Programa de Doctorado en Energía Eléctrica

ALGORITHMS FOR DISTRIBUTION SYSTEM PLANNING: APPLICATIONS TO U.S. SYNTHETIC NETWORKS AND IMPROVING RESILIENCE THROUGH MICROGRIDS

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A mi familia

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Abstract

Climate change is a confirmed and ongoing phenomenon that implies several changes in temperatures and weather patterns on Earth, including an increase in temperatures, melting of the poles, and an increase in the intensity of hurricanes. The most critical factor behind climate change is the emission of greenhouse gases, with energy being responsible for 72% of emissions. In response to these findings, organizations and countries such as the European Union and the United States have formulated action plans to achieve net-zero greenhouse gas emissions in societies and economies by 2050. The proposed policies are primarily concerned with energy management, with a commitment to phase out the use of fossil fuels and promote energy supplied by renewable sources.

Renewable generation technologies are commonly connected to the electrical distribution network. As a result, the top-down paradigm is being abandoned, with a transition from a highly centralized electricity system to a considerably more decentralized system, in which distribution networks are no longer dominated by demand but instead coexist with distributed generation. This paradigm shift has increased the complexity of the distribution network operation, where the bi-directional power flows and the growing flexibility of network assets are becoming more and more common. Such complexity highlights the need for the design of algorithms that optimize the management and planning of network assets, and the need for representative synthetic distribution networks to test and compare the proposed algorithms. This thesis addresses these needs from a network planning perspective with a compendium of four papers.

In the first part of this thesis (papers 1 and 2), a review of the published to date distribution test systems that have a U.S. architecture is carried out, pointing out the limitations they present as a test system to evaluate new algorithms developed by the scientific community. Taking this as a starting point, a novel set of algorithms is presented that allows generating large-scale distribution networks with a U.S. architecture, overcoming the limitations identified in previous test systems.

In the second part of this thesis (papers 3 and 4), distribution network planning is approached from the perspective of reinforcing an existing network through microgrids. First, it is presented a methodology that seeks to maximize network reliability while minimizing investment by installing photovoltaic panels, batteries, and diesel generation groups. Secondly, a model is formulated that aims to maximize the system's resilience while minimizing the investment, in this case, through the installation of remote-controlled switches, the undergrounding of lines, and the installation of photovoltaic panels and batteries. In both cases, the profitability of the solutions is analyzed under different cost assumptions.

Resumen

El cambio climático es una realidad probada y en marcha, referida a una serie de cambios en las temperaturas y patrones climáticos en la Tierra como un incremento en las temperaturas, el deshielo de los polos o un incremento en la intensidad de los huracanes. La causa principal del cambio climático es la emisión de gases de efecto invernadero siendo en su conjunto la energía, la fuente del 72 % de las emisiones totales. En respuesta a estos datos, instituciones y gobiernos como la Unión Europea o Estados Unidos, han desarrollado planes de acción que buscan conformar unas sociedades y economías libres de emisiones de gases de efecto invernadero para el año 2050. Las políticas propuestas, centran sus medidas principalmente en la gestión de la energía, apostando por un abandono del uso de combustibles fósiles y una producción de energía basada en fuentes de generación renovables.

Un factor común de las tecnologías de generación renovables es que la mayor parte de estas se conectan en la red de distribución eléctrica. Como consecuencia, se está viviendo un proceso de transición desde un sistema eléctrico sumamente centralizado hasta un sistema mucho más distribuido, en el que las redes de distribución ya no están dominadas en su mayor parte por la demanda, sino que co-existen demanda y generación. Este cambio de paradigma ha provocado un aumento considerable de la complejidad de la red de distribución, en la que la intermitencia de la generación renovable, los flujos bidireccionales de energía y la creciente flexibilidad de los activos de la red son cada vez más comunes. Dicha complejidad pone de manifiesto la necesidad del diseño de algoritmos que optimicen la gestión y planificación de los activos de red, y la necesidad de redes de distribución sintéticas y representativas que permitan chequear y comparar los algoritmos propuestos. Esta tesis realizada como compendio de cuatro artículos, trata de dar respuesta a estas necesidades desde una perspectiva de la planificación de red.

En la primera parte de esta tesis (artículos 1 y 2) se realiza una revisión de las redes de distribución con una arquitectura USA publicadas hasta la fecha, y se señalan cuáles son las limitaciones que estas presentan como base de pruebas para evaluar los nuevos algoritmos desarrollados por la comunidad científica. Tomando este punto de partida, se presenta un modelo que permite generar redes de distribución de gran escala con una arquitectura USA, resolviendo así las limitaciones identificadas.

En una segunda parte de esta tesis (artículos 3 y 4), se plantea la planificación de la red de distribución desde la perspectiva de reforzar la red existente empleando microrredes. En primer lugar, se presenta una metodología que permite maximizar la fiabilidad de la red mientras se minimiza la inversión a través de la instalación de paneles fotovoltaicos, baterías y grupos diésel. En segundo lugar, se propone un modelo que maximiza la resiliencia del sistema mientras se minimiza la inversión, en este caso, a través de la instalación de la instalación de elementos de maniobra tele-controlados, el soterramiento de líneas, y la instalación de paneles fotovoltaicos y baterías. En ambos casos se analiza la rentabilidad de las soluciones ante distintos escenarios de costes.

Contents

List of publications

Papers as the first author:

I. **F. Postigo Marcos**, C. Mateo Domingo, and T. Gómez San Román, “Improving distribution network resilience through automation, distributed energy resources, and undergrounding,” *International Journal of Electrical Power & Energy Systems*, vol. 141, p. 108116, Oct. 2022, doi: 10.1016/j.ijepes.2022.108116.

II. **F. Postigo Marcos**, C. Mateo Domingo, T. Gómez San Román, and R. Cossent Arín, “Location and Sizing of Micro-Grids to Improve Continuity of Supply in Radial Distribution Networks,” *Energies*, vol. 13, no. 13, Art. no. 13, Jan. 2020, doi: 10.3390/en13133495

III. **F. Postigo**, C. Mateo, T. Gómez, F. de Cuadra, P. Dueñas, T. Elgindy, B.M. Hodge, B. Palmintier, V. Krishnan. “Phase-selection algorithms to minimize cost and imbalance in U.S. synthetic distribution systems,” *International Journal of Electrical Power & Energy Systems*, vol. 120, p. 106042, Sep. 2020, doi: 10.1016/j.ijepes.2020.106042.

IV. **F. E. Postigo Marcos**, C. Mateo, T. Gómez, B. Palmintier, B.M. Hodge, V. Krishnan, F. de Cuadra, B. Mather. “A Review of Power Distribution Test Feeders in the United States and the Need for Synthetic Representative Networks,” *Energies*, vol. 10, no. 11, p. 1896, Nov. 2017, doi: 10.3390/en10111896.

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I. B. Palmintier, T. Elgindy, C. Mateo, **F. Postigo Marcos**, T. Gómez, F. de Cuadra, P. Dueñas. “Experiences developing large-scale synthetic U.S.-style distribution test systems,” *Electric Power Systems Research*, vol. 190, p. 106665, Jan. 2021, doi: 10.1016/j.epsr.2020.106665.

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Abbreviations

DER	Distributed Energy Resources
DG	Distributed Generation
DSO	Distribution System Operator
HILP	High Impact Low Probability
HV	High Voltage
IIT	Instituto de Investigación Tecnológica (Institute for Research in Technology)
LCOE	Levelized Cost of Energy
LTC	Load Tap Changer
LV	Low Voltage
MG	Micro-Grid
MIT	Massachusetts Institute of Technology
MV	Medium Voltage
NREL	National Renewable Energy Laboratory
OPF	Optimal Power Flow
PV	Photovoltaic
RCS	Remotely Controlled Switches
RNM	Reference Network Model
TAMU	Texas Agricultural and Mechanical University

1

INTRODUCTION

1.1. Background

There is no doubt, we are in a time of change. Climate change is a proven and ongoing reality, which involves a series of changes in temperatures and weather patterns on Earth [1]. The consequences of climate change are multiple, concatenated, and catastrophic in the long term [2], including an increase in temperatures, droughts and heatwaves [3], melting of the poles [4], a rise in sea level [5], as well as an increase in the intensity of hurricanes [6].

The leading cause of climate change is the emission of greenhouse gases [7]. Although the numbers by sector vary depending on the country analyzed [8], globally, the primary sources of greenhouse gas emissions are electricity and heat production (31%), transportation (15%), manufacturing processes (12%), and agriculture (11%), where energy as a whole is the source of 72% of total emissions [9].

In response to these data, governments of the European Union [10] and the United States [11] have developed action plans that seek to shape societies and economies with net-zero greenhouse gas emissions by 2050. These strategies are in line with the Paris Agreement [12], which sets targets such as limiting the temperature increase by the end of the century to 2°C, and doing what is possible to keep it to 1.5°C. The proposed policies mainly focus their measures on energy management, given that, as indicated above, energy is the primary driver of greenhouse gas emissions [13]. For this reason, there is a solid commitment to abandon the use of fossil fuels and to promote energy based on renewable generation sources, in which, in most cases, emissions are zero or very low [14].

It should be noted that climate change is not the only reason for the progressive integration of renewable energy sources. Other socioeconomic factors encourage a gradual abandonment of the use of fossil fuels. This is the case of the rise and volatility of energy prices [15], the fruit of rising fuel costs (mainly oil [16] and gas[17]), mostly due to geopolitical instabilities and dependencies. For this reason, the integration of renewable generation technologies, whose primary resources such as wind or sun are available in most locations, reduces these dependencies and lowers the cost of energy.

These arguments set the direction of the global energy system, in which the integration of renewable energy sources is undoubtedly the way forward. On the other hand, the cost of these technologies has fallen sharply in recent years. For example, during the last decade, the cost of PV systems has dropped by 85%, while the cost of onshore wind turbines has decreased by 56% [18]. This reduction in costs has caused the Levelized Cost of Energy (LCOE) of these renewable technologies to be even lower[1] than those associated with technologies that use fossil resources as a source [19].

The major drawback of renewable energy sources is their variability and limited controllability [20] , which has been a handicap for their integration. Unlike fossil generation technologies, whose main advantage is the ability to control production at any time, renewable technologies depend on resources that cannot be a priori controlled, such as the wind or the sun[2]. However, the development of energy storage systems such as batteries, and their significant drop in costs [21], have closed the circle towards a 100% renewable power system in the future.

A common factor of most renewable generation technologies is that, unlike the large thermal power plants that have characterized generation over the last century, renewable generation is typically smaller in size and power, allowing a wider distribution of assets [22]. Consequently, the top-down paradigm is being discarded, moving from a highly centralized electricity system to a much more decentralized system, in which distribution networks are no longer dominated by demand, but co-exist with distributed generation.

Until no more than three decades ago, distribution networks consisted of passive power lines and transformers governed mainly by electromechanical switching elements and minimal or no system monitoring. With the development of renewable generation technologies and the digitalization of the energy sector, distribution networks are no longer a passive asset but a conjunction of electrotechnical and telecommunication assets with many monitoring and control variables. This paradigm shift has led to a considerable increase in the complexity of distribution networks, where the renewable generation intermittency, the bi-directional power flows, and the growing flexibility of network assets has forced the scientific community to rethink how to plan distribution networks [23]. Such complexity highlights the need for the design of algorithms that optimize the management and planning of network assets, and the need for realistic distribution test systems to benchmark the proposed algorithms performance. Therefore, these two needs related to distribution network planning motivate the objectives of this thesis and are further developed in the following section.

Distribution network planning can be defined as the selection of the electrical equipment and its connectivity, in such a way that supply is guaranteed, and operational constraints are

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[1] *The LCOE considered is $31.45 for onshore wind turbines, $29.04 for standalone PV systems, and $37.11 for combined cycles. It should be noted that the levelized variable cost used in this study for the combined cycle is $26.68 in the year 2021, however, at the time of writing this text this cost has been multiplied by 10, accentuating the difference even more.*

[2] *Although there are controllable renewable generation technologies such as hydro with reservoir, in many cases the watersheds are already fully exploited and do not accept new installations.*

met. Moreover, distribution network planning can be approached from a dual perspective depending on the initial situation at the time of planning, greenfield, or brownfield [24]. The planning of the distribution network from scratch is called greenfield, while the planning aimed at reinforcing an existing network is called brownfield. Both approaches have evolved towards greater representativeness and optimization of the resources, as explained hereunder.

Referring to the previous argument, during the last few decades, as computing capabilities have developed, the scientific community has published new algorithms that optimize the management and planning of network assets with greater applicability to real networks. Some of these algorithms are Optimal Power Flows (OPFs), advanced feeder reconfiguration models, or Volt/Var optimization. Firstly, it can be expected that the networks that serve as a basis for testing and benchmarking these algorithms, commonly called test feeders or test systems, are the real networks. However, since the distribution network is considered as a critical infrastructure, real network data cannot be made publicly available because it would pose a risk to network users and utilities threatened by potential physical or cyber-attacks. For this reason, it is necessary to replace real network data by realistic synthetic or real anonymized networks that would help to overcome the aforementioned limitations. Nevertheless, the existing test feeders in the literature were limited in several aspects such as their size or the lack of specific zonal characteristics of the studied area. For this reason, institutions such as the European Commission [25], [26] or the U.S. Department of Energy [27] have funded and developed research projects whose objective is the development of a new generation of test systems.

These new test systems are born as a new generation of the original test feeders published by institutions such as IEEE, EPRI, or PNNL, overcoming the limitations that hinder and reduce the applicability of the obtained results [28]. As previously stated, the main limitations are the small size and the lack of representativeness of the studied area. This last point raises the need to recognize the difference between the two main types of distribution network architectures, which are represented by the different European and U.S. practices and designs.

As shown in Table 1, the differences between both architectures are remarkable, from the number of phases of the feeders, to the length of the low voltage network, or the degree of undergrounding of the network, among others [29]. Both architectures respond mainly to the structure of the urbanism to minimize the cost of distribution assets. For example, the U.S. architecture accommodates a greater load dispersion since the density of customers is much lower than the one found in most European cities. It is worth noting that, although both architectures have been named according to the origin place, both designs have been exported to other countries, usually according to their colonial roots. For this reason, it is essential to note that the new generation of distribution test systems must be zonal featured and represent the differential characteristics of the architecture being modelled.

Table 1: Distribution network architectures

European Distribution Systems	U.S. Distribution Systems
Three-phase feeders	Single-, two- and three- phase feeders
Long LV network (around 200 meters)	Short LV network (about 30 meters)
Large and complex distribution transformers feeding many customers (around 100 customers per transformer)	Small distribution center tapped transformers feeding few customers (around 4 - 10 customers)
Mainly underground (urban)	Mainly overhead (even in urban)
Voltage regulators and Load Tap Changers (LTC) are used in the feeder's head or to raise the voltage where necessary	Massive use of voltage regulators and capacitors in MV
Frequency: 50 Hz	Frequency: 60 Hz

Building large-scale test systems that are representative of a selected area is a complex task due to the large number of variables that need to be considered. Reference network models, based on greenfield planning approaches, were developed in the context of economic regulation applied to distribution utilities to build a reference distribution system in a given distribution area, emulating the technical and economic planning criteria used by utilities and regulators, and considering a wide set of inputs such as consumer location and demand, or electrical equipment parameters and costs, among others. The networks obtained by these models can be used as test systems since they represent realistic synthetic networks that overcome the limitations related to confidentiality of critical infrastructure, and thus can be used as a base for testing new algorithms. Until the start date of this thesis, large-scale representative test systems were only available following a European architecture [30]; however, there was no such large-scale test distribution systems with a U.S. architecture. As detailed in the next section, the analysis of the existing U.S. power distribution test feeders, and the development of new planning algorithms embedded in reference network models to obtain U.S. featured test distribution systems are the main objectives of the first part of this doctoral thesis.

On the other hand, network planning is no longer limited to only traditional equipment reinforcement to meet operational constraints. The integration of DER and the digitalization of the sector have increased the number of control variables in network operation, leading to a greater system flexibility. As the literature confirms [31], the provision of flexibility services can solve many of the existing operational problems without incurring in new network investments, with the consequent savings.

In the literature, it is demonstrated how the use of flexibility provided by distributed resources allow the improvement of the distribution network operation, being the most relevant ones: load control [32] allowing the integration of renewable energy while minimizing its intermittency [33], voltage control [34], minimization of network energy losses [35] and improvement of the network resilience [36] and reliability [37].

The use of flexibility in network operation and planning become especially relevant since the Third Energy Package requires distribution system operators (DSOs) to consider both traditional network passive elements and flexible DERs when planning [38]. This is in addition to the priority and guarantee of access to the grid required by European regulations for those resources using renewable sources [39], [40][3]. Similarly, the Federal Energy Regulatory Commission (FERC) has issued Order No. 2,222 , which allows DERs to participate in regional organized wholesale markets in conjunction with traditional resources through aggregations, promoting a more flexible and resilient power distribution system [41]. In this common framework, the interests of DSOs and utilities are to improve the quality of the distribution service safely, while minimizing investment and complying with the established regulations[4].

As shown in the following section, the second part of this thesis proposes two network planning algorithms to reinforce the distribution system through MGs. These MGs can integrate distributed generation and storage assets into the existing grid enabling them to provide different flexibility services to the grid. In this case, it is investigated how to improve the reliability [42] and the resilience [43] of an existing distribution system (i.e. by following a brownfield approach). It is decided to delve into these two concepts since energy infrastructures such as the power grid have the highest level of interdependence between sectors making it critical. Other sectors like industry, water services, or telecommunications, are highly interconnected and need the power grid for their correct operation [44].

The concept of resilience and reliability commonly go hand in hand since, in both cases, the capacity of a network to maintain the supply of consumers is analyzed. However, the differences between both reliability and resiliency have been analyzed [45]. Reliability studies cover low impact, high probability events at specific points in the network with low restoration times, e.g., faults caused by cable contact or aging. However, resilience analyzes High Impact Low Probability (HILP) events which, unlike reliability, involve structural damage with several affected equipment and high restoration times, e.g., natural disasters such as hurricanes or tornadoes. Table 2 aims to summarize and highlight these main differences.

Table 2: Reliability and resilience main differences

Service	Event impact	Event probability	Simultaneous failures
Reliability	Low	High	No
Resilience	High	Low	Yes

[3] *Article 16 of Directive 2009/28/EC and Article 14 of Directive 2012/27/EU*
[4] *Beyond the place of origin of DSOs (Europe) and utilities (U.S.), the main difference is the organizational structure of both. Utilities are vertically integrated businesses, while DSOs are unbundled.*

1.2. Objectives

As introduced above, this thesis seeks to provide solutions to the increase in the complexity of the distribution power system from a network planning perspective. Additionally, it can be divided into two main parts according to the motivation and research needs. The first part focuses on the development of realistic synthetic distribution systems with a U.S. architecture for the testing of new algorithms, while the second part focuses on the development of algorithms to reinforce the distribution system through MGs in order to improve continuity of supply (reliability and resilience). This section details the objectives of both parts.

The research carried out in the first part of this thesis is part of an ambitious research project called "Smart-DS: synthetic models for advanced, realistic testing of distribution systems and scenarios" inside the ARPA-E GRID DATA program, in which together with other research institutions such as NREL or MIT, the largest synthetic distribution systems to date have been built and published to serve as a tool for testing new algorithms like OPFs or advanced feeder reconfiguration models [46]–[48]. In this first part of the thesis, the conducted research has focused on and covered the following objectives:

- **Objective 1:** Review the state of the art of the test systems published to date that follow a U.S. architecture and find their limitations towards the development of new algorithms. Once reviewed, identify which methodology should be used to generate a new generation of test systems that overcome these limitations.

- **Objective 2:** Develop a set of algorithms that allow generating U.S. featured distribution systems through a reference network model. These algorithms need to overcome the limitations identified in the first objective.

These two objectives have been addressed in the first two JCR papers published as the first author during the thesis development [28], [29]. It should be mentioned that the research carried out in the Smart-DS project has been conducted by dividing the main objective into several tasks that were carried out individually but with the support of the associated working groups. Thus, the publications presented in this part of the thesis are those associated with the tasks the thesis author led. However, as mentioned above, the PhD candidate has collaborated in the research group associated with other tasks participating in additional publications such as the conceptual design of the methodology [49], [50], the development of the distribution system planning model [51], and the validation of the results [52].

On the other hand, the second part of the thesis proposes two planning algorithms to enhance the continuity of supply of a distribution system through the installation of DERs and smart technologies. These DERs allow the creation of isolated MGs in the event of a network stress situation when the original supply is not guaranteed due to a contingency. Distributed generation and storage provide an alternative energy source while the contingency is being addressed. It has been decided to study first the improvement of distribution systems' reliability, before moving on to resilience. This sequence was not chosen randomly; instead, it was determined to begin with network reliability improvement since, among other aspects, network reliability only analyzes the failure of one of the network's components at the same time. As a result, this study may be used to learn and propose a novel methodology to improve resilience, a more complex problem where several network components are unavailable at the same time.

- **Objective 3:** Develop a planning model that, maximizes the reliability of the distribution system while minimizing the investment incurred. The planning options are the installation of PV systems, batteries, and diesel groups.

- **Objective 4:** Develop a planning model that maximizes the system's resilience while minimizing the investment incurred. In this case, the planning options are the installation of PV systems and batteries, Remotely Controlled Switches (RCS), and the undergrounding of lines.

As observed, the planning options selected are different for each of the latter two objectives. In the first one, it has been decided to consider diesel generators to supply affected demand since it is the solution commonly used by DSOs when the main supply is not accessible. In the second one, it has been decided to introduce the installation of RCSs, that allow a division of the network into MG, and the undergrounding of power lines. The deployment of RCSs responds to the problem of multiple failures analyzed in resilience. In this way, it allows better fault isolation while repairing the failed power lines, thus maximizing supply. The undergrounding of power lines addresses the nature of natural atmospheric disasters, with overhead power lines being the most exposed to meteorological events.

The last two objectives have been addressed in the two last JCR papers published as the first author during the thesis development [42], [43].

1.3. Thesis outline

As previously mentioned, this thesis is divided into two parts that attempt, from a planning perspective, to respond to the generation of U.S large-scale test systems, and to the improvement of the continuity of supply by reinforcing distribution systems through DERs/MGs. On one hand, the first part, focused on the development of large-scale synthetic networks following a U.S. architecture, is included in the first two papers and covers objectives 1 and 2. The first paper, is a literature review of test distribution systems with a U.S. architecture and proposes the limitations to overcome in the generation of test systems. The second paper proposes a set of algorithms that allow the generation of large-scale test distribution systems overcoming the limitations previously pointed out. On the other hand, the second part of the thesis focuses on developing algorithms to improve the continuity of supply through DERs/MGs and is included in the last two papers covering objectives 3 and 4. The third and fourth papers propose methodologies to improve the distribution system's reliability and resilience, respectively, while minimizing investment. Figure 1 summarizes the previously mentioned structure.

The following two chapters develop both research lines, and introduce the research carried out in the four papers that compose this thesis. Additionally, in this document, before the introduction section there is a list of all the papers published during the development of the thesis.

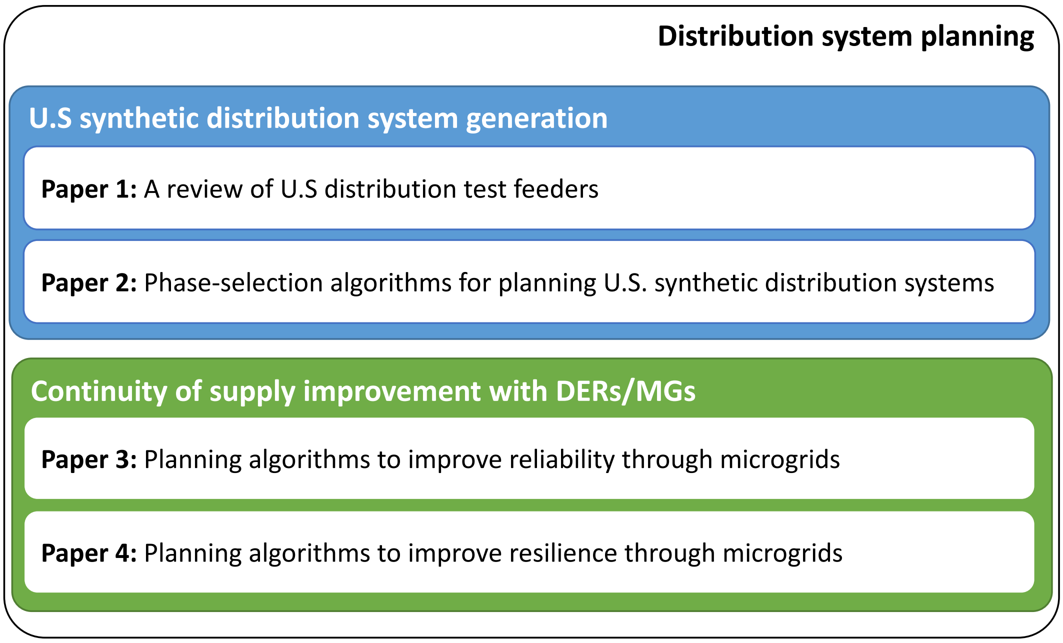

Figure 1: Thesis structure

2

GENERATION OF U.S. SYNTHETIC DISTRIBUTIONS SYSTEMS

Given the increasing penetration of distributed energy resources and new smart network technologies, distribution utilities face new challenges and opportunities to ensure reliable operations, manage service quality, and reduce operational and investment costs. Simultaneously, the research community is developing algorithms for advanced controls and distribution automation that can help to address some of these challenges. However, at the moment this thesis started there was a shortage of realistic test systems that were publicly available for development, testing, evaluation, and comparison of such new algorithms. Concerns around revealing critical infrastructure details and customer privacy severely limit the number of actual networks published that are available for testing.

This section introduces and summarizes the research carried out in the first research line of this thesis associated with the generation of U.S. synthetic distribution systems. This research is further detailed in the first two papers [28], [29] that compose this compendium thesis. Initially, a review of the U.S. featured test systems published to date is presented, and the limitations of these networks when testing and comparing new algorithms are identified. In addition, it analyzes which methodologies or planning models are the most suitable for developing a new generation of test systems that overcome the limitations indicated above. Next, a set of algorithms are presented that, within a large-scale planning model such as a reference network model, allow characterizing the generated test system with features typical of networks with a U.S. architecture.

The two publications associated with the research presented in this section can be found in the annex of this document.

2.1. State of the art

In recent decades, several distribution test feeders and US-featured representative networks have been published by institutions like IEEE, PNNL, or EPRI; however, the scale, complexity, and control data vary widely. The state of the art published as the first paper of this thesis [28],contributes presenting a first-of-a-kind structured literature review of available distribution test networks at the time this thesis started with a special emphasis on classifying their main characteristics and identifying the types of studies for which they have been used. Table 3 shows a brief summary of the networks analyzed in this review, indicating the number of test systems published per institution, as well as their voltage range and number of supply points. This review seeks to assist researchers in choosing suitable test networks for their needs and highlights the opportunities and limitations for further test system development.

Table 3: Test systems review (summary)

Institution	#Test systems	Voltage range (kV)	#Supply points
IEEE	9	4.16-24.9	9-1,177
PNNL	24	12.47-34.5	27-2,000
EPRI	6	12.47-34.6	321-5,694
PG&E	12	4.16-20.78	100-2,000
Other	3	12.47-13.2	16-1,370

Additionally, this research shows the common limitations of these test systems for developing, testing, and evaluating such new algorithms. The main limitations observed are: small size, lack of representativeness, time series, and geographical coordinates, among others.

Thus, these distribution test systems were effective at the time and for specific intent, but have been overused in unintended ways. However, the observed trend in the test feeders published in the last years is to overcome the abovementioned limitations and build large-scale representative networks with reconfiguration capabilities while modeling several technical and economic aspects; for instance, the ones associated with the integration of DERs under different future scenarios.

In addition, a review of the procedures for obtaining test feeders is carried out, including: anonymization of feeders, manual design, clustering and combination of other feeders, and their generation through planning tools. Among them, the planning tools based on numerical and heuristic methods, such as reference network models, seem to be the most suitable way to obtain them. Reference network models are opening new research areas in order to design large-scale realistic test systems and make them suitable for the validation and comparison of advanced distribution system algorithms.

This review lays the foundations for the development of a reference network model to generate distribution systems following a U.S. architecture (RNM-US). Taking as a starting point the conclusions obtained in this review, the second paper of this thesis details a set of planning algorithms that were a fundamental part of this new RNM-US. This research is introduced in the following section.

Associated publications

The state of the art previously introduced is further detailed in the review paper entitled "**A review of power distribution test feeders in the United States and the need for synthetic representative networks**", and published by **MDPI** in **Energies**.

It can be cited as cited as:

F. Postigo, C. Mateo, T. Gómez, B. Palmintier, B.M. Hodge, V. Krishnan, F. de Cuadra, B. Mather "A Review of Power Distribution Test Feeders in the United States and the Need for Synthetic Representative Networks," Energies, vol. 10, no. 11, p. 1896, Nov. 2017, doi: 10.3390/en10111896.

2.2. Phase selection algorithms for planning U.S. synthetic distribution systems

As previously mentioned, reference network models were developed in the context of economic regulation applied to distribution utilities to build a reference distribution system in a given distribution area [53], [54]. At Comillas University, Reference Network Models have been developed with the aim to go a step beyond the purely regulatory objective [55], for example, serving as a basis for the generation of large-scale synthetic grids in a context of rural electrification (REM) [56], or the development of distribution test systems with a European architecture (RNM-EU) [30]. In fact, the RNM-EU designed at Comillas University is the planning core used by the DiNeMo platform developed by the European Commission to generate synthetic grids with European architecture [26]. However, as the previous test system review show, when this thesis started there was not a Reference Network Model able to generate large-scale synthetic networks with a U.S. architecture. This section, as a summary of the second paper of this thesis [29], contributes to the state of the art by providing a set of algorithms that, integrated in a RNM, allow characterizing the generated test system with features typical of networks with a U.S. architecture.

Given the structural differences between European and U.S. distribution systems, the paper associated with this research carries out a comparison between both network architectures. As observed in Table 1 (in the introduction of this thesis), the main differences are the number of phases of the feeders, the length of the low voltage network, the degree of undergrounding, the size of the distribution transformers, or the use of voltage regulators, among others.

Additionally, this research describes an approach for managing one of the key differences in network design: the U.S. practice of connecting residential consumers through single-phase low voltage power lines, and the use of single-, two-, and three-phase feeder sections at the MV level, resulting in the need to manage phase balancing during the design stage. The major contribution of this research is to propose a methodology with two algorithms. The first one determines the number of phases of each MV feeder section guaranteeing the electrical consistency. This process minimizes the investment, maintenance, and energy loss costs at each feeder section. Afterward, the second algorithm assigns a specific phase for each final user by using depth-first-search and tree-partitioning algorithms. In this case, phase balancing is optimized to minimize the phases' imbalance. Figure 2 shows the result of the phase assignment process for the example network used in the associated paper. It should be mentioned that this last algorithm could also be applied to actual networks to rethink which loads are connected to each phase, thus reducing imbalances.

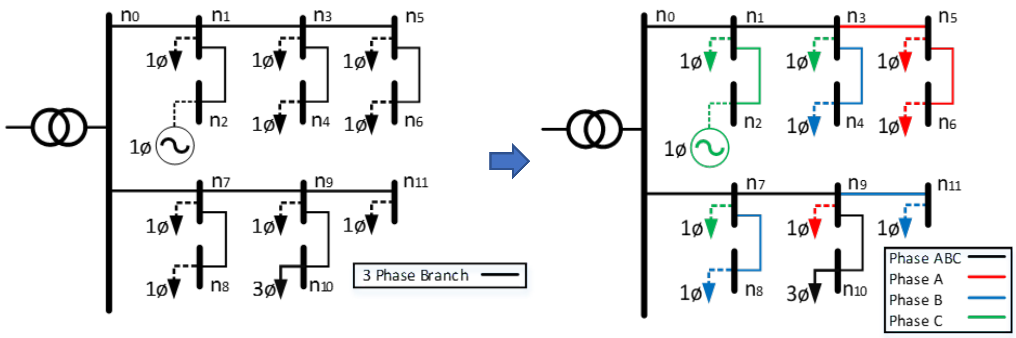

Figure 2: Phase selection process: input network (left), output network (right)

The case study shows that the proposed algorithms are able to address the trade-off between minimizing the imbalance locally and at the system level. Lastly, the performance of the developed algorithms is verified by applying the proposed algorithms to the IEEE 8,500-node test feeder and the Electric Power Research Institute (EPRI) J1 feeder, and comparing the obtained system with the original ones.

The algorithms presented have been integrated into the RNM-US Reference Network Model, in such a way that this model is able to generate large-scale networks with a U.S. architecture. This model overcomes the limitations presented by the existing test feeders and summarized in the first paper of this thesis (section 2.1).

Next Section 2.3 summarizes other publications belonging to this line of research in which the PhD candidate has participated despite not being the main author, in an attempt to complete the research line.

Associated publications

The investigation associated with the previous problem is detailed in the research paper entitled "**Phase-selection algorithms to minimize cost and imbalance in U.S. synthetic distribution systems**", and published by **Elsevier** in **International Journal of Electrical Power & Energy Systems**.

It can be cited as cited as:

F. Postigo, C. Mateo, T. Gómez, F. de Cuadra, P. Dueñas, T. Elgindy, B.M. Hodge, B. Palmintier, V. Krishnan. "Phase-selection algorithms to minimize cost and imbalance in U.S. synthetic distribution systems," International Journal of Electrical Power & Energy Systems, vol. 120, p. 106042, Sep. 2020, doi: 10.1016/j.ijepes.2020.106042.

2.3. Further research

The previous sections have presented the two publications that, as first author, make up the first line of research of this thesis. Besides, the PhD candidate has also collaborated, but not as main author, in additional publications related to this topic.

Firstly, a paper has been published presenting the complete RNM-US Reference Network Model that generates large-scale networks following a U.S. architecture in a very detailed manner and analyzing the methodology used [51]. The largest synthetic distribution systems published to date have been generated using this model. These test systems correspond to the datasets of Santa Fe in New Mexico (SAF) [47], Greensboro in North Carolina (GSO) [[46], and San Francisco Bay Area (SFO) in California [48], with 168.005, 375.334, and 9.868.205 electrical nodes respectively. Figure 3 shows a zoom in image of the SFO test system, while Figure 4 shows the complete representation of the three datasets.

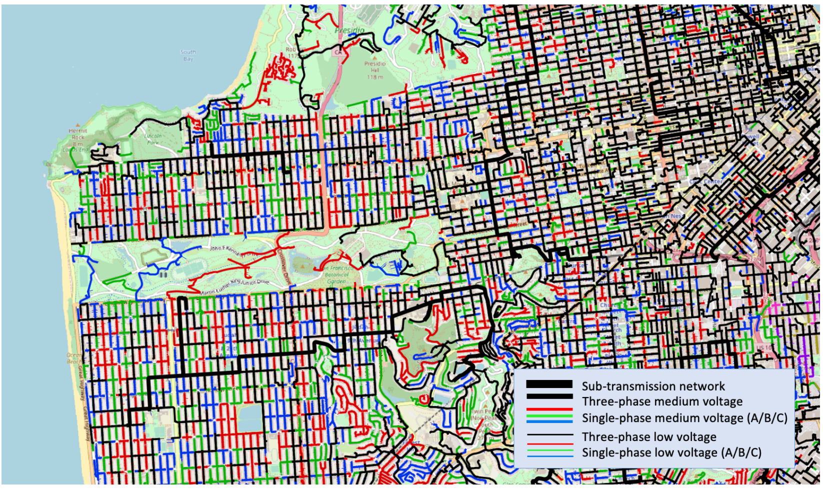

Figure 3: Zoom in of the synthetic distribution system in San Francisco. Reprinted from: C. Mateo et al., “Building Large-Scale U.S. Synthetic Electric Distribution System Models,” *IEEE Transactions on Smart Grid*, pp. 1–1, 2020.

In response to these networks, the need to design a validation process to assess the generated test systems and ensure that they match with the characteristics of the actual existing networks arose. For this reason, a methodology was developed to compare the feeders of the generated datasets (SAF, GSO, and SFO) with a set of actual networks [52]. This overcomes the limitations in releasing actual networks, while enabling to generate and publish synthetic datasets that mimic their characteristics. The proposed verification compares three dimensions, 1) a statistical validation of the equipment used and the topological characteristics, 2) an operational validation, and 3) a validation performed by expert planners from various utilities. In this way, the obtained datasets have been proofed to ensure that they are representative of the real networks.

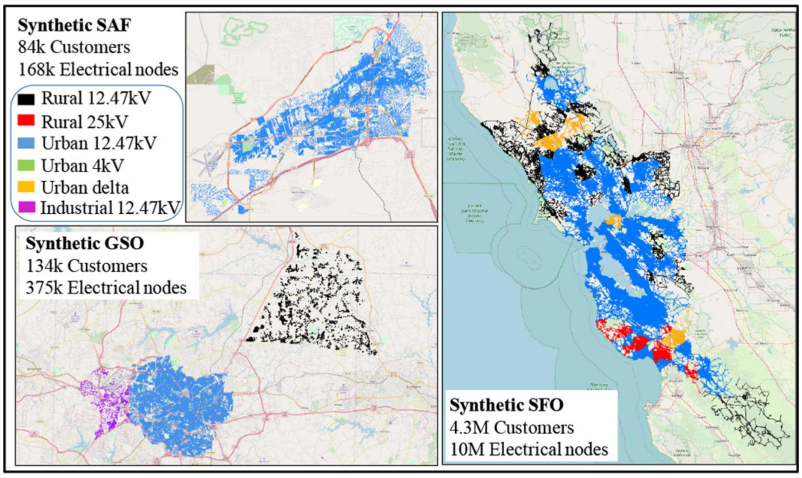

Figure 4: Synthetic distribution system datasets: SAF, GSO, SFO. Reprinted from: V. Krishnan et al., “Validation of Synthetic U.S. Electric Power Distribution System Data Sets,” *IEEE Transactions on Smart Grid*, pp. 1–1, 2020.

On the other hand, and to help new researchers who seek to delve deeper into this line of research, we published an additional paper that underlines the experiences obtained throughout the research [49]. This experience can be translated into a set of lessons learned during the development of these networks, which properly expose and justify the decisions taken in the face of the problems that arose.

Beyond U.S synthetic network generation, during the development of this thesis the PhD candidate has participated in the research and publication of other research topics related with electricity networks. For example the technical implications of PV self-consumption policies in distribution networks generated using a reference network [81], or the decomposition of complex networks, like distribution systems, into graphlets to explain their structure [82].

A complete list of the publications in which the PhD candidate have participated is shown before the introduction section.

3

CONTINUITY OF SUPPLY IMPROVEMENT WITH DERS AND MGS

The steady decline in the cost of DERs, such as distributed renewable generation and storage systems, together with more sophisticated monitoring and control strategies allow power distribution companies to enhance the performance of the distribution system. As previously indicated, for implementing this type of controls, it is necessary to test them on actual systems or with characteristics very similar to the real ones. In the two papers previously presented, a methodology has been proposed to obtain synthetic networks for testing this type of algorithms. Continuing with the objectives of this thesis, the goals of the second research line of this thesis is to propose a set of algorithms to improve the continuity of supply of distribution systems.

Improving the continuity of supply can be observed from two points of view. First, contingency plans can be studied from an operational perspective in order to minimize the loss of supply in the presence of a contingency [57]. On the other hand, and from a distribution network planning perspective, the continuity of supply can be improved through a robust design of the electrical infrastructure [58]. In this thesis, the research focuses on the latter point.

Although the improvement of the continuity of supply is a vast topic, in this thesis the focus is placed on the improvement of reliability and resilience. In the case of reliability, the proposed methodology focuses on radial rural distribution networks located in natural regions where reliability levels are much lower than in urban areas [59]. On the other hand, in the case of resilience, the proposed methodology focuses on the design of a network that is robust to natural disasters, being applicable to both rural and urban networks since both are susceptible to such events [60].

The two papers associated with reliability and resilience improvement, which are part of this thesis as a compendium of publications [42], [43], can be found in the annex of this thesis. In the following, both problems are introduced, and the contributions in this field to the state of the art are summarized.

3.1. Reliability improvement

As previously introduced, this thesis addresses the improvement of reliability in radial distribution grids in rural areas, where traditional reinforcements cannot be carried out because they are located in hard-to-reach environments or in protected natural areas, where the permits to build new lines are difficult to obtain. When a contingency occurs in such a feeder, protection systems isolate it, and all downstream consumers suffer an interruption until service is restored.

A review of the state of the art has been carried out in which, for different papers, it is analyzed whether previous works have proposed a multi-objective optimization that allows determining at the same time the location, the size, and the type of DERs to be used. As observed in Table 4, there is no reference that covers these aspects at the same time. For this reason, a methodology has been proposed to determine the optimal location and sizing of micro-grids (MG) based on a multicriteria optimization in which both the DER investment cost and the network reliability levels are considered. Unlike other publications, this methodology selects the mix of DERs that best fits the network characteristics.

Table 4: DERs planning review

Reference	DERs Location	DERs Size	DERs Type	Multi-objective
[61]	x	x		x
[62]	x	x		x
[63]	x	x	x	
[64]	x	x	x	
[65]	x	x		x
[66]	x	x		x
[67]	x			
[68]	x	x	x	
This thesis [42]	x	x	x	x

In order to exemplify this problem, Figure 5 shows an illustration of a distribution network failure process, and how the type of proposed solutions would help to improve reliability. Initially, the starting point is a distribution network, divided into four zones by RCS. In the case that this network is affected by a failure in zone 1, it would imply the total loss of supply of the entire network.

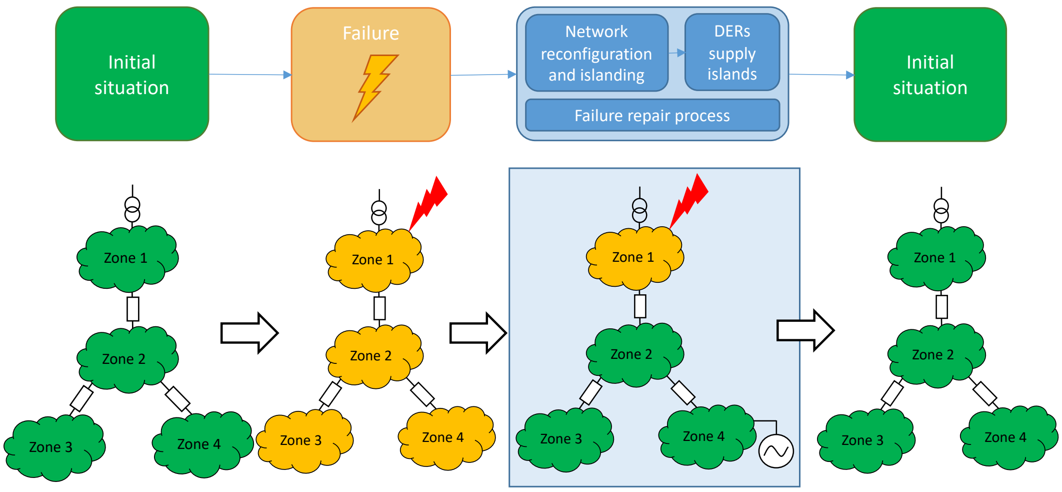

Figure 5: Reliability problem statement

The proposed methodology would allow obtaining solutions to maximize the reliability of the system such as the one boxed in blue. In this solution it is decided to install a set of DERs in zone 4 (for example storage). In this way, in the event of a fault such as the one indicated above, the RCS located under zone 1 would isolate zones 2, 3, and 4 and a MG would be formed whose supply would be provided from the DERs located in zone 4 while the fault in zone 1 is being repaired. Once the failure is solved, the initial situation would be restored.

The proposed methodology has a double optimization, where the size of DERs is initially optimized, and then the possible locations of DERs are exhaustively analyzed to maximize reliability and minimize investment. Consequently, the result is a set of non-dominated solutions, allowing the DSO to choose the one that best suits other possible non-modeled requirements (e.g., local emissions...). This methodology was tested in a real case study, from which some relevant findings have been extracted. The results show that the combination of diesel units and batteries seems to be the most cost-effective option to increase the network's reliability through an islanded operation. During the failure repair time, diesel units would be in charge of covering the base demand of islanded zones, whereas batteries would operate as peaking units. Moreover, the results show that using PV installations for this purpose is not cost-effective since they present a comparatively high investment cost, and they can only supply the demand during sunlight hours, thus being useless to tackle outages occurring at night. Additionally, if battery investment costs were to drop by about 80% concerning current values, MG solutions based mainly on batteries would be the preferred option instead of more highly polluting solutions based on diesel units. Finally, it is observed how DERs are only used in less than 1% of the hours for reliability purposes. For this reason, DSOs or utilities may explore the procurement of a service through which third parties, such as DER owners, would provide network support when a network outage takes place.

This work opens up future research lines to be explored. The main limitation of this study is the degree of automation of the network. The greater the degree of automation of the network, the greater the number of RCSs, and the possibilities of reconfiguring the network, which grows exponentially. Hence, the proposed solution perfectly fits with the problems of rural networks, which are characterized by low automation levels. However, urban areas with higher automation levels may sharply increase the computational load. For this reason, this limitation opens a future research line to apply metaheuristic algorithms (such as genetics algorithms) to overcome this issue. On the other hand, this methodology considers only the failure of one of the network elements at the same time. Nevertheless, in some cases, events such as natural disasters can trigger a set of simultaneous failures that hinder the power supply. This is the case analyzed in the following section, which optimizes the resilience of the system, allowing several simultaneous failures, and overcoming the limitation of the number of RCSs through the application of genetic algorithms.

Associated publications

The investigation associated with the previous problem is detailed in the research paper entitled “**Location and sizing of micro-grids to improve continuity of supply in radial distribution networks**”, and published by **MDPI** in **Energies**.

It can be cited as cited as:

F. Postigo Marcos, C. Mateo Domingo, T. Gómez San Román, and R. Cossent Arín, “Location and Sizing of Micro-Grids to Improve Continuity of Supply in Radial Distribution Networks,” Energies, vol. 13, no. 13, Art. no. 13, Jan. 2020, doi: 10.3390/en13133495.

3.2. Resilience improvement

In recent years, natural disasters such as hurricanes Katrina and Sandy, or deliberate attacks on the power system, have highlighted the importance of a resilient power distribution system that can maximize the energy supply even in the most stressful situations. However, reinforcing the distribution power grid is very costly, and investment decisions must be adequately justified.

According to several studies [69], [70], the features that have been determined as decisive for an improvement in resilience to weather events are: the level of automation through RCSs, the degree of undergrounding of the grid, and the potential of DERs to form MGs and ensure the supply in case of a system failure. Table 5 shows a review of previous works indicating which of them considered the previous features as a planning option, and the ones that employed a single-stage optimization in their decision making.

Table 5: Resilience improvement review

Reference	Optimization: Single-stage	Investment: RCS	Investment: DG/DERs	Investment: Underground Hardening
[71]	x			x
[72]	x			x
[73]	x		x	
[74]	x		x	
[75]	x	x		
[76]	x	x		
[77]	x		x	x
[78]		x	x	x
[79]			x	x
[80]	x[5]		x	x
This thesis [43]	x	x	x	x

[5] *It uses a single-stage optimization but through a three-level decomposition of the problem.*

Following the objectives of this thesis and the research gap observed in Table 5, the subsequent methodology proposes a single-stage multi-criteria optimization model to maximize the resilience of a distribution system through a series of investments while minimizing the total cost incurred. The assets to be invested in under this model are the installation of RCSs, DERs (such as storage and PV units), and the undergrounding of overhead lines.

In order to exemplify the problem and proposed solution, Figure 6 shows an illustration of a distribution network failure process in the face of an atmospheric event such as a hurricane, and how the type of proposed solutions would help to improve resilience. Initially, the starting point is a purely overhead distribution network, divided into four zones by RCS. If this network is affected by extreme wind speeds due to a hurricane, some of the overhead lines in zone 1 and zone 4 could fail simultaneously. The consequences of this event would imply the total loss of supply of the entire network.

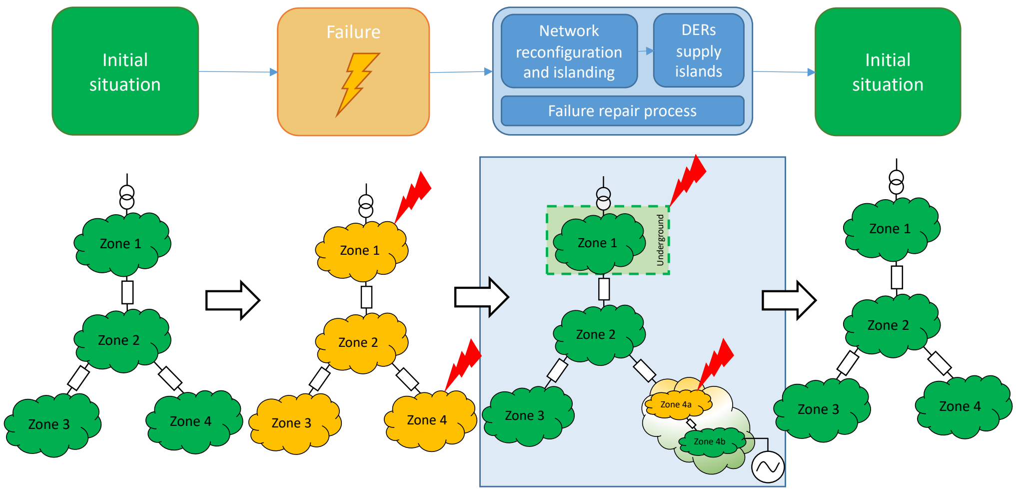

Figure 6: Resiliency problem statement

The proposed methodology would allow obtaining solutions to maximize the resilience of the system such as the one boxed in blue. Three different investments have been assumed in this network: 1) the undergrounding of zone 1; 2) the installation of an RCS in zone 4 so that this zone is divided into zone 4a and zone 4b; and 3) the installation of DERs (PV systems and storage) in zone 4b. These investments would allow that in case of an event such as the one indicated above, zone 1 would not be affected by an atmospheric event and therefore supply to zones 2 and 3 could be maintained; zone 4b would form a MG and would be supplied from the DERs located in this zone; zone 4a would lose its supply. Once the event is over, the failure in zone 4a will be repaired and the initial situation will be restored.

The optimization method is based on a customized genetic algorithm that can be successfully applied to solve large, highly nonlinear problems with integers and continuous variables such as the one we are studying. Unlike the methodology presented in the previous section which proposed a model to improve system reliability, this study presents a methodology able to deal with multiple simultaneous failures, and in which the number of RCSs do not represent a bottleneck.

The major scientific contribution of this model is the integral methodology developed to simultaneously optimize the three very different categories of investment options, RCS, DER, and power line undergrounding while maximizing distribution system resilience. Opposed to the methodologies proposed in previous publications, the approach allows us to discover how these alternatives compete with and complement each other.

The results obtained demonstrate how priorities in investment decisions are established, and the derived benefits in terms on increasing resilience are quantified. Another major contribution of this research is the customization of the genetic algorithm. This modification involves a post-processing of the chromosomes proposed in each generation in order to obtain feasible solutions, in such a way that the scale of the problem studied can be enlarged without penalizing the performance. To exemplify the application of the proposed optimization method, an actual distribution system is simulated under extreme weather conditions.

The obtained results have permitted to establish the order and priority of the investments through a joint optimization. Initially, with a moderate investment, the installation of RCSs can significantly reduce the energy not supplied of the system. Next, if it is desired to further improve resilience, the installation of RCSs should be followed by the undergrounding of overhead power lines, and finally, by the installation of DERs operated as islanded microgrids in case of extreme weather events. Installing DERs for the sole purpose of improving network resilience is less attractive than if they are also used for providing other services during normal system operation. In this case, the total investment would be shared by the different services provided. As commented in the previous section, this is an exciting area for future research.

The presented results demonstrate the effectiveness of the proposed optimization algorithm, showing how significant improvements in system's resilience can be obtained through the suggested methodology.

Associated publications

The investigation associated with the previous problem is detailed in the research paper entitled "**Improving distribution network resilience through automation, distributed energy resources, and undergrounding**", and published by **Elsevier** in **International Journal of Electrical Power & Energy Systems**.

It can be cited as cited as:

F. Postigo Marcos, C. Mateo Domingo, and T. Gómez San Román, "Improving distribution network resilience through automation, distributed energy resources, and

undergrounding," International Journal of Electrical Power & Energy Systems, vol. 141, p. 108116, Oct. 2022, doi: 10.1016/j.ijepes.2022.108116.

4

CONCLUSIONS, CONTRIBUTIONS, AND FUTURE RESEARCH

4.1. Conclusions

Once the papers that compose this doctoral thesis have been presented, it can be affirmed that the research carried out is broad, addressing different planning perspectives and proposing new study directions. Therefore, the conclusions that can be drawn are multiple and combine different lines of research. Beyond the general conclusions and following the structure presented in the introduction of this thesis, the conclusions are derived for each of the analyzed research lines.

Regarding the first part of this thesis, it presents the path toward the generation of large-scale synthetic networks following a U.S. architecture. The conclusions of the test feeders review (first paper) lay the foundations for the development of the presented algorithms (second paper). The first paper presents with a succinct analysis of all the feeders following a U.S. architecture. As concluded, the set of previously existing test feeders following a U.S. architecture only includes small, purely radial, and non-representative distribution system. To overcome these limitations, the development of new, more detailed, and large-scale test networks is proposed, allowing researchers to extend their usability for different algorithms, such as analyzing the impact of DERs integration or reconfiguration studies. For this reason, it is proposed the use of planning tools based on heuristic algorithms, such as reference network models, that allow the development of large-scale networks with a U.S. architecture and with a high degree of detail.

The findings of the previous review establish the research's basis and justify the need for the algorithms developed in the second paper. This paper highlights the differences between U.S. and European networks and proposes a set of algorithms to obtain distribution systems with a U.S. architecture using a Reference Network Model. A fundamental difference between the two types of networks is the number of phases of the feeder sections. Unlike European networks, which are all three-phase, networks with a U.S. architecture can have a variable number of phases according to the downstream load. As previously mentioned, the starting point was a Reference Network Model capable of generating test systems with a European architecture, for this reason, it was necessary to develop two algorithms to provide the generated test systems with a U.S. architecture. The first one determines the number of phases of each of the feeder sections, and the second one assigns to which phase they belong through a load balancing of the end users. The latter algorithm allows obtaining networks with the minimum unbalance or levels like actual networks. To verify their correct performance, the networks obtained using the proposed algorithms are compared with the original test feeders, the IEEE 8,500-node test feeder, and the Electric Power Research Institute (EPRI) J1 feeder. It is concluded that, through the proposed algorithms, a Reference Network Model can obtain large-scale systems with a U.S. architecture and high resolution.

These two papers set the basis of a Reference Network Model able to obtain large-scale networks with a U.S. architecture. In addition, the research carried out provides the groundwork for future developments based on the model proposed, such as the largest synthetic distribution networks published to date [46]–[48]. These investigations, in which the PhD candidate has also participated are presented in section 2.3 , and are approached from the distribution network planning perspective.

On the other hand, the second part of the thesis focuses on the development of algorithms to reinforce the distribution network through DERs and smart technologies to improve the continuity of supply. This research can be divided into two distinct parts according to the planning objectives: planning for reliability improvement, and planning for the improvement of system resilience. In both cases, a multi-criteria optimization has been carried out to minimize the costs incurred.

According to the implementation procedure, both models use different optimization techniques. The proposed methodology for reliability improvement follows a double optimization, where initially the size of DERs is optimized, and then the possible locations of DERs are exhaustively analyzed to maximize reliability and minimize investment. This approach is possible from the computational point of view since reliability only contemplates a single failure in the network simultaneously, and the number of RCSs is reduced as they are not considered as an investment option. However, in the case of resilience, several failures can happen at the same time, and RCSs compete with undergrounding and DERs as investment options. For this reason, it is necessary to apply a customized algorithm to address this problem without a high computational burden.

On the other hand, according to the optimal investments proposed by the presented models, it can be observed that in the case of reliability, using current costs, the combination of diesel generators and batteries is the option that minimizes the investment and maximizes the grid's reliability. In this case, the diesel groups are in charge of providing the base generation, while the batteries act as peakers adapting their operation to the demand profile. Another relevant conclusion is that PV systems are unsuitable for improving the grid's reliability since they are not controllable and cannot supply the demand in hours when the irradiation is insufficient. Nevertheless, in the resilience improvement case, it has been concluded that significant improvements in system resilience can be achieved at a reduced cost by installing just RCSs. If better resilience values are desired, the next investment to be carried out would be the undergrounding of overhead power line sections, followed by installing DERs. Additionally, it has been demonstrated how the improvement of the utilities' logistic capacity and their ability to repair failed lines, has a very similar impact to the execution of the previously mentioned investments and could be seen as an alternative or complementary option.

As observed, using DERs to improve network reliability or resiliency is far from cost-effective. However, a common conclusion is that reliability and resiliency services can be seen as an additional service to others provided under normal operating conditions. This issue is further explained in the future research section (4.3).

This thesis has demonstrated how the development of planning algorithms can address the needs and motivation presented in the background section favoring and promoting the integration of clean energies in a safe and cost-effective manner. Firstly, it responded to the need for a new generation of large-scale networks with U.S. architecture to test new algorithms and developments that optimize the operation and planning of the distribution network. For this purpose, a set of algorithms has been developed that allow the generation of synthetic networks with a U.S. architecture overcoming the limitations of previous test systems. On the other hand, planning algorithms have been designed to maximize supply from a reliability and resilience perspective while minimizing the investment made. In conclusion, this thesis has presented a set of algorithms that contribute to distribution network planning and serve as a tool to facilitate decision-making at the planning stage.

4.2. Contributions

Based on the objectives stated in section 1.2, this thesis has contributed to the state of the art from different perspectives. According to the first line of research associated with developing synthetic distribution networks with a U.S. architecture, the following contributions have been presented:

- Propose a first-of-a-kind structured literature review of the test systems with U.S. architecture published to date and highlight the main limitations of these test systems for testing and benchmarking new algorithms.
- Identify the requirements for developing a new generation of large-scale test systems representative of a U.S. architecture.
- Review the differences between networks following a European architecture and networks with a U.S. architecture.
- Develop a set of algorithms that, integrated into the Reference Network Model (RNM-US), allow the generation of the synthetic networks with a U.S. architecture. In order to check their correct performance, two well-known test feeders have been replicated.

Despite not being the main author of the publications, the PhD candidate has participated in other developments and contributions to the state of the art in this line of research. Among the main contributions we can find:

- Develop the RNM-US and generate the three largest U.S. distribution test systems published to date.
- Develop a methodology to validate the representativeness of test systems and apply it to the three generated ones
- Develop a methodology to build combined transmission and distribution test systems

On the other hand, according to the second line of research focused on developing planning models to improve supply continuity, the following contributions have been presented:

- Develop a planning model to improve the reliability of an existing distribution network while minimizing investment through multi-objective optimization. This model, applicable to full-scale networks, allows sizing, locating, and selecting the type of DERs (diesel groups, storage, or PV systems) that best suits the characteristics and needs of the network.
- Develop a planning model to improve the resilience of an existing distribution network while minimizing the investment through a multi-objective optimization. This model, applicable to full-scale networks, considers the three investments that, according to the literature, allow maximizing the system's resilience: the location of RCS, the undergrounding of power lines, and the sizing and location of DERs such as PV systems and storage. Moreover, the proposed model carries out a single-stage optimization, finding how these investments compete and complement each other.

4.3. Future Research

As demonstrated in this thesis, the distribution network is at the starting line of a path towards a profound transformation. With the sector's digitalization, the distribution system is changing from a set of passive elements to an active system capable of adapting its operation to the current needs. The purpose of this thesis has been to contribute to this paradigm shift. However, research in this area has just begun. Although there are a wide variety of open research lines, this thesis has focused on distribution system planning from the perspective of synthetic network generation and network reinforcement through MGs; therefore, the research proposals presented below focus on these two topics.

Regarding the generation of synthetic networks, the field of improvement is still vast and exciting. For example, at the time of writing this doctoral thesis, NREL is working on a tool that allows complementing the published large-scale networks with different scenarios that include different degrees of DER penetration, generation, and demand profiles, among others. This tool will allow research community to anticipate the effect of a more than likely massive integration of renewable generation technologies in the distribution system and to do so in a highly reliable way since the networks on which the study has been performed are representative of the current grid while preserving confidentiality.

On the other hand, a line of research in which several institutions like IIT, NREL, or TAMU have continued working from the developments proposed in this thesis is the hybridization of distribution system with transmission system to identify their interactions and set TSO and DSO coordination schemes [50]. This second line of research is extremely challenging since the distribution system is a much more capillary system, and therefore, the dimension of the planned distribution network must be large enough to generate a realistic transmission network over it. To this end, a distribution network is generated that covers the entire Texas area, and an associated transmission network on top of it. This work will be published in the upcoming months [83].

In addition, published networks (SAF, GSO, and SFO) open the way to the development, testing, and comparison of a new generation of algorithms capable of dealing with large-scale networks, which can later be applied to actual networks. Some of these algorithms are OPFs, feeder reconfiguration protocols, dynamic studies, optimal DER planning, or a variety of controls that allow utilities and DSOs to implement different operational strategies.

Currently these first three lines of future research are being bottlenecked by the computational capacity and data management capability. Therefore, in order to overcome these limitations, these constraints must be analyzed beforehand.

Moving on to the second part of the thesis associated with the reinforcing of the distribution network through DERs, the future lines of research are even broader. For this reason, the future research lines presented below focus on the topics developed in this thesis, the improvement of reliability and resiliency of the distribution system.

First, the proposed model for reliability improvement provides optimal solutions; however, as network automation increases, the computational burden tends to grow exponentially due to the increase in reconfiguration options when a contingency occurs. Consequently, urban networks with high automation would require an unacceptable computational capacity at some point. For this reason, a fourth exciting line of research is the use of methodologies that hybridize algorithms such as graph theory and artificial intelligence as an alternative to traditional optimization techniques whenever the computational burden makes their use unfeasible. As in heuristics, in most cases, artificial intelligence algorithms do not guarantee obtaining the optimum, but they do guarantee obtaining fast, and in most cases, robust solutions. In the fourth paper presented in this thesis, which proposes a methodology for improving the system's resilience, as traditional optimization was not applicable, the use of genetic algorithms is hybridized with graph theory obtaining very satisfactory results. It should be noted that, while this doctoral thesis is being written, the PhD candidate is working on a new paper that updates a new approach for the optimization of the reliability and voltage control by using evolutionary algorithms (like NSGA2) hybridized with graph theory [84].

A common outcome in reliability and resilience improvement planning is that the proposed DERs would only provide these services for a very few hours per year. This implies that most of the time, they remain on standby and do not provide any service to the grid that could increase its profitability. Therefore, an exciting fifth line of research is the analysis of how different flexibility services, such as voltage and load control or loss minimization, among others can complement each other, and particularly how the resilience and reliability services should be remunerated to enhance the profitability of flexibility service providers.

Finally, an additional future research line, intrinsically related to the previous one is the development of DER operation strategies foreseeing a possible loss of supply. This point is particularly clear in the case of the storage operation. The operation of batteries must maximize their performance by providing several grid services simultaneously and managing the stored energy under the uncertainty of a possible loss of supply.

This thesis opens a broad set of research lines in the distribution network planning and operation field. From synthetic network generation to distribution system reinforcement through DERs, it sets the groundwork for other researchers to build large-scale synthetic distribution test feeders where new algorithms like reliability or resilience improvement can be developed, tested, and benchmarked. This will allow the development of a new generation of algorithms to address the new challenges that will emerge due to the massive deployment of renewable generation and DERs. As demonstrated in this section, distribution system research has only begun, and this is just the start of an exciting broad set of new lines of research to enhance distribution network planning.

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Annex

Papers as the first author:

I. **Paper 1:** F. E. Postigo Marcos et al., “A Review of Power Distribution Test Feeders in the United States and the Need for Synthetic Representative Networks,” *Energies*, vol. 10, no. 11, p. 1896, Nov. 2017, doi: 10.3390/en10111896.

II. **Paper 2:** F. Postigo et al., “Phase-selection algorithms to minimize cost and imbalance in U.S. synthetic distribution systems,” *International Journal of Electrical Power & Energy Systems*, vol. 120, p. 106042, Sep. 2020, doi: 10.1016/j.ijepes.2020.106042.

III. **Paper 3:** F. Postigo Marcos, C. Mateo Domingo, T. Gómez San Román, and R. Cossent Arín, “Location and Sizing of Micro-Grids to Improve Continuity of Supply in Radial Distribution Networks,” *Energies*, vol. 13, no. 13, Art. no. 13, Jan. 2020, doi: 10.3390/en13133495

IV. **Paper 4:** F. Postigo Marcos, C. Mateo Domingo, and T. Gómez San Román, “Improving distribution network resilience through automation, distributed energy resources, and undergrounding,” *International Journal of Electrical Power & Energy Systems*, vol. 141, p. 108116, Oct. 2022, doi: 10.1016/j.ijepes.2022.108116.

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Review

A Review of Power Distribution Test Feeders in the United States and the Need for Synthetic Representative Networks

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Abstract: Under the increasing penetration of distributed energy resources and new smart network technologies, distribution utilities face new challenges and opportunities to ensure reliable operations, manage service quality, and reduce operational and investment costs. Simultaneously, the research community is developing algorithms for advanced controls and distribution automation that can help to address some of these challenges. However, there is a shortage of realistic test systems that are publically available for development, testing, and evaluation of such new algorithms. Concerns around revealing critical infrastructure details and customer privacy have severely limited the number of actual networks published and that are available for testing. In recent decades, several distribution test feeders and US-featured representative networks have been published, but the scale, complexity, and control data vary widely. This paper presents a first-of-a-kind structured literature review of published distribution test networks with a special emphasis on classifying their main characteristics and identifying the types of studies for which they have been used. This both aids researchers in choosing suitable test networks for their needs and highlights the opportunities and directions for further test system development. In particular, we highlight the need for building large-scale synthetic networks to overcome the identified drawbacks of current distribution test feeders.

Keywords: distribution networks; review; state of the art; test feeders; representative networks; distributed energy resources (DERs); synthetic distribution test feeders

1. Introduction

Current distribution networks are undergoing a transformation towards the smart grid paradigm, including rapid increases in the quantity of distributed energy resources (DERs). This has prompted considerable interest from the research and vendor communities to develop innovate tools and algorithms that are adapted to smart distribution networks that provide advanced controls and distribution automation. Tools like Optimal Power Flows (OPFs), Volt/Var optimization, or advanced feeder reconfiguration, enable evaluating specific operational and planning objectives, and thereby can help utilities to implement operational strategies. Some of the objectives commonly sought in these tools are the minimization of total system costs, the minimization of network losses, the maximization of security of supply or a mixture of all these objectives [1]. Moreover, countless studies have been conducted about the impact of DERs on distribution networks in recent years. For instance, under an active network management scheme, studies noted that DERs have the potential to reduce costs for consumers and utilities [2], highlighted the ability for coordinated controls to improve operations with high-penetration solar photovoltaic (PV) [3], explored the hosting capacity for DERs [4], and more.

However, the ability to test and analyze these trends and developments is limited by a scattered and somewhat incomplete set of public test systems. Distribution networks are sometimes considered as the critical infrastructure of a country, and detailed load/customer data prompts privacy concerns. As a result, only a very few actual networks are publically available for use as a test network. This has forced the research community to use only the available test feeders that are published in the literature so far, sometimes for purposes beyond the original intentions of the test feeder creators. For instance, in 1991, the Institute of Electrical and Electronics Engineers (IEEE) Power and Energy Society (PES) published four radial tests feeders providing references for the United States (US) distribution system for the first time. Now, 25 years after this first publication, the number of published US featured test feeders is still limited, despite significant dispersed efforts to add to the set of test feeders.

A test feeder is a distribution network model that is able to replicate the behavior of an actual distribution feeder [5]. In general, these test feeders aim to reproduce the characteristics of an actual network, including specific particularities within a specific region; this feature is called representativeness. In this case, we say that the test feeder is representative of a particular actual network located in a particular area or country. An important use of test feeders is benchmarking, allowing for researchers to evaluate the performance of their algorithms. For instance, in the OPF case, the computing time, the degree of optimality, or even a ratio between them can be used as a benchmark. With emerging widespread grid modernization efforts, testing the corresponding advanced optimization algorithms suggests a need for realistic large-scale distribution test networks. In addition to providing a valuable test platform, test networks are also essential to make consistent comparisons across different advanced algorithms.

This paper provides a comprehensive critical review of US-featured publically available test distribution networks—and their limitations—for use in evaluating and testing advanced OPF and related studies or analyzing DERs integration into smart distribution grids. This is intended to help researchers choose suitable test networks for their needs, while also highlighting opportunities and directions for further test system development. In addition, the paper includes new trends for, and emerging efforts in the creation of, large-scale synthetic distribution networks that could be provided as publically available test networks to the research community.

The paper is organized in the following manner. Section 2 develops a classification of published networks according to their origin, where each sub-section sheds light on different publicly available feeders, their summary features and intended uses. Section 2.1 analyzes the existing IEEE feeders. Section 2.2 studies the taxonomy feeders provided by the Pacific Northwest National Laboratory (PNNL). Section 2.3 examines the Electric Power Research Institute (EPRI) representative feeders. Section 2.4 inspects the prototypical feeders presented by the Pacific Gas and Electric Company (PG&E). Section 2.5 reviews other the relevant test feeders that cannot be classified into the previous sections. Section 3 analyzes the limitations found in the currently available test feeders that were discussed in the previous sections, particularly from the perspective of developing advanced algorithms for advanced controls and distribution automation. Section 4 introduces the need for large-scale synthetic networks and for tools able to generate them. Finally, Section 5 presents the conclusions.

2. Distribution Test Feeders

A distribution network consists of power infrastructures that deliver electricity from the transmission/sub-transmission circuits to the final customers as shown in Figure 1. A wide variety of metrics could be defined to exhaustively characterize a distribution network. Nevertheless, there are some key descriptive components that can provide a simplified overview of it. In this review, we have described existing distribution test feeders using the metrics presented by respective authors or model creators in their publications, in order to be consistent with the original purposes for which these test feeders were created.

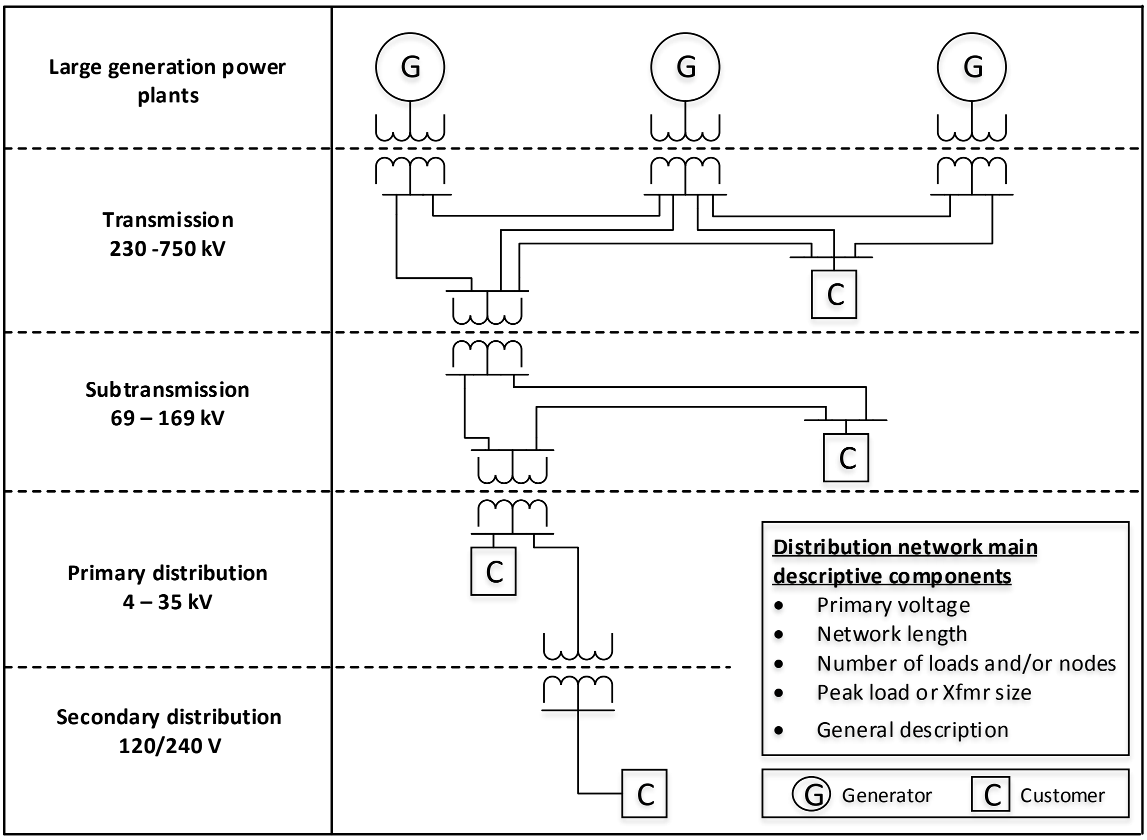

Figure 1. Power system infrastructure grouped by voltage levels.

Distribution test feeders can be built using different methods, as illustrated in Figure 2. The most straightforward one is the first method, which consists of selecting an actual feeder from a real distribution network, and anonymizing to remove private or sensitive data. The rest of the methods build synthetic networks, using real networks as the basis. The second method uses clustering techniques to group several actual networks and then stitches together pieces to build a synthetic representative test feeder for each group of actual networks. The third method builds a test feeder through manual design. This option allows for additional attention to be paid to specific network features but it is only possible with small-scale networks due to its complexity. Finally, the fourth method consists of building synthetic test networks through the use of planning tools that are designed to create realistic networks using the same technical and economic criteria that are used by distribution planners. This option allows for the design of new test networks from scratch with taylor made features. In general, the obtained test feeders should be representative of a set of real distribution networks with specific features. Representativeness is a validation criterion and therefore is not rigidly attached to any of the design methods, and it is possible to be obtained with any of the four described procedures.

In the next sections a bibliography review about the published test feeders is provided. Each section contains a brief description of the network and the most relevant publications where they are used.

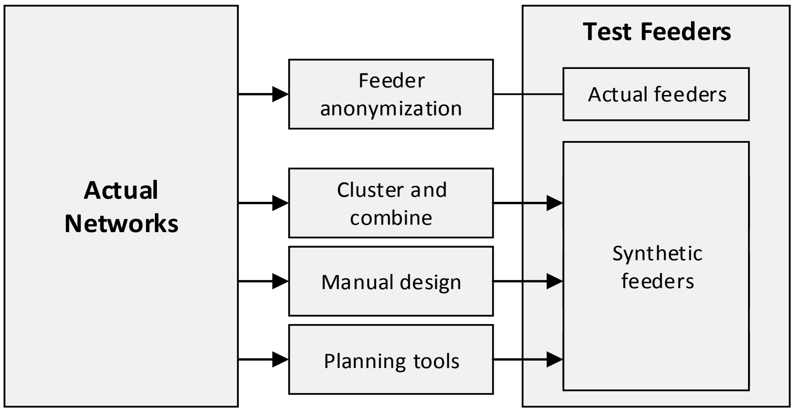

Figure 2. Test feeders building procedures.

2.1. IEEE Feeders

In 1991, the first set of four small test feeders was published [6] by the IEEE PES. Ten years later, a new test feeder was published [7] and was added to the previous set in order to provide a model of a three-phase transformer connection. In 2009, the Roadmap for the IEEE PES Test Feeder was published by the IEEE team [8]. In this paper, the direction and the requirements of the upcoming test feeders were presented, highlighting seven topics to take into account: neutral-to-earth voltage (NEV), short circuit benchmarks, distributed generation (DG) protections, large distribution system models, inverter-based DG models, comprehensive test feeders, and asymmetrical contingencies test feeders. Answering the previous needs, three new test feeders were published, a NEV test case [9], a medium-sized feeder to scale-up algorithms [10], and another with a wide variety of equipment [11]. In 2014, a new meshed low voltage test system was published [12]. The previous IEEE test feeders are presented chronologically. More information about these feeders is presented in Table 1. A recent publication [13], review the actual collection of test feeders and propose specific analytic challenges for future developments.

Table 1. Institute of Electrical and Electronics Engineers (IEEE) Test Feeders Features.

ID	Length (km)	Primary Voltage (kV)	Number of Customers/Loads	Peak load (MVA)	DG (MVA)
13 Node	2.5	4.16	9	3.6	0
123 Node	12	4.16	114	3.8	0
34 Node	94	24.9	24	1.6	0
37 Node	5.5	4.8	25	2.73	0
4 Node	1.3	12.47	1	6.3	0
NEV	1.82	12.47	1	8.9	0
8500 Node	170	12.47	1177	11.1	0
CTF	81.7	12.47/24.9	36	4.17	0.15
342 Node	15.2	13.2	624	49.4	0

2.1.1. 13 Node Test Feeder

This small and highly loaded test feeder referred in [6] includes most of the common features that are used in actual networks like voltage regulators, shunt capacitor banks, overhead and underground lines, and unbalanced loads. This feeder provides a starting point to test power-flow convergence problems for a highly unbalanced system.

2.1.2. 123 Node Test Feeder

This test feeder presented in [6] comprises of common characteristics that are installed in real networks. Several voltage drop problems are found in the feeder highlighting the necessity of voltage management with voltage regulators and shunt capacitor banks. It includes a number of switches to enable simple testing of intrafeeder reconfiguration strategies.

2.1.3. 34 Node Test Feeder

This test feeder described in [6] is a part of a real distribution network located in Arizona. Due to the long length and the unbalanced nature of the feeder, power-flow convergence problems can be studied with this test feeder.

2.1.4. 37 Node Test Feeder

Similar to the 34 Node Test Feeder, this feeder referred in [6] was obtained from an actual distribution network, in this case in California. The three-wire delta lines configuration is not common in US distribution networks; however, this model allows for testing algorithms in this less common environment.

2.1.5. 4 Node Test Feeder

This test feeder presented in [7] was published ten years after the original IEEE test feeders. This test feeder offers a simple model for the analysis of all the available three-phase transformer connections as well as step-up and step-down operations under different scenarios of balanced and unbalanced loads.

Despite their small size, these test feeders are widely used in DERs studies [14–19] and power flow analysis [20,21] among other types of studies.

2.1.6. The Neutral-to-Earth Voltage Test Case and Distribution System Analysis

The proliferation of harmonics that are generated by residential loads is producing an increase in the NEVs. Nowadays, modeling NEV is becoming an important issue, however, it requires more detailed test networks. This test case described in [9] provides a test feeder that explicitly includes pole ground resistances and aims to understand the impact on contact voltage levels and NEV under different parameters of neutral conductor section or ground resistance. This test case is mostly used in load modeling studies [22–24] and harmonics analysis [25].

2.1.7. 8500 Node Test Feeder

This test case referred in [10] was obtained from a real US distribution network with some light changes. The objective of this test feeder is to provide a large-scale reference network that allows for researchers to test algorithms on a more realistic and larger-scale system. Bus relative coordinates are included in the feeder data. It comprises several common North American features like a deep penetration of voltage regulators, per-phase capacitor banks, low-voltage secondaries, and centered-tapped transformers. It was published in two different versions, a balanced secondary-loading version, and a more realistic one with unbalanced secondaries. The primary voltage level is 12.47 kV and the secondaries are split between 120–240 V. This test feeder is widely used in smart grid and DER integration studies [26–28].

2.1.8. Comprehensive Distribution Test Feeder (CTF)

This test feeder presented in [11] aims to present a diverse and detailed network where most of the available configurations and equipment are included. The inclusion of switching devices allows for a range of network reconfiguration possibilities. This capability, combined with several different equipment types like overhead and underground lines, dissimilar transformers, step voltage regulators, induction machines, capacitor banks, and the mixture of distributed and spot unbalanced loads, results in a remarkably complete network where many possibilities can be tested. Despite being so complete, this test feeder has been designed for software testing issues, and outside of this application the results can be unrealistic. This test feeder is often used in smart grid analysis [29,30].

2.1.9. IEEE 342-Node Low Voltage Networked Test System (LVNTS)

This test system described in [12] contains a set of eight 13.2 kV primary feeders connected via delta/grounded-wye transformers to a low voltage meshed network in order to feed 50 MVA of unbalanced loads. The low voltage grid differentiates between the 120/208 V grid system (used in high-density areas) and the 277/480 V grid system (used in large load centers). The aim of this test system is to provide a reference for researchers whose objective is the evaluation of algorithms in non-radial distribution networks. This test system has been designed in order to deal with issues like heavily meshed systems with several parallel low voltage lines and transformers. This test feeder is mostly used in DERs studies [31], and communications planning analysis [32].

2.2. PNNL Taxonomy Feeders

The increasing penetration of smart grid technologies in the United States networks highlights the importance of the availability of test feeders that allow for studying the impact of their integration in a reliable way. Due to the large size of the country and the numerous different utilities, real networks present a wide range of differences in terms of topology and equipment used. For this reason, test feeders should reflect the differences due to parameters, such as climate region or voltage level.

In 2009, PNNL tried to answer this need with the publication of a set of 24 taxonomy radial distribution test feeders that are representative of the US continental area [33]. These synthetic distribution test feeders were developed through a clustering algorithm of 575 actual distribution feeders from 17 different utilities. To carry out this classification, the US was divided into five climate regions, where 35 relevant statistical and electrical properties were studied. A full description about the nature of each feeder is provided in the report [34], and are succinctly summarized in Table 2. This set of feeders is mostly used in DERs studies [35,36], and reliability analysis [36,37].

Table 2. Pacific Northwest National Laboratory (PNNL) Taxonomy Feeders.

ID	Primary Voltage (kV)	Peak Load (MVA)	Nodes	Description
R1-12.47-1	12.5	7152	613	Moderate suburban and rural
R1-12.47-2	12.47	2836	337	Moderate suburban and light rural
R1-12.47-3	12.47	1362	52	Small urban center
R1-12.47-4	12.47	5334	302	Heavy suburban
R1-25.00-1	24.9	2105	323	Light rural
R2-12.47-1	12.47	6046	482	Light urban
R2-12.47-2	12.47	6098	250	Moderate suburban
R2-12.47-3	12.47	1411	768	Light suburban
R2-25.00-1	24.9	17,021	317	Moderate urban
R2-35.00-1	34.5	8893	1031	Light rural
R3-12.47-1	12.47	8417	633	Heavy urban
R3-12.47-2	12.47	4322	263	Moderate urban
R3-12.47-3	12.47	7880	2000	Heavy suburban
R4-12.47-1	13.8	5530	571	Heavy urban with rural spur
R4-12.47-2	12.5	2218	263	Light suburban and moderate urban
R4-25.00-1	24.9	948	230	Light rural
R5-12.47-1	13.8	9430	265	Heavy suburban and moderate urban
R5-12.47-2	12.47	4500	311	Moderate suburban and heavy urban
R5-12.47-3	13.8	9200	1468	Moderate rural
R5-12.47-4	12.47	7700	643	Moderate suburban and urban
R5-12.47-5	12.47	8700	1075	Moderate suburban and light urban
R5-25.00-1	22.9	12,050	946	Heavy suburban and moderate urban
R5-35.00-1	34.5	11,800	338	Moderate suburban and light urban
GC-12.47-1	12.47	5200	27	Single large commercial or industrial

2.3. EPRI Representative Feeders

EPRI provides a set of six large representative feeders (J1, K1, M1, Ckt5, Ckt7, and Ckt24) obtained from real networks. Bus relative coordinates and time series data are included in all feeder´s data in order to provide more realistic cases.

Three of the feeders (J1, K1, and M1) are deeply focused on assessing the impact of different levels of distributed photovoltaic (PV) penetration. Table 3 summarizes the main parameters of these test feeders.

Table 3. The Electric Power Research Institute (EPRI) Test Feeders 1.

ID	Primary Length (km)	Primary Voltage (kV)	Number of Customers/Loads	Peak Load (MW)	DG (MW)
Feeder J1	93.3	12.47	1384	6	1.7
Feeder K1	45.1	13.2	321	6	1
Feeder M1	20.9	12.47	1470	5.5	-

2.3.1. Feeder J1

This is a real feeder located in the Northeastern United States and is referred in [38]. It is composed of residential, commercial, and light industrial customers. This feeder models 1.7 MW of customer-owned PV systems, along with voltage regulators and capacitor banks. Customers have noted overvoltage problems that are assumed to be caused by PV and a slow load tap changer (LTC). This test feeder´s goal is to find solutions in areas with overvoltage.

2.3.2. Feeder K1

This is a real feeder that is located in the Southeastern United States and is presented in [39]. It is composed of commercial and residential customers. This feeder models 1 MW of customer-owned PV systems. A substation LTC provides the voltage regulation as well as a capacitor bank that is placed mid-feeder. No voltage regulators are included. The objective of this test feeder is to test power flow solutions in environments with high penetrations of customer-owned PV without voltage regulators.

2.3.3. Feeder M1

This feeder described in [40] provides a detailed model of secondary feeders. It models reactive compensation that is offered by three-phase radio-controlled capacitor banks. The aim of this test feeder is to test capacitor bank management strategies in order to set a proper power factor.

2.3.4. Ckt 5, Ckt 7 and Ckt 24

These large-scale test networks referred in [41] allow testing power flows in smart grid environments. Table 4 summarizes the main parameters of these test feeders.

Table 4. EPRI Test Feeders 2.

ID	Primary Length (km)	Primary Voltage (kV)	Number of Customers/Loads	Xfmr Size (MVA)	Number of Feeders
Ckt 5	77.2	12.47	1379	16.31	1
Ckt 7	12.9	12.5	5694	19.32	14
Ckt 24	119.1	34.5	3885	69.37	2

These networks are mainly used in studies about high-penetration PV environments, where Volt/Var control strategies are needed to overcome overvoltage problems [42–44].

2.4. PG&E Prototypical Feeders

This set of 12 test feeders presented in [45] offers a taxonomy of the major type of networks that are observed in PG&E´s system. They are obtained through a clustering process of 2700 primary distribution feeders. Different kinds of networks, with a wide variety of sizes (from approximately 100 nodes to 2000 nodes) and customers mixes are represented in this compilation. The aim of these test feeders is to test the impact of DERs under different scenarios.

2.5. Other Test Feeders

Many other test feeders have been used in papers to study different issues, however, only a few of them are publically available for the research community. In what follows, several test feeders that have been published and cannot be classified in the previous groups are presented. Some of these feeders were intended to address the request presented in [8].

2.5.1. Benchmark Models for Low-Voltage Distribution Feeders

This test feeder described in [46] aims to reproduce the characteristics of a real and standard low voltage network. During the design process, a differentiation between residential, industrial, and commercial subnetworks has been made, adjusting equipment and features to the nature of the customer. A deep dive into the layout and geometry of the typical overhead and underground lines is also performed. This test feeder is used in network management analysis [47–49].

2.5.2. Agent-Based Distribution Test Feeder with Smart-Grid Functionality

This 13.2 kV test feeder referred in [50] is obtained from a real distribution network in Iowa where the peak power is close to 14 MVA. Customers are equipped with several smart-grid features, like rooftop PV panels, and price-responsive loads with time series data (e.g., smart air-conditioning devices and electric vehicles). The objective of this test feeder is to provide a tool that enables the analysis of wholesale electric power markets joined with the features of an actual feeder with smart-grid technologies. This test feeder is used in smart-grid studies [51] and planning process analysis [52,53].

2.5.3. Test Feeder for DG Protection Analysis

This 12.47 kV test feeder presented in [54] is extracted from an actual network with weak sub-transmission source impedance connected to a 1.65 MW wind turbine. The aim of this test feeder is to provide a benchmark that allows for testing distributed generation protection elements under four different fault scenarios. This test feeder has been used in power flow analysis [55].

3. Limitations of Previous Test Feeders

Distribution test networks, representing large regions and matching realistic utility features, become necessary for the development of advanced distribution tools, like OPFs, Volt/Var optimization, or network reconfiguration algorithms. The previously described set of test feeders presents a number of limitations that make their use for advanced distribution system applications difficult. Among these limitations we have found some common ones, such as: their small size, the lack of time series data representing demand and generation variability, the absence of representativeness, the lack of geographical coordinates for the physical layout of the network, test feeders that were created for dealing with a single technical or economic issue and do not have sufficient information necessary for other applications, or isolated feeders. In what follows, these limitations are analyzed in more detail. It is important to note that each of these features are present individually in a number of the available test feeders, however, the majority of the available test feeders only contain a small sub-set of the desired characteristics. Common limitations include:

- Smaller sizes: The size of the network is an important issue that should be considered in order to extract reliable conclusions from the studies. This paper proposes the use of the term "large-scale" only when multiple feeders that are connected to a substation are taken into account. In most of the cases, large-scale networks capture more heterogeneity in some factors like voltage levels, equipment variety, or network configurations. This leads to more scalable and robust results and conclusions. Nevertheless, the computational time increases dramatically when the size of the problem increases. The size of the existing test feeders is generally small, the largest ones being the 8500 node test feeder and the EPRI feeders. However, these medium-size test systems are not enough to verify the performance of large-scale solutions that are provided by new algorithms.

- Lack of time series data: Time series data for demands and DERs allow for a more comprehensive analysis of network operations. For example, the integration of DERs, such as battery storage devices with time constraints for their optimal management (due to their storage capacity), makes necessary the use of time series data during the study period of interest. In these cases, the standard single-period OPF should be transformed to a multi-period optimization. Multi-period OPFs allow for solutions that consider temporal constraints from DERs, such as energy storage, electric vehicles, or demand response. For instance, the presented EPRI test feeders (Section 2.3) include time series data with different profiles for the loads.
- Lack of representativeness: The representativeness of a distribution test network is related to the specific zonal characteristics of actual networks. For instance, unlike in Europe, US primary feeders consist of three-phase and single-phase feeder sections that supply electricity in the particular coverage zones. In addition, the number of customers powered by a single medium-voltage/low-voltage distribution transformer in the United States is much smaller than in Europe, as well as the size of the transformer itself. As a consequence, in the United States, the length of low voltage networks is also shorter than in Europe. Another notable difference is the layout of the feeders. In Europe, the vast majority of feeders within urban areas are underground. However, in the United States, underground feeders are limited to some specific residential and commercial areas. In general, urban networks have higher load density than rural networks. The type of network topologies and the type of network equipment can change depending on that the geographic and development considerations of a particular region. For instance, rural networks are topologically much more radial, and the existence of loops connecting different feeders is much less frequent than in urban networks. Finally, the type of equipment that is used by utilities changes from country to country or from region to region. For instance, the presented IEEE 8500 node test feeder includes the detailed characteristics of center-tapped MV/LV distribution transformers used in the United States.
- Missing geographical coordinates: Customer coordinates are not relevant for electrical calculations; however, they give a useful topological image of the network layout. These topological issues play an important role in expansion planning and potential reconfiguration strategies in case of network failures. For instance, the IEEE 8500 node test feeder, as well as the EPRI test feeders, include the geographical coordinates of the different network nodes.
- Design and data available for only a single issue: Some of the described test feeders were designed with the objective of modeling and solving a specific technical or economic operational problem, and in general, they become unsuitable to be used in other types of problems or applications due to the lack of relevant information. One example of this case is the presented Test Feeder for DG Protection Analysis.
- Isolated feeders: Nearly all the existing distribution test systems contain only a single, isolated feeder. This effectively ignores capture voltage and other interactions between feeders that share a substation transformer and complicates testing reconfiguration using feeder-to-feeder switching commonly used for maintenance and fault recovery.

4. Need for Large-Scale Test Networks

As described above, the vast majority of the described test feeders have a variety of limitations. In particular, the research community lacks large-scale and representative test networks making it difficult to check the validity of developed algorithms and to perform reliable and scalable operational and planning studies. This is one of the reasons why public institutions are funding projects that aim to obtain a new generation of test feeders that remove current limitations while keeping the technical rigor present in some of the current test feeders is discussed in Section 2 [56].

Several planning tools that are capable of creating synthetic networks have been developed and reported in the technical literature during the last decade. These planning models are able to locate and size primary and secondary circuits, as well as distribution transformers, through mathematical programming or heuristic algorithms. Earlier efforts with mathematical programming methods like mixed integer linear programming [57] or nonlinear programming [58], are being replaced by heuristic methods like genetic algorithms [59], practical heuristic algorithms [60], or particle swarm optimization [61]. The increasing use of heuristic methods over numerical ones is driven by the computational complexity of planning entire distribution systems. The use of heuristics is particularly relevant for distribution planning because of the much larger node count when compared to transmission network planning. These past efforts have shown that heuristic methods can be dramatically faster and more robust, which becomes especially important when planning large-scale networks.

In Europe, there have been some past efforts to build "reference network models" that can automate the design and layout large-scale distribution networks [60]. Reference network models use heuristics to generate synthetic representative networks from scratch and were originally developed to overcome the information gap that was faced by regulators in assessing appropriate utility costs. Their rich modeling framework make them capable of fulfilling the criteria described in the previous sections. An overview of the main components of such a reference network model is shown in Figure 3, which highlights the various inputs and outputs that a reference network model could use for creating advanced synthetic test feeders for future use cases. However, there are major design differences between the US and Europe, making these past tools unsuitable for use in building US-style networks. Among many other differences, the US use of extensive single-phase segments considerably increases the complexity of developing a reference network model for the US.

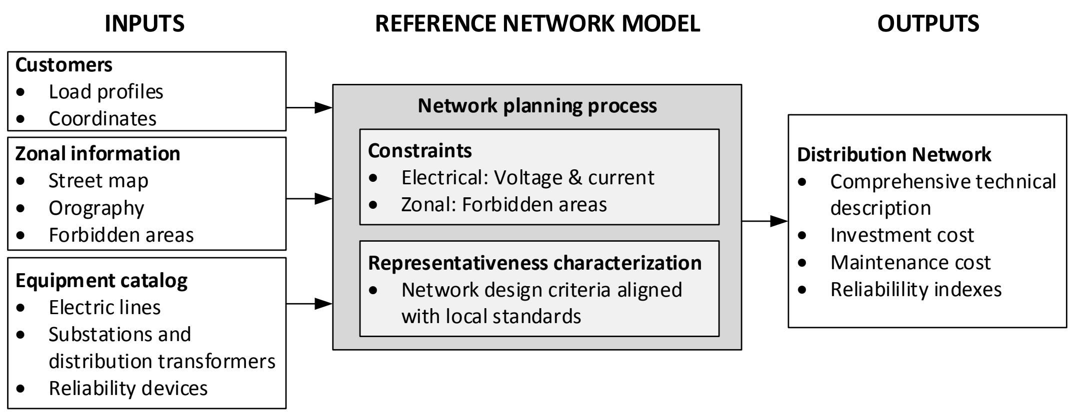

Figure 3. Components of a reference network model proposed for developing advanced, large-scale test systems.

5. Conclusions

Based on the needs of utilities and the scientific community under the new paradigm of smart distribution grids and DER integration, this paper has presented a comprehensive review of the US distribution test feeders published over the last three decades. The paper presented a succinct analysis of all the feeders, classified them based on their origin and intended uses or applications, systematically delineated all of the limitations, and identified future research needs in this field related to test feeder generation. The first set of test feeders includes small, purely radial, and non-representative distribution networks that were effective at the time and for specific intent, but have been overused in unintended ways. However, the observed trend in the test feeders published in the last years is to build large-scale representative networks with reconfiguration capabilities and are able to model several technical and economic operational and planning issues; for instance, the ones that are associated with the integration of DERs under different future scenarios. Planning tools based on numerical and heuristic methods, such as reference network models, are opening new research areas in order to design these required large-scale realistic networks and make them suitable for validating and comparing advanced distribution system algorithms.

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Phase-selection algorithms to minimize cost and imbalance in U.S. synthetic distribution systems

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ABSTRACT

The increasing penetration of distributed energy resources (DERs) has driven a push toward new algorithms and tools for distribution system operation and planning; however, there is a lack of publicly available electrical distribution test systems at the large scale—multi-feeder, multi-substation—which are required for realistically evaluating the performance and scalability of these new developments. This paper presents a Reference Network Model (RNM) aimed to plan large-scale, U.S.-style, synthetic distribution systems. Special emphasis is placed on two algorithms that allow multi-phase feeder design: (1) a method to select the most suitable number of phases for each section considering the connected customers, and (2) a method to assign phases to the users to provide near-balanced phasing while maintaining realistic levels of imbalance. The performance of the developed algorithms is verified by comparing the obtained system designs with the original IEEE 8,500-node test feeder and the Electric Power Research Institute (EPRI) J1 feeder.

1. Introduction

The increasing deployment of smart technologies and digitization is creating new opportunities for network operators and distribution companies, allowing for more efficient integration of distributed energy resources (DERs) [1]. After liberalization n, some regulators started using Reference Network Models (RNMs) to calculate costs, benefits of service and regulated revenues for distribution companies [2].

The RNM presented in this paper is a planning tool capable of generating large-scale synthetic distribution systems from scratch. The objective of the tool is to estimate the design of the most cost-efficient network, that minimizes costs associated with investments, maintenance and energy losses[a], subject to technical constraints (voltage and thermal limits) and topological constraints (topography, lakes, nature reserves, coastlines, etc.), while maintaining adequate levels of reliability. The resulting designs also incorporate adjustments to better match real systems by fine-tuning planning and equipment parameters. These systems can be considered as representative models of real utility distribution systems after successful validation.

The ongoing transformation of smart grids and distribution technologies is driving the research community to develop powerful, robust optimal power flow algorithms to address challenges such as large-scale automation, DER integration, service quality, and system resilience. As we highlighted in [3], the availability of test systems with which to verify, validate, and compare these algorithms is limited for several reasons. On one hand, actual electricity networks may be considered critical infrastructure that prevents distribution network operators from disclosing detailed data. On the other hand, publicly available test systems are mostly small-scale, and/or only designed to tackle a specific operational or design problem, with a lack of representativeness, without time-series load or generation data, or topological information (i.e. geographical coordinates for consumers and installations) among others. Recent efforts have developed large-scale synthetic transmission models (e.g. [4]); however, few large-scale, public distribution system models exist.

The RNM for the European Union (RNM-EU) was developed to generate large-scale distribution systems using European design principles [5]. However, the approximately balanced 3-phase designs for these systems did not require a phase-balancing methods that is critical for the wide-spread use of single-phase lateral lines and customer connections in U.S.-style systems. To the best of our knowledge, presently only the work by Saha et al. [6] deals with the balancing of

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[a] Energy losses can be taken into account as part of the objective function, or instead as a constraint in terms of guaranteeing an adequate level of energy losses.

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phases in U.S.-style synthetic distribution planning. Nevertheless, Ref. [6] proposes a simple method that only considers single-phase consumers and sets a heuristic criterium to decide which feeder sections are three-phase and which others are single-phase laterals. In addition, the authors only consider medium voltage (MV) feeders with no detail for low voltage (LV) secondaries. This paper fills this gap by presenting the phase-balancing approach used in a new RNM-US model capable of designing large-scale systems that capture distinct features of U.S. systems, such as primary single-phase and three-phase feeders and their inherent unbalances. One of the significant contributions in this paper is the development of algorithms to select the number and sequence of phases for each feeder section in both MV and LV. According to classifications proposed in the literature [7], this RNM-US can be framed as a large-scale distribution planning tool able to size and locate primary and secondary feeders and substations while minimizing the total network cost.

This paper is organized as follows. Section 2 compares U.S. and European distribution systems. Section 3 reviews the distribution planning process and describes the general structure of the RNM-US. Section 4 discusses the key algorithms for generating U.S distribution systems. Section 5 presents two test cases to validate the proposed RNM-US.

2. U.S. vs. European distribution networks

Broadly speaking due to historic, socioeconomic and cultural reasons, there are two main distribution system designs worldwide: European and U.S.. Neither is a priori better than the other. Some relevant differences analyzed in previous studies [8] are discussed here.

(1) Primary Feeders: One major difference in the U.S. systems is the coexistence of three-, two-, and single-phase primary feeder sections. Using fewer than three phases is enabled by extending multi-grounded neutral wires beyond the substation. In Wye four-wire configurations, single-, two-, and three-phase sections are possible, while three-wire delta configurations support only two and three phases.

Single- and two-phase laterals allow extending MV primaries to points closer to the final customers. This solution is better adapted to U.S. needs, characterized by low load density areas, lower service voltage, and large distances between consumers. By introducing longer primaries, notable loss reductions are obtained; however, the connection of single-phase loads also causes inherent voltage unbalances.

(2) Distribution Transformers and Secondaries: U.S. residential and small commercial customers are serviced with split-phase, three-wire 120/240 V secondaries, and corresponding transformers. These lower voltages than European systems imply increased low-voltage losses. Shorter low-voltage lengths and reduced low-voltage load, however, partially compensate this effect. When combined with far fewer consumers per transformer, it results in smaller rated capacities of distribution transformers in the United States.

(3) Voltage Control Devices: Voltage regulators are unusual in the European distribution system, and they are used only as a remedial action in certain rural areas that have serious voltage problems. U.S. distribution systems, however, can contain high penetrations of voltage regulators scattered throughout primaries. Similarly, capacitors are widely used in U.S. systems to improve voltage and provide reactive power.

(4) Aesthetics: Both European and U.S. distribution systems are typically overhead in low-density rural and interurban areas. In urban areas in Europe, however, the system is mainly underground, whereas U. S. distribution may mix overhead and underground, even in urban areas, using underground primarily in newer areas or those with very high density.

3 Reference Network Models (RNM)

Existing RNMs cover a wide range of applications. The RNM-EU has been used as a large-scale planning tool in the analysis of electric vehicle impacts on investments in distribution systems [9]; demand response strategies and their effect on savings in distribution systems [10]; the integration and impact of distributed generation [11]; the design of distribution system and generation supply in the electrification of rural areas in developing countries [12]; and the generation of synthetic representative distribution systems in the European Union [13].

Two main alternatives have been used for distribution system planning: numerical and heuristic methods. Mixed-integer linear programming [14] and nonlinear programming [15] are the most commonly used numerical methods. Genetic algorithms [16], discrete particle swarm optimization [17], and practical heuristic algorithms such as branch exchange or minimum spanning tree [5] are the most frequently used heuristics.

Both the RNM-EU and the RNM-US presented in this paper use heuristic methods for distribution planning. They simultaneously consider subtransmission lines and substations, primary feeders, distribution transformers, and secondaries. Heuristic methods allow obtaining robust solutions quickly, providing advantages for computationally limiting applications, such as generating large-scale distribution systems.

3.1. Input and output data

The RNM-US inputs include: (1) a list of users (loads, distributed generators, or both) with their geographic coordinates as well as active and reactive peak power; (2) geographic information about the planning area, such as street maps, the topography, and restricted areas; and (3) a catalog with the technical and economic characteristics of the available electrical equipment to design the network classified by voltage levels. Some additional parameters are included to guide the design. The model provides a detailed topology of U.S. representative synthetic distribution system and other outputs, such as the investment, operation-and-maintenance costs, and reliability indexes.

3.2. RNM-US planning process

As shown in Fig. 1, the RNM-US general structure is divided into four main stages. This model follows a scheme similar to that presented

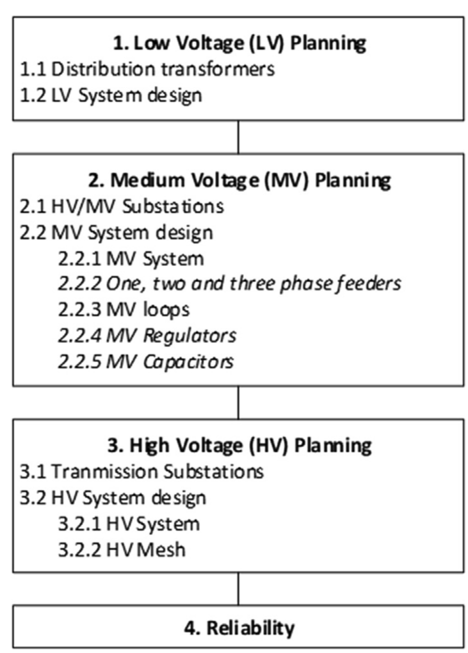

Fig. 1. RNM-US planning process.

in the RNM-EU [5], with newer developments for US-style systems (highlighted in italics). This processed is summarized below, and described in more detail in [18].

Initially, the distribution transformers (medium to low voltage) are located and scaled by grouping several nearby low-voltage users and their peak load. After that, the low-voltage system is designed by connecting low-voltage users to distribution transformers.

Medium-voltage follows the same procedure. In this case, the distribution substations (high to medium voltage) are located and sized considering the distribution transformers capacity (medium to low voltage) and the medium-voltage users. Next, the medium-voltage system is generated by connecting medium-voltage users, distribution transformers, and distribution substations. Then, the single-, two-, and three-phase sections of medium-voltage are determined, as described by the algorithm in Section 4. Additionally, a meshing stage is performed. As observed in actual distribution systems, it is implemented through normally-open medium-voltage loops, allowing for reconfiguration strategies.

As previously described, voltage regulators and capacitors are widely deployed in U.S. networks. Therefore, the RNM-US includes them in the planning process of medium-voltage. Numerous studies have addressed the location of voltage regulators [19] and capacitors [20] in distribution system; thus, this paper does not delve into the selected algorithms to tackle these issues.

Following the same process, the transmission substations (extra high to high voltage) are planned and connected to high-voltage users and distribution substations. In this case, the meshed topology (or ring structure) of the high-voltage sub-transmission network is also designed to achieve the desired reliability level.

The final stage of the planning process is to run the reliability module. If the system design does not yet reach the established reliability targets in terms of SAIDI and SAIFI, additional equipment such as breakers, switches, fuses, or fault detectors are deployed until the desired targets are reached [21].

4. Algorithms for feeder phase selection

After the single- and two-phase lines are laid out, RNM-US determines the phases of each medium-voltage section in two steps: (1) determining the number of phases; and (2) distributing phases A, B, or C. The selection of the number of phases is formulated as the cost-minimization of each feeder section. Phases A, B, or C are then selected to minimize the local and system-level unbalances.

4.1 Setup

Each portion of the distribution system is defined as a set of nodes, n_i, some with one or more attached customers (loads, generators, or both), $c_{i,l}$; and branch sections, $b_{i,j}$, connecting two nodes (with n_i as the upstream node (Fig. 2)). A radial configuration is assumed for medium-voltage feeders, and upstream refers to locations closer to the distribution substation.

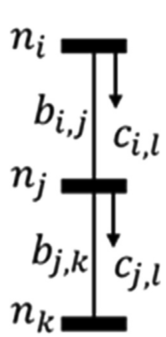

Fig. 2. Nomenclature example.

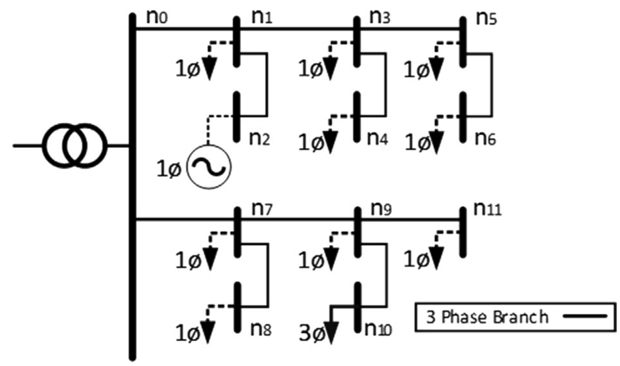

Fig. 3. Stage 0: Initial system.

For simplicity, three commonly used functions are also defined:

- nphases(n_i) Returns the maximum number of phases of the set of network users, $c_{i,l}$, connected to a node. It serves as an input to the model, specifying one, two, or three phases (1ø, 2ø, and 3ø respectively).
- nphases($b_{i,j}$): A similar output function that returns the number of phases of a branch.
- children(n_i): Returns the set of downstream nodes directly connected to "n_i". Terminal nodes return an empty set.

4.2. Stage 0: Initial solution

Initially, the RNM-US builds a feasible distribution system using the highest ampacity three-phase medium-voltage wire available in the equipment catalog. Fig. 3 shows a very simple example of a distribution system at this stage. This initial design allows calculating an approximate power flow used to later refine the design. This initial system is designed using a minimum spanning tree [22] and branch-exchange algorithms [23] to guarantee feasibility in terms of voltages and overloads; however, this design is not yet economically optimal.

4.3. Stage 1: Selection of the number of phases

Two algorithms, applied successively, are presented in stage 1 to improve the stage 0 initial solution. The first (stage 1.1) selects economically optimal feeder sections, and the second (stage 1.2) ensures phase consistency in the whole system. Note that the number of phases for each user is introduced as an input, and the system needs to be designed accordingly.

(1) Stage 1.1- Net Present Value (NPV) of Each Feeder Section: To optimize total network cost, the NPV of each section is calculated. It is computed as the sum of the NPV of investment, maintenance, and energy losses. This calculation takes into account the three main cost drivers in distribution planning, using the previously obtained power flows for loss estimations. This methodology has been widely used in the open literature [24,25].

The equipment catalog has been developed so that the ampacity of each segment is always increasing with the number of phases. Therefore, three-phase segment ampacity is greater than that of its downstream one- or two-phase sections.

As shown in Fig. 4, for a given power flow there is a design option that minimizes the total cost of the feeder section. In this example, "Design A" would be the optimal choice for low power flow ranges, "Design B" for medium power flow ranges, and "Design C" for higher ones. The number of power flow ranges will be equal to the number of feeder section designs in the equipment catalog. The more feeder sections in the equipment catalog, the more design options the model

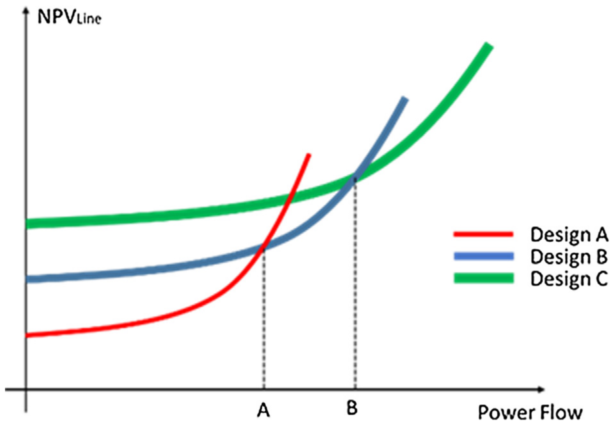

Fig. 4. Example NPV vs power flow: design trade-off for a section.

would have. Using this function, for each feeder section an optimal design option is selected that economically minimizes the NPV and ensures network feasibility in terms of having enough ampacity to prevent overloads.

Fig. 5 shows the resulting example system analyzed in Stage 0 after applying the optimization algorithm presented in this section (stage 1.1). The figure represents three-phase sections with continuous lines and single-phase sections with dotted lines. This design is more economic than the previous one because the sections are better adapted to their power flow levels; however, several phase inconsistencies are detected. There are two reasons for these inconsistencies:

1- The most common is the existence of three-phase users. These users need to be connected to the system through three-phase branches ($b_{i,j}$), but this is not taken into account in the function when choosing the optimal design, which is done separately for each section. For example, in Fig. 5, the number of phases of line n_7-n_9 ($b_{7,9}$) and line n_9-n_{10} ($b_{9,10}$) are not consistent with the three-phase user located at node n_{10}. This can be fixed by forcing the number of phases of the upstream network to be equal to or greater than the phases of the supplied users.

2- Another challenge arises with distributed generation, which can also cause upstream branches to have fewer phases than downstream branches. For example, in Fig. 5, the generator located at n_2 produces an upstream power flow through line n_1-n_2 ($b_{1,2}$) that reduces $b_{0,1}$ requirements compared with $b_{1,3}$. This results in a single-phase section unrealistically supplying a three-phase section.

These situations show the need for an additional algorithm to guarantee consistency in the number of phases.

(2) Stage 1.2- Guarantee Consistency in Number of Phases: Fig. 6 shows

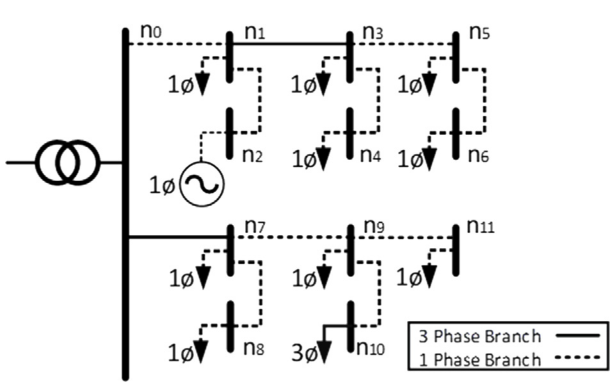

Fig. 5. Stage 1.1: Economically optimal system.

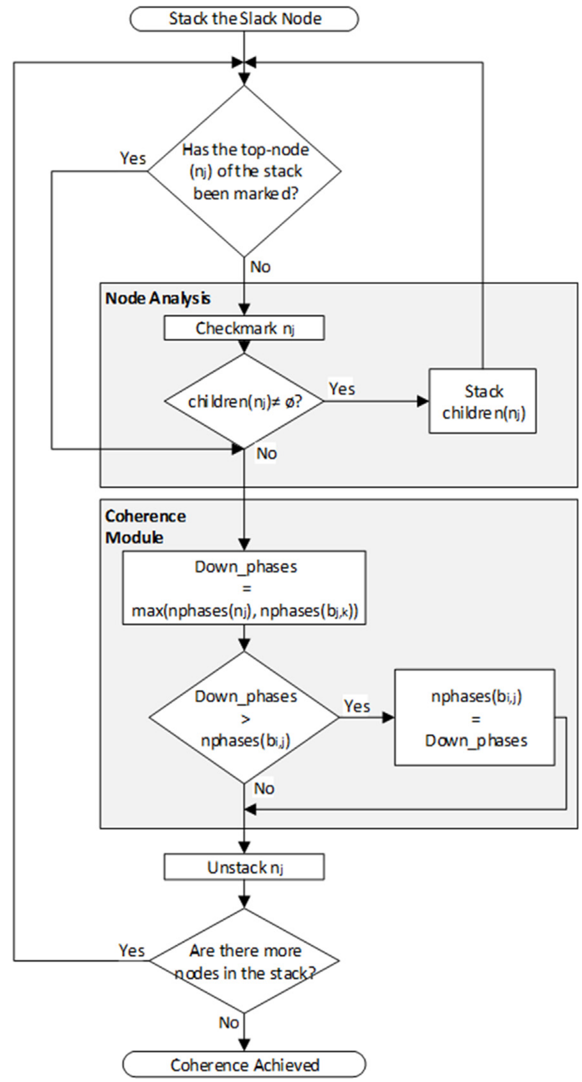

Fig. 6. Phase consistency algorithm.

a detailed flowchart to solve these inconsistencies. A depth-first search (DFS) algorithm is applied through a node stack that brings consistency between nodes and branches [26]. The algorithm first stacks the slack node (normally a substation) and iterates through the graph using a backward-forward logic, efficiently ensuring network consistency. Using DFS, the consistency module is applied to all nodes, starting with the farthest ones. In a nutshell, this process forces sections located upstream of other elements (such as branches and nodes) to have at least the same number of phases as those downstream.

Fig. 7 shows the resulting network after the stage 1.2 consistency process. As observed, consistency between branches and nodes is achieved. For instance, $b_{7,9}$ and $b_{9,10}$ are now three-phase, allowing n_{10} to be fed with the correct number of phases. Further, the infeasible network configuration previously found in $b_{0,1}$ has been solved.

4.4. Stage 2: Selection of A/B/C phases

Once the number of phases is obtained, Stage 2 aims to assign a specific phase A, B, C, or a combination to every network user, and hence the associated network. It is important to note that the algorithḿs objective is not to obtain the minimum imbalance from an operational point of view (say, under different operational situations),

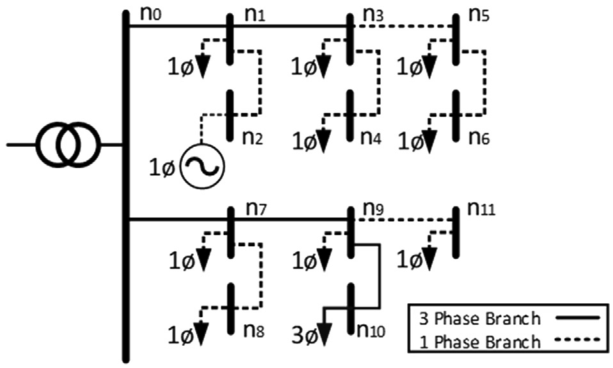

Fig. 7. Stage 1.2: Optimal and feasible system.

but rather to produce a realistic phase balance consistent with industry practice. As a proxy for these practices, RNM-US optimizes the minimum phase imbalance on individual customer's peak energy consumptions (including rated behind-the-meter generation capacities). This enables finding network designing solutions that will connect the various consumers and generators to different phases in the network. This approach still results in phase imbalance due to time-varying loads and the multi-load groupings on single- and two-phase lateral lines.

It is possible to directly obtain a global optimum phase balance solution by directly applying the tree-partitioning problem algorithm at the system level [27]. However, this would not consider the optimization of the unbalance locally. Therefore, we propose an algorithm that allows balancing the phasing both locally and at the system level, starting with the farthest nodes and optimizing the imbalance at every node, using DFS. Fig. 8 shows a flowchart of the algorithm. To determine the most appropriate phase of each user, this algorithm starts with the number of phases of each section, as established in the previous step and initial phase selection of A, AB, or ABC, for single-phase, two-phase, or three-phase network users, respectively.

The balancing module analyzes all the nodes using DFS, starting with the farthest node. For each node, the algorithm calculates the optimal permutation of the downstream phases, which leads to the minimum unbalance. The optimal permutation needs to be selected only in branches that have more than one phase, because the algorithm optimizes the imbalance of the downstream branches, and in the case of single-phase feeders, the downstream imbalance does not depend on the phase selection (A, B or C). To clarify the optimization process, a more detailed mathematical description of the block "Select the optimal phases permutation for $b_{j,k}$ and $c_{j,l}$" follows:

Four variables are defined to explain this optimization.

- $\bar{S}_{bi,j-P}$ represents the apparent power flow in branch $b_{i,j}$ through phase P, where the phase can be A, B, or C.
- $\bar{S}_{c_{j,l}-P}$ represents the apparent power demand from customer $c_{j,l}$ on phase P, where the phase can be A, B, or C. If the user is three-phase, $\bar{S}_{c_{j,l}-A}$, $\bar{S}_{c_{j,l}-B}$ and $\bar{S}_{c_{j,l}-C}$ are the same. If the user is single-phase, two of these elements are zero.
- $\Delta\bar{S}_{bi,j}$ represents the unbalance in branch $b_{i,j}$, computed as shown in Eq. (1).
- $\Delta\bar{S}_{c_{j,l}}$ represents the unbalance in customer demand $c_{j,l}$, computed as shown in Eq. (2). If the user is three-phase, two options can be considered:
  - o Define the user with a common load for all phases and therefore, the unbalance would be zero
  - o Define each phase with a different load, thus obtaining unbalanced three-phase users

The apparent power of phases A, B, and C are desynchronized 0°, 120°, and 240°, so the modulus of the resulting vector can be used as a measure of the unbalance. The higher the unbalance in $b_{i,j}$, the higher

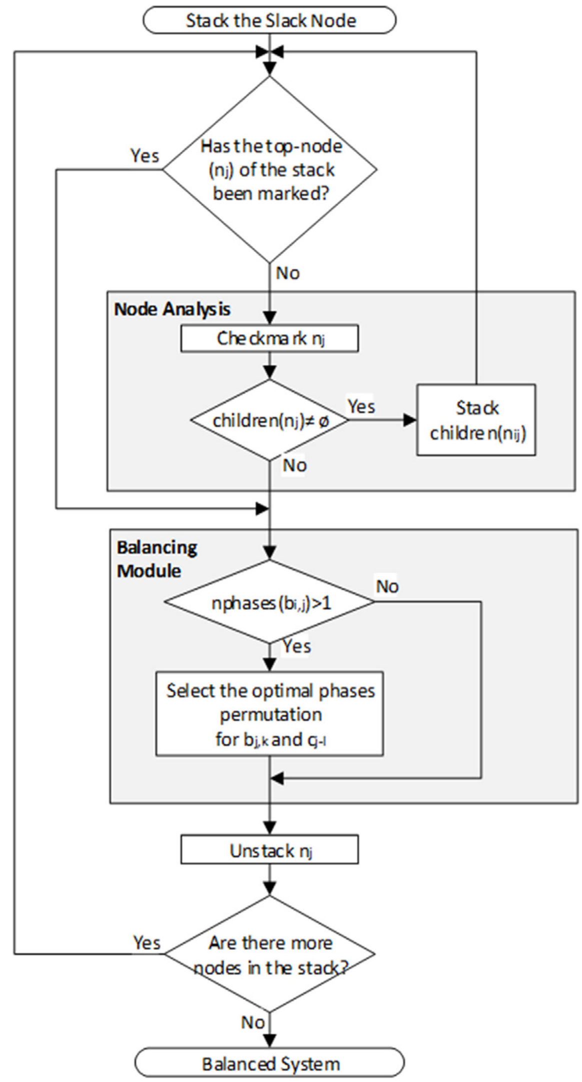

Fig. 8. ABC phase selection algorithm.

the modulus of $\Delta\bar{S}_{bi,j}$.

$$\Delta\bar{S}_{b_{i,j}} = \bar{S}_{b_{i,j}-A}\, e^{0^o j} + \bar{S}_{b_{i,j}-B}\, e^{120^o j} + \bar{S}_{b_{i,j}-C}\, e^{240^o j} \tag{1}$$

$$\Delta\bar{S}_{c_{j,l}} = \bar{S}_{c_{j,l}-A}\, e^{0^o j} + \bar{S}_{c_{j,l}-B}\, e^{120^o j} + \bar{S}_{c_{j,l}-C}\, e^{240^o j} \tag{2}$$

The local unbalance at node n_j ($\Delta\bar{S}_{n\,j}$) is defined by Eq. (3) as the addition of the apparent power vectors of the downstream branches ($b_{j,k}$) and of the consumers ($c_{j,l}$) directly connected to node n_j, as defined by Eqs. (1) and (2) respectively:

$$\Delta\bar{S}_{n\,j} = \sum_k \Delta\bar{S}_{b_{j,k}} + \sum_l \Delta\bar{S}_{c_{j,l}} \tag{3}$$

As an example, consider selecting the optimal phasing to minimize the unbalance at n_7, assuming the apparent power at each node as shown in Table 1. This example shows how the algorithm is able to take into account loads and generators at the same time. For simplicity, assume a single customer per node and a unity power factor.

This process can be divided into two main steps:

Table 1
Customer Demand at Peak Hours for the Example.

Node	1	2	3	4	5	6	7	8	9	10	11
Power (kVA)	7	−3	5	7	6	4	5	3	4	30	4

(1) As previously stated, the algorithm seeks to minimize the local unbalance of the analyzed node (n_j). In this stage, the downstream power of branches $b_{j,k}$ and users $c_{j,l}$ are evaluated starting with the previous initialization. In the case of node n_7, the elements shown in Eqs. (4), (5), and (6) are added to compute the unbalance at node n_7:

$$\Delta \bar{S}_{b_{7,9}} = 14e^{0^oj} + 14e^{120^oj} + 10e^{240^oj} \quad (4)$$

$$\Delta \bar{S}_{b_{7,8}} = 3e^{0^oj} \quad (5)$$

$$\Delta \bar{S}_{c_{7,1}} = 5e^{0^oj} \quad (6)$$

As observed in Eq. (7), there would be a large imbalance as a result of the previous initialization stage, so an optimization stage is required:

$$\Delta \bar{S}_{n_7} = 22e^{0^oj} + 14e^{120^oj} + 10e^{240^oj} \quad (7)$$

To select the optimal phases, the vector components associated with phases A, B, and C can be interchanged using six possible permutations for each element: ABC, ACB, BAC, BCA, CAB, and CBA. As an illustration, permutation BAC would interchange phase A by B, phase B by A, and phase C would remain the same. Hence, permutation ABC implies no phase alteration. Table 2 illustrates the possible permutations of element $\Delta Sb_{7,9}$. In this particular case, two components of the vector are equal, and the six permutations lead to only three different results.

(2) Once the optimization variables are defined, the objective function is formulated to reduce the total unbalance in n_j. Eq. (8) proposes the minimization of the modulus of the apparent power for the elements connected to node n_j:

$$\min(|\Delta \bar{S}_{n\,j}|) = \min(|\sum_k \Delta \bar{S}_{b_{j,k}} + \sum_l \Delta \bar{S}_{c_{j,l}}|) \quad (8)$$

In particular, for node n_7 being optimized in this iteration, the problem is stated in Eq. (9):

$$\min(|\Delta \bar{S}_{n7}|) = \min(|\Delta \bar{S}_{b_{7,9}} + \Delta \bar{S}_{b_{7,8}} + \Delta \bar{S}_{c_{7,1}}|) \quad (9)$$

Because all the possible permutations are known *a priori,* the optimization can follow the tree-partitioning algorithm [27], starting with the elements that have a higher modulus, and computing partial sums until all the elements have been optimized. In the example, this algorithm results in the following phase selections: ABC for branch $b_{7,9}$, CBA for user $c_{7,1}$, and ABC for branch $b_{7,8}$.The resulting unbalance at n_7 has a modulus of 2.6 according to Eq. (13), which is now optimized and significantly reduced with respect to the initial modulus of 10.6, according to Eq. (7).

$$\Delta \bar{S}_{b_{7,9}} = 14e^{0^oj} + 14e^{120^oj} + 10e^{240^oj} \quad (10)$$

$$\Delta \bar{S}_{c_{7,1}} = 5e^{240^oj} \quad (11)$$

$$\Delta \bar{S}_{b_{7,8}} = 3e^{0^oj} \quad (12)$$

$$\Delta \bar{S}_{n_7} = 17e^{0^oj} + 14e^{120^oj} + 15e^{240^oj} \quad (13)$$

Optimizing the unbalance using the tree-partitioning algorithm and applying it using the DFS order guarantees the optimal balance at both the terminal and upstream nodes, subject to the previous optimization at the downstream nodes.

Fig. 9 shows the subsequent system once the algorithm is applied everywhere. For this small system, a perfect local and global power balance is obtained, resulting in a 24-kVA load per phase.

Table 2
Possible Permutations of Sb7,9.

$\Delta \bar{S}_{b_{7,9}}$	P1 ABC	P2 ACB	P3 BAC	P4 BCA	P5 CAB	P6 CBA
$\bar{S}_{b\,j,k-A}$	14	14	14	14	10	10
$\bar{S}_{b\,j,k-B}$	14	10	14	10	14	14
$\bar{S}_{b\,j,k-C}$	10	14	10	14	14	14
$\lvert\Delta \bar{S}_{b_{7,9}}\rvert$	4	4	4	4	4	4

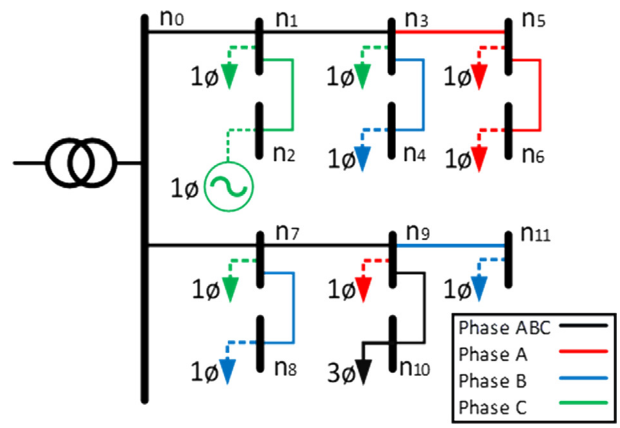

Fig. 9. Stage 2: Optimal phase selection system.

This methodology allows to generate highly balanced networks; however, if the main purpose lies on obtaining synthetic systems with certain targets like the balance degree, it may be convenient to include a pre-defined per-phase imbalance in Eq. (3).

The algorithm is designed to balance radial systems under normal operating conditions. In case of network reconfiguration for service restoration, the connection through a loop may introduce a difference in imbalance depending on the switch and lateral locations and the imbalance of any isolated (de-energized) portions of the network. However, this imbalance will be relatively small given the general spatial diversity of the imbalanced load. Moreover, a higher degree of imbalance is generally acceptable—and common in practice—during such off-nominal operating conditions.

5. Case studies

Following the methodology described in this paper, three large-scale synthetic test systems have been generated and published [28–30], and a full validation process has been carried out in order to validate them [31]. Nevertheless, in order to specifically validate the previously described algorithms, two U.S.-style distribution test systems are replicated using synthetic networks produced by RNM-US: the IEEE 8,500-node test feeder [32] and the Electric Power Research Institute (EPRI) feeder J1 [33]. Both have been widely used by the research community to perform DER analysis. Two metrics are computed for both the original systems and the synthetic ones to test the phase-balancing algorithm performance. First, the single-phase and three-phase ratio is analyzed to test the algorithm's ability to select the number of phases (Section 4.3). Second, the load phase allocation is computed to verify if the algorithm minimizes unbalances at the local and system levels (Section 4.4). As previously mentioned, number of phases and active and reactive power are user provided model inputs.

5.1. IEEE 8,500-Node test feeder

This test feeder corresponds to an actual U.S. distribution network with minor modifications. It includes several U.S. features, such as single- and three-phase feeders and secondaries fed by center-tapped transformers.

Fig. 10 compares the original test system with the built synthetic model. The objective is not to replicate the existing feeder but to design a new one using the existing consumer location, demand and number of phases. Despite some differences, the system topology designed by RNM-US is similar. Some of these differences are due to the fact of not using a street map to build the network, which typically is an input to RNM-US, but it is not available in these test feeders.

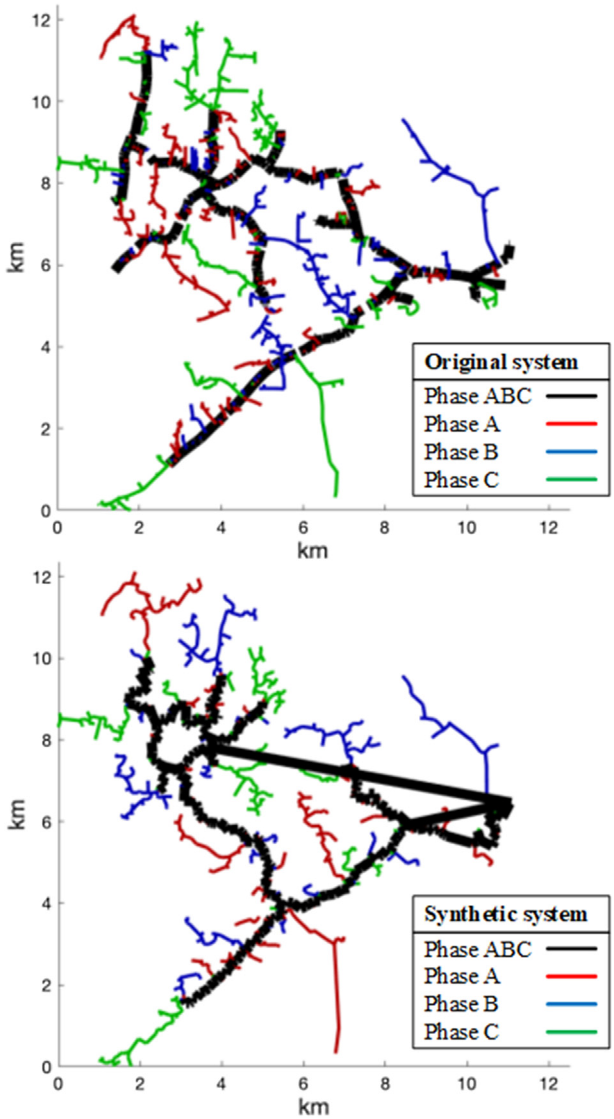

Fig. 10. IEEE 8,500-node test feeder: original (top) vs. synthetic (bottom).

Table 3
IEEE 8,500-Node Test Feeder. Original vs. synthetic.

8,500-Node Test Feeder			Original System		Synthetic System	
			Length (km)	%	Length (km)	%
Line	1Ph	A	42.07	25%	35.23	24%
		B	48.69	29%	28.35	20%
		C	40.58	24%	35.95	25%
	2Ph		0.09	0%	0	0%
	3Ph	ABC	38.49	23%	45.49	31%
			S (kVA)	%	S (kVA)	%
Demand		A	3,411	31%	3,565	32%
		B	4,230	38%	3,675	33%
		C	3,465	31%	3,867	35%
		Total	11,106	100%	11,106	100%

Table 3 compares the metrics of the original and RNM-US systems for the 8,500-node test feeder. Overall, both metrics look very similar, although the RNM-US model is slightly more balanced.

5.2. EPRI feeder J1

This test case features a real distribution network located in the northeastern United States. Furthermore, 22.6% of the network users have distributed generation. Fig. 11 compares the original EPRI-J1 feeder to the synthetic RNM-US results.

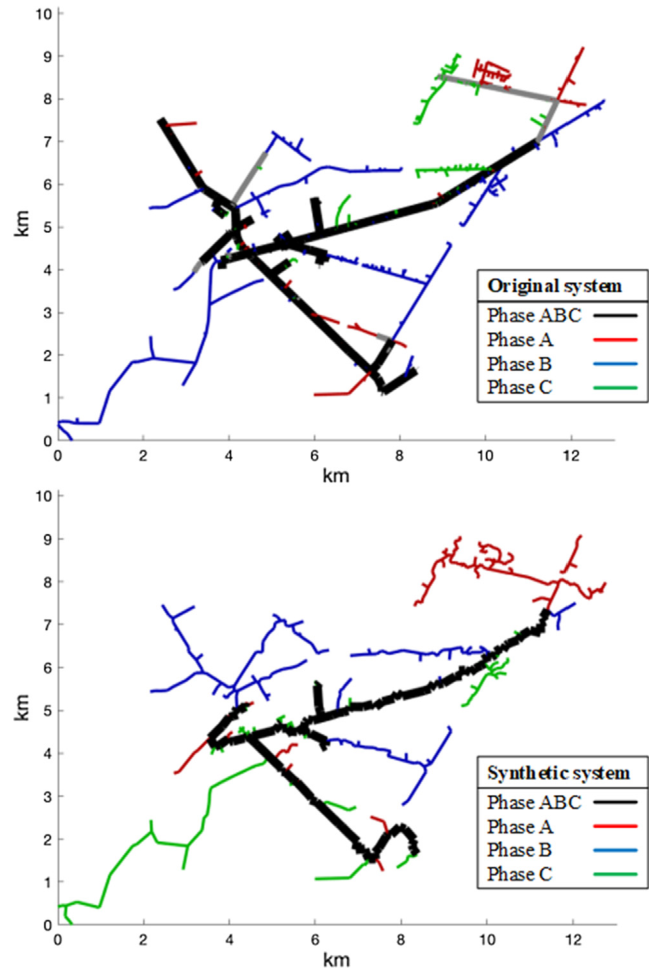

Fig. 11. EPRI Feeder J1: original (top) vs. synthetic (bottom).

Again, the topology generated by RNM-US is very close to the real one, and, the metrics (Table 4) compare favorably, albeit with somewhat more balanced results from RNM-US.

The RNM-US results have also been validated in large-scale synthetic systems, combining three different points of view, statistical, computational and expert feedback [31].

Table 4
EPRI Feeder J1. Original vs. synthetic.

EPRI J1 Test Feeder			Original System		Synthetic System	
			Length (km)	**%**	**Length (km)**	**%**
Line	1Ph	A	12.92	14%	19.88	22%
		B	11.54	12%	20.70	23%
		C	38.12	40%	28.13	32%
	2Ph		6.85	7%	0	0%
	3Ph	ABC	25.47	27%	19.73	22%
			S (kVA)	**%**	**S (kVA)**	**%**
Demand + Generation		A	1,640	32%	1,724	33%
		B	1,680	32%	1,722	33%
		C	1,866	36%	1,739	34%
		Total	5,186	100%	5,186	100%

6. Conclusions

Previous works have developed algorithms for building synthetic European distribution networks (Reference Network Model (RNM-EU)). However, as highlighted in the paper structural differences between European and U.S. distribution systems prompted the need to extend these techniques with novel algorithms to more realistically build U.S.-specific synthetic distribution test cases. This paper describes an approach for managing one of the key differences in network design: the U.S. practice of delivering "single" phase power to small customers and the use of single- and two-phase feeder sections at the MV level, resulting in a need to manage phase-allocation during design. The RNM-US software tool has been used to design three new publicly available large-scale representative U.S. distribution systems. The major contribution of this paper has been to propose two algorithms that determine the number and sequence of phases at each feeder section, and assign the phase to each final user minimizing the unbalance. The selection of the number of phases is carried out by minimizing investment, maintenance, and energy loss costs at each feeder section. The paper shows that this type of optimization requires an additional stage to ensure consistency when single-phase laterals would otherwise be sufficient to serve relatively small three-phase customers. After this step, another algorithm distributes phases A, B, and C based on DFS and tree-partitioning algorithms. The paper shows that the proposed algorithm is able to address the trade-off between minimizing the unbalance locally and at the system level, while still maintaining realistic levels of unbalance. Two case studies using IEEE 8,500-node and EPRI J1 feeders demonstrate that the algorithms can be successfully applied to plan large-scale distribution areas. As future research, the algorithm described in this paper to minimize the unbalance could also be applied to actual networks to rethink which loads are connected to each phase and to reduce the unbalance of the analyzed networks. Another future investigation line to be developed is providing advanced load models (beyond constant P, Q) in order to facilitate some ongoing research topics such as distribution system state estimation.

CRediT authorship contribution statement

Fernando Postigo: Conceptualization, Methodology, Software, Writing - review & editing. **Carlos Mateo:** Conceptualization, Methodology, Software, Writing - review & editing. **Tomás Gómez:** Conceptualization, Methodology, Writing - review & editing. **Fernando de Cuadra:** Conceptualization, Methodology, Writing - review & editing. **Pablo Dueñas:** Validation, Writing - review & editing. **Tarek Elgindy:** Validation, Writing - review & editing. **Bri-Mathias Hodge:** Validation, Writing - review & editing. **Bryan Palmintier:** Validation, Writing - review & editing. **Venkat Krishnan:** Validation, Writing - review & editing.

Declaration of Competing Interest

None.

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Location and Sizing of Micro-Grids to Improve Continuity of Supply in Radial Distribution Networks

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Abstract: The steady decline in the prices of distributed energy resources (DERs), such as distributed renewable generation and storage systems, together with more sophisticated monitoring and control strategies allow power distribution companies to enhance the performance of the distribution network, for instance improving voltage control, congestion management, or reliability. The latter will be the subject of this paper. This paper addresses the improvement of continuity of supply in radial distribution grids in rural areas, where traditional reinforcements cannot be carried out because they are located in secluded areas or in naturally protected zones, where the permits to build new lines are difficult to obtain. When a contingency occurs in such a feeder, protection systems isolate it, and all downstream users suffer an interruption until the service is restored. This paper proposes a novel methodology to determine the optimal location and size of micro-grid systems (MGs) used to reduce non-served energy, considering reliability and investment costs. The proposed model additionally determines the most suitable combination of DER technologies. The resulting set of MGs would be used to supply consumers located in the isolated area while the upstream fault is being repaired. The proposed methodology is validated through its application to a case study of an actual rural feeder which suffers from reliability issues due to the difficulties in obtaining the necessary permissions to undertake conventional grid reinforcements.

Keywords: Micro-grids; continuity of supply; power distribution; power system planning

1. Introduction

The digitalization of the energy industry represents a turning point in the sector development [1]. In the case of electricity network planning [2], until the end of the 20th century, networks were mainly composed of a set of passive assets governed by electromechanical protection elements. With the sector digitalization, a wide range of possibilities enabling an increase in global social welfare has been opened. Regarding system planning and operation, these possibilities are translated into new management strategies that allow optimizing the performance of the system.

Nowadays, the levels of monitoring and control of transmission grids are fairly high; however, transmission only accounts for 3% of the total length of the European electricity network [3]. The remaining 97% corresponds to the distribution system [4], whose monitoring levels are significantly lower, especially in the case of rural networks [5]. These grids are mostly radial. Consequently, a failure in any of the network elements usually implies the loss of supply for all customers located downstream of the nearest circuit-breaking device [6]. Moreover, in many cases, orography hampers fast fault detection and repair, leading to long restoration times and deterioration in quality of service.

It is worth stressing that in more than half of the European countries [4], Distribution System Operators (DSOs) are exposed to incentive-penalty schemes associated with the power quality and continuity of supply indexes in their networks [7]. Increasing grid reliability has conventionally been achieved through traditional network reinforcements, such as the installation of switching and control equipment throughout feeders, the construction of new parallel power feeders, or meshing existing feeders to allow network reconfiguration [8]. However, these solutions are not always possible, since rural networks are sometimes placed in secluded and/or protected areas where permits to build this type of infrastructures are very hard to obtain. To overcome these difficulties, DSOs may consider alternative solutions based on micro-grids (MGs) in order to improve quality of supply without causing a major environmental impact.

MGs can be defined as network subsets with a high degree of automation and distributed energy resources (DERs) that can be operated in an islanded manner [9]. As several international experiences show [10], MGs are not a futuristic solution, but current solutions for which new policies and regulations are already being developed [11]. This is mainly due to the sharp reduction in the costs of DERs in recent years [12].

According to the existing literature, MGs can be classified according to different criteria. In [13], two types of MGs are defined from a regulatory perspective: customer microgrids (or true microgrids) which are located downstream of an end-user meter, and utility microgrids (or milligrids) that involve a segment of the common distribution network. While milligrids are not technologically different from customer microgrids, they are radically different from a regulatory viewpoint, largely because milligrids integrate the conventional utility network as in this case. However, other categorizations can be made as indicated in [14], where a taxonomy is presented based on their use, with the main categories being: remote, utility distribution, community, institutional, military, and commercial. Islanded operation of MGs also imposes new technological requirements on the operation and control of DER. If only inverter-connected DER is available, at least one of the DER units must operate in grid-following or voltage-source-based grid-supporting mode [15].

Regarding distribution networks, MGs are able to increase the number of control variables (e.g., islanded operation), and enable new management strategies [16] that can be applied in order to achieve diverse objectives depending on the network needs [17]. Previous research has already addressed several of these applications, including: decreasing technical losses [18], helping voltage control [19], increasing PV hosting capacity [20], rural electrification [21], increasing global efficiency [22], or market services [23]. Nevertheless, one of the most relevant advantages of these solutions comes from the opportunity of improving continuity of supply in the case of network failures. To this end, some publications have developed methodologies for locating generators [24,25] and reclosers [26] in distribution networks.

Nonetheless, as far as we know, to date, no reference in the literature has addressed the same problem tackled in this paper. This paper proposes a novel methodology that allows obtaining optimal MG designs that enable supplying all those consumers that, after a contingency, could not be supplied from the original source (normally the upstream substation). In this paper, the location, the type (storage, PV systems, and diesel groups) and the size of the DER technologies in charge of feeding the MG are chosen according to a multicriteria optimization, in which both the investment in these new technologies and the increase of reliability obtained with them are evaluated.

The remainder of this paper is structured as follows. Section 2 defines the problem addressed and poses the type of solutions that can be obtained. Section 3 presents the nomenclature used in this paper. Section 4 digs into the methodology applied to optimize the location and size of MGs. Section 5 applies the previously developed methodology to a synthetic realistic rural network. Finally, Section 6 outlines the main conclusions.

2. Problem Statement

As presented in the introduction, this paper addresses the problem of improving the reliability of radial distribution networks in rural and secluded areas. Currently, when a contingency occurs in such a feeder, protection systems isolate it, and all downstream users suffer an interruption until the fault is repaired and service is restored. This paper proposes a methodology for determining the optimal size and location of a set of DERs (a combination of generators and storage), considering both reliability improvements and investment minimization. In the event of a contingency, and once the fault is isolated, the installed DERs allow to keep supplying the affected consumers while the fault is being repaired, thus minimizing the duration of the interruption times of those customers. This process is shown in Figure 1. The proposed reliability improvement application can be combined with other potential services that DERs can provide, such as voltage control or congestion management, since the islanded operation will only be used sporadically when network outages occur.

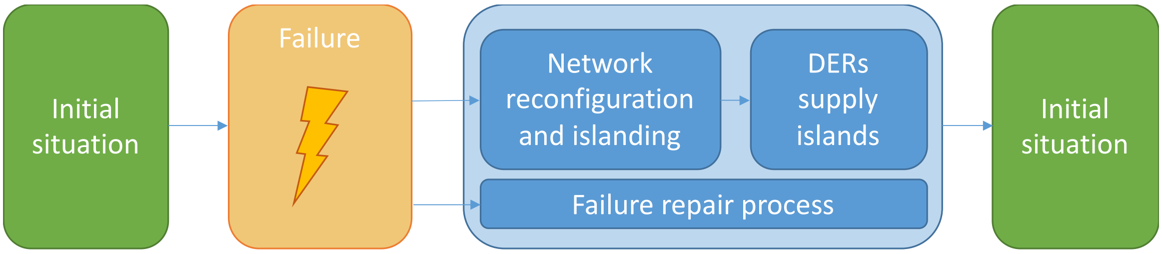

Figure 1. Action plan when a contingency occurs.

For illustrative purposes, this section provides an overview the kind of MG-based solutions that the proposed model would yield, and the main concepts used throughout the paper. However, these concepts are further detailed in Section 3. In this line, Figure 2 shows an example of a network divided into four zones (z_1, z_2, z_3, z_4). These zones are delimited by three smart switches (ss_1, ss_2, ss_3) that enable the reconfiguration of the network when an outage occurs. This figure shows a possible solution to improve the reliability of this network. Two sets of DERs (der_{d1} and der_{d2}) are installed in different zones of the system. The colors used denote that $derd_1$ is designed to supply three zones (z_1, z_2, and z_3), while $derd_2$ is dimensioned to supply just z_4.

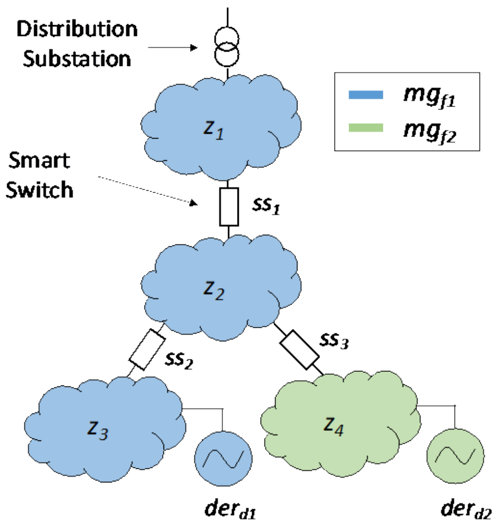

Figure 2. Example of a selected Network Solution.

The Network Solution (ns_{g1}) for the previous network example is described in Figure 3. The distribution network has four zones (z_1, z_2, z_3, and z_4), and two MGs (mg_{f1} and mg_{f2}) designed to improve the reliability of the network. These MGs are dimensioned considering the load within two groups of zones (gz_{c1} and gz_{c2}) and comprise two sets of DERs (der_{d1} and der_{d2}), respectively.

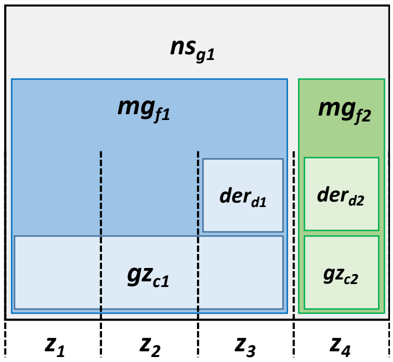

Figure 3. Nomenclature diagram for a selected Network Solution.

Considering the same network, under a conventional scenario, when a failure takes place in $z_{2,}$ the nearest upstream switching element (ss_1) would isolate it from the upstream grid, leaving z_3 and z_4 without supply, while z_1 would continue being supplied from the upstream substation. However, with the Network Solution exemplified in Figure 2, the same fault in $z_{2,}$ would only lead to the loss of supply of the affected zone, since der_{d1} would supply z_3, and der_{d2} would supply $z_{4,}$ while z_1 would continue being supplied from the upstream substation. It should be noted that DERs would only be operated for this purpose while the failed zone is out of service, and only supplying those zones that cannot be supplied from the upstream substation due to the fault location. The rest of the time, these DERs may be used for other purposes like voltage control, energy production, or energy arbitrage in the case of batteries. It is important to note that if the contingency takes place in the same zone where the DERs are located, it is assumed that the corresponding micro-grid would lose its ability to be operated in an islanding manner. For instance, in the example of Figure 2, if the fault occurs in zone z_3, the load of this zone would not be supplied, counting as non-served energy, whereas zones z_1 and z_2 will be supplied by the upstream substation, and der_{d2} would supply $z_{4.}$

The methodology presented in this paper is observed from a DSO point of view. The utility can use this tool to plan the resources of its property used in case of failure, and which traditionally have consisted of diesel units. These DERs could be located in the point located further upstream of the indicated zone. In this way, the network will operate in normal conditions and congestion or voltage problems will be avoided. However, different strategies can be applied according to the wishes of the operator as described in the paper.

3. Terminology and Mathematical Formulation

The exact definitions of the concepts described in Section 2, as well as their mathematical formulation, are provided below in order to facilitate readers' understanding of the description of the methodology in Section 4.

- **Smart Switches (ss_a):** Tele-controlled switching devices able to isolate damaged parts of the network when a failure or contingency takes place. It is assumed that their actuation—status change to open and network reconfiguration—is fast enough to avoid worsening reliability indexes commonly counted for interruption durations longer than 3 min [27]. The set that includes all the smart switches located in the network is defined as SS, while A is the total number of elements—number of smart switches—as shown in Equation (1)

$$SS = \{ss_a\}_{a=1}^{a=A} \tag{1}$$

- **Zone (z_b)**: Network subset bounded by smart switches. The set that includes all the network zones is defined as Z, and B is the total number of zones. B can be obtained as the number of smart switches A plus one. The proposed notation is shown in Equation (2).

$$Z = \{z_b\}_{b=1}^{b=B=A+1} \quad (2)$$

- **Group of Zones (gz_c)**: Set of adjacent network zones potentially supplied by the same generation and storage installations under islanded operation. The set that includes all the possible groups of zones is defined as GZ, and the total number is C. This value depends on the network topology and the number/location of smart switches, and it is calculated as the number of different sets of connected zones as Equation (3) shows.

$$GZ = \{gz_c\ gz_c \subseteq \mathrm{P(Z)}\ AND\ Zones(gz_c)\ are\ connected\}_{c=1}^{c=C} \quad (3)$$

where:

  - "*P (input element)*" is a function that provides the power-set of an input set, in this case, the Zones set. The power-set, in mathematics, is defined as the set of all the subsets of a set.
  - "*Zones (input element)*" is a function that provides the set of zones of which the input element is composed.

- **Distributed Energy Resources ($ders_d$):** Tuple of generation facilities and storage installations as shown in Equation (4). In this paper, different solar PV installations (pv_i), diesel units (du_j), and batteries ($bess_k$) are considered. The indexes i, j, and k determines which elements of the equipment catalog are selected for each DERs design der_d. The PV installations and the diesel units are defined by their rated power (kW). The storage installations are defined by their rate capacity (kWh) and their ratio power/capacity (kW/kWh). In addition, the annualized CAPEX (Capital Expenditure) and OPEX (Operating Expenditures) are considered for all the installations. The set that includes all the possible distributed energy resources combinations, according to the equipment catalog, is defined as DER, and the total number is equal to D.

$$\mathrm{DER} = \{der_d \mid d = (i, j, k)\}_{d=1}^{d=D} \quad (4)$$

Moreover, the set that includes all the optimal DERs for the group of zones gz_c in terms of investment and non-served energy (reliability index) is defined as DER_OPT^c as shown in Equation (5). The total number of optimal DERs for the group of zones gz_c is equal to E. Thus, DER_OPT^c is just the optimal subset of DER for the group of zones gz_c.

$$DER\_OPT^c = \{der\_opt_e^c \mid der\_opt_e^c \subseteq \mathrm{DER})\}_{e=1}^{e=E} \quad (5)$$

- **Micro-Grid (mg_f):** Tuple composed by a group of zones gz_c, a tuple of optimal DERs $der\_opt^c{}_e$ feeding that group of zones, and the zone z_b, where the DERs are located as shown in Equation (6).The set that includes all the possible MG designs is defined as MG, and the total number is equal to F.

$$MG = \left\{mg_f\ mg_f = (\ gz_c,\ der_e^c,\ z_a\ )\ \mathrm{AND}\ z_a Ie\ \mathrm{Zones}\left(\mathrm{mg_f}\right)\ \right\}_{f=1}^{f=F} \quad (6)$$

- **Network Solution (ns_g):** Subset of the micro-grids (MG) set, where all the zones are included but only once, as Equation (7) details. In other words, all the network is included in a network solution like the combination of different MGs. The set that includes all the possible network solutions is defined as NS, and the total number is equal to G.

$$NS = \left\{ ns_g \; ns_g \; \subseteq MG \text{ AND } \mathrm{Z} \subseteq \mathrm{Zones}\left(ns_g\right) \text{ AND } \mathrm{Zones}\left(ns_g\right) \backslash \mathrm{Z} = o \right\}_{g=1}^{g=G} \tag{7}$$

Section 4 presents the developed methodology for obtaining the set of optimal Network Solutions to improve the continuity of supply under network contingencies while minimizing the associated investment of DER installations.

4. Methodology

This section details the methodology developed to obtain the aforementioned Network Solutions, understood as a combination of micro-grid system designs and locations. As shown in Figure 4, the construction of the set of Network Solutions starts with a network partition based on the location of the existing smart switches. Next, based on the grid connectivity layout, all possible Groups of Zones are identified. Subsequently, the DER installations for supplying each of the Groups of Zones—and therefore the MGs—are sized and located, finding the optimal combinations of technologies for each case. This optimization is carried out attending to a double perspective: minimization of investment costs and non-supplied energy. Since this is a multicriteria optimization, the sizing step makes it possible to find several optimal DER combinations for each MG, and therefore, different Network Solutions. Finally, network reliability is assessed for each Network Solution, selecting those ones that are optimal (non-dominated solutions in the Pareto front) in terms of reliability and investment.

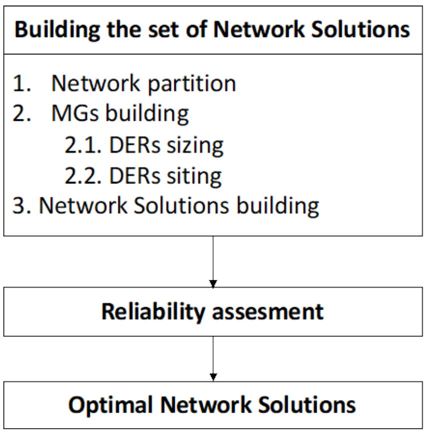

Figure 4. Methodology flowchart.

Broadly speaking, multicriteria optimization problems such as the one addressed herein can be tackled through two main approaches [28]. On the one hand, weights can be assigned to each of the functions to be optimized in order to obtain a single objective function which, once solved, yields a single optimal solution. This solution strongly depends on the weighting factors selected, which vary according to the planner preferences. On the other hand, a second alternative consists of evaluating all the individual objective functions separately and obtain a set of optimal, non-dominated, solutions that belong to the Pareto front. In this case, there is no longer a single solution, but a set of non-dominated ones, i.e., there is no other possible solution that performs better than these in all the separate objective functions at the same time. The methodology proposed in this paper follows this last approach.

Distribution network planning, and specifically the installation of DERs, entails important investments. Thus, it is really convenient for distribution companies to have a wide range of well-performing solutions so that they can choose the one that fits better their needs. The proposed methodology offers the advantage of obtaining all the non-dominated solutions without exploring all possible combinations. This is achieved thanks to a two-step optimization following a bottom-up approach. In the first stage, MGs are constructed sizing the DERs that minimize the MG non-served energy and investment cost. In a second step, an optimization that builds the Network Solutions with minimal non-served energy and investment is performed. Therefore, the total complexity of the whole design problem is significantly reduced. The computational burden of solving this problem is essentially determined by the number of smart switches in the feeder, as they increase the network reconfiguration possibilities. Nevertheless, the type of practical applications of the proposed planning solutions would be mostly installed in rural areas. In rural areas, the level of distribution network automation is typically low (normally between three and eight smart switches per feeder); consequently, the methodology described in this section is totally valid as demonstrated by the case study in Section 4.

In the following sub-sections, the different methodology steps, according to Figure 3, are described in depth, including the assumptions made and the developed mathematical formulation.

4.1. Network Partition

In highly automated distribution networks, as in the case addressed in this paper, when a fault occurs, a fast isolation of the faulted area and a quick network reconfiguration in MGs are essential to avoid affecting reliability indices. For this reason, the zone partition is made depending on the smart switches location. Thus, the total number of zones in which a network is divided is computed as the number of smart switches plus one. Taking as reference the example network structure represented in Figures 2 and 3, the SS and Z sets are calculated, see Equations (8) and (9).

$$SS = \{ss_1, ss_2, ss_3\} \tag{8}$$

$$Z = \{z_1, z_2, z_3, z_4\} \tag{9}$$

Before determining the location of DER, it is important to determine the zones they would be able to supply. For this purpose, all the possible Groups of Zones are determined. According to the definition in Equation (3), the set of all the Group of Zones GZ is determined by every group of interconnected zones that belongs to the power-set of Z. In the example, Equation (10) shows the resulting power-set of Z.

$$\begin{aligned} &P(Z) \\ &= \{\{\,\}, \{z_1\}, \{z_2\}, \{z_3\}, \{z_4\}, \{z_1, z_2\}, \{z_1, z_3\}, \{z_1, z_4\}, \{z_2, z_3\}, \{z_2, z_4\}, \{z_3, z_4\}, \{z_1, z_2, z_3\}, \{z_1, z_2, z_4\}, \{z_2, z_3, z_4\}, \{z_1, z_3, z_4\}, \{z_1, z_2, z_3, z_4\}\} \end{aligned} \tag{10}$$

The pseudocode shown in Table 1 summarizes the process used to obtain GZ from the power-set of Z, and its total number of elements C.

Table 1. Pseudocode for the Group of Zones GZ formation.

Pseudocode

GZ = ø; c = 0
for each "element" in $P(Z)$
    if the "element" is connected
        Add "element" to GZ
        c += 1

Accordingly, Equation (11) presents the GZ obtained for the example network through the pseudocode in Table 1.

$$GZ = \{\{z_1\}, \{z_2\}, \{z_3\}, \{z_4\}, \{z_1, z_2\}, \{z_2, z_3\}, \{z_2, z_4\}, \{z_1, z_2, z_3\}, \{z_1, z_2, z_4\}, \{z_2, z_3, z_4\}, \{z_1, z_2, z_3, z_4\}\} \tag{11}$$

4.2. Micro-Grid Building

Once all the possible Groups of Zones have been obtained, the next step is MG formation. As shown in Equation (6), a MG is defined through the tuple of three elements: a Group of Zones

gz_c, a tuple of optimal DERs $der\_opt^c{}_e$, and finally the zone z_a where the DER installations are located. These last two elements will be the object of study in this sub-section.

The process of obtaining the MGs is carried out in two stages. In the first one, for each Group of Zone gz_c, the optimal elements of the DER set "$der\_opt^c{}_e$" are determined. These are those that minimize investment costs and non-served energy. Secondly, the obtained $der\_opt^c{}_e$ is located in each one of all the zones z_a, which belongs to the considered Group of Zones gz_c. This process is described as pseudocode in Table 2 however, the sizing and siting procedures will be further explained in Sections 4.2.1 and 4.2.2 respectively.

Table 2. Pseudocode for the Micro-Grids MG formation.

Pseudocode

```
MG = ø; DER_OPTc = ø
for each gzc in GZ
    solutions = ø;
        for each derd in DER
            nsecd= Non-Served Energy in gzc supplied by derd
            invd = Investment of derd                              DER sizing
            solutions.add (nsecd, invd)
        for each "element" in solutions
            if "element" belongs to Pareto front
                DER_OPTc.add (derd)
        for each der_optce in DER_OPTc
            for each za in gzc
                mgf= (gzc ,der_optce, za)                          DER siting
                    MG.add(mgf)
```

4.2.1. DER Sizing

In this sub-section, the goal is to obtain for each one of the possible MGs, a set of optimal DERs DER_OPT^c that minimizes the micro-grid non-served energy (it should be noted that the micro-grid non-served energy calculated in this section will be an upper limit, since the actual value can only be determined when the locations of the DERs and the zone where the contingency or fault occurs are established, and how each of the zones is affected by the fault (Section 4.3)) and the investment costs at the same time. Therefore, the following process is repeated for each Group of Zone gz_c in order to explore all the MGs combinations.

The annualized investment (*A.Inv*) and operation and maintenance (*O&M*) cost of each DER installation are specified in an input equipment catalog (see Annex-A). Investment costs are annualized in order to compare facilities with different useful lives. The methodology used to obtain the annualized investment cost of each technology is not described since it is based on basic financial calculations and is outside the scope of the paper; however, Equation (12) aims to provide a simplified expression of the total annual DER cost calculation procedure. On the contrary, the MG non-served energy calculation associated with DER sizing and siting implies a more complex calculation and is described below.

$$Total\ investment = A.Inv_{PV} + A.Inv_{Die} + A.Inv_{Bat} + O\&M_{PV} + O\&M_{Die} + O\&M_{Bat} \quad (12)$$

It should be noted that all selected DER technologies (solar PV, diesel units, and batteries), specified in the input catalog—DER set—are considered in each MG. Thus, those DER combinations that minimize the investment and the MG non-served energy are considered optimal and part of the DER_OPT^c set, while the rest of other DER combinations are discarded. Figure 5 shows this process.

The red triangles represent the optimal subset of DER for the analyzed MG—DER_OPT^c—while the grey circles represent all the rest DER combinations included in the catalog—*DER* set.

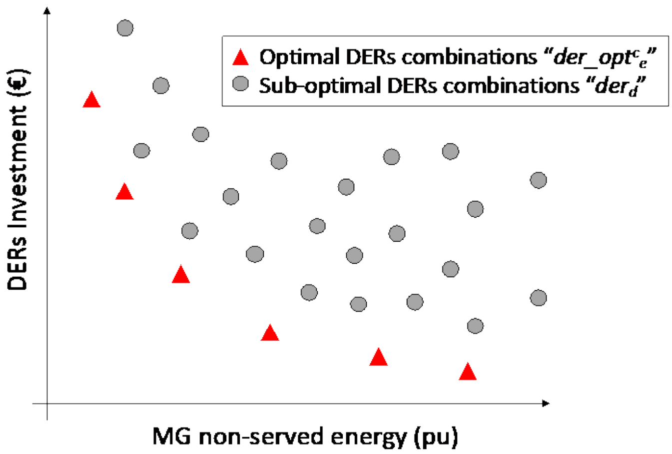

Figure 5. Pareto optimization for DER combinations for each analyzed MG.

To calculate the MGs' non-served energy, two algorithms are used. The first one is based on the installed DER capacity (kW), while the second one is based on the energy demanded by the affected customers during the contingency. The latter is needed due to the energy-constrained operation of batteries. The capacity (kWh) and the power (kW) are the two design parameters of batteries.

NSE Computing Based on Power-Limitation

As shown in Equation (13), the micro-grid non-served energy based on the power-limitation ($NSE_P(h)$), during a contingency that starts at a certain hour h, and with a pre-defined repair time h_{rep}, is calculated by adding the non-served energy during all hours ($NSE_1(h_1)$) in which the failure repair is taking place.

$$NSE_P(h) = \sum_{h_1=h}^{h_1=h+hrep} NSE_1(h_1) \tag{13}$$

It should be mentioned that only those hours with a generation deficit are counted according to Equation (14). In the deficit case, the difference ($Dif_P(h)$) between the micro-grid demand ($D(h)$) and the DER availability at that hour is computed. As previously mentioned, DERs are composed of photovoltaic generation, where ($P_{PV}(h)$) is the estimated PV production at hour h, diesel units, where ($Pdie$) is the rated capacity (kW), and batteries, where ($Pbat$) is the maximum power that can be delivered by the battery, as shown in Equation (15). This calculation is made for all of the hours of the year, since the demand and solar generation profiles vary hour by hour, and the hour when the fault occurs is not a priori known.

$$NSE_1(h) = \begin{cases} Dif_P(h) & Dif_P(h) \geq 0 \\ 0 & Dif_P(h) < 0 \end{cases} \tag{14}$$

$$Dif_P(h) = D(h) - P_{PV}(h) - P_{BAT} - P_{DIE} \tag{15}$$

NSE Computing Based on Energy-Limitation

As previously mentioned, the existence of storage units like batteries adds inter-temporal constraints that necessarily have to be considered under an energy-based approach. Resembling the previous power-based calculation, this micro-grid non-supplied energy approach ($NSE_E(h)$), only accounts for those hours with a generation deficit, see Equation (16).

$$NSE_E(h) = \begin{cases} Dif_E(h) & Dif_E(h) \geq 0 \\ 0 & Dif_E(h) < 0 \end{cases} \tag{16}$$

The difference ($Dif_E(h)$) between the energy to be supplied to the demand ($\sum_{h1=h}^{h1=h+hrep} D(h_1)$) during the repair time of the fault, and the generation that can be provided by the photovoltaic panels ($\sum_{h_1=h}^{h_1=h+h_{rep}} P_{PV}(h_1)$), the batteries ($E_{bat}$) and the diesel units ($P_{die} * h_{rep}$) is shown in Equation (17). It should be noted that the available energy storage in the battery is calculated considering the battery capacity (kWh) and the state of charge of the battery when the fault occurs ($S.C._{pu}$).

$$Dif_{E(h)} = \sum_{h1=h}^{h1=h+hrep} D(h1) - \sum_{h1=h}^{h1=h+hrep} P_{PV}(h1) - E_{BAT} * S.C._{pu} - P_{DIE} * h_{rep} \tag{17}$$

Combined Power and Energy-Based NSE Computing

The final micro-grid non-served energy (*NSE(h)*) from the hour when the fault occurs (h) and during the repair time of the fault (*hrep*), is calculated as the most restrictive of the two previous calculations, power-based $(NSE_P(h))$ or energy-based $(NSE_E(h))$, according to Equation (18).

$$NSE(h) = max(NSE_P(h),\ NSE_E(h)) \tag{18}$$

The micro-grid energy demand ($E(h)$) during the contingency time is obtained through the sum of the hourly demands in that period according to Equation (19).

$$E(h) = \sum_{h_1=h}^{h_1=h+h_{rep}} D(h_1) \tag{19}$$

To express the micro-grid non-served energy in unitary terms, the MG non-served energy coefficient is computed as the ratio between the micro-grid non-served energy (*NSE(h)*) and the total demanded energy ($E(h)$) as shown in Equation (20), assuming that the fault may equiprobably happen in any of the hours of the year.

$$NSE_{pu} = \frac{\sum_h NSE(h)}{\sum_h E(h)} \tag{20}$$

As mentioned above, those non-dominated combinations of the *DER* set that minimize the non-served energy and the investment will be selected as optimal to be part of the DER_OPT^c set. Only the set of optimal DER combinations will be considered in the algorithms presented in the following sections, while the rest of *DER* combinations will be discarded.

4.2.2. DER Siting

The location of DERs is intrinsically related to the reliability of the network. For instance, one DER combination, der_d, can result in very different reliability indexes with the same investment depending on the zone where it is located as shown in the Problem Statement section. For instance, zones with a high number of customers and a reduced network length, assuming that the power lines fault rate is constant per km, would be good candidates to place a set of DERs.

Therefore, the siting algorithm simulates locating the obtained optimal DER combinations, $der\_opt^c{}_e$, in all possible locations, understanding as location, each of the zones that are included in the considered Group of Zones. Thus, for each Group of Zones, gz_c, and optimal set of DER, $der\_opt^c{}_e$, there will be as many different micro-grids, mg_e, as zones are included in the corresponding Group of Zones. This algorithm is clarified in the second part of the pseudocode presented in Table 1.

4.3. Network Solution Building

After the DER siting and sizing process, the complete set of MGs is obtained. However, these MGs only include subsets of the original network; therefore, it is necessary to select different combinations of MGs that connected together form the whole distribution network. As defined in the terminology section, the set of MGs that comprises the whole network is defined as a Network Solution, ns_g, and the set that includes all possible Network Solutions is defined as NS. In addition, it should be noted that all zones must be included in each of the ns_g, but only once—no zone should be included in more than one MG within the same network solution. This process is carried out in two steps, as described below for our example network:

1. The Group of Zones are combined to compose the whole network. Table 3 shows all the possible network combinations for the example network shown in Figure 2.
2. These Groups of Zones that compose the network combinations are substituted with all the MGs that contain them to create the Network Solutions set, NS. It should be emphasized that more than one MG may contain the same group of zones.
3. In the case of our example network (see Figures 2 and 3), the nsg_1 is formed following the network combination number 5, where the Group of Zones $\{z_1, z_2, z_3\}$ and $\{z_4\}$ correspond to mg_{f1} and mg_{f2}, respectively.

Table 3. Network combinations for the example network.

Combination Number	Network Combination
1	$\{\{z_1\}, \{z_2\}, \{z_3\}, \{z_4\}\}$
2	$\{\{z_1\}, \{z_2, z_3\}, \{z_4\}\}$
3	$\{\{z_1\}, \{z_2, z_4\}, \{z_3\}\}$
4	$\{\{z_1, z_2\}, \{z_3\}, \{z_4\}\}$
5	$\{\{z_1, z_2, z_3\}, \{z_4\}\}$
6	$\{\{z_1, z_2, z_4\}, \{z_3\}\}$
7	$\{\{z_1, z_2, z_3, z_4\}\}$

4.4. Reliability Assesment

Once all the possible Network Solutions have been obtained, it is necessary to perform the reliability assessment of each one of them (ns_g included in the NS set). In the following, the method to evaluate the reliability of the system is described. In this case, the SAIDI index is selected to measure grid reliability levels. A Zone Interaction matrix "ZI^{nsg}", is created for each Network Solution, seeking to identify how a contingency in a given zone affects the continuity of supply in another zone. Each element of this matrix is defined by the indices $b1$—rows—and $b2$—columns—where $b1$ represents the analyzed zone and $b2$ the zone where the contingency takes place. The element value can be interpreted as the per-unit non-served energy in z_{b1} under a contingency in z_{b2}. This value is equal to 0 when the z_{b1} is not affected by a contingency in z_{b2}; in the case of being equal to 1, the analyzed z_{b1} is affected by a contingency in z_{b2} and cannot be supplied from any DER, thus not supplying the entire zone demand. Finally, when the z_{b1} is affected by a contingency in z_{b2}, but there are DERs connected to the same MG that are able to supply totally or partially it, this element of the matrix can take a value between 0 and 1 equal to the MG non-served energy coefficient obtained in Equation (20) (see Section 4.2.1). It is important to mention that when a contingency affects one of the MG zones, but there are some zones in this MG that can still be supplied by the associated

DERs, the MG non-served energy coefficient will decrease proportionally to the installed power in the non-served MG zones.

It should be noted that under normal conditions (without contingencies) the operation of the entire network is radial. Only in the contingency case is the failure zone isolated, and the rest of the zones that cannot be supplied from the upstream substation (due to the fault location) would be supplied by the DERs allocated within their associated MGs.

For illustrative purposes, the example network used in the previous sections is analyzed. This network solution is composed of two MGs, the first one "mg_{f1}" is designed to supply z_1, $z_{2,}$ and z_3 where the der_{d1} are located, the second one "mg_{f2}" is only formed by z_4 where der_{d2} are placed. Assuming the installed power in each zone is the same, and mg_{f1} and mg_{f2} have a 0.46 pu and 0.38 pu MG non-served energy coefficients, respectively (result of Equation (20)), the obtained zone interaction matrix for the ns_{g1} is the one shown in Equation (21).

$$ZI^{ns_g} = \begin{pmatrix} 1 & 0 & 0 & 0 \\ 0.19 & 1 & 0 & 0 \\ 0.19 & 0 & 1 & 0 \\ 0.38 & 0.38 & 0 & 1 \end{pmatrix} \tag{21}$$

Once the Zone Interaction matrix ZI^{nsg} is calculated for each Network Solution, the reliability assessment for each Network Solution is carried out until complete the whole *NS* set. For the reliability assessment, it is necessary to consider some additional parameters, such as the number of supply points in each analyzed zone (N_b), the average repair time of the fault in the considered zone ($h\ rep_b$), and the annual failure rate of the network included in the considered zone (f_b) obtained as the sum of the product of the failure rate of overhead lines, expressed per km, times the overhead line lengths in the zone plus the product of the failure rate of underground lines, expressed per km, times the underground line lengths in the zone. Equation (22) shows the *SAIDI* calculation for a generic Network Solution ns_g.

$$SAIDI^{ns_g} = \frac{\sum_{b2=1}^{b1=B} \sum_{b2=1}^{b2=B} f_{b2} * h\ rep_{b2} * N_{b1} * ZI_{b1,b2}^{ns_g}}{\sum_{b1=1}^{b1=B} N_{b1}} \tag{22}$$

4.5. Optimal Non-Dominated Network Solutions

Finally, a second multi-attribute optimization is carried out in which both the calculated reliability indices and the annualized total investment costs of all the Network Solutions included in the *NS* set are compared. Figure 6 shows an example of the results of such optimization. In this case, the optimal—non-dominated—network solutions are represented by triangles, while sub-optimal—dominated—NS are represented by circles.

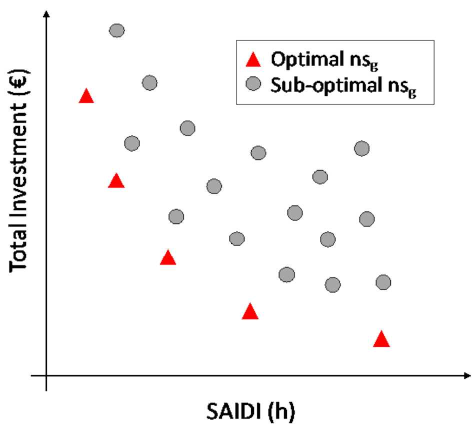

Figure 6. Pareto optimization for NS.

Once the Network Solutions have been selected, a specific location will be assigned for the DERs of each zone according to the established criteria, and a powerflow analysis will be carried out. Those Network Solutions that do not cause operational problems will be validated to be implemented.

5. Case Study

5.1. Description

In this section, the proposed methodology is applied to an actual distribution network. The analyzed feeder presents reliability problems. In addition, the feeder is located in a protected natural area where traditional network reinforcements are not an option due to the difficulty of obtaining permits. For this reason, the DSO in charge of supplying this area is exploring the use of non-conventional network solutions that minimize the impact on the environment.

The MV feeder analyzed presents three smart-switches and follows an identical structure as the example used for describing the proposed methodology, as shown Figure 7.

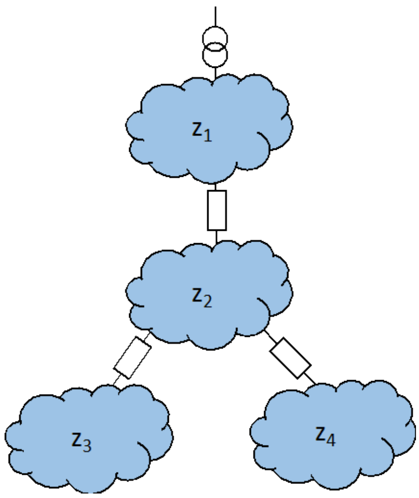

Figure 7. Network structure.

Table 4 shows the number of supply points located in each of the feeder zones, as well as the overhead and underground lengths of the power lines included in each zone.

Table 4. Network characteristics.

Zone	Number of Supply Points	Overhead Length (km)	Underground Length (km)
z_1	0	10.99	0.04
z_2	585	9.54	0.82
z_3	1386	9.94	2.07
z_4	771	6.04	0.15

Regarding failure rates, 12 outages/100 km-year was set for overhead lines and 6 outages/100 km-year for underground lines. Concerning the fault repair time, an average time of 6 h was considered. This data is consistent with the values posed in reference [29].

Regarding the catalog of DERs, Appendix A details the rated capacities, as well as investment and operation and maintenance costs of PV, batteries, and diesel units. It should be mentioned that the irradiation profile used to obtain PV generation is based on the geographical coordinates of the analyzed zone and obtained from [30].

5.2. Results

Applying the abovementioned methodology on the proposed network, 1,531 network solutions were obtained. Figure 8 shows a Pareto diagram in which the obtained reliability index (SAIDI) and the associated annualized investment in each network solution are displayed. Each of the dominated network solutions is represented by a circle, while the non-dominated solutions are represented by (red) triangles. Furthermore, in order to facilitate the selection of the solution that best suits the system needs, an additional parameter has been calculated. This parameter is, for each network solution, the standard deviation of the zonal SAIDIs with respect to the overall network SAIDI, measured in percentage. This parameter is represented by a color code in which the warmer the color the higher disparity between zonal reliability indicators. Therefore, at the same level of overall SAIDI and investment, solutions with similar reliability indices between zones (cooler colors) would be preferred ensuring more homogeneous solutions in terms of reliability.

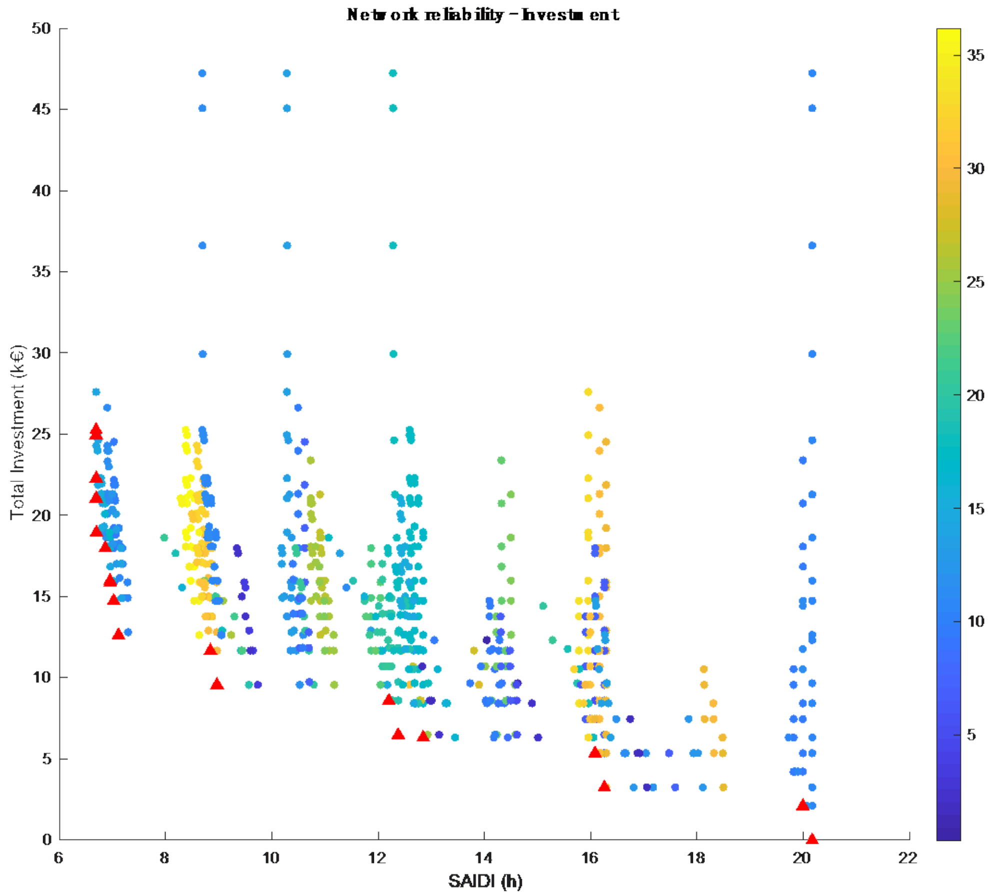

Figure 8. Network solutions for the case study network (colors represent the standard deviation of zonal SAIDI in percentage).

Table 5 presents all the optimal—non-dominated—solutions ordered by their annualized investment cost, the overall SAIDI in hours, and the SAIDI standard deviation between zones. It should be noted that the Base Case (current status of the network without DERs) belongs to the set of optimal non-dominated solutions since it does not imply any investment. On the other hand, it can be seen that as the DER investment increases, solutions with better reliability (lower SAIDI) are obtained. Network solutions, such as number 10, located in the Pareto front elbow, would bring important reductions in SAIDI with moderate investment. The set of 19 optimal network solutions achieve an improvement of up to 13.5 h with an annualized investment of up to 25,263 €.

Table 5. Optimal network solutions for the case study network.

ns_g	Annualized Investment (€)	SAIDI Overall Network (h)	SAIDI Reduction (%)	SAIDI Standard Deviation (%)	SAIDI z_1 (h)	SAIDI z_2 (h)	SAIDI z_3 (h)	SAIDI z_4 (h)
1	25,263	6.7	−67%	14%	7.8	7.1	4.4	0.0
2	24,945	6.7	−67%	14%	7.8	7.1	4.4	0.0
3	22,291	6.7	−67%	14%	7.8	7.1	4.4	0.0
4	21,052	6.7	−67%	14%	7.8	7.1	4.4	0.0
5	18,947	6.7	−67%	14%	7.8	7.1	4.4	0.0
6	17,980	6.9	−66%	16%	8.1	7.2	4.4	0.0
7	15,975	6.9	−66%	13%	8.0	7.3	4.8	0.0
8	15,875	7	−65%	17%	8.3	7.2	4.4	0.0
9	14,736	7	−65%	14%	8.1	7.3	4.8	0.0
10	12,632	7.1	−65%	15%	8.3	7.3	4.8	0.0
11	11,664	8.8	−56%	32%	8.3	15.0	5.1	0.0
12	9560	9	−55%	30%	8.3	15.0	5.6	0.0
13	8592	12.2	−40%	19%	14.7	15.0	5.6	0.0
14	6488	12.4	−39%	19%	15.1	15.0	5.6	0.0
15	6316	12.8	−37%	17%	8.3	15.0	19.4	0.0
16	5348	16.1	−20%	7%	14.7	15.0	19.4	0.0
17	3244	16.3	−19%	7%	15.1	15.0	19.4	0.0
18	2105	20	−1%	11%	22.4	15.0	19.4	0.0
Base Case	0	20.2	0%	11%	22.8	15.0	19.4	0.0

Another important issue to analyze is, for each non-dominated network solution, in which network zone DERs are located and which DER technologies are selected. Table 6 presents this information. For each network solution, it identifies in which zone the DERs are located (DERs *Zone*) and the zones they supply (z_1, z_2, z_3, and z_4). The size of the PV systems (P_{PV}), batteries (P_{BAT} and E_{BAT}) and diesel units (P_{DIE}) are also included. It can be seen that all the optimal solutions include DERs in zone number 3. This is an expected result since this is the area with the highest number of connected supply points and located farthest from the supply point. The same happens with zone number 4 —the zone with the second-highest number of supply points—for similar reasons.

Regarding the DER combinations selected, it is observed that all network solutions except one include diesel units, in some cases supported by batteries. These batteries have a high power (kW)–capacity (kWh) ratio, which leads to the conclusion that batteries are mainly used for peak shaving, avoiding the installation of an additional diesel unit with a low use rate. This effect can be observed by comparing the evolution of selected DERs starting from the Base Case and going through network solutions 18, 17, 16 and 15. It can be observed that as the reliability index improves, the selection of batteries (solutions 18 and 16) is alternated with that of diesel units (solutions 17 and 15). Therefore, a higher granularity in diesel unit sizes presumably would eliminate the need for batteries in the optimal network solutions.

On the other hand, it is observed that there is no optimal solution selecting PV facilities. This is mainly explained by two reasons. The first is the comparatively high PV investment cost. Nowadays, PV systems can be cost-effective when the produced energy is self-consumed and/or sold to the market during the expected life of the installation. However, in this paper, we are assuming that PV is only used to obtain benefits of its production during the small number of hours per year in which network outages take place. The second reason is that, unlike storage or diesel units, the PV production is limited to the sunlight hours. This effect is modeled through solar radiation hourly profiles for the specific network location. The use of annual profiles is recommended to capture seasonality. For example, if the network failure occurs at night or at the end of the day, PV will not be able to provide the necessary energy to supply the isolated customers and to improve the continuity of supply indices.

Table 6. Optimal network solutions for the case study network.

ns_g	DERs Zone	z_1	z_2	z_3	z_4	P_{PV} (kW)	P_{BAT} (kW)	E_{BAT} (kWh)	P_{DIE} (kW)
1	2	0	1	0	0	0	0	0	200
	3	0	0	1	0	0	0	0	400
	4	0	0	0	1	0	0	0	200
2	3	0	1	1	0	0	100	250	400
	4	0	0	0	1	0	0	0	200
3	3	0	1	1	0	0	100	100	400
	4	0	0	0	1	0	0	0	200
4	3	0	1	1	0	0	100	30	400
	4	0	0	0	1	0	0	0	200
5	3	0	1	1	0	0	0	0	400
	4	0	0	0	1	0	0	0	200
6	2	0	1	0	0	0	0	0	100
	3	0	0	1	0	0	100	30	200
	4	0	0	0	1	0	0	0	200
7	3	0	0	1	0	0	100	100	200
	4	0	1	0	1	0	0	0	200
8	2	0	1	0	0	0	0	0	100
	3	0	0	1	0	0	0	0	200
	4	0	0	0	1	0	0	0	200
9	3	0	0	1	0	0	100	30	200
	4	0	1	0	1	0	0	0	200
10	3	0	0	1	0	0	0	0	200
	4	0	1	0	1	0	0	0	200
11	3	0	0	1	0	0	0	0	200
	4	0	0	0	1	0	100	30	100
12	3	0	0	1	0	0	0	0	200
	4	0	0	0	1	0	0	0	100
13	3	0	0	1	0	0	100	30	100
	4	0	0	0	1	0	0	0	100
14	3	0	0	1	0	0	0	0	100
	4	0	0	0	1	0	0	0	100
15	3	0	0	1	0	0	0	0	200
16	3	0	0	1	0	0	100	30	100
17	3	0	0	1	0	0	0	0	100
18	3	0	0	1	0	0	100	30	0

Therefore, it can be concluded that for the network studied, and with current investment costs, the use of diesel units by themselves or in combination with batteries is the most cost-effective network solution to increase the reliability of the system. During network faults, the diesel units would cover the base demand and the batteries would cover the peaks of the isolated supply points.

A sensitivity analysis to the investment cost of the batteries was performed. To isolate the effect of this parameter, a new case was run for which battery systems were the only DER technology available. There are four reasons for this. Firstly, batteries are less environmentally pollutant than diesel units (at least locally). Additionally, batteries are already being used in the optimal solutions of 6. Secondly, PV systems do not seem to be a good option to improve system reliability because their use is restricted to the sunlight hours and, therefore, they cannot be used when outages occur at night. Moreover, unlike batteries, in none of the 18 optimal network solutions the PV systems are chosen as a design option, being more cost-effective to invest in batteries. Third, diesel units are a mature technology from which no major price variations are expected. In this case, the only factor that could increase their cost would be a sharp rise in the cost of diesel (variable cost included in the O&M cost defined in the Annex). However, these are units that operate very few hours per year and are therefore not very sensitive to this factor. Finally, the cost of batteries nowadays presents a steady downwards trend. Therefore, the break-even point for batteries to become the preferred design option was evaluated.

Figure 9 shows the Pareto front for different percentages of battery cost reductions. It can be observed that to obtain a Pareto front similar to the one presented with current investment prices for PV and batteries and including diesel units, reductions in the cost of batteries by close to 80% would be needed.

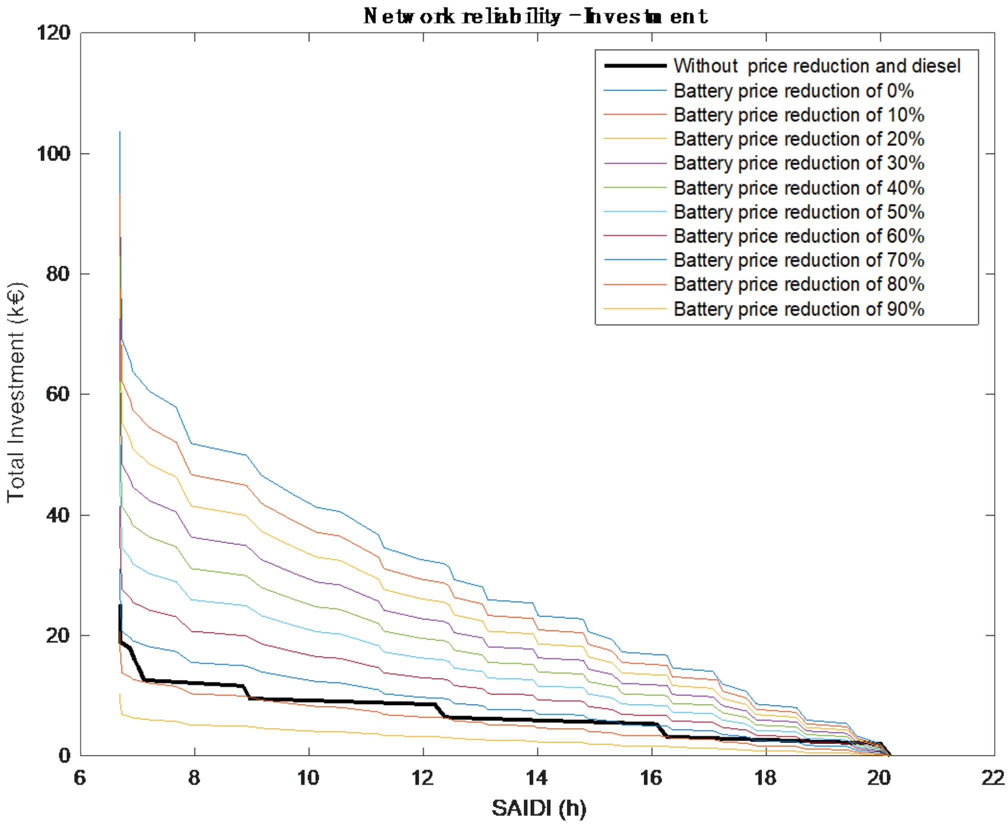

Figure 9. Pareto fronts for different battery price reductions.

Analyzing the results obtained, it can be concluded that diesel generators and batteries (as long as their initial state of charge is sufficient) are the preferred option, since, unlike PV systems, they are available at any time of the day and under any atmospheric conditions. This does not mean that PV systems cannot be used for this purpose, but they do have some features that make them difficult to apply. However, each case must be studied individually and new clean and hybrid solutions such as PV systems with batteries should be considered in future low-cost scenarios.

6. Conclusions

This paper proposes a novel methodology for determining the optimal location and sizing of MGs based on a multicriteria optimization in which both the DER investment cost and the network reliability levels are considered. Unlike other publications, this methodology allows the mix of DERs to be selected that best fits the needs of the network. Additionally, the result is a set of non-dominated solutions, allowing the DSO to select the one that best suits other possible non-modeled requirements (e.g., local emissions). This methodology was tested in a real case study, from which some relevant findings have been extracted, as discussed below.

The results show that the combination of diesel units and batteries seems to be the most cost-effective option to increase the reliability of the network through islanded operation. During the failure repair time, diesel units would be in charge of covering the base demand of islanded zones, whereas batteries would operate as peaking units. Moreover, the results show that selecting solar PV installations for this purpose is not cost-effective. The reason for this is twofold. On the one hand, PV presents a comparatively high investment cost. On the other hand, PV can only supply the demand during sunlight hours, thus being useless to tackle outages occurring at night. However, each case must be studied individually and adjusted to the specific climatic conditions of the network location. Finally, it has been shown that if battery investment costs were to drop by close to 80% with respect to current values, MG solutions based mainly on batteries instead of more highly polluting solutions based on diesel units would be the preferred option.

As observed in the case study, emission-free DERs are expensive and are only used in less than 1% of the hours to enhance the reliability of the distribution grid. For this reason, DSOs may explore the procurement of a service through which third parties, such as DER owners, would provide network support when a network outage takes place. The remuneration of this service would be based on the location of the DER in the network and its commitment to offering the service when requested. In this way, the DSO would reduce investments in network infrastructure and the owners of DERs could obtain additional benefits to the regular ones derived from their participation in the market or cost-savings thanks to behind the meter generation.

This work opens up future research lines to be explored. The main limitation of this study is the degree of automation of the network. The greater the degree of automation of the network, the greater the number of smart-switches, and the possibilities of reconfiguring the network would grow exponentially. For this reason, the proposed solution perfectly fits with the problems of rural networks, which are characterized by low automation levels. However, urban areas with higher automation levels may sharply increase the computational load. For this reason, this limitation opens, for example, a future research line in applying metaheuristic algorithms (e.g., genetics algorithms) to overcome this issue.

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Appendix A DER Investment

The investment in DERs is based on a review of the state of the art of the technologies employed: PV systems, battery-based storage, and diesel units.

The price of the PV systems is composed of the cost of the panels, the cost of the inverter, and the cost of installation. The cost of the panels is based on [31]. For the rest of the costs like de O&M cost, a breakdown according to the reference has been considered. The useful life is based on [32]. Table A1. shows the data used.

Table A1. PV systems data.

Rated Capacity (kW)	Investment Cost (€/kW)
0	850
100	**O&M (€/kW-year)**
200	18.08
400	**Useful life (years)**
800	23

The price of the batteries is based on [33]. Other additional costs like de O&M costs have been considered according to the breakdown given in [34]. For the power-capacity ratio, the costs indicated in [32] have been taken into account. To obtain the total investment cost of batteries for different power-capacity ratios, the power and energy values are averaged. The useful life considers that very few charge/discharge cycles are expected per year in this application. Table A2 shows the data used.

Table A2. Batteries data.

Rated Power (kW)	Power (kW)—Capacity (kWh) Ratio	Investment Cost (€/kW)
0	3.33	314.26
100	1	**Investment cost (€/kWh)**
200	0.4	346.21
400	0.25	**O&M (€/kWh)**
800		0.356
		Useful life (years)
		15

The price of diesel units depends mainly on their rated capacity [35]. Apart from the price of the diesel unit itself, an installation cost of 60% was considered. For the fuel, a cost of 1.3 €/L and an expense of 0.3l/kWh has been assumed [36] to obtain the total O&M cost. A useful life of 20 years is considered, assuming that the unit will be used only a few hours per year. Table A3 shows the data used.

Table A3. Diesel units data.

Rated Capacity (kW)	Investment Cost (€/kW)	O&M (€/kW-year)
0	0	8
100	223.34	**O&M (€/kWh)**
200	125.76	0.3
400	121.26	**Useful life (years)**
		20

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Improving distribution network resilience through automation, distributed energy resources, and undergrounding

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ABSTRACT

In recent years, natural disasters such as hurricanes Katrina and Sandy, or deliberate attacks on the power system, have highlighted the importance of a resilient power distribution system that can maximize the energy supply even in the most stressful situations. However, reinforcing the distribution power grid is very costly, and investment decisions must be adequately justified.

This paper proposes a single-stage multi-criteria optimization model to maximize the resilience of a distribution system through a series of investments while minimizing the total cost incurred. The assets to be invested in under this model are the installation of Remotely Controlled Switches (RCSs), Distributed Energy Resources (DERs) such as storage and photovoltaic units, and the undergrounding of overhead lines. The optimization method is based on a customized genetic algorithm that can be successfully applied to solve large-scale networks. To exemplify the application of the proposed optimization method, an actual distribution network is simulated under extreme weather conditions. The results obtained show how the different type of investments are prioritized and the importance of including managerial and logistic training in distribution companies to deal with extreme weather events.

1. Introduction

In 2005, hurricane Katrina hit the east coast of the United States, leaving 1,836 people dead and costing approximately 81 billion dollars [1]. Just seven years later, hurricane Sandy hit the same area with dozens of lives lost and a cost close to 50 billion dollars [2]. Since then, several public and private institutions have joined efforts to maximize the resilience of the system [3]. The term resilience can be defined as the ability of a system to withstand an extreme event and return to its previous functioning while minimizing the consequences.[1]

In many cases, the consequences produced by this type of event do not affect a single system, but rather the numerous connections between sectors [7] can lead to a series of multiple failures between different systems [8]. According to the study conducted by Luiifj [9], energy infrastructures such as the power grid have the most significant impact on other sectors due to their high level of dependence, with the most affected sectors being industry, water services, and telecommunications.

According to the literature, resilience deals with three main types of events: deliberate attacks, natural disasters, and accidents [9]. Deliberate attacks are actions executed by an adversary seeking to inflict specific damage [10] such as cyber-attacks [11] or terrorist acts. Natural disasters are meteorological events with a high destructive capacity [12], such as hurricanes, tornadoes, or floods [13]. Finally, accidents are very similar to deliberate attacks; however, they are unintentional [14], and are usually due to a defect in event prediction [15]. Sometimes, several types of events can coincide, as was the case of the Fukushima nuclear power plant accident in 2011 [16]. This paper focuses mainly on meteorological events, although some concepts could also be applied to other types of events.

An essential factor to consider is the difference between reliability and resilience in the distribution network [17,18]. Commonly, the electrical system's reliability has been optimized to minimize the impact of high probability and low impact events that frequently occur at a specific point of the network and are usually managed through fault detection and service restoration. On the other hand, resilience deals with the study of High Impact Low Probability (HILP) extreme events, which require long restoration times due to structural damage to the system.

Since the nature of the problem addressed differs from that used in

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[1] The above definition is based on the common framework provided by the formalization proposed by institutions such as the Institute of Electrical and Electronics Engineers [4], the Joint Research Center of the European Commission [5] and the Power Systems Engineering Research Center [6].

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Nomenclature

Acronyms

DER	Distributed Energy Resources
RCS	Remote-Controlled Switches
ENS	Energy Not supplied
MG	Micro-grid
NS	Network Solution
HILP	High Impact Low Probability
HWIF	High Weather Intensity Factors

Sets

C	Set of scenarios
N	Set of network nodes
B	Set of network branches
F	Set of branches affected by an event $F \subseteq B$
O	Set of overhead branches.$O \subseteq B$
T	Set of branches with an already existing RCS $T \subseteq B$
U	Set of initial underground branches.$U \subseteq B$
S	Set of NSs
G_s	Set of MGs included in the NS s

Indexes

n	Index of network nodes,$n \in N$
b	Index of network branches, where the index represents the node located downstream of the branch,$b \in B$
c	Index of the scenarios,$c \in C$
f	Index of the branches affected by an event,$f \in F$
o	Index of overhead branches,$o \in O$
t	Index of branches with an already existing RCS,$t \in T$
u	Index of initial underground branches,$u \in U$
s	Index of network solutions,$s \in S$
g_s	Index of MGs included in the NS s,$g_s \in G_s$

Variables

$a_{o,c}$	Binary, 1 if overhead line o is affected by the event in scenario c, 0 if not
$rcs_{b,s}$	Binary, 1 if branch b in the NS s includes an RCS, 0 if not
$und_{b,s}$	Binary, 1 if branch b in the NS s is underground, 0 if not
$ens_{b,s}$	ENS in the MG containing branch b in the NS s
$gp_{g,s}$	Sum of the peak power of consumers located in the MG g_s
$dt_{g,s}$	Annual downtime of the MG g_s
$ensg_{g,s}$	ENS of MG g_s
$enss_s$	ENS in the NS s
$aa_{s,c}$	Affectation array of NS s, and scenario c
k_s	Number of MGs in NS s
$aibat_s$	Annualized investment in batteries in NS s
$aipv_s$	Annualized investment in PV systems in NS s
$acbat_s$	Sum of the annualized cost of the batteries installed in NS s
$acpv_s$	Sum of the annualized cost of the PV systems installed in NS s
$ombat_s$	Sum of the O&M cost of the batteries installed in NS s
$ompv_s$	Sum of the O&M cost of the PV systems installed in NS s
pf_o^{L}	Failure probability of the overhead branch o, and length L due to an extreme weather event
sf	Severity factor
$taibat_s$	Total annual investment in batteries in NS s
$taipv_s$	Total annual investment in PV systems in NS s
$taiders_s$	Total annual investment in DERs in NS s
$taircs_s$	Total annual investment in RCSs in NS s
$taiund_s$	Total annual investment in underground lines in NS s
tai_s	Total annual investment in NS s
wif	Weather intensity factor

Parameters

D	Average length of a power line between to electrical towers
L_b	Length of branch b
P_n	Peak power of the consumers located at the node n
RT_f	Repair time of a failure in branch f per unit length
$VoLL$	Value of Lost Load

network reliability improvement, the evaluation metrics must be different. In this case, some of the metrics used in the state of the art to assess system resilience are: the probability of a potentially damaging event, the robustness and the recomposition capacity of the system and the impact of the consequences caused by the event [19].

To improve network resilience, two strategies must be employed that are not mutually exclusive and must necessarily go hand in hand. The first requires a system operation based on contingency plans specially designed for this type of events. The second strategy consists of planning the distribution network to obtain a solid and versatile infrastructure capable of overcoming extreme situations. Given the low probability and high impact of these types of events, the planning of the distribution network cannot follow the traditional deterministic approach since it would result in very high costs. According to several studies [20,21], a stochastic perspective is more appropriate and better covers the characteristics of resilient planning. The factors that have been determined [22,23] as decisive for an improvement in resilience are: the degree of undergrounding of the grid, the level of automation through remotely-controlled switching elements (RCS), and the availability of distributed energy resources (DERs) to form micro-grids (MGs) and thus ensure supply to consumers in case of a system failure.

Although most of the publications focused on improving the resilience of the power grid analyze the transmission system [24–26], more and more publications are dealing with the distribution grid, as it is the capillary and indispensable system for supplying the end consumer [27]. This is mainly due to its mostly radial structure in which a contingency[2] can trigger the loss of supply to all consumers located downstream.

Table 1 presents different planning options and categories of investments that have been proposed in the literature to improve system resilience. Commonly, the methodologies proposed in the literature consider one single type of investment to improve system resilience, either the installation of RCSs [28,29], the integration of DG/DERs [30,31], or the power line undergrounding/hardening [32,33]. When there is only one type of investment, the optimization process can usually be solved with a single-stage optimization algorithm; however, as the investment categories increase, the optimization algorithm is divided into consecutive optimization stages due to the difficulty involved [34–37]. Unlike other papers, this paper proposes, for the first time, a methodology that provides for optimizing these three types of investments at the same time (single-stage), avoiding optimizations over multiple stages resulting in sub-optimal solution. The proposed optimization allows us to understand and quantify how these very different

[2] In this paper, the term "contingency" is used to represent a single event damaging the distribution network, while the term "event" is used to represent the reason or cause of the contingencies. Thus, an atmospheric event such as a hurricane can cause several contingencies in a distribution network.

Table 1
Resilience improvement studies comparison.

Reference	Optimization: Single-stage	Investment: RCS	Investment: DG/DERs	Investment: Underground/ Hardening
[28]	x			x
[29]	x			x
[30]	x		x	
[31]	x		x	
[32]	x	x		
[33]	x	x		
[34]	x		x	x
[35]		x	x	x
[36]			x	x
[37]	x[1]		x	x
Our proposal	x	x	x	x

[1]It uses a single-stage optimization but through a three-level decomposition of the problem.

categories of investment compete with and complement each other.

A common drawback is the limitation of the size of the network that can be modelled. Given the complexity of the planning problem due to its combinatorial and nonlinear nature, solving it applying an exhaustive search requires a large computational burden that is currently unattainable in large-scale networks [38]. In this paper, metaheuristic algorithms are proposed to solve this issue. Metaheuristic algorithms propose methodologies applicable to a wide range of situations to find quasi-optimal solutions in problems where the exhaustive search or traditional mathematical programming optimization is not feasible. Examples of metaheuristics include genetic-based algorithms, tabu search, simulated annealing, ant colony, and particle swarming [39]. However, as the literature indicates, the most widely used metaheuristics in distribution network optimization are those based on genetic algorithms given their versatility [40,41].

This research paper contributes to the state of the art by proposing a new stochastic model capable of performing a multi-criteria optimization through metaheuristic algorithms in which network resilience is maximized while minimizing the cost of the investments required. In contrast to previous works, this paper presents, for the first time, a methodology that simultaneously optimizes three very different categories of network investments, allowing us to identify how they compete with and complement each other. The three categories of investments are: i) the undergrounding of overhead lines, ii) the location of RCSs, and iii) the location and sizing of DERs (photovoltaic panels and batteries) at specific and optimal selected nodes in the grid. Previous work was mainly focused on only one or two of those categories. Because this type of events commonly affects large regions, the solution method has also been developed to allow work on large-scale grids. Previous work was mainly demonstrated in small scale test systems.

Section 2 defines the nomenclature used in this paper; Section 3 presents the problem to be solved; The methodology and the formulation used in the design of the planning algorithm is described in detail in Section 4; Section 5 applies the proposed planning methodology in a case study and, finally, Section 6 presents the main conclusions drawn.

2. Problem statement

In the introduction of the paper, it was pointed out how a contingency in the distribution network can lead to the loss of supply to all customers located downstream from the fault. This is mainly due to the radial topology of the network, the limited meshing, and the reduced number of remote-controlled switching devices. These assumptions are commonly considered for reliability assessment; however, they fall short in the face of a HILP event such as a hurricane. A HILP event can cause the loss of several sections of the network simultaneously, and their repair cannot be solved in a short period of several hours. For this reason, this paper proposes a new planning model capable of obtaining new network solutions based on creating MGs that maximize system resilience while minimizing additional investment in network undergrounding, RCSs, and DERs. In addition to the planning model, a preprocessing to characterize HILP events that vary in impact and severity has been developed.

For illustration purposes, an example network is used to facilitate the description of the problem statement. Fig. 1 (left) shows the selected base network. In this network, a contingency in branch $b = 3$ would imply the opening of the RCS located at branch $b = 2$ and the loss of supply to all customers located downstream, leaving only customers connected to nodes $n = 0$ (substation) and $n = 1$ with service.

The solutions proposed by the planning model consist of undergrounding certain feeder sections to limit their exposure to weather events, and the installation of RCSs and DERs at specific nodes in such a way that the automation of the grid and self-sufficiency of consumers under isolated MGs are increased. To facilitate the analysis of the different design alternatives within the space of possible solutions, the concept of network solution is defined. A network solution (NS) consists of a set of planning actions, including the undergrounding of selected branches, the installation of a set of RCSs at specific branches, and the location and sizing of a set of DERs at specific nodes. The methodology developed for the selection of optimal NSs is described in Section 4.

Fig. 1 (right) shows a NS for the example network. It can be seen how branches $b = 3$ and $b = 5$ have been undergrounded, one RCS has been installed at branch $b = 4$,[3] and DERs have been installed at nodes $n = 2$ and $n = 4$. The undergrounding of these branches seeks to improve the network's resilience, for example by ensuring atmospheric events such as hurricanes do not cause failures in power lines. The network division, generated when the newly added RCS opens, allows the reconfiguration of the grid into three MGs in case of a contingency. For example, a failure in branch $b = 3$ would imply opening the RCSs located at branches $b = 2$ and $b = 4$ and the islanding operation of MG $g = 3$, while $g = 1$ will continue to be supplied from the substation connected to $n = 0$, and the consumers located in $g = 2$ would lose the supply. It should be noted that MGs will only be operated in isolation mode in the event of contingencies, and if they cannot be supplied from the upstream substation. Another example would be the loss of all overhead power lines in the event of a hurricane. In this case, customers located at $g = 2$ could continue to be supplied from DERs located at node $n = 2$.

3. Methodology

As indicated in Section 3, this research aims to propose a planning methodology to generate NSs based on MGs to increase the system's resilience while minimizing the total investment. This type of NS

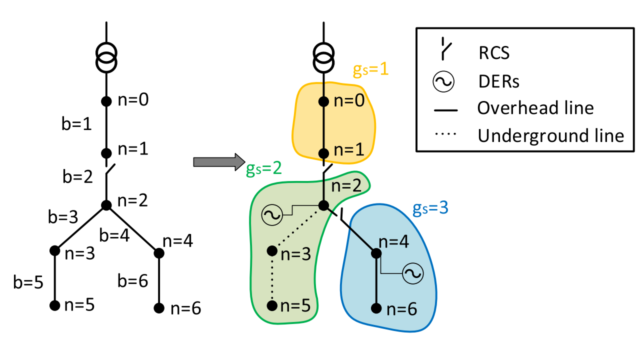

Fig. 1. Example network. Left: Original network. Right: Network solution (NS).

[3] It is assumed that when an RCS is installed at a branch, no intermediate node is added, and the failure probability of the branch remains unchanged.

involves three fundamental actions, the integration of DER installations (in this case, photovoltaic panels and batteries), increasing grid undergrounding, and improving grid automation through the installation of RCSs. In this way, in the event, the damaged network elements will be isolated, and all those customers that can no longer be supplied from the upstream substations will be fed with DERs through isolated MGs obtained by network reconfiguration, if they exist.

Using a multi-criteria optimization algorithm, different NSs are generated and compared in terms of the achieved level of resilience and required investment. It is worth noting the need for joint optimization of the three considered planning actions: network undergrounding, network automation, and DER installations, since, as indicated above, these actions are used simultaneously to improve the network's resilience. The RCSs define and reconfigure the topology of the network after the event, the underground power lines minimize the number of branches affected by atmospheric events such as hurricanes, and the DERs are responsible for supplying those customers that cannot be supplied from the upper voltage level sources, usually the upper primary substation. For this reason, all three elements dependently affect the system's resilience and cannot be considered independently of one another.

This section provides a comprehensive and detailed description of the proposed methodology. Section 4.1 presents a general overview of the complete methodology, with the processes detailed on a step-by-step basis. Then, Section 4.2 describes the details of the optimization algorithm, focusing on the implementation of the genetic algorithm (Section 4.2.1) and the formulation of the objective function (Sections 4.2.2 and 4.2.3 respectively). The optimization algorithm described in Section 4.2 is part of the general methodology presented in Section 4.1; however, due to its innovation and importance, it is described in full in a dedicated section.

3.1. General formulation

A general outline of the proposed planning algorithm is shown in Fig. 2. In the following subsections the different building blocks are described.

3.2. Inputs

As shown in Fig. 2, the algorithm starts from a set of input data that serves as the basis for obtaining the NSs. These inputs are presented below:.

- **Existing distribution network**: The peak power of the consumers, network topology, the position of the switches, underground power lines, and existing loops are specified.
- **Catalog**: List of DER candidates used in the network planning process, detailing the rated power for PV generation and batteries, rated energy (in the case of batteries) and annualized investment cost, annual operation and maintenance costs. It also includes the cost to install a new RCS on an existing line, and the average cost to underground an existing overhead line.

3.3. Event generation

A module is also proposed to generate different types of extreme weather events and, in this way, test the resilience of the distribution network. This module has the versatility of being able to model different types of events according to the needs and risks to which the analyzed network is exposed [27].

The weather intensity factor (*wif*) determines the probability of failure of overhead power lines under an extreme weather event [42]. For example, the East coast of the United States is more exposed to hurricanes [36], while states located east of the Rocky Mountains are more prone to tornadoes [43]. In both cases, the weather intensity factor is wind speed. However, depending on the event, different factors may define the probability of failure of overhead lines, such as the peak ground acceleration in the case of earthquakes [44], or even a mixture of several as in the case of wildfires whereby solar radiation and wind speed are the weather intensity factors [45]. The probability of failure of each overhead line section of length *D,* between two electrical towers can be obtained as a function of the weather intensity factor, as shown in Fig. 3.

Fig. 3 function is defined by equation (1). For weather intensity factors lower than $wif_{critical}$, the probability of failure is zero, while for weather intensity factors greater than $wif_{collapse}$, the probability is equal to 1. For intermediate values, the probability of failure increases as the weather intensity factor increases.

$$pf_o^D(wif) = \begin{cases} 0 & wif < wif_{critical} \\ pf_{o-HWIF}^D(wif) & wif_{critical} \le wif < wif_{critical} \\ 1 & wif \ge wif_{collapse} \end{cases} \tag{1}$$

The proposed model can be used on large-scale networks covering all the feeders of a primary substation, i.e., tens of square kilometers. However, according to the literature [46], the weather intensity factor determining the probability of a line's failure will be very similar within the considered distribution system. This is especially visible in the case of hurricanes, where hundreds of km are affected by similar wind speeds. Therefore, it can be assumed that the weather intensity factor will be constant in the simulations of critical events in the considered distribution systems. Additionally, in distribution networks, the line section length between two electrical towers is very similar since it is mainly determined by the height of the towers. As previously mentioned in this paper, this line section length is called *D*. Thus, it can be stated that the probability of failure of an overhead line with total length L_o will be determined by the equation (2). This expression assumes that the failure probability of the line section between two towers is constant for the entire overhead line and that the possible failures are independent of each other.

$$pf_o^L(wif) = 1 - \left(1 - pf_o^D(wif)\right)^{\frac{L_o}{D}} \forall o \tag{2}$$

Another relevant aspect in characterizing the considered extreme event is the required service restoration time. This indicator is computed from the instant that the event that causes the failure takes place until the service restoration is complete. It is highly dependent on many factors, among others the resources and capabilities of maintenance crews of the distribution utility, the terrain orography, and the destructive capability of the event itself [47]. For this reason, the duration of the service restoration time is highly variable and dependent on each case, highlighting the need for a sensitivity analysis. This paper defines the parameter that sets the time required to repair 1 km of an overhead line affected by the event since the event causes the failure as the severity factor (*sf*).

Therefore, the two parameters that define the modeling of an event are the weather intensity factor (equivalent to the failure probability of an overhead line section of length *D*), and the severity factor (time required to repair one kilometer of an overhead line affected by the event).

3.4. Scenario generation

In order to simulate the random nature of extreme weather events, the proposed methodology uses a Monte Carlo simulation in which a large number of scenarios are generated to simulate each event. Each scenario *c* maintains the weather intensity factor, but the affected lines may change according to the random numbers in equation (3). This equation seeks to identify whether or not an overhead line *o* is affected by the event in scenario *c*. If an overhead line is affected by the event, the variable $a_{o,c}$ will be equal to 1; if not, it will be equal to 0. Line

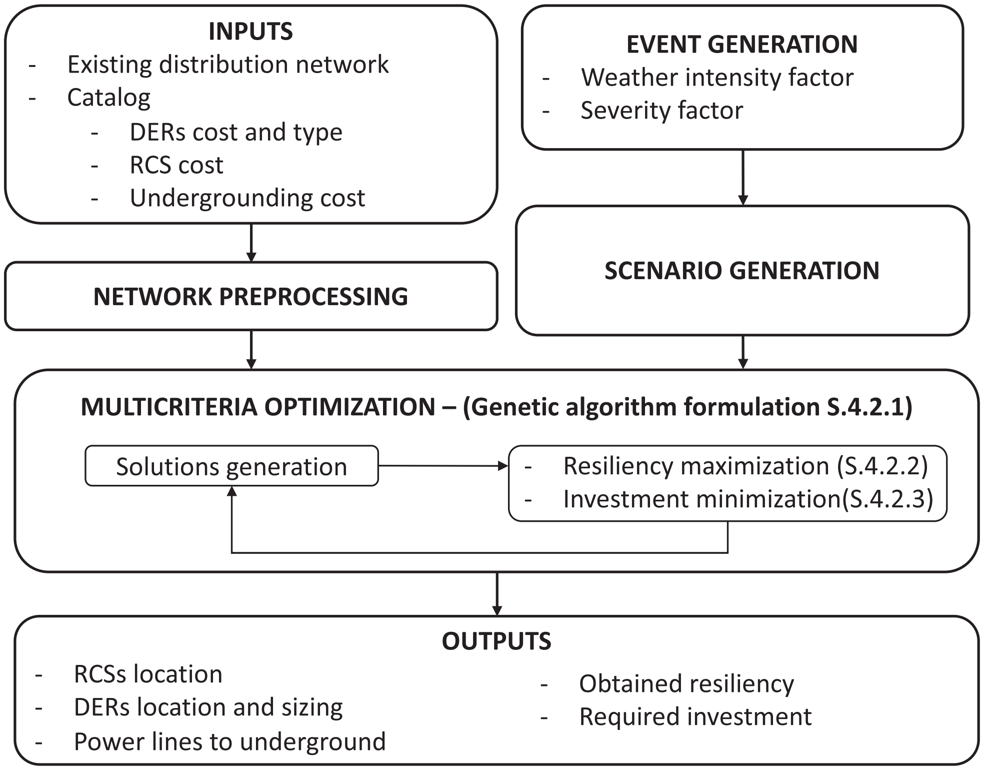

Fig. 2. Methodology flow diagram.

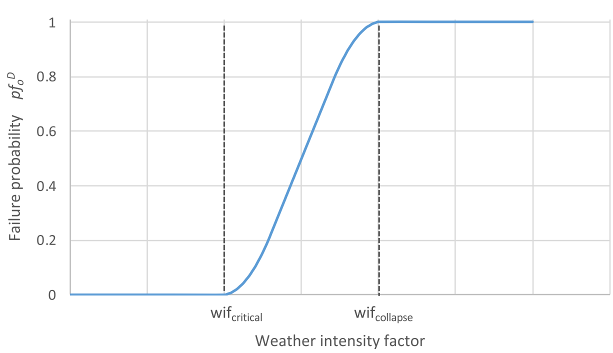

Fig. 3. Overhead line failure probability.

affectation is calculated by comparing the failure probability of each line with random numbers between 0 and 1. If the probability of failure is greater than the random number, the considered line is affected by the event. Each scenario is generated with a different seed so that the failed lines may vary.

$$a_{o,c} = \begin{cases} a_{o,c} = 1 & pf_o^L(wif) > rand(0,1) \\ a_{o,c} = 0 & pf_o^L(wif) \leq rand(0,1) \end{cases} \forall o, c \tag{3}$$

It is assumed that underground lines are never affected by this kind of event.

4. Network pre-processing

Initially, the analyzed network is pre-processed and interpreted as a directed graph to employ complex network theory in the optimization algorithm. Complex network theory allows, among other advantages, the manipulation of an electrical network as a mathematical variable and extracting helpful information quickly and efficiently through its numerous properties [48].

4.1. Multi-criteria optimization

Optimization is then carried out to maximize network resilience while minimizing investment. Classical optimization based on mathematical programming in large-scale networks can currently be computationally infeasible due to multiple nonlinearities. This fact highlights the need for optimization methods such as metaheuristic algorithms to overcome these nonlinearities. In this case, a multi-criteria genetic optimization algorithm is used, which, as previously indicated, maximizes network resilience and minimizes investment employing a multi-attribute objective function. Section 4.2 details this optimization algorithm, emphasizing the formulation (Section 4.2.1) and objective functions (Sections 4.2.2 and 4.2.3 respectively).

One of the fundamental requirements for using genetic algorithms is the high speed in the evaluation of the objective function for the proposed solutions [49], in which a set of initial solutions are evaluated and, according to their optimality, modified to obtain new solutions, as shown in Fig. 2. This process is repeated as many times as solutions are evaluated; therefore, the speed in evaluating the objective function is a critical factor in the model's design. For this reason, the hybridization of complex network theory and genetic algorithms is applied, providing substantial synergies for solving this type of problem and making it computationally feasible.

4.2. Outputs

Finally, the outputs obtained from the optimization model include a set of optimal NSs (non-dominated in the Pareto space). Each of these NSs is characterized by three elements, which are the decision variables of the problem:

- **Location of new RCSs**: Indicating the network branches where they are installed.
- **Location of new underground power lines**: Indicating the network branches to be undergrounded.

- **Location and sizing of DERs**: Indicating the connection node, the rated power (in the case of PV systems and batteries), and, additionally, the rated energy (in the case of batteries).

Therefore, each of the NSs, is defined by a topology, with several MGs, an associated investment in RCSs, undergrounding, and DERs, and a resulting value of energy not supplied in the case of the simulated extreme events that indicates the level of resilience of that NS.

In the following (Section 4.2), the optimization problem is further described, exploring its formulation and the calculation of the resilience and investment attributes.

4.3. Proposed optimization

4.3.1. Formulation

The proposed optimization model seeks to obtain a set of NS S that maximizes resilience while minimizing the investment, selecting different configurations depending on the needs of the analyzed network. As previously indicated, it is necessary to use an optimization that goes beyond traditional methods due to the complexity introduced by the nonlinearity of the problem. For this reason, optimization methods based on metaheuristic algorithms such as genetic algorithms are used.

The formulation of the objective functions for resilience maximization and investment minimization is complex and is detailed in Sections 4.2.2 and 4.2.3, respectively. These functions are evaluated for each of the analyzed NSs independently, obtaining a pair of results for each of them.

An optimization based on genetic algorithms seeks to obtain the value of the genes (decision variables in the optimization) of the chromosomes (set of optimization variables) that obtain the best score in evaluating the objective function, subject to certain constraints. These chromosomes are evaluated in terms of both objective functions, and those with the best solution serve as the basis for creating new generations of chromosomes. These new generations are created performing the operations of mutation (variations in the value of genes) and crossover (exchange of parts of different chromosomes) [49].

In this problem, each of the NSs proposed by the genetic algorithm are modeled with a chromosome, while the genes that compose it are the decision variables of the optimization. Creating new NS is the only common point in which the different NSs interact. The different types of optimization variables are defined below:

- $rcs_{b,s}$: Binary variable that takes a value of 1 when an RCS is installed in branch b, existing as many $rcs_{b,s}$ variables as branches the network has. In case that branch b does not include an RCS, it will take 0 as a value. Fig. 4 shows an example with this notation.
- $ens_{b,s}$: Continuous variable between 0 and 1 that represents, in per unit value, the energy not supplied (ENS) in an MG. The MG this variable refers to is the one to which node $n = b$ belongs. The number of $ens_{b,s}$ variables is equal to the number of branches in the network. It should be noted here that in order to obtain a single value of energy not supplied per MG, only one set of DERs per MG is allowed. Regarding the DERs location, it is worth mentioning that in order to optimize the network's resilience, the most important factor is to determine the MGs where DERs would be located; however, the node in which the DERs are located inside of the selected MGs is not relevant in terms of resilience, because the definition of MG made in the paper assumes that there are not more switching devices that would allow network reconfiguration within the MG. For this reason, it is proposed to locate DERs at the upstream node of the MG, mimicking a radial operation of the network, preventing overloads during the MG-islanded operation and eliminating the need for running power flows. Thus, this set of DERs is located at the upstream node of the MG, in this case, node $n = b$ (lower node of the RCS as shown in Fig. 4). When $ens_{b,s}$ is equal to 1, there are no DERs in that MG. On the contrary, when $ens_{b,s}$ is equal to 0, it implies that the DERs can supply all the power and energy demanded by the MG. Whereas, if $ens_{b,s}$ takes a value between 0 and 1, the installed DERs can increase the autonomy time of the MG but cannot avoid a partial loss of supply. At a later stage, this variable allows us to obtain the set of DERs that meets the indicated energy not supplied while minimizing the investment.
- $und_{b,s}$: Binary variable that takes a value of 1 when the line in branch b is underground, and 0 when it is overhead, therefore, there are as many $rcs_{b,s}$ variables as branches in the network. Fig. 4 shows an example with this notation.

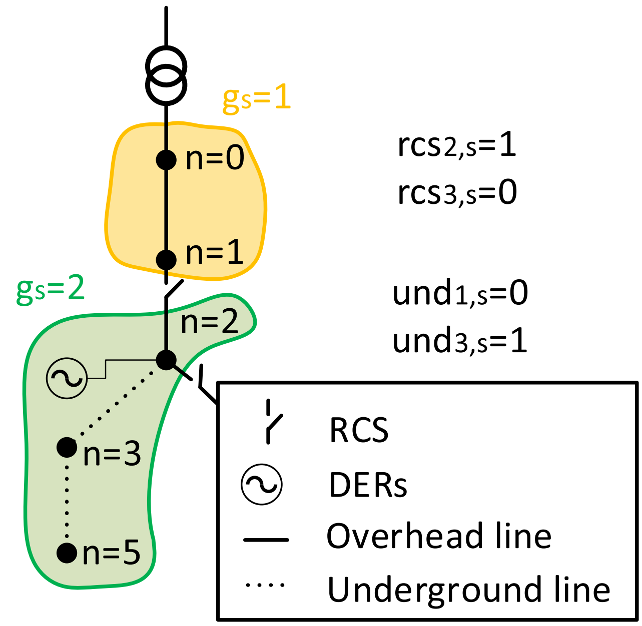

Fig. 4. Network division in MGs and DERs position.

The decision variables of the optimization are composed by $rcs_{b,s}$, $ens_{b,s}$, and $und_{b,s}$ since the union of both of them defines a NS in its totality. As a summary, $rcs_{b,s}$ defines the network division in MGs, $ens_{b,s}$ sets the energy not supplied of each MG that will lead to a set of optimal DERs in a later stage, and finally $und_{b,s}$ indicates the underground lines that serve to improve the resilience of the system. Fig. 5 shows an example of the chromosome coding that is used for the example network used above.

The existing RCSs and underground power lines in the base network are specified as an input to the optimization problem by setting their associated decision variables to 1:.

- The position of the already existing RCSs is indicated according to equation (4):

$$rcs_{b,s} = 1 \forall b \in T \tag{4}$$

- The position of the already existing underground power lines is indicated according to equation (5):

$$und_{b,s} = 1 \forall b \in U \tag{5}$$

The bounds for the variables $rcs_{b,s}$, $ens_{b,s}$, and $und_{b,s}$ are set according to (6), (7), and (8).

$$0 \le rcs_{b,s} \le 1 \forall b, s \tag{6}$$

$$0 \le ens_{b,s} \le 1 \forall b, s \tag{7}$$

$$0 \le und_{b,s} \le 1 \forall b, s \tag{8}$$

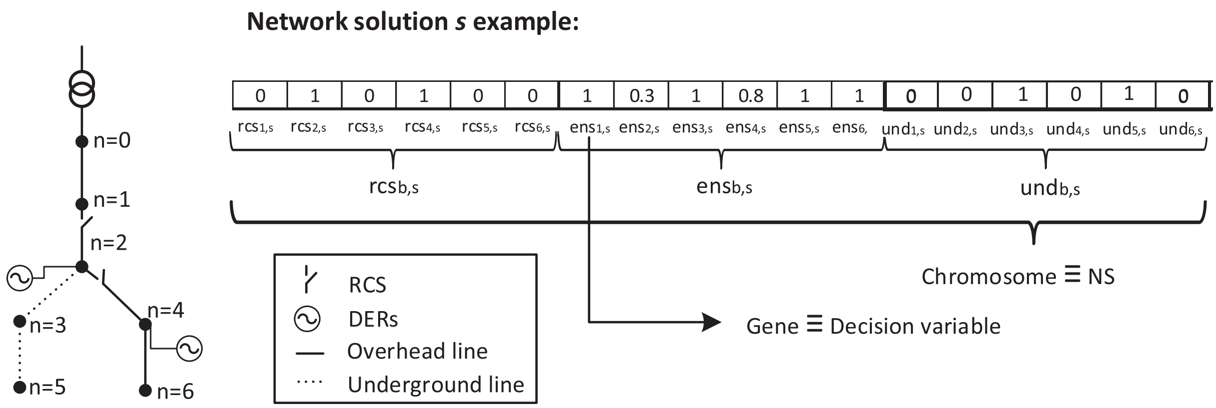

Fig. 5. Example of genetic algorithm coding.

One of the advantages of the proposed optimization is that it has only with one constraint, and it is linear. This constraint indicates that, for all the branches of the network, at most, only one set of DERs per MG can be installed, and that it is located at the upstream node of the MG. This is achieved through the equation (9), in which when $rcs_{b,s}$ is equal to 0 (there is no RCS in branch b), it is forced that no DERs can be installed, where the ENS is equal to 1.

$$rcs_{b,s} + ens_{b,s} \geq 1 \forall b, s \tag{9}$$

For implementation purposes, equations (4), (5) and (9) are not defined as constraints in the problem but as a post-processing of the chromosome when evaluating the objective function. This stems from the difficulty in obtaining random initial solutions that comply with the constraints imposed. In addition, it can be observed that as the generations proposed by the genetic algorithm progress, the algorithm learns, and the chromosomes obtained only include decisions that improve resilience. For example, solutions such as installing an RCS on a line where one RCS was already installed, or DERs in a zone where they already existed, are not proposed since they would not improve resilience and would be detrimental to the investment. With the post-processing step, this is solved because at each evaluation of the objective function, the chromosomes become feasible so that the algorithm can continue discarding them depending only on how optimal they are.

The calculation of the resilience (4.2.2) and investment (4.2.3) of each NS proposed by the genetic optimization algorithm is detailed below. Once the investment and resilience of the analyzed NS are obtained, we can check which solutions minimize the investment and maximize the resilience simultaneously. These solutions are the ones that constitute the Pareto front.

4.3.2. Resilience calculation

The calculation of the resilience metric determines, for a given NS, a representative value to allow a fair comparison of different design options. In this case, after the previously comprehensive literature review, it is decided that the network resilience is calculated as the energy not supplied in case of the simulated extreme events. Fig. 6 shows a flowchart detailing the proposed process for the computation of the network resilience for each NS.

Following the process shown in Fig. 6, the first step is to divide the network into MGs according to the position of the RCSs. Then, the installed power, the annual time out of service, and the energy not supplied of each MG are all computed to form a reduced network topology. The last step is to calculate the resilience of the whole network through the previously calculated parameters and the reduced network topology. These steps are further detailed hereafter.

Initially, for each NS, the network is divided into MGs according to the position of the RCSs defined by $rcs_{b,s}$. This process allows obtaining all the MGs available to face the consequences of a specified event, and the network elements that belong to each of the MGs. The total number of MGs in a NSs is given by k_s, calculated according to equation (10).

$$k_s = 1 + \sum_b rcs_b \forall b \tag{10}$$

For each of the MGs belonging to a NS, the parameters required for calculating the resilience of the NS are determined:.

- **Peak power in a MG ($gp_{g,s}$):** Calculated as the sum of the peak power of the consumers within the MG as shown in Equation (11).

$$gp_{g,s} = \sum_n P_n \forall n \in g_s \tag{11}$$

- **Time out of service ($dt_{g,s}$):** Period during which the MG g_s is out of service. This parameter is calculated as shown in (12), being RT_f and L_f, the restoration time, and the line length of every affected branch that belongs to the analyzed MG g_s. It should be noted that the RT_f parameter depends on the severity of the event, determined by the event features and network characteristics such as accessibility or construction features, while L_f depends on the affectation of the event, as stated in 4.1.

$$dt_{g,s} = \sum_f RT_f {}^* L_f \forall f \in g_s \tag{12}$$

- **MG energy not supplied ($ensg_{g,s}$):** Energy not supplied during the studied period indicated by the optimization variable $ens_{b,s}$. A factor to be taken into account is the presence of loops that allow the network reconfiguration during a contingency. If in any node of the MG g_s analyzed there is a loop, understood as an external supply point able of feeding the installed power of the MG g_s, the $ens_{b,s}$ will take a value of 0. The presence of loops is especially relevant in urban networks where demand density is higher since they provide greater supply reliability. In this paper, it is assumed that there are no congestions that prevent such supply in the case of such external supply.

The network division process allows us to obtain a reduced network composed only of the head node and the nodes located downstream of the RCSs ($n = b$ when $rcs_{b,s} = 1$). This reduction is shown in Fig. 7 and allows moving from large-scale networks with thousands of nodes to one in which each MG is defined by a single node that collects all the relevant information, preserving the topological characteristics required for the study of resilience.

Table 2 shows the parameters needed to calculate the resilience of the example network (Fig. 7) as a reduction of the network applying the abovementioned methodology.

In order to calculate the resilience metric of an NS, it is necessary to analyze which MGs are affected by the event, and to what extent. At this

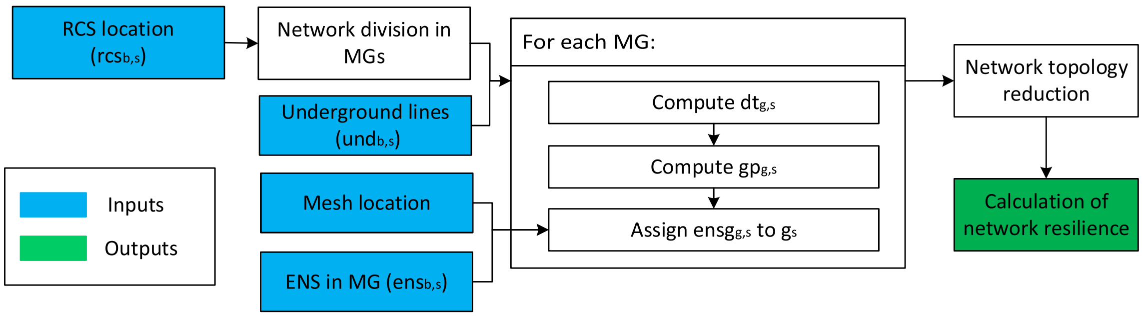

Fig. 6. Resilience calculation flowchart.

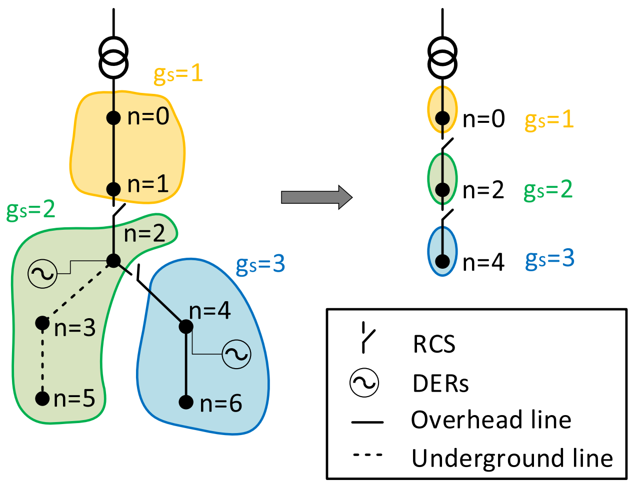

Fig. 7. Example of the NS division and its simplified network.

Table 2
Calculation of the MGs parameters of the example network.

	$gp_{g,s}$	$dt_{g,s}$	$ensg_{g,s}$
$g_s = 1$	$P_0 + P_1$	$RT_1{*}L_1$	$ens_{1,s}$
$g_s = 2$	$P_2 + P_3 + P_5$	$RT_2{*}L_2 + FR_3{*}RT_3{*}L_3 + RT_5{*}L_5$	$ens_{2,s}$
$g_s = 3$	$P_4 + P_6$	$RT_4{*}L_4 + RT_6{*}L_6$	$ens_{4,s}$

point, it is essential to note that several zones may be affected at the same time by the event in the same scenario and, therefore, the network topology determines which MGs can be supplied from the upper substation and which cannot. For this reason, for each NS *s*, and scenario *c*, an affectation array ($aa_{s,c}$) is created automatically, with as many elements as MGs exist. Each of the elements of the $aa_{s,c}$ array can take the following values:.

- 0: If the MG is not affected by the event and can be supplied from the substation.
- 1: If the MG is affected by the event or without being affected, it does not have generation facilities to provide an alternative supply, and the network topology prevents it from being supplied from the upper substation due to an intermediate contingency.
- $ens_{g,s}$: If none of the power lines that comprise the MG are affected, and it has lost the capacity to be supplied from the upper substation due to an intermediate contingency, but it can still be supplied from the generation facilities or the meshes located in the MG.

Finally, the network's resilience is calculated, measured as the average ENS of the scenarios, as shown in equation (13) for a generic NS *s*. In this expression, the ENS of each of the MGs of the analyzed NS is added as the product of the power of each MG ($gp_{g,s}$), the annual time out of service ($dt_{g,s}$), and the affectation array ($aa_{s,c}$).

$$enss_s = \frac{\sum_c \sum_g gp_{g,s} {*} dt_{g,s} {*} aa_{s,c}}{\max(c)} \forall g_S \tag{13}$$

4.3.3. *Investment calculation and DERs sizing*

In order to evaluate the total investment of each evaluated NS, the flow chart shown in Fig. 8 is followed. As observed, we start from the variables $rcsb_{,s}$, $ens_{b,s}$, and $und_{b,s}$, provided by the optimization algorithm. Next, the network is divided into MGs according to the position of the RCS, and the peak power in each of them is calculated in the same way as shown in equation (11). This partitioning together with the ENS (defined by $ens_{b,s}$), allows us to determine which set of DERs minimizes the investment. Then, the investment in DERs is computed and added to the investment in RCSs and network undergrounding to obtain a total value of the investment. This process is further described below.

4.4. *Ders sizing*

The choice of the optimal set of DERs for each MG is made as a selection in a pre-calculated lookup table in which the input parameters are the ENS in the MG ($ens_{b,s}$) and its installed power. This lookup table is obtained at a stage prior to the optimization process and only once. This allows for a reduction of execution times since, as previously mentioned, the speed in the evaluation of the objective function is a fundamental factor for the correct operation of genetic algorithms. To this end, we start from the demand profile of the network consumers and obtain, for different power and ENS levels, those combinations of DERs that minimize the investment. In short, the ENS can be calculated as the ratio of the repair time that DERs can supply customers until the contingency is solved. Those DERs that, for a given power, minimize the ENS and the investment will be selected to be part of the lookup table. This process is further explained in [38].

4.5. *Investment calculation*

The investment calculation is performed by aggregating the investment, and the operation and maintenance costs on an annualized basis for each of the DERs. The annualization process is necessary to compare the optimality of DERs with different lifetimes. In this case, the total investment computation is performed as presented in equations (14), (15), and (16) for batteries and PV systems, however, this process can be replicated for one or several DERs. It should be remarked that the costs of the DERs may vary according to the technology, power, and capacity (in the case of batteries).

$$aibat_s = acbat_s + ombat_s \tag{14}$$

$$aipv_s = acpv_s + ompv_s \tag{15}$$

$$taiders_s = aibat_s + aipv_s \tag{16}$$

Once the investments in DERs for all of the MGs of the NS are

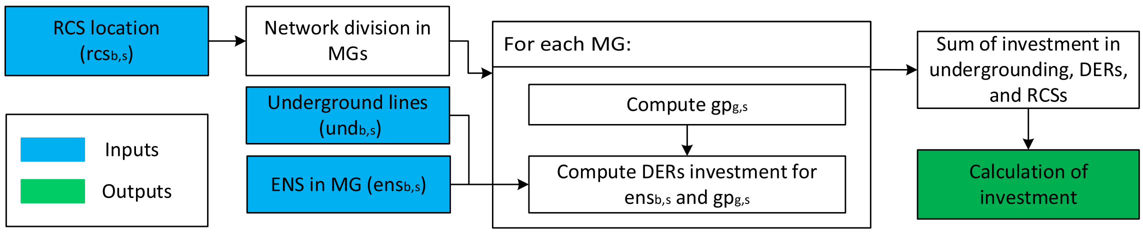

Fig. 8. Investment calculation flowchart.

calculated, the annualized investment of the installed RCSs and the cost of network undergrounding are added to obtain a total value of the investment as shown in equation (17).

$$tai_s = taiders_s + taircs_s + taiund_s \tag{17}$$

5. Case study

5.1. Description

The proposed methodology is applied to a real distribution network affected by extreme weather events. This network has already been used in the study presented in [38], where the problems to obtain the necessary permits to build new support lines due to its location was pointed out. This network has a peak power of 2,742 kW, three RCS, and 74 medium voltage lines, of which 3.08 km are underground, and 36.5 km are overhead. The network structure is shown in Fig. 9.

The decision was taken to select a hurricane as an extreme weather event since, according to the literature, they affect a greater number of consumers [27]. Regarding the base case, a wind speed of 68 m/s is assumed (*wif*), and a repair time equal to 5 h/km (*sf*). According to the literature, a wind speed of 68 m/s on the Florida coast could correspond to a failure probability of 10%[4] [42], where the distribution networks are prepared to withstand a wind speed limit close to 65 m/s [50]. Moreover, 1000 different scenarios are used in the Monte Carlo simulation.

Table 3 shows the costs used for the investments and the annual operation and maintenance (O&M) costs. Manufacturer values have been taken for RCSs [51], while public sources have been used to value the undergrounding of overhead lines [52]. The battery costs have been obtained from [53], while PV system costs have been taken from [54]. The costs have been annualized to be compared with each other since the installation useful lives are different. The annual discount rate used is 7.5%. On the other hand, the useful life is 40 years for RCSs and underground lines, while 15 years has been considered for DERs.

5.2. Results

Fig. 10 shows the Pareto front of the NSs obtained by applying the proposed methodology to the case study, focusing only on NSs with a moderate investment. This figure compares the annualized investment needed to obtain the associated resilience, showing how the initial resilience of the system improves as the investments are increased. Initially, when no investment is made, the ENS of the system due to an event is equal to 43,957 kWh; however, as the investment increases, the ENS is reduced up to 1,300 kWh when the total annuity of investments is 351 k€ (out of scale in Fig. 10). In addition, it can be observed that the most balanced resilience versus investment solutions of the Pareto front are close to 10,000 kWh of ENS and 50 k€ of investment.

Fig. 11 and Table 4 show a breakdown of the investments associated with the results presented in Fig. 10. As can be seen, reductions of close to 80% of the ENS can be obtained by installing RCSs. For higher levels of resilience, other technologies such as line undergrounding would need to be implemented, and only when higher levels of resilience are aimed would it be justified to use DERs for this sole purpose. The following section presents the implications of these results for the profitability of the investments and a sensitivity analysis to the weather intensity and severity factors.

5.3. Discussion and sensitivity analysis

As discussed above, the results show that significant reductions in ENS can be obtained by installing only RCSs. However, if further reductions in ENS are desired, the results indicate that it is appropriate to start undergrounding lines and install DERs. In this context, using DERs for resilience improvement can be seen as an additional network service to those already provided during normal system operation, implying an extra remuneration. However, it can be more debatable the installation of DERs with the only purpose to increase the system's resilience.

It should be remarked that the superiority of simultaneous optimization in comparison to sequential optimization of the different categories of investments (as have been proposed in previous publications) is very clear. Sequential optimization usually is biased to invest in one type of installation over others, depending on the order in which the stages are executed and the stop constraints to go from one stage to the next one [55].

In order to explore the economic implications of the obtained solutions, an assessment of the profitability of the investments, as a post-processing of the obtained results is illustrated below. It is assumed that improvements of the ENS are valued through the VoLL (Value of Lost Load), i.e. the value of a unit of energy not supplied. Therefore, for a given VoLL, for instance, 20 €/kWh [56], it is possible to calculate the minimum frequency of the considered event at which the selected investments would become profitable.

Fig. 12 shows, for the same NS indicated in Table 3, which NSs are profitable (have positive profits, i.e. incomes due to avoided energy not supplied are higher than investment costs) depending on the frequency of the event. As observed, if the considered event has a frequency of occurrence once per year, all the selected investments would become profitable at the set VoLL; however, as expected, as the frequency decreases, the profitability of the investments decrease. They would become unprofitable for frequencies of one event every ten years or more.

Finally, a sensitivity analysis to variations of the weather intensity and severity factors is performed. Fig. 13 shows the results obtained by changing the weather intensity factor in which, setting the severity factor to 5 h, the wind speed varies from 68 m/s to 92 m/s, and, therefore, the probability of failure of the lines from 10 to 90%. As observed, although the initial ENS is very different for the analyzed cases, the most balanced solutions of the Pareto front are in a common range. Investment annuities between 50 and 100 k€ imply resilience levels between 15,000 and 20,000 kWh of ENS. On the other hand, Fig. 14 shows the obtained results with severity factor variations in which, by setting the weather intensity factor to 68 m/s, the time

[4] A critical speed of 65 m/s, and a collapse speed of 95 m/s have been taken according to the indicated literature, assuming an increment of 30 m/s between a zero probability of failure, and a total probability.

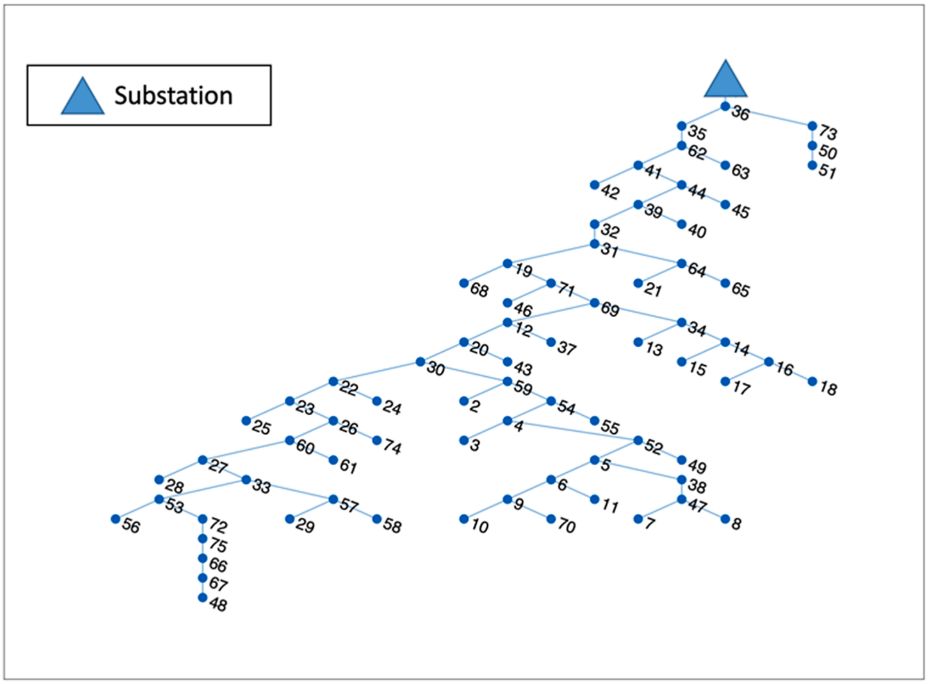

Fig. 9. Distribution network scheme.

Table 3
Investment and O&M costs of network and DER technologies.

Investment	Investment cost	Inv. Annuity	O&M cost
RCS	14,520 €/ud	1,152 €/ud	435 €/ud[1]
Line undergrounding (TI-18VY)	170,751 €/km	13,557€/km	1,772 €/km
DER - Battery systems	156 €/kWh	18 €/kWh	5 €/kWh
DER - PV systems	1,081 €/kW	81 €/kW	32 €/kW

[1]To calculate the operation and maintenance cost of RCSs and DERs, 3% of the investment cost has been assumed.

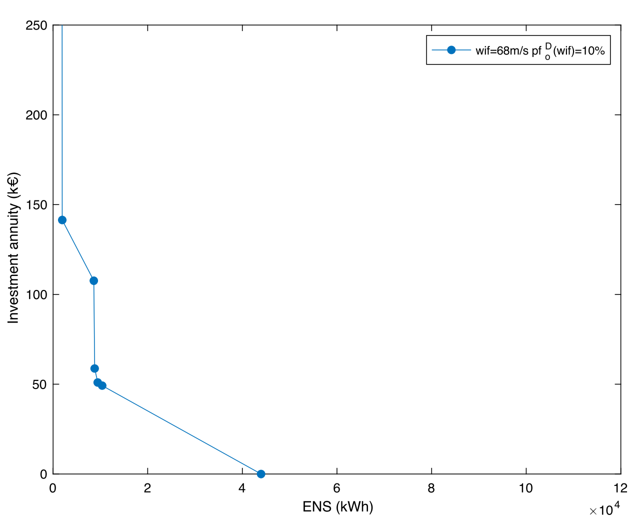

Fig. 10. Network solutions obtained for the case study.

required to repair one kilometer of overhead lines affected by the event varies from 5 to 25 h. The results show that, without any investment, the initial ENS rises proportionally to the increase of the severity factor. Furthermore, the most balanced solutions of the Pareto front are found in a similar region that the ones obtained previously for the weather

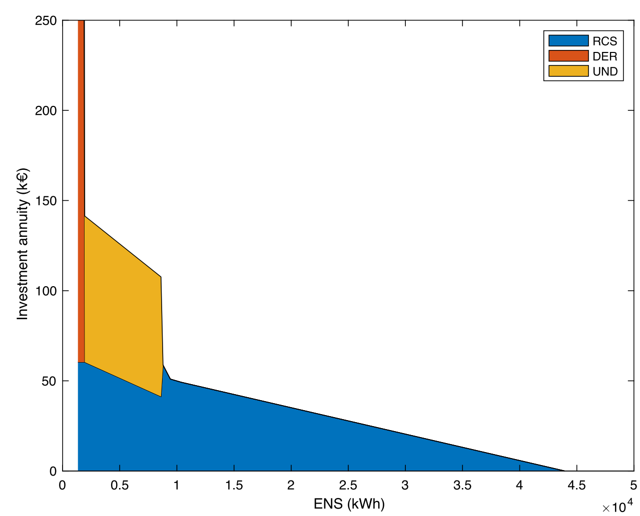

Fig. 11. Unbundled investment for the case study network solutions.

intensity factor sensitivity.

A relevant conclusion of this sensitivity analysis is the impact of the severity factor on the results. Unlike the weather intensity factor that depends on exogenous weather conditions, distribution utilities' managerial and logistic training practices can dramatically improve the severity factor. The impact of this factor is clearly observed in the initial network situation before investments were carried out, where the ENS grows proportionally to it. It should be noted that the NSs obtained with $pf_o^D(wif) = 90\%$ and $sf = 5$ h, present lower ENS values than the solutions obtained with $pf_o^D(wif) = 10\%$ and $sf = 15$ h. This result demonstrates the importance of the severity factor and proposes an improvement in the utility logistics as a complementary alternative to the considered network investments.

6. Conclusions

This paper presents a methodology to maximize the resilience of

Table 4
Unbundled network solutions for the case study.

Network Solution	Investment (k€)	ENS (kWh)	RCS (ud)	Line undergrounding (Km)	Batteries (kWh)	PV (kW)
0	–	43,957	–	–	–	–
1	49,22	10,380	31	–	–	–
2	50,81	9,431	32	–	–	–
3	58,75	8,790	37	–	–	–
4	107,62	8,607	26	4.3	–	–
5	141,42	1,937	38	5.3	–	–
6	351,63	1,342	38	6.0	4,190	931

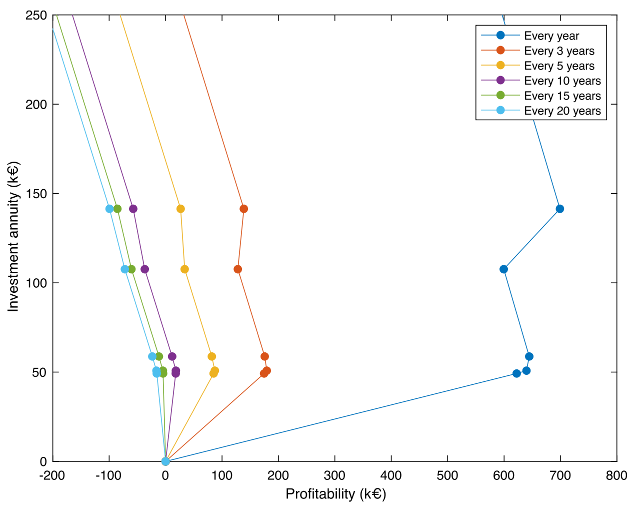

Fig. 12. Network solutions profitability according to the incidence of the event.

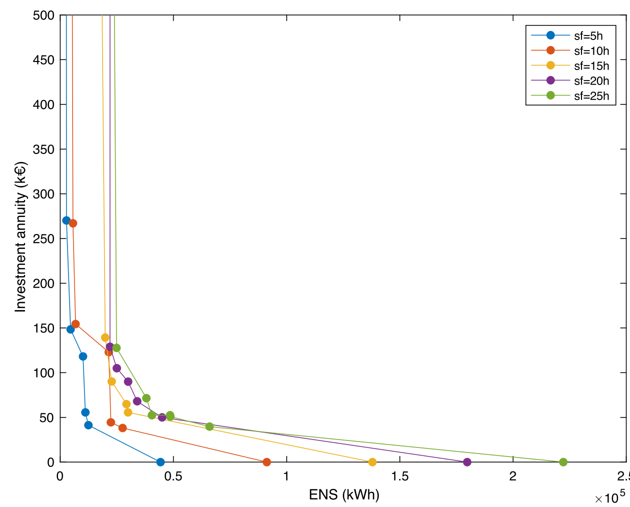

Fig. 14. Network solutions obtained for the case study using different severity factors.

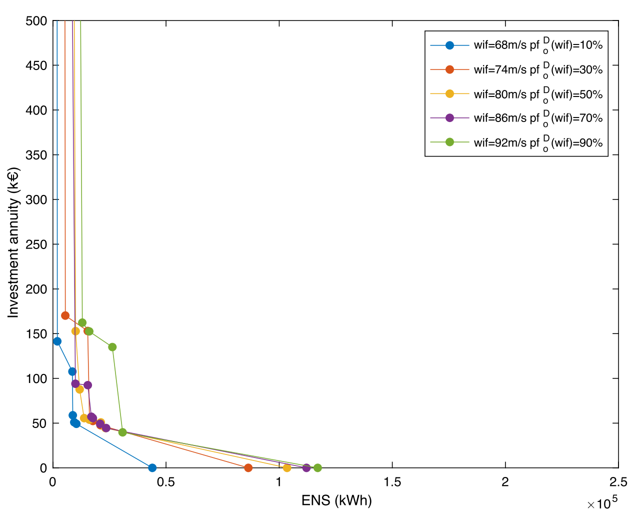

Fig. 13. Network solutions obtained for the case study using different weather intensity factors (wind speeds).

distribution networks while minimizing network and DER investment through single-stage optimization. Three alternatives are presented to improve the resilience of the distribution network, the installation of RCSs, DERs, and the undergrounding of overhead lines. One of the proposed objectives is that the algorithm could be applied to large-scale distribution networks; for this purpose, genetic algorithms are used since they allow dealing with large, highly nonlinear problems with integers and continuous variables such as the one we are studying.

The major scientific contribution of this paper is the integral methodology developed to simultaneously optimize the three very different categories of investments, RCS, DER, and power line undergrounding while maximizing distribution network resilience. Opposed to the methodologies proposed in previous publications, the approach allows us to discover how these alternatives compete with and complement each other. The results obtained demonstrate how priorities in investment decisions are established, and the benefits derived in terms on increasing resilience are quantified. It has proven to be critical in the functioning of the optimization algorithm to introduce some constraints as a post-processing step in the evaluation of the objective function, rather than using mathematical constraints of the problem. This strategy solves convergence problems that would otherwise emerge in the solutions obtained by the genetic algorithm, avoiding local solutions to a problem with a small feasible region.

The results obtained for the realistic case study show how the installation of RCSs can significantly reduce the ENS of the system with moderate investment. The installation of RCSs is followed by overhead line undergrounding, and finally, for the installation of DERs operated as islanded microgrids in case of extreme weather events. Thus, installing DERs for the sole purpose of improving network resilience is less attractive than if they are also used for providing other services during normal system operation. In this case, the total investment would be shared by the different services provided. This is an exciting area for future research.

An important conclusion of the sensitivity analysis conducted is the impact of the severity factor on the results. Unlike the weather intensity factor, which depends on exogenous weather conditions, distribution utilities' managerial and logistic training practices can dramatically improve the severity factor. The impact of this factor is clearly observed in the initial network situation before investments were carried out, where the ENS grows proportionally to it.

The presented results demonstrate the effectiveness of the proposed optimization algorithm, showing how significant improvements in the system's resilience can be obtained through the suggested methodology.

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Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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