



The defence system use case

Deliverable No: D6.3

Work package: WP6

Official delivery date: 30.06.2026

Actual delivery date: 24.06.2026

Dissemination level: Public



Co-funded by
the European Union

Project: 101136119 | HORIZON-CL5-2023-D3-01 | www.twineu.net

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Version	Date	Author(s)	Notes
0.1	15/03/2025	Andrea Mazza, Andrea Porcu	first draft
0.2	29/06/2025	Andrea Mazza, Andrea Porcu, Alessio Sechi	second draft
0.3	04/05/2026	Andrea Mazza, Andrea Porcu, Giorgio Benedetto	Third draft
0.4	18/05/2026	Andrea Porcu, Giorgio Benedetto, Andrea Mazza	Fourth draft
0.5	25/05/2026	Andrea Porcu, Giorgio Benedetto, Andrea Mazza	Revised version addressing comments from external reviewers
0.6	08/06/2026	Andrea Porcu, Giovanni Massa, Giorgio Benedetto, Andrea Mazza	Revised version addressing comments from external reviewers
1.0	30/06/2026	All	First submission
1.1	18/09/2026	Andrea Porcu, Daniele Porcu	Minor adjustments
2.0	30/09/2026	All	Second submission

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Approved by Project Coordinator	Padraic McKeever (Fraunhofer), 24/06/2026 (v1), 30/09/2026 (v2)

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List of Abbreviations and Acronyms

Acronym	Meaning
AC	Alternating Current
BCDLA	Branch Current Decomposition for Loss Allocation
BESS	Battery Energy Storage System
BFS	Backward Forward Sweep
CB	Circuit Breaker
CMC	OMICRON CMC 356 relay test set/amplifier
CP1	Coal-based power plant 1 (project anonymised identifier)
CP2	Coal-based power plant 2 (project anonymised identifier)
DBI	Davies–Bouldin Index
DBSCAN	Density-Based Spatial Clustering of Applications with Noise
DC	Direct Current
DER	Distributed Energy Resources
DG	Distributed Generation
DMPU	Defence and Monitoring Peripheral Unit
DSO	Distribution System Operator
DT	Digital Twin
EAC	Equilibratore Automatico di carico (Automatic Load Balancers)
EMT	Electromagnetic Transient
ENEL	Ente Nazionale per l'Energia Elettrica
Eps	Epsilon parameter / neighbourhood radius in DBSCAN
EV	Electric Vehicle
F-H	Francis turbine – Horizontal axis
FL	Flexible Load
F-V	Francis turbine – Vertical axis
GA	Genetic Algorithm
GP	Gas-turbine power plant/units (project anonymised identifier)
G-VSC	Grid-side Voltage Source Converter
HFO	Heavy Fuel Oil
HIL	Hardware in the Loop
HV	High Voltage
HVDC	High Voltage Direct Current

IGCC	Integrated Gasification Combined Cycle
KPI	Key Performance Indicator
K-V	Kaplan turbine – Vertical axis
LCC	Line-Commutated Converters
LV	Low Voltage
MDF	Maximum Frequency Difference Blocking
MinPts	Minimum number of points/samples in DBSCAN
MSQ	Maximum Voltage Unbalance
MV	Medium Voltage
NetworkX	Python library for network/graph analysis
PCC	Point of Common Coupling
P-H	Pelton turbine – Horizontal axis
PHIL	Power Hardware-in-the-Loop
PNIEC	Piano Nazionale Integrato per l'Energia e il Clima
POD	Point of Delivery
PS	Primary Substation
PV	Photovoltaic
PyGAD	Python Genetic Algorithm library
RES	Renewable Energy Sources
RMS	Root Mean Square
RTS	Real Time Simulators / Real Time Simulation
SA.CO.I.	Sardinia–Corsica–Italy
SA.PE.I.	Sardinia–Italian Peninsula
SAR.CO. / SARCO	Sardinia–Corsica
SCDM	Sistema Comandi Difesa e Monitoraggio – Command Defence and Monitoring System
scikit-learn	Python machine-learning library
SOC	State of Charge
TAR	Topping Atmospheric Residue
TP	Thermoelectric power plant
TSO	Transmission System Operator
UDP	User Datagram Protocol
UW	Unsorted Waste
VSC	Voltage Source Converter

Executive Summary

Deliverable D6.3 of the TwinEU project presents the development and validation of a Digital Twin (DT) of the Sardinian electrical system, aimed at supporting the analysis and enhancement of grid defence strategies under conditions of high renewable penetration and increasing distributed flexibility.

The work focuses on two complementary infrastructure levels:

- the Sardinian transmission network, characterized by a weak islanded structure strongly dependent on High Voltage Direct Current (HVDC) interconnections with mainland Italy;
- two representative medium-voltage distribution systems:
 - an urban network operated by Areti in the City of Rome;
 - a rural network operated by e-Distribuzione in Sardinia.

The Areti urban network of Rome was included to complement the Sardinian rural MV case with a representative distribution system typical of densely populated urban areas. Considering both urban and rural distribution networks allowed the proposed modelling and validation approach to be assessed under different grid conditions, supporting its broader applicability.

Sardinia represents a particularly relevant case study for European power system security due to its low system inertia, ongoing coal phase-out, rapid renewable energy growth, and limited transmission system meshing. Within this context, the DT was designed to evaluate the dynamic behaviour of the system under critical operating conditions, including under-frequency events, generation outages, and network congestion scenarios.

The transmission network was modelled and validated in the HYPERSIM real-time simulation environment using real Transmission System Operator (TSO) data. The simulations demonstrated strong agreement between the digital model and the actual system behaviour, both at the single-generator level and at the system level. Key dynamic indicators — including frequency nadir, overshoot, and settling time — were found to be consistent with operational reference data, confirming the suitability of the model for stability and defence system studies.

In parallel, detailed models of the distribution networks were developed and validated using real Distribution System Operator (DSO) measurements. An automated tool for generating Simulink models of radial distribution systems was also implemented, significantly reducing modelling time and complexity.

A major contribution of the work concerns the characterization of load and generation profiles through DBSCAN clustering techniques applied to large real-world datasets. The analysis included:

- residential loads;
- heat pumps;
- electric vehicle charging stations;
- photovoltaic generation.

These profiles were then used to construct realistic 2030 grid evolution scenarios.

On the planning and optimization side, a genetic algorithm framework was implemented to assess the optimal placement of distributed generation and flexible loads. Results demonstrate that optimized planning strategies can:

- reduce network losses;
- improve fairness in loss allocation;
- maintain compliance with voltage and loading constraints.

Conversely, poorly optimized configurations may lead to severe efficiency degradation and operational constraint violations, especially under high renewable penetration scenarios.

The project also investigated the contribution of Battery Energy Storage Systems (BESS) to frequency support. Real-time simulations showed that properly controlled BESS can effectively mitigate frequency transients while avoiding the load shedding typically associated with traditional EAC (Automatic Load Balancer) relays, thereby improving service continuity and system resilience.

Defence system functionalities were further validated through Hardware-in-the-Loop (HIL) testing, using commercial protection relays integrated within a real-time simulation environment. The tests confirmed the correct operation of the under-frequency protection logic under realistic disturbance conditions.

Finally, the deliverable presents a TSO-DSO co-simulation framework integrating HV and MV simulations through the VILLASnode middleware. In a representative generation-loss scenario, the platform successfully recalculated and applied flexible load redistribution strategies within approximately 7.7 seconds, demonstrating the feasibility of advanced transmission-distribution coordination architectures.

A dashboard was also developed to support the visualisation of the simulation results, enabling users to inspect the main outcomes of the real-time simulation activities and to better interpret the behaviour of the grid under the tested scenarios.

The work demonstrates that Digital Twin technologies can provide an effective platform to:

- analyse power system stability;
- validate defence and protection strategies;
- support the integration of Distributed Energy Resources (DERs) and distributed flexibility;
- improve TSO-DSO coordination in future renewable-dominated power systems.

Overall, the activities carried out through simulated scenarios, HIL testing, and co-simulation environments successfully validated the technical soundness of the Italian pilot and its relevance within the broader European TwinEU framework.

1 Introduction

The stability of the electricity system is the main mission of each TSO. The Island of Sardinia, as the second biggest island of the Mediterranean Sea, has a surface area similar to that of Slovenia, and is interconnected only via HVDC connections to the rest of the European continent: for this reason, it represents a real challenge for transmission operations. Its electricity system is unique in the National and European energy scenario due to the type of loads, the structure and configuration of the generation park, as well as the insularity condition. The main characteristics of the Sardinian electricity grid are [1]:

- a strong reduction in electricity demand since 2012, mainly due to the closure of the Alcoa melting plant [2];
- a highly variable concentration of electricity demand during the year in some coastal areas (especially the north-eastern one) due to the presence of tourist activities;
- coal-based thermoelectric power plants and reduced system inertia compared to the continental network, which expose the grid to the risk of disturbances more frequently than the continental network;
- captive generation for certain types of production cycle of more than 500 MW (e.g., oil refinery);
- a low level of meshing of the transmission grid;
- an extensive distribution network characterised by long medium-voltage overhead lines;
- a growing demand for connection of new renewable energy plants (wind and photovoltaic);
- phase-out of coal-fired plants under European climate agreements [3].

Hence, the island's system is much more sensitive to net load imbalances, which induce over-frequency or under-frequency conditions, with a consequent need to properly address system security [1]. This led to the adoption of a dedicated defence plan aimed at maintaining system security under a wide range of operating conditions.

This is the context for the present study, which aims at evaluating the performance of the current **Sardinian Defence Plan** in under-frequency regime in a controlled environment, also through Hardware-In-the-Loop (HIL) simulations. Different scenarios of Renewable Energy Sources (RES) penetration will be considered. Furthermore, the study also aims at identifying new logic schemes to be integrated into the current defence plan, also considering the potential contribution that can be provided by DERs and, at the same time, also the impact they have on the distribution system itself. To this purpose, the analysis was extended to two representative MV distribution networks, covering both rural and urban operating contexts. In particular, the Areti network in Rome was included as a representative urban distribution system, characterized by typical features of densely populated areas, in order to complement the Sardinian rural case and assess the proposed approach under different distribution-grid conditions.

Scope and regulatory context clarification

The activities presented in this deliverable have been developed and validated within a controlled simulation and experimental environment, including real-time simulation, Hardware-in-the-Loop (HIL) testing, and integrated transmission–distribution co-simulation frameworks.

In order to assess the full technical potential of advanced defence strategies and Digital Twin-based coordination mechanisms, some assumptions have been adopted that extend beyond current

operational practices. In particular, the analysis considers enhanced levels of data exchange between Transmission System Operators (TSOs) and Distribution System Operators (DSOs), as well as the availability and controllability of distributed flexibility resources (e.g., flexible loads, distributed generation, and storage systems).

These assumptions are adopted for research and validation purposes and do not necessarily reflect the present regulatory framework, operational constraints, or market arrangements governing TSO–DSO interactions. The implementation of similar approaches in real power systems would require appropriate regulatory evolution, including clear definition of roles and responsibilities, availability of contractual mechanisms for flexibility activation, and secure data-sharing protocols compliant with cybersecurity and privacy requirements.

Therefore, the results presented in this deliverable should be interpreted as a proof-of-concept demonstration of technical feasibility and potential system benefits, supporting future developments in TSO–DSO coordination and power system defence strategies.

1.1 Task 6.3

In this task, the goal was the creation of a DT of a given portion of the High Voltage (HV) grid and two Medium Voltage (MV) systems. This enabled us to assess some specific defence system strategies, devoted to managing power system stability and security risks and to prevent major events and blackouts. Moreover, the development of the DT also enabled the assessment of the impact that the provision of power by DERs may have on the distribution system. The simulation also included HIL techniques, which were implemented later in the project. More in detail, a Real Time Simulator (RTS) was interfaced with specific physical devices, to duly test protection and control logics, as well as operation strategies, in a protected environment and under virtually real conditions.

1.2 Objectives of the Work Reported in this Deliverable

The objectives of the work reported in this deliverable are the following:

- to give a comprehensive understanding of the electric system under investigation
- to understand the potential of real time simulations to validate novel defence strategy to ensure system stability;
- to explore the different scenarios and the related defence system strategies;
- to understand how the distribution generation and load modelling is addressed;
- to explain the methodology used and the implementation pathway;
- to implement HIL relay testing;
- to setup co-simulations for load shedding algorithm;
- to develop a dashboard to support the visualisation of the simulation results;
- to address the conclusions after the implementation phase.

1.3 Outline of the Deliverable

The remainder of the deliverable is organized as following: Chapter 2 presents an overview of the electrical system under investigation, by focusing on both transmission and distribution systems. A focus about an abnormal operation condition, namely the reverse power flow, and few notes on the Defence System are also shown. Chapter 3 includes some notes regarding the urban distribution system of the City of Rome, from which a network sample has been extracted. The modelling

approaches are explained in Chapter 4. Chapter 5 describes Distribution Network modelling, whereas Chapter 6 and Chapter 7 focus on the Key Performance Indicators and the implementation of the scenarios, respectively. Chapter 8 reports the results, whereas the concluding remarks are shown in the last chapter.

1.4 How to Read this Document

This deliverable is structured to progressively guide the reader from the system context to the implementation and assessment of the proposed defence system use case. This document is self-contained, and no additional deliverables need to be consulted to understand the goals and achievements presented herein. It starts with an overview of the Sardinian electrical system, describing the main transmission and distribution features that motivate the adoption of advanced defence strategies. The modelling approaches adopted for both transmission and distribution networks are then presented, together with the validation activities carried out to ensure model reliability.

Building on this foundation, the document introduces the Key Performance Indicators used to assess the effectiveness of the Digital Twin and the implemented defence logics. Subsequently, a set of simulation scenarios is defined to evaluate system behaviour under stressed operating conditions and increasing RES penetration. The results of real-time simulations, HIL tests, and co-simulation activities are finally presented and discussed, leading to overall conclusions and future perspectives.

2 Overview of the Sardinian electrical system

Sardinia's distinctive geographic conformation, sparse population and Mediterranean climate have shaped an energy system that differs from that of mainland Italy. Historically, the island was never linked to the national natural-gas transmission network because the costs of laying a subsea pipeline outweighed the benefits for its modest market. As a result, Sardinians turned earlier and more decisively to electricity for everyday needs: today 27% of household heating and 45% of industrial consumption are electric, already aligned with European decarbonisation targets. This head start, however, addresses only the demand side of the transition. To complete the journey, Sardinia must now overhaul its supply mix, replacing fossil-fuelled generation with renewables. In this respect the island enjoys exceptional solar and wind resources, offering ample scope to satisfy its own power demand, produce green hydrogen and synthetic fuels for hard-to-abate sectors, and still protect its scenic landscapes through careful siting of new plants. With strategic planning, Sardinia can leverage its early electrification and natural endowments to become a showcase for a fully renewable, island-scale energy system.

2.1 Structure of the power generation system

The thermoelectric power generation system in Sardinia is mainly based on three large power plants, constituted by two coal-based power plants (CP1 and CP2) and one thermoelectric power plant associated to a gasoline refinery plant (TP). In addition, there are two remote-controlled gas-turbine units (GP). Table 2-1 summarises the characteristics of the main thermoelectric plants. The net rated power of the various sections was taken from dedicated platforms [4].

Table 2-1 – Gross installed capacity of the main Sardinian power plants

Plant	Units	Gross installed capacity [MW]	Net installed capacity [MW]	Fuel	Technology	Percentage of the total
CP1	S1	320	296	Coal/biomass	Steam	14.4%
	S2	320	296	Coal/biomass	Steam	14.4%
	Total	640	592	-	-	28.8%
CP2	S1	345	277.8	Coal/biomass	Steam	15.6%
	S2	240	202.2	Coal/HFO	Steam	10.8%
	Total	585	480	-	-	26.4%
TP	SX1	201.55	196.5	Syngas from TAR	IGCC	9.1%
	SX2	201.55	196.5	Syngas from TAR	IGCC	9.1%
	SX3	201.55	196.5	Syngas from TAR	IGCC	9.1%
	Total	604.65	589.5			27.3%
GP	AS1	81	75	Diesel	Gas turbine	3.7%
	AS2	81	75	Diesel	Gas turbine	3.7%
	Total	162	150	-	-	7.3%
Total		1,991.65	1,811.5	-	-	89.8%

The sections of the CP1 power plant and the S1 section of the CP2 power plant are fuelled by coal and can operate in co-combustion with solid biomasses, up to a maximum percentage of 5% for the CP1 units, and 15% for the S1 section of CP2 unit with respect to the total input fuel energy. The three sections have a total capacity of 985 MW, corresponding to 44.4% of the thermoelectric total. The S2 section of the CP2 power plant, with a capacity of 240 MW, corresponding to approximately 10.8% of the thermoelectric total, can be fired with coal and heavy fuel oil (HFO).

In addition to the above plants, there are 38 plants of various types and power that use biomass, including waste-to-energy and biodigestion plants, with a total capacity of 111.28 MW [5].

Furthermore, there are 18 hydroelectric plants with 27 units of various types and power, for a total gross efficient power of 475 MW. Table 2-2 below provides a summary of Sardinian hydroelectric plants.

Table 2-2 Hydroelectric plants gross installed capacity

Power Producer A Plants	Num. of Units	Unit Capacity (MW)	Plant Capacity. (MW)	Type of Turbine
PA1	2	20.9	41.8	F-V
PA2	2	13.2	26.4	F-V
PA3	1	6.32	6.32	F-V
PA4	3	80	240	F-V
PA5	2	4.2	8.4	F-H
PA6	3	9.4	28.2	P-H
PA7	2	5	10	F-H
PA8	1	22.6	22.6	F-V
PA9	1	5.0	5.0	K-V
PA10	1	9.88	9.88	F-V
PA11	1	0.812	0.812	F-H
PA12	1	3.8	3.8	F-V
Total Hydroelectric A	20	---	403.21	
Power Producer B Plants				
PB1	1	20.23	20.23	F-V
PB2	1	4.2	4.2	K-V
PB3	2	15+1.08	16.08	K-V+F-H
PB4	1	28.8	28.8	F-V
PB5	1	1.25	1.25	F-H
PB6	1	1.3	1.3	F-H
Total Hydroelectric B	7	---	71.86	
Total Hydroelectric	27	---	475.07	

F = Francis turbine – K = Kaplan turbine – P = Pelton turbine; V = Vertical axis – H = Horizontal axis

As shown in Table 2-2, 12 plants with 20 units, for a total capacity of 403.21 MW, are owned by one company, while 6 plants with 7 units, for a total capacity of 71.86 MW, are owned by another company.

The biomass-based plants include 25 biogas plants totalling 14.57 MW, 5 landfill biogas plants totalling about 6.55 MW, 5 solid biomass plants totalling 37.24 MW, 2 liquid biomass plants totalling 36.9 MW, and one UW (Unsorted Waste) plant of 16 MW.

2.2 The Sardinian transmission system

The structure of the Sardinian electricity system is shown in Figure 2-1. The region is crossed by a single 380 kV backbone (the longest section of which measures approximately 155 km) that connects Northern Sardinia to the industrial area of Cagliari (where the refinery-related production hub is also located) and enables the transit of important energy flows between the north and south of the island. At the station connected to CP1, the electrical energy produced by the adjacent power station is fed into the grid, representing a relevant production and frequency and voltage regulation source. Five synchronous condensers, strategic for voltage control and inertia, are installed, three of them in Northern Sardinia and two in Southern Sardinia.

Superimposed on the 380 kV grid, there is a ring, consisting of 230 kV lines (with a total length of 552 km), which connects the industrial pole of Portoscuso/Sulcis and the Codrongianos area.

Additionally, there is a 150 kV network composed of Terna substations and Primary Substations (PS) operated by the local DSO (e-Distribuzione) and by third parties; although this voltage level is normally used in the rest of Italy solely for hand-over to the distribution sector, in Sardinia it also fulfils transmission functions.

Table 2-3 shows the number of Terna substations, broken down by voltage level.

Table 2-3 Terna transmission system inventory

Voltage [kV]	Units	Transformation Powers [MVA]	Number of Transformers
380	7	6,617	26
220	8	2490	15
≤150	14	387	12
Total	29	9,494	53

Sardinia's electricity system is interconnected with the national electricity system through two DC power lines, respectively the SA.PE.I. (Sardinia-Italian Peninsula) and the SA.CO.I. (Sardinia-Corsica-Italy). Sardinia is also connected to Corsica by an alternating current power line called SAR.CO. (Sardinia-Corsica).

2.2.1 SA.PE.I. Link

The SA.PE.I. link is based on Line-Commutated Converter (LCC) technology and connects Sardinia to the mainland through two conversion substations, one in Northern Sardinia and the second one on the mainland, as shown in Figure 2-1. It is based on two cables with a total length of about 435 km, with an underwater section of 420 km, which dives to a record depth of 1,640 m, and a land section

of approximately 15 km on the mainland. The connection consists of a double 500 kV HVDC cable, and each cable ensures a transport capacity of 500 MW, for a total capacity of 1,000 MW.

The first underwater cable was laid in 2008 and came into operation in November 2009; the second one was laid in 2010 and came into operation in December of the same year. The two-pole system went into actual operation in July 2011.

The construction of the SA.PE.I. was envisaged to ensure greater flexibility of the Sardinian grid, not only for the purposes of its operational safety, but also to support the potential for considerable development of electricity generation from wind power, as well as to allow Sardinia's electricity operators to participate with fewer exchange constraints in electricity market negotiations. This infrastructure is also of considerable interest for the development of the national and European transmission grid in view of the possible DC connection between the African continent and Europe.

2.2.2 SA.CO.I. Link

The SA.CO.I. link is a high-voltage 200 kV direct current connection built in the 1960s. It was initially based on two mercury vapour conversion stations of 200 MW each, one in Northern Sardinia, the other one on the mainland. On the basis of an international agreement, a supply of electricity to EDF in Corsica through a third conversion station in Corsica was also planned, for an initial maximum power of 20 MW, later increased to 50 MW following additional agreements between ENEL and EDF in 1980. The link was then upgraded (SA.CO.I. 2) in 1992 through the construction of the two new conversion stations (made using thyristors) with a capacity of 300 MW each, which made it possible to fully utilise the capacity of the submarine cables. The location and configuration of the SA.CO.I. link are shown in Figure 2-1.

Due to the limited remaining life related to the aging of the cables and the consequent limitations on transmission capacity and operating flexibility, considering also the vigorous development of the wind power sector since the early 2000s, the SA.CO.I. 2 connection has represented for many years a critical point of congestion in the connection with the mainland, with considerable limitations for Sardinia's electricity operators in the market.

In 2011, the system was joined by the new SA.PE.I. infrastructure connecting with the mainland (the Central-South Zone of Terna's grid), but the connection and transmission capacity between Sardinia, Corsica and the Central-North Zone of Terna's grid remained limited.

2.3 SAR.CO. link

SAR.CO. is a 150 kV alternating current link between Sardinia and Corsica. The link, which came into operation in 2006, has a total length of 31.6 km, with an underwater section of about 16 km, and a capacity of 50 MW.

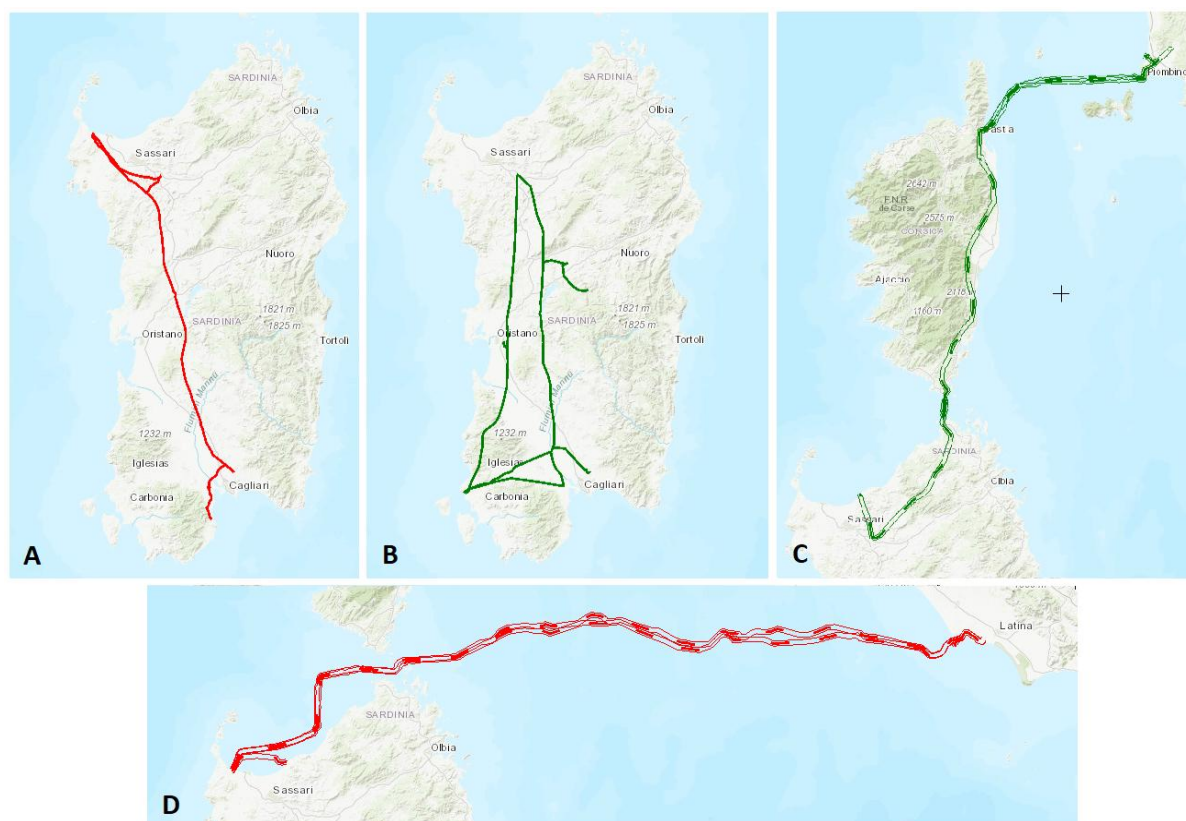


Figure 2-1 HV Sardinian network: (A) 380 kV, (B) 230 kV, (C) 200 kV DC, and (D) 500 kV DC systems (all rights reserved) [6]

2.4 Sardinian Defence System

The current defence system in Sardinia enables the management of particularly heavy frequency transients. The system is based on local frequency relays calibrated on different thresholds, defined by specific network studies. The disconnection plan provides for intervention in both over-frequency and underfrequency regimes. During the project, the analysis has been focused on the under-frequency regime, for the following reason.

In presence of under-frequency events, the countermeasures include the disconnection of the PA4 pumps (if operating) and the interruption of the supply to all the available interruptible industrial loads. For the disconnection of the pumps, a properly calibrated local frequency relay is installed at the power station connected to the plant, to disconnect individual units when specific thresholds are exceeded. The system is redundant: to face any unavailability of the local relay, a detachment command is controlled by the Command Defence and Monitoring System (SCDM), powered by local relays installed at Terna premises.

The disconnection of interruptible users is controlled by the SCDM via the Defence and Monitoring Peripheral Unit (DMPU) devices, activated by local relays installed in three main Terna Stations, when the 49.3 Hz threshold is reached.

About the connection with the mainland Italy, if the SA.PE.I. is exporting energy from Sardinia, the link performs a fast reverse (hence, importing power). Unlike the SA.PE.I., the SA.CO.I. cannot perform fast inversions, to avoid stress of the submarine cables.

In addition, the Under-frequency Load Disconnection Plan is activated based on EAC (Automatic Load Balancers) relays that detach an increasing amount of load until balance is restored in the electrical system. The load shedding performed by EACs acts on diffuse loads fed by the distribution networks. Figure 2-2 shows a general intervention scheme of the underfrequency defence plan.

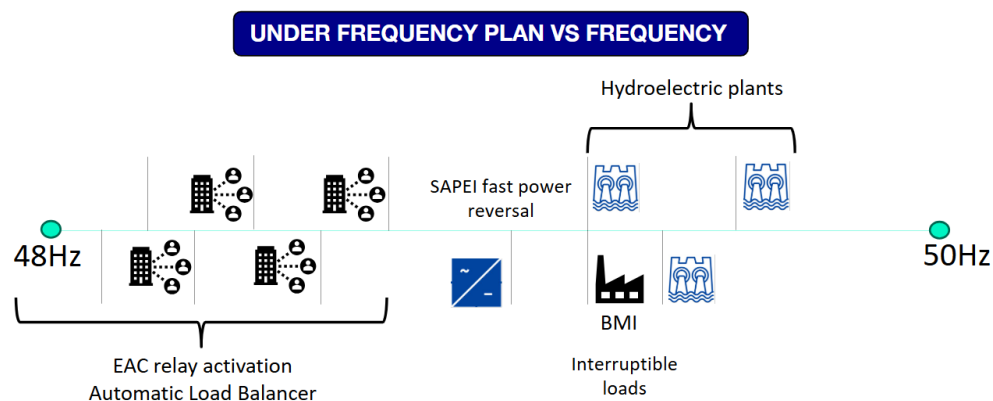


Figure 2-2 Under-frequency plan

Currently, the loads underlying the EAC relays are communicated by the local DSO (e-Distribuzione) to the TSO, twice a year, and therefore, do not consider the variability of the load during the hours of the day, days of the week and seasons. The TSO draws up the defence plan based on the data received.

2.5 The Sardinian distribution system

The Sardinian Medium Voltage (MV) and Low Voltage (LV) distribution network extends over more than 58,000 km, comprising approximately 19,000 km of MV lines and nearly 39,000 km of LV lines.

The infrastructure exhibits heterogeneous characteristics across different regions, reflecting Sardinia's geographical, urban, and demographic distribution (Figure 2-3). In the MV network, 65% of the total (12,426 km) consists of overhead lines, supplemented by 442 km of aerial cables and 6,182 km (32.5%) of underground cables. The predominance of overhead infrastructure underscores its prevalence in internal and less urbanized areas, where hilly and mountainous terrain combined with low population density makes undergrounding both complex and costly.

The LV network, while more extensive, presents a relatively balanced composition: 4,667 km of overhead lines, 19,538 km of aerial cables, and 14,744 km of underground cables. The significant underground portion highlights a focus on urban undergrounding, although substantial overhead sections remain, particularly in rural zones.

Analysis of contracted capacity and customer numbers in the MV network further completes the picture of Sardinia's electricity distribution. The island hosts 2,451 MV customers for a total contracted power of approximately 1,227 GW. However, provincial breakdowns reveal significant disparities aligned with population distribution, industrial activity, and urbanization.

The province of Cagliari has the largest network extension (more than 5,900 km in MV and 13,400 km in LV) and the highest number of LV customers (about 458,743, equal to over 42% of the regional total); it includes also 971 MV customers with a total capacity of 550 MW. This concentration is consistent with the strategic importance of the metropolitan area of Cagliari. The local network is largely underground and structured, to guarantee greater reliability and continuity of service, a typical need in contexts with high population and economic density.

The inland provinces of Nuoro and Oristano, on the other hand, show diametrically opposed characteristics: the networks are smaller and more fragmented (respectively about 3,000–3,500 km in MV and 6,400–6,900 km in LV), with a very low load density and a high presence of overhead lines, which makes them particularly exposed to atmospheric agents. At MV level, Nuoro has just 276 MV customers for 112 MW, while Oristano reaches 403 MV customers and 175 MW. This infrastructural weakness leads to higher costs per user and greater operational difficulties, both in maintenance and in restoring service in the event of a failure.

Sassari occupies an intermediate but significant position. With 6,491 km of MV and 12,118 km of LV, it is the second-largest province by network extent, serving 801 MV customers with a capacity of 390 MW and over 357,000 LV customers. Sassari's network spans both major urban centres and vast rural areas, with over 6,000 km of overhead LV lines, reflecting the territory's complex morphology. This configuration necessitates careful management to balance service reliability and cost efficiency.

Primary transformation nodes (HV/MV substations and satellite centres) are fundamental to understand the Sardinian distribution network's structure. The island hosts 83 primary substations and 29 satellite centres, serving as critical interface for transmitting electricity from HV to MV grids. Cagliari province includes 32 substations and 13 satellites, followed by Sassari with 25 and 9 respectively, while Nuoro and Oristano each have 13 substations and 4 and 3 satellites respectively. This arrangement mirrors demographic distribution and local load requirements.



Figure 2-3 The Sardinian distribution system

3 Urban electrical system: the City of Rome

3.1 Network asset inventory in 2024

The electricity distribution network extends across the Metropolitan City of Rome for approximately 32,400 km and it supplies about 2.9 million residents. Currently, the company distributes electricity to over 1.6 million points of delivery (PODs) in the municipalities of Rome and Formello.

The energy injected into the grid in 2024 amounts to 9.3 TWh, with an annual peak power output of 2,126 MW, recorded on July 30, 2024 at 3:10 PM.

The HV network feeds 70 primary substations, where the HV/MV transformation occurs, originating a MV system spanning approximately 10,939 km, 96% of which is comprised of underground cables. This network supplies 13,452 secondary substations (MV/LV transformation and MV user connections), from which the low-voltage (LV) networks originate, extending for approximately 21,465 km, with 92.6% of it underground.

3.2 DERs connected at the system of the City of Rome

In the Rome area, the most widespread distributed generation (DG) technology is photovoltaic (PV), typical of urban settings. Solar accounts for over 70% of the total generation capacity connected to Areti's distribution network. Other significant technologies include thermal generation from fossil (e.g. methane) or renewable sources (e.g. biogas). Hydroelectric and wind sources are nearly absent due to unsuitable site conditions. Thermal plants are generally medium-to-large in size and often connected directly to primary substations.

PV generation is highly decentralized: over 70% of PV installations are below 6 kW, and 96% are below 25 kW. However, there are also large PV plants, especially in suburban areas, installed on land or rooftops (e.g. parking structures). Thus, the distribution network must manage both the impacts of widespread small-scale PV on LV and the challenges of significant medium-voltage injections from large-scale generators. Recent years show a steady growth of PV, while fossil-based DG has remained stable, with most installations predating the last 5 years. This is largely due to the changing incentive schemes and site availability constraints. The PV distribution across Rome (in MW/km²) correlates with urbanization levels, especially for <100 kW systems usually installed on rooftops. Medium-density residential areas, such as Municipio X, show higher growth. Historical city centres remain limited due to urban planning restrictions.

In the last 3 years, PV growth has been accompanied by electrochemical storage systems, mostly for increasing self-consumption. There is now around 55 MW of installed storage, almost entirely on the LV network. Over 25 MW/year of new storage has been added recently, driven by falling battery prices and national incentives. This trend is expected to continue due to further cost reductions and policy drivers like energy communities and agrivoltaics.

3.3 About the loads

The average net peak load is 2,145 MW, while gross peak is 2,205 MW. The gap, due to DG contribution, has grown from 53 MW in 2018 to 73 MW in 2024. This peak load represents only energy fed into Areti's distribution network and excludes locally consumed DG.

Peak load represents the maximum simultaneous demand, which occurs only for a few hours per year. In 2022–2024, power demand exceeded 2,000 MW only 1% of the time. Most hours (58%) recorded between 1,000–1,500 MW, with only 9% above 1,500 MW, and 32% below 1,000 MW.

4 Transmission system modelling

The model of the transmission system considers only a part of the HV grid existing in Sardinia. The different voltages levels, together with the number of nodes and lines operated at that level are shown in Table 4-1.

Table 4-1 – Transmission system summary

Voltage [kV]	Number of nodes	Number of lines
380	7	8
220	31	38
150	10	2

It is worth noting that the level 150 kV has only two lines implemented (related to the zone where the MV system operated by e-Distribuzione is placed). The loads and generators connected to the rest of the 150 kV system is aggregated and imposed as net load, with its proper sign, to the nodes of the system at 150 kV.

Regarding the generators, as shown in Table 4-2, only a few of them (thermoelectric and some hydropower plants) are dispatchable and may be used to make frequency and voltage regulation; the remaining ones are instead non-dispatchable resources, hence not equipped with any type of governor.

Table 4-2 – Information about the connected generators

Type of generator	Number	Total generation power [MVA]
Dispatchable	7	1725
Non-Dispatchable	19	2410

Regarding the model of generators, it has been verified that the data provided may be used for implementing a *sixth-order generator model*.

The DT model of the Sardinian power grid has been implemented in the HYPERSIM environment. First, a preliminary assessment of a single generating unit is carried out to validate its model before its integration into the overall grid model. Then, the validation of the grid behaviour is shown.

4.1 Single Generating Unit Validation

Before analysing the behaviour of the DT of the Sardinian transmission network, it is necessary to validate the speed governor and excitation system on a single generating unit to verify their correct operation. The generating unit is therefore connected to a reduced-scale test grid, allowing the assessment of the control systems performance under a solid three-phase fault at the generating unit terminals and under load variation conditions. The setup is shown in Figure 4-1.

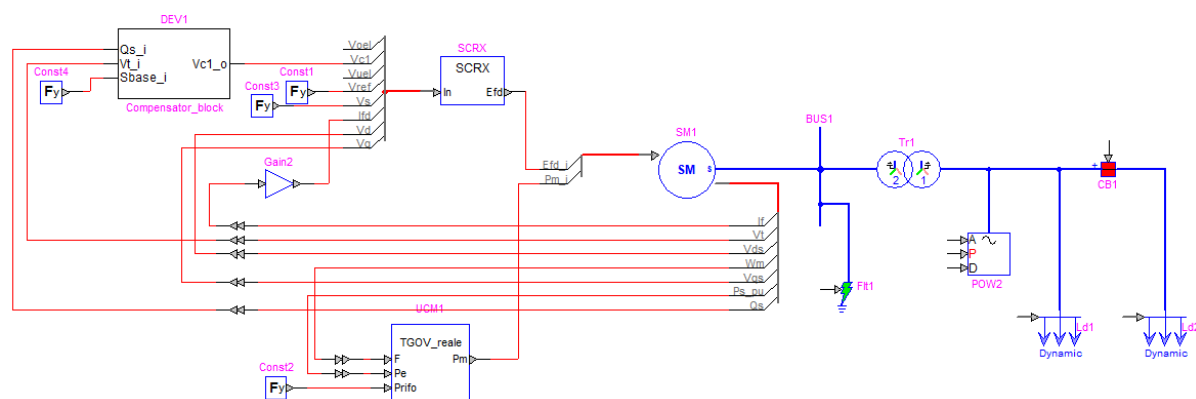


Figure 4-1 Setup for the single generator test

The generating unit under test corresponds to the unit one of the plant CP1, characterized by a nominal apparent power of 370 MVA. It is connected to a load with active power $P= 260$ MW and reactive power $Q= 115$ Mvar.

For validation purposes, the obtained results are compared with the reference time-domain responses provided by the TSO, corresponding to the same generating unit operating under identical loading conditions.

The following variables are analysed: rotor speed, generator terminal voltage and mechanical power output of the tested generating unit. The fault is applied at $t= 2$ s and has a duration of approximately 80 ms, consistent with the typical clearing time of protection systems. Instead, the load variation consists of a 10% decrease of the initial load applied at $t=2$ s. The steady-state active power reaches $P=234$ MW, while the reactive power decreases to $Q=103$ Mvar.

Figure 4-2 shows the generator speed response for both scenarios. In both cases, the simulated model exhibits a high level of consistency with the real behaviour, accurately reproducing the transient dynamics. The observed differences are minor and can be attributed to model simplifications and to the omission of certain system time constants. Table 4-3 highlights that the main dynamic indicators, such as nadir, overshoot and settling time, are in good agreement with the reference values.

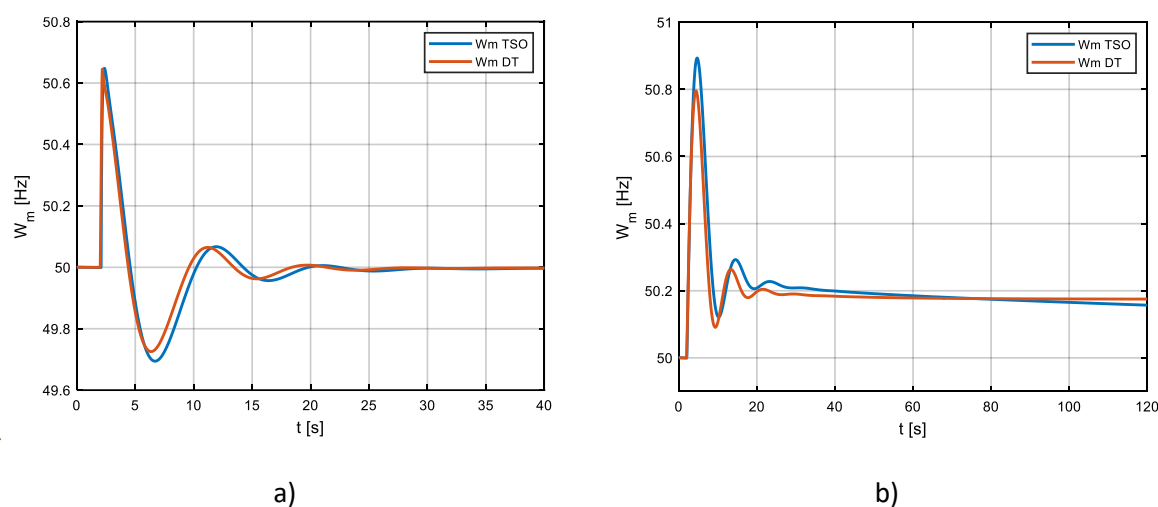
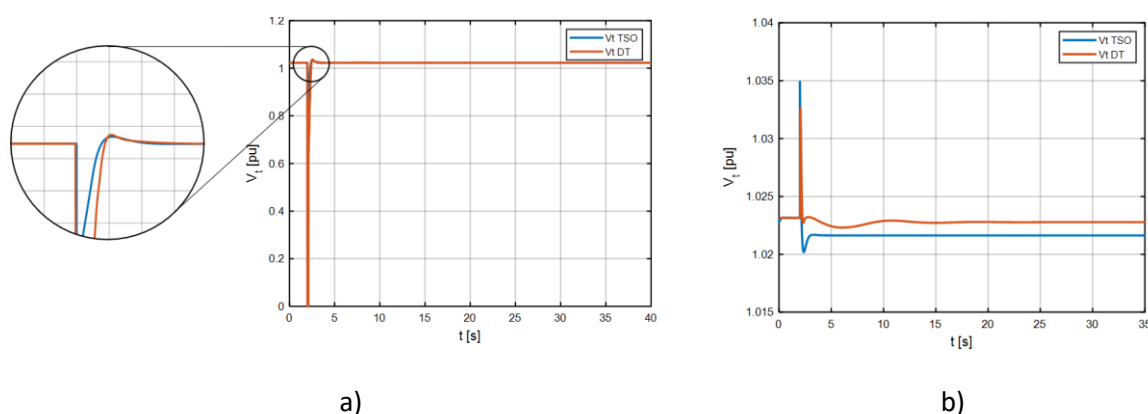


Figure 4-2 Rotor speed comparison: a) Three-phase bolted fault; b) Load variation

Table 4-3 Rotor speed comparison

Scenario	Version	Nadir [Hz]	Overshoot [Hz]	Settling Time [s]
Three phase bolted fault	TSO	49.694	50.648	28
	DT	49.726	50.645	25.5
Load variation	TSO	50.122	50.893	34.2
	DT	50.091	50.796	28.26

Regarding the voltage response, the use of a static exciter instead of the TSO rotating exciter installed in the real system (adopted due to software limitations) has a significant impact on the behaviour of the digital model. As shown in Figure 4-3, noticeable differences can be observed in the voltage response for the two considered scenarios. In particular, in the case of Figure 4-3b, the discrepancy is more pronounced, as the voltage settles at a level different from the real one.

**Figure 4-3 Voltage comparison: a) Three-phase bolted fault; b) Load variation**

Despite these differences, Table 4-4 shows that the main reference indicators remain overall comparable with those of the real system. The only exception is the settling time, which, in the load variation case, exhibits a more oscillatory behaviour. However, these deviations do not significantly compromise the overall validity of the model.

Table 4-4 Voltage comparison

Scenario	Version	Nadir [pu]	Overshoot [pu]	Settling Time [s]
Three phase bolted fault	TSO	0	1.034	2.22
	DT	0	1.037	3.50
Load variation	TSO	1.020	1.035	0.96
	DT	1.022	1.033	15

Regarding the mechanical power response shown in Figure 4-4, similarly to what was observed for the speed, the comparison highlights a high level of agreement between the real system and the digital model. Table 4-5 shows that the differences related to the selected indicators are limited and overall negligible. The only noticeable discrepancy is a slight delay in the model response, which was already observed in the speed analysis.

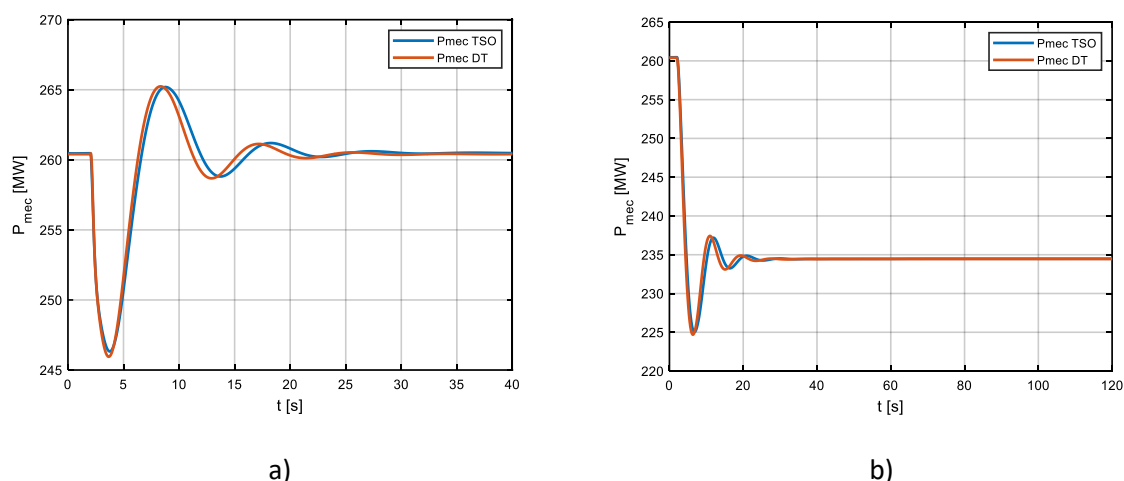


Figure 4-4 Mechanical power comparison: a) Three-phase bolted fault; b) Load variation

Table 4-5 Mechanical power comparison

Scenario	Version	Nadir [MW]	Overshoot [MW]	Settling Time [s]
Three phase bolted fault	TSO	246.33	265.19	32.66
	DT	245.95	265.24	29.7
Load variation	TSO	225.03	237.19	35.1
	DT	224.69	237.43	30.34

Despite these differences, the overall behaviour of the model can be considered representative of the real system for the analysed variables. The model can therefore be regarded as suitable for implementing the portion of the network under study, although analyses that are more sensitive to voltage dynamics may require a more detailed excitation system model.

4.2 DT of Sardinian transmission grid

The network model was constructed using specific data provided by the TSO, including parameters for lines, transformers, and generators.

The thermoelectric power plant generator model is identical to the one validated in Section 4.1.

Regarding the hydroelectric units, the only difference with respect to the single unit lies in the speed governor configuration.

For the network-wide validation, the same test procedures were followed: evaluating the system response to a fault and to a load variation. These tests were conducted using a real-time snapshot of generation and load values, specifically selected under medium-load conditions.

Five generation units located at different substations have been selected for analysis. Specifically, the following generators are considered:

- S1 from power plant CP1;
- S2 from power plant CP2;
- Units 1 and 3 from power plant PA4;
- SX1 from power plant TP.

4.2.1 Fault scenario

Figure 4-5 shows the comparison between the network responses following a simulated fault at a specific point of the system. In the initial transient phase, as highlighted in Figure 4-5b, the generators exhibit a differentiated response, characterized by oscillations with varying amplitudes. This behaviour progressively converges, reaching a common stabilization approximately 6 seconds after the event. In the real system, the convergence time is slightly shorter, around 4 seconds.

The main difference between the real system and the digital model lies in the amplitude of the initial oscillation peaks, which are more pronounced in the DT. This can be attributed to simplifications introduced in the modelling, particularly in the control systems.

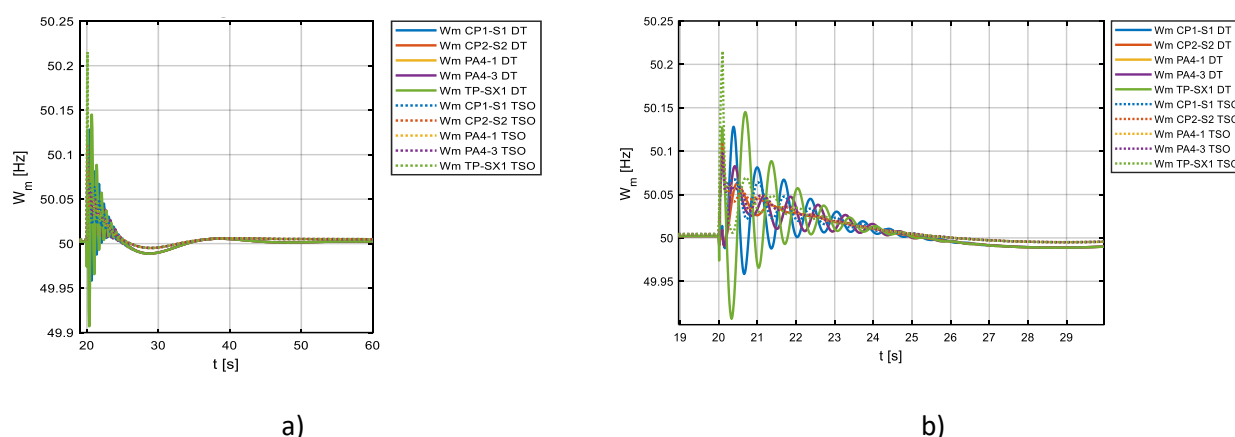


Figure 4-5 Rotor speed response under fault condition

After approximately 5 seconds, the responses become very similar in both amplitude and shape, confirming the ability of the model to give a good representation of the overall system dynamics. Table 4-6 summarizes the comparison of the main dynamic indicators for each generator.

Table 4-6 Rotor speed response under fault condition

Generating unit	Version	Nadir [Hz]	Overshoot [Hz]	Settling Time [s]
CP1-S1	TSO	49.995	50.089	17.06
	DT	49.958	50.128	32.98
CP2-S2	TSO	49.995	50.11	17.06
	DT	49.989	50.063	32.98
PA4-1	TSO	49.995	50.099	17.06
	DT	49.989	50.082	32.98
PA4-3	TSO	49.995	50.099	17.06
	DT	49.989	50.082	32.98
TP-SX1	TSO	49.995	50.215	17.06
	DT	49.907	50.145	32.98

Figure 4-6 shows the generator speed response following a load variation. Unlike the previous case, generators belonging to the same model exhibit an almost identical response, indicating a uniform dynamic behaviour.

Some differences in oscillation amplitude with respect to the real system are still observed, which can be attributed to the modelling of the speed governors, particularly the ones related to the hydroelectric units, for which standard models from the software library have been used.

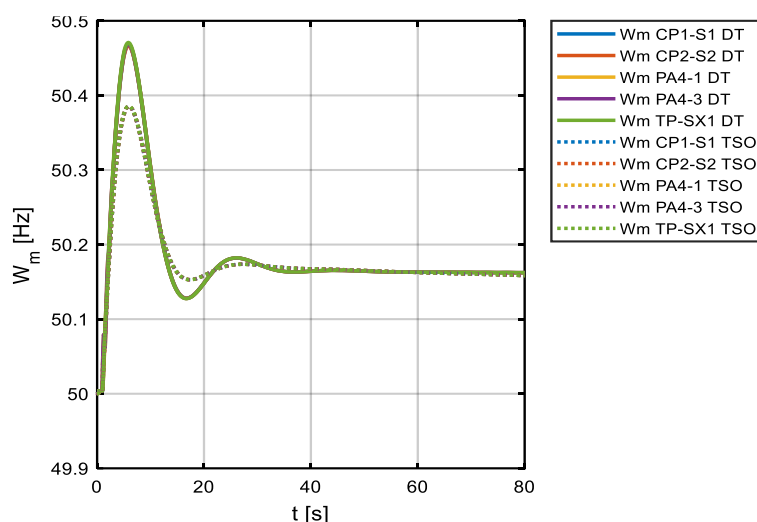


Figure 4-6 Rotor speed response under load variation

Despite these differences, the overall shape and dynamic response remain consistent between the digital model and the real system, confirming the validity of the adopted modelling approach. Table 4-7 reports the main reference indicators used for the comparison, considering that the analysed generators exhibit coincident values.

Table 4-7 Rotor speed response under load variation

Scenario	Version	Nadir [Hz]	Overshoot [Hz]	Settling Time [s]
Load variation	TSO	50.153	50.385	27.92
	DT	50.128	50.468	38.4

Figure 4-7 shows the voltage response during the fault condition. The comparison between the real system and the digital model does not reveal significant differences in terms of overall behaviour. However, the digital model exhibits a slightly less oscillatory response, with a more damped dynamic compared to the real system.

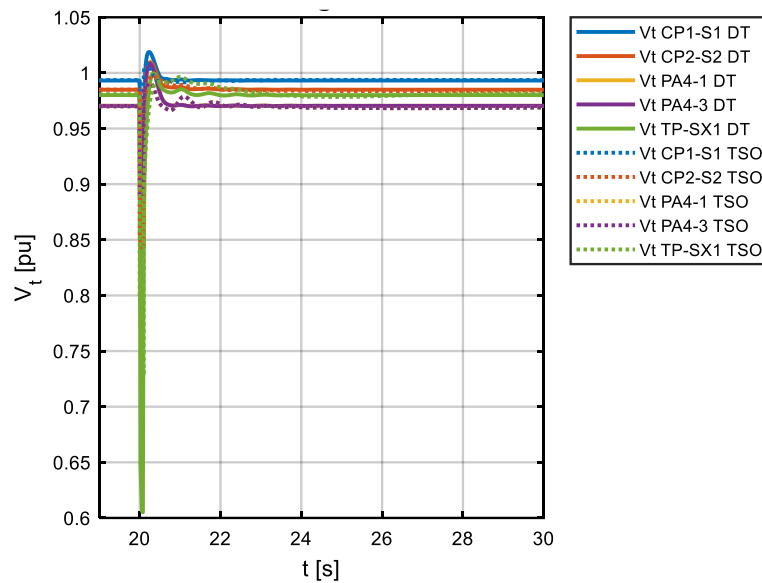


Figure 4-7 Voltage response under fault condition

Despite these differences, the overall shape and response remain consistent between the two models, confirming the validity of the adopted representation. Table 4-8 reports the main indicators for each analysed generator.

Table 4-8 Voltage response under fault condition

Generating Unit	Version	Nadir [pu]	Overshoot [pu]	Settling Time [s]
CP1-S1	TSO	0.912	1.008	2.4
	DT	0.859	1.019	0.74
CP2-S2	TSO	0.841	0.997	3.38
	DT	0.748	1.009	1.16
PA4-1	TSO	0.888	0.991	3.46
	DT	0.823	1.008	0.74
PA4-3	TSO	0.886	0.991	3.46
	DT	0.823	1.008	0.74
TP-SX1	TSO	0.728	0.996	6.66
	DT	0.605	0.999	4.92

Figure 4-8 shows the voltage response of the generators following a load variation. Similarly to the single-generator case, significant differences can be observed between the real system and the digital model.

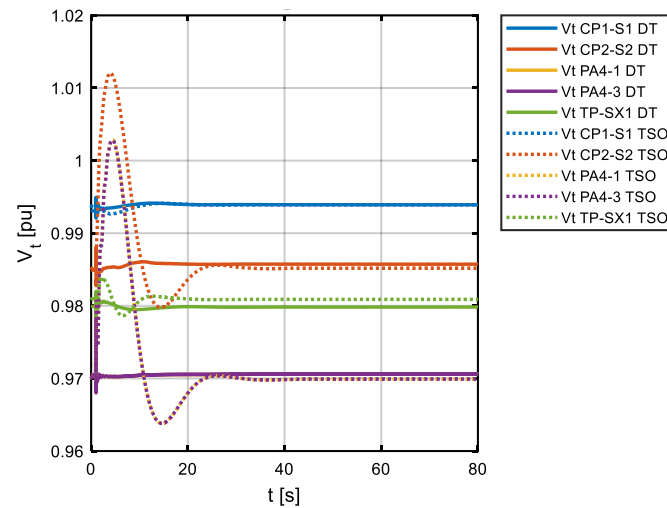


Figure 4-8 Voltage response under load variation

These differences are mainly due to the different types of excitation systems used. The real system, which employs rotating exciters, exhibits a more oscillatory behaviour and a longer transient for some generators. In contrast, the digital model, based on static exciters, shows a faster and more damped response.

The higher response speed of the static exciter allows the transient to decay more rapidly compared to the real system. Table 4-9 reports the reference parameters for the analysed generators.

Table 4-9 Voltage response under load variation

Generating Unit	Version	Nadir [pu]	Overshoot [pu]	Settling Time [s]
CP1-S1	TSO	0.993	0.994	18.34
	DT	0.993	0.994	17
CP2-S2	TSO	0.98	1.012	38
	DT	0.983	0.986	17
PA4-1	TSO	0.964	1.003	38
	DT	0.970	0.971	15
PA4-3	TSO	0.964	1.003	38
	DT	0.970	0.971	15
TP-SX1	TSO	0.979	0.984	17
	DT	0.979	0.981	17

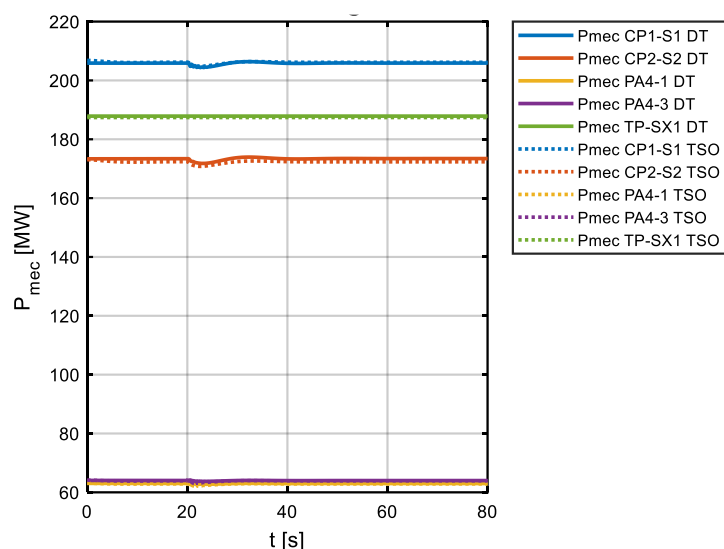


Figure 4-9 Mechanical power under fault condition

In the fault scenario, the mechanical power response of the generators, as shown in Figure 4-9, exhibits a substantial overlap between the real system and the digital model. No significant differences are observed, either in terms of amplitude or dynamic behaviour.

It can also be noted that the TP-SX1 generator does not participate in frequency regulation and therefore does not exhibit any significant variation in its mechanical power response.

Table 4-10 reports the characteristic parameters used for the comparison between the two models.

Table 4-10 Mechanical power under fault condition

Generating Unit	Version	Nadir [MW]	Overshoot [MW]	Settling Time [s]
CP1-S1	TSO	204.71	206.8	23.38
	DT	204.37	206.37	36.54
CP2-S2	TSO	170.8	173.05	27.04
	DT	171.79	173.93	37.38
PA4-1	TSO	61.5	63.74	19.72
	DT	62.72	63.18	27.76
PA4-3	TSO	62.5	64.75	19.72
	DT	62.72	63.18	27.76
TP-SX1	TSO	184.4	-	-
	DT	187.87	-	-

4.2.2 Load scenario

Figure 4-10 shows the mechanical power response of the generators following a load variation. Slight discrepancies can be observed in the nadir values of the real system curves, which can be attributed to the simplifications adopted in the system modelling.

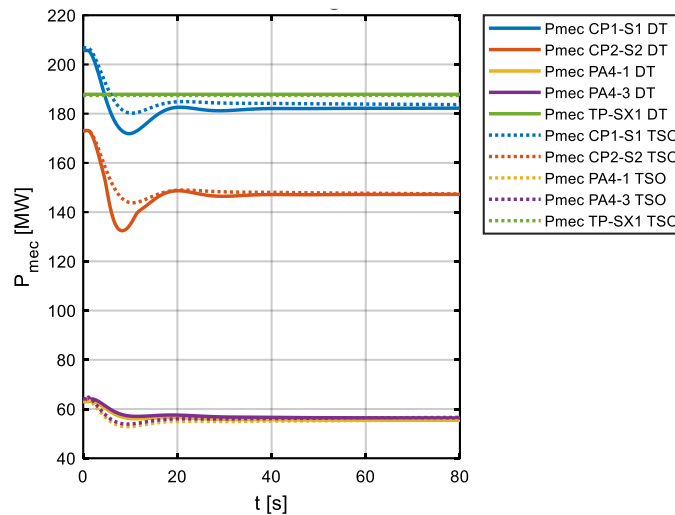


Figure 4-10 Mechanical power under load variation

However, once the transient has decayed, the curves become substantially overlapped, indicating a good agreement between the digital model and the real system. Table 4-11 reports the characteristic parameters used for the comparison of the analysed generators.

Table 4-11 Mechanical power under load variation

Generating Unit	Version	Nadir [MW]	Overshoot [MW]	Settling Time [s]
CP1-S1	TSO	180.22	184.91	21
	DT	171.88	182.62	38
CP2-S2	TSO	143.80	148.96	21
	DT	132.45	148.68	38
PA4-1	TSO	52.81	55.76	17
	DT	55.39	56.56	24
PA4-3	TSO	53.87	56.80	17
	DT	56.39	57.56	24
TP-SX1	TSO	187.4	-	-
	DT	187.87	-	-

The results show a high level of agreement between the digital model and the real system in terms of overall dynamic behaviour. Key indicators such as nadir, overshoot, and settling time are consistent, and the general response of the system is accurately reproduced. Minor discrepancies are observed, mainly in the initial transient phases, where slightly higher oscillations or small-time shifts are present in the digital model.

These differences can be attributed to modelling simplifications, particularly in the representation of control systems, such as speed governors and excitation systems, as well as the use of standard models from the software library.

Despite these limitations, the digital model demonstrates a reliable and physically consistent response, both at generator level and at system level. Therefore, the model can be considered valid for dynamic analysis and suitable for further studies and applications.

5 Distribution system modelling

5.1 Topologies

Table 5-1 shows the details about the number and type of nodes. Figure 5-1 and Figure 5-2, represents the structure of the networks. For e-Distribuzione's network, the different colours in Figure 5-2 represent the information we got from the DSO: the black colour indicate 98 nodes lacking power measurements (typically junction nodes), the 100 yellow nodes have active and reactive measurements where the loads are located, red dots are 10 and represent nodes that have been deactivated or edge nodes of the network with open switches.

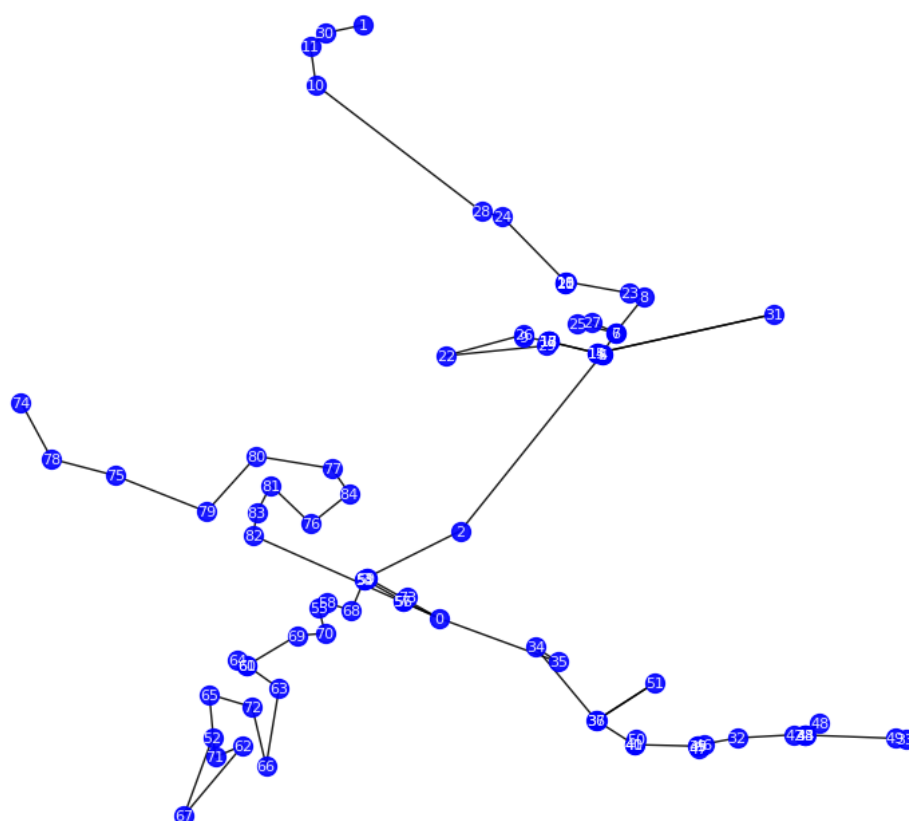


Figure 5-1 Areti network topology

For the Areti network, the system consists of 84 nodes, of which 32 are load nodes. Among these, 23 nodes also host distributed generation. For the e-distribuzione network, the system includes 208 nodes, with 107 load nodes. However, no information is available regarding how many of these nodes host distributed generators.

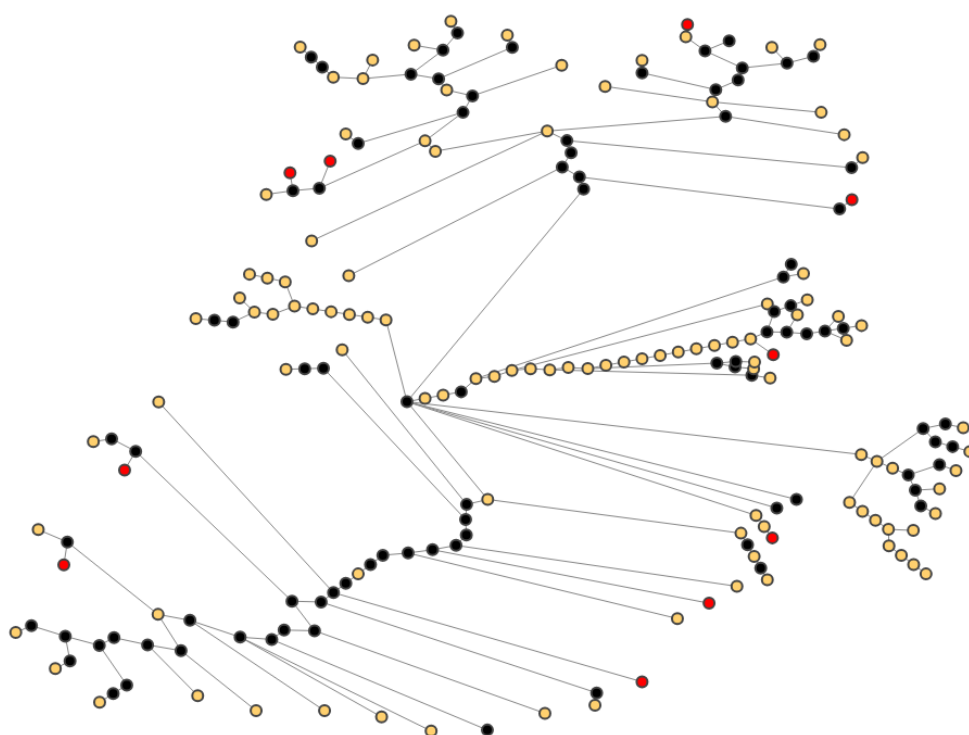


Figure 5-2 Topological E-Distribuzione network representation

Table 5-1 Information about the two real distribution systems

DSO	Total number of nodes	Load nodes	Nodes with generation	Junction nodes	Voltage [kV]
Areti	84	32	23	52	20
E-Distribuzione	208	107	-	101	15

The validation of the models has been done by comparing the obtained nodal voltages with the voltage data provided by Areti for a selected time step. The relative error was evaluated for each node and represented in Figure 5-3. The maximum relative error was equal to 0.08%, confirming the accuracy of the implemented power flow algorithm.

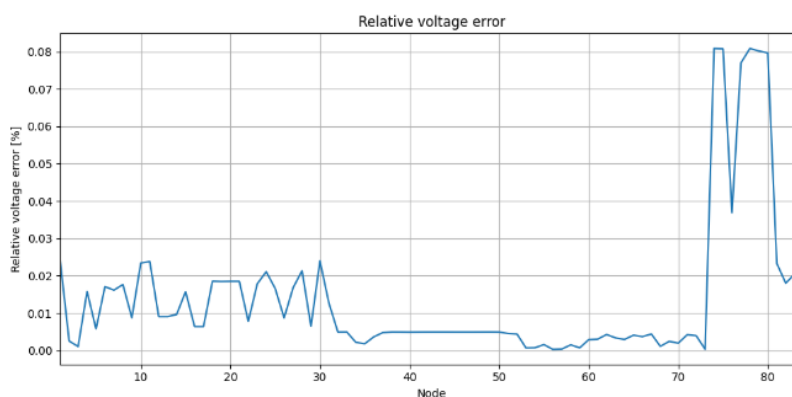


Figure 5-3 Relative nodal voltage error

5.2 Automatic tool to developing real time ready radial network models

The development of an automated MATLAB-based tool for generating Simulink models of radial distribution networks has yielded promising results [7]. Indeed, the tool successfully addresses the challenges of manual model creation by constructing hierarchical Simulink models. Key outcomes include:

1. **Standardized Data Processing:** A standardized intermediate format based on CSV files was implemented, enabling seamless integration of diverse data sources (e.g., CIM/XML, PSS/E, spreadsheets). This ensures consistency and interoperability, reducing preprocessing errors and facilitating compatibility with Simulink.
2. **Efficient Topology Analysis:** A graph-based algorithm, utilizing Python's NetworkX library, accurately identifies radial network structures and optimizes component organization. This approach ensures robust representation of network connectivity, critical for scalable and accurate model generation.
3. **Rapid Model Generation:** The tool automates the creation of Simulink models using a customized code, including three-phase nodes, PI section lines, and dynamic loads. Testing on three sample networks showed significant time savings, with model generation times ranging from approximately 30 to 76 seconds, compared to hours for manual methods.

These results confirm the tool's potential to streamline model development for research and operational planning. Ongoing work will focus on expanding the component library and addressing meshed network topologies to further enhance versatility.

5.3 Load and generation profiles

This section illustrates the application of the Density-Based Spatial Clustering of Applications with Noise (DBSCAN) algorithm for clustering electrical load curves. It presents the main steps of the methodology and the obtained results. Specifically, the analysis includes residential loads and photovoltaic generation, as well as heat pumps and public electric vehicle charging stations; these latter two types of loads, unlike the former ones, are considered strategic grid resources due to their flexibility. The goal is then to characterize the load curves to be used to define the flexibility performances obtainable by the distribution system.

5.3.1 Introduction to DBSCAN clustering algorithm

The DBSCAN algorithm is a non-supervised clustering method that identifies groups of arbitrary shapes based on local density, without requiring the number of clusters to be specified a priori. Its operation relies on two crucial parameters: the neighbourhood radius ϵ and the minimum number of samples MinPts, which define the neighbourhood of a point p :

$$N_{\epsilon}(p) = \{q \in D \mid \text{dist}(p, q) \leq \epsilon\}$$

Based on these criteria, the algorithm classifies data into three categories:

- *core points*, which meet the minimum density requirements;
- *border points*, located on the edge of a cluster;
- *noise points*, representing outliers that do not belong to any aggregation.

By expanding clusters from core points and including all density-reachable samples, DBSCAN ensures high robustness in processing complex datasets, effectively isolating noise and managing non-uniform spatial distributions.

5.3.2 Methodology

The adopted methodological procedure is structured into three main steps:

- *data preprocessing*, which includes handling missing values, data type conversion, feature extraction and analysis, and data standardization;
- *model construction*, which encompasses the dataset creation and the determination of the critical MinPts and Eps parameters;
- *evaluation and analysis* of the results.

Data preprocessing

Data preprocessing plays a key role in ensuring the reliability of the clustering results, as the quality of input data directly affects model performance. This phase included data cleaning, transformation, feature extraction, and normalization to obtain a consistent dataset suitable for the application of the DBSCAN algorithm.

The input data comprise energy measurements retrieved from PODs at 15-minute resolution, spanning the years 2024 and 2025. These quarter-hourly intervals provide the necessary granularity to accurately characterize load profiles and peak demand periods.

No missing values were detected in the 96 time-series variables describing daily load profiles. However, non-informative observations, such as profiles with zero consumption across all time steps, were removed, as they likely represent inactive users or measurement errors. Additional filtering was applied to exclude profiles characterized by unrealistically low peak values, which are not representative of actual consumption behaviour. These non-informative profiles constituted exceptions within the collected data, thereby ensuring that their removal did not compromise the overall reliability of the datasets.

Relevant variables were converted into appropriate formats (e.g., datetime) to enable the extraction of temporal information. The raw energy measurements were then converted into quarter-hourly power values. Subsequently, a set of representative features was derived from the original high-dimensional time series, significantly reducing dimensionality while preserving key consumption patterns.

Finally, data standardization was performed using Z-score normalization (StandardScaler from scikit-learn) to ensure comparability across features with different scales. This step is particularly important for clustering methods such as DBSCAN, as it prevents scale imbalances from biasing the clustering process and supports a more robust and interpretable parameter selection [8].

Model construction

The clustering analysis was performed using the scikit-learn library in Python, specifically implementing the DBSCAN algorithm [8]. The construction of the DBSCAN model required a careful calibration of its two main parameters, namely MinPts and Eps, as they directly affect cluster identification and noise handling.

For each user type, the most distinctive characteristics were extracted. These main features from each load profile are collected into a dataset, which is used both to determine the MinPts and Eps parameters and as input for the DBSCAN algorithm.

The MinPts parameter was determined through an evaluation process aimed at balancing cluster robustness and separation. Higher values of MinPts increase the density requirement for core points, leading to more stable clusters, but may also cause distinct clusters to merge. To support the selection, the Davies–Bouldin Index (DBI) was employed as an internal validation metric. This index evaluates clustering quality by considering intra-cluster compactness and inter-cluster separation, with lower values indicating better performance. The chosen MinPts value represents a trade-off between density robustness and DBI minimization [9].

The Eps parameter was estimated using the k -distance method, based on nearest neighbour distances computed via the `NearestNeighbours()` function from scikit-learn [8]. For each point, the distance to its k -th nearest neighbour (with k equal to MinPts) was calculated and sorted in descending order to produce the k -distance plot. The optimal Eps value corresponds to the “knee” of this curve, which separates dense regions from noise.

The detection of the knee is done with an interactive approach. The user analyses the sorted k -distance graph (e.g., 20-dist when MinPts = 20) and selects a threshold corresponding to the desired noise level. Points with distances above this threshold are classified as noise, while those below are assigned to clusters. This approach allows flexible control over noise reduction and improves clustering quality [10].

Therefore, for each load type, a dedicated dataset of extracted features is built to capture its specific technical and behavioural traits. Consequently, the optimal Eps and MinPts parameters are calculated independently for each category using the defined criteria. As illustrated in Figure 5-4, an example of the k -dist graph and the calibration of the Eps parameter, carried out according to the described procedure. The curve exhibits a well-defined inflection point, the separation between core density and isolated noise is stable. Minor variations around this threshold do not cause significant fluctuations in cluster formation, making a formal sensitivity analysis unnecessary.

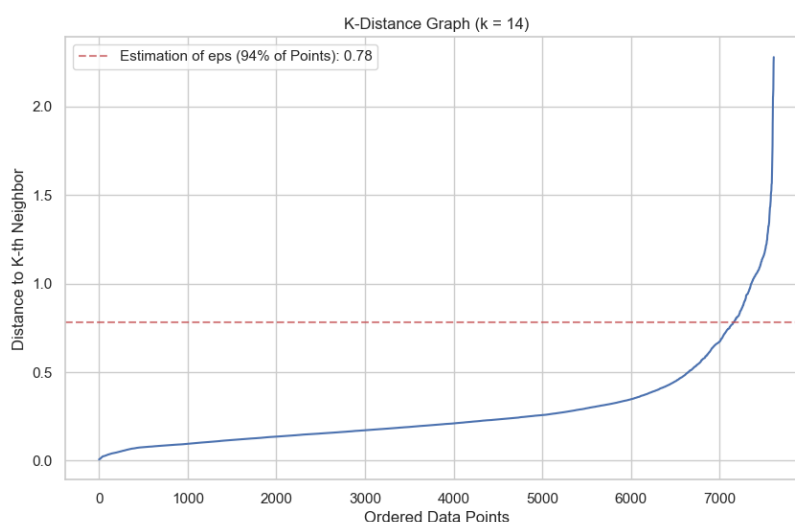


Figure 5-4 Example of k -distance graph

Evaluation and results analysis

In the final phase, the clustering results were analysed and validated using again the DBI, because enables to measures the degree of internal cluster cohesion and their mutual separation (lower index values indicate better segmentation quality) [9].

To complement the quantitative analysis, the mean values of the load curves within each cluster were calculated and plotted to visualize the representative behaviour of each group. This representation made it possible to synthesize the primary characteristics of the consumption profiles, facilitating their interpretation.

Finally, to highlight the differences between clusters, comparison graphs were created to analyse seasonal temporal variations (e.g., between summer and winter periods), differences between weekdays and holidays, and variations related to power levels. These visualizations highlighted distinctive consumption patterns, contributing to a deeper understanding of the behavioural differences among the identified clusters.

5.3.3 Clustering results: flexible loads

Heat pumps

The clustering results for the heat pumps were derived from a dataset of 7,742 load curve observations collected from 74 PODs in Rome during January and July of 2024 and 2025. The analysis was based on a set of extracted features, including Mean, Peak, Standard Deviation, Capacity Factor, Season, Holiday status, and Intended Use.

By applying the DBSCAN algorithm with parameters set at MinPts = 14 and $\epsilon = 0.78$, the model effectively captured the underlying data structure; the chosen epsilon value specifically intercepts the "elbow" of the k -distance plot, successfully limiting the identified noise to 6%. This configuration resulted in the identification of 11 distinct clusters, which are visualized in Figure 5-5, and yielded a DBI equal to 1.876. For heat pumps, the DBI is above average because the clustering captures seasonal trends and differences between weekdays and weekends; since these consumption profiles are similar, the clusters overlap, thus increasing the index.

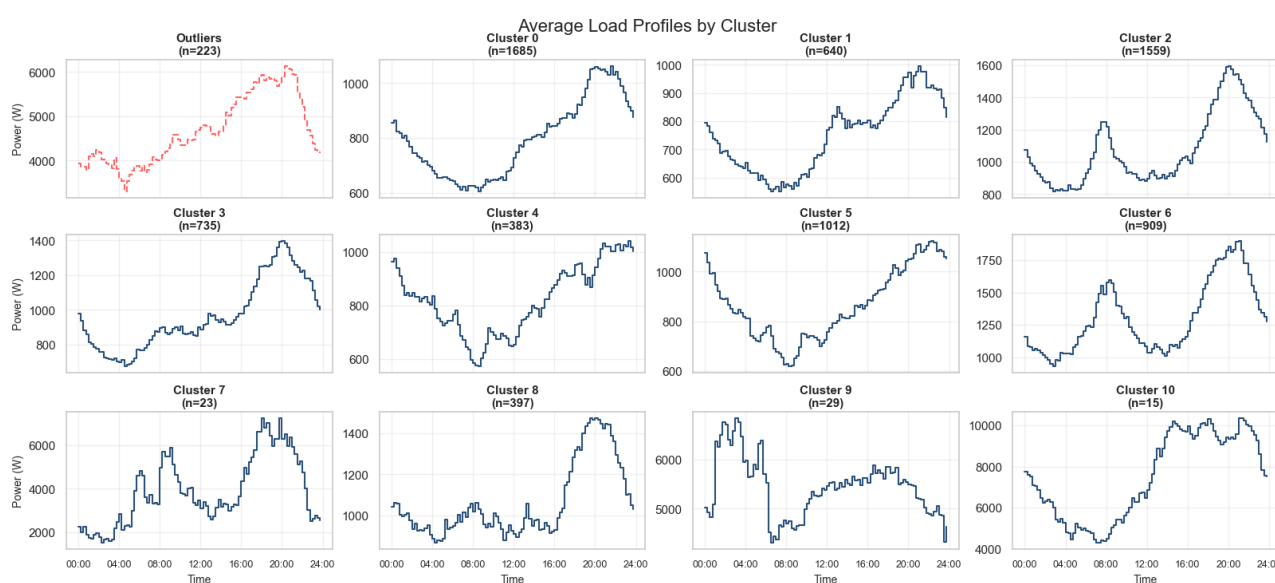


Figure 5-5 Average load profiles by cluster for heat pumps

Among the 12 mean load profiles, the first one represents outliers, the following four represent domestic use profiles, each one corresponding to a specific day type, i.e., winter weekday, winter holiday, summer weekday, and summer holiday. The remaining seven primarily capture loads with unknown intended use. Following this classification, a comparison is presented between the mean curves of the winter weekday and summer weekday domestic clusters (Figure 5-6).

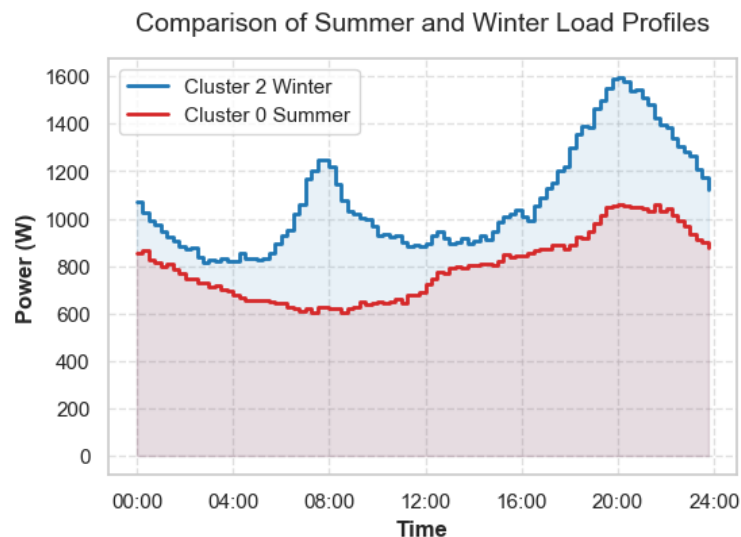


Figure 5-6 Comparison of summer and winter load profiles

Charging stations

The clustering results for electric vehicle charging stations were derived from a dataset of 81,189 load curve observations collected from 747 PODs in Rome during 2024 and 2025. The analysis was based on a set of extracted features, including Capacity Factor, Average Power Category, and Nominal Power Category. Within this framework, the Average Power Category classifies consumption trends into four distinct levels to represent the intensity of utilization, while the Nominal Power Category is utilized to differentiate the various power sizes of the POD.

For the DBSCAN implementation, the parameters were calibrated to $\text{MinPts} = 27$ and $\epsilon = 0.54$. This epsilon value was strategically selected by intercepting the k -distance graph beyond the "elbow" point, successfully limiting the noise to a marginal 0.01%. Such a restrictive configuration was essential to suppress an outlier cluster that otherwise displayed characteristics nearly indistinguishable from a legitimate cluster. As shown in Figure 5-7, the algorithm identified 13 well-defined clusters, yielding a DBI to 0.691, which confirms the high quality and separation of the identified groups.

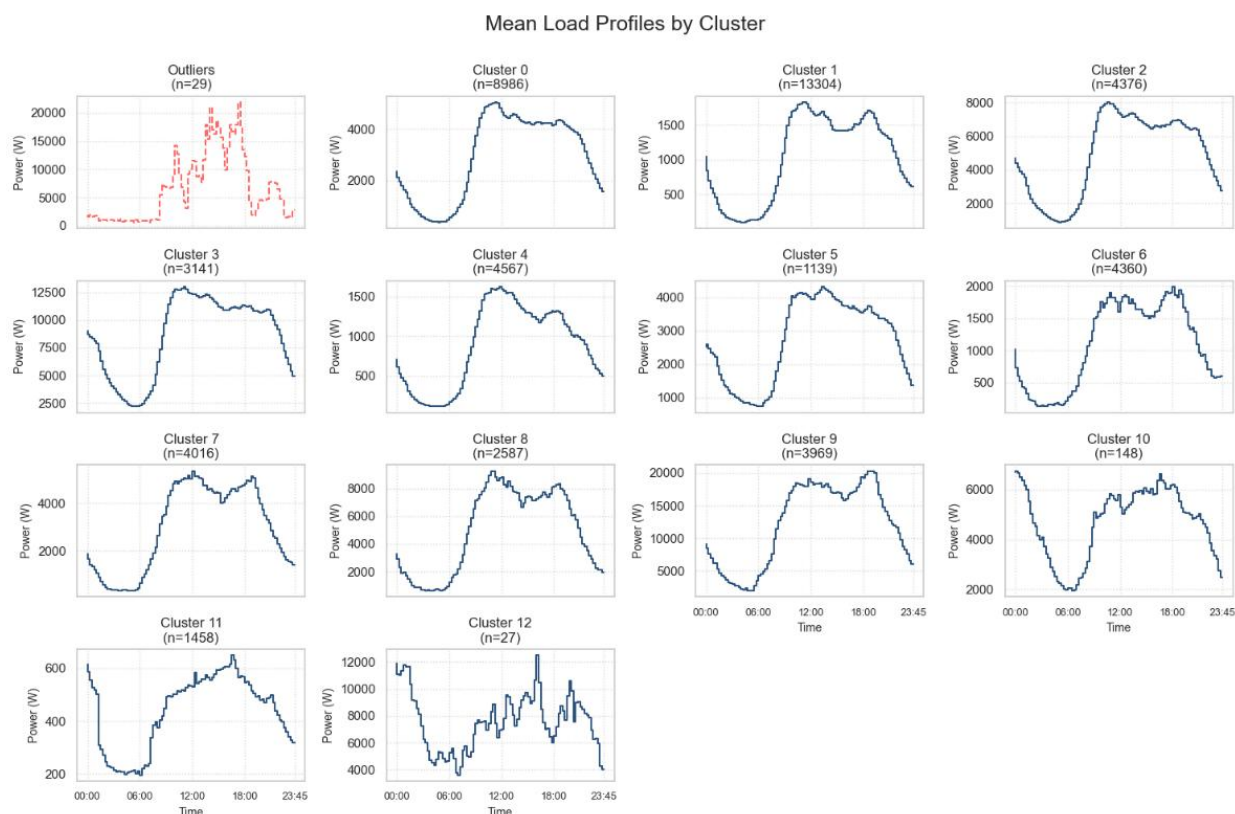


Figure 5-7 Average load profiles by cluster for electrical vehicle charging station

The following image illustrates the four clusters associated with nominal power category 2, which includes the most common size of 22 kW. One cluster is presented for each average power category; specifically, the red curve represents the cluster with the highest degree of utilization.

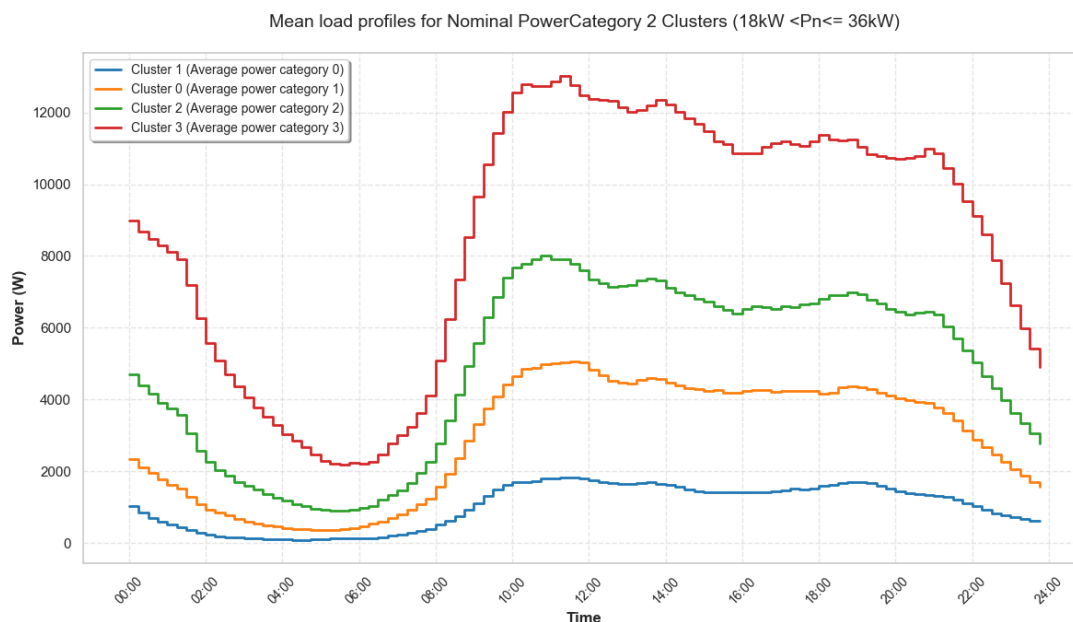


Figure 5-8 Comparison of mean load profiles for category 2 clusters

5.3.4 Clustering results: non-flexible loads and generation

Photovoltaic generation

The clustering analysis for photovoltaic generation was conducted using a feature set comprising Capacity Factor, Seasonality, Power Category, and Intended Use derived from observation of 179 different PODs located in Rome. The feature “Power Category” was specifically utilized to isolate PODs that exhibited a historical maximum peak of power less than 50 W. It was imperative to separate these extremely low-power instances to prevent them from distorting the mean generation profiles of the other clusters.

DBSCAN parameters were set to MinPts = 50 and $\epsilon = 0.04$, intercepting the k-distance graph just beyond the “elbow.” This restrictive configuration resulted in a noise level of 1.5%, a necessary trade-off to minimize the outlier cluster and ensure that only the most dense and representative patterns were grouped. –As illustrated in Figure 5-9, the algorithm identified 8 distinct clusters with a DBI of 0.632, reflecting a high level of internal cohesion. For PV generation, the DBI is excellent because there is very little internal variability, as production depends strictly on solar irradiance rather than unpredictable user behavior.

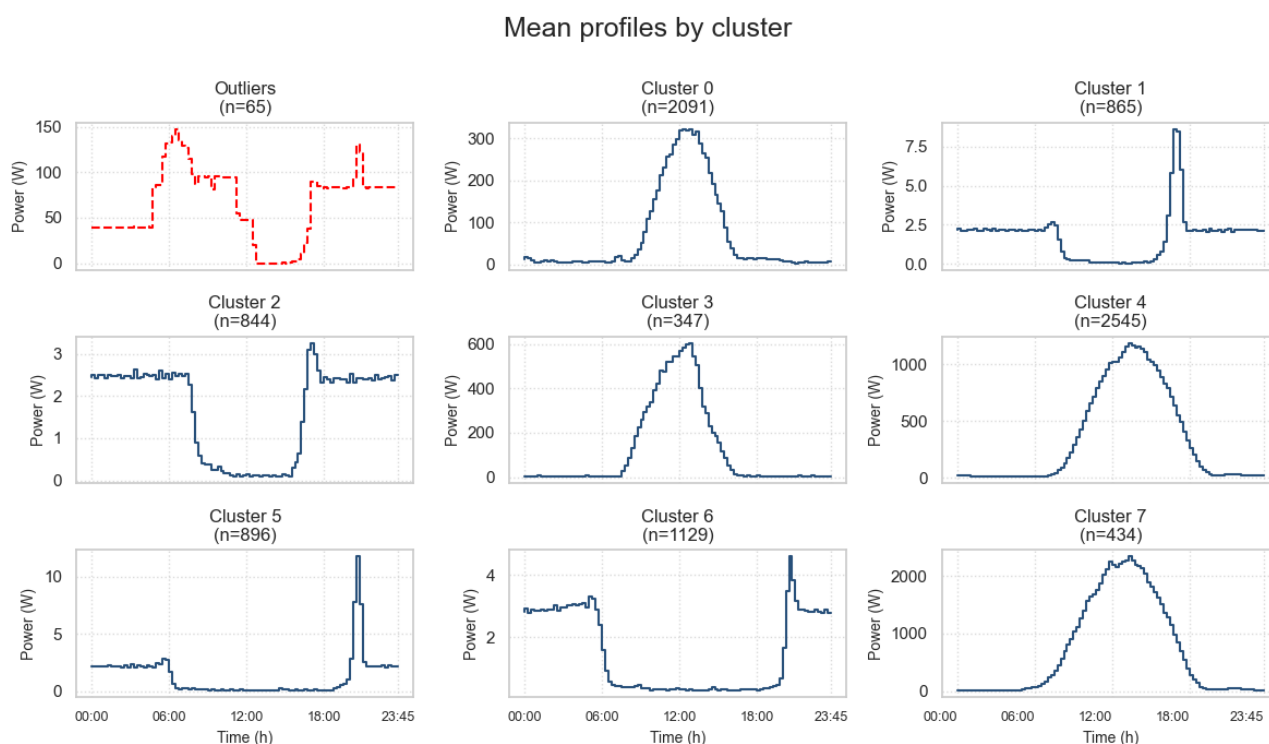


Figure 5-9 Average profiles by cluster for photovoltaic generation

Following the initial identification of 8 clusters, the four groups associated with the low power category (PODs with historical peaks below 50 W) were excluded from the analysis. Figure 5-10 presents a comparison between the four remaining mean profiles, which are distinguished by seasonality and intended use. A key observation emerges from the analysis of the domestic use profiles: these curves exhibit a noticeable delay in morning production compared to other clusters. This phenomenon is likely attributable to the presence of integrated battery energy storage systems, which prioritize charging from the solar array during the early daylight hours before exporting surplus energy.

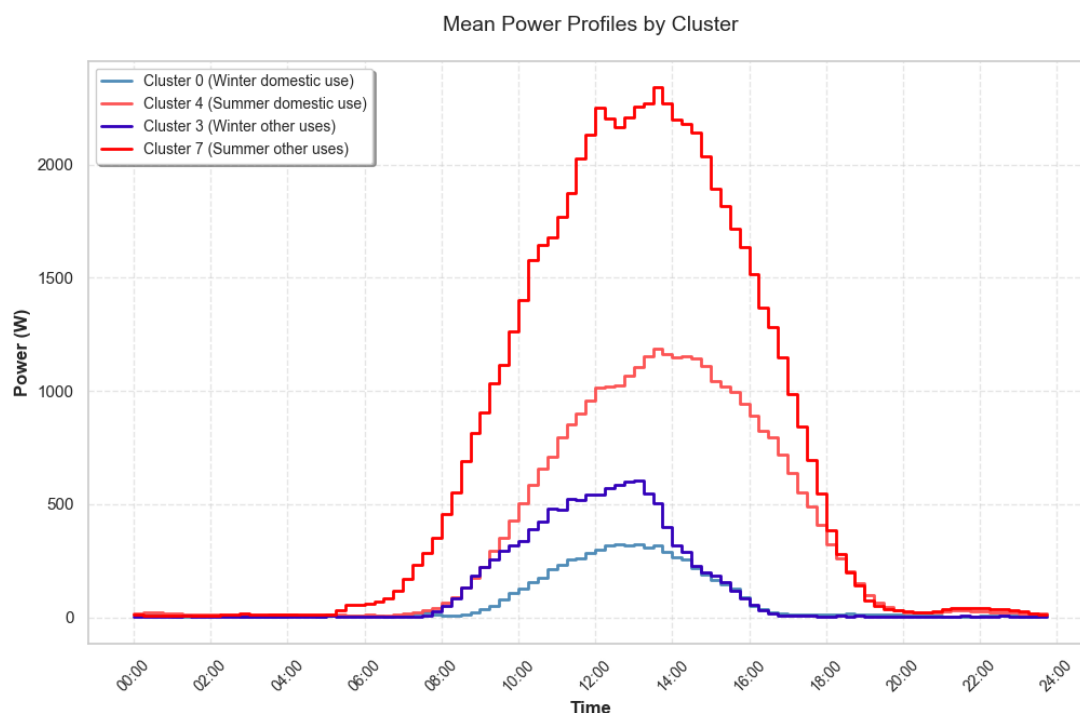


Figure 5-10 Comparison of mean profiles for photovoltaic generation clusters

Residential loads

The final stage of the clustering analysis focused on residential loads, employing a 195,726-load curve dataset collected from 2,956 PODs in Rome during 2024. The analysis was based on a feature set defined by Standard Deviation, Energy, Holiday status, Seasonality, and Energy Category. The Energy Category was specifically introduced to isolate the top 20% of profiles with the highest energy consumption, allowing for a strategic focus on critical clusters that represent the most significant impact on the grid.

To delineate these patterns, the DBSCAN parameters were set to $\text{MinPts} = 34$ and $\epsilon = 0.27$, intercepting the k -distance graph at the "elbow" point. This configuration resulted in a noise level of 4%. As shown in Figure 5-11, the algorithm identified 8 distinct clusters, achieving a DBI of 1.507.

Mean load curves by cluster

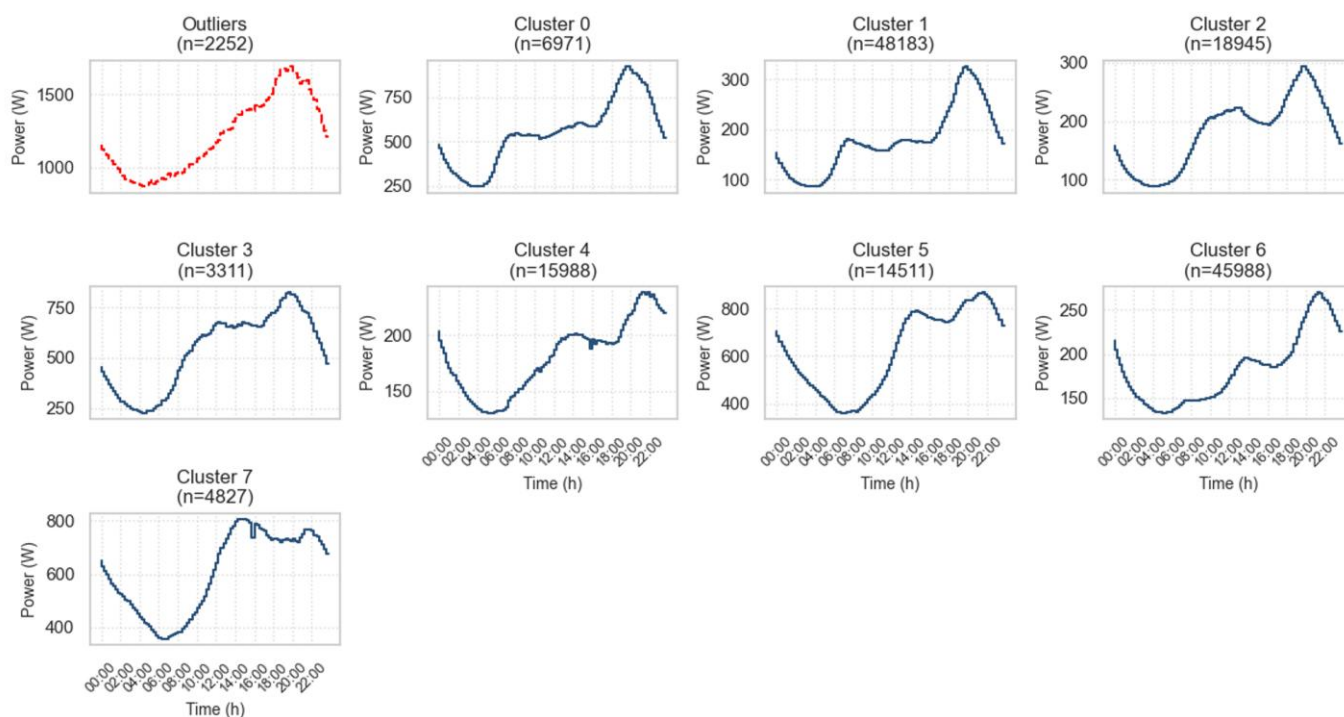
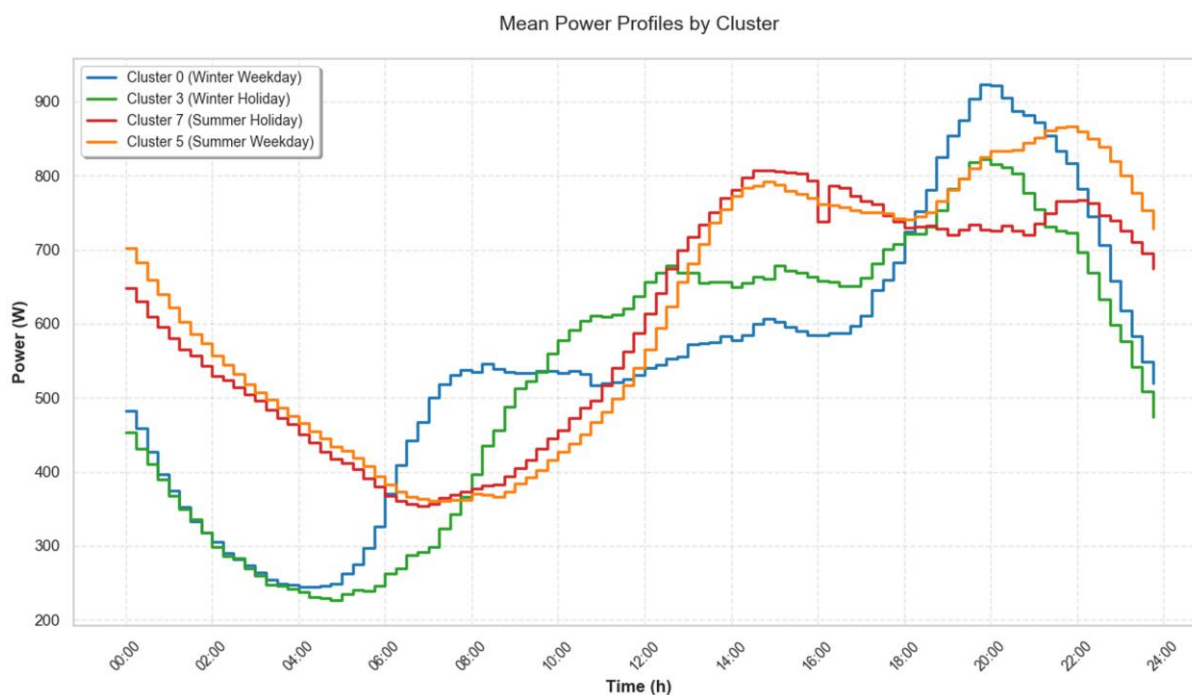
**Figure 5-11 Average load profiles by cluster for residential use**

Figure 5-12 presents the four specific clusters belonging exclusively to the High Energy Category (the top 20% by consumption). These mean profiles map distinct load behaviours across different day types: summer weekday, summer holiday, winter weekday, and winter holiday. By isolating these critical groups, it is possible to observe granular variations in peak demand and base load that are specific to high-energy residential profiles throughout the year.

**Figure 5-12 Mean power profiles by cluster for high consumption residential use**

6 Key Performance Indicators (KPI)

With reference to the DT involving the Defence System and the study on the impact of DERs on distribution system performance, namely IT01 and IT02, respectively, as described in Deliverable D2.2, “TwinEU Use Cases, Pan-European Scenarios and KPIs”, the relevant KPIs are reported in Table 6-1.

Table 6-1 Model evaluation KPIs for IT01 and IT02

ID	Name	Description
IT01_KPI1	EMT component models	Implementation of customized regulators within the transmission system models
IT01_KPI2	Creation of a dashboard	Creation of a dashboard showing in (near) real-time the system status
IT01_KPI3	HIL tests for protection purpose	Test the EAC relay using HIL approach
IT02_KPI1	Reference profiles	Creation of reference profiles of load and generation
IT02_KPI2	Automatization pipeline model building	Creation of tools for simplifying the network implementation in real-time environment
IT02_KPI3	Characterization of flexibility sources	Creation of reference MV profiles for flexibility sources

7 Simulation scenarios

7.1 Transmission system

The scenarios used for this study have been developed according to the TSO and DSO development plans [11] [12]. Sardinia is in the middle of the fastest transformation of any Italian power system: by the end of this decade the island must move from a coal-centred, weakly connected electricity network to a fully decarbonised, highly meshed node of the national grid.

7.1.1 Load, generation and storage/conversion systems

Regarding the load, even after the progressive electrification of mobility and heating sectors, the Terna's studies projects only a modest rise in regional demand: so, the 2030 peak is still expected below 2 GW, with winter mornings and summer evenings alternately driving the yearly maximum. Electrification of transport and a possible revival of energy-intensive metallurgy could lift annual consumption to roughly 9–9.5 TWh by 2030. Regarding the hourly profile, heat-pump diffusion, tourism-driven air-conditioning and an embryonic electro-hydrogen cluster around the Portovesme industrial zone flatten the curve and add steeper ramps at dawn and sunset. These ramps now dominate local adequacy studies and are the real “load driver” for network and storage investments.

With reference to the generation systems, the national “PNIEC Policy 2030” scenario allocates 5.2 GW of new solar PV and 3.1 GW of wind farms to the island, more than trebling today's renewable fleet and bringing total variable RES to 8.3 GW. Parallel policy provisions mandate the complete coal phase-out; both the 640 MW of CP1 power plants and the 585 MW of CP2 units are therefore scheduled for closure within the next few years (as soon as Tyrrhenian Link - T-Link - goes into operation).

To integrate such an asymmetric renewable fleet, Sardinia is assigned to have 14.1 GWh of battery storage (0.4 GWh residential, 3.2 GWh capacity-market contracted, 10.4 GWh utility-scale) in the 2030 target year. Hydrogen electrolyzers reach a modest 300 MW, scheduled to run on curtailed solar in spring afternoons; their electrical impact is negligible today, but they offer a strategic outlet for future over-generation.

7.1.2 Grid architecture

With the new generation mix the present radial 220 kV backbone is no longer adequate. Two strategic projects from Terna's 2025 Development Plan reshape the island's electrical geography:

- **Tyrrhenian Link – West HVDC**, 500 kV, 1000 MW, commissioning 2026, and the East branch (2028), create a bidirectional highway that turns Sardinia from electrical cul-de-sac into the Mediterranean hub.
- **SA.CO.I. 3, the 400 MW HVDC**, 200 kV replacement of the ageing Corsica–Sardinia–Italy link, due 2029, provides an additional northbound evacuation path and hardens resilience against N-1 contingencies.

7.1.3 Simulation scenario

Within the TwinEU project, the Sardinian defence plan is assessed in a real-time simulation environment under a stressed but credible operating condition. In the selected scenario, the island system is characterized by a medium load level at 9:00 p.m., with generation provided by thermal

units (1,154 MW), wind generation (2 MW), and hydro generation (189 MW), while power exchanges with the mainland are set at 302 MW export through the SA.CO.I. HVDC link and the SARCO interconnection. The network topology is further weakened by the planned outage of the SA.PE.I HVDC link for maintenance, resulting in reduced transfer capability and lower operational margins. Under these conditions, the system becomes particularly sensitive to severe disturbances. The activation of the defence plan is triggered by a sequence of contingencies, starting with trip of the CP1–S1 generating unit (207 MW) and followed after 10 seconds by second contingency consisting of the trip of the TP–SX3 generating unit (191 MW), leading to a frequency transient that triggers the intervention of the defence plan. This scenario, summarised in Figure 7-1, is therefore used to verify the effectiveness of the Sardinian defence plan in preserving system security and limiting the propagation of the disturbance.

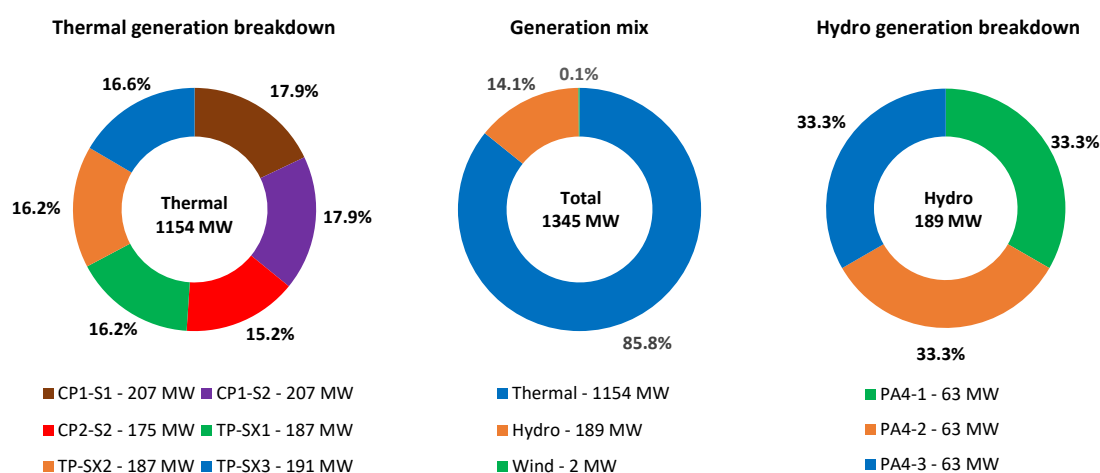


Figure 7-1 Visual summary of the transmission system simulation scenario

7.2 Distribution system

7.2.1 Features of the chosen genetic algorithm

The purpose of the genetic algorithm is to provide distribution system operators (DSOs) with a planning tool to mitigate network performance degradation. By simulating scenarios that incorporate the installation of photovoltaic generation and flexible loads, the genetic algorithm evaluates how network losses and operational constraints can vary.

The chosen methodology makes use of a Genetic Algorithm (GA) implemented using the PyGAD library in Python [13]. The algorithm operates on an initial random population consisting of 50 chromosomes, where each chromosome is formed by 64 genes with decimal values between 0 and 1. These genes are equally partitioned: the first 32 genes evaluate the placement of distributed generation (DG) at secondary substations, while the remaining 32 genes manage the installation of loads at the same locations. In fact, the network considered is the one described in Table 5-1 consisting of 84 branches and 85 nodes (including the slack). However, only 32 nodes are secondary substations with a non-zero connected load.

The performance of each candidate solution is assessed via a multi-objective fitness function that simultaneously pursues system efficiency by minimizing total network losses L_{tot} and social equity by minimizing the Gini index G of the average allocated losses (see Annex B)¹:

$$fitness = -\left(\frac{L_{tot}}{L_0} \cdot \psi_L + \frac{G}{G_0} \cdot \psi_G\right)$$

Specific weights are selected to prioritize different objectives.

To evolve the population toward optimal solutions, the GA employs crossover and mutation operators, with the mutation process guided by the average allocated losses indicator to direct the placement of assets effectively. These values are consistent with established practice in genetic algorithm literature [14]. A high crossover probability (typically in the range of 0.6–0.9) is generally adopted to promote effective recombination of good partial solutions and to enable thorough exploration of the search space, while a low mutation probability is preferred to preserve high-quality solutions discovered during the search, introducing only enough diversity to prevent premature convergence to local optima without disrupting the evolutionary progress. The selected values of 0.8 and 0.1 fall within these commonly recommended ranges and were further validated through preliminary sensitivity tests on the network under study, which confirmed stable convergence behavior within the generation limit.

The optimization process concludes automatically after 250 generations, the number of generations is big enough to guarantee sufficient improvement. At the same time, an early stopping criterion has been implemented, if no improvement is detected in the best solution for 10 consecutive generations the algorithm is stopped.

7.2.2 Network solution algorithm

For network solution is carried out by applying the Backward Forward Sweep (BFS) algorithm [15], which requires the following mathematical elements:

- incidence matrix $\mathbf{L}$: defines the network topology. Its inverse is used to derive the set of branches $\mathfrak{B}_k$ (connecting node 0 to node k) and the set of nodes $\mathbf{R}_b$ supplied by branch b ;
- line impedance matrix $\mathbf{Z}_B$: a diagonal matrix reporting the resistance and reactance values of the branches;
- transversal admittance vector $\mathbf{y}$: contains the semi-susceptances for each branch;
- thermal limits vector $\mathbf{i}_{lim}$: specifies the current-carrying capacity for each branch;
- load matrix $\mathbf{S}_{car}$: records the net power values for each node at every time instant.

Based on the instructions provided by the optimal chromosome, the load matrix $\mathbf{S}_{car}$ is dynamically updated. The daily evolution of these added components is determined by specific increment profiles showed in Figure 7-2 and Figure 7-3, identified through the clustering technique explained in Section 5.3.

¹ Gini indicator of the allocated losses. This index is used to evaluate the fairness of the loss distribution among the nodes: a value of 0 represents a perfectly egalitarian distribution (optimal condition), whereas a value of 1 indicates maximum inequality, where the allocated losses are unfairly concentrated at a single point (poor condition). More information about the allocated losses can be found in Annex B.

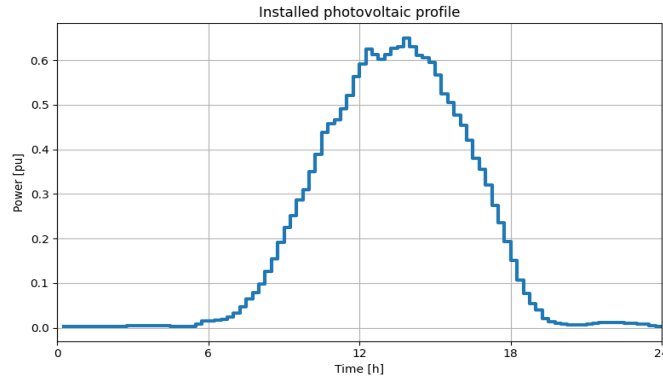


Figure 7-2 Normalized PV power profile

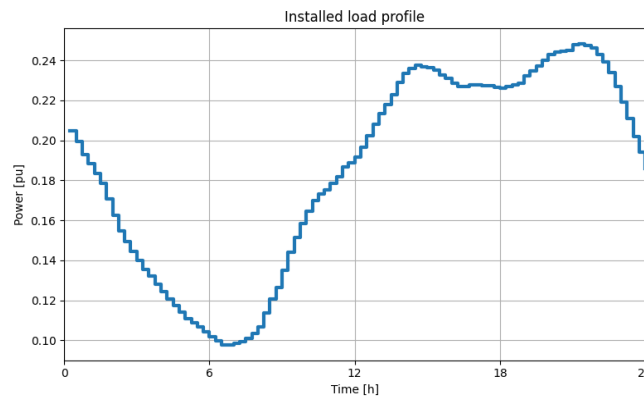


Figure 7-3 Normalized load power profile

7.2.3 Implemented load and generation scenarios

Four scenarios have been implemented. The first two focus on the installation of photovoltaic generation alone, evaluating the impact of both high and low renewable energy penetration. The remaining scenarios explore the application of new photovoltaic generation alongside demand, distinguishing between a highly flexible load profile and a more realistic one characterized by a low concentration of flexible loads.

The amount of new load or generation to be installed across the various scenarios was derived relative to a percentage of the energy absorbed at the slack node. This calculation is performed according to the following formula:

$$P[MW] = \frac{x_i[\%] \cdot E_{slack}[MWh]}{E[pu \cdot h]}$$

In this equation, E represents the energy in "per unit per hour" ($pu \cdot h$), which is derived from the increment curves obtained through the clustering analysis. This approach ensures that the total installed capacity is consistently scaled based on the baseline energy consumption of the network.

The primary results of the genetic algorithm are analysed by comparing total losses and their percentage relative to network consumption, the Gini index calculated based on allocated losses, and the two network constraints under consideration: voltage drop and branch loading levels. Furthermore, the performance of the genetic algorithm is benchmarked against both a random installation scenario and the initial network conditions.

The cases compared are:

- GA BEST: this case represents the use of GA to install generation/load leading to a network performance improvement;
- GA WORST: this case represents the use of GA to install generation/load that leading to a network performance degradation;
- RANDOM: in this case generation and loads are installed randomly.

All tests confirmed that the GA BEST algorithm improves network efficiency compared to the RANDOM installation of generation and load. Conversely, the GA WORST approach maximizes losses, yielding worse results than random algorithm and, in some instances, leading to violations of network constraints.

As an additional remark, the GA BEST (50-50) variant differs from the GA BEST (100-0) in its fitness function: the former assigns equal weight to optimizing total losses and the Gini index, while the latter focuses solely on minimizing total losses.

7.2.4 Base scenario

The *initial conditions* represent the current network's operational configuration (based on the data provided by Areti). In agreement with Areti, a *Base Scenario* was developed by multiplying the all the nodal loads of a factor equal to six, to create network in particularly stress conditions. This high-load configuration serves as the benchmark for the subsequent comparative analysis of the four proposed network planning scenarios.

Table 7-1 shows the performance indices derived from the BFS calculation for both the initial conditions and the Base Scenario. Regarding the former, the daily energy absorbed from the slack bus is 30.45 MWh, while the total losses amount to 14 kWh, corresponding to 0.14 pu. The percentage of total losses is calculated relative to the total power absorbed by the nodes, demonstrating that the energy dissipation is essentially negligible. Furthermore, the maximum voltage drop and the maximum loading level show that the network is currently operating under low load conditions. This under-loaded state directly accounts for the minimal network losses and the negligible voltage drop, confirming the excellent initial performance of the infrastructure.

In the Base Scenario, the daily energy absorbed from the slack node increases to 183.12 MWh. The data shows a significant increase in total losses, maximum voltage drop and maximum loading level.

Table 7-1 Performance Indices for initial condition and base scenario

	Total losses [pu]	Total losses [%]	Gini Index	Max ΔV	Max loading level
Initial condition	0.14	0.047%	0.38	0.08%	5.6%
Base scenario	0.46	0.25%	0.42	0.58%	35.00%

7.2.5 Scenario A: Low renewables penetration scenario

The first scenario analyses the network following the installation of 7.95 MW of PV plants, with a total daily photovoltaic generation equal to 20% of the network's initial energy consumption.

The generation profile used to update the existing load matrix is the curve illustrated in Figure 7-2, which was obtained through clustering and characterizes summer usage for non-domestic users. The domestic generation profile was excluded because of the characteristic morning delay associated with battery storage charging.

Table 7-2 demonstrates that the GA BEST (100-0) algorithm, which prioritizes the optimization of total losses, achieves the lowest overall loss percentage. On the other hand, the GA BEST (50-50) algorithm, despite a slight increase in losses compared to the random scenario, achieved the best Gini index, thereby resulting in lower inequality in the allocation of network losses.

Table 7-2 Performance Indices for low renewable penetration by algorithm

Algorithm	Total losses [pu]	Total losses [%]	Gini Index	Max ΔV	Max loading level
Initial	0.46	0.25%	0.42	0.58%	35.00%
GA BEST (50-50)	0.39	0.26%	0.22	0.68%	34.78%
GA WORST (50-50)	0.37	0.25%	0.51	0.57%	34.72%
RANDOM	0.36	0.25%	0.41	0.57%	34.81%
GA BEST (100-0)	0.30	0.21%	0.40	0.57%	34.70%
GA WORST (100-0)	0.78	0.53%	0.40	1.80%	36.46%

Figure 7-4 highlights how the use of the genetic algorithm leads to a reduction in network losses compared to the initial state. In contrast, the GA WORST algorithms maximize these losses, demonstrating that *improper planning* results in a significant *increase in total network losses*.

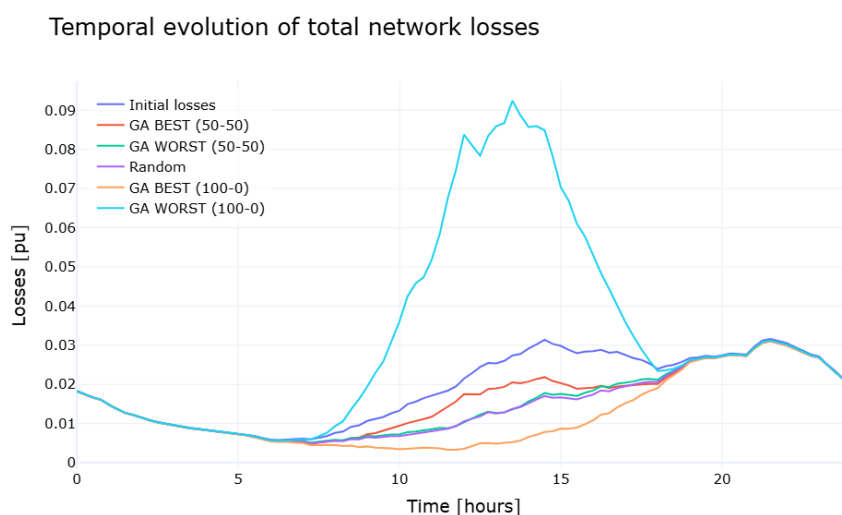


Figure 7-4 Temporal evolution of total network losses for low renewables penetration scenario

7.2.6 Scenario B: High renewables penetration scenario

The second scenario examines considers 27.83 MW of PV plants, whose daily production accounts for 70% of the network's initial energy consumption.

The following table shows that the GA BEST (100-0) algorithm, which prioritizes the optimization of total losses, yields the lowest overall loss. GA BEST (50-50) achieved the best Gini index, thereby ensuring a more equitable allocation of network losses.

Compared to the previous scenario, the GA BEST algorithms show lower total losses in p.u. and maintain very similar values for branch loading levels and maximum voltage drop. The increase in percentage total losses is solely due to them being calculated relative to the network consumption, which has significantly decreased thanks to the higher internal generation.

The GA WORST algorithms yielded solutions that result in violations of voltage and current limits. Such violations are permitted by the algorithm during the early stages of the optimization search; however, as the algorithm is oriented toward maximizing losses, it finds the peak fitness in these initial phases while constraints are still relaxed. The GA WORST algorithm purpose is to demonstrate that, in case of incorrect planning, the same PV amount that before enabled a network performance improvement leads instead to a severe degradation in grid efficiency and to a violation of network constraints.

Table 7-3 Performance Indices for high renewable penetration by algorithm

Algorithm	Total losses [pu]	Total losses [%]	Gini Index	Max ΔV	Max loading level
Initial	0.46	0.25%	0.42	0.58%	35.00%
GA BEST (50-50)	0.32	0.58%	0.19	0.65%	34.14%
GA WORST (50-50)	3.45	6.33%	0.74	5.40%	110.00%
RANDOM	0.40	0.73%	0.28	1.01%	34.16%
GA BEST (100-0)	0.28	0.52%	0.36	0.56%	39.06%
GA WORST (100-0)	3.49	6.41%	0.76	5.50%	110.00%

Figure 7-5 illustrates that the high losses associated with the GA WORST algorithms stem from improper planning of the PV installation; in fact, the losses are concentrated during the central hours of the day, coinciding with peak production. Conversely, the optimization achieved through GA BEST limits total losses, keeping them consistently below the levels resulting from the RANDOM algorithm.

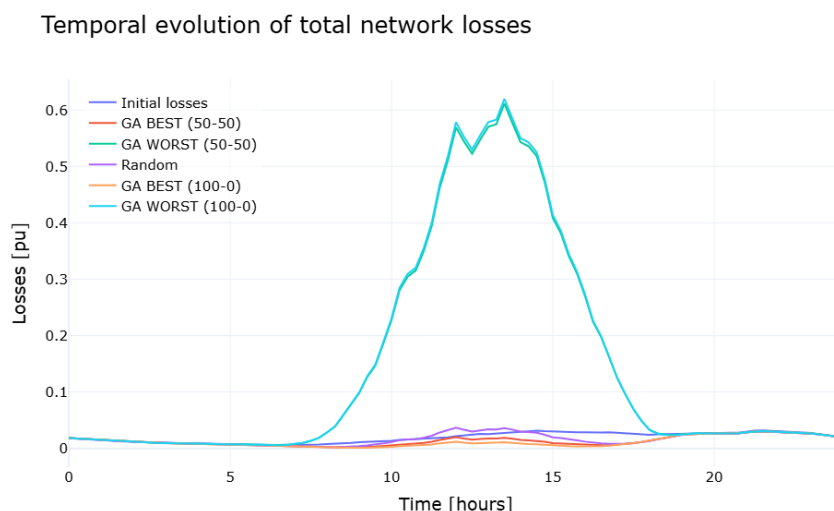


Figure 7-5 Temporal evolution of total network losses for high renewables penetration scenario

7.2.7 Scenario C: Low flexibility scenario

The third scenario integrates the installation of 27.83 MW of PV systems with a new load of 22.49 MW; the production and consumption of these assets correspond to 70% and 65%, respectively, of the energy absorbed by the grid in its base status.

The load follows the aggregate profile shown in Figure 7-3, which includes contributions from new residential loads, charging stations, and heat pumps. For this scenario, characterized by a low concentration of flexible loads, the relative share of each load type is based on 2030 Areti scenario: 87% for residential loads, 10% for heat pumps, and 3% for charging stations [16].

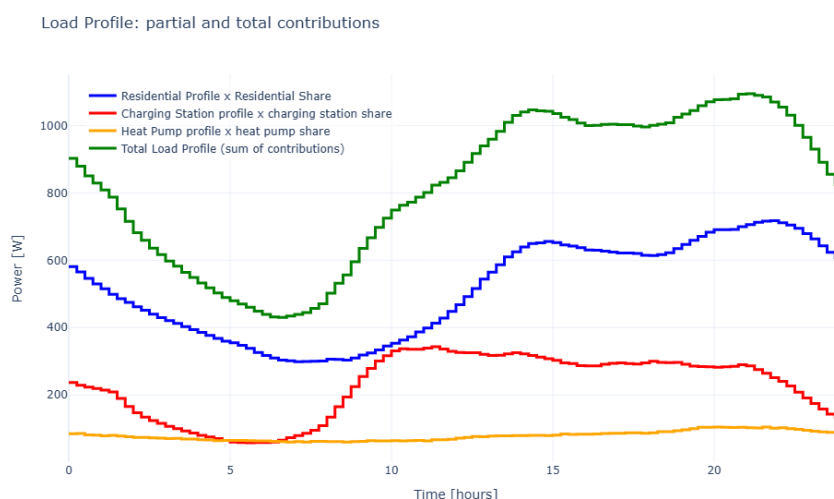


Figure 7-6 Load profile: partial and total contributions for low flexibility scenario

Figure 7-6 illustrates the partial contributions and the total load curve. The individual component curves were determined using the clustering method described in Section 5.3.3 and Section 5.3.4. Specifically, the blue and yellow profiles represent the average load for the residential and heat pump clusters on a summer weekday, each weighted by its respective share; meanwhile, the red curve

illustrates the average profile of a cluster assigned to charging stations with a nominal power of approximately 22 kW. The resulting total curve, shown in green, follows a morphology similar to that of the residential load, which remains the predominant factor.

Table 7-4 demonstrates how the GA BEST (100-0) algorithm succeeds in achieving lower total losses compared to the random scenario, maintaining them at levels similar to the initial network conditions without significantly impacting the Gini index or voltage and current constraints. Meanwhile, the GA BEST (50-50) algorithm proves to be the most effective in ensuring a uniform distribution of allocated losses.

Figure 7-7 shows that the GA BEST algorithm manages to achieve lower losses during central hours compared to the initial configuration, despite the load increase. Conversely, GA WORST exhibits the highest losses during the hours of PV production. During nighttime hours, GA BEST losses increased relative to the initial configuration due to the higher load yet remained lower than those of the RANDOM configuration.

Table 7-4 Performance Indices for low flexibility scenario by algorithm

Algorithm	Total losses [pu]	Total losses [%]	Gini Index	Max ΔV	Max loading level
Initial	0.46	0.25%	0.42	0.58%	35.00%
GA BEST (50-50)	0.57	0.33%	0.10	0.84%	51.02%
GA WORST (50-50)	4.01	2.59%	0.66	5.41%	110.00%
RANDOM	0.68	0.39%	0.31	0.89%	52.404%
GA BEST (100-0)	0.46	0.27%	0.32	0.69%	58.963%
GA WORST (100-0)	3.98	2.58%	0.66	5.46%	109.80%

Temporal evolution of total network losses

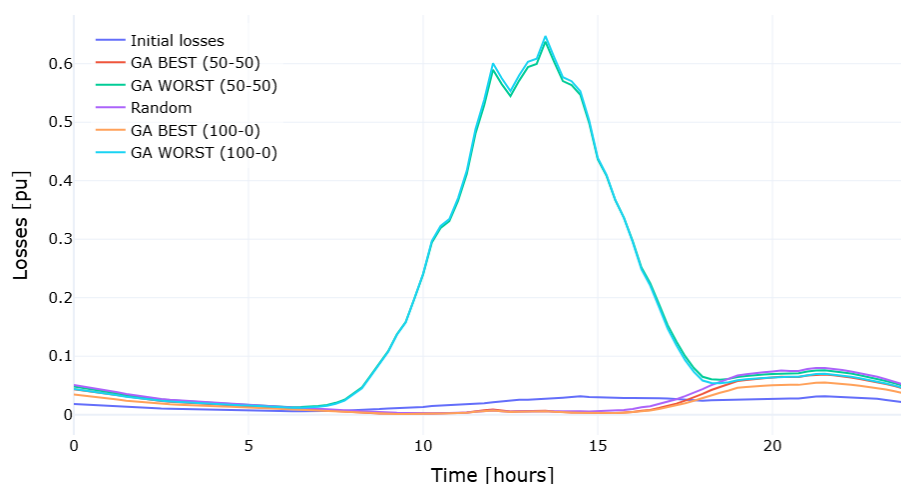


Figure 7-7 Temporal evolution of network losses for low flexibility scenario

7.2.8 Scenario D: High flexibility scenario

The last scenario retains the characteristics of Scenario C, i.e., 27.83 MW of PV and 22.49 MW of loads. However, the *aggregate curve has been modified by limiting new residential loads to only 50% of the total*. The *remaining 50% is allocated to flexible loads*, maintaining the proportionality for heat pumps and charging stations indicated by the 2030 Areti scenarios, specifically 38% and 12% respectively [16]. Figure 7-8 illustrates the resulting aggregate load profile, which is predominantly characterized by the contribution of the charging stations.

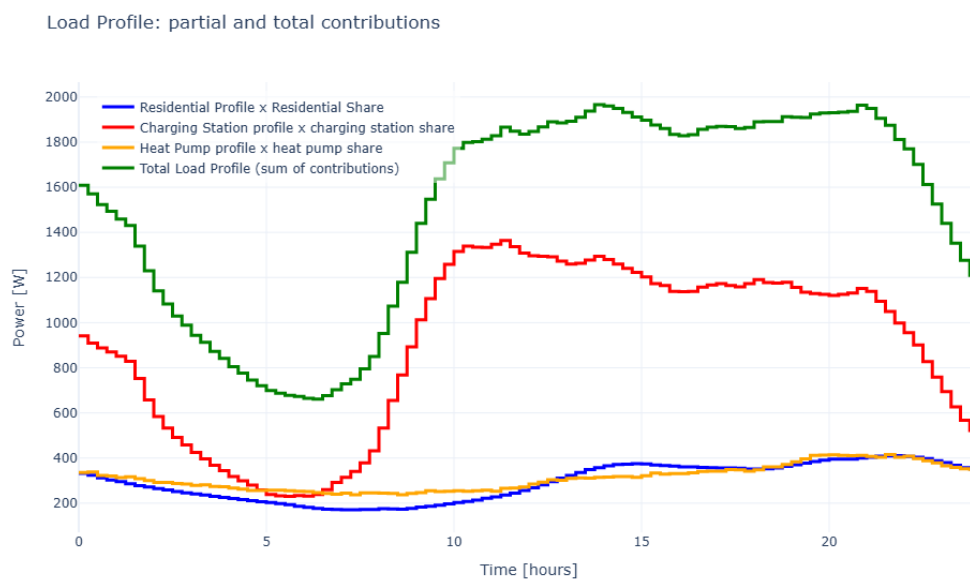


Figure 7-8 Load profile: partial and total contributions for high flexibility scenario

Regarding the high flexibility scenario, the indices shown in Table 7-5 are similar to those of the low flexibility scenario: the GA BEST (100-0) algorithm succeeds in achieving lower total losses compared to the random scenario, maintaining them at levels similar to the initial network conditions. This is accomplished without a significant impact on the Gini index or voltage constraints, while also maintaining a low impact on branch loading levels. At the same time, the GA BEST (50-50) algorithm proves to be the most effective in achieving the most equitable distribution of allocated losses.

Table 7-5 Performance Indices for high flexibility scenario by algorithm

Algorithm	Total losses [pu]	Total losses [%]	Gini Index	Max ΔV	Max loading level
Initial	0.46	0.25%	0.42	0.58%	35.00%
GA BEST (50-50)	0.55	0.32%	0.11	0.83%	50.45%
GA WORST (50-50)	4.12	2.37%	0.64	5.42%	109.99%
RANDOM	0.76	0.44%	0.34	1.17%	51.89%
GA BEST (100-0)	0.43	0.25%	0.34	0.66%	59.18%
GA WORST (100-0)	4.16	2.40%	0.63	5.39%	109.92%

As illustrated in the Figure 7-9, the results remain very similar to the previous case. In summary: GA BEST consistently outperforms the RANDOM configuration and reduces losses during peak hours despite higher loads, while GA WORST shows its poorest performance specifically during PV production periods.

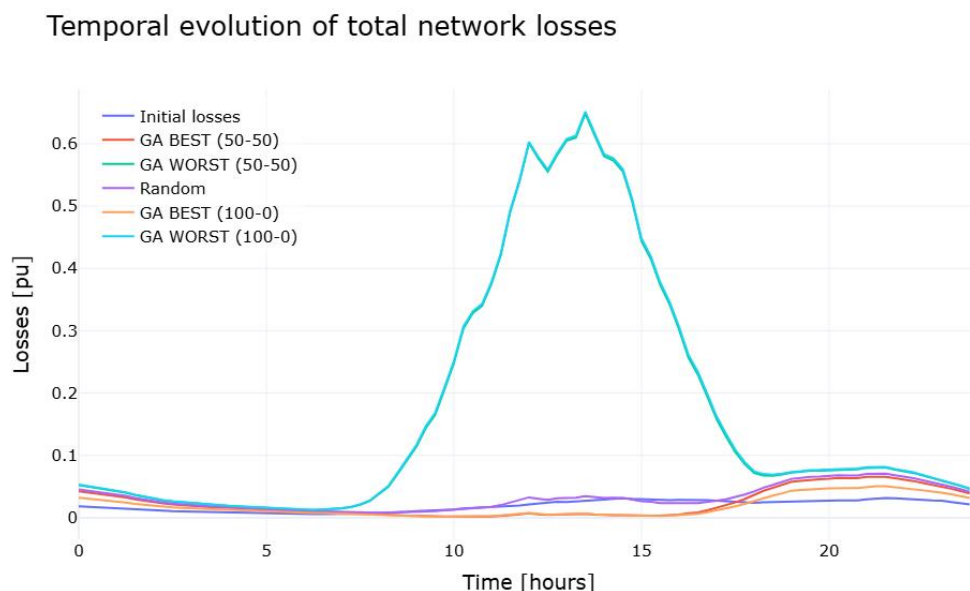


Figure 7-9 Temporal evolution of network losses for high flexibility scenario

7.2.9 E-distribuzione distribution system

The same methodology was applied to the e-distribuzione distribution system, and the corresponding results are reported in Table 7-6 – Table 7-9.

It is important to note that the analysed network already operated under a higher loading condition compared to the previous case study. For this reason, instead of defining a base scenario by scaling the nodal loads with a fixed factor, the different scenarios were developed directly from the initial operating conditions of the network. Under these conditions, the daily energy consumption at the slack node is equal to 31.45 MWh, while the maximum recorded loading level is 43%.

Table 7-6 Performance Indices for low renewables penetration scenario by algorithm

Algorithm	Total losses [pu]	Total losses [%]	Gini Index	Max ΔV	Max loading level
Initial	0.057	0.18%	0.56	1.70%	42.98%
GA BEST (50-50)	0.057	0.23%	0.56	1.70%	42.97%
GA WORST (50-50)	0.055	0.22%	0.66	1.73%	42.79%
RANDOM	0.056	0.22%	0.60	1.71%	42.88%
GA BEST (100-0)	0.050	0.20%	0.62	1.70%	42.62%
GA WORST (100-0)	0.060	0.24%	0.56	1.74%	42.97%

Table 7-6 presents the performance indices of the e-distribuzione network under equivalent conditions for the first scenario. In this case, 1.37 MW of photovoltaic capacity was installed, corresponding to an energy production equal to 20% of the total energy consumption.

Table 7-7 presents the results of the second scenario, characterized by a higher penetration of renewable energy sources. In this case, 4.80 MW of photovoltaic capacity was installed, corresponding to 70% of the total daily energy consumption.

Table 7-7 Performance Indices for high renewables penetration scenario by algorithm

Algorithm	Total losses [pu]	Total losses [%]	Gini Index	Max ΔV	Max loading level
Initial	0.057	0.18%	0.56	1.70%	42.98%
GA BEST (50-50)	0.046	0.5%	0.52	1.70%	45.89%
GA WORST (50-50)	0.076	0.81%	0.67	1.89%	65.46%
RANDOM	0.056	0.60%	0.61	1.76%	44.14%
GA BEST (100-0)	0.044	0.47%	0.57	1.70%	42.00%
GA WORST (100-0)	0.081	0.88%	0.57	1.89%	66.93%

Table 7-8 reports the results for the third scenario, in which, in addition to the installation of 4.80 MW of photovoltaic capacity, the load demand was increased by 4.61 MW, corresponding to a 65% increase with respect to the initial conditions. The additional demand mainly consists of new residential loads, whose aggregated load profile is shown in Figure 7-6.

Table 7-8 Performance Indices for low flexibility scenario by algorithm

Algorithm	Total losses [pu]	Total losses [%]	Gini Index	Max ΔV	Max loading level
Initial	0.057	0.18%	0.56	1.70%	42.98%
GA BEST (50-50)	0.055	0.18%	0.34	1.70%	44.62%
GA WORST (50-50)	0.075	0.25%	0.69	1.81%	50.62%
RANDOM	0.063	0.21%	0.61	1.74%	46.18%
GA BEST (100-0)	0.049	0.16%	0.64	1.69%	42.65%
GA WORST (100-0)	0.098	0.33%	0.51	1.88%	61.20%

Table 7-9 presents the results for the fourth and final scenario, which differs from the previous one in the composition of the new aggregated load. In this case, the load includes a higher share of flexible demand and is mainly characterized by electric vehicle charging stations, as shown in Figure 7-8.

Table 7-9 Performance Indices for high flexibility scenario by algorithm

Algorithm	Total losses [pu]	Total losses [%]	Gini Index	Max ΔV	Max loading level
Initial	0.057	0.18%	0.56	1.70%	42.98%
GA BEST (50-50)	0.056	0.19%	0.36	1.71%	44.64%
GA WORST (50-50)	0.072	0.24%	0.70	1.82%	50.06%
RANDOM	0.062	0.21%	0.63	1.73%	46.54%
GA BEST (100-0)	0.049	0.16%	0.62	1.69%	42.78%
GA WORST (100-0)	0.093	0.31%	0.50	1.85%	57.43%

Overall, the tables confirm the trends already discussed. The GA (50–50) algorithm consistently achieves the best Gini index, ensuring a more balanced distribution of allocated losses while simultaneously limiting total network losses.

Conversely, GA BEST (100–0) is the most effective in minimizing total losses, whereas the two GA WORST algorithms demonstrate how inappropriate planning strategies can negatively affect both network efficiency and the satisfaction of operational constraints.

8 Results

8.1 BESS modelling and testing in real time benchmark environment

In the preliminary phase of the project, due to the unavailability of data for the specific networks outlined in the document, a reference network model was used to develop and validate the distribution grid model [17]. The focus was on integrating Battery Energy Storage Systems (BESS) and Emergency Automatic Control (EAC) relay behaviour to improve frequency stability.

Figure 8-1 illustrates the general configuration of a BESS connected to the grid. The battery storage interfaces with the grid through a bidirectional buck-boost converter, which manages charge and discharge processes during severe operating conditions, such as faults. The hybrid subsystem connects the BESS to the utility grid at the Point of Common Coupling (PCC) from the Grid-side Voltage Source Converter (G-VSC) AC output terminals, via a low-pass filter and an interconnection transformer, modelled as an inductor. These components filter harmonics and isolate the BESS from the utility grid. The BESS's model in Figure 8-2 is divided into three main subsystems:

- the power subsystem;
- the control subsystem;
- the measurement subsystem.

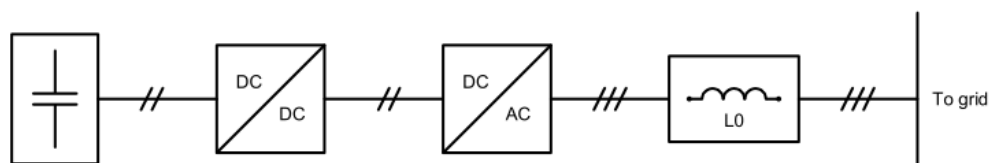


Figure 8-1 BESS general connection scheme

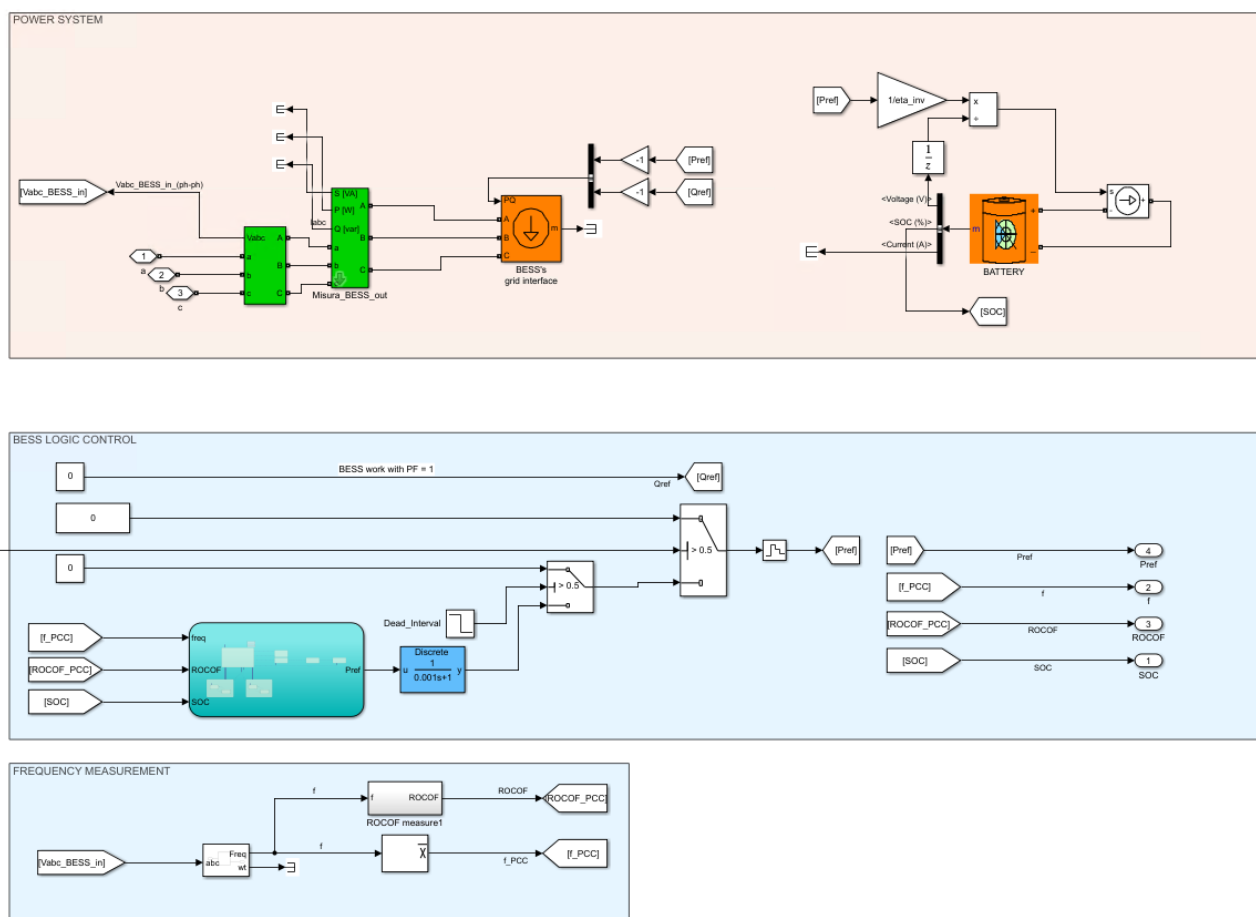


Figure 8-2 BESS Simulink model

To reduce the computational effort during the analysis of extended electromechanical transients, the power subsystem avoids detailed converter models: it employs a three-phase controlled power source in Simulink, which generates active and reactive power at the output terminals as dictated by the control subsystem. A dedicated Simulink block models the Lithium-Ion battery, connected to a controlled current source to simulate energy absorption or supply. This source adjusts the current based on the requested power divided by the battery terminal voltage, updating the State of Charge (SOC) and battery voltage. The control subsystem produces active and reactive power references, termed "Pref" and "Qref," which correspond to the power converter's setpoints in a real system interfacing the BESS to the grid. The control strategy is designed for MW-scale BESS installations, prioritizing rapid frequency response. The strategy optimizes SOC within a range that maximizes battery lifespan, minimizes interference from frequency control on SOC recovery, enhances virtual inertia response during transients, and meets frequency response performance requirements. The active power control strategy is depicted in Figure 8-3, with SOC-based recovery control shown in Figure 8-4.

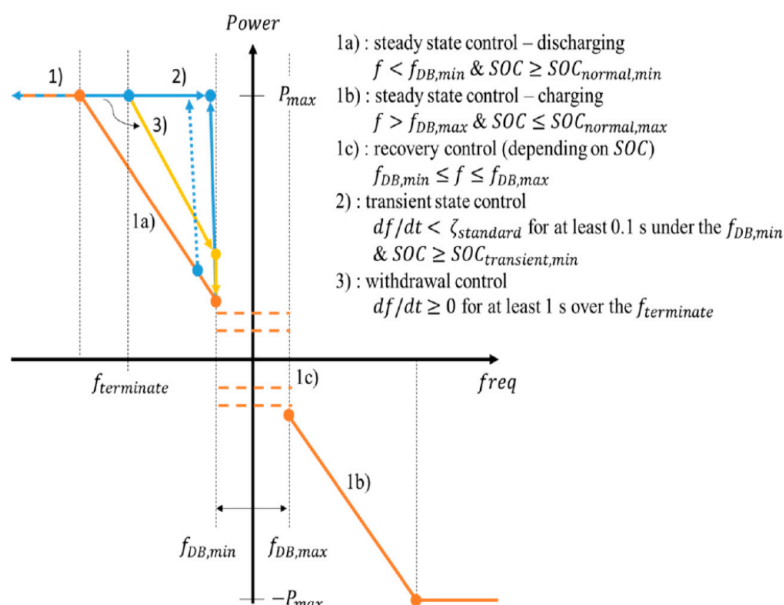


Figure 8-3 Summary of the BESS control strategy

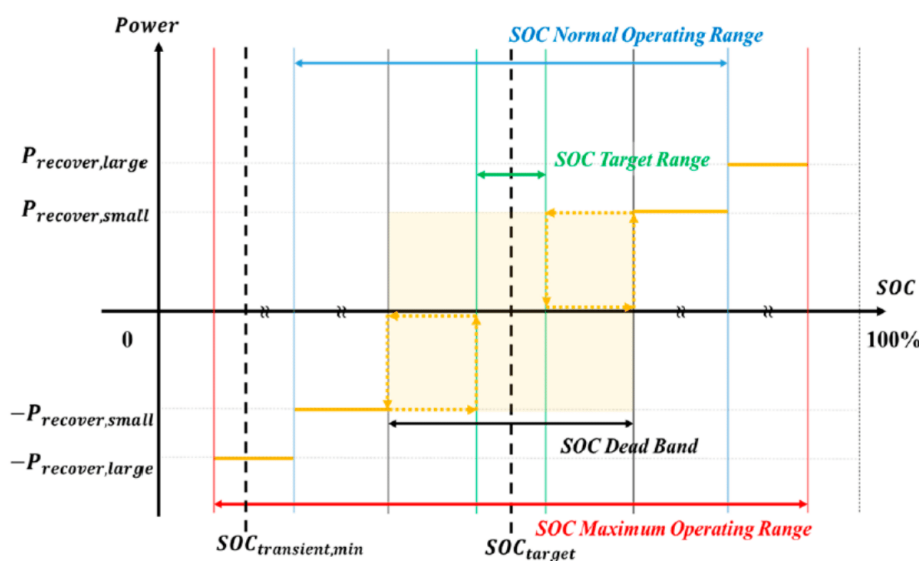


Figure 8-4 Recovery control of BESS on SOC ranges

8.1.1 Methodology and Simulations

Simulations were conducted to assess the performance of different control strategies in response to an 8 MW load step on the high-voltage side of the transformer. The results are reported in Table 8-1. Key parameters include:

- **Frequency Nadir (Hz):** The lowest frequency reached after the load step, indicating the severity of the frequency drop. A higher nadir (closer to the nominal value, e.g., 50 Hz) suggests greater stability.
- **Overshoot (Hz):** The maximum frequency excursion above the nominal value after the nadir.
- **Stabilization Time (s):** The time required for the frequency to stabilize after the disturbance. Shorter times are generally preferable, but trade-offs with nadir and overshoot are critical.

8.1.2 Analysis of Results

All test configurations demonstrated benefits in enhancing frequency stability by providing rapid response to load changes, which mitigates frequency dips and reduces the need for load shedding. The primary difference among the BESS tests lies in the location and number of active BESS units across the network. These variations in BESS placement influence the frequency response characteristics, such as nadir and stabilization time.

The BESS configuration in Test 4 was identified as the optimal strategy, achieving a frequency nadir of 49.975 Hz, no overshoot, and a stabilization time of 10.04 seconds. In this configuration 8 over 10 1 MW BESS units have been activated and compared to the baseline generator simulation, maintained stability without excessive oscillations, though it requires a slightly longer stabilization time. In Figure 8-5 the frequency after the disconnection of the feeders has been showed, while in Figure 8-6 the frequency without disconnection and with the BESS interventions it is presented.

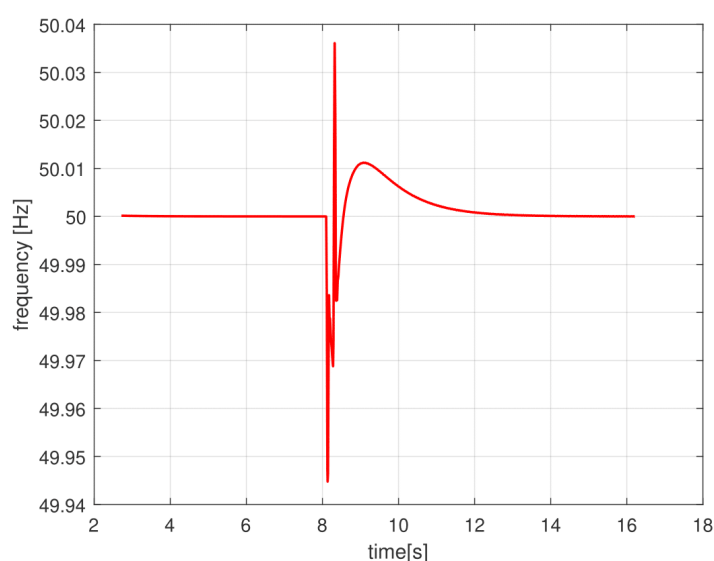


Figure 8-5 Frequency after EAC intervention

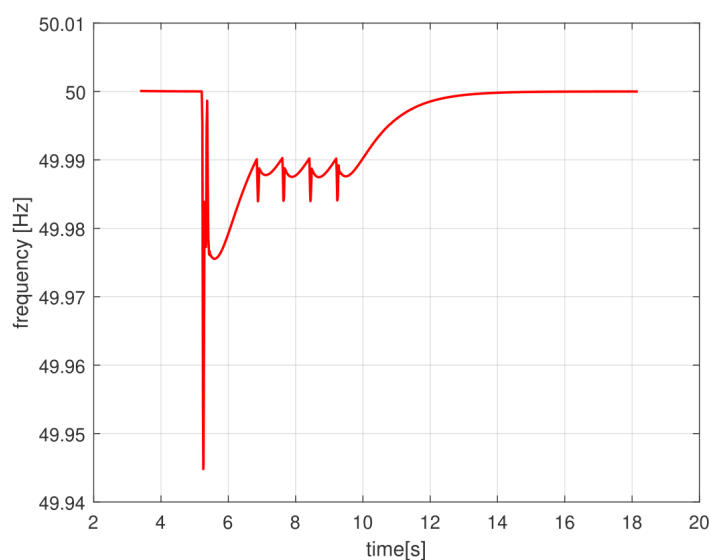


Figure 8-6 Frequency with BESS interventions

Compared to the EAC strategy, which involves load shedding and achieves a lower nadir, the BESS approach appears to be preferable, avoiding service disruptions associated with load shedding. It should be noted that, as already mentioned at the beginning of the section, these preliminary results are based on a reference network model [17], as this activity has been carried out before having received the data of the specific networks described in the document. The model will be adapted and tested on the target networks to ensure its applicability.

The summary of the above results is shown in Table 8-1.

Table 8-1 Summary of the simulation test results

Simulation	Nadir [Hz]	Overshoot [Hz]	Settling Time [s]
Generator	49.950	None	7.5
EAC	49.969	50.001	6.5
BESS (Test 1)	49.960	50.002	9.12
BESS (Test 2)	49.971	50.012	13.69
BESS (Test 3)	49.976	None*	10.79
BESS (Test 4)	49.975	None*	10.04

*None indicates no overshoot.

8.2 HIL test

8.2.1 EAC Relay

To test the operation of the Sardinia Defence Plan under realistic conditions, two multifunctional protection relays were used. The selected devices, the Tesmec TP-MFRG and the Thytronic DMS900A3S0, are standard devices commonly employed in Italian DSO substations (Figure 8-7). In the HIL setup, the three-phase voltage signals processed by the relays were generated by the real-time simulator through its analogue outputs. Then, signals were amplified before being applied to the voltage inputs of the protection devices. In this way, the relay functions were tested under realistic interface conditions, while preserving the closed-loop simulation environment.



Figure 8-7 EAC relays

Both relays integrate the typical functions required by such an application, including current and voltage protection, synchro-check, breaker supervision, automation functions, and communication features suitable for digitally integrated platforms. With specific reference to the EAC protection, the operating principle of both relays is substantially similar. The function is based on frequency measurement derived from the three-phase voltage system. In the adopted configuration, the frequency measurement f , the df/dt measurement, and the frequency averaging used for the df/dt calculation were all performed over 14 half-cycles. Both EAC relays use two independent frequency criteria: the first one coordinated by means of a df/dt condition, the other one to be used as a direct frequency threshold, as shown in Table 8-2. The threshold values reported below were set for modelling and testing purposes and **must not be** interpreted as actual operational protection settings.

Table 8-2 Thresholds 81.b1

<i>fx1 (frequency threshold associated to df/dt)</i>	
Description	Value
fx1 protection type	Underfrequency
Time delay	0.05 s
<i>df/dt (rate-of-change-of-frequency threshold associated to fx1)</i>	
Description	Value
fx1 protection type	Negative
fx1 operating value	0.30Hz/s
Time delay	0.05 s
<i>fx2 (pure frequency threshold)</i>	
Description	Value
fx2 protection type	Underfrequency
Time delay	0.05 s

The EAC operating logic is supervised by dedicated blocking conditions, such as undervoltage, overvoltage, voltage unbalance, inter-phase frequency deviation, reverse active power, and abnormal variation between subsequent periods. Under these conditions, the frequency protection is inhibited to avoid operation when the measured network quantities are not considered reliable. The main blocking parameters used to configure the relays are reported in the table below.

Table 8-3 EAC Frequency Protection – Blocking Thresholds

Undervoltage Blocking (27)	
Description	Value
Pickup threshold	$0.7 V_n/\sqrt{3}$
Operating time	0.00 s
Reset inhibition time	0.05 s
Maximum Voltage Unbalance (MSQ) – (8)	
Description	Value
Pickup threshold	0.10 p.u.
Operating time	0.00 s
Reset inhibition time	0.05 s
Overvoltage Blocking (59)	
Description	Value
Pickup threshold	$1.2 V_n/\sqrt{3}$
Operating time	0.00 s
Reset inhibition time	0.05 s
Maximum Frequency Difference Blocking (MDF) – (γ)	
Description	Value
Pickup threshold	200 mHz
Operating time	0.00 s
Reset inhibition time	0.05 s
Blocking for Variation Between Consecutive Periods	
Description	Value
Pickup threshold	100 μ s

8.2.2 Test results

The Power Hardware-in-the-Loop test setup used for the validation of the protection system is shown in Figure 8-8. The electrical network model, previously described, is implemented in the HYPERSIM environment and executed in real time on the OPAL-RT simulator with a time step of 70 μ s. The analogue outputs of the simulator provide low-level voltage signals with a range of approximately ± 1 V. These signals are sent to the OMICRON CMC 356 amplifier, which scales them up to approximately ± 60 V before supplying the voltage inputs of the protection relays under test.

The protection relays process the amplified voltage signals and generate trip commands according to the internal logic described in Table 8-3. These commands are sent through the relay digital outputs and acquired by the OPAL-RT simulator through digital inputs. In this way, the trip signals are fed back to the real-time model and used to open the corresponding circuit breakers associated with the loads.

This configuration allows the dynamic interaction between the simulated power network and the physical protection devices to be evaluated under closed-loop conditions.

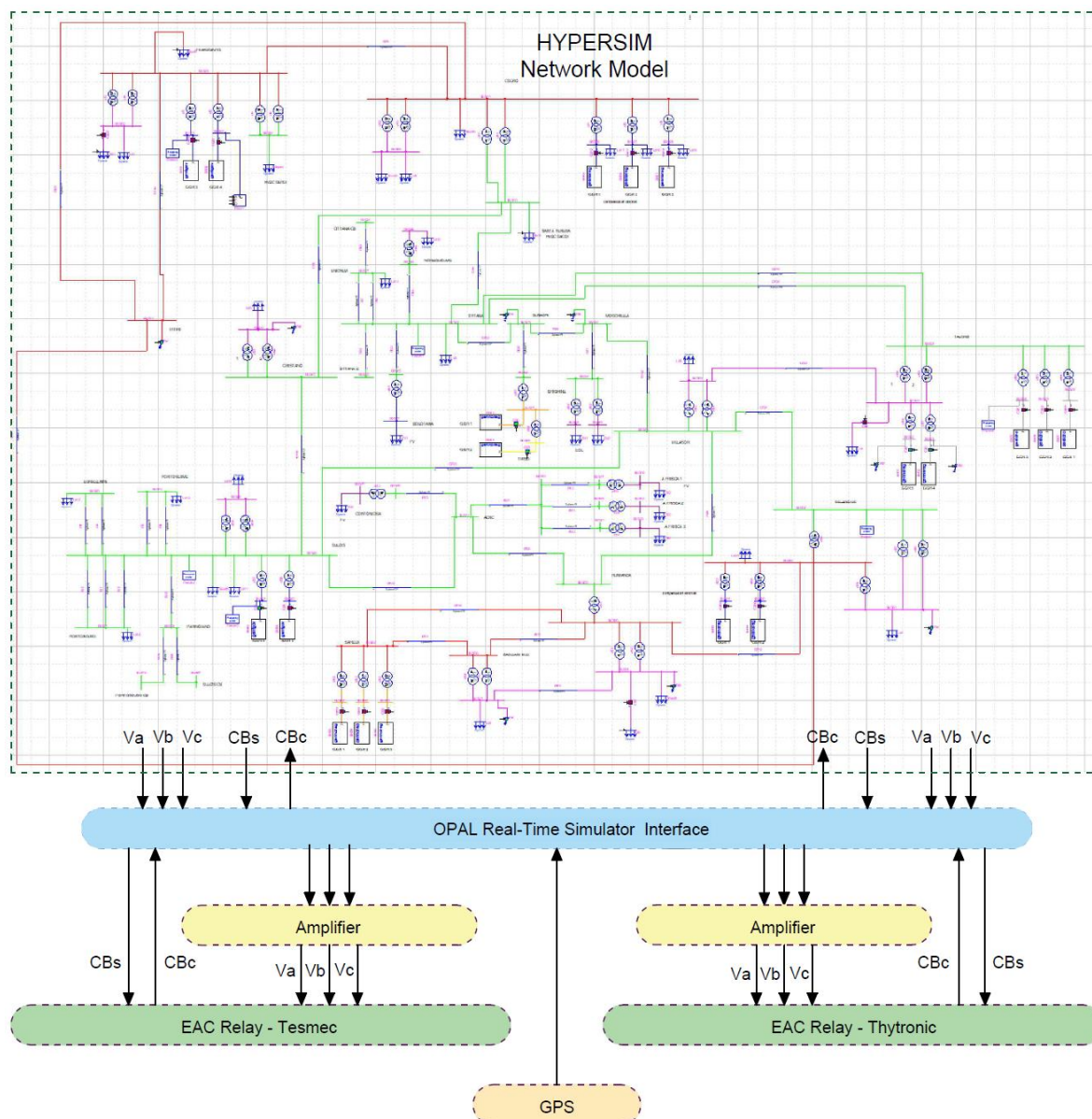


Figure 8-8 Power Hardware-in-the-Loop test bench layout for EAC Relay Testing

The test was performed by introducing a sudden active power imbalance between generation and load in the real-time network model. Starting from steady-state operating conditions, an instantaneous mismatch of approximately 191 MW was applied, producing the under-frequency transient shown in Figure 8-9.

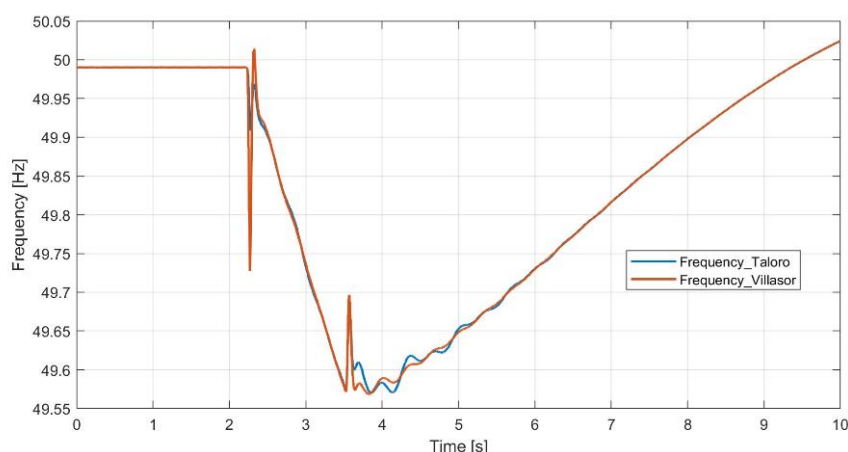


Figure 8-9 Sardinian network frequency vs time

The Figure 8-10 reports the binary status signals of the circuit breakers (CBs) used to identify the main events during the test. The signal `Network_Event` indicates the instant at which the disturbance is introduced in the real-time model, while the signal `EAC` represents the status of the circuit breaker controlled by the protection relay. The disturbance is applied first, causing the under-frequency transient previously reported. After the relay detects the under-frequency condition and its operating criteria are satisfied, a trip command is issued and the corresponding breaker changes state.

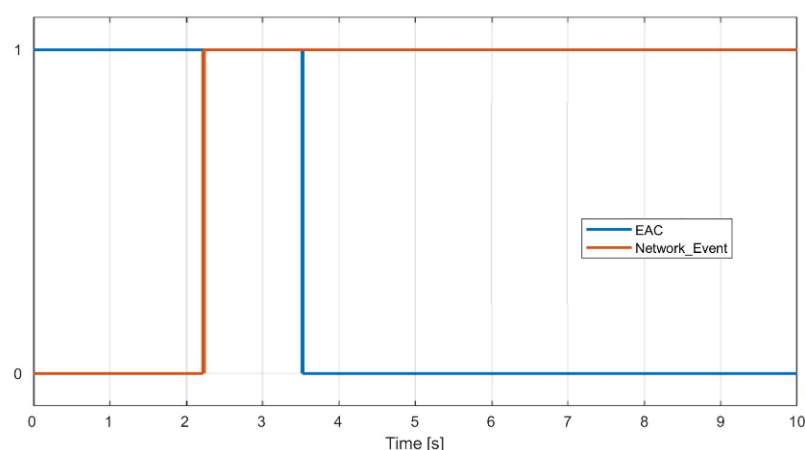


Figure 8-10 Disturbance trigger and relay-operated breaker status during the HIL under-frequency test

The obtained results confirmed the expected behaviour of the system, both in terms of frequency transient evolution and relay trip activation dynamics.

8.3 Transmission system dynamics with aggregated models of distribution systems

In this section, the network response to the sudden disconnection of a synchronous generator is evaluated by applying flexible load shedding actions within the distribution network.

At $t = 1$ s, the hydroelectric generator PA4-2 is disconnected from the system while producing 64.1 MW. The objective of the simulation is to restore the system frequency as close as possible to its nominal value in the shortest possible time through the disconnection of flexible loads (FL).

Two different scenarios are implemented: an urban scenario, developed using data provided by Areti, and a rural scenario, based on data provided by e-Distribuzione. In both cases, three interfaces with the distribution network are considered, each composed of a non-flexible load component and a flexible load component used for the analysed control strategy.

For both scenarios, three different responses are analysed: the generator outage without any corrective action, which serves as a reference case, a two-step load shedding strategy, and a three-step load shedding strategy. The aim is to evaluate how different intervention strategies affect the dynamic response of the system.

8.3.1 Urban network case

For the proposed urban scenario, two different cases are analysed: a high-flexibility case and a low-flexibility case.

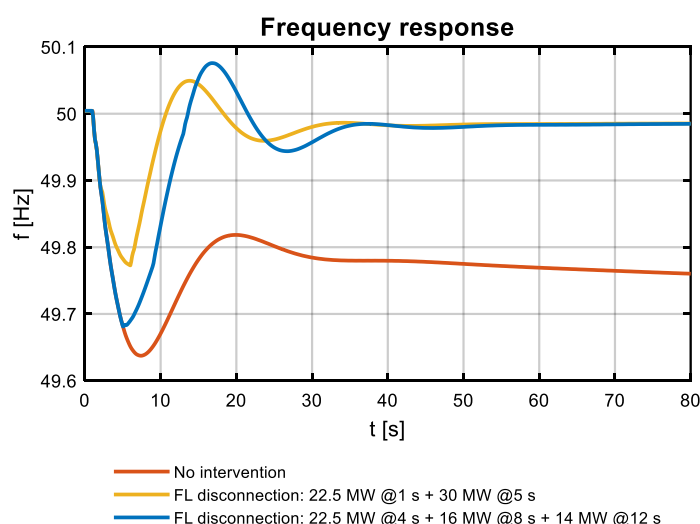


Figure 8-11 Frequency response under high flexibility urban scenario

Figure 8-11 shows the frequency response under the high-flexibility urban scenario. As can be observed, the disconnection of the flexible load allows the system frequency to recover to a value very close to the nominal reference (approximately 49.98 Hz).

Regarding the implemented strategies, the two-step disconnection strategy provides a faster frequency recovery and a more significant effect on the system nadir, while the three-step strategy results in a smoother and less oscillatory response.

Table 8-4 Frequency nadir under high flexibility urban scenario

	Nadir [Hz]
No intervention	49.64
Two step disconnection	49.77
Three step disconnection	49.68

Table 8-4 summarizes the frequency nadir values obtained for the considered strategies under the high-flexibility urban scenario.

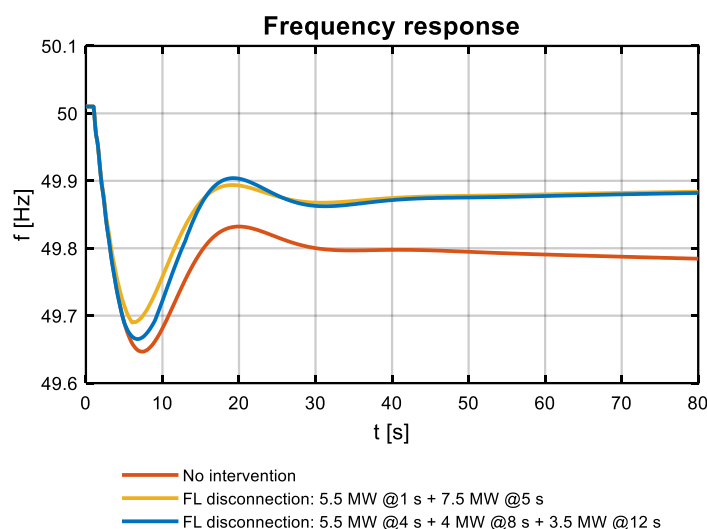


Figure 8-12 Frequency response under low flexibility urban scenario

Figure 8-12 shows the low-flexibility urban scenario, characterized by a reduced amount of available flexible load to evaluate its impact on the network response.

Due to the lower flexible load availability compared to the previous case, the achievable frequency recovery is less significant, reaching approximately 49.89 Hz. However, by observing the obtained responses more closely, it can be noted that the differences between the two implemented strategies are less pronounced than in the high-flexibility scenario.

This suggests that, under low-flexibility conditions, the three-step strategy may be preferable, as it provides a smoother and less aggressive transient response. Table 8-5 shows that the nadir values obtained with the two strategies are relatively close, indicating that neither approach presents a clear advantage in terms of frequency minimum value alone.

Table 8-5 Frequency nadir under low flexibility urban scenario

	Nadir [Hz]
No intervention	49.64
Two step disconnection	49.69
Three step disconnection	49.67

8.3.2 Rural network case

As in the previous case, the rural scenario is analysed under both high-flexibility and low-flexibility conditions.

Compared to an urban environment, where the contribution of flexible load is generally more significant, rural areas are characterized by a lower availability of flexible load resources.

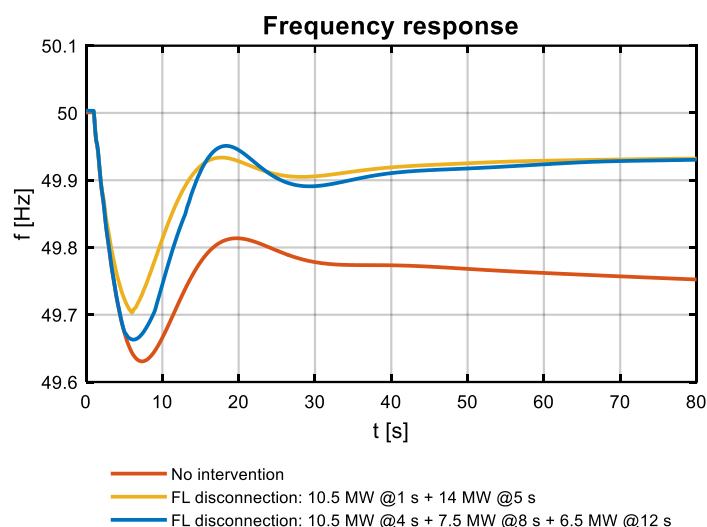


Figure 8-13 Frequency response under high flexibility rural scenario

Figure 8-13 shows the frequency response under the high-flexibility rural scenario. Although the initial operating condition is comparable to the previous urban case, the achieved frequency recovery is less significant, reaching approximately 49.93 Hz even under high-flexibility conditions.

Regarding the implemented strategies, the two-step disconnection approach provides a less severe frequency nadir and therefore represents the preferable solution in terms of frequency support. As shown in Table 8-6, the nadir value varies depending on the adopted strategy.

Table 8-6 Frequency nadir under high flexibility rural scenario

	Nadir [Hz]
No intervention	49.63
Two step disconnection	49.70
Three step disconnection	49.66

Figure 8-14 shows the low-flexibility rural scenario, representing the final analysed case.

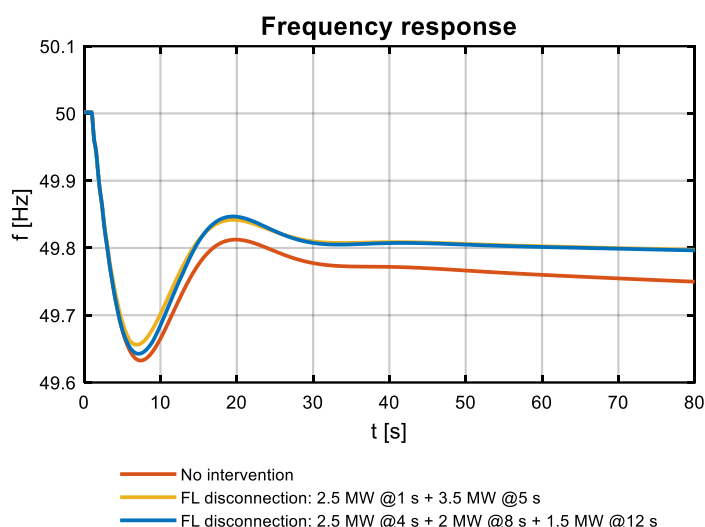


Figure 8-14 Frequency response under low flexibility rural scenario

In this condition, the results indicate that the differences between the two implemented strategies are relatively limited. Due to the reduced amount of available flexible load, the contribution provided by load shedding is not sufficient to fully compensate for the lost generation.

The frequency reaches approximately 49.80 Hz and does not recover to values closer to the nominal reference. Table 8-7 summarizes the frequency nadir values obtained under the low-flexibility rural scenario.

Table 8-7 Frequency nadir under low flexibility rural scenario

	Nadir [Hz]
No intervention	49.63
Two step disconnection	49.66
Three step disconnection	49.65

Overall, the performed simulations highlight that, in urban environments where the contribution of flexible load is significant, the implementation of this type of strategy can provide substantial benefits under conditions similar to the analysed scenario.

Conversely, in rural areas, where the availability of flexible load is considerably lower, the implemented strategies remain beneficial but are not sufficient on their own. In such cases, additional network control strategies should be integrated to achieve a more effective frequency recovery.

8.4 Real-time co-simulation of transmission and distribution systems

Following the successful validation of the algorithm's functionality, the logic was applied to the second use case: real-time load redistribution within a single timestep. This initial phase utilizes a Software-in-the-Loop approach represented in Figure 8-15, designating specific nodes within the simulated MV distribution network to provide flexibility.

The operational workflow is driven by an external trigger, which acts as an activation signal for load shedding and typically includes a target power reduction value. It is worth noting that, in this implementation, the trigger signal is represented by a frequency deviation measured at the TSO level, used here as an illustrative and realistic proxy for a TSO request. In practice, the TSO does not send an explicit digital command to the DSO; the frequency signal was chosen as a representative case study because it is a physically quantity directly linked to system-level imbalances. However, the architecture is designed to be agnostic to the nature of this trigger: in a future implementation, the activation signal could be any arbitrary input, e.g. a market signal, a direct communication from the TSO, or another grid indicator, without requiring changes to the underlying control logic. Upon receiving this signal, the simulation triggers the external control algorithm to dynamically recalculate active power setpoints. These updated setpoints are then fed back into the simulation to adjust the operating points of the dynamic loads.

If a specific target is not provided, such as in a DSO driven scenario, the algorithm seamlessly switches to an autonomous optimization mode, optimizing load profiles while adhering to the predefined operational limits of each participating node. In this case, the redistribution is not triggered by an external request but represents a capability available to the DSO, who can autonomously decide whether and when to remodulate flexible loads in order to achieve a more favourable distribution of losses across the network. The flexible loads considered are those that have agreed to participate in this type of local flexibility market made available by the DSO; it is then up to the DSO to evaluate, based on the resulting loss reduction, whether remunerating these flexible resources is economically advantageous compared to the cost of the losses themselves. This aspect has not been explored, as market-related evaluations fall outside the scope of the project.

Ultimately, the framework evolves from this preliminary setup into a comprehensive, fully integrated co-simulation environment. In this finalized architecture, the High Voltage transmission network is modelled explicitly and executed on a separate, dedicated real-time simulator. To facilitate cross-domain interaction, the HV simulator connects to the MV grid model via the VILLASnode middleware. Serving as the communication gateway, VILLASnode bridges the two simulation environments and manages all necessary data exchange. This setup enables the evaluation of flexibility, capturing the interdependencies and communication latencies between the transmission system, the distribution network, and the control logic.

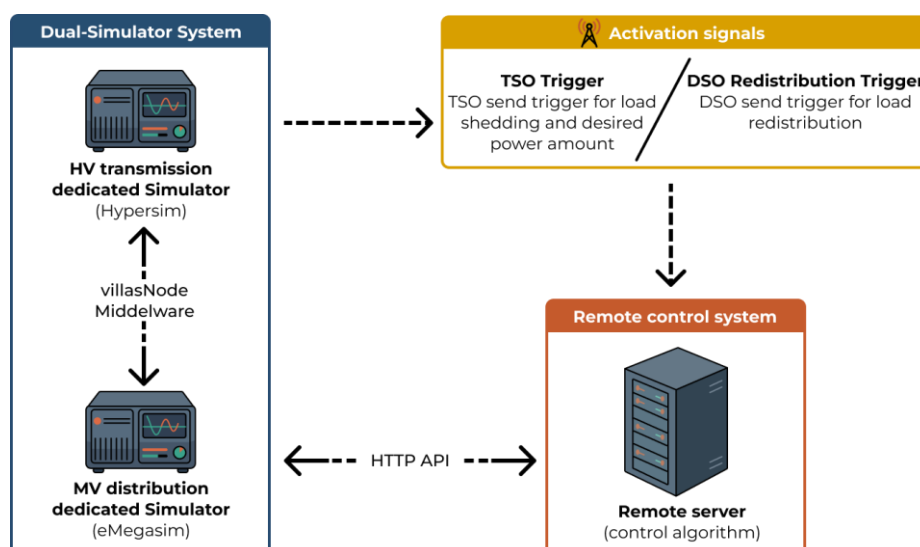


Figure 8-15 Co-simulation system infrastructure

To ensure robust communication over the UDP channel, the exchange of raw voltage waveforms is deliberately avoided. Instead, data transmission is restricted to aggregated, slowly varying quantities. The High Voltage simulator sends voltage RMS values and frequency to the Medium Voltage simulator, where voltages are reconstructed to prevent synchronization issues. Conversely, the MV network returns the active and reactive power measured at the Point of Common Coupling back to the HV simulator. This strategy of using slowly varying signals significantly enhances simulation stability. While UDP protocols are prone to packet loss, the slow variation of these quantities means that retaining the last valid sample during a missed timestep introduces only negligible error. In contrast, losing packets of raw waveform data could cause severe numerical instability. To validate the practical utility of this co-simulation architecture, a representative grid contingency was tested. The scenario involved a sudden 3 MW generation loss within the weakened HV transmission network. The value was selected to represent the sudden disconnection of a medium-sized PV plant, consistent with typical utility-scale installations. This magnitude was chosen in relation to the limited hosting capacity of the MV network section, a significantly larger power imbalance would not have been representative of a realistic operating condition, whereas a 3 MW loss provides a meaningful yet plausible perturbation for the responding network to counteract through load modulation. This event triggered a significant under-frequency transient. Upon detecting this frequency deviation, the distributed control system activated to determine the optimal load modulation strategy among the participating MV nodes. The remote algorithm rapidly computed new active power setpoints, completing the load redistribution calculation in approximately 7.71 seconds, as showed in Figure 8-16. The control system's intervention resulted in a step reduction of active power absorbed at the PCC stabilizing power exchange. Following this intervention, the system frequency progressively recovered toward its nominal value, while the MV bus voltage remained safely within acceptable limits, confirming that local power quality was not compromised. In Table 8-8. the flexible loads and the curtailed load are reported. Ultimately, these results demonstrate that the proposed control framework can successfully respond to TSO-level contingencies within timescales suitable for secondary frequency regulation, validating the architecture as a powerful tool for analysing TSO-DSO coordination.

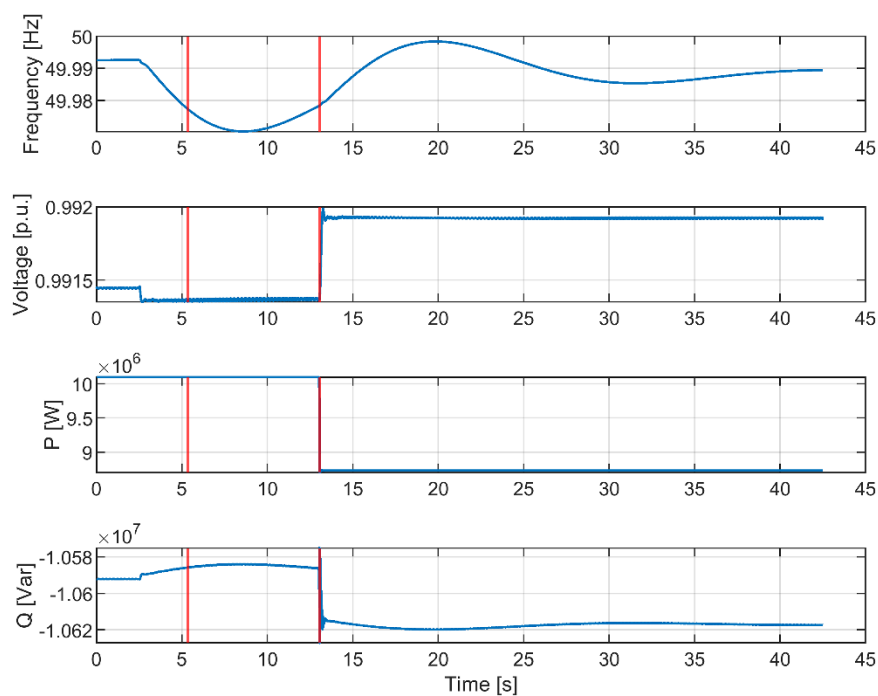


Figure 8-16 Co-simulation frequency response and control system intervention

Table 8-8 Load curtailment and load addition per node of Network

Node	Load curtailed [MW]	Load added [MW]
27	0.14	0
28	0.0028	0
29	0.028	0
46	0.056	0
49	0.042	0
50	0.11	0
61	0.028	0
62	0.306	0
64	0.028	0
68	0.042	0
69	0.042	0
72	0.07	0
74	0.25	0
83	0.223	0

8.5 Dashboard

The co-simulation system has been equipped with a version of the dashboard, shown in Figure 8-17.



Figure 8-17 Dashboard

This tool is a data visualization platform designed for the monitoring of geographically distributed co-simulations. By leveraging a lightweight UDP interface to connect directly with VILLASnode (and other raw udp data transmissions), it ingests and displays electrical variables and data exchanged across the connected nodes. The dashboard provides real-time plotting capabilities tailored for the remote simulation monitoring:

- **Synchronized Scrolling Plots:** Time-series graphs dynamically scroll over a user defined window, with a synchronized X-axis across all visible channels for visual correlation of distributed events.
- **Dynamic Time Windowing:** An intuitive slider allows users to adjust the observed time window on the fly (e.g., from milliseconds up to several seconds of live history).
- **Y-Axis Scaling Controls:** Users can lock plots to strict predefined bounds, use the "Auto Scale Y" for all the plots or for each one to automatically calculate and freeze the optimal boundaries for the visible data. The "Reset Scale", finally, reverts to the plots to the initial configuration.
- **Performance Optimization:** An automatic data downsampling based on user defined refresh time ensures the correct refresh rates and a low CPU footprint, when dealing with the incoming co-simulation data streams.

Furthermore, the application features a strictly modular and highly customizable architecture. Through a single, centralized configuration file, researchers can easily map incoming payloads, adjust UI rendering styles, set unit metrics, and define scale factors, ensuring maximum adaptability to specific requirements.

8.6 KPI Assessment

This section summarises the assessment of the KPIs associated with the pilot, building on the modelling, simulation, HIL testing, and co-simulation activities described in the previous sections. Each KPI is evaluated against the technical evidence produced within this deliverable, in order to link the implemented activities to the expected outcomes of IT01 and IT02. The assessment includes both the defence-system use case and the distribution-system analyses related to distributed energy resources and flexibility, as reported in Table 8-9.

Table 8-9 KPI assessment

KPI ID	KPI name	Assessment
IT01_KPI1	EMT component models	Achieved. The Sardinian transmission-system DT was implemented in HYPERSIM and validated at both generating-unit and network level.
IT01_KPI2	Creation of a dashboard	Achieved.
IT01_KPI3	HIL tests for protection purpose	Achieved. EAC protection relays were tested in a closed-loop HIL setup, confirming the expected under-frequency trip behaviour under realistic interface conditions.
IT02_KPI1	Reference profiles	Achieved. Reference load and generation profiles were derived from real POD measurements using DBSCAN clustering for residential loads, heat pumps, EV charging stations, and PV generation.
IT02_KPI2	Automatization pipeline model building	Achieved. An automated procedure combining Python-based topology analysis and MATLAB/Simulink model generation was developed to support the implementation of radial distribution networks in real-time simulation environments.
IT02_KPI3	Characterization of flexibility sources	Achieved. Heat pump and EV charging-station profiles were characterized and used to define flexible-load scenarios for distribution-network and dynamic frequency-response analyses.

9 Concluding remarks

The work addressed the modelling of the relevant portions of the Sardinian transmission system, the integration of representative distribution networks, and the implementation of real-time simulation environments aimed at assessing the dynamic behaviour of the grid under critical operating conditions and the behaviour of flexibility resources control algorithm under realistic conditions.

The DT of the Sardinian transmission grid has been implemented in the Hypersim real-time environment using data provided by the TSO. The validation activity of both the individual generation units and the network, confirmed that the model accurately reproduces the dynamic behaviour of the real system under fault and load variation scenarios. Key indicators, nadir, overshoot, and settling time, showed good agreement between the model and the TSO reference responses across all considered generators. The small discrepancies observed were attributed to modelling simplifications in the excitation systems, where static exciters were adopted in place of the rotating exciters present in the real plants. These limitations do not compromise the overall validity of the model for frequency dynamics and defence system studies, even though voltage-sensitive analyses may benefit from more detailed excitation modelling in future expansions.

Two real medium voltage distribution networks were modelled: an urban network operated by Areti in the City of Rome and a rural network operated by e-Distribuzione in Sardinia. Both networks were implemented in Python using a Backward Forward Sweep power flow algorithm, validated against DSO-provided measurements. An automated MATLAB-based tool was developed to support the generation of Simulink models of radial distribution networks, significantly reducing model preparation time compared to manual methods. Load and generation profiles were characterised through the application of the DBSCAN clustering algorithm to large datasets of real measurements collected from Points of Delivery in Rome, covering residential loads, heat pumps, electric vehicle charging stations, and photovoltaic generation. The resulting clusters capture the main differences associated with season, day type, power level, providing the basis for realistic scenario definition. The Genetic Algorithm-based optimisation framework demonstrated its effectiveness in improving network efficiency across all four tested scenarios, covering low and high renewable penetration and low and high flexibility conditions. In all cases, the configurations outperformed random installation strategies, reducing total network losses and balancing the losses across the involved nodes, while respecting voltage and branch loading constraints. These findings held consistently across both the Areti urban network and the e-Distribuzione rural network.

Battery Energy Storage Systems were modelled in a real-time Simulink environment and tested against an 8 MW load step. The results confirmed that properly controlled BESS can achieve frequency nadirs comparable to, or better than, the EAC relay intervention, while avoiding the load shedding that is intrinsic to EAC-based strategies. These preliminary results, obtained on a reference network, constitute a promising basis for the application of the BESS model to the target Sardinian networks in subsequent project activities.

The HIL test campaign successfully validated the operation of two commercial EAC protection relays, the Tesmec TP-MFRG and the Thytronic DMS900A3S0, under realistic under-frequency conditions generated by the real-time simulator. The test reproduced the Sardinian under-frequency defence plan logic and confirmed that both relays correctly detected the frequency transient triggered by a 191 MW generation-load mismatch and issued trip commands within the expected timing. The results validated the closed-loop interaction between the simulated network model and the physical

protection devices, confirming the suitability of the HIL approach for testing defence system logics in a controlled environment.

The analysis of flexible load shedding strategies, applied across urban and rural scenarios under both high and low flexibility conditions, confirmed that DER-based interventions can meaningfully support frequency recovery following generation loss events, suggesting that complementary control strategies will be necessary to achieve adequate frequency recovery in rural areas. The co-simulation framework integrating the HV transmission simulator (Hypersim) and the MV distribution simulator (eMegsim) via VILLASnode middleware was successfully validated. The control algorithm, activated by a TSO-level trigger following a 3 MW generation loss, computed optimal load redistribution setpoints across participating MV nodes in approximately 7.71 seconds, while taking into account the operating constraints of the distribution network and avoiding local voltage violations. This result demonstrates the feasibility of the proposed TSO-DSO coordination architecture for frequency regulation.

Despite the progress achieved, it was not possible to connect the Terna operational network to the connector developed within the project due to cybersecurity constraints. This limitation prevented the direct integration of real operational data flows from the Terna environment into the developed platform. Nevertheless, the tests carried out using available models, simulated scenarios, HIL/PHIL configurations, co-simulation interfaces, and the developed dashboard demonstrated the technical validity of the Italian pilot and its relevance within the broader European Digital Twin framework. The dashboard supported the visualisation of the simulation results, providing users with a more accessible way to inspect the main outcomes of the real-time simulation and to interpret the behaviour of the grid under the tested scenarios.

Overall, the activities confirmed that the developed platform can provide a flexible environment for studying the dynamic behaviour of the power system, testing defence strategies, and validating protection schemes in real-time conditions. The Italian pilot therefore showed how Digital Twin technologies can support system operation, security assessment, and future defence system evolution.

Future developments will focus on extending the simulated portion of the Sardinian network, with particular attention to the inclusion of the complete 150 kV system. This extension will allow a more detailed representation of the interaction between transmission and distribution levels and will improve the capability of the platform to analyse local phenomena, defence actions, and the contribution of distributed resources to system stability.

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Annex A Focus on an abnormal operation condition: the reverse power flow

One of the main issues facing is the management of energy flows, controlling the path taken by electricity in the grid to ensure that production and consumption are always in balance and that energy arrives efficiently and safely at withdrawal points.

In traditional power grids, energy flowed from high voltage to lower voltage levels (MV/LV) serving the loads. With the rapid growth of wind and photovoltaics, often distributed in areas with low local consumption, however, there is a reversal of the flow: when the power injected by distributed generation exceeds the local load of a substation, the power "rises" along the distribution network towards the transmission grid. In Sardinia, this phenomenon is favoured by some technical factors: the rapid spread of wind and solar plants on rural land (often privately owned), the seasonal and daily alternation of renewable generation and the limited ability to rapidly expand the grid. The reversal of flows leads to an increase in network losses and therefore a reduction in overall efficiency. In fact, the energy generated in low voltage and not consumed locally must be raised in voltage (through the transformers of the primary substations) to be transported elsewhere, undergoing a "double transformation" and crossing more lines and nodes: consequently, electricity losses increase compared to the case in which that renewable production were consumed on site. In the absence of prolonged reversals, distributed generators instead reduce the losses (because it limits power transfers on the grid). As their share increases, however, distributed generators can cause additional losses. In addition, diffuse bi-directional flows make voltage control on local grid levels more complex, because distribution networks are traditionally designed for unidirectional flow: over- or under-voltage problems may therefore arise in MV/LV nodes that must be managed with additional regulation systems.

The peaks of power absorption that are recorded especially in the summer months, a period in which the island sees a strong increase in population due to tourism. In the evening hours, typically around dinner time, there is a significant peak in demand, determined by the intensive use of air conditioners in private homes and the high energy needs of restaurants and accommodation facilities concentrated in coastal and tourist resorts. This sudden and concentrated increase in the load occurs precisely at a time when production from solar sources drops drastically or is absent, making one of the main renewable sources on the island unavailable. This mismatch between demand and generation further aggravates balancing difficulties and increases the risk of congestion or operational criticalities in a system already strongly constrained in the possibilities of trade with the continent.

Energy storage plants are also being developed and they could absorb excess production during generation peaks and return it at peak times.

Annex B Focus on allocated losses

Among the various indicators our approach is based on calculating the losses allocated to each node. Because the systems hereby considered are radial, we adopt an effective and simple to be implemented method known as the Branch Current Decomposition for Loss Allocation (BCDLA) method [18]. It is worth nothing that unless other existing methods (such as [19] and [20]) the sum of the allocated losses are equal to the physical losses. The BCDLA method uses as input data the power flow results and gives the amount of losses that are due to the net load existing in every node.

Let's indicate the slack node as node 0, with $k = 1, \dots, K$ the nodes containing local generation and/or load, and $b = 1, \dots, B$ branches. Let's also considering T successive time steps, denoted as $t = 1, \dots, T$: the net load at node k and time step t is indicated as $P_{k,t}$. The total losses at time step t are denoted as $L_{\text{tot},t}$. By considering relatively small nodal net power variation, we may denote the change in losses with respect to the base case ($L_{\text{tot},t}|_{\text{new}} - L_{\text{tot},t}|_{\text{base}}$) as proportional to the nodal net power node variation ($P_{k,t}|_{\text{new}} - P_{k,t}|_{\text{base}}$), as:

$$L_{\text{tot},t}|_{\text{new}} - L_{\text{tot},t}|_{\text{base}} \cong \sigma_{k,t}^{(P)} (P_{k,t}|_{\text{new}} - P_{k,t}|_{\text{base}})$$

The coefficient $\sigma_{k,t}^{(P)}$ is called *sensitivity coefficient*. Calculating the sensitivity coefficients implies to run *two power flows* for every small variation made at the net node power. This approach is quite time consuming. However, we use instead the allocated losses, calculated, for radial systems, as [21], [22]:

$$L_{k,t} = \text{Re} \left\{ \bar{I}_{k,t}^* \sum_{b=1}^B \left(R^{(b)} \bar{I}_t^{(b)} \right) \right\}$$

with $R^{(b)}$ indicating the resistance of branch b , $\bar{I}_{k,t}^*$ having the meaning of complex conjugate current absorbed by all the shunt elements connected to node k at time step t , and $\bar{I}_t^{(b)}$ indicating the complex current flowing in the series impedance of branch $b = 1, \dots, B$.

The allocated losses $L_{k,t}$ are not sensitivity coefficients by themselves. However, they embed a meaning similar to the one of sensitivity coefficients. In fact, as shown in :

- ⇒ If the product $\text{sign}\{P_{k,t}\} \cdot \text{sign}\{L_{k,t}\}$ is positive, there is a total loss reduction by reducing the net load power at node k .
- ⇒ If the product $\text{sign}\{P_{k,t}\} \cdot \text{sign}\{L_{k,t}\}$ is negative, there is a total loss increase by reducing the net load power at node k .

Annex C Information about the future scenario of Rome grid

The scenarios for electric consumption in urban areas by 2030 have been developed based on the projections and methodologies outlined in the development plans of the Transmission System Operator and the Distribution System Operators. These scenarios account for the increasing electrification of mobility and heating, the expansion of photovoltaic generation, and the integration of flexible resources. The electrification of transport and heating is expected to moderately increase electricity demand by 2030.

The following aspects will be considered [16]:

- **Base Scenario (Low Impact):** The energy demand increase is estimated at 1.2% nationally (340 TWh), driven by 1.6 million of electric vehicles. Non controllable load profiles are shaped by domestic patterns, aggregating low voltages standard profiles at medium voltage level.
- **Heat pumps:** They are projected to grow from 1.6 million units in 2020 to 4.4 million by 2030 nationally, with the urban area (at city level) under study adding approximately 220,000 new units. Operating at 2.1 kW nominal power for 12 hours daily from November to April, these units contribute an additional 0.46 GW to the city's demand, primarily affecting winter load profiles.
- **Generation Fleet:** PV capacity is expected to grow significantly, increasing from 30 GW in 2023 to 80 GW by 2030. However, deployment in urban area is constrained by municipality level limitations, reducing suitable areas for large-scale installations.
- **Battery Storage:** Systems will be sized to complement PV installations, including residential and utility-scale units. These systems enhance flexibility by reducing grid withdrawal during peak EV charging and heat pump operation periods, particularly in the Distributed Generation scenario.