Università Politecnica delle Marche
Scuola di Dottorato di Ricerca in Scienze dell'Ingegneria
Corso di Dottorato in Ingegneria Industriale

Implementazione, valutazione e strategie di ottimizzazione del Sistema Energetico Smart e delle Comunità Energetiche Locali in un'area urbana: caso studio di una città del Centro Italia

Ph.D. Dissertation of:

Erica Corradi

Supervisor:

Prof. Gabriele Comodi

Assistant Supervisor:

Ing. Danilo Salvi

Ph.D. Course coordinator:

Prof. G. Di Nicola

XX edition - new series

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Abstract

Urban areas occupy 3 % of the Earth's surface and consume 75 % of the natural resources, producing 60-80 % of the global greenhouse gas emissions. From this data, there is the need for the cities to act as ecosystems, innovate, and help nations to become climate neutral by 2050. In this regard, Smart Cities play a fundamental role in achieving this goal imposed by the European Union.

The purpose of this work is to implement, in the Osimo demo-site, two of the main components of a Smart City, namely the Smart Energy System (SES) and Local Energy Communities (LECs), thus assessing the energy, environmental, and economic benefits of these implementations. In particular, the development of the SES takes place through: (i) the "Smart Control Architecture" in which DSM strategies are implemented that allow the optimal management of multi-energy systems; (ii) the installation of new flexibility resources such as Thermal Storage (Thermal Energy Storage - TES), Heat Pump (Heat Pump - HP), Electric Storage (Electric Energy Storages - EESs) etc. to adapt the energy demand to the energy production, and thus energy use considering certain limits. Regarding the LEC, it was decided to select two of the suburban branches where there were major quality problems of the electricity network: the two selected routes had a large number of private photovoltaic systems (PV) that caused voltage problems. Regarding these, it was decided to install the EESs to mitigate the negative effect produced by the installed PV.

Finally, the energy, environmental, and economic analysis have been made per each energy vector considered in this study, starting from a baseline situation of the year 2018 and comparing the results with those of the years 2021-2022. The networks considered are: the district heating network, the water network, and the electricity grid.

Regarding the district heating network, the energy analysis considers the Primary Energy Saving (PES) and the specific energy (E_{sp}) of the fuel currently exploited in the thermal power plant compared to its Low Heating Value (LHV), while the environmental analysis considers the avoided CO_2 and the economic analysis considers the Energy Efficiency Certificates (EECs). Results showed that the implementations in the CHP plant led to a yearly PES of 21.2 %, being almost constant than its value in the year 2018. The yearly specific energy is increased by 0.87. From the environmental point of view, 1,515 tCO_2 have been avoided increasing of 281 tCO_2 than the baseline situation. Finally, the economic analysis showed an increase of 54.5 EEC, which was equal to an economic increase of 13.625 €.

The analysis of the water network, on the other hand, considers the water losses avoided in the whole year 2021 with subsequent energy and economic savings due to the lower use of the pumps of the Padiglione pumping station. Results showed yearly water, energy, and economic savings of 41,192 m^3, 50,113 kWh, and 18,750 €, respectively.

Finally, regarding the analysis of the electricity network, the following Key Performance Indicators (KPIs) of two selected low voltage (LV) networks are evaluated: the improvement of the monitored quality parameters (i.e. voltage); the number of hours, and the energy that the CHP can provide to the network (flexibility); lower congestion management costs for DSO; the amount of energy, and the number of hours when the electricity has been fed into the national grid. Results showed that the improvements of the monitored quality parameters after the EESs installation were the reduction of the maximum voltage of 2.9 % and the increase of the minimum voltage of 5.5 %. The number of hours of the year 2021 in which

the CHP unit has been shut down were 3,213, thus providing a flexibility of 3,855.6 MWh. In addition, the costs of the alternative solutions implementation other than the two EESs installed, namely the secondary MV-LV electricity substations construction, in the identified streets was 149,980 €. Finally, in the year 2021 the amount of the excess of electricity injected into the electric network was equal to 4,584.41 MWh, while the number of hours in which the electricity was injected into the electric network in the year 2021 was 676.

Lessons learned on the bureaucratic and operational aspects, as well as future development, have been also discussed.

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Chapter 1.

1. Introduction

Climate change has become a serious issue that is affecting the whole World: exceptionally warm winters, wildfires out of control, and the faster-than-expected melting of glaciers are all climate-related phenomena. Earth's climate has changed considerably and for several times since the formation of the planet 4.5 billion years ago. It has oscillated between warm and glacial periods; such cycles have always lasted tens of thousands or millions of years. In the last 150 years (industrial era), temperatures have raised fastly: indeed, the previous decade was the warmest period ever recorded so far, with a global average temperature of 1.1 °C above the pre-industrial levels [1]. Currently, the global warming, caused by humans' activities, is continuously increasing by 0.2 °C per decade, and this will lead to considerable impacts on both Earth's environment and living beings when an overall increase of 2 °C compared to the temperature in pre-industrial times will be achieved [1]. Among the humans' activities, the development over the years of both cities and municipalities, which occupy 3 % of the Earth's surface, has led to about 75 % of the natural resources consumption, thus producing 60-80 % of the global greenhouse gas emissions [2].
Climate change is not reversible, but it is possible to mitigate its effects and adapt to its consequences. Mitigation actions aim to reduce the number of emissions released into the atmosphere, for example through the development of clean energy and the increase of forest areas. Drastic changes are needed in key sectors such as transport, energy, industry, housing, waste management, and agriculture.
Tackling climate change means to prevent its effects and making our society more resilient, for example by making more efficient the use of scarce water resources, adapting agricultural and forestry practices, and ensuring that buildings and infrastructures are able to withstand future climatic conditions and extreme weather events.
Over the last decades, the issue of energy efficiency has been one of the most addressed by the entire scientific and political community. The focus on the way the energy is generated has led to encouraging the improvement of the energy production to consume less, but maintain the same habits. In fact, this efficiency is considered a separate energy source. In addition, there is an interest in reducing greenhouse gas emissions and safeguarding the planet.
The clear climate change has prompted the EU Council to open negotiations with the European Parliament on the revision of the Energy Efficiency Directive (EED), which aims to improve existing provisions and achieve climate and energy targets set by 2030 first and 2050 later. This Directive has involved not only Europe, but also the whole world. The European Green Deal (EGD) is the new growth strategy of Europe, namely a set of policy

initiatives proposed by the European Commission to achieve climate neutrality in Europe by 2050: this goal involves not only the greenhouse gas net emissions erasing, but also the development of a fair and prosperous society where the economic growth is decoupled from the resource use, while at the same time the EU's natural capital is conserved and enhanced by promoting citizen's well-being [3].

Carbon neutrality target, energy conservation, carbon emission reduction, and green development have become major concerns that must be addressed. Up to now, the optimization of the energy structure and improvement of the energy efficiency are the main paths to carry on for achieving energy saving and emission reduction [4]. Furthermore, another key aspect is the rapid urbanization that creates immense challenges to a city's sustainability and its management, as well as environmental pollution, traffic congestion, and lack of infrastructure solutions that can withstand the stress caused by the massive population expansion in concentrated spaces [5-7]. Indeed, the United Nation has forecasted that 68 % of the global population will live in cities by 2050; an increase from 55 % in 2018 [8]. The ambitious objectives imposed by Europe, as well as the rapid urbanisation problem, have been incorporated into the previous EU 2014–2020 Programming Period in which the focus was on the rising urban demand for energy, water, waste, mobility and any other services that would be essential to a city's prosperity and sustainability [3]. The key component was the smart city.

Before introducing an accurate definition and presenting the main components of a smart city, J. Kim [9] summarized an interesting literature review on the smart city concept development from the 2000s until now. The initial concept (2000 – 2005) of a smart city started with the "ubiquitous city" (U-City) in which urban problems are solved anytime and anywhere by leveraging the Information Technology (IT). In this first phase, there was only an IT stage. In the following years, the attention moved to the IT infrastructure (2006-2010) and then applied to specific urban areas (2011-2015) and the entire urban areas (2016-2020), shifting the smart city technology from providing general services to customized ones. Since 2020, smart city services for emerging urban threats are being proposed, and existing smart city services have been merged. Essentially, the efficiency is maximized by providing flexible smart city services that can be easily added or removed as required.

In generic terms, a smart city is an urban environment where traditional networks and services are more efficient with the use of digital solutions for improving the inhabitants' lifestyle and business. The use of the Internet of Things (IT), cloud computing, Artificial Intelligence (AI), geospatial infrastructure, and other new information technologies enhance the performance of a city, achieving the deep integration of urbanization and information technology, as well as the precise, digital, and dynamic cities management [4; 10]. In particular, the IT and geospatial infrastructure control the operation and the connection of the six core urban systems of organization (people), business (government), transportation, communication, water, and energy in real-time. A cloud is used then to analyse and integrate the data resources of the city to connect the physical systems and public services [4].

Smart community, smart energy, smart transportation, and smart healthcare are the main components of a smart city, as well as the most common [10; 11]. However, the smart city's composition can be customized based on areas of interest: for example, a particular smart city might consider including a disaster management system in the smart community, while another city plans to integrate a waste management system. Figure 1 shows the most common components of a smart city, while the areas under investigation for the sake of this work are highlighted in red.

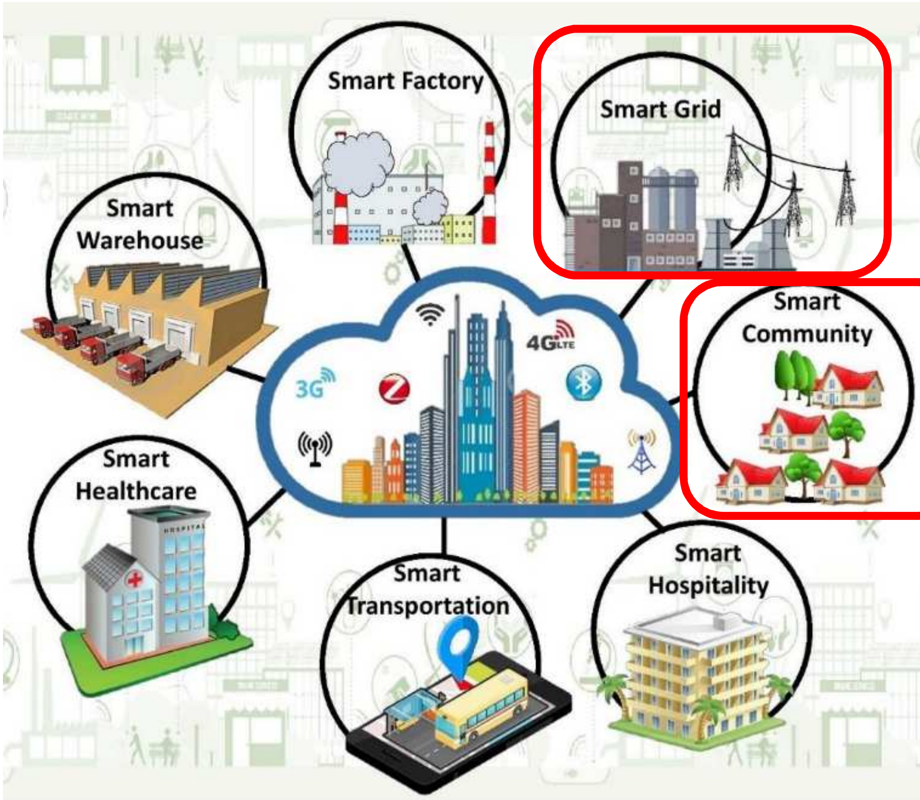

Figure 1. Generic composition of a smart city architecture [10]: the areas under investigation are highlighted in red.

Smart grid and smart community, hereinafter referred to as Smart Energy System (SES) and Local Energy Community (LEC), respectively, are the topics on which this research focuses.

The energy demand increases as the city population grows. The smart energy management is done by adapting the production to the demand in order to run a sustainable future. The energy management involves the communication between consumers and suppliers with the deployment of smart grid and smart meter. As the name suggests, in the Smart Energy System (SES) there are multiple energy forms. SES supports the technology to increase the proportion of clean energy use and achieve goals of carbon emission reduction and carbon neutrality. The recent scientific literature focused on SES optimization method to improve the energy efficiency and reduce carbon emission for the energy sustainable development. Y. Wang et al. [12] have proposed an SES operation optimization method based on a cooperative game, which has saved 26.86 % of the cost and reduced 39.42 % of carbon emissions, by encouraging different subjects to participate in the overall coordinated and optimized operation of the system. G. LV et al. [13] presented a carbon neutral cost calculation method of electricity-heat-gas cogeneration for the SES and built a daily optimal scheduling model that considers demand response and carbon emissions reduction. By adjusting the participation of the clean energy, the system cost has been reduced by 48.6 %, while the overall carbon emissions were reduced by 282 kg by adjusting the carbon neutralization cost coefficients. W. Ma et al. [14] explained and verified the alternating iteration method to calculate the power flow of each network separately and achieving a power flow analysis through the iterative optimization. Results showed that the proposed operation optimization method is effective and feasible, which can effectively improve the integrated energy efficiency and realize the optimized operation of the integrated energy system. Finally, A. T. Hoang et al. [15] analysed the integration of renewable energy sources into energy systems of a smart city, concluding that it is a sagacious perspective and solution aiming to achieve cleaner process and more sustainable development. However, the optimization issues of the energy system for the renewable components integration ensuring good stability, maximizing the operating range, and minimizing the investment costs might be critically evaluated in the future works.

Local Energy Community (LEC) aspires to uplift the citizen satisfaction and wellbeing of urban citizens. In this context, energy community converges large number of smart buildings, water management systems, and waste management systems. Smart buildings include smart homes and other business infrastructure (i.e., offices, schools, data centers, factories, warehouses, etc.), as well as electric storage systems to create more flexibility. LEC focuses on optimizing the energy consumption and reducing the carbon footprint, as well as the energy management to enhance the energy efficiency by connecting smart buildings with smart grids and natural energy plants via existing network. Most importantly, data-driven decision-making ability of smart buildings maximizes the energy efficiency and minimizes the operational costs [10]. LEC describes energy sub-systems that are governed by and for local people [16, 17], and can include both “supply and demand-side sustainable energy initiatives” [18]. Energy community projects are often small-scale and decentralised [19, 20]. Besides contributing to expanding distributed energy systems [18], a community energy approach can offer several co-benefits such as local jobs, local economic development, the strength of local institutions or the increased acceptance for the renewable energy technology [20–24]. Hence, LECs can effectively promote the energy decentralisation, influencing the market, and reducing the monopoly of large energy companies [25]. To do this, it is fundamental to support the autonomous community management that promotes transparency, manages, and reinvests benefits at the local level, promoting sustainable development processes that go beyond the energy concept. The aim is to effectively and unambiguously promote a new governance model that enables the citizen power and the dissemination of LECs, eliminating the structural barriers imposed by the global market.
H. Busch et al. [26] reported the most common benefits of an energy community: (i) economic (in general, rather than creating new jobs); (ii) environmental behaviour of citizens

due to the major awareness of the energy consumption; (iii) the reduction of carbon emissions and energy savings as well; (iv) social cohesion because energy community projects require a general agreement to come together and agree on the details of the energy project by adding a feeling of interconnectedness in the community. Finally, (v) the energy community projects could help to increase the acceptance of the renewable energy technology.

In this work, an Italian case study related to the city of Osimo (AN), located in the Center of Italy, is investigated. Osimo city (~35,000 inhabitants; 265 m a.s.l. of altitude; 106,74 km^2 area) consists of a multi-energy system constituted by electricity, Natural Gas (NG), District Heating (DH), and a 23 % share of non-controllable Renewable Energy Sources (RES) capacity, mostly PhotoVoltaic (PV) panels. Indeed, the Osimo electric network has only one PCC (Point of Common Coupling) with the Italian National Transmission System Operator (TSO), TERNA S.p.A. DEA (Distribuzione Elettrica Adriatica) is the local Distribution System Operator (DSO) and it is 100 % owned by ASTEA S.p.A., the local utility, and it manages the local LV-MV network. In Osimo, LV-MV networks are installed distributed generation plants for an overall rated electrical power of 36,404 kW (July 2019). The power share is the following [27]:

- Combined, Heat and Power (CHP): 1,200 kW_e, coupled with heating DH network (~1,250 final users connected)
- Biogas: 2 plants, 2,019 kW_e
- Biomass: 1 plant, 200 kW_e
- Mini hydropower: 2 plants, 210 kW_e
- PV: 1214 panels ranging from 1 up to 973 kW_ep for a total installed power of 35,828 kW_ep

Other than the electric grid, ASTEA S.p.A. holding, the local utility, manages also other energy networks in Osimo, namely: natural gas network, DH network, municipal water network, other than the CHP power production plant, and a mini-hydropower plant. A consequence of the high share of the distributed generation is that the local energy microgrid during the year has an overproduction of locally produced electricity that is injected into the national electric grid. This aspect will be described in detail in the Chapter 4.
Osimo is an interesting case study that has been already analysed in other works [28-31] due to the use of multiple technologies and energy vectors, besides the geographical location that makes these energy efficiency interventions interesting.
In particular, studies on Water Supply System (WSS) [28], Electric Vehicles (EVs) [29, 30] and the CHP-DH plant [26] have been carried out. In the latter, Comodi et al. [31] described the old CHP-DH plant based on a Steam Injection Gas Turbine (STIG) that has been nowadays replaced with a cogeneration gas engine. Different scenarios were analysed by introducing an Internal Combustion Engine (ICE), a high temperature Heat Pump (HP), and a Thermal Energy Storage (TES) to increase the CHP's flexibility that extends its operating hours at rated conditions. Results showed that the best option was the new cogeneration gas engine which has been sized according to the baseload thermal demand, thus leading to an improvement of both the Primary Energy Saving (PES) and economic revenues. The

configuration with the heat pump, instead, affects positively the profitability, but not the energy efficiency as well as the one with the TES achieved.

The goal of the work is to demonstrate and quantify, using real data, how the innovative technological solutions such as the integration of the SES and the creation of LECs have a positive impact on the environment, energy, and economic points of view. The real data refer to the city of Osimo, which is a demonstration site in two European projects H2020: MUSE Grids and INTERRFACE (see Figure 2).

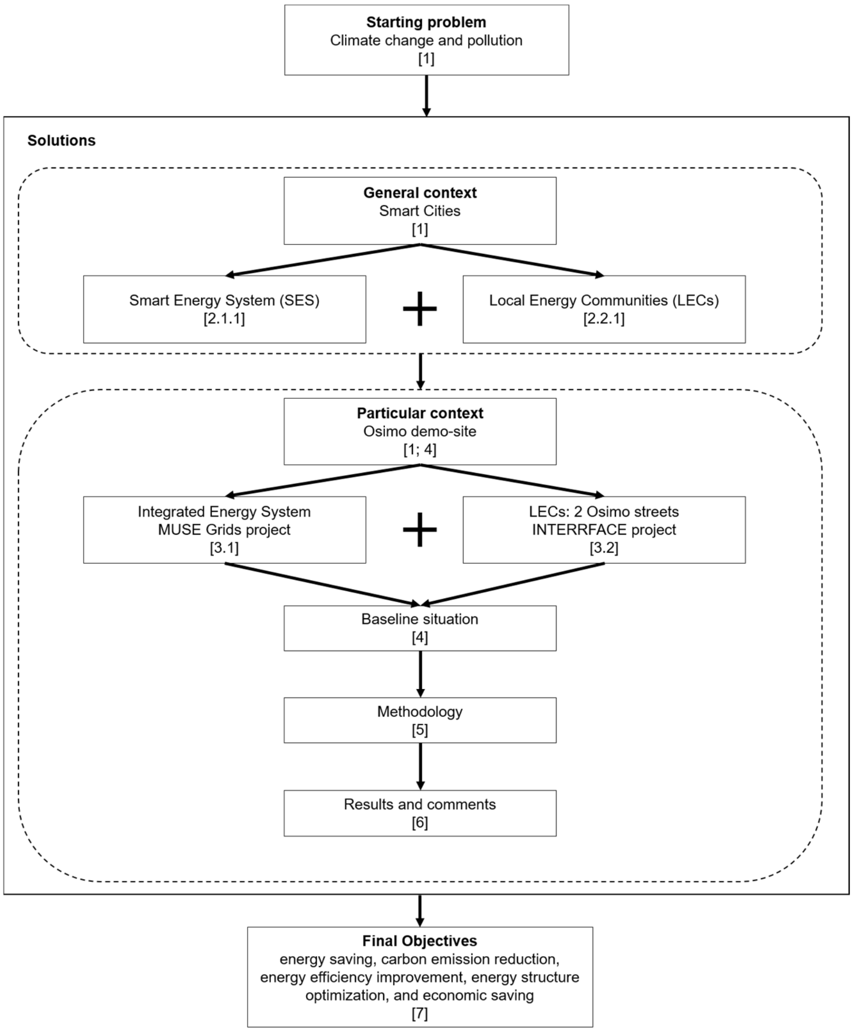

Figure 2. Work's flowchart

Firstly, the current configuration is analysed, showing the critical aspects of the various energy networks of Osimo, namely electricity, water and gas, and finally the post-projects configuration. This work wants to test and promote SES and LECs: at first, it has been developed via the combination of smart electricity, thermal, water, gas grids, etc. with storage technologies, and coordinated to identify synergies between them to achieve the maximization of the energy indipendency and the reduction of the operating costs. The purpose is to reduce the energy carbon footprint while meeting the energy demands and creating real and sustainable energy islands. Then, it has been developed through the interaction of both physical (electricity, natural gas, district heating and water) and non-physical (citizens/communities) networks, where the inhabitants can act and exchange energy to provide reliable and cheap energy by enhancing the collaboration among them. Finally, social and environmental aspects, as well as future development, have been investigated.
After a careful analysis of the literature on the development of smart cities, it was clear that (i) the "smart energy grids" sector is not investigated in depth and (ii) there are no general guidelines for the implementation of smart energy system tested on real cases. In fact, several studies have focused on the development of data platforms for smart cities that consider only some of the aspects that characterize a city as "smart", which are “smart transportation” [32] and “smart services”, such as the management of citizen denouncements [33]. G. Vitor et al [32] in fact, presented a Data Platform for smart city to gather, process, visualize and actuate on mobility and environmental data, without considering the energy grids data. J. Pereira et al [33] instead, reports experiences on the real use of the data platform for the smart services, without considering both the smart energy grids and important modules for the high-level control, such as the prediction module and the DSM (Demand Side Management) module.
A recent study on smart cities [34] instead, analyzes three sectors – energy, transport, and buildings – of eight Smart Cities. In particular, this study shows pathways for smart city development based on these successful cities in using appropriate policies and strategies to overcome the relative hurdles often limiting these three important sectors in improving and achieving the necessary development for smart city status. Regarding the smart energy sector, however, this study focuses only on the heating grid, not considering both the electricity and water grids that are an integral part of this thesis.
Furthermore, two recent studies [35; 36] have developed a Smart Control Architecture for power management in smart cities, whose layers/moduls are quite similar to those presented in this thesis. L. G. Anthopoulos et al [35] defines the role, the uses and the architecture of the “Smart City-as-a-Hub” (SCHub), which can standardize and control all the city flows. In the SCHub architecture, there is no both the prediction module and the DSM module. Q. Xin et al [36] instead, has presented a deep learinig architecture of power management (DLA-PM), which predicts future power consumption for a short period and provides effective communication between power distributors and customers. Compared the DLA-PM with the Smart Control Arhcitecture presented in this thesis, it can be said that they similarly work: both include a real-time energy administration via a shared cloud-based server data monitoring system, optimized selection of standardization technology, a new energy prediction framework, a learning process with decreased time, and lower errors rates. What is lacking in both studies [35; 36] is the application of architecture on real cases.
Ultimately, it can be said that the methodology applied in this study makes an innovative contribution to the knowledge currently available, as it deals with aspects not yet examined. In this thesis, in fact, will be presented general guidelines for the development of a Smart

Control Architecture, able to create a communication between the control logics of low-level (or those of the plants involved in the project), with those of high-level (MUSE GRIDS Cloud). It is important to note that the mathematical models of the various assets involved in this study, as well as the algorithms used for the development of the MUSE GRIDS Cloud, are not the subject of this thesis: they will be treated in a general but in-depth way, including enough information to understand the functionality of every module of which it is composed, to know the structure of the algorithms (understood as input/output interface and the shared information) and to check that the obtained results fulfil the expected objectives.

Chapter 2 presents the main milestones that led to the International Energy and Climate Agreements, including the Paris Agreement, the Clean Energy Package for all Europeans, and the European Green Deal, until their national transposition through the Integrated National Plan for Energy and Climate (PNIEC). Furthermore, Subsections 2.1.1 and 2.2.1 focus on the two main themes of the present thesis: (i) the energy system, in which both the current and the integrated smart energy system are compared, and (ii) the local energy communities in which the main peculiarities are exposed, including definitions, operation, and incentives.

Chapter 3 shows the implementation of: (i) the SES in Osimo within the European project MUSE Grids, and (ii) the development of two LECs within the European project INTERRFACE.

Chapter 4 describes the baseline situation of Osimo demo-site of the year 2018, discussing about the CHP-DH plant (4.1), the Water District Network (4.2), Padiglione (4.3) and Campocavallo (4.4) Pumping Stations (PSs), and Osimo electricity network (4.5).

Chapter 5 shows the methodology used to implement the SES (5.1) and the LECs (5.2) in Osimo demo-site, as well as the equations used to calculate the energy, environmental and economic benefits after these implementations.

Chapter 6 displays and comments the results obtained thanks to the European projects implementation.

Finally, Chapter 7 reports the conclusions of the work, the lessons learnt and possible future developments.

Chapter 2.

2. Regulatory context

2.1 EU Regulation

The first major United Nations conference on international climate issues was held in Stockholm in 1972, stressing a turning point in the development of the international environmental policy.

In particular, 1992 marks the turning point in the adoption of the United Nations Framework Convention on Climate Change - UNFCCC: it is the fundamental international treaty to reduce global warming and manage the consequences of climate change. For the first time, binding targets for reducing gas emissions are being set vis-à-vis industrialised countries. This Convention has entered into force two years later, giving important goals that were then set out clearly and firmly, a few years later, in the Kyoto Protocol.

The Kyoto Protocol, which was adopted in 1997 and entered into force in 2005, laid down targets for the reduction of gas emissions responsible for global warming and projects for the protection of forests and agricultural land, as they are tanks that absorb carbon dioxide called "carbon sinks".

The Paris Agreement [37] (COP21) of December 2015 was the first universal and legally binding global climate agreement adopted by 195 countries. The agreement defines a global action plan whose main points are the following: (i) to keep the average increase of the world temperature below 2 °C compared to the preindustrial levels as a long-term objective, (ii) to ensure that global emissions will reach their highest level as soon as possible, while recognizing that more time will be needed for developing countries; then, it will be fundamental to proceed with a rapid reduction in accordance to the most advanced scientific solutions available.
In addition, it was agreed to have a meeting every five years to set more ambitious targets, based on the scientific knowledge, and to track the progress of the Member States using a system based on transparency and accountability. It also recognized the role of non-Party stakeholders in addressing climate change, including cities, other subnational authorities, civil society, the private sector, and others. Therefore, these entities invited to step up their efforts and support initiatives to reduce carbon emissions.
Through the Paris Agreement, the EU has committed itself to make further progress and reduce greenhouse gas emissions by at least 40 % by 2030.

The achievement of these objectives is entrusted to strategies aimed at saving energy and the production of energy from renewable sources, whose plant solutions are now facing an exponential growth in the global market of industrialized countries. However, most renewable energy plants, in particular wind and solar photovoltaic, are characterized by the intermittence of energy supply, variable throughout the day and in different days of a year; therefore, it is required and extreme flexibility in the coordination between the production and the transmission over the network. On the other hand, their massive introduction into the electricity grid is leading to a discontinuous operation of conventional power plants, which will be less often called to produce electricity. To reconcile these factors, the development of energy storage systems is a solution of the imbalance between the energy production and consumption, which is an issue directly linked to the stability and the overall efficiency of the electricity grid. Up to now, there are many storage technologies on the market, some of them are mature and others not, but they are able to offer high efficiencies, modest costs, and flexibility of operation. Among them, thermal (TESS) or electric (BESS - Battery Electrical Storage System) stand out for their versatility and economic feasibility, offering many solutions and combinations with the various existing production facilities.

To continue to lead the global energy transition, a new framework has therefore been defined: the “Clean energy package for all Europeans” [38].
These new rules establish several ambitious targets to be achieved by 2030, namely to increase by almost a third (at least 32.5 %) the efficiency of the energy consumption, use 32 % of renewable energy, and reduce greenhouse gas emissions by at least 40 %.
The Clean Energy Package contains energy efficiency measures, renewable energy, electricity market structure, security of the electricity supply, and governance rules for the Energy Union. It consists of eight legislative acts providing an update of the framework of the European energy policies, aimed at facilitating the energy transition, defining a modern European energy market, promoting and integrating electricity produced from renewable energy sources and energy efficiency, and strengthening the regulatory framework in which the European and national institutions operate. The eight legislative acts are reported below:

- Directive 2019/944/EU [39] of 5th June 2019 concerning common rules for the internal electricity market;
- Regulation 2019/943/EU [40] of 5th June 2019 on the internal electricity market;
- Regulation 2019/942/EU [41] of 5th June 2019 on the Agency for the Cooperation of National Energy Regulators (ACER);
- Regulation 2019/941/EU [42] of 5th June 2019 on the preparedness for risks in the electricity sector;
- Directive 2018/2001/EU [43] of 11th December 2018 on the promotion of the energy use from renewable sources;
- Directive 2018/2002/EU [44] of 11th December 2018 amending the Directive 2012/27/EU [45] on energy efficiency;
- Directive 2018/844/EU [46] of 30th May 2018 amending the Directive 2010/31/EU [47] on the energy performance of buildings and Directive 2012/27/EU on energy efficiency;
- Regulation 2018/1999/EU [48] of 11th December 2018 on the governance of the Union for Energy and Climate Action.

In particular, the new Directive 2019/944/EU (EMD II) [39], which is aimed at the construction of an internal market governed by common rules that guarantee access to the electric carrier to all, introduces the Citizen Energy Community CEC) concept. It is defined as an energy community that guarantees the operation in the market on equal and non-discriminatory terms compared to other market players, being able to freely assume the roles of the end-customer, manufacturer, supplier, and operator of distribution systems. Consumers are qualified as "active customers" that operate directly or in an aggregate way, sell the self-produced electricity through purchase agreements, and participate in the mechanisms of flexibility and energy efficiency.

On the other hand, the new Directive 2018/2001/EU (RED II) [43] foresees that consumers can become consumers of renewable energy; thus, they can produce, store, and sell the electricity surplus, both individually and in aggregate form, introducing the notion of Renewable Energy Community (REC). These communities will be also able to exchange, within the same community, the renewable energy they produce and access the electricity market, directly or through aggregation, in a non-discriminatory way.
Table 1 summarizes the main differences between the two concepts of the energy community, divided by energy sector, organizational model, participation, control, activity, and purpose.

Another milestone to face with climate change is certainly the Green Deal [49] presented by the European Commission at the end of 2019, whose goal is to transform the EU into a fair and prosperous society, with a modern, resource-efficient, and competitive economy where there are no net emissions of greenhouse gases in 2050 and where economic growth is decoupled from the resource use.
It also aims to protect, conserve, and enhance the EU's natural capital, and protect the health and well-being of citizens from environment-related risks and impacts. At the same time, this transition must be just and inclusive: it must put people first, and pay attention to the regions, industries, and workers who will face with the greatest challenges. Since it will bring substantial change, active public participation and confidence in the transition are paramount if policies are to work and be accepted. A new agreement is needed to bring together citizens in all their diversity, with national, regional, local authorities, civil society, and industry working closely with the EU’s institutions and consultative bodies.

To achieve this goal, the EU strategy, as well as the framework for the green energy transition, is the integration of the energy system, which will be discussed in detail in the next paragraph.

Table 1. The main differences between CEC and REC concepts

	CEC		REC	
Energy Sector	Electricity market - includes only electricity generation also from renewable sources.		The renewable energy market - includes both electricity and heat generation from renewable sources.	
Organization model	Any		Any	
Participation	**Structure**	**Actors**	**Structure**	**Actors**
	Open and voluntary. Allowed cross-border participation.	Any entity. However, members or shareholders engaged in commercial activity on a large scale, and for whom the energy sector constitutes a primary area of economic activity, may not exercise any decision-making power.	Open and voluntary. Allowed cross-border participation.	Physical persons; SMEs (Small Medium Enterprises) whose participation is not the main economic activity; and/or local authorities.
Control	**Structure**	**Actors**	**Structure**	**Actors**
	Actual control	Natural persons; small and micro-enterprises; and/or local authorities.	Actual control	Local authorities; SMEs whose participation is not the main economic activity; and/or natural persons located in proximity of community-owned projects.
Activity	Generation, distribution, supply, consumption, sharing, aggregation, and storage of electricity. Energy efficiency services, electric vehicle charging services, and other commercial energy-related services.		Generation, distribution, consumption, storage, sale, aggregation, supply and sharing of renewable energy. Commercial energy-related services.	
Purpose	Social, economic, and environmental benefits for members/shareholders or the local area where the CEC operates.		Social, economic, and environmental benefits for members/shareholders or the local area where the REC operates.	

2.1.1 Smart Energy System Integration

As previously anticipated, the European Green Deal [49] puts the EU on a path to achieve climate neutrality by 2050 through the deep decarbonisation of all sectors, and higher greenhouse gas emission reductions by 2030. Hence, the energy system is crucial to reach these goals. As shown in Figure 3, the current energy system is still built on several parallel, vertical energy value chains, which rigidly link specific energy resources with specific end-use sectors [50].

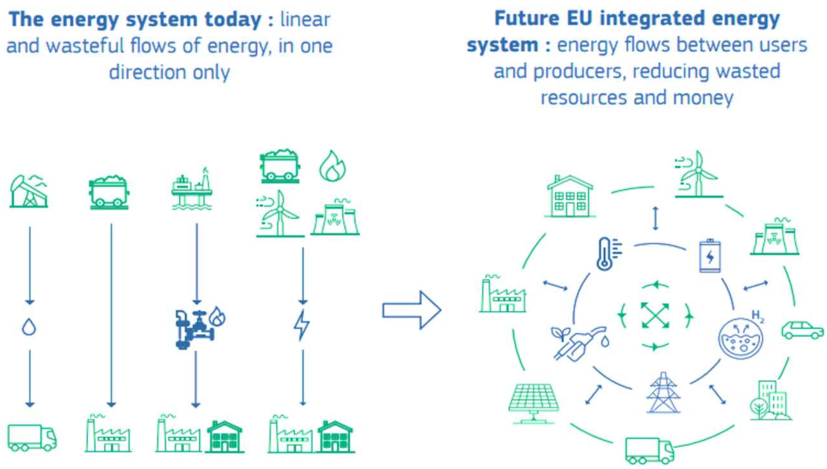

Figure 3. The current energy system vs the integrated smart energy system [45]

For instance, petroleum products are predominant in the transport sector and as a feedstock for industry. Coal and natural gas are mainly used to produce electricity and heating. Electricity and gas networks are planned and managed independently. Market rules are also largely specific to different sectors. This model of separate silos cannot deliver a climate neutral economy. It is technically and economically inefficient and leads to substantial losses in the form of waste heat and low energy efficiency.

The SES integration is the coordinated planning and operation of the energy system 'as a whole', across multiple energy carriers, infrastructures, and consumption sectors. Several factors leading naturally towards greater energy system integration such as declining costs for renewable energy technologies, market developments, rapid innovation regarding storage systems, electric vehicles, and digitalization. However, these are not enough to achieve the integration of the Energy System: indeed, it is necessary to connect the missing links to achieve higher decarbonisation objectives by 2030 and climate neutrality by 2050. To do this, three complementary and mutually reinforcing concepts are pursued:

1 Firstly, a 'circular' energy system with energy efficiency at its core in which the least energy intensive choices are prioritized, unavoidable waste streams are reused for energy purposes, and synergies are exploited across sectors. This is currently happening in CHP plants that use certain waste and residues. However, there is further potential in

reusing waste heat from industrial processes, data centres, or energy produced from bio-waste or in wastewater treatment plants.

2 Secondly, a greater direct electrification of end-use sectors. The rapid growth and cost competitiveness of the renewable electricity production can service a growing share of the energy demand – for instance using heat pumps for space heating or low-temperature industrial processes, electric vehicles for transport, or electric furnaces in certain industries.

3 Thirdly, the use of renewable and low-carbon fuels, including hydrogen, for end-use applications where direct heating or electrification are not feasible, not efficient, or have higher costs.

A more integrated system will also be a 'multi-directional' system in which consumers play an active role in the energy supply.

The benefits of the SES integration are multiple: (i) it helps to reduce greenhouse gas emissions in hard-to-abate sectors, for instance by using renewable electricity in buildings and road transport, or renewable and low carbon fuels in maritime, aviation, or certain industrial processes. It could also ensure more efficient use of energy sources, reducing the amount of energy needed and related climate and environmental impacts. The SES integration will also strengthen the competitiveness of the European economy by promoting more sustainable and efficient technologies, and solutions across industrial ecosystems related to the energy transition, their standardisation and market uptake. Moreover, a better integration will provide additional flexibility to the overall management of the energy system and thus help to integrate increased shares of variable renewable energy production by boosting storage technologies. Finally, by linking up the different energy carriers and through the localised production, self-production, and smart use of distributed energy supply, the system integration can also contribute to greater consumer empowerment, improved resilience, and security of supply.

2.2 IT Regulation

Based on the definitions introduced so far, the Italian context will be discussed in detail. At the end of December 2019, the final version of the Integrated National Plan for Energy and Climate (PNIEC) [51] was published, as foreseen by the Clean Energy Package for all Europeans. The objectives set by the PNIEC are ambitious and include:

- -56 % emissions from large-scale industry;
- -35 % of emissions from the tertiary sector, land and civil transport;
- 30 % renewable target.

To achieve these ambitious objectives, five areas have been identified:

1 Decarbonisation. Italy intends to accelerate the transition from traditional fuels to renewable sources, promoting the gradual abandonment of coal for electricity generation in favour of an electricity mix based on an increasing share of renewables and, for the remaining part, on gas. Policies and measures will be put in place to achieve the internationally and European agreed greenhouse gas reduction targets.

2 Energy efficiency. It is intended to use a mix of fiscal, economic, and regulatory instruments, mainly calibrated by sectors of intervention and type of recipients. However, the integration of energy efficiency into policies and measures with a primary purpose other than efficiency will also be pursued to optimise the cost-benefit ratio of actions.
3 Energy security. The aim of security supply is, on the one hand, to reduce dependence on imports by increasing renewable sources and energy efficiency and, on the other hand, to diversify sources of supply.
4 Development of the internal energy market. A greater degree of market integration is considered an advantage for the European Union, and therefore electricity interconnections and market coupling with the other Member States will be enhanced, but they will be also studied and developed, having regard to the geographical position of Italy and interconnections with third countries to promoting efficient trade.
5 Research, innovation, and competitiveness. Action on energy research and innovation will be guided by three basic criteria: (i) the use of resources and activities for the development of processes, products, and knowledge that have an outlet in open markets, including measures to support the use of renewable technologies, energy efficiency, and networks; (ii) synergistic integration between systems and technologies; (iii) 2030 will be an important stage in the deep decarbonisation process on which Italy is committed in line with the Long-Term Strategy for 2050, which envisages ambitious emission reduction scenarios up to climate neutrality in line with the Community guidelines.

The implementation of the PNIEC will be ensured by the legislative decrees transposing the European directives on energy efficiency, renewable sources, and electricity and gas markets, issued in 2020.
The Resolution 318/2020/R/eel of ARERA, Annex A [52], explains the enhancement and incentive of shared electricity. The first is the result of the deliberations of the Authority, the second of the Ministerial Decree of 15 September 2020. On 12 April 2022 the GSE (Gestore dei Servizi Energetici – Manager of Energy Services) has published the document that illustrates the technical rules and procedures for accessing to the service of valorization and incentive of shared electricity within configurations of groups of self-consumers of renewable energy acting collectively and renewable energy communities [53]. Finally, Legislative Decree 199/2021 [54] allows the implementation of Directive (EU) 2018/2001[43] of the European Parliament and of the Council of 11 December 2018 on the promotion of the use of energy from renewable sources. This will be discussed in detail in section 2.2.1.

2.2.1 Local Energy Communities (LECs)

The Legislative Decree 199/2021 [54] allows citizens, businesses and commercial activities, and local authorities to join to produce and share their electricity from renewable sources. This will occur through training either a group of self-consumers of renewable energy acting collectively or a renewable energy community. Therefore, the legislative decree 199/2021 makes possible and convenient these forms of aggregation, establishing the requirements and introducing an incentive provided by the GSE SpA. Those who want to share energy produced by their plants can join by signing an agreement or becoming partners of a legal

entity (energy community) whose purpose is to provide environmental, economic, or social benefits. The requirements that must be met by the production plants are the following: (i) they must be new (or in any case in case of plant upgrades is considered only the new part), powered by renewable sources, and have individually a maximum power of 200 kW. The consumption utilities and plants must be in the same building in the case of a group of self-consumers, or connected to the same MV/LV transformer cabin in the case of energy communities.
Finally, the document states that the electricity produced by each renewable energy plant that is part of the configurations of the collective self-consumption of renewable energy communities and that is shared has the right, for a period of 20 years, to benefit of an incentive tariff in the form of a Premium Tariff (PT) equal to:

- 100 €/MWh if the production plant is part of a collective self-consumption configuration. A group of self-consumers of renewable energy that acts collectively is a set of at least two self-consumers of renewable energy that act collectively and are located in the same condominium or building. A renewable energy self-consumer means a final customer who, operating in his/her own sites located within defined boundaries, produces renewable electricity for his own consumption and can store or sell self-produced renewable electricity. The self-consumer's renewable energy generating facility may be owned and/or operated by a third party.

- 110 €/MWh if the plant is part of a renewable energy community. The renewable energy community is a legal entity that: (i) is based on open and voluntary participation, is autonomous, and is effectively controlled by shareholders or members who are located near the production facilities held by the renewable energy community; (ii) whose shareholders or members are natural persons, small and medium-sized enterprises (SMEs), local authorities, including municipalities, provided that, for private enterprises, participation in the renewable energy community does not constitute the main commercial and/or industrial activity; (iii) whose main objective is to provide environmental, economic or social benefits at the community level to its shareholders or members or to the local areas in which it operates, rather than financial profits.

The total energy produced and injected into the grid remains in the availability of the configuration's contact person, with the right to use the Dedicated Collection service by the GSE.

Chapter 3.

3. European projects

3.1 MUSE GRIDS

MUSE Grids project, which is the acronyms of Multi Utilities Smart Energy GRIDS. G.A. Number 824441, is part of H2020-LC-SC3-2018-ES-SCC call, whose topic is H2020 - ES-3-2018 – Integrated Local Energy Systems (Energy Islands). Project start and end date are November 2018 and October 2022, respectively: hence, the project duration is 48 months.

In recent years, the energy paradigm is shifting from big-size centralized power plants to small-medium size distributed generation plants injecting power in a bi-directional power flow grid. For this reason, the concept called *Smart energy system* is growing where both physical networks (electricity, natural gas…) and non-physical networks (mobility and citizens/communities) have to interact towards the unique purpose: reduce energy carbon footprint and guarantee an affordable power supply for everyone.

The main concept that MUSE GRIDS aims to demonstrate and promote is the smart energy system, as well as integrated, defined as an approach in which several energy vectors (electricity, heating/cooling, water, gas, etc.) with storage technologies are combined and properly coordinated to use synergies between them. This allows exploiting also the interaction with the users to achieve an affordable energy system for everyone with an optimal solution for each individual energy vector as well as for the overall energy system. Hence, MUSE GRIDS aims to be an industry/social driven lighthouse project for this energy transition.

Smart energy system infrastructure has to be properly managed and designed integrating flexibility assets. However, the main barriers to the integration of the energy networks are not only technical; indeed, most of the coupling technologies enabling networks integration are already available or ready to be launched in the market, such as CHP, Power-to-heat technologies, electrolysers, Vehicle-to-grid (V2G) and vehicle-to-homes (V2H), etc.
The main barrier to fully unleash the potentiality connected to the integration among energy networks is the lack of a holistic approach. Indeed, most of the energy networks are designed independently and managed by different utilities so that not only synergies are difficult, but also potential conflicts among market operators are not completely clear. Moreover, the higher the integration of the energy networks, the higher the need of a high-level management

system able to optimize the synergies of the whole smart energy system. Some of the key challenges of exploiting the synergies between energy supply networks include:

1. The complicated interactions and interdependencies between energy supply networks (e.g., technical, economic and markets), which have not been clearly understood. Design and operation planning of the energy supply needs these issues, to which there are no commercial tools available;
2. No standards are available for grids coupling technologies: indeed, network interfaces have relevant different characteristics;
3. The fragmented institutional and market structures of the different energy systems are often barriers to realise the benefits of synergies between the energy networks;
4. Integration of multiple energy supply networks would result in a more complex energy system to manage and operate. The interdependencies between different energy networks and the ICT infrastructure that facilitates the interoperability would require powerful software models and analysis tools. The integration of multiple energy networks may result in an energy supply system that is more susceptible to cascaded failures, thus reducing the reliability;
5. Grids coupling technologies and solutions have been generally considered in the context of objectives and constraints at the distribution level, not necessarily reflecting on both the impact and the design/operation of the energy systems at the national level. Ignoring the interaction between distribution level energy networks and national infrastructure/ objectives will lead to significant inefficiencies and may compromise the security of the supply.

Figure 4 shows the main technological actions delivered by MUSE Grids towards a Smart Energy System.

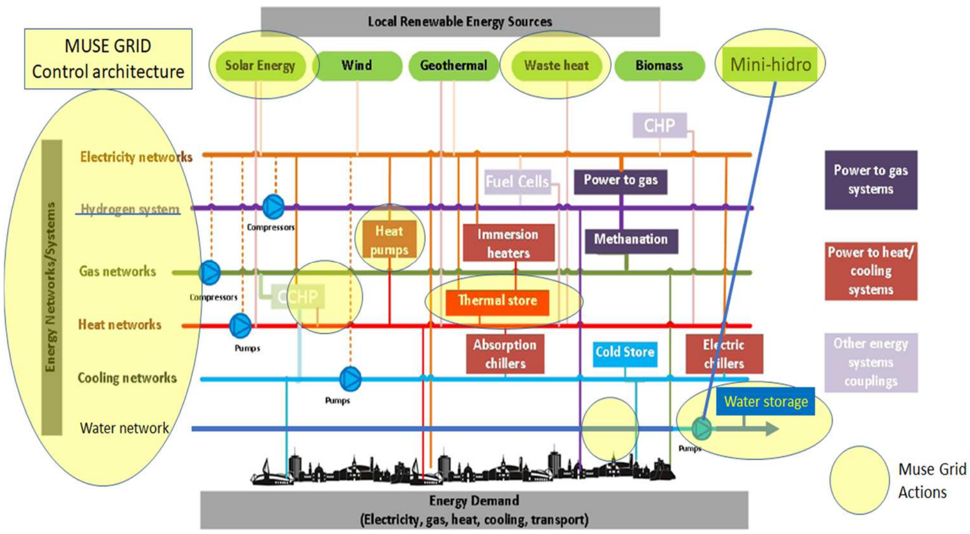

Figure 4. Smart Energy System

MUSE GRIDS faces all these challenges promoting a holistic approach to this integrated Smart Energy System affordable for everyone by:

1. Considering the complex interaction among the three main grid infrastructures (e.g., electricity, heating and cooling, and gas) and a fourth one often underestimated, but relevant for the flexibility such as the water network (Osimo);
2. Developing and validating a tool to optimally coordinate the complex interactions among the different energy systems and grid networks, promoting an optimized management of local and RESs energy production;
3. Developing a planning tool able to optimally design new districts where the grids optimally interact one to each other to save energy;
4. The two pilots (OSIMO town, Italy and OUD HEVERLEE rural area, Belgium) that demonstrated how to guarantee reliable and affordable power even in the case of a weak connection. In particular, the synergies between energy networks can be established and end-users are engaged to the establishment of Local Energy Communities (LECs);
5. Evaluating the potential interaction among the different kinds of flexibility assets (e.g., CHP, EVs etc.)
6. Engaging the EU energy utilities and stakeholders to this "Smart Energy System" transition, promoting relevant policies supporting schemes.

Therefore, the MUSE GRIDS project aims to demonstrate system-wide and in real-life operational conditions with a set of both technological and non-technological solutions adapted to the local circumstances, targeting local urban energy grids (e.g., electricity, heating/cooling, water, gas, and e-mobility). The ultimate goal is to maximize the affordable local energy independency thanks to the optimized management of the production via end-users' centred control strategies, smart grid functionalities, storage, and energy system integration with the objective of paving the way for their introduction in the market shortly. Two large-scale pilot projects have been implemented in two different European regions, one in urban (OSIMO) and the other one in rural (OUD HEVERLEE) contexts with weak connection with the National grids and energy markets to demonstrate:

- how to interconnect the local energy grids;
- how to use synergies in the energy system to maximise efficiency, reduce cost, CO_2 emissions, and energy losses;
- how to reach an affordable energy independency, mainly maximising the local self-consumption based on RES.

The main objective of MUSE GRIDS, hence, is to deliver a key contribution to the roll out of multi-energy management systems in the context of LECs. To this aim, MUSE GRIDS maximally exploits the potential of the demonstrations, user interactions, partnerships, and communication means. Real-life results are the key points in a learning and development process, but also in convincing decision makers and other relevant actors.

The interconnection of the local energy grids will be achieved by integrating in two “real energy islands” different flexible technologies (e.g., EVs, electro-thermal storage, large thermal storage, batteries, etc.) and by optimally managing them via proper multi-energy demand side management (DSM) driven by the end-user’s habits. MUSE GRIDS wants to be a large scale and highly impactful demonstration project that becomes lighthouse and muse for the replication of the smart energy system concept, involving green and autonomous LECs starting from MUSE GRIDS virtual demonstration sites in India (e.g., Bali Island Sundarbans, and West Bengal) Israel (Eilat), Spain (District of Belen-Valladolid and S.Cebrián de Campos- Palencia). Figure 5 shows all the partners involved in the MUSE GRIDS project and their nations are also highlighted.

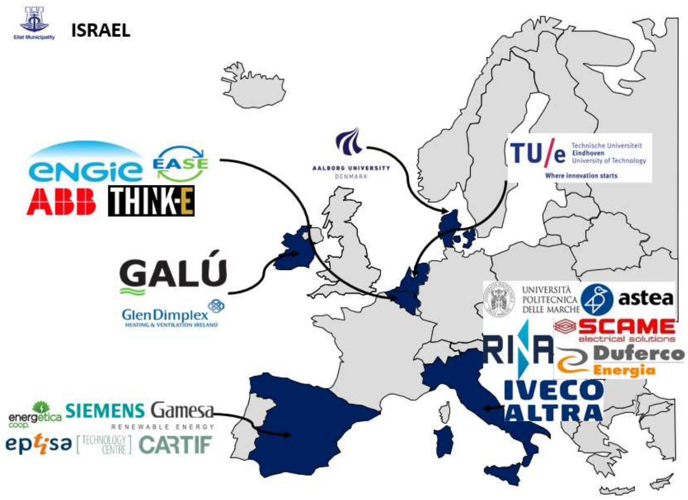

Figure 5. MUSE GRIDS partners

The approach used in Osimo demo-site is to exploit the multi-services company Astea SpA that manages the various energy networks (e.g., electricity, water, district heating. etc.). In particular, it wants to assess that the interaction among several energy networks together with energy storage systems will contribute to the decarbonisation of the municipal microgrids. This goal will be achieved thanks to the optimal coordination of the assets managed by Astea SpA in all the energy networks (e.g., CHP district heating network, pumping stations in water networks, and flexibility of office buildings). MUSE GRIDS’ DSM (Demand Side Management) will be applied to the Astea SpA production assets to minimize the interaction with the national grid operating OSIMO as an energy island. The role of the local operator is to provide current demand and load data to properly setup the controller, as well as technical local constraints, in terms of frequency and voltage limits, to the implementation of the MUSE GRIDS’ DSM and controller.

3.2 INTERRFACE

With the growth of renewables, the increased interconnection of the European grids, the development of local energy initiatives, and the specific requirements on TSO – DSO cooperation as set forth in the different Network Codes and Guidelines, TSOs and DSOs face new challenges that will require greater coordination. The European Commission adopted legislative proposals on the energy market on 30th November 2016 [55], particularly via the Electricity Directive that promotes the cooperation among the network operators as they procure balancing, congestion management, and ancillary services. The measures encourage the procurement of services at both the transmission and distribution levels, recognizing that this will enable more efficient and effective network management and will increase the level of the demand response as well as the capacity of renewable generation that is connected to the European electricity network. TSOs and DSOs, hence, must define the services that they want to procure in collaboration with the market participants, and must set up ways to procure them in a coordinated way. The digitalisation is the key driver for coordination and active system management in the electricity grid, thus enabling TSOs and DSOs to optimise the use of distributed resources to ensure a cost-effective and secure supply of the electricity for all the customers. The electricity grid, together with an appropriate consumer participation and an efficient IT and data exchange infrastructure, is a major enabler, underlying the European energy transition and improving the European economy [56].

The digitalisation also empowers the end-users to become active market participants (prosumers) by supporting self-energy generation and providing demand flexibility; indeed, as mentioned in an OFGEM study, “consumers are showing a greater desire to have control over how their energy is generated and distributed” [57]. The business models are changing to become more customer-centric and reliant on the customer interactivity [58]. Customers’ expectations are changing as technological innovation is transforming their energy choices by altering the way energy system is managed. In parallel, the interaction between all the actors in the energy value chain becomes more immediate, easier, and more structured.

To support this transformation, the INTERRFACE project designs, develops, and exploits an Interoperable pan- European Grid Services Architecture (IEGSA) to act as the interface between the power system (TSO and DSO) and the customers, thus allowing the seamless, and coordinated operation of all stakeholders to use and procure common services.

The state-of-the-art digital tools based on block chains and big data management will provide new opportunities for the electricity market participation and thus engage consumers into the INTERRFACE proposed market structures, which has been designed to exploit ‘every little piece’ of the Distributed Energy Resources (DERs). Value creation and societal welfare through increasing renewable energy integration, energy, and cost efficiency are the driver by the development and implementation of the architecture and the services.

The key principle of INTERRFACE is to “remove barriers” to unleash the potential of the existing and future resources to be an active part in the power system for the benefit of the customers and grid operators. It aims to demonstrate new concepts by deploying pan-EU markets that provide services for congestion management and flexibility by using microgrids and peer-to-peer transactions to engage consumers. In parallel, it creates a platform for further research. Finally, it will create business opportunities and promote SMEs by empowering new participants in the electricity sector. INTERRFACE incorporates a design phase and provides the design of new services, market and INTERRFACE system

architecture design based on customers, grid, and market participants' perspective. It incorporates also a demonstration phase, including the elaboration of well-designed demonstrations, in three discrete pillars: congestion management and balancing issues, peer-to-peer transactions and integrated retail, and wholesale market. It aims to capture the effect of evolving energy markets and services with novel digital and science technologies, and methodologies.
INTERRFACE wants to demonstrate the added value of sharing data among all the participants in the electricity system value chain (e.g., customers, grids, and market), from local, regional to EU level. It also wants to enable TSOs, DSOs and customers to coordinate their efforts to maximise the potential of DERs, demand aggregators, and grid assets to procure energy services in a cost-efficient way and create consumer benefits. It wants therefore to facilitate renewable energy integration and demonstrate the global leadership by the EU electricity sector in a way that is cost effective and secure. It also wants to simulate an integrated wholesale and retail market at local and global levels, engaging consumers/prosumers so as to exploit the DERs capacity and push their deployment into the common EU electricity market.

INTERRFACE strategic objectives are:

- To create a common architecture that connects market platforms to establish a seamless pan-European electricity exchange linking wholesale and retail markets, thus allowing all electricity market players to trade and procure energy services in a transparent and non-discriminatory way;
- To define and demonstrate standardised products, key parameters, and the activation and settlement process for the energy services;
- To drive collaboration in the procurement of grid services by TSOs and DSOs, and to create strong incentives to connected customers by improving market signals and allowing them to procure services based on specific locations and grid conditions;
- To integrate small scale and large-scale assets to increase the market liquidity for grid services, and facilitate the scaling up of new services that are compatible across Europe;
- To promote the state-of-the-art digital technologies that consumers are familiar with in other everyday transactions (e.g., e-auctions, e-commerce, e-banking, and social networks) into the electricity value chain to engage end-users into next generation electricity market transactions, creating incomparable economic benefits by deferring conventional energy infrastructure investments

More specifically, the above-mentioned project objectives are organised by the following set of technical and operational objectives (see Fig. 6):

- To design the Interoperable pan-European Grid Services Architecture (IEGSA). It will achieve this goal by:
    - Building a scalable European architecture for congestion management based on the needs of network operators comprising the IEGSA architecture and its IT implementation;
    - Implementing a pan EU clearing platform that connects wholesale and retail markets across borders, thus providing incentives to DERs, prosumers, and flexibility service providers.

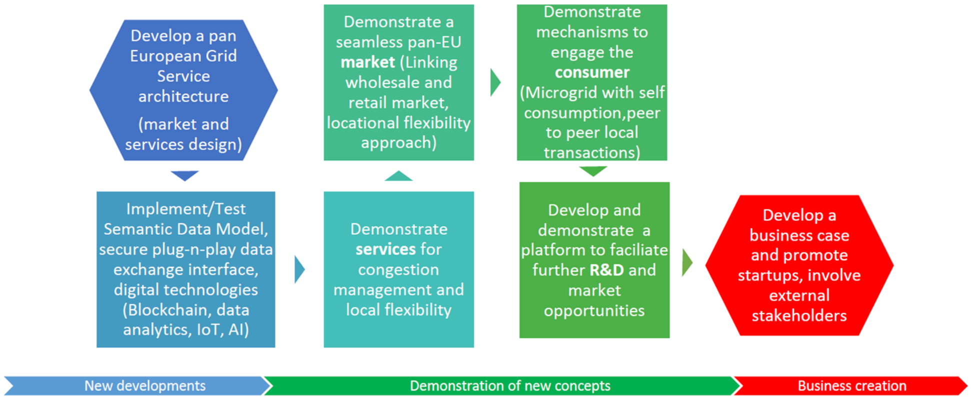

Figure 6. Technical and operational objectives of INTERRFACE

- To design, develop, and deploy a reference IT infrastructure to materialise IEGSA architecture and facilitate the operation of the aforementioned services and the adaptation of energy market tools that will:
    - Incorporate existing tools and IT platforms, which will be used from energy actors to accomplish their services as well as different models that prescribe DSO/market participants' connections;
    - Adopt blockchain technology as a means for secure, reliable, and transparent cooperating agreements and information sharing exploiting its decentralized approach. Thus, the processed data is enlarged with that owned by the different actors of the energy value chain, at same time ensuring global supply chain security and avoiding duplication of efforts and costs for energy operators;
    - Address data interoperability and adjust data granularity within this interdisciplinary and multi-national trading environment, and promoting a systematic way that adopts international standards by designing and developing an integrative and modular interoperable data governance middleware;
    - Adopt and customize advanced data science techniques and tools, including big data analytics and mining techniques, to examine the derived large and varied datasets and uncover (recognize) patterns, trends, and other useful information;
    - Introduce the Internet of Things (IoT) concept to revolutionize the power system asset management by introducing capability of assets and their physical limits into the market logic, and enabling the TSOs and DSOs to procure feasible grid services;
    - Demonstrate an Artificial-Intelligence-based advanced forecasting tool and an innovative market simulation and settlement platform to improve

predictability and give incentives to all the customers to participate into the market.

All rules and dependencies between toolsets, platforms, and data flows will be specified within the platform. The IT implementation aims to facilitate the scaling up of the existing platforms and tools as well as the development of a pan-European universal electricity marketplace that will increase liquidity, integrate new services and will be compatible across borders:

- To test the state-of-the-art digital technologies, such as Block chain and IoT, for peer-to-peer energy transactions that promote local markets and smart asset management. This will be achieved through pilot projects of innovative technologies such as automated marketplace for peer-to-peer local electricity transactions coupled with a smart asset management IoT platform that manages efficiently big data clusters to enable TSOs and DSOs to provide feasible grid services;
- To mitigate congestions and activate local flexibility resources for system balancing services through innovative platforms, operated by TSOs and DSOs in a coordinated manner. This will be demonstrated with innovative technology solutions such as (i) intelligent distribution nodes with predictive controllers and energy storage for dynamic optimal power flow and ancillary services provision, (ii) flexibility marketplaces involving TSOs-DSOs-consumers in a large-scale pilot for managing grid limitations, system frequency, and optimal capacity management for the new user's connections;
- To promote the integration of DERs into the electricity markets, demonstrating mechanisms and platforms that lead to the establishment of a seamless pan-European market empowering all the market participants to provide energy services in a transparent and non-discriminatory way. This will be done by bridging wholesale and retail market characteristics as a highly efficient forecasting tool for distributed demand and generation characteristics. This will support a next generation market simulation and settlement platform, introducing DERs, into wholesale markets. Additionally, based on specific location and grid condition, the spatial dimension of the technological flexibility will be introduced into the current wholesale market approach by the extension of a bidding pricing scheme;
- To engage consumers into the electricity markets with clean energy flows based on a user- operator "alliance" that offsets the variability of the renewable energy with effective demand response, active control, distributed storage, and peer-to-peer local markets. This will be achieved by increasing the self-consumption of the renewable energy in a microgrid area, smoothing net-load variations injected in the national transmission grid through demand response, distributed storage and active control strategies, and by developing and demonstrating an automated marketplace for local energy transactions that serves energy balancing, congestion management, and other flexibility products;
- To demonstrate the IEGSA components and architecture and the relevant IT infrastructure; IEGSA will be deployed in seven Demonstrations which will take place in nine countries (e.g., Greece, Bulgaria, Slovenia, Romania, Hungary, Italy, Finland, Estonia, Latvia), focusing on illustrating specific functions and serving real

need and existing challenges, engaging different actors of the energy value chain. These will be evaluated through definition and validation of operational, regulation conformity, legal, and technical Key Performance Indicators (KPIs). Recommendations will be extracted. The IEGSA tools deployed in the demonstrations primarily address: (a) Congestion management and balancing, locally with DER management and demand response in a microgrid and Intelligent Distribution Nodes (IDNs) for connected buildings, and at system level bridging consumers – DSOs –TSOs in a "single flexibility platform" for efficient energy trading and grid services provision. (b) Peer-to-Peer transactions through EFLEX platform for smart contract and billing for consumer engagement into flexibility services, and an Automated Marketplace with an Integrated Asset Condition Management System (IACMS) linking energy transactions with grid assets capabilities, (c) seamless pan EU-electricity market, providing alternative market platforms for cross-market (wholesale and retail) clearing price modelling, and spatial aggregation of distributed flexibility resources;

- To facilitate further research and new market opportunities across the energy industry by ensuring an efficient dissemination of the INTERRFACE outcomes to key stakeholders. The dissemination activities will be strategically planned and implemented via the Plan for Exploitation and Dissemination of Results. The project will explore clustering with other relevant projects in the Energy pillar and will establish synergies/connections with the projects constituting the "BRIDGE" initiative;
- To create the foundation of new business opportunities, with the selection of SMEs and start-ups that will be selected through an Open Call -following a cascade funding mechanism- for the development of new services. The Open Call will stimulate further interest and spread the accomplishments of INTERRFACE and its technological framework. These new services will capitalise, reuse, and refine the IEGSA platform and will aim to cover further needs of operators, contribute to the generalisation and validation of INTERRFACE framework, whereas introducing new concepts and technologies. The SMEs/ start-ups will be reached through the project dissemination activities with the support of all the consortium partners covering the energy value chain.

The project includes seven large-scale demonstrators (see Fig. 7) that will all test in real-life situations (e.g., electricity networks in Italy, Hungary, Slovenia, Estonia, Finland, Latvia, Bulgaria, Romania, and Greece) integrated markets and platforms defined and incorporated in the Interoperable pan-European Grid Services Architecture (IEGSA) such as: the single flexibility platform, demonstrating grid services by distributed flexibilities shared by the TSOs and DSOs in a coordinated way, for congestion management and balancing in the Baltic region, or the spatial aggregation of technological flexibility platform that introduces the spatial dimension of DERs flexibilities in a jointly set-up innovative wholesale, and retail electricity market design, aligned with the pan-European target model.

Figure 7. The Demo areas involved in INTERRFACE

The demonstration trials have been executed in 3 demo areas (pillars), in the aim to address:

- Demo area 1: Congestion management and balancing issues, locally by involving DSOs, DR mechanisms, storage, and small scale RESs at system level by integrating TSO/DSO and community, and by activating local and cross-border resources to provide flexibility services for system balancing. The expected outcome of this area is to identify the efficiency of using dynamic pricing, to materialise the need of a toolset that offers the optimal call of flexibility sources to solve congestions, balancing, and optimise the use of the interconnectors between the actors of the energy power system. Osimo demo site fits into this context.

- Demo area 2: The use of peer-to-peer transactions for activating flexibility based on free pricing. Within this area, relevant use cases will be developed and tested for congestion management and balancing so as to assess the role of peer-to- peer transactions in future electricity market design and estimate the cost-efficiency they can bring;

- Demo area 3: The necessity of an integrated retail and wholesale market that will be based on the existing Pan-EU wholesale market and will consider the DER/prosumers/storage/other assets to cope with the retail market. The objective is to increase the cost efficiency and create consumers' benefits.

Chapter 4.

4. Baseline situation of the Osimo demo-site

The focus of this chapter is to show the baseline situation of Osimo demo-site referred to the year 2018, which was composed by the CHP-DH plant (4.1), the Water District Network (4.2), Padiglione (4.3), and Campocavallo (4.4) Pumping Stations. Finally, Section 4.5 shows the baseline situation of the electricity network.
In Osimo there is already a SES where coordination between the various energy vectors is made by Astea SpA. Both data processing and technologies that can provide flexibility to the network are still missing in the Osimo demo-site.

Table 2 shows the Astea SpA sites involved in the MUSE GRIDS and INTERRFACE projects and the related installations foreseen by the two projects. The following paragraphs describe the baseline situation of the assets involved in the research project.

Table 2. Astea sites involved in this study and the related installations foreseen

Energy vector	Assets	New installations
DH network	CHP-DH plant	Thermal Energy Storage (TES) Heat Pump (HP)
Water network	District Water Network	n. 1900 residential smart water meters n. 5 district water meters Fixed infrastructure for water/energy smart meters
Water network	Padiglione WPS	No new installations, but it is indirectly involved with the water losses detection of the WDN selected
Water network	Campocavallo WPS	n. 3 Electric Energy Storages (EES)
Electric network	2 streets of Osimo	2 Battery Energy Storage Systems (BESS), one for each street

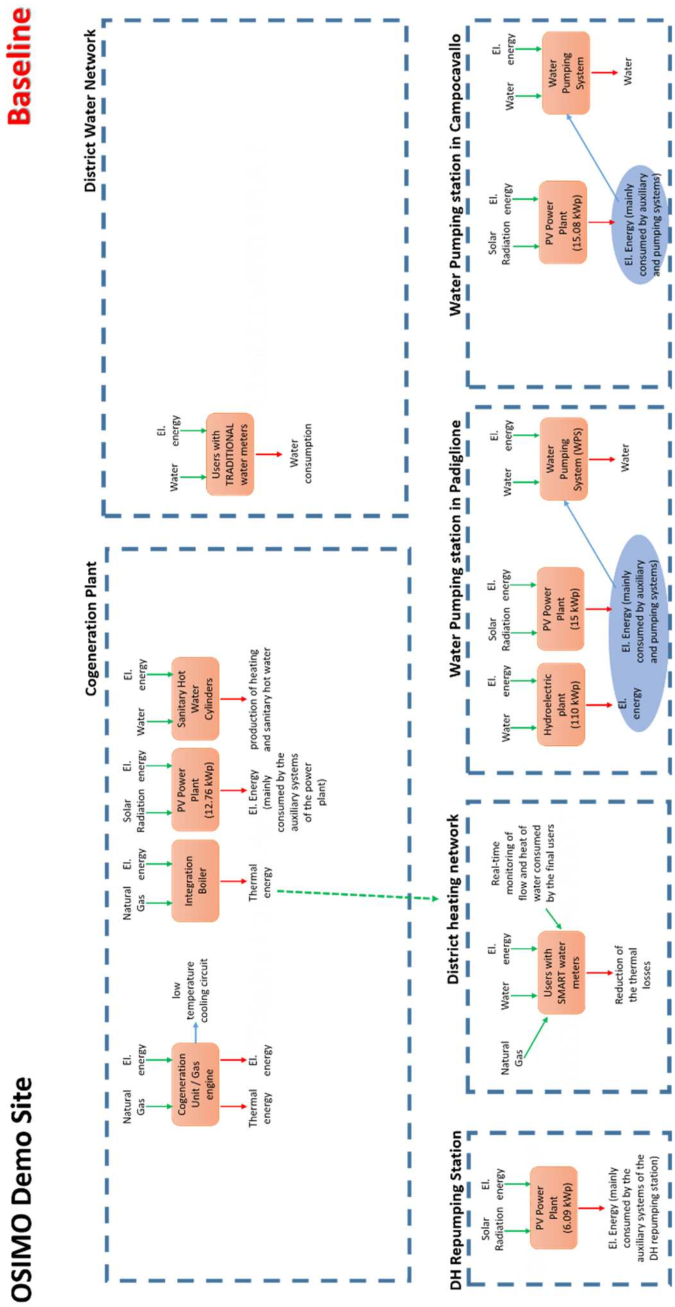

Figure 8. Baseline situation of Osimo demo site

4.1 CHP-DH plant

4.1.1 Thermal power plant

As already discussed in the Introduction, this work analyses the use of a DH network installed in Osimo (AN), a small town located in the Center of Italy. It is the only DH network installed in the Marche region and supplies 3 % of the total heat demand to both residential and industrial end-users. The town belongs to the climatic zone D (Degree Day 2.073) where the minimum temperature is –2 °C during the winter season and the highest is 34 °C in the summer season as shown in Figure 9.

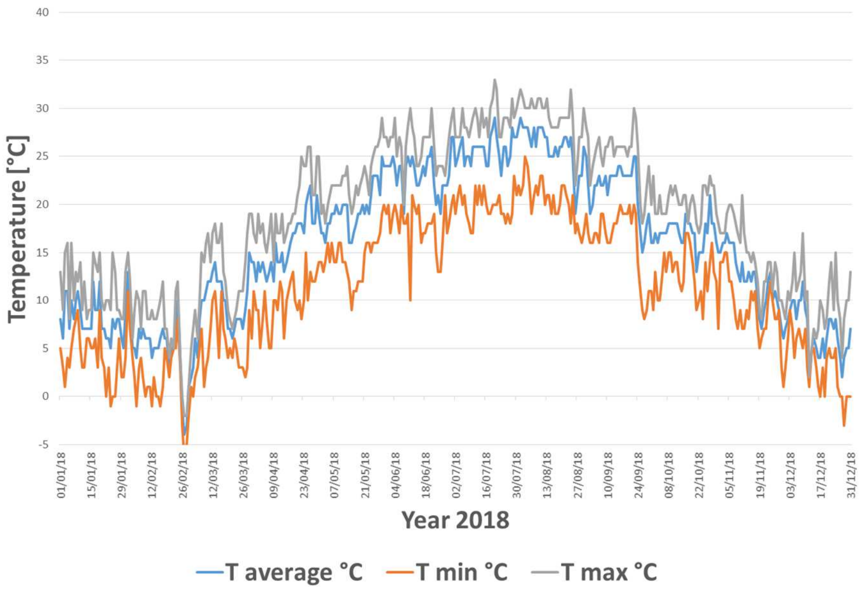

Figure 9. Temperature profiles recorded in Osimo (year 2018)

Heat and electricity are produced through a CHP unit composed of an ICE Natural Gas (NG) fuelled. The rated electrical power is 1.2 MWel, while the heating one is 1.3 MWth. The CHP unit provides flexibility to both DH network and the electricity grid. The thermal energy is used to supply the DH network. The CHP unit operates by following the heat demand of the end-users that will be described in detail in the DH network Subsection: it can modulate the thermal load to produce the required thermal energy.

However, the CHP unit is not the only piece of equipment installed in the thermal power plant connected to the DH network under investigation. Indeed, the plant has also NG boilers (2 boilers having 4.6 MWth and 1 boiler with 4.2 MWth, which one of them used as back-up) that provide additional thermal energy when the demand exceeds the CHP unity capacity. Figure 10 shows the layout of the thermal plant where both CHP unit and boilers are presented [59].

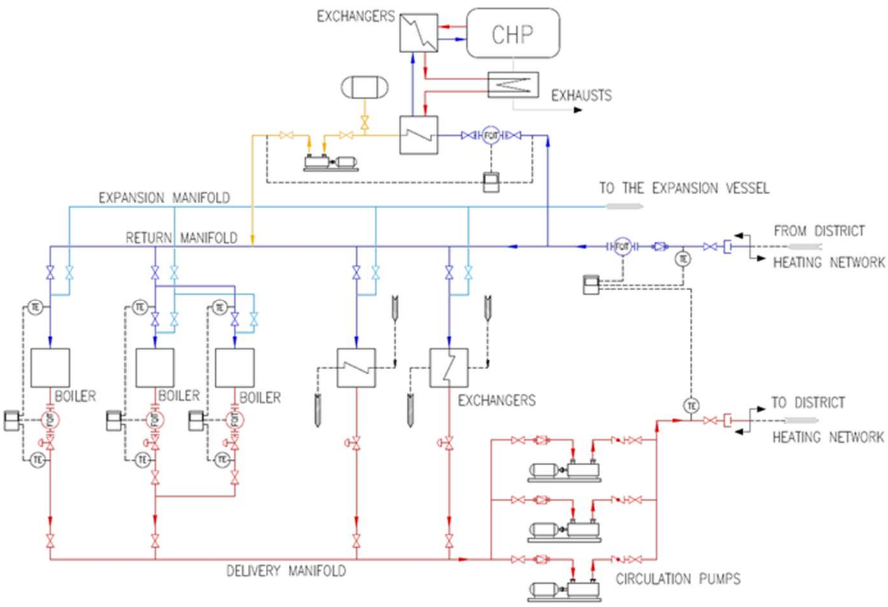

Figure 10. Scheme of the thermal plant connected to the analysed DH network [54]

The CHP unit is connected in series with the boilers, which are connected in parallel. The main technical data of both CHP unit and boilers are listed in Table 3.

Table 3. Technical data of the CHP unit and boilers

Magnitude [Unit of measure]	Values
CHP unit rated electric power [MW]	1.2
CHP unit rated thermal power [MW]	1.3
Boilers rated thermal power [MW]	13.4
$\eta_{th,CHP}$ [-]	0.42
$\eta_{e,CHP}$ [-]	0.41
$\eta_{th,boil}$ [-]	0.962

The operating principle of the thermal power plant, which is mostly used in the winter season, is here described: the water flow rate coming back to the plant through the return pipelines of the DH network, having a temperature of about 60 °C, goes to the cooling circuit of the CHP unit and through a heat exchanger to cool down its exhausts. For the sense of clarity, the cooling circuit plus the heat exchanger on the CHP unit side is named “CHP circuit” hereinafter. In the end, the flow rate elaborated by the CHP circuit is increased from 60 °C to about 75-76 °C. During the winter season, if the output temperature of the flow rate exiting the CHP circuit is lower than the setpoint one in the boilers, all the flow rate will be elaborated by the boilers to reach the set value, keeping in mind that one or two boilers can operate, while the other one is used as a backup.

4.1.2 District Heating Network

The DH network is constituted by 45 km of insulated polyurethane pipelines, namely 22.5 km of supply pipelines plus 22.5 km of return ones, provided with external mechanic protection in polyethylene. It supplies room heating and domestic hot water to about 1,278 end-users, namely 1,204 residential buildings and 74 public or commercial customers. The DH network is composed of two main circuits: the first circuit is directly connected to the thermal power plant and supplies heat to the end-users located at altitudes between 90 and 190 m a.s.l., while the secondary one is physically disconnected from the primary one through two plate exchangers located in a pumping station (old town center) and serves end-users placed between 180 and 255 m a.s.l as shown in Figure 11.

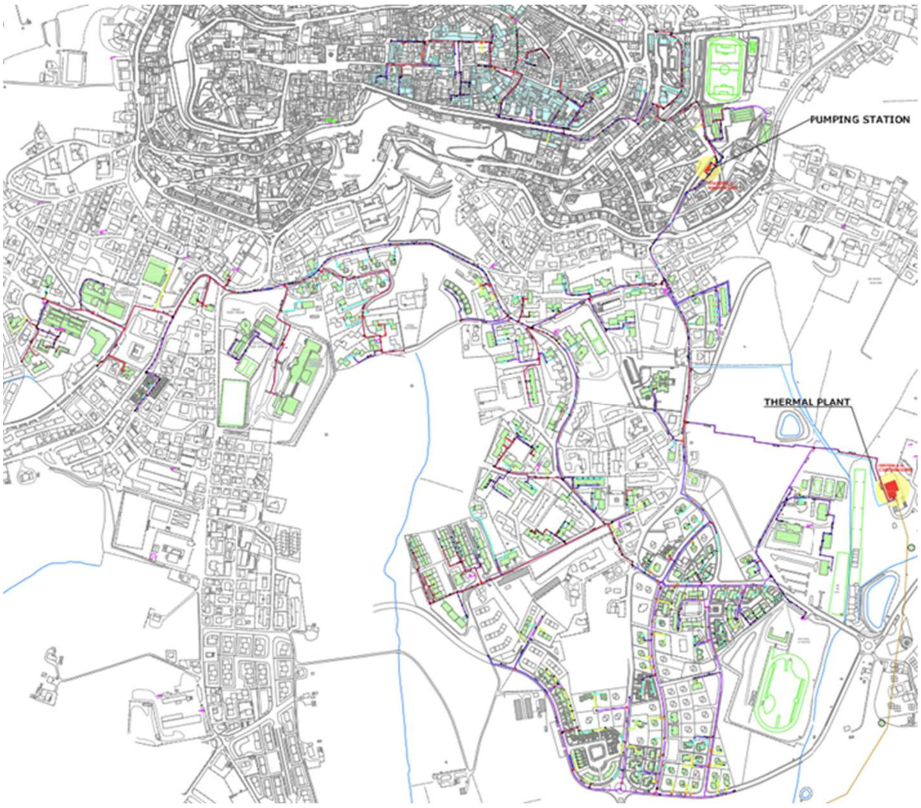

Figure 11. Overview of the DH network (both thermal power plant and pumping station are highlighted in yellow)

The commercial end-users account for 51 % of the total thermal demand, while the residential ones constitute the remaining 49 %.
The DH supply temperature varies depending on the season: the time range in which thermal demand peaks are recorded is the same in all the seasons, mainly from 7:00 to 9:00 and from 18:00 to 20:00, with greater intensity in the winter season. During the winter season, the supply temperature varies from a minimum of 66.1 °C to a maximum of 99.1 °C, in the mid-season it varies from 58.3 °C to 90.8 °C, and during the summer season it varies from 40.4 °C to 87.4 °C. Regarding the return temperature, instead, in the winter season it varies from 55.2 °C to 66.8 °C, in the mid-season it varies from 53.1 °C to 71.5 °C, and in the summer season it varies from 30.4 °C to 64.4 °C.
Table 4 lists the monthly heat losses in the DH network (year 2018) together with the incidence of the heat losses on the total thermal energy produced, showing how the incidence of the heat losses is much higher in the summer season, where the thermal demand is lower and reaching the maximum value of 63.5 % in August, compared to the winter season where the minimum value of 17.6 % is recorded in February.

Table 4. Thermal losses in the DH network (year 2018)

Month	Heat losses [MWh]	Incidence of the heat losses [%]
1	620.9	20.0
2	605.1	17.6
3	683.1	21.9
4	528.3	39.8
5	459.8	53.0
6	407.6	58.7
7	375.9	63.0
8	361.0	63.5
9	388.2	58.0
10	454.3	51.2
11	507.3	26.0
12	591.7	18.2

The local heat demand is provided with a 15-minute resolution for the whole year as shown in Figure 12. The peaks of the heat demand are close to 9.5 MWh in the winter season, namely in January, and drops down to 0.5 MWh in the summer one, namely between June and September.

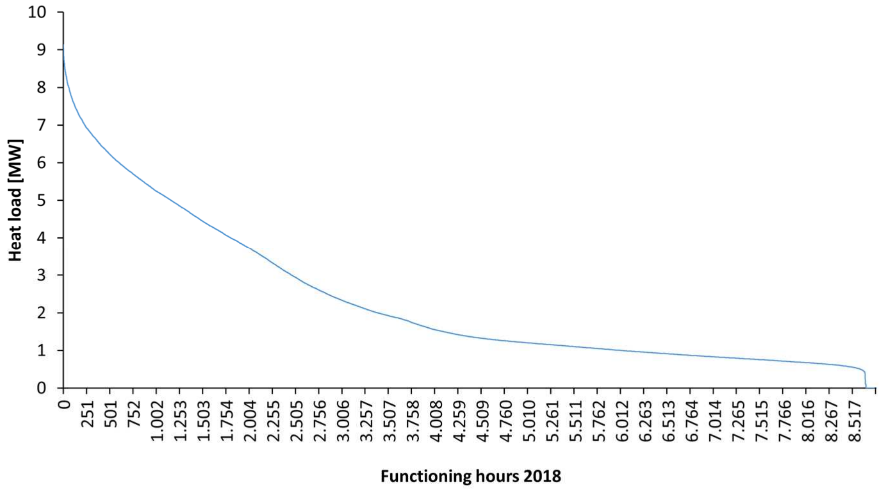

Figure 12. Heat load duration curve (year 2018) provided by the DH

The water supply temperature is regulated throughout the different seasons to compensate the thermal losses inside the DH network. Usually, the CHP unit has the priority on the energy production, while the boilers are switched on whenever the thermal demand exceeds the maximum available thermal power provided by the CHP unit. In the winter season (November – March), the supply temperature is 95 °C and the CHP unit operates always with the boilers, which provide additional thermal power to reach the maximum set temperature. In the mid-season (April – mid-June and mid-September – October), the supply temperature ranges between 78 °C and 85 °C: the ICE modulates its load in the night (from 20:00 to 7:00), while during the day it operates like in the winter season: the boilers are switched-on only if it is needed. In the summer season (mid-June – mid-September), the CHP unit usually does not operate, and the thermal power is entirely produced by the boilers reaching a maximum temperature of almost 75 °C. Indeed, the heat demand required by the end-users falls below the maximum value that can be delivered by the CHP unit: in this case, the machine operates partially being limited below 60 % of the CHP unit rated power. Whenever the value of the thermal power falls below the minimum threshold value of 780 kW, the CHP unit is switched off and the thermal power is entirely supplied by the boilers. Certainly, the repeated switching on/off makes the use of the CHP unit not optimal; thus, several devices must be used to let the CHP unit operate properly and limit the risk of possible failures as well.

Finally, to conclude the overview of the CHP-DH plant, the data for the year 2018 of the gas consumed, monthly operational data/performance parameters of the CHP unit, the monthly specific energy parameters, and the avoided CO_2 are shown.

Figure 13 shows the share of the NG used by the CHP unit and boilers, while Table 5 reports the CHP plant energy performance in the year 2018. It can be noticed that, yearly, the CHP and the boilers consumed almost the same amount of primary energy, namely 1,613,396 Sm^3 by the CHP unit and 1,615,967 Sm^3 by the boilers. Furthermore, only the gas boilers operate in the summer season, while in the mid-season the CHP unit has the priority over the boilers. Table 5 compares the columns related to the “CHP unit Thermal Energy production” and to the “Boiler Thermal Energy production”, respectively.

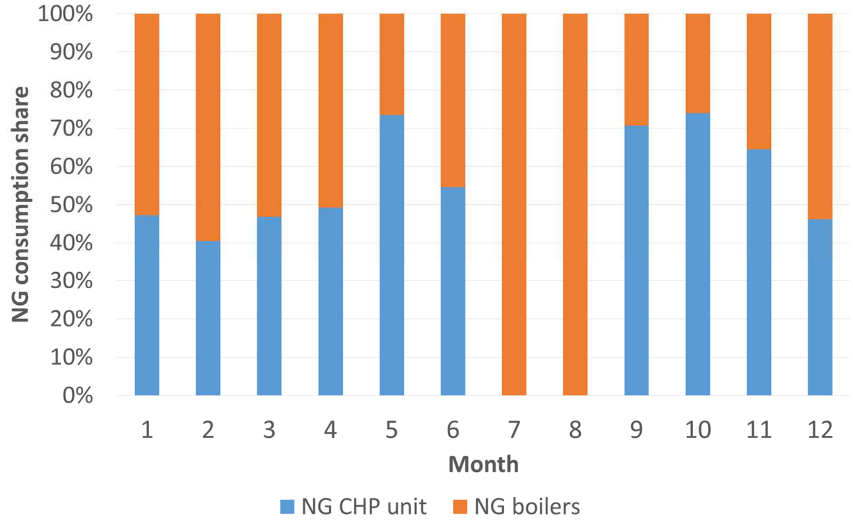

Figure 13. Share of the NG consumption by the CHP unit and boilers (year 2018)

Table 5. Monthly operational data/performance parameters of the CHP unit (year 2018)

Month	CHP NG consumption [Sm^3]	Boiler NG consumption [Sm^3]	CHP TE production [MWh]	Boiler TE production [MWh]	DH load [MWh]	CHP unit EE production [MWh]	CHP unit EE delivered [MWh]
1	229,237	256,339	915.6	2,186.9	2,481.6	881.9	815.7
2	206,858	304,414	822.3	2,619.5	2,836.7	798.3	734.4
3	224,162	255,034	889.7	2,226.7	2,433.3	857.7	793.7
4	102,811	106,013	392.7	933.7	798.1	388.7	365.8
5	122,625	44,269	476.1	392.1	408.4	464.4	438.0
6	61,141	50,989	230.6	464.0	287.0	230.7	216.4
7	0	64,920	0.0	596.3	220.4	0.0	0.0
8	0	62,267	0.0	568.6	207.6	0.0	0.0
9	90,589	37,550	340.8	328.3	280.9	340.8	320.6
10	125,124	43,968	477.8	410.2	433.7	464.1	439.2
11	220,788	121,835	883.7	1,070.2	1,446.6	842.1	788.7
12	230,061	268,369	917.1	2,333.4	2,558.8	879.6	810.8
Total	1,613,396	1,615,967	6346.4	14,129.9	14,393.2	6,148.2	5,723.2

Table 6. Monthly specific energy parameters and the avoided CO_2 (year 2018)

Month	PES [%]	$TE_{sp,CHP}$ [kWh/Sm^3]	$TE_{sp,boil}$ [kWh/Sm^3]	$EE_{sp,CHP}$ [kWh/Sm^3]	$E_{sp,tot}$ [kWh/Sm^3]	ΔE_{sp} [kWh/Sm^3]	$E_{th,el}$ [kWh]	Avoided CO_2 [tonnes]
1	22.1	3.19	6.82	3.85	13.87	4.47	1,310,443	254
2	22.1	3.28	7.09	3.86	14.23	4.83	1,619,263	313
3	21.6	3.10	6.82	3.83	13.74	4.34	1,249,462	242
4	19.9	2.30	5.30	3.78	11.38	1.98	186,833	36
5	20.5	1.83	4.17	3.79	9.78	0.38	18,342	4
6	19.5	1.56	3.76	3.77	9.09	-0.31	-	-
7	0.0	-	3.40	-	3.40	-6.00	-	-
8	0.0	-	3.33	-	3.33	-6.07	-	-
9	19.3	1.58	3.67	3.76	9.01	-0.39	-	-
10	18.9	1.87	4.56	3.71	10.13	0.73	37,521	7
11	21.7	2.96	6.50	3.81	13.28	3.88	663,837	129
12	21.7	3.26	7.11	3.82	14.20	4.80	1,507,701	292
Average	21.2	2.78	6.19	3.81	12.78	3.38	5,799,409	1,123

According to Eq. (1) showed in the next Chapter, Table 6 shows the monthly trend of the PES related to the CHP unit recorded in the year 2018. It can be stated that the CHP unit (not considering the summer months of July and August since it does not operate) is more competitive than the separate production, providing a yearly reduction of the primary energy consumption of 21.2 %. The maximum PES achievable is 22.1 % in January (with $\eta_{th,CHP}$ = 42.5 % and $\eta_{e,CHP}$ = 40.9 %) and February (with $\eta_{th,CHP}$ = 42.3 % and $\eta_{e,CHP}$ = 41.1 %), while the minimum one is 18.9 % in October (with $\eta_{th,CHP}$ = 40.6 % and $\eta_{e,CHP}$ = 39.5 %). Since the PES is greater than 10 %, the Osimo CHP unit falls within the definition of high-efficiency cogeneration (electric power production higher than 1 MWel). Among the energy saving, EEC can be issued by the Italian Government for 10 years.

Another parameter that is fundamental for investigating the energy results of the CHP unit and, indirectly, for analysing the environmental results is the specific energy. Table 6 lists the monthly results related to the specific energy; in particular, there are no advantages in terms of energy exploitation when $\Delta E_{sp} < 0$ (summer period). The same considerations can be done for the boilers, while the electrical specific energy from the CHP unit is constant throughout the year. It is worth noting that the heat losses recorded during the year, being equal to 5,983.1 MWh, have been considered in the energy assessment of the thermal power plant, leading to lower exploitation of the primary energy and thus to lower values of specific energies. Indeed, the heat losses increase from 17.6 % in February to 63.5 % in August when the DH network achieves its minimum production, thus leading to a significant decrease in the specific thermal energy, considering both CHP and boilers, that ranges from 3.28 kWh/Sm^3 in February to 1.56 kWh/Sm^3 in June, and from 7.11 kWh/Sm^3 in December to 3.33 kWh/Sm^3 in August, respectively. On the other hand, the specific electric energy does not suffer grid losses and remains constant due to the need of keeping the heat transfer fluid temperature constant, even when end-users do not need it. It is not allowed to interrupt the

heat supply when there is the minimum demand because the reaction times to increase the thermal load would be too long to adequately satisfy end-users' needs.
To deepen the Osimo DH network analysis and to sum up the outcomes obtained so far, it is interesting to notice that the thermal power plant performance varies between summer/mid-seasons and winter season. Indeed, the formers harm the entire energetic, environmental, and economic points of view from the thermal power plant side, while in the latter there is a considerable improvement due to the higher end-users' demand that leads the thermal power plant to operate most of the time at rated condition.

4.2 Water District Network

Drinking water is distributed through a distribution network connected to several tanks located at high altitude: The tanks compensate the daily peaks and are fed by auxiliary pipelines, which are subsequently fed by the lifting plants (Padiglione and Campocavallo pumping stations) and connected to transport pipelines. The power supply of the Osimo distribution network occurs by gravity or by pressure systems.
The lifting plants, the adductor pipelines, the transport, and the tanks are generally equipped with devices connected to a remote-control system that allows to monitor and act remotely if necessary:

- the water level of the storage tanks;
- pressure and flow rates;
- the state of operation of any electro-mechanical equipment;

Every year, water loss research campaigns are carried out in the historic center using special instruments such as noise-loggers, correlators, and pre-and rods.
The water losses for the year 2018 of the entire city of Osimo were equal to 33 %.
The Water District Network chosen for the implementation of MUSE GRIDS project is the historical centre of Osimo. This choice is due to several factors [60]:

- its higher water losses compared to the average values of the entire water system of Osimo;
- unique pipeline from the tank to the district;
- the presence of underground caves where the pipelines are installed, which are periodically subjected to water infiltration due to leakages and thus leading to structural instabilities of their masonry vaults, and
- considerable energy costs to pump the water (this water district is supplied by the Duomo tank, in turn supplied by the Padiglione pumping station).

The selected WDN has been divided using the District Metered Area (DMA) approach, which consist of dividing the region under investigation to multiple smaller sub-regions. Indeed, it is possible to monitor remotely both the water supply and consumption through smart meters. These sub-regions are precisely called District Metered Areas.
Figure 14 shows the WDN under investigation of the historical centre of Osimo [60]: it has been divided into five sub-regions, which correspond to the number of branches starting from

the main distribution pipeline coming from Tank 14. Each DMA has a number of end-users close to 500.

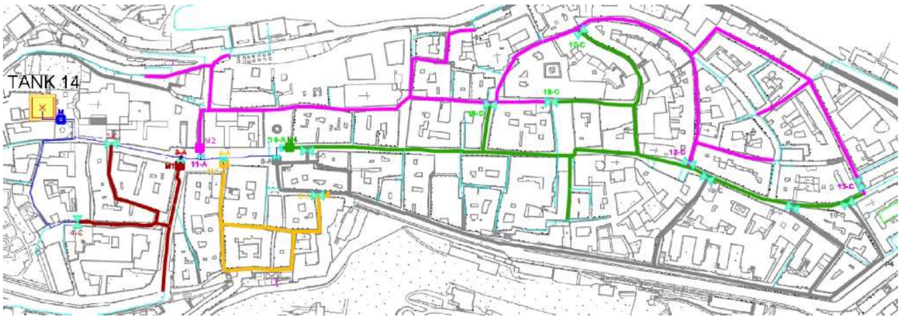

Figure 14. WDN of the historical centre of Osimo divided into five DMAs: each sub-region is highlighted with a different colour [55].

In the year 2018 it was not possible to quantify the water losses of the water district due to the lack of district smart meters. Thus, it has been decided to use the minimum value of the hourly average flow rate supplied to the district, that is usually obtained at night when the users' water demand is very low. This flow rate is also called Minimum Night Flow (MNF), and it consists of both the non-revenue water, water losses along the pipeline, and only a small part of the users' consumption. As a baseline, the MNF of each DMA (see Table 7), available from August 2020, has been taken to evaluate water losses in the water system as described in the methodology.

Table 7. MNF baseline for each DMA

	Minimum Night Flow [m^3/h]				
	M1	**M2**	**M3**	**M4**	**M5**
Baseline	0.72	3.95	0.40	2.97	1.90

4.3 Padiglione Pumping Station

Padiglione PS is the unique pumping station involved in the Duomo tank supply that serves the water district network of the historical center of Osimo. As shown in Figure 15, it is composed by:

- a water pumping system with a nominal electric power of about 500 kW;
- a 110 kWp hydroelectric plant (operating pressure of 22 bar);
- A PV panel plant with a nominal electric power of 15.08 kW.

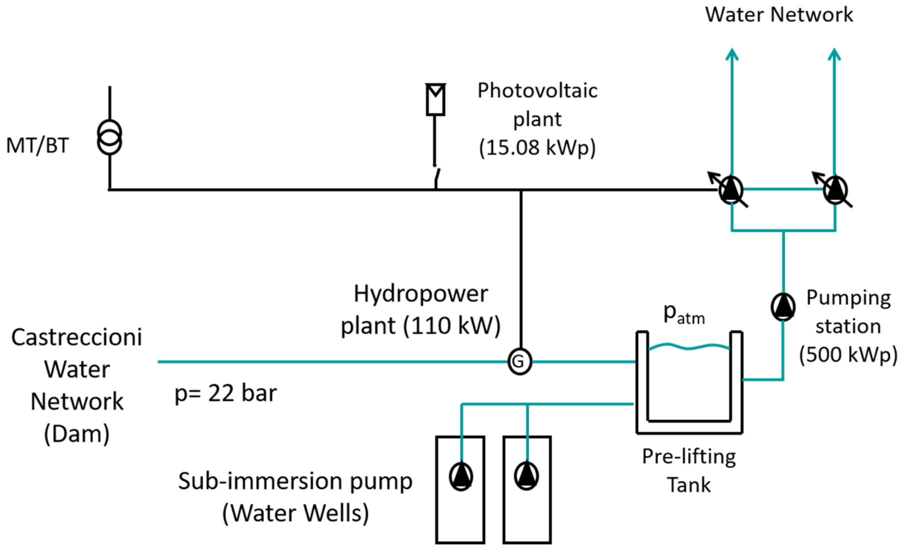

Figure 15. Padiglione Pumping Station layout.

To better understand the operational mode of the pumping station, its working principle is described as follow (see Figure 16): (i) the pre-lifting tank [A] receives water from Water Wells [B] and Castreccioni water network [C]. Due to technical reasons, it is necessary to reduce the water pressure coming from the Castreccioni dam. This is possible through a Pelton turbine that reduces the water pressure from 22 bar to 1 bar. At the same time, it recovers the energy that otherwise would be lost. (ii) From pre-lifting tank [A], the water is sent through:

- n. 2 pumps [D] with a nominal electric power of 15 kW each, average annual flow rate of 38.58 m^3/h (only one works, the other one is a back-up);
- n. 2 pumps [E] with a nominal electric power of 18.5 kW each, average annual flow rate of 22.44 m^3/h (only one works, the other one is a back-up);
- n. 2 pumps [F] with a nominal electric power of 11 kW each, average annual flow rate of 8.8 m^3/h (only one works, the other one is a back-up);

- n. 1 pump [G] with a nominal electric power of 160 kW, average annual flow rate of 121.5 m^3/h; (there is also a back-up pump of 200 kW that is not reported in the scheme below)
- n. 1 pumps [H] with a nominal electric power of 51 kW each, average annual flow rate of 19.87 m^3/h.

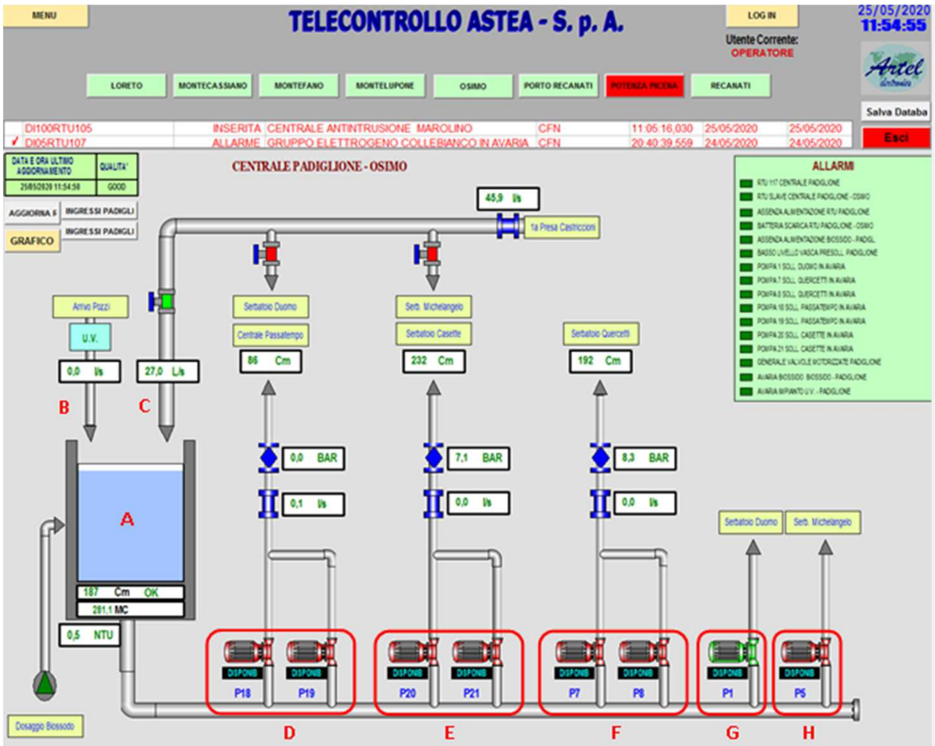

Figure 16. Operational mode of Padiglione Pumping Station, where pre-lifting tank [A], pipelines from Water Wells [B], pipelines from Castreccioni Dam [C], and pumps [D, E, F, G, H] have been highlighted in red.

Regarding the year 2018, the main data of the pumping station, which will be taken as a baseline reference, are listed in Table 8.

Table 8. Monthly operational data/performance parameters of the Padiglione PS (year 2018)

Month	EE produced by Hydro turbine [kWh]	EE delivered [kWh]	EE consumed [kWh]	EE self-consumed [kWh]	Working hours [h]
1	36,494	576	56,679	35,918	528
2	36,164	440	54,964	35,724	672
3	37,674	440	68,190	37,234	720
4	39,377	762	57,154	38,615	720
5	41,430	607	60,033	40,823	744
6	38,826	263	65,433	38,563	720
7	41,491	124	69,035	41,367	738
8	46,242	63	67,030	46,179	744
9	36,747	186	68,860	36,561	672
10	39,560	196	69,584	39,364	744
11	39,444	296	66,279	39,148	720
12	40,995	340	69,201	40,655	744
Total	474,444	4,292	772,442	470,152	8,466

4.4 Campocavallo Pumping Station

Campocavallo Pumping Station (PS) is the second PS in terms of lifted water volumes that supplies water to the remaining part of the Osimo town that is not reached by the one of Padiglione, previously described. It is composed by:

- n. 3 water pumps with a nominal electric power of 200 kW each, maximum flow rate of 162 m^3/h (only one operates, while the others are in stand-by)
- a PV panel plant with a nominal electric power of 15,08 kW

To better understand the operational mode of the pumping station, its working principle is described as follow (see Figure 17, in particular red letters). Campocavallo pumping station takes water directly from the wells on site. The water is then sent to Largo Trieste tank [A] and to Cagiata tank [B].
Largo Triste tank [A] is fed by:

- n. 3 pumps [C] (only one operates, while the others are in stand-by);

- the water supply network from the Castreccioni dam [D] that goes directly into Largo Trieste tank [A] without a pumping system.

Cagiata tank [B], instead, is fed by:

- Petrarca tank (not visible in the scheme above) through a water network that operates by gravity;
- a water supply network derived from the Castreccioni dam that directly feeds Cagiata tank. This additional flow rate is normally used in summer time when the water demand is high.

The two pumps in the scheme above [E], that should serve Cagiata tank, are not actually working. The electric power required is about 15 kW each.

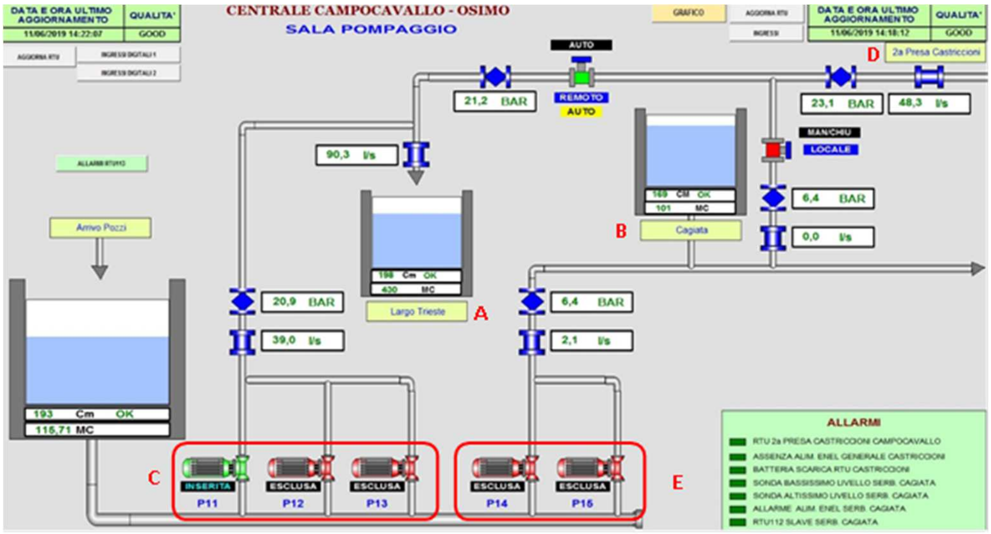

Figure 17. Operational mode of Campocavallo Pumping Station, where Largo Trieste tank [A], Cagiata tank [B], pumps [C and E], water supply network from Castreccioni dam to Largo Trieste tank [D] have been highlighted in red.

The pumps are switched on to maintain the water level into the tanks (Figure 22) within a given range. The necessary electricity is taken from the grid and partially produced by the local PV panels. The electricity produced by PVs is used to cover the electricity demand for pumping the water; however, at the moment the self-consumption ratio is about 90 % as shown in Table 9, which displays the energy produced, delivered, consumed, and self-consumed by the PV plant at the service of the pumping station.

Table 9. Monthly operational data/performance parameters of the Campocavallo PS (year 2018)

Month	EE produced [kWh]	EE delivered [kWh]	EE consumed [kWh]	EE self-consumed [kWh]	EE self-consumed [%]
1	765	64	46,662	701	91.63
2	640	46	53,275	594	92.81
3	1,274	147	62,005	1,127	88.46
4	2,119	197	87,415	1,922	90.70
5	2,292	254	67,712	2,038	88.92
6	2,638	330	70,474	2,308	87.49
7	2,746	221	102,046	2,525	91.95
8	2,428	134	107,598	2,294	94.48
9	1,884	161	76,041	1,723	91.45
10	1,154	90	67,287	1,064	92.20
11	716	42	64,188	674	94.13
12	700	30	62,657	670	95.71
Total	19,356	1,716	867,360	17,640	91.13

4.5 Electricity Network

As anticipated in Chapter 1, Osimo demo-site has several aspects which make it almost unique in Europe. First of all, this demo is a town scale energy island/mini-grid having only a single common communication point with the national TSO Terna, through a primary cabin (red circle in Figure 18). Actually, another backup connection with national grid exists only for backup purposes such as maintenance or disruption of the primary cabin.
This feature has become of particular interest in the last year since the new Italian incentive for Renewable Energy Communities has set boundaries of RECs behind the primary cabin. As a consequence, the whole Osimo town can be considered a Renewable Energy Community.

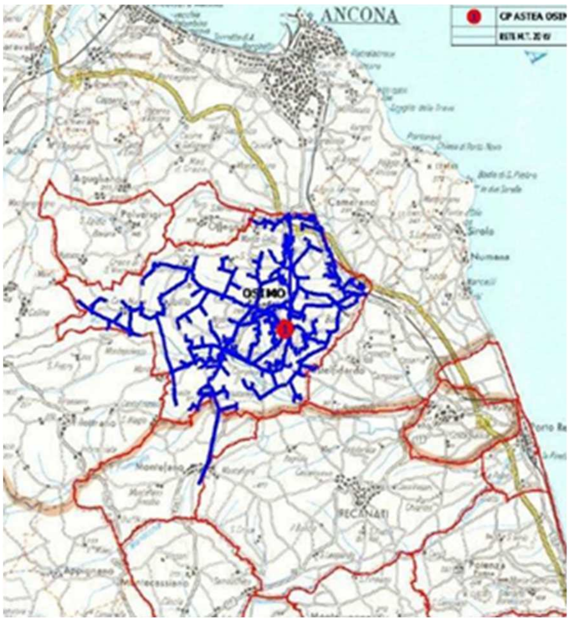

Figure 18. Location of the municipal (mini-grid). The primary cabin is highlighted in red.

Secondly, the urban mini-grid is featured by a large amount of distributed energy systems, mainly PV plants (more than 30 MWp of PV), meeting 29-32 % of the yearly electric energy demand. The yearly electricity withdrawn from the national grid by the municipal mini-grid in the year 2018 is reported in Figure 19. Figure 19 reports the 15-minutes step power flows in the primary cabin and the interface between TSO and DSO. It is worth highlighting that Figure 19 does not represent the real electricity demand of the mini-grid, but the net electricity demand/surplus. The self-consumption of the distributed generation plants should be considered to obtain the real electricity demand. However, from Figure 19 it is possible to see that electricity flow inversion happens all over the year and not only during spring/summer when a major PV production is expected. In particular, in the year 2018:

- the number of hours of flow inversion was 663 (see Table 10);

Table 10. N. of hours in 2018 during which electricity was injected into the national electric grid

Month	**N. of hours feeding the national electric grid**
January	13.75
February	10.25
March	27
April	111
May	82
June	82.5
July	59.25
August	121
September	68
October	24.25
November	13
December	51
Total	**663**

- apart from April and August, most of electricity flow inversions occur during weekend when industry demand is much lower and most of the renewable energy production (PV roofs in industries) is not self-consumed;
- the maximum peak power withdrawn was 38.9 MWe;

  the maximum peak power injected back to the national grid was 19.1 MWe. Usually, the days in which the inversion occurs have the following characteristics:
    - High production of PV panels (warm and clear sunny days)
    - Low electric energy demand (weekends or holidays when industries are closed);
- Total energy injected back was: 3.89 GWh.

A detailed analysis of electricity production consumption of the mini-grid shows that the share of renewable energy on the yearly real electricity demand of the municipal mini-grid is 26 %; when considering also the CHP plant, which is non-renewable, this share increases up to 30 %. To better understand the effect of the RES and DG plant on the pilot mini-grid, Figure 20 focus on some details that were not identifiable in Figure 19.
In particular, Figure 20 reports, per each month, the average daily profile of the electricity withdrawn from the national grid during the working days. The daily profile has the distinctive “duck curve” profile. It is worth noting that during the central hours of the day the energy demand of the pilot is very low, and between April and August there is also an over-generation with the power injected back to the grid.

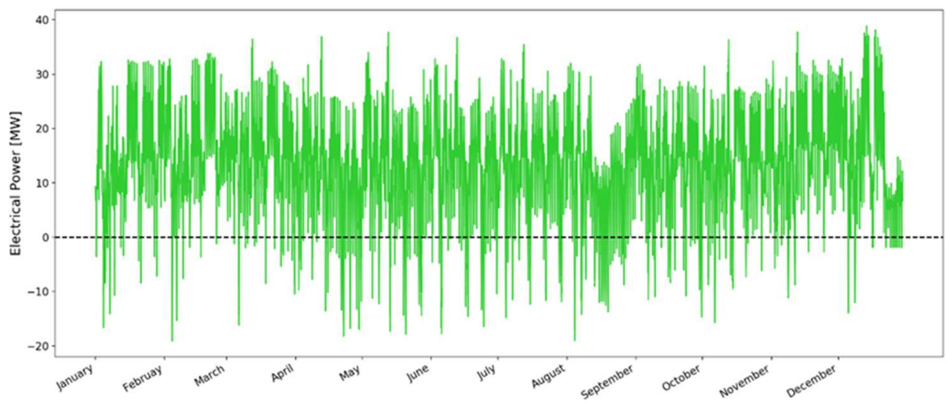

Figure 19. Yearly load profile at primary cabin (year 2018)

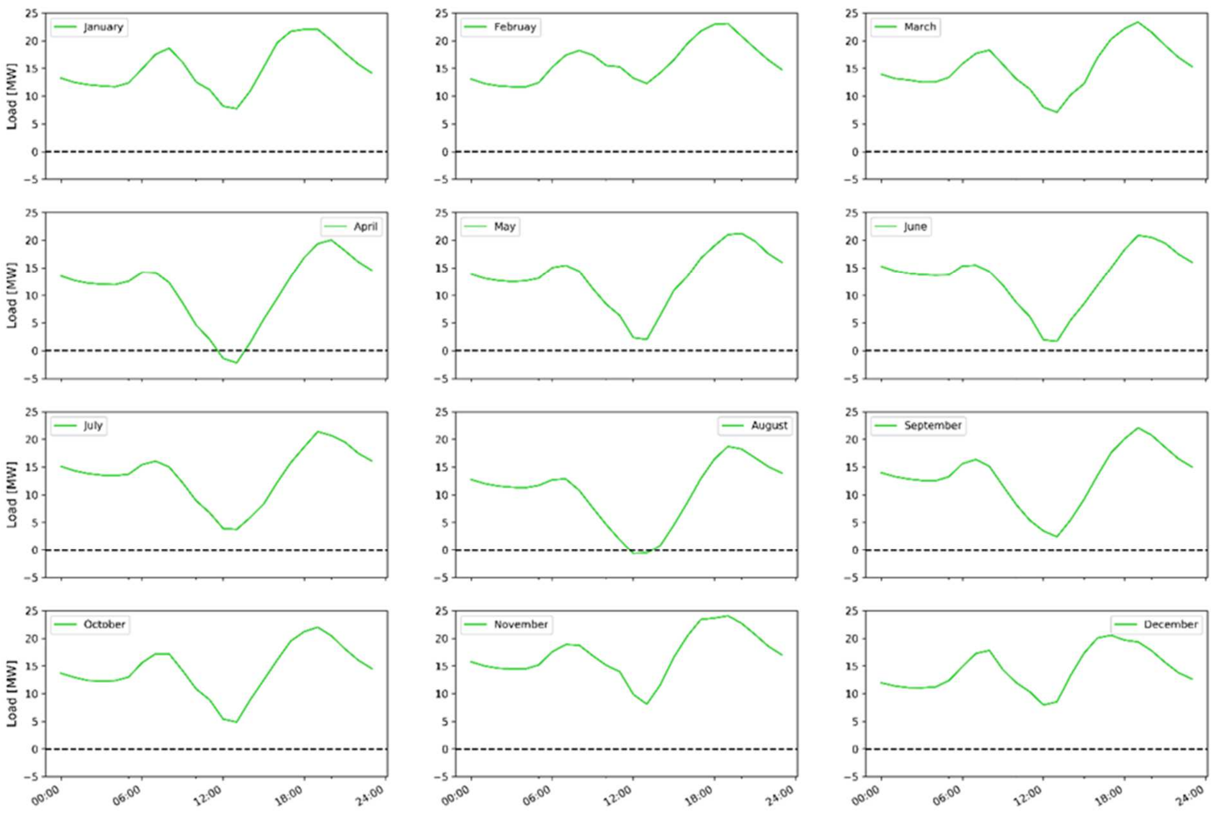

Figure 20. Average Daily profiles

According to the figures preciously showed, it is evident that Osimo demo is featured by a high share or distributed generation technologies, most of them being non-predictable and not-controllable (mainly PV plants).
This high share results in frequent flow inversion in the primary cabin connected to the municipal multi-energy mini-grid and the TSO.
At the DSO level, distributed generation resources can cause quality issues in the distribution network. The causes of the quality issues in the DSO network are mainly:

- **Network balancing.** In sparsely populated areas, mainly in the countryside, in which the electricity consumption is low with respect to PV plant production. During the periods of high photovoltaic production, grid voltage levels rise and overstep the threshold values defined by the CEI EN 50160 standard (affecting the quality of the distribution service), namely:

  $90\ \%\ V_n \leq V \leq 110\ \%\ V_n \quad ; \quad 47.5\ \text{Hz} \leq f \leq 51.5\ \text{Hz}$

- **Network configuration.** The DSO faces quality issues also in densely populated areas in which the electricity consumption is higher than Distributed Energy Resources (DER) production. In this case, the cause of quality issues is due to the configuration of distribution network, which has a radial layout instead of a meshed one, and the LV distribution networks were not designed to interconnect generating units, and thus injecting back power capacity (bi-directional flow).

In both cases, the DSO network faces issues connected to the variation of the network voltage levels. One of the main drawbacks of this situation is that the PV production is smaller since their inverters are set to automatically disconnect the PV plant from the grid if the voltage networks are outside the CEI EN 50160 standard range. This comes true during weekends and holidays when the industries are closed and, consequently, two concurring effects occur: on the one hand, the electricity demand of the mini-grid is much lower than during working days; on the other hand, the renewable production injected into the grid is much higher since most of the rooftop PV plants production is not self-consumed by industries themselves.

Chapter 5.

5. Methodology

This chapter describes the methodology used to implement the Smart Energy System Integration and the Local Energy Communities in Osimo demo site, as well as the equations used to calculate the environmental, energy and economic benefits after these operations. This chapter is structured as follows: Subsection 5.1 presents the methodology used for the implementation of the SES. In particular, Sub-subsection 5.1.1 describes the Smart Control Architecture in Osimo demo site, while Sub-subsection 5.1.2 shows the Flexibility Resources installed. Subsection 5.2 instead, describes the methodology used to select the location where create LECs can be created. Finally, Subsection 5.3 shows the methodology used for evaluating the energy, environmental, and economic aspects of the DH network (5.3.1), water network (5.3.2), and electric network (5.3.3).
Table 11 shows the schematic structure of the methodology used in this research, highlighting the procedure carried out to implement the SES and the LECs in Osimo demo site. Regarding the latter, the parameters involved in the study are analysed.

Table 11. Methodology scheme

METHODOLOGY

Subsection	Title of Subsection	Sub-subsection	Title of Subsection
5.1	Smart Energy System Integration	5.1.1	Smart Control Architecture
		5.1.2	Flexibility Resources
5.2	Local Energy Communities	-	Two streets selected
5.3	Energy, environmental and economic analysis	5.3.1	DH network
		5.3.2	Water network
		5.3.3	Electric network

5.1 Smart Energy System Integration

As mentioned in the previous chapters, one of the peculiarities of the Osimo demo-site is that the city has already the integrated energy system since the various energy vectors are managed by a single company, Astea SpA. The aim of the MUSE GRIDS project is to make Osimo a smart city through the (i) digitalization process to obtain information from the available data, and (ii) the use of technologies that increase energy flexibility combined with both optimization and Demand-Side Management (DSM) strategies.

The term DSM was coined in the early 1980s by EPRI (Electric Power Research Institute) and it is defined as "the planning, implementation and monitoring of those utility activities designed to influence customer use of electricity in ways that will produce desired changes in the utility's load shape, i.e., changes in the pattern and magnitude of a utility's load."[61]. All programs intended to influence the customer's use of energy are considered demand-side management and can be addressed to reduce customer demand at peak times, reduce energy consumption seasonally or yearly, change the timing of the end-use consumption from high-cost periods to low-cost periods and increase consumption during the off-peak periods.

Demand side management can contribute to both increase the customer's satisfaction and coincidentally produce the desired changes in the electric utilities load in magnitude and shape to match the available energy production. More specifically, DSM can introduce several benefits in the power system, such as (i) a reduced electric power generation margin commonly used to deal with peak demands; (ii) a higher operational efficiency in production, transmission, and distribution of electric power; (iii) more effective investments; (iv) lower price volatility; (v) lower electricity costs, and (vi) a more cost-effective integration of highly intermittent renewables [61].

Nowadays the term Demand Side Management is used in a broader sense and includes all the actions addressed to modify the final user's overall demand, not only the electrical one. To this broader definition, this research project wants to MUSE GRIDS.

In order to adapt the energy demand to the energy production, it is necessary to have flexible loads which somehow can adapt the energy use to the resource's availability within certain limits. The correct implementation of a DSM strategy should maintain the same final service to the end users. However, end users should be involved into the DSM programs and made aware about their purposes, thus they are willing also to change their habits, while maintaining an acceptable comfort level.

There are different kinds of flexible loads based on demand side technologies which contain various forms of storage. Those that will be implemented in the Osimo site to help to unlock the available flexibility or to increase it are (i) the Smart Control Architecture and (ii) the Flexibility Resources, which are described in detail in the followings.

5.1.1 Smart Control Architecture

This sub-subsection is focused on the Smart Control Architecture. In particular, the modules integrated in the MUSE GRIDS Cloud, will be described. Furthermore, the Optimal Control Module, that is the core of the MUSE GRIDS Cloud, will be depicted. It is based on solving an optimization problem whose objective function is a mathematical expression of the objectives listed below, and where the boundary conditions are defined by the model of the energy system and their components. As already discussed in the Introductory Chapter, the aim of this thesis is not to go into the details of the algorithms and models used for the development of the Smart Controller (object of other thesis/studies), but document with real data how the technologies implemented in this study contribute to the development of a smart city. However, for completeness of information, in this section includes enough information to understand the functionality of every module of the Smart Controller, to know the structure (understood as input/output interface and the shared information) of the algorithms and to check that the obtained results fulfil the expected objectives. The general smart control architecture is shown in Figure 21.

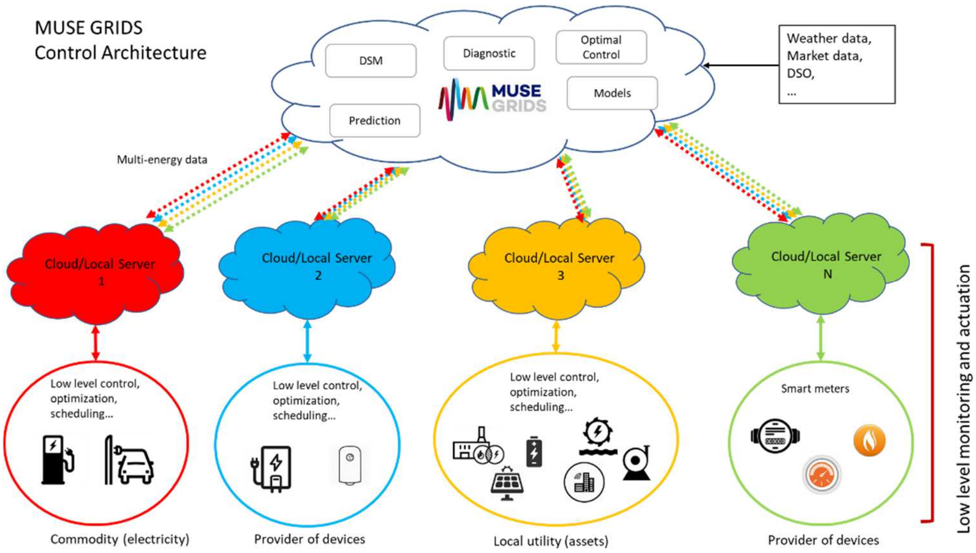

Figure 21. MUSE GRIDS control architecture

The architecture has been defined including criteria for an open, scalable, and replicable architecture that can be deployed in new and existing local energy communities. The idea beyond the proposed architecture is that nowadays providers of devices, local utility, and other actors in the energy community have their own cloud or local server where storing data for monitoring and control purposes. The output of this project is a high-level software solution installed in a cloud or local server that collects open data coming from the low level and recommend suitable energy policies that maximize or minimize objective functions. The

MUSE GRIDS software is composed of different modules to implement DSM and control assets and multi-energy vectors. The high-level software requires input data such as weather data and market data. The software modules developed during the project are prediction module, DSM module, Diagnostic module, Modelling module, Optimal Control module, Stability module, Grid codes module, and Data interface module.
The optimal control module implements a new multi-objective smart controller that is in charge of the energy dispatch to balance demand and generation, and accomplish with the grid connection codes increasing the self-consumption within power-quality and comfort boundary conditions. Moreover, it also uses weather forecasts to implement an optimal control in a prefixed horizon considering demand and generation predictions.

The main objectives of the Multi-Objective Smart Controller are:

- Maximize the primary energy saving;
- Increase the self-consumption of the local energy community;
- Increase the energy efficiency and the performance of each grid;
- Increase local energy district reliability: guarantee of supply reducing external contribution, increasing lifetime, and reducing maintenance.

To achieve all these objectives, the control strategy needs to focus in three different time horizons:

- Day-ahead horizon, based in demand and generation predictions, essential for an optimal management of storage resources and load shifting (or demand side management);
- Quarterly hour horizon, where the operation conditions of the different assets have to be set according to the day-ahead strategy and the actual demand and generation;
- Real-time horizon, which is the capacity to control some of the assets in the range of milliseconds or seconds to guarantee the stability conditions of the grid or attend emergency situations

The day-ahead horizon has been selected in a common decision with the design of the demand forecast algorithms. These algorithms offer a 24 hours' prediction at the beginning of the day according to the weather forecast and the expected demand pattern for that day. Also, 48 hours or 72 hours can be used as time horizon but day-ahead prediction has an accurate balance between prediction error and available flexibility in demand loads and storage. On the other hand, the quarterly hour horizon is determined by the measurement equipment and data acquisition architecture, being 15 minutes the update rate of most of the energy measurements. The Multi-Objective Smart Controller concept with the triple time horizon focus is shown in Figure 22.
A predictive control strategy has been applied with a day-ahead horizon which allows to plan the demand profile (e.g., shifting loads or charging/discharging batteries) according to the expected end users' needs, predicted generated power, and services/constraints required by the grid. In this sense, grid connection codes must be considered not only as real-time restrictions, but also as the energy exchange according to the day-ahead market planning.

In the second level, an optimal control strategy tries follows the production, demand or storage energy baseline calculated in the predictive control for every asset, but it also has to balance the actual demand and available generation and take into account other operating restrictions that could appear and were not predicted so far.
Some of the assets include a part of the metering instruments and communication gateways, a low-level control (or local optimal control) that is in charge of proprietary control modes of some technology providers or that will aggregate the management of a group of assets/devices.

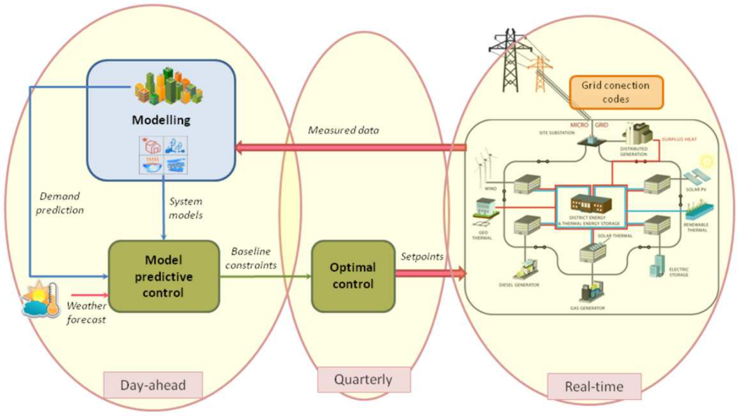

Figure 22. Multi-objective smart controller

This multilevel and multi-objective control adopts a distributed hardware and software architecture. Different software modules are in charge of the different functions required in the control, and they are deployed in spatially distributed hardware equipment according to the three levels of the control and the communication specification among modules and assets.
The software architecture of the smart controller is shown in Figure 23. The architecture has been defined including criteria for an open, scalable, and replicable control that can be deployed in new local energy communities and energy islands. Some of these modules can be deployed using different hardware or software in the different demos according to the restrictions of the already installed devices, plants or IT systems. The common architecture guarantees that all these modules will be “interoperable” and in the future different providers could include new improved versions of the modules.

The main modules of the architecture are:

1. **Data Interface module**: a digital area where data can be stored in well-defined structures and used as input/output interface for communication between controller and the rest of clouds/servers/assets in the system. Each module in the project have their own historian, but the one of importance for the controller is the historian on

the same foundation (a shared platform for different applications/modules) as the controller;

2. **Predictive and Optimal Control module**: application in charge of generate the set-points and orders for all the assets using the forecast models and grid codes modules information. These set-points fulfil the multiple objectives (functional and economic) and restrictions (characteristics of the different flexible assets) in short and long term;

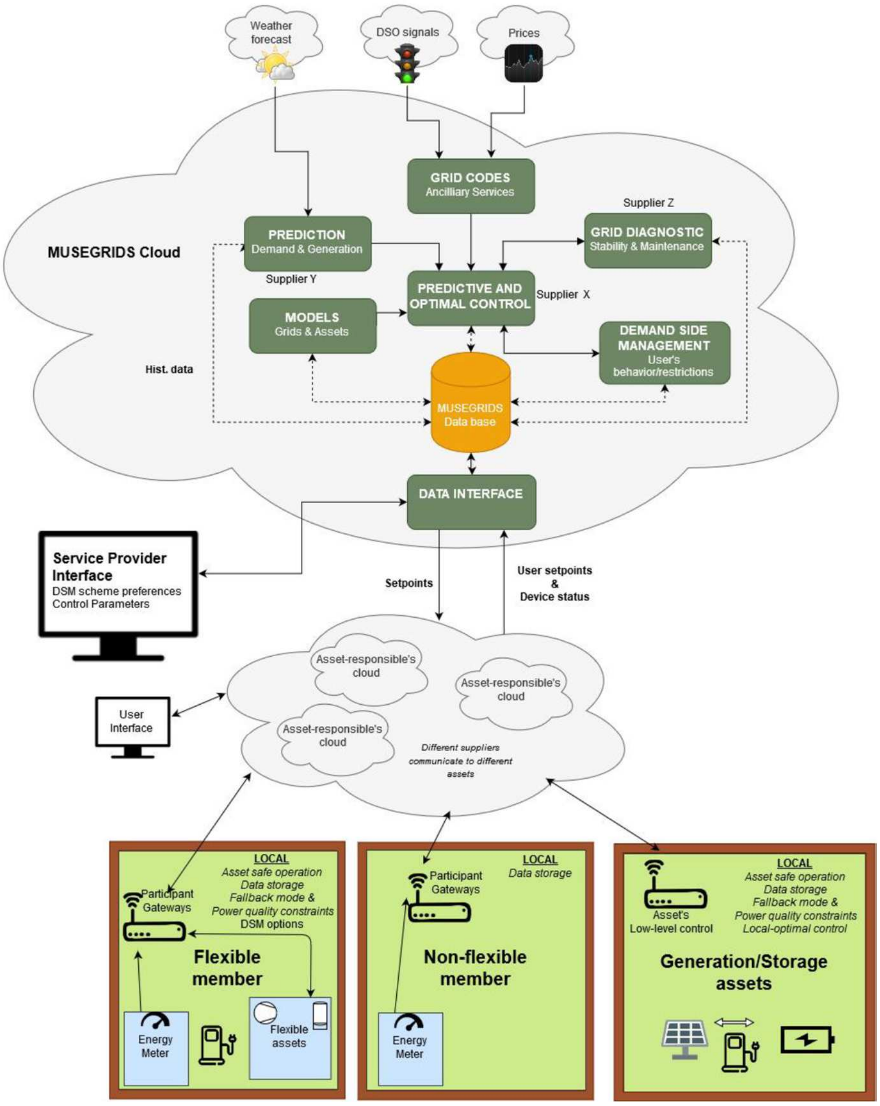

Figure 23. Software architecture

3. **Models module**: there is a twofold objective for these models:
   - generation forecast according to the weather forecast and the plant operation mode;
   - grid models for the optimization algorithm and model predictive approaches;
4. **Demand Prediction module**: is mainly based on historical consumption data and weather forecast. The expected consumption is related to the time of the day, day of the week, time of year (season), and official holidays.
5. **Grid Diagnostic module**: an application which monitor the grid and give an indication of the 'grid health' at each moment. The grid health is used to determine the power quality (stability) constraints and maintenance constraints of the optimizer;
6. **Demand Side Management module**: manage and communicate with industrial/public users whose demand can be easily shifted in time according to some restrictions and using storage/reserve systems (end user's flexibility);
7. **Grid Codes module**: definition of the grid connection codes and management of the provided services to the grid. These modes are communicated to the control module as restrictions, generation availability or energy demand to accomplish with the grid codes;
8. **User Interface**: an application where the operator can command the demo site remotely. The control mode of all the assets of the demo site can be changed and also the control of the whole plant. At Local level, a user interface is also available. All data showed in the User Interface come from the data acquisition system of the Local level.

The last important component of the MUSE GRIDS Cloud is the **MUSE GRIDS Database**. It is devoted to gather all the required information used by the Smart Controller what includes configuration data of the controller, operational parameters of the plants, weather forecast, information about the state of the plants and devices, generation and demand prediction profiles and desired set-points for the different components of the system. The multi-energy system is composed of heterogenous systems belonging to both industrial and consumer sectors, so data collected from the field are normally stored in different types of databases and in different format. Each provider/actor of the energy system will have their own historian, but the one of importance for the controller is the historian on the same foundation (a shared platform for different applications/modules) as the controller.

Besides these modules, other elements can be included in the control architecture even though they are not part of the smart control. Three of these elements are:

1. Local Gateways: hardware or software that is in charge of the communication through industrial protocols (e.g., Modbus, ProfiBus, ProfiNet, etc.) with the local devices. They are part of the data acquisition system: they send the measurements from all the devices of the plant to historian data base and the set points to the assets of the plant. They are also in charge of deploying the fall-back modes;
2. Low-Level Controls: manage the assets at local level considering the set-points received from the smart controller and the actual conditions of the plant. They can also implement advanced DSM strategies under the supervision and global set-

points of the Smart Controller. Low-level control has a key role to guarantee safety and security operation when the connection is lost between local devices and smart control;

3. Weather forecast: it is downloaded from Internet and used as input for the energy dispatch. It is sent to the Central Server to be used in the models.

Interaction among components (data flow)

As explained before, the communication among components will be done using the data base to exchange the required data. So, all the modules will read from the data base their inputs and will write into it their outputs. For a better understanding of the interaction among modules the data flow is shown in Figure 24.

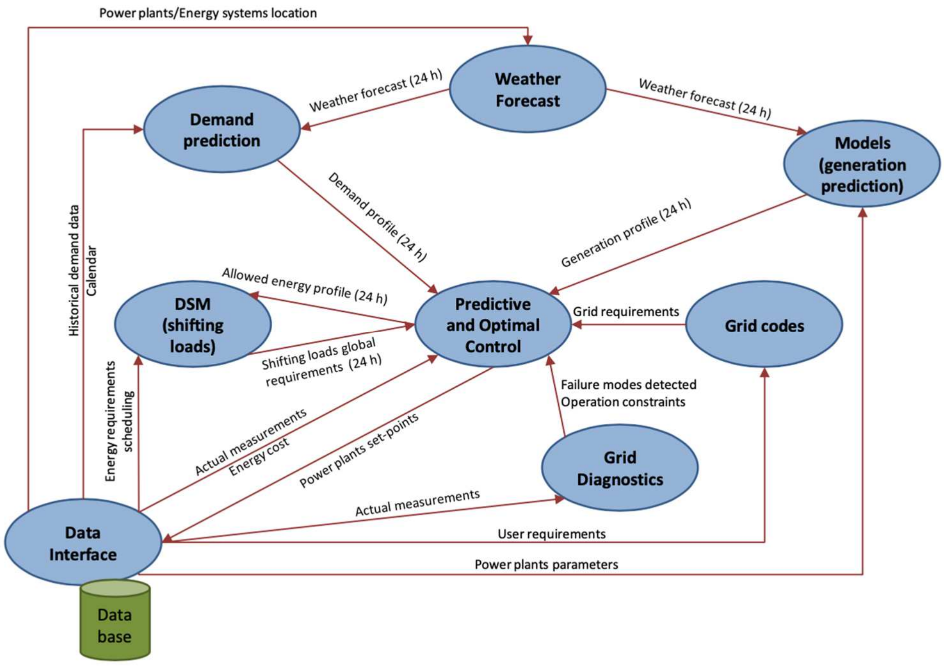

Figure 24. Data flow of the "MUSE GRIDS Cloud" modules

Table 12 includes the description of the information shared and the way of synchronizing the modules execution, while Table 13 and Table 14 shows a detailed description of the inputs and outputs of every module.

Table 12. Shared information in the "MUSE GRIDS Cloud"

	Information shared with the Predictive and Optimal Control module	Coordination procedure
Demand Prediction module	Prediction profiles for the demand loads are calculated and stored; thus, the control module can always access to the last calculated predictions. The parameterization of the algorithms is stored in the database	Scheduled with pre-programmed configuration that should guarantee availability of data prediction when control is executed. Synchronization is done using the prediction time
Models' module	Prediction profiles for the generation plants are calculated and stored; thus, the control module can always access to the last calculated predictions. The parameterization of the algorithms and plant specifications are stored in the database	Scheduled with pre-programmed configuration that should guarantee availability of prediction data when control is executed. Synchronization is done using the prediction time
DSM module	Energy requirements and scheduled profiles of allowed demand in the shifting loads.	Scheduled with pre-programmed configuration that should guarantee availability of allowed load profiles with the required frequency.
Grid codes module	Set-points and restrictions about the power flow between the multi-grid system and the main grid.	Continuous execution with triggered processes depending on the end-users' interaction and new available configuration.
Grid Diagnostic module	State of health of the plant and the equipment to be controlled. This includes the availability of the equipment and the operational limits according to the detected faults.	Continuous execution with triggered processes depending on the variables updates. Control module will access always to the last available data.

Table 13. Inputs for the "MUSE GRIDS Cloud" modules

Module	Inputs	From
Predictive and Optimal Control module	Hourly predicted demand profile of non-controlled load (24 hour)	Demand Prediction module
	Predicted generation profile of generation plants (24 hour)	Modelling module
	Required energy schedule for shifting loads.	Data interface module
	Measured data: -Actual active power per each electric generation asset/load -Actual reactive power per each electric generation asset/load -Actual energy flow per each thermal generation asset/load -Actual state variables per each generation asset and load	Data interface module
	Energy constraints in the grid connection in the next 24 hour	Grid Codes module
	Failure modes detected Operation constraints of the assets: enable/disable and operation limits.	Diagnostic module
	Energy cost per each generation plant / asset.	Data interface module
Weather forecast module	Location of the energy systems and power plants	Data interface module
Demand Prediction module	Historical data: one-year data of load demand/weather measurements (for training/tuning purposes)	Data interface module
	Configuration for the prediction models: parameters and calendar	Data base
	Weather forecast data for next 48 hr: temperature, irradiation, and wind speed	Weather forecast module
Models' module	Models' configuration: parameters of the plants	Data base
	Weather forecast data for next 48 hr: temperature, irradiation, and wind speed	Weather forecast module
DSM module	Required energy schedule for shifting loads.	Data interface module
	Day-ahead allowed energy consumption profile (quarterly / hourly)	Optimal control module
Grid codes module	Configuration parameters for the grid codes: end-user's requirements	Data base
Grid Diagnostic module	State of the assets: alarms, logical state, and operational variables. State of the grid: power flows and voltage-frequency measurements	Data interface module

Table 14. Outputs for the "MUSE GRIDS Cloud" modules

Module	Outputs	To
Predictive and Optimal Control module	Set-points: -Enabling /disabling equipment/device -Active power reference for every generation or storage asset	Data interface module
	Day-ahead allowed to have an energy consumption profile with a quarterly/hourly period for shifting loads	DSM module
Demand Prediction module	Predicted load hourly profile in the next 24 hours.	Optimal control module
Models' module	Predictions for next 24 hr: Predicted generation profile of generation plants.	Optimal control module
DSM module	Set-points of allowed demand: current or scheduled time-series	Data interface module
Grid codes module	Set-points and restriction for active and reactive power at Point of Common Coupling (PCC)	Optimal control module
Diagnostic module	Failure modes detected. Operation constraints of the assets: enable/disable and operation limits.	Optimal control module

Optimization problem

The core of the Smart Controller is the Predictive and Optimal Control module that executes the algorithm that defines the desired operation of the multi-energy system in the next 24 hours. The algorithm solves an optimization problem that translates the global objectives of the MUSE GRIDS project – specifically the ones of the Smart Controller – and the configuration of the energy system to a mathematical language. This section describes how the optimization problem is built and solved to calculate the best operation conditions in the system. A generic optimization problem is defined mathematically as:

$$\begin{aligned} &\underset{x}{\text{minimize}} f(x) \\ &\text{subject to } g_i(x) \leq 0 \; i = 1, \ldots, m \\ &\qquad\qquad h_j(x) = 0 \; j = 1, \ldots, p \end{aligned}$$

where: f: $\mathbb{R}^n \to \mathbb{R}$ is the objective function to be minimized over the n-variable vector x, $g_i(x) \leq 0$ are called inequality constraints, $h_j(x) = 0$ are called equality constraints, and $m \geq 0$ and $p \geq 0$.

Mathematical optimization is a vast field of study where different types of optimization can be found (e.g. Linear programming, integer programming, quadratic programming...) and the methods for solving the problems are usually of a high complexity from a theoretical point of view and also for the required computational resources.

As the Smart Controller needs to work in a real-time basis, understanding this as the ability to make optimal decisions every 15 minutes, one of the objectives when building the optimization problem will be to try to guarantee its simplicity. The optimization problem has been defined for the MUSE GRIDS Smart Controller using a generic approach that allows that it can be used in any demo sites with minor changes or modifications.

The two main parts to define the optimization problem are:

- The objective function: that in the MUSE GRIDS case and according to the global objectives of the Smart Controller should represent the objectives of maximize the primary energy saving, reduce LCOE (Levelized Cost of Energy) and increase the self-consumption of the local energy community.
- The constraints and boundary conditions: that in the MUSE GRIDS case are related to the model of the system and operation conditions of the devices that should guarantee the rest of the Smart Controller objectives, being these to increase energy efficiency and performance of each grid and increase local energy district reliability.

For the definition of the objective function three complementary options have been programmed and validated:

- Minimization of the LCOE: based on the price of the energy production in the different assets (including operation and maintenance costs), the price of the energy sold or bought from the grid, the benefits of selling energy to the demand loads and other operation costs. The optimization problem minimizes the operation cost in the 24-hour time horizon according to the terms included in this objective function.
- Maximization of the self-consumption: based on the energy exchange with the main grid in the PCC can be configured to focus on the global balance in the 24-hour time horizon or in minimizing the amount of energy consumed from the grid in that 24 hours.
- Following of a grid power balance set-point: based on the minimization of the following error and programmed to fulfil the grid codes requirements. Depending on the operation mode of the control, these grid codes has been defined in the boundary conditions of the problem.

A combination of these three objectives can also be achieved building a new objective function and setting different weights for every term of the function. For the validation of the control algorithm this is not a useful approach because it is not easy to understand the decisions of the optimization problem and that is why it has not been programmed.

In relation to the modelling of the energy system in the constraints function the optimization problem includes the next systems:

- Electricity main grid: that exchange power with the rest of system both providing and consuming with the only limitation of the maximum power flow allowed by the owner/operator of the main grid.
- Fully controllable energy source: power generation plant whose output can be controlled from zero to its nominal power. A second restriction is applied to the maximum power available to simulate renewable energy sources where the power is limited to the renewable resource such as wind or irradiance. This maximum available power is provided to the problem as a profile for the next 24 hours. It has been used to simulate PV panels.
- Region controllable energy source: power generation plant whose output can only be controlled in some segments of the whole range between zero and the nominal

power. Restrictions are applied to the minimum and maximum power allowed that are provided to the problem as profiles for the next 24 hours. In relation to the definition of the problem this implies the use of integer variables what make more complex to find the optimal solution. An example is the CHP plant of Osimo that it can be connected only at its nominal power, not allowing a control of its output.

- Electric storage system: that is able to generate or demand electrical power according to its state of charge. The state of charge increases according to the energy supplied to the system and decrease proportionally to the energy supplied from the system to the grid. It is used to simulate the batteries present in the electrical network.
- Shifting demand loads: whose energy demand can be provided with any profile that guarantee that the total required energy is satisfied before a prefixed time limit.
- Non-controllable demand load: this demand simulates the users demand and any other loads that can be randomly connected or disconnected. The demand profile has been predicted and provided to the optimization problem as a demand power that has to be guaranteed.

The systems are modelled with mathematical equations and restrictions, including the energy balance among all the generation sources and demand loads and a linear ordinary differential equation governing the evolution of the electric storage system.
The non-controllable load profile is considered as a fixed value in the problem, and the grid power is a free variable whose value is determined by the power balance of demand and generation. The power plants (fully controllable and region controllable), the electric storage and the sifting load are all controllable and their active power are the variables to be optimized by the problem. The solution of the optimization problem is the combination of the active power profiles of the defined loads and power plants that minimize the objective function of cost (or maximize the self-consumption).
In this case the problem has been defined using the collocation points approach, which transforms the differential equations into linear restrictions [62; 63]. This is done by dividing the total time interval to be controlled into subintervals and approximating the functions involved in the optimization problem by piecewise polynomials of a fixed degree. These polynomials satisfy the differential equation at the subinterval boundaries (called "control points") as well as at auxiliary points inside each subinterval (called "collocation points"). Then, the optimal solution is obtained solving the transformed problem, whose mathematical form is a Mixed Integer Non-Linear Problem (MINLP).
Many different formulations of the optimization problem with the same optimal solution have been considered, with huge differences in the computational cost and robustness of the optimization process between them. (i) When using integer values in the decision of buying or selling power to the electricity main grid in the objective function, the resultant optimization problem is extremely slow, and therefore it is not appropriate to work in a real-time basis. (ii) Then, the problem was modified removing the integer variable and using continuous variables representing separately the power to be bought and sold to the electricity main grid. Even though the solving time of the problem decreases dramatically, the required restrictions in this formulation provokes that the optimization solver sometimes is not able to find the optimal solution (depending on the parameters of the problem). (iii) This drawback was solved by dropping the non-convex restrictions that have to be imposed to these two

continuous variables related to the main grid. In this way, the optimization problem is able to explore solutions that are mathematically feasible even though are not practically feasible (e.g. supply and demand power from the grid at the same time). This helps the optimization algorithm to find a path to the solution that will be always feasible in the real plant thanks to how the objective function and other restrictions are defined (the non-feasible solutions are explored but cannot be an optimal solution). To improve the robustness of the problem the objective function has been also transformed into a convex one using some auxiliary variables. This makes the definition of the problem more difficult to understand and maintain as the variables related with physical variables are replaced with the auxiliary ones. In change it prevents that the algorithm could not find the optimal solution.
The optimization problem is solved using the CasADi open-source tool for nonlinear optimization [63]. This tool provides full-featured interfaces to Python and Matlab that can be used to model and solve optimization problems including ordinary differential equations in the restrictions. Table 15 shows the execution times of the CasADi solvers to find the optimal solutions in the most representative formulations used for the problem. The results have been obtained for a simulated set of demand profiles and weather conditions with a 24-hour time horizon and a time step for the subintervals of the algorithm of 2-hour, 1 hour, 30 minutes and 15 minutes.

Table 15. Execution time[1] of the optimization problem solver

	Control Time Step			
	2-hour	1 hour	30 minutes	15 minutes
Integer value to identify positive and negative grid power	19,565.00 s (5 h 26 min)	600.00[2] s	600.00[2] s	600.00[2] s
Two different variables for positive and negative grid power	2.79 s	11.51 s	40.84 s	499.90 s
Convex restrictions for grid variables	4.08 s	14.19 s	23.97 s	87.50 s
Convex objective function including shifting demand in the problem	3.22 s	9.59 s	13.26 s	61.34 s
Convex objective function including shifting demand. Power grid set-point objective.	2.13 s	9.71 s	11.44 s	56.10 s

[1] The solver was executed in a Intel Core i7-8850H 2.59 GHz processor with 16 GB of RAM.
[2] The solver cannot reach the optimal solution in a reasonable time limit, so it is limited to 10 minutes for the analysis of the obtained results.

Apart of the powerful solving algorithms and the easiness to represent the problem, CasADi has been chosen because it can be used in a cross-platform approach. First the capacity of generate C allow that the function for solving the problem can be easily compiled to be used in different platforms. Also, it allows defining and programming the problem in one platform (e.g. Matlab), generating a file that contains the problem definition and use this file in another different programming language (e.g. Python) to be solved.

In MUSE GRIDS the definition of the problem has been programmed using Matlab while the real-time execution is done using a Python program that calls and solves the defined problem (Figure 25). The use of Matlab allows an easy validation in simulation, as CasADi allows compiling a mex file can be integrated in the already existing Simulink models. On the other hand, for the deployment in the MUSE GRIDS Cloud a Python program is compiled and executed in the server without the need of external run-times (as it would be the case of Matlab).

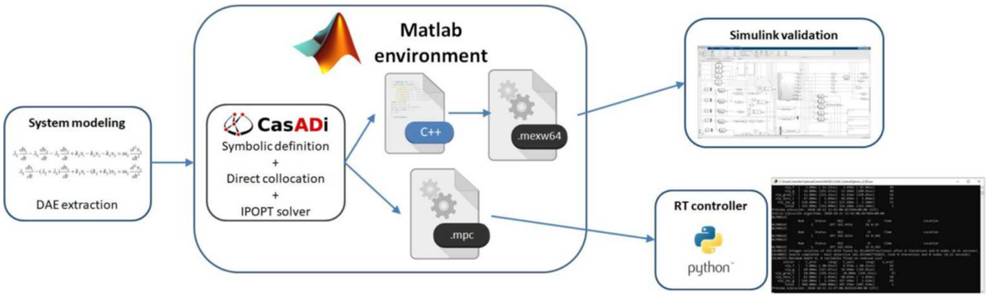

Figure 25. Optimization problem definition and deployment

5.1.2 Flexibility Resources

In this Sus-subsection, the new installations that provide flexibility to the network, such as the thermal energy storage, the electric energy storages, and the remote reading infrastructure are described.

Heat Pump & Thermal Energy Storage

The main actions to increase the flexibility of the CHP-DH plant consist of the installation of a heat pump and thermal energy storage (Figure 26). The former is installed to allow the waste heat recovery from the low-temperature ICE cooling system, and then used to integrate the thermal energy production for the DH network. The other one is used to increase the energy efficiency of the gas engine, avoiding continuous switching on/off cycles even when the load is reduced as in summer or in middle season so that this prime mover can be used instead of conventional boilers for more hours.

In particular, the HP has a rated thermal capacity of about 140 kW and an average COP of about 4. The HP has been designed considering the amount of thermal energy exiting the CHP unit (exhausts), which remains almost constant over time and it is equal to about 130 kW.

Based on the current layout constraints of the existing thermal plant, a TES has been also designed: 12.6 m long, which represents the maximum height within the plant, with a diameter of 3.35 m, which is the best compromise between having a height-to-diameter ratio as high as possible and not have small dimensions that would lead to turbulent water flows within the TES. Indeed, the TES has the aim to obtain a proper water stratification (mixing between hot and cold water), and this can be achieved by, rather than optimally sizing the TES, inserting iron plates with decentralized holes that further slowdown the mixing process

to have the flow as much laminar as possible. The TES improves the performance of the CHP and also enables further introduction of renewable resources. The thermal volume stored can increase the operational hours during the year for the CHP unit (especially during spring and autumn seasons, when the thermal load of the grid decreases) and reduce its load modulation. The TES can be used in parallel to the CHP unit during peak demand hours. Integrated sensors on the tank can give feedback to the control system.
The TES is used as an energy reservoir which provides flexibility to the CHP-DH operation. It allows different control strategies of the CHP unit to accomplish the DSM objectives. Given the high volume involved, the TES does not perform a fast response; thus, its scheduling must be preferably determined in advance with predictive algorithms if specific objectives want to be accomplished within a given time.

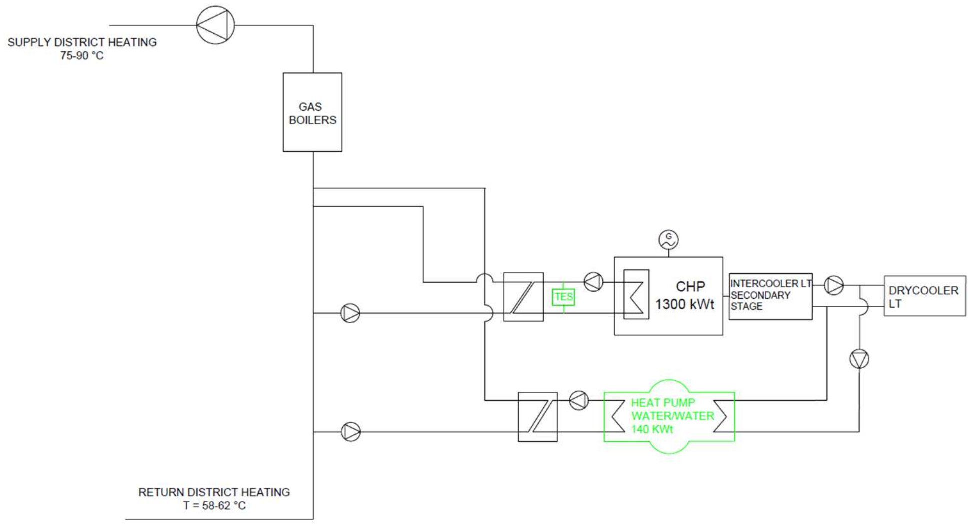

Figure 26. New configuration of the CHP plant: the TES and HP are highlighted in green.

5.1.3 Electric Energy Storages

To increase the share of renewable energy, an electric energy storage with a capacity of 30 kWh has been installed in Campocavallo pumping station to store the surplus PV production. Given the maximum power injected into the grid, such storage provides several hours of storage capacity. This installation wants to be used to demonstrate the use of energy storage systems (namely electric storage) to maximise the renewable energy sources (RES) exploitation (i.e. PV electricity production) through load shifting.
The necessary storage characteristics have been evaluated as follow:

1. Inverter with a power of 6.4 kW + n. 3 storages (6 kWh each one) with a total capacity of 18 kWh;

2. Installation flexibility, suitable to be connected on both DC and AC sides with a single construction solution;
3. Possibility to be used as EPS (Emergency Power Supply) in case of blackout;
4. Compact all-in-one solution with a single management interface;
5. API-based communication protocol that allows easy bi-directional interfacing with external systems.

To improve the quality of the network, especially in terms of the voltage values on the suburban branches selected on the bases of the requirements described in the Section 5.2, two EESs have been installed. These EESs consist of a power rack. The batteries are Pylontech M1 series, whose specifications are shown in the Figure 27. The capacity of each rack is 100 kWh nominal (>80 kWh usable) with a C-rate of 1C (therefore 100 kW of power).

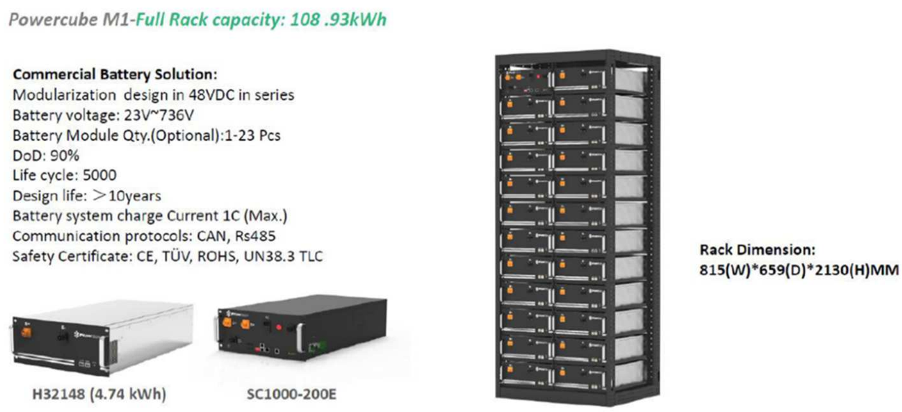

Figure 27. Technical specifications of rack batteries

5.2 Local Energy Communities

A monitoring campaign has been carried out on distribution network transformers. The campaign was held during a weekend in March 2019. This period was chosen for the following reasons:

- March is a period of the year in which the PV plant production is not at its maximum; hence, if quality issues occur in that period, it is even more likely that they will occur in the summer months;
- Usually, during the weekend, the electricity demand of residential areas is higher and can offset the RES production of plants installed in the same LV distribution line. Thus, if quality issues occur in the distribution network serving residential areas during weekends when electricity demand is higher, it is even more likely to occur during working days.

The monitoring campaign was carried out from 29/03/2019 to 31/03/2019 for all the MV/LV cabins (transformers) of the municipal microgrid. The analysis highlighted all the PODs (Points of Delivery) with a voltage higher than 250 V.
Data were also filtered on the basis of three ranges of voltage. Results showed that in three days the total number of times for which the LV went beyond the nominal threshold of 250 V were 1058, as shown in Table 16.

Table 16. Results of the Network Voltage analysis

Voltage range	Occurrences	Comments
Vmin ≤ 210; 250 ≤ Vmax ≤ 255	835	still within the range of CEI EN 50160
Vmin ≤ 205; 255 ≤ Vmax ≤ 260	182	out of the range of CEI EN 50160
Vmin ≤ 200; Vmax ≥ 260	41	this is the range for PV inverter automatic disconnection from the grid

This campaign showed that, in three days, quality issues on the LV lines occurred 223 times; in 41 times, the threshold for the automatic disconnection of the inverters from the grid has been exceeded. Another result of this campaign was to identify the LV lines suitable for installing the two EESs. Two installation sites were selected: one in Monsignor Domenico Brizi Street, and the other one in Edgardo Sogno Street.

5.3 Energy, environmental and economic analysis

This Subsection shows the calculation methods of each energy vector involved in the research project. In particular, Subsections 5.3.1, 5.3.2, and 5.3.3 describe the methodology used to calculate the energy, environmental, and economic benefits of the district heating, water and electricity networks, respectively.

5.3.1 District Heating network

The methodology used for evaluating energy, environmental, and economic aspects of the analysed DH network is here presented.
Table 17 shows the methodology used and presented in this study, highlighting the correlation between the energy and environmental analyses in the thermal power plant with the one in the end-users' side.

Table 17. Methodology used in both thermal power plant and end-users' side

	METHODOLOGY	
Thermal power plant		**End-users**
PES; $E_{sp,tot}$	**Energy analysis**	Not directly studied, but strictly connected to the results obtained in the thermal power plant side
Avoided CO_2	**Environmental analysis**	Not directly studied, but strictly connected to the results obtained in the thermal power plant side
EECs	**Economic analysis**	SAVE

Energy and environmental analysis

The energy analysis has been carried out by analysing two parameters, namely the Primary Energy Saving (PES) and the specific energy (E_{sp}), while the environmental one takes into account the avoided CO_2.
Considering the European countries, the PES formula and its correction factors have been determined by the EU regulation [64]. The PES expresses the saving of the primary energy achievable by a CHP unit compared to the separate production of both thermal energy and electricity. It is calculated as indicated by Eq. (1):

$$PES = \left(1 - \frac{1}{\left(\frac{\eta e,CHP}{\eta e,ref} + \frac{\eta th,CHP}{\eta th,ref}\right)}\right) * 100\ [\%] \qquad (1)$$

where:

- $\eta_{e,CHP}$ is the electrical efficiency of the CHP unit, defined as the ratio between the yearly electricity produced by the cogeneration unit and the energy of the entire fuel supply used to produce both useful heat and electricity by the CHP unit;
- $\eta_{e,ref}$ is equal to 49.81 % [64] and it is the reference efficiency value for the separate electricity production;
- $\eta_{th,CHP}$ is the thermal efficiency of the CHP unit, defined as the ratio between the yearly useful heat produced by the cogeneration unit and the energy of the entire fuel supply used to produce both useful heat and electricity by the CHP unit;
- $\eta_{th,ref}$ is equal to 92 % [64] and it is the reference efficiency value for the separate heat production.

The PES calculation allows to determine whether a CHP unit is highly efficient or not: this qualification can be obtained from plants smaller than 1 MWel if they do not consume more primary energy than the most efficient thermal power plants that produce the same amounts of heat and electricity separately. Similarly, the qualification of high-efficiency cogeneration can be obtained if they guarantee a primary energy saving higher or equal than 10 % [64] for plants having a power capacity higher than or equal to 1 MWel.
Another parameter that is worth to be investigated is the specific energy, which expresses the highest potential energy exploitation from a cubic meter of fuel such as NG in this case. Considering the overall thermal power plant, the specific energy is calculated through Eq. (2):

$$E_{sp,tot} = TE_{sp,CHP} + TE_{sp,boil} + EE_{sp,CHP}\ [\mathrm{kWh/Sm^3}] \quad (2)$$

where $TE_{sp,CHP}$ and $TE_{sp,boil}$ are the specific thermal energy of the CHP unit and boilers, respectively, while $EE_{sp,CHP}$ is the specific electric energy of the CHP unit. Eqs. (3), (4), and (5) show how to evaluate $TE_{sp,CHP}$, $TE_{sp,boil}$ and $EE_{sp,CHP}$ respectively.

$$TE_{sp,CHP} = \frac{\text{Net thermal energy produced by the CHP unit (losses included)}}{\text{fuel consumed by the CHP unit}}\ [\mathrm{kWh/Sm^3}] \quad (3)$$

$$TE_{sp,boil} = \frac{\text{Net thermal energy produced by the boilers (losses included)}}{\text{fuel consumed by the boilers}}\ [\mathrm{kWh/Sm^3}] \quad (4)$$

$$EE_{sp,CHP} = \frac{\text{Net electric energy produced by the CHP unit (losses included)}}{\text{fuel consumed by the CHP unit}}\ [\mathrm{kWh/Sm^3}] \quad (5)$$

Once the total specific energy of the thermal power plant ($E_{sp,tot}$) is calculated, including both thermal and electrical ones, the difference (ΔE_{sp}) of the specific energy is evaluated. This latter is obtained through the thermal plant ($E_{sp,tot}$) and the residential/industrial boilers (Low Heating Value, LHV_{CH4}), which is equal to 9.339 kWh/Sm^3 in the case of NG at standard condition (T = 25 °C, P = 1 bar), in according to Eq. (6), that considering the reference thermal efficiency [64]. The overall energy saving ($Es_{th,el}$), both thermal and electrical included, has been calculated per each month of the year 2019 in which $\Delta E_{sp} > 0$ according to Eq. (7), namely by multiplying ΔE_{sp} with the cubic meters of NG that would have been consumed by residential/industrial boilers. The latter has been calculated by dividing the thermal energy effectively consumed to the LHV_{CH4}, thus ignoring the boilers' thermal efficiency that has been already considered in the ΔE_{sp} calculation (see Eq. (6)). Finally, the tonnes of avoided CO_2 are calculated through Eq. (8):

$$\Delta E_{sp} = E_{sp,tot} - (LHV_{CH4} * \eta_{th,ref}) \text{ [kWh/Sm}^3\text{]} \quad (6)$$

$$Es_{th,el} = \Delta E_{sp} * (\text{Sm}^3 \text{ of NG consumed by residential/industrial boilers) [kWh]} \quad (7)$$

$$\text{Avoided } CO_2 = \frac{Esth,el * FcCO2}{1{,}000} \text{ [tCO}_2\text{]} \quad (8)$$

where:

- Fc_{CO2} is the conversion factor, which is used to evaluate the avoided CO_2 by knowing the energy that would have produced that amount of CO_2, equal to 0.1936 $kgCO_2/kWh$ [65].

Economic analysis – Thermal power plant side

After both energy and environmental analyses, the economic one must be performed to assess the advantages of using a DH network from both thermal power plant and end-users' perspective.

In Italy, the economic advantages due to the use of high-efficiency cogeneration plants are assessed through the so-called Energy Efficiency Certificates (EEC) that remunerate energy producers that have performed energy efficiency interventions on a system, thus achieving primary energy saving over time.

The PES, which has been previously defined, indicates whether the high-efficiency cogeneration requirements have been fulfilled or not according to the size of the thermal power plant, and it is a quantifier of the Italian EEC to be provided to an energy producer as described by Eq. (9) [66]:

$$EEC = (RISP * 0.086) * K \text{ [-]} \quad (9)$$

where:

- (RISP * 0,086) is the saving, if positive, expressed in Tonnes of Oil Equivalent (TOE) and calculated according to Eq. (10):

$$RISP = \frac{ECHP}{\eta e,ref} + \frac{HCHP}{\eta th,ref} - F_{CHP} \text{ [kWh]} \quad (10)$$

where:

- RISP is the primary energy savings, expressed in kWh, achieved by the CHP unit in the solar year in which access to the support scheme is requested;
- E_{CHP} is the electricity produced by the CHP unit in the same solar year expressed in MWh;
- H_{CHP} is the thermal energy produced by the CHP unit in the same solar year expressed in MWh;

- F_{CHP} is the energy consumed by the CHP unit in the same solar year expressed in MWh;
- $\eta_{e,ref}$ is the reference electric efficiency, which is equal to 0.53, and it must be adjusted according to the connection voltage, the amount of both consumed and supplied energies to the grid as well as the climatic zone;
- $\eta_{th,ref}$ is the reference thermal efficiency equal to 0.90;
- K is a harmonized coefficient, equal to 1.386, and calculated as shown in [66].

The values previously reported for the case under investigation are listed in Table 18: it is worth noting that these values change whether considering the EU legislation [65] or the Italian one [67].

Table 18. Different correction factors values and electric and thermal reference efficiencies

Parameters	**EEC calculation (IT legislation [67])**	**PES calculation (EU legislation [65])**
$\eta_{e,ref}$ (a) [-]	0.46	0.53
Correction factor 1: climatic zone (b) [-]	0.00369	0.00369
Correction factor 2: off-site (c) [-]	0.945[1]	0.935[2]
Correction factor 3: on-site (d) [-]	0.925[1]	0.914[2]
$\eta_{e,tot} = (a + b)*(c * EE_{del}^3 + d * EE_{self\text{-}cons}^3)$ [-]	0.4374	0.4981
$\eta_{th,ref}$ [-]	0.90	0.92

[1] These values are related to a connection voltage level between 0.4 and 50 kV.
[2] These values are related to a connection voltage level between 12 and 50 kV.
[3] These values for the case study under investigation are 92 % and 8 %, respectively.

Economic analysis – End-users' side

To make the DH network economically competitive, the management of the DH network under investigation brought the cost of the connection closer to that of a 25-kW condensing boiler. In particular, the cost of a 25-kW condensing boiler varies from 2,000 to 2,500 €: that said, the cost of the connection to the DH network is about 1,800 €. From the end-users' point of view, the economic analysis is carried out by multiplying the effective thermal energy consumed by the end-users (residential/industrial) using the DH network [68] and gas [69] tariffs considering the consumption ranges; thus, the overall yearly costs in 2018 for both DH (DH_{tot}) and Individual Heating (IH_{tot}) have been obtained. In addition, an average cost for maintenance, repairing, mandatory periodic boiler controls, cleaning, and check of the flue gases are added to the individual yearly heating cost, as well as the cost of the electricity used to the boiler switch-on and functioning ($IH_{tot+extra\ costs}$). It is worth noting that all these extra costs have been made available by the company that manages the DH network of this case study, quantified as 170 €/year. For the sense of clarity, Table 19 lists in detail the cost items previously mentioned.

Table 19. List of yearly average costs for a residential/industrial boiler

Parameters	Values
Average cost of maintenance, periodic boiler control, cleaning, and check of the flue gases [€/year]	100
Average cost for repairing [€/year]	50
Average cost of electricity to switch-on the boiler [€/year]	20
Total [€/year]	170

Once the overall yearly costs per end-user, whether connected to the DH or to individual boilers, have been calculated, the present economic analysis related to the end-users' side considers only the residential one. This choice allows to work with reliable and quantifiable data, which can be reproduced on a large scale, and to not fail in the quantification of extra costs that non-residential users would have incurred by using boilers. Furthermore, in this analysis it has been also assumed extra costs for non-residential IH are higher than residential ones: the higher the power of the installed boilers, the higher the operating, maintenance, and spare parts costs.

Hence, residential users have been divided into four groups according to the thermal consumption: (i) yearly energy consumption less than or equal to 5,000 kWh/y (Group 1), (ii) yearly energy consumption between 5,001 and 10,000 kWh/y (Group 2), (iii) yearly consumption between 10,001 and 15,000 kWh (Group 3), and (iv) yearly energy consumption greater than 15,001 kWh/y (Group 4). Then, the difference between the overall yearly costs of the end-users connected to the DH and those who have the IH has been calculated by Eq. 11, thus obtaining the cost difference between the first technology and the second one:

$$\Delta\text{Cost} = DH_{tot} - IH_{tot+extra\ costs}\ [€/\text{year}] \tag{11}$$

Finally, by dividing the cost difference obtained with Eq. (11) with the overall yearly cost for each residential user connected to the DH, Eq. (12) evaluates the percentage of the previous difference to assess the saving (SAVE): negative SAVE values ($SAVE_{<0}$) imply that IH is cheaper than DH; conversely, positive SAVE values ($SAVE_{>0}$) imply that the DH is cheaper than IH.

In the latter case, the percentages of SAVE have been divided in three categories: (i) residential users with a SAVE lower or equal than 10 % ($SAVE_{10}$), (ii) between 10 % and 50 % ($SAVE_{10,50}$), and (iii) greater than 50 % ($SAVE_{50}$). Certainly, SAVE values equal to zero imply that there is no economic difference whether the DH or the IH is used.

$$\text{SAVE} = \frac{\Delta\text{Cost}}{\text{DHtot}} * 100\ [\%] \tag{12}$$

5.3.2 Water Network

As explained in Chapter 4, it is necessary to consider both the WDN of the historical centre of Osimo town under investigation and the Padiglione PS, which serves that water district, to evaluate the energy, environmental and economic benefits of water network. In particular, for the energy analysis is considered the avoided water losses thanks to the monitoring of the MNF of the 5 water sub-districts; for the energy analysis, instead, the electric energy saving of the pumps (Padiglione PS) is considered. Finally, the economic saving has been considered for the economic analysis.

Environmental analysis

The evaluation of the overall avoided water losses $V_{losses\ avoided}$ [m^3] is weekly performed through Eq. (13) by setting as the baseline value of $Q_{s,min,before\ maintenance}$ the one achieved at the end of August 2020, already presented in Chapter 4, Subsection 4.2.

$$V_{i,losses\ avoided} = |Q_{s,min,before\ maintenance} - Q_{s,min,after\ maintenance}| * t\ [m^3] \quad (13)$$

Where $Q_{s,min,before\ maintenance}$ [m^3/h] and $Q_{s,min,after\ maintenance}$ [m^3/h] stand for the MNFs before and after the maintenance of the area of the water district, respectively, while t [h] is the operational time of the water supply in that area.

Energy and Economic analysis

The energy and economic analysis have been carried out by analysing the electric energy saving (Ee_{saving}) and economic saving (EC_{saving}), respectively. Eqs. (14) and (15) show the methodology used to evaluate these two parameters, while Table 20 displays the values of each parameter involved in the compute.

$$Ee_{saving} = V_{losses\ avoided} * [e_1 * (\frac{Wf}{Wtot}) + e_2 + e_3]\ [kWh] \quad (14)$$

$$EC_{saving} = Ee_{saving} * C_e + V_{losses\ avoided} * (\frac{Wcast}{Wtot}) * C_w\ [€] \quad (15)$$

Table 20. Definition and value of each parameter used in Eqs. (14) and (15)

YEAR 2021

Unit electric consumption of Pump From field wells to Padiglione Pumping station [kWh/m^3]	Unit electric consumption of Pump from Padiglione to Underground Tank [kWh/m^3]	Unit electric consumption of Pump from Underground Tank to Hanging Tank [kWh/m^3]	Unit cost of water coming from Castreccioni Dam [$€/m^3$]
0,15	0,98	0,189	0,28
e_1	**e_2**	**e_3**	**C_w**
Unit cost of electric energy [$€/kW_e$]	Water to Osimo District from Castreccioni Dam [m^3]	Water to Osimo District from field wells [m^3]	Total Water supplied to Osimo by field wells and Castreccioni Dam [m^3]
0,217	2 015 026	936 131	2 951 157
C_e	**W_{cast}**	**W_f**	**W_{tot}**

5.3.3 Electricity Network

According to the targets of the INTERRFACE project, the Osimo expectations are:

- Increase the microgrid self-consumption of renewable energy, thus reducing the amount of the power injected into the national grid at the point of common coupling with the national TSO;
- Improve the power quality of the microgrid by acting on the critical LV lines identified by the DSO;
- Promote final-user engagement in DR programs;
- Promote the development of local energy communities.

The Key Performance Indicators (KPIs) identified for the Pilot are:

- The improvement of the monitored quality parameters of suburban branches;
- The number of DR response hours in the year involving CHP-DH plant;
- The number of MWh of flexibility provided by the CHP plant;
- Lower congestion management costs for the DSO;
- The amount of excess electricity injected into the transmission network;
- The number of hours for which electricity is injected into the transmission network in both winter and summer.

In this section, for each KPI, the definition and method of calculation have been described.

The improvement of the monitored quality parameters of suburban branches

To understand the improvement of the quality of the network, especially of the voltage values on the selected suburban branches, a period of one month has been considered in the experimental campaign, specifically the month of May. The choice of this period is due to the number of hours in which the electricity is injected into the transmission network. Indeed, the month of May is the one in which the network is more congested because of the occurrence of the peaks production of the PV plants.

In addition, as previously explained in Chapter 4, the voltage must remain within a certain range of values (360 V - 440 V) to avoid network problems and, even if it is within the acceptable range, it is desirable to avoid as much as possible fluctuations in the voltage value. It was therefore decided to proceed as follows: in the first half of the month, the reactive power and voltage were monitored with the BESS on; similarly, in the second half of the month, these two quantities were monitored with the BESS off.

During the period when the BESS was switched on, the regulation was done through the delivery and absorption of reactive power through the "voltage control service" that controls the absorption of reactive (inductive) power when the main voltage is higher than the nominal value and the reactive power delivery (capacitive) when the mains voltage is lower than the nominal value. The reactive power adjustment curve is based on a diagram of the type shown in Figure 28 in which it is possible to note voltage values, from 395 V to 405 V, in which the reactive power is zero. This means that the BESS does not absorb or deliver reactive power.

When the voltage starts to rise or fall, the BESS works with the absorption or delivery of reactive power to bring the voltage back around 400 V.

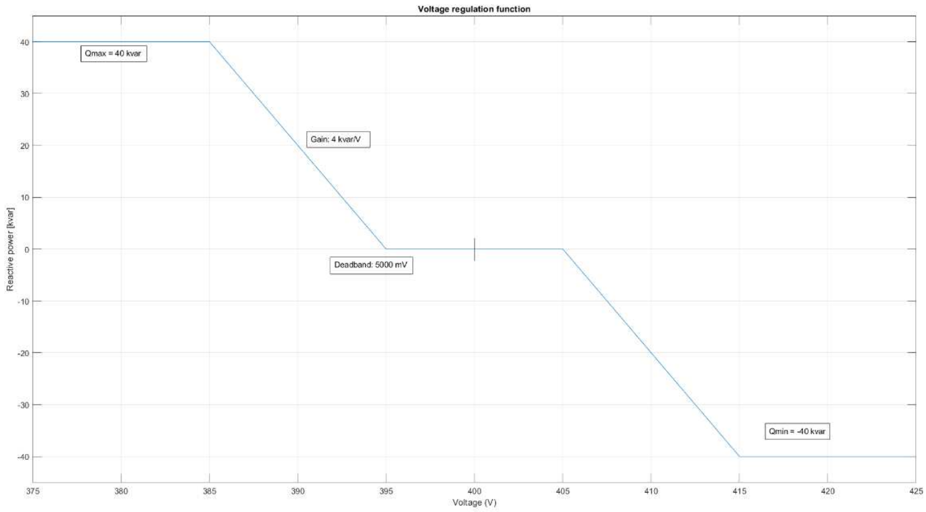

Figure 28. "Voltage control service" curve

Once the voltage data have been extrapolated, the daily maximum and minimum voltage values have been calculated when the BESS was operating or not.
The average of the daily values obtained of the maximum and minimum voltage for both BESS (on and off conditions) have been then calculated. Finally, the percentage reduction of the maximum voltage and the increase of the minimum voltage have been calculated as well.

The number of DR response hours in the year involving CHP-DH plant and the number of MWh of flexibility provided by the CHP plant
The number of MWh of flexibility provided by the CHP plant is calculated as follows: the CHP unit production program of the year 2021 has been considered to know the number of hours in which the CHP engine has been shut down, thus the hours of possible flexibility that it can provide to the transmission network. Once the hours in which the CHP unit has been switched off have been obtained and, considering the CHP maximum electric power output, it is possible to obtain the MWh of maximum flexibility that could provide.

Lower congestion management costs for the DSO
This KPI represents the analytical quantification of the costs that the DSO would have had to bear if it had to solve the congestion network problem through the upgrading of the existing one, identified for both cases (Sogno Street and Brizi Street) in the construction of new secondary MV-LV electricity substations with the construction of MV conduits for the connection of the same to the existing MV network.

The amount and the number of hours when the electricity is injected into the transmission network

The last two KPIs, namely the amount of excess electricity injected into the transmission network and the number of hours when the electricity is injected into the transmission network – in both winter and summer - refer to the entire electric network of Osimo and therefore it needs an introduction of the same, through remote control.

DEA's MV 20 kV network is remotely controlled by means of a Supervision System (SCADA), to which all the states of the remotely controlled elements and the measurements of the electrical parameters detected in the field through appropriate sensors and transducers located at certain points of the network belong.

Through the Supervision system, the remote management of the plants is also being carried out by issuing appropriate commands to certain elements of the field for the management of network assets. The SCADA interfaces the RTU (Remote Terminal Unit) located at the primary plants, namely Primary Cabins HV/ MV (high voltage/medium voltage) and Satellite Cabins MV/ MV, and the PU (Peripheral Units) located at the secondary cabins of the distribution network in MV.

The following figures are representative of the Primary Cabin HV/MV of Osimo, showing the HV, MV, and the Neutral state sections.

Figure 29 displays the page related to the HV disconnector of the DEA HV/MV Primary Cabin of Osimo; as it can be seen from this analysis, the connection point to the National Transmission Network (RTN-TERNA) is unique and it is represented by the AT 189L line. From this line, it is possible to notice the HV 132 kV line from which are derived the two uprights "RED" and "GREEN" HV.

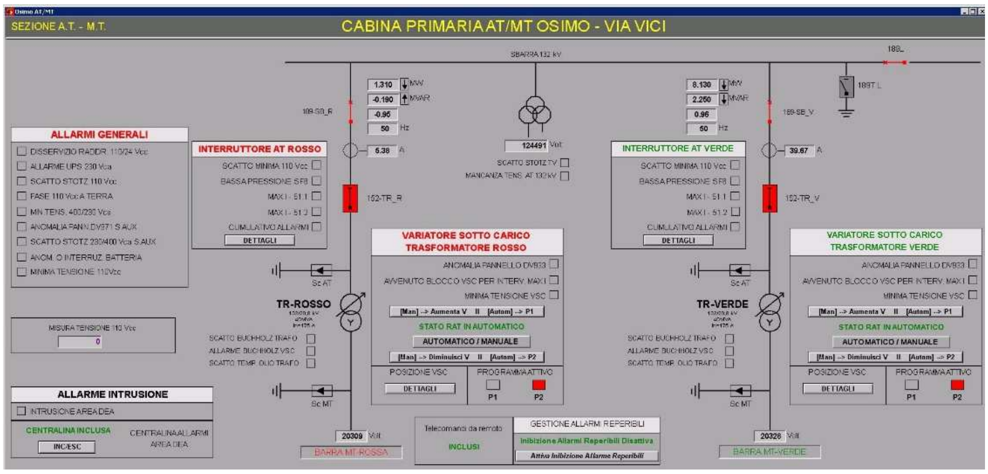

Figure 29. Scheme of DEA HV/MV Primary Cabin of Osimo

Each of them contains an HV/MV 132/20 kV transformer with a nominal power of 40 MVA; The corresponding MV 20 kV half-bar is connected downstream, from which originate the MV distribution lines to the territory and the Feeder lines connecting the Satellite Cabins

(lines MV “Feeder" and "Osimo"); the two half-bars (Red and Green) can be in case of need, united by conjunctor, normally army in open state.
As it can be seen in Figure 29, the monitored parameters (I, P, Q, cosfi, f) are relative to each bar: only I (unidirectional) and P were available in 2021 with the specification of the latter that is derived from the load curve of the control counter located on the MV side of each half-bar since the control of the other parameters has been implemented later using appropriate transducers.
Therefore, the curve of the unidirectional MV current is reported in Figure 30 and the load curve of the active power from the MV network to the HV network (delivered P) is shown in Figure 31. The same considerations can be done in Figures 32 and 33 where the green upright is represented.
The data shown in the figures refer to the day of the maximum inversion of the active energy flow (from the MV network to the HV network) corresponding to the Easter Monday of 2021 (on 05/04/2021).

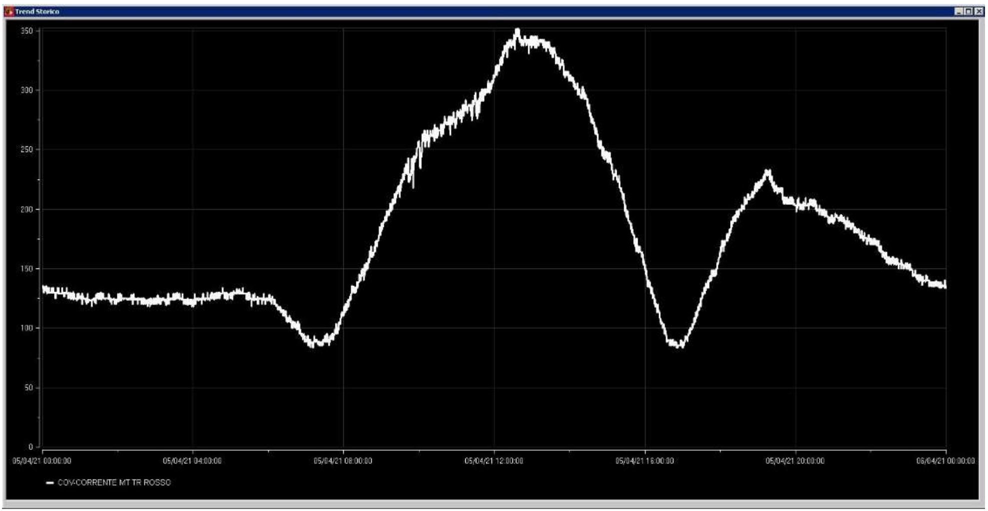

Figure 30. MV RED upright – unidirectional current

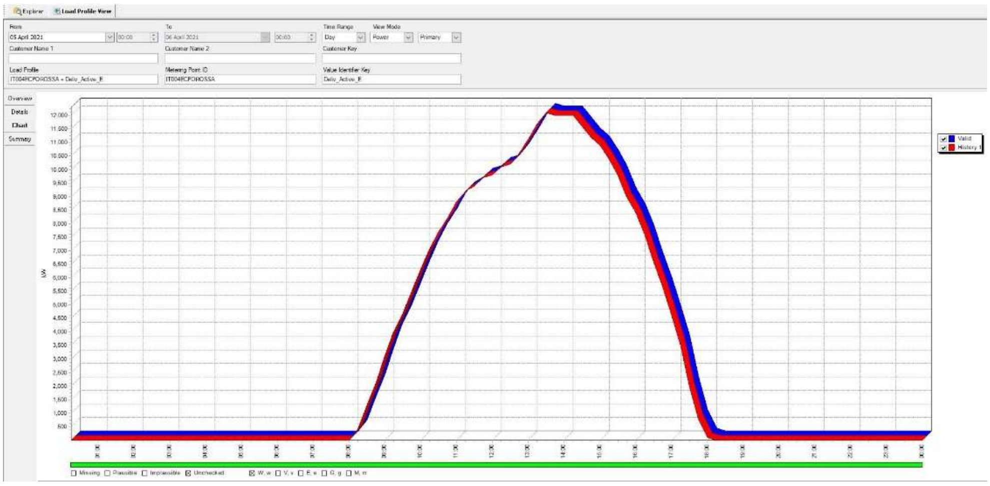

Figure 31. MV RED upright – load curve of the active power from MV to HV network

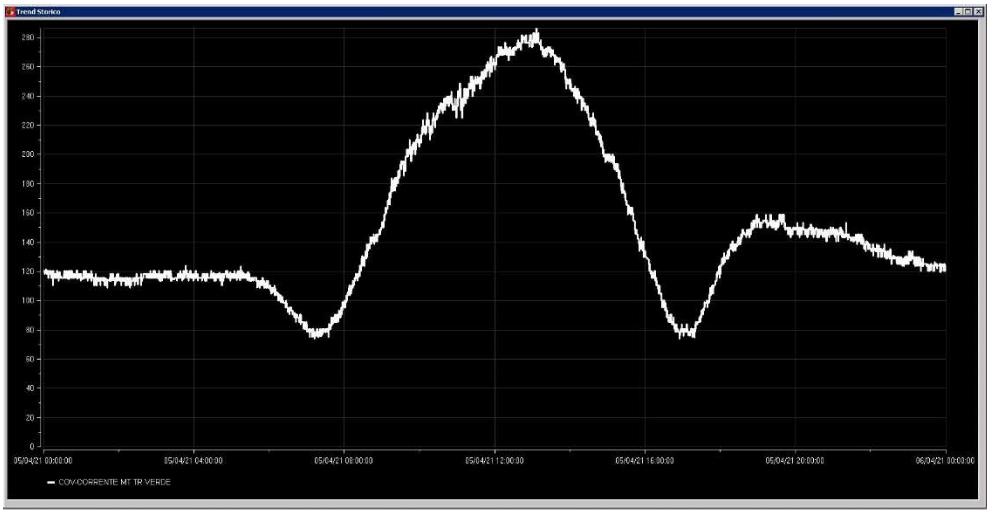

Figure 32. MV GREEN upright – unidirectional current

Figure 33. MV GREEN upright – load curve of the active power from MV to HV network

The following figures are the graphic pages of the MV section (Figure 34) and the section of the Neutral State Management (Figure 35) related to the Primary Cabin HV/MV DEA of Osimo considered above.

It is worth noting that the values of the electrical parameters that can be read do not correspond to the period indicated in the graphs (maximum inversion of active energy). In particular, it can be noted that in Figures 29 and 34 there are energy direction indicators per each MV line and per each mast, as well as indicators of power factor (cosfi), active power, reactive power, and frequency for each MV pillar; these parameters were implemented in February 2022 following the installation and activation of appropriate equipment in the field and the subsequent reconfiguration of the RTU (Remote Terminal Unit) and the SCADA.

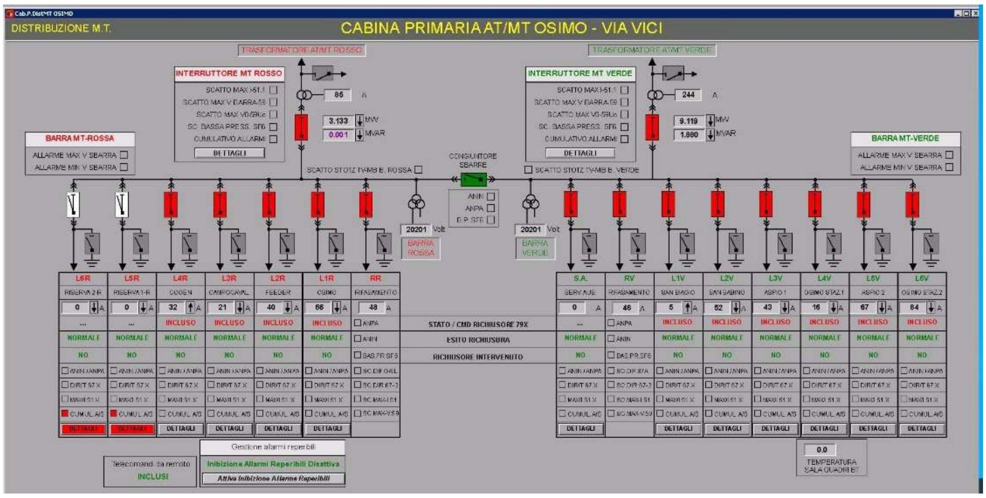

Figure 34. MV section of the HV/MV Primary Cabin of Osimo

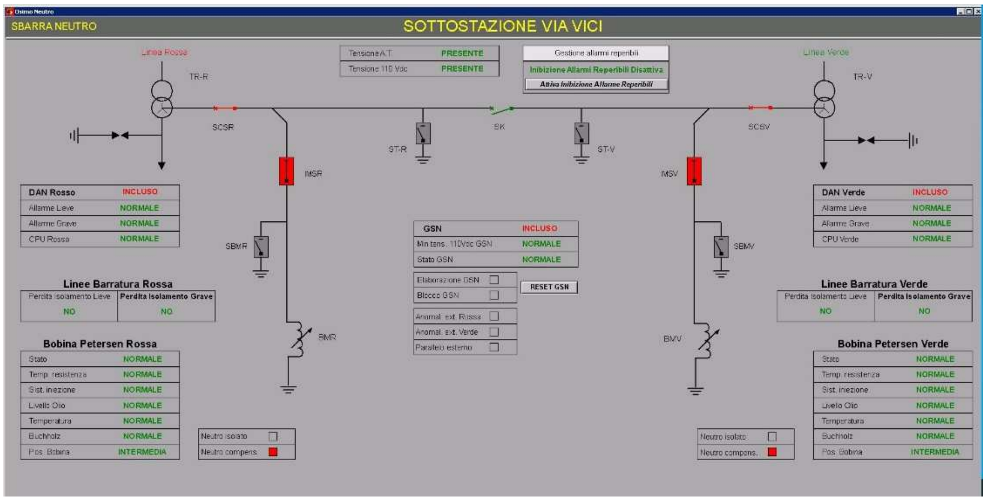

Figure 35. Management page of the MV Neutral State of the HV/MV Primary Cabin of Osimo

Chapter 6.

6. Results and comments

This Chapter discusses the results obtained from the methodology explained in Chapter 5. In particular, Subsections 6.1 and 6.2 show the integration and the operation of the platforms created for both SES and LECs. Subsection 6.3, on the other hand, shows and comments the results obtained with real data from the energy, environmental, and economic point of view of the three considered energy carriers, which are the DH network (6.3.1), the water network (6.3.2), and the electricity network (6.3.3).

6.1 Smart Energy System Integration

The Osimo configuration of the SES after the implementation, is reported in Figure 36, while Figure 37 highlights the interconnections of the new flexibility resources with both the existing technologies and networks.

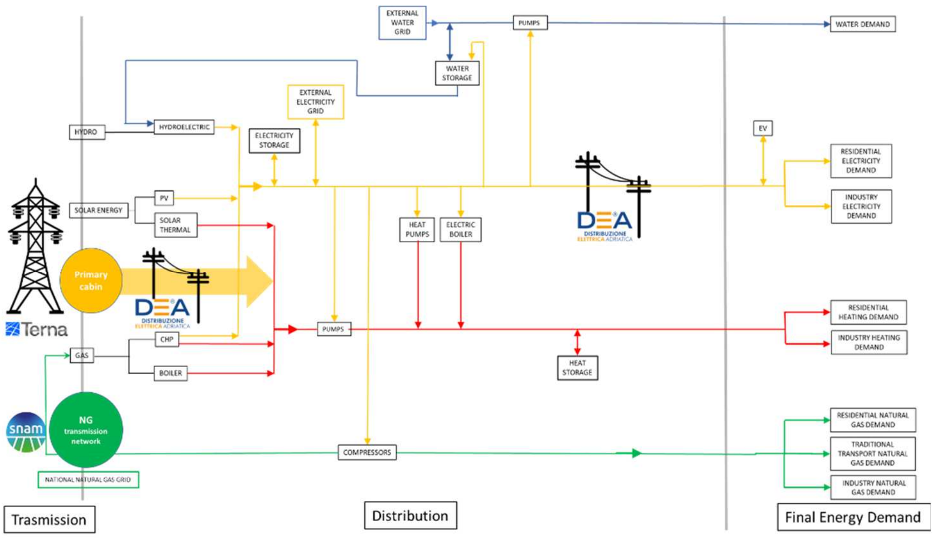

Figure 36. Multi-energy system configuration of Osimo. Blue, yellow, red, and green lines represent the water, electricity, heating, and Natural Gas grid, respectively.

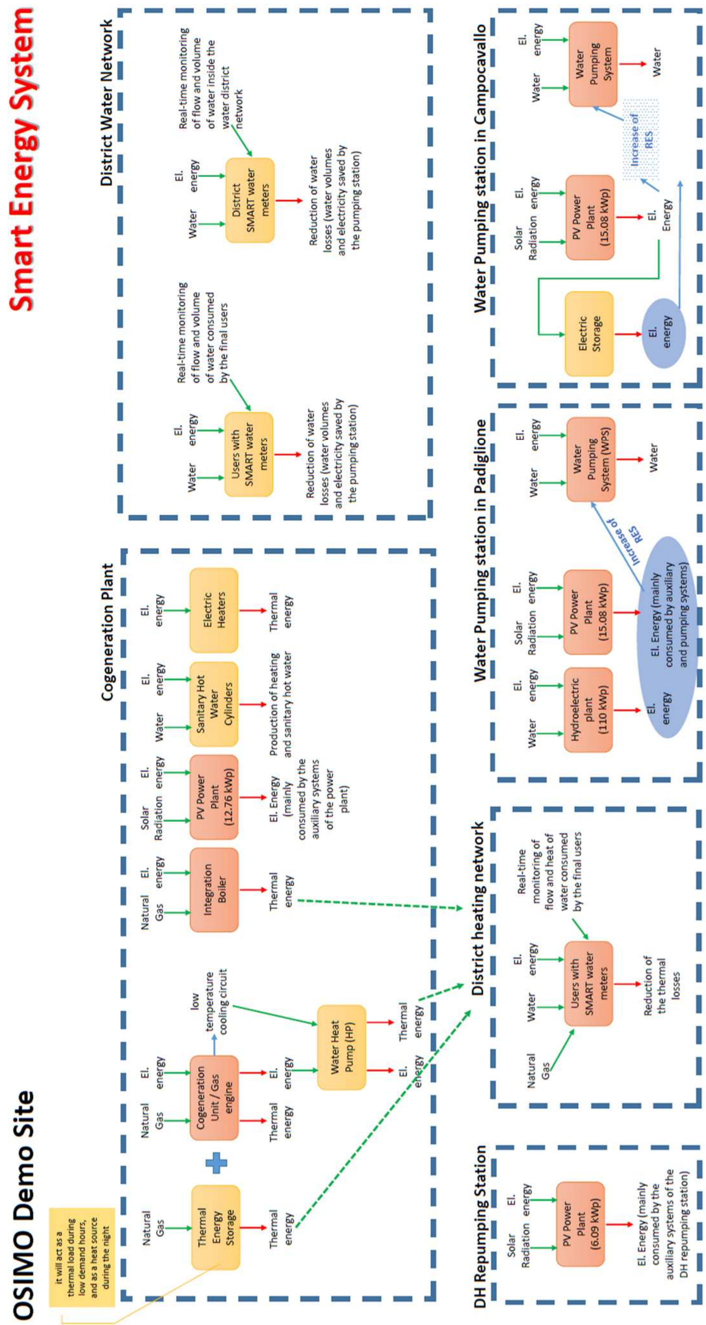

Figure 37. Smart Energy System integration in Osimo demo-site

In particular, Figure 36 shows the four involved networks, namely the water network, electric network, DH network and Natural Gas (NG) network. These four networks are linked together by means of the "connecting technologies": some of these technologies are already installed in the demo-site, namely (i) the CHP plant, which is connected to the NG network, electric network and DH network, and (ii) the pumping stations that connect the electric network with the water one. During the four years project, the Osimo multi-energy municipal microgrid improved since different technologies have been installed to better exploit synergies among the different energy networks, thus achieving the goal of increasing the self-consumption of the electricity produced locally by the distributed generation systems. The use of these technologies allows to match the demand and production when they are out of phase by means of the implementation of DSM strategies.
Furthermore, the Smart Control Architecture (see Figure 38) has been implemented and it is divided in two main levels:

- High level control: it is dedicated to the optimal management of the energy resources and demand loads for a day-ahead prediction horizon. All the hardware and software tools needed at this level are grouped under the so-called "MUSE GRIDS Cloud";
- Low level control: it is dedicated to the real-time operation of the power plants or energy devices with the double function of following the strategy defined by the high-level control and guarantee the stability under the real operation conditions. It is worth noting that the low-level control has been already presented in Chapter 4.

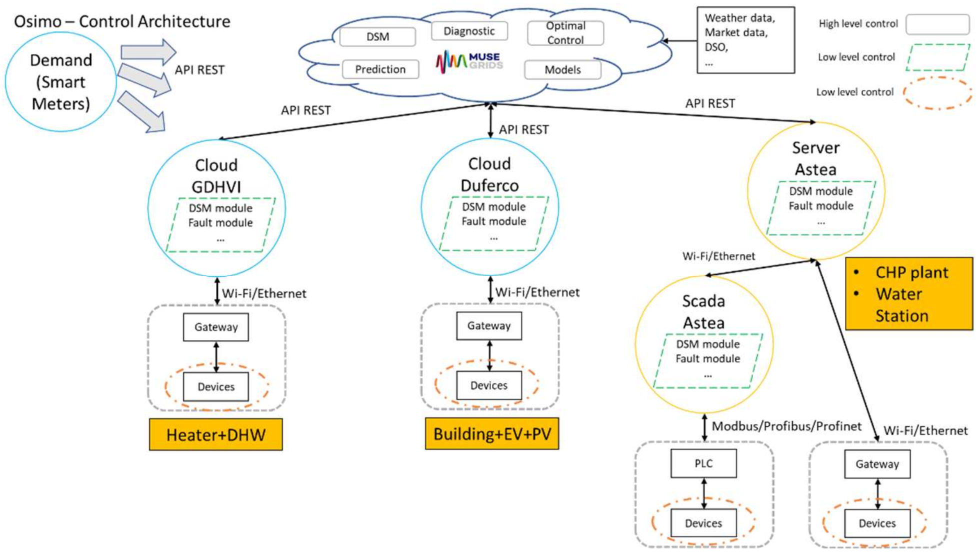

Figure 38. Smart Control Architecture of Osimo demo-site

This section of the thesis wants to be a general guideline for smart controller deployment and defines the objectives to achieve: one is to define the Smart Control (optimal + predictive) strategy and the other is to focus on the relation between low-level and high-level control. For the Osimo demo-site, the following points have been analysed:

- The Optimization problem: the system to be controlled and the objectives to be maximized or minimized;
- Data management: how and which data has been monitored and shared among the services;
- Smart Control Deployment: how the control has been connected and deployed.

6.1.1 Optimization problem definition

The optimization problem in Osimo focuses on the control of the CHP-DH Plant that connects three different grids: natural gas, district heating and electricity networks.
For the multigrid system to be controlled, the assets and devices that have been included in the control are:

- Natural gas engine cogeneration system: its main function is to produce thermal energy for the district heating network when required. At the same time, while producing the thermal energy, it will deliver electrical energy to the grid. Even though it is a controlled power generation plant due to legal restrictions it can operate only at nominal power when it is switched on.
- Natural gas boilers: three boilers are used to provide thermal energy to the DHN when the demand exceeds the production of the cogeneration system. The generated power can be controlled.
- Thermal Energy Storage Tank: controllable storage system used in the DHN. The thermal production of the cogeneration system can be total or partially stored in this device. The output of the TES can be delivered direct to the DHN or through the boilers when the demand is high.
- District Heating Network load: is the aggregated and not controlled thermal demand of the users.
- PV panels: is the aggregated solar energy produced in the Osimo grid. It is a non-controllable renewable power energy source as the produced energy is locally managed at home level. The variability in this production and the high number of installed PV panels is the origin of the difference in the power delivered and consumed at the PCC at different moments of the year.
- Electrical loads: the uncontrolled loads present in the Osimo grid.

Two optimization problems have been defined for the multigrid system related to the cogeneration power plant. Both problems have the common objective of minimization of the natural gas fuel consumption and maximizing self-consumption in the electricity grid. These two problems are linked to the control of the cogeneration system, boilers and TES to provide the required thermal demand of the DHN at the optimal supply temperature. The objective function (OF) balance the minimization of the gas consumption and to avoid the injection of electricity power in the grid. Variable weights can be given to these two objectives to prioritize one over the other when they require opposite decisions about the use of the assets. In fact, there could be situations along the year in which electrical power in the order of 1

MW is injected in the grid, and the disconnection/shifting of the electricity generated in cogeneration system can avoid it. This is possible if the thermal energy balance can be achieved thanks to the use of the boilers, TES or changing the supply temperature.
In particular, the optimization problem defined aimed at assessing the optimal water supply temperatures to the DH network in order to minimize the amount of natural gas fuel used (V_{NG}) in a considered period. The supply water temperature to the DHN (T_{sup}) is the decision variable of the problem. The total fuel use is given by the sum of fuel used in the CHP plant ($V_{NG,chp}$) and in the two boilers ($V_{NG,b1}$ and $V_{NG,b2}$). The optimization problem can be formulated as:

$$OF(T_{sup}) = V_{NG}(T_{sup}) = V_{NG,chp}(T_{sup})+V_{NG,b1}(T_{sup})+V_{NG,b2}(T_{sup})$$

$$\text{Minimize } OF(T_{sup})$$

The water supply temperature Tsup can take values in the range 70 °C (to avoid legionella issues) and 95 °C [70].
The constraints of the problem are:

- the maximum value of the water flow rate in the DHN, due to the pump specifications, is 67 kg s^{-1};
- the minimum value of the return temperature of the DHN is 55 °C (chosen on the basis of available measured data);
- the final users' thermal demand needs to be thoroughly satisfied.

The optimization has been implemented in Python by means of the algorithm SLSQP (Sequential Least Squares Programming) [71].
The obtained results are shown in the sub-subsection 6.3.1, where the suggested DH supply temperature is compared with the real one, also evaluating both the energy and environmental benefits.

6.1.2 Data management and data base deployment

The communication of the different devices, energy assets with the MUSE GRIDS multi-objective smart controller to enable flexibility, and DSM operations, is one of the key aspects of the project. Then, the detail of the connections and control architecture for the Osimo case study is found in Figure 39, where the communication between the assets of Osimo and the MUSE GRIDS server is implemented by using API Rest, and the communication with the GlenDimplex Devices is implemented by using Microsoft EventHub. The MUSE GRIDS server stores the data in a SQL DB and it can communicate with the assets of Osimo through API Rest towards the Astea server.

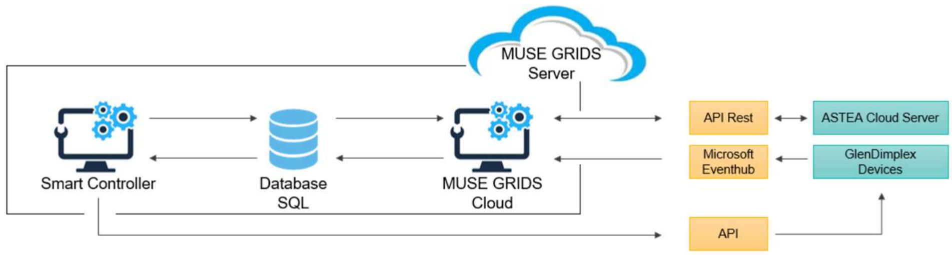

Figure 39. Control and communication architecture for the Osimo case study

The Astea server covers an intermediate position between the field and the cloud, therefore the communication with the lower levels shall be protected and communication with the cloud must be encrypted. The objectives of the Astea server are to collect the data coming from several energy assets of the Osimo's demo site, expose the data to the MUSE GRIDS controller and allow the actuation of DSM strategies defined by the controller.

6.1.3 Smart Control deployment

Osimo CHP plant is a critical asset for supplying the thermal demand of the users. The same apply to the pumping station that supplies water to the users. In this sense the smart control deployment has been designed to avoid any unavailability of the plants or any of the systems.
First, a dedicated server has been set up to host the whole MUSE GRIDS Cloud architecture. This server is completely independent to the ones used by ASTEA in their monitoring and control architecture. Furthermore, to avoid any risk it has been decided that all the tests in the real system will be done in open loop, so any control action decided by the high-level control will be always supervised by a human operator before it can be set up in the system.
For the cogeneration plant system, the optimization problem will provide three different outputs:

- Cogeneration engine switch on/off state;
- Supply temperature to the DHN;
- Tank charging/discharging operation.

These outputs will be generated in a day-ahead basis so the operator/manager of the plant can decide the strategy in the next hours using this information.
Unlike a strategy based in a daily prediction at midnight, in the MUSE GRIDS control strategy the predictive control algorithm is executed every 15 minutes. This means that an updated recommended control profile is continuously calculated according to the real evolution of the system and not only based in a daily prediction for the whole day.
The outputs of the algorithm are available for the operator through a web interface that can be accessed using the user security credentials. This is a previous stage to the use of the API (also based in web services) in case the manager wants to close the loop and use the profiles as the set-points for the devices without the previous supervision.

6.2 Local Energy Communities

In this Section, the Local/Renewable Energy Community composed by two Osimo streets are shown. In particular, Figure 40 shows the monitored data of the private houses of both Brizi and Sogno streets, and PV plants.

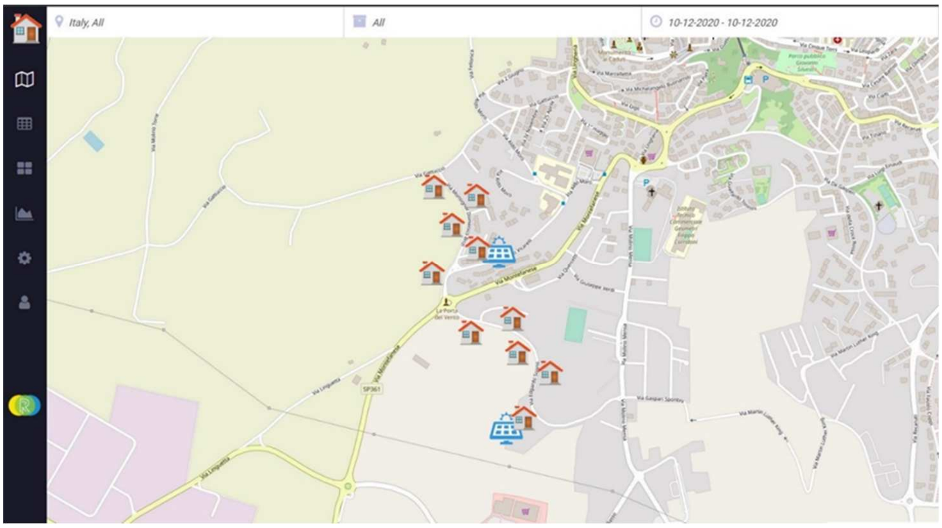

Figure 40. Local/Renewable Energy Community view

The main purpose of the LEC/REC is the aggregation of all the prosumers' consumptions and production in a self-consumption context. Figure 41 shows an example where the visualized data are the cumulative instant; in particular, the weekly electricity consumption and production, and the instant and weekly self-consumption percentage (for all the houses) are reported.

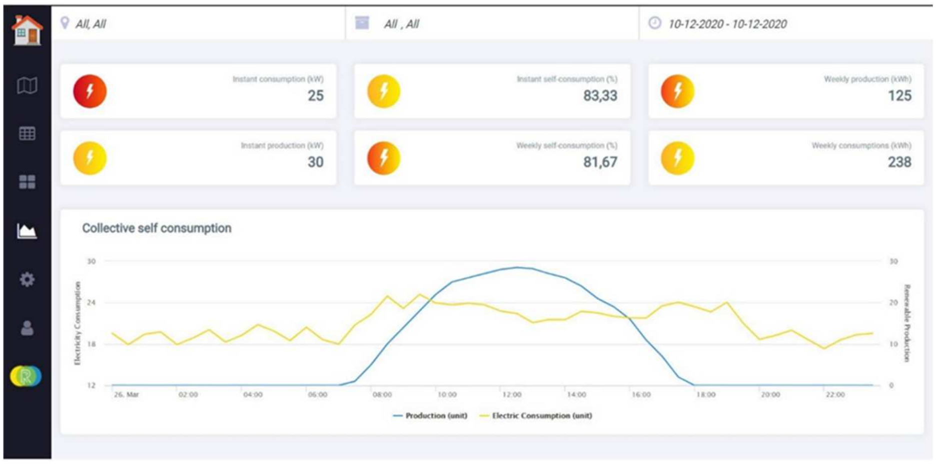

Figure 41. Local/Renewable Energy Community: production and consumption aggregated profile

As shown in Figure 42, the residential electric consumption Monitoring System is based on the IoT software that allows to capture data from the sensors. This platform is able to acquire, record, process, and visualize the desired electrical parameters.

Figure 42. LEC/REC configuration

The system is based on traditional components located at the end-users level that monitor the data. These measures are aggregated in the first instance towards a gateway thanks to wired or wireless communication channels. The gateway can be connected to the Internet directly (via a local network), or via a WI-FI router and/or mobile network (3G-4G). If the internet connection works, the gateway will send data to the platform that records and makes them available in aggregate or single form to the end-user.
A pre-cabled outdoor electrical panel containing the following devices:

- The electrical meter;
- A gateway with a mobile internet connection;
- What is necessary for the safe electrical connection of the above devices.

The monitored data are sent and stored in a cloud to make them available to the end-users via a dedicated App. The platform is configured with aggregation levels for individual users, which have accessed the web-based portal through username and password. It has been also developed to be simple and usable and, at the same time, allows to go into the details of the measures.

Considering that the current regulation rewards the ability of the participants in the scheme to self-consume and share energy, any technology that supports the increase of the condominium self-consumption and energy sharing can make a valuable contribution to the benefits of the collective consumption scheme. Figure 42 shows an example of a configuration of collective self-consumption in which there is an EES to support the maximization of the consumption share (common utilities of the condominium) and energy sharing (household). This scheme of self-consumption involves an Energy Management System - EMS that process the control signals (charge and discharge) to be sent in real time to the EES on the basis of the PV production and consumption measurements of the end-users. The EMS sends the charging signal to the EES when there is a surplus of production of the PV plant compared to the load. Conversely, the discharge of the EES can be activated when the PV production is insufficient to power the loads, and it is aimed at increasing the share of the physical self-consumption (e.g., elevator, lights, central heating, and other common services) and shared (domestic use).

However, the goal of this part of the work is not to calculate the energy-economic performance of a configuration of a REC, but show the tools necessary for its realization as well as their interconnectedness. From the data obtained through the monitoring of the residential end-users, it will be possible, in the future studies, to calculate their energy and economic benefits.

6.3 Energy, environmental, and economic analysis

In this Section, the results of the implementations applied in Osimo demo site are shown. In particular, the analysis is based on the entire data of the year 2021 and a part of the data related to the year 2022: results from the energy, environmental and economic point of view will be then shown. These results are divided considering the analysed energy vector, namely Sub-subsection 6.3.1 shows the results of the DH network and the CHP unit, Sub-subsection 6.3.2 shows the results of the water network. Finally, Sub-subsection 6.3.3 shows the results of the KPIs of the electricity network, which have been already described in Chapter 5.

6.3.1 DH network

This Sub-subsection compares the data of the year 2018 already presented in Chapter 4 with those of 2022. Precisely, 7 months were considered, namely from January to April and from October to December. It is worth noting that from January to April the data of the year 2022 were considered, while from October to December the data of the year 2021 were used. For simplicity, the "hybrid" year will be henceforth called 2022 since the thermal storage went into operation in October 2021. Therefore, for a better comparison of the ex-ante and post-intervention, it was decided to consider this time interval.

Hence, this Sub-subsection, deals with the performance of the thermal power plant focusing on the CHP unit in the year 2018 and 2022, moving then to both energy and environmental results from the thermal power plant point of view. In addition, the economic results from both thermal power plant and end-users' side are shown.

Figure 43 shows the share of the NG used by the CHP unit and boilers in 2022, highlighting per each month the percentage of the NG used, while Figure 44 compares the situation ante and post intervention for the entire year, for both 2018 and 2022 year, against almost the same amount of DH load. Table 21, instead, reports the CHP plant energy performance in the year 2022. As already discussed in Chapter 4, the situation ex-ante intervention was the following: the CHP unit and the boilers consumed almost the same amount of the primary energy, even if in the mid-season only the gas boilers operate, while in the mid-season the CHP unit has the priority over the boilers. Table 21 shows that, yearly, the situation post-intervention is the following: the CHP unit consumed more primary energy than boilers. Furthermore, compared to a slightly higher thermal load in the year 2022, the thermal energy produced by the cogenerator in 2022 is 5734.9 MWh compared to 5298.9 MWh in 2018 with an increase of 8.2 %, which corresponds to an increase in electricity produced of 622.2 MWh, namely 12.2 % compared to 2018.

This result comes from the operational hours of the CHP unit in 2018 were 4440, while those of 2022 were 4825: this increase is mainly due to the use of the thermal storage installed in the CHP plant.

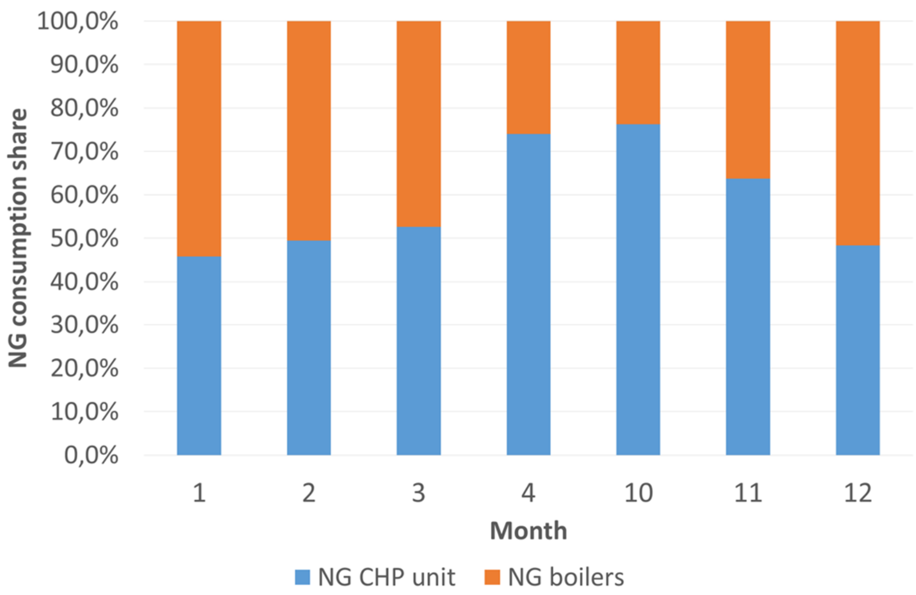

Figure 43. Share of the NG consumption by the CHP unit and boilers (year 2022)

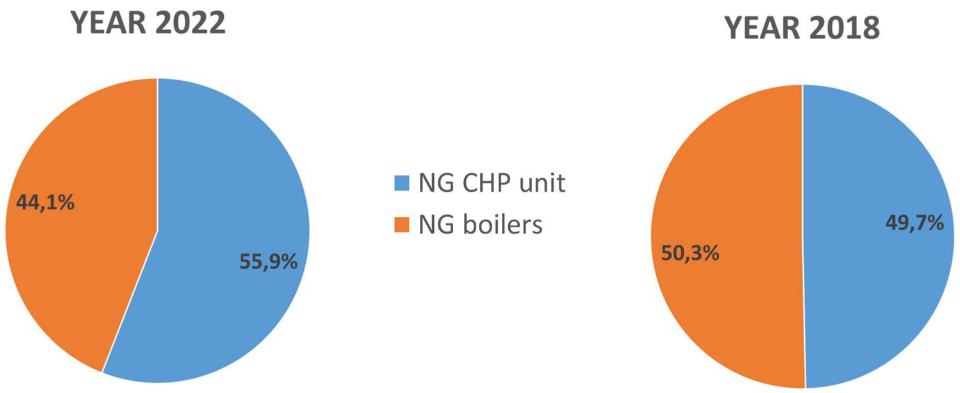

Figure 44. NG consumption comparison (year 2022 vs year 2018)

Table 21. Monthly operational data/performance parameters of the CHP unit (year 2022)

Month	CHP NG consumption [Sm^3]	Boiler NG consumption [Sm^3]	CHP TE production [MWh]	Boiler TE production [MWh]	DH load [MWh]	CHP unit EE production [MWh]	CHP unit EE delivered [MWh]
1	229,560	271,436	888.9	2,530.9	2,811.3	886.2	788.9
2	193,127	197,123	745.5	1,868.8	2,082.1	744.5	666.1
3	226,779	203,758	872.5	1,943.1	2,250.9	874.2	780.1
4	216,967	76,359	838.7	762.2	1,110.3	830.1	760.9
10	171,303	53,480	655.7	572.9	770.4	659.8	603.7
11	222,503	126,877	852.4	1,280.2	1,626.9	858.7	776.7
12	227,202	242,353	881.3	2,308.9	2,623.6	881.3	788.2
Total	1,487,441	1,171,386	5,734.9	11,267.1	13,275.5	5,734.6	5,164.6

According to Eq. (1), Table 22 shows the monthly trend of the PES related to the CHP unit recorded in the year 2022. It can be stated that the CHP unit is more competitive than the separate production, providing a yearly reduction of the primary energy consumption of 21.2 %. The maximum PES achievable is 21.7 % in December (with $\eta_{th,CHP}$ = 41.3 % and $\eta_{e,CHP}$ = 41.3 %), while the minimum one is 20.9 % in April (with $\eta_{th,CHP}$ = 41.1 % and $\eta_{e,CHP}$ = 40.7 %). From these data, it is clear that the annual PES was unchanged compared to the PES of the year 2018 with that of 2022 (21.2 %). On yearly basis, instead, there is not an increase in efficiency: the thermal one decreases by 1.1 %, while the electric one increases by 0.4 %, achieving an overall efficiency decrease of 0.7 % with respect to the configuration without TES and HP. In addition, considering the monthly PES after the installations of both TES and HP, it is always greater than 20 %, while in 2018 the minimum value reached was 18.9 % in October. As previously said, since the PES is greater than 10 %, the Osimo CHP unit falls within the definition of high-efficiency cogeneration (electric power production higher than 1 MWel). Among the energy saving, EEC can be issued by the Italian Government for 10 years long.

Table 22. Monthly specific energy parameters and the avoided CO_2 (year 2022)

Month	PES [%]	$TE_{sp,CHP}$ [kWh/Sm^3]	$TE_{sp,boil}$ [kWh/Sm^3]	$EE_{sp,CHP}$ [kWh/Sm^3]	$E_{sp,tot}$ [kWh/Sm^3]	ΔE_{sp} [kWh/Sm^3]	$E_{th,el}$ [kWh]	Avoided CO_2 [tonnes]
1	21.4	3.18	7.66	3.86	14.71	5.31	1,764,475	342
2	21.3	3.07	7.55	3.85	14.48	5.08	1,250,607	242
3	21.2	3.08	7.62	3.85	14.55	5.15	1,371,658	266
4	20.9	2.68	6.92	3.83	13.43	4.03	529,099	102
10	21.0	2.40	6.72	3.85	12.97	3.57	325,195	63
11	21.1	2.92	7.70	3.86	14.48	5.08	977,038	189
12	21.7	3.19	7.84	3.88	14.90	5.50	1,707,240	331
Average	21.2	3.01	7.51	3.86	14.38	4.98	7,811,121	1,512

Furthermore, considering the average specific energy in the year 2022, the specific thermal and electrical energies of the CHP unit achieve values of 3.01 and 3.86, respectively. These results lead to an increase of ΔE_{sp} in the months of October in which the minimum value is calculated, from 0.73 in 2018 to 3.57 in 2022. In addition, the ΔE_{sp} in 2022 is always more than 3 with an average annual value of 4.98.
Finally, it should be therefore pointed out that the new installations (HP+TES) lead to environmental and economic advantages instead of the energy ones that remains almost the same, which is displayed in Figure 45. In particular, Figure 45 shows the results obtained with the new configurations (year 2022) compared to the baseline layout (year 2018), highlighting how both thermal and electrical efficiencies, the PES, the avoided CO_2, and the EECs vary in different seasons and in the entire year as well.

According to Eq. (9), 721.8 EECs were obtained in the year 2018, reaching the corresponding economic income of 180,454 €. Furthermore, by analysing the new configurations (year 2022), the following results have been obtained, precisely an increase of 54.5 EECs with a further 13,625 €.
It is worth noting that EECs have a strong influence on the CHP unit operation profitability. Before the new implementations, namely the flexibility resources (HP, TES) and DSM strategies, the CHP unit of Osimo case operated primarily in the energy production over boilers: in the winter season, the CHP unit operated at full load, in the mid-seasons it operated at partial load, and in July and August it is switched off. The CHP unit partial load operation in the mid-seasons, as well as the shutdown in the summer months, led to a decrease of the energy production and sale of both heat and electricity, thus leading to a significant loss of EECs and therefore to a lower economic revenue.
As depicted from this analysis, the TES installation allows an early CHP unit switch-on that increases its operating hours and led to a substantial increase of EECs. This result is well displayed in Figure 45: it shows the economic benefits of the new configuration in the entire year, especially highlighting this new solution that performs better in the mid-season with respect the winter one.

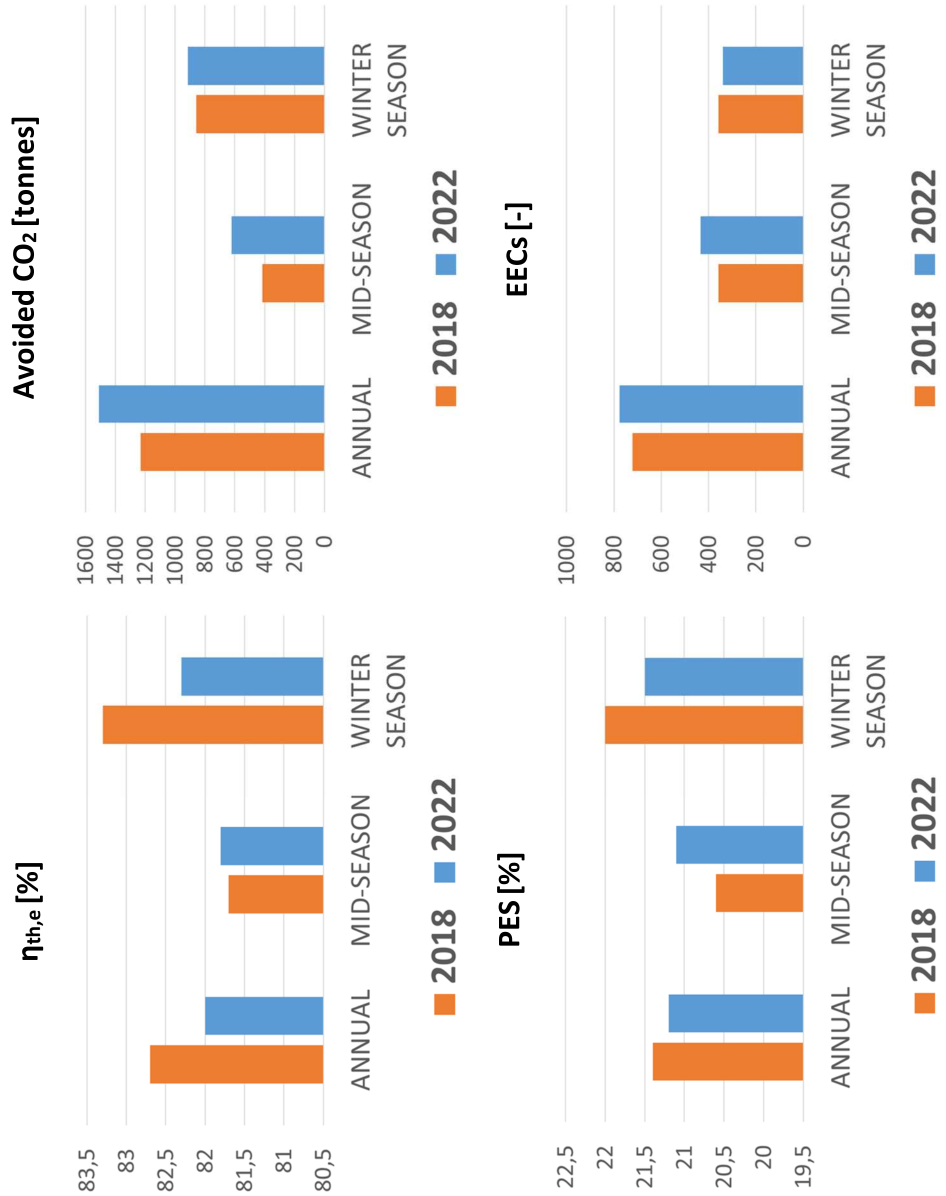

Figure 45. $\eta_{th,e}$, PES, Avoided CO_2 and EECs of the total year, winter season and mid-season for the CHP-DH plant baseline configuration (year 2018) and new configuration with thermal energy storage and heat pump (year 2022)

In addition, it is anyhow important to implement optimization strategies in the planning phase of the CHP unit switch-on not only for the increasing of the operation hours on the engine point of view (i), but also for decreasing the supply temperature on the DH point of view, which is directly related to the network losses. The two options previously mentioned are analysed in the following:

(i) The thermal energy demand of Osimo varies during the day and the months: this behaviour cannot be exactly predicted, and therefore it cannot be planned a priori. However, based on the parameters recorded in the past, it is possible to estimate the trend. According to the season, the heat load provided by the DH network varies depending on the temperature as shown in Figure 46, which highlights a large difference between winter and summer thermal power outputs when considering only the domestic hot water. Analysing the values of the thermal demand in 2018, it is clear that during the day the load curve takes the form of a "camel hump", which becomes more marked in the winter season. Considering the thermal power output of the CHP unit (Figure 46, dotted line), it can be easily shown that there is a greater thermal demand than the one offered in the mid-seasons up to 22. By updating the CHP unit programming, it leads to a daily increase of two hours of the CHP unit operation. The current planning (07:00-20:00 in the mid-seasons), which has been made before 2017 and maintained up to now, took into account that in that period the value of EECs was around 100.00 € and the sale of electricity in those additional hours felt in the low-cost range, being unprofitable. Thus, it was not convenient, even if there was the possibility, to run the CHP unit. Up to now, with the current geopolitics' situation, the selling price of electricity has risen sharply.

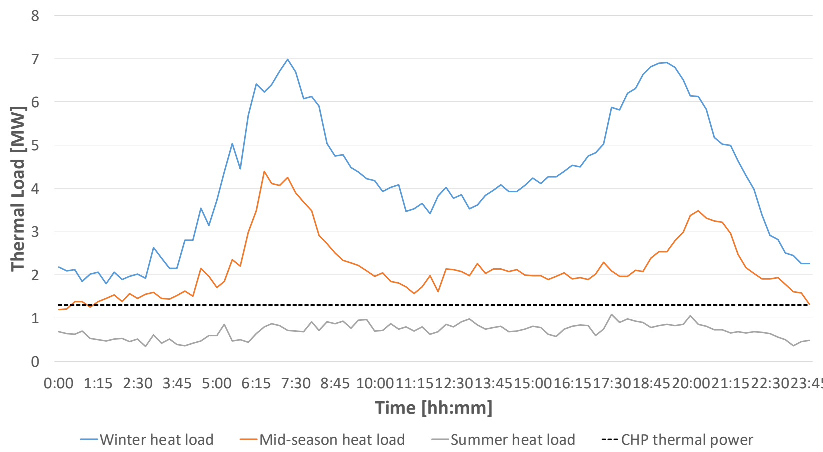

Figure 46. The trend of typical daily heat demand in winter, mid-, and summer seasons

This will be discussed in the last chapter of this thesis, specifically among the lessons learned. Furthermore, the value of an EEC is much higher, accounting to 250.00 €, and thus implies a considerable convenience and the justification of such a discussion.

It is necessary to add, for the sake of clarity, that Figure 46, and in particular the graph concerning the mid-seasons, can be misleading as it does not reflect the veracity of the daily load curve, but the average of four months;

(ii) Thanks to the optimization strategies that take into account also the weather data, it is possible to decrease the supply temperature of the DH network. Figure 47 clearly shows the evolution of the supply temperatures from 2018 until today, during the mid-season. In particular, the blue line displays the trend of the data suggested by the optimization strategy, while the rest of the data are extrapolated from the control system of the CHP unit. Furthermore, the dotted lines reported a better visualization of the trend of both the real and suggested temperature. It is therefore noted that the supply temperature of the DH in March was reduced by about 17 °C from 2018 to 2022.

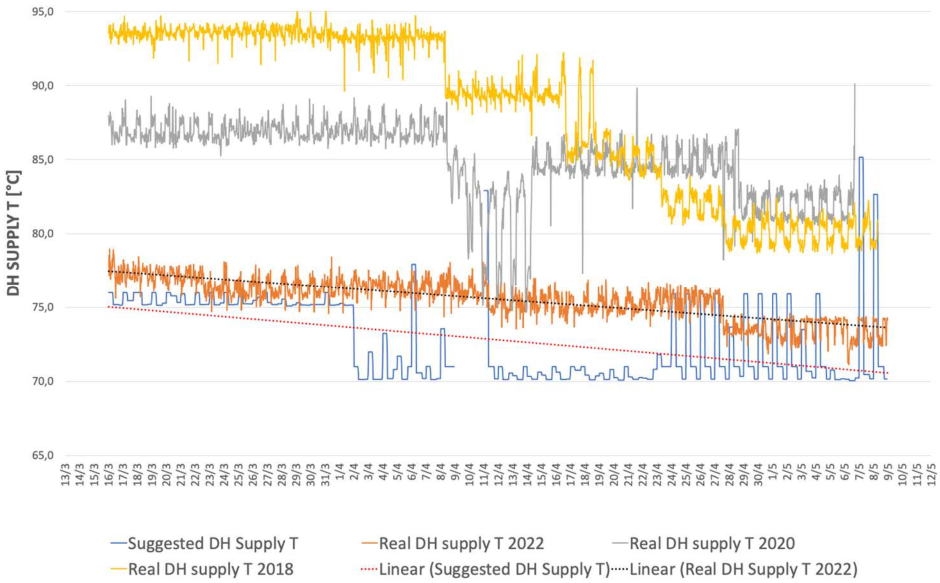

Figure 47. DH Supply temperature of several years

The decrease of the supply temperature is closely related to the network losses. Comparing the network losses of the year 2018 to those of the 2022: (i) the annual network losses decreased by 1.5 %, namely from 23.4 % to 21.9 %; (ii) considering the monthly network losses, the month of October recorded a greater percentage reduction of 13.9 %, from 51.2 % in 2018 to 37.3 % in 2022.

For the economic analysis of the end-users, it is necessary to make a premise: the implementations carried out in the cogeneration plant, object of this work, have no economic implications for the end-users. For the sake of completeness of the results, however, it was decided to report below the performed analysis to show the benefits of the DH over the individual heating.

Data related to 1,154[1] residential users have been used in this analysis (see Figure 48). Group 1, whose consumption does not exceed 5,000 kWh/y, represents 46.2 % (533 users) of the test sample. Group 2, whose consumption ranges from a minimum of 5,001 kWh/y to a maximum of 10,000 kWh/y, represents 45.8 % (528 users) of the sample. Group 3, whose consumption is between 10,001 and 15,000 kWh/y, represents 7 % (76 users) of the sample. Finally, Group 4, composed by residential users with a yearly consumption higher than 15,001 kWh, represents 1 % (17 users) of the sample.

Figure 48 shows that, on a yearly basis, the DH is cheaper than the IH in 84.7 % of the cases. In particular, residential users obtained a maximum saving of 10 % in 55.2 % of the cases, and from a minimum of 10 % to a maximum of 50 % in 27.3 % of the cases. Only in 2.2 % of the cases, a saving greater than 50 % has been obtained only from residential users belonging to Group 1. In 3.3 % of the cases, there was no difference between the two technologies. A negative SAVE has been achieved in 12 % of the cases, meaning that the DH is less convenient than IH. Nevertheless, it is worth noting that in the latter case, and only for one residential user, the maximum percentage of negative SAVE reached in Group 2 is 15 %: in the other cases in Group 2, the negative SAVE is always below 10 %. In Group 1 there is a maximum of 10 % of SAVE<0 and in Group 3 a maximum of 7 % of SAVE<0: this means that the economic advantage of IH does not reach significant percentages such as it occurs in DH.

It is interesting to note that, if the extra costs related to boilers were not taken into account, a higher bill would have been obtained for all the DH end-users in each group. In particular, regarding Group 1, 41.1 % of the end-users would pay more than 30 %; 0.8 % of the end-users would pay more than 10 %, and the remaining 58.1 % of end-users would pay between 10 and 29 % extra. Regarding Group 2, 3.8 % of the end-users would pay more than 30 %, 1.9 % of the end-users would pay more than 10 %, and the remaining 94.3 % end-users would pay between 10 and 29 % extra. Regarding Group 3, 55.3 % of the end-users would pay more than 10 %, and the remaining 44.7 % end-users would pay between 11 % and 21 % extra. Finally, regarding Group 4, 100 % of the end-users would pay 10 % more. The cost difference in the DH bill compared to IH fades a consumption increase (from Group 1 with lower consumption, which recorded a greater increase, to Group 4 with higher consumption and lower increases). This detail is in line with the sentiment of a part of DH users of the Osimo network, which complains about the high cost in the bill, preferring therefore a lower monthly payment and then pay the extra annual costs of the boiler separately. These extra costs are not wrongly taken into account as attributable to IH users, so they are not counted in their household budget. Another important aspect that has not to be underestimated is the facility that IH users can access, compared to those of DH such as preferential taxes and social bonuses, which unfortunately affect the choice of one technology rather than another one.

[1]50 residential users with annual consumption below 1,000 kWh have been excluded from this analysis. It has been assumed that these residential users use alternative technology for domestic heating while remaining connected to the DH network.

Figure 48. Economic results of the residential users (year 2019)

6.3.2 Water network

In this Sub-subsection the results of the whole year 2021 obtained by monitoring the water district network of the historic center of Osimo are shown. As already discussed, it must be considered that each cubic meter of the water flowing into the district under investigation has to be pumped from the pumping station to Tank 13 (named Underground Tank) and, subsequently, from Tank 13 to Tank 14 (named Hanging Tank) through a second pumping station as shown in Figure 49. Hence, the two pumping stations have a specific energy consumption of 0.98 kWh/m^3 and 0.189 kWh/m^3, respectively.

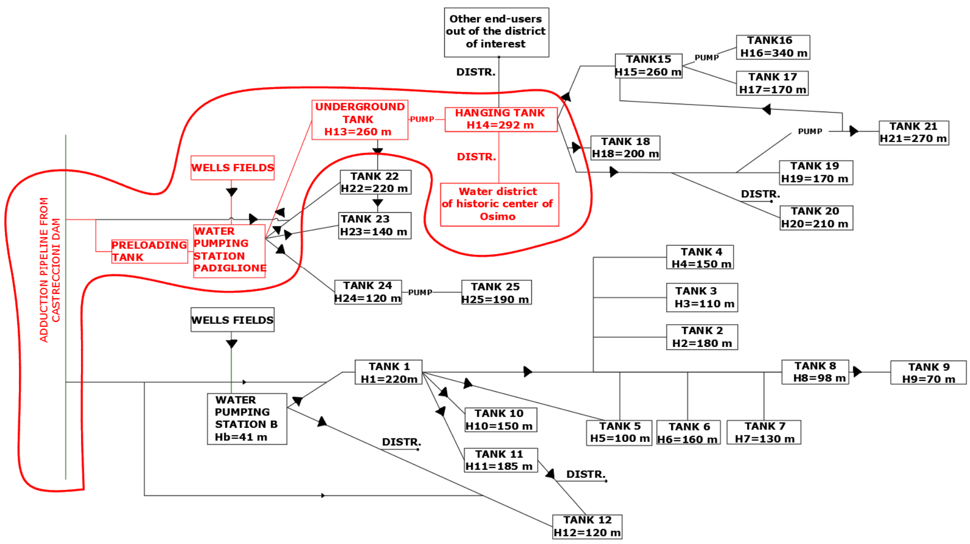

Figure 49. Layout of the Water Supply System (WSS) of Osimo with the pipeline under investigation highlighted in red.

Approximately, two-thirds of the overall supplied water volume comes from the wells and the specific energy consumption of the related pumps is evaluated as 0.15 kWh/m^3, while one-third comes from the Castreccioni dam by gravity-fed pipelines. Therefore, the sum of each specific energy consumption is used for calculating the overall energy saving. After the numerical calculation of $V_{i,\text{losses avoided}}$ according to Eq. (13) for the year 2021, which is 41,191.61 m^3, the energy saving has been evaluated through Eq. (14): its value for the year 2021 is 50,112.94 kWh. Finally, considering an electricity cost of 0.217 €/kWh and that one-third of the water supplied to the district comes from Castreccioni dam with a specific cost of water per cubic meter of 0.28 €/m^3, the overall economic saving has been calculated through Eq. (15). In particular, the overall economic saving amounts to 18,749.59 € in the year 2021.

To better understand how the water consumption monitoring system works, an example of the analysis based on the control of the MNF is shown below and it reports a water loss detection on October 2020. Figure 50 shows that on 7th October 2020 the MNF was 2.09 m^3/h. It gradually increased until it reached, on 12 October, a 4.53 m^3/h, when it was reported the occurrence of a possible rupture in the pipelines of the M4 sub-district (one of the five sub-districts previously described in Chapter 4. See green line of Fig. 14 for its position). Also, the average daily flow rate and the maximum daily flow rate have gradually increased between 7th of October and 12th October due to the break opening. In addition, without this timely intervention reported thanks to the MNF analysis, it would have led to a worsening of this rupture and to an increase of the water loss, as well. Without the MNF analysis, the repair would take place only when its size would allow detection on reporting.

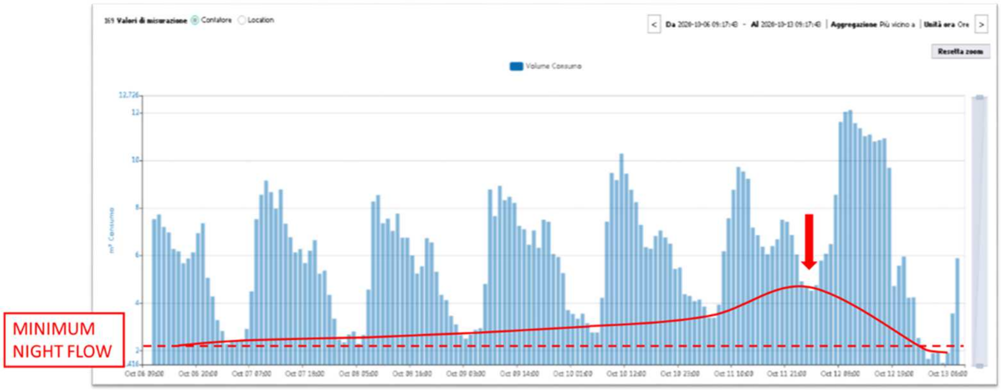

Figure 50. Water loss detection through the MNF method

Finally, for what concern the Campocavallo PS results, after the implementation of the EES, they have been discussed as following:
Table 2, shows the comparison between the percentages of the EE (Electric Energy) consumption in the year 2018 than to 2020. The choice to compare the baseline situation with the year 2020 rather than with another year, is because the electric energy consumed in these two years is almost constant and therefore, also the operating profile of the pumping station.

Table 23. Percentage of electrical energy – year 2018 vs year 2020

EE self-consumed [%]	Month	1	2	3	4	5	6	7	8	9	10	11	12	Tot.
	2018	91.6	92.8	88.5	90.7	88.9	87.5	91.6	94.5	91.5	92.2	94.1	95.7	91.1
	2020	98.3	92.3	94.1	89.7	72.8	63.9	96.7	99.9	99.9	99.2	96.2	93.3	89.6

On an annual basis it is possible to notice that the percentage of the EE self-consumed in 2020 has not improved, compared with the 2018. This is due to both meteorological factors and water demand of users. For example, if a year is characterized by a greater drought, the demand for water increases. As a result, the operating of pumps in the mid-season may vary

from year to year, cancelling the positive effect that electric storage could create. In addition, it must be considered that the Campocavallo pumping station works with a very high percentage of EE auto-consumed and therefore the improvement on an annual basis is not perceptible.
On the other hand, considering a shorter period of time, like the month of August, from Table 23 it is possible to notice that the percentage of EE self-consumed has increased from 94.5 % to 99.9 %: the electric storage has therefore led to an increase in the percentage of auto-consumption of 5.4. In particular, the choice of the month of August is because the EE consumed in the month, is almost constant over the years: this is due to the fact that the operation of the pumping system is not affected by the effect of seasonality.

6.3.3 Electric network

As explained in the previous chapter – Sub-subsection 5.3.3 and here reported for simplicity, the KPIs identified for the Pilot are:

- The improvement of the monitored quality parameters of suburban branches;
- The number of DR response hours in the year involving CHP-DH plant;
- The number of MWh of flexibility provided by the CHP plant;
- Lower congestion management costs for the DSO;
- The amount of excess electricity injected into the transmission network;
- The number of hours for which electricity is injected into the transmission network – in both winter and summer.

In this section, per each KPI, the results and comments have been described.

The improvement of the monitored quality parameters of suburban branches

Thanks to this analysis, it was possible to quantify the contribution made by the BESS introduction in the selected suburban branch: Table 24 shows the maximum and minimum average voltage values in both BESS (operating and non-operating conditions). The maximum voltage reduction obtained is 2.9 %, while the minimum voltage increase in percentage is 5.5 %.

Table 24. Maximum and minimum average voltage values in both BESS ON and OFF conditions

	Average V_{max}	Average V_{min}
BESS ON	414	395
BESS OFF	416	389

This improvement is clearly visible in Figure 51: in the first period when the BESS is switched on, the voltage peaks are less marked than those of the second period when the BESS is turned off.

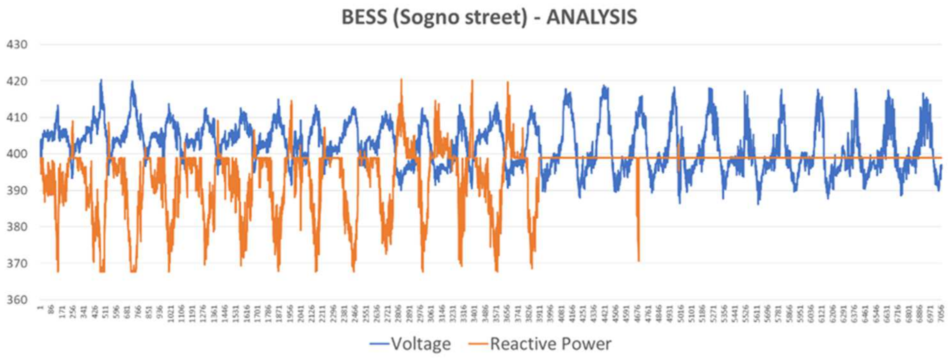

Figure 51. BESS analysis

Therefore, it is possible to state that the BESS introduction has made a positive contribution to the quality management of the network because, if it was absent, there would be higher fluctuations in terms of V_{max} and V_{min}, with the consequent need for the DSO to carry out any upgrading of the network, whose costs are discussed in the "Lower congestion management costs for the DSO" KPI, which is related to the costs avoided thanks to the introduction of the storage.

The number of DR response hours in the year involving CHP-DH plant and the number of MWh of flexibility provided by the CHP plant

The number of hours of the year 2021 in which the CHP unit has been shut down are 3,213. The MWh of flexibility provided by the CHP plants are 3,855.6 MWh, considering that its maximum power is 1.2 MW. This also means that, if the cogeneration plant is included in a flexibility programme of the TSO, the Company will be remunerated for those 3213 hours in which the CHP unit has been shut down, setting the operation of the engine (on/off) according to the electricity demand.

Lower congestion management costs for the DSO

Two cases for the cost's quantification of solutions implementation, other than the two BESS installed, are shown: the two tables below (Tables 25 and 26) show the costs of the alternative solutions to limit the congestion problem of the network, namely the secondary MV-LV electricity substations construction in both Brizi and Sogno streets, respectively. The total avoided cost for both Brizi and Sogno street is 149,980.00 €.

Table 25. Costs of the secondary MV-LV electricity substation construction in Brizi Street

CASE 1 – Brizi street

	Description	m.u.	quantity	Unit cost [€]	Total [€]
1	Excavation works for the power line for cab connection	m	800	56.40	45,120.00
2	Realization of the underground power line MV (laying + cable)	m	800	20.00	16,000.00
3	Realization of Vibrating Reinforced Concrete Cabin	-	1	15,000.00	15,000.00
4	Internal equipment (switch disconnectors)	-	3	1,400.00	4,200.00
5	Internal equipment (MV/LV transformers)	-	1	5,770.00	5,770.00
6	Internal equipment (low voltage switchgear)	-	1	200.00	200.00
7	Internal equipment (PU)	-	1	1,200.00	1,200.00
8	Cabin layout	-	1	2,000.00	2,000.00
				TOTAL AVOIDED COSTS	89,490.00

Table 26. Costs of the secondary MV-LV electricity substation construction in Sogno Street

CASE 2 – Sogno street

	Description	m.u.	quantity	Unit cost [€]	Total [€]
1	Excavation works for power line for cab connection	m	275	76.80	21,120.00
2	Realization of the underground power line MV (laying + cable)	m	550	20.00	11,000.00
3	Realization of Vibrating Reinforced Concrete Cabin	-	1	15,000.00	15,000.00
4	Internal equipment (switch disconnectors)	-	3	1,400.00	4,200.00
5	Internal equipment (MV/LV transformers)	-	1	5,770.00	5,770.00
6	Internal equipment (low voltage switchgear)	-	1	200.00	200.00
7	Internal equipment (PU)	-	1	1,200.00	1,200.00
8	Cabin layout	-	1	2,000.00	2,000.00
				TOTAL AVOIDED COSTS	60,490.00

The amount and the number of hours for which electricity is injected into the transmission network

After the introduction of Chapter 5, the results of the last two KPIs are listed below:

- The amount of the excess of the electricity injected into the transmission network. In the year 2021, the amount of excess electricity injected into the transmission network is equal to 4,584.41 MWh.
- The number of hours in which electricity is injected into the transmission network – in winter and summer. The number of hours in which the electricity is injected into the transmission network in the year 2021 is 676. Table 27 shows the number of hours per each month of the year 2021 year where there was a reversal of electricity flow.

Table 27. Number of hours per month for which electricity is injected into the transmission network

Month	**Number of hours for which electricity is injected into the transmission network**
1	11
2	30.5
3	65.75
4	96.5
5	122.75
6	86
7	50.75
8	131.25
9	59
10	14
11	3.75
12	4.75

As shown in Table 27, the greatest number of hours in which inversion of the flow occurred is in the summer and in the middle seasons (612 hours; 90.53 % of the total hours in which electricity is injected into the transmission network), that is in the months when the photovoltaic systems installed in Osimo produce the greatest amount of electricity that is then injected into the national grid.

Chapter 7.

7. Concluding Remarks

This Chapter shows the overall conclusion of this research. In particular, Subsections 7.1, 7.2, and 7.3 discuss the lessons learned, the conclusions, and the future development, respectively.

7.1 Lessons Learned

This Subsection focuses on the presentation of lessons learnt from the Osimo demo-site. In particular, Sub-subsection 7.1.1 focuses on the presentation of the main lessons learnt from planning, permitting, and installation phase for the assets installed in Osimo that include: thermal energy storage, electric energy storage, a real time acquisition system from DH&W network smart energy meters, and a CHP plant automation system. Additional lessons learnt from the operational phase of the assets are reported in Sub-subsection 7.1.2.

7.1.1 Bureaucratic Lessons Learned

Thermal Energy Storage (TES)

After a preliminary planning phase, the definition of the best solution to connect the TES at the current plant comes from a design phase followed. A list of the main lessons learnt include:

- Planning:
    - Design and structural calculations of TES components needed to be carried out thanks to the support of external engineering companies to better define both dimensional and structural aspects for the correct operation of the storage;
    - At the same time, it was necessary to define the hydraulic, instrumental, and control changes of the existing CHP plant with the support of an external expert;
    - Final design for TES needed to be validated by tank manufacturer.

- Permitting:
    - TES installation permits: the installation is under the local regulatory framework (municipal building regulations); being the installation inside a

building, a formal communication made by a qualified technician (named "SCIA" i.e. "start of activities certified statement") was required, which was then sent to the municipality where the installation took place;
    - From the hydraulic point of view, a TES is a pressurized device, which implied the application of the Pressure Equipment Directive 2014/68/EU (PED) to certify this new equipment;
    - From the structural point of view, a TES is a technological equipment, thus there are not specific permits for this aspect;
    - From the transport point of view, a TES is a Big Size Load and permits are required for road transport as well as for sea transport.
- Installation:
    - No particular lessons learnt because the installation is standard.

Electric Energy Storage (EES)
For the electric storage system installation at the Campocavallo pumping station, the main lessons learnt are:

- Planning.
    - The sizing plays a key role since the optimization of the electric storage system size allows maximizing the electricity self-consumption from the photovoltaic plant and contemporarily minimizing installation costs.
- Permitting.
    - From the electrical point of view, being the EES an active connection, the authorization from the local DSO was required since a change to the existing electrical system is needed;
    - No permit was required for installation works;
    - A new certification for the electrical system needed to be prepared by a specialized technician.
- Installation.
    - The installation did not require any special measures since it is a standard installation.

For what concern the BESS installation in the two Osimo streets instead, during the pilot setup an unexpected drawback arises related to technology acceptance by final citizens. In particular, complaints were related to the installation of BESS in one of the two "local renewable energy communities". This aspect is worth to be mentioned because a BESS is supposed to be a well-known everyday technology. It is even more important because a BESS is considered one of the key enabling technologies for the energy transition. During the quality issues monitoring campaign, two residential areas were identified for the installation of several EESs. Once the sites have been identified, the first step was to obtain the authorization from the municipality and from the City Council about the temporary occupation of the public area. Consequently, a report on the general objectives of the INTERRFACE project was requested. In the report, the benefits brought by the installation of the electrical storage in the selected site were highlighted. In the meanwhile, the residents of the selected areas came to knowledge of the project, and few of them raised doubts about the health issues (aspects related to electromagnetic compatibility) and aesthetic issues (according to some of them, it was damaging the visual impact in a parking lot and close to homes). As a result of these complaints, a public neighbourhood meeting was held. The meeting was attended by the citizen, public authorities as well as the same ASTEA and DEA people who emphasized the peculiarities of the project and demonstrate compliance of storage with industry regulations. A small part of the residents (about 10 %) remained on their own idea and therefore a greater distance from the houses was suggested to avoid troubles in the new site of installation, but the owner of the site did not accept the idea. The final solution identified in the same street has the following features:

- It is located at a reasonable distance from the houses (about 50 m from the nearest house);
- It reduces the visual impact since it will be placed at a lower altitude than the existing road plan. In addition, a green barrier has been foreseen so that it will embellish and further hide the battery container;
- Easy connection to the existing LV network.

Based on this experience, there is a need for a campaign to raise the awareness of these "new" technologies to the citizens.

Real time data acquisition system from DH&W network smart energy meters

To collect the data coming from both district heating (DH) and water networks, a real time data acquisition system has been installed, which is composed of an infrastructure able to capture signals from a large number of smart meters. The main lessons learnt on this include:

- Planning:
    - The supplier company needed to carry out a morphological analysis of the territory and, based on this, it has defined the minimum number of antennas required to acquire the signals from the smart meters.
- Permitting:
    - The remote reading infrastructures have been installed in both buildings owned by ASTEA, whose permit was required, and in buildings owned by third parties that required the redaction of a convention between ASTEA and the building owner;
    - From the installation point of view, emissions are not present for private telecommunications which were finalized only to data acquisitions with business purposes, and thus no permit was needed.
- Installation:
    - The remote reading infrastructure installation was carried out by the specialized technicians of the supplier company; most of the effort was concentrated in the calibration phase.

CHP plant automation system

Finally, the lessons learnt on the CHP unit automation system include the following:

- Planning:

        - A preliminary planning could be carried out by the ASTEA technicians, then the executive design needed to be carried out by a company specialized in automation systems.
- Permitting:
    - Since the intervention was considered as an extraordinary maintenance of the existing plant, any additional permit was required.
- Installation:
    - The installation was performed by specialized technicians of the supplier company; then, a new certification for the system needed to be issued.

7.1.2 Operational Lessons Learned

CHP-DH plant

i. The first lesson learnt on the cogeneration plant is related to the current geopolitical context in which the electricity prices and the natural gas prices in Italy reached 425.60 and 174.00 €/MWh, respectively (data taken from the GME site, Gestore Mercati Energetici – Mercato del Giorno Prima, on 13 July 2022). For this reason, the operation of the cogeneration plant needs to be controlled not only to maximize the environmental benefits, but also to minimize the operational costs. To this aim, the CHP plant automation could be implemented with an additional low-level controller, namely an economic optimization software based on the market parameters related to the CHP-DH plant operation that are:

    - the cost of both electricity and natural gas;
    - the maintenance costs of the CHP unit;
    - the revenues for the sale of electricity and heat;
    - the revenues from the production of the so-called Energy Efficiency Certificates (EECs) and imbalance charges for electricity fed into the grid.

    Entrusting that the CHP unit production program to this software, even with a low thermal demand of district heating users, like in July and August, the CHP unit operation could be convenient from both energy and economic points of view. As explained above, this is due to the current geopolitical context and the energy market prices. Indeed, the EEC markets are fundamental to sustain the cost of the investment, as well as being a source of income from the production perspective. For this reason, it is important to study new possible installation of technologies able to increase the system flexibility such as heat pump and/or thermal energy storage.

ii. The installation of possible further technologies, such as the HP and TES considered in this study, are able to guarantee system flexibility if they are coupled with the CHP unit. The combination of these two new resources give benefits for the entire year: indeed, the HP allows to obtain major benefits in the winter season when the CHP unit is fully operational as well as the heat pump. The TES installation, instead, does not affect in the winter season, but in the mid- and summer seasons. This occurs because the TES allows the CHP unit to operate even in the summer season when the baseline configuration is off. These results can be considered a good indication for generally improving other DH networks located in the north of Europe with a forecast for obtaining better results than those reported in this work due to the colder temperatures throughout the year. These solutions lead to important advantages from energetic, environmental, and economic points of view. Obtained outcomes can be useful to improve other DH networks and push forward the use of these technologies in those countries where the use of DH networks can be favorable.

iii. Also in a small DH network like in Osimo, which is located in medium climate zone, the coupling of CHP and DH is more advantageous in terms of energetic, environmental, and economic points of view for both thermal plant and end users' side;

iv. Although the European Union promotes the use of DH network, highlighting its convenience, comfort, and safety compared to IH, there are still too many bureaucratic obstacles that do not allow the reduction of construction costs, thus increasing the number of served end-users;

v. The common feeling of the consumers of DH networks is that the cost of a DH is higher than that of IH: this aspect is mainly linked to the geographical position of the DH network, as well as the degree of development in a specific area.

Electricity Storage Systems

i. Given the very high self-consumption rate for electricity produced from renewable sources already achieved before the installation of the electricity storage systems in Campocavallo PS, the increase due to these devices is limited and it is not impactful on annual bases.

7.2 Conclusions

The purpose of this thesis is to provide a synopsis of the various elements that characterize a smart city to achieve the climate neutrality by 2050, and focuses mainly on the development of the SES and LECs. Moreover, in this work the installation of flexibility resources and the use of the DSM strategies that allow the optimal management of multi energy vector systems have been evaluated.

From the realization point of view, making a city "smart" is a non-trivial and expensive process, especially in terms of timing: a smart city is a place where traditional networks and services are made more efficient with the use of digital solutions for the benefit of its inhabitants. A smart city goes beyond the use of digital technologies for a better use of the resource and less emissions. It means smarter urban transport networks, upgraded water supply and waste disposal facilities, and more efficient ways to light and heat buildings. It also means a more interactive and responsive city administration, safer public spaces, and meeting the needs of an ageing population.

This study focused only on two components of a smart city: the smart grid and the smart community. The implementation of the former is closely related to the implementation of a Smart Control Architecture with DSM strategies and flexibility resources. These are able to create synergies between energy carriers, thus managing them as a whole and connecting them to infrastructure and consumer sectors. This creates a more circular energy system based on the energy efficiency. The skeleton of the smart energy system remains the digitalization of the energy networks that requires a well-defined methodology, and the reliance on Cloud infrastructures whose fundamental characteristics are flexibility, customization, accessibility, and data analysis. Regarding the implementation of the smart community of the case study under investigation, which focuses on a greater direct electrification of the end-use sectors through storage systems, to date it cannot be considered an energy community. As a REC, a legal entity should have been established based on (i) open and voluntary participation and is autonomous; (ii) shareholders or members that are natural persons, SMEs, local authorities etc. and (iii) as a main objective to provide environmental, economic or social benefits at the community level to its shareholders or members, or to the local areas in which it operates rather than financial profits. In view of the difficulty encountered in the users' engagement, as well as the "fears" of some citizens to have technologies (that are almost unknown to them) near their homes and mistakenly considered dangerous, it was not able to find an agreement among them to establish a renewable energy community. For this reason, the exclusion of the large enterprises such as Astea SpA from the configurations admitted to the service of the enhancement and the encouragement of shared electricity is a negative aspect. Indeed, they could support the communities, proposing the actions to be carried out to achieve the objectives, supporting the investments, managing the production and maintenance of the plants, interfacing with the GSE, and distributing the economic benefits of the initiative to members. It is clear that the relationship between the energy company and the community must be regulated through an appropriate agreement, the details of which can be of delicate negotiation and that can in no way undermine the purposes and objectives that distinguish the energy communities. In addition, the incentive for the enhancement of renewable energy is defined on the share of self-consumed energy; thus, it is therefore necessary to optimize (sizing of plants and storage systems). The role of a third party carrying out these analyses is fundamental to this aim.

Finally, considering all the implementations carried out in the Osimo demo-site to make it a Smart City, the energy, environmental, and economic benefits obtained are the following:

- In the CHP-DH plant, both thermal power plant and end users' sides have been analysed, as well as technical improvements obtained thanks to the new installations. Precisely, two parameters have been used to assess the energy performance of the overall DH network under investigation: the Primary Energy Saving (PES) and the specific energy (E_{sp}). It is worth noting that the specific energy difference (ΔE_{sp}) obtained considering the actual thermal power plant layout, constituted by two boilers and a Combined Heat and Power (CHP) unit, and the IH has been studied, where positive values mean that the Natural Gas (NG) exploitation is better exploited and vice versa. In the seven months considered, there was an increase in specific energy from 2018 to 2022 of 0.87. In particular, the lowest value of the ΔE_{sp} in 2018 was recorded in October, and it was equal to 0.73; in October 2022, this value increased by 2.84. Regarding the PES, a yearly value of 21.2 % has been reached, maintaining it almost constant than its value in 2018. From the environmental point of view, 1,512 tCO_2 are avoided, with an increasing of avoided CO_2 of 281 tCO_2 than the baseline situation. As for the economic analysis on the thermal plant side, thanks to the achievement of 776.3 EECs, it is possible to obtain an economic income of 194,075 €, with an increase of 54.5 EECs than the baseline situation, equal to an economic increase of 13,625 €. Finally, on the user side, the DH was found to be, yearly, cheaper than individual heating in 84.7 % of the cases considering that the management of the cogeneration plant lowered the connection cost till the one referred to a 25-kW condensing boiler installation. The last aspect discussed in the Sub-subsection of the DH network results, is the economic analysis on the end-users' side, which highlighted how the extra cost related to the IH boilers influences the final bill of the end-users: indeed, considering the extra cost, the DH is more convenient than IH and vice versa;

- Regarding the WDN, the avoided water losses for the year 2021 were 41,191 m^3/y. Furthermore, considering the unit electricity consumption of pumps equal to 0.15 kWh/m^3 from the water wells to Padiglione pumping station, 0.98 kWh/m^3 from Padiglione to the underground tanks, and 0.189 kWh/m^3 from the underground to hanging tanks, the energy and economic benefits are 50,113 kWh/y and 18,750.00 €/y, respectively. In addition, the implementation of the EES in Campocavallo PS on annual bases, has not increase the percentage of EE self-consumed. On the other end, the new installation has led to an increase of EE self-consumed from 94.5 % to 99.9 % in the month of August 2020 than the baseline situation.
- Regarding the electricity network, the following KPIs have been evaluated: the improvement of the monitored quality parameters of the suburban branches; the number of DR response hours in the year involving CHP-DH plant and the number of MWh of flexibility provided by the CHP plant; lower congestion management costs for the DSO, and the amount and the number of the hours in which electricity is injected into the transmission network. Considering that the voltage must be in a certain range (360 V – 440 V), the improvements of the monitored quality parameters after the BESS installation were the reduction of the maximum voltage of 2.9 % and the increase of the minimum voltage of 5.5 %. The number of hours of the year 2021 in which the CHP unit has been shut down are 3,213, providing a flexibility of 3,855.6 MWh. Furthermore, the costs quantification of the alternative solutions implementation other than the two BESS installed have been evaluated. To limit the congestion problem of the network, namely the secondary MV-LV electricity substations construction in both Brizi and Sogno streets, the total avoided cost for both streets was 149,980.00 €. Finally, in the year 2021, the amount of the excess of electricity injected into the transmission network was equal to 4,584.41 MWh, while the number of hours in which the electricity is injected into the transmission network in the year 2021 was 676.

7.3 Future Developments

In this Subsection, the future developments of this research are listed hereinafter:

- The involvement of the final users in DSM strategies can be effective for the specific plant if energy conservation strategies want to be implemented. It could be interesting to evaluate how the set-point temperature reduction of all the residential users decreases the DH thermal demand and the thermal losses as well. This would be possible simply with an increased awareness campaign of the end users, as well as with a dedicated App that allows to evaluate in real time the energy, environmental, and economic benefits that would result in setting the internal temperature of their homes at a lower value while maintaining the hygrometric comfort;

- ASTEA communicates every year the scheduling of the 1.2 MWe CHP plant; on this scheduling, then the TSO can ask for deviations (flexibility) for this program until one day before the deviation is required with a15-minutes notice on activation time on the same day.

In this context, DEA already acts as a super-partes facilitator for global ancillary services between the DG supplier and the TSO. Indeed, the TSO and the supplier agree the flexibility program with the supplier without consulting the DSO which must guarantees the quality of distribution network between supplier and primary cabin (Figure 52). Currently, in this pilot an informal coordination exists since ASTEA owns both the CHP power plant and is also 100 % shareholder of DEA.

As already mentioned in the lessons learned, in the current geopolitical context in which the cost of electricity is increased of 361.9 €/MWh than the average value in July 2018, the implementation of the low-level control of the CHP plant with algorithms focused on the economic compensation could be a viable option. The control logic of the CHP unit should no longer be heat-tracking, but electric. This is due to the economic return of a company that is the basis for the development of a district heating network. It would be interesting to evaluate, through future studies, how much energy, environmental, and economic benefits would change if such strategies were implemented.

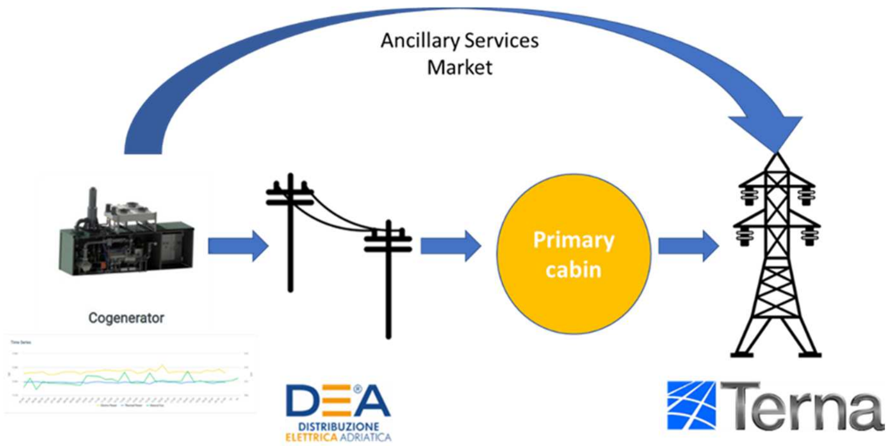

Figure 52. TSO-DSO-Flexibility Supplier, existing situation at Italian Pilot

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