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Enhancing the Interoperability of Smart Grids with Active and Proactive Strategies

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Abstract

Transitioning from a centralized power system infrastructure to a decentralized power system with power generation spread across the distribution network is a rather new shift in modern society. This transition has introduced challenges in achieving resilience and interoperability on the distribution network as well as new technological demands from its users. This dissertation addresses these challenges by focusing primarily on low-voltage and medium-voltage distribution networks, due to their limited redundancy and radial structure which introduce susceptibility to energy disruptions.

These energy disruptions can be caused by several factors, often introducing complex situations. Generally, they can be grouped into two sections: man-made and nature related, with their probability of occurring low. These vulnerabilities on the distribution network are expanded while integration of renewable energy and systems to store energy are increasing.

The main motivation for this research arises from the increasing need for reliable, modular and sustainable systems capable of withstanding normal and extreme conditions. In these extreme conditions, high-impact, low-probability events play a major part as they range from natural disasters to man-made disruptions. While there are solutions, they often fall short of ensuring seamless interoperability between diverse components.

To address these issues, this dissertation proposes the development of a multi-temporal modular, scalable framework built on the principles of integrated digitalized energy systems where it includes scenario-based simulations on two IEEE test distribution networks: 33-bus and 69-bus systems. The core objective is to minimize energy not supplied given a load's priority across a time interval, especially during disruptive scenarios.

Ultimately, this study contributes to the development of smart distribution systems capable of maintaining functionality under stress, while aligning with key United Nations Sustainable Development Goals for affordable, reliable, and sustainable energy infrastructure.

Keywords: Multi-temporal Optimal Power Flow, Smart Grids, High-Impact-Low-Probability events, Energy-Storage-System, Network Reconfiguration, Monte-Carlo Simulation.

Sustainable Development Goals of of the United Nations

The content of this work is aligned with a few Sustainable Development Goals (SDGs) established by the United Nations. These goals are : goals 7, 8 and 9 [1].

This research contributes to the goals by improving the reliability of power distribution networks and the integration of renewable energy resources, while the normal operation of distribution networks is not being met. These contributions can be seen in Table 1.

Table 1: Alignment with the SDGs by United Nations

SDG	Target	Contribution	Indicator
7	7.1	Energy loss reduction	Increase of the reliability of the distribution network
	7.2	Renewable penetration	Increase in renewable energy integration
8	8.2	Economic productivity	Reduction in Energy not Supplied
	8.4	Decentralized Production and Consumption	Increase of Renewable Generation with the use of EES
9	9.1	Distribution Network with more resilience	More resilience from decrease of ENS

The methodology presented in this work enables reliable operation of distribution networks with high penetration of renewable energy sources, while prioritizing critical consumers in accordance with their legally established energy contracts. This approach is aligned with SDG 7, specifically 7.1, 7.2, and 7.a. By optimizing the worst-case scenario concerning energy not supplied, the proposed strategy also contributes to reducing energy losses.

Furthermore, this work supports SDG 8, with a particular focus on 8.2 and 8.4. By deploying energy storage systems within the distribution network, the amount of energy not supplied can be significantly reduced, thereby enhancing overall economic productivity and promoting more efficient resource use.

Finally, the integration of distribution network reconfiguration with renewable energy deployment is consistent with SDG 9, especially 9.1. As previously noted, reducing energy not supplied enhances the resilience and reliability of distribution networks, which is a key component of sustainable infrastructure development.

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Abbreviations and Symbols

Abbreviations

AI	Artificial Intelligence
AMI	Advanced metering infrastructure
DERs	Distributed energy sources
DFR	Dynamic feeder reconfiguration
DSO	Distribution system operator
EES	Energy storage systems
ENS	Energy Not Supplied
ERSE	Energy Services Regulatory Authority
EVs	Electric vehicles
GA	Genetic Algorithms
GES	Grid-scale energy storage
HILP	High-impact low-probability
HV	High Voltage
IDES	Integrated Digitalized Energy System
LECs	Local energy communities
LV	Low Voltage
ML	Machine learning
MTOPF	Multi-Temporal Optimal Power Flow
MV	Medium Voltage
NMGs	Networked microgrids
PMUs	Phasor measurement units
PV	Photovoltaic
RES	Renewable Energy Sources
RI	Resilience Index
SoC	State of Charge
WP	Wind power
DSO	Distribution System Operator
DR	Demand Response
PLL	Phase Lock Loop
GAMS	General Algebraic Modeling System
HSS	Hydrogen Storage Systems
MIQCP	Mixed Integer Quadratically Constrained Program
MISOCP	Mixed Integer Second Order Cone Programming
GBD	Generalized Benders Decomposition
REN	Redes Energéticas Nacionais
SOCP	Second-Order Cone Programming
TSO	Transmission System Operator
KVL	Kirchhoff's Voltage Law

Variables

$P_{i,t}^G$	Active power generation on node i
$Q_{i,t}^G$	Reactive power generation on node i
$V_{i,t}^2$	Squared voltage magnitude on node i
$I_{ij,t}^2$	Squared current magnitude through line ij
$P_{i,t}^L$	Active power load at node i
$Q_{i,t}^L$	Reactive power load at node i
$P_{i,t}^{DR}$	Power reduced by DR program at node i
$\gamma_{d,t}^{DR}$	Linearized curtailed power from DR block d at time t
$\delta_{id,t}^{DR}$	Used portion of DR block d of the load i in CLR
$P_{ij,t}^l$	Active Power through line ij
$Q_{ij,t}^l$	Reactive Power through line ij
$P_{ij,t}^{Loss}$	Active Power loss through line ij
$Q_{ij,t}^{Loss}$	Reactive Power loss through line ij
$\Theta_{i,t}$	Phase angle of bus i
$P_{k,t}^{Dchr}$	Discharged Power on ESS k
$P_{k,t}^{Chr}$	Charged Power on ESS k
$\sigma_{i,t}$	Supply disruption at node i

Parameters

r_{ij}	Resistance of the line from node i to node j
x_{ij}	Reactance of the line from node i to node j
$I_{ij}^{2,Max}$	Squared current capacity limit of the line ij
$P_{i,t}^{LD}$	Active load at node i
$P_{i,t}^{LC}$	Curtailed load at node i
$P_{i,t}^{inj}$	Net hourly active power injection at node i
$Q_{i,t}^{inj}$	Net hourly reactive power injection at node i
$P_{ji,t}$	Hourly active power transmitted from node j to node i
$Q_{ji,t}$	Hourly reactive power transmitted from node j to node i
ϕ_i	Power factor of the load at node i
$P_{i,t}^L$	Priority factor of the load at node i
$P_{id,t}^{DR}$	Priority factor of DR block d of the load i
$P_{i,t}^{LD}$	Active load at node i in per unit
$P_{i,t}^{LS}$	Restored active load at node n
$Q_{i,t}^{LS}$	Restored reactive load at node i
Δt	Time interval (1 hour)
$V_{i,t}^{Max}$	Voltage magnitude upper limit at node i
$V_{i,t}^{Min}$	Voltage magnitude lower limit
$P_i^{G,max}$	Active power upper limit for DG $_i$
$P_i^{G,min}$	Active power lower limit for DG $_i$
$P_{ij,t}^{Max}$	Maximum active power through line ij
$Q_{ij,t}^{Max}$	Maximum reactive power through line ij
$Q_i^{G,max}$	Reactive power upper limit for DG $_i$
$Q_i^{G,min}$	Reactive power lower limit for DG $_i$
$S_{i,t}^{G,max}$	Max apparent power of DG $_i$
η_k^{Chr}	Charging efficiency of the ESS
η_k^{Dchr}	Discharging efficiency of the ESS
E_k^{min}	Minimum energy stored in the ESS
E_k^{max}	Maximum energy stored in the ESS
E_k^0	Initial energy stored in the ESS
$P_{t,max}^{Chr}$	Maximum charging power of the ESS
$P_{k,max}^{Dchr}$	Maximum discharging power of the ESS
$P_{id,t}^{DR,b}$	Capacity of DR block d of load i
$P_{i,t}^{DR}$	Power reduced by DR program at node i
$P_{id,t}^{DR,b}$	Capacity of the DR block d of the load i

Binary Variables

$\omega_{i,t}^{LS}$	Binary variable: If there's curtailment of the load = 1, if it's partially or fully restored = 0
$\omega_{id,t}^{DR}$	Binary variable: If the DR block d of load i is used = 1, if not = 0
y_{ij}	Binary variable: If the line (i, j) is closed = 1, if the line is closed = 0
v_{ij}	Binary variable: Directional connectivity link from node i to node j
$I_{k,t}^{Chr}$	Binary variable: If the EES is charging = 1, if the EES is not charging = 0
$I_{k,t}^{Dchr}$	Binary variable: If the EES is discharging = 1, if the EES is not discharging = 0
$\zeta_{k,t}$	Binary variable: If the EES discharging stopped = 1, if not = 0

Indices/Sets

i, j	Indices of nodes in the distribution system
d	Index of DR blocks
M	Set of nodes with distributed generations
L	Set of nodes with loads
EMG	Set of load nodes in MGs with extra power
Λ	Set of nodes with DR programs
l	Indices of lines in the distribution system
g	Indices of generators in the distribution system
t	Indices of time in the distribution system
k	Indices of storage in the distribution system

Chapter 1

Introduction

This chapter outlines the topics this document covers. It starts with the evolution of electrical grids and then proceeds to detail the objectives and the problems we face in this context.

1.1 Context of the Work

Since the standardization of the use of electricity in everyday life, society has been constructing an ecosystem around it. This ecosystem, the electrical grid, is an interconnected system of power plants, transmission lines and connectors which began very rudimentary and evolved overtime.

At first, the generation was centralized, meaning that power was generated at centralized power plants (primarily fueled by fossil sources) and then transmitted via transmission lines over large distances to end consumers, as it can be seen in Figure 1.1.

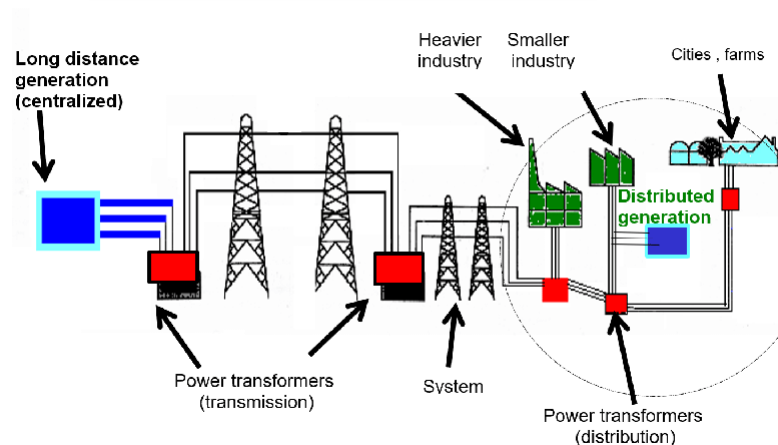


Figure 1.1: Visual representation of a centralized grid [2]

Additionally, the power flow was unidirectional. Energy was generated in the power plants and then transmitted to end-consumers, for example, homes and businesses. This restriction makes the electrical grid limited in terms of flexibility and responsiveness. Not only that, while being a revolutionary system for its time, in the early stages its reliability had subpar performance due to a

large amount of losses occurring during all the stages of: generation, transmission, and distribution. Moreover, its reliance on non-renewable resources contributed significantly to environmental degradation.

Today's society is much different from the 20th century society. Today's society is evolving at a rapid pace, where each community needs more energy on a faster moment's notice. Since then, the electrical power system has become the pillar of global industrial development and even the backbone of everyday life.

With the passing of years, renewable energy gained a lot of attraction because of its fast evolution and competitiveness and became an indispensable energy source. This attraction was in the form of integration of distributed energy sources (DERs), such as photovoltaic (PV), wind power (WP), and electric vehicles (EVs).

Not only that, but as the communities' demand for more sustainable, reliable, and autonomous electricity networks increases, achieving interoperability across interconnected systems becomes essential, especially within medium-voltage (MV) and low-voltage (LV) networks.

Far long were the days of centralized production. With the introduction of renewable energy, it became easy, accessible and cheap for end-consumers to produce small amounts of energy in communities (LECs), leading to the system being distributed. Not only that, this introduction allowed the power flow to be bidirectional letting consumers not only consume energy from the grid but also produce and sell it back, as it can be seen at Figure 1.2.

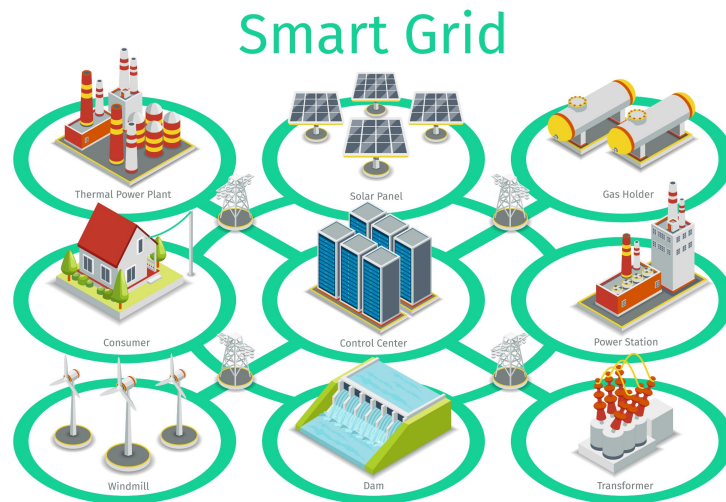


Figure 1.2: Visual representation of a decentralized grid [3]

Another topic to focus is the involvement of Integrated Digitalized Energy System (IDES). IDEs are an ecosystem that leverages end-user engagement, distributed energy resources and a flexible grid-forming technologies to optimize energy generation, distribution, and consumption. Not only that, but they facilitate real-time data exchange, enabling seamless energy flows.

The modern electrical grid often called, smart grid, is defined as an intelligent and controlled electrical grid with the ability to distribute electricity from its generation to end consumers while communicating and delivering information to analyze the behavior of both suppliers and consumers.

Within the broader framework of smart grids, microgrids can be regarded as interconnected components with the overall system. A microgrid is a localized energy network capable of operating either in conjunction with the main grid or independently. It typically comprises a combination of DERs, energy storage systems, and local electrical loads. This enables the grid to form an “island” and continue operating autonomously in the event of disconnection from the main grid, whether due to outages or other external or internal disturbances [4].

1.2 Motivation of the Work

Modern technology advancements allow the modern electrical grid to shape the future of electrical grids as we know them. However, they face growing demands for reliability and flexibility as they move away from centralized systems. The decentralized system requires a high level of interoperability to coordinate resources and energy flows, making monitoring a hard task. Not only that, but traditional centralized energy systems are increasingly challenged by recurring disruptions and the old age of the current infrastructure.

As for our society, the IDEs offers a new approach to integrating renewable energy. With the implementation of real-time interoperability, IDEs bolsters resilience by preparing networks to withstand and recover from disruptions. The flexibility and decentralized control mechanisms ensure that critical loads, such as hospitals and schools, are met even during grid outages and allowing certain loads to shed certain amounts of their load capacity.

Therefore, this work emphasizes its contribution to minimize the energy not supplied (ENS) given a bus’s priority and therefore minimizing electrical customers’ impacts, while ensuring reliable energy delivery to consumers by prioritizing critical load support during high-impact low-probability (HILP) events.

1.3 Goals

The main objective of this dissertation is to develop a multi-temporal ENS optimization focusin on modular and scalable tools that integrates DERs, Energy Storage System (ESS) and demand response (DR).

The aforementioned tool aims to apply optimization models, allowing to manage dynamically energy flows and critical loads across MV and LV networks, while maintaining active and proactive strategies to mitigate the effects of HILP events.

This leads to the following goals:

- Propose a modular and scalable open-source tool for the optimal control and management of smart grids.

- Develop a decision support system for active and proactive actions.
- Develop a multi-temporal interoperable tool for resiliency enhancement of power distribution grids.

1.4 Scope of Work

By targeting MV and LV networks, which are more vulnerable due to limited redundancy and radial topologies, the research seeks to enhance their resilience by minimizing the ENS. Strategies such as dynamic network reconfiguration, including the formation of islanded microgrids, are explored to ensure critical loads are restored rapidly during disruptions.

The research also places a strong emphasis on active and proactive resilience strategies, utilizing multi-temporal optimization models to prepare grids for potential HILP events. While the study focuses on MV and LV networks, it explicitly excludes high-voltage (HV) transmission systems.

1.5 Structure of the Document

This dissertation is structured into six chapters. In Chapter 1, it's introduced the context of the work along with its objectives and scope of the work.

Chapter 2 conducts a literature review, presenting related works on diverse subjects such as renewable energies and smart grids. Existing projects are also outlined.

Chapter 3 delves into the methodology assessment where it is explained in further detail the proceedings taken in order to have the desired results.

Chapter 4 focus on the optimization model implemented and the mathematical formulation, comprising the objective function and constraints.

Chapter 5 showcases the case studies as well as their analyses.

Chapter 6 presents the conclusions and potential developments for future work.

1.6 Materials Needed

For formulating, modelling, and resolving the optimization problem, the General Algebraic Modelling System (GAMS) will be utilized on a Microsoft Surface 7 Pro with 16GB RAM and an Intel® Core™ i7-1065G7 Processor running Windows 11.

Overleaf will be employed for documentation writing while conclusions will be drawn after data collection with the use of Microsoft Excel®.

Chapter 2

State of Art

This chapter provides a foundation for the research by exploring the fundamental concepts of resilience in energy systems, the role of digital technologies, renewable integration with grid-forming capabilities, and understanding HILP events. Furthermore, this chapter has the State of Art and the comparisons from other works. Additionally, the chapter presents the State of the Art in these areas, including comparisons with existing works to highlight research gaps and contributions.

2.1 Key Concepts

2.1.1 Resilience in Energy Systems

Resilience in energy systems refers to the ability to withstand and rapidly recover from disruptions, whether they are natural disasters, cyber-attacks, or equipment failures due to external or internal influences [5].

A resilient energy system must withstand shocks by absorbing the impact of disturbances without significant service interruptions while recovering quickly to restore critical services firstly. While a resilient system must withstand shocks, it should be able to adapt and learn from past events and continuously improve its shock-withstandable ability [6].

Resilience strategies are essential for ensuring reliable power delivery. However, these systems face growing challenges due to the increasing frequency of natural disasters, human-induced risks, and the integration of renewable energy sources (RES). To overcome this, three main resilience strategies are used: system hardening, operational optimization, and distributed energy resources (DER) based restoration.

2.1.1.1 System Hardening

System hardening, a strategy with an intuitive name, involves the enhancement of the physical infrastructure of the electrical grid to withstand extreme weather events, cyber-attacks, and other disruptions.

Strengthening the transmission and distribution network as well as substations to resist physical damage in extreme weather, such as any natural disaster, with robust materials and designs can significantly reduce the vulnerability of critical components [7].

Not only reinforcing the physical components but also reinforcing alternative pathways for the power flow to ensure that if any bus is taken out of service, because of a disruption, the loads affected can be supplied by a new route created because of the existence of a redundant grid [8].

2.1.1.2 Operational Optimization

Operational optimization is the improvement of the efficiency and effectiveness of grid operations to enhance resilience. Utilizing real-time data collection from smart meters and sensors, this data-driven approach allows for dynamic adjustments to power flows and load management, ensuring that critical loads are prioritized during disruptions [9].

Additionally, the Multi-Temporal Optimal Power Flow (MTOPTF) model can help in planning and operating microgrids under both normal and extreme conditions, thereby improving resilience [10].

If, for some reason, the grid must be operated under extreme conditions, the operator must have control over the adjustments of consumer's energy usage during peak hours or emergencies [11].

Not only that, but dynamic feeder reconfiguration (DFR) allows the grid to isolate faults and reroute power dynamically, reducing ENS during emergencies.

2.1.1.3 DER Restoration

The integration of DERs empowers communities to generate and manage their own distributed energy generation, such as solar and wind energy. This decentralization reduces reliance on centralized power plants and enhances local resilience [12].

These types of communities utilize battery storage systems to store excess energy generated from their renewable sources, so that they can be used at any time, helping balance supply and demand, but more importantly, as a backup power during disruptions, allowing the grid to stabilize [4].

Lastly, developing microgrids that can operate independently and isolated from the main grid during emergencies can quickly restore power to critical facilities, improving the grid's resilience and efficiency [13].

2.1.2 Resilience Index

To quantitatively evaluate the network performance, it's adopted a time dependent Resilience Index (RI). The RI is designed to capture the proportion of load successfully supplied throughout the operational planning horizon, offering a direct measure of the system's ability to respond to and recover from disturbances. The planning horizon can fluctuate from small to big, as it's the user's input on the RI calculations.

The RI is defined as Equation 2.1.

$$RI = 1 - \frac{ENS}{TotalDemandedEnergy} \quad (2.1)$$

The value of the RI ranges between 0 and 1. If the value is 1, that indicates full resilience meaning that all loads are fully supplied, whereas lower values indicate reduced resilience due to unmet demand.

2.1.3 Smart Grids and their predominant features

A characterizing feature of smart grids is their ability to facilitate two-way communication, which enables real-time data exchange between utilities and consumers. This interaction empowers consumers, prosumers and even energy agents to make informed decisions with real-time data. Additionally, advanced metering infrastructure (AMI) provides accurate data on energy consumption, allowing utilities to better manage demand and supply, as it can be seen in Figure 2.1.

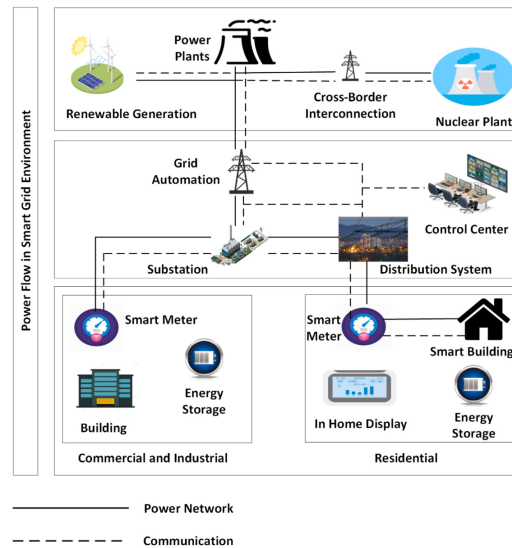


Figure 2.1: Visual representation of a smart grid and its power flow [14]

The integration of DERs not only supports the transition to a more sustainable energy system with less reliance on non-renewable energy sources but also enhances resilience by decentralizing energy sources and improving the flexibility of generation throughout the whole grid [14].

One of the primary benefits of utilizing DERs on the modern grid is the increase in redundancy by distributing generation across multiple sources that either can be local generation or a farm. This decentralization allows for the system to withstand localized disruptions with a higher efficiency than relying only on centralized power plants [8].

The most recent power outage involving vulnerabilities inherent in large, centralized power systems is the Iberic power outage of 28th of April, 2025. Over the last few decades, several factors have indicated the need for micro-grids. As with earlier historical events such as the 2003

Northeast blackout and Hurricane Maria's impact on Puerto Rico, this incident reaffirms the urgent need for more resilient, decentralized grid structures.

As previously mentioned, microgrids ensure a continuous power supply during main grid outages by operating in islanded mode. As they are composed of electrical components with the ability to connect and send in to another, Networked microgrids (NMGs), which are multiple micro-grids connected, allow for resource sharing and dynamic reconfiguration during emergencies as excess power generated in one micro-grid can be shared with another [15].

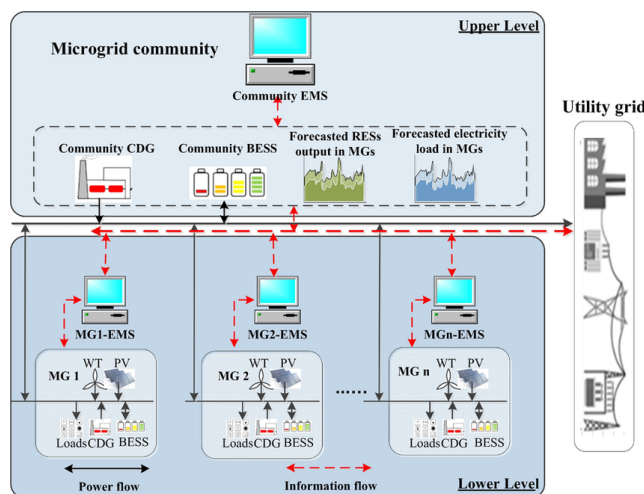


Figure 2.2: Example of a NMGs [15]

However, with every technological development there are benefits and challenges. For microgrids, transitioning between grid-connected and islanded modes requires complex control systems and fast-acting protection mechanisms and protocols. This transition involves the coordination of multiple DERs and ESS in real time which adds extensive simulations and system design to achieve this seamless transition during disruptions [16].

Another important challenge resides in the age of the technology as they lack standardized communication protocols which can cause inadequate real-time synchronization and that leads to resource inefficiencies and delayed fault recovery [13].

Not only that but as with all new technologies, their implementation into main grid's infrastructure has high initial costs.

2.2 Technological Context

2.2.1 Role of Technologies

With the integration of new features, AMI monitoring capabilities can be further utilized with their full potential by further utilize proactive management and rapid response to disruptions. These technologies have vast datasets, both old and new, that were generated by smart meters and

sensors in order to predict demand fluctuations and identify potential failures, as can be seen in Figure 2.3 [9].

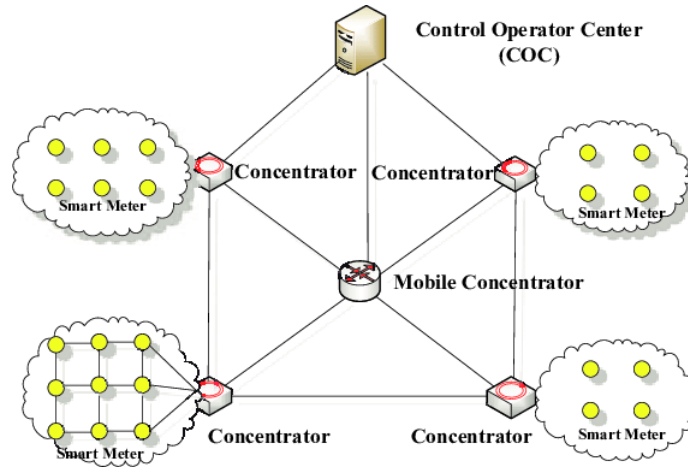


Figure 2.3: Visual representation of an Advanced Metering Infrastructure [17]

These technologies also play an important role in the increased awareness for grid operators by providing real-time insights into grid conditions, making them possible to have an informed decision-making regarding resource allocation and operational adjustments. This capability is particularly crucial during extreme weather events, where rapid response is essential to maintain service continuity [7].

2.2.1.1 Grid's virtual replicas

Digital twins are virtual replicas of physical systems in which operators can simulate and analyze grid behavior under various conditions. Their usage in electrified grids is not new, but in the recent years they have received excellent evolutions. Firstly, with the usage of digital twins, grid behavior can be predicted and vulnerabilities can be found ahead of time and preemptively strategize in a mitigation strategy. These digital twins can be constructed by using real-time data collection from sensors and an AMI infrastructure, as shown in Figure 2.4 [9].

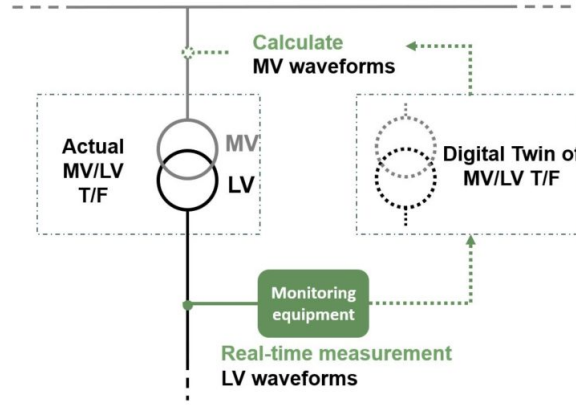


Figure 2.4: Example of a digital Twin [18]

Likewise, these replicas make the deployment of decentralized energy management strategies easier as these strategies to maintain stability during disruptions can be modeled digitally by using DERs, ESS and the conceptualization of micro-grids [19].

2.2.1.2 Real-Time Monitoring and Predictive Analytics

Real-time monitoring provides continuous data streams from designated grid's components. Advanced communication technologies and phasor measurement units (PMUs) capture data on grid parameters, such as voltage, frequency, and power flows. These data streams enable grid's operator to make decisions while encountering early fault detection and load forecasting so that they can ensure a rapid response, as it can be seen in Figure 2.5 [9].

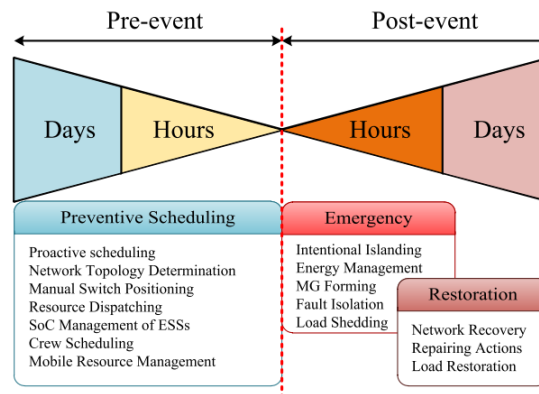


Figure 2.5: Timeline of event operational actions [12]

2.2.1.3 Grid-Forming and Grid-Following generators

The stability of an islanded microgrid hinges on the interplay between two primary types of inverter-based generators: grid-following and grid-forming.

The majority of inverter-based resources, such as solar photovoltaic systems and many wind turbines, operate in a grid-following mode. These generators function as current sources, synchronizing with and injecting power into an already existing, stable grid. They rely on a Phase-Locked Loop (PLL) to track the voltage and frequency of the grid, essentially "following" its lead as it can be seen in Figure 2.6.

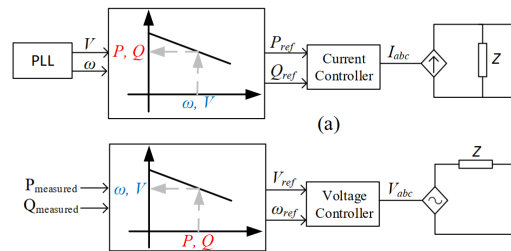


Figure 2.6: Phase-Locked Loop control [20]

However, a grid-following inverter cannot operate on its own; without a grid to follow, it has no reference for voltage or frequency and will cease to operate. This makes them unsuitable for initiating or sustaining an islanded microgrid independently, depending entirely on an external grid reference.

On the other hand, a grid-forming generator is designed to operate as a voltage source. It has the intrinsic ability to establish and regulate the voltage and frequency of the grid. The most common control method for grid-forming inverters is droop control [21].

This strategy mimics the behavior of synchronous generators by allowing a slight, controlled "droop" in frequency as active power output increases, and a similar droop in voltage as reactive power output increases.

A purely grid-following microgrid cannot be islanded. Conversely, a microgrid composed solely of grid-forming units may not be the most economical or efficient solution, as many renewable energy sources are natively grid-following. Therefore, the most robust and practical architecture for an islanded microgrid is a hybrid system with at least one grid-forming generator and one grid-following generator.

2.2.2 Components of Digital Technologies

The ESS are critical components especially for integrating renewable energy sources. They provide the flexibility needed to manage the intermittent nature of renewable generation, with solar and wind energy being the main focus for this intermittent nature of sunlight and high wind speeds. Their integrations provide high levels of renewable penetration, as it allows for the smoothing of fluctuations in energy supply and demand [4].

The ESS are not only meant to be a backup power, they also have grid-forming capabilities creating a stable voltage and frequency reference, allowing for the seamless integration of DERs into

the grid. This capability is essential where localized energy systems must operate independently or in conjunction with the main grid [22].

2.2.3 Demand Response

In the technical aspect, DR is a set of strategies and/or programs that enable the modification of electricity consumption patterns by end users. Their objective is to enhance the flexibility and reliability, particularly during stress events where HILP events are the deciding factor to consider.

Not only that but, DR can play a significant role in optimizing the ENS when there's a HILP event by temporarily reducing a load's demand to better align with the available generation and network constraints. This strategy is particularly useful both during the event and after the event's scenario, where available supply may be limited and selective load curtailment can help prioritize critical loads. DR programs can be designed as price-based or priority-based, as seen in Figure 2.7.

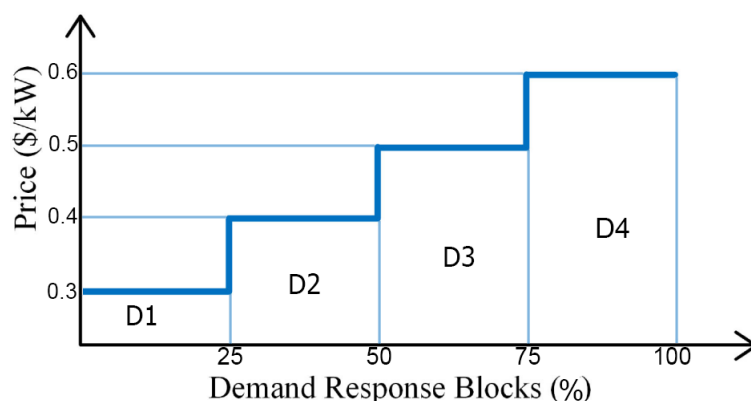


Figure 2.7: DR programs in CLR [23]

By allowing for the controlled curtailment of non-essential loads through pre-arranged contracts with the Distribution system Operator (DSO), DR helps increase the number of restored critical loads and enhances overall system resilience.

2.3 Difference between Active and Pro-active strategies

Active and proactive strategies play distinct yet complementary roles that together contribute to a more resilient and efficient energy network.

Active strategies are characterized by their focus on real time interaction with grid components and on dynamic response to events as they unfold. These mechanisms typically rely on adaptive communication protocols and on distributed agents that negotiate power flows. The strength of active approaches lies in their capacity to adapt swiftly to unforeseen disturbances, ensuring that localized control loops can maintain stability even when measurements or conditions deviate sharply from expectations.

Proactive strategies, by contrast, emphasize anticipation and preparation. They leverage historical data, forecasting algorithms, and model based simulations to identify potential challenges before they occur, allowing the system to reconfigure itself in advance or deploy contingency plans during planned maintenance windows. Similarly, predictive analytics may forecast load patterns or fault probabilities days in advance, enabling the scheduling of energy storage charging and discharging so that resources are positioned optimally when they are most needed. Although proactive measures can greatly reduce the likelihood and severity of foreseeable issues, they depend heavily on the accuracy of forecasting models and on extensive computational resources for simulation and planning.

2.4 Understanding HILP Events

As the name suggests, HILP events, are events with high societal impact that happen occasionally but are regarded to have a low stochastic probability to occur. However, when these events occur a wide area interruption can follow, and the electricity supply is not assured. This interruption in the supply of critical loads provokes a severe impact on society's critical functions [24].

Natural disasters, such as hurricanes, earthquakes, and wildfires, fall in the category of HILP events as they pose significant risks to the stability of society's function but are rare or have a low probability of existing. Not only that, but cyber-attacks also fall in the HILP category. As our grid is modernizing and implementing digital technologies, cyber-attacks are prone to happen [8].

As grids become more interconnected and composed of digital technologies, they become more vulnerable to these types of attacks. So, in order to address these attacks and challenges, it's important to have resilience strategies that can withstand both natural and human-induced disruptions. This includes investing in advanced monitoring technologies and enhancing grid flexibility [7].

2.5 Quality Zones and Quality of Service

The concept of Quality of Service Zones is a classification to establish and monitor service quality standards appropriate to the demographic and geographic characteristics of different areas.

For these classifications, the Quality of Service Zones analysis will be made for mainland Portugal [25]. This system is officially defined in the Quality of Service Regulation from the Energy Services Regulatory Authority (ERSE), and they are as follows:

- Zone A: Encompasses district capitals and localities with more than 25,000 customers. These are high-density areas where service quality standards are expected to be the highest.
- Zone B: Includes localities with a customer base ranging from 2,500 to 25,000. These are areas of medium density.
- Zone C: Comprises all other locations with fewer than 2,500 customers, representing rural and low-density areas where infrastructure challenges may be greater.

This zonal approach allows for the setting of differentiated, realistic, and fair quality targets for technical and commercial service aspects, such as the frequency and duration of interruptions, and response times for customer requests. Specific classifications also exist for the autonomous regions of the Azores and Madeira.

2.6 Reactive Power Regulations for Distributed Generation

The European Union established a regulations of sets binding technical standards for all new power generating units, connecting to the European grid. The regulation is the Commission Regulation 2016/631 [26].

The regulation classifies generating units into four types (A, B, C, and D) based on their size and connection voltage, with requirements becoming progressively stricter for larger installations. With the regulation, generators must be able to operate within a specified reactive power range, defined by a U-Q/Pmax profile. The exact boundaries of this profile are set at the national level by the Transmission System Operator (TSO), but they must fall within the harmonized European requirements.

Since for the previous section, the analysis was made for Portugal area, this further analysis should also be done for Portugal. With this said, Portugal, as a Member State, has transposed the European RfG framework into its national legislation and technical grid codes. The primary entities responsible for this are the energy regulator, ERSE, the TSO, REN (Redes Energéticas Nacionais), and the main distribution system operator (DSO), E-REDES.

The national grid connection requirements, detailed in documents such as REN's Grid Code and technical guides from E-REDES [27], specify the precise parameters for wind generators connecting to the Portuguese network.

In the technical guides, large-scale wind generators are required to operate within a power factor range of at least 0.95 leading to 0.95 lagging at the point of interconnection.

2.7 State of Art

To develop the studies and research, it's necessary to review already implemented and finished projects on the market. Not only reviewing but understanding the scope of prior investigations and their findings is the objective of this section.

The study in [22], addresses the resilient operation of smart distribution grids under physical-cyber-attacks, focusing on HILP events. The authors classify such events into natural hazards and human-induced attacks, emphasizing the latter due to the increasing vulnerabilities in smart grids. The study proposes a comprehensive framework to enhance grid resilience by integrating RES and ESS, leveraging robust optimization to model worst-case scenarios under cyber-physical threats.

The study introduces a resiliency index based on load interruption metrics, evaluating system performance under Denial-of-Service (DoS) and False Data Injection (FDI) attacks. Simulations on modified IEEE 33-bus and real 43-bus systems demonstrate that RES and BESS significantly

improve resilience, with the resiliency index remaining high even under severe attack conditions. The work also highlights the critical role of DERs in mitigating disruptions and ensuring sustainable energy supply, while also identifying gaps for future research, such as advanced robust optimization techniques and economic considerations in resilient grid operation.

Recent advancements in energy storage scheduling and grid resilience have highlighted the critical role of DERs and ESSs in mitigating the impacts of HILP events. The study by [28] addresses the challenge of balancing economic efficiency with disaster preparedness by proposing a variable-type minimum SOC strategy for ESSs and hydrogen storage systems (HSSs). Their research demonstrates that while traditional fixed-type SOC methods prioritize economic gains, they often fail to ensure sufficient energy reserves during outages. In contrast, the variable-type SOC approach dynamically adjusts storage reserves based on anticipated demand, improving power supply capacity by 11.43% to 18.53% despite a modest 2.5% to 2.8% increase in operational costs while incorporating Monte-Carlo simulations to model stochastic disaster scenarios.

Related to microgrid management, [10] proposes a multi-temporal OPF model designed for both normal and contingent operations due to the likes of HILP events. The optimization model is formulated as a mixed-integer quadratically constrained programming (MIQCP) problem, with a second-order conic programming (SOCP) to efficiently manage the quadratic constraints inherent in power flow equations.

The objective function attempts to minimize total operational costs, comprising the cost of energy from dispatchable generators and the main grid, the utilization cost of EES, while modelling the dynamic behavior of their systems over the planning horizon, and to prevent load curtailment during normal operation. This model was implemented on a modified IEEE 33-bus test system which comprised of two DERs (one photovoltaic and one wind type generator) and two thermal generators. The loads were categorized with a priority index related to how important they were to remain supplied in times of contingent operation. In this islanded scenario, the model successfully reconfigures the network and coordinates local resources, showing how the coordination of DERS allowed to supply priority loads.

In [13], the formation of NMGs is explored as a strategy to enhance operational flexibility and resilience in distribution networks, particularly during extreme weather events and large-scale emergencies, more precisely HILP events. The proposed methodology incorporates dynamic network reconfiguration while incorporating DERs, more particularly, PVs systems, and EES. A multi-temporal 24h horizon approach, on the modified IEEE 33-bus system, quantified power imbalances that may occur in each MG and tracked DER operational status, such as state of charge (SoC). This approach allowed reduction on load shedding (LS) by 33.5% in standalone configurations and up to 57.5% when there were power exchanges between MGs.

In [29], it's introduced an automated and rapid load restoration strategy centered on optimal DFR. The research proposes a centralized EMS that can reconfigure a microgrid's topology to supply high-priority loads at minimal cost during both grid-connected and islanded operation. The model forms intentional, autonomous microgrids, each requiring a grid-forming unit. The methodology is formulated as a MIQCP that integrates an OPF problem. The model's efficacy

was demonstrated on a modified IEEE 33-bus system with multiple DGs, two of which possess grid-forming capabilities. In a simulated HILP event that severs the utility connection, the EMS successfully formed two independent microgrids by executing optimal switching actions. The results show that the system restored all critical loads, a considerable portion of medium-priority loads, and some low-priority loads, all while respecting DG capacity limits and converging to a solution in just 13 seconds. This demonstrates the model as a fast and accurate tool for real-world resilience enhancement.

In [6], a bi-level framework is proposed to enhance the resilience of integrated electricity-gas-heating networks by leveraging energy hubs, fast-acting flexible loads, electric vehicles (EVs), power-to-gas (P2G) technologies, and gas storage (GS) systems. However, for this current study only the fast-acting flexible loads portion of the work done is relevant. The study addresses uncertainties in load, RES, and DR participation using a scenario-based method. The case studies used demonstrate that distribution feeder reconfiguration (DFR) increases the resilience index by 36.32% during line outages. The framework highlights the synergistic benefits of multi-energy coordination, dynamic topology adjustments, and distributed resource integration for resilient operation under extreme events equivalent to HILP events.

Lastly, the work done by [12] introduces a comprehensive and scalable framework for resilience enhancement within LECs. The study proposes a MTOF model that accounts for three-phase unbalanced LV networks and integrates diverse DERs, including GES, photovoltaics, and demand-side flexibility. The work shows a unified modelling of network operations across preventive, corrective and restorative time horizons, enabling a dynamic and proactive approach to HILP resilience planning.

The model includes the ability for grid-forming GES units to operate in both grid-connected and islanded modes, thereby supporting intentional microgrid islanding in emergency scenarios.

To evaluate resilience performance, the study develops a time-dependent RI that quantifies ENS relative to a baseline, while accounting for multi-priority customer loads, demand restoration profiles, and flexible contracted power levels. The framework is stress-tested using a five-layer HILP event simulator, which combines spatial-temporal fragility curves, sequential Monte-Carlo simulation, and windstorm trajectory modelling to generate realistic outage scenarios across MV and LV electrical grids.

By utilizing energy system planning, operational control, and resilience engineering, this work contributes a robust methodological foundation and decision-support tool that guides distribution system operators in both real-time operations and long-term infrastructure planning under uncertainty.

The study in [23] presents a two-stage methodology to enhance distribution network resilience during HILP events by MGs, DGs, and DR programs for critical load restoration (CLR). The novelty of this work lies in its integrated consideration of MG ownership and incentive-based DR contracts to optimize the reconfiguration and resource allocation during post-disaster service restoration.

In the first stage, a heuristic is used to determine post-event electrical islands and their radial reconfiguration, prioritizing minimal electrical distances between critical loads and DGs. The second stage applies a generalized Benders decomposition (GBD) to solve a mixed-integer second-order cone programming (MISOCP) model. The objective is to maximize the restored critical loads while factoring in DR participation and operational constraints.

The model distinguishes between privately owned and publicly owned MGs. Only MGs with DR contracts may allow curtailment of their loads in exchange for incentives, thereby enabling surplus power to be redirected elsewhere. The DR contracts are modeled as multi-block emergency DR programs with increasing priorities/prices.

Table 2.1 provides a summary comparing previous studies with the proposed dissertation work, based on the conducted survey of the primary focus of each work. As a result, this proposed dissertation is the result of all the previous key points.

Table 2.1: Comparison of Features in Literature Review

[illegible]

Chapter 3

Methodology Assessment

This chapter outlines the methodology assessment of the work's inner workarounds. This assessment is particularly focused on the probability of failure of towers and lines based on the Monte-Carlo Simulation with Bernoulli's trials. Furthermore, it is concluded what HILP event this work will focus on and how it was achieved.

3.1 Grid's components fragility assessment

Analyzing the stability of the electrical grid under different scenarios is not only done through simulation-heavy calculations, but also through an assessment of the resilience framework. Improving the redundancy of the network and hardening the system, considering the investment cost and time, is a valuable partial solution to the problem of stability, but it lacks consideration of the grid's physical components. The physical components that are worth talking about are the towers and lines that make up the electrical grid.

3.1.1 Towers

Generally, LV and MV towers are made of considerably cheaper materials such as wood and concrete, depending on the installation areas. For LV grids, the towers are generally made with treated wood in rural areas or reinforced concrete in urban or coastal zones due to increased durability and resistance to corrosion. As for MV grids, the towers are usually made of concrete, although steel or composite materials may be used in special applications.

Aspect wise, LV towers are typically short, ranging from 8 to 12 meters, with minimal mechanical reinforcement, while MV poles can reach heights of 12 to 18 meters and include stronger anchoring systems [30].

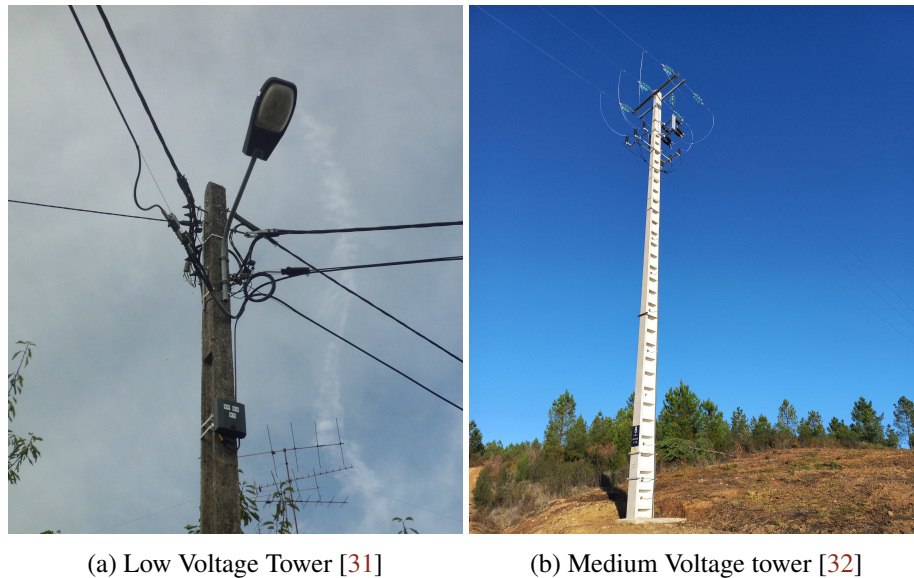


Figure 3.1: Structural comparison of LV and MV towers

Figures 3.1a and 3.1b provide illustrative comparisons between LV and MV towers, showcasing their physical dimensions and structural complexity.

Compared to other networks, HV networks are much more costly than LV and MV networks due to the use of lattice steel towers, guyed masts, or steel tubular towers, which are engineered to handle very high mechanical stresses in both winter and summer conditions.

No only that but, HV towers often exceeding 30 meters in height, are designed to withstand bursts of high wind speed, ice accumulation, and seismic effects. Their lattice structure provides mechanical redundancy and high resistance to buckling.

In addition to wind resistance, LV and MV towers are particularly vulnerable to wildfires due to their material composition—especially wood poles in rural areas, which can ignite or collapse when exposed to fire. Reinforced concrete poles offer some resilience but may still spall or crack under extreme heat.

Another natural event, such as hurricanes impose compound stresses, including wind uplift and lateral pressure, which can cause pole tilting, foundation washout, and even full collapse if not properly anchored. Given a study on a particular area, LV and MV towers must be designed with additional base reinforcement [33].

In addition to that, seismic events can also damage tower bases and anchoring systems. HV towers, while more robust, may experience failures at joints or base plates if not designed to current seismic standards. LV/MV tower may suffer from ground shift and leaning, leading to conductor sag or breakage.

3.1.2 Lines

The usage of power lines varies depending on the environment. In rural and suburban areas, they are generally aerial due to the lower cost compared to underground lines. However, this line of

thought does not apply to urban areas or densely populated cities, where almost every line is underground.

Considering these factors, in LV/MV networks, the usage of bare conductors, like aluminum, is common in rural areas, though insulated aerial bundled cables are increasingly replacing them—especially in urban or wooded areas—to reduce short circuits and improve safety. Another concern in these electrical systems is the long line lengths that sometimes exist, which increase the voltage drop.

The LV lines typically carry voltages of 400/230 V, with conductors supported on crossarms fixed to wooden poles, while MV lines operate in 15 and 30 kV, using more robust insulators and sometimes cross-braced poles for stability. Their susceptibility to wind events is higher due to lower structural inertia and fewer design redundancies compared to HV lines [30].

On the other hand, in HV networks, Aluminum Alloy Conductors or bundled conductors are commonly used to minimize corona discharge and energy loss.

These lines, operate in 60 and 110 kV while including long-span designs, vibration dampers, and anti-galloping devices to mitigate dynamic wind effects.

The lines can be affected by natural events, just like the towers can. With that said, wildfires can severely damage aerial lines, particularly where insulated conductors melt or short-circuit due to radiant heat. This is especially critical in LV/MV systems near forested zones. New designs using fire-retardant coatings or underground cables are becoming increasingly necessary in fire-prone areas and are incentivized by governments alike.

In addition, hurricanes can lead to conductor slap, increased mechanical loading, and insulator breakage, particularly in MV systems with longer spans and fewer damping devices. HV lines are better protected but still require dynamic stabilization components to survive high wind events.

Earthquakes impact underground lines more than aerial lines, particularly in areas with liquefaction risk. Joint displacements, insulation ruptures, and vault collapses can interrupt LV and MV supply. Overhead systems may experience pole leaning or conductor unseating at tension points.

3.1.3 Monte-Carlo Simulation

3.1.3.1 Considerations for fragility assessment

Modern electrical networks consist of several kilometers of power lines and hundreds or thousands of towers, and if a single tower along a line fails, a cascade effect may occur, potentially taking the entire branch out of service.

With this, it is important to assess the fragility of the towers and lines when they are exposed to HILP events where abnormal conditions are commonplace.

Typically, to assess the fragility of a network, historical failure data is required to plot a graph considering the relationship between hazard intensity and the probability of failure. In this study, the hazard is wind speed. However, due to the lack of historical failure records for this specific case, a logarithmic distribution will be used to approximate the probability of failure as wind speed increases.

This approach allows for modeling HILP events, where the tail of the distribution captures rare but severe occurrences. The resulting fragility curve provides a theoretical estimation of how the system's components respond to escalating wind conditions. The accumulative probability of line fault and tower fault can be seen on Figure 3.2.

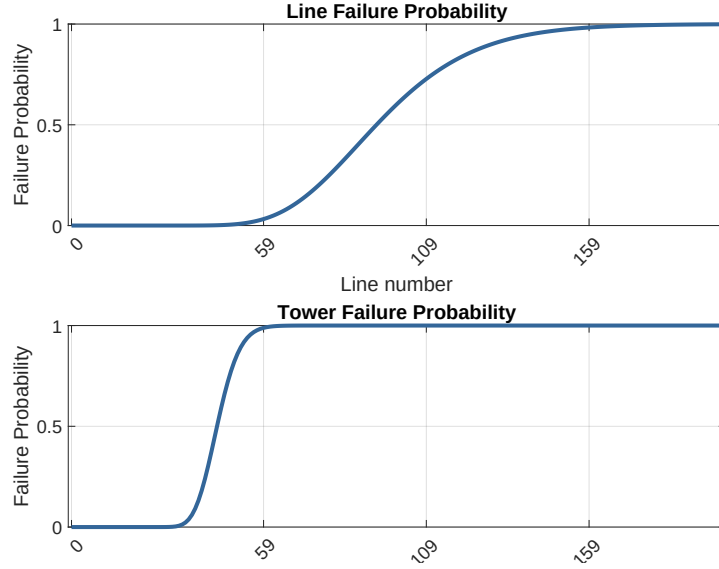


Figure 3.2: Line and Component's fault probability

It has to be noted that these fragility curves refer to the independent collapse of a single transmission tower and line.

The probability of line to go out of service due to wind is shown next:

$$P_{br} = P_{br,B} + P_{br,T} - P_{br,B}P_{br,T} \quad (3.1)$$

In Equation (3.1), P_{br} represents the probability of a line failing as a function of wind speed, while $P_{br,B}$ and $P_{br,T}$ denote the probabilities of failure due to conductor failure and tower collapse, respectively. The probability $P_{br,B}$ is obtained from the fragility curve shown in Figure 3.2. Assuming that transmission towers fail independently and each has the same probability of failure, $P_{br,T}$ is given in Equation (3.2).

$$P_{br,T}(w) = 1 - (1 - P_{T_ind}(w))^{N_T} \quad (3.2)$$

In Equation (3.2), P_{T_ind} is the individual tower failure probability, and N_T is the number of towers along the line. P_{br} is used to identify which branches are vulnerable. If P_{br} exceeds a specified threshold, the line is considered vulnerable and is included in the generation of possible failure scenarios [34] [35].

3.1.3.2 Implementing the Monte-Carlo Simulation

Regarding the numerous existing HILP events, the high wind speeds were chosen to evaluate the potential impact of failures on the electrical grid via a Monte-Carlo simulation.

This simulation allows for the modeling of uncertainty by generating a large number of scenarios where it is possible to observe the resulting network behavior under those conditions.

For each scenario, a wind speed value is randomly sampled from a defined distribution that represents the likelihood of extreme wind events. Once a wind speed is drawn, the corresponding failure probabilities for lines and towers are calculated using the fragility curves presented in Figure 3.2, and the equations previously described. Based on these probabilities, each component is stochastically assigned a failure state (failed or operational) using a Bernoulli trial.

The simulation is repeated over a large number of iterations to ensure statistical convergence. By aggregating the results of all iterations, the Monte-Carlo simulation provides an estimate of the likelihood and severity of line's failures under certain wind condition.

Since the disconnection of the substation, line 01, poses the greatest challenge across all case studies, the simulations were exclusively on scenarios involving the outage of this link. After this filtering, an additional step was performed to ensure that all remaining scenarios were unique, with no duplicates. The flowchart for the whole process can be seen on Figure 3.3.

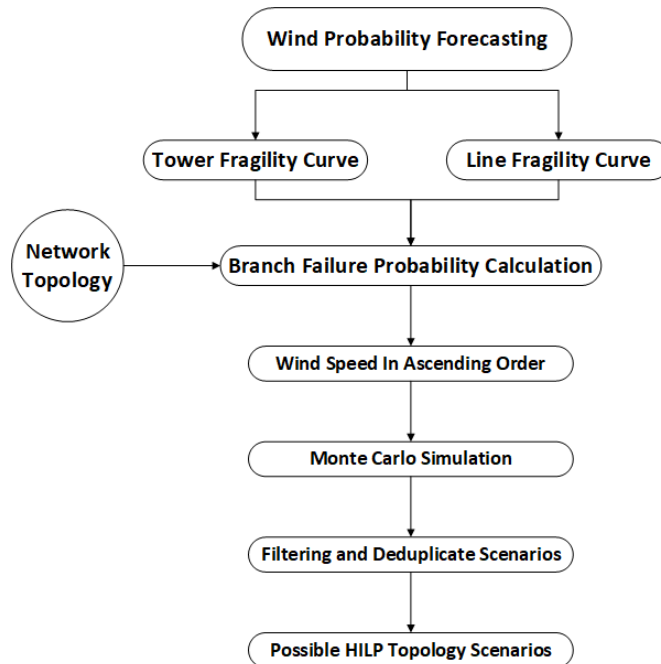


Figure 3.3: Monte-Carlo Simulation Flowchart

3.1.3.3 Wind critical speed

Determining the precise critical wind speed that leads to the out-of-service condition of an line is a complex undertaking, and a generic determination is not a good practice. Tower's span length,

types of conductors and structural designs must also be taken into account.

Given these inherent complexities, having historical data from smart meters alongside a comprehensive geographic understanding helps to determine what sort of wind interval may cause problems to a particular electrical grid.

In the context of this study, which utilizes a test grid environment, the failure probabilities for individual components were calculated from a logarithmic distribution.

This methodological choice facilitates a clear visualization of the critical wind speed intervals pertinent to this specific scenario. The first analysis focuses on wind speeds ranging from 35 to 50 m/s, primarily due to a substantial probability of failure was already evident even at the lower threshold of 30 units.

Figure 3.4 illustrate the failure rate of each line across wind speeds ranging from 35 m/s to 50 m/s for the IEEE 33-bus case.

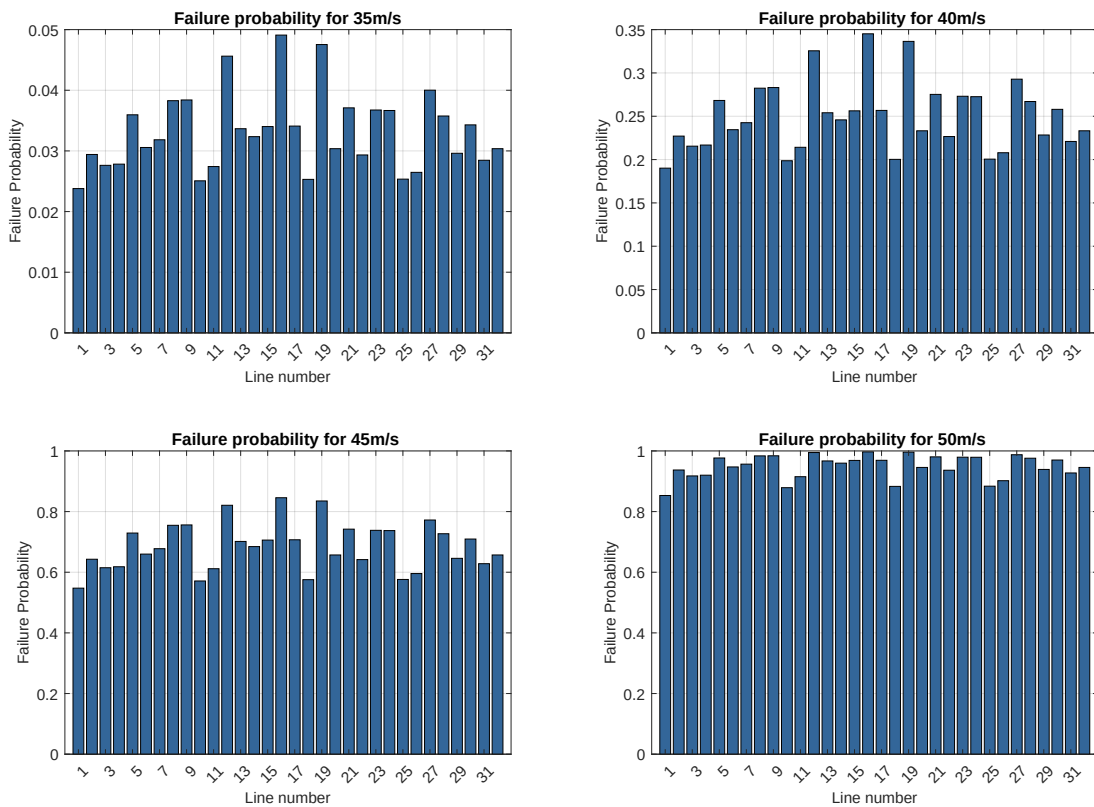


Figure 3.4: Overall failure probability from 35 to 50 m/s for IEEE 33 bus case

Figure 3.5 illustrate the failure rate of each line across wind speeds ranging from 35 m/s to 50 m/s for the IEEE 69-bus case.

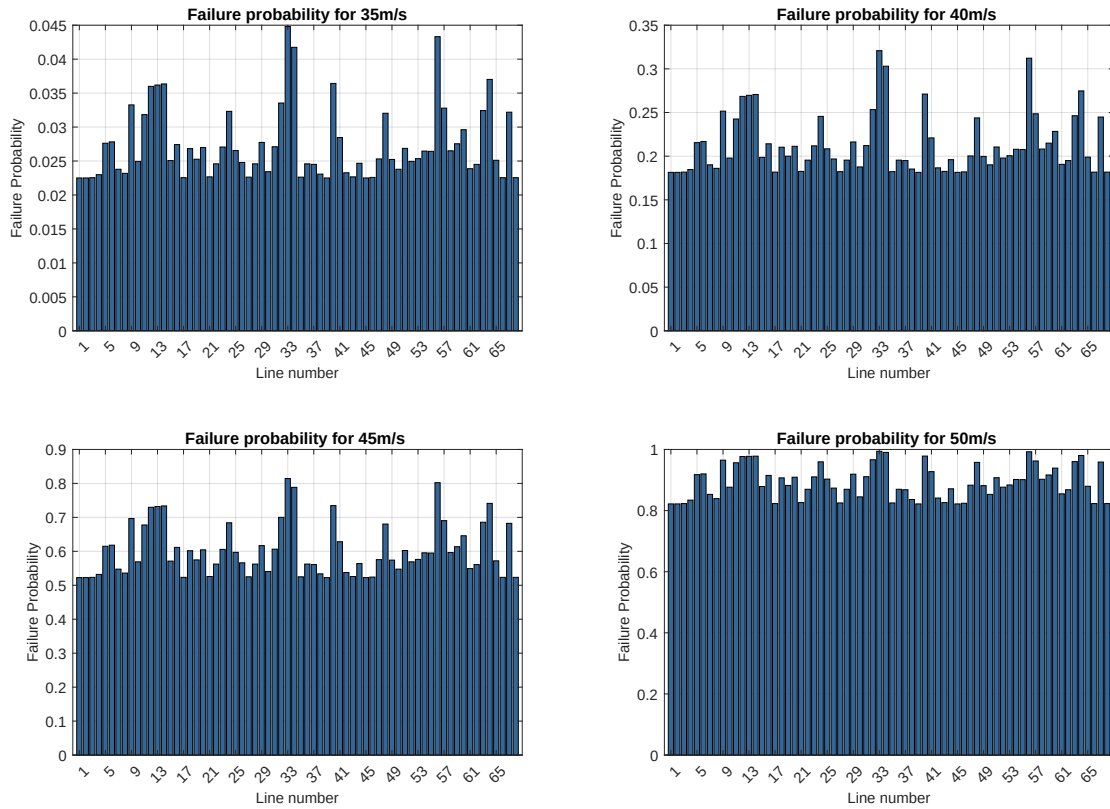


Figure 3.5: Overall failure probability from 35 to 50 m/s for IEEE 69 bus case

Additionally, based on the results of line faults under extreme wind speeds, Table 3.1 presents the ranking of the five lines with the highest fault probabilities for the IEEE 33-bus system.

Table 3.1: Line's ranking based on fault probability for the IEEE 33-bus system

Line's Ranking	Line's Number	35 m/s Wind Speed	40 m/s Wind Speed	45 m/s Wind Speed	50 m/s Wind Speed
1	16	0.0491	0.3452	0.8457	0.9969
2	19	0.0475	0.3364	0.8350	0.9961
3	12	0.0456	0.3255	0.8208	0.9947
4	27	0.0400	0.2928	0.7722	0.9875
5	09	0.0384	0.2831	0.7560	0.9840

Moreover, Table 3.2 presents the ranking of the ten lines with the highest fault probabilities for the IEEE 69-bus system.

Table 3.2: Line's ranking based on fault probability for the IEEE 69-bus system

Line's Ranking	Line's Number	35 m/s Wind Speed	40 m/s Wind Speed	45 m/s Wind Speed	50 m/s Wind Speed
1	14	0.0491	0.3452	0.8457	0.9969
2	13	0.0475	0.3364	0.8350	0.9961
3	12	0.0456	0.3255	0.8208	0.9947
4	32	0.0400	0.2928	0.7722	0.9875
5	09	0.0384	0.2831	0.7560	0.9840
6	24	0.0383	0.2824	0.7548	0.9837
7	11	0.0371	0.2752	0.7421	0.9805
8	06	0.0367	0.2731	0.7382	0.9794
9	29	0.0367	0.2726	0.7373	0.9791
10	05	0.0360	0.2682	0.7292	0.9767

The upper threshold of the analyzed wind speeds was not arbitrarily selected. Major hurricanes typically exhibits wind speeds exceeding 111 mph (approximately 50 m/s), therefore examining the previous figures, 35 m/s was chosen as the singular wind speed for the subsequent simulation analysis [36].

Chapter 4

Problem formulation

This chapter outlines the mathematical formulation of the model used, as well as its constraints. The objective function is a modified version of the one from [23], as the modifications were done to add the soft physical constraints limitations.

4.1 Objective function of the problem

The objective function described by Equation (4.1) of the model aims to maximize the net priority-weighted benefit of the restoration strategy by restoring the most critical loads while minimizing the reliance on DR programs. Specifically, it promotes the restoration of high-priority loads across the network and penalizes the use of DR blocks, which represent partial or full curtailment of lower-priority loads under contractual agreements. This balance ensures that critical infrastructure is prioritized in the restoration process, while DR is used efficiently and only when it provides a net benefit to overall system resilience.

To ensure the model remains robust against physical limitations, like a depleted battery, the objective function includes a high-cost penalty for disrupting supply. This penalty forces the model to consider service interruption as the absolute last resort.

$$\max \sum_{t=1}^t \sum_{i \in L} \text{Pr}_i^L \omega_{i,t}^L - \sum_{t=1}^t \sum_{i \in \Lambda, d \in D_i} \text{Pr}_i^L \text{Pr}_{id,t}^{\text{DR}} \omega_{id}^{\text{DR}} - 1000 \sum_{t=1}^t \sum_{i \in \Lambda} \sigma_{i,t} \quad (4.1)$$

4.2 Problem Constraints and Equations

4.2.1 Active and Reactive Power Balance

The hourly active balance equations are provided in (4.2) while the reactive balance equations are provided in (4.3).

$$P_{i,t}^G + P_{k,t}^{Dchr} - P_{k,t}^{Chr} + P_{ij,t}^{Loss} = P_{i,t}^{LS} \quad \forall i, \quad i \notin \Lambda \quad (4.2)$$

$$Q_{i,t}^G + Q_{ij,t}^{Loss} = Q_{i,t}^{LS} \quad \forall i, \quad i \notin \Lambda \quad (4.3)$$

The nodal power balance equations are divided into two sets of constraints because of the need to differentiate DR allowed nodes from non-DR allowed. The electrical network operator must fulfill the active and reactive power balance by any means necessary, even if it's needed to perform a partial or full curtailment for contingent events.

Based on the previous constraints, the nodal power balance includes the power injection from the substation and the generations spaced across the network, partial or full load curtailment, power through the lines and power transferred to or discharged by the installed EES units.

It should also be noted that the EES system can only provide active power in this model, as well as the integrations of renewables.

4.2.2 Power Loss Constraint

According to the active and reactive power balance, its respective power losses can be expressed as (4.4) and (4.5).

$$P_{ij,t}^{Loss} = R_{ij} I_{ij,t}^2 \quad (4.4)$$

$$Q_{ij,t}^{Loss} = X_{ij} I_{ij,t}^2 \quad (4.5)$$

The calculated power losses are valid for any operating scenario.

4.2.3 Voltage Drop Constraint

The voltage drop across the branches i and j can be expressed as an equality constraint for the normal power flow model. However, this constraint can be upgraded for the radial network with feeder reconfiguration possibilities, resulting in two complementary inequality constraints, provided in (4.6) and (4.7).

$$V_{i,t}^2 - V_{j,t}^2 \geq 2(R_{ij}P_{ij,t} + X_{ij}Q_{ij,t}) + (Z_{ij}^2 I_{ij,t}^2) - (1 - y)M \quad (4.6)$$

$$V_{i,t}^2 - V_{j,t}^2 \leq 2(R_{ij}P_{ij,t} + X_{ij}Q_{ij,t}) + (Z_{ij}^2 I_{ij,t}^2) + (1 - y)M \quad (4.7)$$

The introduction of y is linked with the reconfiguration process, where the variable would be '1' if the branch is connected and '0' if the branch is open. In addition, to guarantee the functionality of this upgraded constraint, the Big-M method is applied with the use of the scalar M , which should be large enough to guarantee the functionality of the model.

If $y = 1$, the second term would be disregarded and the voltage drop constraint will be activated. On the other hand, if $y = 0$, the Big-M will guarantee the non-equality constraints. Analyzing the set of inequations, if there is a case of the connection between two nodes, the voltage drop is represented by the Kirchhoff Voltage Law (KVL).

4.2.4 Transmitted Power Constraint

The transmitted power through the branch ij is modelled as (4.8). In this case, the nodal voltage at the end of the line ij will be considered to model the power flow. Evidently, if there is no connection between bus i and bus j , the current flowing through the branch would be zero, modelled in (4.9).

$$V_{j,t}^2 I_{ij,t}^2 = P_{ij,t}^2 + Q_{ij,t}^2 \quad (4.8)$$

$$0 \leq I_{ij,t}^2 \leq I_{ij,t}^{2,Max} y_{ij} \quad (4.9)$$

In this regard, the bidirectional active and reactive power flows are modeled in (4.10) and (4.11), respectively. The corresponding binary variable for connected branches has been considered to guarantee the feasibility of the power flow constraints as well as the implementation of the Big-M method.

$$-y_{ij} P_{ij,t}^{Max} \leq P_{ij,t} \leq y_{ij} P_{ij,t}^{Max} \quad \forall i \quad (4.10)$$

$$-y_{ij} Q_{ij,t}^{Max} \leq Q_{ij,t} \leq y_{ij} Q_{ij,t}^{Max} \quad \forall i \quad (4.11)$$

4.2.5 Nodal Voltage Constraint

In the distribution power flow problem, maintaining the voltage profile within the permissible bounds is an aspect to be very critical and necessary to enforce. Normally, the minimum value for a node's voltage is 0.9 while the maximum value is 1.1 pu, as it can be seen with Equation (4.12).

$$V_{Min}^2 \leq V_{i,t}^2 \leq V_{Max}^2 \quad (4.12)$$

Since the nodal voltage is assumed to be a positive variable, the quadratic representation does not make the model more complex; therefore the node's voltage constraint is provided in the quadratic statement.

4.2.6 Power Generating Units Constraints

The DG units considered for this study are modeled as dispatchable units, and the operating points of these units should be within the technical power generation limits, which are modeled in (4.13) and (4.14), for the active and reactive power of the dispatchable DGs, respectively.

$$P_i^{G,min} \leq P_{i,t}^G \leq P_i^{G,max} \quad \forall i \quad (4.13)$$

$$Q_{i,t}^{G,min} \leq Q_{i,t}^G \leq Q_{i,t}^{G,max} \quad \forall i \quad (4.14)$$

Another notable observation is that it is assumed that the power flow from the upstream network to the distribution grid is unidirectional and it is not possible to sell the surplus of local power generation to the upstream grid.

4.2.7 Electrical Energy Storage Constraints under HILP event

When solving the problem at hand, it's important to consider constraints related to the energy storage system. In particular, the intrinsic dynamic behavior of these systems plays a key role and should be properly modeled over time. One important aspect is how the energy stored in the battery is represented, and this can be done using either the state of charge or the total stored energy.

The energy stored in the battery can be represented as (4.15). Additionally, since the problem is multi-temporal, the amount of stored energy is dependent on the energy stored in the previous time period and the operation of the EES in charging or discharging modes in the current one. The efficiency of charging and discharging states is also taken into account, valid only for a time greater than.

$$E_{k,t}^{\text{EES}} = E_{k,t-1}^{\text{EES}} + \left(\eta_{k,\max}^{\text{Chr}} \cdot P_{k,t}^{\text{Chr}} - \frac{P_{k,t}^{\text{Dchr}}}{\eta_{k,\max}^{\text{Dchr}}} \right) \Delta t \quad \forall t > 1 \quad (4.15)$$

To ensure the energy stored does not spiral into only charging or discharging ignoring limits, Equation (4.16) makes sure that the stored energy is within the permissible limits.

$$E_k^{\min} \leq E_{k,t}^{\text{EES}} \leq E_k^{\max} \quad (4.16)$$

Additionally, the initial and final energy levels maintained in the battery system are expressed in (4.17) and (4.18), respectively. In this set of equations, the initial energy level for the battery system must be equal to a certain amount. However, the upper limit must not exceed a maximum amount of energy.

$$E_{k,t_1}^{\text{EES}} = E_k^0 \quad (4.17)$$

$$E_{k,t_{24}}^{\text{EES}} \leq E_k^{\max} \quad (4.18)$$

The last three equations, Equations (4.19)-(4.21) are related to the power limits, more specifically about charging and discharging and the functionality of the battery's charging or discharging modes.

$$0 \leq P_{k,t}^{\text{Chr}} \leq P_{t,\max}^{\text{Chr}} \cdot I_{k,t}^{\text{Chr}} \quad (4.19)$$

$$0 \leq P_{k,t}^{\text{Dchr}} \leq P_{k,\max}^{\text{Dchr}} \cdot I_{k,t}^{\text{Dchr}} \quad (4.20)$$

$$0 \leq I_{k,t}^{\text{Dchr}} + I_{k,t}^{\text{Chr}} \leq 1 \quad (4.21)$$

The Equation (4.19) and (4.20) are the limits for charging and discharging and it should be noted that both equations have binary decision variables for both modes, respectively. These two variables are to enforce that the node is charging or discharging energy, and with the integration of Equation (4.21) there is no possible way for a node to be charging and discharging energy at the same time.

4.2.8 Electrical Energy Storage Constraints under Normal operation scenario

Under normal operation of the distribution network, the initial and final energy levels of the ESS must be equal. Accordingly, Equation (4.22) is used when simulating the system's normal operation with ESS support.

$$E_{k,t_{24}}^{\text{EES}} = E_k^0 \quad (4.22)$$

4.2.9 Radial Network Operation Constraints

As it was stated, LV and MV networks must be in a radial topology at all times. However, in the presence of a growing decentralized network, the operational topology can be changed for different seasons or when the main supply fails.

When there's a change in the topology, the distribution network should remain radial for both grid-connected and islanded operation (when the grid is not connected to the main feeder) modes, and to guarantee this, a set of three constraints has been introduced.

Equation (4.23) deals with the direction of the incidence matrix and graph representation of the network. In this case, the binary decision variable $v_{ij,t}$ deals with the connection from node i to node t .

$$v_{ij} + v_{ji} = y_{ij} \quad \forall (ij) \quad (4.23)$$

For the reference bus at each part of the network, either grid-connected or islanded mode, with Equation (4.24), it is not possible to inject the power from the network to the substation bus.

$$\sum_{j \in \Gamma_B} v_{ji,t} = 0 \quad \forall i \in \Gamma_S, \forall (ij) \quad (4.24)$$

The last equation of the set, Equation (4.25), confirms that the maximum power injection to a specific bus is limited to one link. This equation is proposed to avoid forming loops in the network topology while dealing with the total number of branches connected to each bus.

$$\sum_{j \in \Gamma_B} v_{ji,t} \leq 1 \quad \forall (ij) \quad (4.25)$$

4.2.10 Demand Response Operation Constraints

Regarding the Demand Response constraints, there are typically two types of constraints : for DR contracts and for non-DR contracts.

For the non-DR contracts, the status of all the loads in the distribution system can be 0 or 1, where 0 indicates a bus has not been restored and 1 indicates that the bus has been restored, as can be seen on Equation (4.26)-(4.27), for the active and reactive power, respectively.

$$P_{i,t}^{LS} = \omega_{i,t}^L \cdot P_{i,t}^{LD} - P_{i,t}^{LC}, \quad i \notin \Lambda \quad (4.26)$$

$$Q_{i,t}^{LS} = \omega_{i,t}^L \cdot Q_{i,t}^{LD} \quad (4.27)$$

The loads of private MGs with extra generation capacity must be restored, as that's a demand on their contract, therefore, the status of these loads must always be 1, Equation (4.28).

$$\omega_{i,t}^{LS} = 1 \quad \forall i \in EMG \setminus \Lambda \quad (4.28)$$

On the other hand, the DR contracts loads can be restored partially or fully as they don't have the same restrictions as the non-DR contract. With this said, Equation (4.29) represents the amount of load's restored active power while Equation(4.30) represents the amount of load's restored reactive power.

$$P_{i,t}^{LS} = P_{i,t}^{LD} - P_{i,t}^{DR}, \quad i \in \Lambda \quad (4.29)$$

$$Q_{i,t}^{LS} = Q_{i,t}^{LD} - \tan(\phi_i) \cdot P_{i,t}^{DR} \quad (4.30)$$

With the explanation of DR programs previously, the total DR contract of each load cannot be greater than its active power consumption. Therefore, the summation of all DR blocks of said load mustn't be greater than the forecasted active power of the load as it is represented by Equation(4.31).

$$\sum_{d \in D_i} P_{idi,t}^{DR,b} \leq P_{i,t}^{LD} \quad \forall i \in \Lambda \quad (4.31)$$

The amount of applied DR for each load will be the summation of a portion of each DR block as it's shown in Equation (4.32).

$$P_{i,t}^{DR} = \sum_{d \in D_i} \gamma_{id,t}^{DR} \quad \forall i \in \Lambda \quad (4.32)$$

To linearize the previous constraint, it can be replaced with Equation (4.33)-(4.36).

$$\gamma_{id,t}^{DR} \leq P_{id,t}^{DR,b} \omega_{id,t}^{DR} \quad \forall i \in \Lambda, d \in D_i \quad (4.33)$$

$$\gamma_{id,t}^{DR} \leq \delta_{id,t}^{DR} \quad \forall i \in \Lambda, d \in D_i \quad (4.34)$$

$$\gamma_{id,t}^{DR} \geq \delta_{id,t}^{DR} - P_{id,t}^{DR,b} (1 - \omega_{id,t}^{DR}) \quad \forall i \in \Lambda, d \in D_i \quad (4.35)$$

$$\gamma_{id,t}^{DR} \geq 0 \quad \forall i \in \Lambda, d \in D_i \quad (4.36)$$

The amount applied from each load's DR block can't exceed the capacity of a single step, since each step comes with a higher price than the previous one, DR blocks should be used in order—starting with the cheaper steps first. This translates to - if a load uses the d th step of its DR contract, it means all the earlier, less expensive steps must already be fully used, as it can be seen in Equation (4.37).

$$\delta_{id,t}^{DR} \geq \omega_{i(d+1),t}^{DR} P_{id,t}^{DR,b} \quad \forall i \in \Lambda, d \in D_i \setminus \{n\} \quad (4.37)$$

The last two equations describe the status of the DR blocks. Equation (4.38) indicates that if any DR block is used, the load is considered not restored. On the other hand, Equation (4.39) shows that if none of the DR blocks are used, the load is fully restored (i.e., its status is 1).

$$\omega_{i,t}^{LS} \leq 1 - \omega_{id,t}^{DR} \quad \forall i \in \Lambda, d \in D_i \quad (4.38)$$

$$\omega_{i,t}^{LS} \geq \sum_{d \in D_i} (1 - \omega_{id,t}^{DR}) - (n_d - 1) \quad \forall i \in \Lambda \quad (4.39)$$

4.2.11 Physical limitations Constraints

The following equation enforces physical limitations, primarily focusing on load supply continuity.

Equation (4.40) dictates that once a load is restored, it should ideally remain supplied. This means that if a load is restored previously, then it must either stay restored at the next hour. This equation is relaxed with the ability to disrupt the continuity of the supply if it is only needed, otherwise the objective function would receive a heavy penalty.

$$\omega_{i,t}^{LS} + \sigma_{i,t} \geq \omega_{i,t-1}^{LS} \quad (4.40)$$

4.2.12 Energy not Supplied Equation

The ENS quantifies the difference between the total active load demand and the amount of load that is successfully restored at each bus, being defined in Equation (4.41):

$$ENS = \sum_{i=1}^I \sum_{t=1}^T (P_{i,t}^{LD} - P_{i,t}^{LS}) \Delta t, \quad \forall i \quad (4.41)$$

Chapter 5

Results analysis

In this chapter a detailed analysis of two test distribution network models, IEEE 33-bus system and IEEE 69-bus system, is made under different operating conditions. It delves into their normal operation, worst scenario from the Monte-Carlo Simulations and the implementation of ESS to improve ENS.

GAMS was used to solve this optimization problem. The code created to handle the reconfiguration, and the computation includes linear and integer binary variables, continuous linear and nonlinear variables.

5.1 IEEE 33-bus system

In this case, the results from the standard DC operation were validated to enable subsequent modifications of the model for simulating the selected and controlled HILP event, with or without ESS implementation.

5.1.1 IEEE 33-bus system Normal operation

The single line diagram of the network under study is illustrated in Figure 5.1. If the network is in its base case, there is no distributed generation and no DERs in the network. The total active and reactive power demands are 3.715 MW and 2.300 MVar, respectively.

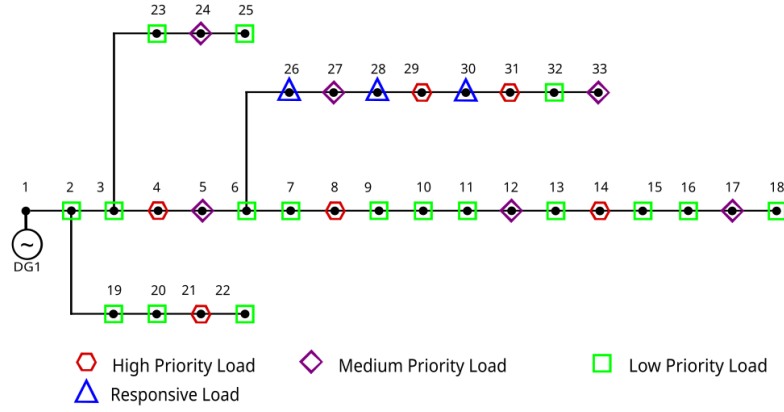


Figure 5.1: IEEE 33-bus system on normal Operation

For the base case, the minimum voltage is 0.913 pu at bus 18, and the reference node is node 1 which the reference voltage is fixed to 1.0 pu and the bus angle to 0.

Regarding node priority, node priority is not considered in the base case, as it assumes full load supply a priori. However, there are 6 nodes with high priority (node 4, 8, 14, 21, 29, 31), 6 medium priority (node 5, 12, 17, 24, 27, 33) and 20 low priority nodes.

Before conducting the analysis on the ENS, the normal operation of the system was validated for both case studies, 33 and 69-bus system.

This validation took place with three validation steps in mind. The first validation method is connecting the system to the substation with only one generator with enough capacity to supply the entire network. The second validation method was to enable network reconfiguration, allowing the five tie-switches to be able to open or close, to decrease power loss and as a result the system changed to the topology seen in Figure 5.2a. The final validation was identical to the second, but it included all the generators used in this work. As a result, the system changed, one more time, to the topology seen in Figure 5.2b.

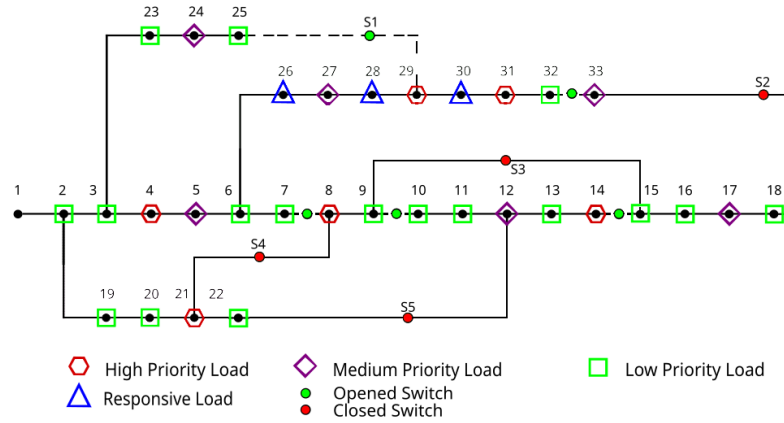
Regarding the results of the active power generation and power loss, they can be seen from Table 5.1.

Table 5.1: Generator output and power loss for the normal, reconfiguration, and reconfiguration with DGs topologies of the 33-bus system.

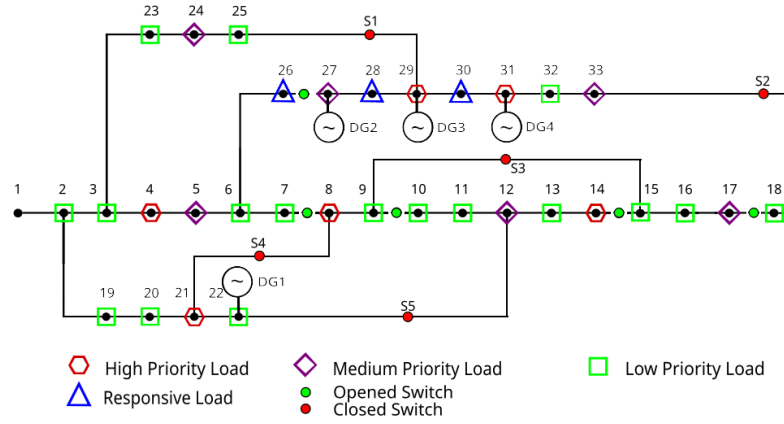
	Normal Operation	Reconfiguration	Reconfiguration with DGs
Power Loss (kW)	202.075	139.160	96.29
Utility (kW)	3917.075	3854.160	49769.19
DG1 (kW)	-	-	2078.45
DG2 (kW)	-	-	10454.79
DG3 (kW)	-	-	2831.34
DG4 (kW)	-	-	5452.76

With each validation method, the power loss of the system was substantially reduced. According to a previous study, the power loss for normal operation is 202.05 kW, and for the reconfigured topology, it is 139.21 kW [37].

When comparing these results with those obtained in this work, they are found to be very similar. The normal operation topology has a 0.01% reduction, and the reconfigured operation topology has a 0.04% increase. These differences are minimal and could be attributed to the solver or numerical precision of the program used to compute the topology. Therefore, it is reasonable to conclude that the results are accurate and effectively validated.



(a) Modified IEEE 33-bus system on normal Operation with reconfiguration



(b) Modified IEEE 33-bus system on normal Operation with reconfiguration and DGs

Figure 5.2: Comparison of the modified IEEE 33-bus system under different operational scenarios.

5.1.2 Modified IEEE 33-bus system analysis

The single line diagram of the modified network is illustrated in Figure 5.3. In the modified network, there are two dispatchable DGs, DG1 and DG2 with the installed capacity of 100 kVA and 630 kVA. In addition to DG1 and DG2, a 300 kVA wind turbine and a photovoltaic unit with a capacity of 425 kVA have been installed at nodes 29 and 31, respectively. The photovoltaic unit

has a unitary power factor, while the wind turbine—as previously seen—must operate within a certain range, in which case the power factor is just over 0.95.

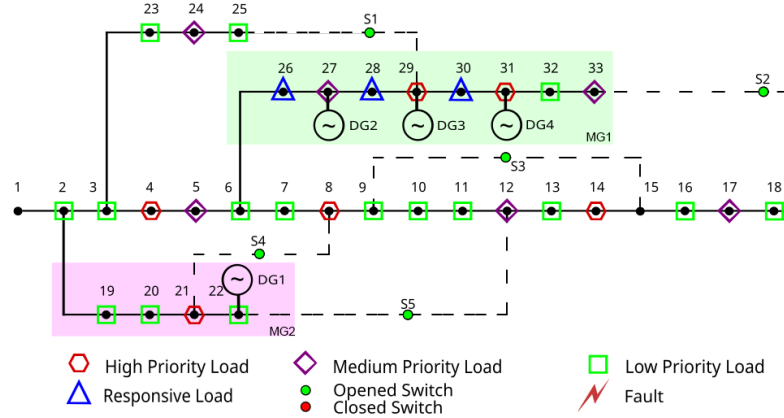


Figure 5.3: Modified IEEE 33-bus system with DGs

To facilitate clearer and more convenient interpretation of the data, Table 5.2 presents all the characteristics of the DGs, along with the microgrid to which each one is currently assigned.

Table 5.2: DGs' Data in the modified IEEE 33-bus system

Generator	Microgrid	Bus	Q^{Max} (kVar)	S^{Max} (kVA)	c_i (\$/kWh)	Type	Slack Possibility
Utility	-	1	-	-	-	Substation	Yes
DG1	MG2	22	50	100	0.005	Thermal	No
DG2	MG1	27	450	630	0.005	Thermal	Yes
DG3	MG1	29	0	425	0.005	PV	No
DG4	MG1	31	93	300	0.005	Wind	Yes

5.1.2.1 Active and Reactive Load Profile

Since the model operates on a multi-temporal level, the loads characterizing the 33-bus system differ from each timestamp. Unlike the other case study, IEEE 69-bus system, this case study uses real consumption data from E-Redes. The data was obtained from E-Redes and corresponds to the 4200-00 Zip-Code (Paranhos) of June 5th, 2023 [38]. The obtained data was mathematically transformed into a load profile, as seen in Figure 5.4. For the simulations either for the 33-bus system and 69-bus system, the data has been multiplied by the total active power of the network.

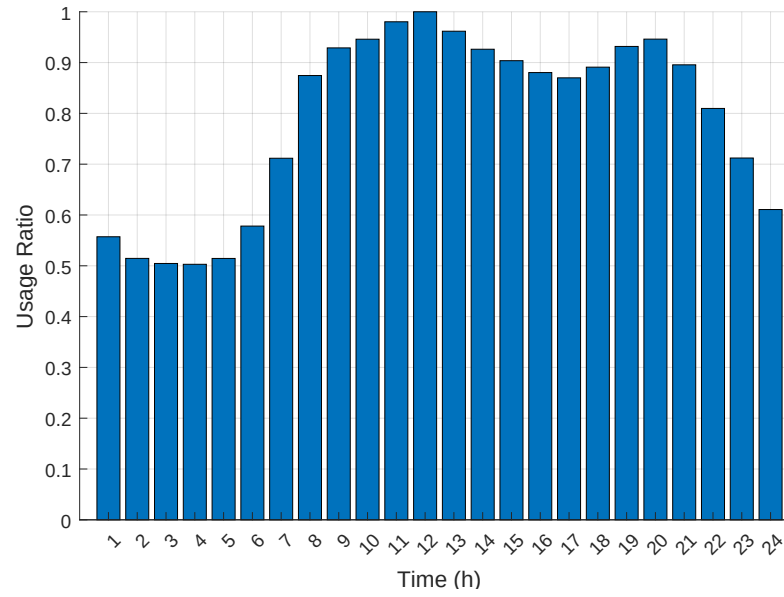


Figure 5.4: Load Profile for the modified IEEE 33-bus system [38]

Photovoltaic and wind systems also require a load profile depending on their Time of Use (TOU). PV systems are dependent on solar irradiance, making their generation profile highly predictable but also limited to daylight hours. Typically, PV output begins to rise shortly after sunrise, peaking around noon and slowly diminishes by sunset. Wind energy presents a more variable and location-specific generation profile. Wind speeds are influenced by geography, weather patterns and atmospheric conditions. In contrast to PV systems, wind turbines can operate at any time of the day or night.

This synergy is seen in Figure 5.5 as it shows the generation peak of solar energy at noon and there is continuous generation of wind energy with several hours of max generation.

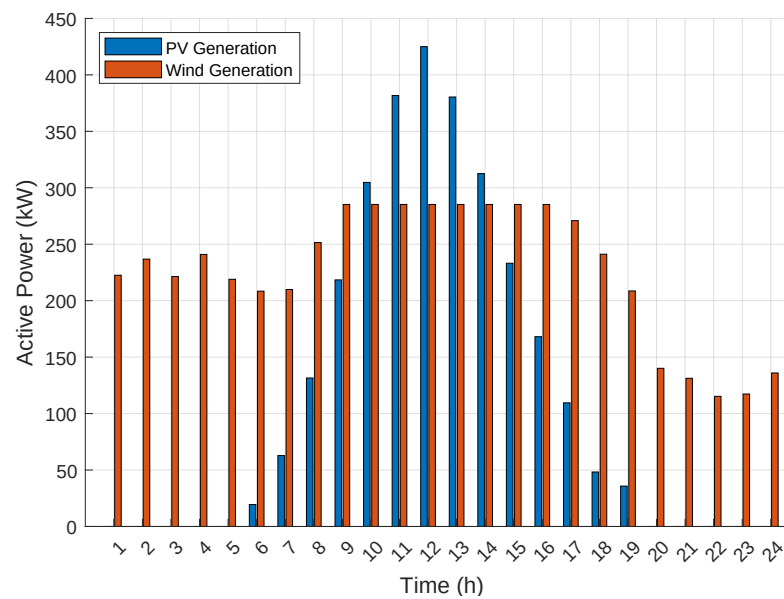


Figure 5.5: PV and Wind load Profile for the modified IEEE 33-bus system

The PV and wind power generation profiles offer opportunities for hybridization of the grid. When both sources are co-located or aggregated within a grid, they can partially offset each other's limitations. For instance, wind generation during night-time can compensate for the absence of solar energy, while daytime PV production can reduce reliance on wind during calm periods.

5.1.2.2 DR Program Allocation

There are two microgrids in this modified distribution system, one privately owned and the other publicly owned. The privately owned microgrid includes three DGs, and the publicly owned contains one DG.

Additionally, the private microgrid accounts for eight nodes: four low-priority, two medium-priority, and two high-priority nodes. The public microgrid accounts for four nodes: three low-priority and one high-priority. While there is a difference between private and public microgrids, the public microgrids doesn't have any kind of contracts with the DSO so they are not eligible for DR blocks management.

The low priority loads in the private microgrid offer four DR blocks, each representing 25% of the total load. In other words, the DSO can utilize all DR blocks, effectively reducing the entire load if necessary. The priority factors associated with these DR blocks are 0.3, 0.4, 0.5, and 0.6, respectively, as seen in Figure 5.6.

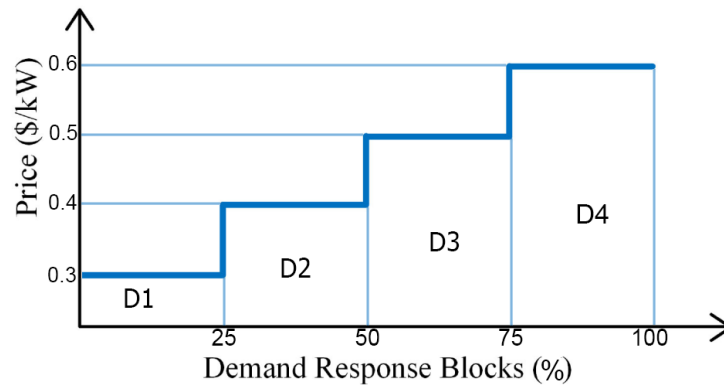


Figure 5.6: DR Response for eligible buses

5.1.2.3 Monte-Carlo simulation cases

With the implementation of the Monte-Carlo simulation for this project, many randomized scenarios were generated to capture a wide range of possible operating conditions. All these scenarios had connectivity with the substation outage. In other words, line 01 was out of service.

In total, 1000 Monte-Carlo cases were simulated. However, due to the specific focus on the outage of line 01 and the removal of duplicate scenarios, only 5 unique cases met the criteria for analysis. Table 5.3 summarizes the out of service lines.

Table 5.3: Scenarios for the simulation of the modified IEEE 33-bus system

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
Disconnected lines	01, 23, 29	01, 16, 31	01, 05, 22	01, 13, 17	01, 16, 25, 31
Total Disconnected lines	3	3	3	3	4
ENS (kWh)	49740.581	49774.366	49725.975	49714.043	49875.408

Analyzing the results from the updated table, Scenario 5 had the worst performance, exhibiting the highest ENS value of all scenarios. Scenario 1 and Scenario 2 also showed relatively poor performance, with an ENS close to that of Scenario 4.

5.1.2.4 Most Critical HILP Analysis

Since scenario 5 is objectively the worst, the single line diagram of that resulting network is illustrated in Figure 5.7.

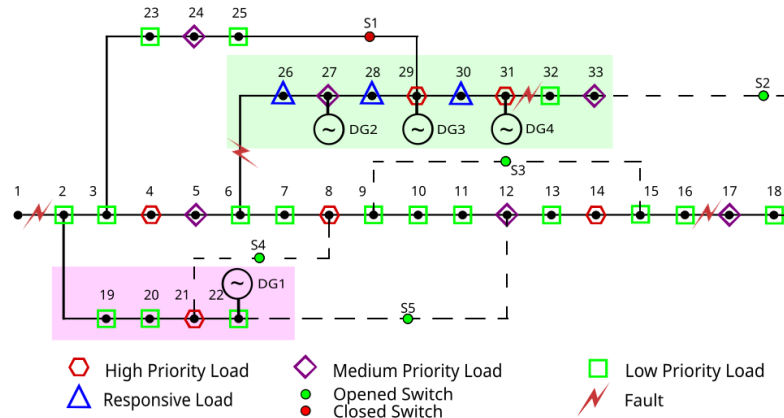


Figure 5.7: Modified IEEE 33-bus system operating based on scenario 5

With the network configuration under Scenario 5 illustrated, the attention can now be turned to discussing its results, more specifically: DG's generation, DR status, created islands, active loads, ENS, load profile for a certain node and RI analysis.

The generation from the thermal and renewable generators, can be seen on Table 5.4. This table provides an overview of the active output where each entry represents a distinct generator unit.

DG1 and DG2, being thermal units, show average stable active power outputs on certain times of the day. DG2 has the highest maximum power outputs for both thermal and renewable generators, with DG4 achieving almost more than half of the DG2 maximum power output.

Comparing both thermal units, their generation patterns are quite similar. Since they are thermal units their generation isn't very dynamic and steadiness is a clear visual sign for that. The key difference between the two generators lies in the rate of generation instead of fluctuation. Since the renewable generators have their generation fixed by their profiles, these thermal units have to compensate the power production and because of that there aren't very variable generation.

Table 5.4: Active generation Output for the modified IEEE 33-bus system

Time	DG1 (kW)	DG2 (kW)	DG3 (kW)	DG4 (kW)
01	86.45277	440.8604	0	222.5227
02	86.24425	440.7987	0	236.8255
03	86.34167	440.8274	0	221.3935
04	86.5686	440.897	0	240.9658
05	86.57149	440.8978	0	218.947
06	86.40524	440.846	19.42939	208.4081
07	86.52646	440.8834	62.79319	209.9137
08	86.43303	440.8536	131.5142	251.5047
09	86.50219	440.8725	218.3916	285.221
10	86.54918	440.8903	304.7522	285.221
11	86.45543	440.8605	381.6875	285.221
12	86.39482	440.842	425	285.221
13	86.3586	440.8312	380.3875	285.221
14	86.50304	440.8761	312.5686	285.221
15	86.47252	440.8658	233.1832	285.221
16	86.45711	440.8571	168.0916	285.221
17	86.57528	440.8982	109.51	270.8888
18	86.47931	440.8676	48.2541	241.154
19	86.57114	440.8975	35.77729	208.5963
20	86.42781	440.8524	0	140.0934
21	86.44312	440.8524	0	131.2482
22	86.47213	440.8623	0	115.2517
23	86.47656	440.8654	0	117.3218
24	86.4843	440.8683	0	135.9531
Total	2075.166	10580.72	2831.34	5452.756

In contrast, the renewable generators display more variable and dynamic output profiles. The photovoltaic generator output clearly shows a solar generation pattern, ramping up sharply in the early morning, peaking around noon and declining towards the evening, consistent with the data from Figure 5.5. The wind generator shows significant fluctuations throughout the day, reflecting the unpredictability of wind conditions.

This behavior is clearly illustrated in Figure 5.8, which shows the time evolution of the generation levels for all units.

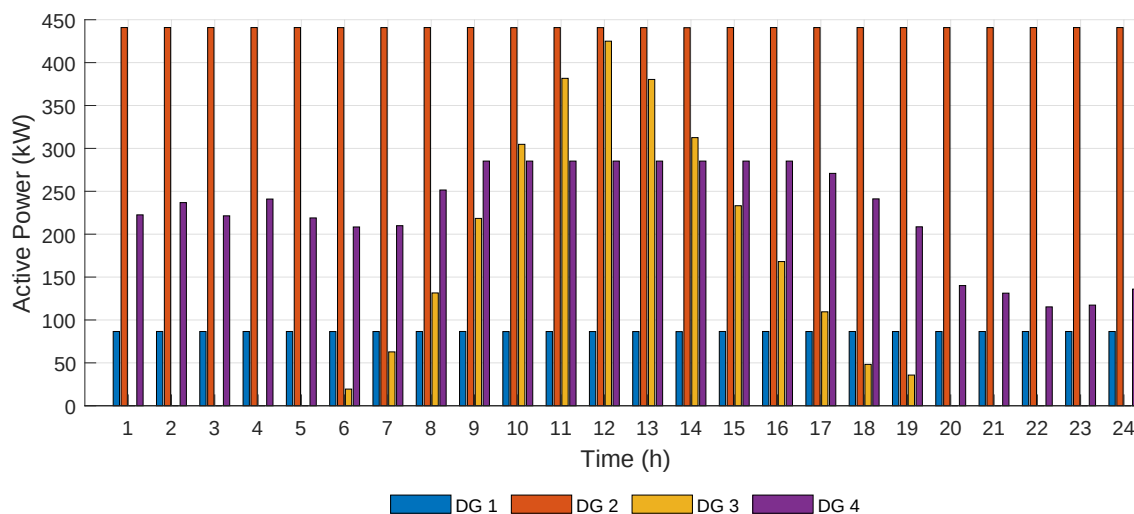


Figure 5.8: Active generation Output for the modified IEEE 33-bus system

Upon detection of the HILP event on the network, the private microgrid activated the DR protocols to curtail eligible loads. The curtailment occurred during some hours of the time sample, as it can be seen on Table 5.5.

Approximately 55% of the private microgrid load was classified as curtailable, while approximately 45% of the load was supplied.

With the percentage alone, the number of hours where the buses were supplied is almost half of the time. However, from the table mentioned above, most DR eligible buses have a similar operation status except for bus 30.

Starting with bus 30, this bus was fully curtailed all day which means the system measured that this load was consuming some energy that could go to other buses with higher priority.

For the others two buses, the data can be more effectively analyzed by considering the DR status in two segments: before and after the 9th and the 17th hour. Prior to the 9th hour, the supply of energy for these buses was varied. Some hours the buses would be fully supplied and other hours they would be curtailed in 75%, 50% or 25%. After the 17th hour, however, the supply would also be varied but full curtailment was more prevalent with some partial curtailment hours.

Among these two buses, bus 28 was supplied 21 out of 24 hours either fully or partially. On the other hand bus 26 was only supplied 19 hours in the same conditions.

This discrepancy between the two segments reflects the priority of the DR buses and the overall network demand. All DR buses have low priority, meaning they were not prioritized for supply compared to other critical loads. When the network had a relatively high energy availability, around the 12th hour, some of these buses briefly received power until conditions no longer permitted it.

On the topic of islands, the network under Scenario 5 successfully islanded into four autonomous islands, as depicted in the single-line diagram (Figure 5.9). Since the occurrence of

Table 5.5: DR loads status during the modified IEEE 33-bus system

Time	Bus 26	Bus 28	Bus 30
1	(1,1,1,1)	(1,1,1,1)	(0,0,0,0)
2	(1,0,0,0)	(1,1,1,1)	(0,0,0,0)
3	(1,1,1,1)	(0,0,0,0)	(0,0,0,0)
4	(1,1,1,1)	(1,1,1,0)	(0,0,0,0)
5	(0,0,0,0)	(1,1,0,0)	(0,0,0,0)
6	(1,1,1,1)	(1,1,1,1)	(0,0,0,0)
7	(1,1,1,0)	(1,1,1,1)	(0,0,0,0)
8	(1,1,0,0)	(1,0,0,0)	(0,0,0,0)
9	(1,1,1,1)	(1,1,1,1)	(0,0,0,0)
10	(1,1,1,1)	(1,1,1,1)	(0,0,0,0)
11	(1,1,1,0)	(1,1,1,1)	(0,0,0,0)
12	(1,1,1,1)	(1,1,1,1)	(0,0,0,0)
13	(1,1,1,1)	(1,1,1,1)	(0,0,0,0)
14	(1,1,1,1)	(1,1,1,1)	(0,0,0,0)
15	(1,1,1,1)	(1,1,1,1)	(0,0,0,0)
16	(1,1,1,1)	(1,1,1,1)	(0,0,0,0)
17	(1,1,1,0)	(1,1,1,1)	(0,0,0,0)
18	(1,1,0,0)	(1,0,0,0)	(0,0,0,0)
19	(0,0,0,0)	(1,1,0,0)	(0,0,0,0)
20	(0,0,0,0)	(1,1,0,0)	(0,0,0,0)
21	(0,0,0,0)	(0,0,0,0)	(0,0,0,0)
22	(0,0,0,0)	(0,0,0,0)	(0,0,0,0)
23	(1,0,0,0)	(1,0,0,0)	(0,0,0,0)
24	(1,1,1,0)	(1,1,1,0)	(0,0,0,0)

faults forced the grid into island mode, it is reasonable to conclude that the formation of these four islands dates back to the first hour of the timescale.

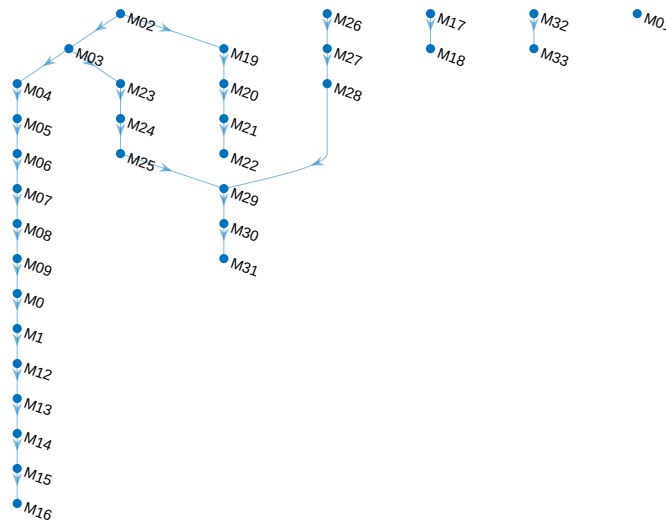


Figure 5.9: Modified IEEE 33-bus system operating based on scenario 5 connectivity

The faults on the lines were crucial in creating these four islands. The first one is already created due to the fault on the first branch. Not only that, but to ensure the network stays radial, the tie-switch that connects bus 18 to bus 33 can't close, automatically creating two islands. The last island is created connecting all the buses except the ones already on the other islands.

- Island 1: Island comprehended by the substation with no other nodes connected to it.
- Island 2: A big island where all of the buses are part of it except bus 17, 18, 32, 33.
- Island 3: Island comprehended by bus 17 and 18.
- Island 4: Island comprehended by bus 32 and 33.

Since the buses on island 3 and 4 are not connected to any DG and their island is not connected to one, they will be always curtailed.

The final ENS and the availability of the nodes for this scenario can be seen from Table 5.6.

Table 5.6: Unsupplied and Supplied Loads During the modified IEEE 33-bus system

Bus	Priority	Unsupplied Load (kWh)	Unsupplied Duration (h)	Supplied Load (kWh)	Supplied Duration (h)
02	Low	1895.20624	24	0	0
03	Low	1705.68563	24	0	0
04	High	0	0	2274.24749	24
05	Medium	205.15214	4	931.97159	20
06	Low	951.30411	20	185.81962	4
07	Low	3790.41245	24	0	0
08	High	716.63482	4	3073.77763	20
09	Low	1010.18963	21	126.9341	3
10	Low	1048.12082	22	89.00291	2
11	Low	586.12946	17	266.71335	7
12	Medium	206.68925	4	930.43448	20
13	Low	1137.12373	24	0	0
14	High	0	0	2274.24749	24
15	Low	1137.12373	24	0	0
16	Low	1137.12373	24	0	0
17	Medium	1137.12373	24	0	0
18	Low	1705.68563	24	0	0
19	Low	1705.68563	24	0	0
20	Low	1705.68563	24	0	0

* Unsupplied and Supplied duration hours are averages.

Table 5.6: Unsupplied and Supplied Loads During the modified IEEE 33-bus system

Bus	Priority	Unsupplied Load (kWh)	Unsupplied Duration (h)	Supplied Load (kWh)	Supplied Duration (h)
21	High	0	0	1705.68563	24
22	Low	1705.68563	24	0	0
23	Low	1705.68563	24	0	0
24	Medium	7104.52746	20	855.33874	4
25	Low	7959.8662	24	0	0
26	Low	390.21738	12	746.90635	24
27	Medium	0	0	1137.12373	24
28	Low	332.0607	11	805.06303	24
29	High	0	0	2274.24749	24
30	Low	3788.59511	24	1.81739	24
31	High	0	0	2842.80936	24
32	Low	3979.93305	24	0	0
33	Medium	1137.12373	24	0	0
Total*		49884.77	16.22	20522.14	9.25

* Unsupplied and Supplied duration hours are averages.

The total energy supplied to the entire system equals to 20522.14 kWh accumulated over 24 hours, having an average of 9.25 hours with nodes of various priorities supplied. On the other hand, the total ENS for the entire system equals to 49884.77 kWh accumulated over 24 hours, having an average of 16.22 hours with nodes of various priorities not supplied.

Regarding the high priority buses, five out of six were entirely supplied, as most are connected close to DG3 and DG4. The only one who was not fully supplied, bus 8, experienced outages of 4 hours.

The medium priority buses almost the opposite result, with only one out of six buses entirely supplied with the rest medium priority buses experiencing outages ranging from 4 hours to 24 hours.

Aside from the high and medium priority buses, most of the other buses were fully curtailed, with unsupplied durations ranging from 11 to 24 hours. Among the three priority levels, the low priority buses exhibited the highest ENS. However, this outcome is expected, as the larger number of low priority buses naturally leads to a higher cumulative ENS. More importantly, the system operated as designed, upholding the prioritization scheme by restricting supply to low priority buses in order to safeguard supply for higher priority loads.

5.1.3 Modified IEEE 33-bus system with ESS

Following the analysis of the previous simulation results, the presented data highlights instances where the existing grid configuration proves insufficient in reliably meeting the demand at specific load points over 24 hours.

To address these deficiencies, an evaluation of the current grid topology must be done and to do so it's needed to identify buses with high or medium priority levels which are susceptible to supply-demand imbalance.

According to Table 5.6, bus 8 is the only high priority bus that wasn't fully supplied. In addition, bus 5 and 24 may also warrant attention. At this stage, the key decision is to determine if these, bus 5 and bus 24, will receive an ESS installation.

Given that bus 5 has low unsupplied duration but is close to other medium priority buses, it can be chosen to have ESS implementation. On the other hand, bus 24 has a high unsupplied duration and high ENS, which leads to the conclusion that it needs to be incorporated with ESS. Therefore, these three buses (5, 8 and 24) are considered suitable candidates for ESS deployment.

Figure 5.10 presents the buses with ESS implementation and the microgrids to which they are currently assigned.

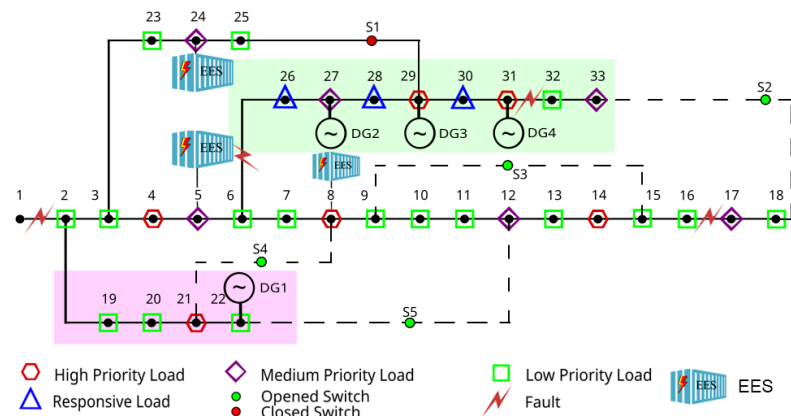


Figure 5.10: Modified IEEE 33-bus system operating with ESS

Meanwhile, Table 5.7 presents the characteristics of the ESS alongside what bus they are connected to.

Table 5.7: ESS placement and characteristics of 33-bus system

Storage Unit	Bus	P_{max}^{Chr} (kW)	P_{max}^{Dchr} (kW)	E^{max} (kWh)	E^{min} (kWh)	η^{Chr} (-)	η^{Dchr} (-)	E_0 (kWh)
1	8	230	240	250	25	0.95	0.95	125
2	24	450	400	500	50	0.95	0.95	250
3	5	100	110	120	12	0.95	0.95	60

The generation from the thermal and renewable generators, can be seen on Table 5.8. This table provides an overview of the active output where each entry represents a distinct generator unit.

Table 5.8: Active generation Output for the modified IEEE 33-bus system with ESS

Time	DG1 (kW)	DG2 (kW)	DG3 (kW)	DG4 (kW)
01	86.57945	440.8836	0	222.5227
02	86.60115	440.9067	0	236.8255
03	86.60115	440.9067	0	221.3935
04	86.60115	440.9067	0	240.9658
05	86.60116	440.9067	0	218.947
06	86.60139	440.9069	19.42939	208.4081
07	86.60141	440.9069	62.79319	209.9137
08	86.60116	440.9067	131.5142	251.5047
09	86.60115	440.9067	218.3916	285.221
10	86.60142	440.9069	304.7522	285.221
11	86.60114	440.9067	381.6875	285.221
12	86.60114	440.9067	425	285.221
13	86.60141	440.9069	380.3875	285.221
14	86.60114	440.9067	312.5686	285.221
15	86.60114	440.9067	233.1832	285.221
16	86.60115	440.9067	168.0916	285.221
17	86.60114	440.9067	109.51	270.8888
18	86.6014	440.9069	48.2541	241.154
19	86.6014	440.9069	35.77729	208.5963
20	86.60142	440.9069	0	140.0934
21	86.60143	440.9069	0	131.2482
22	86.60141	440.9069	0	115.2517
23	86.6014	440.9069	0	117.3218
24	86.5709	440.8751	0	135.9531
Total	2078.378	10581.71	2831.34	5452.756

With the implementation of the ESS, both thermal units, continued to show average stable active power outputs. DG2 maintained a higher maximum power output than DG1 and remained the generator with the highest overall output. However, the integration of the ESS didn't lead to higher or lower power generation.

Although both thermal units exhibited similar generation patterns in the previous study, all the generators did not help in reducing the ENS because that task was left to the ESS units.

For the renewable's generators, they display the same dynamic output profiles because of their generation background. As they are the "helping" set of generators the thermal units are still the backbone of the energy generation.

With the ESS implementation, all the energy from ESS was directly to supply priority buses instead of injecting energy in the overall grid. As for the overall power generation, it stayed quite similar, as it can be seen in Figure 5.11.

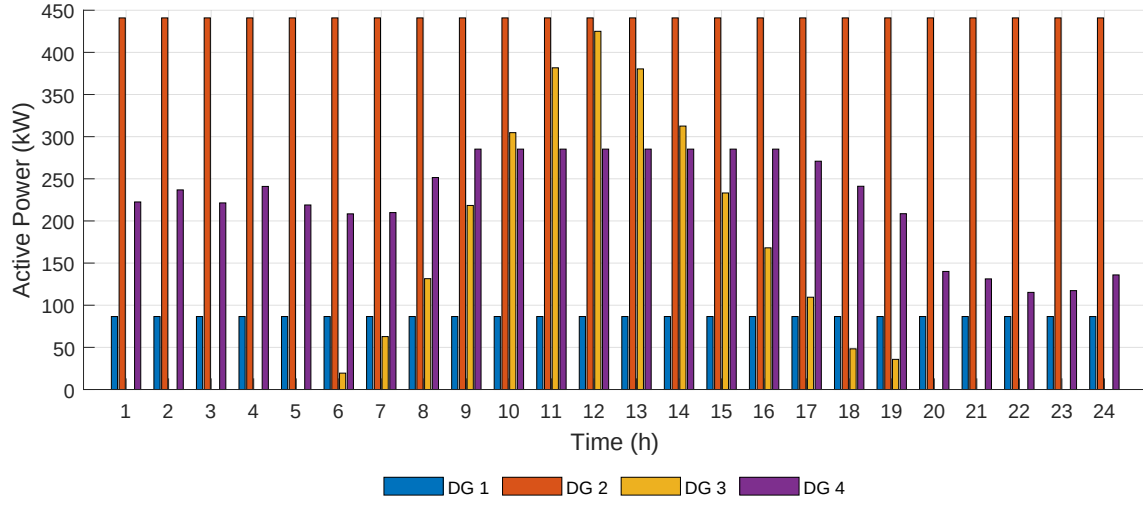


Figure 5.11: Active generation output for the modified IEEE 33-bus system with ESS

Just as it was done previously, upon detection of the HILP event on the network, the private microgrid activated the DR protocols to curtail eligible loads, as it can be seen on Table 5.9.

Table 5.9: DR loads status during the modified IEEE 33-bus system with ESS

Time	Bus 26	Bus 28	Bus 30
1	(0,0,0,0)	(0,0,0,0)	(0,0,0,0)
2	(0,0,0,0)	(0,0,0,0)	(0,0,0,0)
3	(0,0,0,0)	(0,0,0,0)	(0,0,0,0)
4	(0,0,0,0)	(0,0,0,0)	(0,0,0,0)
5	(0,0,0,0)	(0,0,0,0)	(0,0,0,0)
6	(0,0,0,0)	(0,0,0,0)	(0,0,0,0)
7	(0,0,0,0)	(0,0,0,0)	(0,0,0,0)
8	(0,0,0,0)	(0,0,0,0)	(0,0,0,0)
9	(0,0,0,0)	(0,0,0,0)	(0,0,0,0)
10	(0,0,0,0)	(0,0,0,0)	(0,0,0,0)
11	(0,0,0,0)	(0,0,0,0)	(0,0,0,0)
12	(0,0,0,0)	(0,0,0,0)	(0,0,0,0)
13	(0,0,0,0)	(0,0,0,0)	(0,0,0,0)
14	(0,0,0,0)	(0,0,0,0)	(0,0,0,0)
15	(0,0,0,0)	(0,0,0,0)	(0,0,0,0)
16	(0,0,0,0)	(0,0,0,0)	(0,0,0,0)
17	(0,0,0,0)	(0,0,0,0)	(0,0,0,0)
18	(0,0,0,0)	(0,0,0,0)	(0,0,0,0)
19	(0,0,0,0)	(0,0,0,0)	(0,0,0,0)
20	(0,0,0,0)	(0,0,0,0)	(0,0,0,0)
21	(0,0,0,0)	(0,0,0,0)	(0,0,0,0)
22	(0,0,0,0)	(0,0,0,0)	(0,0,0,0)
23	(0,0,0,0)	(0,0,0,0)	(0,0,0,0)
24	(1,1,1,1)	(1,1,0,0)	(0,0,0,0)

This time around, approximately 98% of the private microgrid load was classified as curtailable, while approximately 2% of the load was supplied. When compared to the topology without ESS implementation, curtailment was increased by 43%, resulting in a corresponding 43% decrease in supply load, showing a bigger improvement than expected.

Analyzing the data by considering the DR status in three parts is not necessary since there is only one hour where 2 out of 3 buses were supplied.

With that said, bus 30 is now fully curtailed at every hour. As for the other buses, bus 26 and bus 28 only had 1 hour of supply, both with different patterns of block supply.

Starting with bus 26, the last hour was its only hour of supply and luckily, it was a full supply. On the other hand bus 28 also had supply at that hour but it was partial since only the first two blocks were activated.

Most of these improvements come from the incorporation of the ESS, since it had a noticeable impact on all DR nodes. This outcome reflects the low priority assigned to the DR buses within the network. As these buses were not prioritized for supply, their curtailment levels remained high despite the ESS implementation. This trend of full curtailment is the result of the incorporation of more energy in the system allows the priority buses of demanding more supply as there is more flexibility available. Evidently, this case study uses real data and at the time of the data's sampling, demand was high as its load profile shows.

The final ENS and the availability of the nodes for this scenario can be seen from Table 5.10. The total energy supplied to the entire system equals to 21553.63 kWh accumulated over 24 hours, having an average of 9.56 hours with nodes of various priorities supplied. On the other hand, the total ENS for the entire system equals to 48853.28 kWh accumulated over 24 hours, having an average of 16.56 hours with nodes of various priorities not supplied.

Table 5.10: Unsupplied and Supplied Loads During the modified IEEE 33-bus system with ESS

Bus	Priority	Unsupplied Load (kWh)	Unsupplied Duration (h)	Supplied Load (kWh)	Supplied Duration (h)
02	Low	1839.493	23	55.71297	1
03	Low	1655.544	23	50.14167	1
04	High	0	0	2274.247	24
05	Medium	161.2575	3	975.8662	21
06	Low	1103.696	23	33.42778	1
07	Low	3790.412	24	0	0
08	High	0	0	3790.412	24
09	Low	1103.696	23	33.42778	1
10	Low	1103.696	23	33.42778	1
11	Low	827.772	23	25.07084	1

* Unsupplied and Supplied duration hours are averages.

Table 5.10: Unsupplied and Supplied Loads During the modified IEEE 33-bus system with ESS

Bus	Priority	Unsupplied Load (kWh)	Unsupplied Duration (h)	Supplied Load (kWh)	Supplied Duration (h)
12	Medium	55.90524	1	1081.218	23
13	Low	1103.696	23	33.42778	1
14	High	0	0	2274.247	24
15	Low	1103.696	23	33.42778	1
16	Low	1103.696	23	33.42778	1
17	Medium	1137.124	24	0	0
18	Low	1705.686	24	0	0
19	Low	1655.544	23	50.14167	1
20	Low	1655.544	23	50.14167	1
21	High	0	0	1705.686	24
22	Low	1655.544	23	50.14167	1
23	Low	1655.544	23	50.14167	1
24	Medium	5527.568	15	2432.298	9
25	Low	7959.866	24	0	0
26	Low	1067.013	22	70.11066	24
27	Medium	0	0	1137.124	24
28	Low	1085.314	23	51.80953	24
29	High	0	0	2274.247	24
30	Low	3678.916	23	111.4968	24
31	High	0	0	2842.809	24
32	Low	3979.933	24	0	0
33	Medium	1137.124	24	0	0
Total*		48853.28	16.56	21553.63	9.56

* Unsupplied and Supplied duration hours are averages.

Compared to the previous results, there was an increase in both the average duration of total supply and the total amount of load supplied, as well as the ENS.

Regarding the high-priority buses, now every bus has been supplied for every hour. Looking at the medium priority buses, improvements were made to several buses, even restoring partially a previous fully curtailed bus. Among the remaining low priority buses, their ENS increased.

These results were very telling of how the ESS can decrease ENS when priority buses are targeted. High priority buses were fully supplied, medium priority buses receive some attention by the ESS and therefore improved their ENS but low priority buses were almost forgotten because of their priority nature.

To better understand how ESS performance varies depending on its location within a distribution, it is done an analysis examining the temporal energy profiles of these storage units, visualized in Figure 5.12.

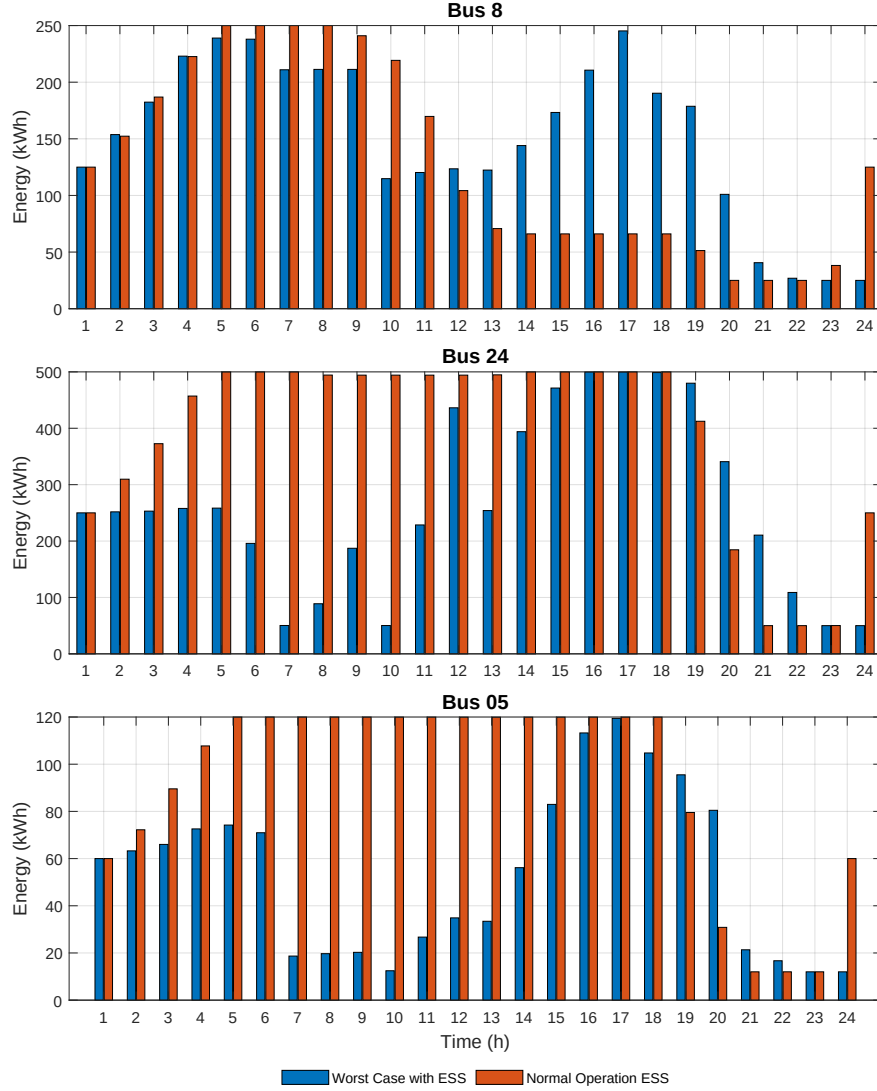


Figure 5.12: Comparison of ESS from the modified IEEE 33-bus system

All the ESS implemented for the worst-case scenario display similar dynamic charge-discharge patterns. On the other hand, all the ESS implemented for normal operation display similar charge-stability patterns.

The ESS located on bus 8, starting at 125 kWh, and initially charges before stabilizing for a few hours. After this stabilization, a significant discharge occurs, and a stabilizing period occurs followed by a charging period. This charging period ended when the network needed more energy in the system and a fast gradual discharge took place, ending the storage at its minimum value. This pattern is widely different from the pattern for normal operation. On the normal operation,

the ESS charges early in the day to discharge a moderate portion around noon, ending charging in second last hour where it coincides with the initial energy stored.

The ESS located on bus 24, starting at 250 kWh, initially is stabilized before entering a period of steep dynamic charging and discharging ending around the 13th hour. After this dynamic period, there's a period of charging ending on a few hours of stabilization. The last couple of hours were met with discharge until the storage was met with its minimum value. Reaching the same conclusion as the previous ESS analysis, on the normal operation, the ESS charges steadily early in the day to discharge an insignificant portion around noon.

The last ESS to be analyzed, located on bus 05 and starting at 60 kWh, has a pattern similar to the last ESS unit than the first. This pattern is marked by subtle charge early in the morning, followed by a steep discharge phase until the minimum storage value is met. After this lowest amount of energy was met, a charge phase starts ending only when the storage reaches its peak so far. For the last hours of the day, the ESS begins a gradual discharge until the minimum storage value. In contrast, under normal operation, the energy profile at this bus differs significantly from the others, characterized by a prolonged period of stabilized energy throughout most of the day, interrupted only by a steep discharge occurring late in the evening where it charges again to coincide with the initial energy stored.

Analyzing all ESS profiles, several supported conclusions can be drawn. First, the early hours of the day reflect a relatively low network demand, as evidenced by the consistent stabilization or charge observed across all ESS units. Second, there is a notable increase in energy demand during the latter hours of the morning and early hours of the afternoon, indicated by a dynamic charge-discharge phase. Finally, during the later hours of the evening, all ESS units have the same profile evidenced by the discharge phase until the storage reaches its lowest possible value. This finding clearly shows that the network has high demand in the last hours of the day.

Based on the previous results of the ENS, another analysis can be made by analyzing one bus on its entirety, therefore bus 08 was chosen and its load profile is illustrated in Figure 5.13.

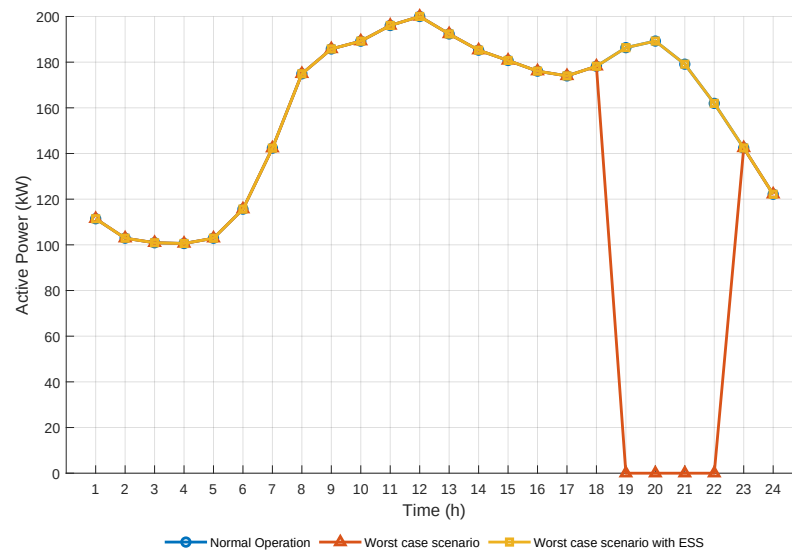


Figure 5.13: Load profile of Bus 05 for the 33-bus case system

In both worst-case scenarios, with and without ESS implementation, the load profile initially follows that of normal operation, with supply maintained for the first eighteen hours. Without ESS, the bus experiences curtailment from that point onward with supply and curtailment phases until the final two hours, when supply is restored. When ESS is implemented, the bus is fully supplied.

Regarding the RI in the 33-bus system, without ESS the RI values range from 19% to 41%, with the lowest reliability occurring during the end of the day. The average RI for this scenario is approximately 30%. With the inclusion of ESS, the RI values range from 23 % to 72 %, and the average RI is approximately 32%. This resilience is not optimal with the real data. This indicates that the network will have its resilience slightly altered with ESS implementation as it can be seen in Figure 5.14.

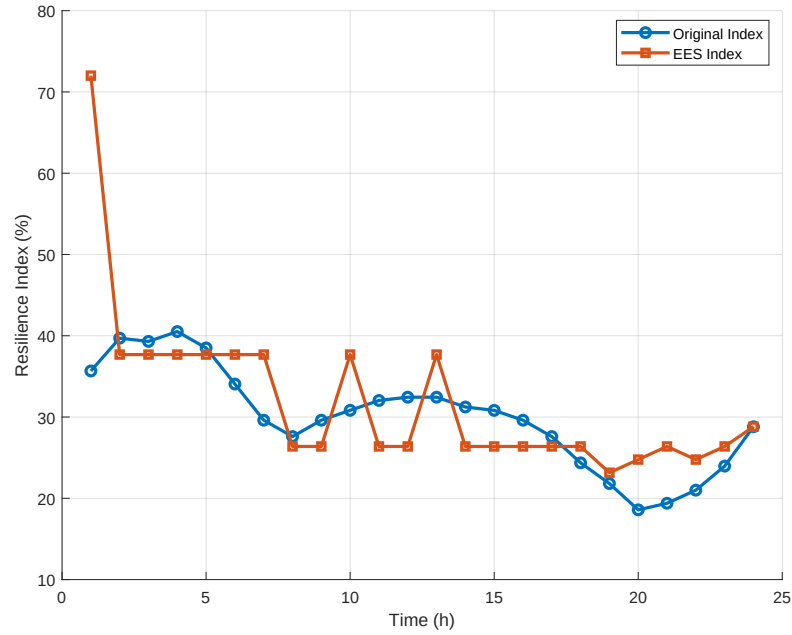


Figure 5.14: RI for the modified IEEE 33-bus system

For the most part, resilience with ESS implementation is better than without it, with only a few hours where it is worse. Additionally, with the implementation of ESS, resilience is a little more dynamic with periods of improvements and declines after another.

Looking at the RI from the previous figure gives us the global RI, but an analysis of the RI from the high and medium priority buses should be done to observe if there were any improvements made when ESS is incorporated. This information can be seen in Figure 5.15.

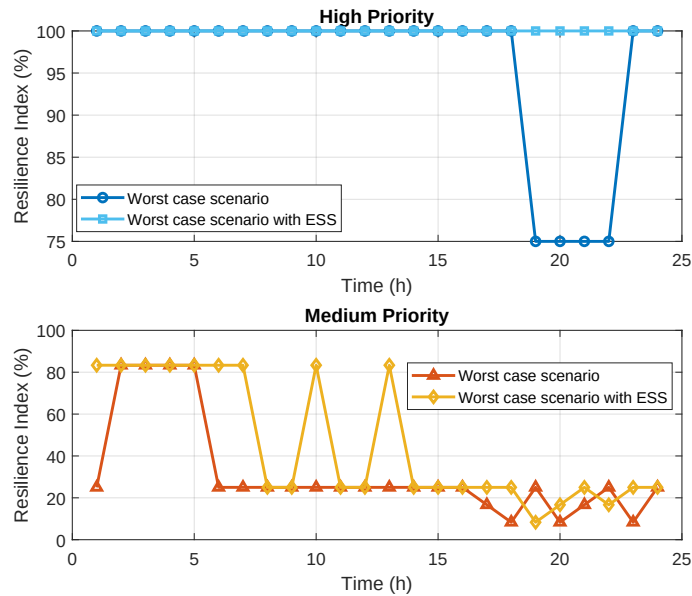


Figure 5.15: RI for the high and medium priority buses of the modified IEEE 33-bus system

As observed and talked about, the RI for the high priority buses is optimal since the bus that wasn't supplied is now supplied. This means that the resilience is unitary, 100%. On the other hand, the RI for the medium priority buses is quite peculiar because of the noticeable pattern both cases follow with cycles of improvements and declines throughout the mid-day for the ESS implementation, and the same patterns for both scenarios in the evening.

5.2 IEEE 69-bus system

In this case, the results from the standard DC operation were validated to enable subsequent modifications of the model for simulating the selected and controlled HILP event, with or without ESS implementation.

5.2.1 IEEE 69-bus system Normal operation

The single line diagram of the network under study is illustrated in Figure 5.16. If the network is in its base case, there is no distributed generation and no DERs in the network. The total active and reactive power demands are 3.80219 MW and 2.6946 MVar, respectively.

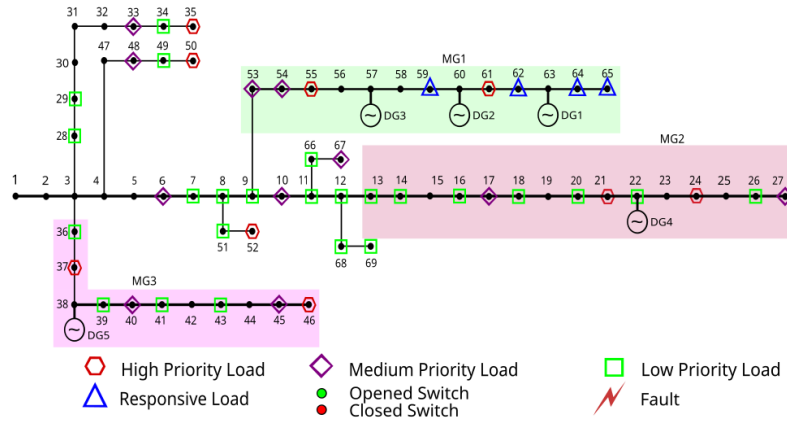


Figure 5.16: IEEE 69-bus system on normal Operation

For the base case, the minimum voltage is 0.909 pu at bus 65 and the reference bus is bus 1 which the reference voltage is fixed to 1.0 pu and the bus angle to 0.

Regarding bus priority, bus priority is not considered in the base case, as it assumes full load supply a priori. However, there are 9 buses with high priority (bus 21, 24, 35, 37, 46, 50, 52, 55, 61), 11 medium priority (bus 6, 10, 17, 27, 33, 40, 45, 48, 53, 54, 67) and 24 low priority buses.

Just like the analysis done on the 33-bus system, this case study was also validated with the same three validation steps. For the second validation method, the system changed its topology to a topology seen in Figure 5.17a. Additionally, the system changed its topology for the final validation with the topology seen in Figure 5.17b.

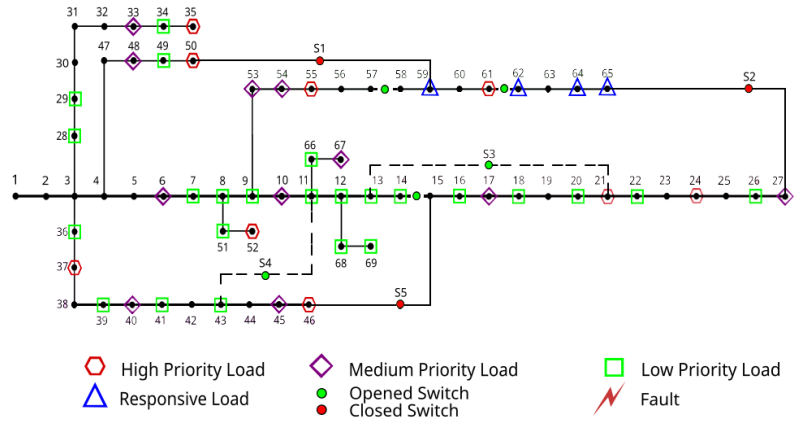
Regarding the results of the active power generation and power loss, they can be seen from Table 5.11.

Table 5.11: Generator output and power loss for the normal, reconfiguration, and reconfiguration with DGs topologies of the 69-bus system.

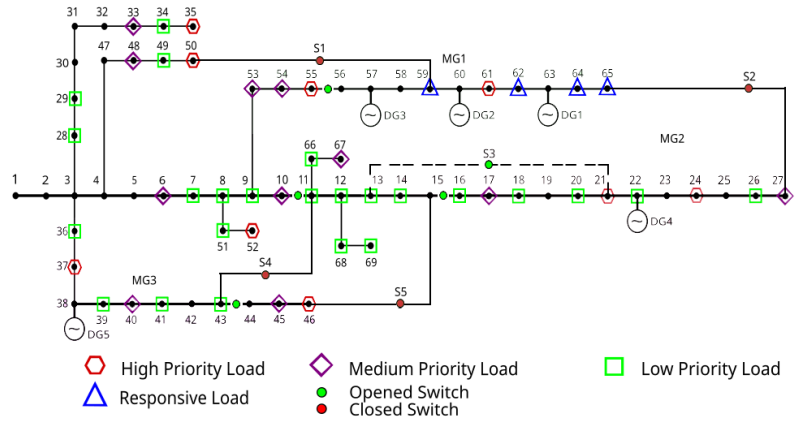
	Normal Operation	Reconfiguration	Reconfiguration with DGs
Power Loss (kW)	224.993	98.619	28.93
Utility (kW)	4027.183	3900.808	34669.72
DG1 (kW)	-	-	18522.62
DG2 (kW)	-	-	12596.40
DG3 (kW)	-	-	3014.758
DG4 (kW)	-	-	2683.1477
DG5 (kW)	-	-	1175.2053

With each validation method, the power loss of the system was substantially reduced. According to the same reference used for validating the IEEE 33-bus system, the power loss for normal operation is 224.993 kW, and for the reconfigured topology, it is 98.616 kW.

When comparing these results with those obtained in this work, they are found to be very similar. The normal topology shows a 0.15% increase and an increase of 0.05% for the reconfigured topology. These differences are minimal and could be attributed to the solver or numerical precision of the program used to compute the topology. Therefore, it is reasonable to conclude that the results are accurate and effectively validated.



(a) Modified IEEE 69-bus system on normal Operation with reconfiguration



(b) Modified IEEE 69-bus system on normal Operation with reconfiguration and DGs

Figure 5.17: Comparison of the modified IEEE 69-bus system under different operational scenarios.

5.2.2 Modified IEEE 69-bus system

The single line diagram of the modified network is illustrated on Figure 5.18. In the modified network, there are three dispatchable DGs: DG1, DG2 and DG3 with the installed capacity of 1130 kVA, 150 kVA and 70 kVA. In addition to the dispatchable units, a 700 kVA wind turbine and a photovoltaic PV unit with a capacity of 700 kVA have been installed at buses 60 and 57, respectively. The renewables units have a unitary power factor.

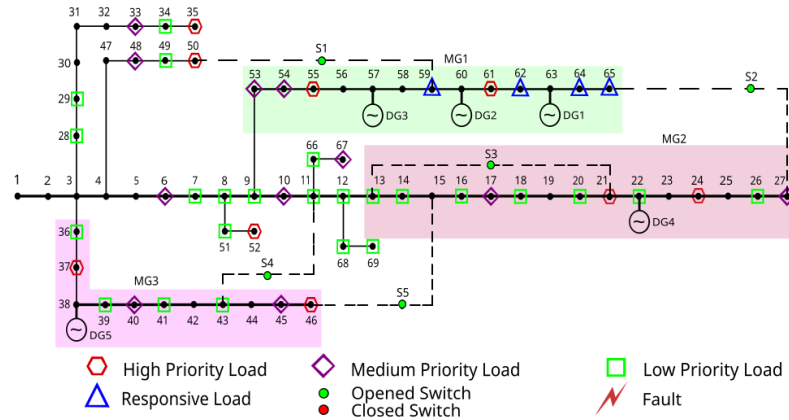


Figure 5.18: Modified IEEE 69-bus system with DGs

To facilitate clearer and more convenient interpretation of the data, Table 5.12 presents all the characteristics of the DGs, along with the microgrid to which each one is currently assigned.

Table 5.12: DGs' Data in the modified IEEE 69-bus system

Generator	Microgrid	Bus	Q^{Max} (kVAr)	S^{Max} (kVA)	c_i (\$/kWh)	Type	Slack Possibility
Utility	-	1	-	-	-	Substation	Yes
DG1	MG1	63	800	1130	0.005	Thermal	No
DG2	MG1	60	200	700	0.005	Wind	No
DG3	MG1	57	0	700	0.005	PV	Yes
DG4	MG2	22	100	150	0.005	Thermal	Yes
DG5	MG3	38	50	70	0.005	Thermal	Yes

5.2.2.1 Active and Reactive Load Profile

Since the model operates on a multi-temporal level, the loads characterizing the 69-bus system differ from each timestamp, just like the previous case study. However, in this system the load profile was not extracted from real data but was built from the ground up using randomized data. In this regard, Figure 5.19 allows for a close look on the multi-temporal load profile of the network.

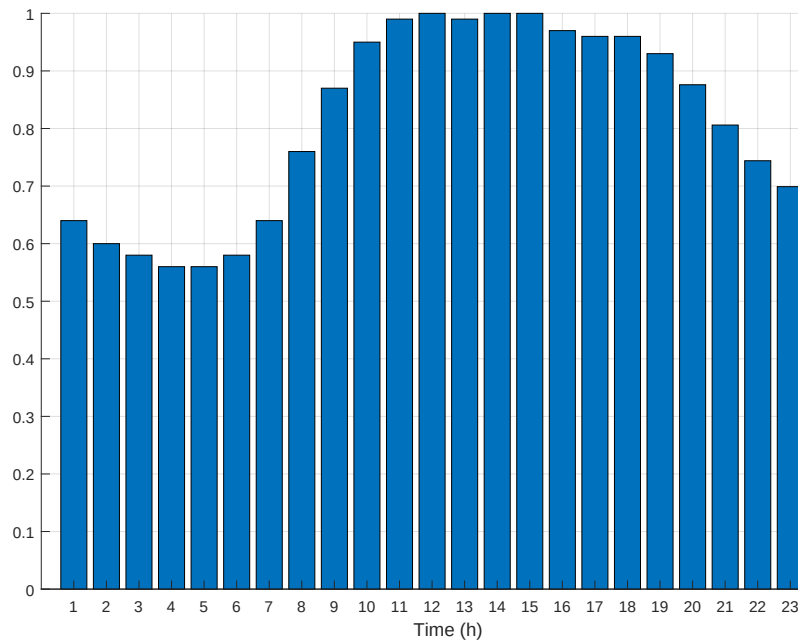


Figure 5.19: Load Profile for 69-bus case

The same explanation of PV and wind power generation profile is also correct for this case study. Both these cases, IEEE 33-bus system and IEEE 69-bus system, can be seen as being modelled by seasonal schedules - the summer and winter. Figure 5.20 allows a close look values.

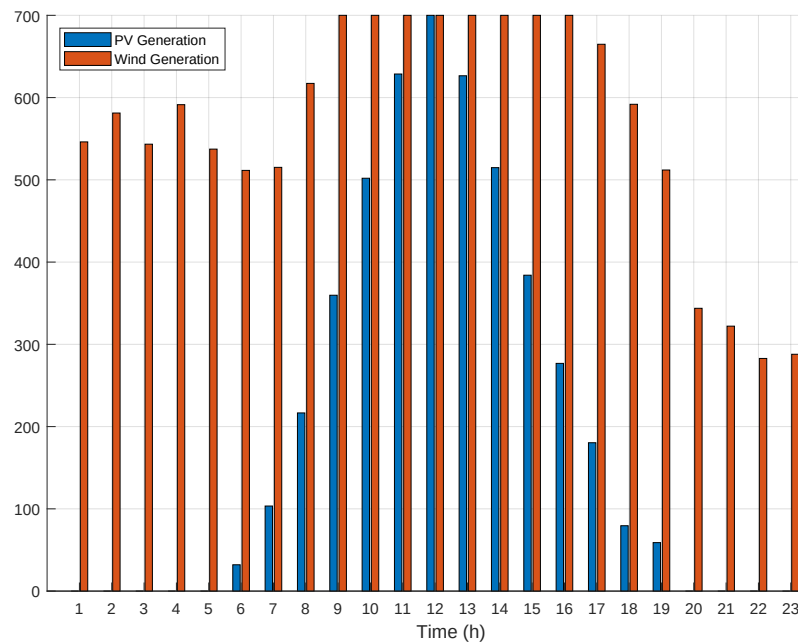


Figure 5.20: PV and Wind load Profile for 69-bus case

In the IEEE 33-bus system, the data shows a less use of power around early in the morning and

late in the evening, which typically aligns when people leave their houses and go do summer activities. Looking at the 69-bus side, almost every day has a high usage ratio which can correspond to more indoors presence.

5.2.2.2 DR Program Allocation

There are three microgrids in this modified distribution system, one privately owned (MG1) and the other two publicly owned (MG2 and MG3). The privately owned microgrid includes three DGs, and the publicly owned contains two DG each, as it can be seen on Figure 5.18.

Additionally, the private microgrid accounts for thirteen buses: five low-priority, two medium-priority, and two high-priority buses. Accumulatively, the public microgrids account for twenty-six buses: eighteen low-priority and four high-priority.

5.2.2.3 Monte-Carlo simulation cases

The same conditions of the IEEE 33-bus system for the Monte-Carlo simulations are still effective for the IEEE 69-bus system. In total, 1000 Monte-Carlo cases were simulated. However, due to the specific focus on the outage of line 01 and the removal of duplicate scenarios, only 6 unique cases met the criteria for analysis. The table 5.13 summarizes the out of service lines.

Table 5.13: Scenarios for the simulation of the modified IEEE 69-bus system

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
Disconnected Lines	01, 14, 20, 40, 41, 60	01, 64	01, 08, 52, 63	01, 13, 65	01, 49
Total Disconnected Lines	6	2	4	3	2
ENS (kWh)	33608.398	33447.845	33316.304	33267.583	33269.531

Analyzing the results from the previous table, the scenario 1 performed the worst among all the options and had the highest ENS. Scenario 1 exhibited the poorest performance among all options, recording the highest ENS value. In contrast, all of the scenarios had ENS values pretty close to each other with scenario 4 being the best of them all.

5.2.2.4 Most Critical HILP Analysis

Since the scenario 1 is objectively the worst, the single line diagram of that resulting network is illustrated in Figure 5.21.

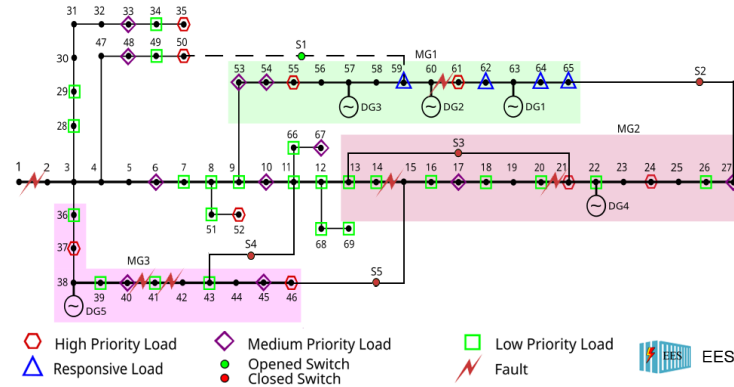


Figure 5.21: IEEE 69-bus system operating based on scenario 1

With the network configuration under Scenario 1 illustrated, the attention can now be turned to discussing its results, more specifically: DG's generation, DR status, created islands, active loads, ENS, load profile for a certain bus and RI analysis.

The generation from the thermal and renewable generators, can be seen on Table 5.14. This table provides an overview of the active output where each entry represents a distinct generator unit.

DG1, DG4 and DG5, being thermal units, show average stable active power outputs on certain times of the day. DG1 has the highest maximum power outputs for thermal units, with DG2 reaching close on power output compared to DG1.

Comparing the three thermal units, their generation patterns are very similar. Since they are thermal units their generation isn't very dynamic as their output is constant and almost uniform. From these three units, DG1 is clearly the one who is supporting the most share of generation for the network while DG5 is only responsible for the rest of the support since it has the overall lowest generation of all five units. This behavior was seen in the last network, 33 bus network.

In contrast, the renewable generators display more variable and dynamic output profiles. The photovoltaic generator output clearly shows a solar generation pattern, ramping up sharply in the early morning, peaking around noon and declining towards the evening, consistent with the data from Figure 5.5 and covering the loss of generation of DG1 because of this increase generation of solar energy. The wind generator shows significant fluctuations throughout the day, reflecting the unpredictability of wind conditions.

This behavior is clearly illustrated in Figure 5.22, which shows the time evolution of the generation levels for all units.

Upon detection of the disturbance on the system, the private microgrid activated the DR protocols to curtail eligible loads. The curtailment occurred during some hours of the time sample, as it can be seen on Table 5.15.

Approximately 57% of the private microgrid load was classified as curtailable, while approximately 43% of the load was supplied.

All buses display clear supply and curtailment patterns, where some of them are displayed simultaneously and others aren't. We can make three parts while looking at the results from the

Table 5.14: Active generation Output for the Modified IEEE 69-bus system

Time	DG1 (kW)	DG2 (kW)	DG3 (kW)	DG4 (kW)	DG5 (kW)
01	798.0494	523.3583	0	111.7979	48.98431
02	798.0123	556.9975	0	111.7784	48.96496
03	798.0475	520.7026	0	111.7969	48.98335
04	797.9814	566.7352	0	111.762	48.9487
05	798.0392	514.9485	0	111.7926	48.97905
06	798.0163	490.1617	32.00134	111.7805	48.96706
07	798.0326	493.7027	103.4241	111.7891	48.9756
08	798.051	591.522	216.6116	111.7988	48.98516
09	798.0444	670.8204	359.7039	111.7954	48.98177
10	798.058	670.8204	501.9449	111.8022	48.98862
11	798.0439	670.8204	628.6618	111.7951	48.9815
12	798.0037	670.8204	700	111.7739	48.96043
13	798.0487	670.8204	626.5205	111.7976	48.98397
14	798.0566	670.8204	514.8189	111.8016	48.988
15	798.0415	670.8204	384.0664	111.7941	48.9806
16	798.0551	670.8204	276.8568	111.8009	48.98726
17	797.8964	637.112	180.3694	111.7233	48.9085
18	798.0417	567.1778	79.47735	111.7942	48.98064
19	797.9762	490.6043	58.9273	111.7611	48.94746
20	797.9803	329.4901	0	111.7628	48.94929
21	797.9802	308.6869	0	111.7629	48.94932
22	797.9041	271.0641	0	111.7249	48.91148
23	797.9677	275.933	0	111.7569	48.94312
24	798.0522	319.7525	0	111.7994	48.98583
Total	19152.38	12824.51	4663.384	2682.742	1175.216

tables. The first part is when there is a full curtailment in at least one of the buses, the second part is when there is a full power supply to at least one of the buses and the third and final part is when there is a partial power supply for at least one of the buses.

We can see the first part in all buses but it's predominantly located on bus 59 and 64. Both buses are initially fully curtailed and spend most of their hours until the 15th hour fully curtailed, with only the exception of bus 59 when it was supplied fully followed by partially. After the first part, there is a clear distinction between both these buses. Bus 59 is clustered with curtailment and a few hours of supply, while bus 64 is always supplied either partially or fully.

Changing the scope for other buses, bus 62 and 65 start off the same. Both are fully supplied for at least the first three hours but that's where they take a divergent turn. For the most part, bus 62 is supplied either partially or fully, except for 5 hours where it was fully curtailed. Bus 65 on the other hand is always tore up on the supply, being fully curtailed and then fully supplied.

The system demonstrated similar capabilities of the last case, 33-bus with no ESS implementation. Although, these DR blocks consists of low priority buses, some of the buses posses a somewhat high percentage of hours supplied. This does not indicate that the system is choosing to

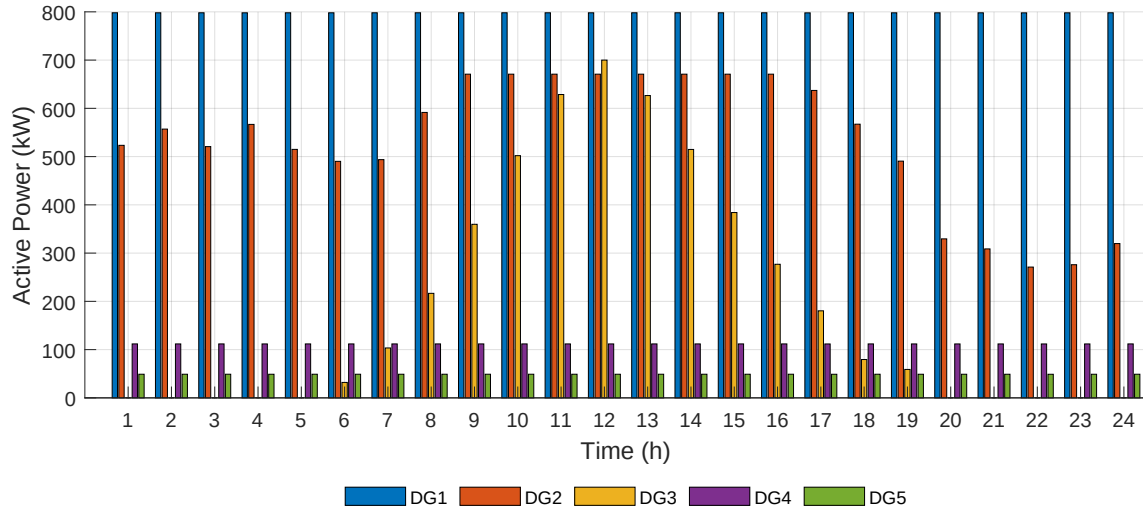


Figure 5.22: Active generation Output for IEEE 69-bus case modified

supply low priority buses over medium or even high priority buses, it just shows how these buses benefit from having buses with active generation close to them.

On the topic of islands, the network under Scenario 1 successfully islanded into two autonomous islands, as depicted in the single-line diagram (Figure 5.23). Since the occurrence of faults forced the grid into island mode, it is reasonable to conclude that the formation of these two islands dates back to the first hour of the timescale.

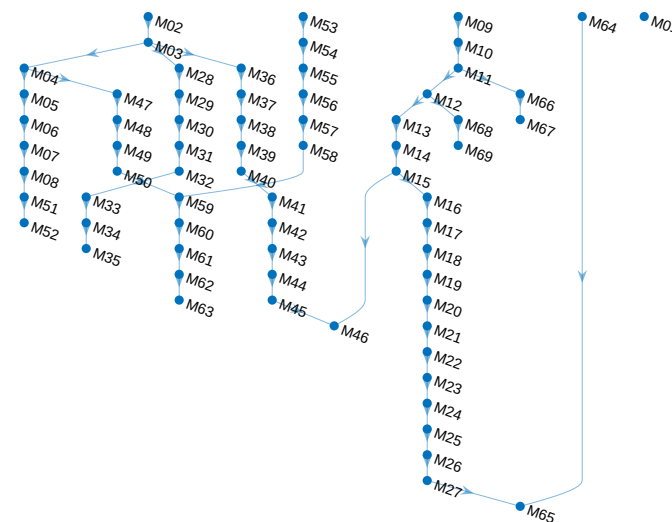


Figure 5.23: Modified IEEE 69-bus system operating based on scenario 1 connectivity

Table 5.15: DR loads status during the modified IEEE 69-bus system

Time	Bus 59	Bus 62	Bus 64	Bus 65
1	(0,0,0,0)	(1,1,1,1)	(0,0,0,0)	(1,1,1,1)
2	(0,0,0,0)	(1,1,1,1)	(0,0,0,0)	(1,1,1,1)
3	(0,0,0,0)	(1,1,1,1)	(0,0,0,0)	(1,1,1,1)
4	(1,1,1,1)	(1,1,1,1)	(0,0,0,0)	(1,1,0,0)
5	(1,0,0,0)	(1,1,1,1)	(0,0,0,0)	(1,0,0,0)
6	(1,1,1,1)	(1,1,1,1)	(0,0,0,0)	(1,0,0,0)
7	(0,0,0,0)	(1,1,1,1)	(0,0,0,0)	(1,0,0,0)
8	(0,0,0,0)	(1,1,1,1)	(0,0,0,0)	(1,0,0,0)
9	(0,0,0,0)	(1,1,1,1)	(0,0,0,0)	(0,0,0,0)
10	(0,0,0,0)	(1,0,0,0)	(0,0,0,0)	(0,0,0,0)
11	(0,0,0,0)	(1,1,1,1)	(0,0,0,0)	(0,0,0,0)
12	(0,0,0,0)	(1,1,1,1)	(0,0,0,0)	(0,0,0,0)
13	(0,0,0,0)	(1,1,1,1)	(0,0,0,0)	(0,0,0,0)
14	(0,0,0,0)	(0,0,0,0)	(0,0,0,0)	(0,0,0,0)
15	(0,0,0,0)	(0,0,0,0)	(0,0,0,0)	(0,0,0,0)
16	(1,1,1,1)	(1,1,1,1)	(1,1,1,1)	(1,1,1,1)
17	(0,0,0,0)	(1,1,1,1)	(1,1,1,1)	(0,0,0,0)
18	(1,1,1,1)	(0,1,1,1)	(1,1,1,1)	(1,1,1,1)
19	(0,0,0,0)	(1,0,0,0)	(1,1,1,1)	(0,0,0,0)
20	(0,0,0,0)	(1,1,1,1)	(1,1,1,1)	(1,1,1,1)
21	(0,0,0,0)	(1,1,1,1)	(1,1,1,1)	(1,1,1,1)
22	(1,1,1,1)	(0,1,1,1)	(1,0,0,0)	(1,1,1,1)
23	(0,0,0,0)	(0,0,0,0)	(1,1,1,1)	(0,0,0,0)
24	(0,0,0,0)	(0,0,0,0)	(1,1,1,1)	(0,0,0,0)

The localization of the initial line's fault play a crucial part on determining the islands. Nevertheless, the fault on the lines resulted on the creation of two islands right at the first hour.

- Island 1: Island comprehended by the substation with no other buses connected to it.
- Island 2: A big island where all of the buses are part of it.

The final ENS and the availability of the buses for this scenario can be seen from Table 5.16. The total energy supplied to the entire system equals to 39982.20 kWh accumulated over 24 hours, having an average of 11.94 hours with buses of various priorities supplied. On the other hand, the total ENS for the entire system equals to 33434.29 kWh accumulated over 24 hours, having an average of 5.84 hours with buses of various priorities not supplied.

Table 5.16: Unsupplied and Supplied Loads During modified IEEE 69-bus system

Bus	Priority	Unsupplied Load (kWh)	Unsupplied Duration (h)	Supplied Load (kWh)	Supplied Duration (h)
02	-	0	0	0	0
03	-	0	0	0	0
04	-	0	0	0	0
05	-	0	0	0	0
06	Medium	7.15	3	43.0534	21
07	Low	573.3972	17	206.6864	7
08	Low	1252.275	21	195.9	3
09	Low	402.3	16	176.97	8
10	Medium	27.16	1	513.492	23
11	Low	2799.805	24	0	0
12	Low	2799.805	24	0	0
13	Low	36.432	5	118.04	19
14	Low	36.832	5	117.64	19
15	-	0	0	0	0
16	Low	726.908	20	151.6515	4
17	Medium	214.44	4	944.1	20
18	Low	1056.3	22	102.24	2
19	-	0	0	0	0
20	Low	0.96	1	18.349	23
21	High	0	0	2201.226	24
22	Low	19.1542	4	83.1835	20
23	-	0	0	0	0
24	High	0	0	540.652	24
25	-	0	0	0	0
26	Low	108.416	9	161.91	15
27	Medium	0	0	270.326	24
28	Low	294.684	13	207.35	11
29	Low	296.764	13	205.27	11
30	-	0	0	0	0
31	-	0	0	0	0
32	-	0	0	0	0
33	Medium	0	0	270.326	24
34	Low	143.988	8	232.5375	16
35	High	0	0	115.854	24

* Unsupplied and Supplied duration hours are averages.

Table 5.16: Unsupplied and Supplied Loads During modified IEEE 69-bus system

Bus	Priority	Unsupplied Load (kWh)	Unsupplied Duration (h)	Supplied Load (kWh)	Supplied Duration (h)
36	Low	280.124	12	221.91	12
37	High	0	0	502.034	24
38	-	0	0	0	0
39	Low	307.344	15	156.072	9
40	Medium	38.736	2	424.68	22
41	Low	1.2	1	21.9708	23
42	-	0	0	0	0
43	Low	27.444	5	88.41	19
44	-	0	0	0	0
45	Medium	141.7411	4	615.5579	20
46	High	0	0	757.299	24
47	-	0	0	0	0
48	Medium	282.346	4	1243.065	20
49	Low	7428.172	24	0	0
50	High	369.312	1	7058.86	23
51	Low	591.705	18	190.3095	6
52	High	0	0	69.5124	24
53	Medium	8.526	2	75.46815	22
54	Medium	0	0	509.7576	24
55	High	0	0	463.416	24
56	-	0	0	0	0
57	-	0	0	0	0
58	-	0	0	0	0
59	Low	1317.242	16	613.6581	24
60	-	0	0	0	0
61	High	6238.66	6	17781.74	18
62	Low	154.2547	6	463.6333	24
63	-	0	0	0	0
64	Low	4005.89	22	377.2526	24
65	Low	635.5356	13	503.6954	24
66	Low	128.772	8	218.79	16
67	Medium	0	0	347.562	24
68	Low	319.592	13	221.06	11
69	Low	360.92	15	179.732	9

* Unsupplied and Supplied duration hours are averages.

Table 5.16: Unsupplied and Supplied Loads During modified IEEE 69-bus system

Bus	Priority	Unsupplied Load (kWh)	Unsupplied Duration (h)	Supplied Load (kWh)	Supplied Duration (h)
Total*		33434.29	5.84	39982.20	11.94

* Unsupplied and Supplied duration hours are averages.

Regarding the high priority buses, only bus 61 and 50 were not entirely supplied with an intermittent outage of either 6 or 1 hour.

The medium priority buses had somewhat similar results, with 7 buses not supplied in their entirety with the rest medium priority buses, experiencing full supply.

Among the remaining buses, no bus was fully supplied. These results still validate the priority given to all loads and their ranking in the power distribution hierarchy.

5.2.3 Modified IEEE 69-bus system with ESS

Following the analysis of the previous simulation results, the presented data highlights instances where the existing grid configuration proves insufficient in reliably meeting the demand at specific load points over 24 hours.

To address these deficiencies, an evaluation of the current grid topology must be done and to do so it's needed to identify buses with high or medium priority levels which are susceptible to supply-demand imbalance.

According to Table 5.16, bus 61, one of the two high priority bus that was not fully supplied, has both a high unsupplied duration and load. With that motion, bus 50, the other high priority bus not fully supplied has only 1 hour of load interruption. For the medium priority buses, bus 17, despite having a low unsupplied load and duration, may also warrant attention due to their priority status. Therefore, these three buses are considered suitable candidates for ESS deployment.

Figure 5.24 presents the buses with ESS implementation and the microgrids to which they are currently assigned.

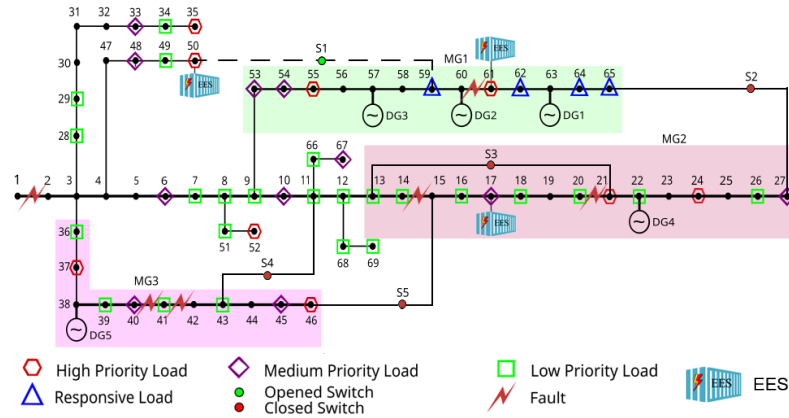


Figure 5.24: Modified IEEE 69-bus system operating with ESS

Meanwhile, Table 5.17 presents the characteristics of the ESS alongside what bus they are connected to.

Table 5.17: ESS placement and characteristics of the modified IEEE 69-bus system

Storage Unit	Bus	P_{max}^{Chr} (kW)	P_{max}^{Dchr} (kW)	E^{max} (kWh)	E^{min} (kWh)	η_{max}^{Chr}	η_{max}^{Dchr}	E_0 (kWh)
1	61	900	1100	1493	149.3	0.9	0.9	746.5
2	50	360	380	400	9.5	0.9	0.9	200
3	17	410	430	450	7.2	0.9	0.9	225

The generation from the thermal and renewable generators, can be seen on Table 5.18. This table provides an overview of the active output where each entry represents a distinct generator unit.

With the implementation of the ESS, DG1, DG4 and DG5 continued to show average stable active power outputs. This result is very similar to the result seen on the other analyzed network as the thermal units are the constant power generation and the other DGs, DG2 and DG3 are renewable units with dynamic generation and help to supply more local loads.

Analyzing the thermals unit's generation patterns more closely, DG4 and DG5 remained generators with the low output, but its production is still stabilized, showing no significant increase or increase due to their residual improvements or retrogression numbers. As for the renewable's generators, they still display more variable and dynamic output profiles.

To conclude, the overall evolution in generation, as it can be seen in Figure 5.11, is a direct result of the ESS impact, as it was concluded when the IEEE 33-bus system was being analyzed. By injecting active power into the network, the ESS manages to supply more critical loads and helps to prevent them by being curtailed.

Just as it was done previously and on the IEEE 33-bus system, upon detection of the disturbance on the system, the private microgrid activated the DR protocols to curtail eligible loads. The curtailment occurred during some hours of the time sample, as it can be seen on Table 5.19.

Table 5.18: Active generation Output for the modified IEEE 69-bus system with ESS

Time	DG1 (kW)	DG2 (kW)	DG3 (kW)	DG4 (kW)	DG5 (kW)
01	795.9543	546.1236	0	109.7546	46.40859
02	798.0592	581.226	0	111.8025	48.98888
03	798.0592	543.3523	0	111.8025	48.98888
04	798.0592	591.3873	0	111.8025	48.98888
05	798.0592	537.3479	0	111.8025	48.98888
06	798.0592	511.483	32.00134	111.8025	48.98888
07	798.0592	515.178	103.4241	111.8025	48.98888
08	798.0593	617.2523	216.6116	111.8025	48.98888
09	798.0593	700	359.7039	111.8025	48.98888
10	798.0593	700	501.9449	111.8025	48.98888
11	798.0593	700	628.6618	111.8025	48.98888
12	798.0593	700	700	111.8025	48.98888
13	798.0593	700	626.5205	111.8025	48.98888
14	798.0594	700	514.8189	111.8026	48.98903
15	798.0594	700	384.0664	111.8027	48.98904
16	798.0594	700	276.8568	111.8027	48.98905
17	798.0592	664.8254	180.3694	111.8025	48.98888
18	798.0594	591.8492	79.47735	111.8027	48.98907
19	798.0592	511.9448	58.9273	111.8025	48.9889
20	798.0594	343.8224	0	111.8027	48.98907
21	798.0594	322.1143	0	111.8027	48.98907
22	798.0594	282.855	0	111.8027	48.98907
23	798.0594	287.9356	0	111.8027	48.98907
24	798.0594	333.6612	0	111.8027	48.98907
Total	19151.32	13382.36	4663.384	2681.214	1173.154

Approximately 82% of the private microgrid load was classified as curtailable, while approximately 18% of the load was supplied. When compared to the topology without ESS implementation, the changes observed were visible. Curtailment was increased by 39%, resulting in a corresponding 39% decrease in supplied load.

Comparing these results with the modified IEEE 33 bus network, there are some resemblances and very similar conclusions.

We can still divide the DR status into two different parts. The first part corresponds to buses with full curtailment, and the second part corresponds to buses with partial curtailment or even full load supply.

Bus 59 and bus 64 were fully curtailed all day, corresponding to the first part of the analysis. The second part is oriented to bus 62 and bus 65.

Bus 62 was supplied until the 13th hour, where in those hours the supply was predominantly in its fullest. After the 13th hour, this bus was fully curtailed except for the 17th hour, where it was fully supply, making this the only bus receiving energy after a full curtailment. This supply is not random. Bus 62 is located near the end of the feeder and right next to the ESS unit, meaning this

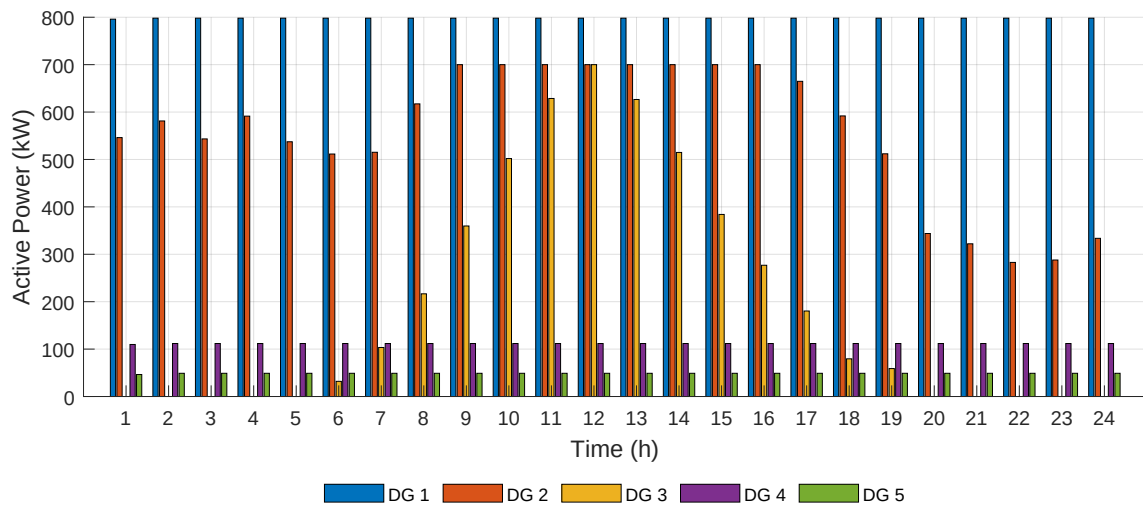


Figure 5.25: Active generation output for 69-bus case modified with ESS

is the first bus receiving energy if there is any available.

Lastly, bus 65 was very similar to Bus 62's operational pattern but with shifting hours. Firstly, this bus starts fully curtailed for the first 2 hours, only then receiving supply. However, after this supply of 4 hours ends, it never receives any again, ending fully curtailed until the end of the day.

These changes compared to the scenario without ESS integration are result of the system redirecting energy for higher priority buses with load's demand. This conclusion on the analysis of the DR blocks, is almost the same as the conclusion reached on the 33-bus system. The system, with the added generation from the ESS, was able to redirect some energy to otherwise higher priority buses and the curtailment for these DR buses increased.

The final ENS and the availability of the buses for this scenario can be seen from Table 5.20.

Table 5.20: Unsupplied and Supplied Loads During the modified IEEE 69-bus system with ESS

Bus	Priority	Unsupplied Load (kWh)	Unsupplied Duration (h)	Supplied Load (kWh)	Supplied Duration (h)
02	-	0	0	0	0
03	-	0	0	0	0
04	-	0	0	0	0
05	-	0	0	0	0
06	Medium	0	0	50.2034	24
07	Low	754.2276	23	25.856	1
08	Low	1400.175	23	48	1
09	Low	560.07	23	19.2	1
10	Medium	0	0	540.652	24

* Unsupplied and Supplied duration hours are averages.

Table 5.20: Unsupplied and Supplied Loads During the modified IEEE 69-bus system with ESS

Bus	Priority	Unsupplied Load (kWh)	Unsupplied Duration (h)	Supplied Load (kWh)	Supplied Duration (h)
11	Low	2707.005	23	92.8	1
12	Low	2707.005	23	92.8	1
13	Low	30.152	5	124.32	19
14	Low	30.152	5	124.32	19
15	-	0	0	0	0
16	Low	849.4395	23	29.12	1
17	Medium	0	0	1158.54	24
18	Low	1120.14	23	38.4	1
19	-	0	0	0	0
20	Low	0	0	19.309	24
21	High	0	0	2201.226	24
22	Low	4.6428	1	97.6949	23
23	-	0	0	0	0
24	High	0	0	540.652	24
25	-	0	0	0	0
26	Low	189.266	15	81.06	9
27	Medium	0	0	270.326	24
28	Low	485.394	23	16.64	1
29	Low	485.394	23	16.64	1
30	-	0	0	0	0
31	-	0	0	0	0
32	-	0	0	0	0
33	Medium	0	0	270.326	24
34	Low	295.4055	17	81.12	7
35	High	0	0	115.854	24
36	Low	485.394	23	16.64	1
37	High	0	0	502.034	24
38	-	0	0	0	0
39	Low	421.176	21	42.24	3
40	Medium	0	0	463.416	24
41	Low	23.1708	24	0	0
42	-	0	0	0	0
43	Low	14.556	3	101.298	21
44	-	0	0	0	0

* Unsupplied and Supplied duration hours are averages.

Table 5.20: Unsupplied and Supplied Loads During the modified IEEE 69-bus system with ESS

Bus	Priority	Unsupplied Load (kWh)	Unsupplied Duration (h)	Supplied Load (kWh)	Supplied Duration (h)
45	Medium	0	0	757.299	24
46	High	0	0	757.299	24
47	-	0	0	0	0
48	Medium	0	0	1525.411	24
49	Low	7181.964	23	246.208	1
50	High	0	0	7428.172	24
51	Low	756.0945	23	25.92	1
52	High	0	0	69.5124	24
53	Medium	0	0	83.99415	24
54	Medium	0	0	509.7576	24
55	High	0	0	463.416	24
56	-	0	0	0	0
57	-	0	0	0	0
58	-	0	0	0	0
59	Low	1866.879	23	64.02121	24
60	-	0	0	0	0
61	High	2351.16	2	21669.24	22
62	Low	298.9197	11	318.9683	24
63	-	0	0	0	0
64	Low	4237.844	23	145.299	24
65	Low	966.9356	19	172.2954	24
66	Low	272.682	17	74.88	7
67	Medium	0	0	347.562	24
68	Low	522.732	23	17.92	1
69	Low	522.732	23	17.92	1
Total*		31540.71	7.47	41875.78	10.59

* Unsupplied and Supplied duration hours are averages.

The total energy supplied to the entire system equals to 41875.78 kWh accumulated over 24 hours, having an average of 10.59 hours with buses of various priorities supplied. On the other hand, the total ENS for the entire system equals to 31540.71 kWh accumulated over 24 hours, having an average of 7.47 hours with buses of various priorities not supplied. Compared to the previous results, there was an increase in both the average duration of total supply and the average

Table 5.19: DR loads status during the modified IEEE 69-bus system with ESS

Time	Bus 59	Bus 62	Bus 64	Bus 65
1	(0,0,0,0)	(1,1,1,1)	(0,0,0,0)	(0,0,0,0)
2	(0,0,0,0)	(1,1,1,1)	(0,0,0,0)	(0,0,0,0)
3	(0,0,0,0)	(1,1,1,1)	(0,0,0,0)	(1,1,1,1)
4	(0,0,0,0)	(1,1,1,1)	(0,0,0,0)	(1,1,1,1)
5	(0,0,0,0)	(1,1,1,1)	(0,0,0,0)	(1,1,1,1)
6	(0,0,0,0)	(1,1,1,1)	(0,0,0,0)	(1,1,1,1)
7	(0,0,0,0)	(1,1,1,1)	(0,0,0,0)	(0,0,0,0)
8	(0,0,0,0)	(1,1,1,1)	(0,0,0,0)	(0,0,0,0)
9	(0,0,0,0)	(1,1,1,1)	(0,0,0,0)	(0,0,0,0)
10	(0,0,0,0)	(1,0,0,0)	(0,0,0,0)	(0,0,0,0)
11	(0,0,0,0)	(1,1,1,1)	(0,0,0,0)	(0,0,0,0)
12	(0,0,0,0)	(1,1,1,1)	(0,0,0,0)	(0,0,0,0)
13	(0,0,0,0)	(1,1,1,1)	(0,0,0,0)	(0,0,0,0)
14	(0,0,0,0)	(0,0,0,0)	(0,0,0,0)	(0,0,0,0)
15	(0,0,0,0)	(0,0,0,0)	(0,0,0,0)	(0,0,0,0)
16	(0,0,0,0)	(0,0,0,0)	(0,0,0,0)	(0,0,0,0)
17	(0,0,0,0)	(1,1,1,1)	(0,0,0,0)	(0,0,0,0)
18	(0,0,0,0)	(0,0,0,0)	(0,0,0,0)	(0,0,0,0)
19	(0,0,0,0)	(0,0,0,0)	(0,0,0,0)	(0,0,0,0)
20	(0,0,0,0)	(0,0,0,0)	(0,0,0,0)	(0,0,0,0)
21	(0,0,0,0)	(0,0,0,0)	(0,0,0,0)	(0,0,0,0)
22	(0,0,0,0)	(0,0,0,0)	(0,0,0,0)	(0,0,0,0)
23	(0,0,0,0)	(0,0,0,0)	(0,0,0,0)	(0,0,0,0)
24	(0,0,0,0)	(0,0,0,0)	(0,0,0,0)	(0,0,0,0)

duration of ENS. The average of hours may have increased but the total amount of ENS decreased, and the total of load supply increased.

Regarding the high-priority buses, there was an observable impact on their performance regarding the unsupplied duration and load. When there was no implementation of ESS, only two buses were being curtailed. However, with the implementation of ESS, one of them was fully supplied and the other had improvements in their curtailment duration.

This improvement on high priority buses was also seen on the medium-priority buses. With the implementation of ESS every medium priority bus was fully supply making the medium priority buses highly resilient.

To better understand how ESS performance varies depending on its location within a distribution, it is done an analysis examining the temporal energy profiles of these storage units, visualized in Figure 5.26.

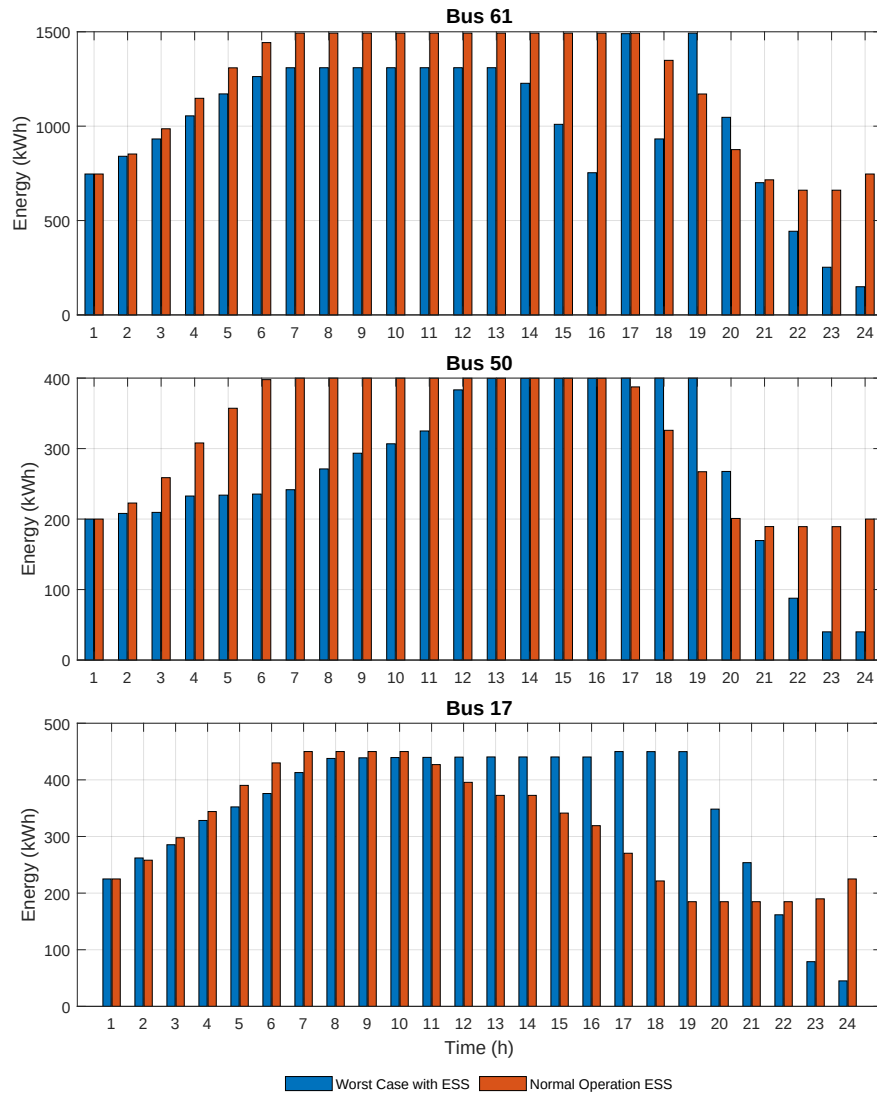


Figure 5.26: Comparison of ESS from the modified IEEE 69-bus system

The ESS located on bus 61, starting at 746.5 kWh, initially charges before stabilizing for a few hours. After this stabilization, a brief period of charge and discharge starts, stopping only for the last few hours of the day when the storage's value was at minimum. This pattern is widely different from the pattern for normal operation. On the normal operation, the ESS charges early in the day to discharge a moderate portion on the last hours of the day, ending stabilizing to coincide with the initial energy stored. In the afternoon, there's a period of stabilization.

The ESS located on bus 50, starting at 200 kWh, and initially charges slowly before stabilizing for seven hours. After this cycle there's a steep discharge, suggesting that the network has high demand late in the evening, as even the previous ESS mentioned had a steep discharge at these hours. Reaching the same conclusion as the previous ESS analysis, on normal operation, the ESS charges steadily early in the day ending stabilizing for most hours only to discharging some energy into the network so that the final energy stored could be equal to the initial energy stored.

The last ESS to be analyzed, located on bus 17 and starting at 225 kWh, has a pattern very

similar to the last ESS unit but stabilizing sooner and longer. On the other hand, on normal operation, the ESS charges steadily early in the day ending stabilizing for most hours only to steadily discharge some energy into the network so that the final energy stored could be equal to the initial energy stored.

Analyzing all ESS profiles, several supported conclusions, consistent with the findings in the modified IEEE 33-bus system, can be drawn. First, the early hours of the day reflect a somewhat low network demand, as evidenced by the consistent charge or stabilization observed across all ESS units. Second, there is a notable increase in energy demand during the late evening, indicated by either a sharp or steady discharge of the ESS profiles. Finally, during periods of normal operation, the ESS rarely needs to supply energy to the buses, since their demand is largely met by other sources, as this is reflected in the prolonged periods of energy stabilization observed across the first two ESS units.

Based on the previous results of the ENS, medium priority buses saw a decrease of ENS, therefore medium buses will be prioritized in the analysis of their load evolution. For this analysis, bus 50 was chosen as its load profile is illustrated in Figure 5.27.

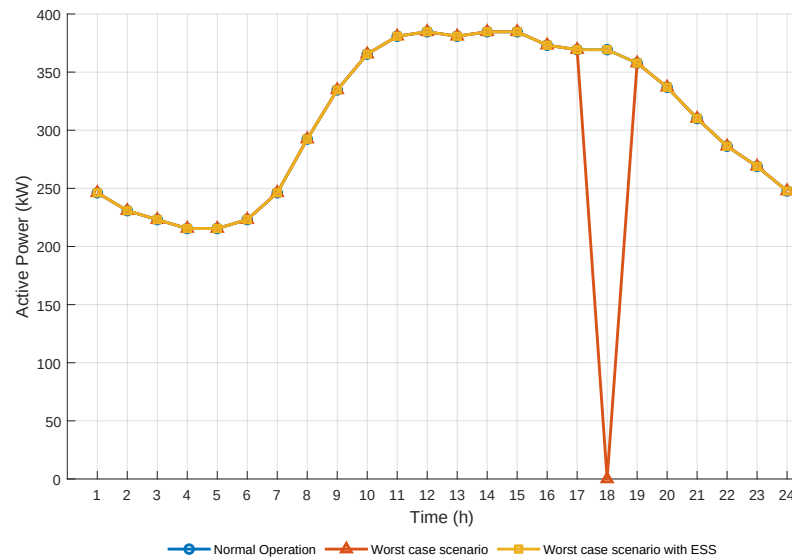


Figure 5.27: Load profile of Bus 50 for the 69-bus case system

In both scenarios of the worst case, with and without ESS implementation, the load profile for the bus 50 is the same as the normal operation topology until the 18th hour, where it needs to shed the load. With ESS implementation, this shedding is not necessary and the bus is fully supplied.

Regarding the RI in the IEEE 69-bus system, without ESS the RI values range from 37% to 70%, with an average of 55%. When ESS is implemented, the RI values improve to a range of 25% to 99%, with an average of 58%. While the improvement is notable in certain hours, it falls short of expectations, just like the modified 33 bus network. This result may lead to conclude that ESS implementation on large networks has its range limited and the characteristics play a crucial

role in order to fine tune the RI. The Figure 5.28 illustrates the RI for the modified IEEE 69-bus system.

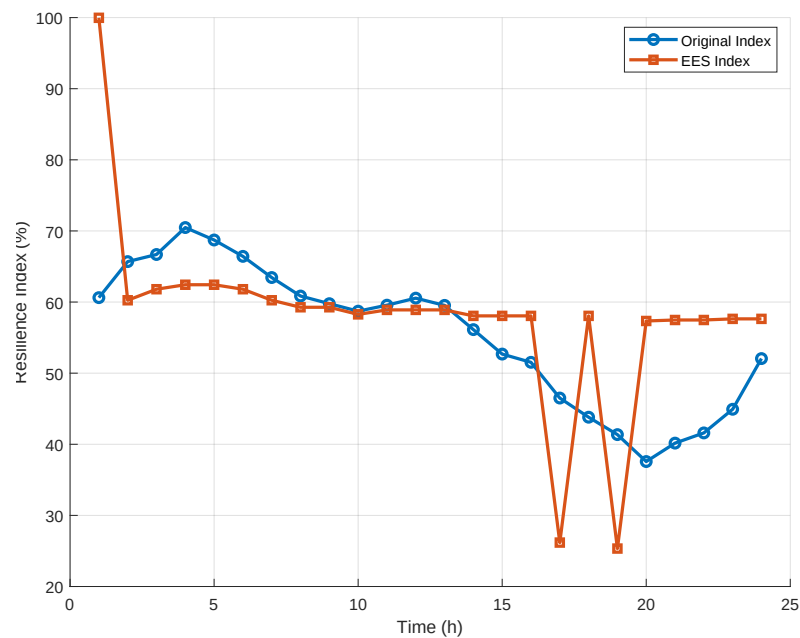


Figure 5.28: RI for the modified IEEE 69-bus system

As stated, when the analysis of the previous IEEE network was being done, an analysis of the RI from the high and medium priority buses should be done to observe if there were any improvements made when ESS is incorporated. This information can be seen in Figure 5.29.

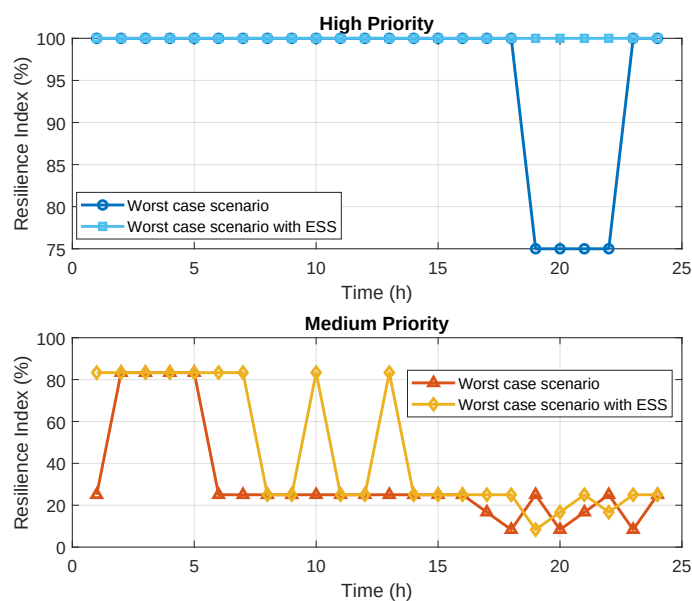


Figure 5.29: RI for the high and medium priority buses of the modified IEEE 69-bus system

As observed and talked about, the RI for the high priority buses with ESS incorporation follows the RI of the worst case for the most part. However, the incorporation of the ESS saw a higher resilience with more hours without ENS. As for the other hours where there is ENS, the resilience was the same as the resilience without ESS integration. On the other hand, the RI for the medium priority buses is optimal since with the inclusion of ESS every bus was supplied.

Chapter 6

Conclusion and Future Work

In this chapter, the study's conclusions are presented, emphasizing its contributions and interpreting the results alongside possible areas for further investigation.

6.1 Conclusion

In this dissertation, two IEEE benchmark distribution networks were modeled to perform a Multi-Temporal Optimal Power Flow, considering both real load profiles and random generated load profiles. The modelling was done in GAMS, utilizing MINLP's solver configuration to minimize ENS, while under the effects of HILP events, considering priority-based load restoration.

Both benchmark distribution networks comprise of thermal generation as well as renewable generation, with addition of energy storage in form of ESS. Furthermore, both networks have public and private microgrids with the latter having contracts with the DSO so that some buses are eligible for DR activities.

These benchmarks networks are the IEEE 33-bus and IEEE 69-bus system. The load profile of the 33-bus system is calculated from real data obtained via E-Redes's open source portal and is reflecting one month of Summer. In contrast, the load profile of the 69-bus system was obtained via random numbers and is reflecting one month of Winter.

The analysis comprises of three different steps of action. The first step is comparing both networks under normal operating conditions with the inclusion of all the integration mentioned above, while allowing the network to reconfigure itself. This reconfiguration is a pattern observed across all steps because of the use of switch-ties.

After that, the second step is an analysis of the worst-case scenario with no ESS integration, where a HILP event is considered, based on 1000 Monte-Carlos Simulations. These simulations are subjected of filtering and deduplication. The last step is the analysis of the same scenario from step two but with integration of ESS so that it's possible to measure if the implementation was a success or not.

Under normal operating conditions, network reconfiguration alone decreased losses on both systems, and the strategic sitting of DGs drove losses even further down. These results prove that

with the increase of strategically DGs, the losses of the network decreases. However, it's important to study the cost of these DGs and their ability to do a black-start, one characteristic that was felt missing when the newest Iberian Peninsula blackout.

When subjected to HILP events, five unique outage combinations in the 33 bus network and six in the 69 bus network emerged as critical. The worst scenario for the 33-bus system was found when there were outages on lines 01, 23, and 29, while on the 69-bus system, it was the combination of lines 01, 08, 52, and 63.

In each case, the faults effectively partitioned the feeders into two electrical islands, revealing the most vulnerable buses and underscoring where resilience investments are most needed. On the 33 bus network, DR covered 95% of the private microgrid load, curtailing low priority demands to preserve supply to other sections of the network, whereas on the 69 bus system DR addressed about 30% of the load with similar prioritization.

For the 33 bus network, the introduction of ESS yielded an overall decrease of ENS, due to the decrease of ENS originating from medium priority buses, even with more low priority buses being curtailed due to the lack of energy for them and based on the increase curtailment of the DR buses. Furthermore, the ENS for the high priority buses didn't change.

In contrast, in the 69 bus system, storage deployment delivered a notably greater resilience benefit, meaningfully lowering the proportion of energy left unserved during the faults.

In the 33 bus network, the addition of energy storage increased insignificantly the average RI. On the other hand, in the 69 bus network, storage raised the average RI by improving service continuity across the outage period, confirming its greater effectiveness in larger, more distributed networks.

Based on the results, the model might be viable for big distribution networks for the long run. However, it could benefit of better ESS specs closely made for each critical bus, as well as less strict constraints.

These findings provide practical guidance for system operators seeking to fortify their grids against increasingly frequent extreme events, and they highlight the importance of strategic asset sizing, prioritization, and flexibility in multi energy network planning.

6.2 Future Work

This work paves the way for several future developments including the integration of AI modelling and decision-making reducing computational burden and helping the DSO in real time. Other possible advances include optimizing the randomness of the Monte-Carlo simulation and automate the placement of the ESS.

Additionally, developing a model that accounts for all seasons of the year, not just Winter and Summer, will enable a more precise and reliable analysis.

6.3 Data and discovery repository

To promote transparency, all underlying data, key findings, and associated GAMS code developed for this research have been made publicly available. The complete dataset and code can be accessed through the following GitHub repository: <https://github.com/DiogoRamosFEUP/Thesis>.

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