connected to that ramification suffer from a supply interruption, and the fault must be located within the branch.

Dichotomic search through manual operation of switches

Secondary substations may be connected to the MV grid in a so-called input-output configuration, a connection in series to the grid through manually operated, normally-closed, load-break switches. This is the usual configuration for underground networks and urban areas.

When a fault in the MV line causes a supply interruption, the switches of the secondary substations can be operated in order to determine whether the fault is up- or downstream the operated switch. In order to locate the fault, a dichotomic search is performed within the group for affected loads with input-output load breakers. This search is an iterative process where the maintenance crew opens the switch in one secondary substation to split the MV feeder in two segments. The circuit breaker at the head of the feeder is closed. If the fault is in the upstream segment, the circuit breaker trips.

Then, service can be restored for the discarded segments at each step of the search when the topology of the network allows it. If the fault is downstream the operated switch, that switch must remain open to isolate the faulty segment and service can be restored upstream by closing the breaker at the primary substation. For faults upstream, service may be restored if there is an available interconnection to another feeder through a normally-open switch. The network can be thus reconfigured by closing the normally-open switch so that the loads may be supplied by an alternative path and the non-healthy segment can be isolated.

The process of fault location and isolation and reconfiguration for service restoration is illustrated with an example in Figure 4.2. The diagram shows two MV feeders connected to the same HV/MV substation (HV/MV) through normally closed circuit breakers (Sa1, Sa2). The two feeders are connected to each other at their end through a normally open switch (Sab). Each feeder has 6 MV/LV transformer substations (TS). In the event of a fault in the MV network between TSa2 and TSa3, Sa1 trips. The maintenance crew would open the manual switch at the right of TSa4 and close Sa1. Sa1 would trip, thus indicating that the fault is upstream TSa4. The crew would then close Sab and open the switch at the left of TSa4, so that the service would be restored for TSa4-TSa6. Next, the crew would repeat the operation, opening the switch at the right of TSa2 and closing Sa1. Sa1 would not trip now and service would be restored for TSa1-TSa2. Finally, the switch at the left of TSa3 would be opened to restore service in TSa3. All consumers would have supply and the faulty segment could be repaired.

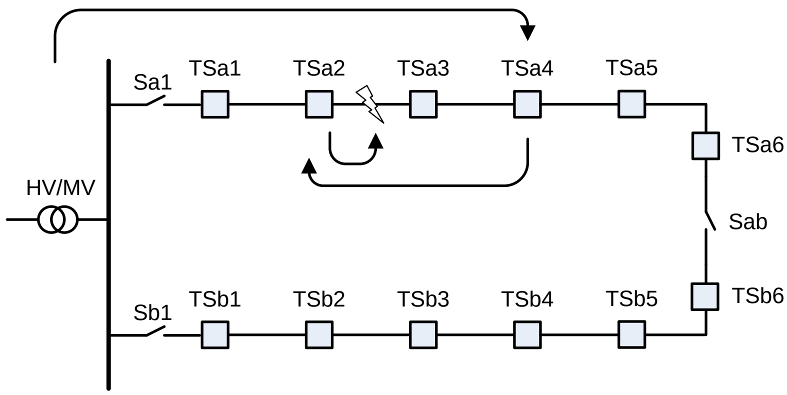


Figure 4.2: Fault management process in an MV network (*HV/MV*: HV/MV substation supplying MV feeders *a* and *b*; *TS*: secondary substations with input and output load break switches; *Sa1*, *Sb1*: normally closed breakers; *Sab*: normally open switch).

Visual inspection of lines

Secondary substations may be alternatively connected to the MV line in a so-called antenna scheme, i.e., in parallel to the grid. In this case, as well as in the case of other configurations with no input and output load breakers, the maintenance crew must locate the fault by walking or driving along the line to visually find the fault. These configurations are more usual in overhead lines, in rural areas.

Fault-pass detectors provide information on whether fault currents have circulated through the MV feeder at that point of the network. In overhead lines, fault detectors are typically visible and feature some luminous indication. This information is used to determine whether the fault is located up- or downstream the device and thus discard the healthy segment.

Repair

When it is no longer possible to isolate the fault, the maintenance crew carries out the repair of the MV line or cable. Finally, service is restored for all network users and operation goes back to pre-fault condition and the original configuration of the grid is re-established.

4.2.2 Effect of automation for fault management

Smart grid solutions for the improvement of continuity of supply include communications, monitoring systems, telecontrol of protections and intelligent local/centralized control systems for the operation of the network. Monitoring and telecontrol are implemented at certain locations of the grid. In the European context, network automation is mainly linked to the secondary substations of distribution systems. The automation degree is defined accordingly as the share of secondary substations which have been upgraded to ‘smart’ or ‘automated’ secondary substations, i.e. those with either remote monitoring capabilities or both monitoring capabilities and remote control of the switchgear. Telecontrol would only be implemented in secondary substations connected to the MV feeder through an input-output configuration with load break switches (or breakers).

Monitoring devices can measure voltage and current at the point of the network where they are located to provide control center with information regarding the power flows, the lack of voltage or overcurrents indicating a fault, etc. Monitoring the network provides the control center with a better knowledge of the state of the network at all times. In the event of a fault, the information from fault-pass detectors is available to trace fault currents, so that it is possible locate the fault in a reduced segment of the MV feeder. Therefore, time required to locate the fault is diminished.

Remote control of switches and breakers allows switching operations to be performed by the distribution operator from the control center, instead of sending a maintenance crew to perform manual operations. Therefore, telecontrol results in a reduction of the time required to locate and isolate a fault for all kinds of networks.

For meshed networks, telecontrol additionally reduces the time required to restore service in those loads that can be supplied by reconfiguration of the network. In that case, those loads may be considered to have suffered only a transient interruption, if restoration is achieved in a time shorter than the regulatory limit, typically established in 3 minutes for most European countries. Consequently, the number of consumers affected by a supply interruption is reduced and the average frequency of service interruptions is decreased.

Control systems can register the information provided by monitoring devices and process it to coordinate switching actions to perform reconfiguration to locate and isolate faults and restore service as much as possible. Different control systems may be in place, both following a centralized or a de-centralized approach with different areas governed by local systems. These systems may propose operation strategies to the distribution operator, requiring human supervision to carry out any actions, or may operate autonomously.

The implementation of network automation for fault management facilitates a much faster service restoration. When a fault occurs, the fault is quickly isolated among the two closest telecontrolled switches or breakers carrying out the dichotomic search process remotely by the operator or autonomously by the control system and service is restored in the healthy segments of the feeder. Then, if there are additional monitoring elements available in the affected segment, the information is used to discard a section of the affected segment to locate the fault. Fault location is completed manually for the remaining segments, following the usual procedure of manual switch operation and/or visual inspection. Finally, the fault is repaired and normal operation is restored. Naturally, the segment of the feeder affected by the supply interruption and the size of the network section that must be subject to manual fault location depends on the amount and location of automated substations.

Different smart grid automation solutions to improve continuity of supply have been developed, tested and implemented by distribution companies (see review of demonstration projects in section 2.3.2). All of these implementations are generally very similar, and the main differences are related to the control system or the logic of the automation in real-time operation of the distribution grid. As explained, 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. Additionally, different implementations consider different shares of automated substations and design automation scenarios (which secondary substations are equipped with monitoring or with monitoring and telecontrol) specifically considering the topology of the distribution networks.

Optimal location of automation

The results obtained by the deployment of automation technologies may largely depend on their location and degree of implementation. Much work has been devoted to the analysis of strategies to determine the optimal location and number of automated elements considering reliability improvements.

When a fault occurs, the fault is isolated between the two closest automated switches. Therefore, the optimal location for telecontrol would be the location with minimal distance to all potential faults (or minimal weighted distance considering the probability of each potential fault). Therefore, it would depend on the network configuration and topology and on the distribution of probability of faults along the MV line. Furthermore, given that different reliability indices average supply interruptions through different variables (i.e. number of consumers, rated capacity, etc.), the interruption of supply of each secondary substation has a different "relative importance" on the resulting improvement measured by the reliability indices. Therefore, the optimal location of automation could change depending on the reliability indices used.

This is a complex issue that deserves further study and analysis. Some authors have proposed different optimization techniques, including among others classical optimization (Ferreira et al., 2015; Siirto, Safdarian, Lehtonen, & Fotuhi-Firuzabad, 2015), particle swarm and artificial bee colony optimization (Alencar, Rodrigues, & da Silva, 2011; Shahsavari, Fereidunian, & Mazhari, 2015), and advanced genetic algorithms such as fast elitist non-dominated sorting technique (Pombo, Murta-Pina, & Pires, 2016; Vitorino, Jorge, & Neves, 2015), and have presented different Pareto frontiers based on shuffled frog leap (Asrari, Lotfifard, & Payam, 2016), enhanced gravitational search (Narimani, Vahed, Azizipanah-Abarghooee, & Javidsharifi, 2014) or genetic algorithms (Pombo et al., 2016). Most of these works assess the reliability improvement through analytical expressions assuming an average restoration time.

Other works focus on the assessment of automation strategies designed specifically for the network analyzed. In this line, a cost-benefit analysis is carried out in (Aggelos S Bouhouras, Andreou, Labridis, & Bakirtzis, 2010), comparing automation infrastructure costs to the reduction in the costs of supply interruptions and energy losses. CoS improvement is computed through simulation. Similarly, authors in (Popovic, Glamocic, & Nimrihter, 2011) propose to assess and rank combinations of monitoring and telecontrol based on the cost of interruptions to consumers and the investment cost of automation. In this work, the cost of interruptions is based on a detailed computation of outage times simulating the actual process of service restoration. An even more detailed fault management process is simulated to determine the optimal position of protection elements in (Allegranza, Mastandrea, & Ruffini, 2005). The optimal implementation degree of automation is investigated in (Rodriguez-Calvo, Frías, Reneses, Cossent, & Mateo, 2014), using a reference network model that is able to simulate the process of service restoration to assess the improvement of CoS.

All in all, different analytical methodologies can be found in the literature as well as many examples of case studies and implementation of pilot projects. However, there is a lack of comprehensive and comparative analyses that evaluate the influence of different technical and reliability measurement parameters that can help infer general rules and understand the potential of the deployment of MV automation under different contexts and conditions.

Intuitively, it can be deduced that having several telecontrolled elements distributed along the line will generally have a more beneficial impact than having these elements concentrated in one section of the network, very close to each other.

Distribution companies usually opt for the general strategy of implementing automation as homogeneously as possible, trying to add automation gradually to divide network sections between two automated nodes into halves. This approach is in line with the process followed when a fault occurs and a maintenance crew must locate the fault manually. Maintenance crews follow a dichotomic search process. This approach implicitly assumes that faults are equally likely to happen on both sides of this middle point. However, in practice, maintenance crews may have experience on typical problematic spots (junctions, areas where construction works are on-going, older sections of the grid, etc.). Thus, implementation strategies may be modified to account for this so that the process may differ. The technical analysis for SRA is focused on automation scenarios based on the strategy just described in order to be consistent with the strategy followed by distribution companies.

4.2.3 Technical SRA

The stage of technical analysis emulates the fault management process previously explained both with and without the automation smart grid solution in place to assess the impact on continuity of supply under different boundary conditions. Technical SRA for automation quantifies the improvement of continuity of supply through simulation and analyzes the effect of boundary conditions through sensitivity analysis.

4.2.3.1 Identification of relevant KPIs

The objective of these use cases is to improve continuity of supply. Continuity of supply is measured through different indices called continuity of supply or reliability indices. Most continuity of supply indices express the average frequency and duration of supply interruptions in the system. Some of the most commonly used include:

- System Average Interruption Frequency Index (SAIFI): average number of interruptions of supply suffered by consumers in a certain network or region, which is computed as the total number of service interruptions suffered by each consumer over a period of time (typically a year) divided by the number of consumers.
- System Average Interruption Duration Index (SAIDI): average outage duration for each consumer in certain network or region, which is computed as the total duration of service interruptions suffered by each consumer over a period of time (typically a year) divided by the number of consumers.
- Customer Average Interruption Frequency Index (CAIFI): average outage duration, which is defined as SAIDI divided by SAIFI.
- Average System Interruption Frequency Index (ASIFI) and Average System Interruption Duration Index (ASIDI): these indices are defined in some countries[45] as alternative to SAIFI and SAIDI, where the frequency and duration of supply interruptions are weighted by rated power instead of number of consumers.
- Average Service Availability Index (ASAI): this index represents the average share of annual hours where the network is available (i.e. there is no interruption) per customer and it can be expressed with respect to SAIDI.
- Energy not supplied (ENS) or Non-served energy (NSE): the volume of energy not supplied is often used to assess the value of energy for network users (or the loss caused by the interruption of supply). However, as it indicates the demand that would have been supplied if there had not been an interruption, NSE cannot be measured. NSE must be estimated based on information on the situation prior to the interruption, historical data, etc.

The implementation of automation smart grid solutions improves the fault management process. This improvement results in a faster service restoration and subsequent reduction of consumers affected by supply interruptions as well as the decrease in the duration of these interruptions for affected consumers. Therefore, the main KPIs for the SRA of this group of use cases are based on indices of continuity of supply. This thesis proposes the use of SAIFI and SAIDI, which are the most commonly used indices, to define the objective KPIs of SAIFI and SAIDI reduction as the difference before and after the implementation of the automation use case. In this case, no intermediate KPIs are deemed necessary for SRA of automation use cases.

[45] In Austria, indices ASIFI and ASIDI are monitored. In Spain and Portugal, NIEPI (equivalent number of interruptions related to the installed capacity) and TIEPI (equivalent interruption time related to the installed capacity), which are very similar to ASIFI and ASIDI are monitored. In Finland, the number and duration of interruptions are weighted depending on the annual consumption to obtain T-SAIDI and T-SAIFI (Transformer-SAIDI and Transformer-SAIFI).

4.2.3.2 Selection of simulation tool

Technical SRA for this group of use cases requires a reliability analysis to compute the indices of continuity of supply before automation is implemented and with the solution in place, so that the improvement of continuity of supply achieved by the use case can be determined.

The proposed reliability analysis is based on the simulation of service restoration for any possible fault in the distribution network[46]. For each fault, the affected consumers are identified and the process to locate the fault and restore service is emulated to compute the total interruption time for each affected consumer. The reliability indices are then determined considering the expected occurrence of each fault, according to deterministic failure rates, and averaging the quality of each consumer (considering the number of consumers as the weighting parameters to obtain SAIFI and SAIDI, or the rated power, if ASIFI and ASIDI are used instead).

The simulation tool must be able to account for the operation of distribution networks and different steps of the fault management process described in section 4.2.1. Furthermore, the simulation tool must be able to model the effect of monitoring and telecontrol according to section 4.2.2 and accurately determine reliability indices for different automation strategies (i.e. with different number and location of monitoring and telecontrolled elements). Additionally, the process of network reconfiguration may also involve load flow analysis to check that any configuration proposed for the network complies with technical constraints and causes no overloads or voltage problems (A. González, Echavarren, Rouco, & Gómez, 2011).

4.2.3.3 Definition of representative networks

In order to simulate fault occurrence, the failure rate of the different elements and sections of the network should be adequately characterized. Failure rates reported in the literature and in the industry are usually based on historical data, acquired by distribution companies that must register supply interruptions in their networks. Usually, a uniform failure rate per km and year is assumed for conductors, differentiating overhead lines and underground cables. Underground cables are more isolated and therefore have typically lower failure rates than overhead conductors. In practice, the fault rate is not homogeneous, as there may be more problematic spots (junctions, areas where construction works are on-going) and due to the different ageing of the infrastructure, since distribution assets have a very long lifecycle and therefore sections of different installation date and technical characteristics may coexist in the same distribution network. The ageing of the infrastructure results in a higher likelihood of elements to fail. The failure rates of transformers and protections are usually much, much lower (of several orders of magnitude). Thus, network length and construction type (overhead/underground) become critical factors to determine fault occurrence.

---

[46] Please note that other methods may be applied to assess reliability (analytical, Monte Carlo simulation, etc.). The reader is referred to (Rivier Abbad, 1999) for more details about different reliability analysis methods.

Furthermore, representative network models should feature representative protections schemes and interconnections or tie points, with the reconfiguration options available in actual networks. Therefore, the network topology and configuration must be adequately characterized: the connection of elements (i.e. connection of secondary substations to the MV grid in input-output configuration or antenna scheme), derivations and ramifications and meshing of the network (i.e. availability of an interconnection through a normally-open switch). Additionally, network reconfiguration options to restore supply should be assessed to check compliance with technical restrictions, so the representative network models must include the impedance and thermal limits of network elements, as well as voltage limits.

Finally, in order to determine continuity of supply indices, the location or rated power of consumers[47] is required to weigh reliability across the network.

Representative network models may consist of a few feeders. One feeder would be enough to simulate the fault detection and isolation process and to monitor the duration of supply interruptions for each consumer. However, in order to study the availability of alternative supply through interconnected feeders to restore service, those feeders that are interconnected should be included in the model, so that thermal limits of all elements involved in reconfiguration can be checked.

In conclusion, the most relevant parameters for the set of network models to be used for the SRA of network automation use cases include the following:

- network topology and configuration: protection elements (circuit breakers, switches), derivations and ramifications and interconnections (meshing);
- impedance and thermal rate of network elements and voltage limits;
- fault rate and length of network branches;
- and number of consumers or rated power of each load.

4.2.3.4 Definition of scenarios

The automation degree is defined in this thesis as the percentage of secondary substations featuring remote monitoring capabilities with fault-pass detection and remote switching of input and output switches of the secondary substation. More specifically, the term partial automation will refer to secondary substations only with monitoring capabilities, while full automation will be used to refer to secondary substations featuring both monitoring and telecontrol of switches.

Automation is scaled-up in terms of density considering the implementation of additional smart secondary substations. In order to assess the effect of different degrees of implementation of the smart grid solution, different automation degrees and set-ups can be designed, considering different and different combinations of secondary substations with monitoring and telecontrol capabilities.

[47] In order to compute SAIDI and SAIFI, which average reliability by number of consumers, the location of consumers is required as input data; whereas their rated power would be required to compute ASIDI and ASIFI.

These are specific to each network, since the number of secondary substations varies. Furthermore, the maximum degree of automation is subject to the configuration of the connection of secondary substations to the MV network: only those connected in an input output configuration through load break switches can feature telecontrol of switches, so for some networks, typically in more rural areas, it is not possible to surpass a certain automation degree.

Moreover, different automation scenarios can be analyzed to consider different approaches regarding the control of fault management, whether the intelligence and decision-making is centralized or de-centralized based on local systems, and whether the operation is performed autonomously by the automation system, or whether a human operator must supervise and confirm the switching operations. These aspects must be incorporated into the simulation of fault management with network automation in place. Depending on the automation approach of the studied solution, network reconfiguration for fault location, isolation and service restoration will be carried out in a different sequence and the time required for the automation system to restore service for the different consumers will differ. Control systems are able to process the information available from monitoring devices and propose the switching sequence to locate the fault and restore service in a very short time (in the range of seconds). However, the time required depends on the technical capabilities of the technologies involved in the communications and control algorithms and, most importantly, on whether human supervision is required, which is bound to increase response time (in the range of minutes). If service is restored for some consumers in a time shorter than the sustained interruption threshold set by regulation, usually 3 minutes, those customers are not affected by a sustained interruption and therefore do not contribute to SAIFI. Therefore, the interaction between the time required to restore service by the automation solution for each consumer and the regulatory threshold can have a relevant effect on reliability indices that can be studied through simulation.

Finally, different loading scenarios can be considered to identify the possibilities for network reconfiguration in the different representative networks. Transferring part of the load of one feeder to a different feeder may cause overloading or voltage problems in the latter. Oftentimes reliability analyses assume that reconfiguration causes no violation of technical constraints, because the interconnection of feeders through normally-open switches are designed specifically for reliability improvement, so usually there is enough capacity margin in the network to enable emergency reconfiguration to supply additional load[48]. In order to assess whether loading can impact SAIFI and SAIDI reduction, the most unfavorable loading scenarios (very high demand with no DG production, or very low demand with a very high production of DG) would be considered to identify whether there would be situations where service cannot be restored for all network users through network reconfiguration (due to technical constraints).

---

[48] Some urban networks are even equipped with support cables, i.e. cables with no load connected through normally-open switches, to be used as an alternative path for supply in case of emergency.

4.2.3.5 Simulation for KPI computation

Simulations must be carried out to compute the improvement of continuity of supply for the representative networks developed.

Intra-national replicability of the results is studied using the representative networks that correspond to the demo country, with a special focus on the most important parameters. As explained, this type of use case will be analyzed for types of network with different types of grid architecture, varying aspects such as how meshed the networks are, elements that allow for switching and reconfiguration, length of feeders, load density, etc. For instance, representative networks that correspond to urban areas will be more meshed, while in rural network there will be less substations with input-output configurations, limiting the maximum achievable automation degree. Then, the scope will be further broadened to consider international replicability. The parameters identified for the demo country may differ for other countries. The representative networks in different countries may differ in architecture, voltage level, initial automation degree, initial reliability level and level of protection and switching elements, etc.

Scaling-up in density is addressed through the automation degree. Building on the work of previous steps, simulations are carried out to determine the values of SAIFI and SAIDI that correspond to the scenarios of different automation degrees of partial and full automation for the representative networks. Additionally, simulation is carried out for the automation scenarios that account for different types of control strategies and different time response.

Additionally, simulation considering loading scenarios can determine the impact of generation and demand in networks with tighter capacity margins on limiting the reliability improvement achieved by network automation[49].

It must be noted that technical boundary conditions are very related to the regulatory, economic and social context as well. Therefore, indirectly, the technical analysis comprises many regulatory and stakeholder-related implications. For instance, regulation with strong incentives for continuity of supply improvement may result in a generally more meshed network topology. Yet another very relevant aspect is the definition of reliability indices established by regulation: the regulatory threshold set for sustained interruptions and the methodology to compute the average frequency and duration of supply interruptions. The use of different reliability indices may lead to slightly different results of improvement of SAIFI and SAIDI. These considerations can also be assessed through simulation, computing KPIs to quantify their effect (the case study in Chapter 6 illustrates such analyses).

---

[49] It must be borne in mind that the proposed SRA is focusing on smart grid use cases independently to understand the effect of the different smart grid solutions available. However, different smart grid use cases may interact resulting into synergies: for instance, demand response, and other DER management actions could solve technical constraints to enable service restoration for a particular network configuration.

4.2.3.6 Review of demo results

According to the proposed SRA methodology, the results obtained from simulation are compared to the results observed and measured in the demo to validate simulation. However, in the case of continuity of supply and fault management, actual demo KPIs may not be able to fully capture the effect of automation due to the low probability of fault occurrence. Very few events are likely to take place within the location and during the period of the demonstration, and simulation may become the only option available to obtain quantitative results[50].

4.2.3.7 Upscaling of simulation results

The resulting KPIs measure average reliability improvement for the system. Therefore, the upscaling of simulation results for a large region (a country, or several countries) would involve assessing the average reliability for the whole region. Different reliability indices use different parameters to weight reliability at each point of the network and compute the average: SAIFI and SAIDI are based on the number of consumers, while ASIFI and ASIDI are related to rated power. Therefore, if KPIs are defined based on the former set of indices, the average reliability improvement would be assessed considering the number of consumers supplied by networks of each type o from the set of representative networks developed. If KPIs were defined based on ASIFI and ASIDI, the total rated power of each type would have to be considered.

In some countries, regulation establishes categories to classify the networks to monitor reliability and set reliability targets. NRAs may publish information segregated for each category[51]. Technical SRA could be performed using representative networks based on this categorization and use the data on number of consumers of each type as scaling-up factors.

4.2.4 Non-technical SRA

At this second stage of non-technical, qualitative analysis, regulatory aspects are integrated into the SRA of automation use cases, together with the viewpoints of relevant stakeholders.

---

[50] In fact, these challenges have been highlighted within the GRID4EU project, where the German demo experienced only one fault event during the demonstration of MV automation, and the Czech demo suffered no fault event and resorted to simulation (GRID4EU project, 2016c).

[51] For instance three types of areas are defined by regulation in Italy based on population density (high, medium and low concentration) (Autorità per l'energia elettrica il gas e il sistema idrico, 2011); and four in Spain (urban, sub-urban, concentrated rural and scattered rural) (Spanish Ministry of Economy, 2000). The case study in Chapter 6 is based on these two countries, using representative networks based on the areas defined by regulation and publicly available information segregated by these categories for upscaling.

4.2.4.1 Regulatory framework: identification, characterization and assessment of regulatory boundary conditions

The decision to implement automation in the distribution network (just as in the case of any other strategy for reliability improvement) is to be made by the corresponding DSO. Therefore, the adoption of this type of smart grid use cases is strongly linked to an ensured cost recovery through allowed revenues and specific incentives for reliability and innovation.

Thus, relevant regulatory topics (from those listed in 3.5.1.1) for use cases based on network automation for continuity of supply improvement include overall DSO revenue regulation and specially reliability regulation, including reliability requirements and incentives for continuity of supply and innovation. Furthermore, in the case of automation of LV networks, the data from smart meters may be used for reliability monitoring (and integrated in the fault management process), so that the regulatory treatment of smart meter roll-out and access to smart meter data is a key enabler.

DSO revenue regulation

The reliability of the network, and therefore continuity of supply, is strongly linked to the levels of investment in network infrastructure and expenditure in operation and maintenance (Gomez and Rivier, 2000). Regulation must ensure that consumers receive an adequate quality of service at a reasonable cost. For this purpose, regulation establishes the revenues that DSOs are entitled to and the procedures and mechanisms to control and enforce certain levels of continuity of supply levels.

Under cost-of-service regulation, DSOs may be incentivized to over-invest in case of too high allowed rate of return (or under-invest in the contrary event), which is known as the Averch-Johnson effect. Meanwhile, incentive-based regulation focuses on short-term cost efficiency, which may discourage investment in innovative solutions.

Revenue regulation has been traditionally focused on conventional investments (“copper and iron assets”). Network automation constitutes a new type of distribution assets, with shorter useful lives, more rapid technological development and a more uncertain impact on the network. Thus, future investment needs become harder to estimate both for the regulator and the DSO.

Ex-post adjustments of the allowed revenues may create regulatory uncertainty that would potentially discourage DSOs from investing, particularly under technology uncertainty. However, ex-ante approaches could create perverse incentives for overestimating the investments required or by deferring planned investments.

Reliability regulation and regulatory incentives for continuity of supply

Incentive-based regulation, which is currently the most widely adopted approach in Europe, promotes economic efficiency through revenue-caps. Specific economic incentives are commonly established in European countries (Council of European Energy Regulators (CEER), 2016) to encourage DSO investment for the improvement of continuity of supply. These incentives are typically based on a reward/penalization scheme linked to the performance of the DSO with respect to certain targets.

Regulatory incentives should be linked to the cost of interruption for network users[52] and drive DSO towards the optimal level of reliability (Fernandes, Candela, & Gómez, 2012).

DSOs elaborate their investment strategies taking regulation into account, in order to maximize their profit (i.e., the total allowed revenue). In theory, DSOs will invest in improving continuity of supply as long as the perceived benefits from the regulatory incentives surpass the costs of improving quality (Sappington, 2005)[53]. Thus, the decision to deploy network automation, or any other solution, to improve continuity of supply will be conditioned by the regulatory framework established by the regulator.

Naturally, the definition of the incentives and penalizations in terms of unitary price for improving reliability has a determining effect on the level of investment DSOs will be willing to undertake[54]. In principle, higher unit incentives would result in higher quality levels (at the expense of higher costs for the consumers). Furthermore, current incentive schemes in some countries introduce discontinuities such as deadbands around the reference value, caps and floors to the maximum bonus or penalty or even consisting of penalties only. For example, regulatory incentives are capped in Spain to +2% and -3% of the total allowed revenue (Spanish Ministry of Industry Energy and Tourism, 2013), and to ±4% of the total controllable costs allowed in Germany (Bundesnetzagentur, 2013). These discontinuities can limit the potential for upscaling automation use cases for distribution companies with reliability levels very close to the reference value where deadbands apply, or when upper limits for incentives are already reached. Moreover, the definition of different types of areas (e.g.: urban, rural, etc.) for reliability requirements and the use of different reliability indices may encourage slightly different strategies for DSOs to invest favoring certain types of areas or network users. For instance, using reliability indices based on load, larger consumers will be prioritized over smaller consumers.

Regulation typically monitors sustained interruptions of supply (as opposed to transient and short interruptions), which are those of a duration longer than a certain threshold, set to 3min. in most European countries (Council of European Energy Regulators (CEER), 2016), while IEEE uses a one-minute threshold for the definition of sustained interruptions (IEEE Power & Energy Society, 2009). The current trend under the smart grid paradigm is going towards higher reliability levels and stricter thresholds, so moving to a 1min.-threshold is currently under discussion in Europe. Furthermore, short interruptions are monitored in many countries, and even included in the regulatory incentives in some

---

52 Reliability regulation has traditionally focused on consumers, but under increasing degrees of DG and other DER penetration, the need to consider all network users is highlighted (Cossent, 2012).

53 The effect of output-based regulation and regulatory incentives has been studied in the literature. The authors of (Cambini et al., 2014; Cambini, Fumagalli, & Rondi, 2016) concluded that penalties play a significant role in the decision to invest, especially where quality performance is very low, whereas rewards affect investment decisions only in areas with top quality performance. Chapter 6 further explores the perspective of the DSO and the cost-benefit analysis for network automation to improve continuity of supply (see section 6.5).

54 A cost-benefit analysis has been conducted for a case study in Chapter 6 to compare the cost of implementing MV network automation and the reliability incentives defined by the Spanish and Italian regulation.

cases[55]. The regulatory threshold for interruptions included in the regulatory targets or incentives can affect the type of automation selected by DSOs. Stricter regulatory thresholds incentivize faster solutions so that reliability improvement is reflected in reliability indices, favoring automation solutions with faster communications and control algorithms. Moreover, regulatory incentives are usually linked to unplanned interruptions originated in the distribution network. Interruptions caused by third parties, due to force-majeure events and planned[56] interruptions may be excluded from the reliability indices. Automation may (or may not) be able to improve reliability also in those cases, so the definition and consideration of such interruptions for regulatory incentives would have to be considered.

Smart metering regulation

Continuity of supply regulation has been mostly focused on the MV network, and the voltage levels monitored vary from country to country (Council of European Energy Regulators (CEER), 2016). Generally, supply interruptions due to faults in the LV networks have been traditionally excluded from regulatory incentives due to the lack of information. However, the currently on-going roll-out of smart meters brings a very high degree of monitoring in the LV network. The information registered by smart meters could be included in quality monitoring and integrated by DSOs in the fault management process.

However, the functionalities to be incorporated into smart metering systems is not standardized. Actually, power quality monitoring is not included in the list of minimum functionalities proposed in the EC recommendation 2012/148/EU (European Commission, 2012a). Furthermore, the possibility of using of smart meters and AMI for LV fault management depends on the model for meter ownership and data management established by regulation.

Innovation incentives

Finally, regulation may specifically promote innovation granting access to public funding for research and demonstration programs so that the industry can test and develop automation solutions. Furthermore, regulation may implement specific economic incentives (e.g.: higher allowed rate of return, tax deduction) to promote innovation, enabling the DSO to mitigate the risk of testing and implementing new solutions with a long-term potential.

---

55 In Italy, for instance, current regulation sets an incentive based on the number of short and long interruptions.

56 Regulation establishes the requirements for planned interruptions, usually related to the time of advance and means for communicating the planned interruption (Council of European Energy Regulators (CEER), 2016). In some cases, these requirements may be so costly that DSOs may prefer to include these interruptions as unplanned.

Following the proposed SRA methodology, the relevant regulatory topics identified must be characterized for the regions considered for SRA[57]. Finally, these relevant regulatory topics must be carefully evaluated to understand how the implementation of automation use cases may lead to different results and may encounter different barriers in regions with a different regulatory framework.

4.2.4.2 Perspective of stakeholders: identification, characterization and assessment of stakeholder-related boundary conditions

The implementation of MV automation involves and affects different actors. The most relevant stakeholders are grid operators in control centers, network users who benefit from reliability improvement (or suffer from the lack thereof), and manufacturers, vendors and service providers for the technologies involved in automation solutions (protections, communications, etc.).

Operators in distribution control centers supervise available information to control the state of the system and make operation decisions. Automation systems involve a higher volume of information available and a profound change in the decision-making process for distribution operation. The potential for scalability and replicability of MV automation is linked to the consumers and their willingness to pay for higher reliability levels.

DG and other DER owners are often neglected in the discussion of reliability and the cost of interruptions, but are also key stakeholders, since they are also subject to the loss of availability of the network during supply interruptions.

4.3 DER management and voltage control to increase of network hosting capacity

This category groups use cases with the main objective of enabling efficient DER integration and avoiding overloads and overvoltages in the networks. Under increasing degrees of penetration of DG, EVs and other distributed resources, distribution networks face new challenges, with counter-flows that may exceed the technical limits of lines that were originally designed for traditional, unidirectional power flows. These use cases are intended to identify and avoid overloads and overvoltages in the MV and LV networks, and to achieve a more efficient operation of the system by reducing the losses.

The smart grid solutions implemented in these use cases include strategies for voltage control to solve network constraints and facilitate integration of DG based on (i) management of the demand and generation profiles in the network and (ii) network reconfiguration performed by the DSO.

---

57 Noteworthy, CEER has been publishing a series of periodical reports on continuity of supply in Europe, where these particular aspects of reliability regulation are described across EU countries (Council of European Energy Regulators (CEER), 2016), which has been cited along this section for further information on the discussed regulatory topics.

Management of demand and generation profiles may be performed using demand side management for flexible consumers, scheduling of charging of electric vehicles, storage by charging and discharging batteries and power factor set-points for DG units. These use cases implement smart grid solutions based on different elements that have a direct impact on voltage profiles, power flows and losses.

4.3.1 Conventional operation of distribution networks: voltage control

Distribution system operators must ensure voltage quality and comply with statutory voltage limits to warrant a stable and safe operation of the system. In Europe, the norm EN50160 establishes that the magnitude of voltage in MV and LV distribution networks must not exceed ±10% of the rated value for at least 95% of the 10-minute average rms values of a week. Furthermore, network elements (conductors, transformers and protections) have certain thermal limits that must not be surpassed, which results in a maximum power flow capacity.

Traditionally, distribution networks have been designed and planned to accommodate different loading scenarios for the expected demand, as well as a certain demand growth in time, while complying with the thermal and voltage restrictions. However, the increasing presence of DG and other DER have profoundly changed power flows in distribution networks. Under the current paradigm, power flows are bi-directional and uncertain, with intermittent power injections that may be located in different points of the network, and may cause reverse power flows and even overvoltages and overloads in some cases. Moreover, power flows are more uncertain and variable due to the implicit variability and uncertainty in DG and DER (Trebolle, Frías, Maza, Tello, & Rodriguez-Calvo, 2012).

In order to satisfy voltage requirements, DSOs may adopt different voltage control strategies. The magnitude of voltage at the head of distribution feeders may be adjusted by changing the transforming relationship of the transformer supplying the feeders. Usually, the HV/MV transformers at distribution substations are equipped with on-load tap changers (OLTC) controlled by clock-based Automatic Voltage Control relays, while MV/LV transformers of secondary substations often feature off-load manual tap changers. Additionally, DSOs may resort to the connection of capacitor banks at certain nodes to support voltage through the injection of reactive power[58]. In case of further voltage problems and overloads, DSOs may have to reinforce distribution networks to increase the capacity of the lines.

[58] Other devices that are used for voltage control in transmission networks for very high voltage levels include synchronous compensators, static var compensators (SVC), and static synchronous compensators (STATCOM). These devices are not common in distribution networks, although their application has been tested in different pilot projects.

4.3.2 Smart operation of distribution networks: DER management and voltage control

In the context of the smart grid, numerous solutions have been proposed to participate in voltage control and mitigation of potential overloads, as observed in the review of smart grid implementations (Chapter 2). The active participation of consumers, DG, storage and EVs in voltage control strategies can provide flexibility and increase the capability of distribution networks to accommodate a higher volume of DER. Consumers with flexible load, such as electric water heating and programmable appliances (dishwashers, washing machines, etc.), may be able and willing to reduce or postpone a certain level of consumption. The charge and discharge of energy storage battery systems and EVs can also be managed in a certain time range. Active power management may be used to mitigate situations of excess of generation of DG and low demand, or situations with peak demand. Distributed generation is often connected to the distribution network through inverters and other power electronics-based devices that can adjust the power factor at the point of connection. The interaction between DSOs and consumers and DER owners must be adequately regulated, providing a mechanism where flexibility is requested by the DSO and offered by available DER, with a fair remuneration. Available options include market mechanisms, time-of-use tariffs to encourage demand response, and the figure of an aggregator or retailer able to manage the flexibility provided by several consumers and DER owners.

Furthermore, automated switching elements can be used to enable network reconfiguration to achieve a better operation state for the system by transferring part of the load or generation of one feeder to another one (or several ones).

Smart grid use cases focused on voltage control and DER management often implement supporting functionalities that can be considered as enablers or facilitators of the former, such as monitoring, state estimation and forecasting systems. The DSO is responsible for the detection and management of voltage problems and overloads. The ability of the DSO to identify these problems depends on the visibility of the state of network through available monitoring equipment at certain points of the network (for instance, at the head of feeders). State estimation algorithms are used to estimate the power flows in the network, fed with the available measures, and using standard load profiles to estimate the demand of each consumer and at each secondary substation. The connection of DG and other DER introduces further uncertainty, and their demand and generation curves must also be estimated for adequate state estimation. In order to anticipate potential problems in the network and request flexibility from demand and DER, or propose network reconfiguration, forecasting of generation and demand becomes very useful for the DSOs.

The implementation of monitoring systems (e.g.: measuring elements, advanced metering infrastructure, data exchange elements, etc.) constitutes an example of a smart grid implementation that can be considered an enabler for other use cases. An enhanced visibility of the distribution network is not a final objective per se but is essential to detect problems and enable a more efficient operation of the system. Appendix A presents the technical analysis of load unbalance in LV networks in relation to the network hosting capacity for PV and EVs, and how the implementation of monitoring and advanced metering infrastructure can help detect load unbalance. Simulation consists in three-phase loadflow analyses to evaluate energy losses and voltage profiles - since no corrective actions are applied, only intermediate KPIs are applicable, to quantify the impact of load unbalance and future integration of EV and DG in the LV network.

These new smart grid solutions add up to conventional operation of the distribution network, mainly based on the use of OLTC at primary substations. Thus, the DSO has now a wider range of alternatives that must be jointly assessed (using available information from all monitoring systems, state estimation, and loadflow analysis) to achieve optimal operation of the system.

4.3.3 Technical SRA

Technical SRA for DER management and voltage control evaluates voltage profiles and energy losses to quantify the increase of network hosting capacity and the improvement of quality of supply and efficiency through loadflow analysis for different simulation scenarios. The effect of boundary conditions is analyzed through sensitivity analysis.

4.3.3.1 Identification of relevant KPIs

As previously explained, the objective of this group of smart grid use cases is to solve or mitigate voltage problems and overloads, reduce losses and enable the connection of more DG without reinforcing the grid. Therefore, adequate KPIs include increase of network hosting capacity, avoided overvoltages, avoided overloads, avoided curtailment of DG production, avoided load shedding and reduction of energy losses.

The network hosting capacity (NHC) is the maximum volume of DER that can be connected to the distribution network. The limiting factor to the integration of DER is the violation of technical constraints, i.e. voltage limits and thermal limits of conductors and transformers. Network hosting capacity is usually computed through simulation by considering the connection of DG to the network and increasing gradually the capacity of the DG until an overvoltage or overloading occurs that cannot be solved through the available solutions and voltage control strategies.

It must be noted that technical constraints are based on certain values of maximum voltage deviation allowed and maximum loading of lines and transformers that can be set discretionally by the regulator, or even tighter operational standards set by the corresponding DSO. The resulting NHC strongly depends on the limits considered. For instance, European regulation allows a maximum deviation of voltage of ±10% (European Committee for Electrotechnical Standardization (CENELEC), 1994), while Spanish regulation sets an stricter limit of ±7%. Thus, given the same distribution network, considering Spanish regulation would result in a lower NHC than considering the European regulation.

There is no single standardized procedure to compute network hosting capacity, with regards to the location of the DG connected and loading scenarios to consider. The most common approach is oriented to identify the most unfavorable situation, so that of all possible volumes of DG capacity allowable, the smallest value is considered as the NHC. In that case, DG is considered to produce at its full capacity and demand is considered to be very low.

Alternatively, NHC may be determined based on a probabilistic approach to determine an average or expected value of NHC, considering all possible different scenarios of loading and location of DG.

4.3.3.2 Selection of simulation tool

The smart grid use cases grouped in this category enable reconfiguration of the network, voltage control actions and management of active or reactive power absorbed or generated by DER. These functionalities modify the power flows, voltage profiles and energy losses in the system. The analysis of these aspects is performed through so-called load flow or power flow analysis.

The load flow problem consists in finding the steady-state operating point of an electric power system. Given the demand and generation at each node and the network electrical characteristics, the voltage at each node and active and reactive power flowing through each branch are determined solving a set of non-linear equations. There are different iterative methods to solve power flow problems, and the SRA of these use cases will be based on load flow analysis adapted to distribution networks, which are radially operated.

Furthermore, the functionalities enabled by the smart grid use cases must be modeled. DER management results in a modification of the active and reactive power injected or absorbed at each node where the participating elements are connected, so these solutions are incorporated to the technical SRA through the loading scenarios subject to load flow analysis. Network reconfiguration is modelled indicating the switches that can be operated to simulate all possible valid configurations, ensuring radiality. Traditional voltage control strategies must also be considered. Tap changing in substations will be addressed as a different value of voltage at the head of the feeder.

4.3.3.3 Definition of representative networks

In the case of SRA of use cases focused on voltage control and DER management, the most relevant aspects for the network models comprising the set of representative networks are network impedances, thermal limits of the network elements and voltage limits. The impedance of the network lines depends on the type of conductor (configuration in terms of number of circuits, whether overhead lines or underground cables, etc.) and the total length. Furthermore, generation and demand at each node are key in loadflow analysis, so representative networks must include the location of demand and DER, including current and future DG, storage and electric vehicle charging points.

Regarding the size or scope required for the representative networks, models comprising a few feeders are sufficient. Because of the radial operation of distribution networks, the voltage profile in each depends only on the generation and demand of the users connected at that feeder and the characteristics of the network element that comprise that feeder. Thus, load flow analysis could be carried out for each feeder independently. However, changes in the tap position of transformers have an impact of all outgoing feeders. Therefore, DER integration in one feeder would not have a direct impact on other feeders, but could lead to actions at the transformer level that would. For this reason, representative networks should consist of several feeders that belong to the same substation.

In the case of smart grid use cases implementing network reconfiguration for voltage control and overloading management, it is important to characterize the possibilities for reconfiguration. Therefore, representative networks must incorporate the number and location of tie points and switches in these cases.

4.3.3.4 Definition of scenarios

Technical SRA of these use cases must adopt two complementary approaches to address the different states of the system that correspond to generation and demand varying in time and compute KPIs: (i) static scenarios or snapshots and (ii) time series scenarios or generation and demand curves.

First, static scenarios or snapshots will be simulated to analyze the specific impact of a use case at a period with a specific volume of generation and demand in the network. Such scenarios will help identify the most unfavorable situations where voltage problems and overloading may occur and to what extent the activation of the use cases can help solve them.

Then, demand and generation profiles will be used to create scenarios so that analyses can be carried out to determine reduction of energy losses, reduction of DG curtailment, avoided overvoltages or overloading in a day and in a year. These analyses will be useful to determine how often problems may occur and how often use cases will be able to solve them. Furthermore, time series must be considered to account for different charging strategies for energy storage batteries and EVs. Demand and generation profiles will investigate profiles for weekdays and workdays, and for summer, winter and spring/autumn. Different types of DG technologies (solar, wind, CHP, biofuel/waste) will be studied according to usual and expected situations in the regions considered for scaling-up and replication (for instance, CHP may be more common in industrial areas, while solar and wind generation may be more frequent where the natural resources are more available). Similarly, different types of consumers will be considered, discriminating voltage level (LV and MV consumers) and use of electricity (residential, commercial, industrial and agriculture). The daily and seasonal discrimination will be considered where relevant, since, for instance, PV generation will vary from one season to another, but not between weekdays and weekends, while presumably the opposite will happen with CHP. The interaction of generation and demand will be determinant to the final loading scenarios and potential voltage and overloading problems.

Regulation has a direct impact on several aspects regarding the design and operation of distribution networks that are translated into different technical boundary conditions. These technical boundary conditions are accounted for by the developed representative networks and scenarios. Reliability requirements may lead to a different degree of meshing of the networks, thus allowing for a wider range of possibilities for reconfiguration. The design of feed-in tariffs and incentives for renewable and distributed generation may lead to the predominance of certain technologies or size of DG in different countries.

4.3.3.5 Simulation for KPI computation

The simulations described above are repeated for the different representative networks developed for the regions under study, and for all scenarios that can account for the technical boundary conditions (DER, demand and generation profiles) that may be found in these regions.

Intra-national replicability of the results is studied using the representative networks that correspond to the demo country, with a special focus on the most important parameters: impedances, limits and characteristics of consumers and connected DER. SRA will address different types of network with different types of conductors and grid length, different elements for reconfiguration, consumers of different size and different use of electricity, different DG technologies, etc. For instance, representative networks that correspond to more rural areas may have longer lines with higher voltage drops and lower number of consumers with a higher peak demand than more urban areas.

Then, international replicability in the same way, considering the representative networks and scenarios developed for other countries. The representative networks in different countries may differ in the conductors used, the level of undergrounding, use of electricity of consumers (for instance, electric heating is more common in some countries), usual size and voltage level of DG technologies (for instance, in some countries solar is usually present in the form of small PV panels connected to the LV level, while in others solar farms are more common, with large amounts of installed capacity connected to the MV level), etc.

These use cases are based on offering the DSO a higher degree of flexibility to manage different resources and thus achieve a better local balance between generation and demand in the distribution networks. It could be considered that a higher implementation degree of these use cases would correspond to having a higher volume of flexible demand, more storage capacity, more DG capacity able to control reactive power, more EVs with a flexible charging period or more switches to enable more network configurations.

The total flexibility that can be provided by consumers and DER can vary widely, depending on the degree of penetration of flexible agents, but also on the type of these DER. Therefore, the analyses carried out to compare results with and without the use of voltage control strategies will be repeated to consider scenarios of higher penetration degree of DG, larger volumes of storage, more load flexibility and higher degree of implementation of telecontrolled switches.

The number of batteries will be increased to assess higher volumes of storage. New locations will be considered for these batteries, to analyze effect of more disperse or concentrated storage capacity, locations near the head of the feeder or downstream, farther from the primary substation, etc. Similarly, storage capacity will be increased by considering different charge and discharge rates, as well as different sizes of the storage units.

Different controllable loads will be considered, considering variations of size, number of consumers (or supply points) and different types of load (for instance, electric heating, smart appliances such as programmable washing machines, etc.)

Higher penetration degree of DG will also be considered, including different technologies, which will have different characteristics in terms of controllability and reactive margins. The effect of the location of DG will also be analyzed.

Finally, for the technical SRA of network reconfiguration, higher degrees of implementation of telecontrolled switching elements, so that there are more options for reconfiguration.

4.3.3.6 Review of demo results

The validation of the technical SRA tools can be achieved comparing the results obtained by loadflow analysis considering the loading scenarios that correspond to the demand and DER in the demo to the actual voltages and losses measured at the demo, before and after DER management is activated.

KPIs of reduction of losses, avoided overvoltage, avoided DG curtailment and avoided overloads can be determined. The concept of network hosting capacity, however, is theoretical, as it cannot be quantified in real-life – it would not be possible to increase the installed DG capacity at all possible nodes gradually until technical constraint were reached. Thus, the KPI of increase of NHC can only be determined through simulation.

4.3.3.7 Upscaling of simulation results

As is the case for all smart grid use cases, the use of representative networks for technical SRA of use cases related to voltage control and DER management involves that the simulation results are representative of the results that can be expected for the whole country. Simulation results obtained for the representative networks can be extrapolated for the country (or region) according to the representativity rate of each representative network, or prevalence of each type of network. In the case of NHC, results can be upscaled based on the amount of installed capacity that correspond to each type of representative network.

4.3.4 Non-technical SRA

The implications of regulation and the viewpoint of the different stakeholders involved for the potential success of voltage control and DER management use cases must be analyzed.

4.3.4.1 Regulatory framework: identification, characterization and assessment of regulatory boundary conditions

Regulation sets the framework to ensure quality of service (i.e. voltage limits, allowed deviations, security margins of available capacity for lines or transformers, etc.), efficiency (i.e. technical losses) and fair network access (i.e. connection of DG and other DER). This group of use cases is aimed precisely at improving the operation of distribution systems, to achieve a more efficient integration of DER. Therefore, regulatory requirements, allowed revenues and economic incentives related to voltage quality, technical losses and DER integration play a key role for the upscaling and replication of these use cases. Furthermore, some of the solutions grouped in this category involve the active participation of DER owners and/or the participation of consumers through demand response. In this case, the regulation aimed at DER and demand is also very important for the adoption of these use cases.

These uses cases require DSOs to have a higher degree of visibility of the state of the network, which involves investing in supervision and monitoring systems, data processing, automation, communication technologies, etc. These use cases increase network hosting capacity and are thus an alternative to conventional network reinforcement, so that required reinforcement investments are deferred. The corresponding costs of smart grid solutions would have to be recovered through the allowed revenues. Therefore, the treatment of DG-driven investments[59] and the incentives to substitute CAPEX by OPEX solutions is a key consideration when assessing scalability and replicability barriers.

Most European countries have incentive regulation in place, but with a distinct treatment of CAPEX and OPEX. Most commonly, a more input-oriented approach is implemented for CAPEX and efficiency gains are required for OPEX. Such approaches would hinder the adoption of smart grid use cases aimed at NHC, which reduce the asset base at the expense of increasing OPEX. Actually, regulation is already moving towards a TOTEX approach in some countries, such as in the case of Italy (Autorità per l’energia elettrica il gas e il sistema idrico, 2015b) and a more output-based regulation, with UK at the forefront of such evolution (Office of Gas and Electricity Markets (OFGEM), 2013). NHC and energy not withdrawn from RES have been used or considered as a revenue driver by some European countries (Council of European Energy Regulators (CEER), 2011b).

Specific innovation incentives can encourage DSOs to implement smart grid solutions and acquire experience on new means of operation. This way, the upscaling of successful tools and solutions is favored. As derived from the review of smart grid projects in Chapter 2, many countries have funded

---

59 Regulation must account for the costs driven by the integration of DG, where peak demand may not be the only suitable indicator to determine investment needs any more. Furthermore, regulation must be flexible to take into account that future investment needs will be harder to estimate in a context of higher technology uncertainty and a more unpredictable behavior of DG.

projects focused on the integration of DG. The large-scale deployment of such solutions may be incentivized through output-based regulation, using for instance NHC as a revenue driver as previously explained. In the case of Italy, pre-selected smart grid projects have been awarded an allowed rate-of-return on investment. The selection of projects has considered a cost-benefit based on increase indicator P_{smart} measuring the expected NHC (Lo Schiavo, Delfanti, Fumagalli, & Olivieri, 2013).

Naturally, regulatory voltage limits are a key factor for voltage control in distribution networks, and so is their enforcement and measurement procedures[60]. Due to the lower level of monitoring in lower voltage levels, voltage quality has been traditionally subject to less scrutiny and penalties applied mostly following network users' complaints. Smart metering, AMI and other monitoring systems will now help detect problems such as voltage problems or load unbalance among the phases of LV networks[61], which may result in a higher level of penalties for DSOs.

In order to encourage DSOs to invest in lowering the technical losses in the network, specific economic incentives are usually adopted by regulation so that DSOs internalize the cost of energy losses. In many countries, these incentives are typically bonus/penalty schemes based on performance with respect to a target set by the regulator, similarly to incentives for continuity of supply[62]. As in the case of reliability incentives, the procedure to monitor losses may lead to DSO prioritizing certain areas or investments, higher unitary prices[63] for these incentives will have a stronger impact in mobilizing investment and asymmetries, deadbands around the target[64] may also impact DSOs' investment strategies. Furthermore, the effect of DG and other DER on network losses is usually not considered by regulation, which may discourage DSOs to allow DG integration.

The design of regulatory incentives for DG and DER will have a very significant impact on the installation of different technologies and sizes in different countries, leading to a very different

---

[60] The European norm EN50160 establishes that voltages must remain within the ±10% range from nominal value for at least 95% of 10 min-measures, which could imply that overvoltage problems could occur for sustained periods of time and not be identified as a violation of regulatory limits.

[61] Load unbalance is further explored in the analysis presented in Appendix A.

[62] In other countries, the DSO must buy the energy losses in the wholesale market. The mechanisms adopted for treatment of electricity losses in distribution in European countries were described by the ERGEG in (Regulators et al., 2009).

[63] Usually these the unitary process of these incentives are linked to the wholesale market price of electricity, which is a transparent and straightforward mechanism. However, it entails a certain degree of uncertainty for the DSO as it is determined ex-post and leads to a cost of losses related to the overall system, which may differ from the state of the network. For instance, in hours of high RES production, electricity prices may be low, while distribution networks with high RES penetration may be more overloaded. In other cases, regulation sets the price of losses ex-ante, which allows DSOs to take these costs into account when deciding their investment strategy.

[64] Incentives to reduce energy losses are for instance capped in Spain to a maximum of at +1% and -2% of the total allowed revenue for each DSO.

context. Regulation may impose different requirements for the connection of DG, regarding reactive power output or power factor, as well as required monitoring and reporting to the corresponding DSO or TSO.

Network charges for DER may comprise connection charges and use of service charges. In most countries only consumers pay use of service charges. However, as DG penetration rates increase, DG is considered as a network user that should be subject to these charges as well. Connection charges may cover only the direct costs of connecting the DG unit to the existing distribution grid (shallow connection charges), the full cost of reinforcing the grid to accommodate the additional DG capacity (deep connection charges), or an intermediate between both (shallowish connection charges). Deep connection charges may act as a barrier to DG development. Furthermore, if DG units bear the costs of any required reinforcements, the DSOs has no incentive to avoid grid reinforcements through the adoption of smart grid solutions. Nevertheless, if DSOs are obliged to attend every connection request or they are penalized for failing to meet a predefined deadline, smart grid solutions may indeed allow DSOs to achieve a faster grid connection and allow DSOs to comply with their obligations.

The interaction between DSOs and network users able to provide flexibility is subject to unbundling[65] requirements and must be regulated. The remuneration of this flexibility must be fair in order to encourage both sides to resort to this voltage control approach. In general, the mechanisms for the active participation of DER in the provision of network services are not developed. In some cases, fixed mandatory requirements or thresholds are established for consumers, DG and other DER (e.g.: power factor). Specific incentives may be set to encourage and remunerate DER units for a better performance with respect to a pre-defined target and thresholds. Commercial agreements between DER and DSO may be possible through the figure of an aggregator, or in the form of standardized bilateral contracts, or local markets could enable the active participation of DER with a fair remuneration.

Similarly, the design of tariffs for consumers can encourage consumers to participate in demand response programs, if the perceived benefit is sufficient. Furthermore, demand response is enabled by smart metering that can provide consumers with information regarding their own consumption. Therefore, the regulation regarding the roll-out of smart meters can impact the SRA of these use cases.

4.3.4.2 Perspective of stakeholders: identification, characterization and assessment of stakeholder-related boundary conditions

This group of use cases involves a high number of actors. The most relevant stakeholders are DSOs, in charge of the operation of the distribution system and thus responsible of voltage quality and of

[65] For the moment, regulation does not allow for DSOs to own and operate storage connected to the grid, as it can be considered as a generation asset, except for specific pilot projects, where exceptions are applied.

the safe and efficient integration of DG and other DER and the agents (consumers involved in demand response, and EV, DG and storage owners) offering their flexibility.

In the face of increasing volumes of DER and therefore more uncertain power flows in their networks, DSOs require a higher visibility of DER. Furthermore, in order to enable smart grid use cases based on DER management, the regulatory framework and some form of commercial or market-based mechanism must be established, where the DSO can estimate the need for network services in advance, and DER (or an aggregator of DER) can offer available flexibility. The new possibilities offered by DER management and network reconfiguration result in a more complex operation and in turn require new intelligent tools to assess and propose operation strategies.

As explained, DER owners will be subject to the regulatory requirements and require a regulatory mechanism that ensures fair remuneration. If the adaptation of the infrastructure to enable the provision of services entails costs for the DER owners, this could be a barrier especially for smaller agents. Furthermore, depending on the economic and social context in different regions or countries, consumers may be more interested in financial support or environmental issues and thus more willing to become DER owners or participate in demand response.

Finally, the interaction with the TSO must be taken into account. Conventionally, the interaction between DSOs and TSOs has been limited to certain regulatory requirements at the point of connection. However, the distribution system may be able to provide network services to the transmission network. Thus, TSOs become very relevant stakeholders that may benefit from a higher degree of flexibility downstream their networks.

4.4 Islanded operation and microgrids to improve continuity of supply

This category groups use cases related to islanded operation, including the islanded operation of parts of the networks as an alternative to enable supply during emergency situations.

Intentional islanded operation means that part of the distribution system is disconnected from the upstream grid and is operated in islanded mode, that is, in isolation from the electric power system, supply demand autonomously, similarly to the operation of power systems in actual islands. The term microgrid has been commonly used to define a LV system that provides the possibility to be disconnected from the upstream MV grid and be operated in islanded mode. Security of supply is a critical issue for power systems, and in the context of the smart grid, the possibility of islanded operation of parts of the distribution network and micro grids offer the potential to improve security of supply. Thanks to the use of distributed generation (DG) and energy storage, islanded operation is possible in parts of the distribution network provided appropriate control systems are deployed. During emergency situations, such as in the event of short circuit or faults that result in supply interruptions, some parts of the distribution network can be disconnected and temporarily operated in island so that the supply of electricity is not disrupted for network users connected in that network section.

The scalability and replicability of islanded operation use cases, as presented in this chapter, has also been discussed in (Rodriguez-Calvo, Izadkhast, Cossent, & Frías, 2015).

4.4.1 Elements for islanded operation

Islanded operation consists in the ability to disconnect a section of a distribution feeder from the grid and operate it in isolation relying on the power generation of DG and/or storage within the islanded area. To ensure the safe and stable operation of the islanded system, a control system (CS), or microgrid central controller (MGCC), is required to keep the system voltage and frequency in the allowable range during islanded operation and the transition from grid-connection to islanded operation. For this purpose, the CS can operate available elements that can provide flexibility to balance generation and demand in the system, including the following:

- Supplying DG and/or storage: the demand in the islanded system may be supplied by DG and/or storage. The production of DG or the discharge of storage is adjusted by the CS to balance generation and demand and thus control frequency. Additionally, the reactive power output of the DG or storage supports voltage control. The capability of DG to sustain islanded operation is related to the controllability of the active and reactive power output and its inertia, which are related to the DG technology and the interphase for the connection to the distribution grid. Usually, the availability and controllability of the production of DG based on thermal generation (e.g. CHP, biomass) is very high, while DG based on intermittent generation (e.g. solar, wind) is subject to meteorological conditions and it may not be possible to adjust. The regulation of reactive power will be subject to the technical characteristics of the generator, and in the case of DG connected through an inverter (which is usual for the case of PV), the limits will be those of the inverter. Generators with high inertia will not provide a response as fast as those with less inertia. In the case of storage, the response is usually very fast, and the controllability of the active and reactive power is limited by the maximum rate of charge and discharge, by the initial state of charge of the battery and the storage capacity, as the battery will not be able to provide further if discharged. Most islanded operation pilot projects are based on a relatively large CHP unit, or in the use of energy storage battery systems in combination with PV or wind power.
- Islanded operation may be facilitated by a system of fast controllable load (FCL) that can be connected and disconnected from the grid for frequency control.
- Under Frequency Load Shedding (UFLS) mechanism[66]: As a last resort, under very low frequency values, load and specific feeders can be disconnected to shed load. The aim is to

[66] The reader is referred to (Lukas Sigrist, 2015; Lukas Sigrist, Egido, & Rouco, 2012a, 2012b, 2013) for further information on the design and performance of UFLS in islanded systems.

shed the minimum possible load whilst ensuring a safe operation of the islanded section. If the frequency reaches a lower threshold, the island is shut down, i.e., all loads and the CHP unit are disconnected.

- Synchrotact: A system is required to reconnect the islanded system to the distribution network ensuring both systems are synchronized in terms of voltage amplitude, frequency and phase angle.

4.4.2 Islanding process

The section of the network that will be subject to this use case may be operated as a part of the distribution system, and may be disconnected from the grid to be operated in isolation. The process to change from one state to another is complex. Figure 4.3 shows the evolution in time of the frequency of the system along the different operation states.

Originally, the section of the network that will be islanded is connected to the grid (grid connected mode, start and final points in Figure 4.3). At a certain point, a triggering event occurs, which may be an interruption of supply caused by an upstream fault or a command from the DSO, and the island system is disconnected from the grid (points 1 and 2 in Figure 4.3). The transition from grid connected mode to islanded mode is a critical moment when the control system must be able to quickly balance generation and demand and maintain frequency deviation within the allowed limits. If the frequency deviation surpasses certain limits (point 3), the system is shut down. Else, if the system is able to stabilize frequency, successful islanded operation has been achieved (point 4 in Figure 4.3). In order to restore frequency after the disconnection from the grid, the control system may shed part of the load that is later reconnected in small load steps. The load shedding mechanism is activated so that load is shed only when frequency deviation exceeds certain limits (f_{min1}, f_{min2} in Figure 4.3) in order to decelerate frequency drop. Then, voltage must be controlled within regulatory limits, and a steady-state is reached. Islanded operation can be sustained as long as the supplying unit is able to provide energy to feed the demand. In order to reconnect to the grid, the system must be synchronized, and the transition from islanded to grid connected mode is carried out (points 5, 6 and 7 in Figure 4.3) controlling the frequency deviation.

Naturally, frequency response must be analyzed for a time range of milliseconds, while voltage may be assessed in the range of minutes, and analyzed through load flow analysis for a steady-state analysis.

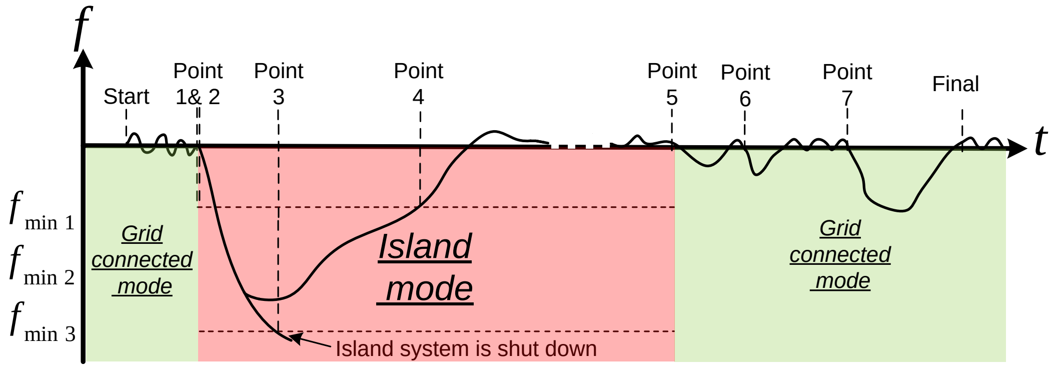


Figure 4.3. Typical frequency deviation in the stages of connection and disconnection of the island.

4.4.3 Technical SRA

Technical SRA for islanded operation use cases aims to study the conditions for a successful and sustained islanded operation. Therefore, technical analyses are based on simulations to assess the evolution of voltage and frequency considering different boundary conditions through loading scenarios.

4.4.3.1 Identification of relevant KPIs

The main objective of islanded operation use cases is to provide an alternative for supply for network users connected to the islanded system. Therefore, the main objective KPI for SRA of islanded operation is the avoided volume of non-served energy, which would correspond to the total demand supplied during successful islanded operation. Then, other relevant KPIs include the volume of curtailed load and the duration of successful islanded operation.

Technical SRA focuses on assessing the conditions that enable successful islanded operation (stable and safe operation), monitoring frequency and voltage to identify problems during islanded operation, especially at the moment of disconnection from the grid. Hence, voltage and frequency deviations are intermediate KPIs computed in simulation.

4.4.3.2 Selection of simulation tool

These use cases are analyzed through a time-domain simulation with the dynamic models of the involved elements where voltage and frequency will be monitored. Simulation comprises the process of connection and disconnection from the grid, considering the steps described in 4.4.2 and represented in Figure 4.3.

The control system implemented in the islanded operation use cases is simulated, along with the dynamics of the loads, the network itself and the DG units. The control algorithm and decision-making process of the control system for islanded operation is emulated (e.g.: load shedding activated by certain limits of frequency deviation, reactive setpoints for voltage control, etc.). The models of the elements (DG, storage, loads and network) must be able to reproduce their dynamic response, which requires a more detailed modelling of the elements. For instance, in the case of a CHP generator, instead of having a steady-state value of active power that is injected in a node, the dynamic DG model would comprise a governor, a synchronous generator and an excitation system with a power system stabilizer.

The islanding and the reconnection to the grid are transition periods (the former from grid connected mode to islanded operation, and the latter from islanded operation to grid connected mode). During these periods, the transient response of the system is analyzed. These transitions must be analyzed for a very small time step, in the range of milliseconds. Successful islanded operation is achieved if frequency and voltage can be controlled within a certain range, so frequency and voltage deviations are monitored throughout technical SRA simulation. Frequency control may involve load shedding, and if frequency deviation surpasses a certain limit, the island is shut down. Therefore, frequency and voltage deviations during islanded operation are very relevant indicators selected as intermediate KPIs for technical SRA.

During islanded operation, once the islanded system is stable and steady-state is reached, generation and demand must remain balanced, and variations may be caused by the production of DG in the case of intermittent generation like solar and wind power, and by the variation of demand in time. These variations are much slower, so simulation focuses on load flow analysis in the range of minutes. The maximum duration of islanded operation that can be sustained may be limited and must be determined by the technical analyses. If the control system depends on battery storage, the amount of stored energy is limited. Furthermore, the maximum discharge rate of the battery or maximum production of DG limits the maximum demand to be supplied. Other DER connected to the islanded section or can also help provide flexibility to balance generation and demand and perform voltage control in the islanded system[67]. Therefore, simulation must take into account the state of charge of the battery, maximum charging and discharging rates, demand and DG production curves according to the type of consumers or DG technologies, time of the day, type of day and season, etc.

4.4.3.3 Definition of representative networks

Technical SRA of islanded operation use cases must evaluate different technical boundary conditions that could be found for the implementation of islanded operation. Representative networks must be adapted to the relevant technical boundary conditions for islanded operation. In this case, the most important aspect are the dynamic response of network elements and the characteristics of the load.

---

[67] Such contribution of DER would also fall within the scope of smart grid use cases based on DER management and voltage control to increase network hosting capacity and could be subject to the same analyses as those described in section 4.3. This case shows the interaction and sometimes overlap of different smart grid use cases.

The architecture of the distribution network directly affects reliability. Therefore, events that may trigger the islanding of a section of the network to avoid an interruption of supply are linked to the architecture and reliability of the upstream network. However, the effect of the network itself on the dynamic response of the system is negligible[68] when compared to the loads, storage units, generators, controllers, inverters, etc. For this reason, rather than models of representative networks, single-node models may be used. The connection of the islanded system to the upstream grid connection is also modelled through an impedance.

The load must be also modeled, considering different types of demand (e.g.: residential, commercial, etc.). In general, loads can be divided into static[69] and dynamic loads (e.g.: heating systems and induction motors). Fast controlled load usually consists of thermostatic load, which can be modeled as a controllable resistance.

Additionally, load curtailment schemes in place must be assessed considering different configurations of the downstream load.

4.4.3.4 Definition of scenarios

Islanded operation will only be successful if the load can be supplied by the DG production or storage connected in the island. Therefore, islanded operation use cases must be simulated for different scenarios of demand and generation of available DG units and state of charge of available storage units.

The main focus of technical SRA is on whether islanded operation can be achieved. For this purpose, most unfavorable conditions, where demand and the initial point of operation of generation and/or storage are not coincident, must be considered.

Furthermore, once the islanded operation is stabilized, the potential evolution of demand in time must be assessed and compared to the potential evolution in time of the DG and/or storage to estimate the maximum duration of islanded operation that can be sustained. Therefore, different scenarios must be considered to account for the state of charge of the battery and maximum charging and discharging rates, as well as demand and DG production curves according to the type of consumers or DG technologies, time of the day, type of day and season, etc.

In order to assess scaling-up in density, scenarios of different penetration degrees of DG that can help balance generation and demand in periods of high consumption during island, different types of DG, different shares of demand flexibility and different volumes of available storage, both in terms of size

---

68 As demonstrated by the results of simulations carried out considering different network characteristics within the islanded portion of the grid including aspects such as length of feeders, load density, etc. (GRID4EU project, 2014b).

69 Static loads can be modeled as a constant current (CC), constant power (CP), or constant impedance (CI).

of storage and in terms of charge and discharge rates of the storage. Moreover, scenarios of different types of consumers must also be designed to address replication to different regions.

4.4.3.5 Simulation for KPI computation

Simulations are carried out to compute the KPIs of frequency and voltage deviation, and thus assess the success and duration of islanded operation, for the network models that can represent the characteristics of the load, DG and storage and the flexibility systems (fast controllable load, under-frequency load shedding mechanism, etc.) of the corresponding region[70]. For successful islanded operation, the volume of avoided non-supplied energy is the energy supplied to the consumers connected to the islanded system.

Simulation must consider the designed scenarios of different volumes and types of storage, DG, demand and other DER, with their corresponding dynamic models, inertia, active and reactive output controllability, degree of flexibility and charge and discharge rates in the case of storage.

As islanded operation is applicable to isolated parts of the system, a large-scale implementation would involve enabling islanded operation different systems or parts of the network to be disconnected and autonomously managed, so there would be no interaction among different implementations. Scalability in terms of size is addressed by considering larger areas for islanded operation. Since the network is not as relevant, a larger section of the network means the corresponding loads, DG, storage and other DER. Simulation addresses intranational and international replication modelling the characteristics of the demand and DG that represent the situation of different countries.

The scalability of the use case of islanded operation in terms of density will be considered by increasing the size or penetration degree of the sources of flexibility for balancing generation and demand.

In this case, there is a stronger overlap between the identified scalability and replicability dimensions than for other groups of use cases.

4.4.3.6 Review of demo results

Islanded operation tests in demonstration projects are mostly carried out as a controlled process, triggered by the DSO, rather than in response to a fault in the upstream system, to make sure that the conditions for islanded operation are adequate[71]. Islanded operation tests usually record

[70] Rather than the technical characteristics of the distribution network, which are not as relevant in the technical SRA of islanding and microgrid use cases

[71] Unsuccessful islanding tests would also be very valuable for the validation of simulation models, but would mean an actual disruption of the consumers in the islanded area, which is usually not deemed acceptable by the DSO.

frequency and voltage during the disconnection of the islanded system from and reconnection to the grid, as reported for instance in the Demos of the GRID4EU project (GRID4EU project, 2015a, 2016b).

The results of such tests can be used to compare the actual performance of the islanded system and the simulations and thus validate SRA.

4.4.3.7 Upscaling of simulation results

Simulation results represent the different situations that may be found for islanded operation, so that the conditions for successful islanded operation can be identified. Results can be directly extrapolated for the whole region studied, according to the characteristics of demand and connected DER. Thus, islanded operation of sections of the grid with similar network users would perform similarly given the same control system and controlling storage or DG were in place.

4.4.4 Non-technical SRA

As in the SRA of other use cases, the implications of regulation and stakeholders for the SRA of this smart grid implementation must be studied.

An important distinction must be made between microgrids downstream of a single meter or point of common coupling ("consumer microgrid" or "true microgrid") and a section of the network where different resources are connected among them through the distribution network and are disconnected from the upstream grid and jointly operated ("utility microgrid" or "miligrid") (Hatziargyriou et al., 2007). From the point of view of the DSO, the former can be regarded as a single network user, whereas the latter is the responsibility of the DSO, which would have important regulatory implications.

4.4.4.1 Regulatory framework: identification, characterization and assessment of regulatory boundary conditions

Regulation of distribution usually forbids islanded operation of sections of the grid[72], so the first step for the deployment of islanded operation systems would be a regulation setting the conditions to be met for allowed islanded operation (for instance, during supply interruptions) and for reconnection to the grid. In order to permit islanded operation of a section of the distribution grid, the system must be adapted, incorporating a control system.

Enabling the islanded operation of a section of the distribution grid entails costs (control system, communications, etc.) for the DSO. Therefore, the investment strategy of DSOs in this regard will be directly influenced by regulatory reliability incentives, both zonal reliability indices (e.g. SAIDI, SAIFI)

[72] In Europe, islanded operation may only happen under two situations: i) under the premises of a consumer and ii) in case of a fault, DSOs resort to diesel generators to reduce the time of interruptions suffered by end consumers.

and economic compensation to be paid to end users individually. Therefore, since the value of islanded operation for DSOs depends on these regulatory incentives, it is important that unit incentives adequately reflect the value of continuity of supply for network users in order to attain an efficient outcome.

Furthermore, the active participation of DG and other DER, including demand response, to support islanded operation of a system is subject to the regulatory framework, as explained for the case of voltage control and DER management smart grid use cases (section 4.3.4.1).

4.4.4.2 Perspective of stakeholders: identification, characterization and assessment of stakeholder-related boundary conditions

Islanded operation relies on the presence of DG, storage and/or flexible loads that can be controlled and that are automatically operated to ensure grid stability. These agents are providing local network services to the DSO (and indirectly to network users connected to the islanded system). Conventionally, the regulatory and commercial mechanisms to enable this type of interaction between DSOs and network users are not in place. In order to enable islanded operation, regulation must provide some scheme of interaction between DSOs and network users, presumably through the figure of the aggregator.

4.5 Conclusions

The different functionalities implemented by smart grid solutions result in different types of impacts. Therefore, the relevant boundary conditions for SRA differ, and the specific simulation tools and KPIs must be adequately adapted. This chapter describes the particularization of the proposed SRA methodology for each type of smart grid use case identified in Chapter 2.

Network automation for the improvement of continuity of supply

This category groups use cases that pursue the objective of improving continuity of supply. These use cases implement smart grid solutions based on automation, fault detection systems and remote control of switching elements, which help improve the process of failure management and service restoration. The effect of these use cases is the reduction of consumers affected by supply interruptions as well as the decrease in the duration of these interruptions for affected consumers. Therefore, the main KPIs that will be used to measure the impact of these use cases are the improvement of the indices of continuity of supply, such as SAIDI and SAIFI.

DER management and voltage control to increase network hosting capacity

This category groups use cases with the main objective of quality of supply improvement, enabling efficient DER integration 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), but all of them have a direct impact on voltage profiles, power flows and losses. Therefore, the proposed technical SRA for this group of use cases will involve performing loadflow analysis for different scenarios that can account for the different strategies and solutions implemented in each use case to compute the KPIs of network hosting capacity, voltage profile, avoided overvoltages, avoided overloads, avoided disconnection of DG units and load shedding. Additionally, losses will also be computed to assess efficiency in the system.

Islanded operation and microgrids to increase security of supply

This category groups use cases that enable the autonomous operation of an area during unavailability of the grid due to faults or planned maintenance activities using storage, DG and flexible demand to balance generation and demand within the island. The impact of islanded operation use cases will be assessed in terms of availability of the network associated to the successful connection and disconnection of islanded operation mode and duration of the islanded operation. The proposed technical SRA for this group of use cases will involve performing time-domain analysis for different scenarios as starting points for the activation of islanded operation, in a dynamic simulation that models the behavior of the system until during disconnection from the grid, islanded operation and re-connection to the grid. The compliance with technical constraints during islanded operation will be checked by monitoring frequency and voltage. Additionally, avoidance of load shedding and disconnection of DG units will also be monitored.

Relevant technical, regulatory and stakeholder-related boundary conditions for each smart grid use case

The proposed particularization of technical SRA for the identified groups of smart grid use cases is based on the simulation approaches, simulation scenarios and KPIs listed in Table 4.1. The characteristics of the representative networks used for each type of use case are described in detail in Chapter 5. Then, Table 4.2 presents the mapping of regulatory topics relevant for the SRA of the three types of smart grid use cases. Finally, Table 4.3 presents the relevant stakeholders for each type of smart grid use case.

Use case	Simulation	Scenarios	KPIs
Automation to improve continuity of supply	Reliability analysis: simulation of failures and fault management process	• Automation implementation degree • Response time of automation	• SAIFI improvement • SAIDI improvement
Voltage control and DER management to increase network hosting capacity	Steady-state load flow analysis	• Location and penetration degree of DER • Characteristics of DER: size, technology, flexibility • Demand response: type of consumer, engagement, flexibility	• Increase of NHC (avoided DG curtailment, overvoltages and overloads) • Reduction of energy losses
Islanded operation to improve continuity of supply	Time-domain analysis: transient analysis of dynamic response	• Characteristics of control system • Characteristics of DER: size, technology, flexibility • Demand response: type of consumer, engagement, flexibility	• Avoided NSE • Duration of successful islanded operation • Frequency and voltage deviation

Table 4.1: Particularization of technical SRA for smart grid use cases.

		Automation for CoS	**Voltage control & DER management for NHC**	**Islanded operation for CoS**
DSO revenue regulation	General regulatory framework	X	X	-
	DER-driven network investments	-	X	-
DSO incentives to reduce losses	Implemented or not	-	X	-
	Type of scheme	-	X	-
	Impact of DER considered?	-	X	-
DSO reliability incentives	Implemented or not	X	-	X
	Type of scheme	X	-	X
	Contribution of DER considered?	X	-	X
DSO incentives for innovation	Specific incentives implemented?	X	X	X
	Design of incentives	X	X	X
DER participation	DER voltage control	-	X	-
	DER curtailment	-	X	-
	DSO visibility over DER	-	X	X
	Contracts DSO-DER	-	X	X
Business models for DER	DSO ownership DG or storage	-	X	X
	Energy resale (storage)	-	X	X
	Aggregation allowed	-	X	X
Network charges for DER	Type of connection charges	-	X	-
	Design of connection charges	-	X	-
	UoS charges for DG	-	X	-
	Design of uso charges for DG	-	X	-
Active demand, smart metering and EV charging	Existing AD mechanisms	-	X	X
	Role of DSO in AD schemes	-	X	X
	Plans for smart metering roll-out	X (LV)	X	-
	Functionalities of smart meters	X (LV)	X	-
	Ownership/access to AMI data	X (LV)	X	-
	Roll-out/ownership of EV charging points			
Islanded operation	Permitted?	-	-	X
	Role of DSOs	-	-	X

Table 4.2: Mapping of regulatory topics relevant for SRA of smart grid use cases.

		Automation for CoS	Voltage control & DER management for NHC	Islanded operation for CoS
Consumers	directly	-	X[1]	X[2]
	indirectly	X	-	X
DER (DG/EV/Storage)	directly	-	X	X
	indirectly	X	-	-
TSOs		-	X	-
Suppliers/Aggregators		-	X	X
Regulators		X	X	X
Manufacturers, software/ICT providers		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] In case demand supplier/aggregator acts as intermediary between consumers and DSOs for demand response

Table 4.3: Mapping of relevant stakeholders for SRA of smart grid use cases.

Chapter 5

Modeling the distribution system: representative networks

The SRA methodology proposed in chapter 3 relies on the use of representative networks. Representative networks are a very useful tool to efficiently assess the technical impact of smart grids. However, the creation of a set of representative networks for a region (i.e. municipality, region operated by one DSO, country) is a very challenging task, subject to different barriers. This chapter is focused on representative networks. First, section 5.1 introduces the rationale behind the concept of representative networks. Then, the process to develop representative networks is discussed in 5.2. Afterwards, section 5.3 evaluates existing approaches to represent distribution networks, including taxonomies, initiatives to release representative networks and research projects. This chapter analyzes the use of representative networks for SRA and identifies the required characteristics for each type of smart grid use case in 5.4. Finally, the conclusions are drawn in 5.5.

5.1 What is a representative network and why do we need it?

Modelling the distribution system adequately is fundamental to enable analyses and simulation to assess the outcomes of implementing smart grid technologies or solutions under different operation scenarios and strategies.

Test networks and simplified **network equivalents** are distribution network models, able to reproduce the behavior of actual distribution networks. Depending on the smart grid functionalities to be analyzed, different types of test networks and network equivalents may be designed, focusing on different aspects and with different levels of detail. The distribution system of any given region (i.e. municipality, country) comprises a vast amount of distribution assets, and the distribution networks supplying the region may be very diverse. Consequently, the results derived from the analysis of a test network would not be sufficient to obtain conclusions for the whole region. However, it would not be convenient to model and analyze every element comprising the distribution system in the region. Therefore, it becomes necessary to have a model that can account for the particularities of different networks in a condensed manner to enable efficient large-scale smart grid analysis. This is precisely the idea behind **representative networks**. A **set of representative networks** is a reduced number of model networks or test networks, where each representative network is the best fit to describe the behavior of a group of real feeders. Representative networks are specifically conceived as a compendium, so that the compilation is able to adequately represent all of the actual networks that comprise a distribution system. The results obtained for representative networks can be scaled-up to assess impact across the represented region based on the prevalence of each representative network in the region. Thus, representative networks are very valuable for large-scale smart grid technical analysis.

Additionally, the concept of reference or representative networks has been proposed as a benchmarking tool for regulation of distribution to set the remuneration for the DSOs (Allan & Strbac, 2001). Although sometimes used indistinctively as synonyms, a clear distinction can be made in this context. **Representative networks** aim to **reproduce** the characteristics of actual networks, while **reference networks** are designed as **quasi-optimal** networks that could supply actual demand. Representative networks for different distribution companies or regions may be compared to each other and ranked, while reference networks may be compared to actual networks to assess their efficiency.

While a set of representative feeders cannot capture every nuance of the whole distribution system in a region, it can serve as a good reference set, able to cover the diversity of actual networks in a manageable number of networks. Thus, the use of representative networks facilitates the analysis of the whole distribution system in a region. Simulations are carried out on a reduced number of network models, so that plentiful different scenarios may be tested. Then, the results obtained for the representative networks may be up-scaled across the region without further simulation, since it can be assumed that each network in the region behaves in the same manner as the corresponding representative network.

Representative networks are a key element for scalability and replicability analyses:

a) having different representative networks enable simulation to account for different technical boundary conditions, addressing replicability; and
b) having a comprehensive set of representative networks with representativity weights or factors for a region enables the projection of simulation results for the region tackling scaling-up.

5.2 Developing a set of representative networks for a distribution system

The creation of a set of representative networks for a region is a very ambitious task that requires a thorough characterization and analysis of the distribution system of the region, to ensure that the representative networks developed can really represent the distribution system of the whole region. The creation of representative networks implies a categorization of the distribution networks into a number of groups according to some criteria. The number of representative networks and the criteria for this categorization must be carefully determined so that the categorization is meaningful while ensuring that the number of representative networks is reduced but sufficient. The resulting representative networks must be comprised by network models that are fit for the study of smart grid solutions.

Accordingly, the process of elaborating representative networks, represented in the diagram of Figure 5.1, is described in three steps: 1) characterize the distribution system, 2) group the distribution networks that comprise the system and 3) determine the representative network for each group. The following subsections provide more details on these three steps.

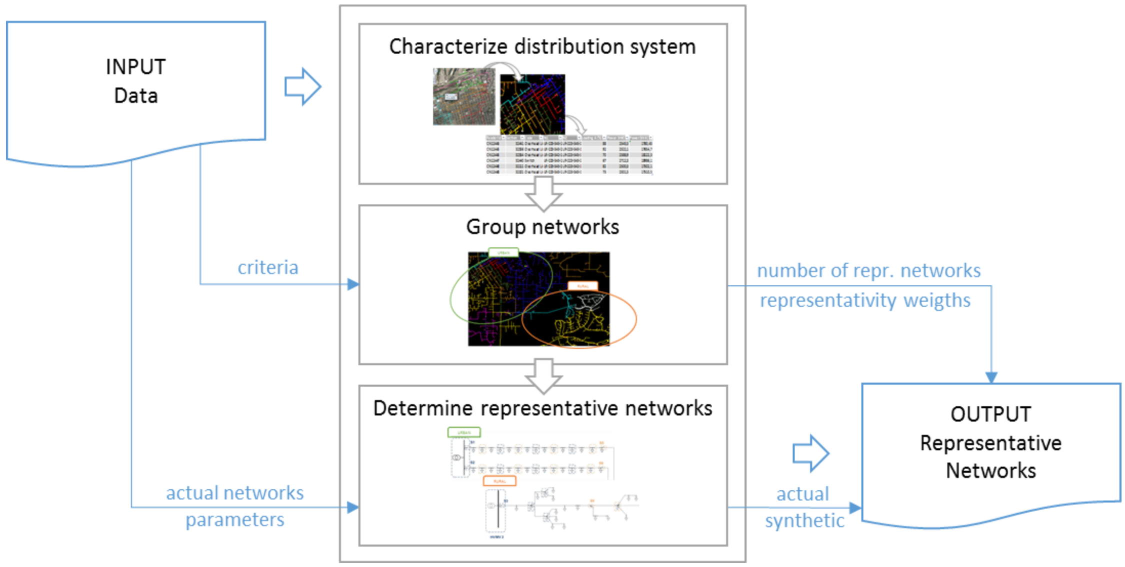


Figure 5.1: Process to develop a set of representative networks.

5.2.1 Characterize the distribution system

Naturally, the distribution system must be characterized so that it can be adequately modelled. For this purpose, data must be gathered on the distribution networks in the region considered. In doing so, the main questions that arise are: what data is required? is the data available? how can these data be obtained? In the ensuing, these questions are answered, discussing the main challenges involved.

Distribution systems comprise network elements, demand and DER that can be characterized by different parameters. Technical characteristics of the network elements include voltage level, types of conductors, configuration of the network (overhead, underground), topology of the network (radial, meshed, arborescent) and length, rated power of transformers, and characteristics of existing protection and voltage regulation elements. The supplied demand and connected distributed energy resources (DER), including distributed generation, storage and electric vehicles, are characterized by their location and peak demand or rated capacity. All of these characteristics may be described by different parameters, since many are interrelated. For instance, a network section may be characterized through the impedance (ohms), or through its length and type of conductor; and the thermal capacity may be expressed as a ratio of nominal current (%), as a current value in amps or as apparent power flow in MVA.

The data on the distribution networks lies within the respective distribution companies. However, the inventory of distribution assets run by the corresponding DSOs may not be complete or updated for certain parts of the distribution system, especially in lower voltage levels. Typically, high and medium voltage networks are monitored by operation systems (e.g.: SCADA), while the degree of monitoring of low voltage networks is very low. Furthermore, modifications in the networks due to operation and maintenance, construction works and connection of new network users are more frequent in the low voltage network, and may not always be registered in the databases of the DSOs. Therefore, the level of detail of the inventories of distribution infrastructure may vary and is usually more limited and imprecise for low voltage networks. The lack of data inevitably limits the capabilities of characterization of the distribution system. Furthermore, the registered characteristics may vary for different distribution companies, depending on information systems in use. The data collected by distribution companies may also be linked to regulatory requirements. Regulation of distribution typically requires DSOs to provide certain information on their investment and infrastructure to monitor the performance of distribution companies and set distribution remuneration. For instance, distribution remuneration in Spain is computed using a reference network model that is fed with data provided by the distribution companies as mandated by the RD222/2008 (Spanish Ministry of Industry Tourism and Commerce, 2008), so DSOs must list the location and contracted power of every connected network user. Due to the large volume of infrastructure, the task of gathering and processing the data can be very cumbersome and costly, both for DSOs to build their inventories and databases, as well as for any agent studying the distribution system of a region.

Moreover, due to confidentiality issues, the data may not be accessible for non-DSO agents building representative networks (e.g. research institutions, consultants). Additionally, the privacy of electricity consumers must be guaranteed, so information regarding the location, contracted power and consumption may be restricted. Aggregated data and statistics may be found in public reports prepared by regulators, policy makers and other institutions such as the Eurelectric report (Eurelectric, 2013) or the benchmarking report of the Council of European Energy Regulators (Council of European Energy Regulators (CEER), 2011a).

All in all, the data used to characterize the distribution system and define a set of representative networks may comprise either a collection of actual networks or aggregated statistical data or typical values for certain parameters. The available input data will influence the possibilities to carry out the following steps. Clustering techniques (explained in 5.3.3) provide powerful tools to analyze the data and categorize networks into groups, but will only be applicable for a list of actual networks. By contrast, network planning models (explained in 5.3.4) can be of great help if actual networks are not available, although other data, such as geographical data, may be required.

5.2.2 Group distribution networks of the system

Defining representative networks implies a categorization of the distribution networks of a region in groups, as many as representative networks comprise the set. This is so because each distribution network in the region is represented by one of the representative networks. The criteria for this categorization must be carefully determined so that the categorization and the resulting representative networks are meaningful.

Most frequently, the classification of distribution networks is achieved in a hierarchical process. First, some high-level categorization is established according to geographic or technical criteria (e.g.: country, voltage level, type of distribution area according to population density, etc.). Then, other parameters may be considered to establish sub-categories within the previously identified groups (e.g.: construction type, overhead/underground). This way, a set of categories are originated and one representative network can be used to represent the whole distribution system.

This categorization is of course linked to the scope of the studied distribution system. For instance, different geographic categories will make sense depending on whether the distribution system covers one or several countries or regions. Furthermore, in some cases, the categorization used may correspond to an actual categorization established by regulation for other purposes. As an example, regulation may establish distribution zone types (e.g.: urban, sub-urban and rural) with different reliability requirements.

Criteria for such a high-level classification may include the following aspects:

- Country, region, DSO
  (e.g.: sub-set of representative networks per country in the EU) (e.g: 5 climate regions in the USA) (e.g.: networks from each DSO, in a taxonomy where several DSOs have been involved)
- Voltage level
  (e.g.: 11kV/22kV for a MV taxonomy) (e.g.: HV/MV/LV for a whole distribution system)
- Type of consumers and distribution areas served
  (e.g.: urban, sub-urban, rural and industrial) (e.g.: urban, sub-urban, concentrated rural and scattered rural) (e.g.: residential, agricultural, commercial and industrial) (e.g.: areas of high, medium and low population density

Sub-categories may be established according to network characteristics such as length (long/short), construction type (overhead/underground), installed capacity (number of transformers, rated capacity of transformers, number of transformers/km), or topological characteristics (high/low ramification, or graph theory concepts such as closeness and centrality). Parameters related to network users may also be used, including the number of consumers, consumer density (number of consumers/km), total demand, or penetration degree of DG. It must be noted that these parameters and characteristics proposed as categorization criteria are interrelated. For instance, urban networks are typically shorter, have a higher number of consumers, are supplied by transformers of higher rated capacity, are quite meshed in structure although radially operated and usually have no or very little ramifications. Meanwhile, rural networks are usually longer, more radial and ramified, with a lower number of consumers and transformers of lower rated capacity.

The categorization established must be able to include all distribution networks and categories must be clearly delimited and disjoint, which means that each network would belong to one and only one category. For instance, if distribution networks were categorized by their construction type, 'overhead' and 'underground' would be valid categories only if networks with sections of both types were clearly assigned to one group: either having an additional category 'mixed type', or defining percentage of total length as the classifying criteria (this way, networks would be for instance considered of type 'overhead' if above 50% of the total length of the network were overhead). If the categorization involves several levels, these principles would have to be respected at each level: for instance, distribution networks could be first categorized per voltage level into MV and LV networks; then MV networks could be categorized into urban, sub-urban and rural; and LV networks could be categorized into overhead and underground. Any distribution network in the system would necessarily belong to one and only one group, among the five existing groups (i.e.: 1) MV urban; 2) MV sub-urban; 3) MV rural; 4) LV overhead; 5) LV underground).

The final number of representative networks is the resulting number of groups or categories. A set of representative networks should be able to adequately describe the diversity of distribution networks in a manageable number of models. Therefore, the number of representative networks should achieve a good compromise to ensure representativity and compactness. Too few representative networks might result in vague or inaccurate modeling, while too many representative networks would be inefficient due to a higher computational burden for simulations and analyses to be carried out.

Logically, once the groups or categories are established, the whole distribution system is categorized, i.e., split into groups. This means that, theoretically, each distribution network would be assigned to one of the groups. An aggregated representativity weight could be determined for each group, based on the percentage of distribution feeders of each group, or the share of consumers connected to distribution networks of each group, or the share of peak demand or rated power corresponding to each group, etc. These representativity weights are the scaling-up factors, which are to be used to scale-up in size simulation results for SRA.

The selection of relevant criteria for the classification of distribution networks in a distribution system, as well as the decision on the adequate number of representative networks, requires a deep understanding of distribution networks and relies on expert knowledge.

If available data includes a full list of the distribution networks comprising the distribution system, statistical data analysis techniques and clustering algorithms (explained in 5.3.3) can be of great help to categorize the networks into groups (or clusters). Statistical data analysis techniques, such as principal component analysis (PCA), can be used to assess the use of different explicative variables, i.e. parameters for categorization. The number of representative networks may be obtained through clustering techniques. Centroid-based clustering algorithms, require that the number of clusters are determined beforehand; while in the case of hierarchical clustering, the results can indicate the theoretical optimal number of clusters.

5.2.3 Determine the representative network for each group

As explained, the number of representative networks is a result of the categorization and grouping of distribution networks. However, one step further must be taken to determine the network that represents each group. The representative networks themselves may be either synthetic networks, or actual networks in the distribution system represented.

Synthetic networks may be designed or created "from scratch" using existing networks as a guide, using a network planning model, such as the Reference Network Model (further explained in section

5.3.4), or using certain clustering techniques (for instance k-means). This approach results in representative networks with average or the best representative value for each of the characteristics considered for the classification or clustering process. Moreover, this approach avoids confidentiality problems that could appear when disclosing data on actual consumers and networks.

Alternatively, and if the data allows (if the available data includes a list of the actual distribution networks in the studied region), one element, i.e. network, of each group may be selected to represent the group. This approach ensures that the resulting representative networks are coherent and realistic. Some clustering techniques, such as k-medoids also apply this approach (see section 5.3.3 for further information on clustering).

5.3 Methods to develop sets of representative networks

Different initiatives, research projects and institutions have worked on the creation of test feeders and representative networks for smart grid analysis and studies. This section presents a review of these works organized as follows: first, available sets of test feeders are presented. Afterwards, representative networks have been organized in three blocks: those created based on expert knowledge, then those where clustering techniques were applied and finally those that used reference network models.

The creation of a set of representative networks requires a deep understanding of network modelling and a deep knowledge of the distribution system to represent. Clustering techniques and reference network models, explained in detail in subsections 5.3.3 and 5.3.4 are very powerful tools that can help in the tasks of processing data and building the representative networks.

5.3.1 Test feeders

The first approach towards the characterization and modelling of distribution networks for technical analysis has been the creation of test feeders that could be used to analyze specific aspects of distribution operation, testing different solutions and technologies.

Although representativity is not the main target of test feeders, these are usually designed to be typical networks, so that the results from the analysis of test feeders are realistic and applicable. In some occasions, test feeders may even be conceived to analyze specific extreme cases.

The IEEE, CIGRE and EPRI have been very active in promoting the use of common test feeders in the academia and industry. Available test feeders can be used by different authors to test their models and tools and to compare the results obtained with the work of others. The efforts of these institutions are described in this subsection.

5.3.1.1 Existing test feeders

5.3.1.1.1 IEEE PES Distribution Test Feeder Working Group

The IEEE Distribution Planning Working Group presented in (Kersting, 1991) test distribution feeders in 1991 for the first time and soon the IEEE PES Distribution Test Feeder Working Group began as an informal Task Force. These test feeders were models of actual radial distribution networks in the US (13-, 34-, 37- and 123-bus distribution feeders). Originally, the main purpose of these test feeders was to be used to evaluate, benchmark and upscale power flow algorithms. The collection of test feeders has been enlarged over the years to include networks with different features (particular transformer and network configurations, light loading scenarios vs networks prone to have voltage drop problems, etc.) and in more recent years LV networks and a network based on European distribution systems. The 11 test feeders may be found in the website[73].

5.3.1.1.2 CIGRE

The CIGRE Study Committee on Distribution Systems and Dispersed Generation has also worked to gather test networks specifically targeted to study the impact of DG. Some of these test networks have been presented in the literature and used for different analyses, such as the European-like LV feeder in (Papathanassiou, Hatziargyriou, & Strunz, 2005), the German-based MV rural network in (Rudion, Orths, Styczynski, & Strunz, 2006) and the US-oriented LV feeder in (Strunz, Fletcher, Campbell, & Gao, 2009).

The brochure of Task Force C6.04.02 Computational Tools and Techniques for Analysis, Design and Validation of Distributed Generation Systems presents the description of the benchmark networks and detailed results of analyses carried out (CIGRE, 2014a).

Further work on the characterization of distribution may be found in (CIGRE, 2014b). This report presents a survey on current distribution planning practices in DSOs around the world and describes future planning as well, and presents a review of methodologies for assessment of network hosting capacity, reliability analysis, etc.

5.3.1.1.3 Electric Power Research Institute (EPRI)

Supported by the US Department of Energy, EPRI has collected data and evaluated several distribution feeders across the U.S. As a result, three MV test feeders are available on their website[74] within the Distributed PV Monitoring and Feeder Analysis project.

All in all, the available test feeders reviewed are listed in Table 5.1.

---

[73] http://ewh.ieee.org/soc/pes/dsacom/testfeeders/index.html

[74] http://dpv.epri.com/index.html

Reference	Date	Voltage levels	Number of networks	Applications
IEEE	1991-2016	LV, MV (4.16, 24kV)	11 test feeders (US-based 9 MV test feeders and 1 LV test feeder; EU-based 1 LV test feeder)	Benchmark of voltage control algorithms
CIGRE	2005-2014	LV, MV (20kV)	1 LV network for EU (3 feeders: residential, industrial and commercial) 1 MV (rural resembling an actual German network) 1 LV network for US (3 feeders: residential, industrial and commercial)	Characterization of distribution Study of DG integration
EPRI	2010	MV (12, 12.47 and 13kV)	3 (northeastern US with high PV penetration, southeastern & short and compact feeder, mostly residential and underground)	Study on PV impact and hosting capacity

Table 5.1: Test feeders in the literature

5.3.2 Representative networks based on expert knowledge

This section presents initiatives that have proposed representative networks in European countries. Universities and research institutions have worked on the construction of sets of representative networks that can be used to carry out the analysis of different strategies and technologies through simulation, based on data gathered from the distribution companies.

5.3.2.1 Existing sets of representative networks based on expert knowledge

5.3.2.1.1 United Kingdom Generic Distribution System (UKGDS)

In the UK, the Centre for Distributed Generation and Sustainable Electrical Energy was formed as a collaboration between the University of Strathclyde, the University of Manchester and the Imperial College London. The United Kingdom Generic Distribution System (UKGDS) [75] project was launched in 2004 with the aim to develop a library of distribution network models for simulation and testing of new tools, methods and technologies. Furthermore, characteristic load profiles and typical generation patterns were developed as well. The UKGDS Model was made publicly available so that it could be used for technical and economic evaluation of DG and new concepts on the operation and performance of distribution networks. The definition of these representative networks has been explained in (United Kingdom Generic Distribution System (UKGDS), 2005).

---

[75] http://www.sedg.ac.uk/ukgds.htm

In order to develop a set of network models representative of UK actual networks, data was gathered from the Long Term Development Statements (LTDSs) that DNOs in the UK must submit to the regulator, as well as working in collaboration with the DNOs. The generic networks were specified by defining a set of high-level descriptions then by selecting real-life, typical networks that matched those descriptions and modifying them to create suitable generic networks. As a result of the UKGDS project, 6 generic EHV-HV[76] networks and 7 MV generic networks were created.

First, each DNO was asked to identify three typical or representative sections of the network. The Grid Supply Points (GSP) were assessed to identify the key factors in characterizing EHV networks. Thus, networks were classified into rural, suburban or urban, according to the area served, circuit length and customer density. Then, networks were further differentiated in terms of their construction (overhead, mixed or underground) and topology (radial or meshed). Additionally, the overall size of the network was identified to be relevant as a discriminating factor, in terms of total load served and number of primary substations. These factors are interrelated, and after assessing the likely combination of factors, finally, six EHV networks were proposed by the UKGDS project.

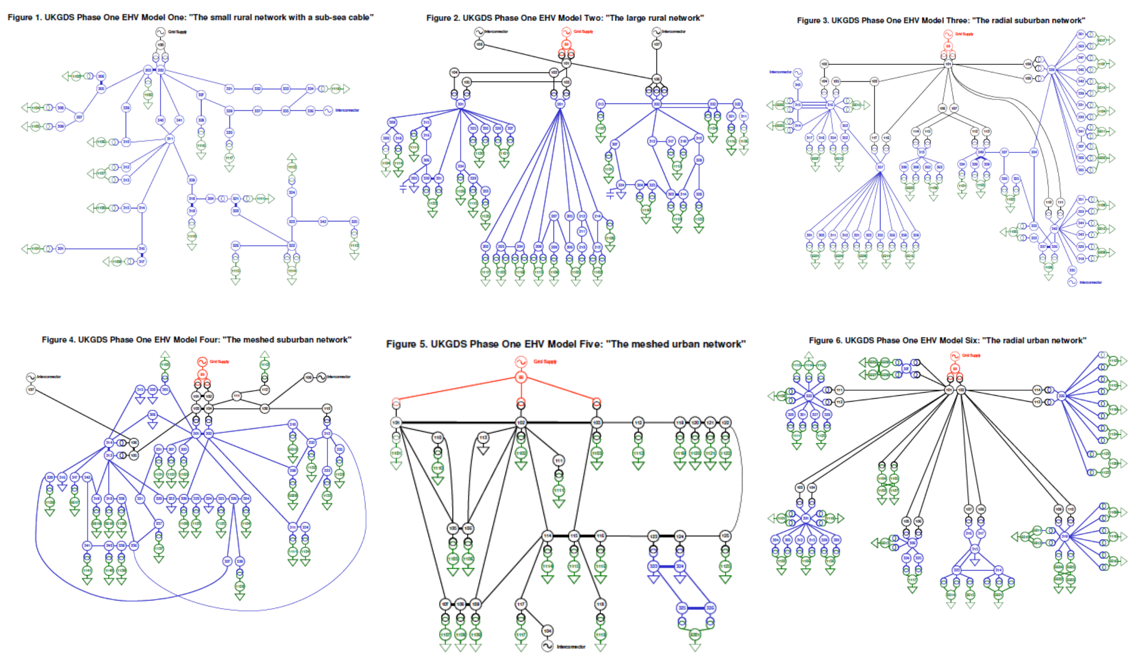


Figure 5.2: Set of UKGDS EHV generic networks. Source: (United Kingdom Generic Distribution System (UKGDS), 2005)

[76] It must be noted that the classification of voltage levels may vary across countries. This thesis will consider voltage levels according to European standardization bodies CEN/CENELEC: LV for voltage below 1kV, MV for voltage values in the range 1-36kV and HV for values in the range 36-220kV. The UKGDS classified generic networks into High Voltage (HV) networks of 11kV and 6.6kV, and Extra High Voltage (EHV) for voltages 132kV, 275kV and 400kV.

MV networks were first classified according to the construction type into underground, overhead or mixed. This criterion was considered to be a proxy for the type of area served, since urban areas are usually supplied with underground networks, while rural areas are normally supplied through overhead networks. Then, for each category of networks, the length of circuits and number of transformers on each circuit were analyzed to identify different types of circuits. Finally, 7 generic networks were built, consisting of several circuits of some of the identified types that were selected as a good representation. The generic networks were constructed using average parameters.

The UKGDS generic networks have been used in academic research for different analyses. The work of (Kiaee, Cruden, & Infield, 2011) studies the use of alkaline electrolysers as a source of flexibility for demand side management. This paper investigates the impact on network voltages and energy losses through modelling and simulation using the UKGDS High Voltage Underground Network.

Imperial College and Sohn Associates have worked together on an OFGEM funded project to assess the cost of distribution network losses (Strbac et al., 2014). Electricity losses were assessed for the whole of GB, based on LV and MV representative networks created with the fractal model (see section 5.3.4.1) and HV representative networks based on the UKGDS tool. The set of HV representative networks developed consist of 6 Generic Grid Supply Point (GSP), 3 urban and 3 rural, calibrated against typical real networks.

Finally, the report (DNV GL et al., 2014) on RES integration prepared for the European Commission has used representative networks based on the UKGDS and fractal model to assess the impact of DG integration and different strategies on distribution planning, expansion and operation. The Generic Distribution Systems (GDS) has been adapted to the population density and typical voltage levels in different Member States in the EU-27. The design parameters of the representative LV networks were adjusted such that the sum of the individual networks corresponds to the overall size and structure of the distribution networks in each country. However, only a limited set of networks has been considered to represent all analyzed countries.

5.3.2.1.2 Swedish Urban and Rural Reliability Test Systems (SURTS and SRRTS) by Elforsk (Sweden)

The Market-Design program[77] of Elforsk launched in 2008 a project to develop representative test systems of Swedish distribution networks appropriate for reliability studies.

The networks were created according to data compiled by the Swedish Energy Markets Inspectorate and consisted of two MV reference networks with several feeders each: Swedish Urban Reliability Test System (SURTS) and Swedish Rural Reliability Test System (SRRTS). These networks represent the diversity of Swedish networks and contain information about structure, customer composition, load data, component failure statistics and cost of power interruptions. These networks were presented in

[77] http://www.elforsk.se/Programomraden/Anvandning/MarketDesign/About/

(Jakobsson Ueda, Engblom, & Alvehag, 2009) and have been made available for further research (in Matlab format).

5.3.2.1.3 Atlantide

The Italian Ministry of Economic Development funded a 3-year research project to create the Digital Archive for the National Electrical Distribution Reference Networks, the ATLANTIDE (Archivio TeLemAtico per il riferimento Nazionale di reTI di Distribuzione Elettrica)[78]. The project started in January 2011, led by ENEL and carried out in partnership with the Italian Universities of Cagliari, Padova, and the Second University of Napoli. The archive aims to provide reference models of distribution networks, and prospective scenarios for the development of the demand and integration of distributed generation and storage in Italy.

In order to identify the representative networks, 5 Italian provinces were pre-selected to form a statistical sample of 454 Primary Stations and their corresponding MV networks. These were classified into rural, urban and industrial and their socio-economic features (population density, inhabitants concentrations, number of industries and service companies) and electrical characteristics (total consumption of electricity, connection of RES, power flow reversal) were analyzed. The main parameters considered to define the representative networks were load density (kVA/km), MV/LV, length (km), user density (cons/km), and generation (kVA/km).

A set of three MV representative networks was created, including a rural, an industrial and an urban network, as presented in (Bracale et al., 2012). Each network comprises several feeders with different topologies and configurations typical of the Italian territory and different load (residential, industrial or commercial) and generation (CHP, PV) conditions.

[78] http://www.progettoatlantide.it/

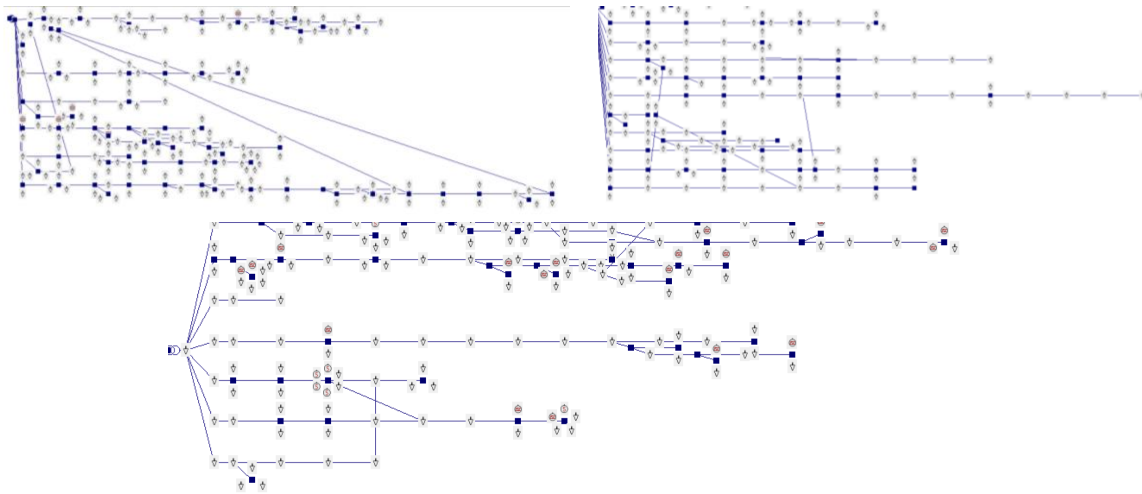


Figure 5.3: ATLANTIDE MV representative networks (from left to right and top to bottom: rural, urban and industrial). Source: ATLANTIDE website[79].

Besides the set of representative networks, the database also made available (i) models of generation units, loads, storage and innovative electrical components (e.g.: Distribution Management Systems and Network Protection Systems); (ii) sets of scenarios of development of distribution systems and demand and generation evolution (e.g.: demand growth, penetration of EV); (iii) online simulation tools to carry out power flow analysis, harmonic analysis, reliability analysis, short circuit analysis, etc.

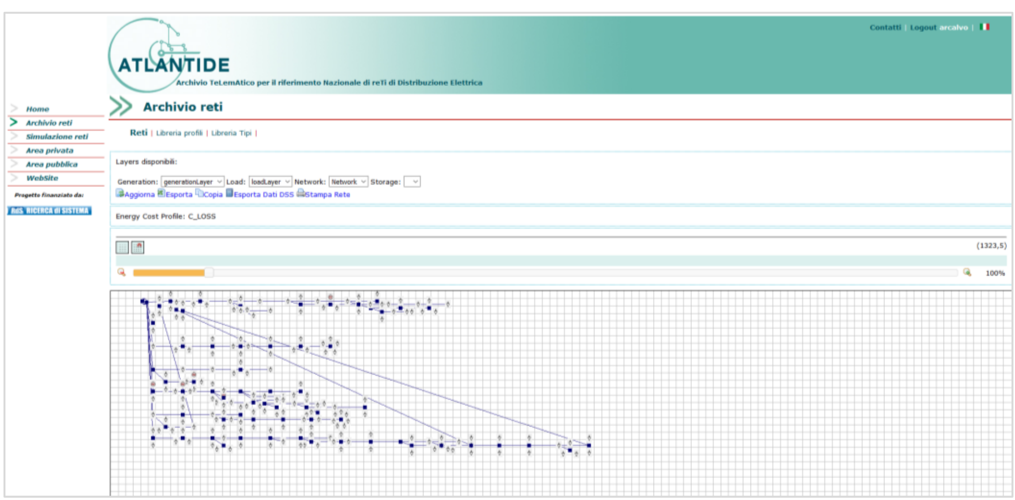


Figure 5.4: ATLANTIDE website: representative network[80].

79 http://www.progettoatlantide.it/archivioReti/archivio/reti/networkLayer/carica.do

80 http://www.progettoatlantide.it/archivioReti/archivio/reti/networkLayer/carica.do

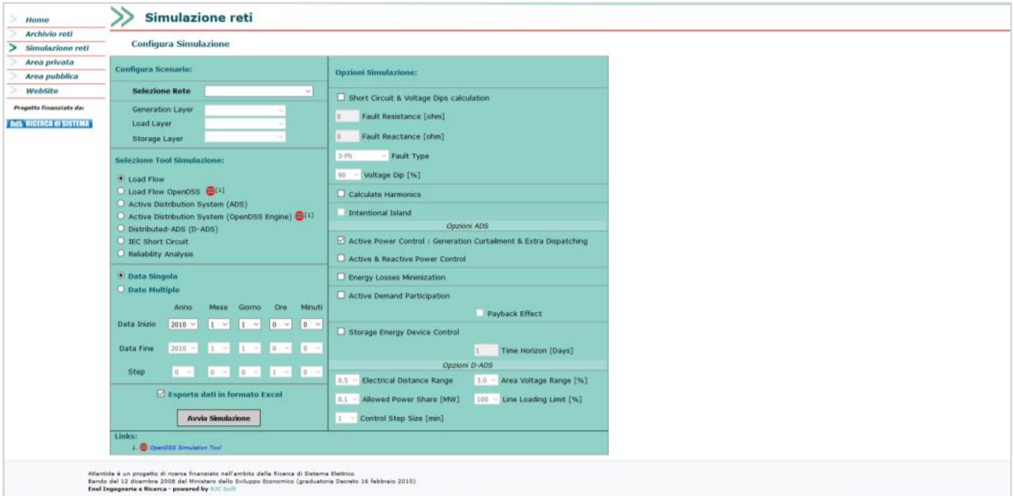


Figure 5.5: ATLANTIDE website: simulation tool[81].

5.3.2.1.4 GRID4EU

The GRID4EU (Large-Scale Demonstration Project of Advanced Smart Grids Solutions with Wide Replication and Scalability Potential for Europe) project comprises six demonstrators in six European countries (Germany, Sweden, Spain, Italy, Czech Republic and France) where different smart grid solutions will be tested, including active management of demand response, distributed generation (DG) and storage, MV and LV network supervision and automation, and islanded operation.

The scalability and developed in GRID4EU comprises a stage of technical analysis based on simulation on representative networks. The smart grid use cases subject to SRA have been classified into three categories to adapt the required technical analysis, according to the objectives pursued, implemented functionalities and corresponding types of impacts: (i) use cases aimed at efficient and increased integration of DER (voltage control strategies, management of DER), (ii) use cases aimed at improved continuity of supply (network automation), (iii) use cases aimed at autonomous operation (islanded operation).

Representative networks have been developed for the Demo countries in collaboration with the DSOs leading the Demos: RWE, Vatenfall, Iberdrola, ENEL, CEZ and ERDF. First, information was gathered from the DSOs on their distribution networks in the Demo region or country (GRID4EU project, 2014b). Then, the following networks have been developed:

- 3 MV networks for Germany of urban, sub-urban and rural type.
- 2 LV networks for Sweden of urban and rural type.

81 http://www.progettoatlantide.it/archivioReti/simulazione/aprilInterfaccia.do

- 4 MV networks and 4 LV networks for Spain, considering the different types of distribution areas set by the Spanish regulation: urban, semi-urban, concentrated rural and scattered rural.
- 4 MV networks for Italy, considering the categorization of distribution areas according to population density set by the Italian regulation: high concentration areas, medium and low concentration. Additionally, there is a LV network that can be considered typical for rural areas.
- 2 MV and 2 LV networks for the Czech Republic, of urban and rural type for each voltage level.
- 4 LV networks for France, considering 2 urban networks and 2 rural networks. One of the rural networks is completely underground, while the other one is made up of overhead lines.

Unfortunately, due to confidentiality concerns of the involved DSOs, these representative networks have not been made publicly available.

Additionally, 3 network models for dynamic analysis based on the Demos carrying out islanded operation use cases: i) a network model for a MV system with CHP, fast controllable load, load and DG; ii) a network model for a LV system with storage and DG; and (iii) a LV network model with PV.

The proposals for representative networks based on expert knowledge reviewed are summarized in Table 5.2.

Reference	Date	Data	Voltage level	Number of networks	Area	Applications
UKGDS	2005	Data from DNOs through Long Term Development Statements (LTNS) and interaction with the DNOs	HV (132kV) and MV (11kV)	6 EHV + 7 HV	UK	Loadflow analysis for DER integration, losses assessment, economic analysis
Elforsk	2009	Data compiled by the Swedish Energy Markets Inspectorate	MV (10kV)	2 (urban and rural)	SE	Reliability analysis
ATLANTIDE	2011-2013	Data from ENEL: statistical sample of 454 Primary Stations (116 rural, 175 urban, 165 industrial)	MV (15kV)	3 (urban, rural and industrial)	IT	Power flow analysis, harmonic analysis, reliability analysis, short circuit analysis
GRID4EU	2012-2015	Data provided by RWE, Vatenfall, Iberdrola, ENEL, CEZ, ERDF	MV (35, 20, 15, 10kV) and LV	26 (2-4 per country & voltage)	DE, SE, ES, IT, CZ, FR	Power flow analysis, reliability analysis, dynamic analysis of islanded operation

Table 5.2: Representative networks based on expert knowledge

5.3.3 Representative networks based on clustering techniques

This section presents taxonomies and databases of representative distribution networks obtained using different data analysis and clustering techniques.

Clustering is aimed to divide data elements into classes or clusters so that items in the same class are as similar as possible, and items in different classes are as dissimilar as possible. Clustering may be applied to a large database of distribution networks in a distribution system (region, country, distribution networks operated by a distribution company, etc.) to classify these networks into a reduced number of groups and determine the network that can best represent the networks of each category and thus form a set of representative distribution networks for the considered system.

Clustering algorithms differ mainly (i) in the process to form the clusters (i.e. how to efficiently find them), and (ii) in the criteria to define clusters (i.e. how to consider similarity and dissimilarity to determine in which cluster, how to measure the distance between items in the same and in different clusters). The most relevant clustering algorithms used in the context of distribution representative networks include connectivity models or hierarchical clustering and centroid-based models (e.g.: k-means, k-medoids).

Hierarchical or connectivity-based **clustering** groups items to form "clusters" based on their distance. Clustering can be represented in a dendrogram, where the elements are placed along the x-axis, while the y-axis represents the distance at which elements are grouped into clusters, as shown in Figure 5.6. Hierarchical clustering can be agglomerative (each single element is considered a cluster and they are successively grouped into clusters) or divisive (the complete set of data is considered a single cluster and it is successively divided into partitions).

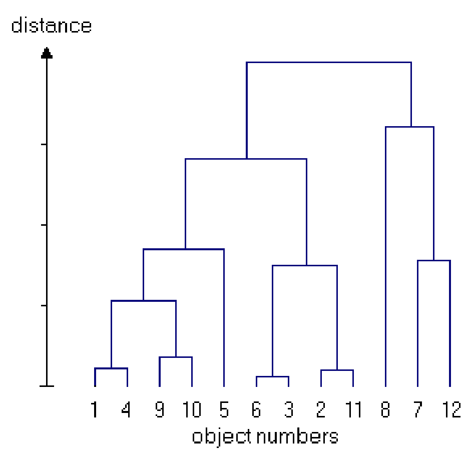


Figure 5.6: Example of a dendrogram. Source: Statistics4u[82].

82 http://www.statistics4u.com/fundstat_eng/cc_dendrograms.html

In **centroid-based clustering**, clusters are represented by a central vector, which may not necessarily be a member of the data set. Given a certain number k, clustering can be formulated as the optimization problem to determine the k cluster centers and assign each item to the cluster with the cluster center that is nearest, i.e. minimizing squared distances. The most common approach is the k-means algorithm, which finds a local optimum by solving it repeatedly with different random initializations. K-means++ is a slight variation of the algorithm where the selection of initial cluster centers is improved. K-medoids is a variation of these algorithms where cluster centers are actual elements of the data.

The number of representative networks used to represent a distribution system should be reduced, to allow for efficient analysis and compact representation of the system. However, a very low number of representative networks would be less accurate. In the case of centroid-based clustering, the number of clusters must be previously defined. The optimal number of clusters may be determined following different approaches, such as the Elbow method. This technique evaluates the percentage of variance explained as a function of the number of clusters. The number of clusters is selected so that an additional cluster does not improve modeling of the data very much (the point that would correspond to an elbow shape in the plot of percentage of variance explained by the clusters against the number of clusters).

The main benefits of hierarchical clustering are its flexibility to determine the number of clusters and the visualization of the resulting clusters and the distance between clusters in a dendrogram. One drawback of hierarchical clustering is that it requires a similarity matrix between all elements. For large data sets, generally greater than 200 elements, using a hierarchical approach can be time consuming. By contrast, the main advantage of centroid-based clustering is the computational efficiency, which becomes extremely relevant in the case of very large samples of networks. The main disadvantage of this method is the need to specify the number of clusters in advance. None of these methods are very robust to the presence of outliers, so often data must be pre-processed and normalized.

5.3.3.1 Existing taxonomies based on clustering

5.3.3.1.1 Westinghouse EC distribution feeders

The application of clustering to build representative distribution feeders that could be used for analyses of a whole distribution system was first proposed in (Willis, Tram, & Powell, 1985). The distribution networks operated by Westinghouse Electric Company (1,305 MV feeders) were analyzed to obtain 12 representative feeders through k-means clustering. The representative feeders were used to (i) estimate the losses, average voltage level, maximum voltage drop and capacitor requirements for the entire system, and (ii) to estimate the impact of voltage reduction for load management on load, losses and voltage profiles. To enable the extrapolation of the results observed in the representative feeders, the authors proposed to compute the weighted average of results for each cluster with the load represented by each representative feeder with respect to the total load of the system.

The authors assessed the performance of different approaches. First, the results obtained and the processing and execution times were compared for k-means clustering, geometric multidimensional clustering as proposed in (Long, Wilreker, & Strintzis, 1977), manual selection of representative feeders by the utility's engineering staff, and the analysis of the complete system. K-means turned out to be the most accurate and efficient. Additionally, the use of different combinations of variables for clustering was studied, and the best results were obtained when using voltage level (12.47, 34.5kV), total load, residential load, commercial load and industrial load, length, share of 600mcm conductor and rated power of transformers and number of industrial consumers. Regarding the number of clusters, k-means algorithm requires a pre-determined objective number, which was set to 12. However, the authors applied k-means clustering for different numbers of clusters (6, 8, 10, 12, 14 and 16). The option of selecting 10 representative feeders proved to be the most satisfactory option for the authors. Weighting factors based on load also proved to be better than number of feeders, line length, and number of customers of all feeders in each cluster.

5.3.3.1.2 Benchmark LV distribution networks for Germany

The authors of (Dickert, Domagk, & Schegner, 2013) highlight the need for LV benchmark networks to represent the LV distribution system. Furthermore, the need to identify the most critical networks for extreme value analysis is also stressed.

The authors describe their proposal to obtain representative networks based on German conditions. First, principal component analysis is used to reduce the number of dimensions, i.e. the number of variables used for clustering (originally the data available includes, rated voltage and rated power of the distribution transformer; PCA results in 4 variables for clustering: total length, cable length, overhead-line length and number of delivery points). Then, clustering is carried out using the k-means approach and 6 groups are deemed adequate to represent LV networks. Additionally, the authors discuss an approach to model branching in the networks.

5.3.3.1.3 Modern Grid Initiative Distribution Taxonomy

Department of Energy’s (DOE) Modern Grid Initiative (MGI) aims to support research and facilitate the evaluation of smart grid technologies with the creation of an open, central repository of detailed distribution feeder information[83].

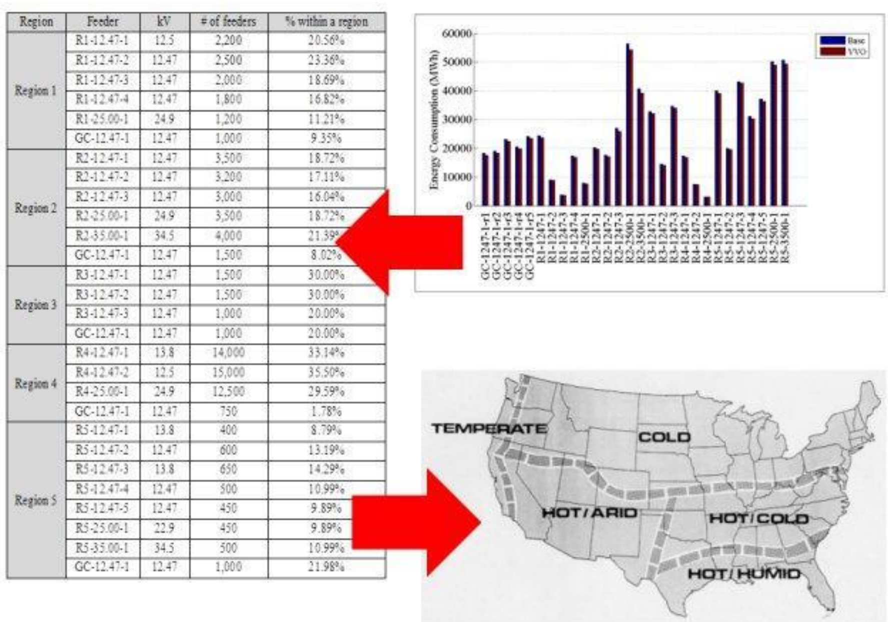
The Pacific Northwest National Laboratory (PNNL) has developed a set of 24 *prototypical feeder models* (i.e. representative networks) that can be used to study smart grid technologies through simulation (Kevin P Schneider et al., 2008). Furthermore, weighting factors are provided for these representative networks so that it is possible to *aggregate the effects* (i.e. scale-up the results) of the smart grid technologies to regional and national levels.

---

[83] https://sourceforge.net/p/gridlab-d/code/HEAD/tree/Taxonomy_Feeders/

The PNNL has collected and analyzed MV distribution radial feeder models from 17 electric utilities around the US (575 feeders). First, the distribution networks has been grouped according to voltage level and climate region (the US has been divided into 5 major climate regions). Then, hierarchical agglomerative clustering has been performed on the mean values and standard deviations of several electrical characteristics (length, overhead/underground, connected kVA, feeder rating, residential, commercial, industrial and agricultural demand), and topological characteristics (geographic, impedance and capacity degree, diameter, closeness, and centrality). Finally, a feeder is selected as the most representative for each cluster, resulting in a set of 23 representative networks. The set of representative networks comprises 3 to 7 representative networks for each region, identified by voltage level and type of area (resulting in different combinations of heavy/light/moderate urban/suburban/rural). Additionally, one representative network, common to the five regions, was added to represent industrial and commercial networks.

The weighting factors provided in the report are based on estimates of population distributions and estimates of the relative distribution of loads between urban, suburban, and rural areas. Thus, the weighting factors consist of an estimate of how many of each of the prototypical feeders exist in each region, and the number of inhabitants in each region. It must be noted that only radial distribution feeders were examined, so that urban areas in large cities are not represented by these representative networks and therefore scaling-up of results would suffer from this limitation.



Region	Feeder	kV	# of feeders	% within a region
Region 1	R1-12.47-1	12.5	2,200	20.56%
	R1-12.47-2	12.47	2,500	23.36%
	R1-12.47-3	12.47	2,000	18.69%
	R1-12.47-4	12.47	1,800	16.82%
	R1-25.00-1	24.9	1,200	11.21%
	GC-12.47-1	12.47	1,000	9.35%
Region 2	R2-12.47-1	12.47	3,500	18.72%
	R2-12.47-2	12.47	3,200	17.11%
	R2-12.47-3	12.47	3,000	16.04%
	R2-25.00-1	24.9	3,500	18.72%
	R2-35.00-1	34.5	4,000	21.39%
	GC-12.47-1	12.47	1,500	8.02%
Region 3	R3-12.47-1	12.47	1,500	30.00%
	R3-12.47-2	12.47	1,500	30.00%
	R3-12.47-3	12.47	1,000	20.00%
	GC-12.47-1	12.47	1,000	20.00%
Region 4	R4-12.47-1	13.8	14,000	33.14%
	R4-12.47-2	12.5	15,000	35.50%
	R4-25.00-1	24.9	12,500	29.59%
	GC-12.47-1	12.47	750	1.78%
Region 5	R5-12.47-1	13.8	400	8.79%
	R5-12.47-2	12.47	600	13.19%
	R5-12.47-3	13.8	650	14.29%
	R5-12.47-4	12.47	500	10.99%
	R5-12.47-5	12.47	450	9.89%
	R5-25.00-1	22.9	450	9.89%
	R5-35.00-1	34.5	500	10.99%
	GC-12.47-1	12.47	1,000	21.98%

Figure 5.7: MGI distribution taxonomy representative networks for the five regions identified and representativity weights, Source: (Kevin P Schneider et al., 2008).

The MGI network models have been used to estimate of the benefits of Conservation Voltage Reduction (CVR) in (K P Schneider, Fuller, Tuffner, & Singh, 2010). Time-series simulations were performed on the representative networks and the results were scaled at a national level. The results indicated that heavily loaded, higher voltage feeders should be prioritized[84].

5.3.3.1.4 National Feeder Taxonomy Australia

The Commonwealth Scientific and Industrial Research Organisation (CSIRO) and the state-owned distribution company AusGrid have built a set of representative feeders to facilitate the understanding of how the results and findings of smart grid trials apply across different regions and network topologies (Berry, Moore, Ward, Lindsay, & Proctor, 2013).

This report provides a characterization of MV distribution networks in Australia based on the data provided by AusGrid and other distribution network service providers (DNSPs) from across Australia. Then, a set of 17 representative feeders is built using clustering and expert review[85] from the over 350 feeders analyzed, together with their estimated prevalence across Australia to enable scaling-up. Additional data is provided for the representative feeders, such as actual supply interruption events registered. Furthermore, illustrative load profiles have been made available together with the representative network models based on SINCAL software.

This work used the k-medoids clustering on numerous variables categorized into feeder loading (rating and number of consumers), cabling (length, ratio of overhead and underground, use of Single Wire Earth Return systems, average positive sequence impedance), voltage characteristics (base voltage, number of voltage regulators, number of distribution transformers) and network topology (betweenness, page rank and closeness).

As a result, urban clusters have distinguished industrial, commercial, residential and mixed feeders, in addition to capturing key differences in residential densities (medium and high), base voltage levels (11 and 22kV) and construction (mainly overhead or underground). Rural clusters have categorized feeders with load characteristics (agricultural and mining, the suburban fringe and rural residential areas), voltage levels (11, 22 and 33kV) and feeder length (short and long). Rural clusters also underline differences in the application of SWER and regulators. Additionally to the 15 clusters obtained, the taxonomy has been refined to include two additional clusters have been created manually for central business districts (CBDs) and remote rural areas.

---

[84] A complete deployment of CVR (at 100% of distribution feeders), would provide a 3.04% reduction in annual energy consumption. When deployed only on heavily loaded feeders with higher voltage, an implementation degree of 40% would reduce annual energy consumption by 2.4%.

[85] Experts from the DNSPs were engaged to ensure real-world validity. Furthermore, results were presented to and discussed with the experts from the Pacific Northwest National Laboratory who were involved in the MGI taxonomy (Kevin P Schneider et al., 2008).

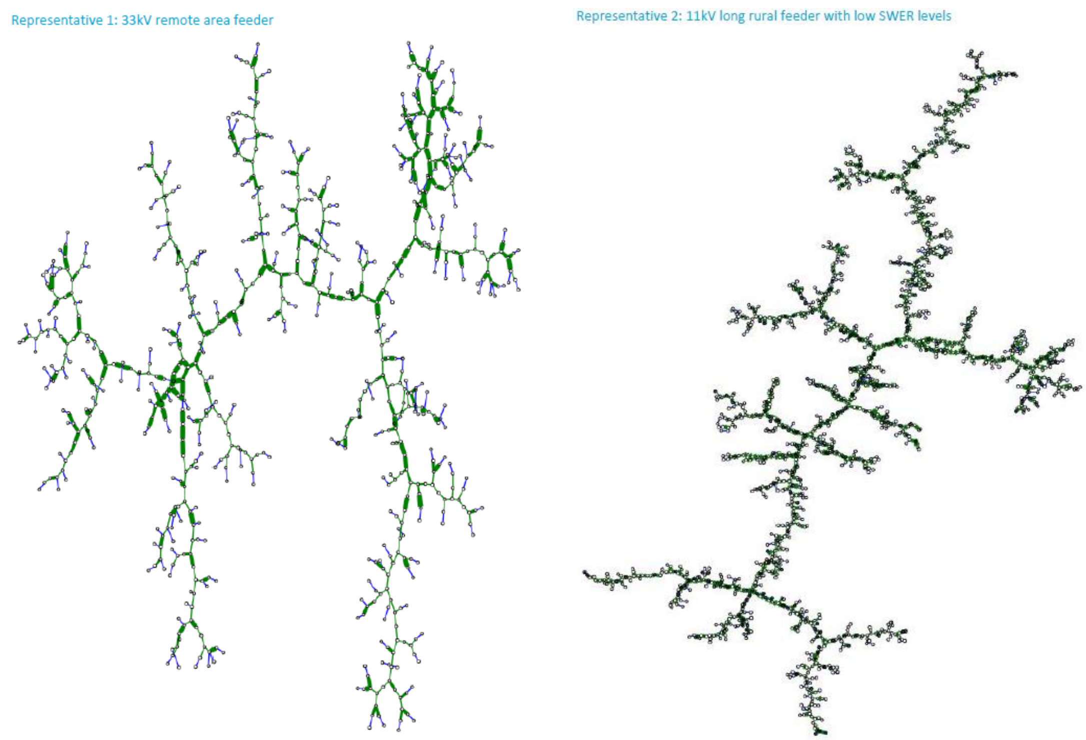


Figure 5.8: Examples of two of the representative networks developed for the National Feeder Taxonomy Australia. Source: (Berry et al., 2013)

5.3.3.1.5 Taxonomic description for western Australian MV and LV distribution networks

The work of (Li & Wolfs, 2014) presents a set of 9 MV representative feeders and 8 LV representative feeders to represent the distribution network of western Australia. The data analyzed consisted of 204 MV (22 kV) feeders and 8,858 LV feeders operated by the DNSP Western Power Corporation.

The authors have applied hierarchical clustering by Ward's method and discriminant analysis to consider a reduced number of network parameters[86]. The selected parameters include installed transformer capacity per customer, MV and LV circuit length, number of customers per distribution transformer, number of customers served and peak load for MV networks. In the case of LV networks, the variables selected for clustering include underground feeder length, load capacity of residential customers, number of residential customers, overhead feeder length, total load capacity/rating ratio, which is an estimate of the distribution transformer loading at the peak time, load capacity excluding residential customers and number of non-residential customers. Clustering has resulted in a group of

[86] After an iterative process with statistical analysis and engineering insight, the authors of this work have selected 6 variables for clustering of the MV networks and 7 variables in the case of LV networks, which are very low numbers in comparison to the PNNL MGI taxonomy, which used 37 parameters to carry out clustering of MV feeders.

representative feeders that are the actual feeders better suited to represent each group. The MV representative networks can be described as urban/ mixed/ suburban/ rural, further differentiated as light/ moderate/ heavily loaded and residential/industrial in the case of urban networks and short/ long in the case of rural networks. Similarly, LV representative networks as characterized as small/ median, commercial/ residential/ industrial, with high/ low transformer utilization and overhead/ underground/ short lines.

5.3.3.1.6 Low Voltage Network Solutions (LVNS) Project in UK

The Low Voltage Network Solutions project studied the LV network and its capacity to accommodate low carbon technologies (LCT) and included the actual deployment of monitoring at 200 substations in the distribution networks operated by Electricity Northwest Limited (ENWL). The University of Manchester analyzed network data from the corresponding of 383 feeders to build a set of representative LV networks (Low Voltage Network Solutions (LVNS) Project, 2014).

The most important topology features and monitored variables for the feeders included: number of consumers, total length, mean power, power factor, neutral current, main path impedance, number of DG units, capacity of DG units.

The variables used for clustering were selected through a trial and error approach. The final selection included the number of domestic unrestricted, domestic two rate, small non-domestic off-peak, small non domestic unrestricted and two-rate, and medium non-domestic consumers; length; main path distance, average and total path impedance; neutral current, active and reactive power and power factor. Following the approach adopted in PNNL's MGI Taxonomy (Kevin P Schneider et al., 2008), the mean values and standard deviations of the selected variables were considered.

This work has applied and compared two different partition and one hierarchical clustering algorithm: improved k-means++ and k-medoids++, and agglomerative hierarchical clustering based on Ward's variance method. The clusters obtained were validated through different statistical measures and the optimal value of k (i.e. number of clusters) was determined. The k-medoids++ proved to be the most suitable algorithm.

After a filtering process, a final set of 11 representative feeders has been obtained, divided in two groups, 8 networks with no PV (domestic and non-domestic, with high/medium/low number of consumers, low/medium/high power consumption and high/medium/low cable length), and 3 networks with high/medium/low PV penetration. The prevalence of each of these representative feeders is also provided.

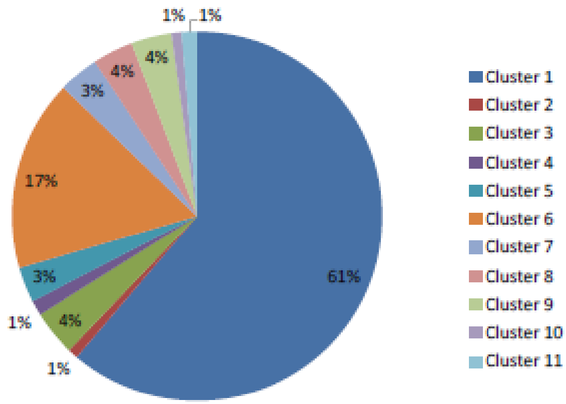


Figure 5.9: Representativity weight for the representative feeders developed in the LVNS project. Source: (Low Voltage Network Solutions (LVNS) Project, 2014).

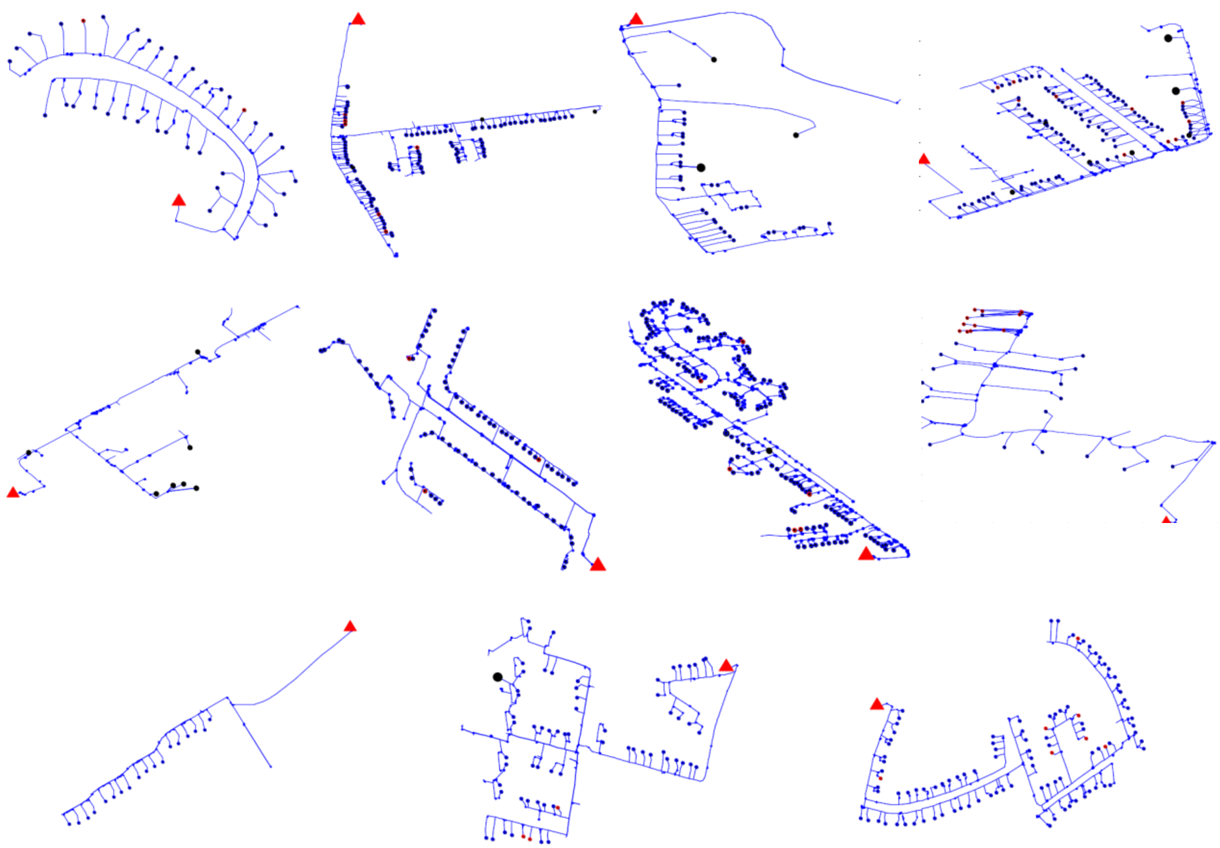


Figure 5.10: LV representative networks developed for the LVNS project. Source: (Low Voltage Network Solutions (LVNS) Project, 2014).

The article (Rigoni, Ochoa, Chicco, Navarro-Espinosa, & Gozel, 2016) described the work of the LVNS project on developing representative residential LV feeders for North West of England. Additionally, this paper presented the application of an additional clustering technique has been used, the Gaussian

Mixture Model (GMM). The results obtained from this technique were very similar to the improved k-means++. Furthermore, PV-related features used for clustering: number of PV units, PV-supplied demand, PV penetration (number of consumers per PV unit) and average PV capacity (per PV unit).

5.3.3.1.7 California Solar Initiative Screening Distribution Feeders: Alternatives to the 15% Rule

The research project 'Screening Distribution Feeders: Alternatives to the 15 percent Rule' (Electric Power Research Institute, 2015) is part of the California Solar Initiative (CSI) established by the California Public Utilities Commission (CPUC) aimed at improving the Utility Application Review and Approval process for the connection of DER to the distribution grid. This project was carried out by the Electric Power Research Institute (EPRI), National Renewable Energy Laboratory (NREL), and Sandia National Laboratories (SNL) with collaboration from Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E). From the data collected from the three utilities (a total of 8,163 feeders), clustering of feeder characteristics was carried out to attain a set of 16 feeders representative of the distribution networks in California. Additionally, analysis of PV impacts to those feeders has been carried out to suggest refinement of the current processes for the connection of new PV units.

The report (Electric Power Research Institute, 2014) describes in detail the work carried out for clustering and analysis of the feeder database. The data gathered from each utility was subject to K-means expectation-maximization clustering and the number of clusters for each group was determined applying the Cubic Clustering Criterion (CCC).

One of the primary characteristics to manually reduce clusters was voltage class. The considered feeders ranged from 4 kV to 33 kV, with a majority of 12kV feeders. Therefore, the majority of the clusters were 12kV, while three clusters were used to specifically represent 4 kV and 33 kV. The variables used for clustering varied for each utility according to the available data and were determined using a correlation map to select independent variables. In the case of one of the utilities, the selected variables comprised total three-phase, two-phase and single-phase circuit length, number of voltage regulators and switched capacitors, number of feeder tie points, rated transformer capacity, feeder peak load, share of residential, commercial, and industrial demand and feeder peak load time. Thus, several clusters were created for each utility. The resulting clusters were further examined to determine similar primary characteristics, suppress redundant clusters and thus reduce the number of clusters to a total of 16 feeders. The representative feeder for each cluster is an actual feeder selected within the cluster based on its distance from the center.

5.3.3.1.8 Optimal integration of distributed energy resources PSE-REDES 2025

The project 'Optimal integration of distributed energy resources' (PSE-REDES 2025) was developed in 2009-2010 as part of the Singular Strategic Project 'Development and implementation of technological alternatives for the Spanish electricity network for 2025' funded by the Spanish Ministry of Science and Innovation and the European Regional Development Fund. The project aimed to develop software tools for the optimal integration of distributed resources in the electrical networks.

Within this project, the distribution network operated by Unión Fenosa Distribución was characterized (PSE-REDES 2025 Project, 2010).

Typical distribution networks have been modelled to analyze the impact of DG on voltage control. First, data from 3,145 MV feeders was gathered and classified into categories according to the distribution areas defined by regulation based on population density: urban, semi-urban, concentrated rural, scattered rural and mixed for feeders serving several types of distribution areas. The parameters identified for clustering included network length, the share of overhead and underground lines, number of secondary substations (MV/LV) and density of inhabitants. In order to select the typical network for each group, the average values of parameters were used and the standard deviation was minimized.

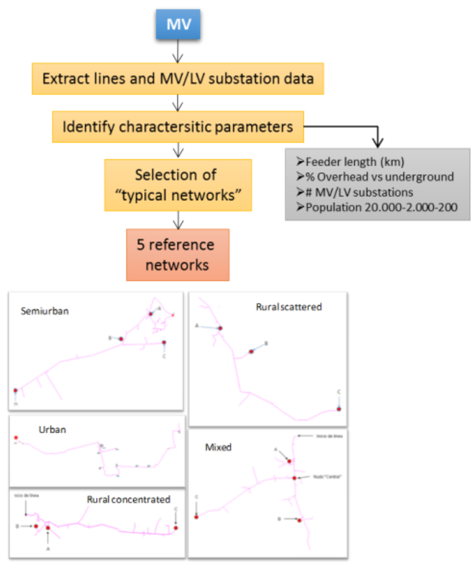


Figure 5.11: Creation of representative networks for the PSE-REDES2025 project. Source: (PSE-REDES 2025 Project, 2010).

The main works reviewed are gathered in Table 5.3, where the adopted clustering algorithms are listed, together with the approach to select the variables for clustering (i.e. categorization parameters) and the number of clusters (i.e. number of representative networks).

Reference	Clustering algorithm	Variables for clustering	Criteria to determine number of clusters
Willis et al	K-means (compared to EPRI-clustering and no-clustering)	• Clustering run with different combinations to select the best • Voltage level, load (residential/ commercial/ industrial), length, conductor type, rated power of transformers	• Authors' estimation: 12 • Clustering run with different values to find best option (10)
Modern Grid Taxonomy	Hierarchical agglomerative by Ward's method	• Pre-classification: region and voltage • Clustering with a set of 35 variables: mean and std deviation of electrical and topological variables	• Min. sum of squared errors for each region: 3-7 per region (voltage & load density/area type) • Elbow criterion for total number of clusters: 23 • Authors' added a general cluster to a total of 24
Australia National Taxonomy	K-medoids	• Clustering with 14 variables, then refined by experts to weight and transform variables • Loading, cabling, voltage, network topology	• Average silhouette width (intra- and inter- cluster distances): 17 (voltage, area type, consumer type, cabling) • Authors' added clusters for large cities to a total of 19
Western Australia taxonomic description	Hierarchical agglomerative by Ward's method	• Pre-classification: MV and LV • Iterative process of ANOVA test and engineering insight • 6 variables for MV and 7 for LV related to installed capacity, length, number of customers (residential /non-residential)	• Semi-partial R2 (SPRSQ); pseudo-F (PSF) statistic and pseudo-T2 test • 9 MV (type of area, load density, length) • 8 LV (size, consumer type, transformer utilization and cabling).
California Solar Initiative	K-means	• Pre-categorization per utility and voltage level • Principal Component Analysis:11-12 variables per utility related to length and conductor type, voltage regulators, load mix (residential, commercial, industrial), load shape (peak, minimum load, seasonality) and existing DG	• Cubic Clustering Criterion for each utility • Authors discarded redundant clusters to a total of 16
Low Voltage Network Solutions (LVNS)	K-medoids++ (compared to hierarchical, k-means++, GMM)	• Pre-categorization with/ without PV • Clustering with 15 variables selected through trial and error, mean and std deviation of electrical and topological variables	• Total Sum of Square Errors (SSE) and average silhouette width for no PV/ PV • Authors discarded clusters to a total of 11 (8 with no PV, 3 with PV)

Table 5.3: Representative networks built with clustering techniques

5.3.4 Representative networks built with reference network models

As explained in the introduction of this chapter (section 5.1), representative and reference networks have been used in regulation as a benchmark to determine efficient costs, expected reliability levels and even reference levels of energy losses. The so-called reference network models (RNM) or norm models are the software tools that have been developed to build such networks. RNMs have been applied electricity distribution regulation in Spain, Sweden, Chile, Peru and Brazil.

These models are able to account for the particularities of distribution networks (linked to the geography and technical restriction of electric networks) and their impact on network investments, serving as a more adequate benchmark alternative to black-box approaches. These models build reference networks to connect and supply end-consumers at a minimal cost, taking into account the geographical location, level of consumption and voltage level of consumers. Moreover, the planning criteria applied by these models complies with reliability requirements, maximum voltage drop, thermal rating of elements that constitute the network, etc. The reference networks are built using available elements (standard cables, lines, transformers, protection elements, etc.), selecting the candidates from a database or catalogue. Typically, these models support large-scale network planning, including up to millions of supply points.

Reference network models are therefore designed to build the model of the distribution networks of any given region, provided that the necessary data is available. Thus, reference network models may be used to support the definition of a set of representative networks. Several authors have used RNMs to build the representative networks, which corresponds to the third of the three steps identified in section 3.1.2.2.

5.3.4.1 Existing representative networks built with reference network models

5.3.4.1.1 Generic networks created with the fractal-based algorithm in UK

The Imperial College London has developed a fractal-based algorithm that allows creation of generic networks (Gan et al., 2009). This model builds LV, MV and HV networks separately. First, LV networks are created based on fractal science, starting from sets of LV consumers categorized according to their type of demand (domestic with/without electric heating, commercial and industrial) setting controlled parameters (branching rate, consumer's separation and other). The networks obtained are statistically similar with different network layout, but same load density, substation density and overall network lengths. Then, MV networks are generated from the MV/LV transformers (output of the LV network creation) together with industrial consumers, with a controllable branching rate. Finally, the HV network is created by connecting and supplying the HV/MV transformers applying the N-1 reliability requirement with double circuits and double transformers.

The report (Strbac et al., 2010) studies the benefits of demand response enabled by smart meters to decrease peak demand and thus reduce the need for distribution network reinforcement in the context of penetration of Electric Vehicles (EVs) and Heat Pumps (HPs). Representative distribution networks have been created and analyzed to compute the cost of network reinforcement at GB level. 3 LV representative networks have been generated with the fractal model, locating MV/LV transformers in the centers of clusters and considering average feeder lengths reported by several DNOs in the UK. The set of LV representative networks comprised a network for a city/town area with a load density of 8 MVA/km^2, a semi-urban/rural network with a 2 MVA/km^2 load density and a rural network with a load density of 0.5 MVA/km^2. Assuming a proportion of 10% of urban, 70% of semi-urban/rural network and 20% of rural networks, the higher voltage levels were built. The HV network model was derived from a network topology in Coventry.

The fractal model was used to assess the cost of LV network design strategies and thus determine the optimal number of substations and total costs, average transformer sizes and losses in distribution networks for urban and rural areas in (Gan, Mancarella, Pudjianto, & Strbac, 2011).

The same model is also used in (Mancarella, Gan, & Strbac, 2011) for the study of electro-thermal networks.

Additionally, network reinforcement due to the increase of electric heating and EVs was assessed in (Pudjianto et al., 2013) using 2 LV representative networks (urban and rural) created with the fractal model. The article proposes strategies to minimize this cost through smart network control and demand response technologies (smart EV charging, smart heat pumps, and optimized control of network voltage regulators).

As explained in section 5.3.2.1.1, MV representative networks created with the fractal model to assess the cost of distribution network losses for an OFGEM funded project (Strbac et al., 2014) and to assess RES integration in the report (DNV GL et al., 2014) prepared for the European Commission.

5.3.4.1.2 European DSO observatory

The Joint Research Centre of the European Commission (JRC) has launched the DSO Observatory project focused on the characterization of European distribution system operators and their distribution networks (Prettico et al., 2016).

Within this project, Comillas Pontifical University has elaborated a set of MV and LV representative networks using a Reference Network Model (RNM) (Domingo et al., 2011). Furthermore, these networks have been used to analyze the impact of Renewable Energy Sources (RES) penetration and network automation can have on their technical performance. The network models are publicly available by request at the JRC website[87].

Technical and structural data was collected from 79 DSOs[88] in the EU through an online survey. These data were used to build 36 indicators, divided in three categories, i.e. network structure and reliability indicators, network design and distributed generation indicators. Then, 10 of these indicators were chosen to create representative distribution networks, including the number of LV

---

[87] http://ses.jrc.ec.europa.eu/distribution-system-operators-observatory

[88] Overall, these 79 DSOs manage more than 70% of the electricity supplied by all DSOs serving over 100,000 customers.

consumers per MV consumer, LV circuit length per LV consumer, LV underground ratio, number of LV consumers per MV/LV substation, MV/LV substation capacity per LV consumer (kVA), MV circuit length per MV Supply Point (km), MV underground ratio, number of MV Supply Points per HV/MV substation, MV/LV transformer substation capacity in urban areas, MV/LV transformer substation capacity in rural areas.

The representative networks developed comprise a total of 13 representative distribution networks: 3 large-scale, geo-referenced MV and LV networks (urban, semi-urban and rural) and 10 feeder-type networks of different voltage levels (5 MV and 2 LV), different types and topologies (urban, semi-urban and rural), and automation degree (high/low).

5.3.4.1.3 Use of RNM for the USA

Comillas Pontifical University and Massachusetts Institute of Technology (MIT) have worked together to adapt the RNM to model to build distribution networks that can be used as representative of the US. This work is still on-going, with several applications already in the literature.

MIT's Future of Solar (Massachusetts Institute of Technology, 2015) is a very comprehensive report that addresses solar generation from a multi-disciplinary perspective. In addition to other technological, environmental, economic and social aspects, the impact of large amounts of PV on transmission and distribution networks has been analyzed using 12 prototype networks for different scenarios of PV penetration. These prototype networks were built with the RNM and comprise a high population density and a low population density network for 6 different States. MIT's Utility of the Future[89] has also used these 12 prototype networks to assess distribution costs and design network tariffs.

The U.S. Department of Energy's Advanced Research Projects Agency-Energy (ARPA-E) has funded the project Synthetic models for advanced, realistic testing of distribution systems and scenarios (Smart-DS), to be finished in 2018 with the participation of the National Renewable Energy Laboratory (NREL), MIT, Comillas, GE Grid Services and Alstom Grid. This project aims to adapt the RNM using data provided by US utilities. These networks will be used for different analyses considering scenarios of demand and DER integration.

Furthermore, the RNM model developed in Comillas has also been adapted for rural electrification by the Universal Energy Access Research Group at MIT and Comillas to identify areas better suited for on-grid or off-grid electrification (Ciller Cutillas, 2015; Ellman, 2015; Gonzalez-Garcia, Amatya, Stoner, & Perez-Arriaga, 2015).

The reference network models used to build sets of representative networks described throughout the previous subsections are listed in Table 5.4.

---

[89] http://energy.mit.edu/research/utility-future-study/

Model	Reference	Representative networks	Application
Fractal	(Strbac et al., 2010)	• 3 LV representative networks (city/town, semi-urban/rural, rural) • MV network (10% urban, 70% semi-urban/rural 20% of rural)	• Reinforcement requirements • Reduction of peak demand with DR, EVs and HPs
	(Pudjianto et al., 2013)	2 LV representative networks (urban and rural)	Smart EV charging, smart HPs, and voltage regulators to reduce reinforcement costs
	(Strbac et al., 2014)	• LV and MV representative networks created with the fractal model • LV: two urban networks, two semi-urban, four semi-rural and four rural networks	Cost of network losses
	(DNV GL et al., 2014)	Limited set of networks for EU-27	Impact of DG integration
RNM	DSO Observatory (Prettico et al., 2016)	• 3 MV&LV large-scale geo-referenced networks (urban, semi-urban and rural) • 8 feeder-type MV networks (U, SU, R) • 2 feeder-type LV networks (U & SU)	Impact of PV and wind integration Impact of network automation
	MIT's Future of Solar (Massachusetts Institute of Technology, 2015)	12 networks (high & low density for 6 States)	Impact of PV integration
	MIT's Utility of the Future (Massachusetts Institute of Technology, 2016)	12 networks	Distribution costs
	Smart-DS		Scenarios of demand and DER integration

Table 5.4: Representative networks built with reference network models

5.3.5 Assessment of proposed approaches

Different approaches and techniques have been used in the pursuit of building network models that can adequately represent the distribution system in a region, as presented in Section 5.3. It is important to remark that the reviewed works have been presented in different blocks depending on whether clustering techniques or reference network models have been used (or whether the approach adopted relied only on expert knowledge), which does not exactly correspond to different methodologies: although these tools have been used independently, clustering techniques and network planning models are tools that can be used to support in some phases of the construction of representative networks[90].

5.3.5.1 Overview of existing sets of representative networks

The review of existing sets of representative networks has pointed out that there is a need for such exercise and that some countries are already pushing towards open repositories of network data to facilitate knowledge sharing and provide resources for research. The table below provides an overview of the geographical scope and the date where the main initiatives have taken place.

[90] The use of clustering and networks planning models is not exclusive. On the contrary, they are complementary and both could be used together, as will be explained in section 5.4.

Reference	Date	Geographical scope	Voltage level	Approach
IEEE	1991-2016	US, EU	MV, LV	Test feeders
CIGRE	2005-2014	US, EU	MV, LV	Test feeders
EPRI	2010	US	MV	Test feeders
UKGDS	2005	UK	HV, MV	National set of representative networks
Elforsk	2009	Sweden	MV	Representative networks
ATLANTIDE	2011-2013	Italy	MV	National intiative to create open database of representative networks, generation and demand and simulation tools
GRID4EU	2013-2016	EU-scope (DE, SE, ES, IT, CZ, FR)	MV, LV	Representative networks for analysis of different countries
Willis et al	1985	US	MV	Application of clustering to obtain representative feeders for a large set of data
Modern Grid Taxonomy	2008	US	MV	Application of clustering to obtain national set of representative networks with representativity weights
California Solar Initiative	2014-2015	California	MV	Application of clustering to obtain set of representative networks with representativity weights
Australia National Taxonomy	2013	Australia	MV	Application of clustering to obtain national set of representative networks with representativity weights
Western Australia taxonomic description	2014	Australia	MV, LV	Application of clustering to obtain representative feeders for a large set of data
Low Voltage Network Solutions (LVNS)	2014	UK	LV	Application of clustering to obtain representative feeders for LV networks
Fractal model	2010	Open (UK, EU)	MV, LV	Model to generate LV and MV networks
DSO Observatory	2016	EU	MV, LV	Use of RNM to obtain set of representative networks for Europe
REM	2015-2016	Open (IN, PE)	HV, MV, LV	Model to generate networks for remote rural areas

Table 5.5: Overview of developed sets of test feeders and representative networks.

Objectives pursued by developed representative networks

The interest on the analysis of smart grid solutions in distribution networks has emerged in response to the change of paradigm that has occurred in the electric power system in recent years, going from conventional generation and unidirectional power flows to the decentralized, disperse, small-scale generation connected to distribution networks producing bidirectional power flows.

Therefore, the initiatives to develop representative networks have been launched with the main objective to use for the assessment of the impact of the envisioned integration of DER in the MV and LV networks and smart grid solutions available. Therefore, most developed representative networks consist of a few feeders and are used to carry out load flow analysis for different scenarios of DER penetration and different strategies of DER management and voltage control.

Agents involved in development of representative networks

These initiatives are most frequently promoted, funded and launched by National Regulatory Authorities (NRAs), national research institutions, EU-institutions and other international non-profit associations for knowledge sharing (CIGRE, IEEE). Regulatory entities have launched projects to develop representative networks with the aim to enable analyses that can identify the most promising solutions and the expected impacts of innovative solutions and strategies and thus guide policies to incentivize those solutions. Educational and research institutions, and professional associations also promote this kind of projects in order to foster knowledge sharing and make representative network available to other researchers.

The work of developing the representative networks is most frequently carried out by universities, such as universities in the UK, Spain, Italy, Germany and Australia and research centers, such as national laboratories in the US (NREL, SANDIA, PNNL) and Australia (CSIRO).

DSOs are often involved in these projects to provide the data and expertise to review the representative networks obtained. Depending on the national regulation and the philosophy of the company, some DSOs are more willing to share data, while others are subject to very strict confidentiality, which imposes a very significant hurdle on the construction and use of representative networks for research and analysis.

Table 5.6 presents an overview of the agents involved in the financing and development of the reviewed representative network initiatives, as well as the data considered.

Reference	Financing	Development	Data
UKGDS	-	University of Manchester, University of Strathclyde	15 DNOs in the UK
Elforsk	-	Elforsk (Swedish industry research association)	Fortum Distribution AB
ATLANTIDE	Italian Ministry of Economic Development	University of Cagliari, University of Padova, II University of Napoli	ENEL
GRID4EU	European Commission	Comillas Pontifical University	RWE, Vatenfall, Iberdrola, ENEL, CEZ, ERDF
Willis et al.	-	Westinghouse Electric Company	Westinghouse Electric Company
Modern Grid Taxonomy	US DOE	PNL	17 utilities in the US
California Solar Initiative	California Public Utilities Commission (CPUC)	EPRI, SANDIA, NREL	Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E)
Australia National Taxonomy	-	CSIRO	AusGrid and other DNSPs
Western Australia taxonomic description	-	Curtin University, Central Queensland University	Western Power Corporation
Low Voltage Network Solutions (LVNS)	OFGEM	University of. Manchester	Electricity North West Limited (ENWL)
Dickert et al.	-	TU Dresden	-
DSO Observatory	Joint Research Centre (JRC) of the European Commission	Comillas Pontifical University	79 European DSOs with the support of Eurelectric
REM	-	Comillas Pontifical University, Massachusetts Institute of Technology (MIT)	-
Fractal	-	Imperial College London	-

Table 5.6: Agents involved in initiatives to develop representative networks.

The work of data gathering and analysis to build a good set of representative networks consumes a very large amount of resources. If already developed models are shared among researchers and projects, more resources can be devoted to the development of simulation tools and the analysis of different scenarios and solutions. Therefore, many of the reviewed projects have resulted in the creation of open platforms and websites to host the developed network models. Some of these websites even include information for demand and generation profiles, loading and DER penetration scenarios, simulation models, etc. and enable users to upload their own models and data, such as in the case of the ATLANTIDE project. However, in some occasions, these websites have a determined lifespan linked to the associated research project (and allocated funding) and in time become no longer maintained and updated.

5.3.5.2 Use of clustering techniques

Clustering requires extensive and detailed data. Ideally, in order to apply clustering algorithms, the values of all relevant parameters must be registered for all networks in the distribution systems. This means that as larger areas are considered for representation, the volume of required data grows exponentially. Usually, the data gathered must be pre-processed to exclude outliers and feeders or networks with incomplete data. Furthermore, the activity of electricity distribution is performed by many distribution companies of different regional scope. Therefore, data for a national study would involve many different companies, with different information systems and data formats, which would result in an impractical (unbearable) workload to undertake. Most of the reviewed approaches rely on the use of a large amount of distribution networks, but not the totality of them. Theoretically, a representative sample should be considered. In practice, the reviewed works have selected a significantly large amount of data and carried on with clustering techniques together with expert knowledge to determine reasonable representative networks. PNNL's Distribution Taxonomy contacted 17 utilities among the many utilities operating in the US. The California Solar Initiative used data from the 3 largest utilities in California. In the case of CSIRO's National Feeder Taxonomy the considered data was gathered from 11 of the 16 distribution companies (Distribution Network Service Providers, DNSPs) operating in Australia and sampled aiming for a random selection (although with a certain bias by including all feeders outgoing from a substation).

According to the three steps identified to define representative networks described in section 3.1.2.2, clustering techniques have been used to help categorize distribution networks (step 2) and shaping representative networks (step 3). Clustering has been used to categorize the networks, assessing the use of different parameters to delimit the groups, evaluating the optimal number of networks in the set, creating the groups (clusters) and assigning each distribution network to a group, so that representativity weights may be easily determined. Additionally, clustering techniques have determined the networks to represent each cluster, selecting the feeder that is closest to the center of the cluster.

Most of the works reviewed have established a pre-categorization prior to clustering analysis: MV and LV have been analyzed separately for the Western Australia taxonomic description, MV distribution networks have been classified into five geographic regions for the PNNL's National Taxonomy, and distribution networks from different utilities have been addressed separately for the California Solar Initiative.

Then, the works reviewed have proposed the use of several variables for clustering related to loading, often discriminating the type of consumers (residential, commercial, industrial), length and cabling, and network topology, based on different concepts. The correlation between variables has been studied in some cases, and Principal Component Analysis has been used to reduce the number of variables used for clustering.

Regarding the number of clusters, the different works have come up with different numbers of representative networks (from 9 to 25). In order to assess the optimal number of clusters, statistical measures have been used: minimizing the sum of squared errors, with Elbow criterion, average silhouette width, semi-partial R2 (SPRSQ); pseudo-F (PSF) statistic and pseudo-T2 test and Cubic clustering criterion. In most cases, the resulting clusters have been later refined by experts to suppress redundant clusters (in the case where a pre-classification into regions has been carried out) or to add representative networks that were deemed relevant but were under-represented in the data used for clustering.

The reviewed works have used different clustering algorithms, including hierarchical agglomerative clustering by Ward's, k-means, k-medoids and improved k-medoids. There is no consensus on which clustering algorithm is better suited for the development of representative networks. The authors of (Low Voltage Network Solutions (LVNS) Project, 2014; Rigoni et al., 2016) have compared the use of different methods to conclude that improved k-medoids has been the most efficient for the studied cases, but the results are relatively similar.

5.3.5.3 Use of reference network models

According to the three steps identified to define representative networks described in section 3.1.2.2, reference network models have been used to shape representative networks (step 3).

Initially developed as a tool for network planning and to provide a benchmark for distribution regulation, network planning and reference network models have also been used to generate large-scale models that can be used as representative networks for smart grid analysis.

RNMs produce synthetic networks to supply a certain demand, so usually the localization and maximum demand of consumers and other network users must be introduced as input data. Alternatively, some reference network models extract this information from street view maps based on assumptions on number of inhabitants per type of building, etc.

In order for reference network models to produce realistic networks that can be representative of regions, countries or distribution companies, RNMs must be well-adapted to the design and operation criteria of the distribution system. This is done through the network elements (conductors, transformers, protection devices) used by the model to build the networks, which must be in accordance to standard equipment in place in the distribution system to represent; and reliability requirements (continuity of supply, voltage profiles) that shape resulting networks.

Summary

- Objective and application of developed representative networks: analysis of DER integration and smart grid technologies
- Agents involved in creation of representative networks: National regulatory authorities and institutions for funding; universities and research centers for the development of representative networks; and DSOs to provide the data
- Different approaches have been used but there is no clear "winner"
- Use of clustering techniques: categorization of distribution networks (step 2) and shaping representative networks (step 3)
- Use of RNM: shaping representative networks (step 3)
- Clustering requires detailed list of the distribution networks comprising the system to represent
- RNM must be adapted to distribution planning criteria and requires data on demand

5.4 Lessons learned for scalability and replicability analysis

This section focuses on representative networks for SRA, to make a comparative assessment of the reviewed proposals and methods, list the requirements and ideal characteristics of representative networks and describe the implications for SRA.

Representative networks should be able to provide **simplicity**, **transparency** and **representativity** of a region for the analysis of the impact of smart grid technologies and the upscaling of the obtained results. One of the main objectives of using representative networks is to reduce the complexity of modelling and the number of simulations that must be carried out to assess a large area. Furthermore, considering that large-scale analysis of smart grid solutions (such as SRA) will be used to guide investment and regulation and policy-making, it is of the utmost importance to obtain results that are as transparent and traceable as possible, easy to understand and explain[91]. Moreover, the quality, accuracy and coherence of SRA results using representativity networks is unavoidably linked to the representativity of the developed set of representative networks, which of course depends on the available data.

The definition of a set of representative networks for a region is very challenging and faces several barriers. The representativity of the network models depends mainly on the availability of data and its accuracy. Several approaches, techniques and tools have been developed to assist in the task of

[91] It is especially relevant to have transparent, predictable results for decision-making that leads to the approval/support/financing of competing smart grid solutions or projects.

creating sets of representative networks, with different strengths to make the most of available data and information. These issues will be discussed in this section.

5.4.1 Barriers to gather data

The task of gathering the data can be very cumbersome due to the large volume of infrastructure in terms of number of distribution network elements.

The detailed data on the distribution elements lies within the respective distribution companies. The registered characteristics may vary for different distribution companies, and the format of information may differ depending on information systems in use.

Furthermore, the inventory of DSO assets may not be comprehensive or updated for certain parts of the distribution system, especially for lower voltage levels. There is a high number of network elements of a very long lifespan, and modifications in the network may be needed for repairs and new connections. Therefore, the cost of an updated detailed inventory is quite high for distribution companies. A more imprecise inventory limits the capabilities of characterization of the distribution system. Traditionally, the degree of monitoring of distribution networks has been limited, again especially for lower voltage levels. However, the current evolution towards a smarter grid has involved an increasing level of monitoring equipment at different points of the MV network. Additionally, large-scale deployment of smart metering is a reality in many European countries (e.g.: Sweden, Spain, Italy, etc.). The information gathered from smart meters is helping identify what consumers are connected to which LV line and phase, and thus completing and improving distribution network databases.

Moreover, due to confidentiality issues, the data may not be accessible for non-DSO agents building representative networks (e.g. research institutions, consultants). The privacy of network users must be ensured, and distribution companies are often reluctant to share data that can be used as a benchmark against other distribution companies. Public institutions, national regulatory authorities, the European Union and other associations are pushing to foster data exchange and devoting research funds to make data publicly available.

5.4.2 Use of clustering algorithms and reference network models

Ideally, representative networks should be obtained as a result of a clustering process applied to every single distribution network in the area to represent. However, this would not be practical or efficient due to the vast amount of information to process; or even possible, due to unavailability of data, as discussed above. The main drawbacks of approaches applying clustering techniques are the complexity and of course the large amount and level of detail of the input data required.

However, in the future, as monitoring increases and smart metering is deployed, distribution companies are bound to have a more accurate and updated information to characterize their distribution networks. Moreover, technological advances will enable larger and larger volumes of data to be efficiently processed. Further work will be needed to explore clustering as a supporting tool to develop sets of representative networks that can be used for smart grid analysis.

Reference network models are a great tool to build distribution networks when no database is available, or in order to avoid the confidentiality issues related to the use of actual networks. The networks developed with the help of RNMs are realistic and may be used as representative networks. RNMs however require a very detailed characterization of demand, including geographical location, which may be even more problematic due to privacy of the data. This can be solved through an estimation of demand and consumers based on maps and demographics. Since RNMs must be adapted to the planning criteria of different regions, developed models may present the limitation of having a certain domain of validity, so different versions may have to be developed in order to cover regions with very different distribution networks, such as for instance in the case of Europe and the US, where distribution networks are based on secondary substations with large MV/LV transformers high undergrounding ratios and three-phase LV outgoing feeders in the former; and MV networks consisting of three-phase main trunks with two- or single-phase branches with smaller MV/LV transformers, lower undergrounding ratios and short LV lines in the latter.

The use of RNMs to define representative networks supports the task of creating the networks that can be used as representative. However, these models do not support the task of categorization of distribution networks: distribution networks must be grouped according to some criteria into a number of categories. RNMs could be used to create distribution networks for the whole region to analyze, using maps standard equipment and technical constraints derived from the relevant regulation and grid codes as input data. Then, the resulting feeders could be used as input data for clustering analysis, so that statistical analysis was the basis to determine the number of representative networks and the parameters to be used as variables for clustering.

This PhD thesis proposes the use of representative networks to compute through simulation KPIs that measure the impact of smart grid solutions on the system. The use of these reduced network models facilitates the understanding of simulation results and the implications of the variation of different parameters for the different types of networks. However, representative networks require a categorization of distribution networks into a certain number of groups or clusters, and, as explained in the proposed SRA methodology (Chapters 3 and 4), simulation results must be upscaled to extract the scaling-up and replication rules.

Alternatively, large-scale reference networks could be used for simulation instead of using a limited number of representative networks based on a few feeders. RNMs could be used to model the whole distribution system. Such large-scale reference networks would require adapted simulation tools, able to cope with much larger volumes of data and large-scale computation[92], and simulation results would not require upscaling. Instead, efforts would have to be devoted to understand the final results.

5.4.3 Other issues

When a first categorization of distribution networks is established according to geographical criteria, analyzing networks from different regions, countries, or even those operated by different distribution companies separately, the resulting representative networks for each region, country or DSO may have similar representative networks, or some of these could be "repetitive". For instance, GRID4EU has created set of MV representative networks for each of the 6 Demo countries, resulting in six groups of 2 to 4 distribution networks of urban, sub-urban and (concentrated/scattered) rural type. The urban networks for some countries are very similar to each other, whereas a categorization that had not considered countries separately may have had resulted in only a few urban networks different from each other from the technical point of view. Such non-technical categorizations result in a less efficient set of representative networks, since a higher number of simulations will be needed to obtain results. However, such categorization can facilitate the understanding of the results and their upscaling, and can be of help for subsequent analysis, for instance when including regulatory aspects that vary from one country to another.

The prevalence of each of the representative networks in the set for the studied region must be expressed through some kind of representativity weights. The main objective of using representativity networks is to enable the upscaling of simulation results in the form of KPIs. Therefore, depending on the type of results, representativity weights may be given as the number of feeders of each type among the total, number of consumers connected to each type of network, energy delivered through each type of network, etc.

Representativity weights or factors would be obtained directly if data from all networks were accessible. If clustering is used, each of the studied networks is categorized so that the number of networks that belong to each identified cluster or representative type of network is a direct result. Typically, when clustering has not been used, estimates of the prevalence of each representative network may be produced, taking into account the parameters that have been used to classify the networks. If a pre-categorization has been established, based on the voltage level, region, or type of areas, demographic data and statistics can be used to determine the "amount" of networks of each type. However, it is important to keep in mind that the objective is to upscale simulation results, so the type if results will condition the parameter to scale up results. For instance, in the case of a smart grid implementation consisting of network automation to improve continuity of supply, technical SRA will be based on reliability analyses for a set of representative networks. If the KPI of reliability

[92] As computation capabilities have been developed, there are currently available simulation tools to carry out reliability, loadflow and dynamic analysis for large-scale networks, so this would be technologically plausible nowadays.

improvement is based on the reduction of SAIDI and SAIFI, the number of consumers of each type of representative network will probably be a better variable to scale-up the results of simulation, than the number of networks of each type.

5.4.4 Representative networks for SRA of smart grid solutions: automation, voltage control, islanded operation

Distribution network models must be able to mimic the behavior of actual distribution systems for the specific smart grid implementations to analyze. Therefore, the representative networks should be designed in accordance with the smart grid functionalities analyzed. The technical characteristics and parameters that are most relevant for the definition of representative networks will depend on the nature of the results pursued from the analyses to be carried out. Smart grid solutions have been classified in chapter 2 into three different categories for technical analysis: (i) network automation to improve continuity of supply, (ii) DER management and voltage control to improve distribution operation and DER integration, and (iii) micro-grids and islanded operation. Table 5.7 provides lists the most relevant parameters and the size or scope for adequate representative networks for SRA of each group of smart grid solutions.

As explained in Chapter 2 (section **¡Error! No se encuentra el origen de la referencia.**), the technical SRA of smart grid implementations based on **network automation** to improve continuity of supply will be based on reliability analyses to determine continuity of supply indices before and after the smart grid solution is implemented. Therefore, the representative networks should reproduce faults occurring in actual networks and should enable the simulation of the process of fault detection, isolation and service restoration.

In order to simulate fault occurrence, the failure rate of the different elements and sections of the network should be adequately characterized (usually, assuming a uniform fault rate per km for conductors, so that length becomes a critical factor to determine fault occurrence). Furthermore, representative network models should feature representative protections schemes and interconnections or tie points, with the reconfiguration options available in actual networks. Additionally, network reconfiguration options to restore supply should be assessed to check compliance with technical restrictions, so the representative network models must include the impedance of network elements and thermal limits of conductors and transformers must be known. Finally, in order to determine continuity of supply indices, the location or rated power of consumers[93] is required to weigh reliability across the network.

Representative network models may consist of a few feeders. One feeder would be enough to simulate the fault detection and isolation process and to monitor the duration of supply interruptions

[93] In order to compute SAIDI and SAIFI, which average reliability by number of consumers, the location of consumers is required as input data; whereas their rated power would be required to compute ASIDI and ASIFI.

for each consumer. However, in order to study the availability of alternative supply through interconnected feeders to restore service, those feeders that are interconnected should be included in the model, so that thermal limits of all elements involved in reconfiguration can be checked.

In the case of smart grid implementations based on **DER management and voltage control** strategies to enable efficient operation of distribution and integration of DER, technical SRA will be based on load flow analyses to determine voltage profiles and power flows. These will be used to assess energy losses reduction and network hosting capacity improvement before and after the smart grid solution is implemented. The impedance of the network elements must be adequately captured by the representative networks so that the results load flow analyses are correct. Furthermore, thermal limits and regulatory voltage limits must be taken into account so that technical constraints are complied with. The impedance of the network lines are usually estimated determined through the length and type of conductor of the lines and cables. Generation and demand profiles at each node are key in loadflow analysis, so representative networks must include the location of demand and DER, including DG units, storage, electric vehicles, etc. Because of the radial operation of distribution networks, the voltage profile in each depends on the voltage at the head of the feeder, the generation and demand of the users connected at that feeder and the conductor of that feeder. Thus, load flow analysis could be carried out for each feeder independently. However, actions at the head of the feeder, such as changes in the tap position of transformers have an impact of all outgoing feeders. Therefore, DER integration in one feeder would not have a direct impact on other feeders, but could lead to actions at the transformer level that would. For this reason, representative networks should consist of several feeders that belong to the same substation.

In the case of DER integration in LV networks, where phase unbalance can be a relevant issue, three-phase models should be used, taking into account the connection of loads to the different phases and the grounding scheme to evaluate the voltage profiles and power flows in each phase and thus assess the effect of load unbalance.

Islanded operation of a section of the network is enabled by the active participation of DER including DG units, storage, or demand flexibility to balance generation and demand within the islanded system during the period of islanded operation. Additionally, a control system is required to secure stability and safe islanded operation mode, able to perform frequency and voltage control at the moment of disconnection from the grid, during islanded operation, and at the moment of re-connection to the grid. The disconnection from and re-connection to the grid are critical and must be dynamically analyzed to study the frequency and voltage transient response of the system. Therefore, the dynamic response of the elements of the network must be modelled. The effect of the network itself on the dynamic response of the system is negligible when compared to the loads, storage units, generators, controllers, inverters, etc. For this reason, rather than a set of representative networks, a single-node model may be used.

Use case	Relevant network parameters	Required scope/size
Network automation	• Protections scheme • Interconnections • Length and failure rate • Impedances and thermal limits • Location or rated power of consumers	A few interconnected feeders
DER management and voltage control	• Impedances and thermal limits of conductors and transformers • Location of demand and DER • Connection of loads to phases and grounding system	A few feeders from the same substation Three-phase model
Micro-grids and islanded operation	• Dynamic models of elements: loads, batteries, DG units, including controllers and inverters	Single-node model

Table 5.7: Smart grid SRA needs for representative networks

5.5 Conclusions

The **vast amount and diversity** of distribution assets across regions and countries makes it difficult to assess the impact of smart grid solutions at a large scale. A set of representative networks can be used to succinctly describe typical distribution networks in a region and efficiently evaluate different smart grid technologies through simulation. The results obtained for the representative networks can then be **scaled-up** to assess impact across the region based on the prevalence of each representative network in the region.

The creation of a set of representative networks for a region is a very challenging task. Three steps have been identified in the process of elaborating representative networks: 1) **characterization** of the distribution system, 2) **categorization** of the distribution networks that comprise the system and 3) **shaping of the representative networks**. The creation of representative networks implies a categorization of the distribution networks into a **number** of groups (sufficiently reduced to ensure efficiency and enough to ensure accuracy) according to some **criteria** to achieve a meaningful set of representative networks. Furthermore, the resulting representative networks must be adapted to the type of simulation and results of each type of smart grid solution.

The quality of SRA results using representative networks is unavoidably linked to the representativity of the developed set of representative networks, which depends on the quality of available data or knowledge of the distribution system. The **lack of publicly available data** mainly due to confidentiality issues complicates the construction of representative networks. Different approaches have been followed, and the use of clustering techniques and reference network models have proven to be very helpful tools. **Clustering** techniques can be applied to a detailed list of distribution networks to determine the optimal number of representative networks, to assess the most representative variables for categorization, to classify each network into groups and to select the representative network for each group. **Reference network models** can be used to create synthetic, large-scale networks that can be used as representative networks.

Ideally, representative networks would be obtained as a result of a clustering process applied to every distribution network in the area to represent. However, this may not be possible due to the large amount and high level of detail of input data required. Alternatively, RNMs could be used to build a database of distribution networks, and then clustering could be applied to select the representative feeders. Often, representative networks are based on expert knowledge. In that case, scaling-up factors are selected based on the considered KPIs (e.g.: number of consumers for SAIDI and SAIFI improvement, installed capacity for NHC increase, etc.).

The representative networks should be **designed in accordance with the smart grid functionalities analyzed**. Representative networks for the SRA of **network automation** to improve continuity of supply must comprise a few feeders, where protection elements and interconnections are modelled. Failure rates, impedance and thermal limits of network elements, as well as the location of consumers must be replicated so that actual faults can be reproduced, and the process of fault detection, isolation and service restoration can be simulated. Representative networks to assess **DER management and voltage control** strategies to reduce energy losses and increase network hosting capacity must adequately capture the impedance and thermal limits of network elements. Representative networks must comprise several MV (or LV) feeders supplied by the same primary (or secondary) substation. Load flow analyses will check compliance with technical constraints and regulatory voltage limits for different scenarios of generation and demand. In order to assess the effect of load unbalance for DER integration in LV networks, three-phase models should be used, with special focus on the connection of loads to the different phases and grounding schemes. Finally, in the case of **islanded operation**, the effect of the network on the dynamic response of the system is negligible, so a single-node model may be used instead of a set of representative networks. Dynamic analysis would require a detailed model of the loads, storage units, generators, controllers, inverters, etc. to study the frequency and voltage transient response of the system during the disconnection from and re-connection to the grid, as well as the islanded operation.

Chapter 6

Case study: SRA of MV network automation to improve continuity of supply

This chapter presents the scalability and replicability analysis of MV network automation to improve continuity of supply in Spain and Italy. Thus, the application of the proposed SRA methodology (described in Chapter 3) is illustrated and described in detail, according to the particularization of SRA for smart grid use cases based on network automation to improve continuity of supply (described in Chapter 4, section 4.2). Furthermore, this case study illustrates the type of results obtained by SRA as proposed in this thesis. The case study is introduced in section 6.1. Then, the two stages of technical and non-technical analysis are developed in sections 6.2 and 6.3 respectively, following the structure of the steps defined in Chapter 3, to conclude with resulting SRA rules in section 6.4.

Additionally, a cost-benefit analysis has been carried out using the SRA results in section 6.5. First, from the societal point of view, the costs of implementing automation have been compared to the benefits for the network users derived from the improvement of continuity of supply. Then, considering the point of view of the DSO, in charge of making investment decisions in a regulated business, the CBA has focused on regulatory incentives for continuity of supply.

This chapter is self-contained thus supporting stand-alone reading. Therefore, the SRA steps described in chapter 3 and the particular aspects proposed in Chapter 4 for use cases based on network automation are reiterated in this chapter for the sake of clarity.

6.1 Description of the case study

The case study presented in this chapter aims to illustrate the full application of the SRA methodology developed in this thesis. Rather than focusing on a specific demonstration, this case study will assess MV network automation, including the results observed and reported in different pilot projects and considering implementations of different characteristics in terms of the specificities of the solution deployed. The SRA is carried out according to the SRA methodology proposed in Chapter 3 and particularized for automation use cases in Chapter 4, section 4.2.

The SRA in this chapter has also been presented partially in different articles. The SRA methodology was proposed in (Rodriguez-Calvo, Cossent, & Frias, 2017) and a simplified case study was of MV network automation was used to illustrate the methodology. Some of the simulation analyses presented in this chapter have been included in (Rodriguez-Calvo et al., 2016). Furthermore, previous work on the analysis of MV network automation and smart secondary substations resulted in other publications (Rodriguez-Calvo, Frias, et al., 2012; Rodriguez-Calvo, Frías, et al., 2012).

The countries selected for this case are Spain and Italy. These are two large countries in Europe at the forefront of the evolution towards the smart grid, with a high penetration degree of DG.

Actually, Italy has been a pioneer in the deployment of network automation to improve continuity of supply. By the late 90s, the level of reliability of Italian distribution networks was quite low in comparison to other European countries. In 2000, the Italian regulator introduced continuity of supply regulation through a quality-adjusted price-cap formula linked to the duration of interruptions to improve continuity of supply in Italy and to bridge the gap between the North and the South of the country. In order to comply with the regulatory quality requirements, DSOs took different actions, increasing investment levels by up to 50% during that regulatory period (Ajodhia, Lo Schiavo, & Malaman, 2006). The major Italian DSO, ENEL Distribuzione, launched a medium-term program aimed at improving the quality of supply, implementing a new grounding system in MV networks (Petersen coil) and MV network automation for fault detection, isolation and service restoration including remote control of 80,000 secondary substations (out of a total of 347,000 secondary substations) by 2004 (Cerretti, Lembo, Primio, Gallerani, & Valtorta, 2003) with very positive results[94]. As regulation included in 2008 the number of interruptions, MV automation was updated to achieve automatic service restoration and thus reduce SAIFI indices (Cerretti, Scrosati, & Consiglio, 2011). The case of Italy has provided very valuable real-life experience that can be used to validate SRA analyses.

The level of network automation in the Spanish distribution system is much lower. Reliability levels are relatively high in comparison to other European countries(Council of European Energy Regulators

[94] For instance, a reduction of restoration time of 18% was reported in the region of Lombardia halfway through the implementation of automation in (Bargigia, Cerretti, Di Lembo, Rogai, & Veglio, 2003).

(CEER), 2016) thanks to the investment of Spanish DSOs in different redundancy schemes and a higher degree of network meshing with respect to Italian networks. Network automation has recently become the subject of demonstration projects, such as the smart grid in Castellón[95] and the Bidelek Sareak project[96] in Bilbao lead by Iberdola; the Smart City lead by Endesa in Malaga (Endesa, 2014); and the advanced distribution project in Segovia recently launched by Unión Fenosa[97]. Furthermore, investing in telecontrolled switches is increasingly becoming part of the necessary upgrade of ageing infrastructure[98].

6.2 Technical SRA

The technical analyses to assess the scaling-up and replication of the implementation of MV network automation in Spain and Italy is presented in this section, following the steps defined in the SRA methodology proposed in section 3.4 in Chapter 3.

6.2.1 Identification of relevant KPIs

The main objective of this use case is to improve continuity of supply, and this is achieved by reducing the time required for the FDIR process. Therefore, as explained in Chapter 4, section 4.2.3.1, the impacts of the use case can be measured in terms of frequency and duration of supply interruptions for network users. The adequate KPIs of the use case would be the improvement of continuity of supply indices, such as reduction of SAIDI and reduction of SAIFI achieved by automation, taking as baseline the values of these indices when no automation is in place.

6.2.2 Selection of simulation tool

As explained in Chapter 4, section 4.2.3.2, technical SRA of network automation use cases focuses on assessing the improvement of reliability indices thanks to implemented solutions.

The proposed reliability analysis for the technical SRA of MV automation is based on the simulation of service restoration for all possible faults in the MV distribution network to compute continuity of supply indices with and without automation. Thus, the approach followed to assess reliability is predictive deterministic. The simulation tool reproduces the usual procedure for service restoration in distribution networks explained in Chapter 4, section 4.2.3.2, taking into account available monitoring

---

95 https://www.iberdroladistribucion.es/redes-inteligentes/primera-red-inteligente-castellon (accessed in March 2017).

96 http://bidelek.com/ (accessed in March 2017).

97 https://www.unionfenosadistribucion.com/es/redes+inteligentes/1297323554177/proyecto+seda.html (accessed in March 2017).

98 Endesa has recently invested 1.2M€ to upgrade existing protections and equip the distribution network of the Balearic Islands with telecontrolled switches. Source: http://elperiodicodelaenergia.com/endesa-ha-invertido-12-millones-de-euros-en-82-interruptores-de-telemaniobra/ (accessed in March 2017).

and telecontrol. For each fault, the affected consumers are identified and the process to locate the fault and restore service is emulated to compute the total interruption time for each affected consumer. The reliability indices SAIFI and SAIDI are then determined considering the expected occurrence of each fault, according to deterministic failure rates, and averaging the quality of each consumer by the number of consumers. For this purpose, a simulation tool has been developed within this PhD thesis. The developed tool is programmed in Matlab and is designed to compute the frequency and duration of interruptions of supply for each network user. Therefore, additionally to SAIFI and SAIDI, other continuity of supply indices could also be obtained. For instance, ASIFI and ASIDI would be obtained by weighting the individual interruption frequency and duration with the rated power of each network user.

It must be noted that reliability indices will be computed to account for sustained interruptions of supply that are unplanned, excluding force-majeure events. Therefore, the simulation tool developed for the technical SRA of MV automation considers supply interruptions caused by faults located in the network branches, excluding multiple simultaneous faults and the failure of protection elements and transformers, which have a much lower occurrence probability[99] (several orders of magnitude) (Electric Power Research Institute (EPRI), 2001). Furthermore, for the sake of simplicity, the simulation tool developed for this case study computes the time required to execute network reconfiguration assuming that it is always possible to transfer load from one feeder to another, and therefore does not run load flow analysis to check that proposed configurations do not violate technical constraints.

The developed simulation tool is similar to other approaches suggested in the literature. The authors of (Allegranza et al., 2005) assessed reliability improvement by computing the total interruption time for each consumer considering several time parameters of a fixed duration, while (A. González et al., 2011; Popovic et al., 2011)[100] included speed parameters as well to compute the time required for travelling based on the distances travelled by maintenance crews. The authors of (Aggelos S Bouhouras et al., 2010) used the commercial software NEPLAN Reliability Analysis[101], based on a fixed fault rate and restoration time for each element of the network.

Figure 6.1 shows the flow chart diagram of the simulation tool designed to evaluate continuity of supply for MV distribution networks. The failure of each branch j of the MV distribution network is simulated and the time $t_{i,j}$ required for the restoration of service of each affected load i is computed in the following steps (numbered 1-4 in the flow chart in Figure 6.1): (1) identify affected loads; (2) apply smart grid solution; (3) send maintenance crew for (3.1) manual switching and (3.2) visual

[99] The probability of failure of a transformer or protection elements is several orders of magnitude smaller than the probability of a fault in a network branch.

[100] Furthermore, in her PhD, González combined the proposed algorithm for reliability assessment with reconfiguration algorithm to ensure the feasibility of proposed configurations through loadflow analysis (A. G. González, 2014).

[101] http://www.neplan.ch/description/reliability-analysis-2/

inspection; and (4) repair the fault. At each step, the list of loads where service has not been restored (NRL) and the list of loads to check (L2C) in the fault location process are updated.

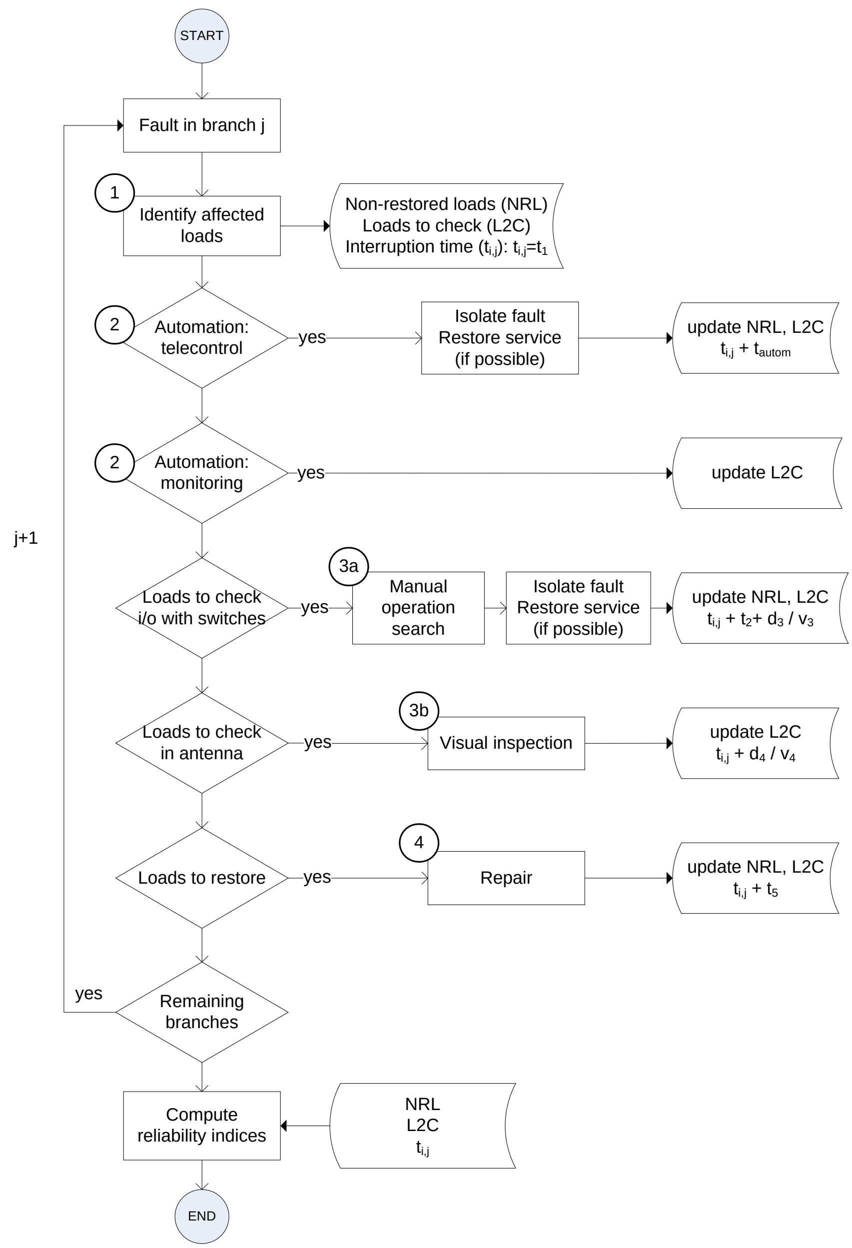


Figure 6.1: Flow chart of simulation tool for reliability assessment.

1. Identify affected loads

When a fault occurs, protections trip to automatically isolate the fault and service is interrupted for a group of loads. The simulation tool identifies which loads are affected by a service interruption, and sets to zero the time of service interruption for those loads that are not affected.

If the fault occurs in the main trunk of the feeder, the circuit breaker at the head of the feeder trips and service is interrupted for all loads in the feeder.

If the fault occurs in a ramification or derivation from the main trunk, it is assumed that there is a fuse at the point of ramification that opens the circuit. Therefore, the ramification is isolated from the main trunk and all downstream loads are affected by a service interruption. By contrast, loads in the main trunk and other ramifications or derivations are not affected, and the interruption time remains unaffected.

2. Apply smart grid solution

If there is automation in the network considered, the time to perform automatic FDIR t_{autom} is computed.

First, the fault is isolated among the two closest telecontrolled switches. Any load upstream the isolated segment would then recover supply, and any load downstream would be out of supply. If the feeder is interconnected to other feeders through normally-open switches, the system would perform network reconfiguration and service would be then restored for the discarded loads downstream the fault. The simulation model updates the group of affected loads and adds the time to isolate the faulty segment and reconfigure for service restoration, if applicable, to the corresponding loads. Afterwards, if there are monitoring elements within the interrupted segment, the fault would be located within a smaller section, so the simulation tool would discard the corresponding loads for the fault location process.

As an illustrative example, an MV feeder is depicted in Figure 6.2, with 6 secondary substations connected through input and output load break switches[102]. Secondary substations 2 and 5 are fully automated, equipped with monitoring and fault-pass detection capabilities and telecontrolled switchgear. Secondary substation 3 is partially automated, equipped with monitoring and fault-pass detection capabilities. Given a fault in the segment between loads 3 and 4, the protections at the primary substation would trip and supply in loads 1-6 would be interrupted. Thanks to telecontrol in automated secondary substations 2 and 5, the input switch of 5 would be opened and the output switch of 2 would be closed, isolating the fault. The switch at the head of the feeder would be closed to restore service in loads 1-2. Then, the interconnection at the feeder end would be used to restore supply to loads 5-6. Monitoring in secondary substation 3 would discard the branch 2-3, so manual fault location would focus on branches 3-4 and 4-5.

[102] MV/LV transformers are typically connected to the MV network either in a so-called input-output configuration, or in antenna, as explained in chapter 4.

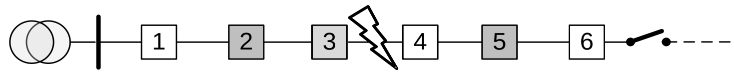


Figure 6.2: MV feeder with automation (secondary substations 2, 3 and 5 are equipped with fault-pass detection, secondary substations 2 and 5 also feature remotely controlled load break switches).

The time required by the automation system to clear the fault is an input parameter to the simulation model and must account for the type of automation system implemented: the speed of the control system to process the information and determine the required switching actions, the speed of the communication system to transmit the information and the type of control system. In the case of a local control system, fault isolation is performed automatically. By contrast, in the case of a centralized, supervised control system, the switching actions proposed by the system must be confirmed by a human operator, which involves a longer response time.

3. Send maintenance crew

Next, a maintenance crew[103] is sent to the field to locate the fault through manual switching operations and/or visual inspection of the lines. The simulation model adds a fixed time t_1 to account for the time taken by the crew to arrive.

3.1. Manual switching

For any loads configured in an input-output configuration remaining in the group of loads for fault location, the simulation tool mimics the process of dichotomic search[104] through manual operation of the switches of the secondary substations. For each step k the required time is determined as the sum of a fixed time $t_{2,k}$ to account for the time needed for the maintenance crew to operate the switches and a variable term $t_{3,k}$ to account for the time required to reach the switch to operate, depending on the distance to travel $d_{3,k}$. At each step, a group of loads is discarded for the fault location. Additionally, if the discarded loads are connected upstream of the fault, or if there are interconnections available for reconfiguration, service is restored for this group of loads. The time required per step is successively added to the corresponding loads remaining for service restoration.

3.2. Visual inspection

[103] It is assumed that the initial location of the maintenance crew is at the primary substation of the MV feeder where the simulated fault occurs.

[104] For the dichotomic search process, the following criterion is assumed for the maintenance crew: the first input-output secondary substation to operate is the one in the middle of the segment to search, that is, given a number of n secondary substations, the crew would go to substation number $n/2+1$ if n were an odd number, and in case of an even number n, the closest substation to the location of the maintenance crew between number $n/2$ or $n/2+1$

In overhead lines, for any loads connected in an antenna scheme, or with no input and output switches, the maintenance crew must walk along the line until the fault is reached. The time required at this step t_4 is proportional to the distance to cover d_4.

4. Repair

Finally, once the fault is located, a repairing time t_5 is added to any load where service has not yet been restored. At this point, service has been restored for all loads, so the simulation of the fault is concluded.

All in all, the interruption time $t_{i,j}$ for load i due to a fault in branch j can be expressed as in:

$$t_{i,j} = \alpha_{i,autom} \cdot t_{autom} + \alpha_{i,1} \cdot t_1 + \sum_k \alpha_{i,k} \cdot \left(t_2 + {d_{3,k}}/{v_3}\right) + \alpha_{i,4} \cdot {d_4}/{v_4} + \alpha_{i,5} \cdot t_5 \quad (6.1)$$

where the variables $\alpha_{i,autom}$; $\alpha_{i,1}$; $\alpha_{i,k}$; $\alpha_{i,4}$; $\alpha_{i,5}$; $d_{3,k}$; and d_4 are obtained through simulation, and t_1 ; t_2 ; v_3 ; v_4 ; and t_5 are input parameters. The values used for simulation parameters are presented in Table 6.2 and have been selected based on the experience from working with European DSOs in research projects, in accordance with the available literature (Allegranza et al., 2005; Conti et al., 2014; Popovic et al., 2011) and adjusting the results to the reliability levels reported for Spain and Italy (Council of European Energy Regulators (CEER), 2016).

The travelling speed and time required for operation of switchgear may vary depending on the location and accessibility characteristics of the switchgear (whether pole-mounted, underground or in a walk-in substation), the type of area and route to travel (whether an unpaved road in a very rural area or a city with highly transited streets), the location, availability and experience of the maintenance crew, etc.

Simulation Step	**Parameter**	**Value**
Response of FDIR automation system	t_{autom} (min)	0.5
Response of maintenance crew	t_1 (min)	10
Operation of load break switches	t_2 (min) v_3 (km/h)	8 55
Visual inspection	v_4 (km/h)	35
Fault repair	t_5 (min)	100

Table 6.1: Simulation parameters.

For the purpose of reliability assessment, an actual supply interruption is the sum of the interruptions suffered by the affected users. Throughout the fault management process, service is restored for different sections of the network, so that the duration of the supply interruption varies for network users connected to different secondary substations. Thus, the duration of the interruption is the sum of the corresponding interruption duration ($t_{i,j}$) for the affected users.

Then, reliability indices SAIDI and SAIFI are computed through equations (6.2) and (6.3), considering only those supply interruptions with a duration above the regulatory threshold for sustained interruptions t_{reg}[105] (as expressed in equations (6.4) and (6.5)):

$$SAIFI = \frac{\sum_j [\lambda_j \cdot L_j \cdot \sum_i [cons_i \cdot int_{i,j}]]}{\sum_i cons_i} \tag{6.2}$$

$$SAIDI = \frac{\sum_j [\lambda_j \cdot L_j \cdot \sum_i [cons_i \cdot t\_int_{i,j}]]}{\sum_i cons_i} \tag{6.3}$$

$$int_{i,j} = \begin{cases} 0, & t_{i,j} < t_{reg} \\ 1, & t_{i,j} \geq t_{reg} \end{cases} \tag{6.4}$$

$$t\_int_{i,j} = \begin{cases} 0, & t_{i,j} < t_{reg} \\ t_{i,j}, & t_{i,j} \geq t_{reg} \end{cases} \tag{6.5}$$

6.2.3 Definition of representative networks

In order to analyze the **replicability** potential for Spain and Italy, distribution networks in these countries will be modeled through a set of **representative networks**. Two sets of representative networks are used in this case study: the publicly available representative networks of the ATLANTIDE project for Italy, and a specifically-designed set of representative networks based on the GRID4EU project for Spain.

The ATLANTIDE project, described in Chapter 5, section 5.3.2.1.3, developed a set of representative networks for Italy. The resulting set of representative networks comprised three MV networks labelled as urban, industrial and rural. These networks will be used in this case study to analyze the scalability and replicability of MV network automation in Italy. Each network consists of a primary substation and the corresponding 7-11 outgoing MV feeders and supplied secondary substations (MV consumers or secondary substations feeding several LV lines and LV consumers).

In the case of Spain, the representative networks that will be used for this case study have been defined according to publicly available data (Corfee et al., 2011; Eurelectric, 2013) and expert knowledge for the GRID4EU project (GRID4EU project, 2016d). This set of representative networks is comprised by an urban, a sub-urban and a rural MV network with a few feeders supplied by different primary substations[106]. The MV feeders supply the demand of several MV consumers and secondary substations feeding LV consumers, represented by the MV/LV transformers.

---

105 The regulatory threshold for sustained interruptions is established by regulation and is set to 3 min in most European countries (Council of European Energy Regulators (CEER), 2016). However, in the current smart grid context and the increasing implementation of automation systems, there is an on-going discussion to reduce this threshold to 1 min.

106 The MV feeders in the representative networks do not constitute the totality of MV feeders outgoing from each primary substation. Typically, primary substations in Spain feed several MV feeders, but these network models include only a few of them in order to allow representing the interconnection of feeders from different primary substations while ensuring simplicity of the model for faster simulation.

Table 6.2 lists their main technical parameters of the representative networks, while Figure 6.3 shows the diagrams, where the lines represent MV feeders, secondary substations (i.e. MV/LV transformers) are represented by triangles, connected in an input-output configuration or in antenna through switches. The dashed lines represent the redundant interconnections between feeders through normally-open switches to enable network reconfiguration. The diagram shows the connectivity between the network elements, it does not represent the actual topography. Therefore, although the diagram shows equidistant secondary substations, this depiction does not correspond to the actual distances.

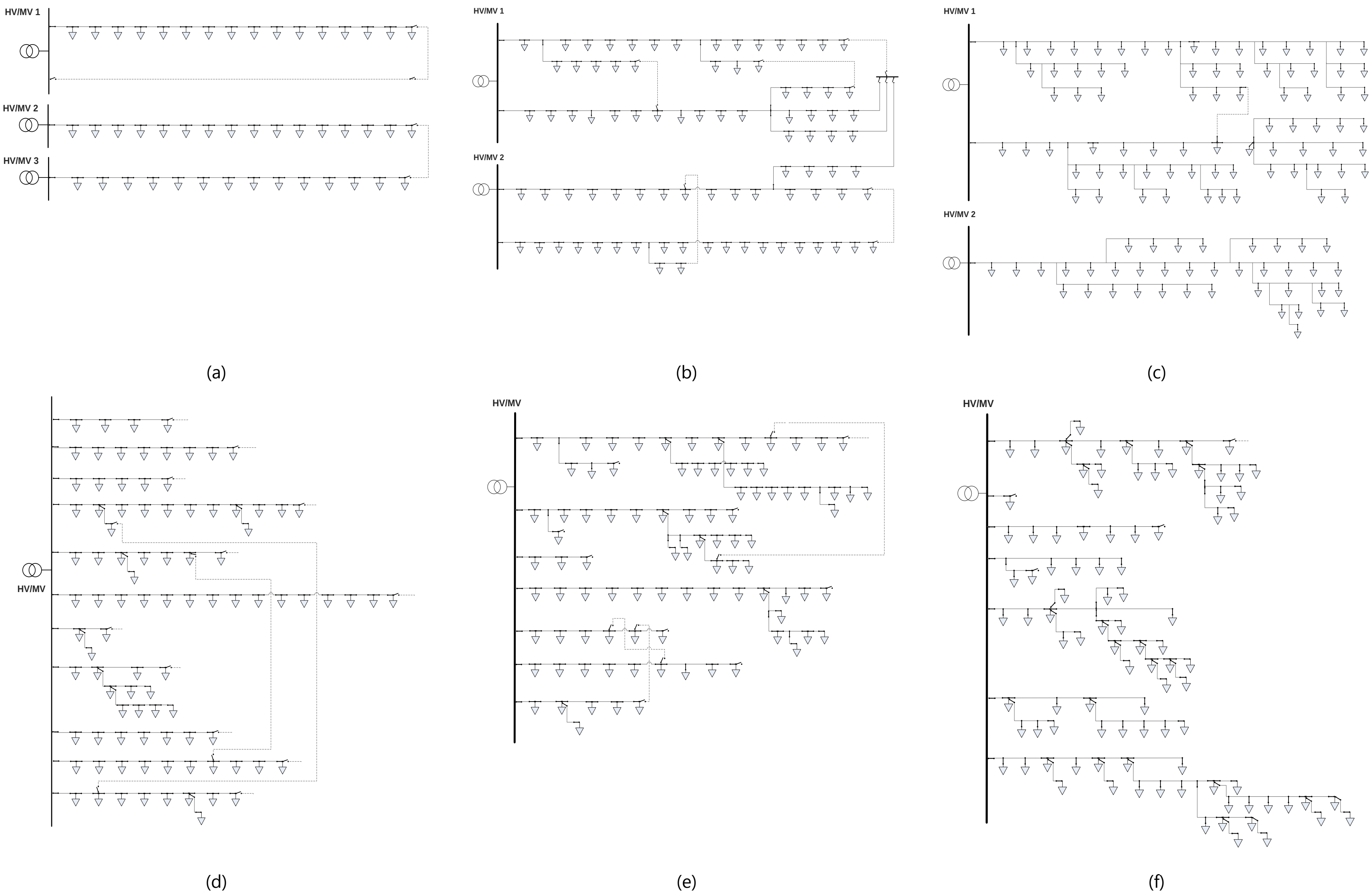


Figure 6.3: Representative networks for Spain: a) urban, b) sub-urban, c) rural; and Italy: d) urban, e) industrial, f) rural.

	SPAIN			ITALY		
	Urban (a)	**Sub-Urban (b)**	**Rural (c)**	**Urban (d)**	**Industrial (e)**	**Rural (f)**
Installed capacity (kVA)	27,880	41,820	21,080	28,336	38,190	18,138
Number of consumers	5,775	11,305	4,822	12,627	14,608	17,416
Total length (km)	23.0	84.5	124.7	27.7	77.2	157.5
Undergrounding degree (%)	100%	86%	0%	100%	57%	14%
Number of sec. subst.	46	85	118	93	113	96
Number of MV feeders	3	4	3	11	7	6

Table 6.2: Technical parameters of representative networks.

As explained in section 6.2.2, the computation of reliability indices is based on a deterministic fault rate expressed as the number of faults per year. This fault rate corresponds to the failure rate of the conductor. The failure rate of conductors differs for overhead lines and for underground cables, and is proportional to the length of the lines[107]. The value of the fault rate used for simulation may be adjusted to account for the different reliability levels in different regions or countries, which may in turn be related to the age of installations, weather conditions, etc.

6.2.4 Definition of scenarios

The technical SRA of MV network automation to improve continuity of supply will consider a set of scenarios to address the scalability in density of the implementation of automation, and the implications of different automation solutions.

Scaling-up in density is related to a higher degree of implementation of network automation. In this PhD thesis, the term **automation degree** has been defined in Chapter 4 (section 4.2.3.4) as the share of secondary substations (MV/LV transformers) equipped with either monitoring and/or telecontrol capabilities. More specifically, **partial automation** refers to secondary substations with fault-detection capabilities (monitoring) and **full automation** refers to secondary substations that feature both fault-detection and remote control of the switches that connect the secondary substation to the MV grid in an input-output configuration (monitoring and telecontrol). Accordingly, several scenarios of different values of partial and full automation degree will be considered to evaluate scalability in density.

The implementation of automation entails the upgrade of some of the existing secondary substations that are automated. Therefore, there are discrete decisions involved and automation scenarios are specific to each network. The automation scenarios considered for this technical SRA have been

[107] The values of failure rate of distribution networks are typically expressed in the literature as number of failures per km and year (McDermott & Dugan, 2003).

designed following an approach similar to that followed by distribution companies. In line with the fault location process based on a dichotomic search, the location of the automated secondary substations is selected so that there is the same number of non-automated substations among automated secondary substations. Nevertheless, different combinations of implementation of monitoring and telecontrol are also simulated to assess the effect of other automation configurations. It must be noted that only secondary substations with switches (input-output configuration[108]) may feature telecontrol. Therefore, in networks with secondary substations that are connected in antenna[108] to the MV grid, which may be the case of more rural networks, the degree of automation cannot reach 100% for telecontrol.

Although SRA is not focused on the technological aspects and details of the specific solutions implemented for smart grid use cases, the technical analysis addresses the parameters that have an impact on the results of the use case. In this case, the time required by the automation system to perform fault management functionalities is very relevant.

Automation reduces drastically the overall duration of the fault management process by avoiding several manual steps. In the event of a fault, service is restored for consumers located in a healthy section of the network by the automation in a very short time (t_{autom}). If this time for service restoration is shorter than the regulatory threshold (t_{reg}), these consumers are no longer considered to have suffered from a long interruption, which results in a reduction of SAIFI. Thus, the same reliability improvement may result in a very different value of SAIFI reduction, since it can be limited by the response time of the automated FDIR system with respect to the regulatory threshold.

The time required for automated service restoration is mainly determined by the architecture of the smart control system and the communications and control technologies in place. As explained in Chapter 4 (section 4.2.2), DSOs may choose to implement the control system as a centralized solution subject to the supervision of the operators at the distribution control center, or as a local, autonomous system. Human supervision involves higher response times, so average outage times are slightly higher. This could imply surpassing the regulatory limit for automatically restored loads, so that the reduction of SAIFI would be smaller than that registered for faster smart grid solutions. In order to analyze and compare variations in the implementation of automation use cases, different values for the parameter t_{autom} will be tested.

Table 6.3 summarizes the parameters considered for the scenarios analyzed within the technical SRA of this case study, which include scenarios of different automation degree to address scalability in density and scenarios of automation solutions with different time requirements.

---

[108] See Chapter 4, section 4.2.1 for a detailed explanation of input-output and antenna configuration of secondary substations.

Objective	Parameters defining scenarios	Considered range
Scaling-up in density	Automation degree (x% + y%)	
	▪ Partial automation (x%)	x% = 0% to 100%
	▪ Full automation (y%)	y% = 0% to k% (k is the share of secondary substations with input-output configuration through switches)
Automation solution	Response time of automation (t_{autom})	t_{autom} = 0; 30s; 1min; 3min; 5min

Table 6.3: Scenarios for SRA of MV automation to improve continuity of supply.

Thus, simulation for KPI computation will involve the following analyses:

- Full automation to assess different shares of secondary substations with both monitoring and telecontrol capabilities (section 6.2.5.1).
- Partial automation to assess different shares of secondary substations with monitoring capabilities (section 6.2.5.2).
- Combination of partial and full automation to equip secondary substations with either monitoring or both monitoring and telecontrol capabilities (section 6.2.5.3).
- Architecture of automation control system to assess different values for the parameter t_{autom} (section 6.2.5.4)

6.2.5 Simulation for KPI computation

Building on the work of previous steps, simulations are carried out to determine the KPIs of SAIFI and SAIDI improvement that correspond to different automation scenarios for the representative networks.

6.2.5.1 Full automation: upgrade of secondary substations with both monitoring and telecontrol

Figure 6.4 and Figure 6.5 show the resulting values of SAIFI and SAIDI respectively for different degrees of full automation for the representative networks for Spain and Italy. The results clearly show that as more secondary substations are upgraded, the improvement of reliability indices becomes much smaller, the effect is not linear. Since fault location and service restoration are based on a process where the network is split into halves at each step, the initial steps affect a much larger number of consumers and the distances to cover are much longer than in subsequent steps.

The results also manifest that the impact of implementing a certain degree of automation is much higher for poorer levels of reliability (i.e., higher initial values of SAIDI and SAIFI). Higher reliability indices involve a higher frequency of fault-events and a longer duration of interruptions when these occur. Automation has an impact on both: by quickly isolating healthy portions of the network, a significant amount of consumers do not suffer the interruption of supply, so the overall frequency of interruptions declines. Additionally, the time required for service restoration is reduced, avoiding steps for the maintenance crew process of travelling and manually operating switches. The higher the number of interruptions, the higher number of interruptions avoided; and the longer the distance to cover and the higher the number of secondary substations to operate, the deeper the impact of automation on reducing interruption durations.

It can be stated that in general, 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 results from implementing automation.

In general, urban networks are more meshed, underground grids and most secondary substations are connected to the MV grid in an input-output configuration through switches. Meanwhile, rural areas have longer lines, with a lower degree of undergrounding, and a more radial structure with ramifications. Secondary substations are often connected to the MV line in antenna (with no switches).

Due to the higher availability of secondary substations with switches, there are more options for implementing automation in urban networks. The automation degree for the rural, the sub-urban and the industrial networks can only be increased until a certain point and this is why the corresponding curves in Figure 6.4 and Figure 6.5 do not reach 100% automation degree – instead, implementing telecontrol in all secondary substations with input and output switches results in a 6% automation degree for the rural network representative for Spain, and 25% for the Italian rural network.

Moreover, urban networks offer more possibilities for network reconfiguration through the operation of the switches in the secondary substations, as well as for partial restoration of service during the fault management process since these networks are more meshed. Ideally, in a completely meshed network, an automation degree of 100% would result in no interruptions of supply, since it would always be possible to isolate the fault among two telecontrolled secondary substations, and service could be restored through an alternative path, which is the case for the urban representative networks for Spain and Italy. The MV feeders of the Italian industrial network has less interconnections, and therefore SAIFI and SAIDI values do not come close to zero for very high automation degrees.

The number of consumers affected by the reliability improvement achieved by automation is much higher for urban networks than in the case of rural areas. Therefore, more urban networks have a higher potential for automation than more rural networks, if the cost of automation were to be compared to the benefits derived for consumers.

The evolution of SAIFI and SAIDI as automation increases show similar trends for the six representative networks. There is a stagnation effect of the achieved improvement at an automation degree of 20-25% in all networks (except in the Spanish rural network where telecontrol can only be implemented in 6% of secondary substations). Comparing the two countries, initial reliability is a bit lower in Spain, and networks are more meshed, so the impact of automation is, in general, deeper (the SAIFI and SAIDI curves for the Spanish networks in Figure 6.4 and Figure 6.5 show steeper slopes).

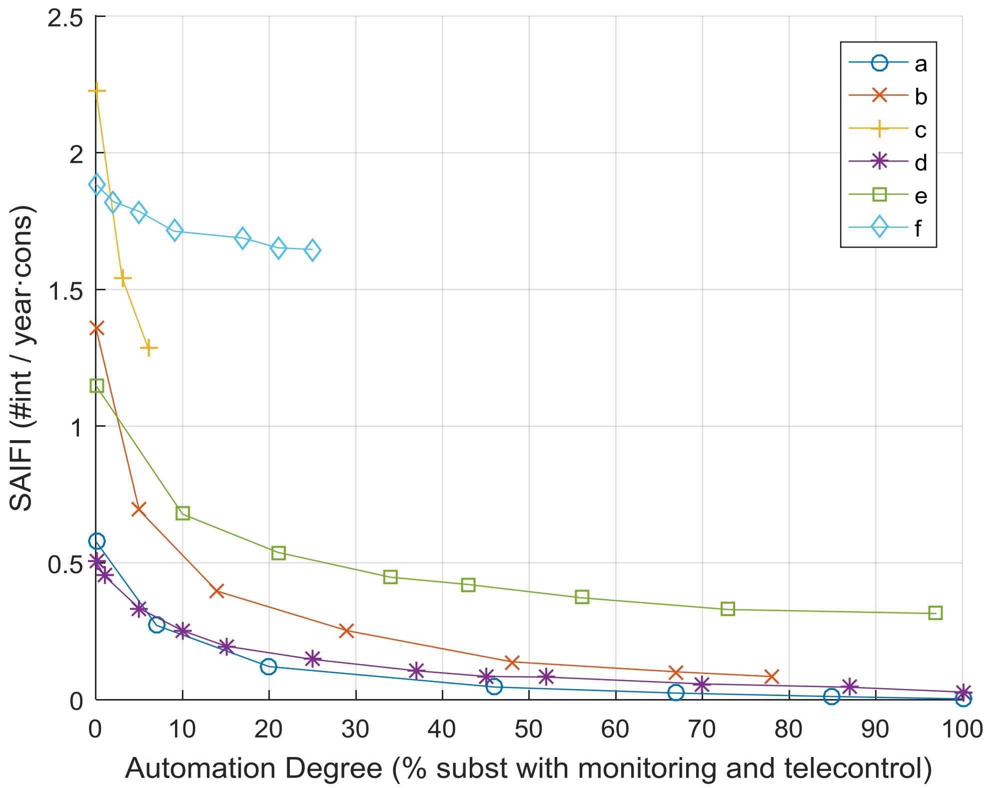


Figure 6.4: SAIFI for different degrees of full automation (i.e. monitoring and telecontrol) for the representative networks for Spain: a) urban, b) sub-urban, c) rural; and Italy: d) urban, e) industrial, f) rural.

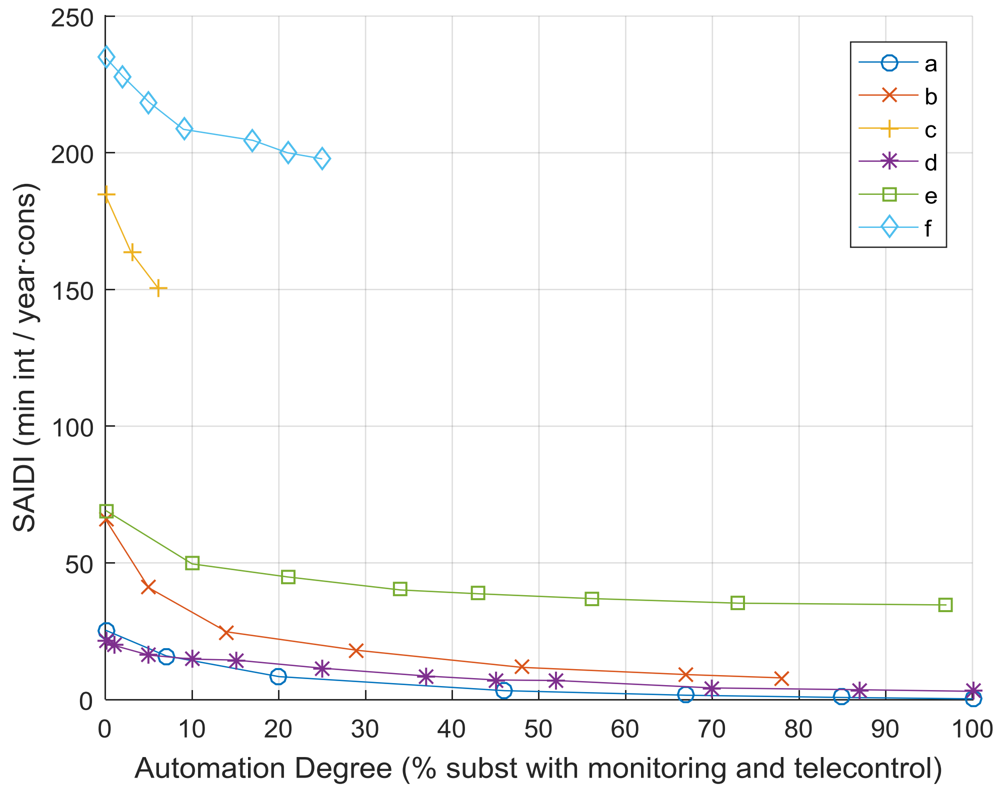


Figure 6.5: SAIDI for different degrees of full automation (i.e. monitoring and telecontrol) for the representative networks for Spain: a) urban, b) sub-urban, c) rural; and Italy: d) urban, e) industrial, f) rural.

6.2.5.2 Partial automation: upgrade of secondary substations with monitoring for fault detection

A less costly alternative for automation can be considered, consisting in implementing only monitoring capabilities in secondary substations. Monitoring (with no telecontrol) results in the reduction in the duration of supply interruptions, helping in the process of fault location to detect the affected section of the grid faster. This upgrade does not involve fast reconfiguration of the network to restore service, i.e. in a time shorter than the regulatory threshold, so the number of affected consumers remains the same for MV faults. Thus, SAIFI values are not modified, and SAIDI values show a much lighter variation with respect to the degree of upgraded secondary substations than in the case of monitoring and telecontrol, as can be seen in the results obtained from simulation for the representative networks for Spain and Italy in Figure 6.6.

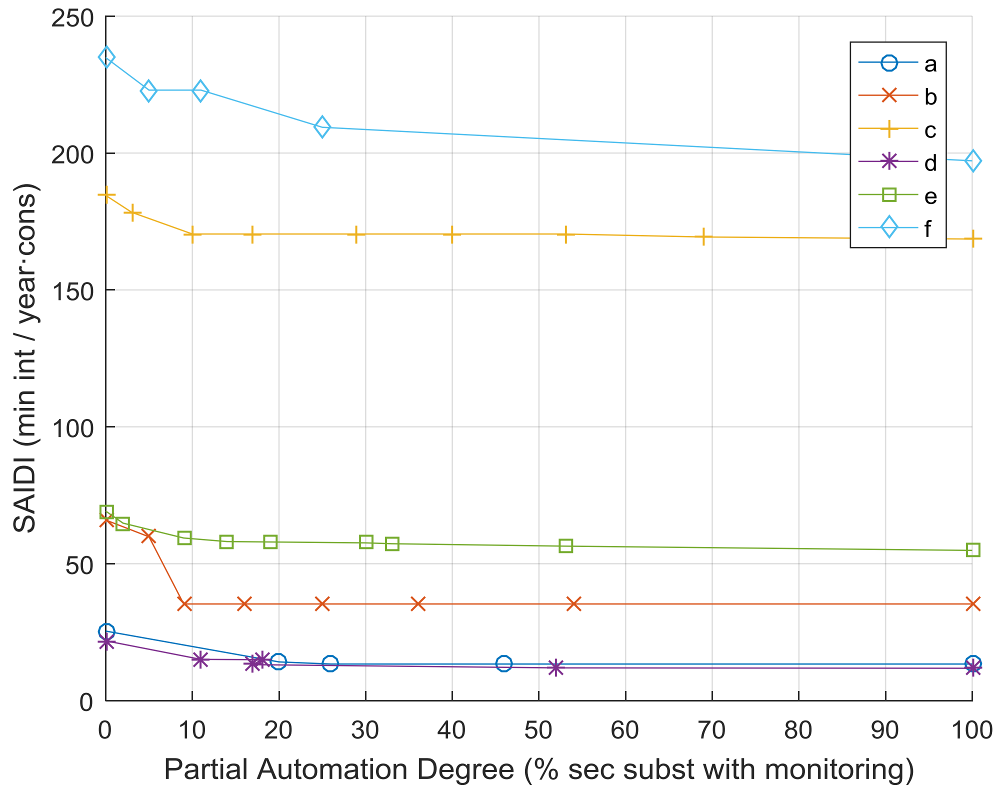


Figure 6.6: SAIDI values for different degrees of partial automation (i.e. fault-pass detection) for the representative networks for Spain: a) urban, b) sub-urban, c) rural; and Italy: d) urban, e) sub-urban, f) rural.

Given that monitoring achieves a much less significant impact on CoS improvement, it can be seen as a less-costly, complementary feature in urban and sub-urban networks with some telecontrol. In the case of rural networks, monitoring may be the only feasible option when no load break switches are available. Where implementing telecontrol is not possible, monitoring can be a good alternative to reduce outage times. The overall impact is mild when compared to telecontrol, but since distances to cover are much longer, the effect of reducing the area to search has a deeper impact on the duration of interruptions than in the case of urban networks.

6.2.5.3 Combining partially and fully automated secondary substations

Simulations have been carried for the scenarios of different combinations of partially and fully automated secondary substations for the representative networks for Spain and Italy.

The graphs in Figure 6.7 to Figure 6.12 show the resulting SAIFI and SAIDI values for some of the tested automation scenarios for the representative networks for Spain. At the diagrams, each bar represents one automation scenario, with a certain share (% shown by the bars filled in orange) of secondary substations equipped with monitoring (partial automation) and a certain share (% shown by the bars filled in blue) of secondary substations equipped with telecontrol and monitoring (full automation). For each scenario, the 'x' presents the value (in the right-hand side axis) of SAIFI (or

SAIDI). The scenarios are arranged so that the first set (from left to right) corresponds to scenarios of increasing degree of full automation, then scenarios of increasing monitoring, with no telecontrol, and then combinations of increasing monitoring on top of increasing degrees of full automation.

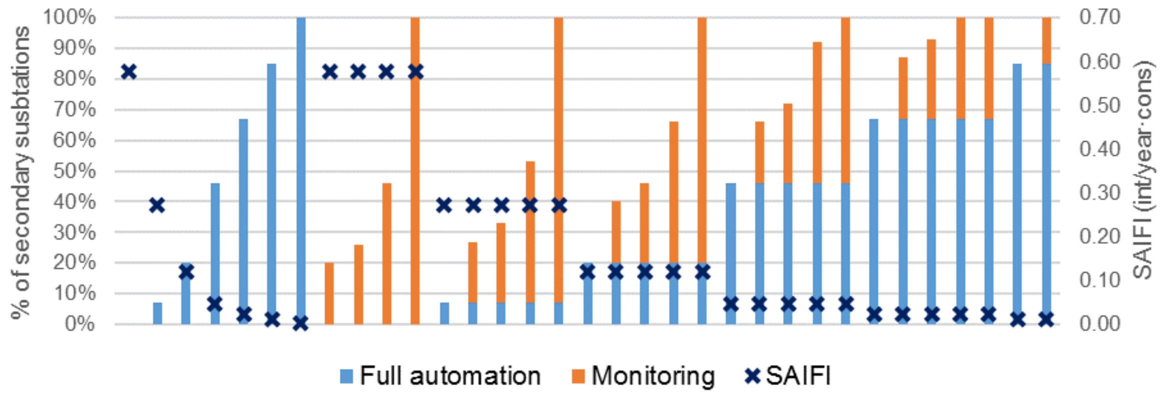


Figure 6.7: SAIFI values for different degrees of partial and full automation for urban network for Spain.

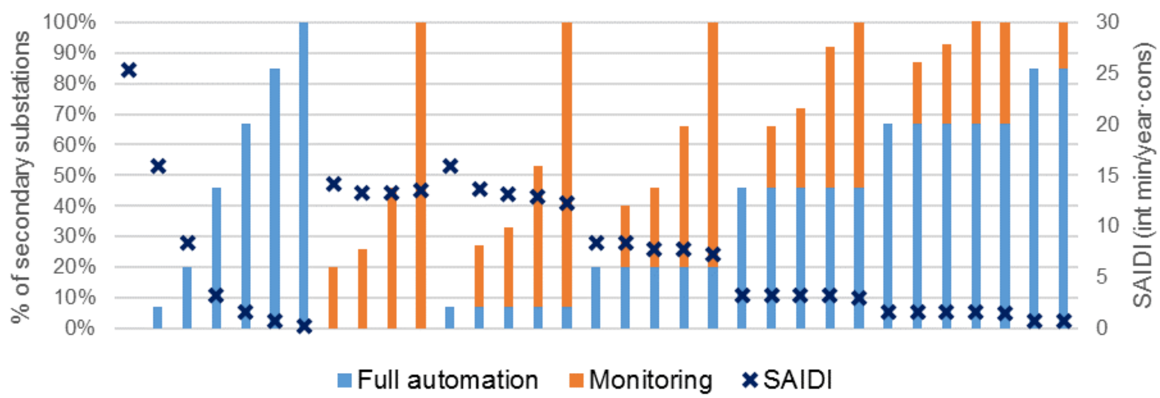


Figure 6.8: SAIDI values for different degrees of partial and full automation for urban network for Spain.

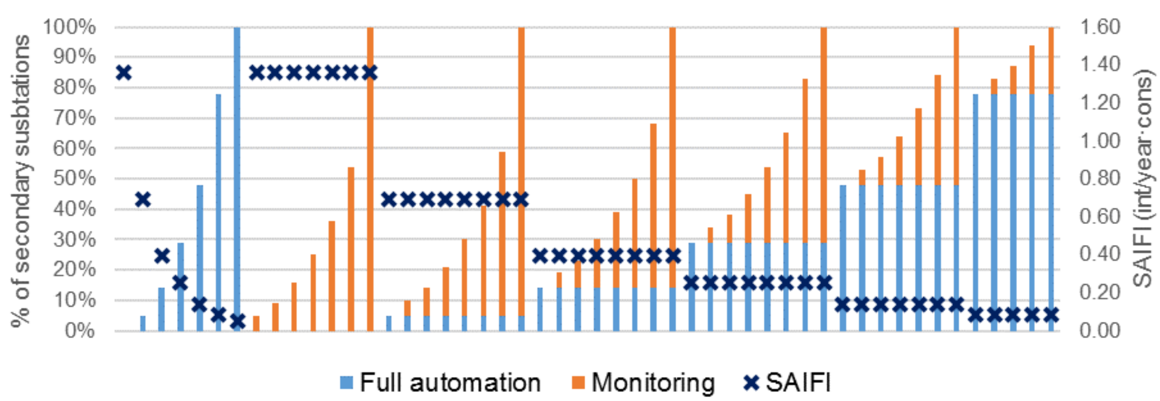


Figure 6.9: SAIFI values for different degrees of partial and full automation for sub-urban network for Spain.

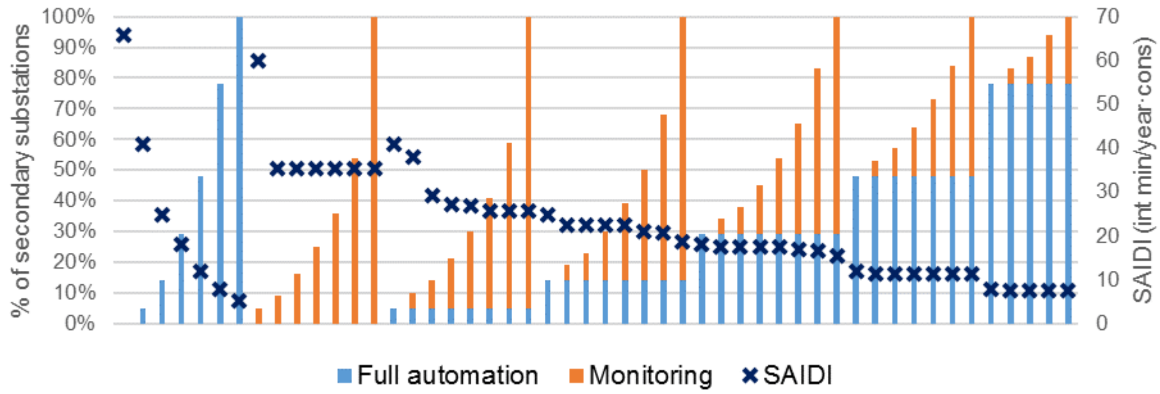


Figure 6.10: SAIDI values for different degrees of partial and full automation for sub-urban network for Spain.

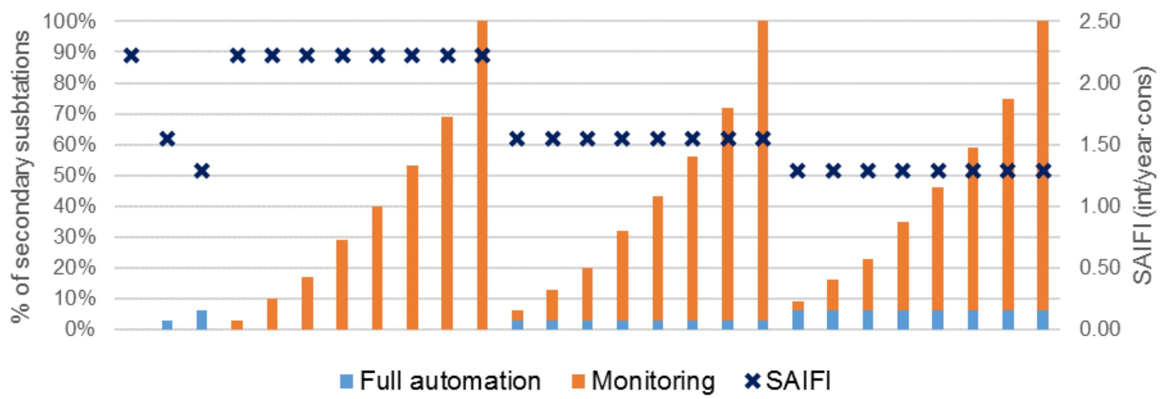


Figure 6.11: SAIFI values for different degrees of partial and full automation for rural network for Spain.

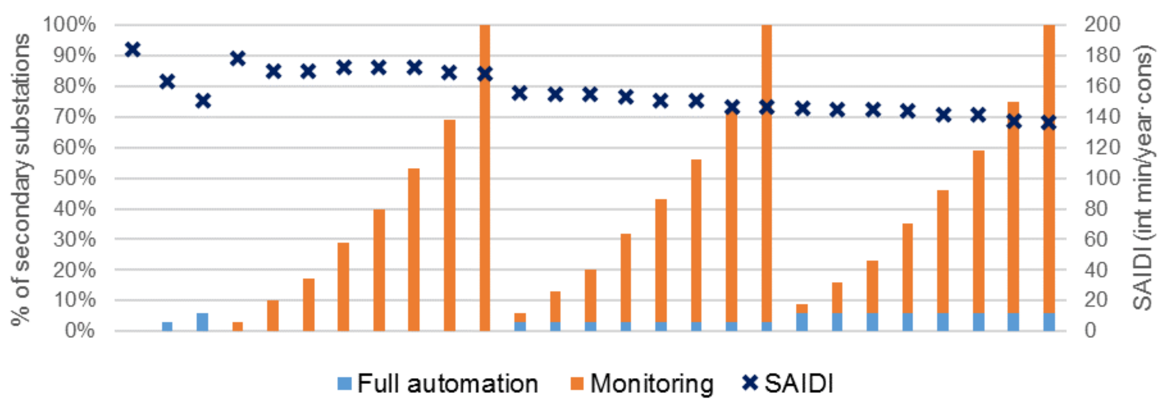


Figure 6.12: SAIDI values for different degrees of partial and full automation for rural network for Spain.

As expected, whenever telecontrol is an option, increasing the degree of full automation has always a much, much deeper effect on the improvement of continuity of supply, reducing both SAIDI and SAIFI, than any degree of partial automation. Adding monitoring on top of full automation can help further reduce the duration of supply interruptions, especially for low degrees of full automation in urban and sub-urban networks that are meshed (see Figure 6.8 and Figure 6.10), so that the information provided by the monitoring elements can be used to achieve a much faster restoration of consumers in a healthy section. By contrast, in very rural networks, the addition of monitoring does reduce the time required to locate the fault (often through visual inspection of the line) and thus the duration of the interruption for all consumers, but with no alternative path for supply available, service cannot be restored for affected consumers until the fault is repaired (see Figure 6.12). The results obtained for the Italian representative networks show very similar trends, and the same conclusions may be extracted.

Simulation results evidence that combining partially with fully automated secondary substations can certainly reduce SAIDI, but that this achievement is very topology-dependent. The location of partially and fully automated secondary substations must be selected so that the additional information provided by the monitoring equipment can be useful for manual fault management once the automatic reconfiguration has been carried out. For instance, Table 6.4 presents the results obtained for several scenarios in the Italian urban representative networks. All scenarios (1.a to 4.c in Table 6.4) have a degree of partial automation of 11%, where a, b and c involve the addition of monitoring capabilities to different secondary substations. The presented results show that the implemented monitoring a, b or c, leads to a slightly different improvement of SAIDI, despite having the same degree of automation (partial and full). Furthermore, depending on the degree of full automation, the performance of the different scenarios of implemented monitoring change. Taking the case of no telecontrol (scenarios 1.a to 1.c in Table 6.4), the best result is yielded for scenario b. However, in the case of a full automation degree of 15% (scenarios 3.a to 3.c in Table 6.4), the best monitoring scenario is c.

Scenario	Netw.	Full autom degree (%)	Partial autom degree (%)	SAIFI (int / year·cons)	SAIDI (min / year·cons)
initial	1	0%	0%	0.50	21.84
1.a	1	0%	11%	0.50	15.84
1.b	1	0%	11%	0.50	13.97
1.c	1	0%	11%	0.50	15.04
2.a	1	5%	11%	0.33	14.83
2.b	1	5%	11%	0.33	14.08
2.c	1	5%	11%	0.33	15.06
3.a	1	15%	11%	0.20	14.24
3.b	1	15%	11%	0.20	14.34
3.c	1	15%	11%	0.20	13.91
4.a	1	25%	11%	0.15	11.33
4.b	3	25%	11%	0.15	11.38
4.c	3	25%	11%	0.15	11.40

Table 6.4: SAIFI and SAIDI for different scenarios with partial and full automation in the Italian urban representative network.

6.2.5.4 Architecture of automation control system

This subsection discusses the results obtained for different values of time response of automation t_{autom} for the representative networks for Spain and Italy. SAIDI and SAIFI values are presented in Figure 6.13 and Figure 6.14 respectively.

The results show that the response time of the automation system has a mild effect on the duration of supply interruptions.

If the automation system is able to restore service for consumers in a non-affected area in a time below the regulatory threshold set for long interruptions, which is the case of scenarios of t_{autom} = 0; 30s and 1min, the SAIFI is reduced as the degree of automation increases. As long as the response time is kept within this range, the response time of automation has no impact on the achieved reduction of SAIFI, as can be observed in Figure 6.14.

The reduction of SAIDI is slightly affected by the response time of automation, since it introduces a certain delay in the process to restore service for affected consumers. Therefore, the average duration of supply interruptions is subject to an increase of t_{autom} and the SAIDI increases to a lower extent, since the average duration of interruptions includes consumers no longer affected by interruptions thanks to automation. The impact on SAIDI indices is too subtle to be seen in the graphic results in Figure 6.13. For instance, implementing a full automation degree of 7% in the Spanish urban representative network achieves a SAIDI reduction of 9.26min/cons·year for t_{autom}=30s, while the achieved SAIDI reduction for t_{autom}=1min is 9.12min/cons·year.

If the automation system restores service for consumers in a non-affected area in a time above the regulatory threshold, these consumers are considered to have suffered a long interruption, and therefore, included in the computation of SAIFI and SAIDI. The results obtained in the case of t_{autom}=5min show that automation is no longer able to achieve a reduction of SAIFI (see Figure 6.14). Logically, in this case, the reduction of SAIDI is also lower for slower automation systems, as can be observed in Figure 6.13.

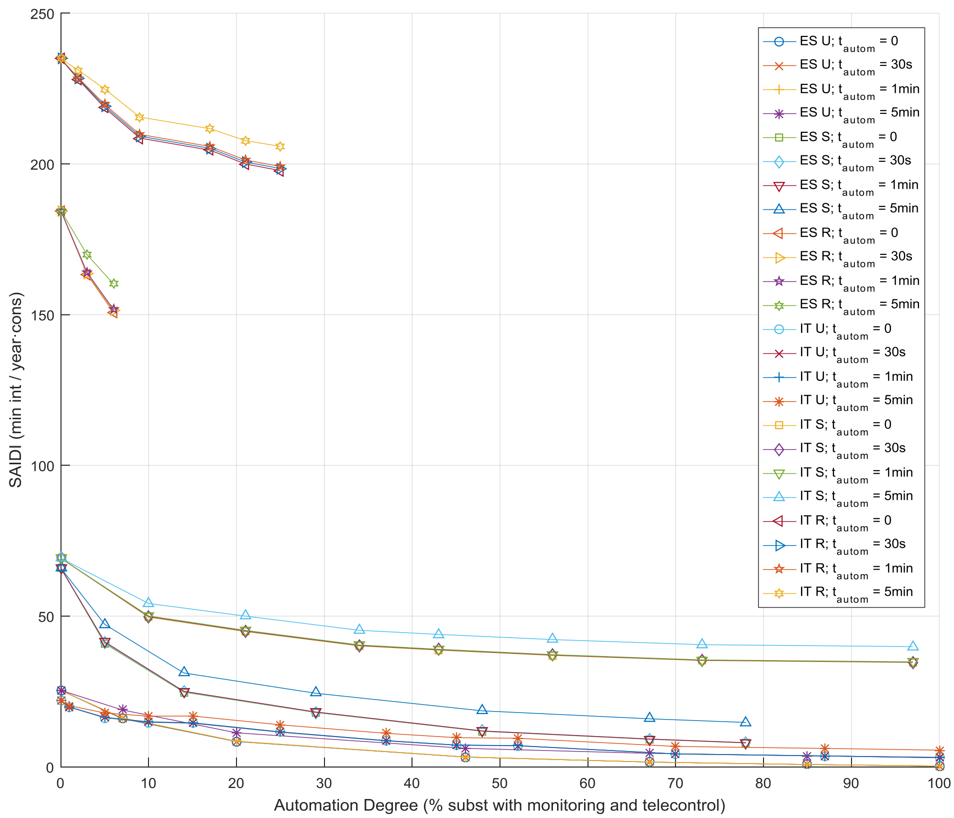


Figure 6.13: SAIDI values in the Spanish urban representative network as full automation degree increases for different values of response time of the automation system (t_{autom})

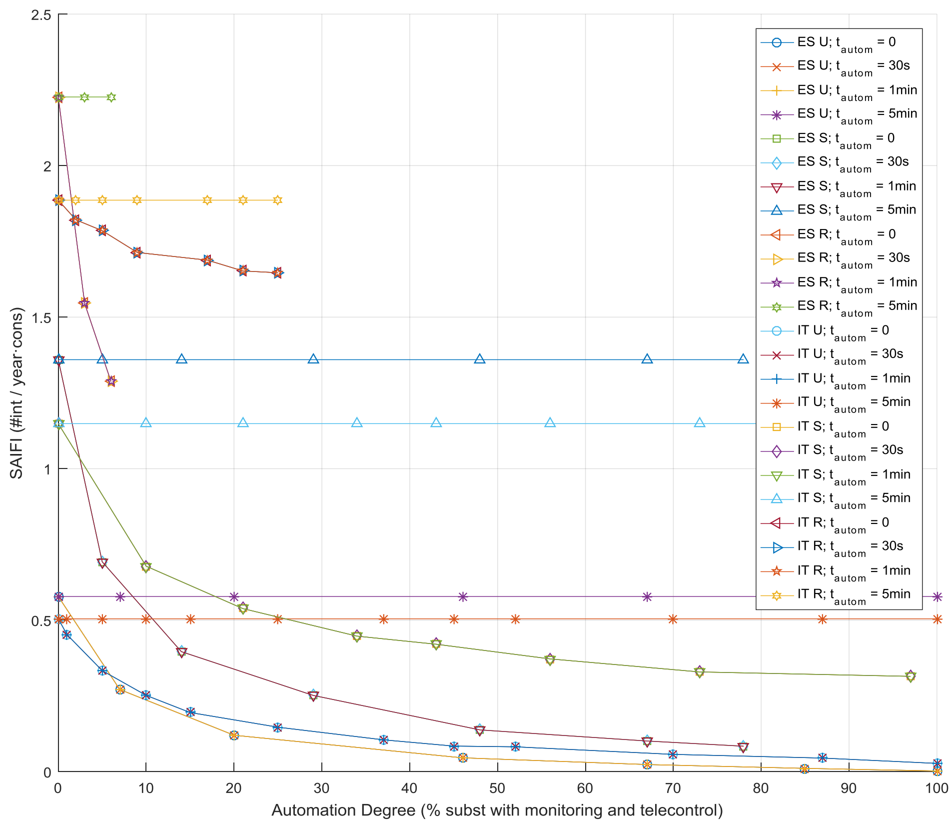


Figure 6.14: SAIFI values in the Spanish urban representative network as full automation degree increases for different values of response time of the automation system (t_{autom})

The results obtained in the simulations carried out show that improving response times for automation control systems can have an impact both on SAIDI and SAIFI, but this is almost negligible if response times are kept within the order of seconds. Human supervision can be the turning point making restoration times surpassing regulatory thresholds, thus affecting SAIFI values.

6.2.6 Review of demo results

The KPIs of SAIFI and SAIDI improvement obtained through simulation can be compared to the KPIs monitored and measured in demos to ensure the coherence of the technical analysis.

In the case of fault management, actual demo KPIs may not be able to fully capture the effect of automation due to the low probability of fault occurrence. Very few events are likely to take place within the location and during the period of the demonstration[109]. This is precisely why SRA studies are of the utmost importance in order to evaluate the deployment of the smart grid. Simulation may become the only option available to obtain quantitative results. In fact, these challenges have been highlighted in several demonstration projects. For instance in the GRID4EU project, where the German demo experienced only one fault event during the demonstration of MV automation, and the Czech demo suffered no fault event and resorted to simulation, modelling the distribution network where the automation was implemented (GRID4EU project, 2016c).

The GRID4EU demos observed a reduction of failure management time by 22% (90 to 71 min) for the automation of 10% of secondary substations in the German demo, while the Czech demo reported a reduction of 85% (94 to 14 min) for the automation of 20% of the secondary substations (GRID4EU project, 2016a, 2016b). The project carried out by the Italian DSO ACEA reported an improvement of SAIDI of 30% thanks to the implementation of a degree of MV network automation of 6% (ACEA Distribuzione S.p.a., 2014). These results are very much aligned to the reduction of SAIDI obtained for the urban Italian representative network, where an automation degree of 7% (full automation) reduced SAIDI by 9 minutes, from 25min to 16 min (reduction of 37%).

6.2.7 Upscaling of simulation results

The results obtained for the two sets of representative networks are scaled-up to the corresponding countries considering the representativity weight of each of the networks. In some countries, including both Spain and Italy, regulation establishes categories to classify the networks to monitor reliability and set reliability targets.

In Italy three zones are defined by regulation based on population density: high, medium and low concentration (Autorità per l'energia elettrica il gas e il sistema idrico, 2011). Table 6.5 gathers the definition criteria for these areas, number of consumers in Italy corresponding to each area and registered continuity of supply in 2014. The ATLANTIDE project developed the urban, industrial and rural networks, that can be considered to fit into the regulatory classification. Therefore, the results obtained through simulation for the urban network account for high concentration areas in Italy, the results for the industrial network represent the areas of medium concentration in Italy, and low concentration areas are represented by the rural network.

Meanwhile, in Spain the regulation sets four types of areas (urban, sub-urban, concentrated rural and scattered rural) (Spanish Ministry of Economy, 2000) and publishes the information on installed capacity, number of consumers and reliability levels segregated by these categories, as presented in

[109] Faults could be artificially emulated on-field by intentionally disconnecting a section of the network and opening the circuit breaker at the head of the feeder. This would allow testing the implemented solution, but it would not contribute to the assessment of the overall impact on reliability. Furthermore, even if under controlled situations and in pilot projects, DSOs, network users and regulators are extremely reticent to allowing supply interruptions.

Table 6.6 for year 2015. The representative networks developed for Spain comprise an urban, a sub-urban and a rural network, so the results obtained through simulation for these networks account for these regulatory areas, assuming that the rural network represents consumers in both concentrated rural and scattered rural areas.

	High concentration	Medium concentration	Low concentration
Definition (inhabitants)	>50,000	5,000 - 50,000	<5,000
Number of consumers (LV)	10,299,163	18,099,570	8,794,619
SAIFI (int) [110]	1.15	1.70	1.93
SAIDI (min) [110]	29.45	42.45	57.09

Table 6.5: Distribution of demand and reliability levels in Italy in 2014 for the distribution zones established by regulation. Source: Italian Regulatory Authority for Electricity Gas and Water[111].

	Urban	Sub-urban	Concentrated Rural	Scattered Rural
Definition (inhabitants)	>20,000	2,000 – 20,000	200 – 2,000	<200
Installed capacity (MVA)	71,568	53,734	27,799	12,664
Number of consumers	14,982,561	9,446,433	3,232,917	1,204,363
NIEPI (int)[112] [113]	0.66	1.05	1.52	2.25
TIEPI (min)[112] [113]	27.06	43.62	84.84	115.50

Table 6.6: Distribution of demand and reliability levels in Spain in 2015 for the distribution zones established by regulation. Source: Spanish Ministry of Industry, Energy and Tourism[114].

The results obtained from simulation for the representative networks for Italy and Spain are weighted by the number of consumers reported in Table 6.5 and Table 6.6 to obtain the national reliability levels expected when implementing automation. Figure 6.15 and Figure 6.16 show the hypothetical evolution of reliability indices SAIFI and SAIDI respectively as automation is increased.

---

[110] These values correspond to sustained, unplanned supply interruptions attributed to the DSO.

[111] http://www.autorita.energia.it/sas-frontend-cse/estrattoreLink

[112] Spanish regulation monitors reliability indices NIEPI (equivalent number of interruptions related to the installed capacity) and TIEPI (equivalent interruption time related to the installed capacity). For the sake of comparability, NIEPI and TIEPI values can be considered as a proxy for SAIFI and SAIDI values, as previously done by CEER in (Council of European Energy Regulators (CEER), 2011a). The regulatory analysis in section 6.3.1 investigates further the implications of using different indices for continuity of supply.

[113] These values correspond to sustained, unplanned supply interruptions attributed to the DSO.

[114] https://oficinavirtual.mityc.es/eee/indiceCalidad/total.aspx

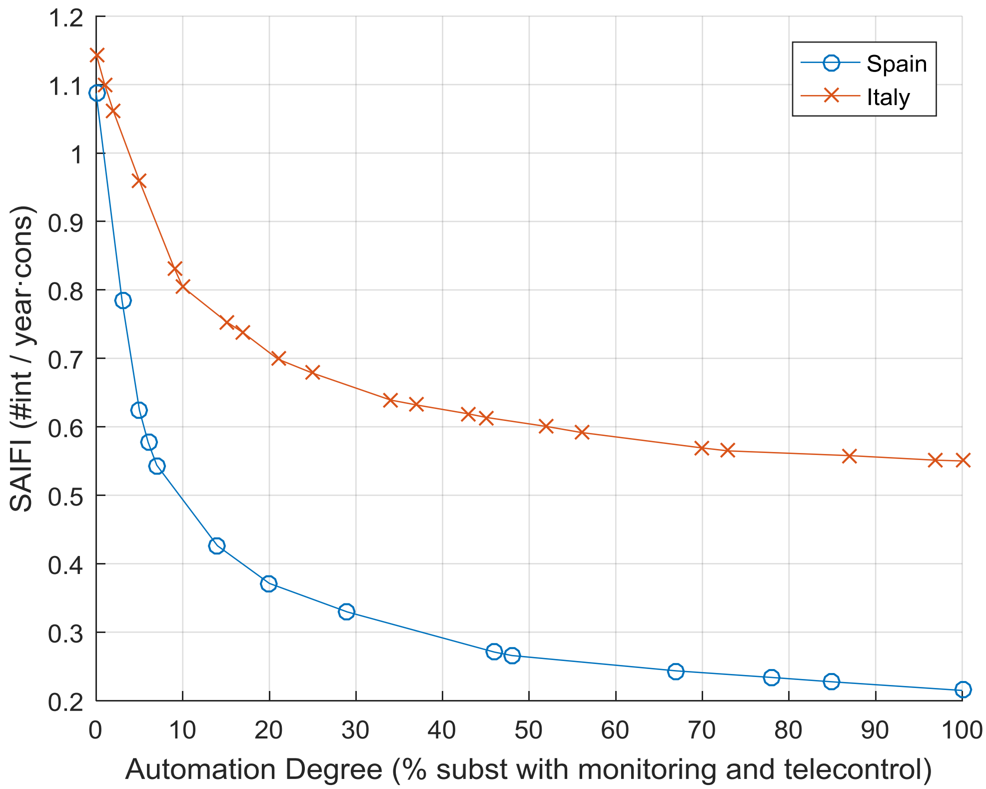


Figure 6.15: Hypothetical evolution of SAIFI for the implementation of MV automation in Spain and Italy.

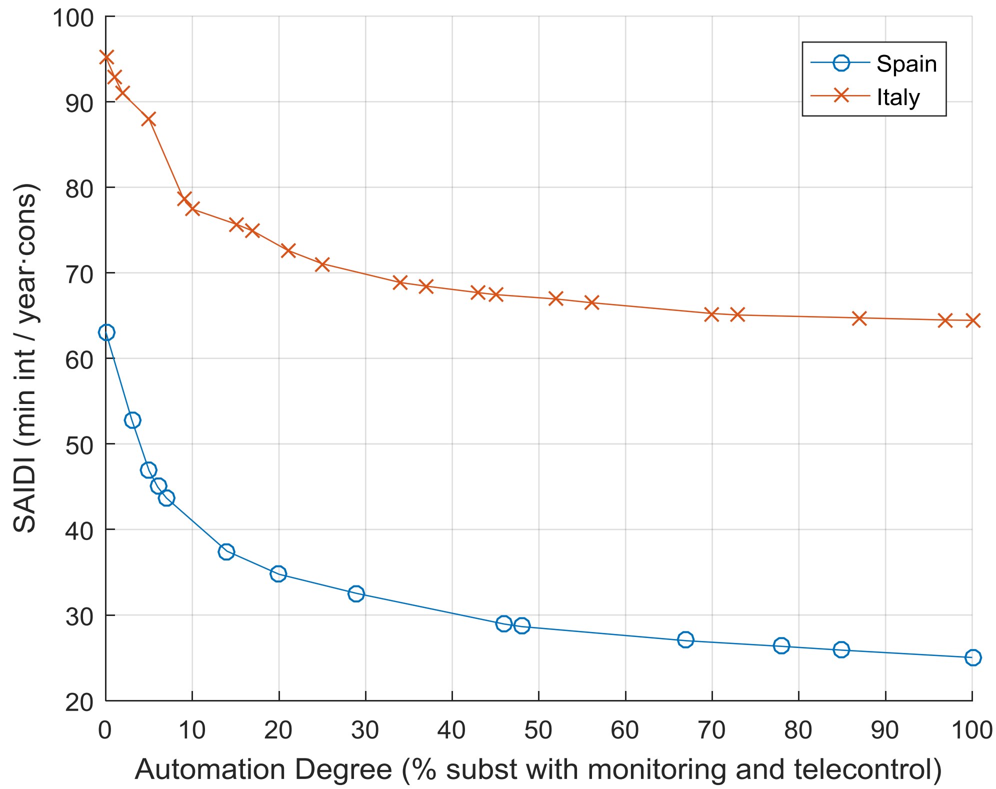


Figure 6.16: Hypothetical evolution of SAIDI for the implementation of MV automation in Spain and Italy.

The demand structure in Italy is much more rural and less urban than in Spain, therefore national reliability indices are higher. Furthermore, as Spanish networks are more meshed, telecontrol is able to achieve a much higher reliability improvement for high levels of automation degree. The resulting curves show the potential of MV network automation to improve continuity of supply in these two countries. Again, the saturation effect can be observed: as shown in the previous sub-section, it is clear that an automation degree around 20-25% achieves the highest reliability improvement.

Indeed, some DSOs have already deployed automation at a large scale following an approach aligned with the findings of technical SRA: urban areas have been prioritized and mild automation degrees has been implemented to achieve large reliability improvements. In Belgium, automation has been gradually implemented in the last years to reach nowadays 5-25% of MV/LV substations, depending on the DSO and type of area (higher degree of automation has been adopted for networks in more urban areas) (GRID4EU project, 2015c). In Italy, ENEL reported a reduction of SAIDI by 70% in the last years thanks to the large-scale implementation of automation, with remote control in 30% of secondary substations (Cerretti et al., 2003, 2011). The SRA case study presented in this chapter yields a much lower estimation for SAIDI reduction of (for an automation degree of 30%, the reduction of SAIDI would not surpass a 30%), which is explained by several factors. First, the reported reliability improvement achieved by ENEL corresponded not only to the implementation of automation, but also to the upgrade of grounding systems in the MV network (Cerretti et al., 2003). Furthermore, this case study has been adjusted to the current reliability level in Italy, which is quite high, assuming that no automation is in place. However, the reality in Italy is that such high reliability level corresponds to networks with deployed automation. In order to obtain more similar reliability improvements.

The upscaling of results presented in this case study is not without limitations. Still, the results of this case study for SRA allow for interesting conclusions. In order to obtain more accurate and realistic results from SRA, further work should be devoted to obtaining a set of representative networks really able to account for the variability of distribution networks. Representative networks should be defined using data from the actual distribution networks in these two countries and determining their real representative weights. A more thorough analysis would also be necessary to obtain more robust results, including sensitivity analyses to the relevant parameters and additional simulation scenarios to cover additional possibilities for implementation degree.

6.3 Non-technical SRA

At this stage, economic and regulatory aspects are to be integrated into the SRA, together with the viewpoints of relevant stakeholders. The main objective is to identify drivers for the deployment of MV automation to improve continuity of supply, as well as potential barriers or obstacles that must be overcome for the replication and scaling-up of this use case.

6.3.1 Regulatory framework

The regulatory analysis involves identifying the regulatory topics that are relevant to the implementation of the use case of MV automation to improve continuity of supply and characterizing the regulation regarding these topics in Italy and Spain to assess their effect on the replication and scaling-up of MV automation in these two countries.

6.3.1.1 Identification of relevant regulatory topics

As explained in 4.2.4.1, the regulatory topics relevant to the SRA of the use case of MV automation to improve continuity of supply include DSO revenue regulation, DSO reliability incentives and DSO incentives for innovation.

The specificities of the revenue regulation and the incentives for continuity of supply and innovation (of there are any in place) are key factors that will drive DSOs investment on MV network automation to improve continuity of supply. Furthermore, the efforts of the DSOs will be strongly influenced by the definition of continuity of supply indices, favoring certain areas, types of consumers, or focusing on different elements and solutions, depending on the regulatory framework.

These relevant topics must be carefully analyzed, to understand how DSOs in Italy and Spain would face the deployment of MV automation, answering the questions listed in Table 6.7.

DSO revenue regulation	General regulatory framework
DSO reliability incentives	Implemented or not
	Type of scheme
DSO incentives for innovation	Specific incentives implemented?
	Design of incentives

Table 6.7: Relevant regulatory topics for the SRA of use cases implementing network automation to improve continuity of supply

6.3.1.2 Characterization of regulatory boundary conditions

In Europe, after the liberalization and unbundling of the electricity sector, regulation has focused on economic efficiency and most countries have implemented some form of revenue cap regulatory scheme. In order to avoid the deterioration of quality of supply, incentive-based regulation has been introduced and most European countries have specific regulatory incentives for continuity of supply in place (Council of European Energy Regulators (CEER), 2016).

At the moment of writing this PhD thesis, DSO revenue regulation in both Italy and Spain is mainly based on a revenue cap scheme with different regulatory incentives[115]. Some differences exist among the two countries, which are described throughout this section.

6.3.1.2.1 DSO revenue regulation in Spain

The current remuneration system in Spain is established by the Royal Decree 1048/2013 (Spanish Ministry of Industry Energy and Tourism, 2013). Considering regulatory periods of six years, a revenue cap is set individually for each distributor. The baseline for the allowed revenue for each distribution company is revised at the beginning of the regulatory period. The assets are valued considering standard unit values given in (Spanish Ministry of Industry Energy and Tourism, 2015) and efficiency factors. Capital investment is remunerated at a rate linked to national treasury bonds. New investments must be pre-approved according to an annual investment plan that must be prepared by DSOs and presented to the regulator. In addition, there is a set of incentives for continuity of supply, reduction of energy losses and fraud detection[116] that is added to the allowed revenue each year.

---

115 Actually, in both countries there are some mixed elements of cost of service and incentive regulation.

116 Previous regulation, established by the Royal Decree 222/2008, implemented the revenue cap scheme with incentives for continuity of supply and reduction of losses for regulatory periods of four years. Regulation was reformed to account for amortization, adjust the rate of return for electricity distribution [actually, this was done for all regulated activities, T&D] and introduce some other modifications.

6.3.1.2.2 DSO revenue regulation in Italy

The Italian regulation has been reformed and the length of the regulatory period has been extended to eight years divided into two sub-periods of four years each through Deliberazione 654/2015/R/EEL (Autorità per l'energia elettrica il gas e il sistema idrico, 2015a).

The regulatory scheme for the first sub-period (2016–19) is similar to the previous regime[117], based on a revenue-cap scheme applied to the operational expenditure (OPEX) and cost-of-service regulation for capital investment (CAPEX). The cost of capital is remunerated with a fixed rate of return, estimated with a Weighted Average Cost of Capital (WACC) methodology, while the operational expenditures are required to decrease with an X efficiency factor.

In the second sub-period (2020-2023), revenue regulation will evolve into a TOTEX approach, to avoid that DSOs opt for capitalization policies over operational solutions in order to maximize allowed revenues.

Moreover, quality regulation is accomplished through 'output-based' incentives in the form of a reward and penalty scheme linked to continuity of supply performance. Additionally, input-based incentives are in place to reduce energy losses and to improve DG integration by allowing an increased rate of return (i.e.an "extra-WACC") for specific investments (i.e. the substitution of conventional MV/LV transformers with low-losses transformers), and projects (i.e. automation and smart grid pilot projects).

6.3.1.2.3 DSO reliability incentives in Spain

Regulation for continuity of supply in Spain is based on reliability indices TIEPI (installed capacity equivalent interruption time) and NIEPI (installed capacity equivalent number of interruptions), defined in ECO/797/2002 calculated as indicated in (6.6)-(6.7).

$$TIEPI = \frac{\sum_{i=1}^{n} P_i \cdot T_i}{P} \tag{6.6}$$

$$NIEPI = \frac{\sum_{i=1}^{n} P_i}{P} \tag{6.7}$$

where:

n is the number of power interruptions in the area over a period of time,

Ti is the duration of the power outage *i*,

P_i represents the nominal capacity of the MV/LV transformers interrupted during the power outage *i* plus the MV power contracted by the demand affected by the outage *i*, and

117 Incentive-based regulation was established by the Italian regulator, the AEEGSI, in 2000 in the form of a 'price cap' for regulatory periods of 4 years. In 2004 the government established that the capital expenditure was to be passed-through to consumers (Law n. 290/2003).

P is the nominal capacity of all the MV/LV transformers plus the MV power contracted by the demand in the area considered.

These indices are similar to the indices ASIDI (average system interruption duration index) and ASIFI (average system interruption frequency index), defined by the IEEE Power & Energy Society in (IEEE Power & Energy Society, 2012),which are based on the total load connected (instead of the number of customer affected as is the case of SAIDI and SAIFI).

Reliability indices are computed taking into account unplanned[118] long interruptions, defined as those with a duration over 3 minutes, excluding those caused by generation, transmission, force majeure or third parties. As explained in section 6.2.7, reliability is monitored for the four type of zones defined: urban, sub-urban, concentrated rural and scattered rural areas, for each municipality and DSO.

The regulatory incentive for continuity of supply in Spain is based on a scheme of rewards/penalties computed annually for each DSO proportional to the improvement/increase of TIEPI, according to the formulas provided in the RD1048/2013[119]. The total value of the incentive is capped to +2% and -3% of the total allowed revenue for the company (incentives excluded). Furthermore, any DSO that significantly outperforms the national average by obtaining a TIEPI lower by over 50% of the national average, will not be penalized beyond that level. The reduction (or increase) of the total duration of supply interruptions (considering a three-year moving average of TIEPI multiplied by the total nominal power) is valued at a NSE cost (established as thirty times the average hourly electricity market price). A coefficient is applied to the incentive to account for the improvement (or deterioration) of NIEPI[120]. An additional coefficient is applied to increase the incentive (or decrease the penalization) according to the performance of the DSO with respect to other DSOs in terms of TIEPI. A third factor is used to decrease the reward in case thresholds values set for each type of zone have been surpassed.

Additionally, the regulation defines maximum individual values of NIEPI and TIEPI for each type of zone in RD1634/2006. Consumers suffering a higher number or duration of interruptions are entitled to a reduction in their electricity bill of up to 10%. The compensation is defined in RD1955/2000 and

---

118 Supply interruptions will only be considered as planned, and therefore, excluded from the reliability indices TIEPI and NIEPI to compute regulatory incentives, if (i) announced to and authorized by Regional Government 72h in advance, and (ii) announced to affected customers 24 hours in advance (individually noticed to consumers at voltages higher than 1 kV and essential services, and through advertising posters in visible spots and 2 of the most widely circulated printed media in the province for all other consumers).

119 Previous regulation (Spanish Ministry of Industry Tourism and Commerce, 2008) established a regulatory incentive comprised by a NIEPI and a TIEPI term for each type of area. These terms were proportional to the variation of TIEPI and NIEPI with respect to target, or reference, values based on the average between the DSO's indexes and the national average, multiplied by the corresponding installed capacity and number of consumers and priced at 100 c€/kWh and 150 c€/consumer and interruption, respectively for TIEPI and NIEPI. The incentive was capped to ±3% of the DSO total allowed remuneration (excluding incentives).

120 If NIEPI improves, the reward is increased, or the penalization remains the same. If NIEPI has increased, the reward is decreased, or the penalization is increased.

is proportional to the average power demand and the price of electricity paid by the consumer. Other network users (DER) are not entitled to such compensation.

6.3.1.2.4 DSO reliability incentives in Italy

The output-based regulation for the period 2016-2023 is established in Deliberazione 483/2014/R/eel (Autorità per l'energia elettrica il gas e il sistema idrico, 2015b). Incentives for continuity of supply were established in Italy in 2000 through a mechanism of penalties and rewards for DSOs linked to the reliability performance of DSOs with respect to a target. Originally, this incentive was based on the duration of supply interruptions, and since 2008 the number of interruptions is also considered, including both long and short interruptions. Supply interruptions are defined by Italian regulation as long (t>3min), short (1s<t<=3min) and transient (t<=1s).

Target levels are established for the duration and number of interruptions per type of area of load density[121]. These targets are supposed to be accomplished in the regulatory period, so each year, actual performance is compared to an eighth of the difference to the target. The number and duration of supply interruptions is computed including unplanned[122] interruptions, caused by the DSO (excluding force majeure or external causes), although DSOs may choose to include interruptions due to external causes as well (with adjusted target values and economic incentives).

The AEEGSI carried out a survey in 2003 to investigate cost of non-supplied energy for consumers in Italy based on the concepts of willingness to pay and willingness to accept. Survey-based methods are in fact recommended by the CEER for regulation (Council of European Energy Regulators (CEER), 2010) and most commonly used in the electricity sector. The economic valuation of reliability improvement (or deterioration) were then established based on the findings of this survey, as explained in (Bertazzi, Fumagalli, & Lo Schiavo, 2005), considering a different cost for residential and non-residential network users.

The current regulatory incentives include different coefficients for economic valuation of the improvement (or deterioration) of the total duration of supply interruptions with a dead-band around the target value of ±10% for each type of area, and coefficients to evaluate performance in the total number of interruptions (short and long). The total economic reward (or penalization) awarded to a DSO is limited to a maximum economic amount per network user served, which differs per type of area.

Additionally, there is a system in place for compensation to individual MV network users suffering a number of interruptions (short and long) higher than certain minimum requirements set per type of

---

121 As explained in section 6.2.7, the Italian regulator establishes three types of areas for reliability regulation based on population density: high, medium and low concentration (Autorità per l'energia elettrica il gas e il sistema idrico, 2011) (see Table 6.5).

122 Planned supply interruptions must be noticed 3 working days in advance. The advance notice requirement is reduced to 24 hours in case of interventions after faults or during emergencies.

area. This compensation is proportional to the interrupted power valued at a cost that differs for network users consuming or injecting power into the grid. The penalty for the DSO is capped to a maximum value per individual user, and a maximum total amount.

6.3.1.2.5 DSO incentives for innovation in Spain

The Spanish regulation does not provide any specific incentive to encourage investment in innovative solutions. The Spanish government has funded research activities and pilot projects on different topics, including efficient DER integration and smart grid solutions through different programs and competitive calls in cooperation with the industry. Unfortunately, there has not been an obligation to disclose the results, so the available information is limited.

6.3.1.2.6 DSO incentives for innovation in Italy

Italian regulation has promoted innovation through input-based incentives by allowing an extra 2% incremental points on WACC over a period of 12 years for specific investments, including the substitution of conventional MV/LV transformers with low-losses transformers to reduce losses and the implementation of telecontrol of switches to reduce the duration of supply interruptions.

Furthermore, this increased WACC has also been applied to promote smart grid 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[123]. The index used for selecting demonstration projects were based on a cost-benefit analysis, considering the benefits of increasing the renewable electricity supply and the reduction of losses[124].

Current regulation given by the Deliberazione 483/2014/R/eel establishes an economic incentive for the implementation of MV network monitoring solutions to increase observability of power flows and DER injections and voltage regulation solutions. The incentive is proportional to the level of complexity of the network solution, renewable DG capacity and network installed capacity. Additionally, regulation provides funding for smart city projects.

6.3.1.2.7 Mapping of regulatory boundary conditions in Spain and Italy

The Spanish and Italian regulatory frameworks for DSO revenue regulation and incentives for continuity of supply and innovation have been characterized, and the boundary conditions are summarized in Table 6.8 according to the regulatory topics identified in Table 6.7 as relevant to the SRA of network automation to improve continuity of supply.

---

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

[124] A synthetic indicator IP has been defined as the product of indicator Psmart, which measures the increase of NHC achieved by the proposed demonstration project, and technical scores corresponding to further benefits, divided by the project costs.

		Spain	Italy
DSO revenue regulation	General regulatory framework	Combined model of price cap (OPEX) and standard unitary costs (CAPEX)	Combined model of price cap (OPEX) and rate of return (CAPEX)
DSO reliability incentives	Implemented or not	Yes	Yes
	Type of scheme	Reward/penalty mechanism with respect to own performance	Reward/penalty mechanism with respect to target values
	Differentiate for area/region	Area (population density: urban, sub-urban, concentrated rural, scattered rural)	Area (population density: high, medium and low concentration)
	Indices	TIEPI & NIEPI (ASIDI & ASIFI)	Number and duration of interruptions (SAIDI and SAIFI+MAIFI)
	Threshold	t>3min	t>3min for duration and t>1s for number of interruptions
	Interruptions considered	Unplanned interruptions, attributed to the DSO	Unplanned interruptions, attributed to the DSO
	Deadband	No	Yes, ±10%
	Cap/Floor	+2%/-3%	Yes
	Individual compensations?	Yes, for all consumers	Yes, for MV network users
	Unitary price?	Linked to electricity price	Based on outage cost for residential and non-residential consumers
	Potential contribution of DER considered?	No	No, but DER is entitled to individual compensation
DSO incentives for innovation	Specific incentives implemented?	No	Yes
	Design of incentives	N/A	Input-based incentive: increased WACC for innovative solutions

Table 6.8: Regulatory boundary conditions in Spain and Italy according to the relevant regulatory topics for the SRA of use cases implementing network automation to improve continuity of supply.

6.3.1.3 Assessment of the effect of regulatory boundary conditions on the replication and upscaling of the use case

In order to provide an adequate level of reliability, DSOs must incur in capital and operational expenses that must be recovered through the allowed revenues. Network automation solutions offer a great potential to improve continuity of supply, but the economic viability of implementing such solutions is completely linked to the regulatory framework.

6.3.1.3.1 Effect of DSO revenue regulation

Input-based approaches based on CAPEX pass-through exclude capital investment from efficiency gain requirements. Therefore, smart grid investments are encouraged, as long as these are included in the RAB. This would favor the implementation of smart grid solutions that do increase the asset base without significantly reducing OPEX, like MV network automation.

In the case of Italy, this is exactly why automation was implemented. Regulation not only enabled the pass-through of DSO investments, but also investments in telecontrol and MV active network automation were awarded an increased rate of return for an increased period of time. This was awarded for automation implementations that complied with the requirements imposed by the regulator. Nevertheless, this approach does not comply with the principle of technology-neutrality, which could hamper the implementation of innovative automation solutions of different characteristics.

The input-oriented regulation in Spain based on standard investment costs in combination with actual costs to determine RAB additions encourages DSOs to reduce per unit costs. However, it does not promote reduction in the "amount" of physical assets, so conventional solutions based on network reinforcement and redundancy of network elements could be preferred to automation solutions, depending on how these units were considered. Furthermore, requiring the DSO to provide annual investment plans increases the need to include CAPEX in a efficiency-oriented scheme so as to avoid the incentive DSOs may see to overestimate or inflate investment needs through flexible remuneration systems, such as profit-sharing schemes or menu regulation, with pre-defined rules for ex-post adjustment to mitigate uncertainty (Cossent, 2013)[125].

6.3.1.3.2 Effect of DSO reliability incentives

Incentive-based regulation encourages economic efficiency. However, in order to ensure adequate reliability levels, specific regulatory reliability incentives are designed to encourage DSO investment aimed at continuity of supply. Therefore, the existence of such reliability incentives is in principle a positive feature of the regulation for the scaling-up of MV network automation use cases in a country. However, the definition of these incentives will have a decisive impact on its effectiveness.

The unit incentive determines the strength of reliability incentives. Broadly speaking, the higher this unit incentive, the stronger the incentives to improve continuity of supply, but at a higher cost for

---

[125] In fact, the Italian regulator has implemented this approach for the implementation of 2nd generation smart metering systems. DSOs must submit a roll-out plan for regulatory approval. Then, allowed expenditures are determined using an Information Quality Incentive (IQI) matrix to promote efficiency and reliable information from the DSO. Finally, roll-out is monitored and penalties apply if performance targets are not reached.

network users. The unit incentive can be seen as the price of quality or the cost for consumers of the lack of quality. In Spain, the unit incentive is directly linked to the price of electricity (multiplied by thirty) while the unit incentive is set in Italian regulation based on the cost of interruptions for consumers estimated through surveys (Bertazzi et al., 2005). However, due to the different formulas and reliability measurement approaches, it is not possible to set a quantitative comparison between the two countries. In order to determine whether these two approaches are sufficient to encourage the implementation of smart grid solutions, an economic analysis would have to be carried out, to compare the marginal cost of improving reliability through these solutions against the regulatory incentives in each country (Fernandes et al., 2012; Rodriguez-Calvo et al., 2014). Such cost-benefit assessment is illustrated in section 6.5, using the simulation results obtained for the technical SRA as an input.

Actual reward-penalty schemes sometimes deviate from a theoretical linear and symmetrical scheme. When quality regulation through incentives was implemented, symmetric incentive schemes (with both penalties and rewards) were considered to strengthen the acceptance of this system, according to (Ajodhia & Hakvoort, 2005). Deadbands around the reference or target indices, such as the 10% dead-band in Italy, asymmetric incentives or caps and floors, such as the +2% and -3% cap in Spanish regulation, introduce discontinuities that may distort the effectiveness of these incentives, thus affecting the scalability and replicability potential of automation solutions. DSOs with reliability levels within the deadband, especially when far from its limits would perceive weak incentives to improve continuity of supply through automation. The authors of (Cambini, Croce, & Fumagalli, 2014) studied the actual investment strategy followed by DSOs under the Italian regulatory scheme of reliability incentives. Results showed that penalties played a significant role in the decision to invest, especially in areas with lower quality; whereas rewards affected the investment decision only in areas with top quality performance. In areas with average quality performance, the incentives did not impact investment strategies. Caps and floors are used to mitigate the exposure of DSOs and rate payers. However, this could be a barrier for the scalability of automation solutions, which achieve a great reliability improvement for low degrees of implementation that could result in a regulatory incentive limited by the cap.

Besides, the procedure to monitor continuity of supply (reliability indices used, interruptions considered, etc.) and assess improvement (target values, benchmarking across companies, distinction by zones or types of network users, etc.) may favor the investment on certain solutions, areas, types of consumers, etc. Including only unplanned interruptions attributable to the DSO from the regulatory incentives (i.e. excluding planned interruptions and those caused by external agents or due to force majeure) strengthens the incentives for DSOs to implement network monitoring and automation, as the relatively gain in reliability levels becomes larger.

Effect of regulatory threshold for supply interruptions

Moreover, the regulatory threshold for long interruptions can affect the type of automation selected by DSOs. Italy and Spain, like most European countries, have a limit of 3 minutes for long interruptions. However IEEE standards consider a one-minute threshold for the definition of sustained interruptions (IEEE Power & Energy Society, 2009)[126]. What is more, the Italian reliability incentive for improving the number of interruptions include short interruptions as well, that is, supply interruptions with a duration above 1s. The effect of different regulatory thresholds can be analyzed in the same way that automation systems with different time response t_{autom} were assessed (see section 6.2.5.4). Simulations have been carried out to compare the reliability improvement achieved by automation with different values for response time t_{autom} under the usual 3-minute limit, and a tighter margin of 1min, and the total number of interruptions, including short and long interruptions (i.e. MAIFI+SAIFI), according to the Italian regulatory reliability incentives. Table 6.9 shows the results obtained for the case of the Spanish urban representative network.

---

[126] It must be noted that IEEE standards are often the guideline to establish mandatory requirements in the US.

			t_{reg}=1min		t_{reg}=3min	
t_{autom} (min)	Automation degree (%)	MAIFI[127] + SAIFI (int/cons)	SAIFI (int/cons)	SAIDI (min/cons)	SAIFI (int/cons)	SAIDI (min/cons)
0s	0%	0.58	0.58	25.38	0.58	25.38
0s	7%	0.27	0.27	15.99	0.27	15.99
0s	20%	0.12	0.12	8.40	0.12	8.40
0s	46%	0.05	0.05	3.26	0.05	3.26
0s	100%	0.00	0.00	0.28	0.00	0.28
55s	0%	0.58	0.58	25.38	0.58	25.38
55s	7%	0.58	0.27	16.24	0.27	16.24
55s	20%	0.58	0.12	8.51	0.12	8.51
55s	46%	0.58	0.05	3.30	0.05	3.30
55s	100%	0.58	0.00	0.28	0.00	0.28
1min05s	0%	0.58	0.58	25.38	0.58	25.38
1min05s	7%	0.58	0.58	16.62	0.27	16.28
1min05s	20%	0.58	0.58	9.02	0.12	8.53
1min05s	46%	0.58	0.58	3.88	0.05	3.31
1min05s	100%	0.58	0.58	0.90	0.00	0.28
2min	0%	0.58	0.58	25.38	0.58	25.38
2min	7%	0.58	0.58	17.15	0.27	16.53
2min	20%	0.58	0.58	9.55	0.12	8.64
2min	46%	0.58	0.58	4.41	0.05	3.35
2min	100%	0.58	0.58	1.43	0.00	0.28
5min	0%	0.58	0.58	25.38	0.58	25.38
5min	7%	0.58	0.58	18.88	0.58	18.88
5min	20%	0.58	0.58	11.29	0.58	11.29
5min	46%	0.58	0.58	6.15	0.58	6.15
5min	100%	0.58	0.58	3.17	0.58	3.17

Table 6.9: Reliability indices achieved by automation under different regulatory thresholds (t_{reg}) for automation solutions of different time response (t_{autom}) in the Spanish urban representative network

As previously explained, the regulatory threshold can limit the observed SAIFI improvement. If the automation system is not able to restore service in a time shorter than the regulatory threshold (i.e. t_{autom} surpasses t_{reg},), automation has no longer an effect on SAIFI. This effect can be observed when comparing the resulting values of SAIFI for t_{autom}=55s and t_{autom}=1min5s under a 1-minute regulatory threshold. Although the actual reliability improvement for network users would be almost the same

127 It must be noted that MAIFI accounts for short and long interruptions, including transient faults that are cleared by reclosers. These faults are not taken into account for SRA simulations, so actual MAIFI values could be slightly higher, and then, the reliability improvement quantified in SRA could be considered a reasonable estimation and lower bound to the actual improvement that could be achieved with automation.

in both cases, there is a great reduction of SAIFI if t_{autom}=55s, while the SAIFI values remain unchanged when the automation solution implemented has t_{autom}=1min5s. Additionally, the regulatory thresholds also limits SAIDI improvement, to a much lower extent, since the network users whose service is automatically restored are considered to have suffered an interruption of a duration that is added to the SAIDI index. Considering t_{reg}=3min, there is no interference of the regulatory threshold in the observed reliability improvement, so automation with t_{autom}=55s and t_{autom}=1min5s result in the same reliability improvement (except for the slightly higher SAIDI values due to the 10s extra in the restoration of service for all consumers).

The Spanish regulation allows DSOs to increase the rewards for reliability improvement if the number of interruptions below 3 minutes is reduced, so the implementation of automation solutions would be favored, and the effect of the different response times for different technologies and control systems would be negligible. Human supervision could be the turning point, with restoration times surpassing the regulatory threshold, thus unable to reduce SAIFI (TIEPI) values. In the case of Italian regulation, as short interruptions are also included, automation is favored by the incentive to reduce the duration of supply interruptions, but in order to be rewarded for the reduction of the number of interruptions, DSOs would have to invest in automation solutions able to restore service in a time below 1s.

Use of different reliability indices: SAIFI-SAIDI and ASIDI-ASIFI (TIEPI-NIEPI)

Furthermore, the use of different reliability indices may encourage slightly different strategies for distribution companies to invest in improving reliability. The analyses performed in the technical SRA step (section) employed SAIDI and SAIFI, because they are the most widespread indicators used (as is the case of Italy). As previously explained, these indicators measure the average frequency and duration of supply interruptions weighed by the number of consumers. Therefore, they place an equal weight on all consumers independent of their size and consumption. By contrast, the indices used in Spain (based on TIEPI and NIEPI), prioritize improving reliability for larger consumers, because they are based on the amount of affected power.

Moreover, the reliability improvement achieved by automation may differ slightly depending on the selected set of indices and the structure of the demand (in terms of rated power and number of consumers). Please, note that both sets of indices would yield the exact same results if all consumers had the same load and reliability.

The implications of using different sets of reliability indices under different demand structures are illustrated in by the results obtained for the simulations for the urban and rural Spanish representative networks, presented in Table 6.10 and Table 6.11, respectively[128]. For each network, the demand has

[128] This analysis has been carried out only for the Spanish representative networks, since the demand in the Italian representative networks created in the ATLANTIDE project does not specify the number of consumers at each secondary substation.

been redistributed, maintaining the same total installed capacity and number of consumers (denoted in the first column in Table 6.10 and Table 6.11). First, a homogeneous demand structure has been considered, where all secondary substations have the same rated power and supply the same number of consumers (Dem 1). Then, a heterogeneous demand has been studied, where all secondary substations have the same rated power but supply a different number of consumers, so that areas with lower reliability have a higher number of consumers (Dem 2). A third scenario has been considered, where all secondary substations have the same number of consumers supplied but their rated power is higher for some consumers, located at the zones with poorer reliability, i.e. ramifications in the rural case (Dem 3).

For homogeneous demand, SAIFI and ASIFI values are the same, and the same happens with SAIDI and ASIDI. In the case of demand scenario 2, since installed capacity remains the same, ASIFI and ASIDI values do not change. However, the SAIFI and SAIDI values vary as displayed in Table 6.10 and Table 6.11. For both networks, SAIFI-SAIDI indicate a slightly poorer reliability level than ASIFI-ASIDI, and the improvement achieved by automation is also modified, since a higher share of consumers is located where interruptions are more frequent and of longer duration. On the contrary, in demand scenario 3, where rated power varies, so do ASIFI and ASIDI. However, since the number of consumers is the same at all points of the network, SAIFI and SAIDI values are exactly those obtained for the scenario 1 of homogeneous demand.

Simulation results show that in urban areas the differences among the two sets of indices are less visible than in rural areas, for instance with a maximum difference between SAIDI and ASIDI of 0.02min (9%) in network 4 and 27.69min (17%) in network 6 for demand scenario 3. This is because the reliability of the network is much more homogeneous along the network buses. On the contrary, in the case of more rural networks, more remote locations and ramifications of the network, especially those without an alternative path for supply through reconfiguration, suffer from much poorer reliability than other nodes in the main trunk, so the selected averaging parameter may become more relevant.

Dem	Autom. (%)	SAIFI (int / year·cons)	SAIDI (min / year·cons)	ASIFI (int / year·kW)	ASIDI (min / year·kW)
1	0%	0.58	25.30	0.58	25.30
1	7%	0.27	16.05	0.27	16.05
1	20%	0.12	8.50	0.12	8.50
1	67%	0.02	1.46	0.02	1.46
1	100%	0.00	0.27	0.00	0.27
2	0%	0.58	26.84	0.58	25.30
2	7%	0.28	17.69	0.27	16.05
2	20%	0.13	9.20	0.12	8.50
2	67%	0.02	1.56	0.02	1.46
2	100%	0.00	0.24	0.00	0.27
3	0%	0.58	25.30	0.58	26.34
3	7%	0.27	16.05	0.28	17.12
3	20%	0.12	8.50	0.13	8.97
3	67%	0.02	1.46	0.02	1.53
3	100%	0.00	0.27	0.00	0.25

Table 6.10: SAIFI, SAIDI, ASIFI and ASIDI values for different demand scenarios for the Spanish urban network

Dem	Autom. (%)	SAIFI (int / year·cons)	SAIDI (min / year·cons)	ASIFI (int / year·kW)	ASIDI (min / year·kW)
1	0%	2.25	256.83	2.25	256.83
1	3%	1.63	187.50	1.63	187.50
1	6%	1.39	164.89	1.39	164.89
2	0%	2.39	293.80	2.25	256.83
2	3%	1.78	220.71	1.63	187.50
2	6%	1.64	196.79	1.39	164.89
3	0%	2.25	256.83	2.37	285.73
3	3%	1.63	187.50	1.78	217.98
3	6%	1.39	164.89	1.61	192.57

Table 6.11: SAIFI, SAIDI, ASIFI and ASIDI values for different demand scenarios for the Spanish rural network

6.3.2 Perspective of stakeholders

The analysis of the stakeholders' perspective involves identifying the groups of stakeholders involved in the implementation of MV automation and characterizing their perspectives under the Spanish and the Italian boundary conditions to understand how they could benefit from or oppose to automation.

6.3.2.1 Identification of relevant stakeholders

The implementation of MV automation involves and affects different actors. The most relevant stakeholders are (i) distribution companies, in charge of deciding on the deployment of automation and responsible for the operation of the networks; (ii) network users who benefit from reliability improvement (or suffer from the lack thereof); (iii) manufacturers, vendors and service providers for the technologies involved in automation solutions (protections, communications, etc.) and (iv) the national regulatory authorities, who set the reliability requirements and allowed revenues for distribution companies.

6.3.2.2 Characterization of stakeholder-related boundary conditions

The characteristics of the main stakeholders in Spain and Italy can be considered quite similar in both countries, with respect to their behavior and perspectives towards the implementation of MV network automation to improve continuity of supply. The general context of DSOs and consumers in Spain and Italy is briefly described in this section to help frame the discussion of the effect of stakeholder-related boundary conditions in the following section.

In Spain, there are five large DSOs and over 300 with less than 100,000 customers. The distribution areas covered by the larger DSOs are depicted in the map in Figure 6.17.

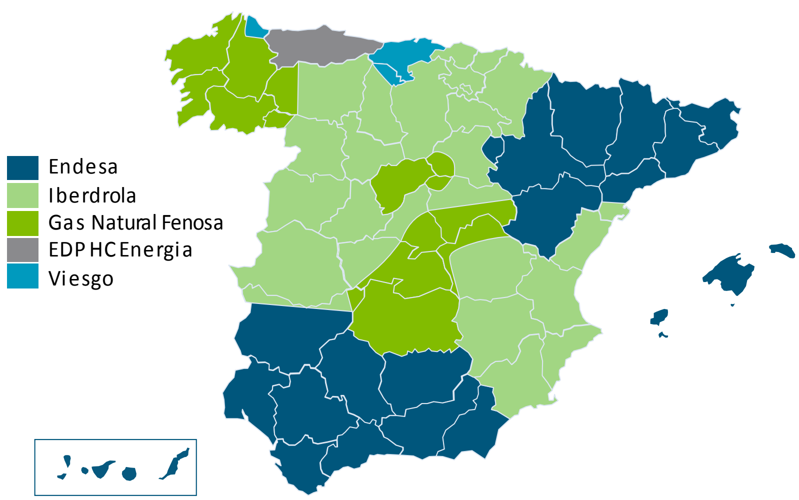


Figure 6.17: Map of distribution areas covered by the five main DSOs in Spain. Source: Energía y Sociedad[129].

[129] http://www.energiaysociedad.es/manenergia/actividades-reguladas-en-el-sector-electrico/

In Italy, the main DSO is e-distribuzione (formerly state-owned utility ENEL, then unbundled DSO ENEL Distribuzione), covering 86% of the total consumers in Italy. There are other nine local DSOs with over 100,00 customers and over 100 smaller DSOs. The largest local DSOs include A2A Reti Elettriche (local DSO in Milan) covering 4% of customers, Areti (formerly Acea Distribuzione and local DSO in Rome) covering 3.5% of customers, and Aem Torino Distribuzione (local DSO in Torino and Parma) covering 1.4% of customers.

Noteworthy, the Italian regulator carried out a survey to study the cost of supply interruptions for Italian consumers (Bertazzi et al., 2005), based on monitoring the willingness to pay for higher quality and willingness to accept compensations for the loss of quality. From a rational economic perspective, the WTP and WTA of a consumer are equivalent concepts. However, the survey results yielded significantly lower values of WTP, as shown in Figure 6.18, which shows the values of WTP and the indicator (WTA+WTP)/2 for the groups of consumers surveyed.

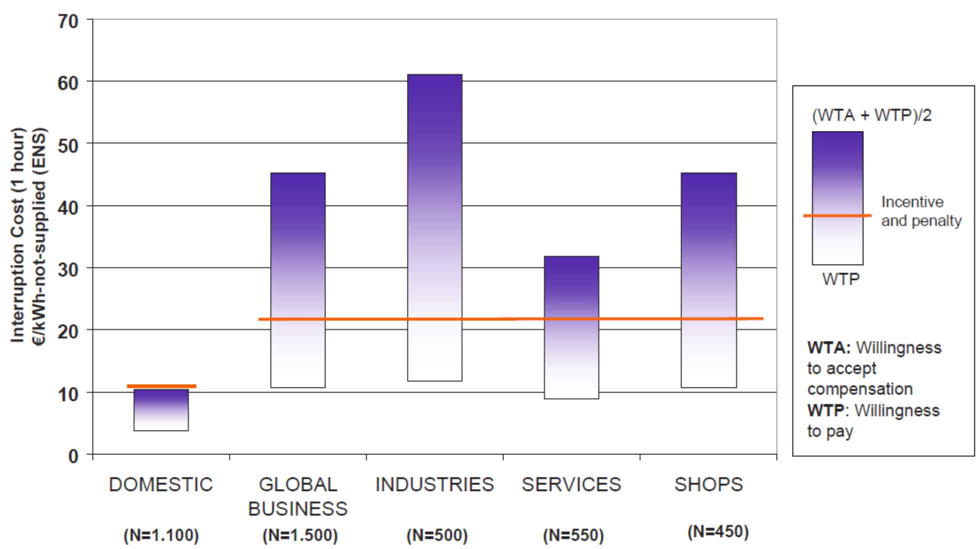


Figure 6.18: Values of WTP and (WTP+WTA)/2 obtained from the results of the survey carried out by the AEEGSI in Italy. Source: (Bertazzi et al., 2005).

According to the survey carried out by the European Commission (European Commission, 2013), the degree of satisfaction with the market for electricity services is among the lowest ranked service markets in Europe (28th out of the 31 markets monitored). Specifically, satisfaction levels in Italy and Spain are among the lowest ranked across the EU.

6.3.2.3 Assessment of the effect of stakeholder-related drivers and barriers

This section discusses the drivers and barriers related to the perspective of the identified groups of relevant stakeholders for the implementation of MV automation to improve continuity of supply.

Distribution companies

Distribution companies decide on reliability investments, how much to invest, and which solutions to deploy, both conventional and innovative, from network refurbishments to MV network automation solutions. The investment strategy is greatly influenced by regulation, allowed revenues and reliability and innovation incentives. Additionally, DSOs may be encouraged to invest in reliability to avoid a bad reputation for poor quality, especially in the case of distribution companies that belong to a large holding company active in competitive markets (e.g.: retail, generation, etc.) and other sectors (e.g.: gas, water, etc.), case in which such reputation could spill over to the other business (Ajodhia et al., 2006).

Operators in distribution control centers supervise available information to control the state of the system and make operation decisions. Automation systems usually involve a higher degree of monitoring, so that the volume of information available to process is much higher. Usually, the deployed automation will be integrated in the available control software systems. However, adjustments may be necessary, or even the substitution of software tools with new solutions. In these cases, training may be necessary for the operators. Operators may oppose to changes in their working software tools, may fear losing control of the system, or even may feel that their job is at risk. By contrast, engaged operators may see automation as an aid to their work, guiding the service restoration process. It is therefore important to implement well-designed control tools and engage operators in the process.

Furthermore, internal DSO rules may impede the implementation of local or autonomous systems so that operators must supervise and validate operations proposed by the automated system. Such restrictions could harm the potential for fast restoring of the service.

Network users: Consumers and DER owners

Although network users are not active participants in the implementation of MV network automation, they are directly affected by its deployment, as they suffer the supply interruptions and would benefit from reliability improvement. Thus, network users demanding higher quality levels are a driver for network automation use cases scalability and replicability. Furthermore, distribution costs are borne by the network users through the tariff, so the level of quality demanded by network users will be related to the cost of supply interruptions[130].

The costs of supply interruptions for consumers varies depending on the use of electricity of the different consumers at different times and the duration of supply interruptions. Supply interruptions

[130] It must be noted that sensitive consumers, such as hospitals or prisons, usually have their own back-up generators or storage to ensure electricity supply at all times. This may be also the case for consumers in areas, of extremely poor reliability levels with a high cost of improving reliability in the network is very high, as for instance in many countries in Latin America, where consumers may resort to the use of independent storage or back-up generators.

may cause damages related to loss of production, equipment damage, spoilage of perishable elements (e.g.: refrigerated food, raw materials in industrial processes), welfare loss due to lack of comfort (e.g.: electric heating, air conditioning) and loss of leisure time, and other indirect costs (e.g.: loss of competitiveness or market share) (Linares and Rey, 2012).

As discussed in the regulatory analysis (Chapter 4, section 4.2.4), regulators frequently define reliability incentives for DSOs on the basis of the estimated valuation of reliability for consumers, in order to drive DSOs towards the optimal balance between the cost of reliability and the level of quality for consumers. In general, industrial and large consumers are more aware of the cost of supply interruptions. By contrast, it is more difficult for residential to evaluate the monetary loss related to supply interruptions. Furthermore, as electricity supply is perceived as a public good, consumers tend to have a sense of entitlement unrelated to the cost of improving quality of supply. Furthermore, the lack of trust of consumers in electric power companies can also act as a barrier for smart grid deployment (Wolsink, 2012).

Publishing continuity of supply indices has enhanced transparency and enables benchmarking quality of service across DSOs, regions and countries. Nevertheless, consumers are not likely to be able to detect continuity of supply improvements when reliability levels are already high.

The discussion on the cost of supply interruptions has traditionally focused on consumers (Council of European Energy Regulators (CEER), 2011a; IEEE Power & Energy Society, 2012) thus neglecting other network users that are also subject to the loss of availability of the network during supply interruptions: the owners of distributed energy resources, including distributed generation (DG), electric vehicles and storage units. During supply interruptions, DG units are disconnected, so that they are unable to inject and sell their production into the network. The cost of interruptions for DG is related to the price perceived by DG, either selling their production in the wholesale market or through regulatory mechanisms, such as feed-in tariffs. Additionally, the cost of interruptions may include start-up costs, depending on the DG technology. EV and storage consuming or producing electricity face the same damages than consumers and DG units, correspondingly. Therefore, DER should also be considered in the assessment of the cost of interruptions (Cossent, 2012), especially in the current context of increasing penetration degree of DG and EV in distribution networks.

Manufacturers and service providers

The implementation of MV network automation involves the development, provision and deployment of different technologies, components and solutions. Therefore, the involved equipment manufacturers, software developers, system integration firms and ICT services providers are central stakeholders for the scaling-up and replication of network automation use cases.

The scaling-up and replication of MV network automation is favored by standardization and interoperability of available automation solutions, technology maturity and affordability of automation.

Standardization ensures interoperability and enhances competition in manufacturing, allowing that multiple vendors can offer equivalent solutions, thus reducing costs. However, in a context of uncertainty for commercial innovation, developers and manufacturers may be strategically inclined to develop proprietary standards or oppose to fully interoperable and standardized solutions to retain market share or create a captive demand. On the other hand, standardization may enlarge the potential customer base of manufacturers and vendors, as DSOs may be reluctant to rely on a single supplier for a specific solution.

In order to facilitate the development of adequate network automation solutions, a successful collaboration between DSOs and the industry in the framework of specific R&D projects can help shape specifications and functionalities, providing both parties some hedging against technology risks and reducing development costs. Furthermore, engaging providers of different elements or systems that should interact among them may facilitate system integration. Nevertheless, automation solutions may have to be developed ad-hoc are adapted to the different infrastructure, conditions and information systems of different DSOs, which may hamper the replicability of such solutions for other DSOs.

National Regulatory Authorities

Naturally, the national regulatory authorities (NRAs) are key stakeholders, as they must set an adequate regulatory framework to ensure quality of electricity supply at a reasonable price for network users. Regulators may face different barriers in their duty to develop regulation that enables the upscaling and replication of network automation to improve continuity of supply. As a result of what may be called resource-bounded regulators (Glachant et al., 2012), regulators may not have the necessary resources (human resources, budget or training) to assume the regulatory burden that may be involved in order to change regulation, oversee the behavior of companies and focus on the deployment of smart grid solutions in distribution networks. 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, enhancing the exchange of lessons learnt and best practices among regulators from different countries can significantly foster the replicability of MV network automation. As regulation is addressed separately in the previous section (section 6.3.1), the regulator is excluded from further stakeholder analysis.

6.4 SRA rules

Naturally, a more comprehensive SRA would lead to more categorical and verified conclusions. However, this case study offers preliminary results that show some interesting trends that can be summarized in the following SRA rules:

- Effect of increasing automation is non-linear; there is a saturation effect
  At first, implementing a mild degree of automation achieves a drastic improvement of continuity of supply. Increasing MV automation to a higher degree, by contrast, improves continuity of supply at a lower rate. Therefore, large-scale adoption of MV automation should be carefully planned to achieve the optimal level of automation.
- Greater impact on continuity of supply in meshed networks
  In radial networks with no interconnections among different feeders, the time required for fault detection can be improved, but there is no possibility to recover non-faulty segments of the network. In meshed networks, typically used for urban areas, both the number of interruptions and their duration may be reduced.
- Greater impact on networks with poorer reliability
  Given a certain network topology, poorer levels of reliability due to higher fault rates or higher feeder lengths leave a greater margin for improvement, so the implementation of automated substations will be more beneficial.
- Automation should be prioritized in urban areas
  Urban networks are typically more meshed, have more secondary substations with switches that can feature telecontrol and a higher number of consumers to benefit from reliability improvement.
- Regulation plays an important role in the uptake of MV automation by DSOs
  Regulatory reliability requirements and the scheme and volume of continuity of supply incentives may encourage DSOs investment on automation. Furthermore, monitoring indices based on consumers may lead to the prioritization of highly populated residential areas for automation, while indices based on load may favor more commercial areas with larger consumers.
- Network users are the main beneficiaries of improving continuity of supply
  Network users demanding higher quality levels are a driver for the implementation of network automation. However, network users must bear the costs and expect a certain level of quality for a reasonable price. Residential consumers may be less aware of their interruption costs or may not be able to observe reliability improvements, so enhancing the communication and information may be helpful to engage these consumers in favor of smart grid automation solutions.
- Engagement of operators needed for success
  Distribution operators will work with a new solution. Proper information and training can help increase their levels of acceptance.

6.5 Cost-benefit analysis of the implementation of network automation to improve continuity of supply

This section presents the CBA of network automation using the results obtained for the case study of SRA of MV network automation in Spain and Italy. As explained in Chapter 3, SRA results can be used as an input to perform cost-benefit analysis. Cost-benefit analysis aims to assess the economic worth of a project, comparing the costs and the expected benefits within a certain time frame, typically related to the expected useful life of the project. Cost-benefit analysis is therefore an important tool to support decisions related to the selection, adoption and investment on projects.

The implementation of automation to improve continuity of supply in MV networks is a capital-intensive project, so the degree of automation to implement should be based on a cost-benefit analysis that takes into account social welfare. On the other hand, the agent deciding and directly implementing this project is the DSO, with the objective to maximize the profitability of the activity of electricity distribution under the corresponding regulatory framework. Therefore, CBA should be performed from these two different perspectives. From the point of view of the system, the cost of deploying the smart grid solution must be compared to the value of reducing supply interruptions for network users. Alternatively, from the point of view of DSOs, investment would be recovered from the allowed revenues, through regulatory incentives for the improvement of reliability would. The results obtained from the system perspective would help regulators and policy-makers to understand whether these type of smart grid solutions should be encouraged, while the results obtained in the second case would help adjust regulatory incentives. Additionally, the latter would be of interest for DSOs to guide design the investment strategy (considered together the overall revenue regulation). The methodology applied for CBA was first presented in (Rodriguez-Calvo et al., 2014).

In the first case, the benefits are related to the real cost borne by network users and the savings derived from avoided interruptions, which can only be estimated, while in the second case, the benefits derived from the regulatory incentives are actual payments to distribution companies set by the regulator based on monitored reliability indices and regulatory targets. The assessment of the reliability improvement achieved by automation is carried out by SRA and quantified in the form of KPIs SAIFI and SAIDI reduction. Thus, SRA simulation results are a key input to the CBA.

6.5.1 Methodology for cost-benefit analysis

In order to determine the optimal degree of automation (A*), the net cost of interruptions for the system must be minimized. The net cost for the system (NC) is the sum of the investment in smart MV/LV substations (I) and the cost of supply interruptions (C), as stated in (6.8). As previously explained, two alternative approaches have been adopted to assign an economic value to the improvement of continuity of supply: (i) considering the cost of interruptions of supply for affected network users (E), and (ii) considering the regulatory incentives granted to distribution companies for the improvement of continuity of supply (R). The minimum net cost is obtained at the point where the marginal cost for network users due to supply interruptions equals in absolute value the marginal cost for the system due to investment requirements as shown in the diagram in Figure 6.19 and as expressed in (6.9), assuming that A*≠0. The use of marginal costs conveys the idea of how much/to what extent investing to increase the automation degree reduces the cost for network users. Furthermore, unlike total costs, marginal costs are not affected by the size of the network so that the results obtained for different networks may be compared.

$$NC = C + I \tag{6.8}$$

$$\min(NC) = \min(C + I\,) \rightarrow \frac{d(C+I\,)}{dA} = 0 \;\rightarrow\; -\frac{dC}{dA} = \frac{dI}{dA} \tag{6.9}$$

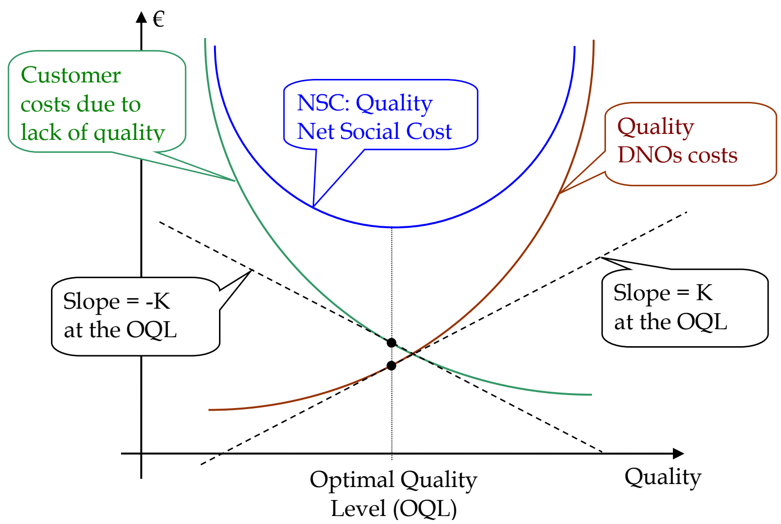


Figure 6.19: Minimization of net social cost in terms of quality of supply. Source: (Rivier & Gomez, 2000).

The diagrams in Figure 6.20 illustrate the CBA process to determine the optimal automation degree from the social perspective (diagram at the left-hand side of Figure 6.20) and the automation degree encouraged by regulation from the perspective of distribution companies (diagram at the right-hand side of Figure 6.20).

First, the cost of NSE for different automation degrees is estimated using the SAIDI values obtained from the technical SRA. The resulting values of NSE cost are then fitted to an analytical cost function (E(A)) using mathematical regression techniques. The marginal cost is obtained as the derivative of the cost function with respect to the automation degree. Similarly to the cost of ENS, the cost of automation (I) is computed for the same values of automation degree. The cost function (I(A)) that best fits the data is obtained by regression and then the marginal cost is calculated as the derivative of the cost function. Finally, the optimal automation degree (A*) may be determined as the point where the curves of negative marginal interruption of supply cost function and marginal cost of automation function intersect.

The CBA from the point of view of the DSO follows a very similar methodology. The first step is to compute the regulatory incentives that correspond to the different values of automation degree studied (R). In order to do so, the values of continuity indices obtained in the technical analysis are used to compute the reliability improvement for each automation degree with respect to the situation of no automation. This reliability improvement is translated into the economic incentives that would be granted to a distribution company using the formulae established by the regulation. Then, the data is fitted into an analytical function (R(A)) using mathematical regression techniques. Next, the marginal incentive is obtained as the derivative of R(A) with respect to the automation degree. The point where the curves of marginal cost of automation and marginal incentive intersect can be regarded as the automation degree encouraged by regulation (A′).

It must be borne in mind that the reduction of the NSE is an actual benefit that consumers will perceive and appreciate. However, these benefits may be regarded by DSOs as an intangible benefit that can contribute to the company image, while regulatory incentives, by contrast, are actual payments to DSOs that can motivate investment. Ideally, regulatory incentives should drive DSOs to invest to achieve the optimal degree determined by the social cost of supply interruptions[131].

[131] Actually, these curves are very difficult to estimate accurately. Furthermore, regulatory incentives must be designed in coherence with the regulation in place for the recognition of new investments. Moreover, regulatory incentives are computed annually, while the deployment of network automation involves investments of a lifecycle of several years.

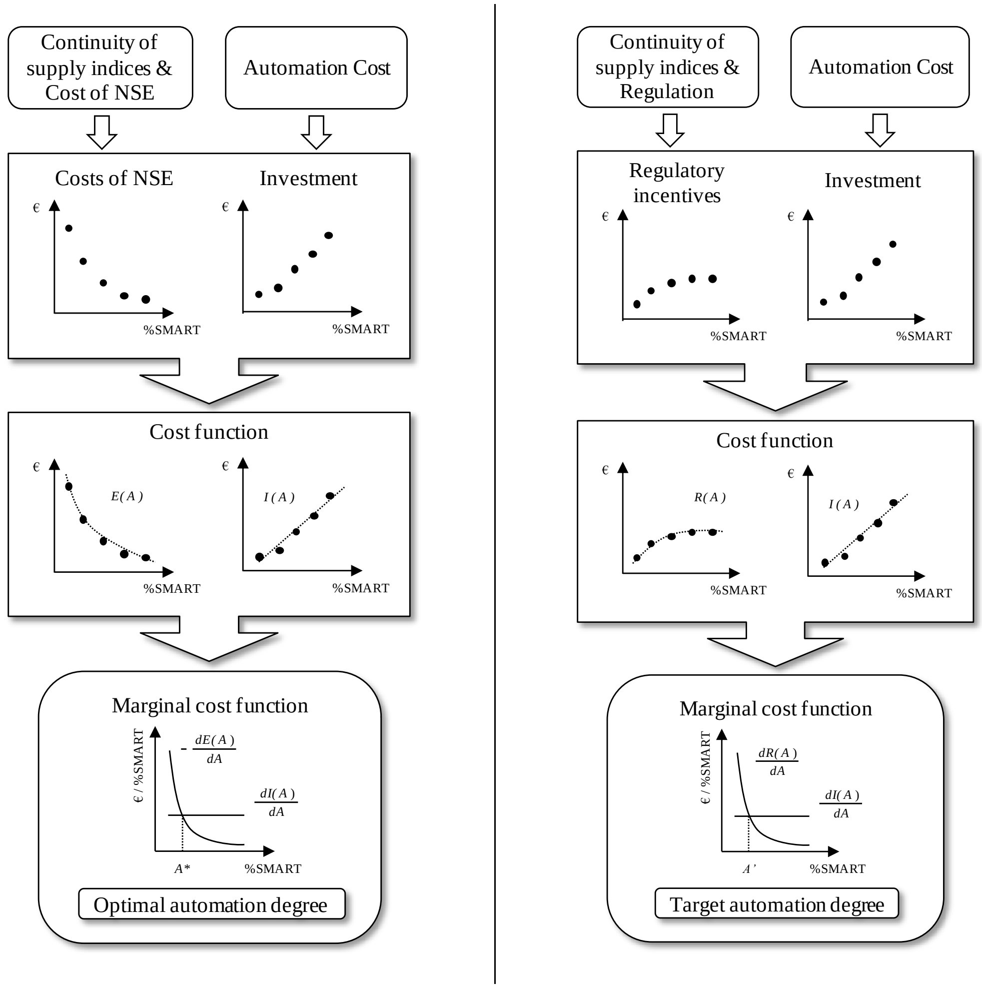


Figure 6.20: Methodology for the cost-benefit analysis to determine: (i) the optimal automation degree considering the cost of NSE for network users (left); and (ii) the automation degree encouraged by regulatory incentives for continuity of supply (right).

6.5.2 Cost of MV network automation

Network automation involves communication, software and equipment requirements. Thus, the deployment of remote monitoring and telecontrol in secondary substations may comprise the installation of new elements and the upgrade or replacement of existing equipment. Therefore, the cost of automation corresponds to the investment cost of telecontrolled protection switchgear, control software and communications, as well as the cost of installation, commissioning and upgrade of equipment, and the cost of operation and maintenance of these elements throughout its useful life.

These costs are not straightforward to compute, and may vary depending on the implementation degree considered, on the available MV network infrastructure prior to the deployment of automation, on the specific solutions and technologies employed, etc. Communications will be based on different technologies depending on the characteristics, functionalities and scale considered for the implementation, so a significant lumpiness effect must be considered for the associated costs for different automation degrees. Additionally, there are economies of scale that must be taken into account. Furthermore, some of the required equipment, communications infrastructure and control systems may be implemented to enable additional functionalities (e.g. network monitoring for predictive maintenance and voltage control, network reconfiguration for voltage control and reduction of losses, etc.), so that the cost would be shared and would have to be allocated to different use cases (or alternatively, costs would have to be compared to a higher sum of aggregated benefits).

In this illustrative cost-benefit analysis the investment cost of MV network automation is considered[132], assuming a linear cost function, with an average unit cost of 12,500 € per secondary substation with monitoring and telecontrol capabilities (Rodriguez-Calvo et al., 2014). The useful life of network automation equipment considered for the evaluation of the investment will be assumed to be 15 years, in line with previous literature (Su & Teng, 2007) and with the Spanish regulation, which establishes a useful life of 12 years for smart grid related investments and 15 years for electronic monitoring and switching elements (Spanish Ministry of Industry Energy and Tourism, 2015).

6.5.3 Cost of supply interruptions for the system

Supply interruptions result in an economic loss for network users due to the unavailability of the network leading to non-supplied energy (NSE) for consumers and energy not fed into the grid for DG owners. As automation is implemented, reliability improves and the total cost of interruptions is reduced. It is not easy to quantify these cost savings, since demand that has not been supplied (or production that has not been injected) cannot be measured, but only estimated. Furthermore, the actual cost of NSE for consumers is uncertain.

The cost of supply interruptions for consumers varies depending on the use of electricity of the different consumers at different times and the duration of supply interruptions. The assessment of the cost of non-served energy (CNSE) has been a widely-researched topic and values proposed range widely. The authors of (Linares & Rey, 2013) review values proposed in the literature ranging from 0.15 to over 50€/kWh, and estimate the cost of NSE between 4 and 6 €/kWh for Spain (with an average cost of NSE of 8.11€/kWh for households), with significant variations among sectors, geographical regions, or times of the day. The survey carried out in Italy by the regulator based on WTP and WTA resulted in estimations of 10.8€/kWh and 21.6€/kWh for residential and non-residential consumers.

Additionally, the cost of interruptions for DG is related to the price perceived by DG, either selling their production in the wholesale market or through regulatory mechanisms, such as feed-in tariffs. Furthermore, the cost of interruptions may include start-up costs, depending on the DG technology.

---

[132] Other costs during the useful life of automation, such as operation and maintenance costs, are disregarded in this CBA, since the increment with respect to the situation of no automation, for any implementation degree, is expected to be several orders of magnitude lower than investment costs.

In this illustrative cost-benefit analysis a simplified cost of interruptions will be considered. The average time of interruption suffered is given by the reliability index SAIDI. The amount of power that would have been consumed is estimated through a characteristic load factor (LF) and the nominal capacity of secondary substations (Pinst) to represent the typical demand, i.e. average consumption for each secondary substation, based on historical data[133]. Thus, the volume of NSE is computed as stated in (6.10) and the cost of interruptions is obtained as stated in (6.11) considering the cost of non-served energy.

In the case of Spain, a NSE cost of C_{NSE}=5 €/kWh (Linares & Rey, 2013) and an average load factor of LF=0.6 (Comisión Nacional de Energía, 2010) have been assumed. The values used for the CBA for Italy are C_{NSE}=10 €/kWh (Bertazzi et al., 2005) and LF=0.8.

$$NSE = SAIDI \cdot Pinst \cdot LF \quad (6.10)$$

$$C_t = C_{NSE} \cdot NSE \quad (6.11)$$

$$C = \sum_{t=0}^{N} \frac{C_t}{(1+r)^t} \quad (6.12)$$

The reliability improvement results in reduced costs of supply interruptions that last for as long as automation is in use. Therefore, the total cost of interruption C must be assessed over a period of time (N) regarded as the useful life of equipment. For this purpose, the net present value (NPV) is computed to take into account the time value of money through a discount rate[134] (r), according to (6.12), where Ct represents the annual cost of interruptions for year t. The net present value of the cost of interruptions has been computed for a period (N) of 15 years (Su & Teng, 2007) considering a discount rate of r=7% (CIGRE, 2014b; Cossent, 2013; Rodriguez-Calvo et al., 2014).

6.5.4 Regulatory incentives for DSOs

Under incentive based regulation, in order to prevent DSOs from reducing costs at the expense of deteriorating quality of service, continuity of supply is regulated by means of different bonus/penalty mechanisms linked to performance of DSOs regarding certain targets for reliability indices (Council of European Energy Regulators (CEER), 2011a). These mechanisms are designed so that distribution

---

[133] Actually, Portuguese regulation uses a similar approach to estimate NSE as a product of TIEPI and the average hourly energy distributed.

[134] The discount rate represents the time value of money in time, which means that future money is worth less than present money due to the interest-earning potential of money, the risk or uncertainty of future cash flows and inflation. Typically, the discount rate considered for investment projects is the weighted average cost of capital (WACC) of the company undertaking the project. The capital asset pricing model (CAPM) is often used when the risk differs from that of the company. Furthermore, regulation assesses distribution investment through a rate of return (Council of European Energy Regulators (CEER), 2017). Different values of discount rate have been used for automation projects, ranging from a 2.5% for the societal CBA of JRC (Vitiello et al., 2015) to 8% for the CBA of automation in (A. S. A. S. S. Bouhouras, Labridis, & Bakirtzis, 2010), including for instance 5% for automation in Finland (Siirto et al., 2015), 6.9% for active networks (CIGRE, 2014b), or 7% for smart grid investments (Cossent, 2013).

companies internalize the costs of interruptions in their investment strategies. Such incentives should drive DSO investment towards the optimal level of quality. Distribution companies are incentivized to invest to improve continuity of supply until the point where the improvement of continuity of supply is such that the marginal cost of smart MV/LV substations equals the marginal incentive received (Fernandes et al., 2012; Rivier & Gomez, 2000).

It must be borne in mind that reliability incentives are one of the terms comprising the allowed revenues for DSOs, so that automation costs may be recovered and remunerated in different forms, as recognized investments with a rate of return on investment.

Section 6.3.1.2 has described the regulatory mechanisms for continuity of supply in place in Spain and Italy at the moment of writing this PhD thesis.

Reliability incentives in Spain are set according to the RD1048/2013 (Spanish Ministry of Industry Energy and Tourism, 2013), based on the improvement of a three-year moving average of reliability index TIEPI (similar to ASIDI), weighted by a factor to consider the improvement of a three-year moving average of reliability index NIEPI (similar to ASIFI) and a factor to incorporate the relative position of the DSO with respect to the national average in the past (considering a six-year period). The reliability incentives that would be granted to a DSO for the improvement in continuity of supply achieved implementing automation would be received for three consecutive years, with a lag of 2 years with respect to the year of the deployment of automation.

In order to compute the incentives, reliability has been assumed to stay constant, with the reliability indices obtained for simulation with a 0% automation degree for years prior to automation and considering that once automation is implemented, the reliability indices are those obtained through simulation for the corresponding degree of automation. It must be taken into account that the actual allowed incentive for a DSO could also be affected by: (i) past performance of the reliability compared to the national average; and (ii) a cap of 2% of the total annual remuneration perceived by the company the previous year[135].

The reliability incentives for Italy have been established in 483/2014/R/eel (Autorità per l'energia elettrica il gas e il sistema idrico, 2015b), based on specific targets for the number of interruptions (short and long interruptions, using a reliability index that includes MAIFI and SAIFI) and duration of interruptions (based on SAIDI) for the three types of distribution areas (high, medium and low concentration of population) and type of network users (residential and non-residential). Reliability performance is averaged with the previous year, and the objectives set must be accomplished throughout the 8-year regulatory period, so that each year the incentive is based on a sub-objective (an eighth of the difference from starting actual reliability level and objective). The value of the

[135] In this thesis, the regulatory incentives that would correspond to a Spanish DSO are computed assuming that the cap is not reached. In order to determine whether this cap is reached, it would be necessary to consider the total allowed revenues of a specific DSO.

incentives and penalties is based on unitary cost values established in different intervals. Current prices allow a deadband of ±10% around the regulatory target. Furthermore, there is a deadband of ±5% around the annual sub-objective particular for each DSO for the number of interruptions. Additionally, both the total bonus (or penalty) for the number of interruptions and the bonus (or penalty) for the duration of interruptions are each capped through a maximum cost per LV network user.

In the case of Italy, a constant reliability level has also been assumed to compute the incentives owing to the implementation of automation, considering the reliability indices obtained for simulation with a 0% automation degree for years prior to automation and considering that once automation is implemented, the reliability indices are those obtained through simulation for the corresponding degree of automation.

6.5.5 Discussion of CBA results

The graphs in Figure 6.21 and Figure 6.22 present the automation costs, the interruption costs for network users due to NSE and the net cost that must be minimized for the urban and sub-urban representative networks developed for the SRA of Spain, while Figure 6.23 and Figure 6.24 correspond to the urban and industrial representative networks for Italy respectively. As previously explained, the cost of smart MV/LV substation are represented by a linear function.

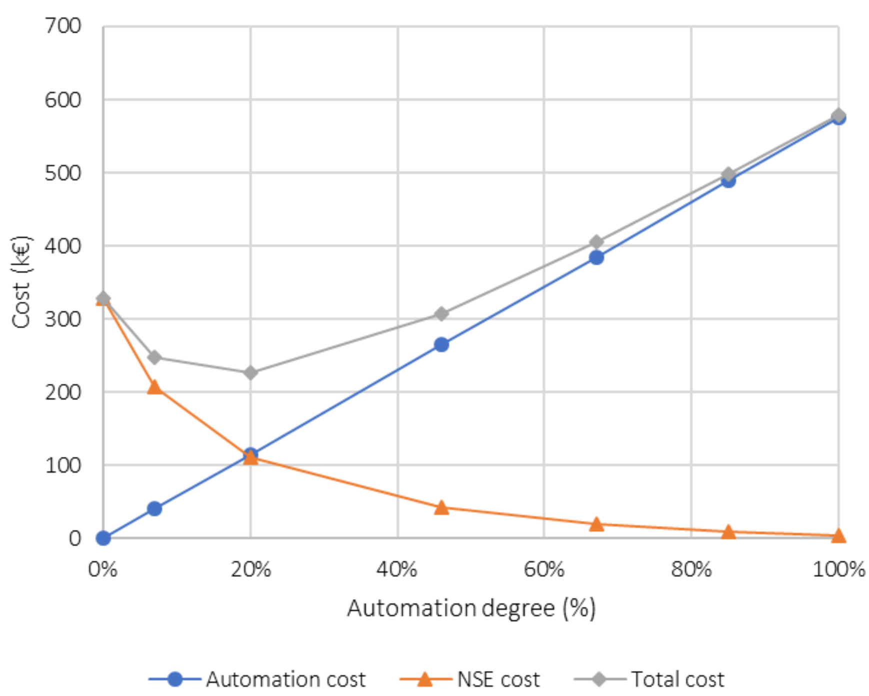


Figure 6.21: Automation cost, interruption cost for network users due to NSE, and total cost for the urban representative network for Spain

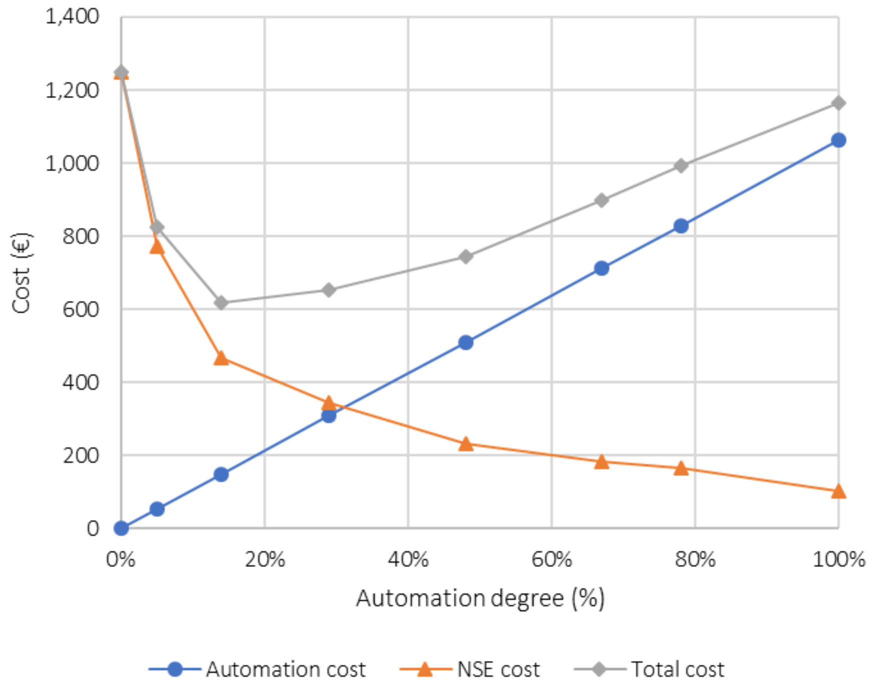


Figure 6.22: Automation cost, interruption cost for network users due to NSE, and total cost for the sub-urban representative network for Spain

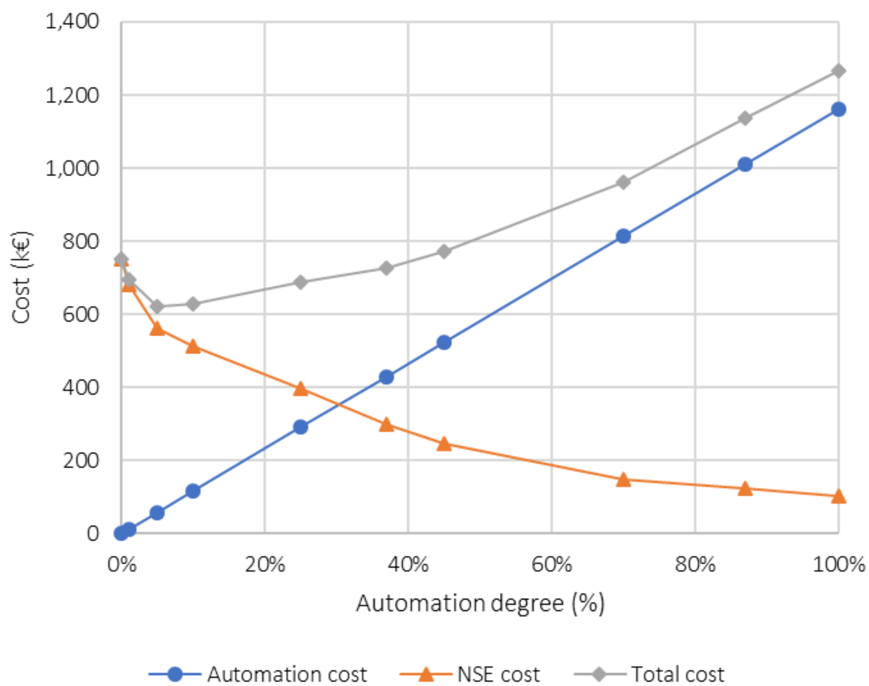


Figure 6.23: Automation cost, interruption cost for network users due to NSE, and total cost for the urban representative network for Italy

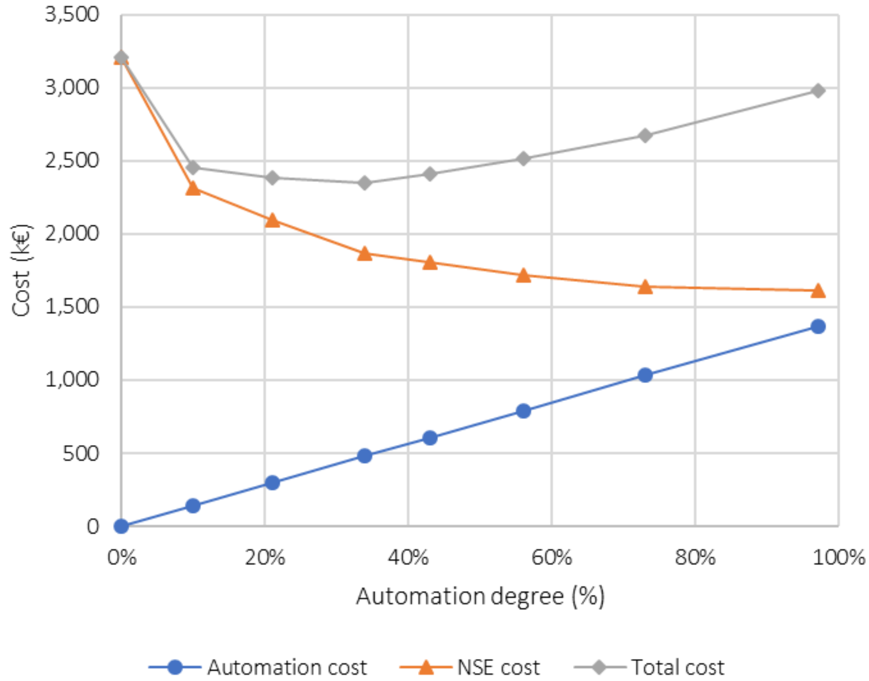


Figure 6.24: Automation cost, interruption cost for network users due to NSE, and total cost for the industrial representative network for Italy

The results obtained considering the regulatory incentives to improve continuity of supply are presented in Figure 6.25, Figure 6.26, Figure 6.27 and Figure 6.28, for the Spanish urban, Spanish sub-urban, Italian urban and Italian industrial representative networks respectively. These graphs show the automation costs, allowed incentives for DSOs due to improvement of continuity of supply, and net benefit for DSOs (i.e. allowed incentive minus the automation cost) for increasing degrees of automation.

Spanish regulatory incentives are based on the improvement of continuity of supply for each DSO, comparing the performance of a DSO in a region to past performance of the same DSO in the same region. This means that any improvement results in an economic reward, and that implementing no automation would result in no reward and no penalty (zero improvement results in zero incentive).

This is not the case in Italy, where incentives are set according to target reliability indices set by the regulator, considering deadbands around the target and different costs for different performance bands.

In the urban network, the reliability level prior to automation is above the target (both the total number of short and long interruptions and the duration of long interruptions are lower than the target values), so there is a bonus for the DSO for any automation degree, even if no automation is implemented (the regulatory incentive depicted in a green curve with square markers in Figure 6.27 does not intersect the y-axis at zero for a 0% automation degree, but at 24k€). Since short interruptions are taken into account, automation does not result in an improvement of the total number of interruptions, so the corresponding regulatory incentive does not increase with automation degree. As the duration of interruptions is reduced, the corresponding regulatory incentive increases. The total regulatory incentive along the 8-year regulatory period is an increasing reward, as can be seen in Figure 6.27.

In the case of the industrial network, the number of interruptions is kept below the target, but the duration of supply interruptions is longer than the target set by the regulator, so a penalty applies. As automation is implemented, the duration of interruptions is reduced until at around a 35% automation degree, the regulatory target is reached. As the performance of the DSO is averaged with the previous year, during the first year there is a negative incentive (i.e. penalty) for any automation degree. Meanwhile, in successive years, the result is a penalty that decreases as more automation is implemented for automation degrees below 35%, and a bonus for higher automation degrees, with a band from 35-60% where the bonus is linked only to the number of interruptions with a zero incentive due to a duration of interruptions within the regulatory deadband. Considering the incentives received throughout the 8-year regulatory period, the DSO is subject to a penalty that is reduced as automation increases.

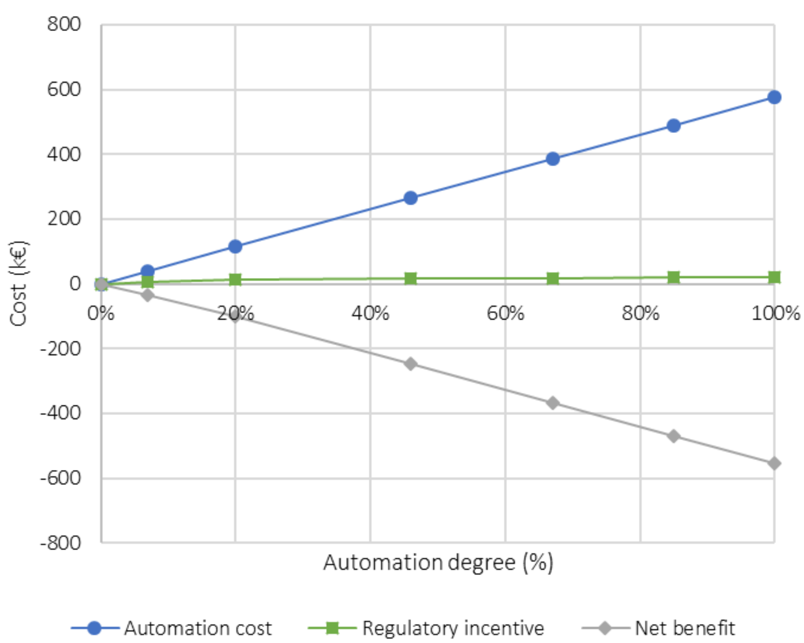


Figure 6.25: Automation cost, allowed incentives for DSOs due to improvement of continuity of supply, and net benefit for DSOs for the urban representative network for Spain

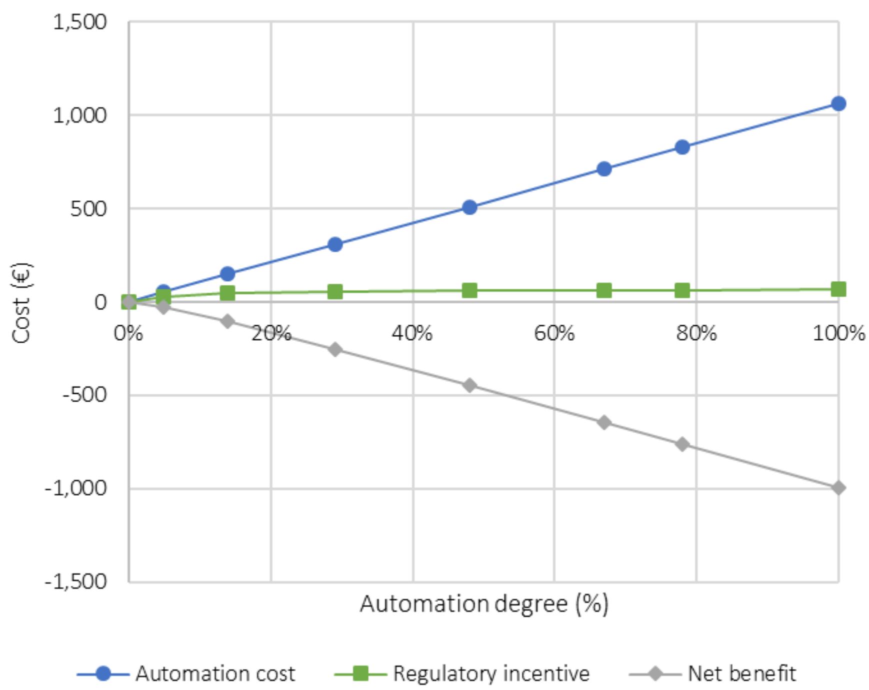


Figure 6.26: Automation cost, allowed incentives for DSOs due to improvement of continuity of supply, and net benefit for DSOs for the suburban representative network for Spain

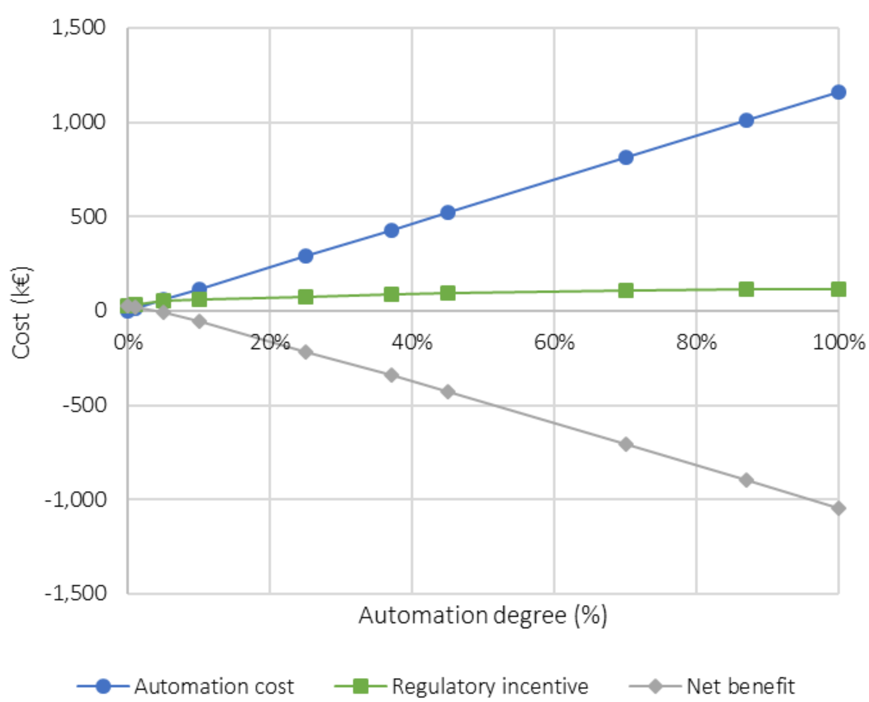


Figure 6.27: Automation cost, allowed incentives for DSOs due to improvement of continuity of supply, and net benefit for DSOs for the urban representative network for Italy

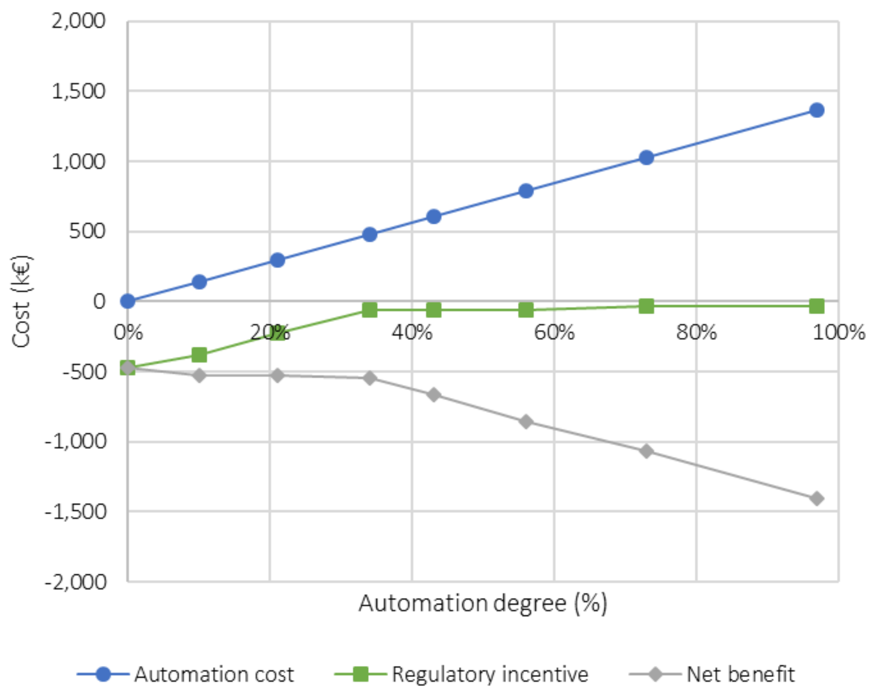


Figure 6.28: Automation cost, allowed incentives for DSOs due to improvement of continuity of supply, and net benefit for DSOs for the industrial representative network for Italy

Interruption costs have been fitted to exponential curves in the case of NSE costs and linear curves in the case of regulatory incentives for each test case so that these functions can be derived to obtain the marginal costs. While the exponential curves have been found to be a good approximation of NSE costs, the regulatory incentives are not continuous and the linear fitting curve is a quite rough approximation. Alternatively, more simulations could provide information for a higher number of automation degrees, and the marginal costs could be obtained as the slope of the linear distance among two consecutive results.

The marginal automation costs, marginal NSE savings (i.e. minus marginal NSE costs) and marginal regulatory incentives have been represented in Figure 6.29 and Figure 6.30 for the Spanish urban and sub-urban representative networks respectively and in Figure 6.31 and Figure 6.32 for the Italian urban and industrial representative networks respectively.

The intersection of the marginal cost savings with the marginal automation cost indicates the optimal automation degree from the social perspective. The same way, the intersection of marginal regulatory incentives with the marginal automation cost would indicate the optimal investment in terms of automation degree from the point of view of the DSO. These marginal cost curves allow easily performing sensitivity analysis on automation costs by simply shifting the corresponding curve.

The results obtained indicate that the optimal degree of automation is 19% for the Spanish urban representative network, 24% for the Spanish sub-urban representative network, 5% for the Italian urban representative network and 14% for the Italian industrial representative network. By contrast, the regulatory incentives for improvement of continuity of supply would not suffice to encourage investment in any case and no optimal investment can be defined.

It must be noted that the figures presented in this illustrative, simplified cost-benefit analysis are subject to several assumptions and depend strongly on the values considered for the main parameters involved. First and most importantly, the cost of automation and the cost of NSE for network users are key parameters. The cost of NSE for network users is, as discussed in section 6.5.3, very hard to determine, and values may vary widely depending on the type of consumer, the time of the day and the duration of the interruption, etc. The cost of automation is not straightforward to determine, as several elements may be involved and shared for different functionalities, as discussed in section 6.5.2. Naturally, higher interruption costs and lower automation costs would lead to a higher ideal level of automation, and vice versa.

The economic parameters of discount rate and considered timeframe also have an important effect on the resulting optimal degree of automation. Higher values for the discount rate would imply that the benefits achieved from higher reliability in the future are less valued than revenues closer in time, and would result in lower net present value of the NSE cost savings or regulatory incentives, resulting in a lower optimal automation degree. From the perspective of an investor, in this case the DSO, proposed discount rates may be higher to account for aversion to uncertainty, while lower discount rates could be used from the social perspective (Vitiello et al., 2015).

Reliability incentives set by regulation aim to encourage adequate levels of continuity of supply, so that the DSO internalizes the cost of interruptions in their investment decisions to some extent, and the full cost of automation may be recovered through the allowed revenues for CAPEX and OPEX. Therefore, reliability incentives may not cover automation costs and still act as a driver for the deployment of MV network automation. Furthermore, it must be noted that current regulation in Spain and Italy is the result of different processes of evolution of regulation and continuity of supply. Italian regulation was very active to promote improvement of continuity of supply in the past, and devoted specific incentive mechanisms for network automation in previous years through an increased WACC and period for recovery of investment. In the case of Spain, reliability was improved to a high extent in the years 2003-2011[136] (Council of European Energy Regulators (CEER), 2016) and the current context of economic crisis has led to reductions in the allowed revenues and incentives.

[136] SAIDI values were decreased in average at a rate of 10 minutes per year during the period 2003-2011. Then, SAIDI values have remained in a similar level across 2011-2014.

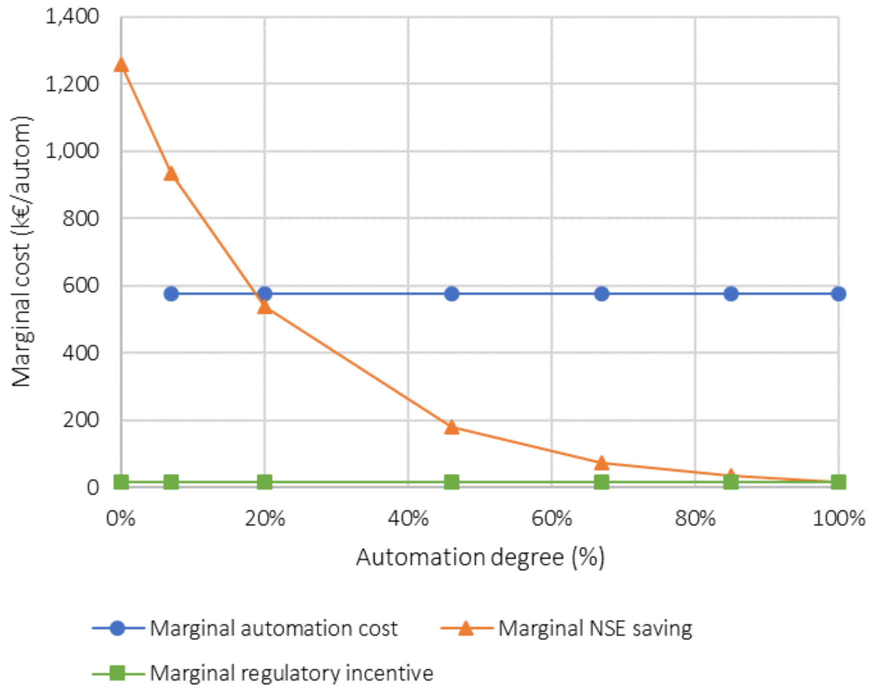


Figure 6.29: Marginal automation cost, marginal cost saving due to NSE reduction and marginal regulatory incentives for DSOs for the urban representative network for Spain

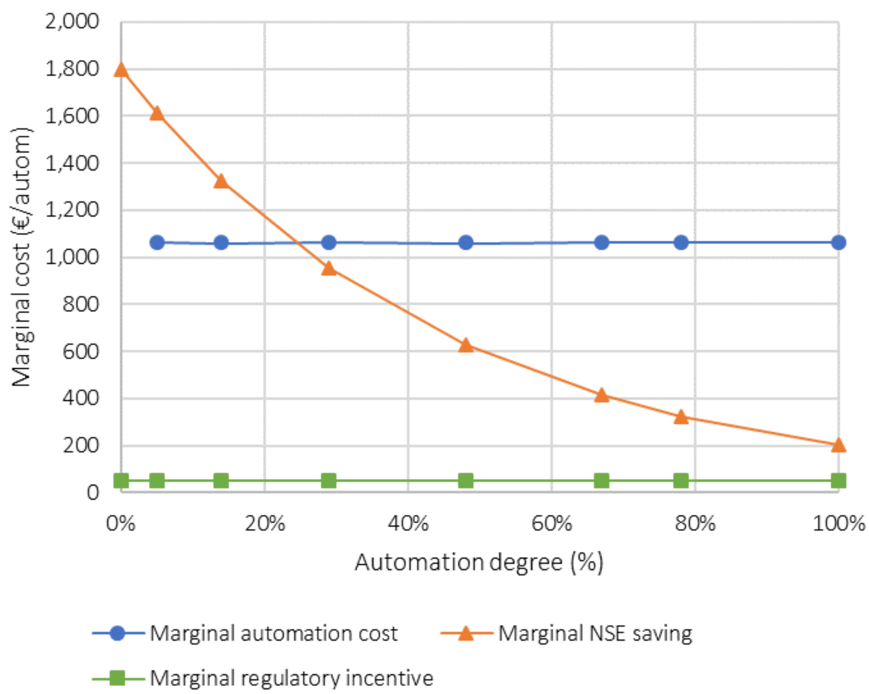


Figure 6.30: Marginal automation cost, marginal cost saving due to NSE reduction and marginal regulatory incentives for DSOs for the suburban representative network for Spain

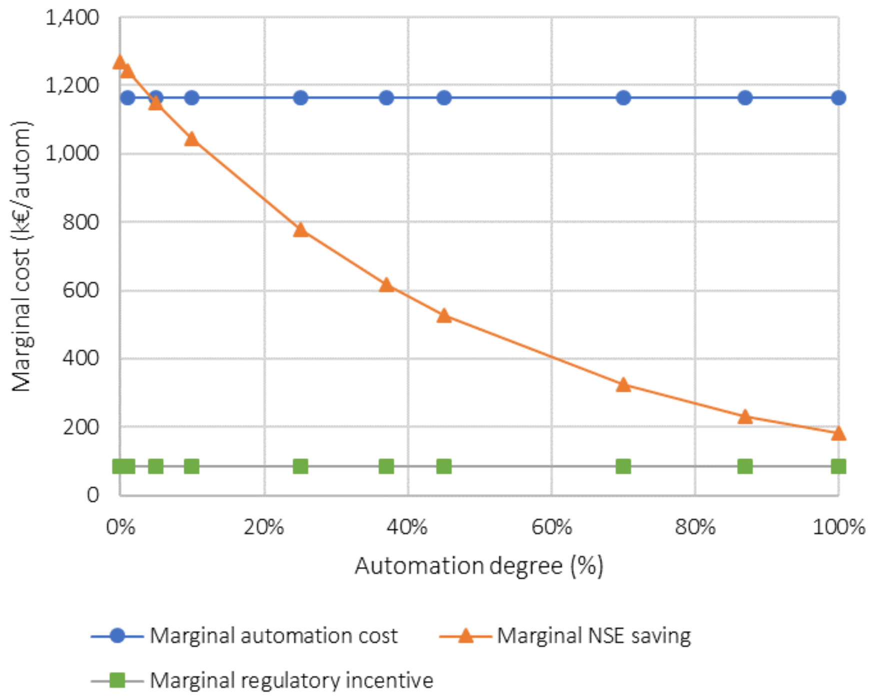


Figure 6.31: Marginal automation cost, marginal cost saving due to NSE reduction and marginal regulatory incentives for DSOs for the urban representative network for Italy

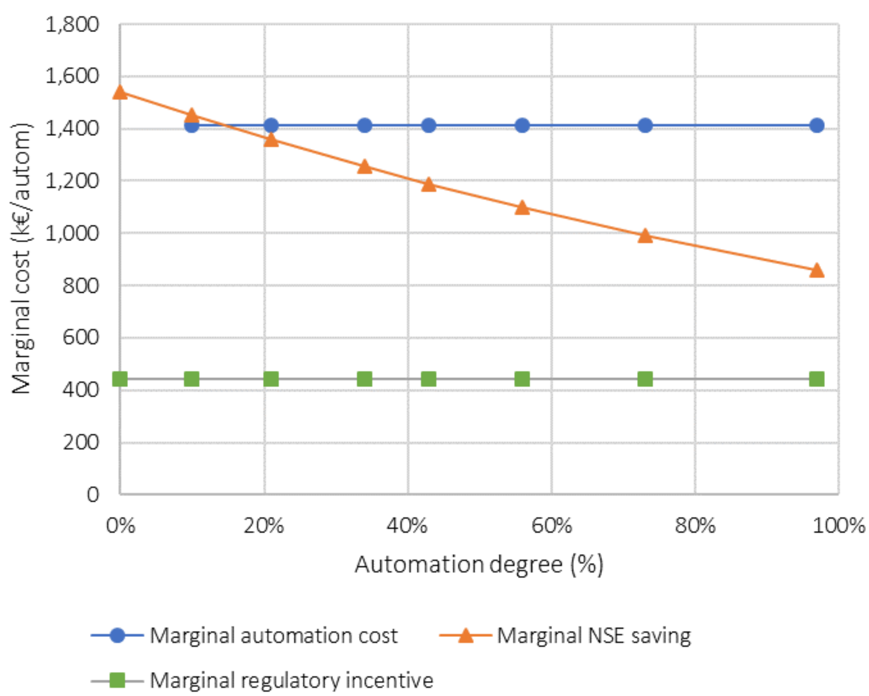


Figure 6.32: Marginal automation cost, marginal cost saving due to NSE reduction and marginal regulatory incentives for DSOs for the industrial representative network for Italy

6.6 Conclusions

This chapter illustrates the application of the proposed SRA methodology through a case study. The case study addressed the SRA of MV network automation to improve continuity of supply in Spain and Italy. Additionally, the use of SRA results for CBA is exemplified.

The SRA has been carried out following the steps defined for the proposed SRA methodology (Chapter 3), and in accordance with the particularization of the methodology proposed for network automation (Chapter 4, section 4.2). A software tool has been specifically designed to assess reliability, able to account for MV automation through a detailed simulation of the fault management processes. The representative networks developed by the ATLANTIDE project have been used for Italy, while a set of representative networks has been developed ad-hoc for the case of Spain according to publicly available data and expert knowledge from the GRID4EU project. The technical, regulatory and stakeholder-related boundary conditions have been characterized and assessed for Spain and Italy.

A more comprehensive SRA would lead to more categorical and verified conclusions. However, the results of this case study are able to provide interesting conclusions in the form of SRA rules. The technical SRA has shown that the effect of automation on continuity of supply is much greater for meshed networks, so urban areas should be prioritized. Furthermore, scaling-up in density to increase the implementation degree of automation does not behave linearly, but rather a deeper impact is achieved for lower automation degrees. Regulation plays a key role in the decision-making process as to whether to invest in implementing MV automation, through the determination of allowed revenues (how these investments are considered and remunerated) and reliability requirements and incentives (how reliability is monitored and translated into bonuses or penalties). Regarding stakeholders, network users should be the focus to determine the optimal reliability levels.

Then, a CBA has been carried out using the results obtained for the SRA case study. The CBA has been performed from two different perspectives: (a) from the point of view of social welfare, comparing the cost of deploying the smart grid solution to the value of reducing supply interruptions for network users; and (b) from the point of view of DSOs, assessing how investment would be recovered from the allowed revenues and regulatory incentives for the improvement of CoS currently in place in Spain and Italy. Thus, the CBA aims to determine the optimal degree of automation as the point where the marginal cost for network users due to supply interruptions (marginal regulatory incentives due to improvement of CoS) equals in absolute value the marginal cost of automation due to investment requirements.

The results of the CBA are intended as illustrative figures, subject to several assumptions and strongly dependent on the values considered for the cost of NSE and automation as well as economic parameters (discount rate, etc.). These results indicate an optimal degree of automation is 19% for the Spanish urban representative network, 24% for the Spanish sub-urban representative network, 5% for the Italian urban representative network and 14% for the Italian industrial representative network. By contrast, the regulatory incentives for improvement of continuity of supply would not suffice to encourage investment in any case.

The SRA and CBA results presented in this case study suffer from important limitations with respect to the representativity of the data considered. In order to obtain more accurate and realistic results from SRA, further work should be devoted to obtaining a set of representative networks really able to account for the variability of distribution networks. Representative networks should be defined using data from the actual distribution networks in these two countries and determining their real representative weights. A more thorough analysis would also be necessary to obtain more robust results, including sensitivity analyses to the relevant parameters and additional simulation scenarios to cover additional possibilities for implementation degree.

Chapter 7

Conclusions and future work

The last chapter of this document is committed, in the first place, to summarize the main conclusions that resulted from the research carried out in this thesis work. After presenting the main conclusions, the original contributions made during the development of the thesis are discussed. Finally, some lines of research that are worth being further explored in the future are identified.

7.1 Summary and conclusions

The smart grid responds to the need for a passive distribution network and aging infrastructure to adapt to a new situation driven by policy targets for carbon reduction and technological advances that have resulted in the increasing presence of distributed energy resources (distributed generation, electric vehicles, active demand, and distributed storage). The smart grid paradigm involves the upgrade of the infrastructure, addition of a digital layer, a change of paradigm in the business, and a more active participation of the users.

Strong investment has been devoted to assessing the potential outcomes of their deployment based on the use of analytic models and simulation, and the actual implementation of smart grid solutions in demonstration and pilot projects. Testing smart grid solutions in pilot projects and demonstrators provides real-life experience, but the results are limited, since it is subject to the specific conditions of the demonstrator. Furthermore, testing is very costly and is therefore of limited scale. The use of analytic models and simulation allows for assessment of smart grid solutions under different conditions. However, the models may be limited by required assumptions and simplifications leading to inaccurate results. Therefore, studying the scaling-up and replication of the impacts of smart grid solution is of the utmost importance to explore the complementarity of both approaches and maximize the learning potential from demonstration. SRA can therefore help reduce the required investments on demonstration projects, guiding the design of future research and bridging the existing gap between demonstration projects and widespread adoption of the smart grid.

Based on a review of the conceptual framework for SRA and proposed approaches, this PhD thesis proposes a functionality-oriented SRA which aims to help infer what results may be expected when implementing the smart grid use case elsewhere (replication) or at a large scale (upscaling). This PhD thesis proposes a SRA methodology comprising a quantitative and detailed technical analysis based on simulation to compute the KPIs that measure the impact of the use case on the system; and a second stage of a more qualitative non-technical analysis, to include regulatory aspects and the perspective of the different stakeholders involved.

The stage of technical SRA is implemented in several steps: (1) identification of relevant KPIs, (2) selection of simulation tool, (3) definition of representative networks, (4) definition of scenarios, (5) simulation for KPI computation, (4) review of demo results, and (5) upscaling of simulation results. The SRA methodology incorporates the experience gathered from real-life testing of the smart grid use case in demos, comparing the KPIs measured in the demo and those obtained through simulation. The use of representative networks enables upscaling of simulation results through a representativity rate or scaling-up factor for the whole region considered.

The stage of non-technical analysis addresses the regulatory framework and the perspective of stakeholders involved to identify barriers and drivers for the implementation of smart grid solutions.

The analysis is conducted following the steps of (1) identification of relevant topics, (2) characterization of the boundary conditions, and (3) assessment of the effect of the boundary conditions on the replication and upscaling of the use case for both regulation and stakeholders.

The proposed SRA methodology is applicable to study the expected impacts from the implementation of any smart grid solution. However, depending on the functionalities implemented in the smart grid use case and the objectives pursued, the type of impacts differ. The relevant boundary conditions for SRA differ, and the specific simulation tools and KPIs must be adequately adapted. As a result from the review of demonstration projects and modelling approaches to assess the impact of different smart grid solutions, this thesis proposes to group smart grid use cases into three main categories for SRA, based on the type of impacts caused and objective pursued: (i) network automation to improve continuity of supply, (ii) DER management and voltage control to increase network hosting capacity, and (iii) islanded operation and micro grids to improve continuity of supply. The detailed implementation of the proposed SRA methodology has been particularized for these three groups of smart grid use cases. Accordingly, this thesis has identified the characteristics required for representative networks for the SRA of each group of smart grid use cases, adequate modelling and simulation approaches, appropriate KPIs and the relevant regulatory topics and stakeholders.

Furthermore, SRA has been carried out for a case study to illustrate the steps and application of the proposed SRA methodology, and the use of SRA results for CBA. The selected case study focuses on MV network automation to improve continuity of supply in Spain and Italy to obtain several SRA rules using the representative networks developed by the ATLANTIDE project for Italy, and a set of representative networks developed ad-hoc for the case of Spain. Then, a CBA has been carried out using the results obtained for the SRA case study to compare the cost of deploying the smart grid solution to the value of reducing supply interruptions for network users (social point of view) and to the regulatory incentives for the improvement of CoS currently in place in Spain and Italy (perspective of the DSO).

The objectives of SRA are very ambitious and the proposed methodology is not exempt of barriers that can result in limitations in the obtained results. The proposed SRA is based on the use of simulation models, representative networks and generation and demand scenarios. Therefore, the validity and robustness of SRA results depends on the representativity and suitability of the representative networks and demand scenarios considered and the fitness of the simulation model(s) to quantify the selected KPIs. In order to ensure the quality of SRA, it is necessary to have enough data available to correctly characterize the distribution system. However, gathering the data may be hindered by confidentiality issues, and analyzing the data can be very cumbersome due to the large volume of infrastructure involved. Furthermore, sensitivity analyses for the technical SRA cannot cover every single variation, parameter and scenario. Therefore, expert analysis is required in order to identify the relevant boundary conditions and extract SRA rules. Moreover, the validation of simulation models with demonstration projects, comparing the values registered for the KPIs to those obtained through simulation under the same conditions, is not straightforward, as demonstrations may not be able to reflect certain impacts.

In spite of these difficulties, SRA provides very valuable insights to identify the most promising smart grid use cases for different contexts and regions. Therefore, SRA is of great interest for regulators and policy-makers, to guide funding of further R&D projects and facilitate the adoption of favorable smart grid solutions, setting adequate regulatory incentives and suppressing existing barriers. Additionally, SRA is extremely relevant for the incumbent industry, including distribution companies, service providers and manufacturers to guide their investment and shape their strategy for different smart grid solutions.

7.2 Original contributions

This thesis proposes a methodological framework to assess the scalability and replicability of the impact of smart grid use cases in distribution networks. The development of this final objective has yielded the following original contributions:

- Taxonomy of smart grid implementations for scalability and replicability
  This thesis has analyzed the main concepts involved in scalability and replicability to develop a theoretical, systematized framework for SRA in the context of the smart grid, which had not been yet formalized. A structured assessment of smart grid implementations has resulted in the identification of three groups of smart grid use cases to map smart grid solutions for SRA: (i) network automation to improve continuity of supply; (ii) DER management and voltage control to increase network hosting capacity; and (iii) islanded operation and microgrids to improve continuity of supply.
  This contribution is comprised in Chapter 2 and Chapter 3. Chapter 2 is focused on smart grid implementation, modelling and assessment. The mapping of smart grid use cases is presented in section 2.5. Chapter 3 is focused on scalability and replicability and contributes to the theoretical framework for SRA in section 3.1.

- Definition of a methodology to perform SRA of smart grid use cases
  This thesis has defined a methodology to perform SRA of smart grid use cases incorporating the technical, economic, regulatory and social aspects involved. Furthermore, the detailed implementation of the developed SRA methodology has been particularized for the three identified groups of smart grid use cases.
  This thesis proposes the appropriate simulation approach, KPIs and simulation scenarios for the technical SRA of each type of smart grid use case. Moreover, the thesis identifies the regulatory and stakeholder-related boundary conditions relevant for SRA of each type of smart grid use case.
  This contribution is presented in Chapter 3 and Chapter 4. The proposed SRA methodology is presented in Chapter 3 and has resulted in a journal paper currently under review

(Rodriguez-Calvo, Cossent, & Frias, 2017). The particularization of the SRA methodology is presented in Chapter 4 and is reflected in (Carlos Mateo et al., 2016; Rodriguez-Calvo et al., 2016, 2015; Rodriguez-Calvo, Cossent, & Frías, 2017), which focus on different types of smart grid use cases (automation, DER management in the form of LV monitoring, DER management in the form of battery storage, and islanded operation, respectively).

- Assessment of representative networks for SRA
  Representative networks are key for the proposed SRA. This thesis has assessed the different approaches to define representative networks. Moreover, this thesis has identified the characteristics required for representative networks for the SRA of each type of smart grid use case.
  This contribution is presented in Chapter 5 and is expected to become a journal paper.

- Case study
  The proposed SRA methodology has been applied to a realistic smart grid case study: MV network automation to improve continuity of supply for Spain and Italy. This use case illustrates the detailed implementation of the methodology and the type of results from SRA. A simulation tool has been specifically developed in this thesis for the assessment of automation and the reliability improvement achieved. Additionally, a CBA has been carried out using the results of SRA.
  This contribution is presented in Chapter 6 as well as in several articles. The case study is partially contained in (Rodriguez-Calvo, Cossent, & Frias, 2017) to illustrate the proposed SRA methodology. The technical analyses of automation and the simulation tool developed are presented in (Rodriguez-Calvo et al., 2016). The methodology for CBA is presented in (Rodriguez-Calvo et al., 2014).

7.3 Research publications

The work developed in this thesis has resulted in the following JCR journal papers, three of them published and two currently under review:

- (Rodriguez-Calvo et al., 2014) A. Rodriguez-Calvo, P. Frías, J. Reneses, R. Cossent, C. Mateo. “Optimal investment in smart MV/LV substations to improve continuity of supply”. International Journal of Electrical Power & Energy Systems. vol. 62, pp. 410-418, November 2014.
- (Carlos Mateo et al., 2016) C. Mateo, A. Rodriguez-Calvo, J. Reneses, P. Frías, A. Sánchez. “Cost-benefit analysis of battery storage in medium voltage distribution networks”. IET Generation Transmission & Distribution. vol. 10, no. 3, pp. 815-821, February 2016.
- (Rodriguez-Calvo, Cossent, & Frías, 2017) A. Rodriguez-Calvo, R. Cossent, P. Frías. “Integration of PV and EVs in unbalanced residential LV networks and implications for the smart grid and

advanced metering infrastructure deployment". International Journal of Electrical Power & Energy Systems. vol. 91, pp. 121-134, October 2017.

- (Rodriguez-Calvo, Cossent, & Frias, 2017) A. Rodriguez-Calvo, R. Cossent, P. Frías. "Scalability and Replicability Analysis of large-scale Smart Grid implementations: approaches and proposals in Europe". Under review for publication in Renewable & Sustainable Energy Reviews.
- (Rodriguez-Calvo et al., 2016) A. Rodriguez-Calvo, R. Cossent, P. Frías. "Assessing the potential of MV automation for distribution network reliability improvement". Under review for publication in International Transactions on Electrical Energy Systems.

Additionally, during the development of the thesis, the Author of this thesis has also authored and co-authored non-JRC and conference papers:

Non-JRC journal articles:

- (Trebolle, Frías, Maza, Tello, et al., 2012) D. Trebolle, P. Frías, J.M. Maza Ortega, J. Tello, A. Rodriguez-Calvo. "El control de tensión en redes de distribución con generación distribuida (III)". Anales de Mecánica y Electricidad. vol. LXXXIX, no. III, pp. 11-18, August 2012.
- (Rodriguez-Calvo, Frías, et al., 2012) A. Rodriguez-Calvo, P. Frías, J. Reneses, C. Mateo, L. del Río, S. Bañales. "Mejora de la calidad del suministro eléctrico mediante centros de transformación inteligentes". Anales de Mecánica y Electricidad. vol. LXXXIX, no. III, pp. 11-17, June 2012.

Peer-review conferences:

- (Rodriguez-Calvo et al., 2015) A. Rodriguez-Calvo, S. Izadkhast, R. Cossent, P. Frías, "Evaluating the determinants of the scalability and replicability of islanded operation in medium voltage networks with cogeneration", International Symposium on Smart Electric Distribution Systems and Technologies - EDST 2015. ISBN: 978-1-4799-7737-6, pp. 80-87, Vienna, Austria, 08-11 September 2015.
- (C. Mateo et al., 2015) C. Mateo, A. Rodriguez-Calvo, P. Frías, J. Reneses, A. Sánchez, S. Bañales, L. del Río, M. Zaldumbide, J. Gómez, "Analysis of the impact of battery storage on power distribution systems", 23rd International Conference on Electricity Distribution - CIRED 2015. Lyon, France, 15-18 June 2015.
- (Rodriguez-Calvo, Frias, et al., 2012) A. Rodriguez-Calvo, P. Frías, J. Reneses, C. Mateo, "Optimal degree of smart transformer substations in distribution networks for reliability improvement", 3rd IEEE PES Innovative Smart Grid Technologies (ISGT) Europe Conference. Berlin, Germany, 14-17 October 2012.

7.4 Future research

The development of this thesis has led to different lines of future research that may provide very interesting results. This section summarizes them and explains their possible relevance. The identified lines for future research have been grouped under three main categories: further methodological contributions to SRA, future research on the implementation of the proposed SRA methodology and future research focused on further applications of the proposed SRA methodology.

Methodological

- Solution-oriented SRA

  This PhD thesis has focused on a functionality-oriented SRA to understand the effect of boundary conditions on the impacts expected from the smart grid solutions and implemented functionalities. Solution-oriented SRA is complementary to the approach proposed in this thesis and should be integrated in the discussion of large-scale smart grid deployment. The scalability and replicability of the solutions themselves is challenging and constitutes a pre-requisite that must be carefully considered.

- Understanding stakeholders

  The proposed SRA methodology aims to integrate the perspective of all relevant stakeholders to understand how their behavior can affect the deployment and performance of smart grids. This PhD thesis has described the main motivations of the identified groups of stakeholders. However, further analysis would be very valuable to have a deeper understanding and reach more detailed (or even quantitative) conclusions. Social aspects can be analyzed using agent-based modelling and exploring other fields, such as behavioral economics applied to the context of smart grids. Furthermore, business models that allow the interaction of network users and other stakeholders should be analyzed in detail.

Implementation

- Representative networks

  The quality of SRA results is completely subject to the adequacy and representativity of the representative networks used for the analyses. Therefore, representative networks deserve further attention and work.

  The use of clustering techniques and reference network models is very promising and should be further explored to determine which clustering techniques are better-suited, and to explore the synergies between clustering techniques and reference network models.

  In the current context of smart meter deployment and higher degree of monitoring in distribution networks, DSOs will have new available data to characterize their networks in detail.

- Simulation scenarios
  In line with the new available data previously mentioned, big-data analysis will be key to maximize the potential to better characterize demand and DER. This in turn will result in more accurate simulation scenarios for SRA.

Application

- Application to other case studies
  The aim of this PhD thesis is to provide the framework for SRA of smart grids. However, the concept of smart grid covers a very wide range of solutions and technologies. The particularization of the methodology describes the detailed implementation adapted to the three main types of smart grid use cases identified. Then, the case study is able to develop a fully-fledged SRA for the specific use case of monitoring and telecontrol in MV networks.
  It would be very interesting to apply the particularized methodologies for case studies of the two remaining groups of use cases. This way, simulation approaches could be further explored.

- Integration of SRA and CBA
  The results of SRA quantify the impacts of smart grid implementations and can therefore serve as an input for the cost-benefit analysis. This thesis has explored the applicability of SRA results for CBA in the case study of MV automation. However, further research could build on the synergies and complementarities between these two analyses to provide an integrated methodology that allows for a comprehensive evaluation that can help decision-making for the deployment of the smart grid across different regions with different boundary conditions.

Appendix A

Integration of PV and EVs in unbalanced residential LV networks

This Appendix presents the partial application of the proposed technical SRA methodology to analyze the case study of monitoring and advanced metering infrastructure to detect load unbalance in LV networks. The effect of load unbalance is studied in relation to the network hosting capacity for PV and EVs in LV residential networks.

In order to facilitate the reading of the thesis, it has been included as an appendix instead of as introducing an additional case study chapter, as the case study of Chapter 6 is able to provide a better illustration of full SRA. This work has been presented in the article (Rodriguez-Calvo, Cossent, & Frías, 2017).

A.1 Introduction

Traditionally, distribution networks were not monitored and there was little information regarding the actual state of operation, especially in lower voltage levels. However, this has changed with the large-scale roll-out of smart meters[137]. Smart meters can register real-time energy consumption including voltage, phase angle and frequency measures. Thus, Automatic Meter Infrastructure (AMI) systems can be used to create a distributed monitoring system of the low voltage (LV) grid (Dede et al., 2015). Such monitoring enables an enhanced visibility of the distribution network and thus provides very valuable information that may be used by distribution companies to perform power quality and fault analysis and detect issues such as non-technical losses and voltage unbalance (Depuru, Wang, & Devabhaktuni, 2011).

Unbalance has been often neglected by distribution system operators (DSOs) due precisely to the lack of monitoring data in the LV grid (Liu & Milanovic, 2015). Nevertheless, voltage unbalance is a relevant problem that results in higher energy losses, higher neutral currents (which in turns contributes to voltage drop), a less efficient utilization of network assets (a highly unbalanced grid reaches its hosting capacity limit much sooner than a balanced grid so that network reinforcement costs are moved forward in time) and possible damage to electric equipment (de Hoog, Alpcan, Brazil, Thomas, & Mareels, 2015; Douglass, Trintis, & Munk-Nielsen, 2016; Harrison, 1987; Ma, Li, & Li, 2016; Pasdar & Mehne, 2011; Smolleck, 1992). Voltage unbalance is mainly caused by the difference between the single-phase loads connected to each phase. In higher voltage levels both generation and demand are typically three-phase and balanced[138]. Unbalance is especially relevant in LV networks, where most consumers are single-phase loads. Originally, at the time of connection, single-phase loads are assigned to the three phases in a balanced manner, but the loads are asymmetrical and vary differently in time. Furthermore, when new consumers are connected to the grid, the phase allocation may not be optimal. In practice, high values of current unbalances are observed. Moreover, the presence of single-phase distributed energy resources (DER), such as electric vehicles (EVs) and photovoltaic (PV) generation connected to LV networks is bound to further increase unbalance.

In the future, as higher volumes of DER are integrated in the LV grid, it will be of the utmost importance to prioritize monitoring in those areas where the hosting capacity of the network is more limited and problems are more likely to arise. Rural networks are usually more sensitive to unbalance

---

[137] Smart metering has already been implemented in several countries across Europe such as Italy, Finland and Sweden, and is currently on-going in many other (e.g.: Spain, the Netherlands, UK, Ireland)Actually, it is expected that by 2020 around 70% of European consumers will have a smart meter (European Commission, 2014a).

[138] It must be noted that distribution networks in Europe are generally based on secondary substations with three-phase MV/LV transformers (as opposed to the USA, where MV networks frequently feature single-phase or two-phase systems in lateral branches) (Short, 2005).

in loads, since in more densely populated urban areas LV networks are typically much shorter and loads tend to be more balanced.

In this Appendix the effect of unbalance on DER integration in rural LV networks is assessed. For this purpose, simulation analyses have been conducted to determine energy losses and voltage profiles in several rural and semi-rural LV networks under different degrees of unbalance in the system and varying penetration degrees of distributed generation (DG) in the form of PV panels and EV in the form of slow charging connections.

The methodology applied to carry out these analyses is defined in section A.2. Then, section A.3 describes the case study and section A.4 discusses the results obtained, together with the implications for the use of AMI and LV supervision solutions for monitoring. Finally, section A.5 concludes with the final remarks.

A.2 Methodology

This section describes the methodology applied for the study of the integration of EVs and PV in unbalanced LV networks, based on three-phase unbalanced power flow analyses.

A.2.1 Measuring unbalance in the LV network

Unbalance can be quantified following different approaches. Most commonly, regulation uses the percentage voltage unbalance factor (VUF), defined by the International Electrotechnical Commission (IEC) as the coefficient between negative and positive component of voltage. Other indices include the phase voltage unbalance rate (PVUR) defined by Institute of Electrical and Electronics Engineers (IEEE) and the line voltage unbalance rate (LVUR) defined by the National Equipment Manufacturer's Association (NEMA). An exhaustive comparison and assessment of suitability of different indices for voltage unbalance may be found in (Chen, Yang, & Yang, 2013; Tangsunantham & Pirak, 2013).

The European Standard EN 50160 states that the 95% of the 10 min average voltage unbalance must not exceed a value of 2%, or up to 3% for some specific locations, over a one-week period (European Committee for Electrotechnical Standardization (CENELEC), 1994). Other countries impose even stricter limits to unbalance, such as the UK or Malaysia, where the statutory limit for voltage unbalance is 1.3% and 1%, respectively. However, these standards are usually not enforced since voltage unbalances are hardly ever measured in practice.

For the sake of simplicity, this work follows the PVUR approach to measure voltage (and current) unbalance u_U, defined as the maximum deviation from the mean, according to (A.1), where U_m is the mean of the RMS values of voltage (current) of the three phases and U_j is the RMS value of the voltage (current) at each phase.

$$u_U = \frac{\max\limits_{j}(U_j - U_m)}{U_m} \cdot 100\% \tag{A.1}$$

Load unbalance will be directly translated into current unbalance, as voltage variations in each node due to load unbalance are assumed to be negligible. Voltage unbalance changes along the network and may be calculated once the voltage profile is determined through power flow computation.

This work aims to assess the effect of increasing unbalance caused by unbalanced load and the introduction of DER, so load unbalance is the input used to define the scenarios for loadflow analysis. Unbalance scenarios have been defined to cover a wide range of possible operational situations. The baseline is a fully balanced system, where the total load is equally distributed across the three phases at all nodes. The degree of unbalance is gradually incremented by transferring a share of the load from two of the phases to the other one, up to a completely unbalanced network, where all the load is connected to the same phase and the current circulates exclusively through one phase. Therefore, the degree of load unbalance u_Z ranges from 0% to 100%, increasing gradually by 5% and is defined according to (A.2), where Z_A, Z_B and Z_C are the loads connected to phases A, B and C respectively, and Z is the load connected to each phase in the balanced system.

$$\begin{aligned} Z_A &= Z + 2 \cdot u_Z \\ Z_B &= Z - u_Z \\ Z_C &= Z - u_Z \end{aligned} \tag{A.2}$$

It must be noted that this definition of load unbalance based on the share of load transferred differs from the approach of PVUR where maximum deviation is measured. Thus, for a certain degree of load unbalance, the corresponding value of the phase current unbalance rate would be twice the load unbalance degree (e.g.: a fully unbalanced system, with a load unbalance degree of 100% would have a load distribution of $Z_A = Z + 2 \cdot Z$ and $Z_B = Z_C = 0$ and the corresponding currents $I_A = 3 \cdot I$ and $I_B = I_C = 0$ would then have phase current unbalance rate of $u_I = \frac{\max_j (I_j - I_m)}{I_m} \cdot 100\% = \frac{(3 \cdot I - I)}{I} \cdot 100\% = 200\%$).

A.2.2 Technical analysis: unbalanced three-phase power flow

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 algorithm has been implemented in Matlab environment.

The main results of the analyses performed include the energy losses and compliance with voltage limits expressed through the share of consumers who experience under-voltages and the share of consumers who experience over-voltages.

For each network, a set of three phase load flows have been run, varying the degree of load unbalance for 21 distinct values, from 0% to 100%. The analysis is performed on an hourly basis covering a full day considering the average power consumption for each of the 24 hours. Additionally, the analysis is carried out for different penetration levels of EVs and PV generation.

A.3 Case Study

Table A.1 summarizes the main characteristics of the grids considered for the case study. The selected networks include five purely rural LV networks and two semi-rural ones. These hypothetical networks have been elaborated according to public data gathered in (Prettico et al., 2016) so that the resulting grids are realistic for distribution in European countries.

Network	Type	Length (km)	Underground (%)	Pinst (kVA)[139]	#cons	ΣPmax (kW)[140]	#LV feeders
n1	Rural	1.89	0%	630	39	281.4	3
n2	Rural	4.57	0%	250	24	121.1	4
n3	Rural	1.48	0%	75	21	128.0	3
n4	Rural	0.58	100%	100	27	128.3	3
n5	Rural	0.87	41%	100	14	123.8	3
n6	Semi-Rural	1.75	100%	630	233	487.7	5
n7	Semi-Rural	2.16	100%	800	214	685.9	7

Table A.1: Technical parameters of the representative LV networks.

Distinct degrees of load unbalance have been considered (in total, 21 different values) in order to cover a wide range of possible operational situations. The baseline is a fully balanced system, where the total load is equally distributed across the three phases at all nodes. The degree of unbalance is gradually incremented by transferring a share of the load to one phase at all nodes, up to a completely unbalanced network, where the current circulates exclusively through one phase. The same degree of load unbalance is maintained along the network so that conclusions can be derived for the results of the loadflow analysis. For this purpose, the load at each node (i.e., each consumer) is assigned to the three phases according to the input of load unbalance considered for each analysis scenario. A more realistic approach connecting each consumer to one phase in a random distribution would lead to a non-homogeneous unbalance degree and any given total unbalance degree would correspond to a wide range of possible combinations of phase-distribution of loads.

The hourly demand profile considered represents an average working day based on the data published by the Spanish TSO, Red Eléctrica de España (REE) (Red Eléctrica de España, 2015). All end consumers have been assumed to be residential and follow the same consumption pattern, represented in Figure 7.1 as load coefficients. Sensitivity to the level of loading of the network has been addressed by considering 4 different scenarios of demand consumption, expressed as a percentage of the peak demand recorded for each consumer. Thus, the four values of this parameter assessed are 50-75-100-125%, which are applied as a coefficient to the demand profile, as can be

[139] Pinst: Rated capacity of the MV/LV transformer.

[140] ΣPmax: Sum of the maximum demand registered

seen in Figure 7.1. The loading level of 125% has been included in order to identify potential problematic situations under more unfavorable scenarios.

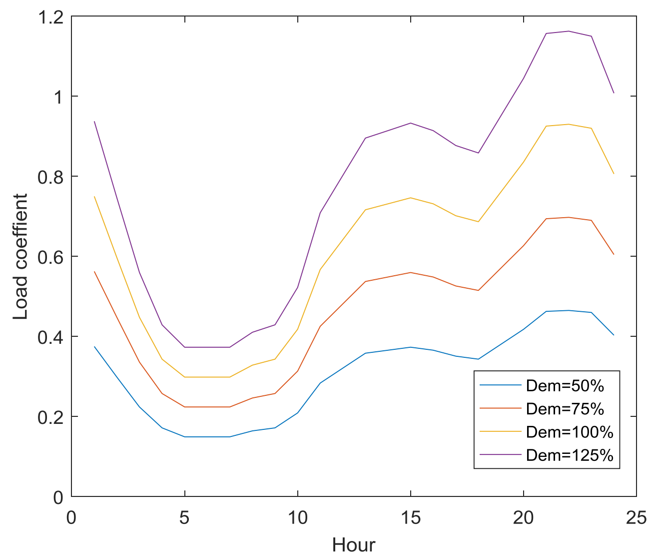


Figure 7.1: Total demand profile for scenarios of different loading levels (25%, 50%, 75% and 100% of peak demand for each consumer).

Regarding the integration of EVs, single-phase slow charging during the night has been assumed, given that the focus is on residential areas. EVs are considered as a domestic load, excluding vehicle-to-grid capabilities. The integration of EVs has been assessed through 4 scenarios of EV penetration, expressed as a total charging power of 10-20-30-40% of the total peak demand of the consumers.

Figure 7.2 shows the four total load profiles used for the case study, considering a loading level of 100% for demand plus the charging of EVs for the different values of penetration degree contemplated.

In order to isolate the effect of load unbalance degree and avoid the interference of the effect of different locations of EV charging points and lumpiness in EV penetration degree due to discrete EVs, this work has assumed a homogeneous EV demand. The EV penetration has been allocated to each and every node of the network. This way, general conclusions can be extracted from the analysis and the trends of the impact of unbalance can be observed. Actual EVs constitute very large loads in comparison to domestic appliances and other LV loads connected to a single point of the network, with a typical charging power of 3.68kW[141] for slow charging sustained throughout the whole charging period, around 8h-10h depending on the initial state of charge of the battery. Therefore,

[141] According to IEC62196 standard Type 2, EV single-phase LV connections includes a 16A-3.68kW connection for slow charging (mode 2) (International Electrotechnical Commission, 2014).

real-life integration of EVs would result in a more heterogeneous demand with a different degree of load unbalance.

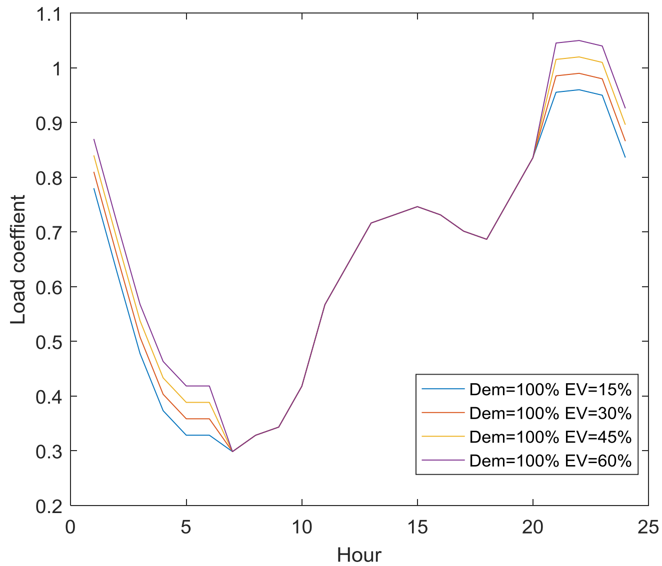


Figure 7.2: Total load profile for scenarios of different penetration of EV (15%, 30%, 45% and 60% of total peak demand) for a demand level of 100% of total peak demand.

Considering distributed generation, this work has analyzed the penetration of solar PV, which is the technology most widely connected to the LV networks. The production of PV has been determined based on typical irradiation levels for southern Europe during summer using PV-GIS (Amillo et al., 2014; Suri, Dunlop, & Jones, 2002). As in the case of EVs, four scenarios of solar PV penetration have been evaluated, including 25-50-75-100% of the total peak demand. The load profiles selected for the case study with PV integration are based on a loading level of 50%, a lower level than in the case of EV penetration to tackle a more unfavorable case (lower demand to absorb the PV production, where excess generation may increase voltage in the networks). The resulting net demand curves are depicted in Figure 7.3.

The PV has been assumed to be homogeneously located, assuming the same percentage of generation given by the PV penetration degree at each node, in order to assess the effect of a certain degree of load unbalance in the network, as in the case of EV penetration. Actual PV units in rural residential areas are typically rooftop panels of around 10kW, depending on the available rooftop area, which means a very high maximum power injection with respect to the typical demand of residential consumers and EV charging power.

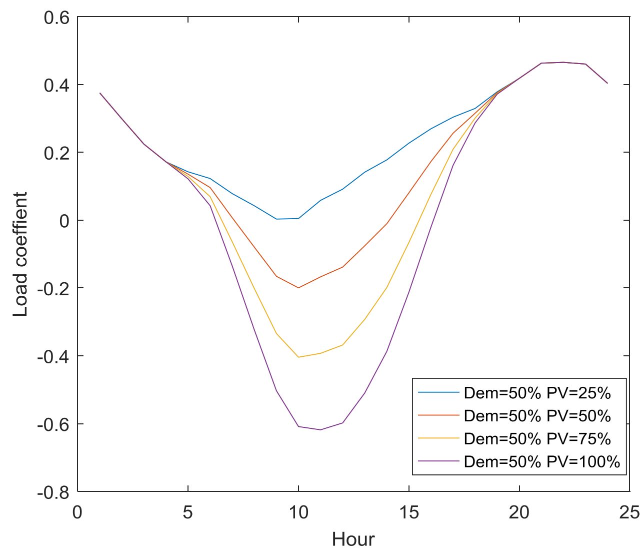


Figure 7.3: Total load profile for scenarios of different penetration of PV (25%, 50%, 75% and 100% of total peak demand) for a demand of 50% of total peak demand.

A.4 Results and discussion

This section presents the results obtained for the analyses carried out and discusses the interaction of phase unbalance with the integration of EV and PV, and their effect on energy losses and voltage profiles. Furthermore, sub-section A.4.4 discusses the implications for monitoring and the implementation of LV supervision solutions.

A.4.1 Phase unbalance and loading level

The graphs in Figure 7.4 depict the results obtained for the different LV grids considered under different loading levels. It can be observed that the increase in phase unbalance results in higher energy losses. This effect has an exponential behavior so that the losses of a completely unbalanced system range from 2.5 up to 3.8 times the losses for a fully balanced network. 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.

Moreover, higher loading levels lead to a deeper impact of unbalance so that energy losses are higher. Since energy losses increase with the square of the current, scenarios with higher load have higher losses and the increase of energy losses due to phase unbalance is much higher. 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. *n4* and *n5*), lower values of the losses factor have been generally obtained, whereas the opposite effect is observed for the semi-rural networks (i.e., *n6* and *n7*), which tend to be more heavily loaded.

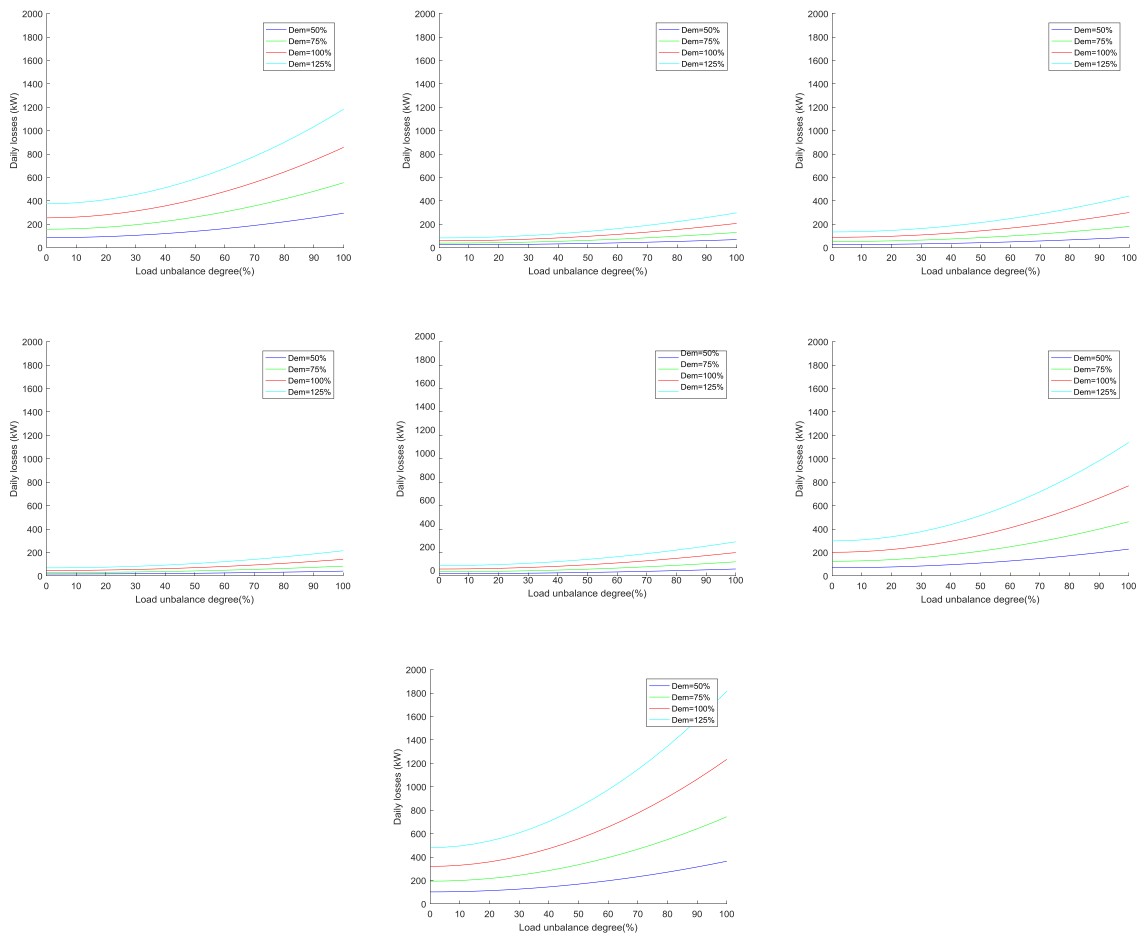


Figure 7.4: Daily energy losses under different loading levels and degree of unbalance in the LV networks. From left to right: first row n1, n2, n3; second row n4, n5, n6; third row n7.

The degree of phase unbalance also affects bus voltages. The higher the unbalance, the more noticeable the effect of loading levels on bus voltages, so that the voltage drop along the line is increased. European regulation establishes that voltage in the LV network must remain within 10% of its nominal value during 95% of the time (European Committee for Electrotechnical Standardization (CENELEC), 1994). Figure 7.5 illustrates compliance with voltage limits as load unbalance increases depicting the share of consumption points that experience a voltage below 90% of its nominal value at a certain hour in a day, considering the voltage at each of the three phases.

It must be noted that according to the definition of load unbalance, as load is transferred to a phase from the other two phases, the voltage drop increases in the more loaded phase, but decreases in the other two phases as they are relieved from part of the load. This effect can be observed in Figure 7.5

for network *n1* under a demand of 125% with respect to peak demand when comparing the totally balanced system to an unbalance degree of 5%.

It can be seen that voltage drop is mainly a problem in long overhead feeders such as *n1*, *n2* and *n3*; where unbalance results in significant voltage constraint violations. Network *n1* would be an extreme case in which network may need reinforcing, as under-voltage is observed even with degrees of phase unbalance as low as 5% in the case of maximum demand (loading of 100% of peak demand), or under an increase of demand. The effect of unbalances on under-voltages in the other networks, much shorter and largely underground in the case of *n4*, *n6* and *n7* and reinforced with conductors of much wider section in the case of *n5*, is limited to situations with a very high load and very highly unbalanced grids.

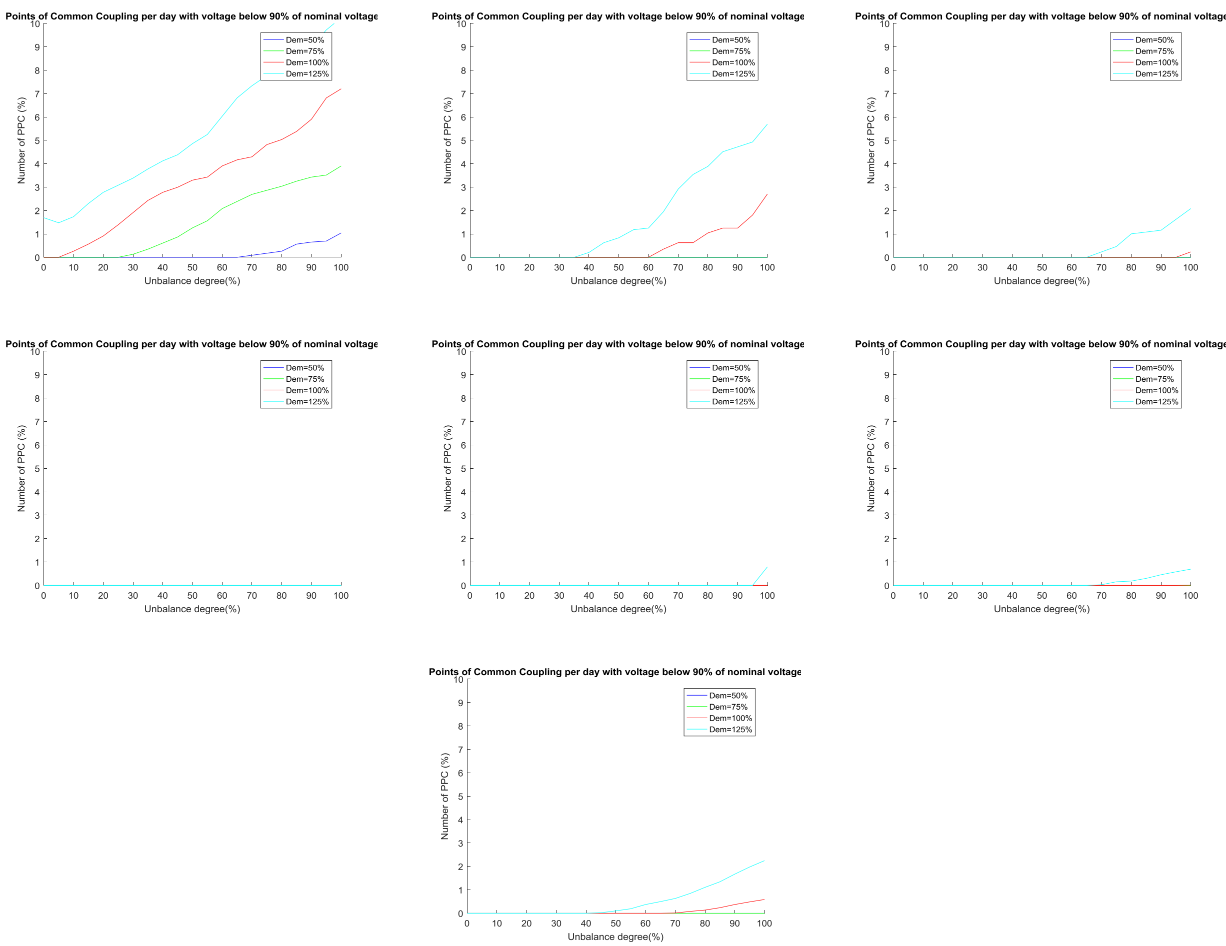


Figure 7.5: Share of buses experiencing under-voltages under different loading levels and degree of unbalance in the LV networks. From left to right: first row n1, n2, n3; second row n4, n5, n6; third row n7.

A.4.2 Integration of electric vehicle

The introduction of electric vehicles is an added demand for the LV grid. EV charging in residential areas is expected to take place during the night, where the demand is low. Therefore, the impact of EV integration on energy losses and voltage profiles in unbalanced LV networks is prone to be very similar to the previously discussed cases.

The total effect on losses for different penetration levels of EV is low. The same exponential behavior discussed above is observed. Thus, unbalance drives 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 7.6 shows the daily losses that correspond to a residential demand level of 100% with an EV penetration degree of 15%, 30%, 45% and 60% with respect to total peak demand in comparison to the case of demand and no EV penetration (red curve). It must be noted that, unlike in Figure 7.4, each of the diagrams in Figure 7.6 is represented in a different scale so that the increment in losses driven by EV integration can be better appreciated.

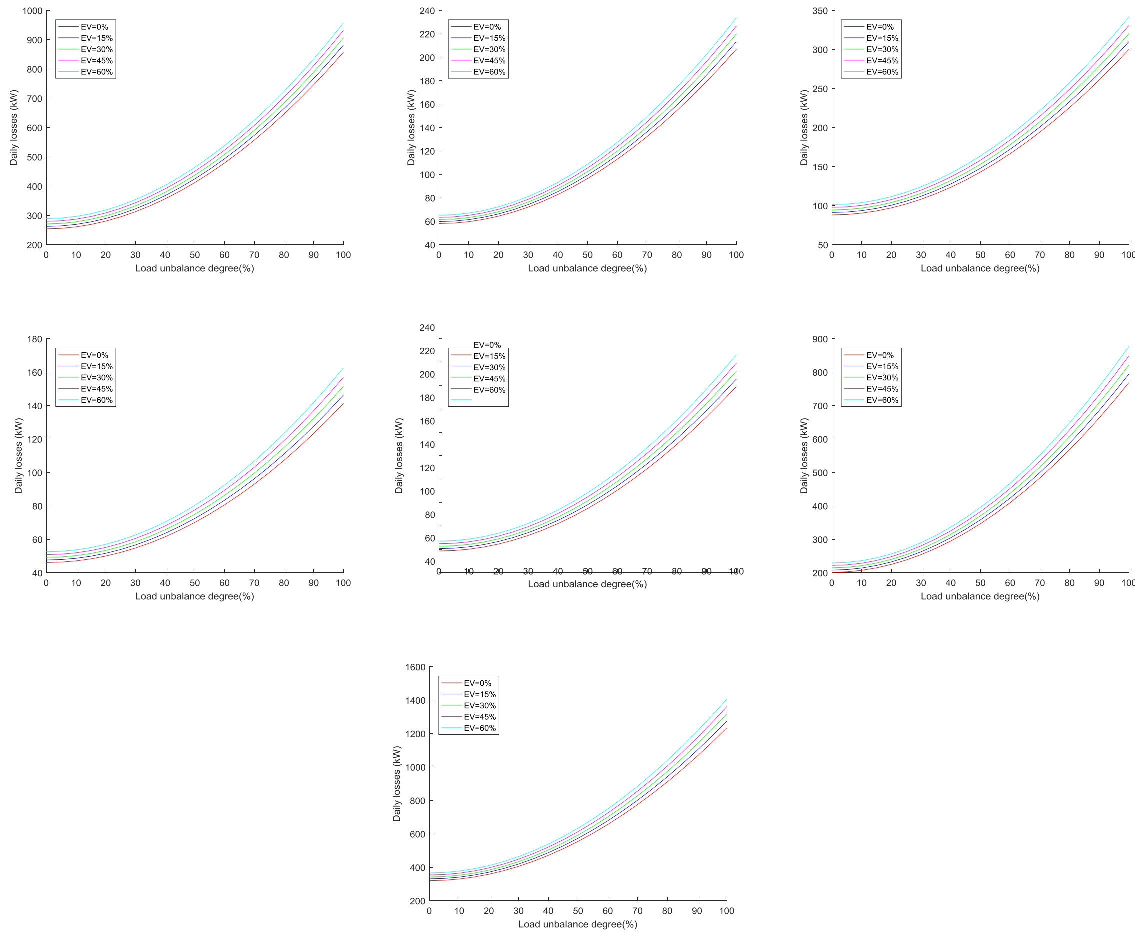


Figure 7.6: Daily energy losses under different EV penetration levels and degree of unbalance in the LV networks. From left to right: first row n1, n2, n3; second row n4, n5, n6; third row n7.

In the case of bus voltage profiles, the effect of EV charging is an increase of voltage drop during the charging hours. In residential areas, EV charging adds to the peak of domestic demand in the evening, where consumers arrive home. Therefore, the occurrence of under-voltages follows a similar pattern to the case with only load previously analyzed too. Under-voltages were only observed in five of the networks analyzed, namely *n1*, *n2* and *n3*, due to the physical characteristics of these networks which present long overhead feeders; and, to a lesser extent, *n6* and *n7* because these are much more heavily loaded, so that given EV penetration degrees represent a very large volume of additional demand.

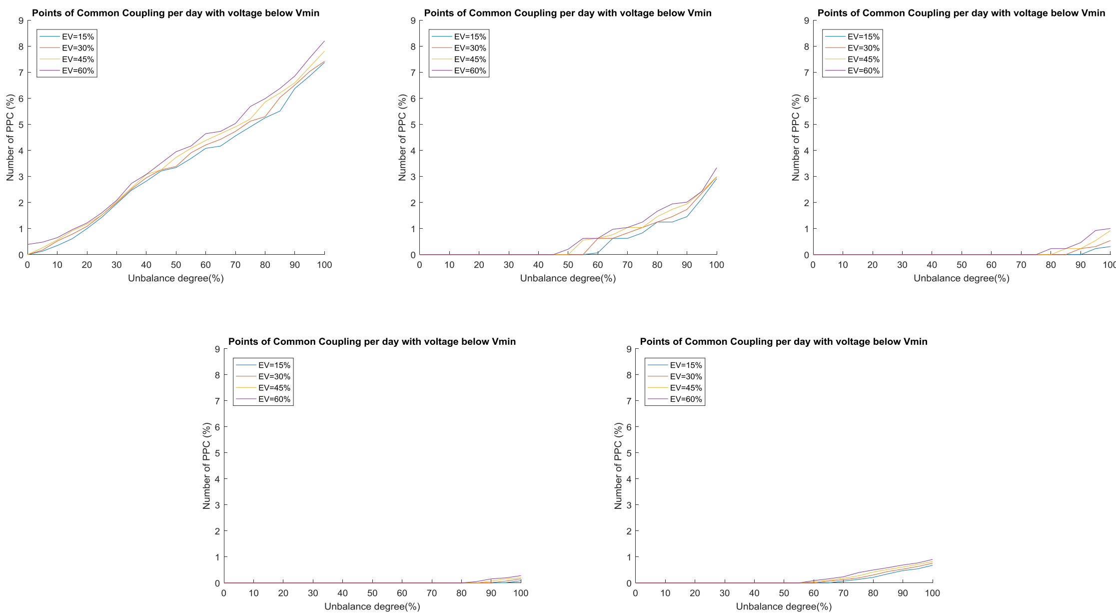


Figure 7.7: Share of buses experiencing over-voltages under different EV penetration levels and degree of unbalance in the LV networks. From left to right: first row n1, n2, n3; second row n6, n7.

Note that different charging strategies may result in a different impact on the system, depending on the interaction with demand. For instance, if EV charging took place starting later in the night, where residential demand is lower, the number of buses experiencing voltage levels below the minimum threshold would be presumably lower. By contrast, in a commercial area, maximum demand and EV charging would be coincident and take place during working hours, so losses would be further increased and undervoltage problems would be more frequent. Furthermore, it must be noted that fast charging has not been considered because due to the high required capacity, fast charging points would most probably be connected as a three-phase, and even directly to the MV grid. Therefore, in spite of rising network loading and losses, system unbalance would not be affected.

A.4.3 Integration of solar PV

The generation of PV connected to the LV network is consumed by the local demand, so that net demand is reduced and consequently energy losses are reduced as well. In residential areas, the demand is relatively low during the hours of PV production, especially in working days. However, further integration of PV may result in PV generation surpassing demand, so that power flows are reversed. As observed in Figure 7.3, for low loading of the lines and high PV penetration degrees, the net peak generation is higher than the peak demand during the evening. Consequently, the total daily energy losses are slightly reduced for a 25% and 50% PV penetration but then increase again for 75% or 100% penetration, as can be seen in Figure 7.8.

With respect to the effect of unbalance on energy losses, comparing these results with those previously obtained in the scenarios without generation, it can be observed that moderate penetration levels (of up to 75%) actually mitigate the increase in losses driven by system unbalances. The steep increase in daily losses that previously occurred beyond a threshold of 30-40% 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.

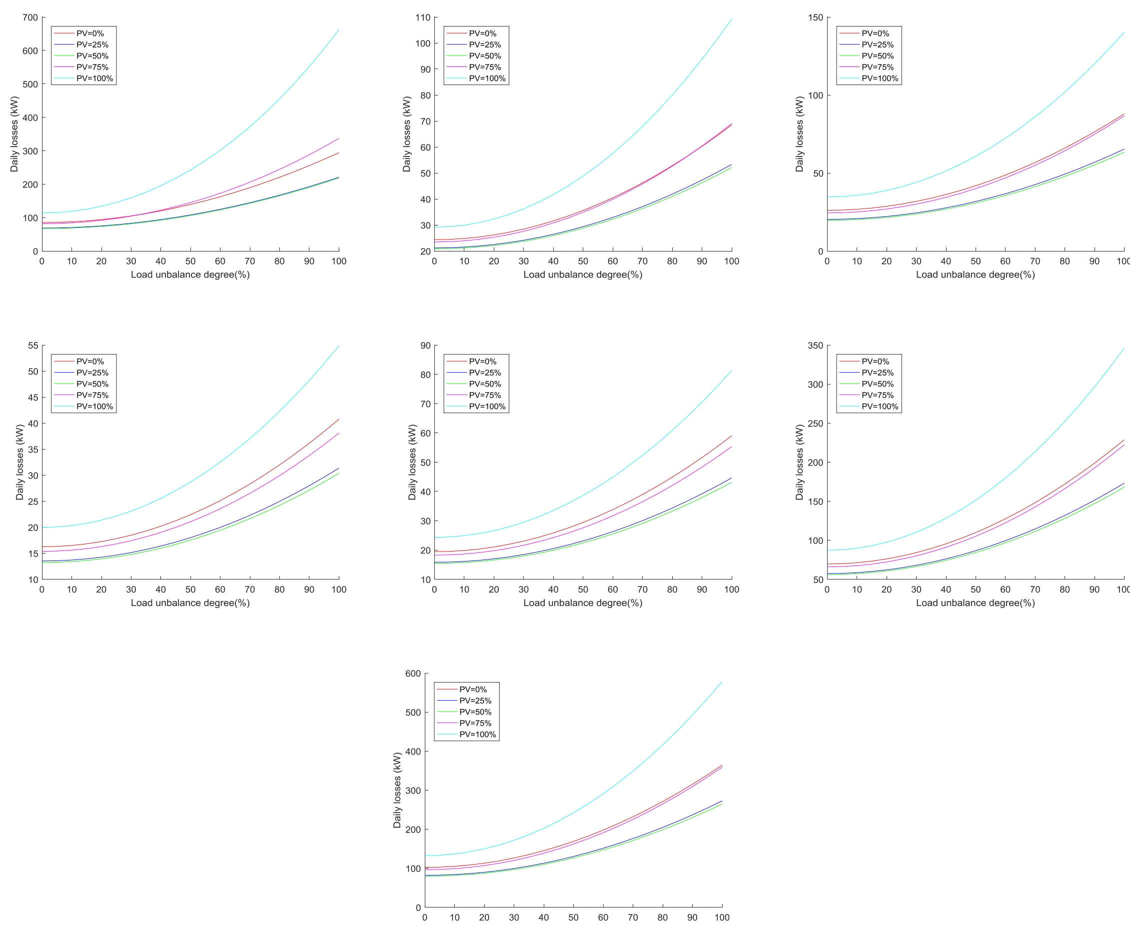


Figure 7.8: Daily energy losses under different PV penetration levels and degree of unbalance in the LV networks. From left to right: first row n1, n2, n3; second row n4, n5, n6; third row n7.

Considering voltage profiles, the impact of PV penetration and system unbalance significantly differs from the scenarios where only loads were connected to the LV grid. 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 for high demand scenarios, a much lower number of buses would experience under-voltages. Furthermore, this problem is virtually non-existent for the remaining grids. 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 7.5. 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, especially for lower demand levels.

Figure 7.9 shows the compliance with voltage levels for a loading level of 50% of peak demand and the different scenarios of PV penetration studied in networks *n1* and *n2* where overvoltages limit the amount of PV that can be integrated in the network. The degree of unbalance clearly causes a higher number of voltage violations due to excessively high bus voltages. In network *n1* a degree of phase unbalance around 15% causes problems for high PV penetration. 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. In the remaining networks, over-voltages only arise for very large PV penetration levels and unbalance degree in very specific buses.

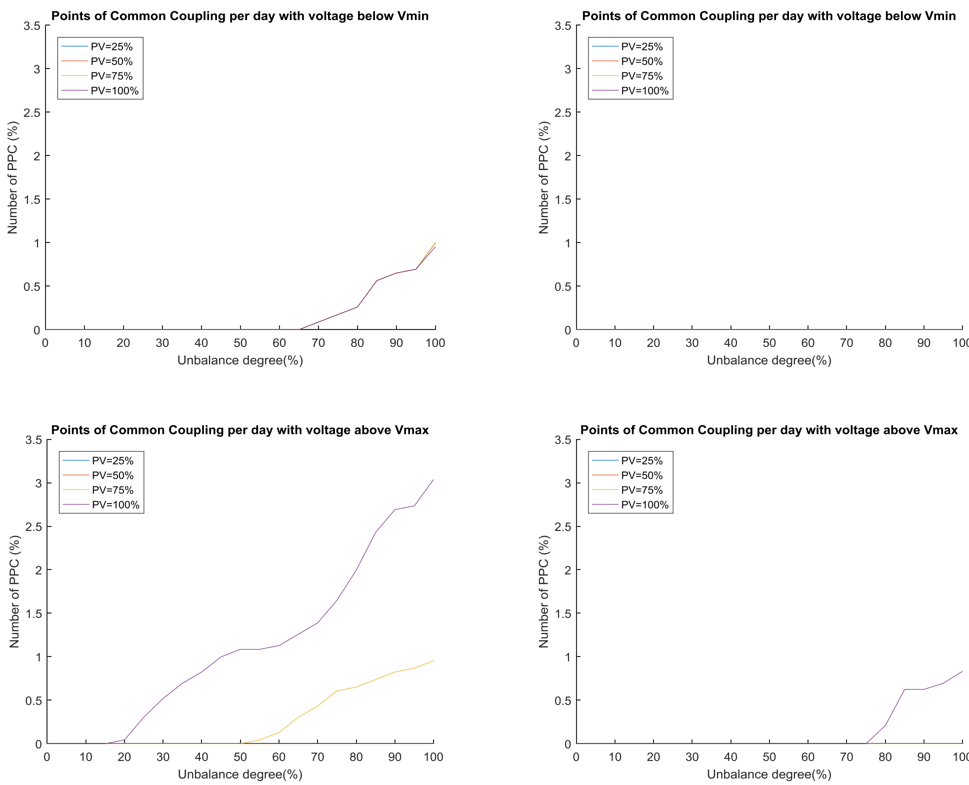


Figure 7.9: Share of buses experiencing undervoltages (top row) and overvoltages (bottom row) under different PV penetrations and degree of unbalance in the LV grids in networks n1 (left) and n2 (right).

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 would result in even more limited PV hosting capacity.

A.4.4 Analysis for different voltage limits

The previous analyses have considered the voltage limits established by current European regulation with a margin of 10% of its nominal value (European Committee for Electrotechnical Standardization (CENELEC), 1994). Other countries impose stricter limits, such as in the case of Spain, where voltage drop cannot exceed 7% of the nominal value (Spanish Ministry of Economy, 2000). The effect of considering different regulatory limits or operational standards has been assessed for the studied networks and scenarios. Stricter voltage regulation limits the network hosting capacity, resulting in network reinforcement requirements to accommodate increasing shares of DER. Furthermore, the effect of phase unbalance becomes more noticeable, since technical constraint violations occur at an earlier stage.

Figure 7.10 illustrates the share of nodes experiencing undervoltages for a loading level of 100% (depicted in dashed lines), and adding to the demand an EV penetration degree of 60% (depicted in continuous lines). Undervoltage is defined considering a maximum voltage deviation of 5%, 7% and 10% of nominal value in networks *n2* and *n3*. As seen in sub-sections A.4.1 and A.4.2, network *n2* experienced voltage problems only for high degrees of phase unbalance above 60%. The introduction of EVs resulted in higher voltage drops, so that voltage problems already appeared for a 45% degree of load unbalance. However, if the voltage limitation is set to 7% of nominal value, an unbalance degree of 20% already causes overvoltage problems, and the introduction of EV would not be possible for an unbalance degree above 15%. An even stricter limit would not allow the introduction of EVs, since demand alone would already cause overvoltages. No voltage problems were previously identified for network *n3* for a minimum voltage of 90% of nominal value, unless very high levels of unbalance were considered. Considering voltage limits of 7% and 5% results in overvoltages for mild load unbalance degrees.

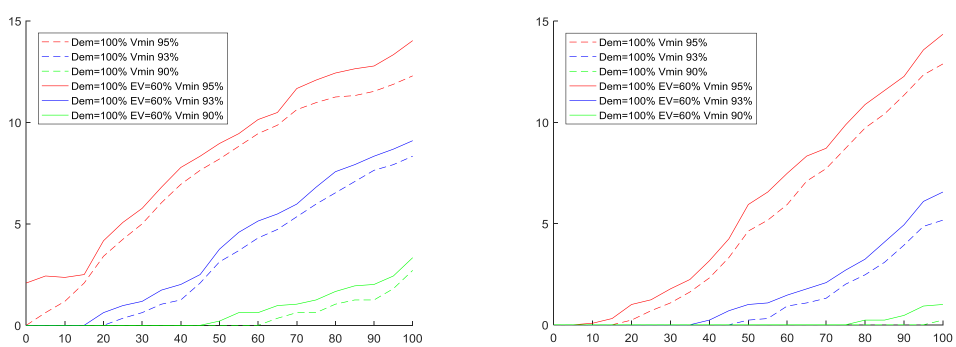


Figure 7.10: Share of buses experiencing undervoltages with and without EV integration considering different voltage limits. Networks n2 (left) and n3 (right).

The same conclusions may be extracted in the case of PV integration in LV networks. As an illustrative example, Figure 7.11 shows the share of nodes with voltage below the minimum and above the maximum thresholds for a penetration degree of PV of 100% of peak demand for a loading level of

75%. As previously observed, no undervoltage problems are detected for a low level of load. Rather, the opposite problem may be expected, when a very high penetration degree of PV leads to overvoltage problems, as is the case of network *n2* for an unbalance degree above 75%. Considering voltage margins of 5% and 7% of nominal value results in overvoltage problems for mild levels of phase unbalance (15% and 40% respectively). In the case of *n3*, such PV penetration degree results in voltages above the 105% threshold for phase unbalance above 40%.

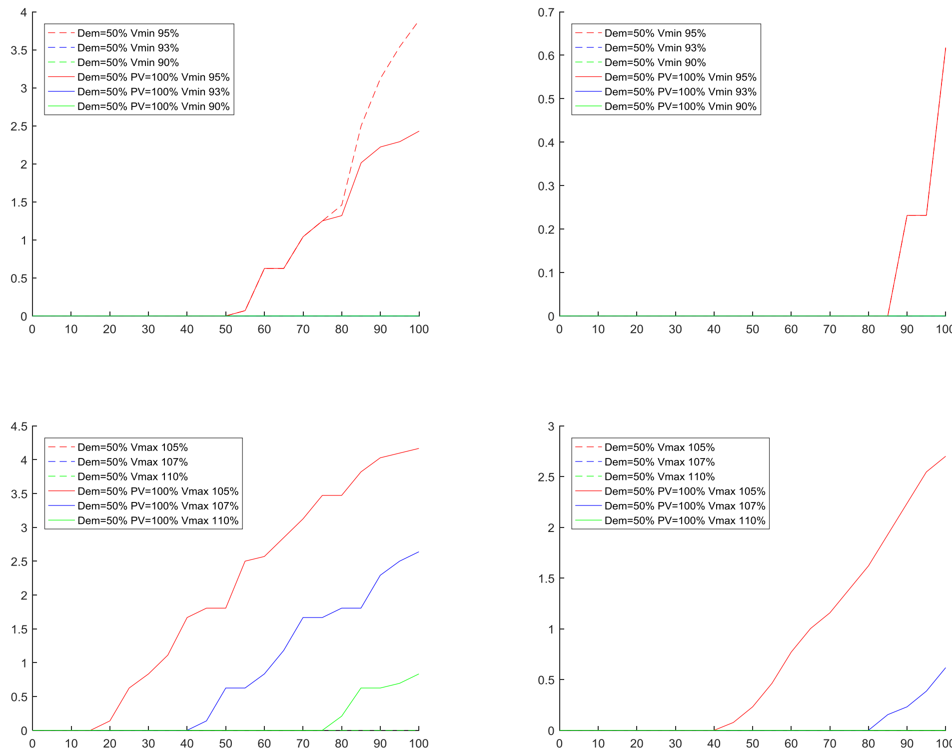


Figure 7.11: Share of buses experiencing undervoltages (top row) and overvoltages (bottom row) with and without PV integration considering different voltage limits. Networks n2 (left) and n3 (right).

Yet a very relevant issue is the duration of voltage problems caused by the integration of DER in LV networks. Regulation typically establishes that voltage limits must be complied during most of the time, leaving a certain buffer of time where limits may be surpassed. Due to the different behavior of PV and EV, this will affect the integration of each type of DER differently. PV may cause high voltage rises leading to overvoltage problems during peak production hours, i.e. at noon. However, the assumed EV charging is a flat demand curve, so that undervoltages caused will be sustained in time, leading to higher degrees of violation of voltage limits than in the case of PV.

A.4.5 Implications for the implementation of LV supervision solutions

The results presented throughout this section underline the fact that phase unbalance limits significantly the hosting capacity of LV networks. Even though high penetration degrees of EVs and PV may be achieved, load unbalance highly increases the voltage drops during EV charging and the voltage rise caused by excess of PV production, so that voltage limits may be surpassed with volumes of DER lower than expected. Furthermore, in order to allow the connection of DER, distribution companies must reinforce the feeders and transformers in the network. Thus, phase unbalance brings forward in time the need for reinforcement, which in turn leads to higher network costs, as highlighted by the authors of (Ma et al., 2016), where a model is developed to quantify the additional reinforcement cost.

For these reasons, it becomes necessary to monitor unbalance and voltage along LV lines in order to detect potential voltage problems. Furthermore, the information from smart meters can help distribution companies identify the association between consumers and the feeders and phases they are connected to and thus keep an updated inventory, which is not often the case for LV infrastructure.

Different LV supervision solutions have been tested in smart grid projects to integrate and process the information provided by different elements in the LV network, such as AMI infrastructure and smart meters, monitoring devices in the LV outgoing LV lines at secondary substations and LV cabinets. Clearly, the implementation of such LV supervision solutions brings many benefits for the operation of the LV grid. However, there are several aspects that must be taken into account and potential barriers that could hinder their exploitation.

There is a potentially enormous amount of data that could overload the operator and hinder the detection of problems in the LV network. It is therefore very important to carefully select the relevant data. Furthermore, an overlying intelligent system may be needed in order to make sense of all the data and manage events and alarms.

AMI infrastructure can acquire and record different measures and data. 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, among which power quality monitoring is not included (European Commission, 2012a). The EC smart meter benchmarking report states that most Member States leave at the discretion of roll-out responsible parties (most frequently DSOs) the inclusion of alternative functionalities (European Commission, 2014b). Therefore, potentially limited smart meter functionalities may be an important barrier to LV monitoring. Otherwise, billing information and historical consumption may be suitable for planning applications and network studies, but not for operation. Similarly, the potential of such solutions may be hampered if this deployment does not reach a significant share of end consumers.

Furthermore, the possibility of using AMI data for LV network supervision depends on the model for meter ownership and data management. In most Member States where smart metering has been or is being deployed, the DSO are in charge of deploying and owning the meters (Smart Grids Task

Force. Expert Group 3, 2013). However, in countries with independent metering point operators, the access of DSOs to the information may be limited.

A.5 Conclusions

This Appendix has studied the effects of future integration of DER in the LV network, namely PV generation and EVs, where phase unbalance is often neglected but relevant nevertheless. This work is focused on the evaluation of energy losses and voltage profiles in residential LV grids in rural and semi-rural areas for different penetration degrees of PV and EV and different degrees of phase unbalance.

It can be concluded that the increase in phase unbalance results in exponentially higher energy losses, particularly in networks that are more heavily loaded. The degree of phase unbalance also affects voltages so that higher unbalance leads to higher voltage variations along the line. Voltage constraints violations may occur especially in long overhead feeders. The penetration of EV and PV may increase unbalance of distribution networks, as these are relatively large single-phase loads or power injections. The interaction of EV charging strategies and demand is key: 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 PV slightly reduces the losses in the system for low penetration degrees and mitigate the increase in losses driven by system, but higher shares of PV produce the opposite effect. For high 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. As unbalance causes higher voltage variations, it further reduces network hosting capacity, since voltage limits are surpassed for lower degrees of penetration of DER. Logically, the hosting capacity of networks will be constrained by the regulatory voltage limits and the criteria to monitor compliance. As a result from limited hosting capacity, network reinforcement will be required as more DER is connected to the grid, so it can be concluded that load unbalance brings network reinforcement costs forwards in time.

It is clear that the effect of unbalance is not negligible, and it is becoming more and more relevant under the current context of increasing connection of single-phase DER in the LV grid. In the context of the smart grid, AMI can help DSOs monitor the network and thus identify high degrees of unbalance, so that corrective actions may be taken. The results from this work show that where high integration of DER is expected, the monitoring of more loaded and longer networks should be prioritized. However, the information available for network operation will depend on the type of monitoring devices and smart meters, their degree of implementation and the accessibility of DSOs to these data.

References

ACEA Distribuzione S.p.a. (2014). *Progetto Pilota Smart Grid*. Retrieved from http://www.autorita.energia.it/allegati/operatori/elettricita/smartgrid/Relazione Finale ACEA D.pdf

Ahn, C., & Peng, H. (2013). Decentralized Voltage Control to Minimize Distribution Power Loss of Microgrids. *IEEE Transactions on Smart Grid*, *4*(3), 1297–1304. http://doi.org/10.1109/TSG.2013.2248174

Ajodhia, V., & Hakvoort, R. (2005, September). Economic regulation of quality in electricity distribution networks. *Utilities Policy*. http://doi.org/10.1016/j.jup.2004.07.008

Ajodhia, V., Lo Schiavo, L., & Malaman, R. (2006). Quality regulation of electricity distribution in Italy: an evaluation study. *Energy Policy*, *34*(13), 1478–1486. http://doi.org/10.1016/j.enpol.2004.11.016

Alarcon-Rodriguez, A., Ault, G., & Galloway, S. (2010). Multi-objective planning of distributed energy resources: A review of the state-of-the-art. *Renewable and Sustainable Energy Reviews*, *14*(5), 1353–1366. http://doi.org/10.1016/j.rser.2010.01.006

Alencar, T., Rodrigues, A., & da Silva, M. da G. (2011). Switches Allocation in Distribution Network Using Particle Swarm Optimization Based on Fuzzy Expert System. In *17th Power Systems Computation Conference*.

Allan, R. N., & Strbac, G. (2001). Performance regulation of distribution systems using reference networks. *Power Engineering Journal*, *15*(6), 295–303. http://doi.org/10.1049/pe:20010604

Allegranza, V., Mastandrea, I., & Ruffini, A. (2005). Optimising the investments on distribution networks to meet the rules for continuity of supply: a novel planning and operation tool. In *18th International Conference and Exhibition on Electricity Distribution (CIRED 2005)* (Vol. 2005, pp. v5-20-v5-20). IEE. http://doi.org/10.1049/cp:20051302

Amillo, A., Huld, T., & Müller, R. (2014). A New Database of Global and Direct Solar Radiation Using the Eastern Meteosat Satellite, Models and Validation. *Remote Sensing*, *6*, 8165–8189. http://doi.org/10.3390/rs6098165

Arnold, M., Rui, H., & Wellssow, W. H. (2011). An approach to Smart Grid metrics. *IEEE PES Innovative Smart Grid Technologies Conference Europe*, 1–7. http://doi.org/10.1109/ISGTEurope.2011.6162662

Asrari, A., Lotfifard, S., & Payam, M. S. (2016). Pareto Dominance-Based Multiobjective Optimization Method for Distribution Network Reconfiguration. *IEEE Transactions on Smart Grid*, *7*(3), 1401–1410. http://doi.org/10.1109/TSG.2015.2468683

Australian Manufacturing Council. (1996). *Key Performance Indicators Manual: a Practical Guide for the Best Practice Development, Implementation and Use of KPI's*. Allen & Unwin Pty., Limited. Retrieved from https://books.google.es/books?id=u2NfAAAACAAJ

Autorità per l'energia elettrica il gas e il sistema idrico. (2011). Deliberazione ARG/elt 198/11 - Testo integrato della regolazione della qualita dei servizi di distribuzione e misura dell'energia elettrica, per il periodo di regolazione 2012-2015 (in Italian). Retrieved from http://www.autorita.energia.it/it/docs/11/198-11arg.htm#

Autorità per l'energia elettrica il gas e il sistema idrico. (2015a). 654/2015/R/EEL Regolazione tariffaria dei servizi di trasmissione, distribuzione e misura dell'energia elettrica, per il periodo di regolazione 2016-2023.

Autorità per l'energia elettrica il gas e il sistema idrico. (2015b). Deliberazione 483/2014/R/eel - Testo integrato della regolazione output-based dei servizi di distribuzione e misura dell'energia elettrica, per il periodo di regolazione 2016-2023 (in Italian).

Bargigia, A., Cerretti, A., Di Lembo, G., Rogai, S., & Veglio, G. (2003). Telecontrol and automation on Enel Distribuzione's network: strategy and results. In *CIRED 2003, 17th International Conference on Electricity Distribution* (pp. 12–15).

Beaudin, M., Zareipour, H., Schellenberglabe, A., & Rosehart, W. (2010). Energy storage for mitigating the variability of renewable electricity sources: An updated review. *Energy for Sustainable Development*, *14*(4), 302–314. http://doi.org/10.1016/j.esd.2010.09.007

Berry, A. M., Moore, T., Ward, J. K., Lindsay, S. A., & Proctor, K. (2013). National Feeder Taxonomy - Describing a Representative Feeder Set for Australian Electricity Distrbution Networks. CSIRO.

Bertazzi, A., Fumagalli, E., & Lo Schiavo, L. (2005). The use of customer outage cost surveys in policy decision-making: the Italian experience in regulating quality of electricity supply. In *18th International Conference and Exhibition on Electricity Distribution (CIRED 2005)* (Vol. 2005, pp. v6-41-v6-41). IEE. http://doi.org/10.1049/cp:20051418

Birman, K. (2012). *Computational Needs for the Next Generation Electric Grid Proceedings*. Retrieved from http://escholarship.org/uc/item/44m064tj

Blumsack, S., & Fernandez, A. (2012). Ready or not, here comes the smart grid! *Energy*, *37*(1), 61–68. http://doi.org/10.1016/j.energy.2011.07.054

Bondi, A. (2000). Characteristics of Scalability and Their Impact on Performance. *Proceedings of the 2nd International Workshop on Software and Performance*, 195–203. http://doi.org/10.1145/350391.350432

Bonfiglio, A., Delfino, F., Denegri, G. B., Invernizzi, M., Procopio, R., Amann, G., … Monizza, G. (2013). A set of KPIs to quantify environmental & technical benefits of renewing actions on transmission grids. In *2013 IEEE Grenoble Conference* (pp. 1–6). IEEE. http://doi.org/10.1109/PTC.2013.6652233

Bonfiglio, A., Procopio, R., Delfino, F., Invernizzi, M., & Denegri, G. B. (2013). Definition and validation of key performance indicators to assess the effectiveness of smarting actions on a distribution network. In *22nd International Conference and Exhibition on Electricity Distribution (CIRED 2013)* (pp. 1495–1495). Institution of Engineering and Technology. http://doi.org/10.1049/cp.2013.1262

Bonnefoy, P., & Hansman, R. J. (2008). *Scalability of the Air Transportation System and Development of Multi-Airport Systems: A Worldwide Perspective*.

Bossart, S. J., & Bean, J. E. (2011). Metrics and benefits analysis and challenges for Smart Grid field projects. *IEEE 2011 EnergyTech, ENERGYTECH 2011*, 1–5. http://doi.org/10.1109/EnergyTech.2011.5948539

Bouhouras, A. S. A. S. S., Labridis, D. P. D. P. P., & Bakirtzis, A. G. A. G. (2010). Cost/worth assessment of reliability improvement in distribution networks by means of artificial intelligence. *International Journal of Electrical Power & Energy Systems*, *32*(5), 530–538. http://doi.org/10.1016/j.ijepes.2009.06.005

Bouhouras, A. S., Andreou, G. T., Labridis, D. P., & Bakirtzis, A. G. (2010). Selective automation upgrade in distribution networks towards a smarter grid. *Smart Grid, IEEE Transactions on*, *1*(3), 278–285.

Bouhouras, A. S., Andreou, G. T., Labridis, D. P., & Bakirtzis, A. G. (2010). Selective Automation Upgrade in Distribution Networks Towards a Smarter Grid. *IEEE Transactions on Smart Grid*, *1*(3), 278–285. http://doi.org/10.1109/TSG.2010.2080294

Bracale, A., Caldon, R., Celli, G., Coppo, M., Dal Canto, D., Langella, R., … Turri, R. (2012). Analysis of the Italian distribution system evolution through reference networks. In *2012 3rd IEEE PES Innovative Smart Grid Technologies Europe (ISGT Europe)* (pp. 1–8). IEEE. http://doi.org/10.1109/ISGTEurope.2012.6465702

Brocco, A. (2013). Ad-Hoc Self-Organized Microgrid for Rural Electrification and Post-disaster Response. In *2013 IEEE Green Technologies Conference (GreenTech)* (pp. 315–321). IEEE. http://doi.org/10.1109/GreenTech.2013.55

Broman Toft, M., Schuitema, G., & Thøgersen, J. (2014). Responsible technology acceptance: Model development and application to consumer acceptance of Smart Grid technology. *Applied Energy*, *134*, 392–400. http://doi.org/10.1016/j.apenergy.2014.08.048

Bundesnetzagentur. (2013). Qualitätsregulierung Netzzuverlässigkeit Strom 2012/2013 (in German). Retrieved from https://www.bundesnetzagentur.de/SharedDocs/Downloads/DE/Sachgebiete/Energie/Unternehmen_Institutionen/Netzentgelte/Strom/Qualitaetselement/BegleittextQ-RegStrom2012-13.pdf?__blob=publicationFile&v=1

Cambini, C., Croce, A., & Fumagalli, E. (2014). Output-based incentive regulation in electricity distribution: Evidence from Italy. *Energy Economics*, *45*, 205–216. http://doi.org/10.1016/j.eneco.2014.07.002

Cambini, C., Fumagalli, E., & Rondi, L. (2016). Incentives to quality and investment: evidence from electricity distribution in Italy. *Journal of Regulatory Economics*, *49*(1), 1–32. http://doi.org/10.1007/s11149-015-9287-x

Castro Legarza, U., & Álvarez Pelegry, E. (2016). Generación distribuida en Reino Unido y Estados Unidos (Nueva York y Maine). Nivel de penetración de la generación fotovoltaica y regulación. *Cátedra de Energía Orkestra. Instituto Vasco de Competitividad*. Retrieved from http://www.orkestra.deusto.es/es/investigacion/publicaciones/cuadernos-orkestra/897-generacion-distribuida-reino-unido-estados-unidos-nueva-york-maine

CEDEC, EDSO4SG, ENTSO-E, Eurelectric, & GEODE. (2015). General guidelines for reinforcing the cooperation between TSOs and DSOs.

Celli, G., Pilo, F., Pisano, G., & Soma, G. G. (2014). Reference scenarios for Active Distribution System according to ATLANTIDE project planning models. *2014 IEEE International Energy Conference (ENERGYCON)*, 1190–1196. http://doi.org/10.1109/ENERGYCON.2014.6850574

CEN/CENELEC/ETSI. (2011). *Final report of the CEN/CENELEC/ETSI Joint Working Group on Standards for Smart Grids*. Retrieved from http://www.etsi.org/WebSite/document/Report_CENCLCETSI_Standards_Smart Grids.pdf

CEN/CENELEC/ETSI. (2012). *Smart Grid Reference Architecture*.

Cerretti, A., Lembo, G. Di, Primio, G. Di, Gallerani, A., & Valtorta, G. (2003). Automatic fault clearing on MW Networks with neutral point connected to ground through impedance. In *17th International Conference on Electricity Distribution* (pp. 12–15).

Cerretti, A., Scrosati, G., & Consiglio, L. (2011). Upgrade of ENEL MV Network Automation to Improve Performances in Presence of Faults and to Deal DG. In *CIRED 2011, 21st International Conference on Electricity Distribution*.

Chen, T.-H., Yang, C.-H., & Yang, N.-C. (2013). Examination of the definitions of voltage unbalance. *International Journal of Electrical Power & Energy Systems*, *49*(1), 380–385. http://doi.org/10.1016/j.ijepes.2013.02.006

CIGRE. (2014a). *Benchmark Systems for Network Integration of Renewable and Distributed Energy Resources*. *Technical Brochure 575, final report of Task Force C6.04.02*.

CIGRE. (2014b). *Planning and Optimization Methods for Active Distribution Systems*. *Technical Brochure 591, final report of Working Group C6.19*.

Ciller Cutillas, P. (2015). *Clustering-related improvements in the Reference Electrification Model*. *MSc Thesis*. Comillas Pontificial University.

Clement-Nyns, K., Haesen, E., & Driesen, J. (2010). The Impact of Charging Plug-In Hybrid Electric Vehicles on a Residential Distribution Grid. *IEEE Transactions on Power Systems*, *25*(1), 371–380. http://doi.org/10.1109/TPWRS.2009.2036481

Colak, I., Fulli, G., Sagiroglu, S., Yesilbudak, M., & Covrig, C. F. (2015). Smart grid projects in Europe: Current status, maturity and future scenarios. *Applied Energy*, *152*, 58–70. http://doi.org/10.1016/j.apenergy.2015.04.098

Comisión Nacional de Energía. (2010). *Propuesta de valores para los coeficientes de pérdidas zonales a utilizar en el cálculo del incentivo de reducción de pérdidas de las empresas distribuidoras*.

Conejo, A. J., Morales, J. M., & Baringo, L. (2010). Real-Time Demand Response Model. *IEEE Transactions on Smart Grid*, *1*(3), 236–242. http://doi.org/10.1109/TSG.2010.2078843

Conti, S., Rizzo, S. A., El-Saadany, E. F., Essam, M., & Atwa, Y. M. (2014). Reliability Assessment of Distribution Systems Considering Telecontrolled Switches and Microgrids. *IEEE Transactions on Power Systems*, *29*(2), 598–607. http://doi.org/10.1109/TPWRS.2013.2287301

Corfee, K., Korinek, D., Hewicker, C., Pereira Morgado, H., Zillmer, J., & Hawkins, D. (2011). Distributed Generation in Europe. *KEMA. California Energy Commission. Publication Number: CEC-400-2011-011*.

Cossent, R. (2012). Setting regulatory incentives for continuity of supply in smart distribution grids. In *2012 3rd IEEE PES Innovative Smart Grid Technologies Europe (ISGT Europe)* (pp. 1–8). IEEE. http://doi.org/10.1109/ISGTEurope.2012.6465845

Cossent, R. (2013). *Economic Regulation of Distribution System Operators and its Adaptation to the Penetration of Distributed Energy Resources and Smart Grid Technologies*. *PhD thesis*. Universidad Pontificia Comillas.

Cossent, R., Olmos, L., Gomez, T., Mateo, C., & Frias, P. (2010). Mitigating the impact of distributed generation on distribution network costs through advanced response options. In *2010 7th International Conference on the European Energy Market* (pp. 1–6). IEEE. http://doi.org/10.1109/EEM.2010.5558669

Council of European Energy Regulators (CEER). (2010). *Guidelines of good practice on estimation of costs due to electricity interruptions and voltage disturbances*.

Council of European Energy Regulators (CEER). (2011a). *5th CEER Benchmarking Report on the Quality of Electricity Supply*.

Council of European Energy Regulators (CEER). (2011b). CEER status review of regulatory approaches to smart electricity grids, (July).

Council of European Energy Regulators (CEER). (2014). CEER Status Review on European Regulatory Approaches Enabling Smart Grids Solutions ("Smart Regulation"). Council of European Energy Regulators. http://doi.org/Ref: C1-EQS-57-04

Council of European Energy Regulators (CEER). (2016). 6th CEER Benchmarking Report on the Quality of Electricity and Gas Supply. Retrieved from http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER_PAPERS/Electricity/Tab3/C13-EQS-57-03_BR5.1_19-Dec-2013_updated-Feb-2014.pdf

Council of European Energy Regulators (CEER). (2017). CEER Report on Investment Conditions in European Countries.

Covrig, C. F., Ardelean, M., Vasiljevska, J., Mengolini, A., Fulli, G., Amoiralis, E., … Filiou, C. (2014). Smart Grid Projects Outlook 2014. *European Commission, Joint Research Centre*. http://doi.org/10.2790/22075

de Hoog, J., Alpcan, T., Brazil, M., Thomas, D. A., & Mareels, I. (2015). Optimal Charging of Electric Vehicles Taking Distribution Network Constraints Into Account. *IEEE Transactions on Power Systems*, *30*(1), 365–375. http://doi.org/10.1109/TPWRS.2014.2318293

Dede, A., Della Giustina, D., Rinaldi, S., Ferrari, P., Flammini, A., & Vezzoli, A. (2015). Smart meters as part of a sensor network for monitoring the low voltage grid. In *2015 IEEE Sensors Applications Symposium (SAS)* (Vol. 416, pp. 1–6). IEEE. http://doi.org/10.1109/SAS.2015.7133616

Depuru, S. S. S. R., Wang, L., & Devabhaktuni, V. (2011). Smart meters for power grid: Challenges, issues, advantages and status. *Renewable and Sustainable Energy Reviews*, *15*(6), 2736–2742. http://doi.org/10.1016/j.rser.2011.02.039

Dickert, J., Domagk, M., & Schegner, P. (2013). Benchmark low voltage distribution networks based on cluster analysis of actual grid properties. *2013 IEEE Grenoble Conference*, 1–6. http://doi.org/10.1109/PTC.2013.6652250

Dietrich, K., Latorre, J. M., Olmos, L., & Ramos, A. (2012). Demand Response in an Isolated System With High Wind Integration. *IEEE Transactions on Power Systems*, *27*(1), 20–29. http://doi.org/10.1109/TPWRS.2011.2159252

Divya, K. C., & Østergaard, J. (2009). Battery energy storage technology for power systems—An overview. *Electric Power Systems Research*, *79*(4), 511–520. http://doi.org/10.1016/j.epsr.2008.09.017

DNV GL, Imperial College, & NERA Economic Consulting. (2014). *Integration of Renewable Energy in Europe*.

Domingo, C. M., Gómez, T., Román, S., Member, S., Sánchez-miralles, Á., Pascual, J., … Martínez, A. C. (2011). A Reference Network Model for Large-Scale Street Map Generation. *IEEE Transactions on Power Systems*, *26*(1), 190–197.

Douglass, P. J., Trintis, I., & Munk-Nielsen, S. (2016). Voltage Unbalance Compensation with Smart Three-phase Loads. In *Power Systems Computation Conference (PSCC) 2016*.

Dupont, B., Meeus, L., & Belmans, R. (2010). Measuring the "smartness" of the electricity grid. In *2010 7th International Conference on the European Energy Market* (pp. 1–6). IEEE. http://doi.org/10.1109/EEM.2010.5558673

Electric Power Research Institute. (2010). *Methodological Approach for Estimating the Benefits and Costs of Smart Grid Demonstration Projects*.

Electric Power Research Institute. (2011). Estimating the Costs and Benefits of the Smart Grid.

Electric Power Research Institute. (2014). Clustering Methods and Feeder Selection for PV System Impact Analysis, (3002002562).

Electric Power Research Institute. (2015). Alternatives to the 15% Rule. Final Project Summary.

Electric Power Research Institute (EPRI). (2001). A Review of the Reliability of Electric Distribution System Components: EPRI White Paper.

Ellman, D. (2015). *The Reference Electrification Model: A Computer Model for Planning Rural Electricity Access*. Massachusetts Institute of Technology.

Endesa. (2014). Smartcity Málaga. Un modelo de gestión energética sostenible para las ciudades del futuro. Retrieved from https://www.endesa.com/content/dam/enel-es/home/prensa/publicaciones/otraspublicaciones/documentos/SMARTCITY MALAGA UN MODELO DE GESTION ENERGETICA SOSTENIBLE.pdf

ERGEG European Regulators Group for Electricity & Gas. (2010). *Position Paper on Smart Grids - An ERGEG Conclusions Paper*. Retrieved from http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER_PAPERS/Electricity/2010/E10-EQS-38-05_SmartGrids_Conclusions_10-Jun-2010_Corrigendum.pdf

EU Commission Task Force for Smart Grids. (2010). *Functionalities of smart grids and smart meters Final Deliverable*.

Eurelectric. (2011). 10 steps to smart grids: Eurelectric DSOs' ten-year roadmap for smart grid deployment in the EU.

Eurelectric. (2013). *Power Distribution in Europe - Facts & Figures*.

European Commission. (2007). A European strategic energy technology plan (SET Plan) - Towards a low carbon future.

European Commission. (2011). Energy Roadmap 2050.

European Commission. (2012a). Commission Recommendation 2012/148/EU of 9 March 2012 on preparations for the roll-out of smart metering systems.

European Commission. (2012b). Directive 2012/27/EU of the European Parliament and of the Council of 25 October 2012 on energy efficiency.

European Commission. (2013). Monitoring Consumer Markets in the European Union Part I. Retrieved from http://ec.europa.eu/consumers/consumer_evidence/consumer_scoreboards/market_monitoring/docs/consumer_market_monitoring_2013_part_2.pdf

European Commission. (2014a). Cost-benefit analyses & state of play of smart metering deployment in the EU-27.

European Commission. (2014b). Report from the Commission: Benchmarking smart metering deployment in the EU-27 with a focus on electricity.

European Commission. (2016). Clean Energy for all Europeans. *Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee, the*

Committee of the Regions and the European Investment Bank.

European Committee for Electrotechnical Standardization (CENELEC). (1994). Voltage Characteristics in Public Distribution Systems, EN 50160.

European Distribution System Operators for Smart Grids (EDSO4SG). (2016). Digital DSO. A vision and the regulatory environment needed to enable it.

European Electricity Grid Initiative. (2010). *Roadmap 2010-18 and Detailed Implementation Plan 2010-12*.

European Electricity Grid Initiative. (2013a). *Implementation Plan 2014-2016*.

European Electricity Grid Initiative. (2013b). *Research and Innovation Roadmap 2013-2022*.

European Technology Platform for Smart Grids. (2010). *Strategic Deployment Document for Europe's Electricity Networks of the Future*.

European Technology Platform for SmartGrids. (2006). *Vision and Strategy for European Electricity Networks of the Future*.

European Technology Platform for SmartGrids. (2007). *Strategic Research Agenda for Europe's Electricity Networks of the Future*. Retrieved from http://www.smartgrids.eu/documents/sra/sra_finalversion.pdf

European Technology Platform for SmartGrids. (2012). *SmartGrids SRA 2035: Strategic Research Agenda Update of the SmartGrids SRA 2007 for the needs by the year 2035*. Retrieved from http://www.smartgrids.eu/documents/sra2035.pdf

Faruqui, A., Hledik, R., & Sergici, S. (2009). Piloting the Smart Grid. *The Electricity Journal*, *22*(7), 55–69. http://doi.org/10.1016/j.tej.2009.06.012

Fernandes, C., Candela, A., & Gómez, T. (2012). An approach to calibrate incentives for continuity of supply in the Spanish electricity distribution system. *Electric Power Systems Research*, *82*(1), 81–87. http://doi.org/10.1016/j.epsr.2011.08.020

Ferreira, G. D., Gazzana, D. S., Bretas, A. S., Bettiol, A. L., Carniato, A., Passos, L. F. do N., … Molina, F. H. (2015). Multiobjective MILP model for optimal allocation of automated switching devices in electric power distribution systems. In *IEEE Eindhoven PowerTech* (pp. 1–6). IEEE. http://doi.org/10.1109/PTC.2015.7232715

Fraunhofer ISE. (2017). Recent facts about photovoltaics in Germany. Retrieved from http://pschuetzenduebe.webclient5.de/wp-content/uploads/130912-Recent-Facts-PV-Germany.pdf

Gan, C. K., Mancarella, P., Pudjianto, D., & Strbac, G. (2011). Statistical appraisal of economic design strategies of LV distribution networks. *Electric Power Systems Research*, *81*(7), 1363–1372. http://doi.org/10.1016/j.epsr.2011.02.001

Gan, C. K., Silva, N., Pudjianto, D., Strbac, G., Ferris, R., Foster, I., & Aten, M. (2009). Evaluation of alternative distribution network design strategies. In *IET Conference Publications* (pp. 690–690). IET. http://doi.org/10.1049/cp.2009.0923

Georgilakis, P. S., & Hatziargyriou, N. D. (2013). Optimal Distributed Generation Placement in Power Distribution Networks: Models, Methods, and Future Research. *IEEE Transactions on Power Systems*, *28*(3), 3420–3428. http://doi.org/10.1109/TPWRS.2012.2237043

Giordano, V., & Bossart, S. (2012). *Assessing Smart Grid Benefits and Impacts: EU and U. S. Initiatives*.

Giordano, V., Gangale, F., Fulli, G., & Sánchez-Jiménez, M. A. (2011). Smart Grid projects in Europe: Lessons learned and current developments. *European Commission, Joint Research Centre*. Joint Research Centre (JRC), European Commission. Retrieved from http://ses.jrc.ec.europa.eu/sites/ses/files/documents/smart_grid_projects_in_europe.pdf

Giordano, V., Meletiou, A., Covrig, C. F., Mengolini, A., Ardelean, M., Fulli, G., … Filiou, C. (2013). Smart Grid projects in Europe: Lessons learned and current developments 2012 update. *European Commission, Joint Research Centre*. Retrieved from http://ses.jrc.ec.europa.eu/sites/ses.jrc.ec.europa.eu/files/documents/ld-na-25815-en-n_final_online_version_april_15_smart_grid_projects_in_europe_-_lessons_learned_and_current_developments_-2012_update.pdf

Giordano, V., Onyeji, I., Fulli, G., Sánchez Jiménez, M., & Filiou, C. (2012). *Guidelines for conducting a cost-benefit analysis of Smart Grid projects*. Retrieved from http://scholar.google.com/scholar?hl=en&btnG=Search&q=intitle:Guidelines+for+conducting+a+cost-benefit+analysis+of+Smart+Grid+projects#0

Glachant, J.-M., Khalfallah, H., Perez, Y., Rious, V., & Saguan, M. (2012). Implementing Incentive Regulation and Regulatory Alignment with Resource Bounded Regulators. *EUI Working Paper RSCAS*. http://doi.org/10.2139/ssrn.2481918

Gonzalez-Garcia, A., Amatya, R., Stoner, R., & Perez-Arriaga, I. (2015). Evaluation of universal access to modern energy services in Peru. Case study of scenarios for Electricity Access in Cajamarca. Enel Foundation.

Gonzalez-Sotres, L., Mateo, C., Frias, P., Rodriguez-Morcillo, C., & Matanza, J. (2016). Replicability Analysis of PLC PRIME Networks for Smart Metering Applications. *IEEE Transactions on Smart Grid*, *3053*(c), 1–1. http://doi.org/10.1109/TSG.2016.2569487

González, A., Echavarren, F. M., Rouco, L., & Gómez, T. (2011). Fault location and service restoration method for large-scale distribution networks. In *17th Power Systems Computation Conference*. Stockholm.

González, A. G. (2014). *Implicaciones de la continuidad de suministro en el diseno de la tarifa de red de distribucion*. Comillas Pontifical University.

GRID+ Project. (2012). D4.1 Review of state of the art. Retrieved from http://www.gridplus.eu/Documents/Deliverables/GRID+_D4.1_r0.pdf

GRID+ Project. (2013a). D3.4 Define EEGI Project and Programme KPIs.

GRID+ Project. (2013b). D4.2 Data collection of DSO projects. Retrieved from http://www.gridplus.eu/Documents/Deliverables/GRID+_D4.2_v0.pdf

GRID+ Project. (2014). D4.4 Assessment of scalability and replicability of smart grid projects - Barriers and R&D needs.

GRID4EU project. (2014a). gD2.6 Stakeholder acceptance reports involving existing and new barriers. Retrieved June 1, 2016, from http://grid4eu.blob.core.windows.net/media-prod/24615/grid4eu_gwp2_deliverable_gd26_final.pdf

GRID4EU project. (2014b). gD3.2 & gD3.3 Technical scalability and replicability of relevant use cases. Methodology and application. Retrieved from http://grid4eu.blob.core.windows.net/media-prod/23993/grid4eu_gwp3_d3-23-3_technical-sra.pdf

GRID4EU project. (2015a). dD6.9-2 Final assessment of the demonstrator's operation using the KPIs.

GRID4EU project. (2015b). gD3.1 Definition of a common methodology for scaling-up and replication. Retrieved June 1, 2016, from http://grid4eu.blob.core.windows.net/media-prod/23989/grid4eu_gwp3_deliverable_gd31_final.pdf

GRID4EU project. (2015c). gD3.7 Replication potential in Belgium. Retrieved June 1, 2016, from http://grid4eu.blob.core.windows.net/media-prod/28763/grid4eu_gwp3_deliverable_gd37_final.pdf

GRID4EU project. (2016a). dD1.4 Technical and economic evaluation of an autonomous switching system in the MV-network. Retrieved June 1, 2016, from http://grid4eu.blob.core.windows.net/media-prod/28707/grid4eu_demo1_deliverable_dd14_final.pdf

GRID4EU project. (2016b). dD5.4 Demonstration activities results. Retrieved June 1, 2016, from http://grid4eu.blob.core.windows.net/media-prod/28723/dd5_4_v3_0_public-version.pdf

GRID4EU project. (2016c). gD2.7 Final KPIs report. Retrieved June 1, 2016, from http://grid4eu.blob.core.windows.net/media-prod/28751/grid4eu_gwp2_deliverable_gd27_final.pdf

GRID4EU project. (2016d). gD3.5 Scalability and replicability rules. Retrieved June 1, 2016, from http://grid4eu.blob.core.windows.net/media-prod/28755/grid4eu_gwp3_deliverable_gd35_final.pdf

GRID4EU project. (2016e). gD3.8 Replicability at International level: Application of GRID4EU SRA to California and Brazil. Retrieved August 31, 2016, from http://grid4eu.blob.core.windows.net/media-prod/28767/grid4eu_gwp3_deliverable_gd38_final.pdf

GTM Research. (2010). The Smart Grid in 2010: Market Segments, Applications and Industry Players.

Harrison, D. H. (1987). Voltage unbalance on rural systems. *Power Engineering Journal*, *1*(3), 149. http://doi.org/10.1049/pe:19870028

Hartmann, A., Linn, J. F., & Wolfensohn Center for Development. (2008). Scaling up: a framework and lessons for development effectiveness from literature and practice. http://doi.org/10.1016/j.febslet.2011.12.024

Hatziargyriou, N., Asano, H., Iravani, R., & Marnay, C. (2007). Microgrids. *IEEE Power and Energy Magazine*, *5*(4), 78–94. http://doi.org/10.1109/MPAE.2007.376583

IEEE Power & Energy Society. (2009). IEEE Std 1159-2009, IEEE Recommended Practice for Monitoring Electric Power Quality. http://doi.org/10.1109/IEEESTD.2009.5154067

IEEE Power & Energy Society. (2012). IEEE Std 1366-2012, IEEE Guide for Electric Power Distribution Reliability Indices. http://doi.org/10.1109.2004.94548

IGreenGrid Project. (2016). D5.1 Technical and economic evaluation of replicability and scalability of solutions to increase the Distributed Energy Resources.

IGreenGrid Project, SiNGULAR Project, & SuSTAINABLE Project. (2012). Modalities for interaction during the course of the project. Retrieved from http://www.singular-fp7.eu/home/images/deliverables/Deliverable_5.3.pdf

International Electrotechnical Commission. (2014). IEC 62196 Plugs, socket-outlets, vehicle connectors and vehicle inlets - Conductive charging of electric vehicles.

International Energy Agency (IEA). (2011). Technology roadmap smart grids.

International Energy Agency (IEA). (2016). Global EV Outlook 2016: Beyond one million electric cars.

International Renewable Energy Agency. (2013). Smart Grids and Renewables - A Guide for Effective Deployment.

International Smart Grid Association Network (ISGAN). (2014). TSO-DSO interaction: An Overview of current interaction between transmission and distribution system operators and an assessment of their cooperation in Smart Grids. *ISGAN Discussion Paper Annex 6 Power T&D Systems, Task 5*.

Ipakchi, A., & Albuyeh, F. (2009). Grid of the future. *IEEE Power and Energy Magazine*, *7*(2), 52–62. http://doi.org/10.1109/MPE.2008.931384

Jakobsson Ueda, M., Engblom, O., & Alvehag, K. (2009). Representative Test Systems for Swedish Distribution Networks. In *CIRED 2009, 20th International Conference and Exhibition on Electricity Distribution CIRED* (pp. 8–11).

Joint Research Centre, Giordano, V., Onyeji, I., Fulli, G., Sánchez Jiménez, M., & Filiou, C. (2012). *Guidelines for Cost Benefit Analysis of Smart Metering Deployment*.

Kazemi, S., Lehtonen, M., & Fotuhi-Firuzabad, M. (2012). Impacts of Fault Diagnosis Schemes on Distribution System Reliability. *IEEE Transactions on Smart Grid*, *3*(2), 720–727. http://doi.org/10.1109/TSG.2011.2176352

Keane, A., Ochoa, L. F., Borges, C. L. T., Ault, G. W., Alarcon-Rodriguez, A. D., Currie, R. A. F., … Harrison, G. P. (2013). State-of-the-Art Techniques and Challenges Ahead for Distributed Generation Planning and Optimization. *IEEE Transactions on Power Systems*, *28*(2), 1493–1502. http://doi.org/10.1109/TPWRS.2012.2214406

KEMA for the GridWise Alliance. (2009). *Smart Grid Project Evaluation Metrics*.

Kersting, W. H. (1991). Radial distribution test feeders. *IEEE Transactions on Power Systems*, *6*(3), 975–985. http://doi.org/10.1109/59.119237

Kiaee, M., Cruden, A., & Infield, D. (2011). Demand side management using alkaline electrolysers within the UKGDS simulation network. *CIRED 2011, 21st International Conference on Electricity Distribution*.

Kim, J.-Y., Jeon, J.-H., Kim, S.-K., Cho, C., Park, J. H., Kim, H.-M., & Nam, K.-Y. (2010). Cooperative Control Strategy of Energy Storage System and Microsources for Stabilizing the Microgrid during Islanded Operation. *IEEE Transactions on Power Electronics*, *25*(12), 3037–3048. http://doi.org/10.1109/TPEL.2010.2073488

Kim, S.-J., & Giannakis, G. B. (2013). Scalable and Robust Demand Response With Mixed-Integer Constraints. *IEEE Transactions on Smart Grid*, *4*(4), 2089–2099. http://doi.org/10.1109/TSG.2013.2257893

Kulkarni, P., Gormus, S., Fan, Z., & Ramos, F. (2012). AMI Mesh Networks—A Practical Solution and Its Performance Evaluation. *IEEE Transactions on Smart Grid*, *3*(3), 1469–1481. http://doi.org/10.1109/TSG.2012.2205023

Li, Y., & Wolfs, P. J. (2014). Taxonomic description for western Australian distribution medium-voltage and low-voltage feeders. *IET Generation, Transmission & Distribution*, *8*(1), 104–113. http://doi.org/10.1049/iet-gtd.2013.0005

Lima, J. W. M., Noronha, J. C. C., Arango, H., & dos Santos, P. E. S. (2002). Distribution pricing based on yardstick regulation. *IEEE Transactions on Power Systems*, *17*(1), 198–204. http://doi.org/10.1109/59.982214

Linares, P., & Rey, L. (2013). The costs of electricity interruptions in Spain. Are we sending the right signals? *Energy Policy*, *61*, 751–760. http://doi.org/10.1016/j.enpol.2013.05.083

Linder, G. W., Baumgart, D. E., & Brock, B. C. (1979). Supervisory Control And Automation Of Remote Substations Utilizing The Switched Telephone Network. In *7 IEEE/PES Transmission and Distribution Conference and Exposition* (pp. 391–393). IEEE. http://doi.org/10.1109/TDC.1979.712716

Liu, Z., & Milanovic, J. V. (2015). Probabilistic Estimation of Voltage Unbalance in MV Distribution Networks With Unbalanced Load. *IEEE Transactions on Power Delivery*, *30*(2), 693–703. http://doi.org/10.1109/TPWRD.2014.2322391

Lo Schiavo, L., Delfanti, M., Fumagalli, E., & Olivieri, V. (2013). Changing the regulation for regulating the change: Innovation-driven regulatory developments for smart grids, smart metering and e-mobility in Italy. *Energy Policy*, *57*, 506–517. http://doi.org/10.1016/j.enpol.2013.02.022

Long, R. W., Wilreker, V. F., & Strintzis, M. G. (1977). A geometric multidimensional clustering algorithm. In *Joint Automatic Control Conference*.

Low Voltage Network Solutions (LVNS) Project. (2014). D3.7 Characterisation of LV Networks. University of Manchester.

Lyons, P. F., Wade, N. S., Jiang, T., Taylor, P. C., Hashiesh, F., Michel, M., & Miller, D. (2015). Design and analysis of electrical energy storage demonstration projects on UK distribution networks. *Applied Energy*, *137*, 677–691. http://doi.org/10.1016/j.apenergy.2014.09.027

Ma, K., Li, R., & Li, F. (2016). Quantification of Additional Asset Reinforcement Cost From 3-Phase Imbalance. *IEEE Transactions on Power Systems*, *31*(4), 2885–2891. http://doi.org/10.1109/TPWRS.2015.2481078

Mancarella, P., Gan, C. K., & Strbac, G. (2011). Fractal models for electro-thermal network studies. *Proceedings of the 17th Power Systems Computation Conference (PSCC)*.

Massachusetts Institute of Technology. (2015). The Future of Solar Energy.

Massachusetts Institute of Technology. (2016). *Utility of the Future. An MIT Energy Initiative response to an industry in transition*. Retrieved from http://energy.mit.edu/wp-content/uploads/2016/12/Utility-of-the-Future-Full-Report.pdf

Mateo, C., Rodriguez-Calvo, A., Frías, P., Reneses, J., Sánchez, A., Bañales, S., … Gómez, J. (2015). Analysis of the impact of battery storage on power distribution systems. In *23rd International Conference on Electricity Distribution (CIRED)*.

Mateo, C., Sánchez, Á., Frías, P., Rodriguez-Calvo, A., & Reneses, J. (2016). Cost–benefit analysis of battery storage in medium-voltage distribution networks. *IET Generation, Transmission & Distribution*, *10*(3), 815–821. http://doi.org/10.1049/iet-gtd.2015.0389

Mateo Domingo, C., Gomez San Roman, T., Sanchez-Miralles, Á., Peco Gonzalez, J. P., & Candela Martinez, A. (2011). A Reference Network Model for Large-Scale Distribution Planning With Automatic Street Map Generation. *IEEE Transactions on Power Systems*, *26*(1), 190–197. http://doi.org/10.1109/TPWRS.2010.2052077

May, K., Vingerhoets, P., & Sigrist, L. (2015). Barriers regarding scalability and replicability of smart grid projects. In *International Conference on the European Energy Market, EEM* (Vol. 2015–Augus, pp. 15–18). http://doi.org/10.1109/EEM.2015.7216773

McDermott, T. E., & Dugan, R. C. (2003). PQ, reliability and DG. *IEEE Industry Applications Magazine*, *9*(5), 17–23. http://doi.org/10.1109/MIA.2003.1227867

Ministry of Power - Government of India. (2013). Smart Grid Vision and Roadmap for India. Retrieved from http://www.nsgm.gov.in//upload/files/India-Smart-Grid-Vision-and-Roadmap_DSG.pdf

Narimani, M. R., Vahed, A. A., Azizipanah-Abarghooee, R., & Javidsharifi, M. (2014). Enhanced gravitational search algorithm for multi-objective distribution feeder reconfiguration considering reliability, loss and operational cost. *Generation, Transmission & Distribution, IET*, *8*(1), 55–69. http://doi.org/10.1049/iet-gtd.2013.0117

National Institute of Standards and Technology. (2012). *Smart Grid: A Beginner's Guide*.

Ochoa, L. F., & Harrison, G. P. (2011). Minimizing Energy Losses: Optimal Accommodation and Smart Operation of Renewable Distributed Generation. *IEEE Transactions on Power Systems*, *26*(1), 198–205. http://doi.org/10.1109/TPWRS.2010.2049036

Office of Gas and Electricity Markets (OFGEM). (2013). Strategy decision for the RIIO-ED1 electricity distribution price control: Outputs, incentives and innovation. Supplementary annex to RIIO-ED1 overview paper.

OFGEM, Frontier Economics, & EA Technology. (2012). *A framework for the evaluation of smart grids*.

Padt, F., Opdam, P., Polman, N., & Termeer, C. (2014). *Scale-Sensitive Governance of the Environment*. (F. Padt, P. Opdam, N. Polman, & C. Termeer, Eds.)*Scale-Sensitive Governance of the Environment*. Wiley-Blackwell. http://doi.org/10.1002/9781118567135

Palma-Behnke, R., Reyes, L., & Jimenez-Estevez, G. (2012). Smart grid solutions for rural areas. In *2012 IEEE Power and Energy Society General Meeting* (pp. 1–6). IEEE. http://doi.org/10.1109/PESGM.2012.6345389

Papathanassiou, S., Hatziargyriou, N., & Strunz, K. (2005). A benchmark low voltage microgrid network. In *CIGRE Symposium Power systems with dispersed generation: technologies, impacts on development, operation and performances*.

Parmenter, D. (2007). *Key Performance Indicators (KPI): Developing, Implementing, and Using Winning KPIs*. *Zhurnal Eksperimental'noi i Teoreticheskoi Fiziki*. Wiley. http://doi.org/978-0470545157

Pasdar, A., & Mehne, H. H. (2011). Intelligent three-phase current balancing technique for single-phase load based on smart metering. *International Journal of Electrical Power & Energy Systems*, *33*(3), 693–698. http://doi.org/10.1016/j.ijepes.2010.11.019

Pérez-Arriaga, I. J. (2013). *Regulation of the Power Sector*. (I. J. Pérez-Arriaga, Ed.). London: Springer London. http://doi.org/10.1007/978-1-4471-5034-3

Pérez-Arriaga, I., Ruester, S., Schwenen, S., Batlle, C., & Glachant, J.-M. (2013). THINK - From Distribution Networks to Smart Distribution Systems: Rethinking the Regulation of European Electricity DSOs. http://doi.org/10.2870/78510

Personal, E., Guerrero, J. I., Garcia, A., Peña, M., & Leon, C. (2014). Key performance indicators: A useful tool to assess Smart Grid goals. *Energy*, *76*, 976–988. http://doi.org/10.1016/j.energy.2014.09.015

Pieltain Fernandez, L., Gomez San Roman, T., Cossent, R., Mateo Domingo, C., & Frias, P. (2011).

Assessment of the Impact of Plug-in Electric Vehicles on Distribution Networks. *IEEE Transactions on Power Systems*, *26*(1), 206–213. http://doi.org/10.1109/TPWRS.2010.2049133

Pilo, F., Pisano, G., Scalari, S., Dal Canto, D., Testa, A., Langella, R., … Turri, R. (2012). ATLANTIDE - Digital archive of the Italian electric distribution reference networks. In *CIRED 2012 Workshop: Integration of Renewables into the Distribution Grid* (pp. 165–165). IET. http://doi.org/10.1049/cp.2012.0783

Pombo, A. V., Murta-Pina, J., & Pires, V. F. (2016). A multiobjective placement of switching devices in distribution networks incorporating distributed energy resources. *Electric Power Systems Research*, *130*, 34–45. http://doi.org/10.1016/j.epsr.2015.08.012

Popovic, D. S., Glamocic, L. R., & Nimrihter, M. D. (2011). The optimal automation level of medium voltage distribution networks. *International Journal of Electrical Power & Energy Systems*, *33*(3), 430–438. http://doi.org/10.1016/j.ijepes.2010.10.004

Prettico, G., Gangale, F., Mengolini, A., Lucas, A., & Fulli, G. (2016). *Distribution System Operators Observatory, From European Electricity Distribution Systems to Representative Distribution Networks*.

PSE-REDES 2025 Project. (2010). PT4.2 Análisis de la contribución efectiva de las generación distribuida al control de tensiones.

Pudjianto, D., Aunedi, M., Djapic, P., & Strbac, G. (2014). Whole-Systems Assessment of the Value of Energy Storage in Low-Carbon Electricity Systems. *IEEE Transactions on Smart Grid*, *5*(2), 1098–1109. http://doi.org/10.1109/TSG.2013.2282039

Pudjianto, D., Djapic, P., Aunedi, M., Gan, C. K., Strbac, G., Huang, S., & Infield, D. (2013). Smart control for minimizing distribution network reinforcement cost due to electrification. *Energy Policy*, *52*, 76–84. http://doi.org/10.1016/j.enpol.2012.05.021

Ravichandran, A., Malysz, P., Sirouspour, S., & Emadi, A. (2013). The critical role of microgrids in transition to a smarter grid: A technical review. In *2013 IEEE Transportation Electrification Conference and Expo (ITEC)* (pp. 1–7). IEEE. http://doi.org/10.1109/ITEC.2013.6573507

Red Eléctrica de España. (2009). El suministro de la electricidad. Un equilibrio entre generación y consumo.

Red Eléctrica de España. (2015). El Sistema Eléctrico Español 2015 (in Spanish).

Regulators, E., Contact, G., Energy, E., Asbl, R., Arrondissement, B., & Rpm, B. (2009). Treatment of Electricity Losses by Network Operators ERGEG Position Paper Conclusions Paper, (February).

Report, T., & Electric Power Research Institute. (2004). *Power Delivery System of the Future A Preliminary Estimate of Costs and Benefits* (Vol. 3).

Rigoni, V., Ochoa, L. F., Chicco, G., Navarro-Espinosa, A., & Gozel, T. (2016). Representative Residential LV Feeders: A Case Study for the North West of England. *IEEE Transactions on Power Systems*, *31*(1), 348–360. http://doi.org/10.1109/TPWRS.2015.2403252

Rivier, J., & Gomez, T. (2000). A conceptual framework for power quality regulation. In *Ninth International Conference on Harmonics and Quality of Power. Proceedings (Cat. No.00EX441)* (Vol. 2, pp. 469–474). IEEE. http://doi.org/10.1109/ICHQP.2000.897724

Rivier Abbad, J. (1999). *Calidad del servicio. Regulación y optimización de inversiones*. Comillas Pontifical University.

Rodriguez-Calvo, A., Cossent, R., & Frias, P. (2017). Scalability and Replicability Analysis of large-scale Smart Grid implementations: approaches and proposals in Europe. *Working Paper IIT-17-044A under Review for Publication in Renewable & Sustainable Energy Reviews*.

Rodriguez-Calvo, A., Cossent, R., & Frías, P. (2016). Assessing the potential of MV automation for distribution network reliability improvement. *Working Paper IIT-17-045A under Review Sor Publication in International Transactions on Electrical Energy Systems*.

Rodriguez-Calvo, A., Cossent, R., & Frías, P. (2017). Integration of PV and EVs in unbalanced residential LV networks and implications for the smart grid and advanced metering infrastructure deployment. *International Journal of Electrical Power & Energy Systems*, *91*, 121–134. http://doi.org/10.1016/j.ijepes.2017.03.008

Rodriguez-Calvo, A., Frías, P., Reneses, J., Cossent, R., & Mateo, C. (2014). Optimal investment in smart MV/LV substations to improve continuity of supply. *International Journal of Electrical Power & Energy Systems*, *62*, 410–418. http://doi.org/10.1016/j.ijepes.2014.04.062

Rodriguez-Calvo, A., Frías, P., Reneses, J., Mateo, C., del Río, L., & Bañales, S. (2012). Mejora de la calidad del suministro eléctrico mediante centros de transformación inteligentes. *Anales de Ingeniería Mecánica*, *LXXXVIV*(III), 11–17.

Rodriguez-Calvo, A., Frias, P., Reneses, J., Mateo, C., Frías, P., Reneses, J., & Mateo, C. (2012). Optimal Degree of Smart Transformer Substations in Distribution Networks for Reliability Improvement. In *3rd IEEE PES Innovative Smart Grid Technologies (ISGT) Europe Conference*. http://doi.org/10.1109/ISGTEurope.2012.6465733

Rodriguez-Calvo, A., Izadkhast, S., Cossent, R., & Frías, P. (2015). Evaluating the determinants of the scalability and replicability of islanded operation in medium voltage networks with cogeneration. In *International Symposium on Smart Electric Distribution Systems and Technologies (EDST)* (pp. 80–87).

Rudion, K., Orths, A., Styczynski, Z. a., & Strunz, K. (2006). Design of benchmark of medium voltage distribution network for investigation of DG integration. *2006 IEEE Power Engineering Society General Meeting*, 1–6. http://doi.org/10.1109/PES.2006.1709447

SANDIA National Laboratories, Akhil, A., Huff, G., Currier, A., Kaun, B. C., Rastler, D. M., … Gauntlett, W. D. (2013). *DOE/EPRI 2013 electricity storage handbook in collaboration with NRECA*. *Report SAND2013-5131*. Retrieved from http://www.emnrd.state.nm.us/ECMD/RenewableEnergy/documents/SNL-ElectricityStorageHandbook2013.pdf

Sappington, D. E. M. (2005). Regulating Service Quality: A Survey. *Journal of Regulatory Economics*, *27*(2), 123–154. http://doi.org/10.1007/s11149-004-5341-9

Schneider, K. P., Chen, Y., Chassin, D. P., Pratt, R. G., Engel, D., & Thompson, S. (2008). *Modern Grid Initiative: Distribution Taxonomy Final Report*. *Pacific Northwest National Laboratory (PNNL)*. Retrieved from http://scholar.google.com/scholar?hl=en&btnG=Search&q=intitle:Modern+Grid+Initiative+Distribution+Taxonomy+Final+Report#0

Schneider, K. P., Fuller, J. C., Tuffner, F. K., & Singh, R. (2010). Evaluation of Conservation Voltage Reduction (CVR) on a National Level. *Pacific Northwest National Laboratory*. http://doi.org/10.2172/990131

Shahin, A., & Mahbod, M. A. (2007). Prioritization of key performance indicators: An integration of analytical hierarchy process and goal setting. *International Journal of Productivity and Performance Management*, *56*(3), 226–240. http://doi.org/10.1108/17410400710731437

Shahsavari, A., Fereidunian, A., & Mazhari, S. M. (2015). A joint automatic and manual switch placement within distribution systems considering operational probabilities of control sequences. *International Transactions on Electrical Energy Systems*, *25*(11), 2745–2768. http://doi.org/10.1002/etep.1989

Short, T. A. (2005). *Electric Power Distribution Electric Power Distribution Equipment and Systems*. CRC Press.

Sigrist, L. (2015). A UFLS Scheme for Small Isolated Power Systems Using Rate-of-Change of Frequency. *IEEE Transactions on Power Systems*, *30*(4), 2192–2193. http://doi.org/10.1109/TPWRS.2014.2357218

Sigrist, L., Egido, I., & Rouco, L. (2012a). A Method for the Design of UFLS Schemes of Small Isolated Power Systems. *IEEE Transactions on Power Systems*, *27*(2), 951–958. http://doi.org/10.1109/TPWRS.2011.2174448

Sigrist, L., Egido, I., & Rouco, L. (2012b). Performance Analysis of UFLS Schemes of Small Isolated Power Systems. *IEEE Transactions on Power Systems*, *27*(3), 1673–1680. http://doi.org/10.1109/TPWRS.2011.2182066

Sigrist, L., Egido, I., & Rouco, L. (2013). Principles of a Centralized UFLS Scheme for Small Isolated Power Systems. *IEEE Transactions on Power Systems*, *28*(2), 1779–1786. http://doi.org/10.1109/TPWRS.2012.2227839

Sigrist, L., Lobato, E., Rouco, L., Gazzino, M., & Cantu, M. (2017). Economic assessment of smart grid initiatives for island power systems. *Applied Energy*, *189*, 403–415. http://doi.org/10.1016/j.apenergy.2016.12.076

Sigrist, L., May, K., Morch, A., Verboven, P., Vingerhoets, P., & Rouco, L. (2016). On Scalability and Replicability of Smart Grid Projects—A Case Study. *Energies*, *9*(3), 195. http://doi.org/10.3390/en9030195

Siirto, O. K., Safdarian, A., Lehtonen, M., & Fotuhi-Firuzabad, M. (2015). Optimal distribution network automation considering earth fault events. *IEEE Transactions on Smart Grid*, *6*(2), 1010–1018. http://doi.org/10.1109/TSG.2014.2387471

Smart Energy Demand Coalition (SEDC). (2014). Mapping Demand Response in Europe Today. Retrieved from http://www.febeliec.be/web/infosession strategic demand reserve _ 16_5_2014/1011306087/list1187970122/f1.html%5Cnhttp://sedc-coalition.eu/wp-content/uploads/2014/04/SEDC-Mapping_DR_In_Europe-2014-04111.pdf

Smart Grids Task Force. Expert Group 3. (2013). EG3 First Year Report: Options on handling Smart Grids Data.

Smolleck, H. A. (1992). A new look at the effects of unbalanced voltages upon synchronous and induction machines. *Electric Power Systems Research*, *25*(3), 199–206. http://doi.org/10.1016/0378-7796(92)90019-W

Sortomme, E., Hindi, M. M., MacPherson, S. D. J., & Venkata, S. S. (2011). Coordinated Charging of Plug-In Hybrid Electric Vehicles to Minimize Distribution System Losses. *IEEE Transactions on Smart Grid*, *2*(1), 198–205. http://doi.org/10.1109/TSG.2010.2090913

Spanish Ministry of Economy. (2000). Real Decreto 1955/2000, de 1 de diciembre, por el que se regulan las actividades de transporte, distribución, comercialización, suministro y procedimientos de autorización de instalaciones de energía eléctrica (in Spanish). Boletín Oficial del Estado.

Spanish Ministry of Industry Energy and Tourism. (2013). Real Decreto 1048/2013, de 27 de diciembre, por el que se establece la metodología para el cálculo de la retribución de la actividad de distribución de energía eléctrica. Boletín Oficial del Estado.

Spanish Ministry of Industry Energy and Tourism. (2015). Orden IET/2660/2015 por la que se aprueban las instalaciones tipo y los valores unitarios de referencia de inversión, de operación y mantenimiento por elemento de inmovilizado y los valores unitarios de retribución de otras tareas reguladas que se emplear. Boletin Oficial del Estado. http://doi.org/BOE-A-2012-5403

Spanish Ministry of Industry Tourism and Commerce. Real Decreto 222/2008, de 15 de febrero, por el que se establece el régimen retributivo de la actividad de distribución de energía eléctrica, 67Boletín Oficial del Estado (2008).

Sridhar, P., & Madni, A. (2009). Scalability and Performance Issues in Deeply Embedded Sensor Systems. *International Journal On Smart Sensing And Intelligent Systems*, *2*(1), 1–14. Retrieved from http://www.s2is.org/Issues/v2/n1/papers/paper1.pdf

Srivastava, A. K., Kumar, A. A., & Schulz, N. N. (2012). Impact of Distributed Generations With Energy Storage Devices on the Electric Grid. *IEEE Systems Journal*, *6*(1), 110–117. http://doi.org/10.1109/JSYST.2011.2163013

Strbac, G., Djapic, P., Ortega, E., Stanojevic, V., Markides, C., Aunedi, M., … Sutton, A. (2014). Management of electricity distribution network losses. Executive summary.

Strbac, G., Gan, C. K., Aunedi, M., Stanojevic, V., Djapic, P., Dejvises, J., … Claxton, A. (2010). Benefits of Advanced Smart Metering for Demand Response based Control of Distribution Networks. Summary report. Centre for Sustainable Electricity and Distributed Generation (SEDG) Report for Energy Networks Association (ENA).

Strbac, G., & McDonald, J. (2004). United Kingdom Generic Distribution System. Retrieved June 1, 2016, from http://www.sedg.ac.uk/ukgds.htm

Strunz, K., Fletcher, R. H., Campbell, R., & Gao, F. (2009). Developing benchmark models for low-voltage distribution feeders. *2009 IEEE Power and Energy Society General Meeting, PES '09*, (July), 1–3. http://doi.org/10.1109/PES.2009.5260227

Su, C. L., & Teng, J. H. (2007). Economic evaluation of a distribution automation project. *Industry Applications, IEEE Transactions on*, *43*(6), 1417–1425.

Suri, M., Dunlop, E. D., & Jones, A. R. (2002). GIS-based inventory of the potential photovoltaic output in Central and Eastern Europe. In *Photovoltaics in Europe. From Photovoltaic Technology to Energy Solutions* (pp. 1039–1042).

SuSTAINABLE project. (2012). D8.2 Scaling-up and replication rules considering the requirements and local conditions in demo sites.

Tangsunantham, N., & Pirak, C. (2013). Voltage unbalance measurement in three-phase smart meter applied to AMI systems. *2013 10th International Conference on Electrical Engineering/Electronics, Computer, Telecommunications and Information Technology, ECTI-CON 2013*, 1–5. http://doi.org/10.1109/ECTICon.2013.6559601

Trebolle, D., Frías, P., Maza, J. M., & Martínez Ramos, J. L. (2012). El control de tensión en redes de distribución con generación distribuida (I). *Anales de Ingeniería Mecánica*, *LXXXIX*(I), 21–28.

Trebolle, D., Frías, P., Maza, J. M., Tello, J., & Rodriguez-Calvo, A. (2012). El control de tensión en redes de distribución con generación distribuida (III). *Anales de Ingeniería Mecánica*, *LXXXVIV*(III), 11–18.

U.S. Department of Energy Electricity Delivery and Energy Reliability. (2009). *Smart Grid System Report*. Retrieved from http://www.smartgrid.gov/sites/default/files/doc/files/2009-014655 - SGSR FINAL VERSION 2 2 2012 print ready.pdf

U.S. Department of Energy Electricity Delivery and Energy Reliability. (2012). 2010 Smart Grid System Report to US Congress. Retrieved from http://www.smartgrid.gov/sites/default/files/doc/files/2009-014655 - SGSR FINAL VERSION 2 2 2012 print ready.pdf

United Kingdom Generic Distribution System (UKGDS). (2005). Defining the Generic Networks.

United Nations. (1998). *Kyoto Protocol to the United Nations Framework Convention on Climate Change*.

United Nations. (2006). *Expanding access to modern energy services. Replicating, Scaling Up and Mainstreaming at the local level. Lessons learned from community-based energy initiatives*.

United Nations. (2015). Paris Agreement.

United Nations Development Programme. (2013). Scaling Up Development Programmes.

Vallés, M., Reneses, J., Frías, P., & Mateo, C. (2016). Economic benefits of integrating Active Demand in distribution network planning: A Spanish case study. *Electric Power Systems Research*, *136*, 331–340. http://doi.org/10.1016/j.epsr.2016.03.017

Vandael, S., Claessens, B., Hommelberg, M., Holvoet, T., & Deconinck, G. (2013). A Scalable Three-Step Approach for Demand Side Management of Plug-in Hybrid Vehicles. *IEEE Transactions on Smart Grid*, *4*(2), 720–728. http://doi.org/10.1109/TSG.2012.2213847

Vardakas, J. S., Zorba, N., & Verikoukis, C. V. (2016). Power demand control scenarios for smart grid applications with finite number of appliances. *Applied Energy*, *162*, 83–98. http://doi.org/10.1016/j.apenergy.2015.10.008

Vitiello, S., Flego, G., Setti, A., Fulli, G., Liotta, S., Alessandroni, S., … Parisse, D. (2015). *A Smart Grid for the city of Rome - A Cost Benefit Analysis*. Retrieved from http://ses.jrc.ec.europa.eu/sites/ses.jrc.ec.europa.eu/files/publications/acea_jrc_report_online.pdf

Vitorino, R. M., Jorge, H. M., & Neves, L. P. (2015). Multi-objective optimization using NSGA-II for power distribution system reconfiguration. *International Transactions on Electrical Energy Systems*, *25*(1), 38–53. http://doi.org/10.1002/etep.1819

Wang, J., Conejo, A. J., Wang, C., & Yan, J. (2012). Smart grids, renewable energy integration, and climate change mitigation – Future electric energy systems. *Applied Energy*, *96*, 1–3. http://doi.org/10.1016/j.apenergy.2012.03.014

Wang, P. (2013a). Smart Grid Project Catalogue: Part 1, by Project Application. *International Smart Grid Action Network (ISGAN) Inventory Report*.

Wang, P. (2013b). Smart Grid Project Catalogue: Part 2, by Contribution to Policy Goal. *International Smart Grid Action Network (ISGAN) Inventory Report*.

Wang, P. (2014). Smart Grid Drivers and Technologies by Country, Economies, and Continent. *International Smart Grid Action Network (ISGAN) Framework of Assessment Report*. Retrieved from http://www.iea-isgan.org/index.php?r=home&c=5/378

Willis, H., Tram, H., & Powell, R. (1985). A Computerized, Cluster Based Method of Building Representative Models of Distribution Systems. *IEEE Transactions on Power Apparatus and Systems*, *PAS-104*(12), 3469–3474. http://doi.org/10.1109/TPAS.1985.318897

Wolsink, M. (2012). The research agenda on social acceptance of distributed generation in smart grids: Renewable as common pool resources. *Renewable and Sustainable Energy Reviews*, *16*(1), 822–835. http://doi.org/10.1016/j.rser.2011.09.006

Working Group III of the Intergovernmental Panel on Climate Change, Edenhofer, O., Pichs-Madruga, R., Sokona, Y., Seyboth, K., Matschoss, P., … Stechow, C. von. (2011). IPCC Special Report on Renewable Energy Sources and Climate Change Mitigation. Cambridge University Press.

Working Group on Distribution System Design. (1984). Bibliography on Distribution Automation 1969 - 1982. *IEEE Transactions on Power Apparatus and Systems*, *103*(6), 1176–1182.

World Economic Forum, & Accenture. (2010). Accelerating Successful Smart Grid Pilots. Retrieved from http://www.smartgridnews.com/artman/publish/Business_Strategy_Resources/Accelerating-successful-smart-grid-pilots-3017.html