COMILLAS
UNIVERSIDAD PONTIFICIA
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MÁSTER UNIVERSITARIO EN INGENIERÍA INDUSTRIAL

TRABAJO FIN DE MÁSTER

Modelling Demand Side Response for Heat Pumps through locational network tariffs

Autor: Luis Cabot Sancho

Director: José Pablo Chaves Ávila

Co-directores: Matteo Troncia, Nicolás Mariano Morell Dameto, Orlando Mauricio Valarezo Rivero

Madrid

Julio de 2023

Declaro, bajo mi responsabilidad, que el Proyecto presentado con el título

Modelling Demand Side Response for Heat Pumps through locational network tariffs

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Autorizada la entrega del proyecto

EL DIRECTOR DEL PROYECTO

Fdo.: José Pablo Chaves Ávila   Fecha: 19/07/2023

José Pablo Chaves Ávila

Fdo.: Matteo Troncia   Fecha: 19/07/2023

Agradecimientos

A mi familia por su apoyo incondicional y a todo el equipo que me ha ayudado a sacar adelante este trabajo: José Pablo Chaves-Ávila, Matteo Troncia, Nicolás Morell y Orlando Valarezo. Muchas gracias por vuestra dedicación.

MODELLING DEMAND SIDE RESPONSE FOR HEAT PUMPS THROUGH LOCATIONAL NETWORK TARIFFS

Author: Cabot Sancho, Luis
Supervisor: José Pablo Chaves Ávila
Collaborating Entity: ICAI – Universidad Pontificia Comillas

Abstract

The following Master's Thesis deals with the study of the ability to solve problems in a low-voltage network by a heat pump operating in a network with tariffs that vary according to the feeder to which consumers are connected or are defined in an aggregated manner.
Palabras clave: Demand Response, flexibility, heat pumps y tariffs

1. Introduction

The provision of electric power has been the driving force behind the industrial and social transformation of the world for more than a century and has become one of the essential resources of our society [1]. As a consequence of the efforts to combat Climate Change, the electric power system is evolving along three key dimensions: decarbonisation, digitalisation, and decentralisation (3 Ds).

Before the liberalisation of the electricity sector, initiated in the European Union in 1996, the activity was concentrated in companies characterised by a strong vertical structure. Electricity was generated by centralised producers, transported by unidirectional flows through the grid, and consumed by the end users [2]. However, things are different nowadays, regulatory changes and the development of new technologies (distributed renewable generation, energy storage, electric vehicles, etc.), and the need to involve network customers in solving operating issues have altered these assumptions. Therefore, it is necessary to formulate and develop innovative market models for the electricity sector.

Despite the existence of various innovative model proposals for the transformation of the electricity market, such as a local distribution network model developed by Lind et al., [3]; a heat pump model developed by Morell et al., [4]; an efficient LFM formulation through linear programming (LP) optimisation by A. Paredes and J. A. Aguado [5]; a MILP model called Smart Energy Service Provider (SESP) to schedule flexible energy resources by P. Olivella-Rosell [6]; etc. These market models exploit a simplified representation of the electric behaviour of the FSPs (PV plants, wind generators, demand-side resources) which restrains its development and validation due to being inaccurate and unrealistic.

This thesis aims to fill the identified gap by enhancing the accuracy of the representation of heat pumps in market models for the electricity system. Focusing on merging a realistic FSPs model, as the one proposed in [4], into a local distribution network with tariffs for Demand Response proposed by Troncia, M. and Valarezo, O. [42].

2. Methodology

The aim of this study is to analyze whether the flexibility provided by heat pumps operating in a network with tariffs allows solving problems in a local distribution network.

To achieve this, the study considers two groups of equations. The first group consists of Python formulas developed by Troncia, M., and Valarezo, O. [42], which calculate tariffs for different hours of the day, considering overvoltage and undervoltage issues in the network buses. The second group of equations is a dynamic thermal model of a house, developed by Morell et al. [4] and Bastida et al. [43], where new formulas are defined to describe the evolution of temperature inside homes, being more comprehensive and realistic than previous formulations.

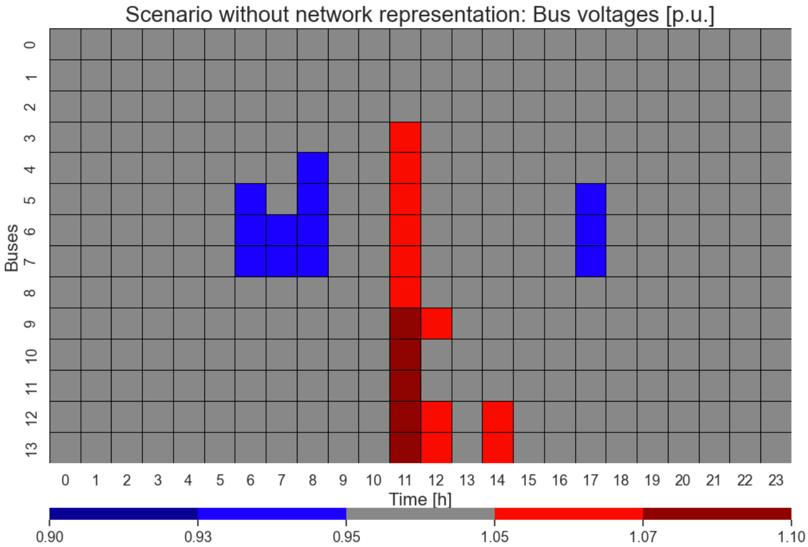
Based on this, three models have been developed to minimize the operation cost of the heat pump. The first model considers only PVPC prices, while the second and third models take into account the tariffs calculated based on the issues identified when executing the first model. The difference between the second and third models is that while the second model applies the same tariff to the entire network, the third model divides the network into groups of nodes, having different tariffs for each group.

Two case studies have been considered for analysis, one with PVPC prices for a working day and another with weekend prices. In each case study, the results obtained when executing each model are compared, divided into three scenarios (Base, A, and B). Additionally, the sensitivity to the tariff amount is analyzed for each model using two different amounts.

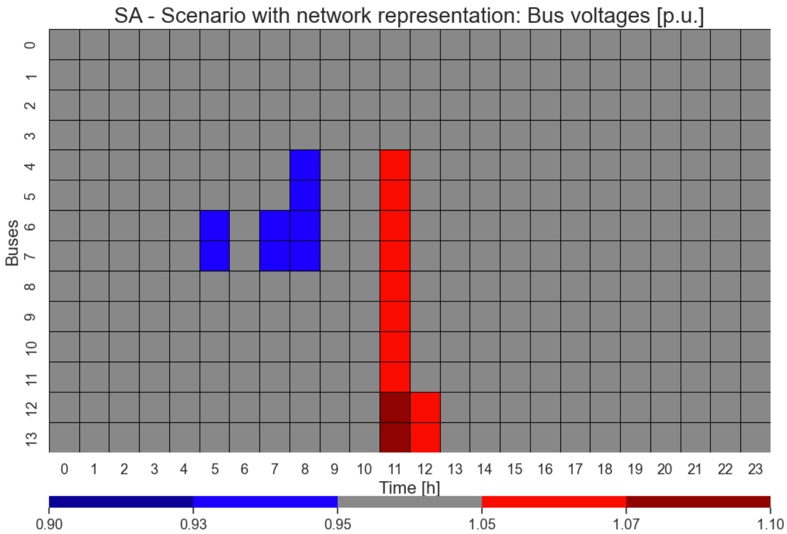
Finally, by analyzing the results, several conclusions are drawn, and further steps are proposed for future research.

3. Results

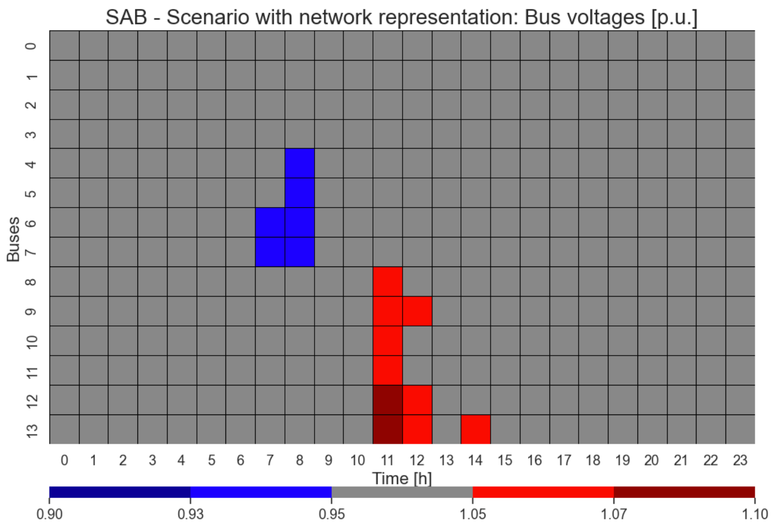
When executing the different models, it is observed that by incentivizing and penalizing consumption through tariffs, it is possible to modify the consumption profile of heat pumps and resolve some of the congestion issues observed in the base scenario. The results of the case study with PVPC prices for a working day and considering only one tariff amount are summarized below:



Escenario Base – Network issues



Escenario A – Network issues



Escenario B – Network issues

4. Conclusions

Based on the analysis conducted regarding the resolution of network issues through the modeling of a heat pump in a network with tariffs for demand response, the following conclusions have been reached:

The best configuration for tariff calculation considers the location of nodes to compute network charges. By applying appropriate coefficients and a higher level of detail regarding node issues, a greater number of network problems can be resolved.

In the analysis of weekends, it has been concluded that due to low electricity prices and the incentives provided by the tariffs, they do not generate a sufficient price difference from the base scenario to adequately drive the heat pump's demand response and contribute to network operation. Therefore, in case of low electricity prices, location-based tariffs should be carefully designed to create a stronger price signal and promote demand response.

Overall, the study demonstrates the potential of demand response solutions using heat pumps to address network problems. It highlights the importance of considering tariff structures, differentiation by node location, and sensitivity to tariff amounts to achieve optimal network performance. However, the applicability of granular location-based tariffs may be limited. Further research and optimization efforts (e.g., including other flexible service providers in the simulation) are needed to fully address all network problems and maximize the benefits of flexibility markets.

5. References

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[3] Cossent, R.; Lind, L.; Valarezo, O; Troncia, M.; Chaves-Ávila, J. *Scalability and replicability analysis of the market platform and standardised product. CoordiNet H2020 project.* June 2022

[4] Morell Dameto, N.; Chaves-Ávila, J.P.; Dueñas Martínez, P.; Gómez San Román, T. *Heat Pumps operation model, Formulation summary*

[5] Paredes, A. and Aguado, J. *Capacity and Energy Local Flexibility Markets for Imbalance and Congestion Management.* Recovered from: https://ieeexplore.ieee.org/document/9562971

[6] Olivella-Rosell, P. et al. *Optimization problem for meeting distribution system operator request in local flexibility markets with distributed energy resources.* Recovered from: https://www.sciencedirect.com/science/article/abs/pii/S0306261917311522

[42] Troncia, M.; Valarezo, O. *Local Distribution Network.* Recovered from: https://github.com

Resumen

El siguiente Trabajo de Fin de Máster (TFM) trata sobre el estudio de la capacidad para resolver problemas en una red de baja tensión por parte de u bomba de calor operando en una red con tarifas que varían según el alimentador al cual están conectados los consumidores o se definen de manera agregada.

Palabras clave: Demand Response, flexibilidad, bombas de calor y tarifas

1. Introducción

La provisión de energía eléctrica ha sido la fuerza impulsora detrás de la transformación industrial y social del mundo durante más de un siglo y se ha convertido en uno de los recursos esenciales de nuestra sociedad [1]. Como consecuencia de los esfuerzos para combatir el Cambio Climático, el sistema eléctrico está evolucionando en tres dimensiones clave: descarbonización, digitalización y descentralización (3 D).

Antes de la liberalización del sector eléctrico, iniciada en la Unión Europea en 1996, la actividad estaba concentrada en empresas caracterizadas por una fuerte estructura vertical. La electricidad se generaba por productores centralizados, se transportaba a través de la red en flujos unidireccionales y se consumía por los usuarios finales [2]. Sin embargo, en la actualidad las cosas son diferentes, los cambios regulatorios y el desarrollo de nuevas tecnologías (generación distribuida de energía renovable, almacenamiento de energía, vehículos eléctricos, etc.) y la necesidad de involucrar a los clientes de la red en la solución de problemas operativos han alterado estas suposiciones. Por lo tanto, es necesario formular y desarrollar modelos de mercado innovadores para el sector eléctrico.

A pesar de la existencia de diversas propuestas de modelos innovadores para la transformación del mercado eléctrico, como un modelo de red de distribución local desarrollado por Lind et al., [3]; un modelo de bomba de calor desarrollado por Morell et al., [4]; una formulación LFM eficiente a través de la optimización de programación lineal (LP) de A. Paredes y J. A. Aguado [5]; un modelo MILP llamado Proveedor de Servicios Energéticos Inteligentes (SESP) para programar recursos energéticos flexibles de P. Olivella-Rosell [6]; etc. Estos modelos de mercado explotan una representación simplificada del comportamiento eléctrico de los Proveedores de Servicios Flexibles (plantas fotovoltaicas, generadores eólicos, recursos de la demanda), lo que limita su desarrollo y validación debido a su inexactitud e irrealismo.

Esta tesis tiene como objetivo llenar la brecha identificada al mejorar la precisión de la representación de las bombas de calor en modelos de mercado para el sistema eléctrico. Se enfoca en combinar un modelo realista de Proveedores de Servicios Flexibles, como el propuesto en [4], en una red de distribución local con tarifas para la respuesta a la demanda propuesta por Troncia, M. y Valarezo, O. [42].

2. Metodología

El objetivo del presente trabajo consiste en analizar si la aportación de flexibilidad por parte de bombas de calor operando en una red con tarifas permite resolver problemas en una red de distribución a nivel local.

Para ello, el trabajo tiene en cuenta dos grupos de ecuaciones. El primer grupo de ecuaciones consiste en una serie de fórmulas en Python desarrolladas por Troncia, M. y Valarezo, O. [42], que calculan las tarifas para diferentes horas del día, teniendo en cuenta los problemas de sobretensión y subtensión en los buses de la red. El segundo grupo de ecuaciones es un modelo térmico dinámico de una vivienda, desarrollado por Morell et al. [4] y Bastida et al. [43], donde se definen nuevas fórmulas para describir la evolución de la temperatura dentro de las casas, siendo mucho más completas y realistas que las formulaciones anteriores.

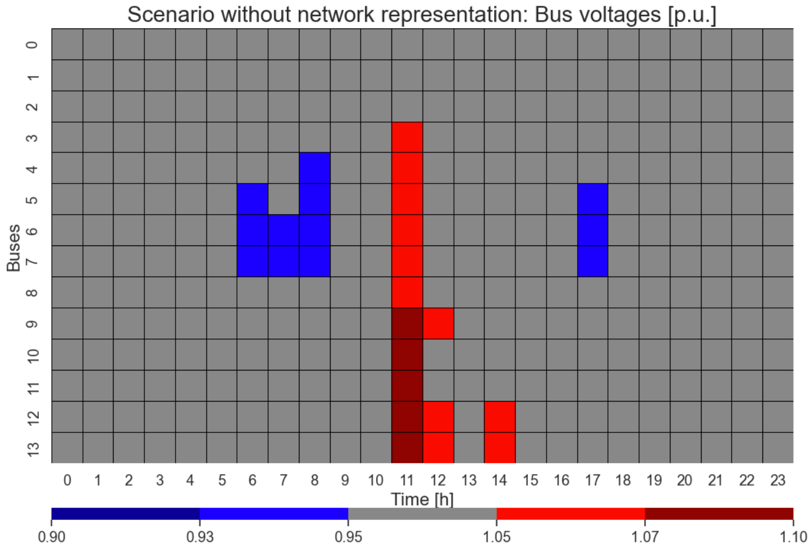
Con esto, se han desarrollado tres modelos que buscan minimizar el coste de operación de la bomba de calor. El primero sólo tiene en cuenta los precios PVPC; mientras que el segundo y el tercero tienen en cuenta las tarifas calculadas según los problemas obtenidos al ejecutar el primer modelo. La diferencia entre el segundo y el tercer modelo es que mientras el segundo modelo aplica la misma tarifa a toda la red, el tercer modelo contempla la división de la red en grupos de nudos, teniendo tarifas distintas para cada grupo.

Para el análisis se han tenido en cuenta dos casos de estudio, uno con precios PVPC para un día laborable y otro con precios de fin de semana. En cada caso de estudio se comparan los resultados obtenidos al ejecutar cada modelo, dividiéndolo en tres escenarios (Base , A y B). Además, para cada modelo se analiza también la sensibilidad al importe de las tarifas usando dos importes distintos.

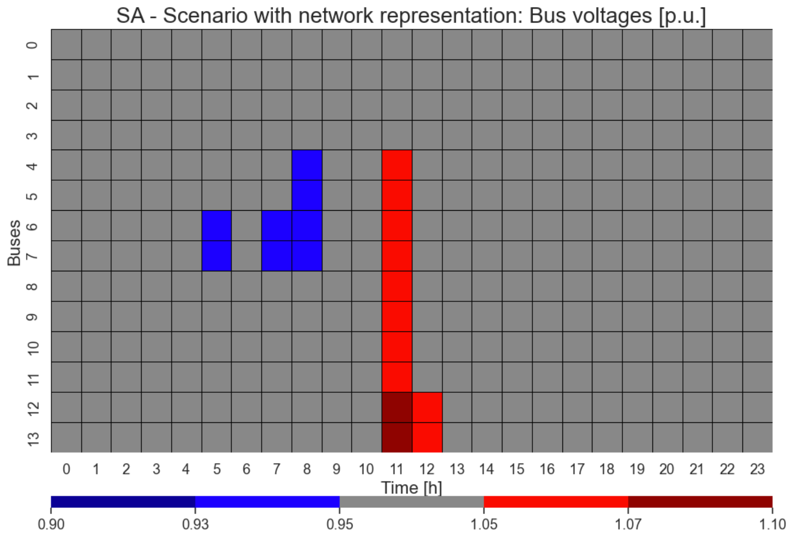
Finalmente, al analizar los resultados se formulan una serie de conclusiones y se proponen siguientes pasos.

3. Resultados

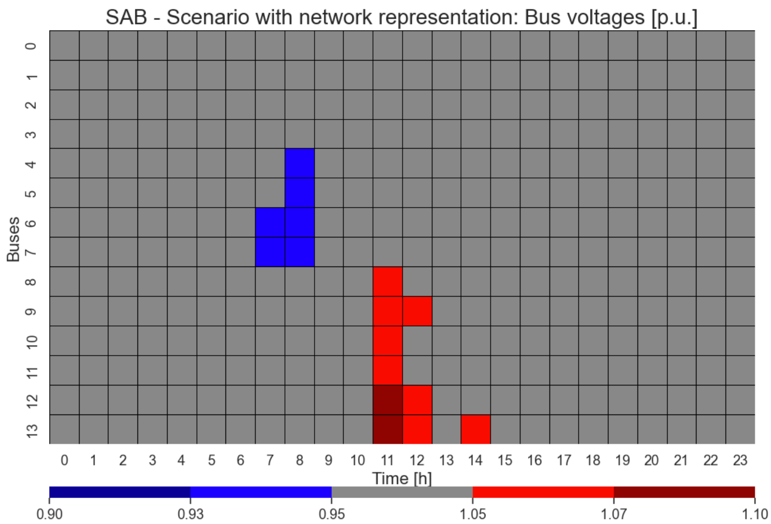
Al ejecutar los distintos modelos observa cómo gracias a incentivar y penalizar el consumo mediante las tarifas, se consigue modificar el perfil de consumo de las bombas de calor y resolver parte de los problemas de congestión observados al ejecutar el escenario base. En este resumen se adjuntan los resultados del caso de estudio con precios PVPC para un día laborable y sólo teniendo en cuenta un importe de tarifas.



Escenario Base – Problemas de la red



Escenario A – Problemas de la red



Escenario B – Problemas de la red

4. Conclusiones

A partir del análisis realizado sobre la resolución de problemas de red mediante la modelización de una bomba de calor en una red con tarifas para la respuesta a la demanda.

Se ha concluido que la mejor configuración para el cálculo de las tarifas es aquella que considera la ubicación de los nodos para calcular los cargos de la red. Al aplicar coeficientes adecuados y un mayor nivel de detalle sobre los problemas de los nodos, se logra resolver un mayor número de problemas de la red.

En el análisis de los fines de semana, se ha concluido que, debido a los bajos precios de la electricidad y los incentivos proporcionados por las tarifas, estas no generan una diferencia suficiente en el precio del escenario base para impulsar adecuadamente la respuesta a la demanda de la bomba de calor y contribuir a la operación de la red. Por lo tanto, en caso de bajos precios de electricidad, las tarifas por ubicación deben ser diseñadas cuidadosamente para crear una señal de precio más fuerte y promover la respuesta a la demanda.

En general, el estudio demuestra el potencial de las soluciones de respuesta a la demanda utilizando bombas de calor para abordar problemas de red. Se destaca la importancia de considerar estructuras tarifarias, diferenciación por ubicación de nodos y la sensibilidad a las cantidades de las tarifas para lograr un óptimo rendimiento de la red. Sin embargo, la aplicabilidad de tarifas granulares por ubicación puede ser limitada. Se necesita más investigación y esfuerzos de optimización (por ejemplo, incluir otros proveedores de servicios flexibles en la simulación) para abordar completamente todos los problemas de la red y maximizar los beneficios de los mercados de flexibilidad.

5. Referencias

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1. Introduction

1.1. Changes in electric power system

The provision of electric power has been the driving force behind the industrial and social transformation of the world for more than a century and has become one of the essential resources of our society [1]. As a consequence of the efforts to combat Climate Change, the electric power system is evolving along three key dimensions: decarbonisation, digitalisation, and decentralisation (3 Ds).

Before the liberalisation of the electricity sector, initiated in the European Union in 1996, the activity was concentrated in companies characterised by a strong vertical structure. Electricity was generated by centralised producers, transported by unidirectional flows through the grid, and consumed by the end users [2]. However, things are different nowadays, regulatory changes and the development of new technologies (distributed renewable generation, energy storage, electric vehicles, etc.), and the need to involve network customers in solving operating issues have altered these assumptions. Therefore, it is necessary to formulate and develop innovative market models for the electricity sector.

This design will take into account the main trends in the transition of the power sector mentioned before: **Decentralisation**, implementation of new technologies, such as distributed renewable generation and energy storage that limit the dependence on large electricity companies; **Digitalisation**, allowing consumers to act upon electricity prices and have a more active role in the markets thanks to new communication technologies; and **Decarbonisation**, accomplishing the CO2 emissions reduction target set by the European Union.

1.2. Motivation

The quantitative assessment of market functioning in realistic scenarios is fundamental for formulating recommendations to foster the ongoing energy transition and innovation in the electricity sector.

Despite the existence of various innovative model proposals for the transformation of the electricity market, such as a local distribution network model developed by Lind et al., [3]; a heat pump model developed by Morell et al., [4]; an efficient LFM formulation through linear programming (LP) optimisation by A. Paredes and J. A. Aguado [5]; a MILP model called Smart Energy Service Provider (SESP) to schedule flexible energy resources by P. Olivella-Rosell [6]; etc. These market models exploit a simplified representation of the electric behaviour of the FSPs (PV plants, wind generators, demand-side resources) which restrains its development and validation due to being inaccurate and unrealistic.

To address these limitations, models should consider with more detail the categories of resources involved in the service provision. Among the variety of technologies, heat pumps and electric vehicles represent the resources of main interest at the distribution system level [7].

This thesis aims to fill the identified gap by enhancing the accuracy of the representation of heat pumps in market models for the electricity system. Focusing on merging a realistic FSPs model, as the one proposed in [4], into a local distribution network with tariffs for Demand Response proposed by Troncia, M. and Valarezo, O. [42].

1.3. Objectives

The objectives of this project are the following:

1. **Learn:** from existing literature and previous work on the topic of modelling flexibility of heat pumps and local flexibility markets.
2. **Contribute to society:** This project aims to provide a solution to one of today's major challenges, the transition of the energy sector.
3. **Obtain conclusions:** with the development of a more complete model and the simulation of different scenarios, it is intended to understand the limits and benefits of flexibility of the heat pumps and reaction to different tariff models.

2. Flexibility as a tool to support the electricity system

With the increasing adoption of renewable energy and distributed energy resources (DERs), their integration into the distribution grid poses new challenges for system operators. To cope with these challenges, distribution system operators are seeking market tools to enable more active system management and control using flexibility.

Currently the main concepts for flexibility in the network are implicit flexibility and explicit flexibility; both with different approaches on how to bring flexibility to the network.

The explicit flexibility refers to the ability to adjust energy demand or generation in response to price signals or incentives provided through flexibility markets. In these markets, participants actively and voluntarily provide flexible services to the power system [20].

On the other hand, implicit flexibility refers to the inherent response capacity of energy consumers and generators without direct participation in flexibility markets. This flexibility is related to tariff structures imposed by regulators or public service providers, where incentives or charges are established to encourage consumers to adjust their energy consumption during periods of high or low demand [21].

Both types of flexibility play a significant role in demand management and the integration of renewable energies into electrical systems. That is why this chapter will examine both typologies in detail.

2.1. Flexibility definition

EURELECTRIC defines flexibility as the possibility of adjusting patterns of generation and consumption in reaction to a signal (price or activation signals) to contribute to different services [22]. In other words, flexibility in the electrical systems refers to the ability of the involved agents (i.e., generators, consumers, system operators, etc.) to adjust their energy production or consumption to adapt to fluctuations in the supply and demand of the electricity market. This flexibility can also be used as a solution for active distribution network management dealing with local network congestion and voltage issues [23].

These fluctuations can be due to multiple factors, such as the variability of intermittent renewable energy production, changes in energy demand or incidents in the electrical grid (i.e., overloads, short circuits, electrical equipment failures, etc.).

2.1.1. Sources of flexibility

Within the concept of electrical flexibility, there are different types depending on the resources and technologies used. Next, the most common ones are explained in detail:

1. **Supply-side flexibility:** It refers to the ability of the power plants to adjust their energy production according to fluctuations in energy supply or demand on the grid. This is

achieved by the coordinated operation of various generation, transmission, and distribution units, which are controlled to balance the energy systems [24].

2. **Demand-side flexibility:** It refers to the ability of energy consumers to adjust their consumption to adapt to fluctuations in energy supply on the grid. This is typically achieved through demand side management (DSM), a set of practices and strategies used to manage and reduce electricity consumption, which may include energy shifting according to price signals or for a higher self-consumption ratio of on-site renewable energy. Heating, ventilation, and air conditioning (HVAC) systems have been demonstrated to have enormous potential in DSM [25] due to their ability to provide demand-side flexibility by utilising the building's thermal mass inertia.
3. **Grid-side flexibility**: It refers to the capacity of the electrical system itself to detect and respond to changes in the supply and demand of electrical energy, as well as incidents in the grid (i.e., power cuts or equipment failures). This can be achieved by installing real-time control and monitoring equipment.

2.2. Flexibility markets

Local flexibility markets provide opportunities to trade flexibility among distribution system operators and other participants (e.g., aggregators) in an economically efficient way [26].

The DERs are normally connected to residential homes, smart buildings, microgrids, and distribution systems and mainly include distributed generators (DGs), energy storages, and controllable loads (e.g., heat pumps, and electric vehicles) [27]. These can be potential providers of flexibility with the right technologies. The layout of a residential home today could be as depicted in Figure 1:

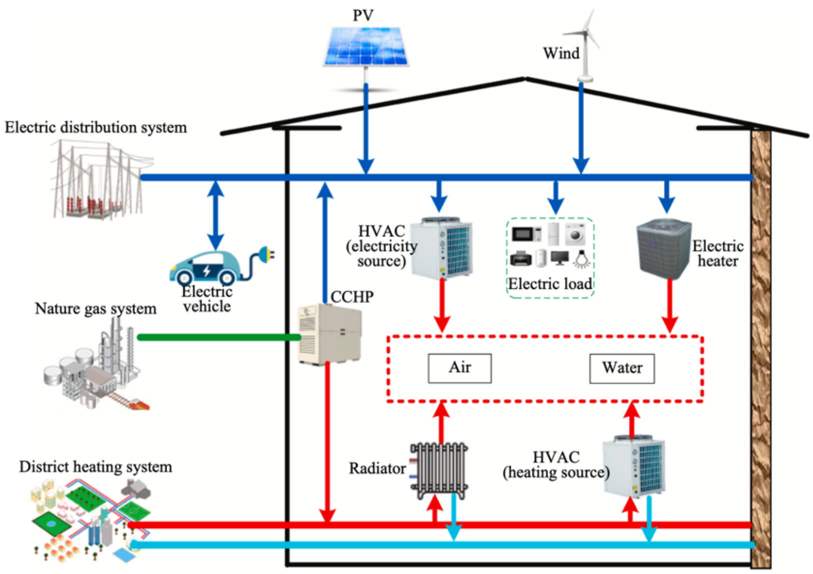


Figure 1: Energy systems scheme of residential home. Source: Xiaolong, J. [26]

2.2.1. Key participants in local flexibility markets

A local flexibility market (LFM) can be defined as an electricity flexibility trading platform to trade flexibility in geographically limited areas such as neighbourhoods, communities, towns, and small cities [28].

In LFMs, various agents play a fundamental role in their proper functioning. Generally, the key participants are:

1. **Distribution System Operator (DSO):** is the operator of the distribution system, whose main task is to deliver electricity to customers in a cost-effective, sustainable and efficient way. The DSO is responsible for the secure operation of the distribution system and the quality of electricity delivery services [29]. The DSO can procure flexibility for different operational purposes (i.e., congestion management, voltage control, loss minimization, etc.) and planning purposes (i.e., deferring the need for network reinforcements) [26]. An example of a DSO in Spain would be the electricity company Endesa Distribución.
2. **Balance Responsible Party (BRP):** BRPs are defined as traders in energy markets on behalf of their client's portfolio [26]. They are responsible for maintaining the energy balance in the system and are accountable for deviations from that balance [30]. If the BRP failed to maintain the balance, it would be charged for imbalance costs. Therefore, BRPs could procure flexibility to optimize their portfolio and realize their energy obligations. BRPs can be retailers, generators, or aggregators; and they are only responsible for balancing the client's portfolio [26].
3. **Aggregator:** a service provider that gathers and manages groups of prosumers to trade their energy and flexibility in the energy and flexibility markets [31]. In LFMs, individual DERs (Distributed Energy Resources) and prosumers have limited bargaining power due to their low flexibility volumes. To overcome this, aggregators gather the individual flexibility and offer various flexibility services in the LFMs. Aggregators act as representatives for DERs and prosumers to trade in LFMs and receive payment from DSOs and BRPs for providing flexibility services.
4. **LFM (Local Flexibility Market) Operator:** it provides a flexibility trading platform and is also responsible for the market clearing as well. Market cleaning is the process that collects the flexibility offers and flexibility requests, and determines trading results (i.e., price and quantity of flexibility to be traded) [26].

In the following image (Figure 2), there is a diagram in which the different agents can be seen and how they interact with each other.

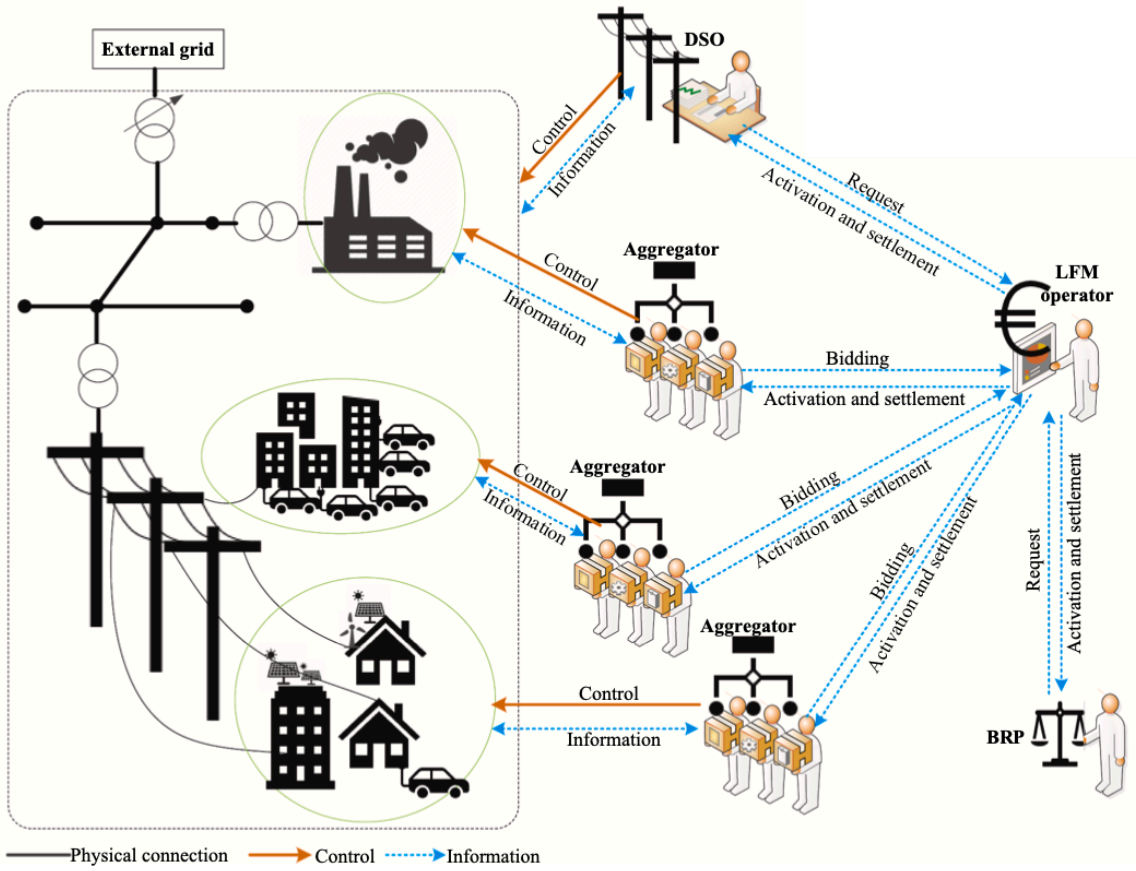


Figure 2. Schematic overview of a Flexibility Market. Source: Xiaolong, J. [26]

2.2.2. Types of flexibility markets

In recent years, a large number of flexibility market initiatives have emerged at the European level. Despite addressing the same problem, none of these platforms are exactly the same, differing in the services they provide, the functions they perform, ownership, and many other factors.

Currently, there are studies that analyse the different types of markets and propose methodologies to compare them. For example, in the paper by Valarezo et al., [32]; they propose a common methodology to compare the different flexibility markets recently developed in Europe. In this work, the analysed flexibility markets (a total of 22) are classified into two main categories: market platforms and aggregator platforms. The former is understood as marketplaces in which DER and/or aggregators can offer their flexibility and DSOs and/or TSOs can procure it. The latter refers to platforms where DER can provide flexibility through an independent aggregator or a supplier acting as an aggregator [32].

2.2.2.1. Local flexibility markets

These classifications are more focused on national or international markets, where the supply and demand of flexibility is managed on a large scale, and agents are typically large companies.

In local flexibility markets, the approach is different. Participants in these markets are usually small and medium-sized enterprises, energy communities, or even individual households, who can offer smaller amounts of flexibility. Additionally, in these local markets, the supply and demand of flexibility are managed at a smaller and closer scale. Therefore, in this work (more focused on a local level), a classification of local flexibility markets from OMIE [33], which differentiates between long term and short-term flexibility, is proposed.

Local markets for long-term flexibility

Negotiation in Long-Term Local Markets is organized based on the requirements received from the DSOs, convened in the long term. In these auctions, DERs can offer their availability (up or down) to cover the convened requirement when necessary during the service window (delivery period) [33]. The main reasons why DSOs may convene such requirements are maintenance and other known and scheduled situations that may cause network overloads, forecasts of demand peaks, or occasional or recurring generations in an area. In Figure 3, a scheme of its operation can be seen.

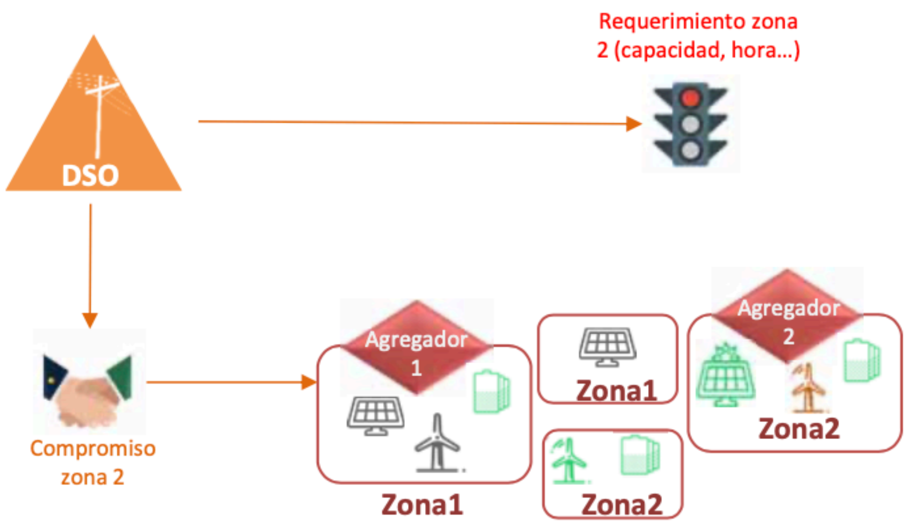


Figure 3. Long-term flexibility markets scheme. Source: OMIE [33]

Local markets for short-term flexibility

The negotiation in Short-Term Local Markets (for the same day or the next day delivery) is organized in two modalities:

- **Continuous**: in which agents can participate freely in the zones where their facilities are located. It is designed, for example, for isolated systems (Figure 4).
- **Auctions:** or at request of the DSO, convened under the requirement of a DSO due to imminent congestion forecast in one of its zones (Figure 5).

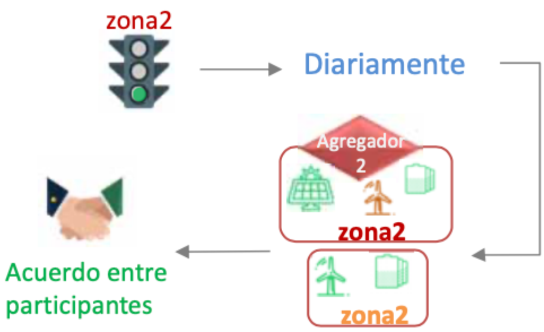


Figure 4. Free short-term flexibility market. Source: OMIE [33]

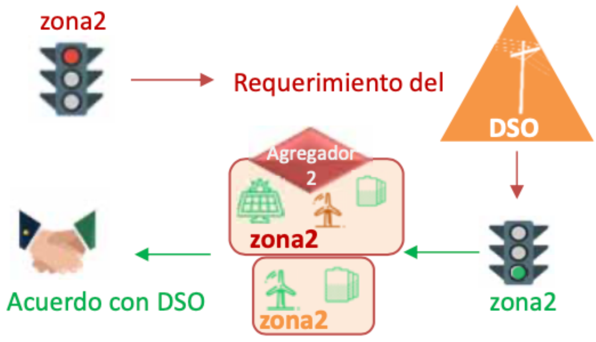


Figure 5. Auction based short-term flexibility market. Source: OMIE [33]

2.2.3. Benefits & Challenges

As mentioned at the beginning of this chapter, in recent years, flexibility markets have emerged as a promising solution to address the challenges of the electric power system transition, along the 3 Ds: decarbonization, digitalization, and decentralization. However, like any initiative, these markets also represent a series of challenges associated with the benefits they aspire to provide. In this section, after explaining what flexibility markets are (including the different types) and the elements that compose them, we will analyse in greater detail the main benefits and challenges with the aim of providing a 360º view of them.

2.2.3.1. Key benefits

The main benefits for all service markets participants of adopting market-based approaches for local flexibility are outlined below [34].

Efficiently match supply and demand for flexibility

The presence of local flexibility resources provides a level playing field for service providers to compete against conventional energy resources and enables them to supply power at a reduced cost while also delivering maximum value to the entire energy system. As a result, resources are allocated more efficiently with precise pricing for market participants.

Integrate demand-side flexibility

Load flexibility, also known as demand-side flexibility, is an approach that can help to transition to a more cost-efficient energy system. It involves grouping lead together into aggregate units, allowing operators to reduce the costly production of peak power. Current approaches (cost-based) struggle to integrate loads because they are based on the varying cost of electricity to consumers, as well as the time and location of the consumption. Integrating load flexibility not only helps to reduce off-peak power usage and generate savings, but also addresses grid congestion, manages fluctuations, and encourages investment from a diverse range of flexibility providers.

Work together with coupled sectors

Without any sector-specific tariffs, this type of partnership that exist to assist with decarbonization can better facilitate integration of renewables and achieve climate targets. Tariffs design can also contribute to potential grid loss savings. An example of collaboration between the energy sector and other industries could be electric vehicles being used to provide grid services or retrofit building to be more energy-efficient and provide demand response services.

Contribute to energy efficiency and access to local energy

Focusing on local flexibility can help identify new energy opportunities, such as building control systems that show source of energy waste, Additionally, consumers may prefer locally produced energy, even if it is more expensive, promoting the development of renewable sources at a local level. The availability of local flexibility gives these consumers the option to adjust their consumption to when local production is available.

Market platform operation by neutral third parties

By allowing non-active, neutral third parties to operate the market, risk of conflict of interest is avoided for active parties in. terms of trading facilitation and price formation. This also offers unbundling at the DSO level, which gives market participants fair access to regulated grid assets to ensure they are fully utilized.

2.2.3.2. Challenges

The main challenges identified for the flexibility markets are summarized below.

Varying standards

Some in the industry would like to see the European Union introduce regulatory requirements for non-wires alternatives [35]; there are currently few regulations in place regarding DSO implementation of DERMS regarding granular hosting capacity visibility and optimizing DER integration as a non-wires alternative [36].

Cybersecurity

The European Smart Grids Task Force highlights the increasing need for consumer data from authenticated and connected devices, which has led to an increased reliance on third-party cloud services. This dependence on external services raises concerns about data security and the need for vendors to fully comply with cybersecurity regulations [37].

Public and operator acceptance

The need to integrate multiple energy and distributed resources could add complexity to the system. The management and coordination of these resources can be challenging and may require new skills and tools for the market and DSOs. Additionally, integrating DERMS and

ADMS solutions can be costly and time-consuming, which may delay DSOs adoption of the technology [38].

2.3. Tariffs

Demand response has the potential to become one of the most cost-effective flexibility sources in a power system, key to enabling the integration of a high share of VRE generation. This Demand response can be achieved through Time of Use (ToU) tariffs, based on consumers reaction to price signals (also referred as implicit demand response) [39].

Understanding these tariffs is crucial for achieving a successful energy transition towards a more flexible, sustainable, and profitable electrical system. Therefore, in the following sections, a more detailed explanation of their nature will be provided.

2.3.1. Tariffs definition

Electricity tariffs in the electric sector refer to the price structures established to determine the cost that consumers must pay for electricity supply. These tariffs are designed to cover the operation, maintenance, and expansion costs of the electrical grid, as well as to promote efficiency in electricity usage.

Electricity tariffs are typically set by regulators or electric companies and can vary based on factors such as the type of consumption (residential, commercial, industrial), the time of day (time-of-use tariffs), or geographic location. In addition to covering costs, tariffs may also include components that reflect the economic value of electricity, such as generation costs, capacity charges, or incentives for efficient energy use.

The design of tariffs aims to balance several principles, including cost recovery, economic efficiency, consumer equity, and transparency in price setting [40][41]. By providing a clear and understandable structure, tariffs allow consumers to estimate and control their electricity expenses while providing incentives to promote more efficient and sustainable energy use.

2.3.1.1. Time of Use tariffs (ToU)

With the aim of encouraging consumers to become active participants in the electricity market and enable them to contribute to the flexibility of the electric system, a new tariff system called Time of Use tariffs (ToU) is being implemented.

As the name suggests, these tariffs have time-varying price signals, which are determined based on the balance of the power system or short-term wholesale market price signals (such as day-ahead or intraday price signals).

Through these price signals, consumption can be incentivized or discouraged to shift to different time periods. This allows for a balance between electricity supply and demand and improves system efficiency.

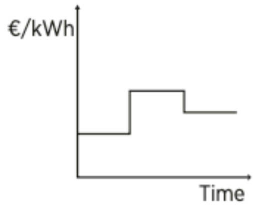
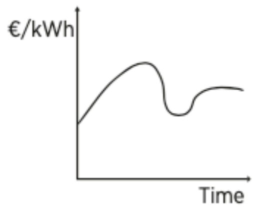
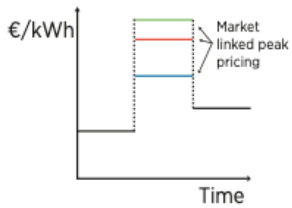
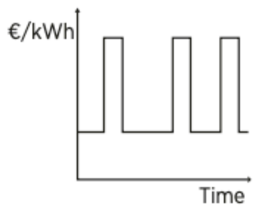
2.3.1.2. Location based tariffs

There is another type of tariff that is used when there are constraints on the electricity network. These are known as location-based tariffs, which reflect the costs associated with congestion in electrical networks (e.g., nodal pricing). They incentivize consumers and prosumers (participants who can both buy and sell electricity) to reduce electricity consumption from the grid or inject electricity into the grid based on network congestion. Therefore, ToU tariffs can be applied to the supply of electricity or the use of the electricity network, or both [39].

2.3.2. Forms of Time-of-Use tariffs

Time-based tariff structures can be static (e.g., tariffs determined in advance) or dynamic (e.g., tariffs determined in “real time” based on the actual system conditions). Dynamic tariff structures include real-time pricing, variable peak pricing, and critical peak pricing /critical peak rebates. Time-based rate programmes require advanced metering infrastructure (AMI). The table below gives an overview of time-based demand response pricing options [39].

Table 1: Forms of Time-of-Use tariffs [39]

Type of tariffs	Nature of pricing	Illustrative graphical representation	Features
Static ToU pricing	Static		This typically applies to usage over large time blocks of several hours, where the price for each time block is determined in advance and remains constant. It can use simple day and night pricing to broadly reflect on-peak and off-peak hours, or the day can be split into smaller segments, allowing several slack periods. Seasonality can also be taken into account.
Real time pricing	Dynamic		Prices are determined close to real-time consumption of electricity and are based on wholesale electricity prices. Electricity prices are calculated based on at least hourly metering of consumption, or with even higher granularity (e.g., 15 minutes). Such tariffs are mostly composed of the wholesale price of electricity plus a supplier margin.
Variable peak pricing	Combination of static and dynamic		A hybrid of static and dynamic pricing, where the different periods for pricing are defined in advance, but the price established for the on-peak period varies by market conditions.
Critical peak pricing	Combination of static and dynamic		A rate in which electricity prices increase substantially for a few days in a year, typically during times the wholesale prices are the highest. E.g., French Tempo tariff is a contract with a fixed price all year except for a maximum of 22 days with very high prices. Customer are notified of

2.4. Challenges

As of today, there is still a long way to go for full implementation of these new tariff systems known as ToU. However, various competent institutions are working towards making it a reality. An example is the International Renewable Energy Agency (IRENA), which in a publication on Time-of-Use tariffs [39] outlines the necessary requirements for their implementation. These requirements are stated in Table 2.

Table 2: Time of Use (ToU) tariffs implementation requirements [39]

TECHNICAL REQUIREMENTS	Hardware	Advanced metering infrastructure (AMI)
	Software	Energy management systems
	Communication protocols	Develop common Iterable standards
REGULATORY REQUIREMENTS	Wholesale market	Easier and equal access
	Distribution System	Innovative ICT infrastructure financing models
	Retail market	Define a standardised methodology for computing dynamic prices
STAKEHOLDERS ROLE AND RESPONSIBILITIES	Consumers	Engage in demand response programmes
	Retailers	Involve the customer in the design of the tariff
	Regulators	Encourage pilot programmes and disseminate the results publicly

3. Flexibility regulation

Flexibility of the energy use has emerged as a solution to optimize the operation of an increasingly complex and dynamic electrical system, due to the irruption of renewable energies and its liberalization [46]. However, the implementation of the mechanisms to acquire system services through the flexibility of network customers presents regulatory challenges that require a review and adaptation of current legislation.

Regulation is a crucial factor in this process of transformation of the electrical grid, as it establishes the rules and legal frameworks that govern it. In this way, it provides the necessary security and stability for agents to compete on equal terms and fosters innovation, ultimately leading to market improvement.

This thesis aims to provide an overview of the various current regulations that address the issue of the flexibility on the grid. To do this, the regulation of the European Union, including Spain, and other important countries such as Great Britain and Australia will be analysed. It should be noted that all around the flexibility is relatively recent, so regulation is constantly evolving.

As seen in the previous chapter, there are two approaches to providing flexibility to the network. In this chapter, European and Spanish legislation is more focused on Flexibility markets (explicit); while regulations in Great Britain and Australia are more oriented towards Demand Response (implicit).

3.1. European regulation

The European Union has been at the forefront of regulatory efforts to promote the integration of flexibility services in energy markets. In June 2019, resulting from the **Clean Energy Package,** the European Parliament and the Council of the European Union adopted Directive (EU) 2019/944 [8], which establishes common rules for the internal electricity market and is known as the Electricity Markey Design Directive. This directive is a significant milestone in the development of flexibility markets in the EU, as it provides a comprehensive legal framework for the integration of flexibility services in the electricity markets of EU members.

This new regulation modifies Directive 2012/27/EU, introducing relevant changes for flexibility markets. Some of the most relevant changes are the following:

A. Need for a flexibility market
Consideration 9 indicates the need for a market that rewards flexibility to effectively achieve the EU's renewable energy objectives.

B. Importance of the consumer role
Consideration 10 highlights the importance of the consumer in achieving the necessary flexibility to adapt the electricity system to renewable, distributed, and variable electricity

generation. Emphasis is also placed on technological advances that have provided management opportunities to consumers, although the need for greater real-time information that allows them to be active participant in the energy market is also remarked.

C. Access to markets

There is a need to eliminate legal and commercial barriers that prevent consumers from self-generating, consuming, storing, or selling self-generated electricity in the market, while ensuring their adequate contribution to system costs. Examples of these obstacles include disproportionate fees for internally consumed electricity, obligations to feed the energy system with self-generated electricity, and administrative burdens such as the need for self-generating consumers who sell electricity to the grid to comply with applicable consumer requirements (Consideration 42 and Article 15).

D. Interoperability

Consideration 55 indicates that is mandatory for all smart metering systems that are to be deployed to be interoperable and capable of providing the necessary information to the consumer. Interoperability at the data model level will facilitate data exchange, resulting in further development of smart grids. On other hand, near-real-time access to consumption data will allow consumers to modulate their energy usage and offer their flexibility to the grid, receiving compensation for it and obtaining savings in their electricity bills.

E. DSO requirements

Distribution grid operators are urged to cost-effectively integrate new electricity generation, especially facilities generating electricity from renewable sources and new load such as those resulting from heat pumps and electric vehicles (Consideration 61).

F. Incentives

Member States shall provide a legal framework that allows and incentivizes distribution system operators to obtain flexibility services, particularly for managing congestion in their areas in order to improve efficiency in the operation and development of the distribution network (Article 32).

In conclusion, the regulatory measures adopted by the European Union to promote the integration of flexibility services in energy markets represent a significant milestone for the development of such markets. The implementation of this directive will contribute to achieving the EU's renewable energy and greenhouse gas emissions reduction objectives and will also empower consumers to be active participants in the transformation of the energy sector.

3.1.1. Spanish regulation

Due to Spain's limited interconnection, there is a large need for flexibility provided locally. Coupled with high utilisation prices due to European wide high wholesale prices, the value of the Spanish market is high [9].

As a member state of the European Union, Spain must incorporate Directive (EU) 2019/944 into the national law. However, Spain, has been somewhat delayed in transposing it, being notified by the European Commission through a formal letter for it [10].

In the document developed by the association *ENTRA, Agregación y Flexibilidad,* titled "*Hoja de Ruta para la flexibilidad de la demanda en España"* [11]; eight relevant elements are identified to enable and promote the Spanish electrical System to foster demand flexibility, justifying the articles of the European Directives to be transposed at the national level. This has been summarized in Table 3:

Table 3: Elements to enable demand-side flexibility in the Spanish electricity system [11]

Elements to enable demand-side flexibility in the Spanish electricity system		
1	Appropriate legal framework that consolidates truly in integrated markets, focused on the consumer, flexible, equitable, and transparent	Transposition of Articles 1, 3, and 8 of Directive 2019/944/EU
2	The opening of all electricity markets to the participation of distributed energy resources, including demand management	Transposition of Articles 1, 3, 8, and 22 of Directive 2019/944/EU, along with the development of Articles 1, 3, 5, 6, 7, 8, 12, and 14 of Regulation 2019/943/EU
3	To provide active customers, market participants providing aggregation services such as retailers and independent aggregators, with non-discriminatory access to electricity markets	Transposition of Articles 1, 2.8, 2.20, 3, 8, 15, 17, and 31 of Directive 2019/944/EU, along with the development of Articles 1, 3, 5, 6, 7, 8, 12, and 13 of Regulation 2019/943/EU
4	Create a capacity market	Developing articles of Chapter IV of Regulation 2019/943/EU
5	Creating local flexibility markets and establishing incentives for the use of flexibility in distribution networks, promoting their evolution and adaptation to demand-side flexibility	Transposition of Article 32 of Directive 2019/943/EU Transposition of Articles 15, 40, and 51 of Directive 2019/944/EU, along with the development of Articles 1, 3, and 12 of Regulation 2019/943/EU
6	Allowing the participation of renewable energy communities and citizen energy communities in flexibility services	Transposition of Article 16 of Directive 2019/944/EU and Article 22 of Directive 2018/2001
7	Appropriate price signals in both the wholesale and retail markets	Transposition of Article 19, 20, and 21 of Directive 2019/944/EU, along with the development of Articles 1 and 3 of Regulation 2019/943/EU

8	Allowing all flexibility service providers to have access to relevant data, with explicit consent from the consumer	Transposition of Articles 17, 23, and 24 of Directive 2019/943/EU

3.2. Other regulations

Although the European Union is highly advanced in terms of regulating flexibility, this does not prevent other countries from also being at the forefront in the development of frameworks to encourage the integration of flexibility services in their electricity systems. An example of this are Great Britain and Australia; which will be discussed in greater detail in this section.

3.2.1. Great Britain

Great Britain's electricity market system is also immersed in a process of decentralization, digitalization, and carbon reduction. To achieve this goal, the commercialization of flexibility through Flexibility Platforms is one of the solutions highlighted by the government.

This process of reducing carbon emissions began in 2008, when the **Climate Change Act** [12] was approved, setting a target for reducing greenhouse gas emissions by 80% by 2050, with strong support from all political parties in the country. This target was updated in 2019 to 100% reduction. Currently, in 20023, greenhouse gas emissions have been reduced by 49% compared to 1990 [13].

More recently, in 2021, the Government along with Ofgem (Office of Gas and Electricity Markets) presented the **Smart Systems and Flexibility Plan** [14]. This document specifies the areas to consider in future thinking on electricity markets. There are as follows:

1. **Facilitating flexibility from consumers;** support consumers to provide flexibility to the system and reduce their energy bills: deployment and use of smart technologies, removing barriers to the provision of consumer flexibility services, appropriate regulation for flexibility service providers, protecting consumers in a smart energy system.
2. **Removing barriers to flexibility on the grid: electricity storage and interconnection;** how to address policy and regulatory barriers facing electricity storage and changes needed to support increased levels of interconnection capacity.
3. **Reforming markets to reward flexibility;** how electricity markets arrangements can unlock the full benefits of flexibility at national and local level.
4. **Digitalising the system;** highlights the importance of data and digitalization in managing the transition to smarter and flexible energy system.

In addition, Ofgem currently has an open call, Call for Input: The Future of Distributed Flexibility [15], where a common vision for distributed flexibility is proposed. The document presents three archetypes for what this infrastructure could look like, and seeks feedback for its development with the industry. It also discusses the need to work on specific market issues and broader energy system capabilities to unlock distributed flexibility.

3.2.2. Australia

Just like other countries, Australia is undergoing a process of transforming its electrical system with the goal of reducing emissions. To achieve this, the Australian government has recognized new opportunities stemming from advancements in technology and widespread adoption of renewable energy generation in households, and one of these opportunities is the Demand Response.

This statement is supported by the **Investment Plan 2021** [16] of the Australian Renewable Energy Agency (ARENA), which highlights demand side flexibility as a key focus are under their strategic priority to optimize the transition to renewable electricity.

To achieve a coordinated transition, the newly elected Australian government, which came into power last summer, has developed a series of initiatives that build upon those of the previous government, but with greater ambition. The new government has committed to achieving net zero by 2050 and emissions reduction of 43 per cent by 2030. These commitments are reflected in the Australian **Renewable Energy Agency Amendment (Powering Australia) Regulations 2022** [17], and the **ARENA Corporate Plan** [18].

The first document, Powering Australia, enables the agency to support energy efficiency and electrification technologies. Electrification technologies encompass various advancements such as electric vehicle chargers, heat pumps, and mining applications. This marks a departure from the previous regulation, which supported clean energy technologies including carbon capture and soil carbon, as well as blue hydrogen. Under the new regulation, support for these last-mentioned technologies will no longer be provided [19].

In the second document, the ARENA Corporate Plan, the vision of the institution on tackling the decarbonization challenge of the electricity system is outlined. It also presents the key activities to achieve this vision, which primarily involve funding projects aligned with their strategic priorities. All this has been summarized in Figure 6, where projects considered strategic (including flexibility) can be seen.

Figure 6: ARENA Corporate Plan summary. Source: ARENA [18]

4. Methodology

In this chapter, the modelling of a heat pump for its subsequent inclusion in a network with tariffs for demand response is developed. This allows the study of a heat pump behaviour and analysis of the benefits it can bring to the transformation of the electric system. To achieve this, the first step involves analysing the equations that this thesis aims to combine.

The first group of equations consists of a series of Python formulas developed by Troncia, M. and Valarezo, O. [42], which calculate the tariff amounts for different hours of the day, considering the issues of overvoltage and undervoltage in the network buses. The second group of equations, is a dynamic thermal model of a house, developed by Morell et al. [4] and Bastida et al. [43], in which new formulas are defined to describe the evolution of temperature inside homes, being much completer and more realistic than previous formulations.

4.1. Calculation of network Tariffs for Demand Response

As explained in the previous section, the use of tariffs is one of the approaches to provide flexibility to the grid. In this thesis, a series of equations developed in Python by Troncia, M. and Valarezo, O. [42], are used to calculate the tariffs. These formulas take into account the issues of the different nodes in the network at different times of the day, as well as the electricity prices for those hours. With that in mind, the equations determine the tariff amounts for each hour of the day.

The objective of these tariffs is to modify the consumption profile of devices connected to the network nodes and address issues. The equations can be divided into three steps:

1. *Network coefficients*

The first step is to calculate the Network coefficients ($dfNetCoeff$) for each hour of the day. To do this, the voltages of each bus in the network is considered for each hour of the day (BVM_S00), a maximum voltage (Vm_Max), and a minimum voltage (Vm_Min) are set, as well as the range within which the coefficients will vary (k_upward and $k\_downward$).

With all this information, the *NetCostCoeffCalc* function returns a coefficient for each hour of the day. In this way, during hours when overvoltage problems are observed, the coefficients will be closer to the lower range, and for those with undervoltage problems, they will be closer to the upper range.

2. *Energy coefficient*

To convert the Network coefficients into tariffs, a parameter is required that relates power and price, which is referred to as the Energy coefficient ($EnergyCoeff$). This

Energy coefficient represents a percentage of the chosen average electricity price for the case study.

3. *Network cost*

Finally, the amount of the tariffs to be applied to each hour of the day ($dfNetCost$) is calculated as follows: if the Network coefficient for that hour is greater than 1, the tariff is obtained by multiplying the Network coefficient by the Energy coefficient. If the Network coefficient is less than 1, the tariff is calculated by subtracting 2 from the coefficient and multiplying it by the Energy coefficient. In the case that the Network coefficient is 0, the tariff amount will also be 0.

If a higher granularity is desired, with different tariff amounts for certain groups of buses or even differentiated by individual buses, the same steps would be performed for each group of buses. The process would be repeated for each chosen group, inputting their respective voltages with the variable BVM_S00. If there is a need to increase the tariff amounts, it would only be necessary to widen the range (k_upward and $k\_downward$) accordingly.

This section provides a brief explanation of the tariff calculation process. For a more detailed understanding of all the mentioned formulas, one can refer to the GitHub repository of Troncia, M. and Valarezo, O. [42].

4.2. Dynamic Thermal model of a house

Nowadays, conventional temperature controllers in buildings do not consider their thermal dynamics, which makes them easier to implement, but with the disadvantage that a large part of the heat provided by the heating systems is wasted. To prevent this, there are literature that focuses on developing new thermal models for buildings.

An example is the model proposed by Morell et al. [4], based on those developed by Bastida et. al. [43], which will be used in this thesis as a reference. In this paper, an approach is proposed to model the thermal behaviour of a building based on equivalent thermal parameters, where equivalent resistive and capacitive (RC) networks are employed to model the heat flow through a solid surface, such as walls, rood, and windows. Using this approach simplifies design process, as can be seen in Figure 7.

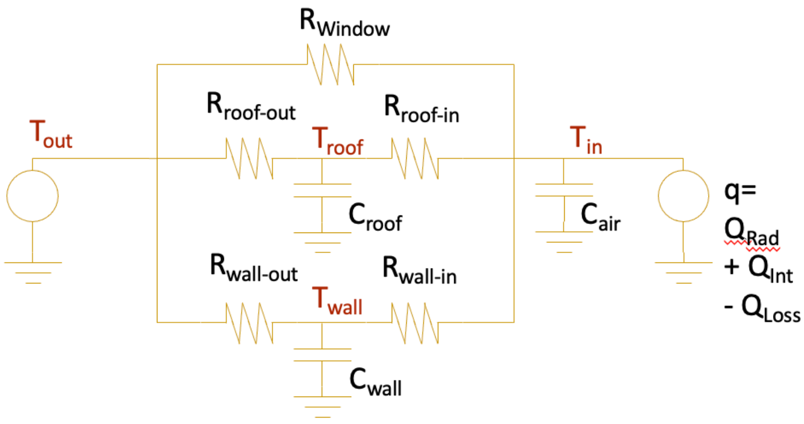


Figure 7: New thermal mode. Source: Morell, N. [4]

In this Figure, the different heat sources that are considered, outside temperature (t_{out}) and the heat introduced (q), and different layers that are considered (walls, roofs, and windows) when calculating the indoor temperature (t_{in}) are shown. The latter is not considered a layer at all as it cannot store the heat (it does not have a capacitor). This is because glass is a very poor thermal insulator, unlike walls and roofs, which can store heat (t_R and t_W). The resistance in the diagram represents the resistance that materials offer to the flow of heat.

Thanks to this, the following formulas can be obtained to calculate the temperature of the roof ($t_{R,h}$) for a given period, which takes into account the temperature of the roof itself in the previous instant, the temperature of the neighbour ($t_{neighbor}$), the temperature inside the house ($t_{int,h-1}$), and its thermal resistivity. This results in the following expression:

$$t_{R,h} = t_{R,th-1} + \left(T_{neighbor} - t_{R,h-1}\right)\frac{R_{Rout}}{C_R}\Delta h + \left(t_{int,h-1} - t_{R,h-1}\right)\frac{R_{Rin}}{C_R}\Delta h$$

The temperature of the walls ($T_{W,h}$) is calculated in the same way, considering their specific thermal properties:

$$t_{W,h} = t_{W,h-1} + \left(T_{out,h-1} - t_{W,h-1}\right)\frac{R_{Wout}}{C_W}\Delta h + \left(t_{int,h-1} - t_{W,h-1}\right)\frac{R_{Win}}{C_W}\Delta h$$

To calculate the indoor temperature, the thermal resistivity of the windows and the heat provided by the heating systems are also considered:

$$t_{in,h} = t_{in,h-1} + \left(t_{R,h-1} - t_{in,h-1}\right)\frac{R_{Rin}}{C_{air}}\Delta h + \left(T_{out,h-1} - t_{in,h-1}\right)\frac{R_{Ww}}{C_{air}}\Delta h$$
$$+ \left(t_{W,h-1} - t_{in,h-1}\right)\frac{R_{Win}}{C_{air}}\Delta h + \frac{q_{h-1}}{C_{air}}\Delta h$$

The heat provided by the heat pump ($q_{in,h-1}$) may not be the same as the received by the building (q_{h-1}), as it is necessary to consider heat losses and the solar radiation received by the house:

$$q_{h-1} = Q_{Rad,h-1} + q_{in,h-1} - Q_{Loss,h-1}$$

With these formulas, it is possible to determine the temperature that will be present in the house at the next instant ($t_{in,h+1}$), depending on the heat that is provided through the heat pump (q_h). This will be essential for calculating the flexibility that the heat pump can provide to the network.

4.3. Proposed model

Having as a reference the two models presented in the previous sections, the objective here is to obtain a model that enables optimization of the behaviour of a heat pump operating in a network with tariffs for demand response and to understand its behaviour.

For this purpose, the process is divided into three parts: first, the basic pump model is developed, which will allow us to define the pump power to maintain the living temperature within the ranges defined by the residents. A second model is developed, which will consider the prices set the day before and will seek to minimize costs; and lastly, the model that takes into account energy prices set the day before as the cost coefficients for demand response.

A summary table on the new nomenclature used is included:

Table 4: Nomenclature used for the proposed model

INDICES AND SETS	
$h \in H$	Hour
$f \in F$	Feeder
H	Set of hours
F	Set of feeders
PARAMETERS	
Ce_h	Cost of electricity in day-ahead market
Ct_h	Cost tariffs for demand response
$Ct_{f,h}$	Cost tariffs for demand response per feeder *f*
$T_{out,h}$	Temperature outside the building in period *h*
$T_{neighbor}$	Temperature of the neighbour's house
T_{in}^{min}	Minimum temperature that can be inside
$Q_{loss,h}$	Heat losses in period *h*

$Q_{rad,h}$	Solar radiation received by the building
COP	Coefficient of Performance

VARIABLES

$t_{in,h}$	Temperature inside the house in period *h*
$t_{in\ f,h}$	Temperature inside the house in period *h* per feeder *f*
$t_{W,h}$	Temperature of the walls in period *h*
$t_{W\ f,h}$	Temperature of the walls in period *h* per feeder *f*
$t_{R,h}$	Temperature of the roof in period *h*
$t_{R\ f,h}$	Temperature of the roof in period *h* per feeder *f*
p_h	Power consumed in period *h*
p_h^i	Power consumed in period *h*
$p_{f,h}^i$	Power consumed in period *h* per feeder *f*
q_h	Heat introduced inside in period *h*
$q_{f,h}$	Heat introduced inside in period *h* per feeder *f*
$q_{in,h}$	Heat introduced by the pump in period *h*
$q_{in\ f,h}$	Heat introduced by the pump in period *h* per feeder *f*

4.3.1. Heat pump model

Following the formulation proposed by Morell et al. [4] and Bastida et al. [43], this section aims to develop a series of formulas that allow defining the power profile of a heat pump in a given period (p_h) taking into account the constraints set by the residents. These constraints will basically be a range of temperatures in which the inhabitants want to keep their homes (T_{in}^{min} and T_{in}^{max}), which will subsequently limit the flexibility that the heat pump can provide to the grid, which is expressed as follows:

$$T_{in}^{min} \leq t_{in} \leq T_{in}^{max}$$

The indoor temperature (t_{in}) depends on the temperature inside the house and the heat provided in the previous instant (q_h); as well as the temperature of walls (t_W) and roofs (t_R). This is summarized in the following formulas:

$$t_{in,h+1} = t_{in,h} + \left(t_{R,h} - t_{in,h}\right)\frac{R_{Rin}}{C_{air}}\Delta h + \left(T_{out,h} - t_{in,h}\right)\frac{R_{Wh}}{C_{air}}\Delta h$$

$$+\left(t_{W,h}-t_{in,h}\right)\frac{R_{Win}}{C_{air}}\Delta h+\frac{q_h}{C_{air}}\Delta h$$

$$t_{W,h+1}=t_{W,h}+\left(T_{out,h}-t_{W,h}\right)\frac{R_{Wout}}{C_W}\Delta h+\left(t_{int,h}-t_{W,h}\right)\frac{R_{Win}}{C_W}\Delta h$$

$$t_{R,h+1}=t_{R,h}+\left(T_{neighbor}-t_{R,h}\right)\frac{R_{Rout}}{C_R}\Delta h+\left(t_{int,h}-t_{R,h}\right)\frac{R_{Rin}}{C_R}\Delta h$$

To calculate the heat provided by the pump (q_{in}), radiation (Q_{rad}) and heat losses (Q_{loss}) must be taken into account.

$$q_{in,h}=q_h+Q_{loss,h}-Q_{rad,h}$$

With this data and knowing the COP of the pump, is possible to obtain its power (p):

$$p_h=\frac{q_{in,h}}{COP}$$

Thus, the model that would allow a first consumption profile of the pump to be obtained without any restrictions other than the temperature range set by the residents, would be the following:

$$\min \sum_{h\in H} p_h$$

s.t.

$$p_h=\frac{q_{in,h}}{COP}, \qquad \forall_h \in H$$

$$q_{in,h}=q_h+Q_{loss,h}-Q_{rad,h}\,, \qquad \forall_h \in H$$

$$t_{in,h+1}=t_{in,h}+\left(t_{R,h}-t_{in,h}\right)\frac{R_{Rin}}{C_{air}}\Delta h+\left(T_{out,h}-t_{in,h}\right)\frac{R_{Ww}}{C_{air}}\Delta h+\left(t_{W,h}-t_{in,h}\right)\frac{R_{Win}}{C_{air}}\Delta h+\frac{q_h}{C_{air}}\Delta h\,, \qquad \forall_h \in H$$

$$t_{W,h+1}=t_{W,h}+\left(T_{out,h}-t_{W,h}\right)\frac{R_{Wout}}{C_W}\Delta h+\left(t_{int,h}-t_{W,h}\right)\frac{R_{Win}}{C_W}\Delta h\,, \qquad \forall_h \in H$$

$$t_{R,h+1}=t_{R,h}+\left(T_{neighbor}-t_{R,h}\right)\frac{R_{Rout}}{C_R}\Delta h+\left(t_{int,h}-t_{R,h}\right)\frac{R_{Rin}}{C_R}\Delta h\,, \qquad \forall_h \in H$$

$$T_{in}^{min}\le t_{in,h}\le T_{in}^{max}, \qquad \forall_h \in H$$

4.3.2. Optimisation model with no network representation in tariffs

Once obtained the basic pump model, which returns a consumption profile based only on the temperature range, the following model aims to optimize that profile (p_h^i) by taking into account the PVPC prices of the energy market (Ce_h). The goal of this model is to minimize daily energy costs while respecting the technical constraint for the heating and electric capability curve.

The model defined to achieve this goal is as follows:

$$\min \sum_{h \in H} p_h^i \, Ce_h$$

s.t.

$$p_h^i = \frac{q_{in,h}}{COP}, \qquad \forall_h \in H$$

$$q_{in,h} = q_h + Q_{loss,h} - Q_{rad,h}\,, \qquad \forall_h \in H$$

$$t_{in,h+1} = t_{in,h} + \left(t_{R,h} - t_{in,h}\right)\frac{R_{Rin}}{C_{air}}\Delta h + \left(T_{out,h} - t_{in,h}\right)\frac{R_{Ww}}{C_{air}}\Delta h + \left(t_{W,h} - t_{in,h}\right)\frac{R_{Win}}{C_{air}}\Delta h + \frac{q_h}{C_{air}}\Delta h\,, \qquad \forall_h \in H$$

$$t_{W,h+1} = t_{W,h} + \left(T_{out,h} - t_{W,h}\right)\frac{R_{Wout}}{C_W}\Delta h + \left(t_{int,h} - t_{W,h}\right)\frac{R_{Win}}{C_W}\Delta h\,, \qquad \forall_h \in H$$

$$t_{R,h+1} = t_{R,h} + \left(T_{neighbor} - t_{R,h}\right)\frac{R_{Rout}}{C_R}\Delta h + \left(t_{int,h} - t_{R,h}\right)\frac{R_{Rin}}{C_R}\Delta h\,, \qquad \forall_h \in H$$

$$T_{in}^{min} \leq t_{in,h} \leq T_{in}^{max}, \qquad \forall_h \in H$$

4.3.3. Optimisation model with network representation in tariffs

In this section, two optimization models will be formulated for the consumption of the heat pump, both with the network cost coefficients for demand response. These coefficients are calculated based on the constraints that appear in the network and aim to shift the demand to solve network issues.

The idea is to compare the results of the Base Scenario and the network problems with those of the two following models.

The formulation will be very similar to the previous model but adding the amount of the tariffs to the PVPC prices. Additionally, in the first model, the location of the nodes will not be considered, with the tariffs being the same for all; while in the second model, tariff differentiation will be made between feeders.

4.3.3.1. Tariffs for DR but with no local differentiation

As mentioned before, this model is very similar to the previous one, with the difference that the coefficients for DR (Ct_h) have been added to the electricity cost in the objective function. The amount of these tariffs will be the same for the entire network.

The resulting model is as follows:

$$\min \sum_{h \in H} p_h^i \left(Ce_h + Ct_h\right)$$

s.t.

$$p_h^i = \frac{q_{in,h}}{COP}, \qquad \forall_h \in H$$

$$q_{in,h} = q_h + Q_{loss,h} - Q_{rad,h}\,, \qquad \forall_h \in H$$

$$t_{in,h+1} = t_{in,h} + \left(t_{R,h} - t_{in,h}\right)\frac{R_{Rin}}{C_{air}}\Delta h + \left(T_{out,h} - t_{in,h}\right)\frac{R_{Ww}}{C_{air}}\Delta h + \left(t_{W,h} - t_{in,h}\right)\frac{R_{Win}}{C_{air}}\Delta h + \frac{q_h}{C_{air}}\Delta h\,, \qquad \forall_h \in H$$

$$t_{W,h+1} = t_{W,h} + \left(T_{out,h} - t_{W,h}\right)\frac{R_{Wout}}{C_W}\Delta h + \left(t_{int,h} - t_{W,h}\right)\frac{R_{Win}}{C_W}\Delta h\,, \qquad \forall_h \in H$$

$$t_{R,h+1} = t_{R,h} + \left(T_{neighbor} - t_{R,h}\right)\frac{R_{Rout}}{C_R}\Delta h + \left(t_{int,h} - t_{R,h}\right)\frac{R_{Rin}}{C_R}\Delta h\,, \qquad \forall_h \in H$$

$$T_{in}^{min} \leq t_{in,h} \leq T_{in}^{max}, \qquad \forall_h \in H$$

4.3.3.2. Tariffs for DR but with local differentiation

For the differentiation between nodes in this section what needs to be taken into account is that the pumps operating in different feeders will have different tariffs ($Ct_{f,h}$) and different consumption profiles ($p_{f,h}^i$). The rest of the variables will also be different for each feeder.

Another important change is the addition of an additional summation to the objective function to consider all the defined feeders.

The resulting model is as follows:

$$\min \sum_{h \in H} \sum_{f \in F} p_{f,h}^i \left(Ce_h + Ct_{f,h}\right)$$

s.t.

$$p_{f,h}^i = \frac{q_{in\,f,h}}{COP}, \qquad \forall_h \in H; \forall_f \in \mathrm{F}$$

$$q_{in\,f,h} = q_{f,h} + Q_{loss,h} - Q_{rad,h}\,, \qquad \forall_h \in H; \forall_f \in \mathrm{F}$$

$$t_{in\,f,h+1} = t_{in\,f,h} + \left(t_{R\,f,h} - t_{in\,f,h}\right)\frac{R_{Rin}}{C_{air}}\Delta h + \left(T_{out,h} - t_{in\,f,h}\right)\frac{R_{Ww}}{C_{air}}\Delta h + \left(t_{W\,f,h} - t_{in\,f,h}\right)\frac{R_{Win}}{C_{air}}\Delta h + \frac{q_{f,h}}{C_{air}}\Delta h\,, \qquad \forall_h \in H; \forall_f \in \mathrm{F}$$

$$t_{W\,f,h+1} = t_{W\,f,h} + \left(T_{out,h} - t_{W\,f,h}\right)\frac{R_{Wout}}{C_W}\Delta h + \left(t_{int\,f,h} - t_{W\,f,h}\right)\frac{R_{Win}}{C_W}\Delta h\,, \qquad \forall_h \in H; \forall_f \in \mathrm{F}$$

$$t_{R\,f,h+1} = t_{R\,f,h} + \left(T_{neighbor} - t_{R\,f,h}\right)\frac{R_{Rout}}{C_R}\Delta h + \left(t_{int\,f,h} - t_{R\,f,h}\right)\frac{R_{Rin}}{C_R}\Delta h\,, \qquad \forall_h \in H; \forall_f \in \mathrm{F}$$

$$T_{in}^{min} \leq t_{in,h} \leq T_{in}^{max}, \qquad \forall_h \in H; \forall_f \in \mathrm{F}$$

5. Case study

In this section, the aim is to demonstrate the usefulness of flexibility in addressing overvoltage and undervoltage issues in a low-voltage network. To tackle these problems, the behaviour of a household heat pump in a network with tariffs for Demand Response has been modelled using the formulation explained in the previous chapter.

For analysis purposes, a low-voltage network has been established, with the pumps being integrated through various nodes. The network and its nodes which can be observed in the Figure 8, is a LV network from J. Dickert et. al. that has been created using a panda power function. This function is explained in Pandapower 2.13.1 documentation [47].

The parameters used to obtain this network are the followings:

- Feeders range: short.
- Line type: cable.
- Customer: multiple.
- Case: average.
- Trafo type: 0.4 MVA 20/0.4kV

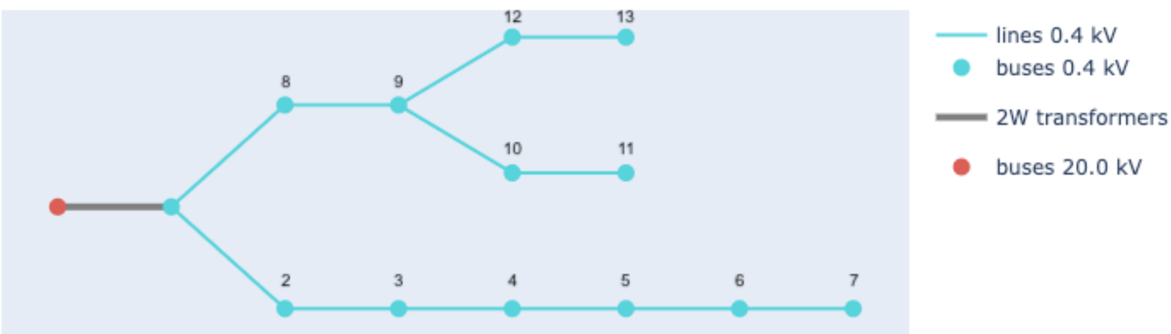


Figure 8: Low voltage electricity network for the case study. Source: Own elaboration

The study involves the analysis of three distinct scenarios:

- Base Scenario: no network representation in tariffs.
- Scenario A: tariffs for Demand Response but with no locational differentiation.
- Scenario B: tariffs for Demand Response but with locational differentiation.

Furthermore, Scenarios A and B will be examined with two different demand response rates to assess the sensitivity of the heat pumps' consumption profiles to the amount of the rates. In the document, it will be distinguished as Scenario X – High amount, and Scenario X – Low amount. This analysis will encompass both PVPC prices on working days and prices on weekends.

For all scenarios, a temperature range of 20 to 25°C and an external temperature representative of a winter day in Madrid have been selected. To observe the solutions offered by network tariffs for DR, 15 heat pumps, with a nominal power of 3kW each, have been connected to the selected nodes (3, 5, 7, 9, 11 and 13). In these nodes, different consumption profiles can be observed; for example in buses 3 and 8 a consumption profile more typical of a residential neighbourhood can be observed, in bus 7 a consumption profile more similar to that of industry can be observed. This can be seen in Figure 9.

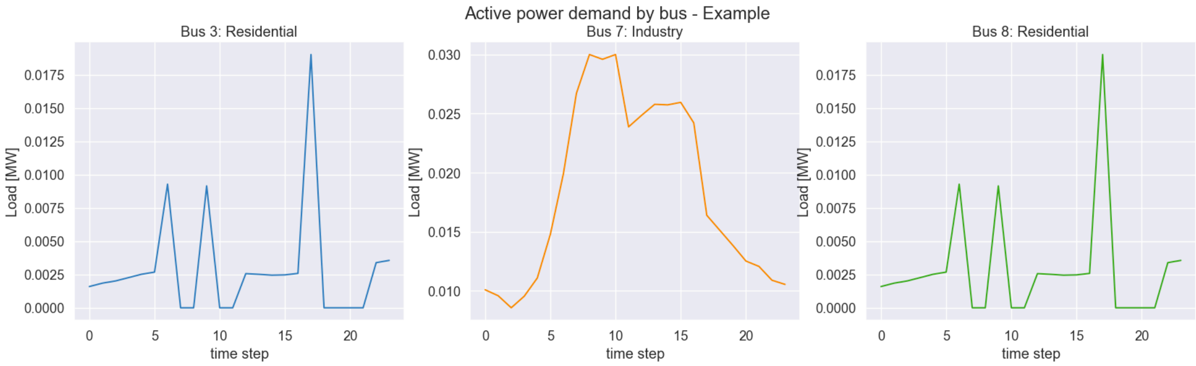


Figure 9: Consumption profiles. Source: Own elaboration

In buses 3 and 7, photovoltaic (PV) generation is also taken into account. This can be seen in Figure 10.

Figure 10: PV generation. Source: Own elaboration

It has been assumed that the heat pumps have the same consumption profile for each node as the same parameters and the same tariffs scheme are considered.

As mentioned in section 4.1 on tariff calculation, it is also necessary to set a minimum (V_{min}) and a maximum (V_{max}) voltage. For this work, the maximum has been set at 1.05V and the minimum at 0.95V.

5.1. PVPC prices for a working day

The PVPC prices used are those corresponding to June 30th, 2023, obtained from Red Eléctrica website [44].

5.1.1. Base Scenario: No network representation in tariffs

With the temperature range and the fixed evolution of the outdoor temperature, when running the model for the Base Scenario (considering only the PVPC prices), the following results are obtained.

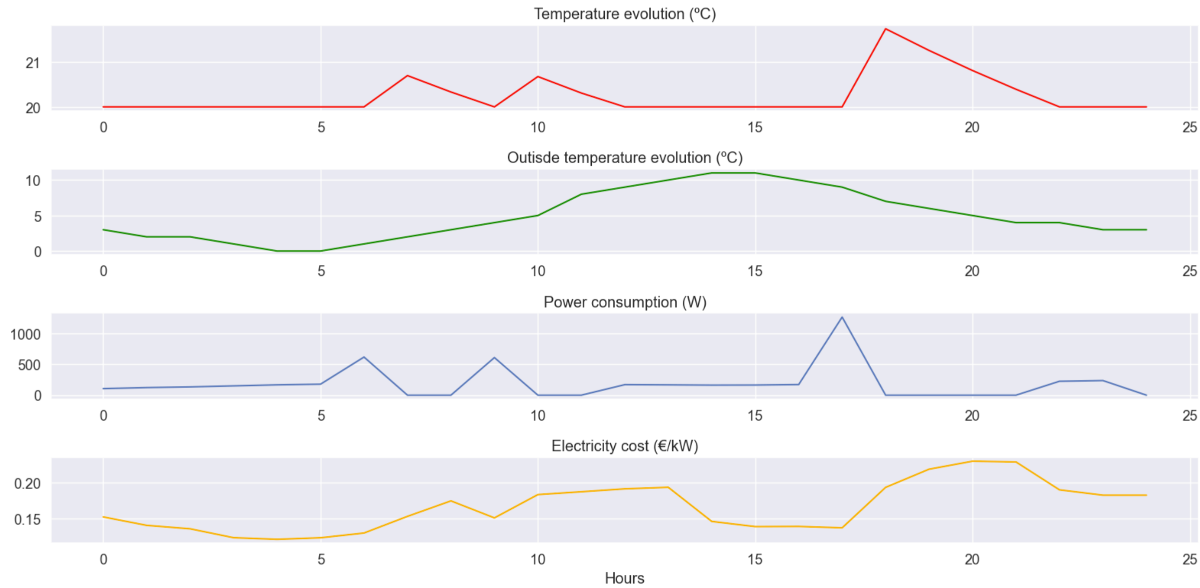


Figure 11: Summary heat pump modelling result | Base Scenario (workday) . Source: Own elaboration

Looking at the Figure 11, in the first graph, can be observed the evolution of the indoor temperature, which remains between 20 and 25°C throughout the period. The green line represents the outdoor temperature, ranging between 0 and 12°C.

The third graph depicts the consumption profile of the heat pump. Three significant consumption peaks can be observed during the day, occurring at 6 AM, 9 AM, and 5 PM. It is notable that these peaks in consumption coincide with the decreases in prices, as shown in the last graph.

With this configuration, the following voltage magnitude constraints violations are obtained:

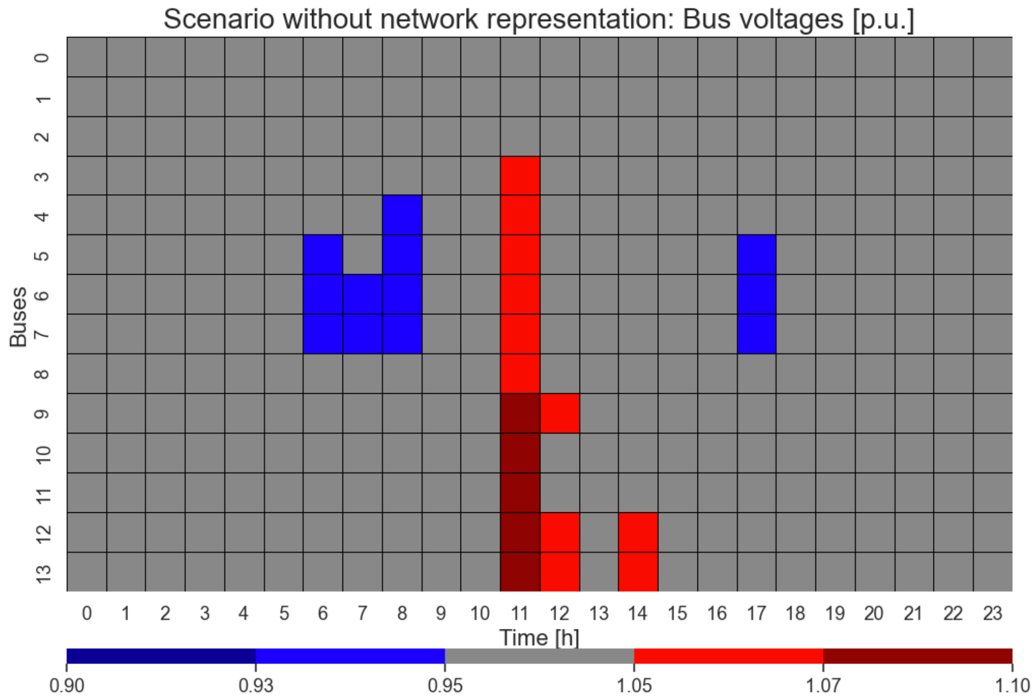


Figure 12: Network problems per bus and time | Base Scenario (workday) . Source: Own elaboration

Figure 12 shows the hours and buses where it is necessary to decrease consumption due to undervoltage issues (blue) or increase it due to overvoltage issues (red). Overvoltages are due to an excess of PV generation (as shown before), while undervoltages are due an excess of loads. As indicated in the legend at the bottom, the darker the shade, the greater the magnitude of the problem.

It can be observed that overvoltage issues are concentrated between 11 AM and 2 PM in almost all nodes of the network. On the other hand, undervoltage problems occur between 6 AM and 8 AM, as well as at 5 PM. In this latter case, unlike the former, the issues are concentrated in buses 4 to 7.

These issues are used to determine the network cost coefficients for Demand Response. This tariff is added to the PVPC cost to incentivize or discourage consumption during different hours in order to resolve the problems.

5.1.2. Scenario A: Tariffs for DR but with no local differentiation

In this first scenario, the DR coefficients are added to the PVPC price without differentiation by feeder, resulting in the same coefficients for all buses. The model is then run with two different values for the DR coefficients, namely Scenario A – Low amount and Scenario A – High amount, in order to assess sensitivity to prices.

__Coefficients for Demand Response – Low amount__

When running the model considering these tariffs in the objective function, the following result is obtained as shown in Figure 13.

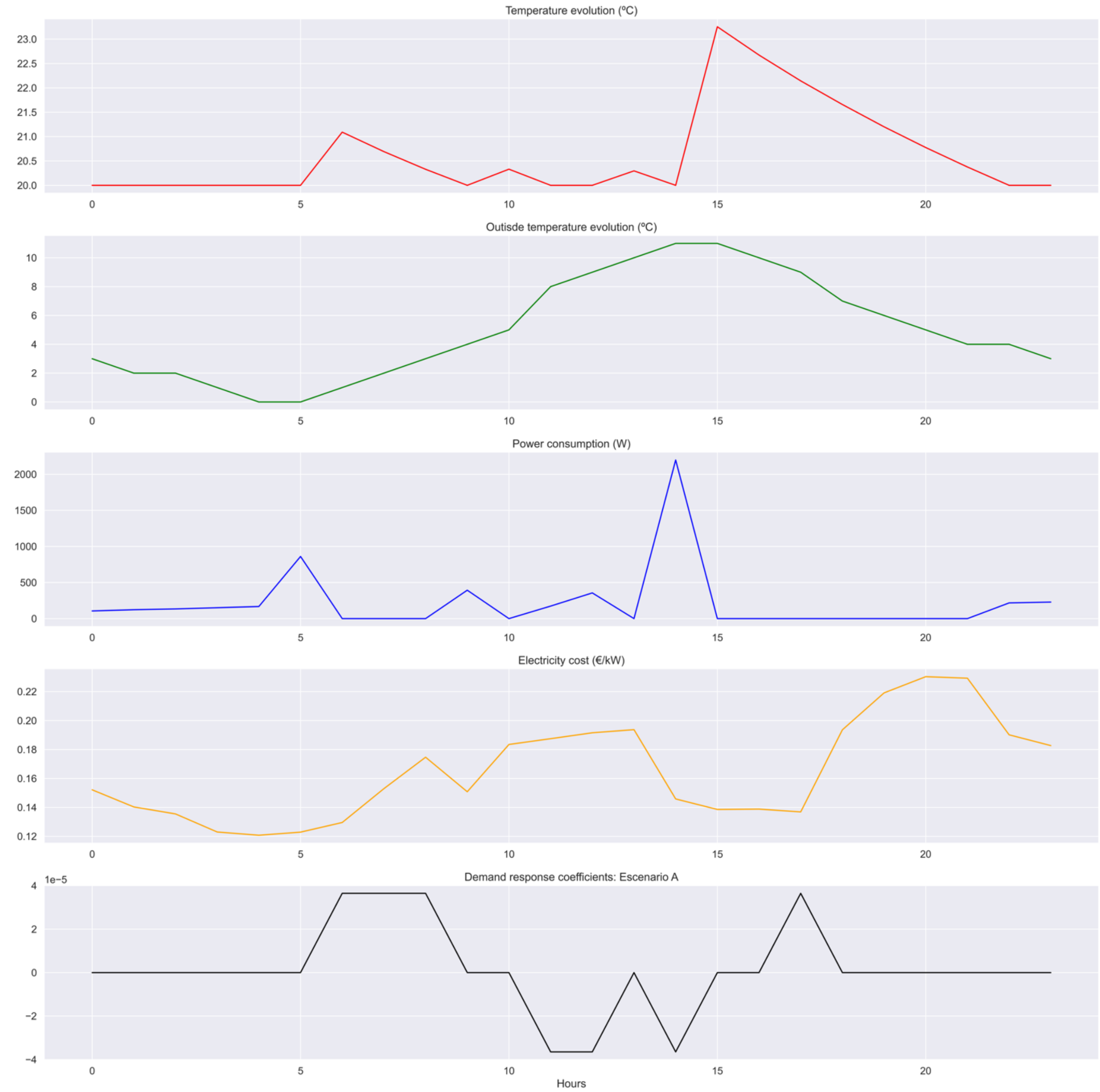


Figure 13: Summary heat pump modelling result | Scenario A – Low amount (workday) . Source: Own elaboration

In this result, changes can already be observed compared to the previous one. Starting with the temperature, a higher maximum temperature is reached in this case. This is due to the higher peak of consumption observed at 2 PM, which leads to a temperature peak at 3 PM. Similar to before, the consumption peak corresponds to a time of cheaper energy resulting from the combination of PVPC prices and DR tariffs.

Figure 14 shows the differences between the consumption profiles of Scenario SA01 and the Base Scenario can be observed more clearly.

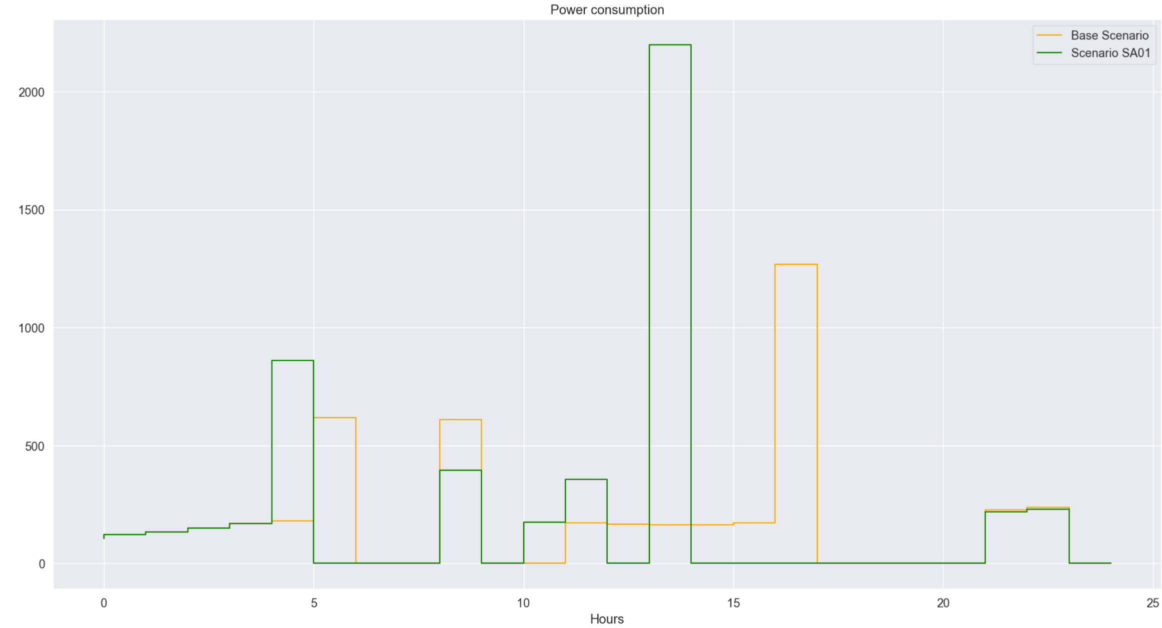


Figure 14: Comparison between consumption profiles | Base Scenario vs Scenario A – Low amount (workday) . Source: Own elaboration

In Figure 14, it can be observed how the new consumption profile shifts the consumption to 5 AM and does not consume between 6 AM and 8 AM. Additionally, there are consumption peaks at 12 PM and 2 PM (with the latter being significantly higher), allowing for a cessation of consumption at 5 PM.

All these differences aim, as mentioned earlier, to resolve the issues observed in the Base Scenario. Analysing the network, the problems within it would be as shown in Figure 15.

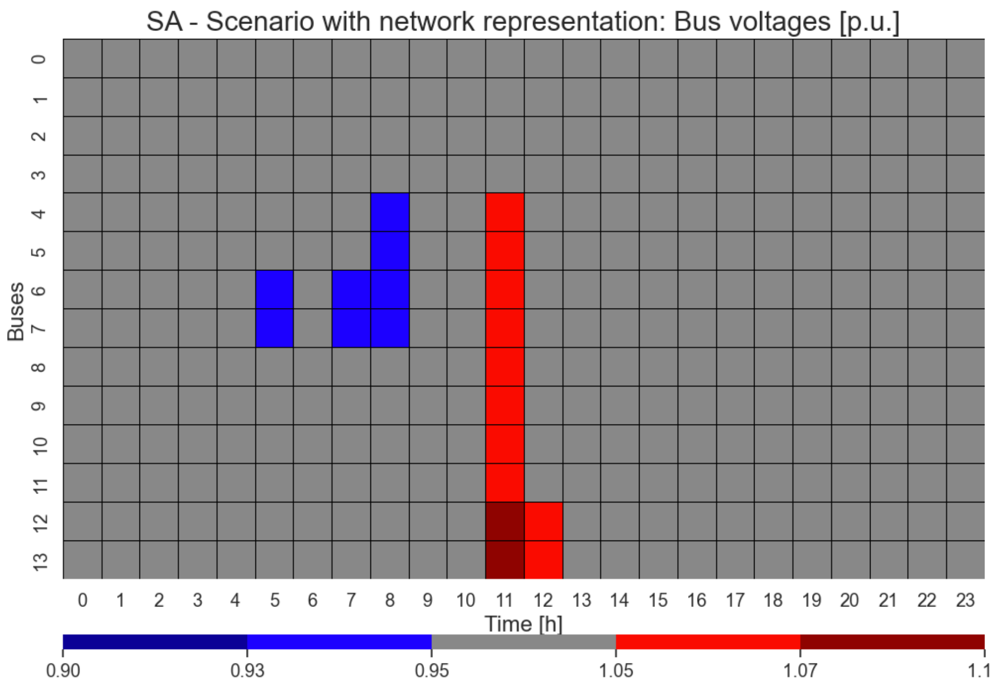


Figure 15: Network problems per bus and time | Scenario A – Low amount (workday) . Source: Own elaboration

Despite not solving all the problems, looking at Figure 15, it can be asserted that some of them have been addressed. Thanks to the DR coefficients implemented in the network tariffs, which have modified the consumption profile, the issues of excessive demand at 6 AM and 5 PM have been resolved (although a new issue has emerged at 5 AM). Additionally, part of the under-demand issues at 11 AM (reducing the intensity of the red), 12 PM (bus 9), and the complete issues at 2 PM have been resolved.

<u>Coefficients for Demand Response – High amount</u>

The objective of this subsection is to execute the same model as before, using the same type of DR coefficients, but with a higher amount. This approach aims to analyse the sensitivity of the heat pumps' consumption profiles to prices when it comes to resolving network issues.

Following the same steps, we obtain the following graphs:

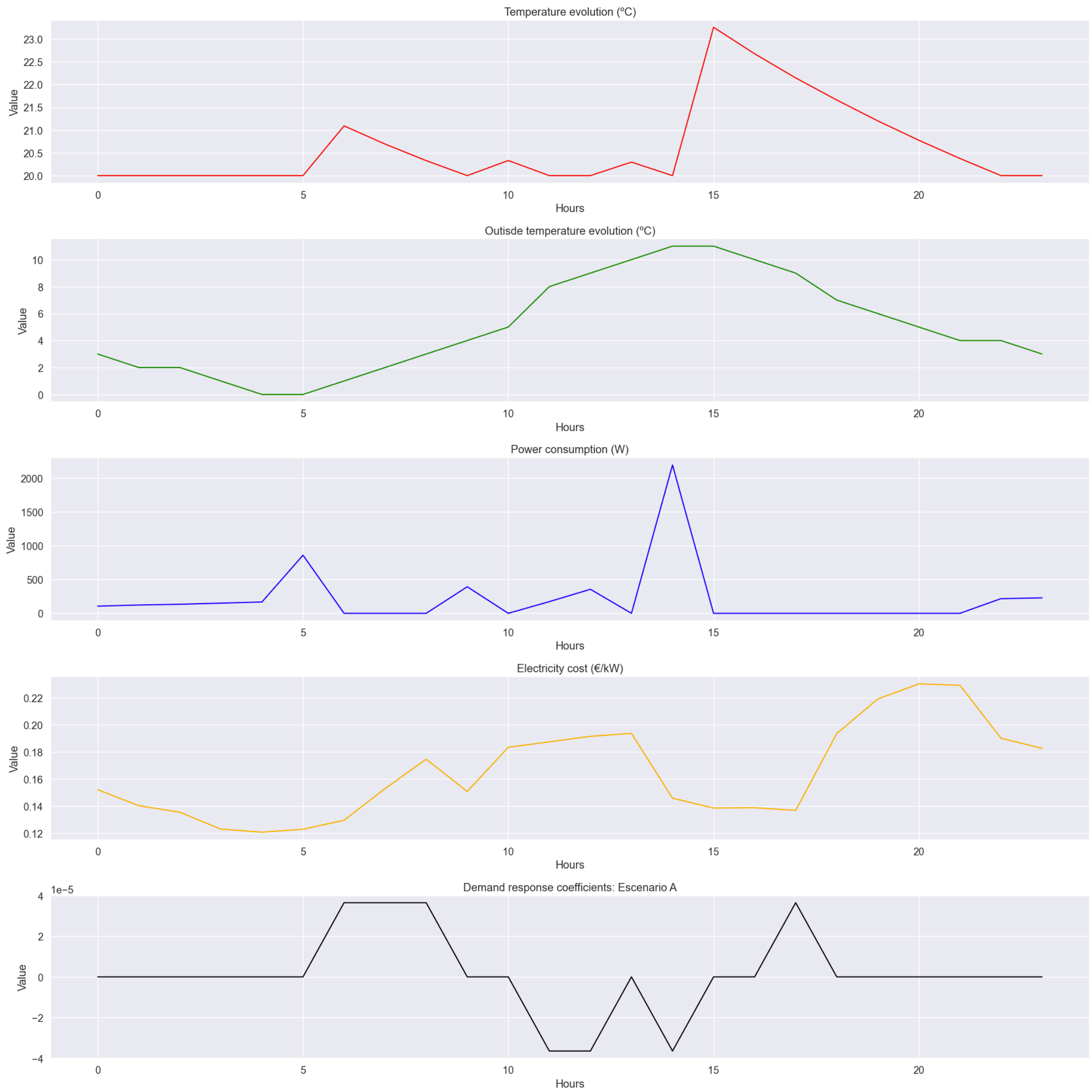


Figure 16: Summary heat pump modelling result | Scenario A – High amount (workday) . Source: Own elaboration

At first glance, looking at Figure 16, we can affirm that the consumption profile has not changed, and therefore, the temperature inside the house remains the same. Figure 17 provides a better visualization:

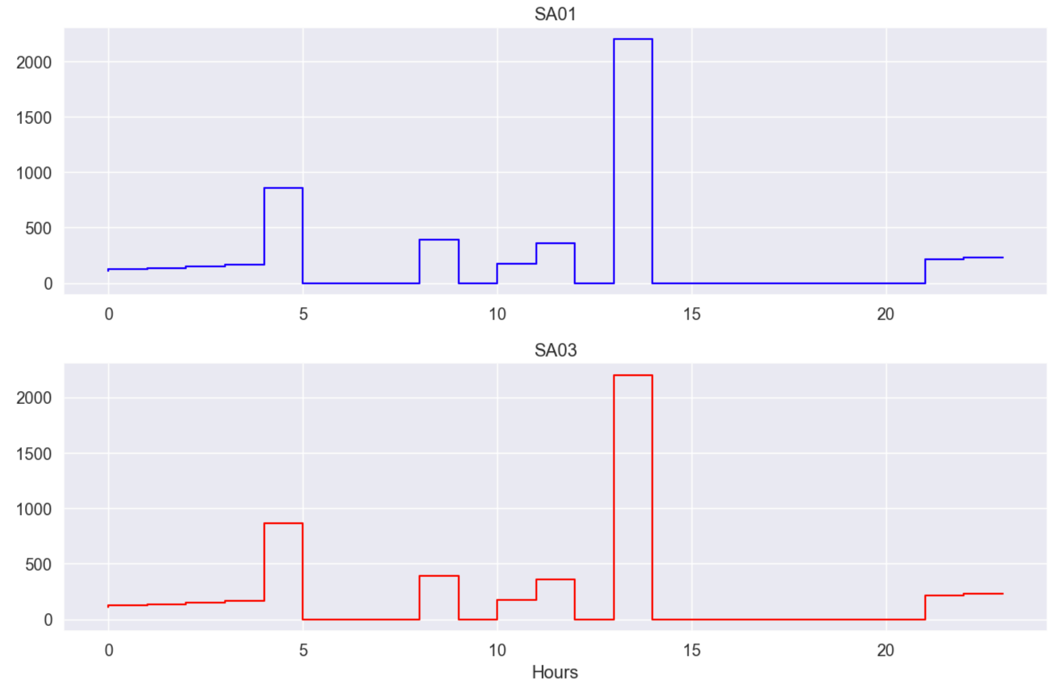


Figure 17: Comparison between consumption profiles | Scenario A – Low amount vs Scenario A – High amount (workday) . Source: Own elaboration

If we analyse the issues in the network:

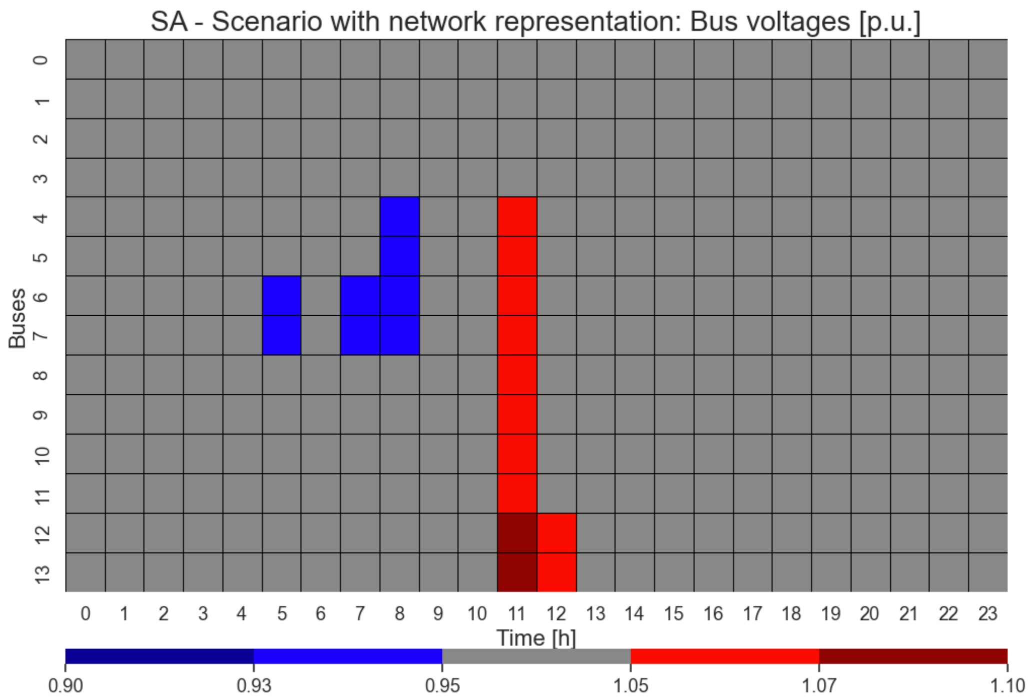


Figure 18: Network problems per bus and time | Scenario A – High amount (workday) . Source: Own elaboration

The issues in this case remain the same as when using the DR coefficients SA01. It can be concluded, then no sensitivity to prices is observed when resolving network problems.

5.1.3. Scenario B: Tariffs for DR but with local differentiation

In the scenario B, similar to the previous one, the DR coefficients with locational differentiation are taken into account. However, in this case, the location of the bus to be resolved is considered. For this purpose, a distinction is made between two feeders (F0 and F1) that have different tariffs to address the issues observed in the Base Scenario. Feeder 0 covers nodes 2 to 7, while feeder 1 covers nodes 8 to 13.

Similarly to Scenario A, the study is conducted for two different amounts of the DR tariffs to analyse the sensitivity to prices.

Coefficients for Demand Response – Low amount

When running the model with the new DR coefficients that differentiate between the two feeders, the following results are obtained:

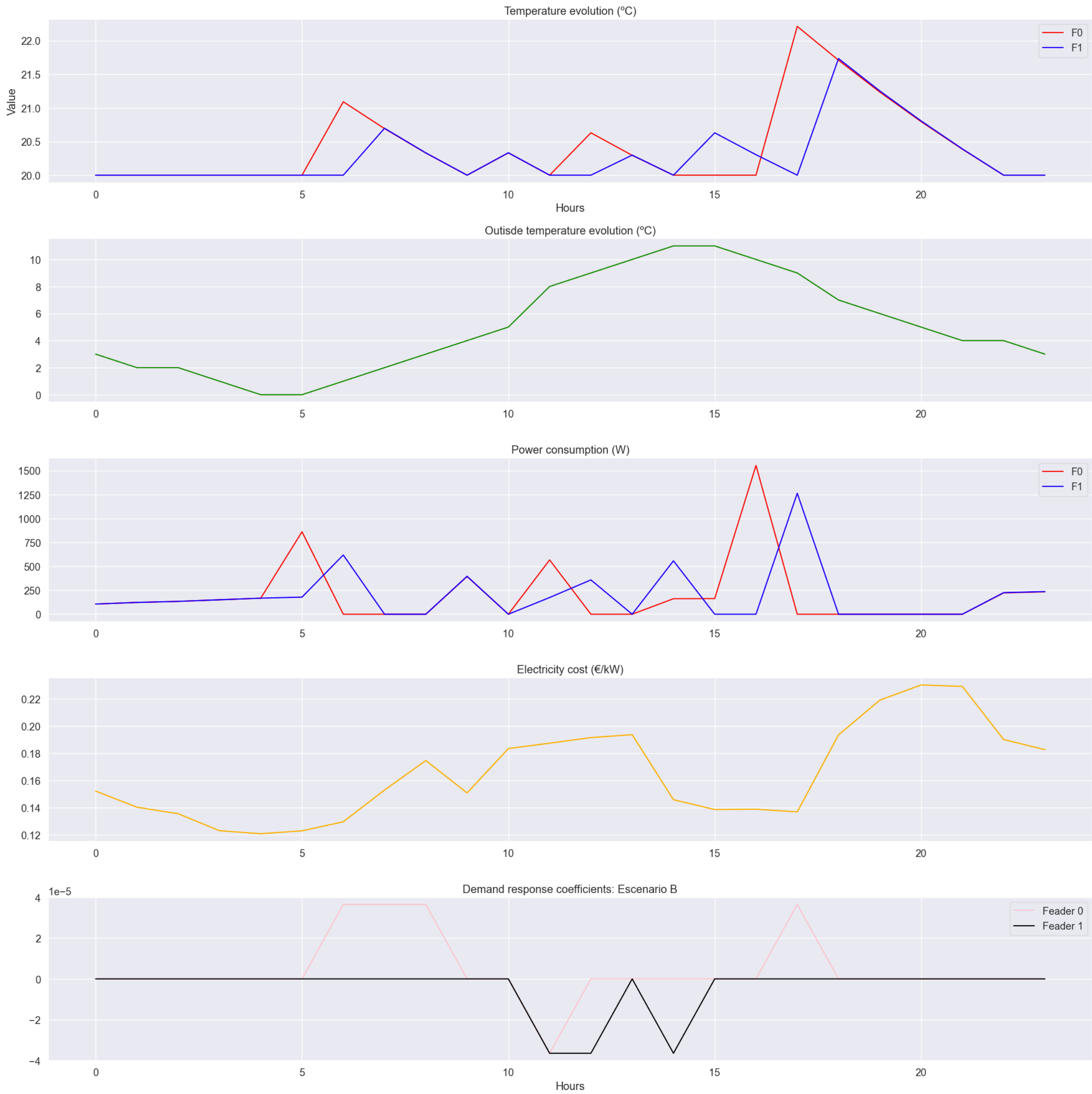


Figure 19: Summary heat pump modelling result | Scenario B - Low amount (workday) . Source: Own elaboration

In the Figure 19, the same information is presented as in the previous scenarios, but broken down by feeder for temperature, power, and DR coefficients. It is worth noting that at first glance, the effect of differentiating by feeder can be observed, as we obtain two distinct consumption profiles that respond to the incentives associated with each feeder.

In the Figure 20, can be observed the difference of each one with the profile of the Base Scenario:

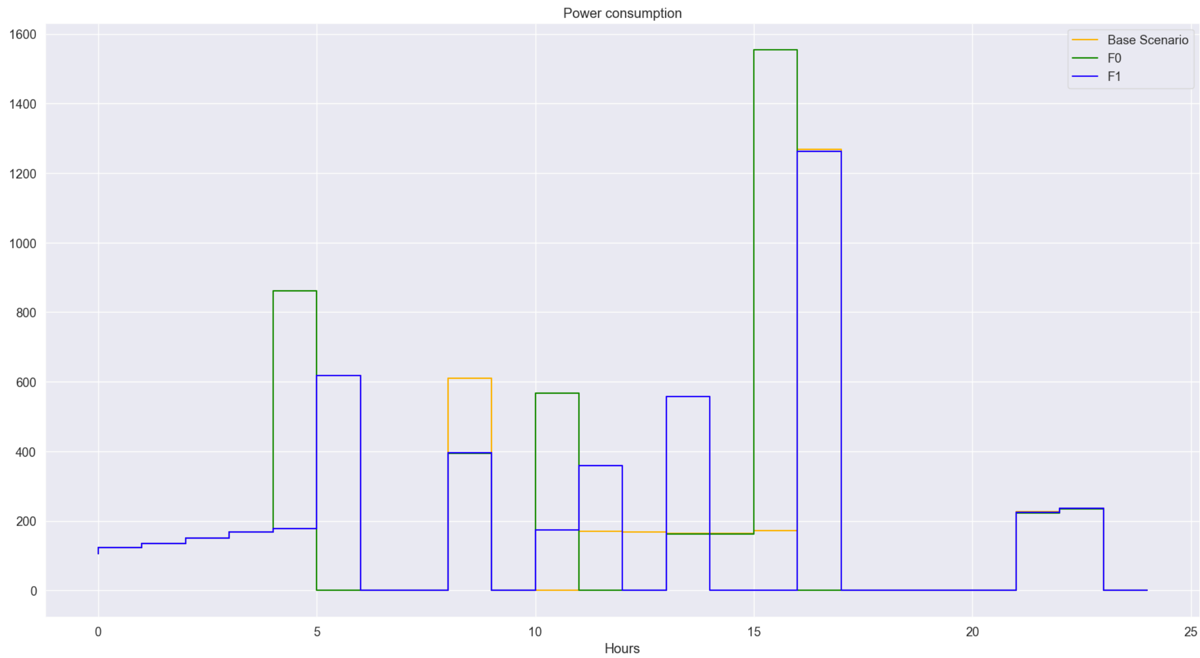


Figure 20: Comparison between consumption profiles | Scenario B – Low amount vs Base Scenario (workday) . Source: Own elaboration

In Figure 20, yellow refers to the consumption profile of the Base Scenario, while green and blue refer to the F0 and F1 feeders respectively. In relation to F0, it can be seen how the consumption is advanced and with a higher power for both 5 AM and 4 PM; in addition to an additional peak at 10 AM. On the other hand, it can be seen how F1 overlaps more with the Base Scenario, although there is some minor difference at 8 AM, 11 AM and 1 PM. These differences allow for better adaptation to the corresponding issues of each group of nodes.

By analysing the network issues, the following results are obtained:

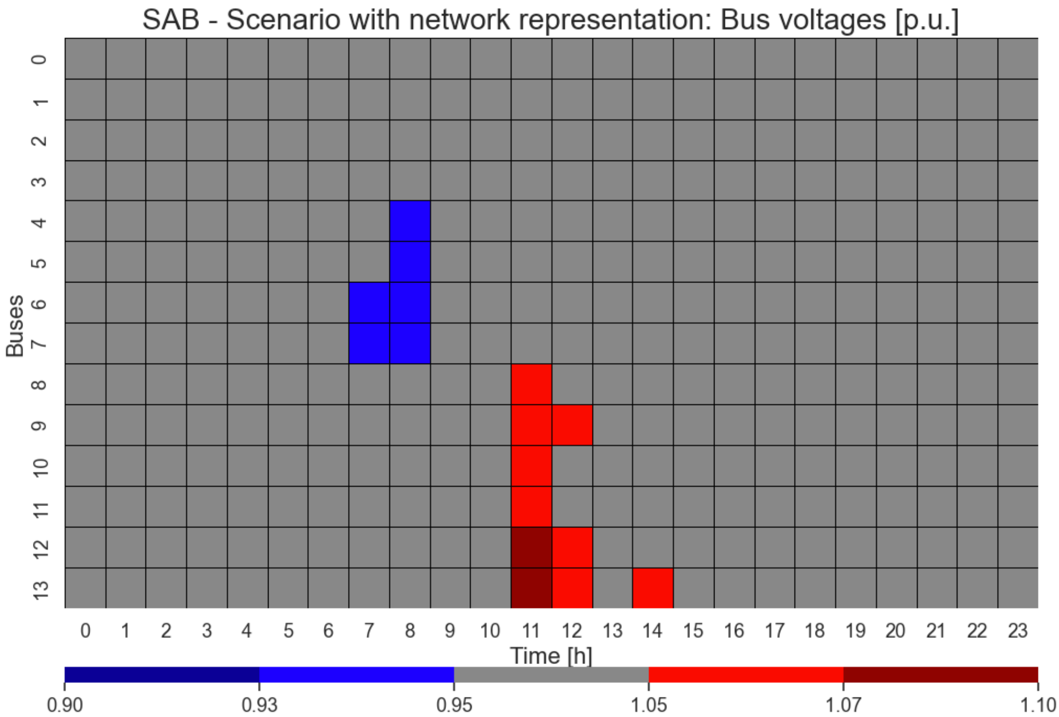


Figure 21: Network problems per bus and time | Scenario B – Low amount (workday) . Source: Own elaboration

Despite not resolving all the issues, it can be observed that thanks to the differentiation between two feeders for the calculation of the DR coefficients, a greater number of network problems are resolved. The issues of excessive demand (undervoltage) at 6 AM and 5 PM are eliminated, as well as a significant portion of the issues at 11 AM and half of the issues at 2 PM.

Coefficients for Demand Response – High amount

As done in Scenario A, the objective of this subsection is to analyse the sensitivity to the amount of the DR coefficients in the scenario where differentiation by node is considered.

When running the model considering the DR coefficients of higher amount the following results are obtained:

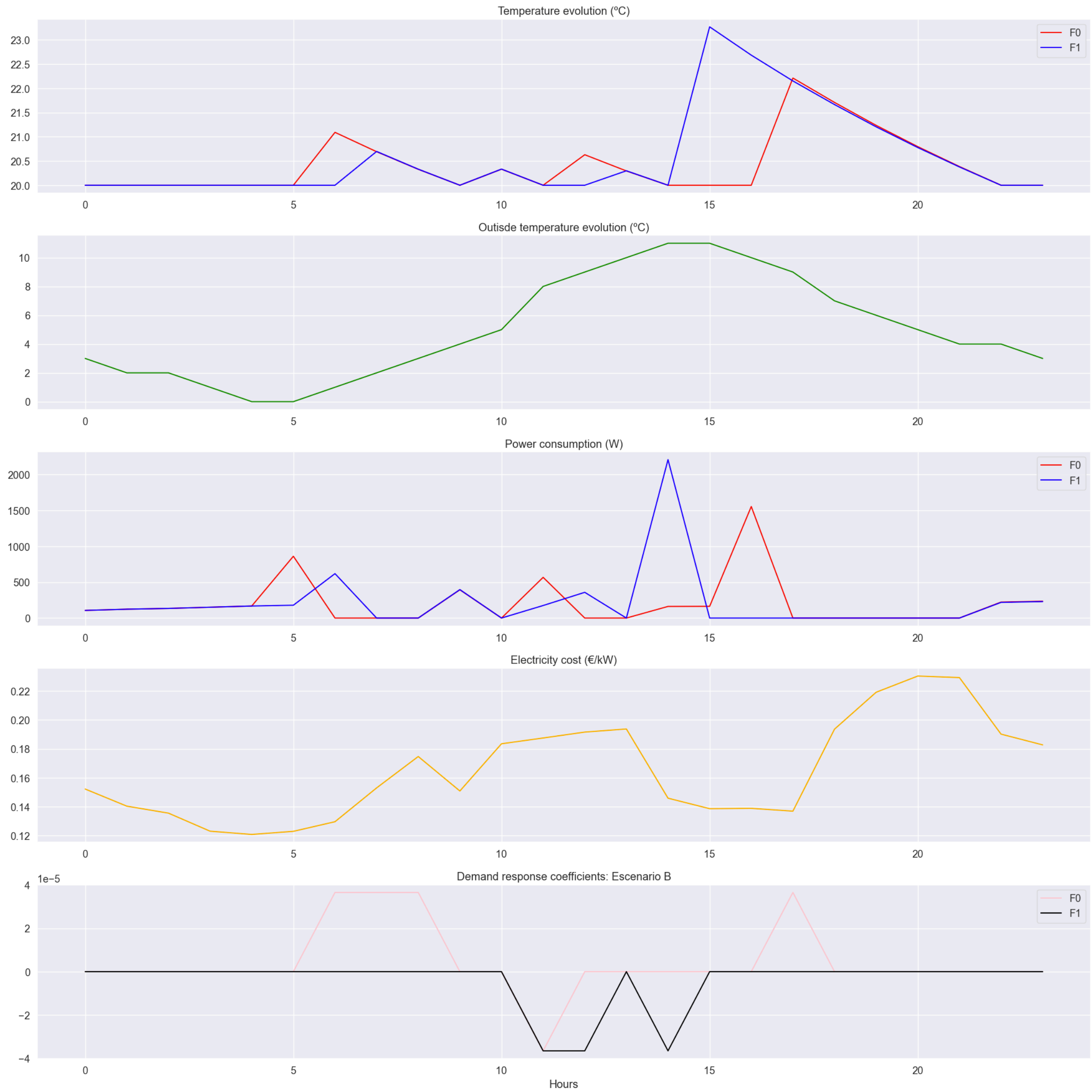


Figure 22: Summary heat pump modelling result | Scenario B – High amount (workday) . Source: Own elaboration

In this case, a difference can be observed compared to the profiles in the previous scenario (low amount). At first glance, it can be seen that the greater difference between the valleys and peaks drives to a different optimal point for HP operation. In this case, the consumption peak of feeder 1 (red) has shifted to 2 PM (previously it was at 5 PM), and as a result, the temperature peak also occurs earlier.

In these graphs, it can be observed more easily:

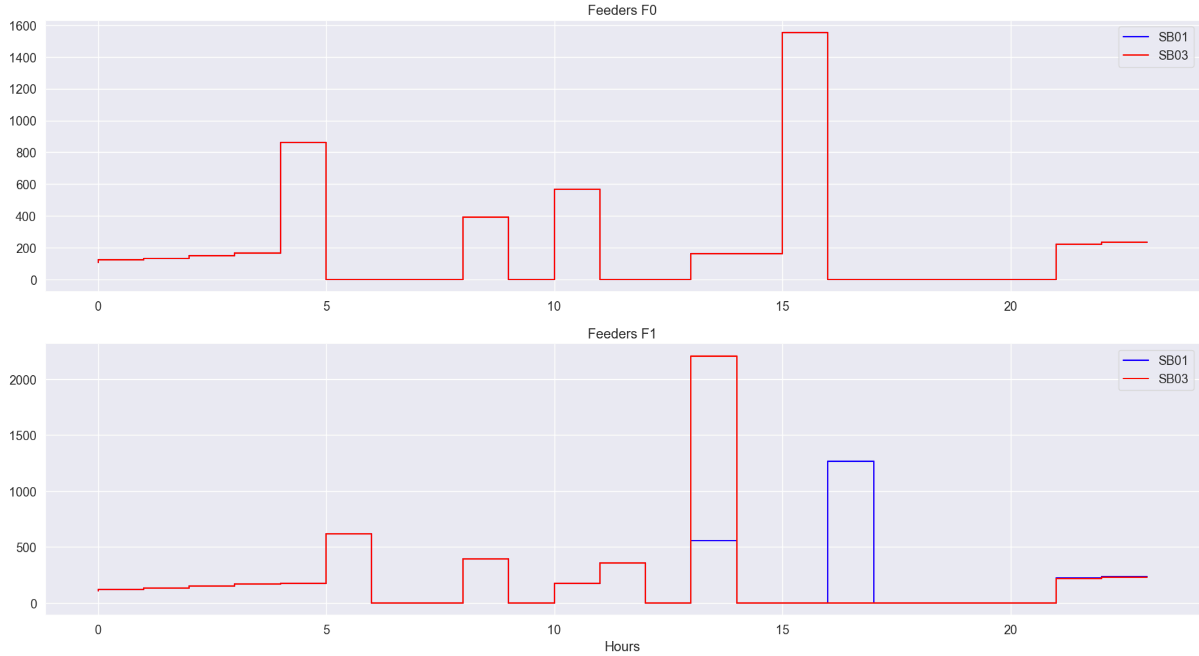


Figure 23: Comparison between consumption profiles | Scenario B – Low amount vs Scenario B – High amount (workday) . Source: Own elaboration

If we analyse the network issues, shown in Figure 24, the following observations can be made:

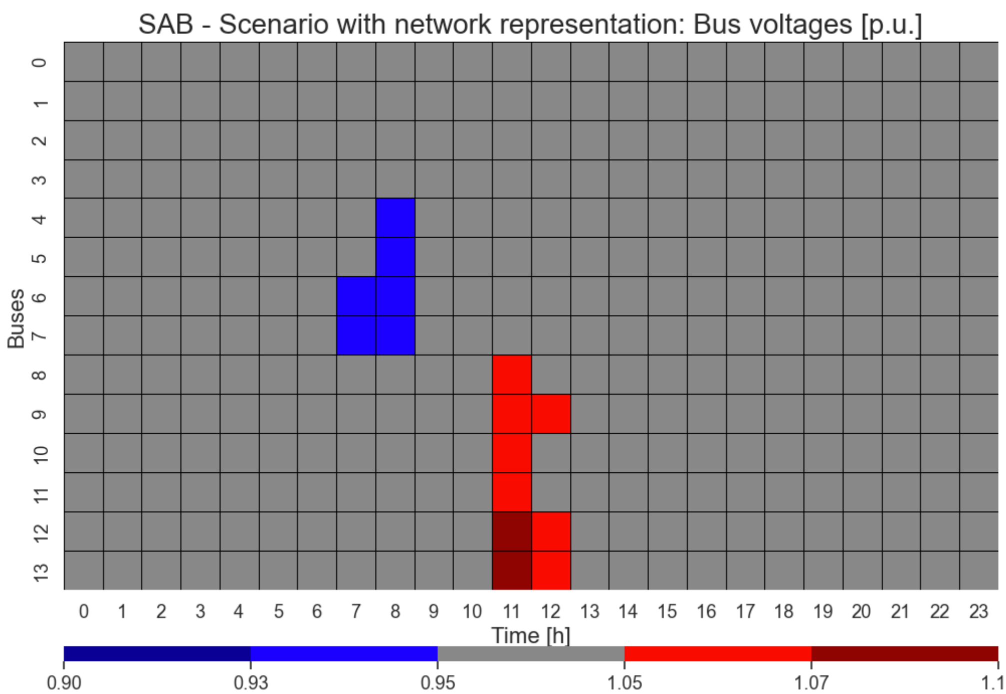


Figure 24: Network problems per bus and time | Scenario B – High amount (workday) . Source: Own elaboration

Unlike Scenario A, where no differentiation was considered in analysing the bus issues and obtaining the DR coefficients, in this case, there is some sensitivity to the amount of the tariffs. Thanks to the increase in the amount, in this case, the overvoltage issues at 2 PM have been completely resolved.

5.2. PVPC prices for a weekend day

The PVPC prices used are those corresponding to July 2st, 2023, obtained from Red Eléctrica website [44]. During weekends, especially on Sundays, the demand for electricity typically decreases significantly. On Sundays, many businesses are closed or operate with reduced activity, and people tend to spend more time at home or participate in leisure activities. As a consequence, the overall electricity demand is lower compared to weekdays.

Furthermore, summer Sundays are characterized by very cheap electricity prices during daytime is the high penetration of solar photovoltaic (PV) generation in the power system.

5.2.1. Base Scenario: No network representation in tariffs

When running the model without considering network tariffs and using electricity prices typical of a weekend day, the following results are obtained:

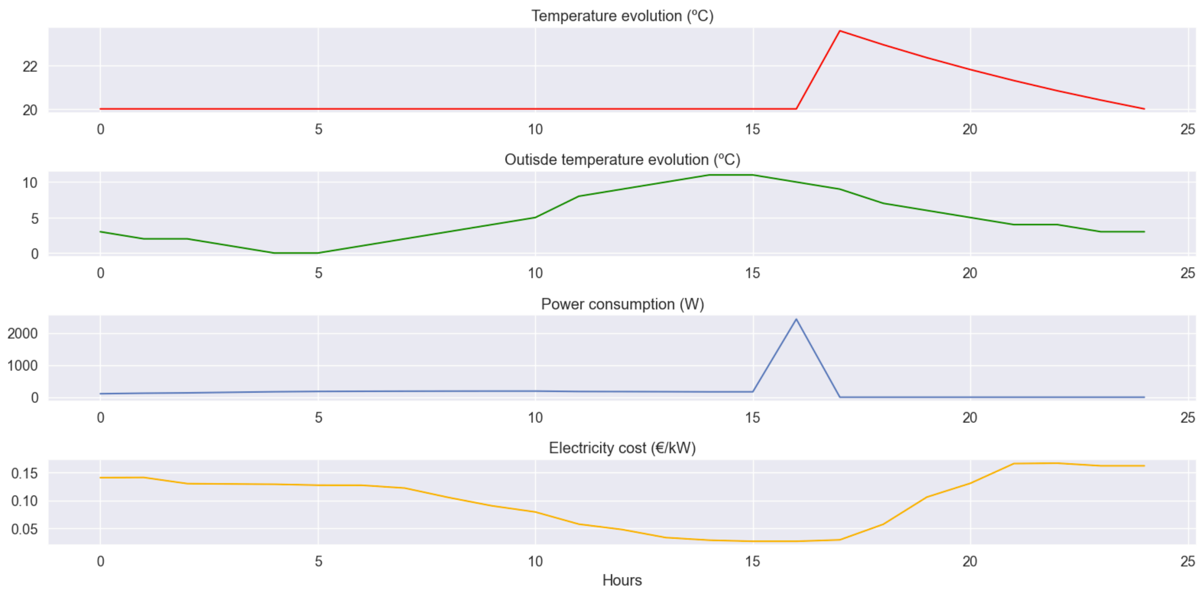


Figure 25: Summary heat pump modelling result | Base Scenario (weekend day) . Source: Own elaboration

In these graphs, several differences can be observed compared to the Base Scenario with PVPC prices on a working day. Firstly, it is notable that the evolution of the energy cost, which is the main driver of the heat pump's consumption profile, is much simpler for a weekend day. There is a single valley in the cost graph, corresponding to daylight hours.

Because of this smoother evolution of electricity prices, the heat pump's consumption profile exhibits a single power peak at 4 PM. This peak coincides with the minimum electricity price for that day. Prior to 4 PM, the model remains in thermal equilibrium (temperature in the minimum range) with the pump running at minimum power. It is after that power peak caused by the minimum electricity price that the pump is switched off. This can be seen in more detail in Figure 26.

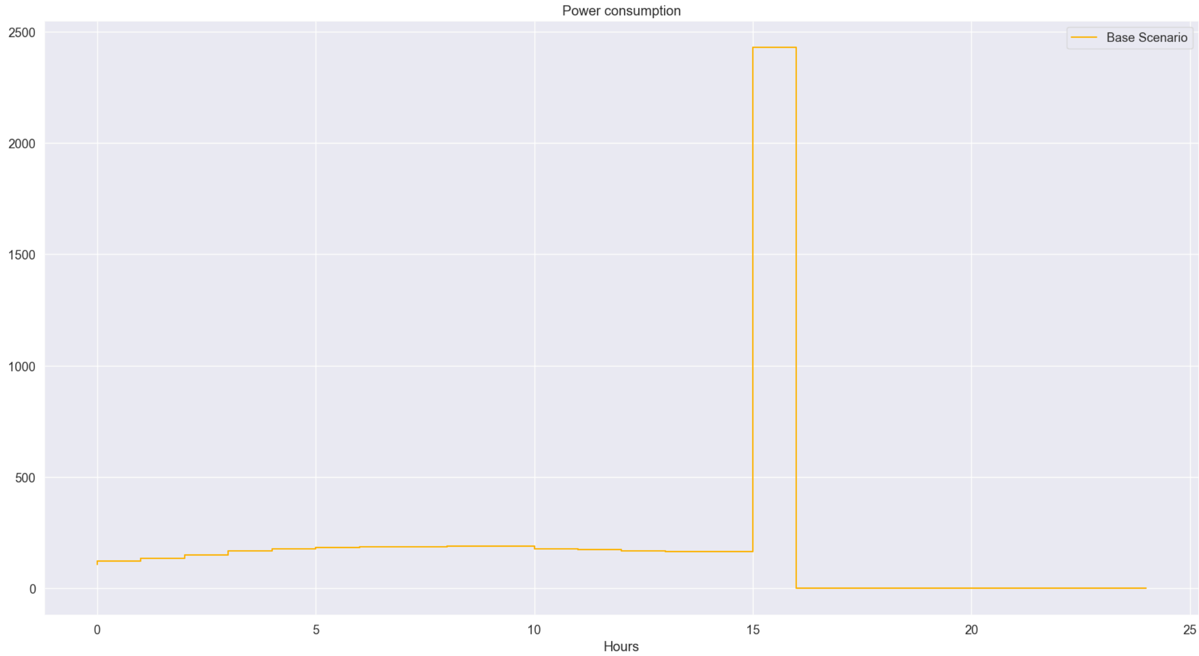


Figure 26: Heat pump consumption profile | Base Scenario (weekend day). Source: Own elaboration.

Regarding the temperature evolution (Figure 25), it remains constant at 20°C (the set minimum temperature) until 5 PM. At that time, due to the heat pump's consumption peak, the temperature rises to approximately 23°C. After 5 PM, as the heat pump is turned off, the temperature gradually decreases with a certain slope due to thermal inertia, returning to 20°C.

As done in the previous case, the next step is to connect the pumps to the selected nodes and analyse the network issues. The following problems have been identified:

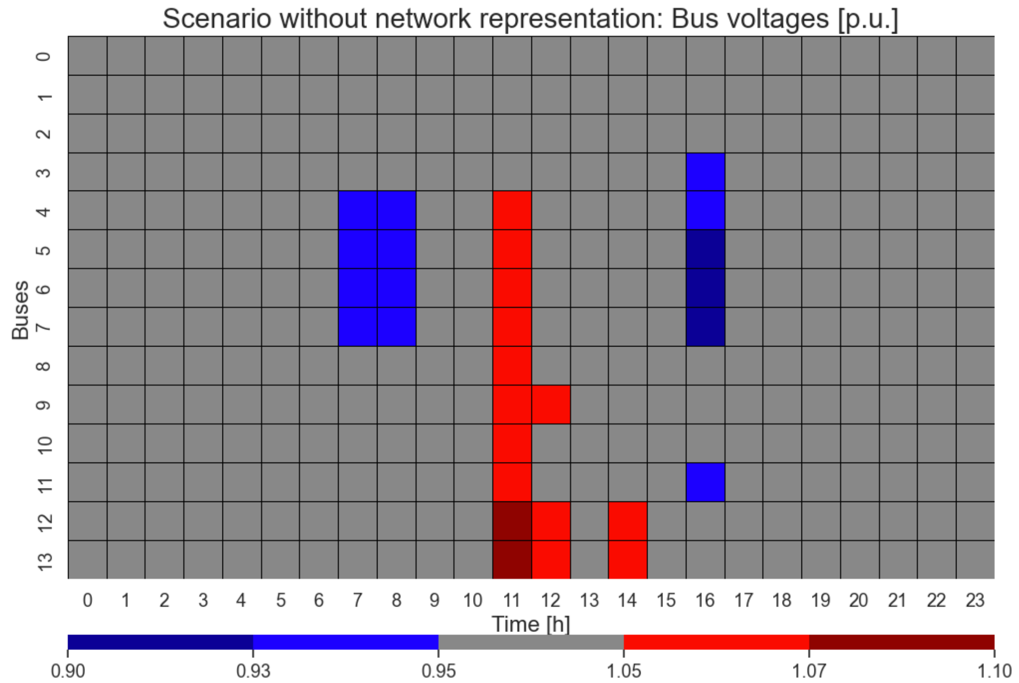


Figure 27: Network problems per bus and time | Base Scenario (weekend day) . Source: Own elaboration

By analysing Figure 27, it can be observed that they are similar to those in the study with PVPC prices for a working day, but not exactly the same. In this case, despite being concentrated in the same hours, there are a greater number of undervoltage problems, and they are of greater magnitude (darker blue). This is due to the concentration of the heat pump's demand at 4 PM.

Regarding the overvoltage problems, they are concentrated in the same bus hours, although it can be observed that the magnitude of the problems in buses 9, 10, and 11 is lower.

These issues, as in the previous case study, will be used to calculate network cost coefficients for Demand Response.

5.2.2. Scenario A: Tariffs for DR but with no local differentiation

Similar to the previous case study, in this scenario, the model will be executed considering the coefficients for Demand Response without considering the node location. Additionally, two analyses will be conducted with two different amounts to assess the sensitivity to the tariff amount.

Coefficients for Demand Response – Low amount

When running the model considering the tariffs in the objective function, the following results are obtained:

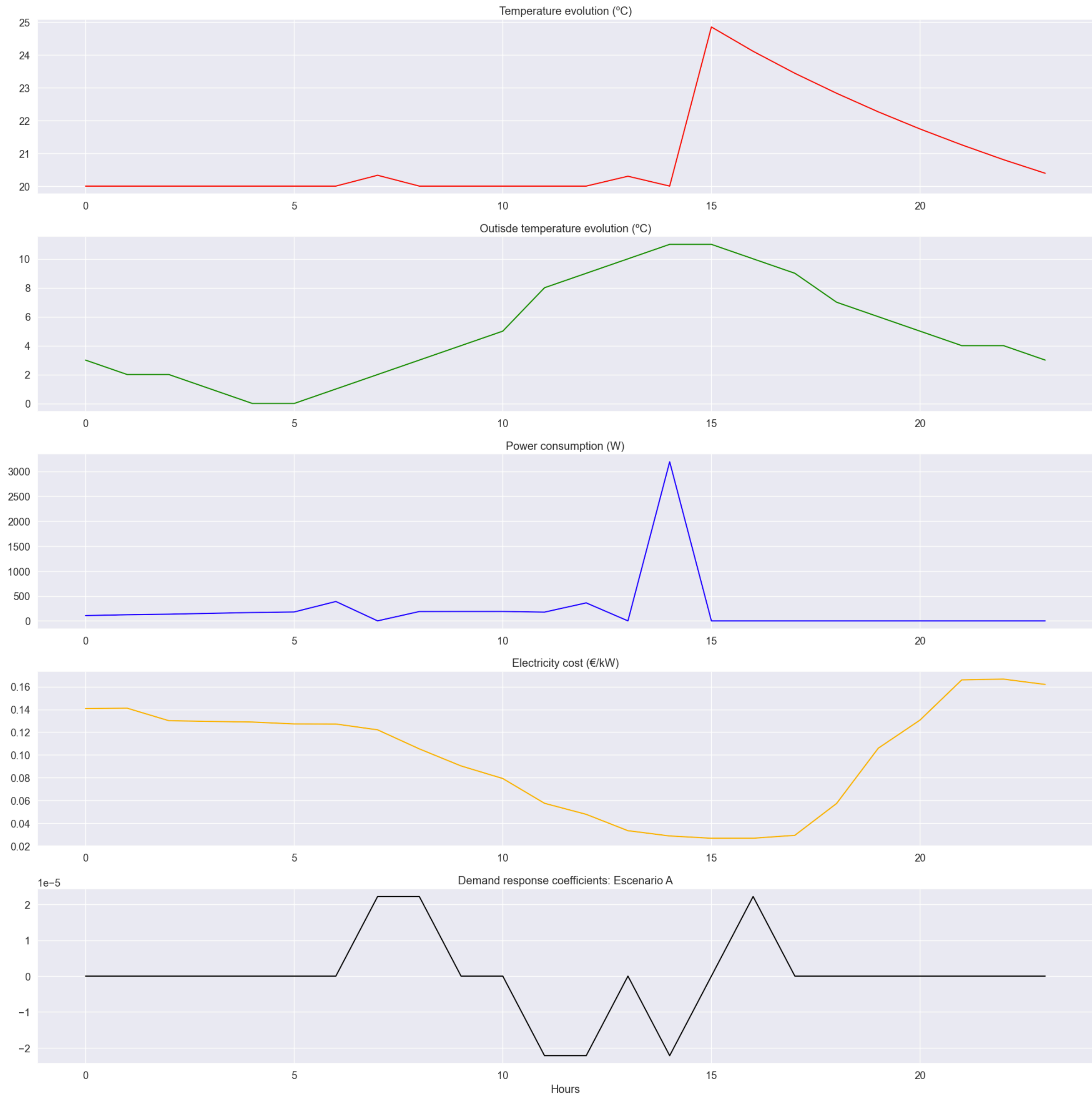


Figure 28: Summary heat pump modelling result | Scenario A – Low amount (weekend day) . Source: Own elaboration

In these graphs, the effects of the DR coefficients can be observed. In the last graph, we can see these coefficients, which disincentivize consumption during hours where demand reduction is necessary and incentivize it during hours where demand increase is needed. As a result, the temperature evolution within the house has changed compared to the previous case, with small increments at 7 AM and 1 PM, reaching a maximum temperature of 25°C.

The difference in temperature evolution is a consequence of the change in the heat pump's consumption profile. This can be better observed in Figure 29.

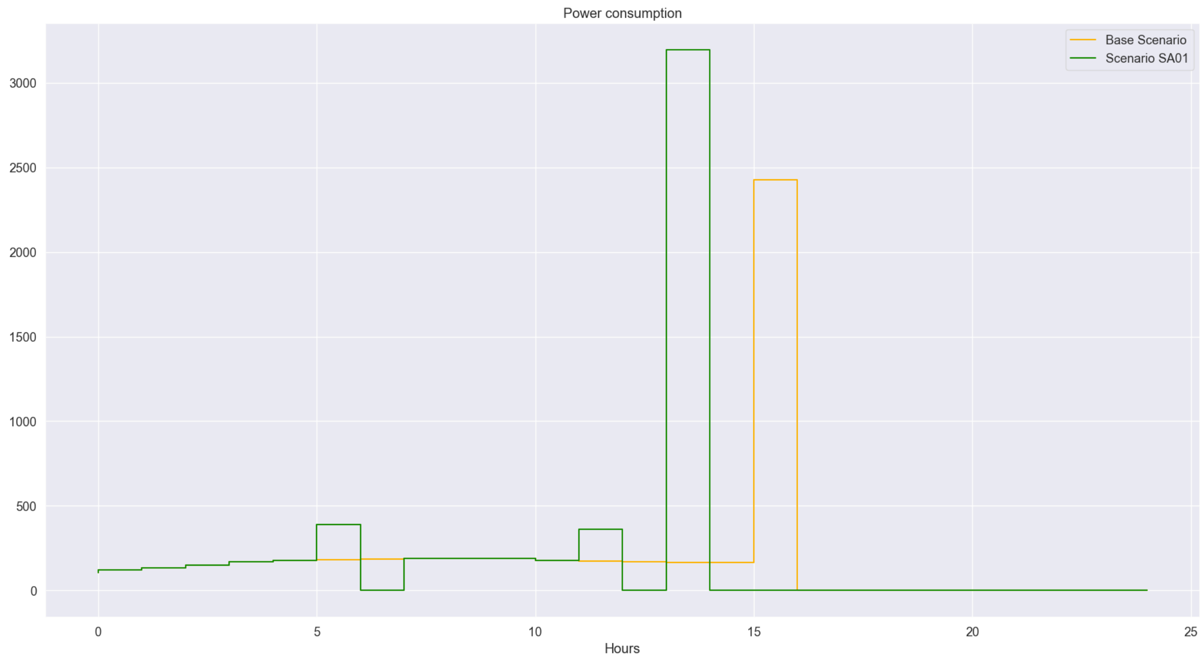


Figure 29: Comparison between consumption profiles | Base Scenario vs Scenario A – Low amount (weekend day) . Source: Own elaboration

In this graph, three main differences can be observed. Firstly, there is an advancement of the consumption peak from 4 PM to 2 PM (consuming higher power), which allows for no consumption for the rest of the day. This aims to address the overvoltage (insufficient demand) issues at 2 PM and the undervoltage (excessive demand) issues at 4 PM. The other two differences are the increases in consumption at 5 AM and 11 AM, which enable the heat pump to be turned off in the following hour in each case.

The next step is to analyse the network and see if these changes in consumption have resolved any issues in the network.

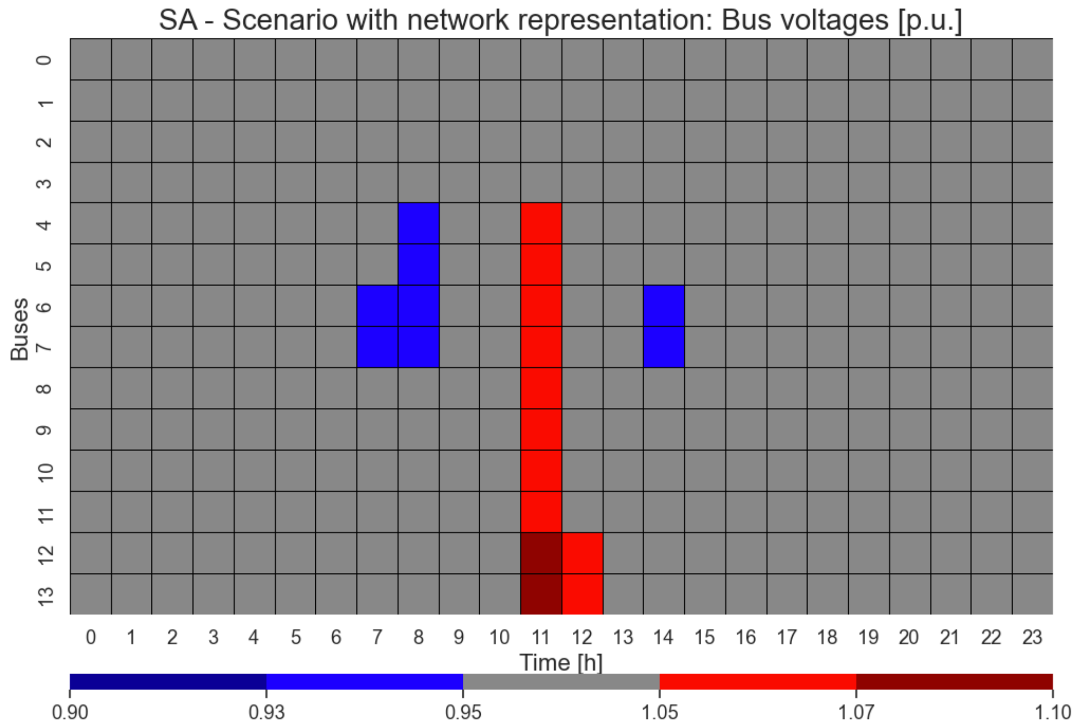


Figure 30: Network problems per bus and time | Scenario A – Low amount (weekend day) . Source: Own elaboration

By observing Figure 30, it can be seen that the incorporation of DR tariffs has successfully resolved various issues in the network. It is worth noting that the undervoltage issues at 4 PM have been completely resolved, as well as a portion of the issues at 7 AM (bus 4 and 5). Regarding the overvoltage problems, the issues at 2 PM have been resolved, along with a portion of the issues at 12 PM (bus 9). However, new excess demand issues have emerged at 2 PM (bus 6 and 7).

It is worth highlighting the similarity between this graph and its counterpart for the case study with PVPC prices for working days. The only difference is that in this scenario, there are no undervoltage issues at 2 PM. This is mainly due to the difference in prices, which leads to a concentration of consumption in the off-peak hours, resulting in excess demand issues.

<u>Coefficients for Demand Response – High amount</u>

In this case, the same model as in the previous section is executed, but with a higher amount for the tariffs to analyse the impact of the increase. The following graphs are obtained:

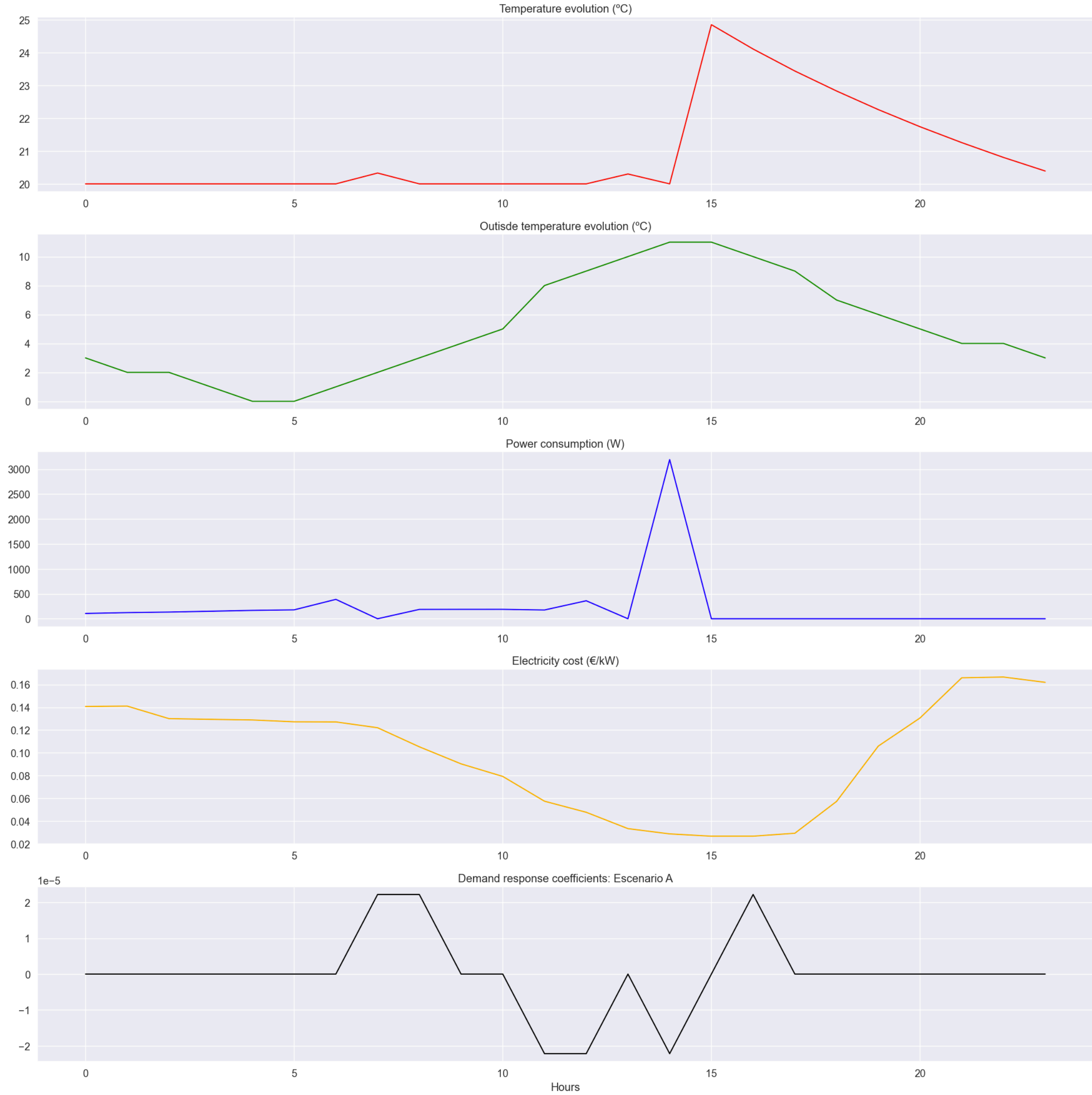


Figure 31: Summary heat pump modelling result | Scenario A – High amount (weekend day) . Source: Own elaboration

Similar to the case study with PVPC prices for a working day, it can be observed that increasing the amount of the DR coefficients does not alter the consumption profile compared to the case with lower amount tariffs. This can be better seen in Figure 32.

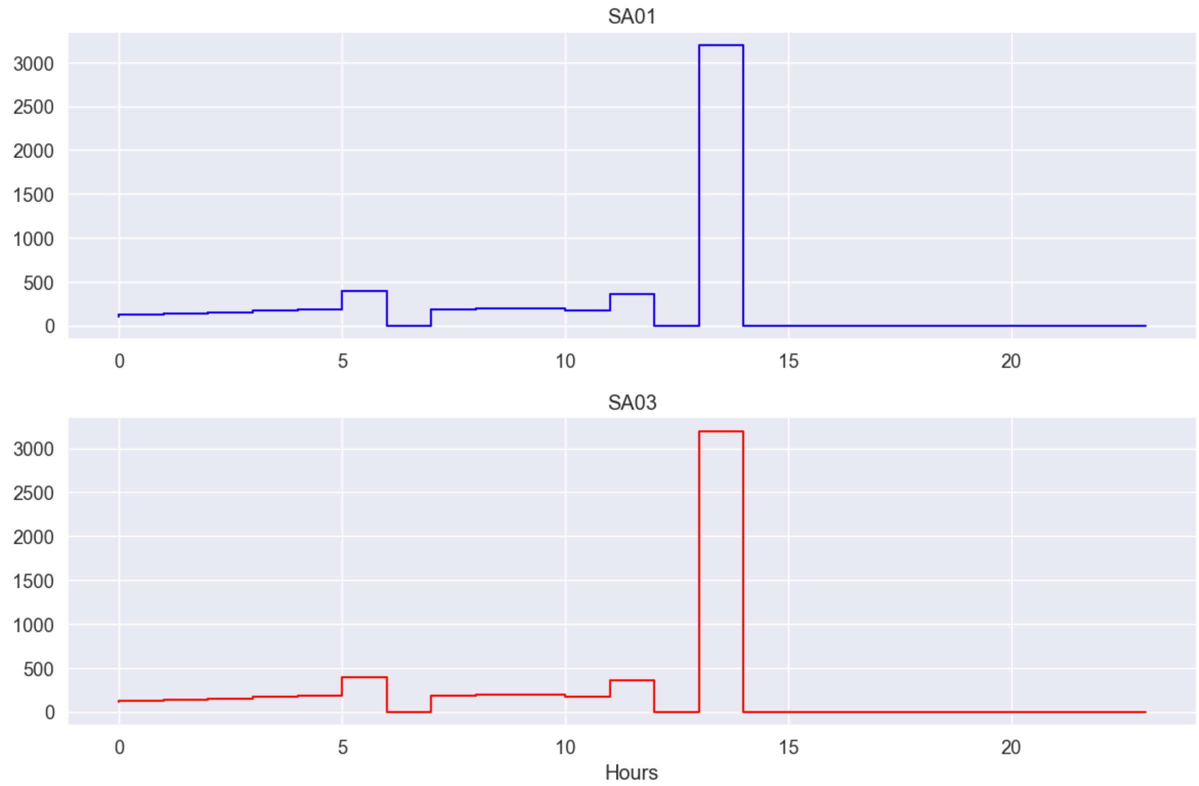


Figure 32: Comparison between consumption profiles | Scenario A – Low amount vs Scenario A – High amount (weekend day) . Source: Own elaboration

If we analyse the network issues, as the consumption profile remains unchanged, the same problems persist:

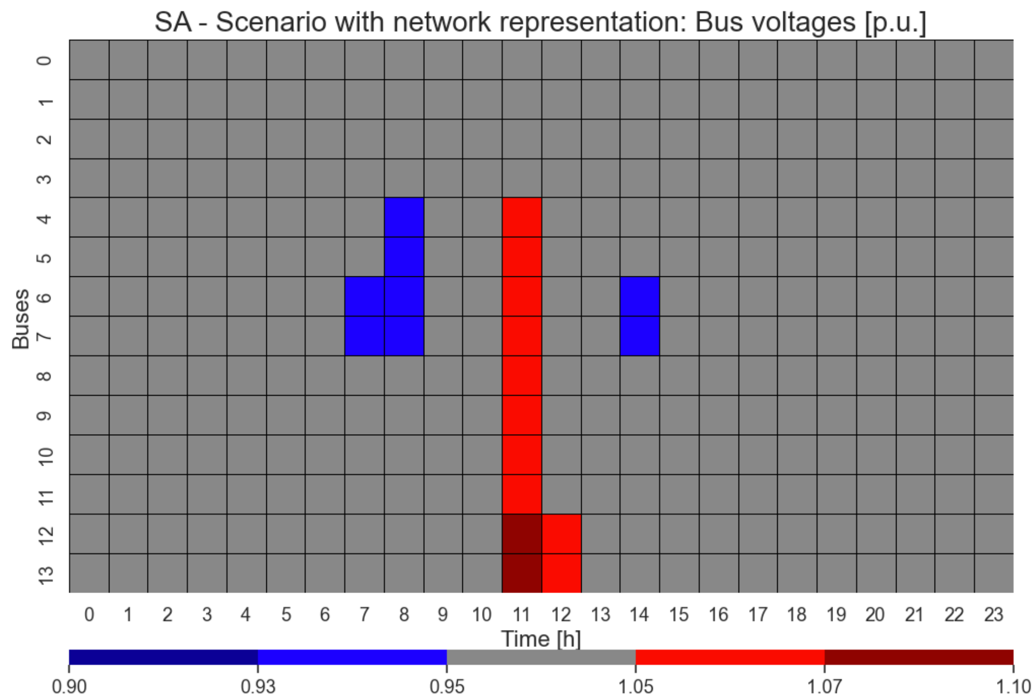


Figure 33: Network problems per bus and time | Scenario A – High amount (weekend day) . Source: Own elaboration

5.2.3. Scenario B: Tariffs for DR but with local differentiation

In this final scenario, the same analysis as in the case study with PVPC prices for a working day are conducted. To address the network issues, the DR coefficients will be added to the electricity prices differentiating by feeder.

Additionally, the sensitivity to tariff prices are analysed using two different amounts.

Coefficients for Demand Response – Low amount

When running the model with the tariffs differentiated between feeders, the following results are obtained:

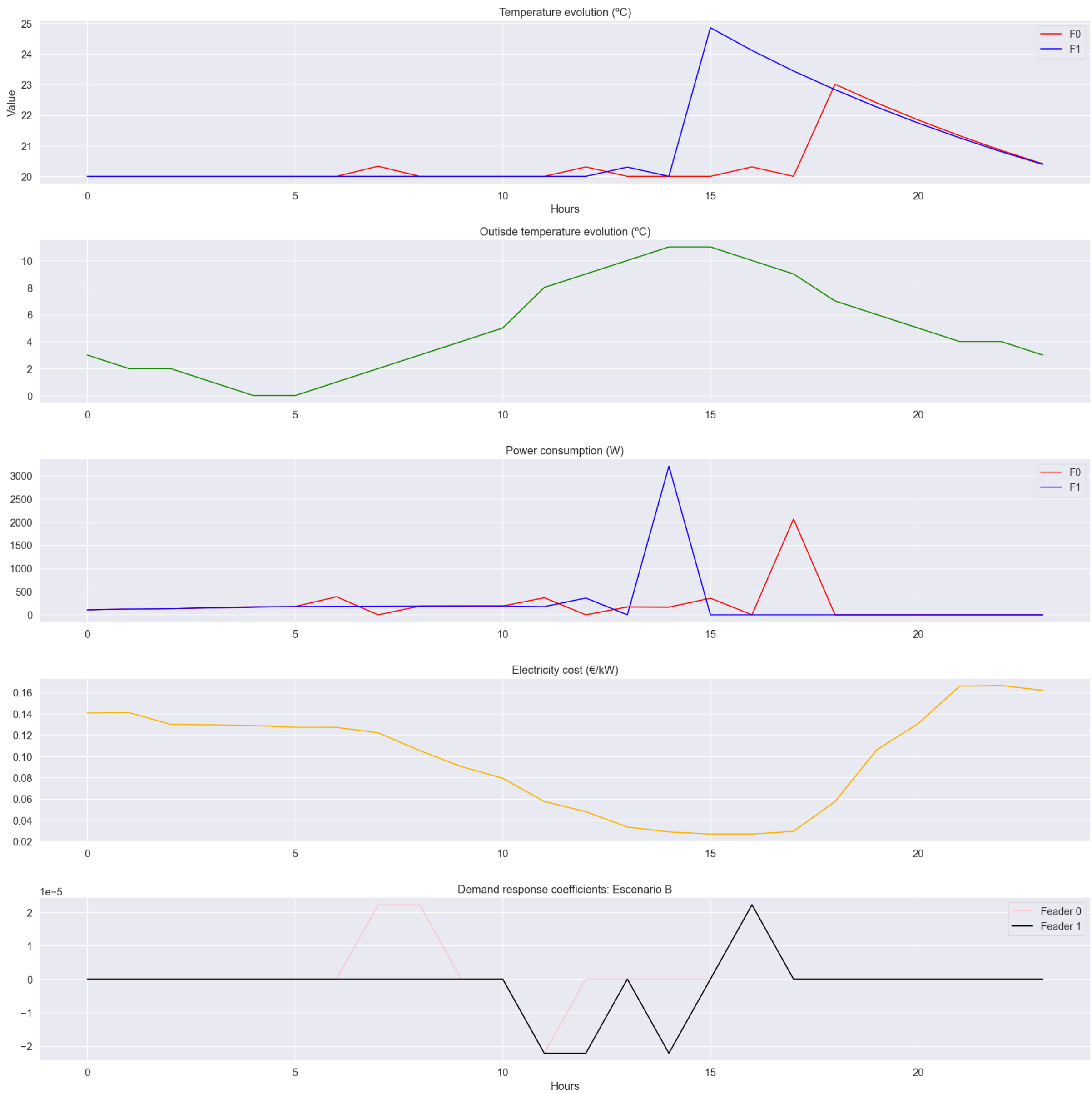


Figure 34: Summary heat pump modelling result | Scenario B – Low amount (weekend day) . Source: Own elaboration

Similarly to the case study with PVPC prices for a working day, these graphs illustrate the difference between tariffs for feeders F0 and F1 (last graph), as well as the variation in consumption profiles due to different DR coefficients. These consumption profiles, in turn, influence the temperature evolution inside the dwelling.

Comparing with the case of PVPC prices for a working day, it can be asserted that the behaviour is not very similar. Due to the curve of electricity prices in this case, the consumption profiles of both feeders do not overlap as much with the Base Scenario consumption profile. This can be better visualized in Figure 35.

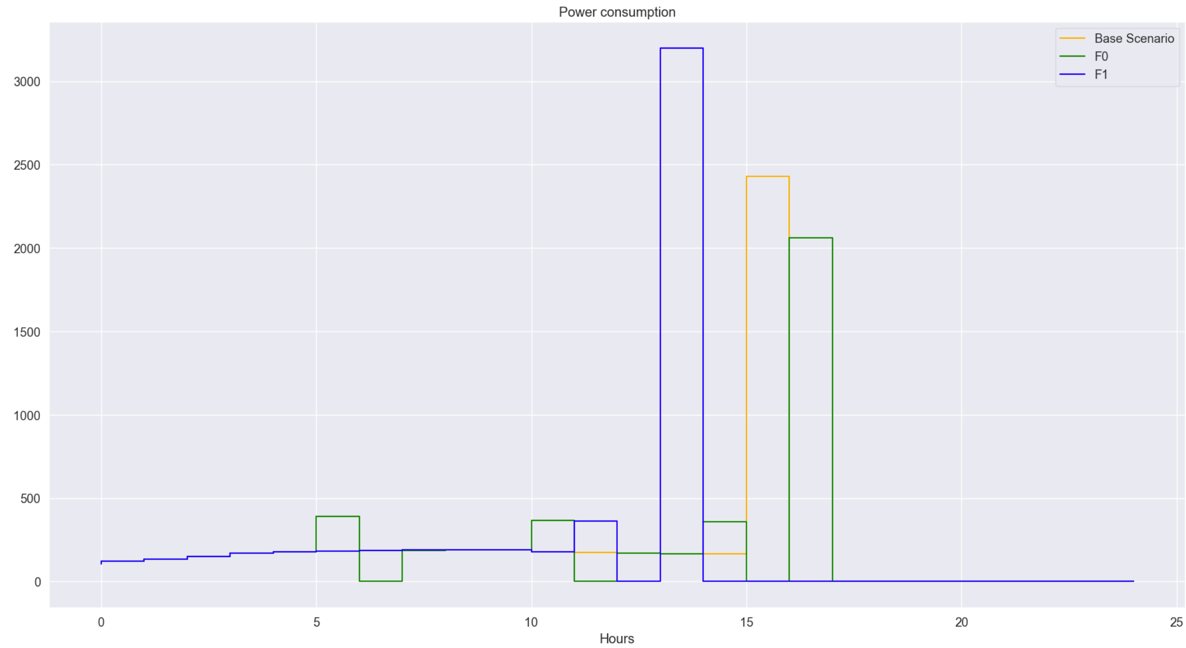


Figure 35: Comparison between consumption profiles | Base Scenario vs. Scenario B – Low amount (weekend day) . Source: Own elaboration

In this graph, we can see how the peak consumption for the three profiles is different. The next step is to see how the problems in the network are resolved. These problems are shown in Figure 33.

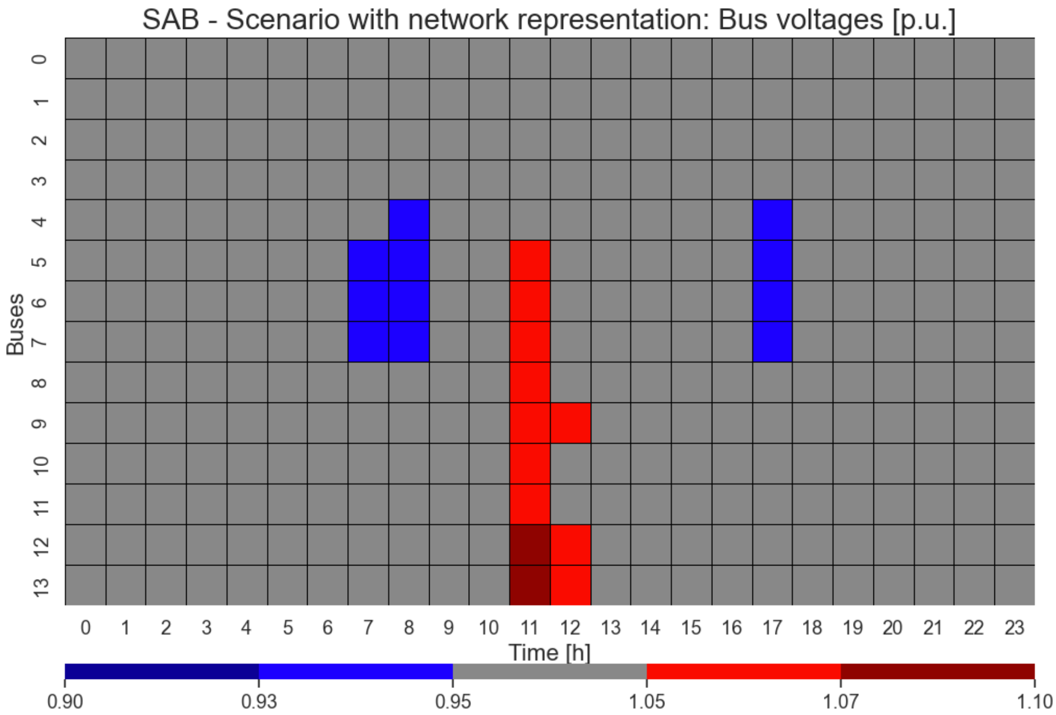


Figure 36: Network problems per bus and time | Scenario B – Low amount (weekend day) . Source: Own elaboration

The differentiation based on node location has helped resolve some of the issues in the network compared to the Base Scenario, although not as effectively as in the Scenario A. Some undervoltage problems at 17:00 and the bus 5 at 07:00, as well as overvoltage problems at the bus 9 at 12:00, still remain unresolved. However, there are no new excess demand issues at 14:00, and the lack of demand problem at 11:00 in the bus 4 has been resolved.

Comparing it to the case of PVPC prices for a working day, it can be concluded that this configuration has been less beneficial. This is mainly due to the extremely low prices (around 0.04 €/kWh) and the incentives given by the tariffs since depending on a fraction of the average daily price, do not create a differential on the Base Scenario price that drives the Demand Response of the heat pump enough to react properly and contributes to network operation.

Coefficients for Demand Response – High amount

Just like in all the scenarios analysed in this study, the impact of higher tariff rates on problem-solving in the network is being analysed. When running the model that considers node localization with higher rates, the following results are obtained as presented in Figure 37.

Figure 37: Summary heat pump modelling result | Scenario B – High amount (weekend day) . Source: Own elaboration

At first glance, it can be seen that there are no differences compared to Scenario B with low amount tariffs. However, Figure 38 provides a more detailed view on these differences:

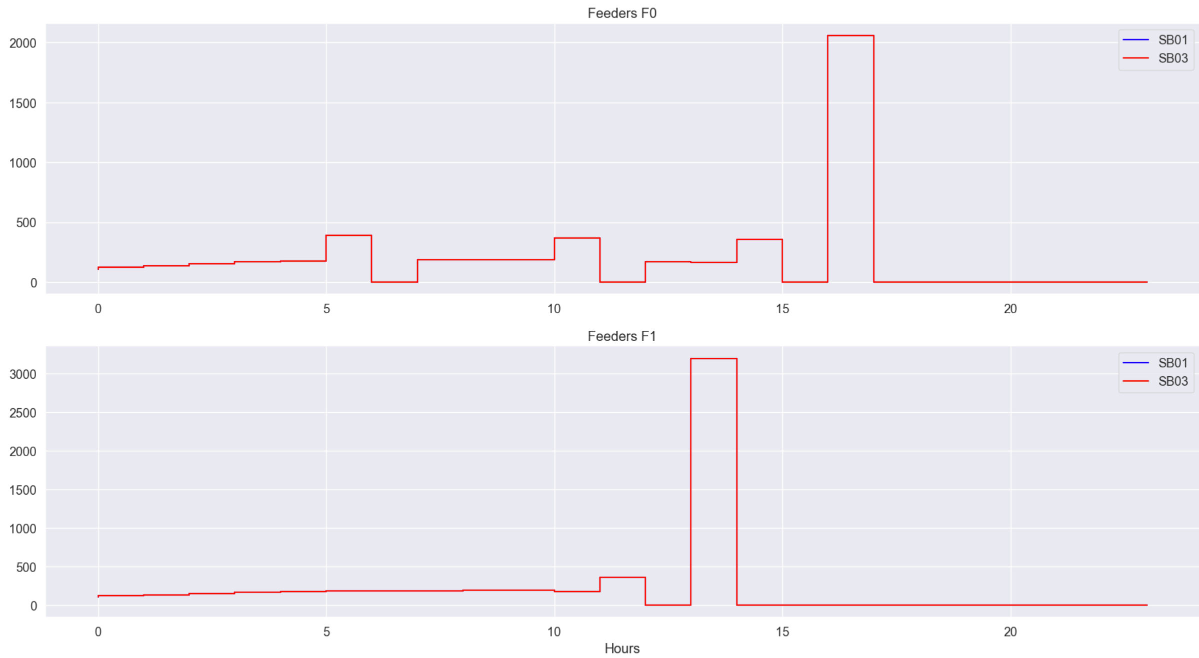


Figure 38: Comparison between consumption profiles - Scenario SB01_F0 + F1 vs SB03_F0 + F1 (weekend day) . Source: Own elaboration

As anticipated, Scenarios SB01 and SB03 have identical consumption profiles. Given this, the network problems would be the same.

6. Conclusions

Based on the analysis conducted in the previous section regarding the resolution of network issues through the modelling of a heat pump operating in a network with tariffs for demand response, this chapter aims to summarize the conclusions that have been reached.

Starting with the analysis conducted for working days and considering the different results obtained in the analysed scenarios, it has been concluded that the best configuration for the tariffs calculation is the one that takes into account the location of the nodes for computing network charges. By considering a higher level of detail regarding the node issues and applying appropriate coefficients, it has been demonstrated that a greater number of network problems can be resolved.

Regarding the analysis conducted for weekends, it has been concluded that due to the low PVPV prices and the incentives given by the tariffs since depending on a fraction of the average daily price, they are not able to create a differential on the base scenario price that drives the Demand Response of the heat pump enough to react properly and contribute to network operation. Hence, in case of low electricity prices, the locational tariffs have to be carefully designed considering creating a stronger price signal to drive Demand Response.

Overall, the study demonstrated the potential of demand response solutions using heat pumps to address network problems. The results highlighted the importance of considering tariff structures, differentiation by node location, and sensitivity to tariff amounts in order to achieve optimal network performance. However, locational granular tariffs may not be possible to apply. Further research and optimization efforts (e.g., adding other flexible service providers to the simulation) are needed to fully address all network problems and maximize the benefits of flexibility markets.

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Appendix 1: Alignment with Sustainable Development Goals (SDGs)

The 2030 Agenda for Sustainable Development, adopted by all United Nations Member States in 2015, provides a shared blueprint for peace and prosperity for people and the planet, now and into the future. At its heart are the 17 Sustainable Development Goals (SDGs), which are an urgent call for action by all developed and developing countries in a global partnership [45].

The thesis's main goal is to develop an innovative market model for the electricity sector driven by decarbonisation, digitalisation, and decentralisation. These drivers are closely aligned with the different goals of the 2030 Agenda for Sustainable Development, with **SDG7 Affordable and clean energy** being the main SDG that this project complies with. However, there are other objectives that this project complies with: **SDG8 Decent work and economic growth**, electricity is a driver of growth and the creation of new and more efficient market models will foster economic growth; **SDG11 Sustainable cities and communities**, thanks to digitalisation, the electricity consumption of the cities will be more intelligent and sustainable; and **SDG13 Climate action**, reducing CO2 emissions by the electricity sector will help in the combat against climate change and its impacts.

Figure 39: Sustainable Development Goals. Source: United Nations