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PLANNING AND FLEXIBLE OPERATION OF STORAGE SYSTEMS IN POWER GRIDS: FROM TRANSMISSION TO DISTRIBUTION NETWORKS

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Abstract

Planning and operation of power networks considering the presence of Renewable Energy Sources (RES) and Battery Energy Storage (BES) systems is a timely subject, which involves different aspects and technological solutions. Within this wide context, this thesis has addressed some technical issues relevant to the transmission grid – essentially concerning the expansion planning problems – and to the distribution one – concerning both planning and optimal day-ahead dispatching of Renewable Energy Communities (RECs) energy sources.

In particular, the first part of the thesis has been devoted to the expansion planning problem of transmission grids with high penetration of RES. Both stationary and transportable battery energy storage (BEST) systems have been considered in the planning model, so to obtain the optimal set of BES, BEST and transmission lines that minimizes the total cost in a power network. First, a coordinated expansion planning model with fixed transportation cost for BEST devices has been presented and validated through the modified Garver's 6-node system. Then, the model has been extended to a planning formulation with a distance-dependent transportation cost for the BEST units, applied to a real China regional grid with high renewable energy penetration, and its tractability has been proved through a case study based on a 190-bus test system. The main improvement given by the more refined extended planning formulation relays on its applicability to any power systems, and not only to those where BEST fixed transportation cost could be a reasonable assumption. For both planning formulations, a single-stage approach has been considered as the investment decisions are obtained for a single year planning horizon.

The first part of this thesis has been largely inspired by my internship at Tsinghua University, China, where part of the relevant work has been accomplished. In China, a large amount of RES generation is located far away from loads and BEST systems seem to represent a promising and innovative solution. In other contexts such as Europe in general, and Italy in particular, where the power network paradigm at the distribution level is moving towards a user-centric scheme, planning of RES and BES units is becoming an important issue at the level of renewable energy communities.

The second part of this thesis is then devoted to the analysis of planning and management of RECs equipped with RES and BES systems. The relevant activity has been inspired by my involvement in the framework of Climate-KIC GE.C.O project, aimed at the creation of a renewable energy community in a district of the city of Bologna.

Initially, the planning of Photovoltaic (PV) and BES systems in a REC with an incentive-based remuneration scheme according to the Italian regulatory framework has been analysed, and two planning models, according to a single-stage (static), or a multi-stage (dynamic) approach, through which long term loads uncertainty and solar irradiation can be considered, have been proposed in order to provide the optimal set of BES and PV systems allowing to achieve the minimum energy procurement cost in a given REC. A comparative analysis of the two above mentioned model formulations has been carried out; then, several cases differing by the value of discount rate, planning horizon, and by assuming or not a minimum BES investment for each prosumer, have been studied through the multi-stage planning approach. The obtained solutions have been compared to the case when the investment cost is zero, characterized by different operational costs and incomes, in order to quantify the effective benefits of the optimal planning scheme achieved.

Further, the optimal management of the available resources has been addressed along with the optimal scheduling of storage systems so to minimize the energy procurement cost for a considered community, while fully exploiting the possible revenues foreseen. To this end, the second part of this thesis is devoted to the study of the day-ahead scheduling of resources in renewable energy communities, by considering two types of REC. The first one, which we will refer to as “cooperative community”, allows direct energy transactions between members of the REC, and aims to minimize the total energy procurement cost given by the energy exchanged with the external provider; the second type of REC considered, which we shall refer to as “incentive-based”, does not allow direct transactions between members but includes economic revenues for the community shared energy, which, according to the Italian regulation framework, is the minimum, at each hour, between the renewable energy fed into the electrical grid by the REC and the total energy demand required to the grid by the community. Moreover, dispatchable renewable energy generation has been considered by including producers equipped with biogas power plants in the community. Such analysis aimed also to quantify the contributions of all the components that build up the energy procurement cost for both types of REC. A comparative analysis with and without dispatchable generation units has been presented and discussed.

Finally, the dissertation provides the description of the Climate-KIC GE.C.O project, which relies not only on the availability of PV units and of BES systems, but also on the availability of an energy management system capable of optimally dispatching the energy flows among the prosumers and among the prosumers and the network (day ahead dispatch). In order to accomplish that, data relevant to these energy flows need to be available, and for this reason the existing smart metering technologies have been thoroughly reviewed, and some selected smart meters have been installed at one location of the GE.C.O area (i.e. CAAB, Centro Agro Alimentare Bologna) also within the framework of the present dissertation. The power profiles of some prosumers of the district area of interest, gathered thanks to the installed smart meters are reported, along with data of clusters of prosumers connected to two main feeders of the relevant area. The instruments installed at the CAAB area have been also used both to implement an acquisition system and to characterize the profile of some of the characteristics loads present in the area. They are expected to be of great assistance in the validation of the models.

Contents

List of Figures

List of Tables

Nomenclature

Acronyms

AD	Anaerobic Digestion
ADMM	Alternating Direction Method of Multipliers
API	Application Programmable Interface
ARERA	Autorità di Regolazione per Energia Reti e Ambiente
BES	Battery Energy Storage
BEST	Battery-based Energy Storage Transportation
CEC	Citizen Energy Community
CEP	Clean Energy Package
CES	Community Energy Storage
COP	Conference of Parties
CT	Current Transformer
DSO	Distribution System Operator
EMD	Electricity Market Directive
EMS	Energy Management System
ESS	Energy Storage System
EU	European Union
GHG	Green House Gas
GOPT	Grid Optimization Planning Tool
GSE	Gestore dei Servizi Energetici
HRP	High Renewable Penetration
IoT	Internet of Things
LFP	Lithium Iron Phosphate
LHV	Lower Heating Value
LV	Low Voltage
LP	Lineal Programming
MESS	Mobile Energy Storage System
MILP	Mixed Integer Lineal Programming
MiSE	Italian Ministry of Economic development
MV	Medium Voltage
NILM	Non-Intrusive Load Monitoring
NZ	Number-of-nonzero
NZE	Net Zero Emissions Scenario
NPV	Net Present Value
OF	Objective Function
PLC-C	Power Line Communication - Chain 2
POD	Point of Delivery
PV	Photovoltaic

P2P	Peer-to-Peer
PVGIS	Photovoltaic Geographical Information System
REC	Renewable Energy Community
RED II	Renewable Energy Directive
RES	Renewable Energy Sources
2G	Second Generation
SCUC	Security Constraint Unit Commitment
SME	Small or Medium Enterprise
SNOCU	Smart Node Control Unit
SoE	State of Energy
TESS	Transportable Energy Storage System
DU	Users Devices
VRE	Variable Renewable Energy

List of Symbols

Model of the Transmission Expansion Planning with BEST

Ω_L	Set of all lines.
Ω_{LC}	Set of candidate lines.
Ω_{LE}	Set of existing lines.
Ω_{OP}	Set of operating conditions.
Ω_I	Set of thermal units.
Ω_{bes}	Set of BES systems.
Ω_{best}	Set of BEST systems.
$\Omega_{i_b}^{L_1}$	Set of lines whose sending end node is i_b.
$\Omega_{i_b}^{L_2}$	Set of lines whose receiving end node is i_b.
$\Omega_{i_b}^{I}$	Set of thermal units located at node i_b.
$\Omega_{i_b}^{w}$	Set of wind farms located at node i_b.
$\Omega_{i_b}^{pv}$	Set of photovoltaic systems located at node i_b.
$\Omega_{i_b}^{i_{bes}}$	Set of BES systems located at node i_b.
$\Omega_{i_b}^{i_{best}}$	Set of BEST systems located at node i_b.
Δt	Time step.
d_j	Duration of operating condition j, i.e. number of days included in each operating condition j.

n_{oc}	Number of operating conditions.
C_i^{gen}	Generation cost of thermal unit *i*.
C^{shed}	Load shedding operation cost.
$K_{dist}^{i_{best}}$	BEST transportation cost for each unit distance travelled.
$K^{i_{best}}$	Fixed transportation cost for each trip of BEST system.
C_l^{Line}	Annualized investment cost of line *l*.
$C_{i_{bes}}^{Storage}$	Annualized investment cost of BES system i_{bes}.
$C_{i_{best}}^{Best}$	Annualized investment cost of BEST system i_{best}.
$E_{t=0}^{i_{best}}$	Energy content of BEST system i_{best} at time t=0.
$\eta_{ch}^{i_{best}}, \eta_{dis}^{i_{best}}$	Charge and discharge efficiency of BEST systems i_{best}.
T	Set of time intervals.
M	A large enough constant.
$E_{\min}^{i_{best}}, E_{\max}^{i_{best}}$	Minimum and maximum energy content of BEST system i_{best}.
$P_{\min,ch}^{i_{best}}, P_{\max,ch}^{i_{best}}$	Minimum and maximum charging power of BEST system i_{best}.
$P_{\min,dis}^{i_{best}}, P_{\max,dis}^{i_{bes}}$	Minimum and maximum discharging power of BEST system i_{best}.
$SoE_{i_{best},j,t}^{best}$	State of Energy of BEST system i_{best} at time t in operating condition j.
$E_{t=0}^{i_{bes}}$	Energy content of BES system i_{bes} at time t=0.
$\eta_{ch}^{i_{bes}}, \eta_{dis}^{i_{bes}}$	Charge and discharge efficiency of BES systems i_{bes}.
$E_{\min}^{i_{bes}}, E_{\max}^{i_{bes}}$	Minimum and maximum energy content of BES system i_{bes}.
$P_{\min,ch}^{i_{bes}}, P_{\max,ch}^{i_{bes}}$	Minimum and maximum charging power of BES system i_{bes}.
$P_{\min,dis}^{i_{bes}}, P_{\max,dis}^{i_{bes}}$	Minimum and maximum discharging power of BES system i_{bes}.
$SoE_{i_{bes},j,t}^{bes}$	State of Energy of BES system i_{bes} at time t in operating condition j.
$n_0^{i_{best}}$	Number of days where BEST is not providing any contribution to the system.
X_l	Binary variables that equals 1 if line *l* is build and 0 otherwise.
$Y_{i_{bes}}$	Variables that indicate whether to settle the BES system i_{bes}.
$V_{i_{best}}$	Variables that indicate whether to settle the BEST system i_{best}.
$P_{i,j,t}^{gen}$	Power output of thermal unit i at time t in operating condition j.
$P_{i_b,j,t}^{Load}$	Load demand at node i_b at time t in operating condition j.
$L_{i_b,j,t}^{shed}$	Load shedding power at node i_b at time t in operating condition j.
$n_{Trip}^{i_{best}}$	Trips number of BEST system i_{best}.
$n_{dist,j}^{i_{best}}$	'Bus distance' between operating conditions j and j+1 of BEST system i_{best}.
$n_j^{i_{best}}$	Bus position of BEST system i_{best} in operating condition j.

$n_{0,j}^{i_{best}}$	Variable indicating whether BEST system i_{best} is operative in operating condition j.
$P_{i_{best},i_b,j,t}^{best,ch}$	Charging power of BEST system i_{best} at node i_b, at time t in operating condition j.
$P_{i_{best},i_b,j,t}^{best,dis}$	Discharging power of BEST system i_{best} at node i_b, at time t in operating condition j.
$r_{i_{best},j,t}^{best}$	Reserve content of BEST system i_{best} at time t in operating condition j.
$P_{i_{bes},j,t}^{bes,ch}$	Charging power of BES system i_{bes} at time t in operating condition j.
$P_{i_{bes},j,t}^{bes,dis}$	Discharging power of BES system i_{bes} at time t in operating condition j.
$r_{i_{bes},j,t}^{bes}$	Reserve content of BES system i_{bes} at time t in operating condition j.
$P_{w,j,t}^{wind}$	Power output of wind farm w at time t in operating condition j.
$P_{v,j,t}^{PV}$	Power output of PV generator v at time t in operating condition j.
$F_{l,j,t}$	Power flow of line l at time t in operating condition j.
$\vartheta_{i_b,j,t}$	Voltage angle of node i_b at time t in operating condition j.

Planning model of a REC

Ω	Set of participants in the REC, with $i, j, k \in \Omega$.
N	Total number of participants in the REC.
P	Set of years in the planning horizon.
π_{buy}^{t}, π_{sell}^{t}	Price of buying and selling energy from and to the external grid at t, respectively.
C_p^{Inv}	Total investment cost at year p.
C_p^{Oper}	Operative cost at year p.
C_p^{Inc}	Incentive received by the community at year p.
$C^{Storage}$	Investment cost of storage system.
C^{PV}	Investment cost of photovoltaic system.
$Y_{i,p}$	Total investment decisions on BES system of i from year 0 to year p.
$I_{i,p}$	Total investment decisions on PV system of i from year 0 to year p.
r	Discount rate.
$P_{\text{sell\_Grid}\,i}^{t,j,p}$	Power sold to the external utility grid by i at t, in j of year p.
$P_{\text{buy}\,i,j}^{t,j,p}$	Power bought to the external utility grid by i at t, in j of year p.
I_{E_s}	Incentive given for the shared energy.
$E_{Shared}^{t,j,p}$	Shared energy of the REC at t, in j of year p.
$P_{\text{PV}\,i}^{t,j,p}$	Photovoltaic power output of prosumer i at t, in j of year p.
$P_{\text{Load}\,i}^{t,j,p}$	Power load of prosumer i at t, in j of year p.

$P_{\mathrm{ch}\,i}^{t,j,p}$, $P_{\mathrm{dis}\,i}^{t,j,p}$	Charging and discharging power of the *i*-th battery at *t*, in *j* of year *p*, respectively.
$M2_{\mathrm{f}\,i}^{t,j,p}, M2_{\mathrm{w}\,i}^{t,j,p}$	Power fed in and withdrawn by the PV and BES systems of prosumer *i*, at time period *t*, in operating condition *j* of year *p*, respectively.
$z_i^{t,j,p}$	Binary variable to decouple meter M2 measurements for *i* at *t*, in *j* of year *p*.
$K_i^{j,p}$	Ratio factor between $\sum_{t\in T} M2_{\mathrm{w}\,i}^{t,j,p}$ and $\sum_{t\in T} M2_{\mathrm{f}\,i}^{t,j,p}$ of prosumer *i* at *t*, in *j* of year *p*.
$P_{i,j,t,p}^{f}$	PV forecast generation profile for *i* at *t*, in *j* of year *p*.
$u_i^{t,j,p}$	Binary variable to prevent simultaneous purchases and sales by *i* at *t*, in *j* of year *p*.
$E_{\mathrm{BES}\,i}^{t,j,p}$	State of energy of battery *i* at *t*, in *j* of year *p*.
$u_{\mathrm{BES}\,i}^{t,j,p}$	Binary variable to avoid concurrent charging and discharging of the *i*-th battery at *t*, in *j* of year *p*.
$E_{\mathrm{BES}\,i}^{\mathrm{min}}$	Minimum level of stored energy in battery *i*.
$E_{\mathrm{BES}\,i}^{\mathrm{max}}$	Maximum storage capacity of battery *i*.
$P_{\mathrm{BES}\,i}^{\mathrm{max}}$	Maximum value of discharging and charging power of the *i*-th battery.
$P_{\mathrm{BES}\,i}^{\mathrm{min}}$	Minimum value of discharging and charging power of the *i*-th battery.
I_{PV}^{max}	Maximum investment of PV systems.
C_a^{PV}	Annualized investment cost of PV system.
$C_a^{Storage}$	Annualized investment cost of storage system.

Day ahead scheduling of the REC

B	Set of branches of the internal network in the REC, with $b \in B$.
$P_{\mathrm{buy\_Grid}\,i}^{t}$	Power bought from the utility grid by *i* at *t*.
$P_{\mathrm{sell\_Grid}\,i}^{t}$	Power sold to the external utility grid by *i* at *t*.
$P_{\mathrm{buy}\,i,j}^{t}$	Power bought by *i* from *j* at *t*.
$P_{\mathrm{sell}\,i,j}^{t}$	Power sold by *i* to *j* at *t*.
$P_{\mathrm{PV}\,i}^{t}$	Photovoltaic power output of prosumer *i* at *t*.
$P_{\mathrm{Load}\,i}^{t}$	Power load of prosumer *i* at *t*.
$P_{\mathrm{ch}\,i}^{t}$, $P_{\mathrm{dis}\,i}^{t}$	Charging and discharging power of the *i*-th battery at *t*, respectively.
$L_{b,i}^{t}$	Estimated losses in branch *b* originated by the energy transactions of the *i*-th prosumer at *t*.
R_b	Resistance of branch *b* of the internal network.
V_{n}	Line-to-line rated voltage value.
$F_{b,i}^{t}$	Power flow in branch *b* at *t*, due to the energy transaction that involves the *i*-th prosumer.
A_{Grid} , A	Matrices of the configuration of the network.

u_i^t	Binary variable to prevent simultaneous purchases and sales by *i* at *t*.
$P_{\text{sell }i}^{\max}$	Power limit for *i* when selling.
$P_{\text{buy }i}^{\max}$	Power limit for *i* when buying.
$E_{\text{BES }i}^{t}$	State of energy of battery *i* at *t*.
$u_{\text{BES }i}^{t}$	Binary variable to avoid concurrent charging and discharging of the *i*-th battery at *t*.
L	Set of segments employed by the piece-wise linearization of the losses, with index *l*.
$H_{\text{Flow }b,l}^{t}$	Breakpoint of the power flow associated with branch *b* and segment *l* at *t*.
$H_{\text{Loss }b,l}^{t}$	Breakpoint of the losses associated with branch *b* and segment *l* at *t*.
$a_{b,l}^{t}$	SOS2 (Special ordered set of type 2) variables associated with the power flow/losses breakpoints in *b* at *t*.
F_b^t	Power flow in branch *b* at *t* due to all the relevant transactions.
$C_{\text{biogas}\,i}^{t}$	Cost of using the biogas unit *i* at *t*.
$P_{\text{biogas}\,i}^{t}$	Power output of the dispatchable generator owned by *i* at *t*.
$C_{\text{gas}\,i}$	AD gas cost of biogas unit *i*.
U	Set of segments employed by linearization with breakpoints x_{u}..
α_u , β_u	Linearization parameters of the *u*-th segment.
$P_{\text{biogas}}^{\max}$, $P_{\text{biogas}}^{\min}$	Maximum and minimum power output of the biogas unit, respectively.
$C_{\text{fuel}\,i}^{\text{max day}}$	Maximum value of the daily fuel consumption of biogas unit *i*.
SU_i^t	Non-negative variable to indicate whether the biogas unit *i* starts up at *t* or not
w_i^t	Binary variable, which indicates whether the biogas unit *i* is on or off during time interval *t*.
E_{Shared}^{t}	Shared energy of the REC at *t*.
$M2_{\text{f }i}^{t}$, $M2_{\text{w }i}^{t}$	Power fed in and withdrawn by the PV and BES systems of prosumer *i*, at time period *t*, respectively.
z_i^t	Binary variable to decouple meter M2 measurements for *i* at *t*.
K_i	Ratio factor between $\sum_{t\in T} M2_{w\,i}^{t}$ and $\sum_{t\in T} M2_{\text{f }i}^{t}$ of prosumer *i* at *t*.

ADMM implementation

λ_i^t	Lagrange multipliers of prosumer *i* at *t*.
ρ	Penalization parameter.
m	Scale factor.
v	Iteration of the ADMM algorithm.

$\hat{P}^{t}_{\text{buy\_Grid } i}$	Profile of $P^{t}_{\text{buy\_Grid } i}$ obtained at the previous iteration.
$\hat{P}^{t}_{\text{sell\_Grid } i}$	Profile of $P^{t}_{\text{sell\_Grid } i}$ obtained at the previous iteration.
$\hat{P}^{t}_{\text{buy } i,j}$	Profile of $P^{t}_{\text{buy } i,j}$ obtained at the previous iteration.
$\hat{P}^{t}_{\text{sell } i,j}$	Profile of $P^{t}_{\text{sell } i,j}$ obtained at the previous iteration.
r_i^t	Primal residual for prosumer *i* at *t*.
ε	Convergence tolerance of the ADMM algorithm.

Chapter 1. Introduction

Introduction

"*Indeed, as UN Secretary-General Antonio Guterres has said, climate change is "the defining issue of our time." [...] Our focus, however, should not be limited to halting downward spirals. Because climate change is an issue that will leave no one untouched, it has the potential to catalyze heretofore unseen global solidarity and action. Our success or failure in actualizing this potential is in fact the defining issue of our time.*" (Daisaku Ikeda 2020)

1.1 Climate Neutrality and Energy Transition

The above sentence has somehow inspired the content of the Introduction of this dissertation. As a matter of fact, it is becoming increasingly crucial for countries around the world to accept the challenges of addressing the climate crisis, and move forward to achieve carbon neutrality.

On the other hand, as a student of the PhD program in Electrical engineering at University of Bologna I have immediately realised how important, in order to accomplish the above target, can be the progressive electrification of energy loads and the large-scale deployment of electricity production units fed by renewable energy sources, both at the transmission and distribution levels of the power network.

More in detail, the first-ever universal global climate change agreement is the Paris Agreement, adopted at the Paris climate Conference of Parties (COP) in December 2015, i.e. COP21. The Paris Agreement sets out a global framework to avoid dangerous climate change by limiting global warming to well below 2°C and pursuing efforts to limit it to 1.5°C. It also aims to strengthen countries' ability to deal with the impacts of climate change and support them in their efforts. In the context of the COP21 meeting, the European Union (EU) committed itself to limit Green House Gas (GHG) emissions as low as required to stay below a 2 °C rise in average global temperature. The EU adopted an ambitious policy package entitled "Clean Energy for all Europeans" package (Clean Energy Package, CEP), which includes GHG emission reductions (40% less than the levels of 1990, the reference year), energy efficiency (32.5% less primary and final energy than projected in 2007 before the economic crisis) and renewable energy (32% as a share of gross final energy consumption) in the year 2030. Recently, the European Union's emissions reduction target for 2030 has been revised: in September 2020, the EU Green Deal has proposed the reduction target to be set at 55 %, alongside a revision of the EU's climate and energy legislation (EU 2020). The Commission adopted the communication 'Stepping up Europe's 2030 climate ambition - Investing in a climate-neutral future for the benefit of our people' (commonly known as the 2030 EU Climate target plan): it includes the said updated 2030 emissions reduction target of net 55 % compared to 1990 levels, from the previous 40 % emissions reduction target, and an inclusive climate neutrality (i.e. net zero greenhouse gas emissions) by 2050. To implement the increased ambition, the EU is working on the 'Fit for 55' package, which contains legislative proposals to revise the entire EU 2030 climate and energy strategy. It is also worth mentioning that within the EU has established a mission (Mission Climate Neutral and Smart Cities (see https://ec.europa.eu/info/research-and-innovation/funding/funding-opportunities/funding-programmes-and-open-calls/horizon-europe/missions-horizon-europe/climate-neutral-and-smart-cities_en)) that will support and promote 100 European cities in their systemic transformation towards climate-neutrality by 2030 (on April 28 2022, the list of 100 cities has been published at https://ec.europa.eu/commission/presscorner/detail/en/ip_22_2591: 9 Italian cities have been selected overall, among which the city of Bologna).

In such a transition towards a "carbon-neutral" paradigm, it is crucial to fully exploit the available Renewable Energy Sources (RES), and electrification of the energy system is a key component to achieve the ambitious targets.

1.2 Electrification, Renewable Energy Sources and Storage Systems

Electricity's share of the world's final consumption of energy now stands at 20% but it is foreseen to rise significantly in future years: in the Net Zero Emissions by 2050 Scenario (NZE), electricity accounts for around 50% of final energy use by 2050 (IEA 2021). In the European context the electricity will reach around 41%-53% of final energy use by 2050 depending on the different scenarios (ISPRA 2021), and, in particular in Italy demand is estimated to grow at an average annual rate of 0.9% per year, corresponding to 341 TWh in 2026 in the Development Scenario (Terna 2016).

The fully exploitation of RES is the most promising strategy to pave a way towards a more sustainable electricity supply (Hesse et al. 2017). The analysis of recent developments clearly shows an ongoing success of increasing RES penetration and allows a projection towards RES having a crucial role of energy supply in a future sustainable energy system (REN21 Secretariat 2017). The total cumulative wind and solar power installations are around 750 GW (GWEC 2021) and 780 GW (SolarPower Europe 2021), respectively; and are expected to reach more than 1.2 TW and 1.9 TW by the end of 2025, respectively. In particular, in Europe the growth of wind and solar installations (including both large utility-scale facilities and distributed generation for self-consumption and energy sharing) is expected to reach about 450 GW of new installed capacity by 2030, achieving a total share in electricity production of 13% from solar and 30% from wind; while by 2050 the increased RES installed capacity will totalize 1,270 GW, reaching a total installed RES capacity of 2,210 GW by 2050 (Enel 2020).

With higher shares of Variable Renewable Energy (VRE), such as Photovoltaic (PV) and wind-turbine generators, in modern power grids, the task of balancing electricity demand and power supply over time for all demand points connected to the grid becomes increasingly challenging, e.g. (Carrasco et al. 2006). It is indeed necessary to match distributed and intermittent power generation with load demand at each time within the entire grid, and this applies to both the transmission and distribution level. While measures taken in power grid expansion and flexible demand allow for improved relocation and balancing of electricity flows, Energy Storage Systems (ESSs) are capable to effectively equalize fluctuations and can compensate a mismatch of power generation and consumption via a coordinated power supply and energy time-shift. Among various different storage technologies, Battery Energy Storage (BES) systems have strong advantages, such as very fast response time, high efficiency, low self-discharge and feasibility of scaling due to the modular structure. BES systems are foreseen to significantly rise up to between 100 GWh and 167 GWh in 2030 (IRENA 2017).

1.3 Present and near-future challenges for power systems

As already mentioned, due to the high penetration of non-dispatchable power generation units, such as VRE ones, power system operation and planning are facing several challenges to ensure reliability, flexibility and security of supply. Not only the strong variability of VRE needs to be matched with load demand, but also enough transmission must be built to deliver VRE from generation bases, usually in remote locations to load centers (Sun et al. 2015). Moreover, in transmission grids under high share of VRE, the intermittent and variable nature of green energy resources leads to a significant increase in the transmission capacity needed to ensure the security of supply. As a result, transmission line utilization rate is decreasing. In this regard, ESSs play a key role: they provide resiliency against VRE curtailment and are able to mitigate the intermittency of renewable energy by storing energy during period of high renewable production and releasing energy during period of low renewable production. BES can provide many benefits and, being rather compact in size, can be used in mobile applications. Furthermore, when dealing with transmission networks, BESs not only allow the shift of peak load flow induced by either load or renewable energy, hence postponing or reducing the investment of transmission lines, but they also increase the support on frequency and voltage enabling higher transmission capability. In the light of the above, it is crucial to adequately plan and manage storage units and renewable energy sources in power systems. Also, in huge countries like China where VRE curtailment is still a major challenge, innovative technologies such as Battery-based Energy Storage Transportation (BEST) should be considered. BEST is the transportation of modular BESs modules via train cars or trucks. Such an innovative solution can further exploit the potentiality of BESs in terms of load shifting and VRE utilization.

Considering now the distribution networks, the deployment of ESSs is fundamental as the overall network performance can be enhanced by their optimal placement, sizing, and operation: an optimally sized and placed ESSs can facilitate peak energy demand fulfilment, enhance the benefits from the integration of renewables and distributed energy sources, aid power quality management, and reduce distribution network expansion costs.

The distribution parts of power systems are progressively moving to a scheme based on distributed RES, in which customers play a new active role through self-generation of electrical energy. While in the past, a central power plant was used to generate energy for everyone, now, electricity can be produced locally using, for instance, PV panels, biogas or wind farms. In this new paradigm there is a new key player: the prosumer, who is a consumer that uses for instance PV panels to cover part of his/her energy demands, stores part of this energy in batteries for later use and, in addition, can not only buy but also sell energy with the utility grid. In this framework, prosumers can aggregate in collective self-consumption or energy community schemes (CEER 2019). These emerging aggregation schemes empower citizens as they represent key actors in energy transition paradigm through which power grid is becoming user centric. It is therefore of utmost interest to properly plan and manage ESSs and RES in transmission and distribution systems too.

1.4 Energy communities

Within the Clean Energy Package, there are two European directive whose aim is to improve the energy efficiency, namely Directive 2018/2001 and Directive 2019/944 that concern the electricity sector in general and Energy Communities in particular, (see (EU 2018) and (European Parliament and Council of the EU 2019)).

With CEP, EU introduced the concept of Energy Communities, which are groups of citizens that decide to join forces to equip themselves with systems and apparatuses to produce and share energy from renewable energy sources. The Renewable Energy Directive (RED II) and the Electricity Market Directive (EMD) provide basic definitions and requirements for the activities of individual and collective self-consumption as well as for two types of energy communities, namely the Citizen Energy Community (CEC), and the Renewable Energy Community (REC), to be discussed next.

The economic justification for the formation of an energy community is related to the remuneration scheme foreseen for those communities. One point that has to be taken into account anyway, is that the difference between the price of the energy supplied by the external energy provider and the price sold by the community to the main grid can be significant, e.g. due to the costs of the ancillary services, so the aggregation of prosumers in collective schemes shall be convenient. It is certainly of interest therefore to study the most convenient solutions for these communities, and this can be the object of both the planning phase and of the subsequent management one.

It is worth noting that both REC and CEC scheme can include biogas power generation, particular convenient as it represents a renewable and dispatchable energy source that can be suitable coupled and managed with PV generation and storage, which represents another technical issue deserving proper attention.

The states member of the European Union were expected to transpose the European directive 2018/2001 by June 2021, although for various reasons, including the pandemic, such a deadline has been postponed. The way these directives have been transposed into laws have certainly an influence on the optimal management of the energy communities, which is a further aspect of interest.

1.5 Contributions

This dissertation concerns the wide context of planning and operation of power networks considering the presence of renewable energy sources and of battery energy storage systems.

In particular, this thesis has addressed some technical issues relevant to the expansion planning of the transmission grid, and to both planning and optimal dispatching of renewable energy communities concerning the distribution one.

More specifically, the first part of the thesis has been devoted to the solution of the transmission expansion problem in transmission grids with high penetration of renewable energy sources. Both stationary and transportable battery energy storage systems (BES and BEST, respectively) have been considered in the planning scheme along with transmission lines to obtain the optimal set of devices that minimizes the total cost in a considered power network. First, we have presented a coordinated planning model by considering fixed transportation cost for BEST devices, and then, the study has been extended to a planning formulation with a distance-dependent transportation cost for the BEST units. The latter can be suitable applied to any power systems and not only to those where BEST fixed transportation cost could be a reasonable assumption. The proposed planning models are static as they only consider the investment decisions for a single year planning horizon (single-stage planning).

The main contributions of this first part are described in the following.

The mathematical formulation of long-term planning models with mobile storage units suitable for transmission system under high share of variable renewable energy has been accomplished. To the best of our knowledge, there is little evidence of previous research addressing the problems of transmission planning with BEST, which is a much more complex problem compared with operation model investigated in some of the papers above referred to e.g. (Sun et al. 2015), (Sun et al. 2016). The tractability of the extended model formulation has been proved, and, also, the relevant mathematical formulation, described in Chapter 2, makes use of continuous variables, which allow for the evaluation of both the optimal size and location of stationary and transportable storage systems.

Further, an alternative mathematical approach, accomplished by the use of Number-of-nonzero (NZ) operator, has been implemented for the relevant vehicle scheduling problem. Such an approach avoids the need of several complex constraints involving a large number of binary variables that may cause numerical problems in the optimization, and results to be suitable for transmission grids.

The second part of the dissertation concerns renewable energy communities planning and operation.

Initially, the planning of PV and BES systems has been addressed for a REC of residential prosumers. The developed planning model aimed to obtain the optimal set of resources allowing to achieve the minimum energy procurement cost for a given REC includes the incentive-based remuneration scheme adopted within the Italian regulation framework. Both a single-stage (static) and a multi-stage (dynamic) approach have been adopted and relevant optimization models have been implemented. We have validated the two model formulations by comparing them to each other with equivalent input data sets. Then, the multi-stage planning approach, which allows to take into account load and solar irradiation long-term uncertainties, has employed for a sensitivity analysis, in which discount rate, number of years in the planning horizon, and the constraint of a minimum investment on BES systems for each prosumer have been assessed.

The main contribution of the planning analysis of the second part consists on the development of a single-stage and of a multi-stage planning models for the evaluation of the economic viability of new facilities such as PV and BES systems in a REC with the incentive-based mechanism foreseen by the Italian regulation framework.

Moreover, the obtained results show that while within the considered assumptions the investment on PV systems is always convenient, while BES systems are not necessarily always included in the planning scheme. However, if each member of the community is forced to contribute with a minimum investment on BES systems – considered technically appropriate for a better handling of short term instability issues – the obtained results indicate that the optimal set of investments guarantees that the consequently increased saving and revenues achieved allow to pay back the larger initial investment in 5 or 6 years, which is interestingly not so different from the case when investing in PV systems only. In general, a higher discount rate leads to a lower initial investment in all the considered case studies.

Also, the proposed planning models could be suitable adapted also for other types of renewable energy communities, e.g. community where direct transactions between members are allowed.

Then, the problem of the day-ahead scheduling of RECs resources has been investigated by considering two types of REC, and two relevant optimization models have been developed. The first type of REC, which we shall refer to as "cooperative community", allows direct energy transactions between its members, and aims to minimize the total energy procurement cost given by the energy exchanged with the external provider. The, second one, which we shall refer to as "incentive-based community", does not allow direct transactions between members, but includes economic incentives for the community shared energy according to the Italian regulation framework. Hence, in this case, the day ahead scheduling of the community minimizes the daily energy procurement cost by including the revenues for the community shared energy too. This work stands on the results obtained within the framework of a previous PhD dissertation by C. Orozco (C. Orozco 2021). An innovative contribution is represented by the fact that dispatchable renewable energy generation has been considered in this part of the dissertation too, by including producers equipped with biogas power plants in the community; the consequent contributions of all the components that build up the energy procurement cost for both types of REC has been quantified. Relevant results show that, within the considered assumption and for the examined cases, the incentive mechanism approach adopted by the Italian regulation framework seems to be more profitable with respect to a cooperative community in which transactions between prosumers are allowed. It is important to realize, however, that the daily procurement cost of a community incentivized according to the Italian regulation framework is much more dependent on the prices of the energy exchanged with the grid. Moreover, by introducing producers equipped with biogas power plants in the community, it is shown that a REC can reduce indeed its dependence from the utility grid and therefore its energy procurement cost. Also, the difference on the daily energy procurement cost between the two types of REC results to be higher when biogas generators are included: for the considered cases and input data (such as e.g. the prices of the energy exchanged with the grid), sharing biogas energy is almost always more convenient for the incentive-based community. The differences on the objective functions that minimize the daily energy procurement costs for the two communities support that result. As already mentioned, in incentive-based RECs, members have to use the external grid to share the renewable energy for which they receive a remuneration, so when sharing biogas energy, the total procurement cost of the community changes not only according to the biogas cost (as it is for a cooperative community) but also as it reflects the price difference between the energy sold and bought to the community along with the value of the incentive.

The main contributions of the day ahead analysis of the second part concern the development of a model for day-ahead scheduling of RECs that takes into account not only the presence of BES units but also of biogas dispatchable renewable generation units for both cooperative communities and incentive-based ones.

The obtained results show that within the considered assumption, the incentive mechanism approach adopted by the Italian regulation framework seems to be more profitable with respect to a cooperative community in which transactions between prosumers are allowed.

Although the daily procurement cost of a community incentivized according to the Italian regulation framework is much more dependent on the prices of the energy exchanged with the grid, by introducing producers equipped with biogas power plants in the community, a REC can reduce indeed its dependence from the utility grid and therefore its energy procurement cost.

Finally, the dissertation has provided the description of the GE.C.O project, which relies not only on the availability of PV units and of BES systems, but also on the availability of an energy management system capable of optimally dispatching the energy flows among the prosumers and among the prosumers and the network (day ahead dispatch).

The main contributions of the part of the dissertation relevant to the GE.C.O project are: 1) the critical analysis of available smart metering technologies, and the installation of the most appropriate of them at the GE.C.O site, which will be fundamental in the validation of the models; 2)the acquisition of the power profiles of some prosumers of the district area of interest, gathered thanks to the installed smart meters.

1.6 Outline

The structure of the thesis is the following:

Chapter 2 provides a description of the transmission expansion planning problem including stationary and transportable battery energy systems. Two long-term transmission planning models, which differs for the allocation of the BEST transportation cost, have been presented and validated. Both the proposed mathematical models consider BES and BEST units in the planning scheme, hence giving as output the optimal set of transmission lines, BESs and BESTs that allows to achieve the minimum cost in a considered power system.

The planning model formulation presented in the second part of the chapter present a remarkable enhancement to the model previously considered because it allows to quantify the effective distance that needs to be covered for the transportable storage displacements, and thus a proper allocation of the BEST transportation cost can be achieved. Such a planning model could be usefully applied for any power systems and not only for those in which disregarding the effective distance to be covered for BEST displacements could be an acceptable approximation. Moreover, the model scalability has been proven by considering significantly large portions of power networks with large penetration of renewables.

Chapter 3 is devoted to the study of the planning problem of battery energy storage and photovoltaic systems for a REC with an incentive-based remuneration scheme according to the Italian legislative framework. Two planning models, adopting a single-stage or multi-stage approach, have been presented and validated by comparing them to each other with equivalent input data sets. Both the proposed models consider BES and PV units in the planning scheme, hence giving as output the optimal set of BES and PV systems that allows to achieve the minimum energy procurement cost in a considered REC, including investment and operation costs. Several cases studies, which differs for the value of the discount rate, the number of years in the planning horizon, and whether or not the inclusion of the constraint of a minimum investment on BES systems for each prosumer, have been considered by adopting the multi-stage planning approach.

Chapter 4 introduces the mathematical formulation to solve the day-ahead scheduling problem in a REC with the presence of PV-storage units and local loads. Such a formulation, standing on the work presented in (C. Orozco 2021), is extended to the case of a REC with the presence of dispatchable biogas generating units. In this chapter, the problem has been addressed not only for a cooperative community where transactions between prosumers are allowed, but also for an incentive-based community according to the Italian legislative framework. The chapter includes several scenarios which has been studied and compared for both the considered types of REC.

First, the base case of a REC with several prosumers, equipped with PV and BES systems other than loads, has been considered; then, the study has focused on a REC, consisting of several prosumers and biogas-powered producers. Several scenarios, obtained by varying the number of dispatchable units, the fuel availability, the gas cost, and by including or not BES units, have been analysed.

Chapter 5 is devoted to the description of the pilot project G.E.CO., which aims to develop and experiment a Green Energy Community in the district of Pilastro – Roveri of Bologna.

Chapter 6 presents the concluding remarks of the thesis.

Appendix A describes the distributed approach based on the Alternating Direction Method of Multipliers (ADMM) algorithm that has been implemented in the day ahead scheduling of a cooperative community in Chapter 4.

Chapter 2. Transmission Expansion Planning with Battery-based Energy Storage Transportation

Introduction

Variable Renewable Energy (VRE) is becoming relevant in power system across the world as it supplies an increasing percentage of the demand. The total cumulative wind and solar power installations are around 750 GW (GWEC 2021) and 780 GW (SolarPower Europe 2021), respectively; and are expected to reach more than 1.2 TW and 1.9 TW by the end of 2025, respectively. In China, both the wind power capacity and solar power capacity reached 200 GW by the end of 2019 (Backwell 2019), and in 2020 China installed half of all new global offshore wind capacity (GWEC 2021).

Due to the high penetration of non-dispatchable power generation units, such as VRE ones, power system operation and planning has facing several challenges to ensure reliability, flexibility and security of supply. Two of the major problems related to primary energy source conversion are: 1) how to match Renewable Energy Sources (RES), affected by strong variability, with load demand; and 2) how to build enough transmission to deliver VRE from generation bases, usually in remote locations to load centers (Sun et al. 2015). Moreover, in transmission grids under high share of VRE, the intermittent and variable nature of green energy resources leads to a significant increase in the transmission capacity needed to ensure the security of supply. As a result, transmission line utilization rate is decreasing. In this regard, the key role of Energy Storage Systems (ESSs) needs to be fully exploited in order to face the above-mentioned challenges related to power system transition. ESSs provide resiliency against VRE curtailment and are able to mitigate the intermittency of renewable energy by storing energy during period of high renewable production and releasing energy during period of low renewable production. Despite other kinds of grid ESSs, Battery Energy Storage System (BES) can provide many benefits such as fast response time, low maintenance and, being rather compact in size, can be used in mobile applications. Furthermore, when dealing with transmission networks, BESs not only allow the shift of peak load flow induced by either load or renewable energy, hence postponing or reducing the investment of transmission lines, but they also increase the support on frequency and voltage enabling higher transmission capability.

In light of the above, this chapter deals with optimal coordinated storage and transmission planning models under high share of renewable energy, in which Battery-based Energy Storage Transportation (BEST) are included. BEST is the transportation of modular BESs modules via train cars or trucks. Through such an innovative solution the potentiality of BESs in terms of load shifting and VRE utilization can be further exploited. This is particularly attractive for huge countries like China where VRE curtailment is still a major challenge.

BEST application provides a reasonable but rather expensive alternative for managing the transmission congestion. However, BES technology is increasingly developing, and its price is expected to continuously drop while due to the decrease of transmission line utilization rate, new transmission facility may not be an economically feasible option for power system operation (Sun et al. 2017). Moreover, in case of natural disaster, mobile storage units enhance the power system resilience by providing energy quickly to emergency areas.

In the technical literature, quite few works regard the use of mobile energy storage systems in the power grid. In (Sun et al. 2015), Sun et al. established a spatiotemporal network to optimize locational and hourly charging/discharging schedule of BEST. The authors, in (Sun et al. 2016), established a Security Constraint Unit Commitment (SCUC) model for investigating the benefit of BEST to relieve transmission congestion. In (Yao, Wang, and Zhao 2019), a post-disaster joint restoration scheme considering Transportable Energy Storage System (TESS) was proposed to study the effect of transportability of TESS for a more reliable distribution system. In (Gupta et al. 2018), an efficient SCUC with integrated BEST model was presented and solved using Benders Decomposition approach. A stochastic programming model was proposed in (Sun et al. 2017) to optimize the schedules of power system with battery transportation under high share of wind energy, taking into account both load and wind energy forecasting uncertainties.

Lu & Li proposed a long-term planning with BEST in power system considering the investment cost of power generation, transmission line and BESs (Lu and Li 2017). The obtained results showed that, the proposed mixed integer linear programming model could not solve large problems. In (Yan et al. 2018) a new approach, called Battery Transportation and Logistics was proposed to investigate the transportation and logistics model for delivering green energy to end users. A multi-stage transport and logistic optimization approach where the batteries are charged in the renewable power plants and transported back and forth by railways between the renewable power plants and cities, was proposed in (Yan et al. 2019). In (H. Abdeltawab and Mohamed 2019), a sizing and allocation algorithm of Mobile Energy Storage System (MESS) was proposed, which showed that the MESS could maintain the power quality while achieving the profit for the distribution system operator. In (H. H. Abdeltawab and Mohamed 2017), authors presented a day-ahead energy management system for a truck-mounted mobile energy storage system that aims at minimizing the total energy procurement cost in a distribution system. Finally, the benefit of mobile storage systems of enhancing the distribution system resilience was investigated in (Yao, Wang, and Zhao 2019), (Yao et al. 2018), (Kim and Dvorkin 2018) and (Lei et al. 2019).

In that respect, we note that in literature there is still a lack concerning BEST integration in the transmission grid. On the one hand, several papers investigate BEST optimal operations and locations (Sun et al. 2017), (Sun et al. 2016), (Gupta et al. 2018), and on the other hand, very few works consider mobile storage systems in the expansion planning problem (Lu and Li 2017), (Koopmann, Scheufen, and Schnettler 2013), and this is accomplished using a different mathematical formulation from the ones proposed in this chapter.

This chapter addresses the long-term planning problem providing the best combination of transmission lines and storage units to achieve minimum cost in the considered power systems. These planning models include both stationary and mobile storage systems as candidate units and provides the optimal storage units site, size and scheduling for each operating condition, i.e. typical day, considered.

In its first part, this chapter focuses on the coordinated planning model with fixed transportation cost for BEST devices. The model is then validated and tested in the modified Garver's 6-node system.

In the second part of the chapter, a coordinated planning formulation including a distance-dependent transportation cost for BEST units is presented, allowing the proper allocation of the operating cost of the transportable storage units. The model is then investigated in a real regional grid with high RE penetration in China, and finally proved its tractability through a case study based on a 190-bus test system.

2.1 Planning Model Coordinated with both Stationary and Transportable Storage Systems with fixed transportation cost

The planning model presented in this section solves a coordinated expansion problem involving transmission, storage and Battery-based Energy Storage Transportation, providing the optimal BEST site, size and scheduling for each operating condition, i.e. typical day, considered. The proposed planning model is static as it only considers the investment decisions for a single year planning horizon (single-stage planning). Long-term uncertainty of load growth and available production capacity is neglected to achieve feasible solutions in a reasonable computational time. One long-term scenario is considered and the correlation of load and VRE production is represented by means of several operating conditions, addressing short-term uncertainties. Each operating condition is represented by 24-hour load demand, obtained from the actual power system (Zhuo et al. 2020), and the hourly wind and Photovoltaic (PV) daily available production based on simulated data. Both wind and PV output data are simulated considering the bus location and statistics of VRE in real power system, by means of Grid Optimization Planning Tool (GOPT) power system analysis software (Zhuo et al. 2020). In each operating condition, BEST can be charged and discharged only in one bus because it seems reasonable not to allow intra-day BEST routes when dealing with transmission networks. Therefore, this model assumes BEST displacements only between different operating days.

The main assumptions adopted in this model are the following:

- The model is static. It only considers the investment decisions to supply the demand of a target year (Single-stage planning).
- DC power flow representation is adopted, and line losses are neglected.
- The generation planning is given as a boundary condition.
- To represent daily storage cycles, demand and VRE production correlations, each operation condition is described by 1 day with hourly resolution.
- Only one future scenario is considered, long-term uncertainties are neglected.
- Daily energy balance for both transportable and stationary storage units.
- Gaussian Distribution of VRE uncertainty in spinning reserve requirement.
- BEST operating cost has fixed value for each single route, whatever the displacement of the storage system. We assume bounded area where BEST can operate; in that respect it is reasonable not to address distances between buses in the operations cost.

- No BEST intra-daily routes are allowed. This model proposes BEST displacements only between different operating conditions, i.e. operating days.

It should be noted that a single target year model as we usually conduct rolling planning model, as the "gradual changing" of power system is so complex, that when we want to investigate some specific problem, e.g., the role of BEST in power system, we usually simplify the model into a single target year planning problem, so to reduce the computational burden and time, usually relevant in such models. The physical meaning of single target year is to calculated the optimal combination of resources (in our case, transmission lines and storage) in one year accounting its operation cost and equivalent investment cost in one year. The most critical point is that the investment cost of transmission lines and storage must be annualized, which is what we do. The total investment cost is amortized equally within the investment payback period, considering the discount rate. Therefore, the operation cost and investment cost are comparable.

2.1.1 ***Model formulation***

The objective is to minimize the total cost, that is the sum the annualized investment costs, C^{Inv}, and the operation costs, C^{Oper}, of the system under study.

$$OF = \min \ (C^{Inv} + C^{Oper}) \tag{2.1}$$

where

$$C^{Inv} = \sum_{l\in\Omega_{LC}} C_l^{Line} X_l + \sum_{i_{bes}\in\Omega_{bes}} C_{i_{bes}}^{Storage} Y_{i_{bes}} + \sum_{i_{best}\in\Omega_{best}} C_{i_{best}}^{Best} V_{i_{best}} \tag{2.2}$$

$$\begin{aligned} C^{Oper} = & \sum_{j\in\Omega_{OP}} d_j \sum_{t=1}^{T} \Delta t \sum_{i\in\Omega_I} C_i^{gen} P_{i,j,t}^{gen} + \\ & + \sum_{j\in\Omega_{OP}} d_j \sum_{t=1}^{T} \Delta t \sum_{i_b} C^{shed} L_{i_b,j,t}^{shed} + \\ & + \sum_{i_{best}\in\Omega_{best}} n_{Trip}^{i_{best}} K^{i_{best}} + \sum_{i_{best}\in\Omega_{best}} \frac{C_{i_{best}}^{Best}}{365} (n_0^{i_{best}} + n_{Trip}^{i_{best}}) \end{aligned} \tag{2.3}$$

In (2.1) C^{Inv} denotes the annualized investment cost of transmission lines, BESs and BESTs. X_l are binary variables that equal 1 if line *l* is build and 0 otherwise; variables $Y_{i_{bes}}, V_{i_{best}}$ indicate whether to settle the stationary i_{bes} and transportable i_{best} storage systems, respectively. Constants $C_l^{Line}, C_{i_{bes}}^{Storage}, C_{i_{best}}^{Best}$ represent the annualized investment cost of: line *l*, included in the set of candidate lines Ω_{LC}, stationary storage systems i_{bes}, and transportable storage systems i_{best}, respectively.

C^{Oper} includes only variable costs and as defined in (2.3), it is given by the sum of three components: the fuel consumption of conventional generating units, the load shedding penalty and the BEST operation cost, consisting on the last two terms, respectively. Variable $P_{i,j,t}^{gen}$ indicates the power output of thermal unit *i* at time *t*, in operating condition *j*, and $L_{i_b,j,t}^{shed}$ represents load shedding power at node i_b, at time *t*, in operating condition *j*. C_i^{gen}, C^{shed} are constants representing the operation costs of thermal unit *i* and of load shedding, respectively. Δt indicates the duration of one time period and d_j represents the duration of the operating condition *j*. Finally, variables $n_0^{i_{best}}, n_{Trip}^{i_{best}}$, introduced to allocate the BEST transportation cost, represent the number of operating conditions where the transportable storage system i_{best} is not used, and the trips number of transportable storage system i_{best}, respectively.

BEST operation cost is given by the sum of $\sum_{i_{best}\in\Omega_{best}} n_{Trip}^{i_{best}} K^{i_{best}}$ and $\sum_{i_{best}\in\Omega_{best}} \frac{C_{i_{best}}^{Best}}{365}(n_0^{i_{best}} + n_{Trip}^{i_{best}})$.

The first term represents the total BEST transportation cost, where the transportation cost between two buses, $K^{i_{best}}$, is assumed to be constant as in this section BEST is allowed to move in restricted areas. The second term represents the cost associated to the operating conditions (i.e. days) where BEST is not providing any contribution to the system, plus one BEST inoperative day for each trip of the device. Further, the fixed operation and maintenance costs of transmission lines, BESs and BESTs are usually equal about 1-1.5% of the investment cost and thus can be included in the coefficient of their investment cost, respectively.

The following constraints, i.e. constraints (2.4) - (2.10), describe BEST model formulation.

Constraints (2.4) enforce energy limits for transportable storage systems in each time period and operating condition.

$$\begin{gathered}
V_{i_{best}} E_{t=0}^{i_{best}} + \sum_{ib}\sum_{t=1}^{t_n} (\eta_{ch}^{i_{best}} P_{i_{best},i_b,j,t}^{best,ch} - P_{i_{best},i_b,j,t}^{best,dis} / \eta_{dis}^{i_{best}})\Delta t \geq V_{i_{best}} E_{i_{best}}^{\min} \\
V_{i_{best}} E_{t=0}^{i_{best}} + \sum_{ib}\sum_{t=1}^{t_n} (\eta_{ch}^{i_{best}} P_{i_{best},i_b,j,t}^{best,ch} - P_{i_{best},i_b,j,t}^{best,dis} / \eta_{dis}^{i_{best}})\Delta t \leq V_{i_{best}} E_{i_{best}}^{\max} \\
\forall i_{best}, j, t_n = 1,2,\dots,T
\end{gathered} \tag{2.4}$$

Constraints (2.5) enforce transportable storage energy balance per day.

$$\begin{gathered}
\sum_{ib}\sum_{t=1}^{T} (\eta_{ch}^{i_{best}} P_{i_{best},i_b,j,t}^{best,ch} - P_{i_{best},i_b,j,t}^{best,dis} / \eta_{dis}^{i_{best}})\Delta t = 0 \\
\forall i_{best}, j
\end{gathered} \tag{2.5}$$

Constraints (2.6) are charging and discharging bounds for transportable storage systems.

$$V_{i_{best}} P^{i_{best}}_{\min,ch} \le P^{best,ch}_{i_{best},i_b,j,t} \le V_{i_{best}} P^{i_{best}}_{\max,ch}$$
$$V_{i_{best}} P^{i_{best}}_{\min,dis} \le P^{best,dis}_{i_{best},i_b,j,t} \le V_{i_{best}} P^{i_{best}}_{\max,dis} \quad \forall i_{best}, i_b, j, t \tag{2.6}$$

Constraints (2.7) set the mutual exclusion constraint of the charge and discharge state of the BEST. It enforces the BESTs to be only in one bus of the network in each time period and operating condition.

$$NZ(P^{best,ch}_{i_{best},i_b,j,t}) + NZ(P^{best,dis}_{i_{best},i_b,j,t}) \le 1$$
$$\forall i_{best}, j, t \quad NZ = number\ of\ non\ zeros \tag{2.7}$$

As we are dealing with a transmission network, we feel it reasonable to enforce BESTs to be in one bus only of the network in each operating condition, that in our case refers to a day.

$$NZ(\sum_{t=1}^{t_n} P^{best,ch}_{i_{best},i_b,,j,t} + \sum_{t=1}^{t_n} P^{best,dis}_{i_{best},i_b,j,t} + P^{best,ch}_{i_{best},i_b,j,t+1} + P^{best,dis}_{i_{best},i_b,j,t+1}) \le 1$$
$$\forall i_{best}, j, t, t_n = 1,2,3,..,T-1 \tag{2.8}$$

It should be noted that the application of the number of non-zero function as done in (2.7) and (2.8) (which in the equations and in the following has been referred to as NZ function for simplicity) makes it possible to successfully model transportable storage systems avoiding the use of additional binary variables, which could increase drastically the computational burden, especially for large scale power network.

Constraints (2.9) enforce reserve content bounds for transportable storage systems in each time period and operating condition.

$$0 \le r^{best}_{i_{best},j,t} \le P^{i_{best}}_{\max} V_{i_{best}} + \sum_{ib=1}^{N_b} (\eta^{i_{best}}_{ch} P^{best,ch}_{i_{best},i_b,j,t} - P^{best,dis}_{i_{best},i_b,j,t} / \eta^{i_{best}}_{dis})$$
$$r^{best}_{i_{best},j,t} \Delta t \le SoE^{best}_{i_{best},j,t} - E^{\min}_{i_{best}} V_{i_{best}} \qquad \forall i_{best}, j, t \tag{2.9}$$

where

$$SoE^{best}_{i_{best},j,t} = V_{i_{best}} E^{i_{best}}_{t=0} + \sum_{ib} \sum_{t=1}^{t} (\eta^{i_{best}}_{ch} P^{best,ch}_{i_{best},i_b,j,t} - P^{best,dis}_{i_{best},i_b,j,t} / \eta^{i_{best}}_{dis}) \Delta t \tag{2.10}$$

Constraints (2.11) - (2.15) show BES mathematical model.

Constraints (2.11) enforce energy limits for stationary storage systems in each time period and operating condition.

$$
\begin{aligned}
&Y_{i_{bes}} E_{t=0}^{i_{bes}} + \sum_{t=1}^{t_n} (\eta_{ch}^{i_{bes}} P_{i_{bes},j,t}^{bes,ch} - P_{i_{bes},j,t}^{bes,dis} / \eta_{dis}^{i_{bes}}) \Delta t \geq Y_{i_{bes}} E_{i_{bes}}^{\min} \\
&Y_{i_{bes}} E_{t=0}^{i_{bes}} + \sum_{t=1}^{t_n} (\eta_{ch}^{i_{bes}} P_{i_{bes},j,t}^{bes,ch} - P_{i_{bes},j,t}^{bes,dis} / \eta_{dis}^{i_{bes}}) \Delta t \leq Y_{i_{bes}} E_{i_{bes}}^{\max} \\
&\forall i_{bes}, j, t_n = 1, 2, ..., T
\end{aligned}
\tag{2.11}
$$

Constraints (2.12) enforce stationary storage energy balance per day.

$$
\begin{aligned}
&\sum_{t=1}^{T} (\eta_{ch}^{i_{bes}} P_{i_{bes},j,t}^{bes,ch} - P_{i_{bes},j,t}^{bes,dis} / \eta_{dis}^{i_{bes}}) \Delta t = 0 \\
&\forall i_{bes}, j
\end{aligned}
\tag{2.12}
$$

Constraints (2.13) are charging and discharging bounds for stationary storage systems.

$$
\begin{aligned}
&Y_{i_{bes}} P_{\min,ch}^{i_{bes}} \leq P_{i_{bes},j,t}^{bes,ch} \leq Y_{i_{bes}} P_{\max,ch}^{i_{bes}} \\
&Y_{i_{bes}} P_{\min,dis}^{i_{bes}} \leq P_{i_{bes},j,t}^{bes,dis} \leq Y_{i_{bes}} P_{\max,dis}^{i_{bes}} \quad \forall i_{bes}, j, t
\end{aligned}
\tag{2.13}
$$

Constraints (2.14) enforce reserve content bounds for stationary storage systems in each time period and operating condition.

$$
\begin{aligned}
&0 \leq r_{i_{bes},j,t}^{bes} \leq P_{\max}^{i_{bes}} Y_{i_{bes}} + \eta_{ch}^{i_{bes}} P_{i_{bes},j,t}^{bes,ch} - P_{i_{bes},j,t}^{bes,dis} / \eta_{dis}^{i_{bes}} \\
&r_{i_{bes},j,t}^{bes} \Delta t \leq SoE_{i_{bes},j,t}^{bes} - E_{i_{bes}}^{\min} Y_{i_{bes}} \quad \forall i_{bes}, j, t
\end{aligned}
\tag{2.14}
$$

where

$$
SoE_{i_{bes},j,t}^{bes} = Y_{i_{bes}} E_{t=0}^{i_{bes}} + \sum_{t=1}^{t} (\eta_{ch}^{i_{bes}} P_{i_{bes},j,t}^{bes,ch} - P_{i_{bes},j,t}^{bes,dis} / \eta_{dis}^{i_{bes}}) \Delta t
\tag{2.15}
$$

Finally, (2.16) – (2.24) show TEP and network technical constraints.

The energy balance at each node of the system is represented in constraint (2.16).

$$
\begin{aligned}
&\sum_{i \in \Omega_{i_b}^{I}} P_{i,j,t}^{gen} + \sum_{w \in \Omega_{i_b}^{w}} P_{w,j,t}^{wind} + \sum_{v \in \Omega_{i_b}^{pv}} P_{v,j,t}^{\mathrm{PV}} - \sum_{l \in \Omega_{i_b}^{L1}} F_{l,j,t} \\
&+ \sum_{l \in \Omega_{i_b}^{L2}} F_{l,j,t} + \sum_{i_b \in \Omega_{i_b}^{i_{best}}} (P_{i_{best},i_b,j,t}^{best,dis} - P_{i_{best},i_b,j,t}^{best,ch}) + \\
&+ \sum_{i_{bes} \in \Omega_{i_b}^{i_{bes}}} (P_{i_{bes},j,t}^{bes,dis} - P_{i_{bes},j,t}^{bes,ch}) = P_{i_b,j,t}^{Load} - L_{i_b,j,t}^{shed} \qquad \forall i_b
\end{aligned}
\tag{2.16}
$$

Constraints (2.17) and (2.18) include DC power flow for existing and prospective lines in each time period and operating condition.

$$\begin{gathered} F_{l,j,t} - (\vartheta^{l}_{i_{b1},j,t} - \vartheta^{l}_{i_{b2},j,t}) / x_l = 0 \\ \forall l \in \Omega_{LE}, j, t = 1,2,3,...,T \end{gathered} \tag{2.17}$$

$$\begin{gathered} -M(1-X_l) \le F_{l,j,t} - (\vartheta^{l}_{i_{b1},j,t} - \vartheta^{l}_{i_{b2},j,t}) / x_l \\ F_{l,j,t} - (\vartheta^{l}_{i_{b1},j,t} - \vartheta^{l}_{i_{b2},j,t}) / x_l \le M(1-X_l) \\ \forall l \in \Omega_{LC}, j, t = 1,2,3,...,T \end{gathered} \tag{2.18}$$

Constraint (2.19) enforce transmission capacity limits for existing and prospective lines, respectively.

$$\begin{gathered} -F_l^{\max} \le F_{l,j,t} \le F_l^{\max} \\ \forall l \in \Omega_{LE}, j, t = 1,2,3,...,T \\ -X_l F_l^{\max} \le F_{l,j,t} \le X_l F_l^{\max} \\ \forall l \in \Omega_{LC}, j, t = 1,2,3,...,T \end{gathered} \tag{2.19}$$

Constraints (2.20), (2.21) and (2.22) refer to the production bounds of thermal units, wind units and solar ones, respectively.

$$\begin{gathered} P_i^{gen,\min} \le P_{i,j,t}^{gen} \le P_i^{gen,\max} \\ \forall i, j, t = 1,2,...,T \end{gathered} \tag{2.20}$$

$$\begin{gathered} 0 \le P_{w,j,t}^{wind} \le P_{w,j,t}^{f} \\ \forall w, j, t = 1,2,...,T \end{gathered} \tag{2.21}$$

$$\begin{gathered} 0 \le P_{v,j,t}^{\mathrm{PV}} \le P_{v,j,t}^{f} \\ \forall v, j, t = 1,2,...,T \end{gathered} \tag{2.22}$$

Constraints (2.23) enforce load shedding bound, when allowed.

$$\begin{gathered} 0 \le L_{i_b,j,t}^{shed} \le P_{i_b,j,t}^{Load} L_{rate}^{shed} \\ \forall i_b, j, t = 1,2,...,T \end{gathered} \tag{2.23}$$

Spinning reserve requirement are satisfied with constraints (2.24) in each time period and operating condition.

$$\begin{gathered} \sum_i (P_{i,j,t}^{gen,\max} - P_{i,j,t}^{gen}) + \sum_w (P_{w,j,t}^{f} - P_{w,j,t}^{wind}) + \\ + \sum_v (P_{v,j,t}^{f} - P_{v,j,t}^{\mathrm{PV}}) + \sum_{i_{best}} r_{i_{best},j,t}^{best} + \sum_{i_{bes}} r_{i_{bes},j,t}^{bes} \ge R_{j,t} \\ \forall j, t \end{gathered} \tag{2.24}$$

Variables $P_{w,j,t}^{wind}$, $P_{v,j,t}^{\mathrm{PV}}$ and $F_{l,j,t}$ represent the power output of the wind farm w, the power output of the PV generator *v* and the power flow of line *l* at time *t* in operating condition *j*, respectively. $\Omega_{i_b}^{L_1}, \Omega_{i_b}^{L_2}$ are the sets of lines whose sending end and receiving end node is i_b, respectively. Variables $P^{best,dis}_{i_{best},i_b,j,t}$, $P^{best,ch}_{i_{best},i_b,j,t}$, $P^{bes,dis}_{i_{bes},j,t}$ and $P^{bes,ch}_{i_{bes},j,t}$ indicate the discharging and charging power of the BEST system i_{best} and the BES system i_{bes} at time t in operating condition j, respectively. Constants $P^{f}_{w,j,t}$, $P^{f}_{v,j,t}$ and $P^{Load}_{i_b,j,t}$ represent the forecasted power output of the wind farm w, the forecasted power output of the PV generator v and the load demand at node i_b at time t in operating condition j, respectively. $r^{best}_{i_{best},j,t}$ and $r^{bes}_{i_{bes},j,t}$ are the variables indicating the reserve content of the BEST system i_{best} and the BES system i_{bes} at time t in operating condition j, respectively., And finally, $R_{j,t}$ represents the spinning reserve requirement at time t in operating condition j.

Moreover, as we are dealing with a transmission network, we feel it reasonable to enforce BESTs to be in one bus only of the network in each operating condition, that in our case refers to a day. In that respect, we have used the number of non-zero function (henceforth referred to as NZ function for simplicity), that makes it possible to successfully model transportable storage systems avoiding the use of additional binary variables, which could increase drastically the computational burden, especially for large scale power network.

A. Problem solving

The optimization problem described in this paragraph has been addressed by adopting two different approaches.

In the first one, the optimization problem is tackled by expressing the investment cost of stationary and mobile storage units through binary variables. In that case the size of stationary and transportable storage systems is fixed, thus only storage systems location is optimized.

In the second case when increasing the complexity of the mathematical model due to the introduction of spinning reserve, we had to relax these binary variables and turn them into continuous ones, in order to achieve the numerical solutions in a reasonable computational time. Further, it is worth noting that in this case both size and position of stationary and transportable storage systems are given as output of the optimization problem.

Further, as previously mentioned, the proposed methodology shows a novel representation of the transportable storage systems, which allows to avoid the inclusion of additional binary variables, and therefore to decrease the complexity of the problem. To accomplish that, we have made use of the NZ function, which output is the number of nonzero elements of a generic input matrix. The application of the NZ function allows to add two constraints only, namely (2.7) and (2.8), to successfully implement the scheduling of the transportable storage systems, which we feel represent a novel contribution to the subject. The reason for using the NZ operator is further based on the fact that while in general a non-convex problem cannot be turned into a convex one, it can be transformed into a Mixed Integer Linear Programming (MILP) problem. However, in the planning problem we are dealing with, the feasible region is non-continuous, thus it can be efficiently modeled through non-convex terms only. It is worth noting that, on the other hand, sometimes having more constraints reduces the feasibility region of the problem and may accelerate the calculation speed, but this applies to Linear Programming (LP) problems, while for MILP problem the discussion is still open and it might be true the opposite, namely that less constraints may help, as it can be inferred from (Borisovsky, Eremeev, and Kallrath 2014) and (Klotz and Newman 2013).

To accomplish the model implementation, Matlab environment with Yalmip interface has been identified as the most suitable set that allows to analyze more complex cases than those dealt with so far in the literature. Within that environment it is possible to use both Cplex and Gurobi as solvers. Cplex offers high-resolution gap, and it is suitable for validating the model in the Garver's 6-node system, while Gurobi is desired when dealing with more complex systems such as the ones of section 2.2 because it allows to adopt easily the proper resolution gap, achieving a suitable trade-off between resolution time and precision.

2.1.2 *The modified Garver's 6-node system*

The proposed model has been tested and validated on the modified Garver's 6-node system shown in Figure 2.1. This system includes five nodes and six lines. In our validation test, a sixth node is considered, which is not connected to the system, but lines can be built to connect it. Any corridor can accommodate at most three lines (prospective plus existing).

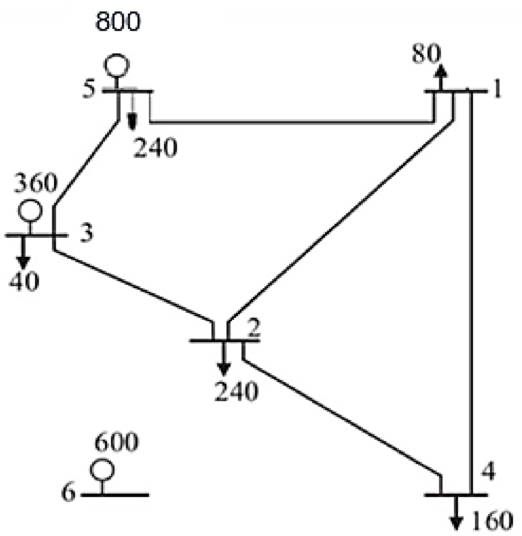


Figure 2.1 The modified Garver's 6-node system

Table 2.1 represents data of existing and candidate lines while Table 2.2 includes data of generation systems.

Table 2.1 Existing and candidate lines data

From	To	R [p.u]	X [p.u]	Limit [MW]	Cost [10^6 $]	Already Build?
1	2	0.10	0.40	100	40	Yes
1	3	0.09	0.38	100	38	No
1	4	0.15	0.60	80	60	Yes
1	5	0.05	0.20	100	20	Yes
1	6	0.17	0.68	70	68	No
2	3	0.05	0.20	100	20	Yes
2	4	0.10	0.40	100	40	Yes
2	5	0.08	0.31	100	31	No
2	6	0.08	0.30	100	30	No
3	4	0.15	0.59	82	59	No
3	5	0.05	0.20	100	20	Yes
3	6	0.12	0.48	100	48	No
4	5	0.16	0.63	75	63	No
4	6	0.08	0.30	100	30	No
5	6	0.15	0.61	78	61	No

Table 2.2 Generation power units' data

Node	Capacity [MW]	Type	Cost [$/MWh]
5	800[a]	wind	0
3	360	coal	48
6	600	coal	52

[a] Indeed the Wind Power Capacity of the Garver's case is 400 MW instead of the assumed 800 MW, which we use for our calculation in order to deal with systems with larger renewable penetration

Data of candidate BES and BEST are illustrated in Table 2.3 and Table 2.4, respectively.

Table 2.3 Candidate BES data

Type	$P_{\max,dis}^{i_{bes}}/P_{\max,ch}^{i_{bes}}$ [MW]	$P_{\min,dis}^{i_{bes}}/P_{\min,ch}^{i_{bes}}$ [MW]	$E_{min}^{i_{bes}}$ [MWh]	$E_{max}^{i_{bes}}$ [MWh]	$\eta_{ch}^{i_{bes}}$	$\eta_{dis}^{i_{bes}}$
1	100	0	20	600	0.85	0.85
2	50	0	10	300	0.9	0.9

Table 2.4 Candidate BEST data

$P_{\max,d}^{i_{best}}$ [MW]	$P_{\max,c}^{i_{best}}$ [MW]	$P_{min,d}^{i_{best}}$ [MW]	$P_{\min,c}^{i_{best}}$ [MW]	$E_{min}^{i_{best}}$ [MWh]	$E_{max}^{i_{best}}$ [MWh]	$\eta_{ch}^{i_{best}}$ / $\eta_{dis}^{i_{best}}$
25	25	0	0	15	150	0.9

In the following, two study cases are presented: the first one allows for the investigation of stationary and mobile storage systems position, while the second one, in which variables $Y_{i_{bes}}$ and $V_{i_{best}}$ are set as continuous ones, permits also to identify the optimal size of both BES and BEST.

A. *Case I: Allocating position of BES and BEST*

The main settings and assumptions are the following:

- Load shedding is not allowed.
- The spinning reserve requirement is neglected.
- BES and BEST decision variables, i.e. $Y_{i_{bes}}$ and $V_{i_{best}}$ are set as binary variables. Only storage position is allocated.
- The number of operating conditions, selected to reproduce the most representative days of the year, is set equal to 24, therefore each month is represented by two operating days.
- The annualized investment cost of stationary and mobile storage systems is set equal to 30 $/kWh.
- In agreement with (2.3) the BEST transportation cost is addressed through the value of $K^{i_{best}}$, which is set equal to 5000 $ in this test system.
- The initial transportable storage systems state of charge is set equal to the half of their maximum energy content.
- $P_{\min,ch}$ and $P_{min,dis}$ of both stationary and transportable storage systems, they are set equal to zero.
- Two BESs candidate are considered at each node, i.e. one of type 1 and one of type 2.
- The number of BESTs candidate is set equal to 1 due to the complexity of the model implementation. BEST can be moved among all the 6 buses of the system.

Three cases are carried out to compare the effectiveness of the proposed model: 1) transmission lines only as possible investment (benchmark case), 2) BESs and new lines as candidate facilities, 3) BEST, BESs and new lines as candidate facilities.

Table 2.5 shows the simulations results for the three cases above.

Table 2.5 Case I simulations results of the validation test

	Total cost [10^6\$]	Inv. cost [10^6\$]	Oper. cost [10^6\$]	BEST oper. cost [10^3\$]	Lines build [-]	BES [-]	BEST [-]
Only lines candidates	334	171	163	-	4 6 9 10 11	-	-
BESs and lines candidates	319	157	162	-	1 4 6 9 10	10 (type 2)	-
BEST, BESs and lines candidates	312	154	158	10	3 4 6 9 10	10 (type 2)	1

The results obtained demonstrate that the model can effectively coordinate the transmission planning with BESTs and BESs. Indeed, as shown in Figure 2.2, when considering storage units in the planning scheme, shorter lines need to be built. As a result, the total cost decreases significantly with respect to the benchmark scenario: 15 million \$ and 22 million \$ are saved in cases 2 and 3, respectively.

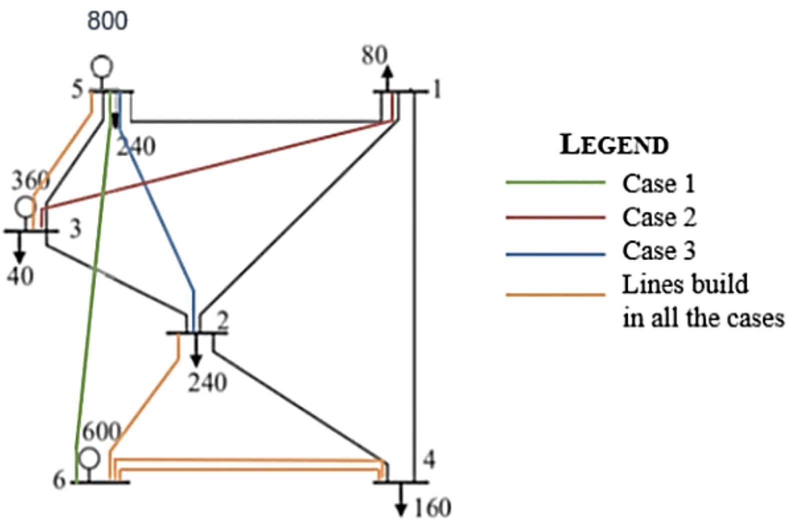


Figure 2.2 Lines build in the three sub-cases analyzed in case I

When considering BEST, BESs and new lines as candidate facilities, the solution includes one stationary and one transportable storage unit, which allows the system to reduce operations cost by decreasing significantly wind power curtailment, as shown in Figure 2.3.

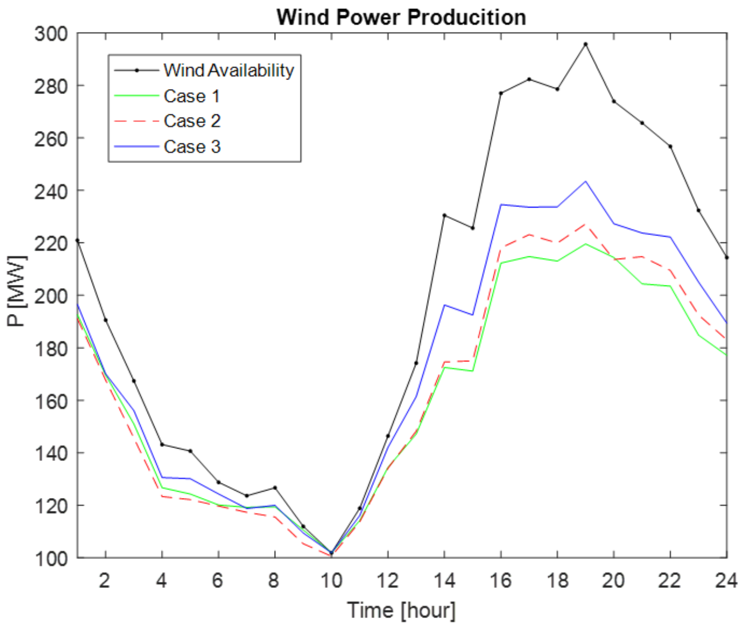


Figure 2.3 Wind power availability and production profiles in case I

B. Case II: Allocating position and size of BES and BEST

Dealing with BES and BEST position and size allocation, some further settings and assumptions are considered, in addition to those relevant to case I:

- The spinning reserve requirement is allocated.
- The number of operating conditions, selected to reproduce the most representative days of the year, is set equal to 12, therefore each month is represented by one operating day.
- In agreement with (2.3) the BEST transportation cost is addressed through the value of $K^{i_{best}}$, which is set equal to 3750 $ in this test system.
- BES and BEST decision variables, i.e. $Y_{i_{bes}}$ and $V_{i_{best}}$, are set as continuous functions, so that also storage systems size can be determined.

As already mentioned, the introduction of the spinning reserve requirement in the mathematical model set of constraints increases the complexity of the planning problem. Therefore, for this case we have set the decision variables $Y_{i_{bes}}$ and $V_{i_{best}}$ as continuous ones. This strategy allows to achieve numerical solutions with a reasonable computational burden. Moreover, with this approach both size and position of stationary and transportable storage systems are allocated.

Table 2.6 summarizes the simulations results of the same sub-cases of Table 2.5 but refers to the case where both size and position of storage systems are allocated.

Table 2.6 Case II simulations results of the validation test

	Total cost [$10^6$$]	Inv. cost [$10^6$$]	Oper. cost [$10^6$$]	BEST oper. cost [$10^3$$]	Lines build [-]	BES [-]	BEST [-]
Only lines candidates	355	171	184	-	4 6 9 10 11	-	-
BESs and lines candidates	339	156	183	-	1 4 6 9 10	2 BESs of type 1 (260 MWh)	-
BEST, BESs and lines candidates	304	119	185	7	4 6 9 10	-	1 (300 MWh)

As shown in Table 2.6, allocating storage systems both position and size the total cost decreases significantly with respect to the benchmark scenario. In particular, 16 million $ and 51 million $ are saved in cases 2 and case 3, respectively.

It is worth noting that the operation costs of the system shown in Table 2.6 are much higher than those of the previous study case (Table 2.5), and this is mainly due to the introduction of the spinning reserve requirement, which significantly increases the operations cost of the system. Moreover, in case II we have set only 12 operating conditions, thus the simulations are less detailed than those with 24 operating conditions of the previous study case.

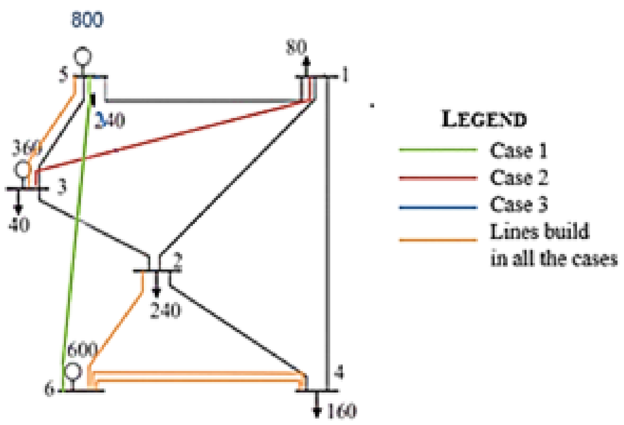


Figure 2.4 Lines build in the three sub-cases analyzed in case II

As shown in Figure 2.4 when considering the transportable storage system in the planning scheme, one less line needs to be built, reducing therefore significantly the total investment cost. Furthermore, regarding the other two sub-cases without BEST the transmission lines included in the planning scheme are the same ones of the previous study case, as it turns out by comparing Figure 2.2 and Figure 2.4.

It should be stressed that in the proposed test system the strategy of relaxing the decision variables $Y_{i_{bes}}$ and $V_{i_{best}}$ improves the solution only when considering BEST devices in the planning scheme because with such a device we can avoid the investment of one transmission line, so reducing significantly the investment cost. The other two sub-cases achieve higher total costs due to the higher operations costs, as previously discussed.

The wind power production is similar in all the three proposed sub-cases, as shown in Figure 2.5. Indeed, the transportable storage systems allows to achieve a significant reduction on the system investment cost as previously mentioned, but in our case we are considering a network with the variable renewable production concentrated in one bus only, thus if wind curtailment is not economically penalized BEST may not bring too many advantages in that respect because it is mainly used to supply a transmission line.

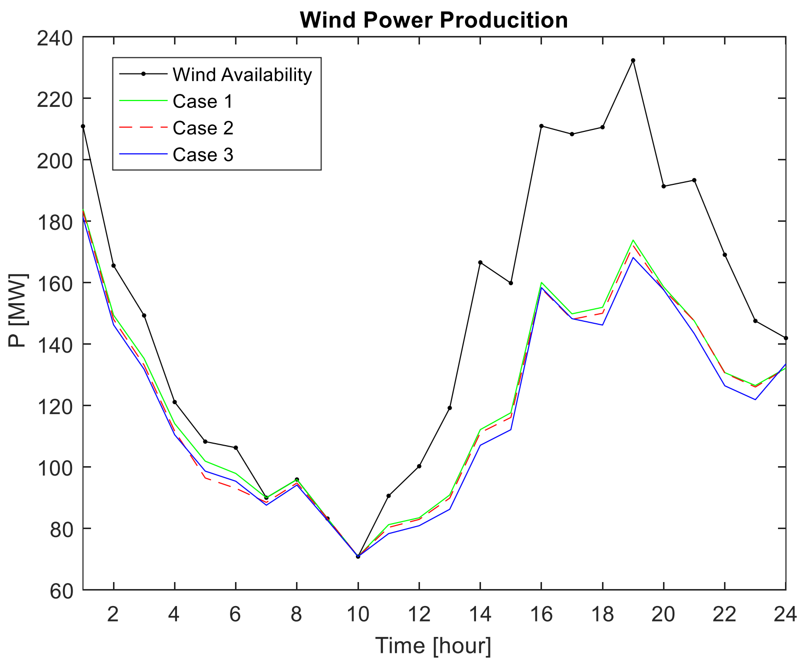


Figure 2.5 Wind power availability and production profiles in case II

Furthermore, as shown in Figure 2.6 the transportable storage system provides also a contribution concerning the compliance of the network spinning reserve requirement.

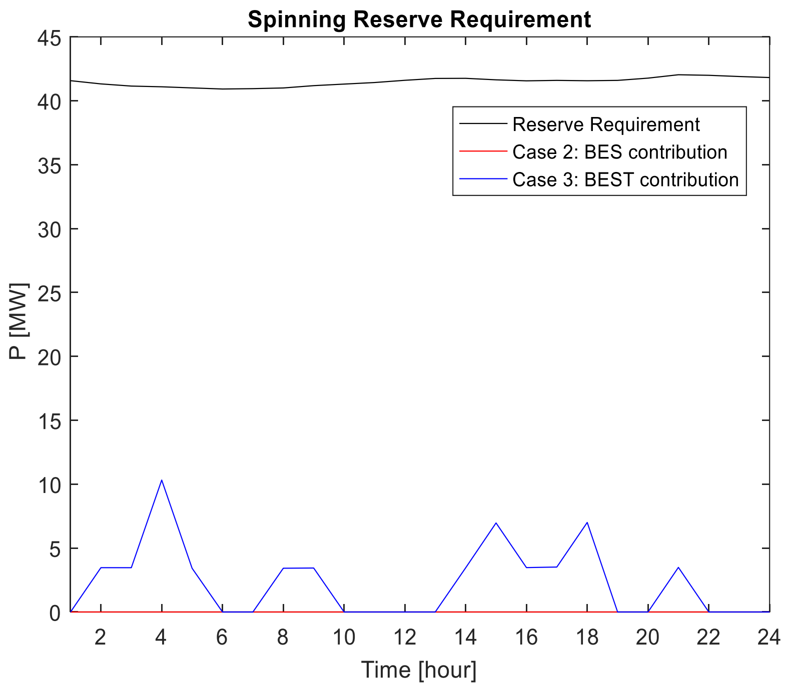


Figure 2.6 Spinning reserve profiles in case II

As shown in Table 2.6, BEST installation allows to avoid the investment of one transmission line, reduces the total expansion planning cost and as shown in Figure 2.6, it provides contributions to fulfill the technical constraints of the power grid. Moreover, it could significantly encourage the reduction of renewable energy curtailment if economically penalized, as it is expected for the near future.

2.2 Transmission Planning with Battery-based Energy Storage Transportation and distance-dependent transportation cost

This section is focused on a planning model that provides the best combination of transmission lines and storage units, both stationary and transportable, to achieve the minimum cost in a considered power system, like the problem addressed in the first part of this chapter.

Nonetheless, the planning model formulation presented in this second part of the chapter, introduces major enhancements to the model previously considered, that regards mainly the allocation of a proper transportation cost which allows quantifying the effective distance that needs to be covered for the transportable storage displacements.

In that respect, it is no longer assumed that the operation cost of the transportable storage units has a fixed value for each single route, whatever the displacement of the storage system. In this section, BEST transportation cost is addressed and calculated considering a fixed distance between consecutive buses. In other words, it is assumed that the distance between e.g. buses 3 and 4 is equal to the distance between buses 4 and 5, so that the distance between 3 and 5 is double than that between two consecutive buses such as 3 and 4 or 4 and 5.

The other main assumptions adopted for the planning model shown in section 2.1 remain valid also in this formulation.

It is worth noting that dealing with uncertainties related to VRE power generation, two aspects need to be addressed:

1) The output profiles of wind and solar power generation can significantly change when considering different days.

2) The forecast of VRE power generation, such as wind and solar, is uncertain in the daily dispatch.

Our model addresses the first kind of uncertainty using scenario-based model, which can also reflect the operation of BEST. We do not consider the second uncertainty using stochastic or robust models; instead, we consider it using the reserve capacity constraints through Gaussian Distributions. Indeed, as shown in (N. Zhang et al. 2014), the uncertainty of wind power can be captured by introducing reserve capacity constraints through the Gaussian copula. In (N. Zhang et al. 2014) it is shown that such an approach achieves similar results compared with the stochastic unit commitment.

2.2.1 *Model formulation*

As already shown in the first part of this chapter, the objective function of a transmission expansion planning is the minimization of the total cost, given by the sum of the annualized investment costs and the operation costs of the system under study:

$$OF = \min\left(C^{Inv} + C^{Oper}\right) \tag{2.25}$$

where

$$C^{Inv} = \sum_{l \in \Omega_{LC}} C_l^{Line} X_l + \sum_{i_{bes} \in \Omega_{bes}} C_{i_{bes}}^{Storage} Y_{i_{bes}} + \sum_{i_{best} \in \Omega_{best}} C_{i_{best}}^{Best} V_{i_{best}} \tag{2.26}$$

$$
\begin{aligned}
C^{Oper} &= \Delta t \sum_{j\in\Omega_{OP}} d_j \sum_{i\in\Omega_I} C_i^{gen} \sum_{t=1}^{T} P_{i,j,t}^{gen} + \\
&+ \Delta t \sum_{j\in\Omega_{OP}} d_j \sum_{t=1}^{T} \sum_{i_b} L_{i_b,j,t}^{shed} C^{shed} + \\
&+ \sum_{i_{best}\in\Omega_{best}} n_{dist}^{i_{best}} K_{dist}^{i_{best}} + \sum_{i_{best}\in\Omega_{best}} \frac{C_{i_{best}}^{Best}}{365} (n_0^{i_{best}} + n_{Trip}^{i_{best}})
\end{aligned}
\qquad (2.27)
$$

The objective function and the investment cost shown in (2.25) and (2.26) are the same of the previous model formulation already shown in (2.1) and (2.2).

The main difference between those two models consists in the calculation of the operation cost C^{Oper} that, as shown in (2.27), it is given by the sum of three components: the fuel consumption of conventional generating units, the load shedding penalty and the BEST operation cost, respectively. BEST operation cost is given by the sum of the last two terms of (2.27). The third term of (2.27) represents the total BEST transportation cost, where $n_{dist}^{i_{best}}$ represents the distance to be covered for the transportation of the BEST system i_{best} and $K_{dist}^{i_{best}}$ is the transportation cost for each unit distance travelled. As already mentioned, in this model the distance covered by BEST, i.e. $n_{dist}^{i_{best}}$ is formulated considering that the distance between consecutive buses has a fixed value, but no limitations exist concerning the BEST mobility paths. The fourth term of (2.27) represents the cost associated to the operating conditions (i.e. days) where BEST is not providing any contribution to the system, namely $n_0^{i_{best}}$, in addition to one BEST inoperative day for each trip of the device, namely $n_{Trip}^{i_{best}}$. As already mentioned previously, the fixed operation and maintenance costs of transmission lines, BESs and BESTs are usually equal about 1-1.5% of the investment cost. It is therefore included in the coefficient of their investment cost, respectively.

Concerning the BEST operation cost, the following equations define $n_{dist}^{i_{best}}$, $n_0^{i_{best}}$ and $n_{Trip}^{i_{best}}$, respectively.

$$
n_{dist}^{i_{best}} = n_{dist}^{0} \sum_{j=1}^{n_{oc}} n_{dist,j}^{i_{best}} \quad \forall i_{best} \qquad (2.28)
$$

where

$$
\left\{
\begin{aligned}
n_{dist,j}^{i_{best}} &= \left| n_j^{i_{best}} - n_{j+1}^{i_{best}} \right| && \forall j = 1,\ldots,n_{oc}-1 \\
n_{dist,j}^{i_{best}} &= \left| n_1^{i_{best}} - n_{n_{oc}}^{i_{best}} \right| && j = n_{oc}
\end{aligned}
\right. \quad \forall i_{best} \qquad (2.29)
$$

and

$$n_j^{i_{best}} = find\sum_{t=1}^{T}(P_{i_{best},i_b,j,t}^{best,ch} + P_{i_{best},i_b,j,t}^{best,dis}) \quad \forall i_{best}, j \tag{2.30}$$

$$n_0^{i_{best}} = n_{oc} - \sum_{j=1}^{n_{oc}} n_{0,j}^{i_{best}} \quad \forall i_{best} \tag{2.31}$$

where

$$n_{0,j}^{i_{best}} \le NZ(\sum_{t=1}^{T} P_{i_{best},i_b,j,t}^{best,ch} + P_{i_{best},i_b,j,t}^{best,dis}) \quad n_{0,j}^{i_{best}} \in [0,1] \ \forall i_{best}, j \tag{2.32}$$

$$n_{Trip}^{i_{best}} = NZ(n_{dist,j}^{i_{best}}) \quad \forall i_{best} \tag{2.33}$$

where:

- $n_{dist}^{i_{best}}$ is the distance to be covered for the transportation of the BEST system i_{best}.
- n_{dist}^{0} represents the distance between adjacent buses,
- $n_{dist,j}^{i_{best}}$ denotes the non-dimensional ‘bus distance’ between operating conditions j and j +1 of the BEST system i_{best},
- $n_j^{i_{best}}$ represents the bus number of the BEST system i_{best} in operating condition j,
- $n_0^{i_{best}}$ is the number of operating conditions where the BEST system i_{best} is not used, and
- $n_{0,j}^{i_{best}}$ indicates whether the BEST system i_{best} is operative in operating condition j.

Note that with this BEST model, we allow the BEST displacement not only between two adjacent buses but any two buses of the area of interest.

The remaining part of the model formulation has been already shown in equations (2.4) – (2.24).

A. Problem Solving

As already done in section 2.1 for the Garver’s 6-node system, initially variables $Y_{i_{bes}}$ and $V_{i_{best}}$, indicating whether to settle the stationary i_{bes} and transportable i_{best} storage systems respectively, are set as binary variables. In that case, being the size of stationary and transportable storage systems fixed, storage systems location only is optimized. Subsequently, the spinning reserve requirement is included in the model set of constraints, thus increasing the complexity of the mathematical problem. Therefore, binary variables $Y_{i_{bes}}$ and $V_{i_{best}}$ have been relaxed and set as continuous ones.

Further, as previously mentioned, the proposed planning model is implemented within Matlab environment by making use of Yalmip as interface. Moreover, dealing with a complex mathematical formulation tested in large scale systems, Gurobi is chosen as a solver because it allows to easily set the suitable optimization gap, managing properly both resolution time and precision.

2.2.2 *The HRP-38 system*

In this section, the proposed High Renewable Penetration (HRP)-38 test system, deeply investigated in (Zhuo et al. 2020) and based on a regional power system in China, is presented. The HRP-38 system, shown in Figure 2.7, operates at 750 kV according to the reality. Four power generation technologies are considered in the HRP-38 system: thermal units, hydro, Photovoltaics (PV) and wind turbines.

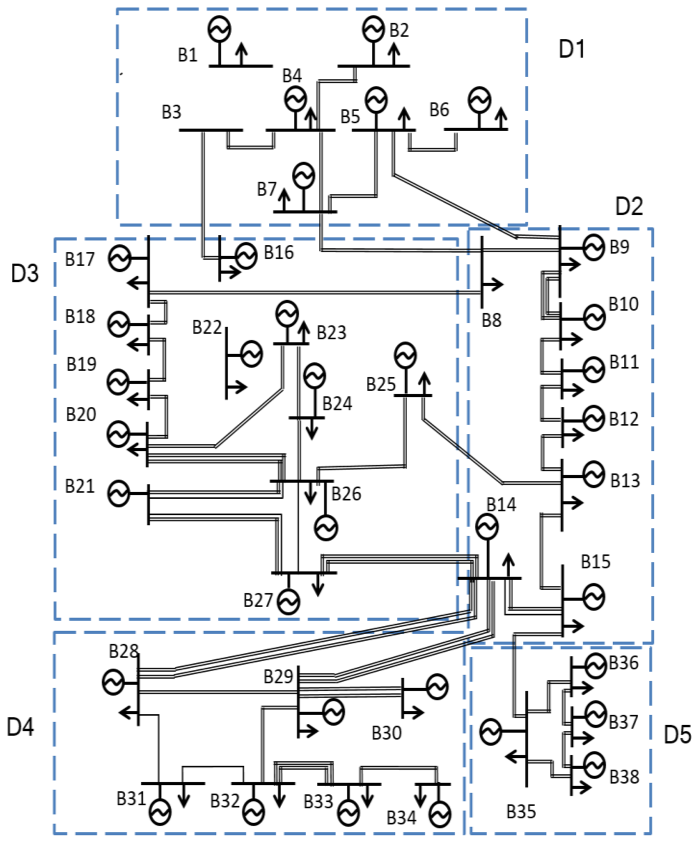


Figure 2.7 HRP-38 test system

Both wind and PV output data are simulated considering the bus location and statistics of variable renewable energy in real power system, by means of GOPT power system analysis software (Zhuo et al. 2020). Table 2.7 includes the data related to each regional area of the proposed HRP-38 test system and Figure 2.8 shows its generation mix.

Table 2.7 Data of HRP-38 test system

Installed capacity [MW]	D1	D2	D3	D4	D5	Total
Hydro	18000	12000	31000	6000	0	67000
Thermal	140500	22500	15000	49600	34000	261600
Solar	52800	32100	54600	22200	22200	183900
Wind	48000	36600	6000	9000	10800	110400
Total	259300	103200	106600	86800	67000	622900
Peak load [MW]	1110000	51000	27000	72000	39000	300000

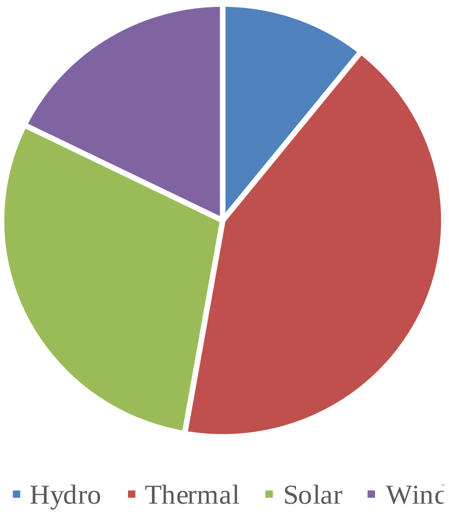


Figure 2.8 Generation mix of HRP-38 test system

In order to achieve solutions in a reasonable computational time, the following simplifications are adopted:

- All the lines n_l with a reactance X_l and an investment cost C_l^{Line} in the same corridor were grouped considering just 1 line whose reactance and annualized investment cost are, respectively:

$$X_T = \frac{1}{\sum_{l=1}^{n_l} \frac{1}{X_l}}$$

$$C_l^{Line} = \sum_{l=1}^{n_l} C_l^{Line}$$

- All the $n_{k,i}$ generators of the same type in the same bus i were grouped considering just 1 generator whose generation power is:

$$P_{T,i} = \sum_{k=1}^{n_{k,i}} P_{k,i}$$

- Considering conventional units, the operating costs are the weighted average of the operating costs of all the units which is composed by.

Table 2.8 and Table 2.9 include data of BES and BEST candidates, respectively.

Table 2.8 Candidate BES data for the HRP-38 system

$P_{\max,dis}^{i_{bes}}$ [MW]	$P_{\max,ch}^{i_{bes}}$ [MW]	$E_{min}^{i_{bes}}$ [MWh]	$E_{max}^{i_{bes}}$ [MWh]	$\eta_{ch}^{i_{bes}}$	$\eta_{dis}^{i_{bes}}$
600	600	120	1200	0.9	0.9

Table 2.9 Candidate BEST data for the HRP-38 system

$P_{\max,dis}^{i_{best}}$ [MW]	$P_{\max,ch}^{i_{best}}$ [MW]	$E_{min}^{i_{best}}$ [MWh]	$E_{max}^{i_{best}}$ [MWh]	$\eta_{ch}^{i_{best}}$	$\eta_{dis}^{i_{best}}$
350	350	70	700	0.9	0.9

The investment cost of BES and BEST is the sum of the cost related to the battery storage system power capacity, including all the electronic equipment, and the cost related to the energy capacity of the device. These costs, annualized with a life cycle equal to 15 years and a discount rate (WACC) of 10%, are respectively set equal to 300 kCNY/MW and 55 kCNY/MWh, which is an assumption based on the fact that the cost for Lithium Iron Phosphate (LFP) storage system (China Industrial Association of Power Sources 2018) will be continuously and significantly dropping as the technology is fast developing and spreading. Also, it is worth noting that we are disregarding possible penalties on renewable energy curtailment that would render the use of BES and BEST even more convenient.

In the following sub-sections, namely sub-section 2.2.2A and sub-section 2.2.2B, two study cases are presented and applied to the HRP-38 system: the first one allows for the investigation of stationary and mobile storage systems position, while the second one permits also to identify the optimal size of both BES and BEST.

A. *Case I: Allocating position of BES and BEST*

The simulations are performed according to the following settings and assumptions:

- Load Shedding is allowed.
- The spinning reserve requirement is neglected.
- BES and BEST decision variables, i.e. $Y_{i_{bes}}$ and $V_{i_{best}}$, are set as binary variables. Only storage position is allocated.
- The number of operating conditions, selected to reproduce the most representative days of the year, is set equal to 12, therefore each month is represented by one operating day.
- All the candidate storage systems are LFP batteries.
- In agreement with (2.27) the BEST transportation cost is addressed through the value of $K_{dist}^{i_{best}}$, which is set equal to 760 CNY/km in the case under study.
- The distance between adjacent buses, n_{dist}^{0}, is set equal to 100 km.
- The initial storage systems state of charge is set equal to the half of their maximum energy content.
- Regarding $P_{\min,ch}$ and $P_{min,dis}$ of both stationary and transportable storage systems, they are set equal to zero.
- In this case study, Gurobi is chosen as a solver, and the resolution gap is set equal to 2%.
- The number of BESs candidate is set equal to 10, therefore there are 2 stationary storage systems candidates for each area of the system.
- The number of BESTs candidate is set equal to 1 due to the complexity of the model implementation, and BEST is restricted in a specific area of the network.

The last assumption means that we have set five different sub-cases, each one restricting BEST within one of the five regional areas only. A benchmark case, which does not have BEST available, is also included.

Table 2.10 shows the simulations result for case I, which we are dealing with.

The results show that allocating storage systems position, BEST is part of the optimal set of investment for any sub-case analyzed, whatever the area of mobility. As shown in Table 2.10, BEST installation brings several advantages, such as the decreasing of load shedding of about 30%, the reduction of the total cost of 0.4% and the decrease of wind and solar energy curtailment of 35% and 8%, respectively. Comparing the most convenient BEST, namely the one restricted in area 2, with another sub-case, e.g. BEST restricted in area 4, load shedding is around 40% less and VRE curtailment is about 15% lower.

Table 2.10 Case I simulations results (most convenient solutions are denoted with bold fonts)

	BEST in Area 1	BEST in Area 2	BEST in Area 3	BEST in Area 4	BEST in Area 5	No BEST candidate
Total cost [10^9CNY]	175.4	**175.0**	175.3	175.3	**175.1**	175.7
Investment cost [10^9CNY]	5.1	**5.1**	4.8	4.6	**4.9**	4.5
Operation cost [10^9CNY]	170.3	**169.9**	170.5	170.7	**170.2**	171.2
Operation BEST cost [10^6CNY]	4.6	**3.0**	5.2	3.0	**1.6**	-
BESs [-]	4	**4**	4	3	**3**	4
BEST [-]	1	**1**	1	1	**1**	-
Load shedding [10^6 MWh]	0.04	**0.03**	0.04	0.05	**0.04**	0.04
Wind Curtailment [10^6 MWh]	11.4	**7.9**	9.8	11.0	**11.1**	12.2
Solar Curtailment [10^6 MWh]	25.6	**29.4**	31.9	33.0	**31.8**	31.9

Figure 2.9 shows the operation of both stationary and transportable storage systems in the transmission network under study through the power profile of: a) the total satisfied demand minus the total generation, b) the total BESs discharge power minus the total BESs charge power, and c) BEST discharge power minus BEST charge power.

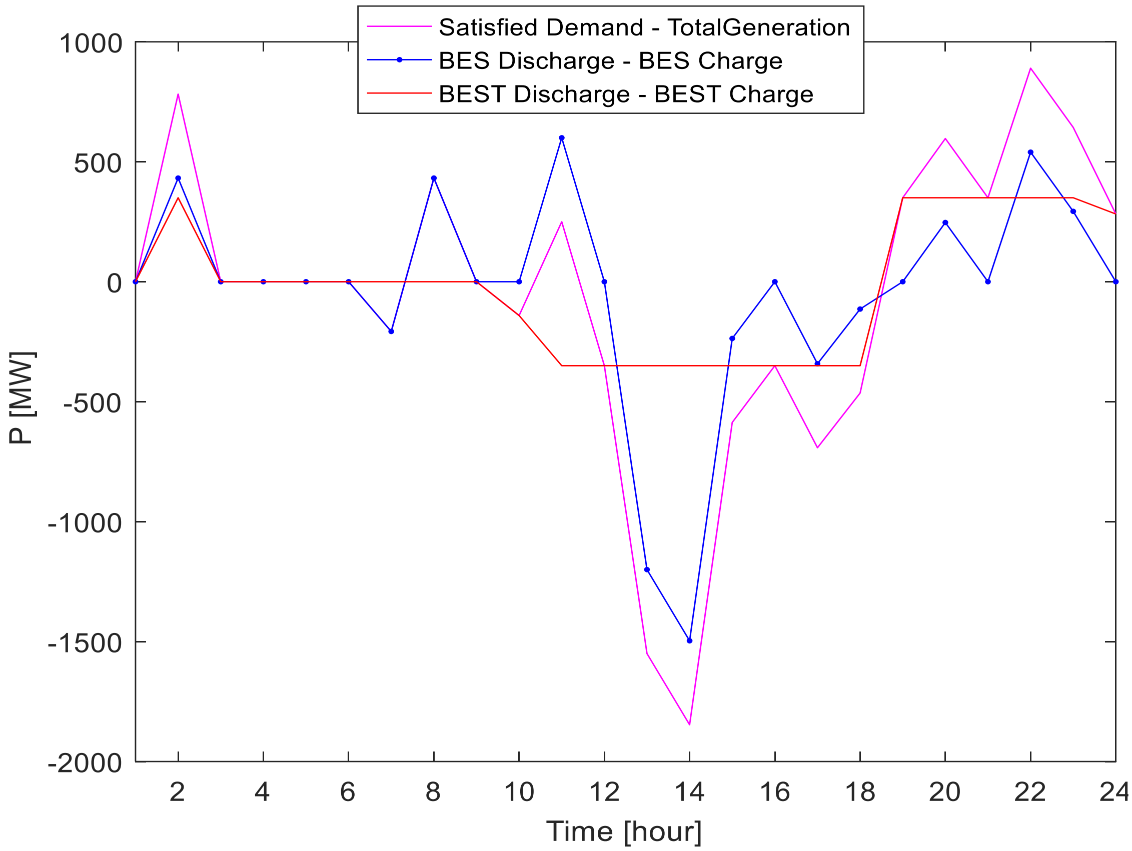


Figure 2.9 Case I power profile of: a) demand satisfied - total generation, b) total BESs discharge power – total BESs charge power, and c) BEST discharge power - BEST charge power, in one operating condition

Figure 2.10 and Figure 2.12 show the BEST usefulness among the two above-mentioned areas of the HRP-38 system in terms of renewable power curtailment and load shedding, through the trend of the renewable curtailment power profile and the load shedding profile respectively.

Figure 2.11 illustrates the renewable curtailment of each operating condition, which in our case study corresponds to the representative day of each month. Regarding the correlation between load shedding and operating conditions, the uncovered load is concentrated in the last operating condition only, which reflects the trend of the last month of the year.

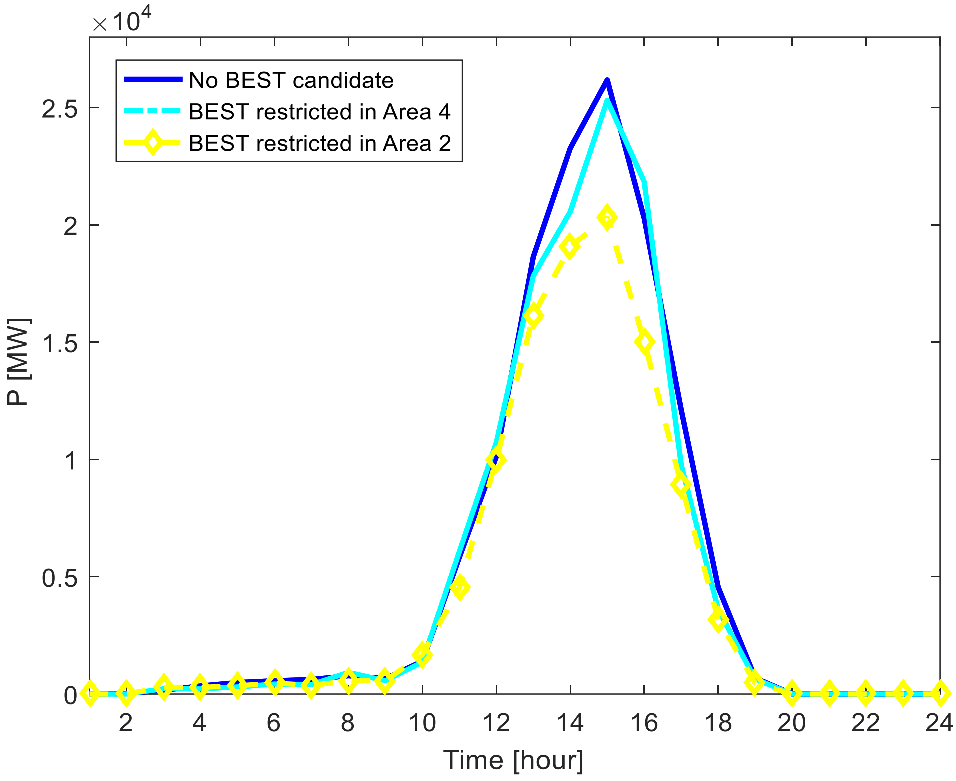


Figure 2.10 Case I renewable curtailment comparison in operating condition 6

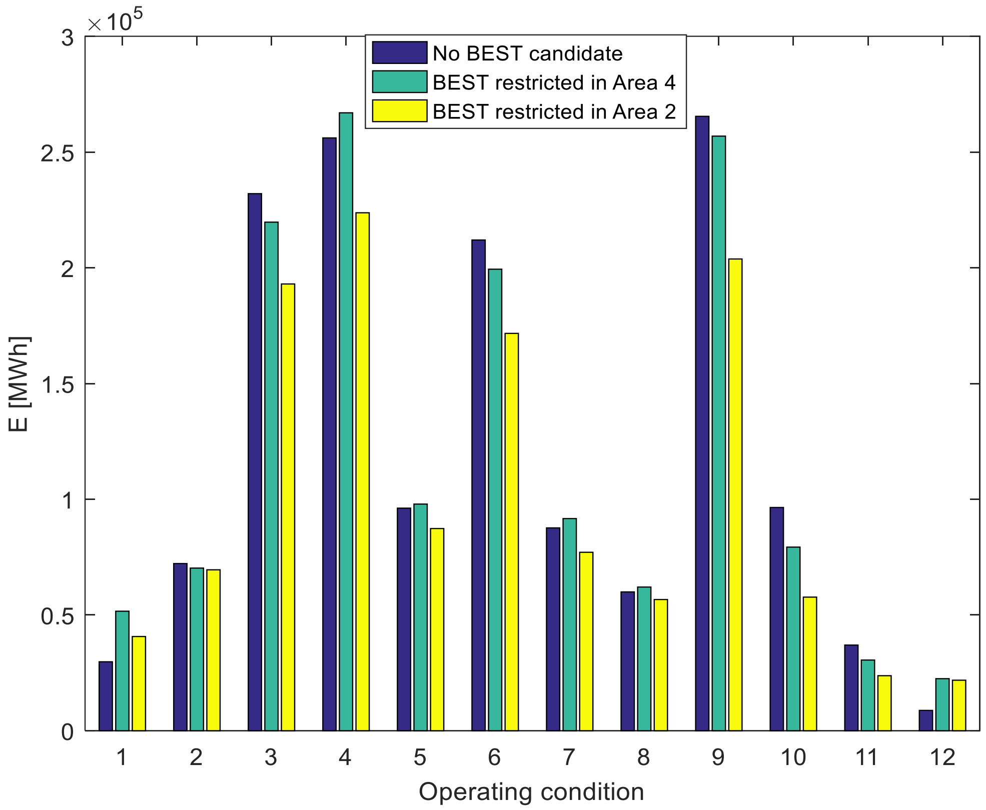


Figure 2.11 Case I renewable curtailment in each operating condition

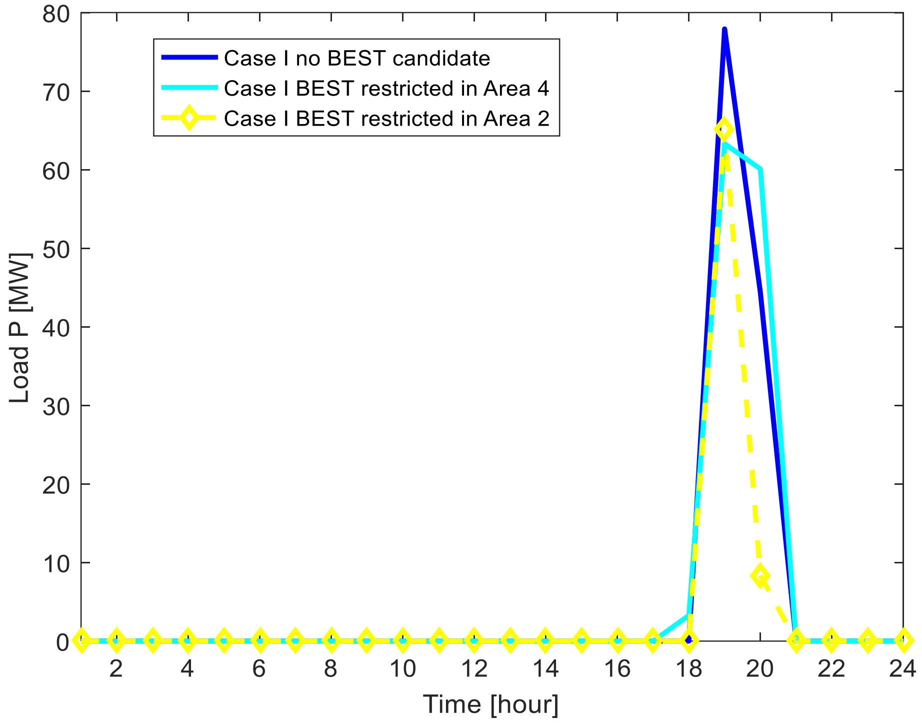


Figure 2.12 Case I load shedding comparison in operating condition 3

Figure. 2.13 shows the location of the BEST device in each operating condition and for each area of mobility of the power system under study.

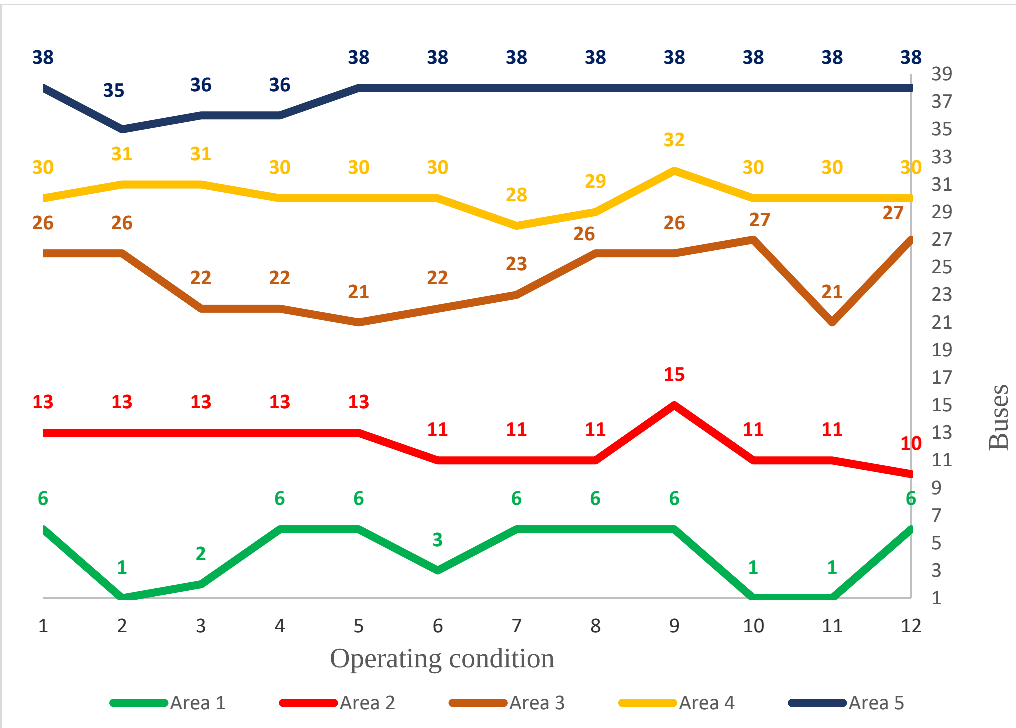


Figure. 2.13 Case I: BEST position in each operating condition

B. Case II: Allocating position and size of BES and BEST

Dealing with BES and BEST position and size allocation, some further settings and assumptions are considered, in addition to those relevant to case I:

- The spinning reserve requirement is allocated.
- BES and BEST decision variables, i.e. $Y_{i_{bes}}$ and $V_{i_{best}}$, are set as continuous functions, so that also storage systems size can be determined.
- In agreement with (2.27) the BEST transportation cost is addressed through the value of $K_{dist}^{i_{best}}$, which is set equal to $45\ \text{CNY/km}$ in the case under study.
- For this case, the value of $C_{i_{best}}^{Best}$ in (2.27) is fixed and it is assumed to be equal to 2.1 MCNY.

Table 2.11 summarizes the simulations results of the same sub-cases of Table 2.10 but refers to the case where both size and position of storage systems are allocated.

Table 2.11 does not include the load shedding quantity because allocating storage systems size and position, load shedding is equal to zero in all scenarios investigated.

Comparing Table 2.10 and Table 2.11, one can infer that in case II the total storage systems installed capacity is larger and concentrated in fewer nodes than for the previous study case. Such a result causes the total cost reduction and the load shedding equal to zero because it allows to set the most convenient size of each device in each bus of the network.

In case II, the suitable areas for BEST are different from the ones of case I; this is due to the fact that in case II, it is allowed to choose the most convenient size of the storage systems in each bus of the network, and therefore for some areas, like area 1, 3 and 5, BESs is more convenient. Nevertheless, as shown in Table 2.10 and Table 2.11, the most convenient BEST is the one restricted in area 2 for both the cases investigated.

Table 2.11 Case II simulations results (the most convenient solution is denoted with bold fonts)

	BEST in Area 1	BEST in Area 2	BEST in Area 3	BEST in Area 4	BEST in Area 5	No BEST candidate
Total cost [10^9CNY]	174.5	**174.1**	174.4	174.5	175.5	174.4
Investment cost [10^9CNY]	4.5	**5.0**	4.8	4.9	5.6	4.9
Operation cost [10^9CNY]	170.0	**169.1**	169.5	169.6	169.9	169.5
Operation BEST cost [10^6CNY]	-	**0.4**	-	0.06	-	-
BESs [-]	4 (6.2 GWh)	**2 (5.0 GWh)**	2 (6.0 GWh)	2 (4.7 GWh)	2 (7.0 GWh)	4 (6.2 GWh)
BEST [-]	-	**1 (1.2 GWh)**	-	1 (2.2 GWh)	-	-
Wind Curtailment [10^6 MWh]	10.8	**11.9**	12.4	11.6	12.0	12.3
Solar Curtailment [10^6 MWh]	30.9	**31.3**	28.4	30.3	31.4	30.4

Figure 2.14 shows the operation of both stationary and transportable storage systems in the transmission network under study through the power profile of: a) the total satisfied demand minus the total generation, b) the total BESs discharge power minus the total BESs charge power, and c) BEST discharge power minus BEST charge power. Comparing such trends with those of Figure 2.9, it can be inferred that in case II storage systems have a more relevant impact in the system under study.

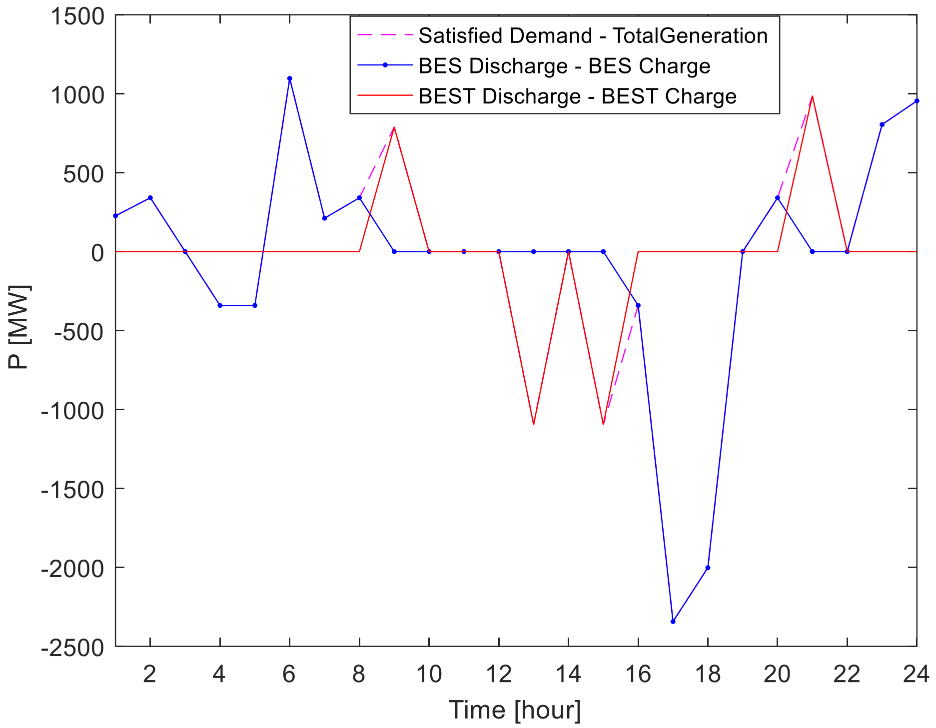


Figure 2.14 Case II power profile of: a) demand satisfied - total generation, b) total BESs discharge power – total BESs charge power, and c) BEST discharge power - BEST charge power, in one operating condition

Figure 2.11 and Figure 2.16 show the total VRE curtailment of BEST restricted in area 2 and area 4, compared with the benchmark scenario. BEST investment causes the decrease of VRE energy curtailment with respect to the benchmark scenario in few sub-cases only. Indeed, in this study case the size of storage systems is a variable in the optimization problem and compared to case I the benchmark scenario provides a reduction of both the total cost and the VRE curtailment. However, the transportable storage system may not bring a considerable further reduction of the VRE curtailment, because in this study it is not economically penalized.

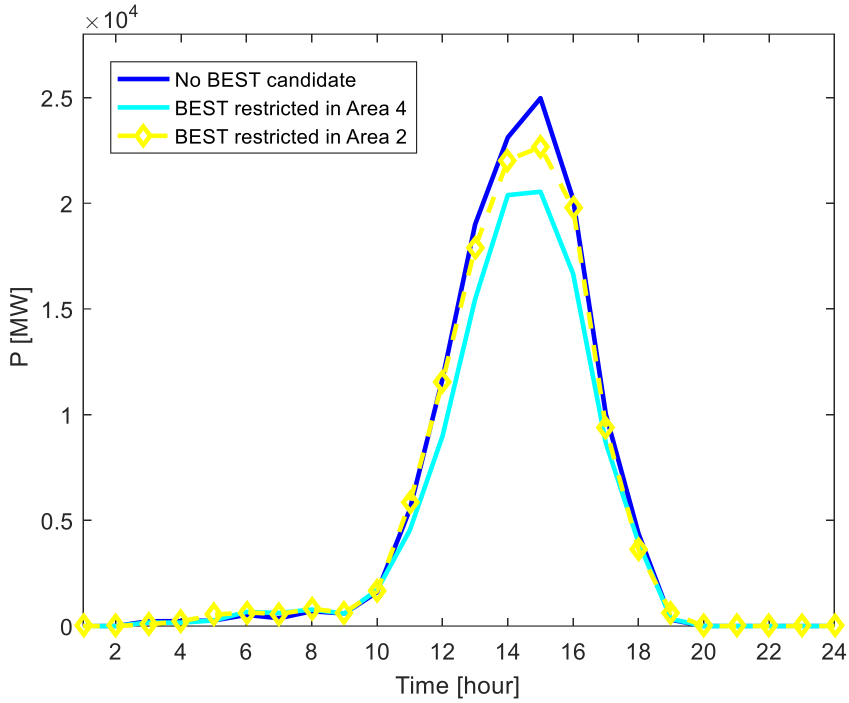


Figure 2.15 Case II variable renewable curtailment comparison in operating condition 10

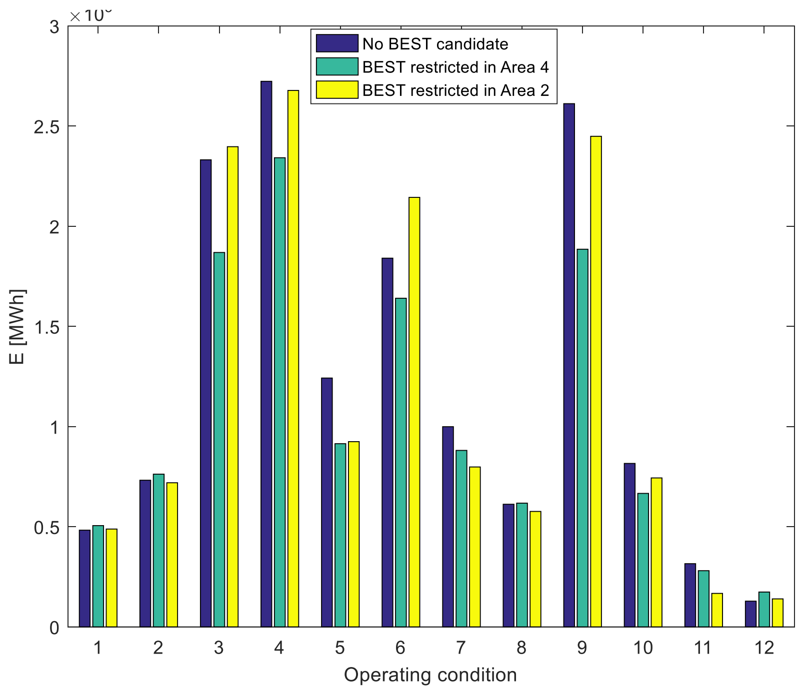


Figure 2.16 Case II renewable curtailment in each operating condition

BEST position in each operating condition is shown in Figure 2.17 for both the areas of interest, namely Area 2 and Area 4. When BEST is allowed to move among buses of the most convenient area of the network, i.e. Area 2, it changes its position almost every operating day and that reflects the transportable storage usefulness in that area.

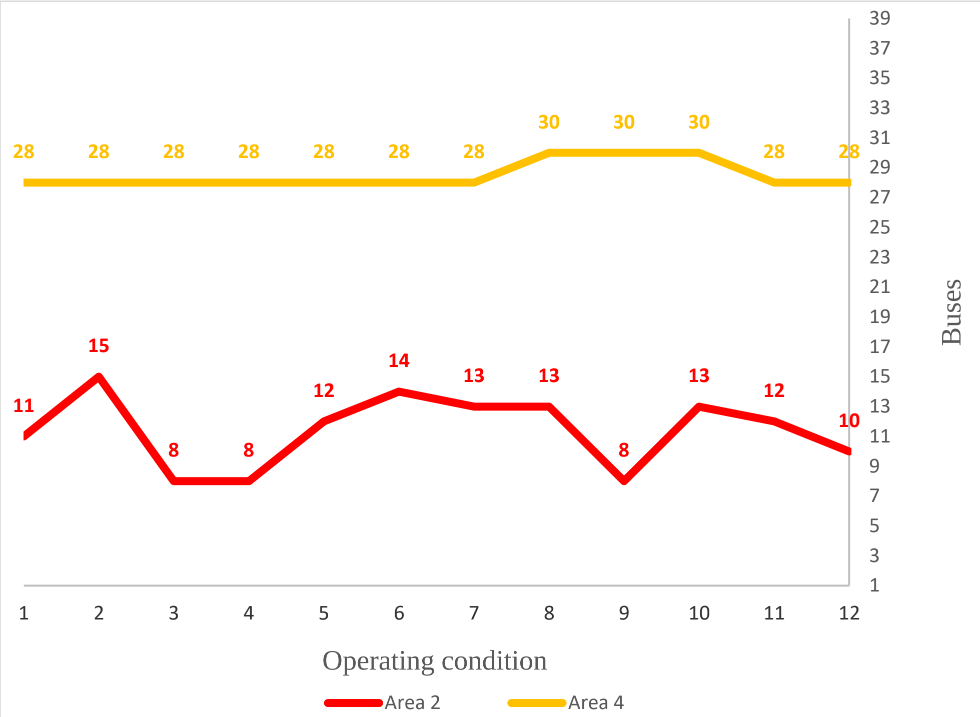


Figure 2.17 Case II: BEST position in each operating condition

2.2.3 *Scalability of the Proposed Model*

In this section the proposed model is applied to a 190-bus test system to analyze its scalability to a larger system with larger renewable energy penetration. As shown in Figure 2.18 the proposed system is given by the interconnection of five HRP-38 systems. The generation and network settings in each area are the same with the settings in section 2.2.2; the 190-bus system consists of 295 generators and 369 lines (275 existing lines plus 94 candidate ones).

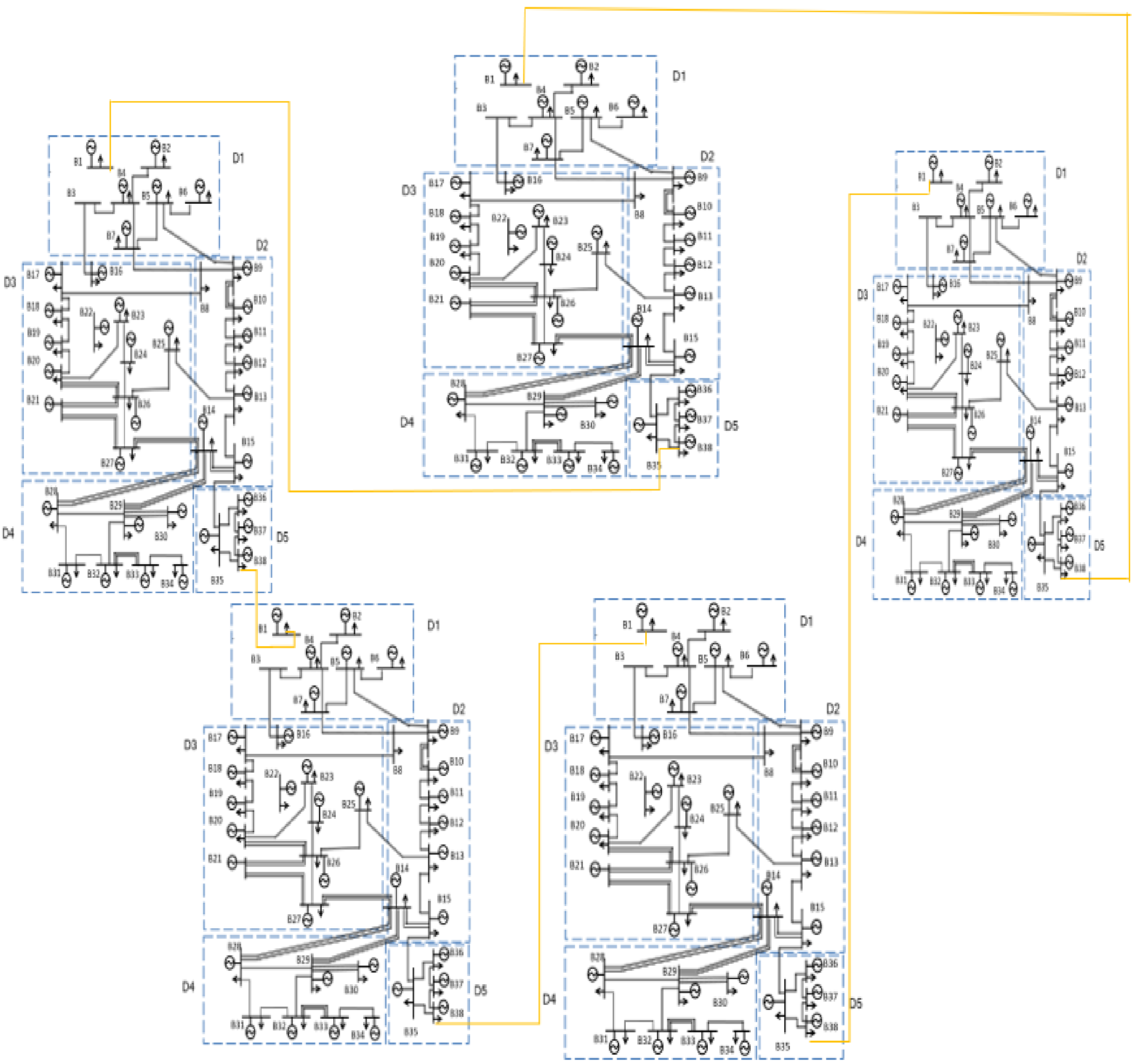


Figure 2.18 The 190-bus test system

Study cases of sub-section 2.2.2A and sub-section section 2.2.2B, namely case I and case II, are analyzed in the proposed 190-bus test system. Relevant results are provided in Table 2.12 and refer to the case where BEST is restricted in a specific area of the network, i.e. area 2 of the "first" HRP-38 system.

Table 2.12 190-bus system simulations results

	Case I	Case II
Total cost [10^9CNY]	966.2	940.5
Investment cost [10^9CNY]	11.2	20.4
Operation cost [10^9CNY]	955.0	920.1
Operation BEST cost [10^6CNY]	4.1	0.2
BESs [-]	5	5 (47.8 GWh)
BEST [-]	1	1 (7.7 GWh)
Wind Curtailment [10^6 MWh]	90.7	90.1
Solar Curtailment [10^6 MWh]	187.0	190.3

The obtained results show that even for the larger network the most convenient solution is reached when allowing the identification of both optimal size and position of the storage devices.

2.3 Conclusion of the chapter

This chapter has addressed the transmission expansion planning problem including stationary and transportable battery energy systems (BESs and BESTs, respectively). Two long-term transmission planning models, adopting a novel Time-Space Network approach for the BEST vehicle scheduling problem, have been presented and validated. Both the proposed mathematical models consider BES and BEST units in the planning scheme, hence giving as output the optimal set of transmission lines, BESs and BESTs that allows to achieve the minimum cost in a considered power system.

The vehicle scheduling of the transportable storage system has been accomplished through the use of the number of non-zero (NZ) function. The implementation of such mathematical function in the optimization model set of constraints, avoids the inclusion of additional binary variables, as generally accomplished for addressing vehicle scheduling, which would considerably increase the computational burden especially when dealing with large scale power systems.

The proposed mathematical models have been investigated in two study cases, which differ by the type, binary or continuous, of the variables indicating whether to settle the stationary or transportable battery system, allowing the identification of either the storage systems optimal location or both optimal location and size of storage systems. In the first approach, such variables are set as binary ones and thus only storage systems position is given as output of the optimization procedure, while in the second one they are set as continuous variables, thus not only the optimal position but also the optimal size of storage systems is allocated.

Both the proposed models address the transmission expansion planning problem with stationary and transportable storage systems adopting almost the same approach in terms of network representation, BES and BEST operation and BEST scheduling. Even though, the planning model formulation presented in the second part of the chapter present a as slightly as remarkable enhancement to the model previously considered. In particular, the planning model introduced in section 2.2 allows to quantify the effective distance that needs to be covered for the transportable storage displacements, and thus to allocate the proper transportation cost for the BEST units. In that respect, such planning model could be usefully applied for any power systems and not only for those where disregarding the effective distance to be covered for BEST displacements could be an acceptable approximation.

Moreover, networks with high renewable penetration have been considered for both models analysis. The planning model including a fixed transportation cost has been validated through the Garver's 6-node system, while the second one with the distance-dependence transportation cost has been investigated on the real China system of the North-western grid, namely the HRP-38 bus network, that includes five regions. Moreover, the latter planning model has been tested also in a larger power network, such as the 190-bus system of sub-section 2.2.3, which allows to show the scalability of the proposed mathematical formulation as it results to be suitable also for large scale power systems.

The analysis presented in this chapter allows to infer what follows. First of all, transportable storage systems represent a suitable alternative to manage transmission congestion in power networks with high penetration of renewable energy. Furthermore, the inclusion of BEST units in the planning scheme allows the reduction of renewable energy curtailment almost in all the cases analyzed. Nonetheless, the contribution of transportable storage units could be significantly relevant when economic penalties related to renewable energy curtailment would be applied. Moreover, the proposed approach of allocating both position and size of storage systems results to be more convenient with respect to the case where storage systems size is fixed, and also it allows to ensure all the demand. Thus, when technically feasible, it is the desirable approach. The adoption of transportable storage units could be promising also for facing emergency situations and enhancing power grid resiliency, which are different problems with respect to the one analysed in this chapter but where the proposed BEST representation could be usefully applied. Finally, the above-mentioned NZ function could be suitable in any mathematical optimization problem that involves a large number of binary variables.

Chapter 3. Planning of a Renewable Energy Community

Introduction

With the “Clean Energy for all Europeans”, a set of eight legislative acts on the energy performance of buildings, renewable energy, energy efficiency, governance and electricity market design introduced and approved by the European Union in recent years (see (EU 2018) and (European Parliament and Council of the EU 2019), EU introduced the concept of Energy Communities: groups of citizens that decide to join forces to equip themselves with systems and apparatuses to produce and share energy from renewable energy sources. The Renewable Energy Directive (RED II) and the Electricity Market Directive (EMD) provide basic definitions and requirements for the activities of individual and collective self-consumption as well as for two types of energy communities, such as:

Citizen Energy Community (CEC): a legal entity, based on voluntary and open participation, controlled by members or shareholders that are natural persons, local authorities, including municipalities or small enterprises. It may engage in generation (including from RES), distribution, supply, consumption, aggregation, energy storage, energy efficiency or charging services for electric vehicles or provide other energy services to its members of shareholders (European Parliament and Council of the EU 2019).

Renewable Energy Community (REC): a legal entity whose primary goal is to provide environmental, economic, or social community benefits for its shareholders/members or for the local area it operates within, instead of financial profits. It is autonomous and controlled by shareholders or members. The community shareholders may be natural persons, Small or Medium Enterprises (SMEs) or local authorities, including municipalities (EU 2018).

Similarities and differences between both REC and CEC have been presented in Table 3.1.

Table 3.1 Differences between REC and CEC; adapted from (Frieden et al. 2019)

Adapted criteria	Renewable Energy Community	Citizen Energy Community
Geographical limitation	Effective control is limited to members living in proximity of the RE projects owned by the community.	No geographic limitations relating to activities, effective control or eligibility for membership in a CEC.
Membership	Based on local control and excludes large enterprises from membership	SMEs and large size enterprises can participate but are excluded from effective control.
Energy sources	All sorts of RES	All sources of electricity, not necessarily renewable.
Major purpose	Stimulating the growth of local community ownership to expand the share of RE at the national level.	CEC as a new 'non-commercial' energy market actor that can engage across the electricity market.

In this context, the Italian government has fully transposed the articles 21 and 22 of RED II in to the (Legislative decree n°199 2021), which has been published on the 30th of November 2021 in the Official Journal.

According to the Italian complete transposition of RED II, two main conditions are needed to set up a renewable energy community, which are:

(a) members of the community are connected to the same primary substation;

(b) renewable energy plants for the production of electricity in the community should not exceed the peak power of 1000 kW and have to come into operation after the 15th of December 2021, the date on which the legislative decree came into force. Already existing renewable generation facilities may also be included, but not for more than 30 per cent of the total power capacity of the community.

It is worth noting that the previous, preliminary version of such a transposition, dated February 28, 2020, was setting points a) and b) as follows:
(a) members of the community are connected to the same secondary substation;
(b) renewable energy plants for the production of electricity in the community should not exceed the peak power of 200 kW and had to come into operation after the March 1st 2020

The remuneration scheme provided by the Italian economic framework for renewable energy communities is based on incentives that the community shall receive for the achieved shared energy, given at each hour by the minimum between the renewable energy fed into the electrical grid by prosumers and the total energy demand required to the grid by the community.

The shared energy is valorized through the MiSE incentives and the ARERA refunds, as described in the following.

To promote renewable energy communities and jointly acting self-consumption development, on 16th September 2020, the Italian Ministry of Economic development (MiSE) has signed a decree which define the feed-in premium for the shared energy. The incentives granted by MiSE last 20 years and they are equal to 110 €/MWh for renewable energy communities.

Moreover, according to RED II, the shared energy should not be subjected to network charge which are not cost-reflective. The Italian Autorità di Regolazione per Energia Reti e Ambiente (ARERA) is authority designed to define the network charges non applicable to the shared energy has generated models, to calculate the amount of charges refund. The Italian Gestore dei Servizi Energetici (GSE) is the authority entitled to calculate the consumers refunds applying ARERA's schemes. The refunds consider the benefits generated by self-consumption, which are related to: **Grid losses:** proximity between generation and consumption generates less power flow through high voltage grid so less losses; **Connection to the grid:** optimization of generated and consumed energy, eventually implementing storage technologies, could reduce the connection costs; **Network expansion and development:** the energy generated in-situ could lead to lower maximum power request at the point of delivery by the prosumers and to less power flow through the grid; the former conditions may allow grid investments deferral; **Dispatching:** self-consumption may reduce dispatching costs, however due to renewable sources volatility the transmission system operator must ensure a certain energy reserve capacity to maintain system stability, this tends to increase the dispatching costs.

For the renewable energy community, the shared energy refunds (C_{AC}) is equal to product between the self-consumed shared energy (E_{AC}) and the monthly flat-rate unit fee ($CU_{Af,m}$), as shown in the following.

$$C_{AC} = CU_{Af,m} \times E_{AC} \text{ [€]}$$

$CU_{Af,m}$ is obtained as the sum of the transmission fee variable part for low voltage consumer ($TRAS_E$) and the higher value of the distribution variable component for low voltage consumer (BTAU).

One of the most important challenge for the development of energy communities is the optimal planning of renewable energy and distributed energy storage systems so to minimize the total community energy cost and fully exploiting the revenues, among which, for instance, current economic incentives.
In literature there are several works dealing with the planning of PV and BESs units at building/community level, such as e.g. (Pourakbari-Kasmaei et al. 2020) (Chatterji and Bazilian 2020), while others concern the planning of Community Energy Storage (CES), e.g. (Parra et al. 2017) (Sardi et al. 2017). Many works are also related to the optimal planning schemes in microgrids, e.g. (Coelho et al. 2017), or planning strategies in energy communities, e.g. (Ghiani et al. 2019). However, there is still the need of investigation regarding the optimal investment and management scheme that may be implemented in a renewable energy community taking into account specific legislative frameworks, given their recent implementation; in this respect we shall deal with the issue devoting our attention to the current Italian one above illustrated.

In light of the above, this chapter concerns the study of the optimal planning of PV units and of battery storage systems in a renewable energy community, which may refer either to a small industrial site or to a housing units acting as a prosumers, considering revenues and limitations according to the present Italian legislative framework.

In particular, a multi-stage planning model that considers the Net Present Value (NPV) of photovoltaic and storage systems investments, other than operation costs and revenues for the considered REC is proposed. More specifically, both generating PV units and battery energy storage systems have been considered in the planning scheme to find the optimal investments (planning) and optimal management strategies (operation) to supply the REC energy demand in the most convenient way under the current Italian framework. In the considered multi-year planning scheme, the investment decision of both BES and PV systems can be made in the most suitable year of the considered planning horizon.

In the first part of the chapter, such a planning model has been compared to the single-stage planning approach, which identifies the optimal size of PV and storage systems that minimize the total cost, given by the annualized investment costs of both PV and BES units and the operation cost, including both the energy exchange with the external utility grid and the revenues related to the shared energy among the prosumers of the considered REC.

Then, a number of case studies for a REC consisting of five residential prosumers have been performed and analysed, by varying the value interest rate, the planning horizon, and considering or not a minimum investment on BES systems for each prosumer.

It is worth noting that for the considered residential energy community, the relevant input data such as prosumer load profiles have been taken from experimental measures in the framework of a project that is carried out by University of Bologna, namely SelfUser (see https://www.selfuser.it/).

3.1 Multi-stage planning of storage and photovoltaic systems in a Renewable Energy Community

This section is focused on a multi-stage planning model, which involves both battery energy storage and photovoltaic systems in the investment decisions of a renewable energy community. The model is dynamic, as it considers the investment decisions to supply the demand over the whole planning horizon (multi-stage planning). The planning scheme provides the optimal size of photovoltaic unit, and of storage system along with its scheduling for each member of the REC and for each operating condition, which is described by the load demand and solar irradiation for each day with hourly resolution. Long-term uncertainty of load growth and available production capacity are taking into account by varying the load profiles and solar irradiations in the years, as described in section 3.3.2. Load demand is obtained from experimental measures obtained within the framework of SelfUser project (see https://www.selfuser.it/). The hourly photovoltaic profile production is based on data provided by the ‘Photovoltaic Geographical Information System’ (PVGIS) (see https://ec.europa.eu/jrc/en/pvgis) for several years along with the investment decision. For the sake of computational burden alleviation, line losses are neglected, which looks as a reasonable approximation when dealing with a planning problem.

3.1.1 ***Mathematical model***

The formulation of the multi-stage planning model in a given energy community, is shown in the following.

The set of years in the planning horizon has been denoted as $P = \{1, 2, \ldots, p_{\mathrm{end}}\}$, the set of members of the community $\Omega = \{1, 2, \ldots, N\}$, the set of time intervals $T = \{1, 2, \ldots, t_{\mathrm{end}}\}$, and set of operating conditions $\Omega_{OP} = \{1, 2, \ldots, OP_{\mathrm{end}}\}$.

The objective function shown in (3.1) consists on the minimization of the Net Present Value (NPV) of the total costs and incomes achieved over the whole planning horizon P assuming the discount rate r, as described in (3.2).

The obtained solution providing a non-zero investment cost has then to be compared to the NPV for the case when the investment cost is zero, which will be characterized by different operational costs and incomes, in order to quantify the effective benefits.

$$OF = \min NPV \tag{3.1}$$

$$NPV = \sum_{p=0}^{P} \frac{(C_p^{Inv} + C_p^{Oper} - C_p^{Inc})}{(1+r)^p} \tag{3.2}$$

When investments are at year p=0 only, equation (3.2) becomes (3.3).

$$NPV = C_{p=0}^{Inv} + \sum_{p=1}^{P} \frac{(C_p^{Oper} - C_p^{Inc})}{(1+r)^p} \tag{3.3}$$

$$C_p^{Inv} = \sum_{i \in \Omega} C^{Storage}(Y_{i,p} - Y_{i,p-1}) + C^{PV}(I_{i,p} - I_{i,p-1}) \qquad \forall\ p = 1,2,...,P \tag{3.4}$$

$$\begin{aligned} Y_{i,p} &\geq Y_{i,p-1} \\ I_{i,p} &\geq I_{i,p-1} \end{aligned} \qquad \forall\ p = 1,2,...,P \tag{3.5}$$

$$C_p^{Oper} = \sum_{\substack{t \in T \\ j \in \Omega_{OP} \\ i \in \Omega}} [(\pi_{\text{buy}}^t P_{\text{buy\_Grid}\,i}^{t,j,p} - \pi_{\text{sell}}^t P_{\text{sell\_Grid}\,i}^{t,j,p}) d_j] \Delta t \qquad \forall\ p = 1,2,...,P \tag{3.6}$$

$$C_p^{Inc} = \sum_{\substack{t \in T \\ j \in \Omega_{OC}}} I_{E_s} E_{Shared}^{t,j,p} d_j \qquad \forall\ p = 1,2,...,P \tag{3.7}$$

C_p^{Inv} represents the total investment cost at year p, including both storage and photovoltaic systems. Constants $C^{Storage}$ and C^{PV} represent the investment cost of storage and photovoltaic systems, respectively.

Constraints (3.5) show that continuous variables $Y_{i,p}$ and $I_{i,p}$ represent the total investment decisions/values of BES and PV systems of prosumer i, from year 0 to year p; new investments at year p are therefore represented by $(Y_{i,p} - Y_{i,p-1})$ and $(I_{i,p} - I_{i,p-1})$, respectively.

C_p^{Oper} represents the operative cost at year p, given by the cost and revenues of the energy exchanged with the grid by the community. $P_{\text{buy\_Grid}\,i}^{t,j,p}$ represents the power bought from the utility grid by prosumer i, at time period t, in operating condition j of year p and $P_{\text{sell\_Grid}\,i}^{t,j,p}$ corresponds to the power sold to the external utility grid by prosumer i, at time period t, in operating condition j of year p. The prices when buying and selling energy from and to the external utility grid (in €/kWh), are represented with π_{buy}^t and π_{sell}^t, respectively, and Δt is the time step.

C_p^{Inc} represents the incentive received by the community at year *p*. I_{E_s} (in €/kWh) corresponds to the incentive given for the shared energy $E_{Shared}^{t,j,p}$. I_{E_s} are set equal to 0.118 €/kWh according to the Italian regulation framework. The shared energy computation is described in the following.

A. The shared energy computation

We shall make reference to a community in which for each prosumer the connection of PV units and storage systems, with relevant meters, both bidirectional, can be described by the scheme of Figure 3.1. Meter M1 records the energy exchanged with the network, while meter M2 measures the energy produced by the PV unit and the released by the one storage system during the discharge process or absorbed during the charging phase.

Constraint (3.8) defines the power accounted by meter M2 of prosumer *i* shown in Figure 3.1. Two variables are introduced to count the bidirectional flow measured by M2: $M2_{\mathrm{f}\,i}^{t,j,p}$ and $M2_{\mathrm{w}\,i}^{t,j,p}$, which represent the power fed in and withdrawn by the PV and BES systems of prosumer *i*, at time period *t*, in operating condition *j* of year *p*, respectively.

$$P_{\mathrm{PV}i}^{t,j,p} + P_{\mathrm{dis}\,i}^{t,j,p} - P_{\mathrm{ch}\,i}^{t,j,p} = M2_{\mathrm{f}\,i}^{t,j,p} - M2_{\mathrm{w}\,i}^{t,j,p} \qquad i \in \Omega, t \in T, j \in \Omega_{OP}, p \in P \tag{3.8}$$

$$\begin{cases} M2_{\mathrm{f}\,i}^{t,j,p} = 0 & \text{if } \mathrm{z}_i^{t,j,p} = 0 \\ M2_{\mathrm{w}\,i}^{t,j,p} = 0 & \text{if } \mathrm{z}_i^{t,j,p} = 1 \end{cases} \qquad \mathrm{z}_i^{t,j,p} \in \{1,0\},\ i \in \Omega, t \in T, j \in \Omega_{OP}, p \in P \tag{3.9}$$

Constraints (3.10) bound the value of the ratio between $\sum_{t\in T} M2_{\mathrm{w}i}^{t,j,p}$ and $\sum_{t\in T} M2_{\mathrm{f}i}^{t,j,p}$, i.e. $K_i^{j,p}$, which reflects an approximation of the factor γ_i introduced by the GSE for the calculation of the shared energy (GSE 2021). The maximum value of factor $K_i^{j,p}$ is here assumed to be lower than 1.

$$\begin{aligned} & K_i^{j,p} * \sum_{t\in T} M2_{\mathrm{f}\,i}^{t,j,p} = \sum_{t\in T} M2_{\mathrm{w}\,i}^{t,j,p} \\ & K_i^{j,p} \geq 0 \qquad\qquad i \in \Omega, j \in \Omega_{OP}, p \in P \\ & K_i^{j,p} \leq 1 \end{aligned} \tag{3.10}$$

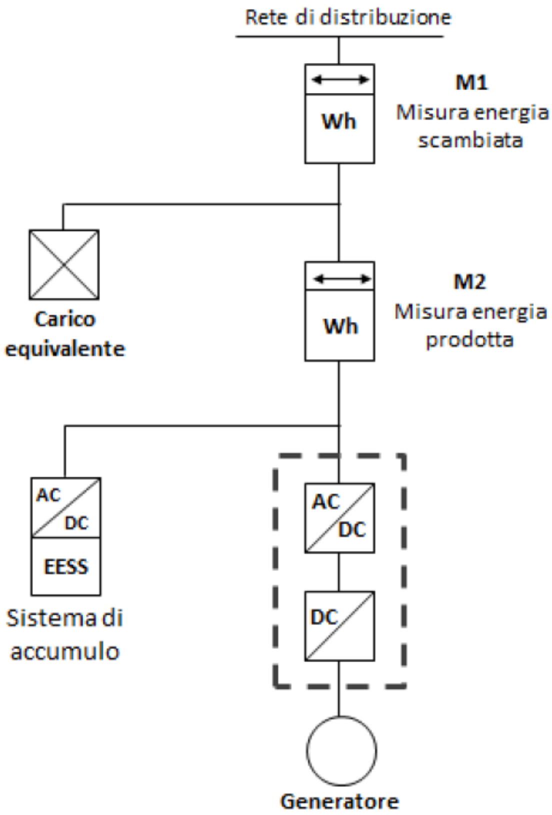


Figure 3.1 Configuration of the connection of PV and storage systems in the distribution grid, according to (Italian CEI standard 0-21 2019)

It should be noted that the formulation provided by GSE has been simplified in our formulation for the sake of limiting the computational burden. However, the proposed computation of the shared energy results to be almost equivalent of the shared energy calculated with the formulation provided by GSE. Further, the assumption of $K_i^{j,p}$ lower than 1 is always true when considering prosumers with generation and storage. In such a situation our formulation is equivalent to the one provided by GSE.

Constraints (3.11) set the shared energy to be the minimum between the total energy sold to and bought from the external grid by the community, including factor $K_i^{j,p}$, described in (3.10), which accounts for the operation of storage systems.

$$\begin{aligned} &E_{Shared}^{t,j,p} \le \sum_{i\in\Omega} P_{\text{sell\_Grid}\,i}^{t,j,p}(1-K_i^{j,p})\Delta t \\ &E_{Shared}^{t,j,p} \le \sum_{i\in\Omega} P_{\text{buy\_Grid}\,i}^{t,j,p}\Delta t \qquad t\in T,\, j\in\Omega_{OP},\, p\in P \\ &E_{Shared}^{t,j,p} \ge 0 \end{aligned} \tag{3.11}$$

B. *Technical constraints*

In the following all the technical constraints of the model are shown.

$$P_{\mathrm{PV}\,i}^{t,j,p} + P_{\mathrm{dis}\,i}^{t,j,p} + P_{\mathrm{buy\_Grid}\,i}^{t,j,p} = P_{\mathrm{Load}\,i}^{t,j,p} + P_{\mathrm{ch}\,i}^{t,j,p} + P_{\mathrm{sell\_Grid}\,i}^{t,j,p} \qquad i \in \Omega, t \in T, j \in \Omega_{OP}, p \in P \tag{3.12}$$

(3.12) corresponds to the power balance for prosumer *i* at time period *t*, in operating condition *j* of year *p*, where the forecast profile of load is given by parameter $P_{\mathrm{Load}\,i}^{t,j,p}$, the charging and discharging power of the battery owned by prosumer i are represented with the non-negative variables $P_{\mathrm{ch}\,i}^{t,j,p}$ and $P_{\mathrm{dis}\,i}^{t,j,p}$, respectively. According to (3.13), the output profile of PV generation $P_{\mathrm{PV}\,i}^{t,j,p}$ is given by the investment decision, i.e. $I_{i,p}$, and the forecast generation profile provided by PVGIS represented by $P_{i,j,t,p}^{f}$.

$$0 \le P_{\mathrm{PV}\,i}^{t,j,p} \le I_{i,p} P_{i,j,t,p}^{f} \qquad \forall i, j, t, p \tag{3.13}$$

Binary variables $u_i^{t,j,p}$ in (3.14) are introduced to prevent simultaneous purchases and sales by the prosumer *i*.

$$\begin{cases} P_{\mathrm{buy\_Grid}\,i}^{t,j,p} = 0 & \text{if } u_i^{t,j,p} = 0 \\ P_{\mathrm{sell\_Grid}\,i}^{t,j,p} = 0 & \text{if } u_i^{t,j,p} = 1 \end{cases} \qquad u_i^{t,j,p} \in \{1,0\} \tag{3.14}$$

For the storage systems the set of constraints (3.15) - (3.18) are considered.

Expression (3.15) enforce energy limits for BES systems in each time period *t* and operating condition *j* of each year considered in the planning horizon *P*.

$$\begin{gathered} Y_{i,p} E_{\mathrm{BES}i}^{t=0,j,p} + \sum_{t=1}^{t_n} (\eta_{\mathrm{ch}\,i} P_{\mathrm{ch}\,i}^{t,j,p} - P_{\mathrm{dis}\,i}^{t,j,p} / \eta_{dis\,i}) \Delta t \ge Y_{i,p} E_{\mathrm{BES}\,i}^{\min} \\ Y_{i,p} E_{\mathrm{BES}i}^{t=0,j,p} + \sum_{t=1}^{t_n} (\eta_{\mathrm{ch}\,i} P_{\mathrm{ch}\,i}^{t,j,p} - P_{\mathrm{dis}\,i}^{t,j,p} / \eta_{dis\,i}) \Delta t \le Y_{i,p} E_{\mathrm{BES}\,i}^{\max} \\ \forall i, j, p, t_n = 1, 2, ..., T \end{gathered} \tag{3.15}$$

Constraints (3.16) enforce BES daily energy balance.

$$\begin{gathered} \sum_{t=1}^{T} (\eta_{\mathrm{ch}\,i} P_{\mathrm{ch}\,i}^{t,j,p} - P_{\mathrm{dis}\,i}^{t,j,p} / \eta_{dis\,i}) \Delta t = 0 \\ \forall i, j, p \end{gathered} \tag{3.16}$$

Constraints (3.17) are charging and discharging bounds for BES systems.

$$\begin{aligned} &Y_{i,p} P_{\mathrm{BES}\,i}^{\min} \leq P_{\mathrm{ch}\,i}^{t,j,p} \leq Y_{i,p} P_{\mathrm{BES}\,i}^{\max} \\ &Y_{i,p} P_{\mathrm{BES}\,i}^{\min} \leq P_{\mathrm{dis}\,i}^{t,j,p} \leq Y_{i,p} P_{\mathrm{BES}\,i}^{\max} \qquad \forall i,t,j,p \end{aligned} \tag{3.17}$$

Binary variables $u_{\mathrm{BES}\,i}^{t,j,p}$ in (3.18) are introduced to prevent simultaneous charge and discharge of BES systems.

$$\begin{cases} P_{\mathrm{ch}\,i}^{t,j,p} = 0 & \text{if} \quad u_{\mathrm{BES}\,i}^{t,j,p} = 0 \\ P_{\mathrm{dis}\,i}^{t,j,p} = 0 & \text{if} \quad u_{\mathrm{BES}\,i}^{t,j,p} = 1 \end{cases} \qquad u_{\mathrm{BES}\,i}^{t,j,p} \in \{1,0\} \qquad \forall i,t,j,p \tag{3.18}$$

Finally, constraint (3.19) is introduced to bound the investment of PV systems to a maximum value, corresponding to the total maximum available PV surface.

$$\sum_{i\in\Omega} I_{i,p} <= I_{PV}^{\max} \qquad p = P \tag{3.19}$$

3.2 Single-stage planning of storage and photovoltaic systems in a Renewable Energy Community

In this subsection, we also present a single-stage planning approach, which addresses the same planning problem of the previous section but considering one year only. The single-stage approach has some interest, as earlier shown in Chapter 2, as it can be effective in reducing the computational burden yet maintaining a certain use fulness and significance of the obtained results, although long term uncertainties cannot be taken into account.

Objective function (3.20) consists on the minimization of the total cost, given by the sum of the annualized investment costs, the operation costs and the revenues for the incentivize shared energy in a given renewable energy community.

$$OF = \min C^{Inv} + C^{Oper} - C^{Inc} \tag{3.20}$$

$$C^{Inv} = \sum_{i\in\Omega} C_a^{Storage} Y_i + C_a^{PV} I_i \tag{3.21}$$

$$C^{Oper} = \sum_{\substack{t\in T \\ j\in\Omega_{OP} \\ i\in\Omega}} [(\pi_{\mathrm{buy}}^{t} P_{\mathrm{buy\_Grid}\,i}^{t,j} - \pi_{\mathrm{sell}}^{t} P_{\mathrm{sell\_Grid}\,i}^{t,j}) d_j] \Delta t \tag{3.22}$$

$$C^{Inc} = \sum_{\substack{t\in T \\ j\in\Omega_{OP}}} I_{E_s} E_{Shared}^{t,j} d_j \tag{3.23}$$

The total investment cost of (3.21) includes both storage and photovoltaic annualized investment costs, represented by $C_a^{Storage}$ and C_a^{PV} respectively.

As shown in (3.22), C^{Oper} represents the operative cost of the target year, given by the cost and revenues of the energy exchanged with the grid by the community; while C^{Inc} in (3.23) represents the revenues collected by the community given by the incentivized shared energy achieved during the whole year.

The rest of the single-stage planning model is described by constraints (3.24) - (3.19) assuming p=1.

3.3 Case studies and results

In this section, we present some case studies and relevant results of the proposed planning models in order to illustrate the capabilities of the proposed model.

First, we compared the two planning approaches, i.e. multi-stage and single-stage models, considering equivalent input data; then some case studies with the multi-stage planning approach are presented and discussed.

The proposed planning model are implemented within Matlab environment and Gurobi is chosen as a solver. The results shown in the following are obtained with an optimization gap of 1%.

The number of operating conditions for each year, selected to reproduce the most representative days of the year, is set equal to 12, therefore each month is represented by one operating day.

3.3.1 *Comparison between multi-stage and single-stage planning approaches*

As already mentioned, in order to compare multi-stage and single-stage planning models, equivalent input data must be considered. In that respect, load demand and solar irradiation profiles used for the single-stage target year, which are shown in the following, are kept constant during the whole planning horizon of the multi-stage planning problem.

Figure 3.2 shows the solar irradiation profiles of two operating conditions, representing January and August, which reflect winter and summer seasons of the considered target year. Data are given for the Bologna city area by PVGIS simulator.

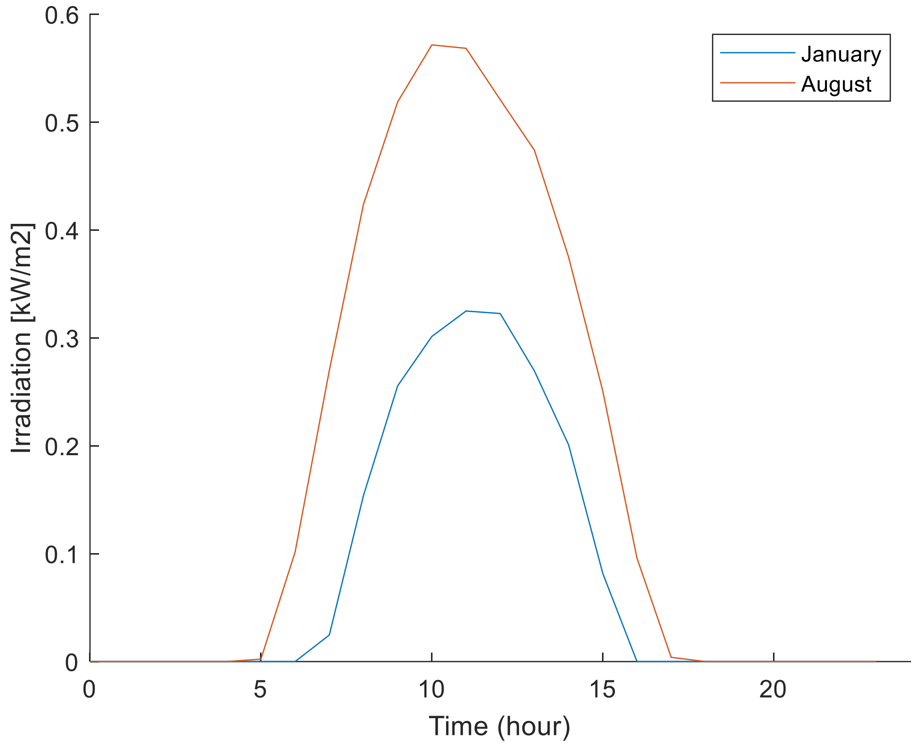


Figure 3.2 Solar irradiation profiles, obtained from PVGIS

The input data of the candidate storage systems are shown in Table 3.2. It is worth noticing that the maximum energy and storage capacity of each BES unit is given as output of the optimization models through continuous variables Y_i . Nonetheless, the value of charge and discharge efficiency, the ratio between maximum and minimum energy capacity, and the ratio between energy and power capacity of each BES unit is assumed equal to the values shown in Table 3.2.

Table 3.2 Candidate storage system data

$P_{\max,dis}$ [kW]	$P_{\max,ch}$ [kW]	$E_{min}^{i_{bes}}$ [kWh]	$E_{max}^{i_{bes}}$ [kWh]	$\eta_{ch}^{i_{bes}}$	$\eta_{dis}^{i_{bes}}$
20	20	2	20	0.9	0.9

A. *Case study with predefined PV generation*

The first case study here presented is based on the following assumptions:

- PV generation is given as an input data, so the planning problem focuses on the investment of storage systems only;

- Load and irradiation profiles of the single stage target year are assumed to be equal for each year of the planning horizon of the multi stage model;
- Each member of the community must invest at least on a storage system of 6 kWh;

Load demands of Figure 3.3 represent the power profiles of the three considered prosumers for one operating condition, which is January, and reproduce the typical demands of apartment buildings given by experimental measures. Power profiles of the other operating conditions are obtained by using a scale-factor for each month, which has been calculated according to the load demand variation provided by the energy bill data.

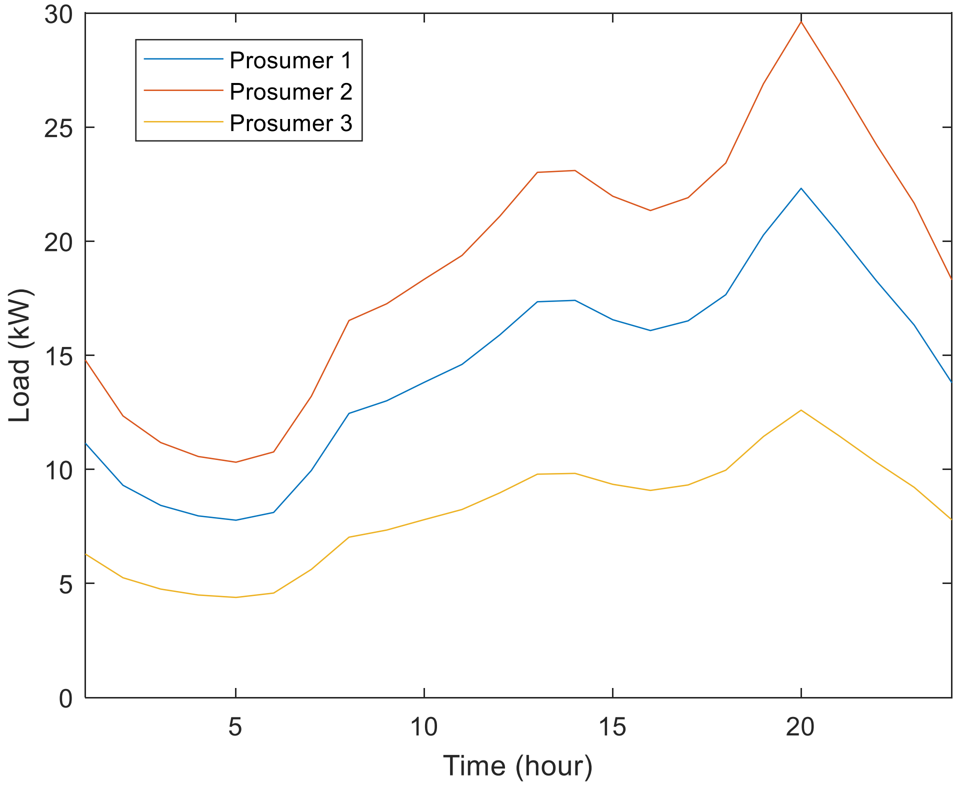


Figure 3.3 Load demand profiles of the three considered prosumers for one operating condition

The planning horizon considered is 5 years and the discount rate set equal to 5%. The investment costs of storage systems used in the multistage planning approach is 250 €/kWh. The latter has been annualized with a life cycle equal to 5 year and a discount rate of 5%, so the equivalent annualized investment cost results to be equal to 57.7 €/kWh. The total PV generation considered for the whole community is equal to 97 kWp.

Table 3.3 shows the results obtained for the considered case study.

As shown in Table 3.3, the net present value of the multistage planning approach given by the proposed optimization model is almost the same of the one calculated for the single stage considering the investment, cost and revenues of the target year, which has been obtained within the optimization procedure, equal for each year of the planning horizon. All these cost and revenues have been actualized at year *p*=0 and then the obtained NPV value has been compared to the one obtained with the multistage approach. As shown in Table 3.3, the difference of the two planning approaches in terms of NPV value is about 0.3%.

Moreover, the result of the case without BES investments gives a lower NPV, i.e. a lower cost according to our formulation, which means that the investment on storage systems is not convenient in this case, which can be interpreted as a consequence of imposing that each member of the community must invest at least on a storage system of 6 kWh. In that respect, it seems reasonable that for both planning approaches, the total installed storage capacity is very close to the minimum investment set as assumption (i.e. 18 kWh).

Table 3.3 Results of the single stage-multi stage comparison case study with predefined PV generation

	Single-stage	*Multi-stage*
NPV without BES [10^3 €]	308.3	308.3
NPV with BES [10^3 €]	310.7	311.6
NPV error [%]	0.3	
Total BES installed [kWh]	18	23

Figure 3.4 shows the cumulative cash flows achieved by comparing cash flows obtained with storage investment and without storage. In other words at year equal to 0, the cumulative cash flow is equal to the value of the investment, at year equal to 1, savings due to the investment achieved during the first year (actualized or not actualized, orange or blue bar in Figure 3.4, respectively) has been added to the cumulative cash flow at the previous year, and so on for all years included in the planning horizon. As shown in the Figure 3.4 the initial investment is not convenient: savings due to the investment achieved during the whole planning horizon are not sufficient to justify the investment. In this regard, as already mentioned, storage systems are included in the planning scheme because we assumed a minimum storage investment for each member of the community.

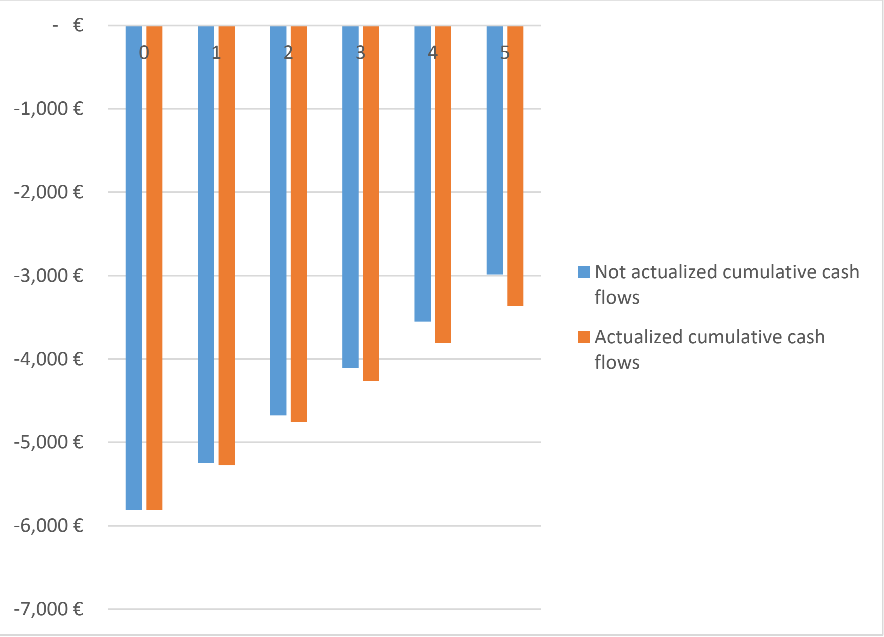


Figure 3.4 Cumulative cash flows of the comparison case study with predefined PV generation

B. Case study with PV and BES in the planning scheme

The case study here presented is based on the following assumptions:

- Both PV and BES decisions are included the planning problem;
- Load and irradiation profiles of the single stage target year are assumed to be equal for each year of the planning horizon of the multistage model;
- Each member of the community must invest at least on a storage system of 6 kWh;

Figure 3.5 shows the power profiles of the five considered prosumers for the operating condition that represents January. Also in this case, consumption profiles reflect the behaviour of apartment buildings, and load demand of the other operating conditions are obtained by using a scale-factor for each month according to the load demand variation provided by the energy bill data.

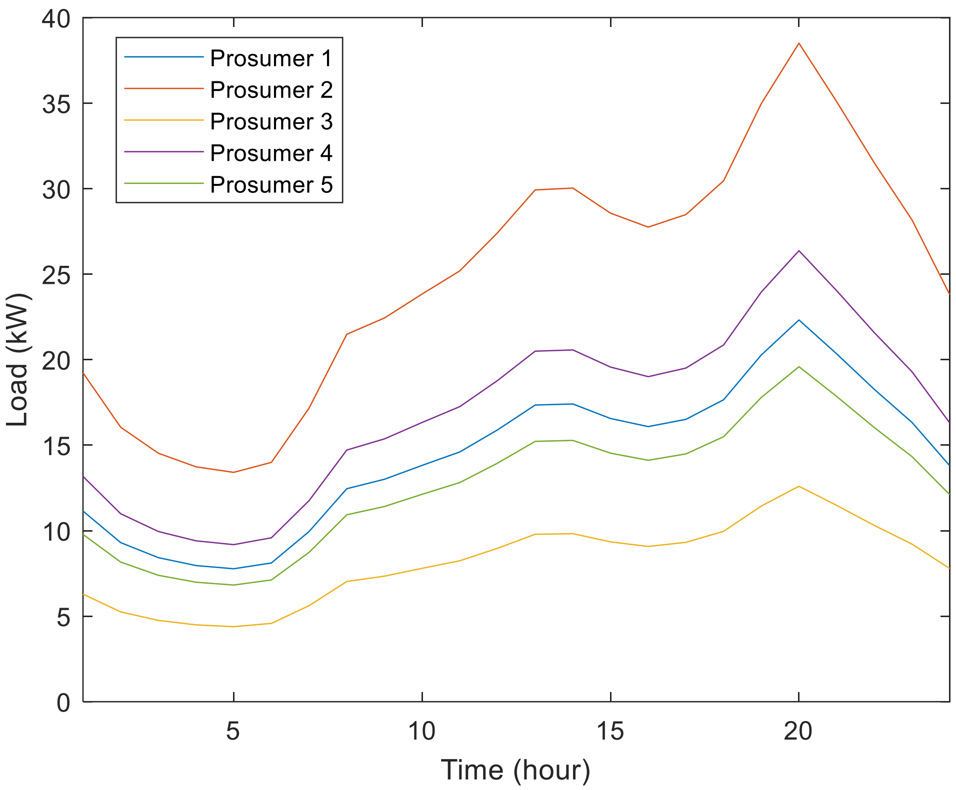


Figure 3.5 Load demand profiles of the five considered prosumers for one operating condition.

The planning horizon is 10 years and the discount rate is set equal to 5%. The investment costs of storage and photovoltaic systems used in the multistage planning approach is 500 €/kWh and 1250 €/kWp, respectively, which annualized with a life cycle equal to 10 year and a discount rate of 5%, give an equivalent annualized investment costs equal to 64.7 €/kWh and 161.9 €/kWp respectively.

Table 3.4 shows the results obtained for the above-mentioned case study. Similarly to the previous case, the net present value of the multistage planning approach given by the optimization model has been compared to the equivalent NPV obtained with the results of the single stage optimization, i.e. considering the investment, cost and revenues of the target year equal for each year of the planning horizon, and then actualized at year p=0. As shown in Table 3.4, the two planning approaches give almost the same value of NPV: their relative difference is about 0.02%.

Furthermore, by comparing the results with the case without BES and PV investments, it is shown that in this case investing in storage and photovoltaic systems is convenient because that let us achieve a lower NPV (i.e. a lower cost). For both planning approaches, the total installed storage capacity is higher than minimum investment set as assumption (i.e. 30 kWh) and reach about 45-50 kWh, while the total PV installed is 220 kWp in both cases.

Table 3.4 Results of the comparison case study without predefined PV generation

	Single-stage	*Multi-stage*
NPV without BES and PV [10^3 €]	1477.0	1477.0
NPV with BES and PV [10^3 €]	1224.1	1224.3
NPV error [%]	0.02	
Total BES installed [kWh]	45	51
Total PV installed [kWp]	220	220
Total PV surface used [m^2]	1540	1540
Total PV available surface [m^2]	1540	1540

Similarly to Figure 3.4, Figure 3.6 shows the cumulative cash flows achieved by comparing cash flows obtained with and without BES and PV investments.

As shown in Figure 3.6, the initial investment is convenient in this case as the savings achieved during the whole planning horizon justify the initial costs: at year equal to 5 the cumulative cash flows are positive, meaning that the savings and revenues achieved due to the investment on BES and PV systems are large enough to pay back the initial investment cost in 5 years.

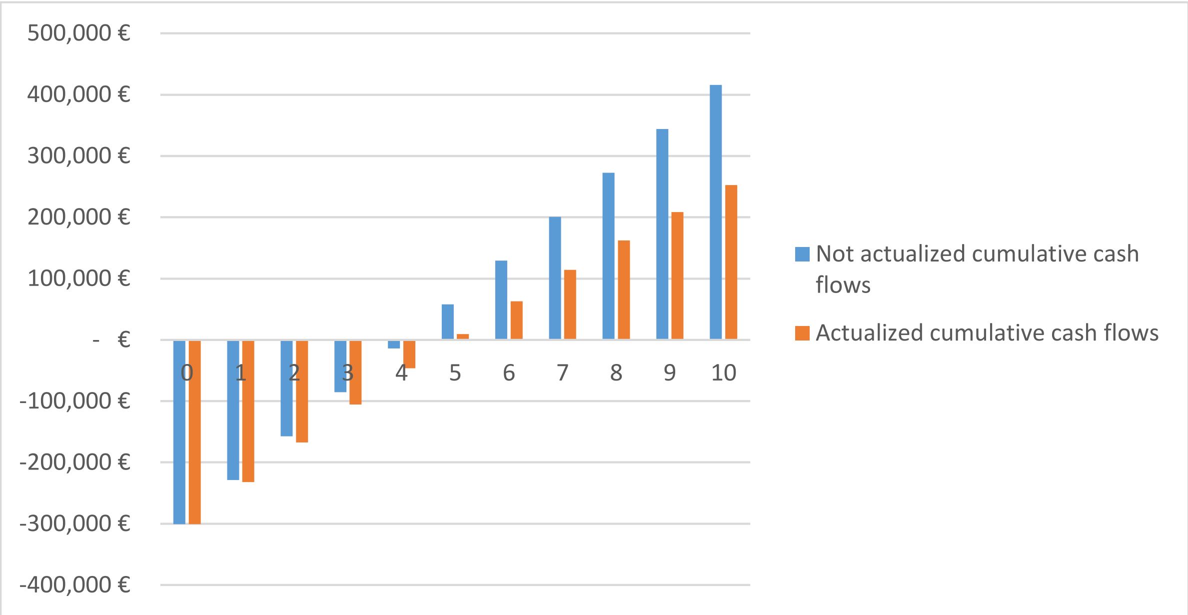


Figure 3.6 Cumulative cash flows of the comparison case study without predefined PV generation

3.3.2 *Case studies and results of the multi-stage planning model*

We now consider long term uncertainty adopting the multi-stage planning approach: load is assumed to increase by 1% each year and solar irradiation is assumed to change each year according to the data given by PVGS for several years in the Bologna city area. The community considered is composed by five prosumers, each having the same load profile of Figure 3.5 at the first year. The investment costs of storage and photovoltaic systems is assumed equal to 500 €/kWh and 1250 €/kWp, respectively. Regarding candidate storage systems data, we shall refer to Table 3.2 already utilized.

A. Case studies with a planning horizon of 10 years

In the following, we describe case studies that have been adopted to test the multi-stage planning model. The planning horizon is here assumed to be equal to 10 years.

Case I – considers a discount rate *r* equal to 5%. Each member of the community is free invest or not in storage systems;

Case II – same scheme as Case I, but with a discount rate *r* equal to 8%;

Case III – considers a discount rate *r* equal to 5%. Each member of the community must invest at least on a storage system of 6 kWh;

Case IV – same scheme as Case III, but with a discount rate *r* equal to 8%;

Table 3.5 shows the results obtained for the above-mentioned case studies.

Table 3.5 Results for case studies with a planning horizon of 10 years

	Case I	Case II	Case III	Case IV
NPV without BES and PV [10^3 €]	1434.2	1243.5	1434.2	1243.5
NPV [10^3 €]	1175.3	1057.6	1191.3	1068.5
Total BES installed [kWh]	0	0	63	53
Total PV installed [kWp]	220	220	220	220
Total PV surface used [m^2]	1540	1540	1540	1540
Total available PV surface [m^2]	1540	1540	1540	1540

In the first two case studies, where a minimum value of BES investment is not set, the optimal plans obtained show that it is convenient to invest on PV systems only. Instead, in case III and case IV the optimal investment plan involves both PV and BES systems. As shown in Table 3.5, when assuming a minimum investment for each member of the community (i.e. Case III and Case IV) the NPV obtained is slightly larger than the case without such assumption (i.e. Case I and Case II). Also, results of Table 3.5 show that when a higher value of discount rate is considered the total investment is always lower or equal than the case with a smaller discount rate. Moreover, all the considered case studies show a net present value lower than the NPV obtained without investments, i.e. the planning scheme obtained for each case study results to be convenient within the considered planning horizon.

Similarly to Figure 3.4 and Figure 3.6, the following figures, i.e. Figure 3.7 - Figure 3.10, show the cumulative cash flows (actualized or not actualized, orange or blue bars) obtained by comparing cash flows of the optimal plan scheme and cash flows without investments for each case study. The year at which bars assume positive values represent the year where savings and revenues achieved with the installation of BES and PV systems have pay back the initial investment. It should be noted that some years seem not having the blue or orange bar but this is due to the fact that the not actualized or actualized cumulative cash flows are very small so in such years they can be considered almost equal to 0.

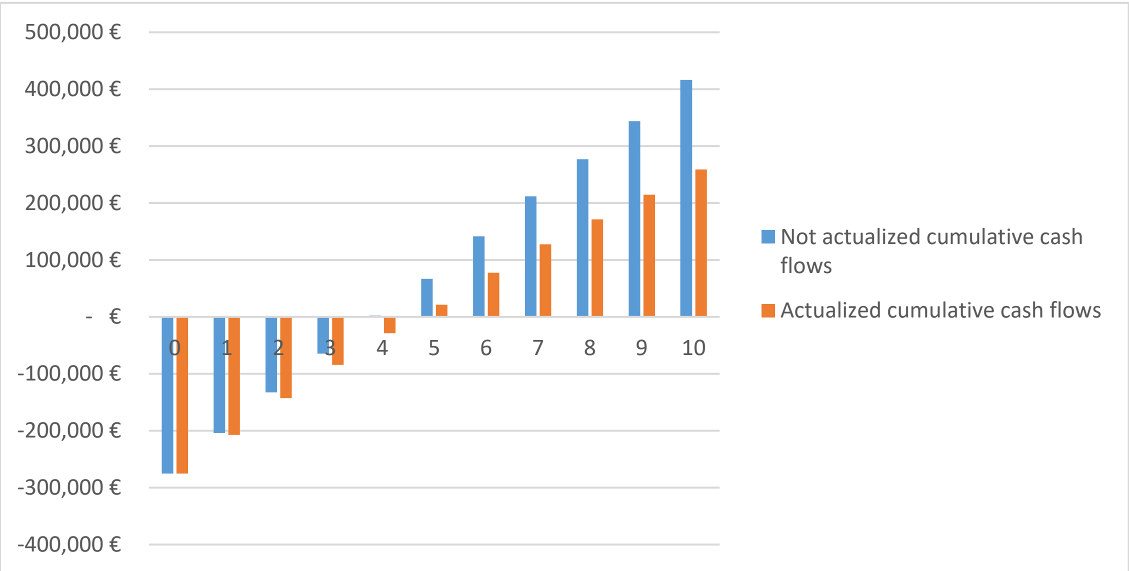


Figure 3.7 Cumulative cash flows of Case I with P=10

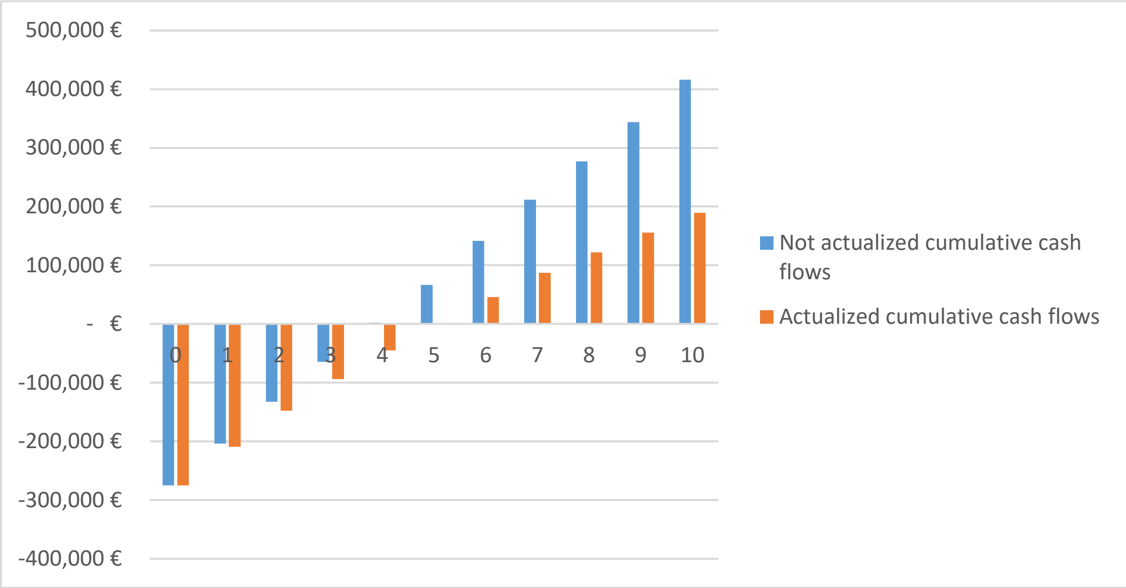


Figure 3.8 Cumulative cash flows of Case II with P=10

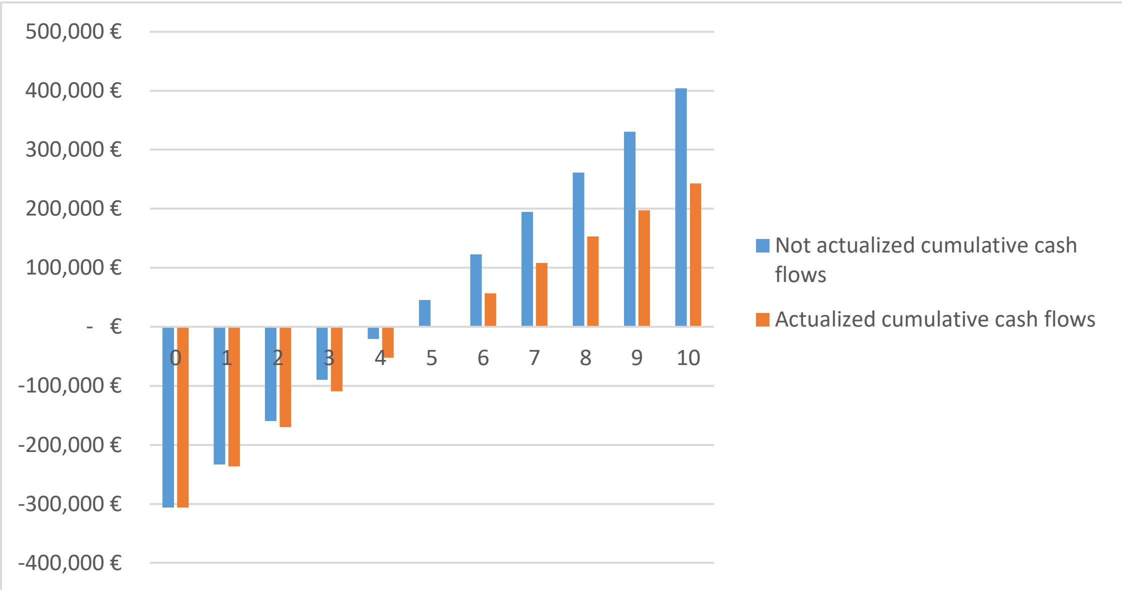


Figure 3.9 Cumulative cash flows of Case III with P=10

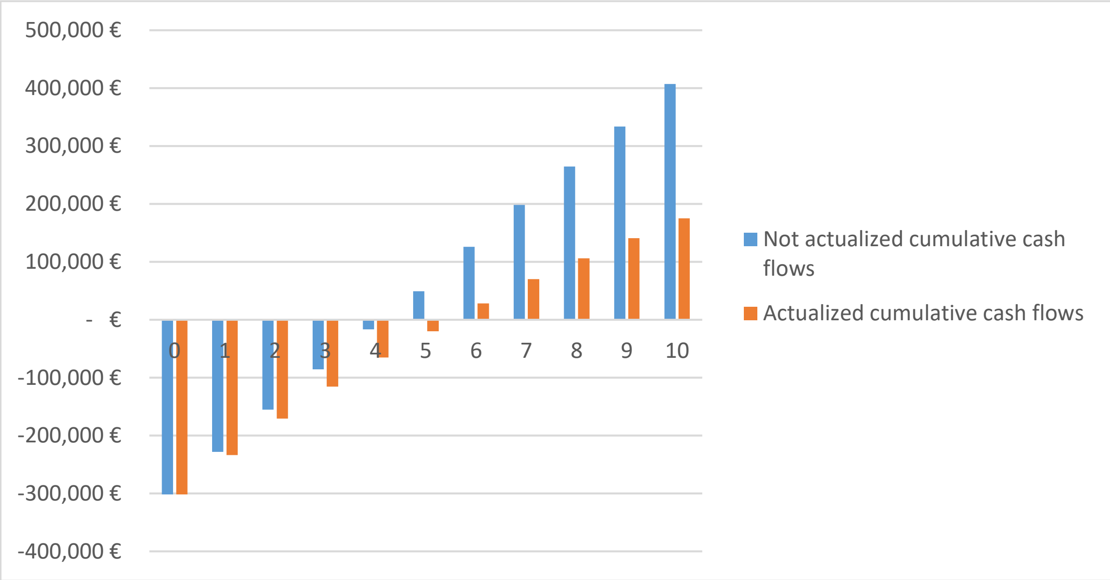


Figure 3.10 Cumulative cash flows of Case IV with P=10

B. Case studies with a planning horizon of 6 years

In the following, we present the same case studies illustrated in the previous subsection but with a planning horizon equal to 6 years. Results are shown in Table 3.6.

Table 3.6 Results for case studies with a planning horizon of 6 years

	Case I	Case II	Case III	Case IV
NPV without BES and PV [10^3 €]	926.3	843.0	926.3	843.0
NPV [10^3 €]	853.3	792.3	862.6	808.0
Total BES installed [kWh]	18	0	45	43
Total PV installed [kWp]	196	174	198	185
Total PV surface used [m^2]	1372	1215	1382	1292
Total available PV surface [m^2]	1540	1540	1540	1540

In the first two case studies, where a minimum value of BES investment is not set, the NPV obtained is slightly lower than the case with such assumption (i.e. Case III and Case IV), and the optimal plans obtained show that it is convenient to invest on BES systems when considering a lower discount rate only. Also, results of Table 3.6 show that when considering a planning horizon of 6 years, it is not worth making full use of the total available PV surface, as it is for a longer planning horizon (see Table 3.5). Also, even with a planning horizon of 6 years results show that: when a higher value of discount rate is considered the total investment is lower than the case with a smaller discount rate; the NPV achieved with the optimal investment on BES and PV systems is lower than the NPV obtained without investments for all the considered case studies.

Figure 3.11- Figure 3.14 have been made by adopting the same procedure as the one described for Figure 3.4 - Figure 3.10, so they show the cumulative cash flows (actualized or not actualized, orange or blue bars) obtained by comparing cash flows with and without the investment on PV and BES systems for each case study. As already mentioned when bars assume positive values, it means that at that year savings and revenues achieved with the installation of BES and PV systems have pay back the initial investment.

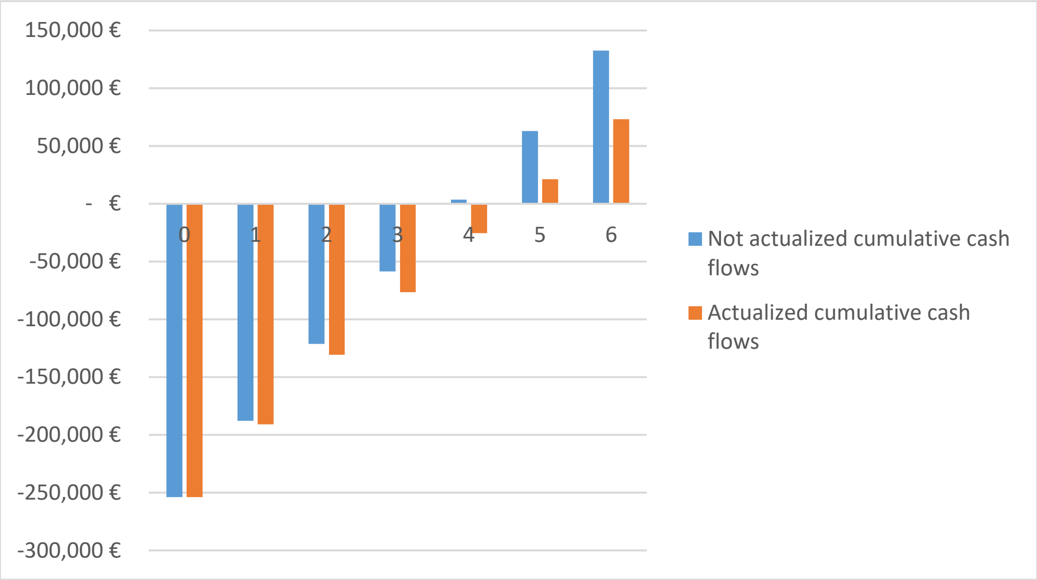


Figure 3.11 Cumulative cash flows of Case I with P=6

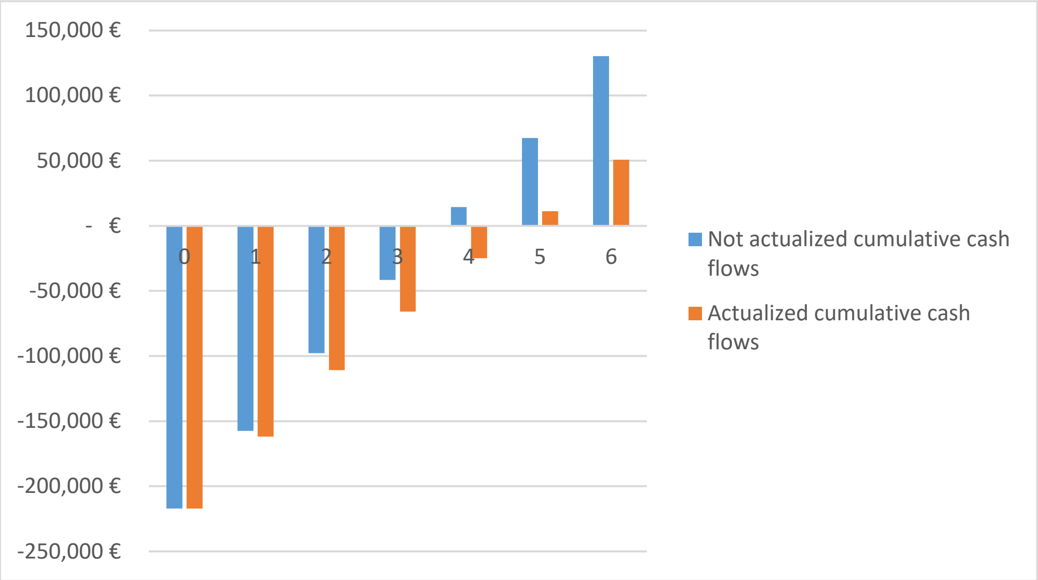


Figure 3.12 Cumulative cash flows of Case II with P=6

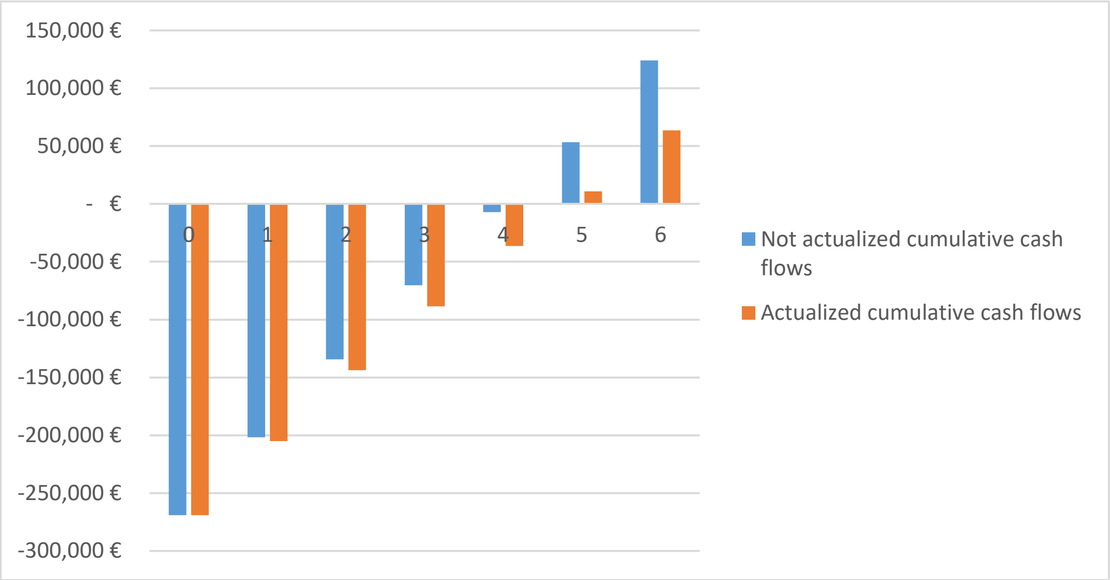


Figure 3.13 Cumulative cash flows of Case III with P=6

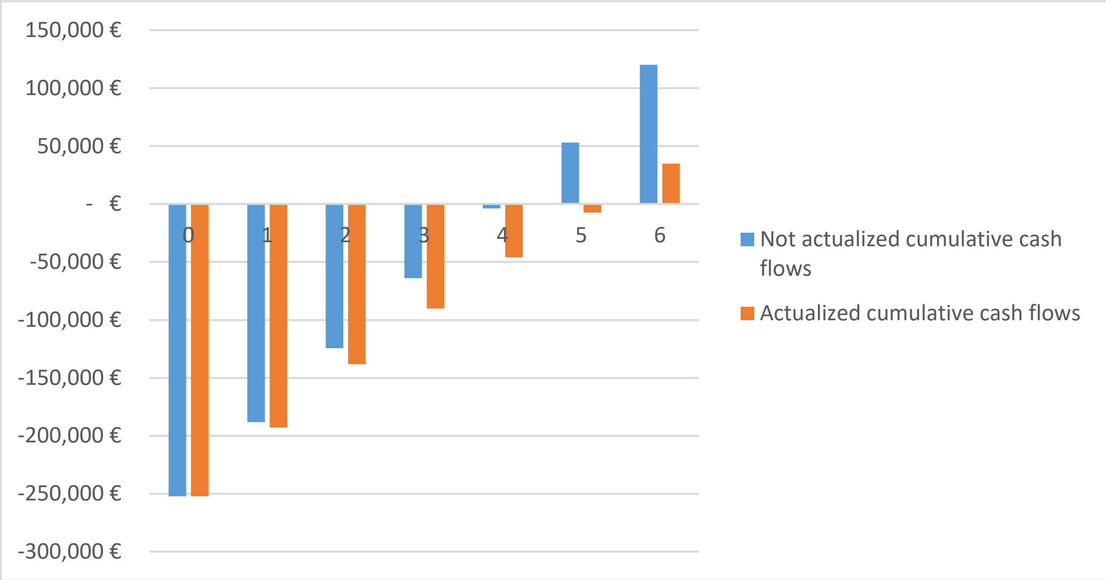


Figure 3.14 Cumulative cash flows of Case IV with P=6

3.4 Concluding remarks

This chapter has addressed the planning problem of battery energy storage and photovoltaic systems (BES and PV, respectively) for a renewable energy community (REC) with an incentive-based remuneration scheme according to the Italian regulatory framework (and assuming constrained dynamics of the prices of the energy exchanged with the grid, which may not be necessarily always the case). Two planning models, adopting a single-stage (static) or multi-stage (dynamic) approach, have been presented and validated by comparing them to each other. Both the proposed models consider BES and PV units in the planning scheme, hence giving as output the optimal set of BES and PV systems that allows to achieve the minimum cost in a considered REC.

First, the two planning approaches, i.e. multi-stage and single-stage models, have been compared considering equivalent input data. Results show that the net present value (NPV) and the optimal set of BES and PV systems obtained within the two planning approaches are very close, and the small difference obtained falls within the optimisation gap of 1%.

Then, long term uncertainty of load growth and solar irradiation has been considered by adopting the multi-stage planning approach. The proposed mathematical model has been investigated for planning horizons of 10 years and 6 years. Several cases, which differ by the value of discount rate and by assuming or not a minimum investment on BES systems for each member of the community, have been studied. In all the considered cases and for both planning horizons, the optimal investment plan results to be convenient: savings and revenues due to the installation of BES and PV systems, within the assumptions made concerning load profiles, solar irradiation and discount rate, pay back the initial investment in the order of 5 or 6 years, with small differences depending on the specific constraints. With the proposed model it is however possible the analysis of different scenarios, which represents one of the possible subjects for future work.

With a long planning horizon of 10 years the community makes full use of the total available PV surface, and the relevant results show that investing in PV systems is always convenient. Instead, BES systems not always are included in the planning scheme. However, if each member of the community is forced to contribute with a minimum investment on BES system, the obtained results suggest that the optimal set of investments guarantee that the higher saving and revenues achieved allow to pay back the higher initial investment in 5 or 6 years, as obtained also when investing only in PV systems. Moreover, a higher discount rate leads to a lower initial investment in all the considered case studies.

It should be noted that since we are dealing with planning problems, as well as for the models presented in the previous chapter, the computation time is quite significant, as simulations can take up to days. Instead, regarding the difficulty of convergence, the cases examined showed a certain sensitivity of the model and the optimization tool to the number of prosumers, and to the approximation chosen for the calculation of incentives, a sensitivity that was partially analysed, proving to be not negligible. Further analysis of this sensitivity was considered a topic worthy of further research, which was not addressed in this thesis.

Finally, the proposed planning models could be suitable adapted also for renewable energy communities based on different remuneration scheme, e.g. community where direct transactions between members are allowed.

Chapter 4. Day-Ahead Scheduling of a Renewable Energy Community

Introduction

In recent years, the European Union has been promoting the active role of citizens as one of the main actors of the energy transition in their local environment, and through its regulation framework has been setting the conditions for allowing direct energy transactions between electricity end-users and their neighbours, within a so-called energy community.

In literature, many studies evaluate the effects of the implementation of a Peer-to-Peer (P2P) energy trading among the community members on the energy procurement costs, e.g. (Paudel et al. 2020) (Cadre et al. 2019), in part motivated by RED II. In a P2P prospective, the difference of prices for energy consumed and energy fed in a typical supply contract, leave a margin for an intra-community energy trading: a prosumer whose production exceed its own consumption can directly sell energy to a member of the community who needs it. Such transaction can be performed according to an energy price which is higher than the one established by the prosumer's supplier for the energy fed, and lower than the energy price paid by the other user for the consumed energy to its supplier: if those conditions are satisfied the transaction is profitable for both prosumer and consumer. Moreover, in the perspective of great revenues or savings deriving from energy trading among the community members it should be evaluated the possibility of a reduction in the incentives needed for energy community projects, which still remain profitable other than less dependent on incentive schemes (Y. Zhou, Wu, and Long 2018). One of the main references, among real implementations of local energy market schemes between end-users, is the Brooklyn microgrid project (Mengelkamp et al. 2018).

However, the transposition into law of the European directives is a responsibility of each member state, which can choose the most suitable implementation according to its specific context. As already mentioned, the Italian transposition of European directive RED II, related to the renewable energy community (REC), expects that members of a REC maintain their traditional supply contract. In Italy, each prosumer of the REC shall pay for the total energy consumed and receive revenues for the total energy fed, according to the supplier prices. Moreover, the considered renewable energy community shall receive revenues, as described in Chapter 3, directly proportional to the shared energy, which is given at each hour by the minimum between the renewable energy fed into the electrical grid by prosumers and the total energy demand required to the grid by the community (see Figure 4.1). According to that context, the economic benefits for the community derive from incentives and refunds on the shared energy, other than the reduction of prosumers' energy bill due to his own self-consumption (prosumers' self-consumption is not included in the Italian remuneration scheme for a REC; even though it represents a reduction in prosumers' energy bill), and the income due to the energy sold to the grid.

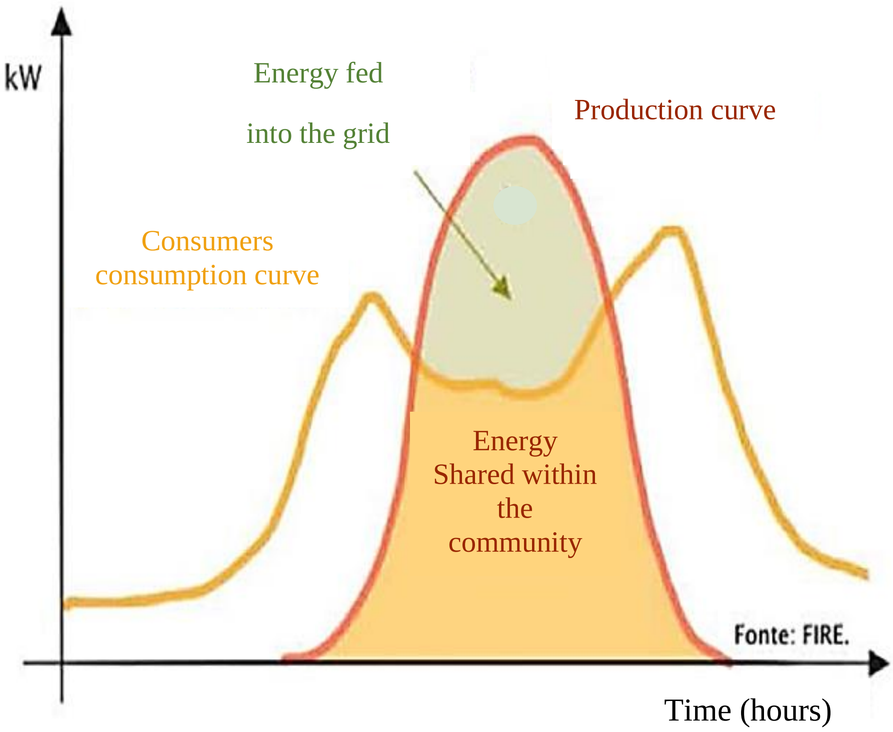


Figure 4.1 Consumption and production curves

An important point to mention within this context is the following. When considering energy communities equipped with storage units other than distributed generation units based on renewable resources, the implementation of an adequate energy management system (EMS), able to operate the installed equipment and to cost-effectively optimize the exploitation of the available energy resources, is crucial for the achievement of the optimal operation of the community's assets. The following figure shows a principle scheme of the EMS, which highlights three layers: day ahead, intraday and real-time phases.

After the day-ahead dispatching of BESs or renewable dispatchable sources, e.g. biogas units, which is the object of the present chapter, intraday scheduling that updates the decisions of the day-ahead planning in order to use more refined short-term scheduling information and contingencies is necessary; then, a real-time algorithm needs to receive periodically the data provided by the intra-day model, and seek to manage the BES and the controllable loads in such a way to achieve the desired set point imposed by the intra-day algorithm.

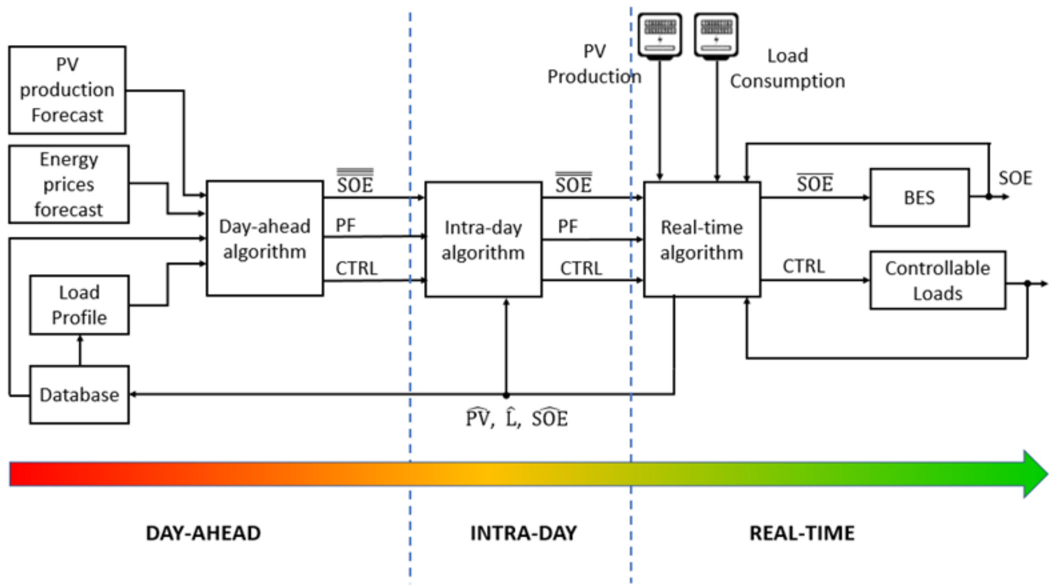


Figure 4.2 EMS block-scheme

This chapter, as mentioned, is devoted to one phase/algorithm of the three ones above mentioned, namely the development of the day ahead scheduling of a renewable energy community that defines the optimal set values for the dispatchable energy resources minimizing the daily energy procurement cost of the REC. The members of the community can be residential or commercial/industrial sites connected to the same distribution network. Each participant may be equipped with local generation units (PV panels and/or biogas units in this chapter) and BES units to cover the local demand. Hence, each participant can act as a prosumer, consuming or producing electricity during different time periods. The main input are the forecasts of photovoltaic production and load consumption.

In the first part of this chapter we deal with a scenario in which participants in a REC not only can transact energy with the external energy provider, but also in the community with the other members. The considered energy community includes, as mentioned, one or more producers equipped with dispatchable generation units, i.e. biogas power plant. The exploitation of renewable resources represents an attractive aspect of the integration of dispatchable generators;

for instance by using anaerobic digestion (AD) technologies, which allows the electricity generation from waste generated by e.g., agriculture activity (Thimsen 2004). To perform the day ahead scheduling, both a centralized and a distributed approach, based on the Alternating Direction Method of Multipliers (ADMM), have been studied. Typically, such scheduling problem of resources can effectively be addressed by centralized models. Nevertheless, distributed approaches have gained special interest, e.g. (Moret and Pinson 2019), because with respect to the centralized approach, the distributed one can define the optimal scheduling of the community while preserving the privacy and independence of each participant.

The community scheme considered in this first part of the chapter is characterized by being local and cooperative that is all the prosumers are connected to the same distribution network and collaborate, without any competitive behaviour, for the common goal of minimizing the costs related to the exchanges with the utility grid. The work presented stands on the research accomplished in (C. Orozco 2021).

The second part of the chapter deals with a scenario in which participants in a REC can transact energy with the external energy provider only and maintain their traditional supply contract according to the Italian legal framework. The only economic benefits for the community derive from the incentives on the shared energy, other than the bill reduction due to prosumers' self-consumption. The day ahead scheduling of the community is performed to minimize the daily procurement cost of the REC, also including the revenues for the community shared energy.

The optimal day ahead scheduling of the above-mentioned renewable energy communities have been investigated considering several case studies: initially we have studied a community consisting of several prosumers, each equipped with photovoltaic and storage units, then we have also included in the community some producers, equipped with biogas power plants. Finally, the results obtained for both the considered renewable energy communities have been compared and discussed.

4.1 A cooperative REC with dispatchable generating units

4.1.1 *Centralized approach for the day-ahead scheduling of the community*

The scheduling function of the community can be formulated as a centralized optimization problem, in which the set values for the operation of all the participants are defined by a central control unit.

In such a scenario, the central unit collects all the characteristics of the available equipment in the community, as well as the data regarding forecast profiles of the local energy generation and consumption and keeps all of the information updated.

The scheme shown in Figure 4.3 corresponds to a community with an internal Low Voltage (LV) distribution network, which is connected to a point of common coupling, through a Medium Voltage (MV)/LV transformer, to the external utility grid. In the considered scenario, each prosumer uses the available energy resources in cooperation with the other participants to minimize the energy procurement cost of the entire REC. As the considered collective of prosumers has been assumed having a collaborative behaviour, the participants cannot act as producer and as consumer simultaneously.

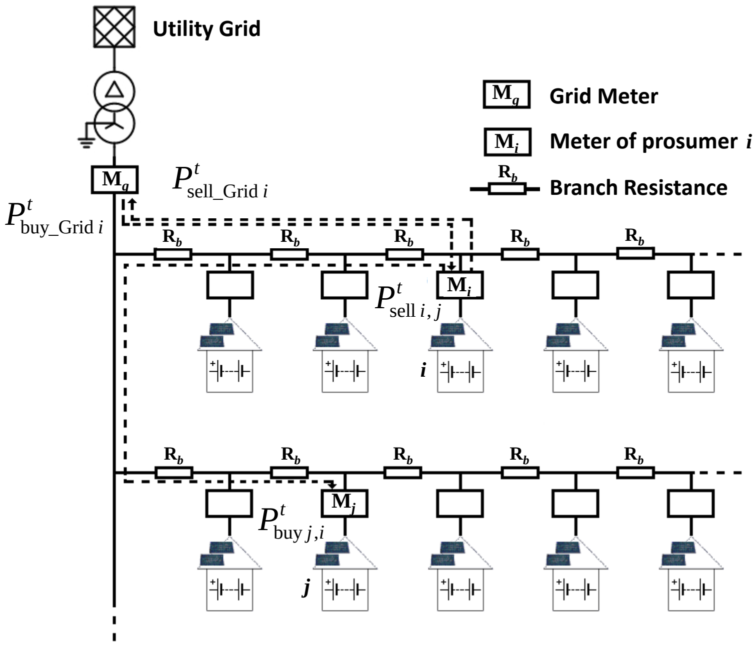


Figure 4.3 Scheme of the renewable energy community. Adapted from (Lilla et al. 2020)

The grid meter M_g in Figure 4.3, located at the point of common coupling with the external utility grid, is bidirectional and measures the energy exchanged during each time interval. In Appendix A, a distributed alternative is also proposed, in which the presence of the bidirectional meter M_i owned by each prosumer i will be relevant for measuring the energy that the specific prosumer exchanges with the internal network during each time interval.

It is important to realize that, the operation of such a collective of prosumers requires the implementation of an EMS, as above mentioned, for the optimal exploitation of the available resources; in particular, this chapter deals with the EMS function devoted to the day-ahead scheduling of the community to define the optimal scheduling during the following day. The resulting operational plan is especially focused to provide set values for the BES and dispatchable generation units, other than the energy transactions between participants in the community. The prices associated with energy transactions with the energy provider are here assumed predefined.

The electricity billing procedure for the considered cooperative REC can be described according the following steps.

I. In each time interval, if the community buys energy from the utility grid (measured by M_g), the relevant cost is allocated to each consumer *i* (i.e., to each prosumer who consumes energy more than the local generation in that time interval) proportionally to the ratio between its consumption measured by M_i and the total consumption in the community (i.e., the sum of the measured energies by all the prosumers acting as consumers).

II. If the community sells energy to the utility grid (measured by M_g), the corresponding revenue is allocated to each producer *j* (i.e., to each prosumer that produces energy more than the local load in that time interval) proportionally to the contribution of *j* to the total REC production (i.e., to the ratio between the energy measured by M_j and the sum of the measurements of all the prosumers acting as producers).

III. Each consumer *i* is also charged for the energy bought from the producers of the community (i.e., for the difference between the measurement of M_i and the energy allocated to consumer *i* in step I). The corresponding revenue of producer *j* is estimated proportionally to the contribution of *j* to the total community production as in step II. The day-ahead scheduling procedure calculates the energy prices for each producer *j* in each time interval.

4.1.2 *Mathematical model of the REC with PV and BES units*

This section presents the formulation of the optimization problem, which minimizes the total energy procurement cost by defining the optimal scheduling of the energy resources for the following day. For this purpose, the set of participants in the community has been denoted as $\Omega = \{1, 2, \ldots, N\}$, the set of time intervals *t* in the 24-hour horizon as $T = \{1, 2, \ldots, t_{end}\}$, and $B = \{1, 2, \ldots, b_{end}\}$ corresponds to the set of branches *b* in the internal network of the community.

The objective function (4.1) is defined, which corresponds to a typical minimization of the total energy procurement cost given by the costs associated with the exchanges of electricity with the external electricity provider during the day.

$$OF = \sum_{\substack{t\in T\\ i\in\Omega}} \left(\pi^t_{\text{buy}} P^t_{\text{buy\_Grid}\,i} - \pi^t_{\text{sell}} P^t_{\text{sell\_Grid}\,i} \right) \Delta t \tag{4.1}$$

where $P^t_{\text{buy\_Grid}\,i}$ represents the power bought from the utility grid by prosumer *i* at time period *t* and $P^t_{\text{sell\_Grid}\,i}$ corresponds to the power sold to the external utility grid by prosumer *i* at time period *t*. The power profiles included in this chapter are expressed in kW.

The prices when buying and selling energy from and to the external utility grid (in €/kWh), i.e., π^t_{buy} and π^t_{sell}, respectively, are assumed deterministic for the next day. Time step Δt is equal to 0.25 h within an optimization horizon of 24 hours (i.e., divided into 96 periods).

The constraints considered by the community model are the following:

$$P^t_{\text{sell}\,i,j} - P^t_{\text{buy}\,j,i} = 0 \qquad i \text{ and } j \in \Omega \tag{4.2}$$

$$\begin{aligned} &P^t_{\text{PV}\,i} + P^t_{\text{dis}\,i} + P^t_{\text{buy\_Grid}\,i} + \sum_{\substack{j\in\Omega\\ j\neq i}} P^t_{\text{buy}\,i,j} = \\ &P^t_{\text{Load}\,i} + P^t_{\text{ch}\,i} + P^t_{\text{sell\_Grid}\,i} + \sum_{\substack{j\in\Omega\\ j\neq i}} P^t_{\text{sell}\,i,j} + \tfrac{1}{2}\sum_{b\in B} L^t_{b,i} \end{aligned} \qquad i \text{ and } j \in \Omega \tag{4.3}$$

$$\begin{cases} P^t_{\text{buy\_Grid}\,i} = 0 \text{ and } P^t_{\text{buy}\,i,j} = 0 \text{ if } u^t_i = 0 \\ P^t_{\text{sell\_Grid}\,i} = 0 \text{ and } P^t_{\text{sell}\,i,j} = 0 \text{ if } u^t_i = 1 \end{cases} \qquad \begin{matrix} u^t_i \in \{1,0\} \\ i \text{ and } j \in \Omega \end{matrix} \tag{4.4}$$

$$0 \le P^t_{\text{buy\_Grid}\,i} \le P^{\max}_{\text{buy}\,i} \quad 0 \le P^t_{\text{sell\_Grid}\,i} \le P^{\max}_{\text{sell}\,i} \qquad i \in \Omega \tag{4.5}$$

$$0 \le P^t_{\text{buy}\,i,j} \le P^{\max}_{\text{buy}\,i} \quad 0 \le P^t_{\text{sell}\,i,j} \le P^{\max}_{\text{sell}\,i} \qquad i \text{ and } j \in \Omega \tag{4.6}$$

$$E^t_{\text{BES}\,i} = E^{t-1}_{\text{BES}\,i} + (P^t_{\text{ch}\,i}\eta_{\text{ch}\,i} - P^t_{\text{dis}\,i}/\eta_{\text{dis}\,i})\Delta t \qquad \begin{matrix} i \in \Omega \\ t > 1 \end{matrix} \tag{4.7}$$

$$\begin{cases} E^{t=1}_{\text{BES}\,i} = E^{\max}_{\text{BES}\,i} + (P^{t=1}_{\text{ch}\,i}\,\eta_{\text{ch}\,i} - P^{t=1}_{\text{dis}\,i}/\eta_{\text{dis}\,i})\Delta t \\ E^{t_{\text{end}}}_{\text{BES}\,i} = E^{\max}_{\text{BES}\,i} \end{cases} \qquad i \in \Omega \tag{4.8}$$

$$\begin{cases} P^t_{\text{ch}\,i} = 0 \text{ if } u^t_{\text{BES}\,i} = 0 \quad u^t_{\text{BES}\,i} \in \{1,0\} \\ P^t_{\text{dis}\,i} = 0 \text{ if } u^t_{\text{BES}\,i} = 1 \quad i \in \Omega \end{cases} \qquad i \in \Omega \tag{4.9}$$

$$0 \le P^t_{\text{dis}\,i} \le P^{\max}_{\text{BES}\,i} \quad 0 \le P^t_{\text{ch}\,i} \le P^{\max}_{\text{BES}\,i} \qquad i \in \Omega \tag{4.10}$$

$$E^{\min}_{\text{BES}\,i} \le E^t_{\text{BES}\,i} \le E^{\max}_{\text{BES}\,i} \qquad i \in \Omega \tag{4.11}$$

Constraint (4.2) represents the equilibrium between non-negative variable $P^t_{\text{buy } j,i}$, which is the power bought by prosumer *j* from *i* at time period *t*, and non-negative variable $P^t_{\text{sell } j,i}$, which is the power sold by prosumer *i* to *j*. Constraint (4.2) couples all the selling transactions between prosumer *i* and the other participants in the community, so that the price is the same for all the selling transaction of the participants in time interval *t*.

Constraint (4.3) corresponds to the power balance for prosumer *i* in time interval *t*: where the forecast profiles of PV generation and load are given by parameters $P^t_{\text{PV } i}$ and $P^t_{\text{Load } i}$; the charging and discharging power of the battery owned by prosumer *i* are represented with the non-negative variables $P^t_{\text{ch } i}$ and $P^t_{\text{dis } i}$, respectively; $L^t_{b,i}$ represents an estimation of the losses in branch *b* originated from the energy transactions concerning the *i*-th prosumer. Since each transaction is between two prosumers, only half of the power loss is attributed to each prosumer. The omission of the concurrent presence of the transactions of all the prosumers is an approximation justified by the lack of counter-flows due to the assumed non-competitive behaviour of the participants in the community.

$L^t_{b,i}$ in (4.3) is defined by the following constraints.

$$L^t_{b,i} = \frac{R_b}{3V_n^2}\left(F^t_{b,i}\right)^2 \qquad i \in \Omega \qquad (4.12)$$

$$\begin{aligned} F^t_{b,i} = {} & A_{\text{Grid } b,i} P^t_{\text{buy\_Grid } i} - A_{\text{Grid } b,i} P^t_{\text{sell\_Grid } i} \\ & + \sum_{j\in\Omega} A_{b,i,j} P^t_{\text{buy } i,j} - \sum_{j\in\Omega} A_{b,i,j} P^t_{\text{sell } i,j} \end{aligned} \qquad i \text{ and } j \in \Omega \qquad (4.13)$$

In (4.12), R_b corresponds to the resistance of branch *b*, V_n is the line-to-line rated voltage value, and $F^t_{b,i}$ is the three-phase power flow in branch *b* due to the transaction that involves *i*-th prosumer. The relative transactions are assumed positive when directed from the substation to the end of the feeder, and negative in the opposite direction. Constraint (4.12) assumes rms bus voltage values equal to the rated value; the same constraint considers a balanced LV network and neglects reactive power flows.

In (4.13), the position of each branch with respect to the buses where the prosumers are connected is described by 2-D matrix A_Grid and 3-D array *A*, assuming a radial configuration:

- $A_{\text{Grid } b,i}$ is the *b,i* element of matrix A_Grid. When the power flow due to the energy transaction between the *i*-th prosumer and the external energy provider crosses the branch *b*, it takes the value 1; in any other case, it takes the value 0.

- $A_{b,i,j}$ is the b,i,j element of array A. If the power flow created when i buys from j, crosses the branch b in the assumed positive direction, then the value of the element is equal to 1. If the corresponding power flow crosses in the negative direction, the value of the element is -1. The value is 0 if the branch b is not crossed by the power flow created by the corresponding energy transaction between prosumers i and j.

Indicator constraints (4.4) employ the binary variable u_i^t, to prevent simultaneous purchases and sales by the prosumer i.

Constraints (4.5) and (4.6) limit the energy bought and sold by prosumer i at each period t: where $P_{\text{sell } i}^{\max}$ is the largest value between 0 and $P_{\text{PV } i}^{t} - P_{\text{Load } i}^{t} + P_{\text{BES } i}^{\max}$; $P_{\text{buy } i}^{\max}$ is the largest value between 0 and $P_{\text{Load } i}^{t} - P_{\text{PV } i}^{t} + P_{\text{BES } i}^{\max}$; $P_{\text{BES } i}^{\max}$ is the maximum power output of the BES unit owned by prosumer i.

The state of energy (SoE) of the battery of prosumer i is given by (4.7) and (4.8), which represent a simple energy balance model, where $E_{\text{BES } i}^{t}$ is the SoE at time t (in kWh) and $E_{\text{BES } i}^{\max}$ is the maximum storage capacity. The non-negative parameters $\eta_{\text{ch } i}$ and $\eta_{\text{dis } i}$ are values lower than 1 and represent the charging and discharging efficiencies, respectively. In (4.8) the BES units are assumed fully charged at the beginning and at the end of the day. The binary variable $u_{\text{BES } i}^{t}$ in indicator constraints (4.9) prevents the concurrent charging and discharging processes of the batteries. In (4.10), the discharging and charging power of the BES units are bound within the maximum value $P_{\text{BES } i}^{\max}$. Constraint (4.11) limits the value of the SoE between minimum level $E_{\text{BES } i}^{\min}$ and maximum $E_{\text{BES } i}^{\max}$.

In the proposed Mixed Integer Linear Programming (MILP) model for the centralized scheduling of the REC, constraint (4.12) is replaced by its piecewise linear approximation, e.g., (Williams 2013). For such a linearization, a set L of segments has been created. Each segment is defined by breakpoints $H_{\text{Flow } b,l}^{t}$, obtained by dividing the allowed range of F_b^t into $|L|$ intervals. Each breakpoint $H_{\text{Flow } b,l}^{t}$ defines a breakpoint $H_{\text{Loss } b,l}^{t}$ of the piecewise representation of L_b^t, which is given by

$$F_b^t = \sum_{l \in L} a_{b,l}^t \; H_{\text{Flow}\, b,l}^t \tag{4.14}$$

$$L_b^t = \sum_{l \in L} a_{b,l}^t \; H_{\text{Loss}\, b,l}^t \tag{4.15}$$

$$\sum_{l \in L} a_{b,l}^t = 1 \quad l \in L \tag{4.16}$$

where $a_{b,l}^t$ are SOS2 variables, i.e., they are linked with a special ordered set of type 2 constraints, so that, at most two and consecutive variables can be non-zero. Since the losses are calculated separately for each transaction, the model (4.14)-(4.16) is applied for each prosumer *i* by using the power flow defined by (4.13).

4.1.3 *Integrating biogas generation in the REC*

The operation of electrical systems that integrate biogas power generation, non-dispatchable renewable generation and energy storage systems has been widely studied as in e.g., (B. Zhou et al. 2018; España et al. 2021; X. Zhang, Sharma, and He 2012). In (Lai et al. 2017), a techno-economic analysis of an off-grid hybrid system including PV-Storage systems and AD-biogas power plant has been presented, where the biogas consumption per kWh has been represented by the quadratic function included in (Engine and Data 2009).

The scheduling problem for electrical systems including dispatchable units can be addressed by means of centralized and distributed approaches, as in e.g., (Xu et al. 2019), where a Lagrangian dual approach has been adopted in order to solve the scheduling problem of a multicarrier energy system for interconnected microgrids.

This section is focused on the expansion of the introduced models (i.e., centralized model of section 4.1.2 and distributed model of Appendix A) of the REC to consider one or more participants equipped with a dispatchable generator, specifically a biogas-powered generator.

In the following, the corresponding formulation to deal with the scheduling problem of the community that also considers the cost of energy generation from biogas will be introduced. In this context, we will study the impact of the presence of biogas power production on the prices of the energy transactions between community participants. The corresponding problem will be addressed by both a centralized and distributed approach and analysed for several case studies.

4.1.4 ***Biogas-powered producer formulation***

One of the main characteristics of the community model in this section is that the total energy procurement cost considers those associated with the biogas-powered generation i.e., specifically with the fuel consumption.

Following (Lai et al. 2017), the cost of the biogas power generation of a *i*-th member of the community has been defined by (4.17), where the fuel consumption per kWh has been represented by the quadratic function included in (Engine and Data 2009)

$$C^t_{\text{biogas}\,i} = C_{\text{gas}\,i}\,\frac{P^t_{\text{biogas}\,i}[a(P^t_{\text{biogas}\,i})^2 + bP^t_{\text{biogas}\,i} + c]}{LHV} \tag{4.17}$$

with parameters *a*, b and c equato 0.0016 (btu/kW3h), -3.935 (btu/kW2h) and 10641 (btu/kWh) respectively (according to (Lai et al. 2017)).

In (4.17) , $P^t_{\text{biogas}\,i}$ (in kW) corresponds to the power output of the dispatchable generator owned by *i* in time interval t and $C_{\text{gas}\,i}$ is the AD gas cost (in €/ ft3). The Lower Heating Value (LHV) has been considered equal to 905 btu/ft3.

In order to include (4.17) into an MILP model of the community's operation, the corresponding cost is replaced by its piece-wise linear approximation according to equations (4.18)-(4.20). For this purpose, the allowed range of the biogas power output is divided into N_x intervals, each one defined by breakpoints x_u, such that U = {1, 2, …, N_x} denotes the set of segments. At each interval of the power output, breakpoints x_u define a corresponding interval of associated costs, where α_u and β_u represent the linearization parameters of the u-th segment. The allowed range is defined by $P^{\max}_{\text{biogas}}$ and $P^{\min}_{\text{biogas}}$ (in kW), which are the maximum and minimum power output, respectively.

$$C^t_{\text{biogas}\,i} \geq \frac{C_{\text{gas}\,i}}{LHV}(\alpha_u P^t_{\text{biogas}\,i} + \beta_u w^t_i) \qquad u \in U \tag{4.18}$$

$$\alpha_u = a(x_u^2 + x_{u-1}^2 + x_u x_{u-1}) + b(x_u + x_{u-1}) + c \qquad u \in U \tag{4.19}$$

$$\beta_u = a x_{u-1}^3 + b x_{u-1}^2 + c x_{u-1} - \alpha_u x_{u-1} \qquad u \in U \tag{4.20}$$

with

$$\begin{cases} x_u = P_{\text{biogas}}^{\min} & \text{if } u = 1 \\ x_u = P_{\text{biogas}}^{\min} + u\dfrac{P_{\text{biogas}}^{\max} - P_{\text{biogas}}^{\min}}{N_x} & \text{if } u > 1,\ u \in U \end{cases} \tag{4.21}$$

Constraints (4.22)-(4.26) complete the model of the biogas power plant owned by prosumer *i*.

$$P_{\text{biogas}\,i}^{\min} \le P_{\text{biogas}\,i}^{t} \le P_{\text{biogas}\,i}^{\max} \tag{4.22}$$

$$\sum_t \frac{P_{\text{biogas}\,i}^{t}[a(P_{\text{biogas}\,i}^{t})^2 + bP_{\text{biogas}\,i}^{t} + c]}{LHV}\Delta t \le C_{\text{fuel}\,i}^{\max\text{day}} \tag{4.23}$$

$$\begin{cases} SU_i^{t=1} \ge w_i^{t=1} \\ SU_i^{t} \ge w_i^{t} - w_i^{t-1} & \text{if } t > 1 \end{cases} \tag{4.24}$$

$$\sum_t SU_i^t \le 1 \tag{4.25}$$

$$\begin{cases} P_{\text{biogas}\,i}^{t} = 0 & \text{if } w_i^t = 0 & w_i^t \in \{1,0\} \\ P_{\text{biogas}\,i}^{t} \ge P_{\text{biogas}\,i}^{\min} & \text{if } w_i^t = 1 & i \in \Omega \end{cases} \tag{4.26}$$

Constraint (4.22) limits the power output of the biogas unit within its minimum and maximum value (i.e., $P_{\text{biogas}\,i}^{\min}$ and $P_{\text{biogas}\,i}^{\max}$, respectively). In (4.23), the daily amount of fuel consumption (in ft^3) is bound by maximum value $C_{\text{fuel}\,i}^{\max\text{day}}$. In (4.24), the non-negative variable SU_i^t is used to indicate whether the biogas power plant owned by *i* starts up at time interval *t* or not, whilst (4.25) allows each biogas power plant to be started-up only once during the following day.

Constraint (4.26) includes binary variable w_i^t, which indicates whether the biogas power plant owned by prosumer *i* is on or off during time interval *t*.

The case studies included in this chapter consider a biogas power generator with $P_{\text{biogas}\,i}^{\max}$ equal to 20kW; $P_{\text{biogas}\,i}^{\min}$ is assumed equal to 20% of $P_{\text{biogas}\,i}^{\max}$. Since the size of the considered biogas power plant is quite small, start-up and shut-down costs are neglected.

4.1.5 *Centralized and Distributed approaches with the integration of biogas*

In order to consider the participation in the community of producers that own biogas-fuelled generators, the centralized and the ADMM models proposed in section 4.1.2 and Appendix A respectively, are extended to include the relevant cost and operational constraints associated to such units.

A. Objective function and formulation for the centralized model

In the centralized model, the *OF* (4.1) is modified by including the piece-wise linearization of cost (4.17); thus, the total objective function minimizes the total energy cost given by

$$OF = \min \sum_{\substack{t \in T \\ i \in \Omega}} \left[\pi_{\text{buy}}^{t} P_{\text{buy\_Grid}i}^{t} - \pi_{\text{sell}}^{t} P_{\text{sell\_Grid}i}^{t} + C_{\text{biogas}\,i}^{t} \right] \Delta t \tag{4.27}$$

Then, the scheduling problem is solved considering the set of constraints (4.2)-(4.16) and (4.17)-(4.26).

For the community with dispatchable generation, the power balance constraint (4.3) is replaced with (4.28), in which the power output at time period *t* of the available biogas-power generators are included

$$\begin{aligned} & P_{\text{PV}i}^{t} + P_{\text{dis}i}^{t} + P_{\text{buy\_Grid}i}^{t} + P_{\text{biogas}i}^{t} + \sum_{\substack{j \in \Omega \\ j \neq i}} P_{\text{buy}i,j}^{t} = \\ & P_{\text{Load}i}^{t} + P_{\text{ch}i}^{t} + P_{\text{sell\_Grid}i}^{t} + \sum_{\substack{j \in \Omega \\ j \neq i}} P_{\text{sell}i,j}^{t} + \frac{1}{2} \sum_{b \in B} L_{b,i}^{t} \end{aligned} \qquad i \in \Omega \tag{4.28}$$

The maximum power that a biogas-powered producer *i* can sell (i.e., $P_{\text{sell}\,i}^{\max}$) corresponds to $P_{\text{biogas}i}^{\max}$.

B. Objective function and formulation for the distributed model

The scheduling problem is suitable to be represented with a distributed optimization model based on the ADMM procedure. In this case, the *OF* (4.27) is decomposed into sub problems for each participant *i* in the community

$$OF_i = \min \sum_{t \in T} \begin{bmatrix} \pi_{\text{buy}}^{t} P_{\text{buy\_Grid}\,i}^{t} - \pi_{\text{sell}}^{t} P_{\text{sell\_Grid}\,i}^{t} + C_{\text{biogas}i}^{t} \\ + \sum_{\substack{j \in \Omega \\ j \neq i}} \lambda_j^{t} P_{\text{buy i},j}^{t} - \lambda_i^{t} \sum_{\substack{j \in \Omega \\ j \neq i}} P_{\text{sell}\,i,j}^{t} + \ell_i^{t} \end{bmatrix} \Delta t \tag{4.29}$$

where $C_{\text{biogas}i}^{t}$ corresponds to the piece-wise linearization of cost (4.17) for the *i*-th member of the community that owns a generator (otherwise it will be equal to zero); ℓ_{i}^{t}, defined by (0.2), penalizes the imbalances between the intended energy transactions of *i* and the other participants.

Problem (4.29) is iteratively solved by each one of the members of the community, individually considering, for each participant *i*, constraints (4.4)-(4.16), power balance (4.28) and constraints (4.17) - (4.26) relevant to the operation of a dispatchable generator owned by *i*.

Following the implementation of the ADMM approach of Appendix A, the values of λ_i^t are iteratively updated to reduce the imbalances associated with the energy transactions that involves *i*. For this purpose, at each iteration, all the participants share with the others the resulting values of their local values, namely $\hat{P}^t_{\mathrm{buy}\,i,j}$ and $\hat{P}^t_{\mathrm{sell}\,i,j}$ in (0.2).

The ADMM procedure reaches the convergence when the values that reflect the imbalances are bellow a defined tolerance ε (assumed equal to 20 W in the case studies included in this section). The implemented approach follows the updating scheme for the penalization parameter ρ and scale factor m at each iteration (introduced in Appendix A) to speed up the convergence of the distributed solution.

Once the procedure converges, ℓ_i^t tends to zero, and the value of the total *OF* for the community is equal to the summations of the resulting values of every *i*-th sub problem.

4.1.6 *Case study of a renewable energy community with PV and BES units*

We now consider a REC composed of two LV feeders, like the one illustrated in Figure 4.3. Each feeder consists of five lines, each with resistance R_b = 189 mΩ. Five prosumers are connected to each feeder (numbered from the beginning of the feeder to the end): prosumers 1-5 to a feeder and prosumers 6-10 to the other. Each prosumer may be equipped with a PV-storage system and a load.

The load profiles adopted for each prosumer are shown in Figure 4.4. For all the PV units we assumed the same profile of the ratio between power output and panel surface, shown in Figure 4.5. The area of the PV unit of each prosumer is given in Table 4.1. Figure 4.5 also shows the price profile of the energy bought from the utility grid (i.e., π^t_{buy}). We assume that the price of the energy sold by the community to the utility grid (i.e., π^t_{sell}) is half of π^t_{buy}. The total daily consumption of the community is 313 kWh and the corresponding PV production is 231 kWh (73.8% of the load).

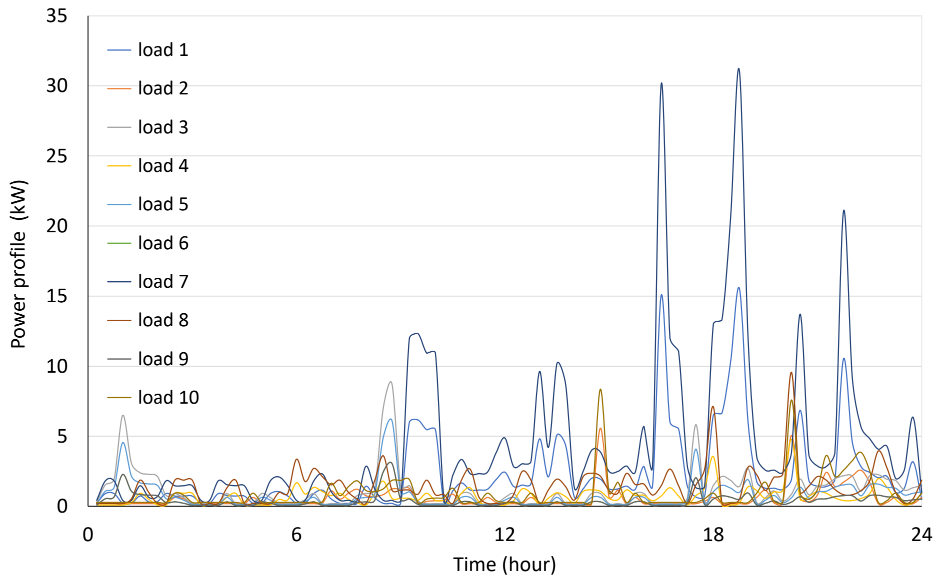


Figure 4.4 Load profile of each prosumer.

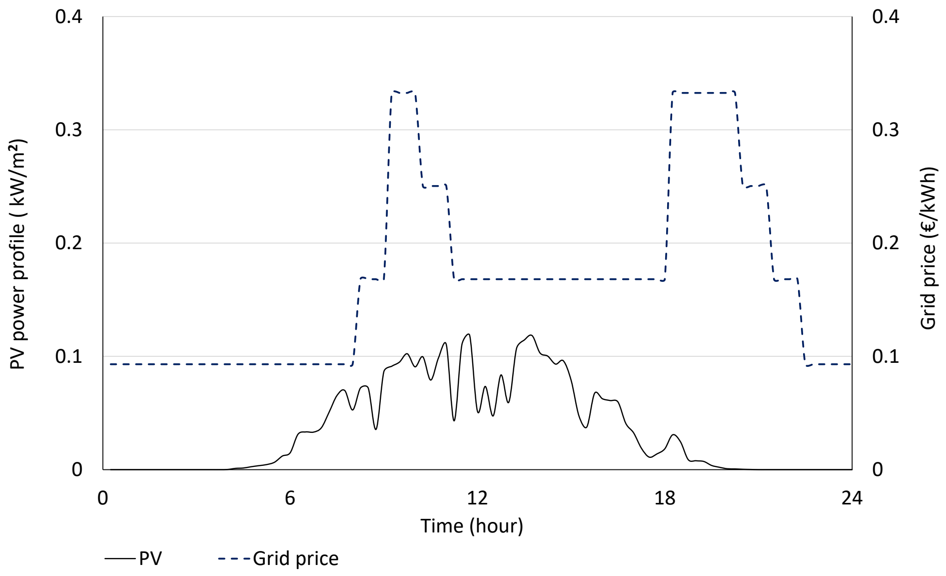


Figure 4.5 Profile of the PV production and Grid purchase price.

Table 4.1 PV panel surface for each prosumer.

Prosumer	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
Area (m^2)	32	14	21	32	28	14	42	32	14	42

Sizes $E_{\mathrm{BES}}^{\max}$ of the BES units are shown in Table 4.2 and the corresponding $P_{\mathrm{BES}}^{\max}$ values are assumed to be equal to the ratio $E_{\mathrm{BES}}^{\max} / \Delta t$. The total capacity of the BES units is 30 kWh (13% of the daily PV production).

Table 4.2 Sizes of the BES units in the community.

Prosumer	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
Size (kWh)	5	3	4	2	3	1	2	2	2	6

To test the proposed centralized formulation, the MILP model of the community has been implemented in the AIMMS Developer modelling environment and solved by using the Cplex solver. As already mentioned, all the calculations refer to a time window of one day, divided into 96 periods of 15 minutes each.

Figure 4.6 shows the total power flow at the connection of the community with the external energy provider. The total *OF* value of (4.1) obtained by means of the centralized scheduling of the resources in the community, is €18.06.

The power profiles from each prosumer when it exchanges energy with the others i.e., when selling and buying, are presented in Figure 4.7 and Figure 4.8, respectively.

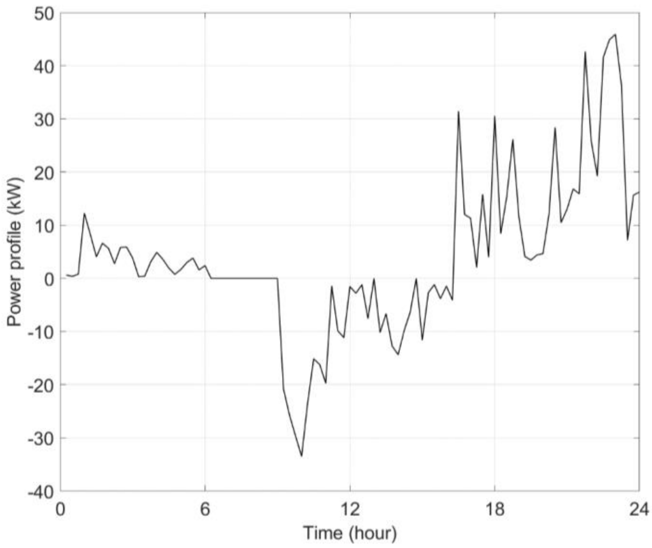


Figure 4.6 Power flow exchanged with the external energy provider (positive if consumed by the community), obtained using the centralized approach.

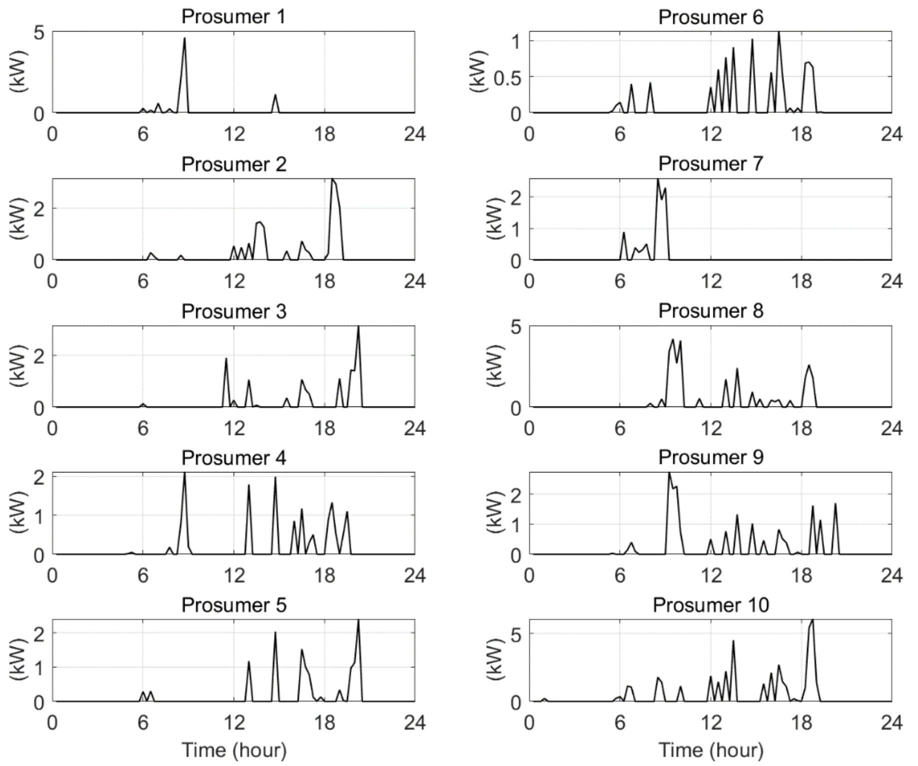


Figure 4.7 Power flows from every prosumer when it sells to the others (excluding the utility grid), obtained using the centralized approach.

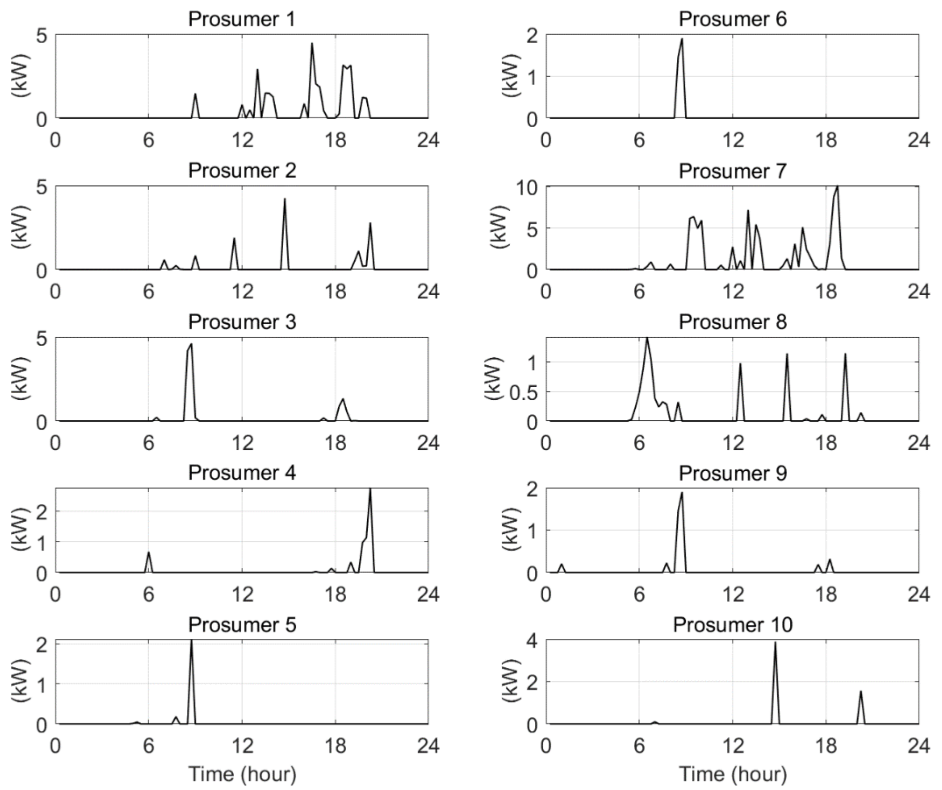


Figure 4.8 Power flows from every prosumer when it buys from the others (excluding the utility grid), obtained using the centralized approach.

Figure 4.9 shows the detail of the SoE profiles of each BES unit, whilst Figure 4.10 provides the profiles of the total energy contained in the BES units of the community.

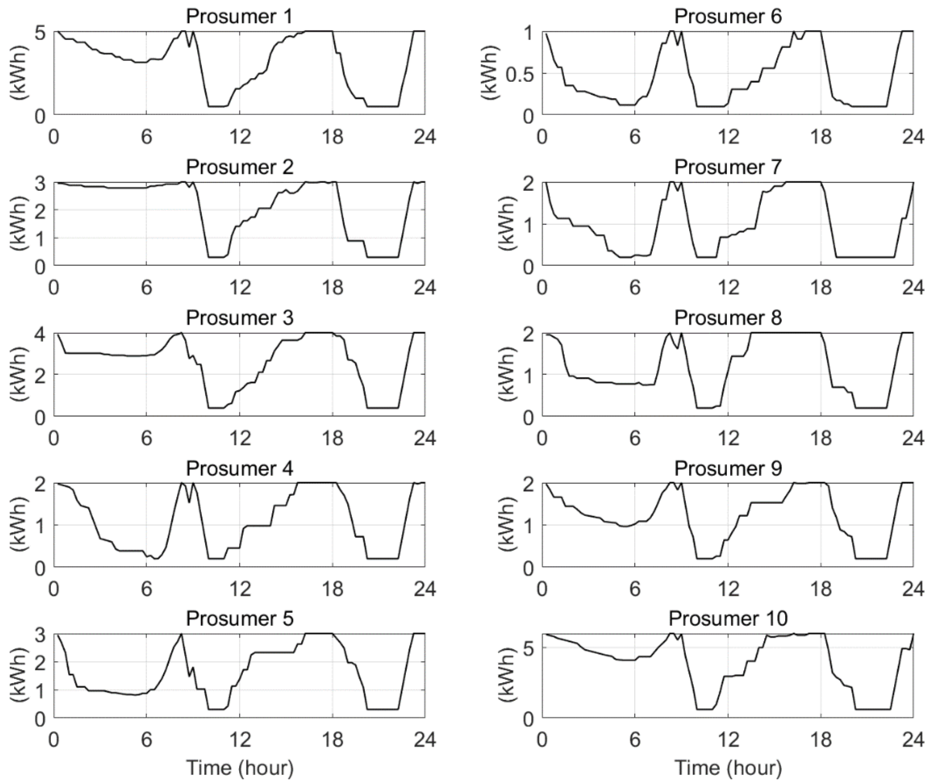


Figure 4.9 Battery SoE for each prosumer, obtained using the centralized approach.

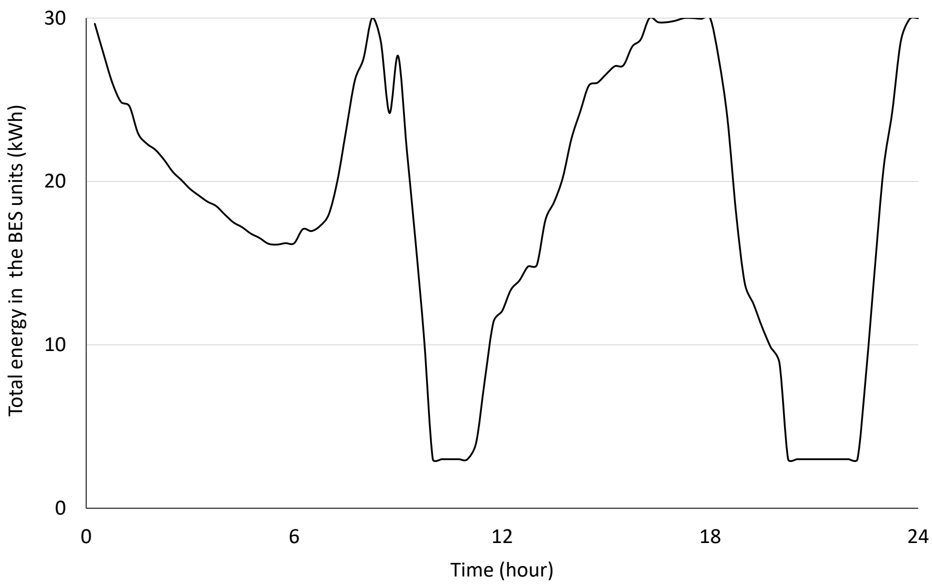


Figure 4.10 Total energy in the batteries of the community, obtained using the centralized approach.

Figure 4.11 shows the energy prices for the participants in the community at time period *t*. For the case of the centralized model, the prices correspond to the Lagrangian multiplier associated to constraint (4.2). In Figure 4.11, the dotted lines correspond to the prices of the energy purchased from and sold to the utility grid (i.e., π_{buy}^{t} and π_{sell}^{t}, respectively), whilst the solid round markers represent the prices of prosumers when acting as producers and selling energy to any other participant in the community. The comparison of Figure 4.11 and Figure 4.6 shows that the prices of the energy transactions in the community are not equal to π_{buy}^{t} or π_{sell}^{t} when there is no power exchange with the utility grid, that is during the time interval starting just after 6 am.

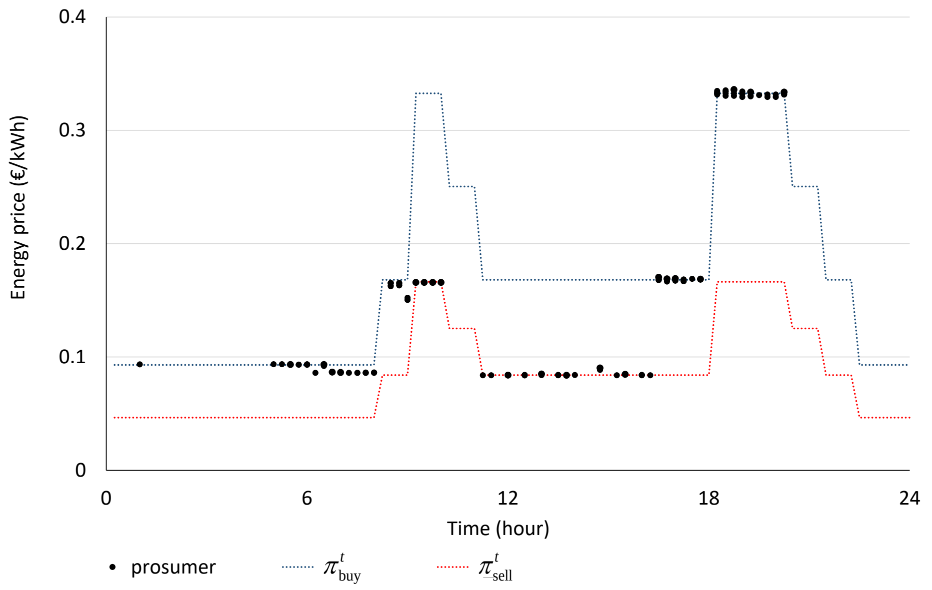


Figure 4.11 Energy prices of selling prosumers, obtained using the centralized approach.

Table 4.3 and Table 4.4 compare the individual energy procurement costs of each member of the REC, taking into account: the exchanges with the external energy provider; the exchanges with other prosumers; and the prices of Figure 4.11. Furthermore, the tables show the corresponding values obtained by preventing the transactions between prosumers. The total energy procurement cost of the community is around 16% less than the corresponding cost without energy transactions between prosumers.

Table 4.3 Energy procurement cost in € (negative values indicate revenues) for each prosumer in feeder 1, obtained using the centralized solution.

Prosumer	**1**	**2**	**3**	**4**	**5**
Cooperative – Centralized	5.23	0.08	0.96	-0.99	-0.65
Without internal exchanges	5.46	0.28	1.10	-0.82	-0.46

Table 4.4 Energy procurement cost in € (negative values indicate revenues) for each prosumer in feeder 2, obtained using the centralized solution.

Prosumer	6	7	8	9	10
Cooperative – Centralized	-0.21	14.79	1.63	-0.47	-2.30
Without internal exchanges	-0.15	16.38	1.71	-0.30	-1.67

4.1.7 *Case studies of a renewable energy community with PV, BES and biogas units*

In the following, we describe the case studies that have been adopted to test the performance of both centralized and distributed approaches. For comparative purposes, the case studies preserve total values of the daily-energy generated by PV units, the daily-energy demand and installed storage capacity (i.e., 231 kWh, 313 kWh and 30 kWh, respectively) of the base case introduced in the previous section.

Case I – considers a REC with a biogas-powered plant owned by one of the participants (with $P_{\text{biogas}\,i}^{\max}$ = 20 kW, $C_{\text{gas}\,i}$ = 9.97 €/mcf and $C_{\text{fuel}\,i}^{\max\,\text{day}}$ =3300 ft3), together with nine prosumers equipped with PV units, BES units and local loads each. The corresponding scheme has been illustrated in Figure 4.12a.

Case II – same scheme as Case I, but without any BES unit.

Case III – same scheme as Case I, but considering a more restricted fuel consumption availability in the biogas unit ($C_{\text{fuel}\,i}^{\max\,\text{day}}$ =1000 ft3).

Case IV – considers a community of eight prosumers equipped with PV units and batteries (other than loads and, in addition, two biogas-powered plants, as in Figure 4.12b). The maximum power output, and the gas cost of both biogas power plants, are set equal to 20kW and 9.97 €/mcf, respectively.

Case V – same scheme as Case IV, but with different gas costs $C_{\text{gas}\,i}$ for each biogas-powered generator (9.97 €/mcf for Biogas 1 and 10.97 €/mcf for Biogas 2). The maximum power output is equal to 20 kW for both generators.

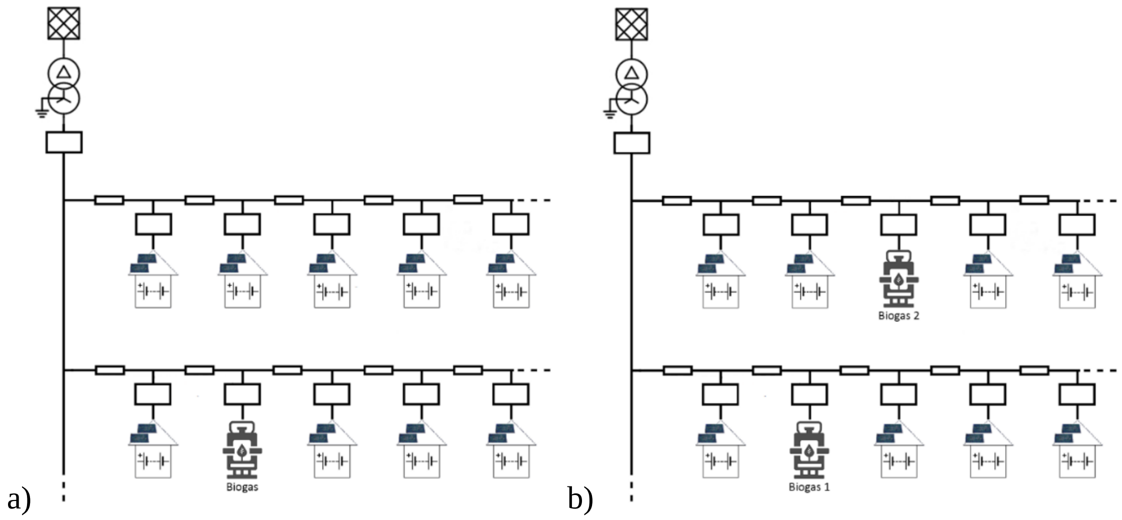


Figure 4.12 Scheme of the community that includes biogas-powered producers: a) Cases with a biogas unit; b) Cases with two biogas units

Table 4.5 shows the OF value, total daily fuel consumption and percentage of the community self-consumption for each case study. The reported results have been obtained by employing both the centralized and the ADMM approaches. Moreover, Table 4.5 shows the total solution time needed from each approach and the total number of iterations of the distributed solution.

In general, the results in Table 4.5 for the centralized and the ADMM approaches are similar and confirm that the scheduling problem of the community with dispatchable units is suitable to adopt both approaches. It is important to notice that the ADMM approach is oriented to limit the information that participants share in the community and not directly oriented to improve the solution time in the case studies.

Table 4.5 Case studies results for the community with the presence of biogas generation

	Approach	Case I	Case II	Case III	Case IV	Case V
OF (€)	Centralized	5.2	11.4	7.0	1.7	3.2
	ADMM	5.5	11.4	7.3	1.8	3.6
Total fuel consumption ($10^3 \cdot ft^3$)	Centralized	2.0	2.0	1.0	3.4	2.7
	ADMM	2.0	2.0	1.0	3.4	3.4
Self-consumption (%)	Centralized	72	70	69	73	73
	ADMM	70	70	66	73	73
Solution time (s)	Centralized	35	15	48	62	30
	ADMM	910	400	920	940	935
Iterations	ADMM	41	26	51	64	38

For Case I, Figure 4.13 shows the energy prices of the prosumers and the biogas-powered producers when selling energy in the community (excluding transactions with the external provider); Figure 3.32 also shows marginal cost for the Biogas unit and the energy price when buying and selling energy to the external grid. The total power flow exchanged with the external grid (assumed positive if it is consumed by the community) and the power output of the biogas unit are shown in Figure 4.14.

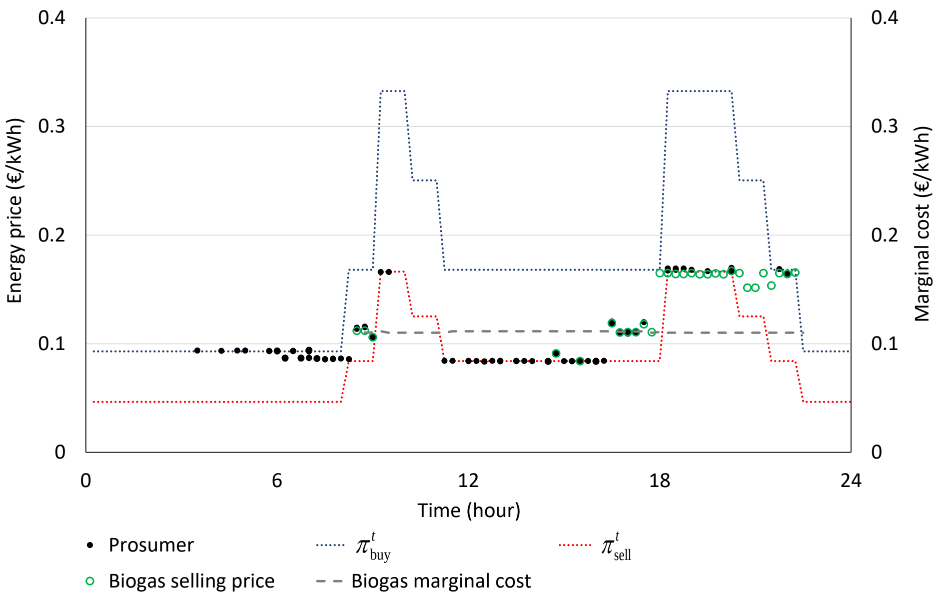


Figure 4.13 Energy prices in the community and marginal cost for the biogas unit in Case I

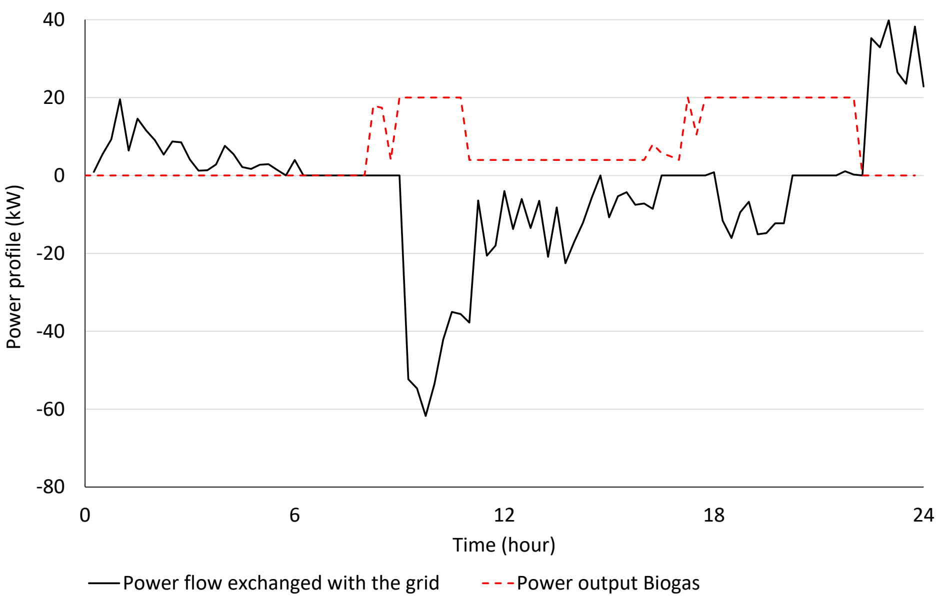


Figure 4.14 Total power flow exchanged by the community with the external grid (positive if consumed by the community) and power output of the biogas unit in Case I

From Figure 4.13 and Figure 4.14, we can see that the prices of the energy in the community (i.e., associated with transactions between participants) are, in general, aligned with the marginal cost of the biogas unit for those moments when the REC does not exchange energy with the utility grid.

At the end of the day (around 9 pm and 10 pm), the prices in the community are higher than the marginal cost of the biogas unit, even during the period without exchange of energy with the external grid. In this period, energy production from the biogas-powered generator, as well as charging and discharging processes in the prosumers BES units, occurs simultaneously.

This effect on the prices is reasonably related to the activity of the BES units that, at the end of the day, are constrained to reach the same energy level at the beginning of the day. To see such an effect of the BES units' operation on the prices, Figure 4.15 and Figure 4.16 show the corresponding results for Case II (without any BES unit).

In Figure 4.15, for the scenario without BES units, the prices of the energy transactions in the community are aligned; to π_{buy}^{t} if the community globally imports energy, to π_{sell}^{t} if the community is globally exporting energy and to the biogas marginal price if there are not energy exchanges with the external grid while the biogas unit is operating.

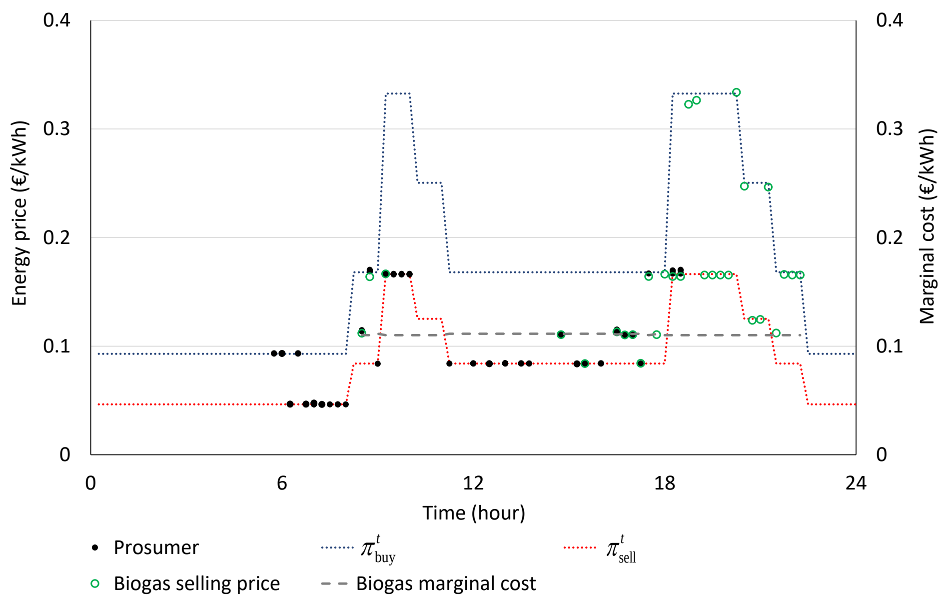


Figure 4.15 Energy prices in the community and marginal cost for the biogas unit in Case II

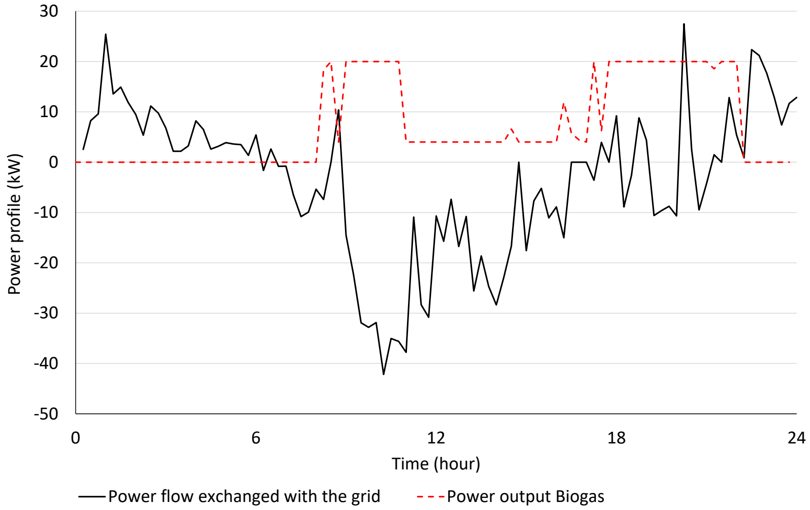


Figure 4.16 Total power flow exchanged by the community with the external grid (positive if consumed by the community) and power output of the biogas unit in Case II

Now, let us consider the effect of $C_{\text{fuel}\,i}^{\text{max day}}$ on the scheduling solution of the community. Figure 4.17 shows the daily profile of the fuel consumed for both Case I and Case III. When the daily fuel availability is large enough (Case I), the biogas power plant is in operation almost all day, being at minimum power during the midday hours. On the other hand, if the total fuel consumption is limited to a lower value (Case III), the biogas power plant is used for a shorter time period, concentrated, in this case, in the evening; hence, aligning the operation of the generator with a convenient period of the day in order to reduce the total procurement costs.

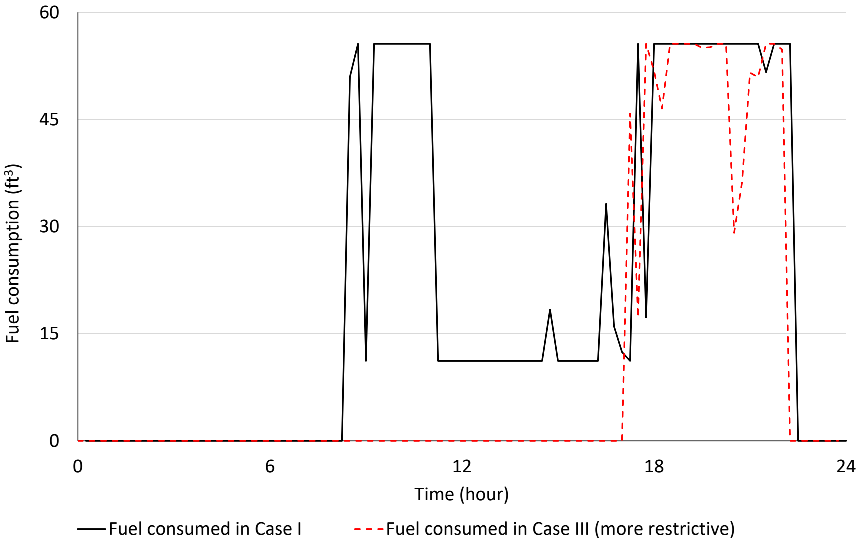


Figure 4.17 Daily profile of the fuel consumed by the Biogas unit in Case I with $C_{\text{fuel}\,i}^{\text{max day}}$ =3300 ft^3 (black line) and Case III with $C_{\text{fuel}\,i}^{\text{max day}}$ =1000 ft^3 (red dashed line)

In Case IV and V, with two biogas units, with equal and different gas costs, respectively, the selling prices of both biogas units are aligned with a common value. The corresponding prices for Case IV are illustrated in Figure 4.18, and in Figure 4.19 for Case V.

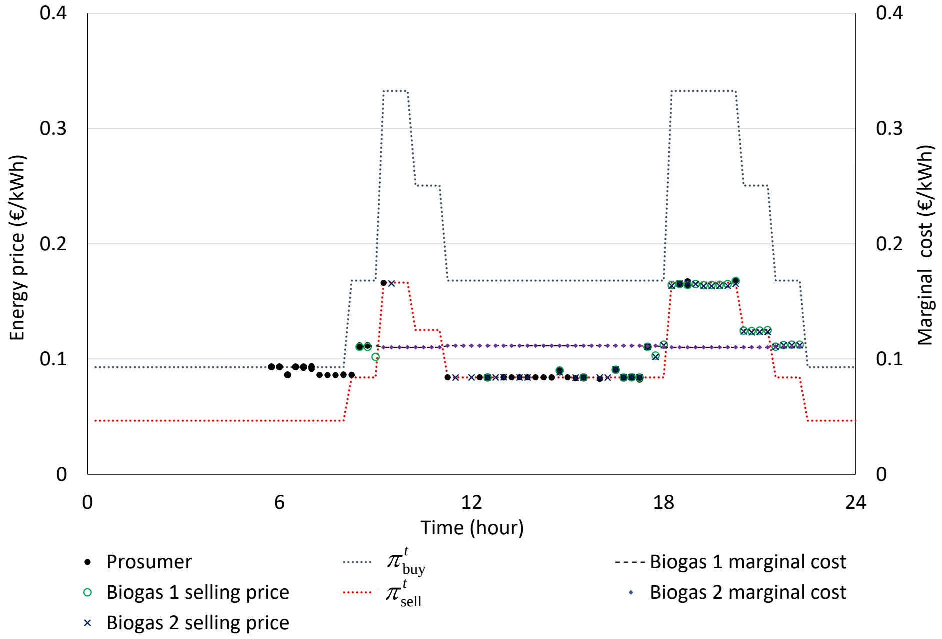


Figure 4.18 Energy prices in the community and marginal cost for the biogas units in Case IV

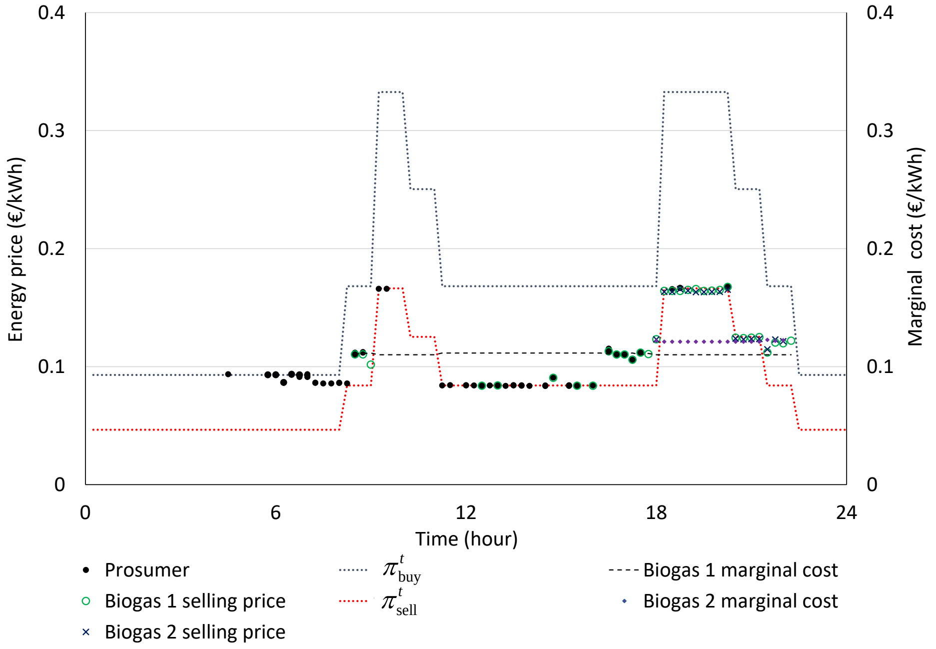


Figure 4.19 Energy prices in the community and marginal cost for the Biogas units in Case V

Figure 4.20 shows the daily profile of fuel consumed by the two dispatchable units in Case IV, in which the same gas cost has been assumed for both generators, while Figure 4.21 shows the fuel consumption profiles for the biogas units in Case V (assuming different gas costs).

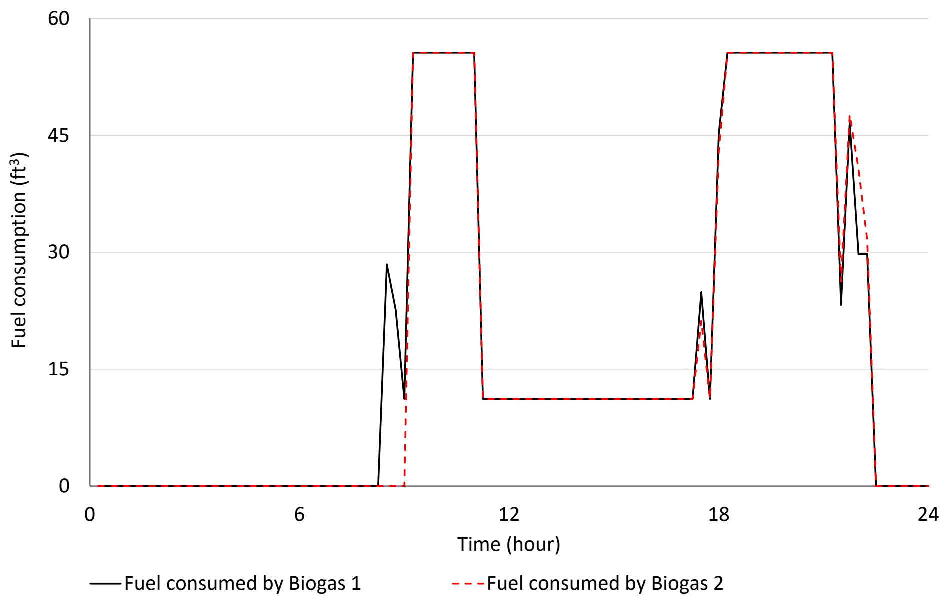


Figure 4.20 Daily profile of the fuel consumed by the biogas units in Case IV: Biogas 1 (black line) and Biogas 2 (red dashed line), both with the same $C_{\mathrm{gas}\,i} = 9.97$ €/mcf

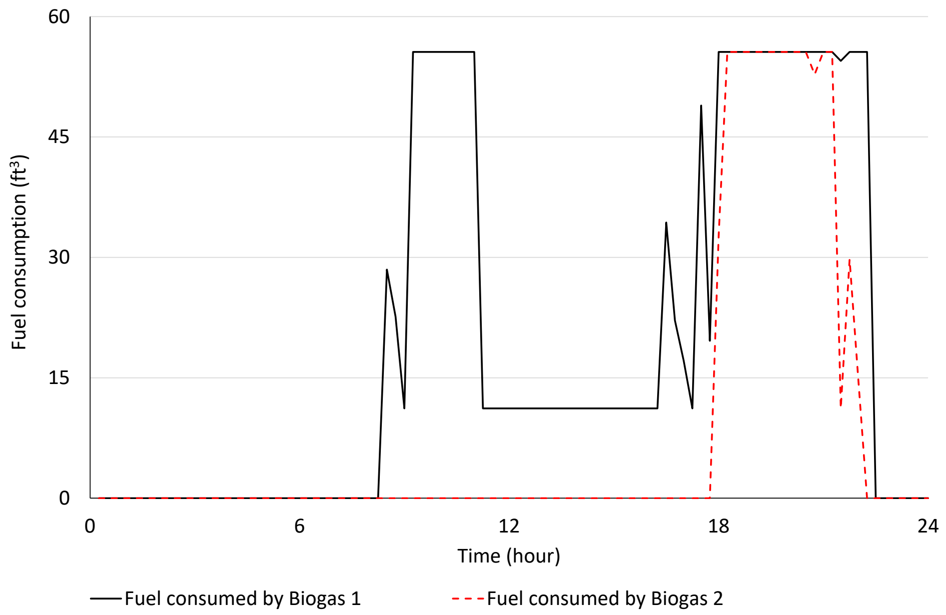


Figure 4.21 Daily profile of the fuel consumed by the biogas units in Case V: Biogas 1 with $C_{\mathrm{gas}\,i} = 9.97$ €/mcf (black line) and Biogas 2 with $C_{\mathrm{gas}\,i} = 10.97$ €/mcf (red dashed line)

The comparison between Figure 4.20 and Figure 4.21 shows that the higher cost for the Biogas unit 2 in Case V limits its use to a shorter time period than the one defined for the Biogas unit 1. Consequently, in that case, the operation of Biogas 2 is limited to a period between 6 pm and 10 pm, in which the conditions seem to be the most convenient to reduce the procurement cost, as previously discussed.

4.2 A case of interest: day ahead scheduling of a REC according to the Italian reception of RED II

The case of interest introduced in this section considers a REC in which the energy transactions between the members of the REC are not allowed, according to the Italian reception of the European directive RED II. In the considered REC, participants can transact energy with the external energy provider only, and maintain their traditional supply contract. In this framework when members of the REC are sharing energy, i.e. a member is selling energy to the grid and at same time another member is buying energy from the grid, they receive revenues and pay for that energy according to the price of selling and buying set by the external provider at that time, respectively. Moreover, the community receive incentives for that shared energy, that need to be allocated to the members according to rules established by the members of the considered community.

This section introduces the day ahead scheduling of the community to minimize the daily energy procurement cost of the REC, also including the revenues for the community shared energy, according to the Italian regulation framework. Several case studies are carried out and the total energy daily procurement cost, the optimal set values of the battery energy storage systems and of the biogas units have been compared to the ones obtained in the previous section for a cooperative REC.

4.2.1 *Mathematical model*

For the formulation of the day ahead scheduling problem, which minimizes the total energy procurement cost, the set of participants in the community has been denoted as $\Omega = \{1, 2, \ldots, N\}$ and the set of time intervals t in the 24-hour horizon as $T = \{1, 2, \ldots, t_{end}\}$.

The objective function (4.30) minimizes the total energy procurement cost given by the costs associated with the exchanges of electricity with the external electricity provider during the day and revenues given for the shared energy.

$$OF = \min \sum_{\substack{t \in T \\ i \in \Omega}} \left[\pi^t_{\text{buy}} P^t_{\text{buy\_Grid}\,i} - \pi^t_{\text{sell}} P^t_{\text{sell\_Grid}\,i} \right] \Delta t - \sum_{t \in T} I_{E_s} E^t_{Shared} \tag{4.30}$$

where $P^t_{\text{buy\_Grid}\,i}$ represents the power bought from the utility grid by prosumer i at time period t and $P^t_{\text{sell\_Grid}\,i}$ corresponds to the power sold to the external utility grid by prosumer i at time period t. The prices when buying and selling energy from and to the external utility grid (in €/kWh), are represented with π_{buy}^{t} and π_{sell}^{t}, respectively, and Δt is the time step. I_{E_s} (in €/kWh) corresponds to the incentive given for the shared energy E_{Shared}^{t}. I_{E_s} are set equal to 0.118 €/kWh according to the Italian regulation framework. In the following, the shared energy computation is described.

A. *The shared energy computation*

According to the already discussed shared energy computation in section 3.1.1A, constraint (4.31) defines the power accounted by the meter M2 of prosumer *i* (see Figure 3.1). Variables $M2_{\text{f}\,i}^{t}$ and $M2_{\text{w}i}^{t}$ represent the power fed in and withdrawn by PV and BES systems of prosumer *i*, respectively.

$$P_{\text{PV}i}^{t} + P_{\text{dis}\,i}^{t} - P_{\text{ch}\,i}^{t} = M2_{\text{f}\,i}^{t} - M2_{\text{w}\,i}^{t} \qquad i \in \Omega,\ t \in T \tag{4.31}$$

$$\begin{cases} M2_{\text{f}\,i}^{t} = 0 & \text{if } \mathrm{z}_i^t = 0 \\ M2_{\text{w}\,i}^{t} = 0 & \text{if } \mathrm{z}_i^t = 1 \end{cases} \qquad \mathrm{z}_i^t \in \{1,0\},\ t \in T, i \in \Omega \tag{4.32}$$

Constraints (4.33) bound the value of K_i, which represent the ratio between $\sum_{t \in T} M2_{\text{w}i}^{t}$ and $\sum_{t \in T} M2_{\text{f}\,i}^{t}$. K_i reflects an approximation of the factor γ_i introduced by the GSE for the calculation of the shared energy (GSE 2021). The maximum value of factor K_i is here assumed to be lower than 0.1.

$$\begin{aligned} & K_i * \sum_{t \in T} M2_{\text{f}\,i}^{t} = \sum_{t \in T} M2_{\text{w}\,i}^{t} \\ & K_i \geq 0 \qquad\qquad i \in \Omega \\ & K_i \leq 0.1 \end{aligned} \tag{4.33}$$

It should be noted that the proposed calculation of the shared energy results to be almost the same of the shared energy calculated with the formulation provided by GSE, which has been simplified in our formulation for the sake of computational burden reduction.

Constraints (4.34) set the shared energy to be the minimum between the total energy sold to and total energy bought from the external grid by the community, including factor K_i, described in (4.33), which accounts for the operation of storage systems.

$$
\begin{aligned}
&E_{Shared}^{t} \le \sum_{i\in\Omega} P_{\text{sell\_Grid}\,i}^{t}(1-K_i)\Delta t \\
&E_{Shared}^{t} \le \sum_{i\in\Omega} P_{\text{buy\_Grid}\,i}^{t}\,\Delta t \qquad\qquad t\in T \\
&E_{Shared}^{t} \ge 0
\end{aligned}
\tag{4.34}
$$

B. *Technical constraints*

$$
P_{\text{PV}\,i}^{t} + P_{\text{dis}\,i}^{t} + P_{\text{buy\_Grid}\,i}^{t} = P_{\text{Load}\,i}^{t} + P_{\text{ch}\,i}^{t} + P_{\text{sell\_Grid}\,i}^{t} \qquad\qquad i\in\Omega \tag{4.35}
$$

(4.35) corresponds to the power balance for prosumer *i* in time interval *t*: where the forecast profiles of PV generation and load are given by parameters $P_{\text{PV}\,i}^{t}$ and $P_{\text{Load}\,i}^{t}$; the charging and discharging power of the battery owned by prosumer i are represented with the non-negative variables $P_{\text{ch}\,i}^{t}$ and $P_{\text{dis}\,i}^{t}$, respectively. For the storage systems the set of constraints (4.7) - (4.11) are considered.

$$
\begin{cases}
P_{\text{buy\_Grid}\,i}^{t} = 0 \quad \text{if } u_i^t = 0 \\
P_{\text{sell\_Grid}\,i}^{t} = 0 \quad \text{if } u_i^t = 1
\end{cases}
\qquad\qquad u_i^t \in \{1,0\} \tag{4.36}
$$

Finally, the binary variable u_i^t in (4.36) is introduced to prevent simultaneous purchases and sales by the prosumer *i*.

4.2.2 *Model formulation with the integration of biogas*

In order to consider the participation in the community of producers that own biogas-fuelled generators, the model proposed in section 4.2.1 is extended to include the relevant cost and operational constraints associated to such units.

The OF (4.30) is modified by including the piece-wise linearization of cost (4.17); thus, the total objective function minimizes the total energy cost given by

$$
OF = \min \sum_{\substack{t\in T\\ i\in\Omega}} \left[\pi_{\text{buy}}^{t} P_{\text{buy\_Grid}\,i}^{t} - \pi_{\text{sell}}^{t} P_{\text{sell\_Grid}\,i}^{t} + C_{\text{biogas}\,i}^{t} \right] \Delta t - \sum_{t\in T} I_{E_s} E_{Shared}^{t} \tag{4.37}
$$

Then, the scheduling problem is solved considering the set of constraints (4.34)-(4.36) and (4.17)-(4.26).

For the community with dispatchable generation, the power balance constraint (4.35) is replaced with (4.38), in which the power output at time period *t* of the available biogas-power generators are included

$$P_{\mathrm{PV}\,i}^{t} + P_{\mathrm{dis}\,i}^{t} + P_{\mathrm{biogas}\,i}^{t} + P_{\mathrm{buy\_Grid}\,i}^{t} = P_{\mathrm{Load}\,i}^{t} + P_{\mathrm{ch}\,i}^{t} + P_{\mathrm{sell\_Grid}\,i}^{t} \qquad i \in \Omega \tag{4.38}$$

4.2.3 *Case study of a renewable energy community with PV and BES units*

In the case study presented in this section, we have adopted the same load and PV profiles of section 4.1.6 for each prosumers of the REC. Also all the input parameters related to BES units, such as size and rated power, are assumed equal of the ones adopted in section 4.1.6.

To test the proposed formulation, the MILP model of the community has been implemented in the Matlab modelling environment and solved by using the Gurobi solver.

The total *OF* value of (4.30) obtained for the scheduling of the resources in the community is € 16.9 instead of €18.06 of (4.1), meaning that the incentive mechanism adopted in Italy seems more profitable for the community than allowing direct transactions between prosumers. The total shared energy during the day is 90 kWh.

Figure 4.22 shows the power profiles of PV generation, load, net power exchanged with the grid (i.e. the power sold to minus the power bought from the grid) and the power profile of the BES unit of prosumer 3, given as an example of the behaviour of all the other prosumers of the REC.

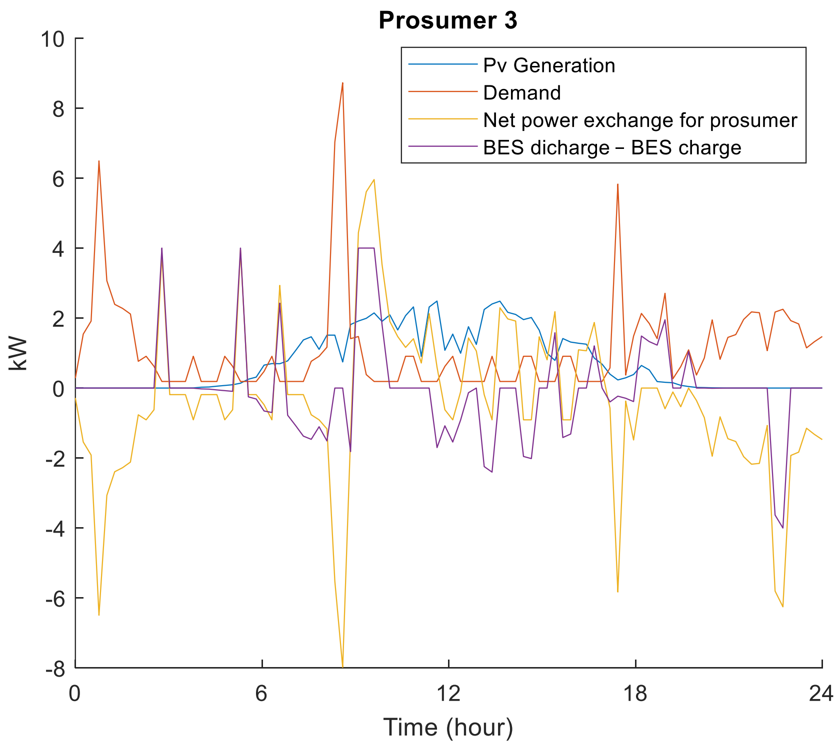


Figure 4.22 Power profiles of prosumer 3

Figure 4.23 illustrates the detail of the SoE profiles of each BES unit of the REC, whilst Figure 4.24 presents the profiles of shared energy, total energy sold to and total energy bought from the grid by the community, showing that the shared energy is below the minimum of the other two quantities at each time, according to its definition.

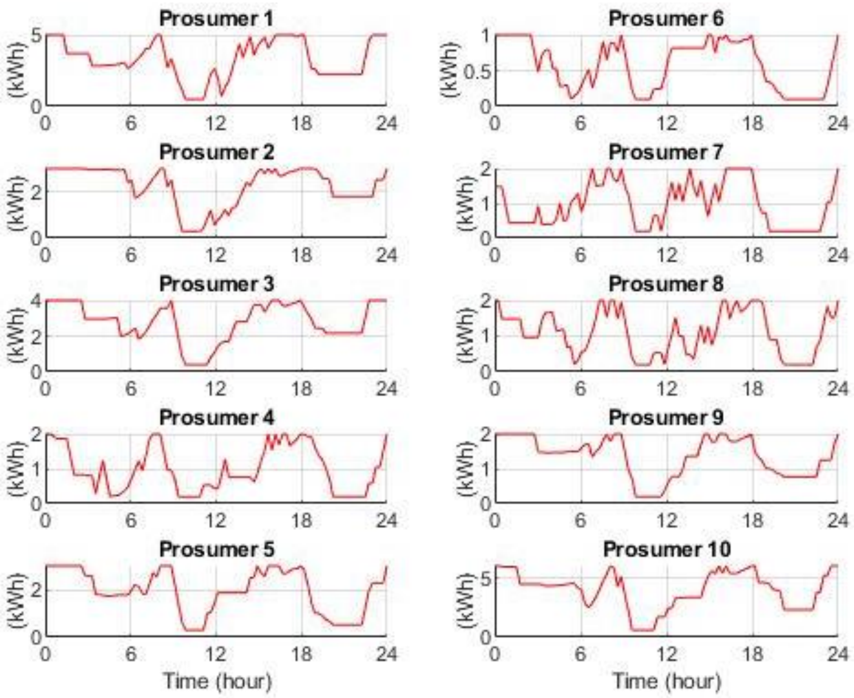


Figure 4.23 Battery SoE for each prosumer of the REC.

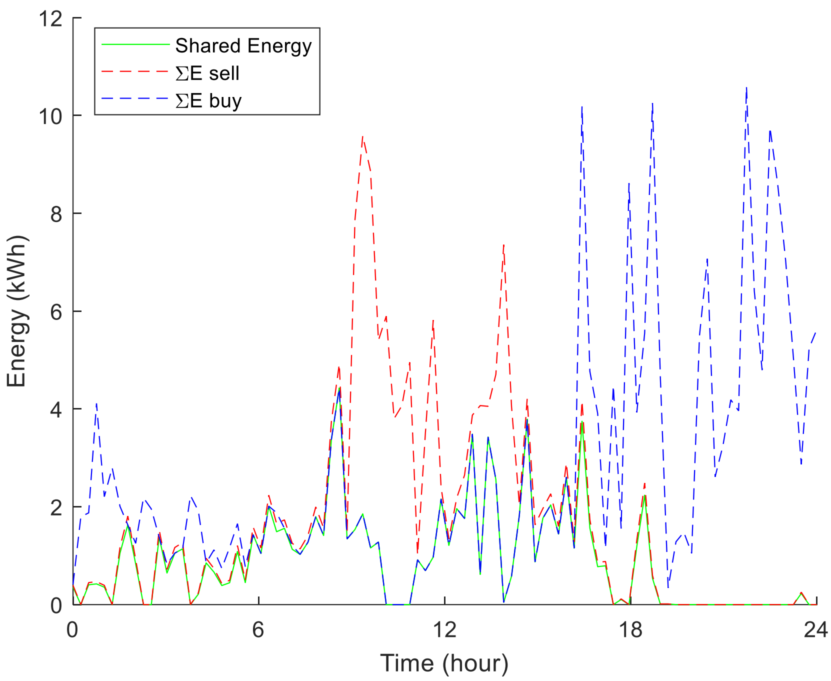


Figure 4.24 Shared energy, total energy sold to and total energy bought from the grid profiles

4.2.4 *Case study of a renewable energy community with PV, BES and biogas units*

In the following, we present the results obtained for the day ahead scheduling of a renewable energy community with PV, BES and biogas units, according to the Italian regulation framework.

Case studies of Table 4.6 refers to the cases previously illustrated in section 4.1.7, other than Case 0 introduced as a base case in which biogas units are not included. For all the considered cases the incentive mechanism approach adopted by the Italian regulation framework seem to be much more profitable for the REC with respect to a cooperative community in which transactions between prosumers are allowed. Nonetheless, it is worth noting that the *OF* value of (4.1) do not reflect the transactions between prosumers because their summation do not change the total daily procurement cost. Instead, the *OF* value of (4.30) includes also the shared energy of the community as direct transactions are not allowed.

Table 4.6 Case studies results for the community with the presence of biogas generation

	Type of REC	Case 0	Case I	Case II	Case III	Case IV	Case V
OF (€)	Cooperative REC	18.06	5.2	11.4	7.0	1.7	3.2
	Incentive-based REC	16.90	-1.7	7.7	4.3	-6.0	-4.3
Total fuel consumption ($10^3 \cdot ft^3$)	Cooperative REC	-	2.0	2.0	1.0	3.4	2.7
	Incentive-based REC	-	2.8	2.8	1.0	4.4	3.7
Solution time (s)	Cooperative REC	29	35	15	48	62	30
	Incentive-based REC	386	801	0.19	366	57	347

Figure 4.25 and Figure 4.27 show the power profiles of PV generation, load, net power exchanged with the grid (i.e. the power sold to minus the power bought from the grid) and the power profile of the BES unit of prosumer 2 in case I and case II respectively, given as an example of the behaviour of all the other prosumers of the REC. Figure 4.26 shows the battery SoE of prosumer 2 in case I and show the typical behaviour of the BES units in the considered case study.

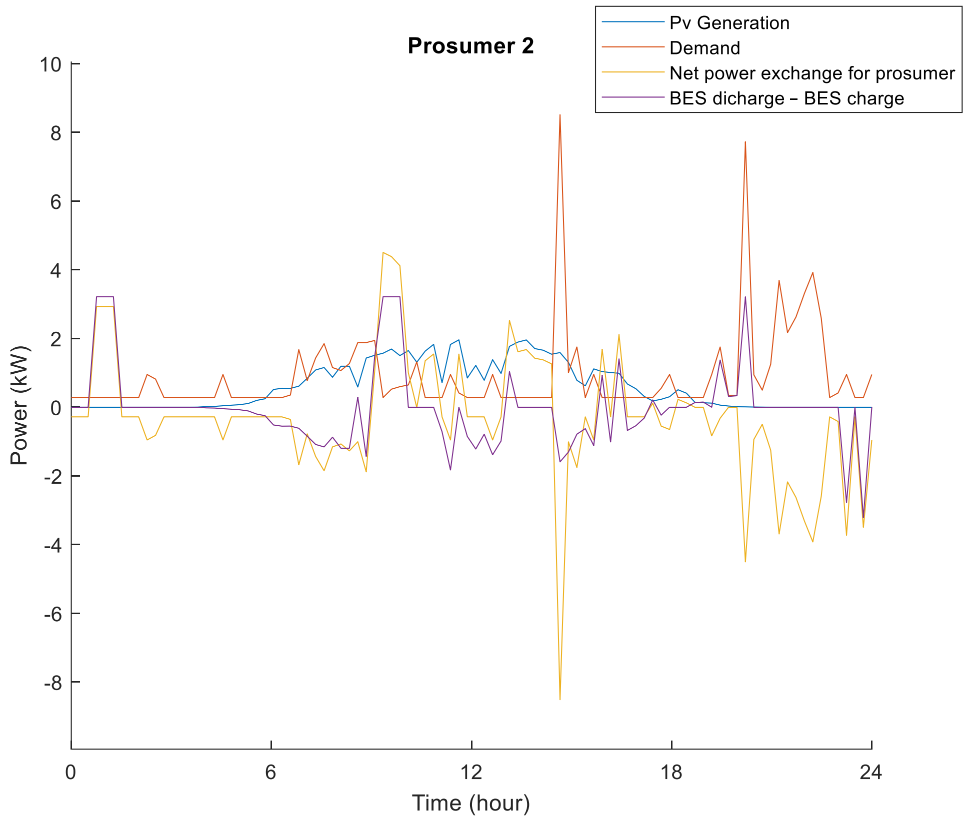


Figure 4.25 Power profiles of prosumer 2 in case I

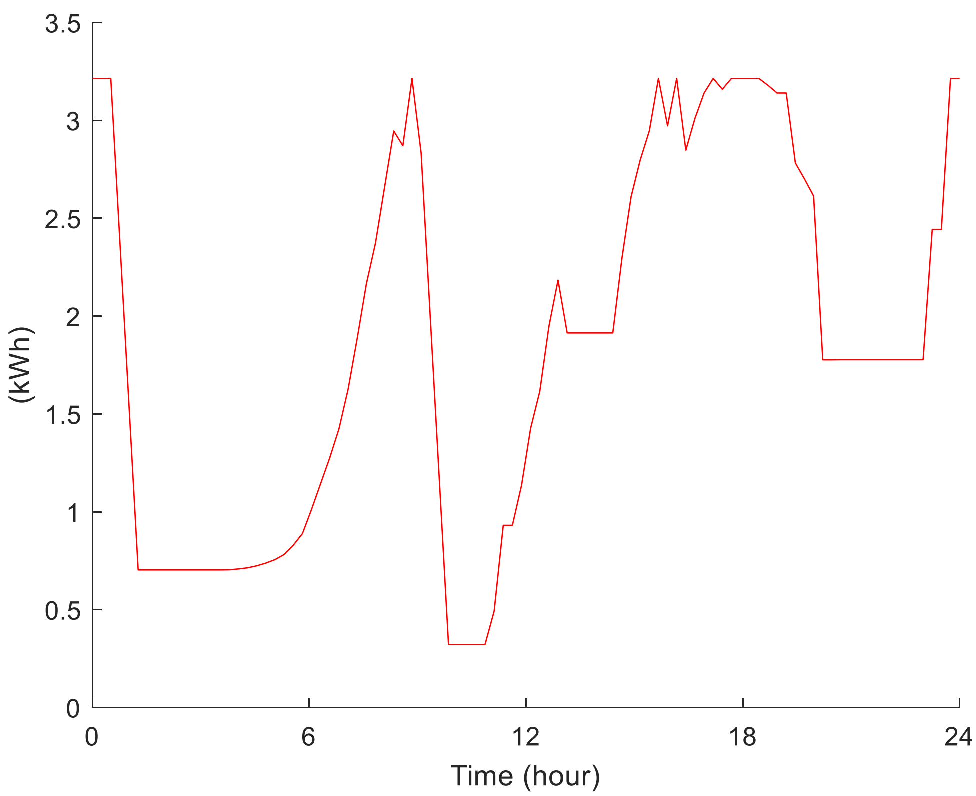


Figure 4.26 Battery SoE for prosumer 2 in case I

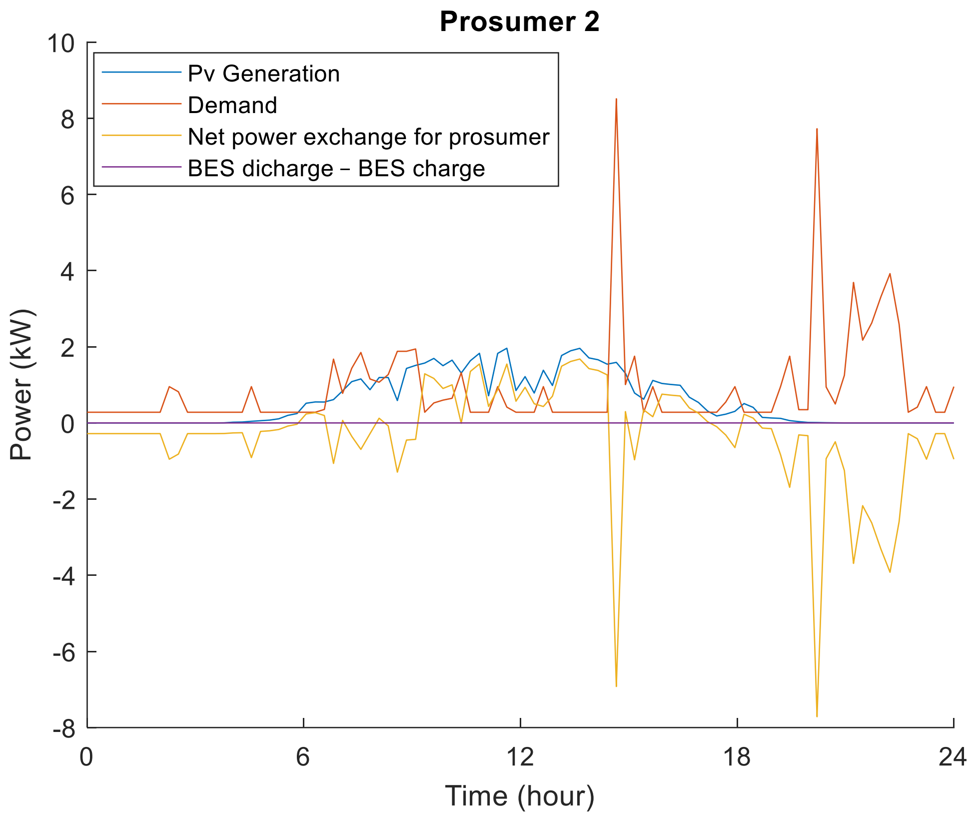


Figure 4.27 Power profiles of prosumer 2 in case II

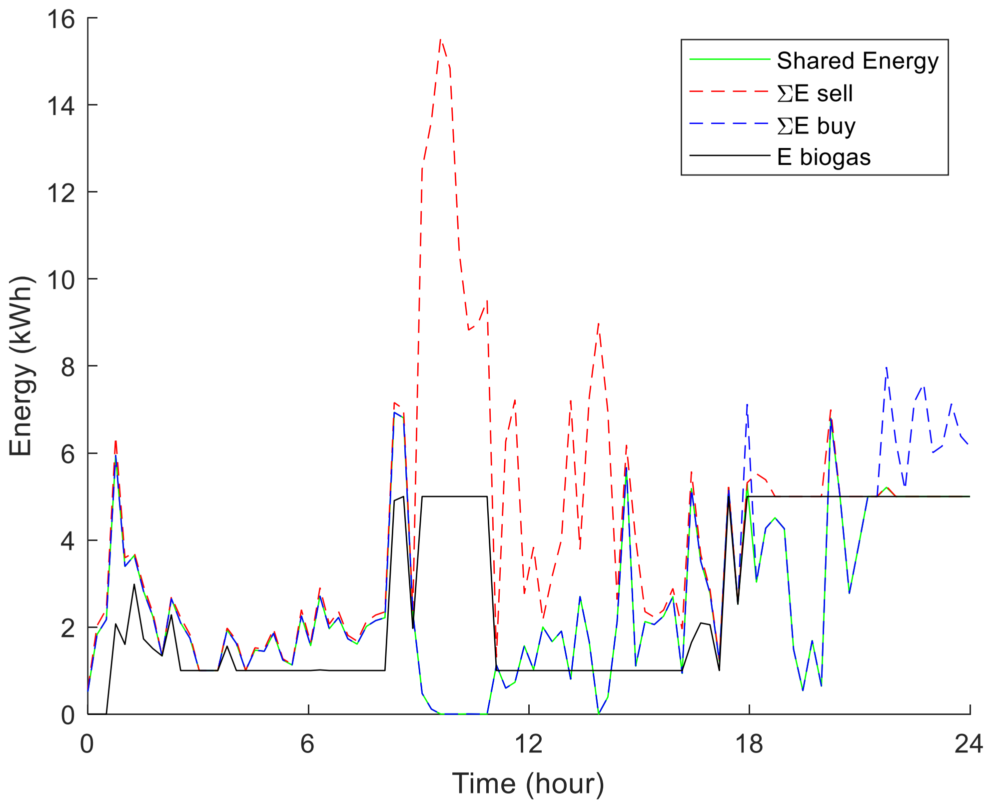


Figure 4.28 Shared energy, total energy sold to and total energy bought from the grid, and biogas profiles in case I

Figure 4.28 presents the profiles of shared energy, total energy sold to and total energy bought from the grid by the community, and the biogas production in case I. When the energy of the biogas (black line profile) in Figure 4.28 has higher values with respect to the shared energy, it means that biogas energy is sold to the external utility grid and this happened in particular two times during the day, which correspond to the times where the prices exchanged with the external grid have the highest value, as shown in Figure 4.29. In these time intervals of the day the biogas marginal cost is lower than the price of the energy sold to the grid, meaning that the biogas producer can sell energy to the grid and earn money other than covering the biogas production cost.

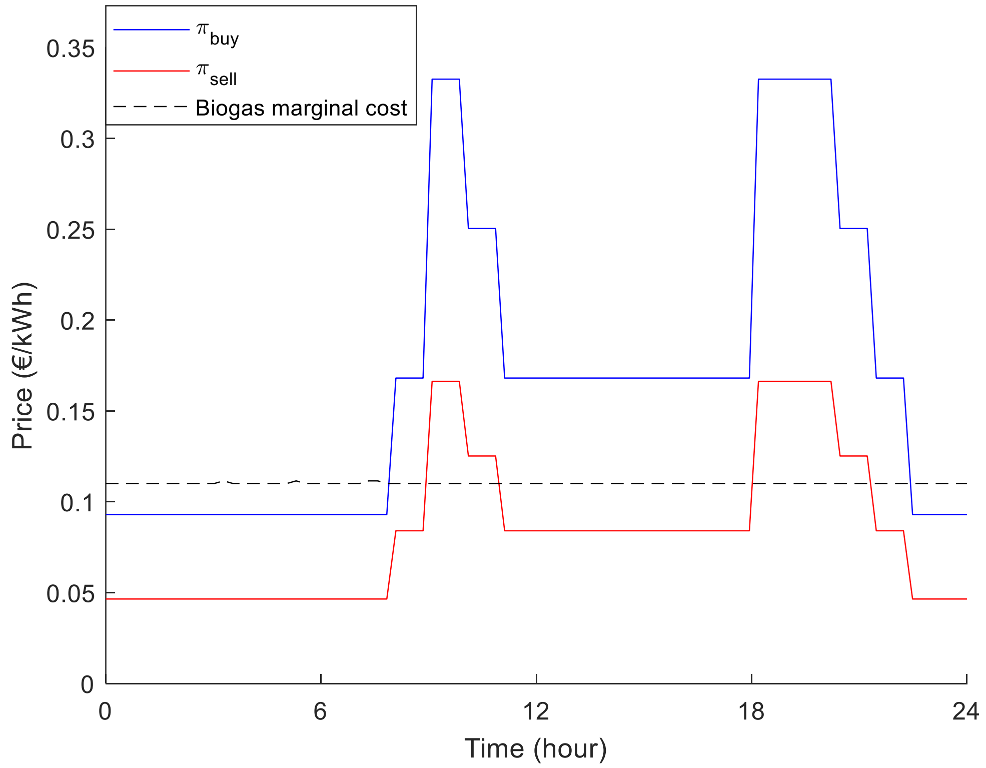


Figure 4.29 Prices of the energy exchanged with the grid and biogas marginal cost

Figure 4.30 shows the cost comparison of the biogas shared energy and explain the values of the objective functions obtained in Table 4.6. Considering a cooperative REC, if the biogas producer sells energy to another prosumer of the REC, the total community cost is increased according to the biogas cost and the cost/revenues due to the transactions between members of the REC do not change the procurement cost of the community according to *OF* (4.27). Instead, considering an incentive-based REC, when the biogas producer sells energy to another prosumer of the REC, this energy is sold to the grid and bought from the grid, respectively according to the prices of the energy provider. Also, the total community cost is increased according to the biogas cost, and the REC receive incentives for such amount of energy according to (4.37).

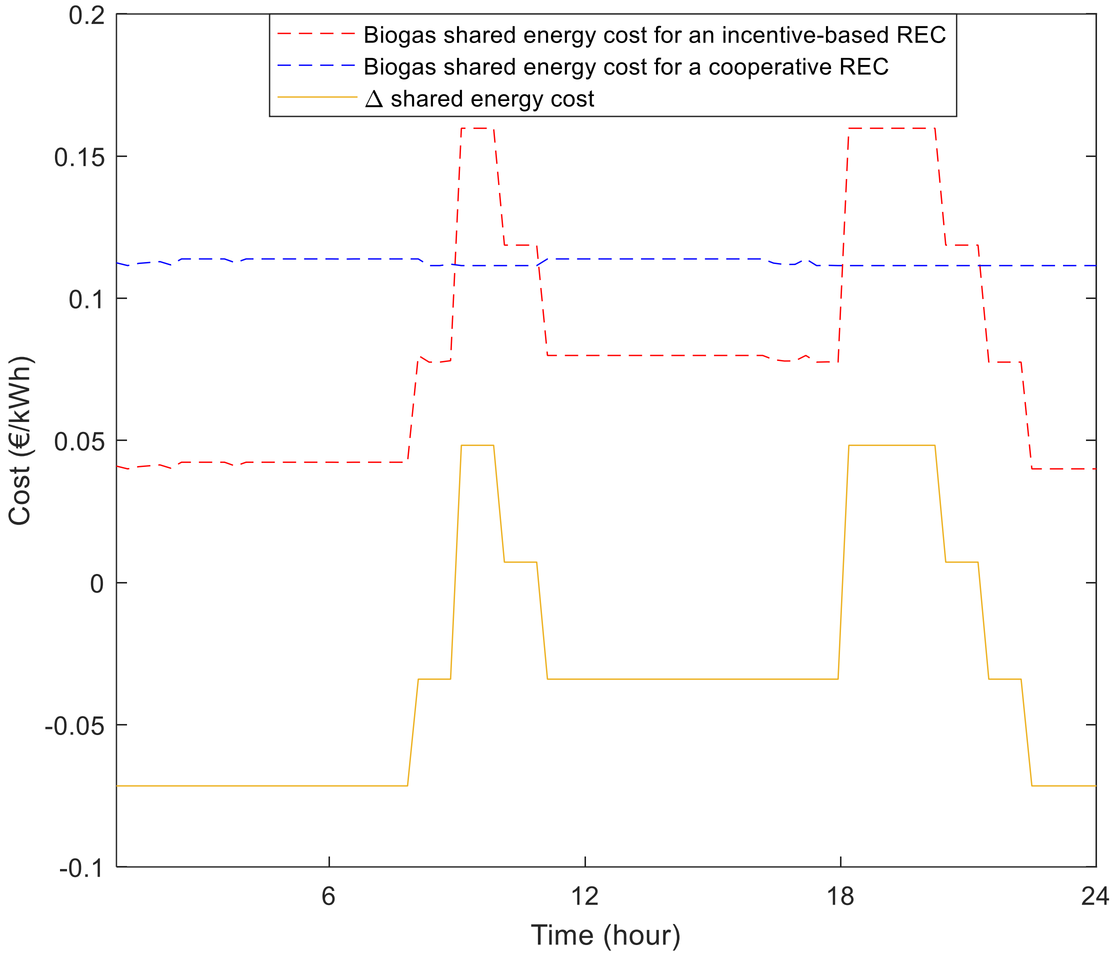


Figure 4.30 Biogas shared energy cost comparison

Figure 4.31, Figure 4.32 and Figure 4.33 show the profiles of shared energy, total energy sold to and total energy bought from the grid by the community, and the biogas production in case II, case III and case IV, respectively.

As shown in Figure 4.32, when the fuel availability is restricted, the biogas production is limited in a short time interval of the day, which is one of the most convenient time interval of the day for the biogas producer, according to Figure 4.29.

Figure 4.33 show that the at the end of the day both biogas generators are on, because prosumers of the LEC need to fully charge their batteries to accomplish the technical constraint set in the proposed formulation, thus the energy demand of the community is high.

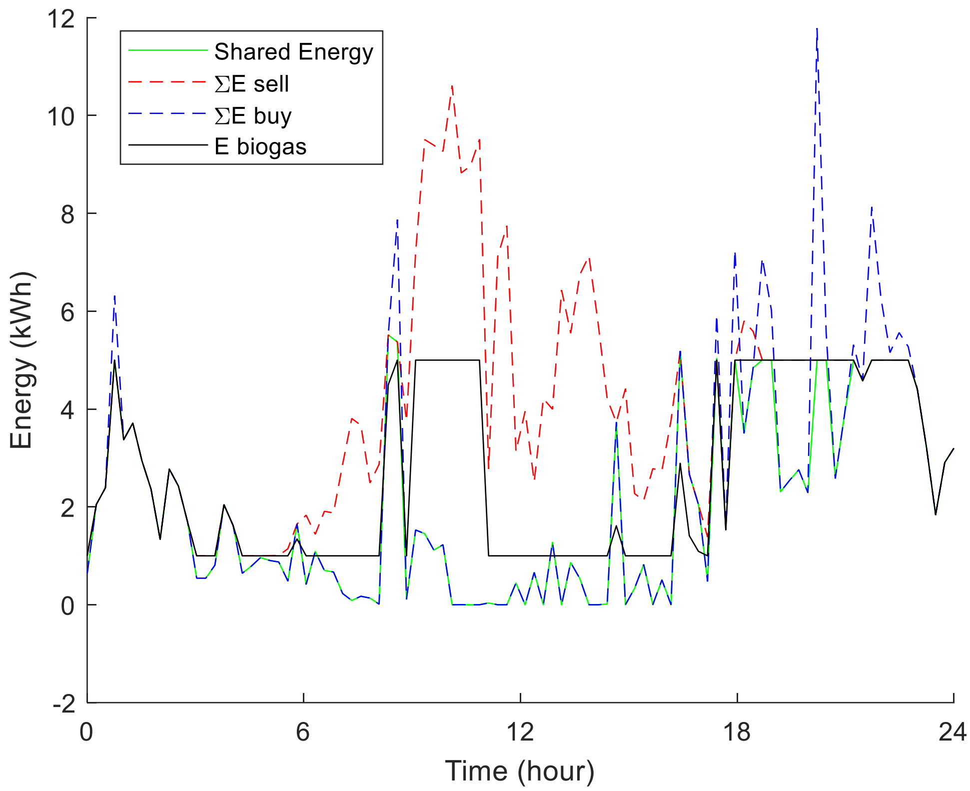


Figure 4.31 Shared energy, total energy sold to and total energy bought from the grid, and biogas profiles in case II

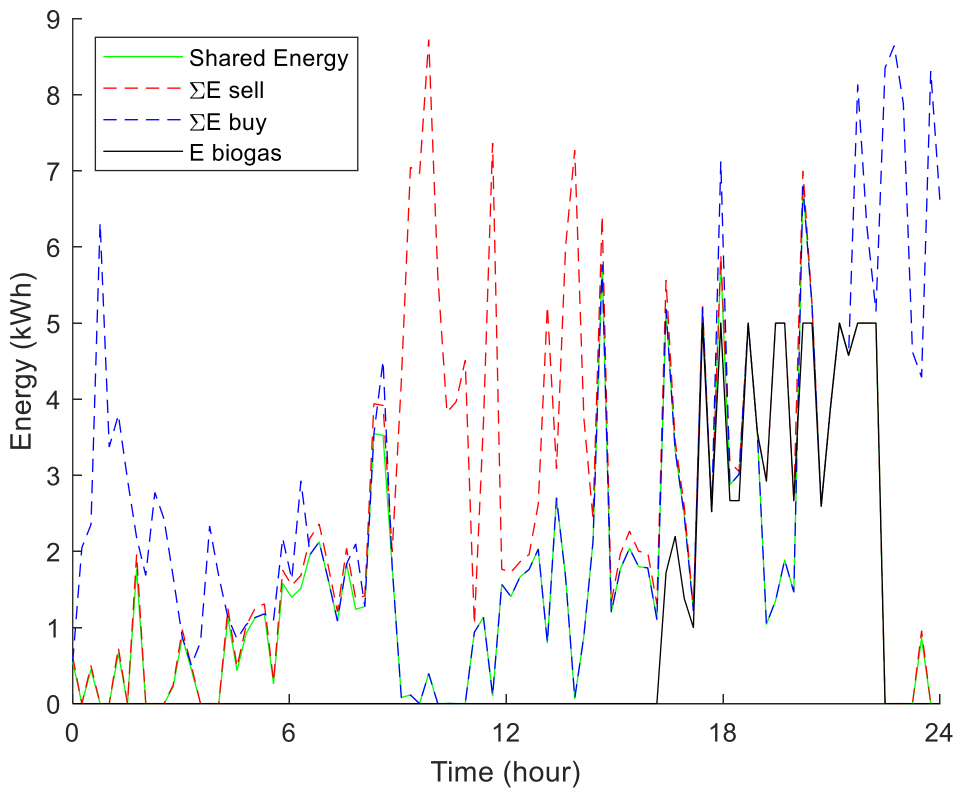


Figure 4.32 Shared energy, total energy sold to and total energy bought from the grid, and biogas profiles in case III

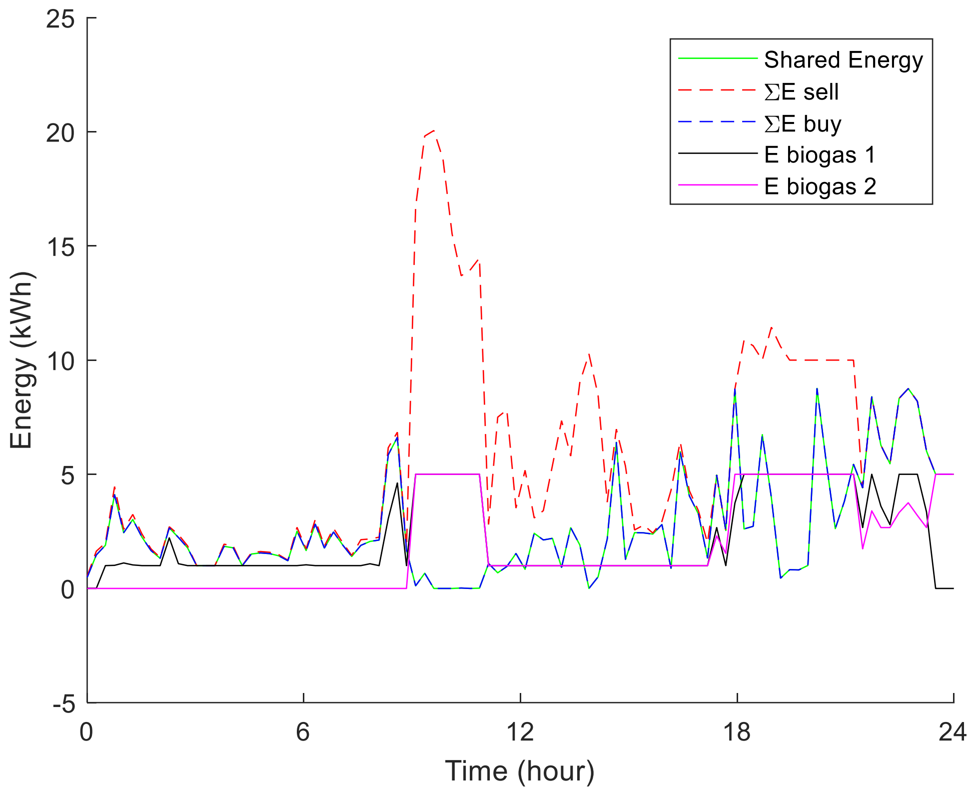


Figure 4.33 Shared energy, total energy sold to and total energy bought from the grid, and biogas profiles in case IV

Finally, Figure 4.34 shows the energy profiles of case V, and Figure 4.35 shows the prices of the energy exchanged with the grid and biogas marginal costs in case V. In this case the second biogas generator has higher fuel cost with respect to the other one, thus it results to be convenient at the end of the day only, when its marginal price is lower than the price received for selling energy to the grid and also in the consequent few hours where the energy demand of the REC is high due to the BES state of charge constraint.

It is interesting to notice that when two biogas generators are available in the community, i.e. case IV and case V, the procurement cost of the REC regards mainly the biogas production because the total energy sold to the grid by the community (red dashed lines of Figure 4.33 and Figure 4.34) is always equal or higher than the total energy bought from the grid by the community (blue dashed lines of Figure 4.33 and Figure 4.34), and thus all the energy bought by the community during the day is shared energy, for which the community receives incentives. As consequence, the community in these cases fully covers its energy needs; such consideration is not valid for the cooperative REC because without incentives the biogas production is not convenient in the first part of the day, as shown in the first part of the chapter.

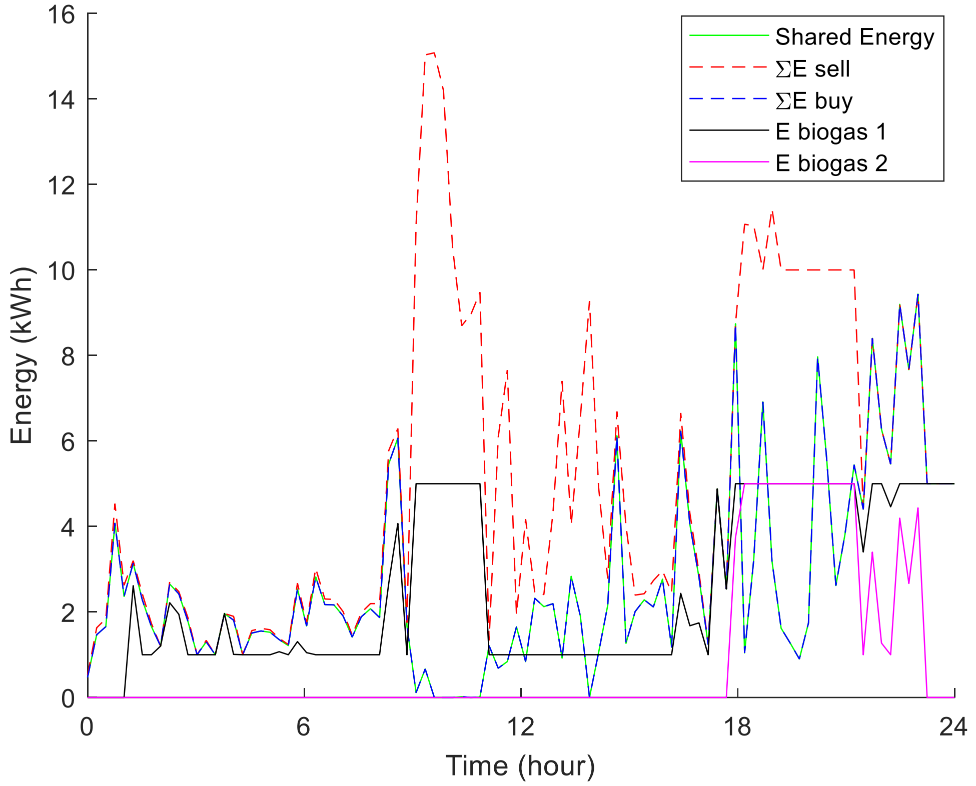


Figure 4.34 Shared energy, total energy sold to and total energy bought from the grid, and biogas profiles in case V

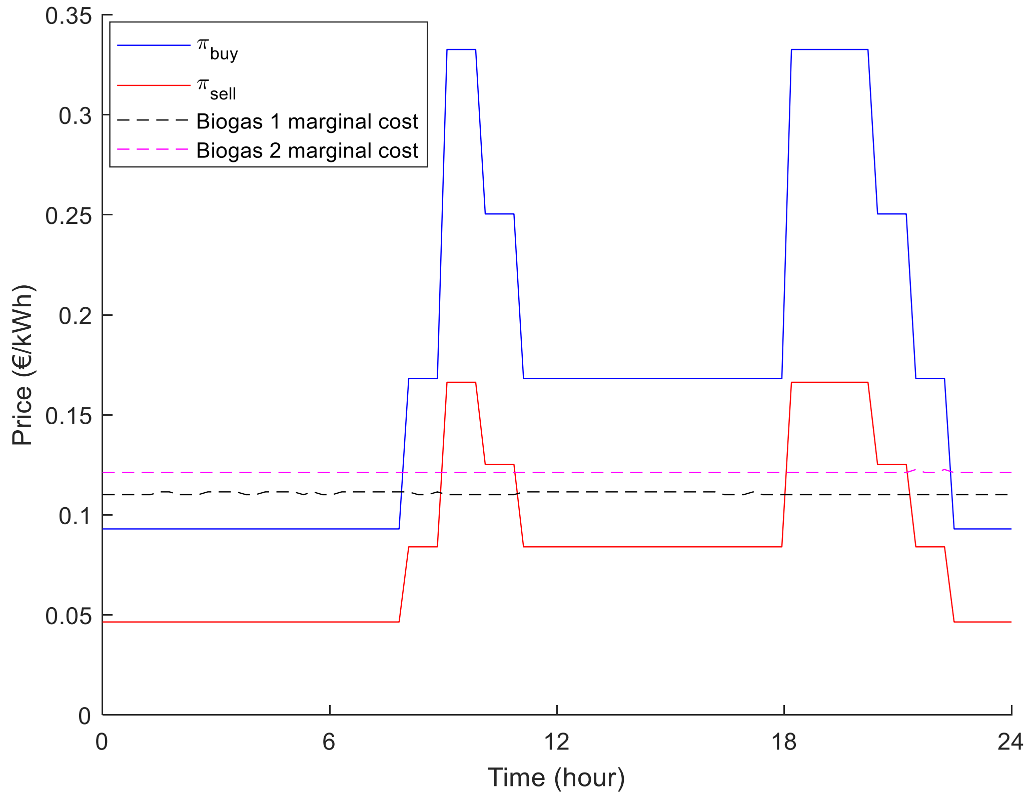


Figure 4.35 Prices of the energy exchanged with the grid and biogas marginal costs in case V

4.3 Conclusions of the chapter

This chapter has been focused on the study of the day-ahead scheduling of resources in renewable energy communities.

Two types of renewable energy communities have been investigated: the first one, according to the European directive RED II, allows direct energy transactions between members of the REC, and it is characterized by being local and cooperative: all the members are connected to the same distribution network and collaborate, without any competitive behaviour, for the common goal of minimizing the costs related to the exchanges with the utility grid. In this case costs and revenues due to the transactions between members of the REC are not included in the objective of the minimization because they do not change the procurement cost of the community.

The second type of REC considered does not allow direct transactions between members but includes economic incentives for the community shared energy, which at each hour is the minimum between the renewable energy fed into the electrical grid by the REC and the total energy demand required to the grid by the community. Hence, in this case the day ahead scheduling of the community minimizes the daily procurement cost of the REC, also including the revenues for the community shared energy.

The models and the relevant analysis presented in this chapter were aimed to quantify the contributions of all the components that build up the objective functions for both types of REC.

A comparative analysis has been presented as well, within certain assumptions concerning, among others, prices of the energy exchanged with the grid and value of incentive.

Within this framework, the results obtained for these two types of REC show that, in general, the examined cases support the conclusion that the incentive mechanism approach adopted by the Italian regulation framework is more profitable with respect to a cooperative community in which transactions between prosumers are allowed. Nonetheless, the daily procurement cost of a community incentivized according to the Italian regulation framework is much more dependent on the prices of the energy exchanged with the grid (which may change significantly).

Moreover, by introducing producers equipped with biogas power plants in the community, it is shown that a REC can considerably reduce its dependence from the utility grid and therefore its energy procurement cost. Results show that if the biogas production is limited or a higher fuel cost is considered, the power plant is operative only in the most convenient time interval of the day, which is the evening in the system under study. Also, considering a cooperative community the presence of biogas power plants in the REC modifies the prices of the internal energy transactions between members, which can be aligned with the marginal cost of the fuel when there are no exchanges with the external provider. It is worth noting that in this chapter we have considered biogas generators, in which the gas is produced by the anaerobic digestion of waste; however, it is important to realise that the proposed model formulation can be suitable adapted for any type of local dispatchable generator.

Additionally, the difference on the daily energy procurement cost between the two types of REC results to be higher when biogas generators are considered, and this for the following reasons. Considering a cooperative REC, when the biogas producer sells energy to another prosumer of the same REC, the total community energy cost is increased according to the biogas cost. On the other hand, for an incentive-based REC, when the biogas producer sells energy to another prosumer of the REC, this energy is either sold to the grid or bought from the grid according to the prices of the energy provider. Further, the total community cost is increased according to the biogas cost, and the REC receives incentives for such amount of energy.

For the considered cases, sharing biogas energy is almost always more convenient for the incentive-based community.

As already underlined, the above results depend on the prices of the energy exchanged with the grid that have been considered; the developed model allows however for the appropriate cost appraisal even with different prices values.

Finally, while dealing with day-ahead scheduling problems the computation time is significantly reduced compared to the planning models, as simulations can take up to minutes and not to days.

Chapter 5. G.E.CO. project

Introduction

This section is devoted to the Climate-KIC pilot project G.E.CO. (see https://italy.climate-kic.org/projects/geco-green-energy-community/) that aims to develop and experiment a Green Energy Community in the district of Pilastro – Roveri of Bologna, shown in Figure 5.1. According to the European Union (EU) Clean Energy Package (CEP), G.E.CO. intends to tackle all the socio, technical and economic aspects that contribute to the creation of the renewable energy community, contributing to the clean energy packet transposition into the national law framework, increasing the sustainability, reducing the energy poverty and generating a low carbon economy cycle, enabling it through the digitalization, data collection, smart optimization algorithms, blockchain technologies and Internet of Things (IoT). The community will not only provide competitive clean energy but also contribute to fight climate change, develop cooperation among neighbours and provide added value to local economy. Citizens have a key role in this project: they have the possibility to produce energy other than only consume it; thus, as prosumers, they can play an active role in the electricity generation and distribution.

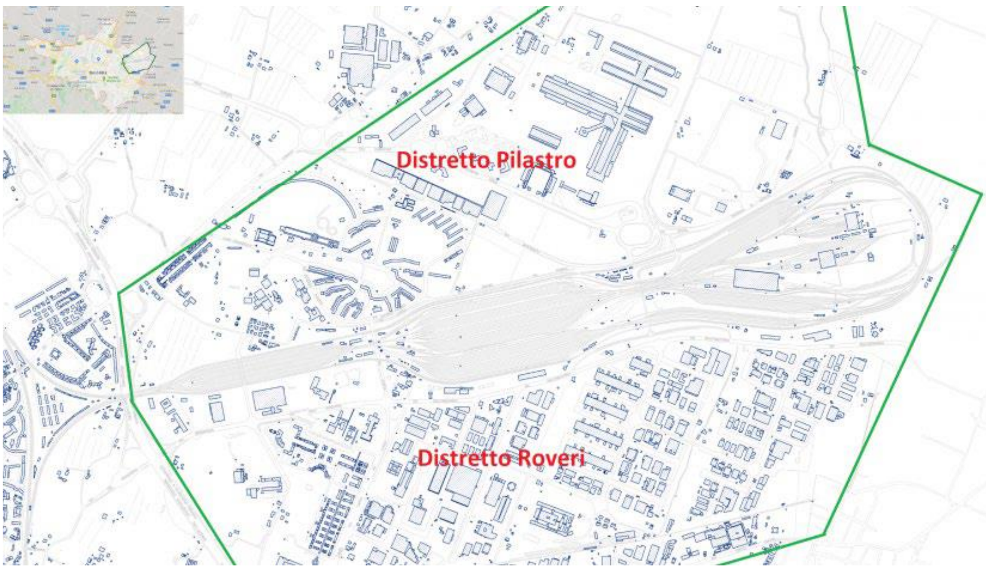


Figure 5.1 District involved in G.E.CO. project (adapted from: http://www.comunirinnovabili.it/geco-green-energy-community/)

G.E.CO. is a project co-funded by EIT Climate-KIC and carried out by: ‘AESS – Agenzia per l’Energia e lo Sviluppo Sostenibile’, which is the project coordinator, ‘ENEA – Agenzia nazionale per le nuove tecnologie’, l’energia e lo sviluppo economico sostenibile’ and ‘UniBo – University of Bologna’. The project involves both private and public entities and the main partners are ‘CAAB – Centro AgroAlimentare di Bologna’ and the ‘Agenzia locale di sviluppo Pilastro/Distretto Nord-Est’. Moreover, G.E.CO. is supported by ‘GSE – Gestore Servizi Energetici’, ‘RSE – Ricerca sul Sistema Energetico’, Emilia-Romagna region, city of Bologna, ‘Confcooperative’, Confindustria Emilia-Romagna, ‘Innovacoop’, ‘Bastelli HTS S.r.l.’ and ‘Nute Partecipazioni s.p.a.’ (see https://www.gecocommunity.it/) .

5.1 Objectivies

In line with the 2030 Agenda, the Paris Agreement and the Clean Energy Package, G.E.CO.’s goal is to encourage and optimize generation and self-consumption of renewable energy to help reduce greenhouse gas emissions by 2022. The project is therefore aimed at helping to achieve the decarbonization targets, increasing the use of renewable energy and developing the local economy, of which the spread of energy communities is one of the tools.

G.E.CO. is being developed by means of a system approach, considering the technical, legal, administrative, financial and social aspects and it is developing the best cost-benefit options and in the most efficient way possible, making the best with the available resources:

- From the technical point of view, the project seeks to experiment the newest and the most advanced smart solutions for the real time state estimation of the distribution network inside the local energy community, that represents the prerequisite for the optimal management of the distributed resources of generation and consumption. The main objective of the optimal management is to maximize the energy self-consumption controlling the storage and the decentralized energy resources, increasing as well the flexibility through real time monitoring and predictive analysis. It is worth noticed that planning and scheduling optimizations models shown in the main chapter of this thesis, i.e. Chapter 3 and Chapter 4, have been carried out in order to achieve the above mentioned objectives, as further discussed in the next section.
- From the social, cultural and behavioural perspective the project is focused on citizen empowerment with a community approach: engaging and informing the citizens and local businesses concerning the climate issue and giving to the community the opportunity to adopt actions to mitigate the climate change. It is expected that the creation of the energy community in the district would enable the reduction of the electricity cost for social housing, improve

local businesses, optimize the power flow in local substations, increase the self-consumption of renewable energy and reduce the demand peaks.

- Legal and administrative aspects will be considered in the set-up of G.E.CO. legal entity, smart contracts and blockchain applications. The project outcomes will provide support to national stakeholders (GSE, Terna, RSE) as pilot project.

5.2 Preliminary analysis and contributions to the project

As already mentioned, G.E.CO. is being developed in the area of Roveri and Pilastro. Both are included in the same city neighbourhood, named San Vitale-San Donato, but they have different features. The first has an industrial prevalence and the second a private housing and commercial offices presence. In particular, the district is divided into:

- a residential area with 7.500 inhabitants (1400 inhabitants in social housing);
- a commercial area of about 200.000 sqm composed by commercial centres (Pilastro, Meraville and FICO);
- and an industrial area of about 1.045.500 sqm (CAAB, Granarolo, Roveri).

To achieve the project goals, the planning optimization models of Chapter 3 have been developed in order to study the best investment, of both renewable generation and storage systems, that minimizes the community energy cost, considering industrial as well as residential areas, being both part of the district of interest.

A key area of the project is the one of CAAB and FICO shown in Figure 5.2. In this area two projects are carried on: the first one is related with the installation of a photovoltaic power plant while the second one concerns the installation of a biogas cogeneration plant. The latter is desirable in a renewable energy community because it provides dispatchable renewable energy and it also involves both electric and thermal energy. Moreover, the biogas plant has the double objective of improving: the renewable energy production in the area as well as the management of organic waste. The studies related to the management of an energy community with a biogas power plant and the evaluation of its benefits are performed in Chapter 4.

Figure 5.2 CAAB and FICO area

5.3 Load and production profiles in Pilastro-Roveri district

According to the recently approved Italian transposition of the renewable energy directive 2018/2001, the production plants and consumer Point of Delivery (POD) of a renewable energy community can be connected to a primary substation, which must be the same one for the member of the given community. Within this legislative framework, there is the possibility to create two major energy communities in the district of Roveri and Pilastro, whose secondary substations can be selected among those highlighted with the relevant pins in the yellow and red areas shown in Figure 5.3. Collecting and elaborating the measures performed by the Distribution System Operator (DSO) in the primary substations which feed the Pilastro-Roveri district, namely “San Donato” and “Quarto Inferiore”, it is possible to estimate the production and consumption power within the district.

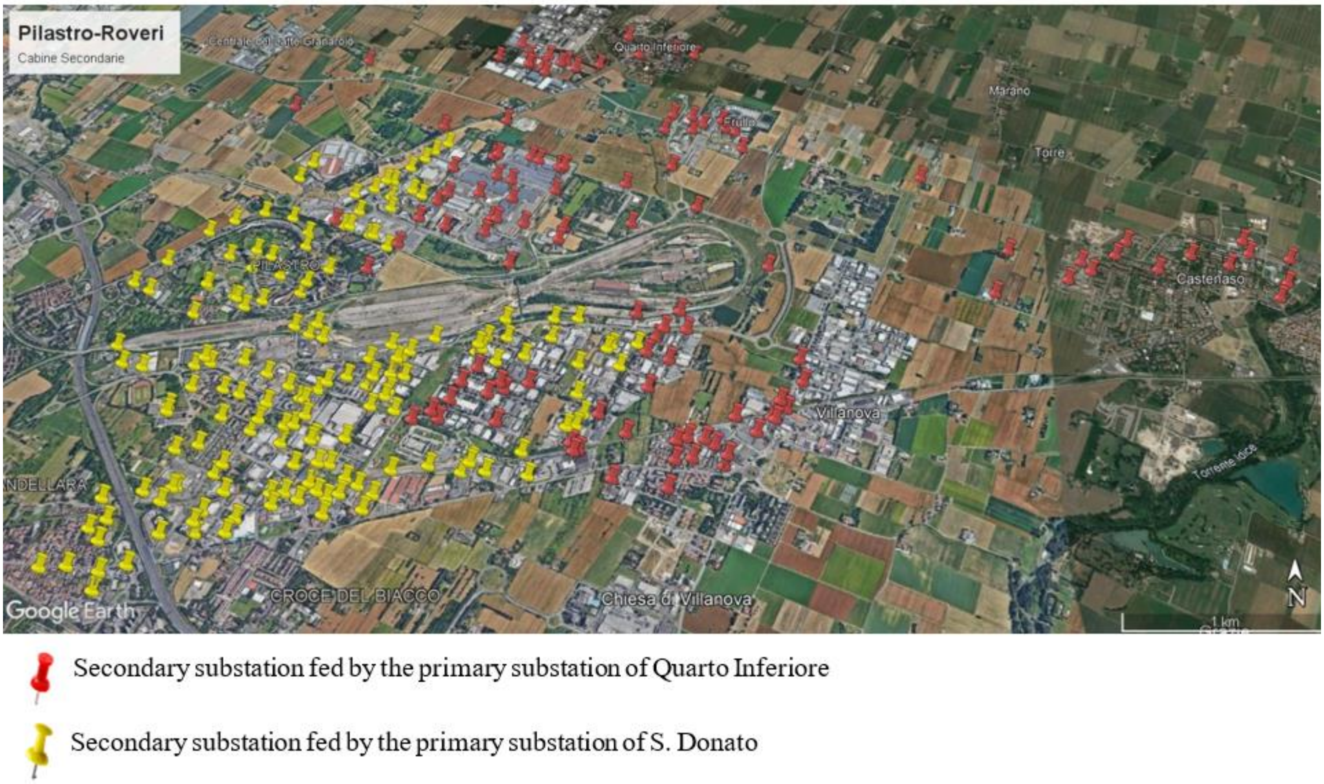


Figure 5.3 Secondary substations of the G.E.CO. district

Moreover, the number of secondary substations fed, their location and energy information about user connected to them has been collected for each feeder belonging to the two primary substations. Data needed for such an elaboration have been obtained thanks to a specific Memorandum of Understanding signed by the DSO of interest, e-distribuzione, and the three partners of the G.E.CO project, AESS, ENEA and UniBo. The location and the energy dimension delimited by each secondary substation are fundamental information to take planning decisions on the creation of renewable energy communities.

5.3.1 *Secondary substations*

Figure 5.4 and Figure 5.5 show the geographical location of each secondary substation in Pilastro-Roveri district; substations have been clustered by feeder, namely substations fed by the same feeder are represented by the same pin color.

As visible in the following figures, the San Donato substation feeds mainly the western part of the district while the Quinto Inferiore one feeds mostly the eastern one.

Figure 5.4 Secondary substations fed by S. Donato primary substation

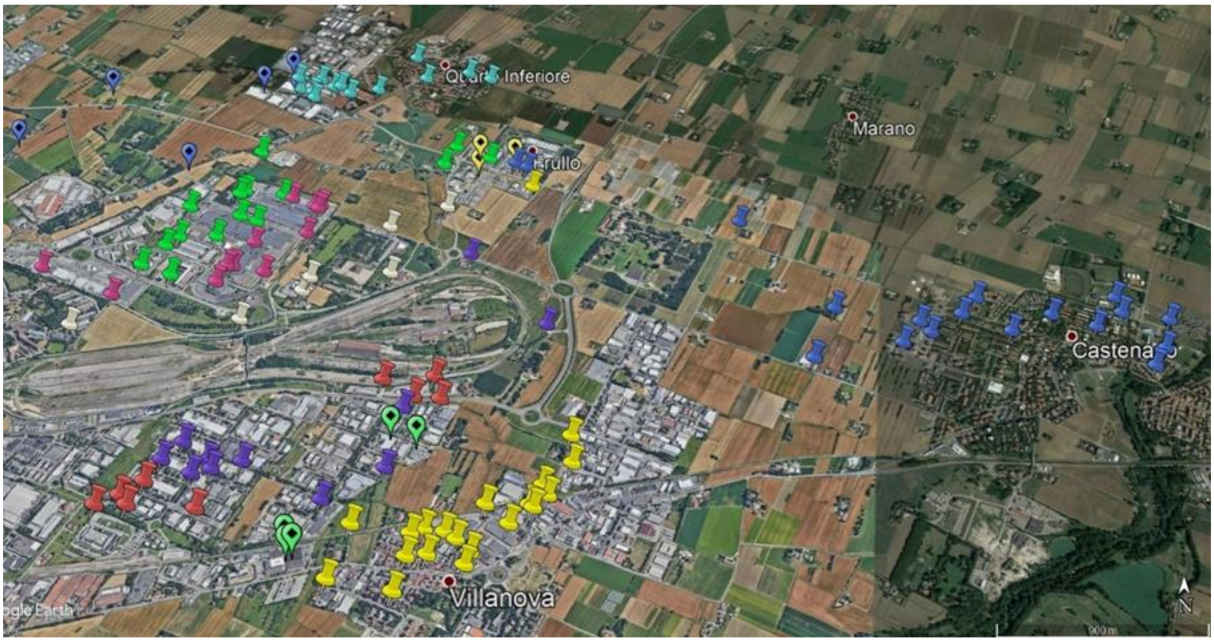


Figure 5.5 Secondary substations fed by Quarto Inferiore primary substation

For each secondary substation the following data have been collected:

- CP_Den: primary substation which fed the secondary substation
- Linea_Den: feeder which fed the secondary substation
- Address

- Nodo_Cod: identifier of the substation
- Latitude and longitude
- n_TR: number of transformer installed in the substation (0 means that the transformer is not of the DSO but of the final costumer)
- Pot_tot: total power of the installed transformer (0 means information non available, see former point)
- Tot_cli: total number of costumers connected to the substation
- CFT_Den: identifier of the technical area jurisdiction
- BT_n_UT_mon: n° of single-phase LV (low voltage) users connected to the substation
- BT_pot_UT_mon: total consumption power of single-phase LV users connected to the substation
- BT_n_UT_tri: n° of three-phase LV users connected to the substation
- BT_pot_UT_tri: total consumption power of three-phase LV users connected to the substation
- BT_n_prod: n° of LV prosumers connected to the substation
- BT_pot_prod: total power that can be injected into the grid by LV prosumers
- MT_N_cli: n° of MV (medium voltage) users connected to the substation
- MT_Pot_prel: total consumption power of MV users connected to the substation
- MT_Pot_imm: total power that can be injected into the grid by MV prosumers
- MT_Pot_imm: nominal power of the MV prosumers generators

As shown in Figure 5.6, an interactive map has been created using google earth pro to easily access the data: by simply clicking on the pin representing the substation a pop up will appear and show all the relevant information.

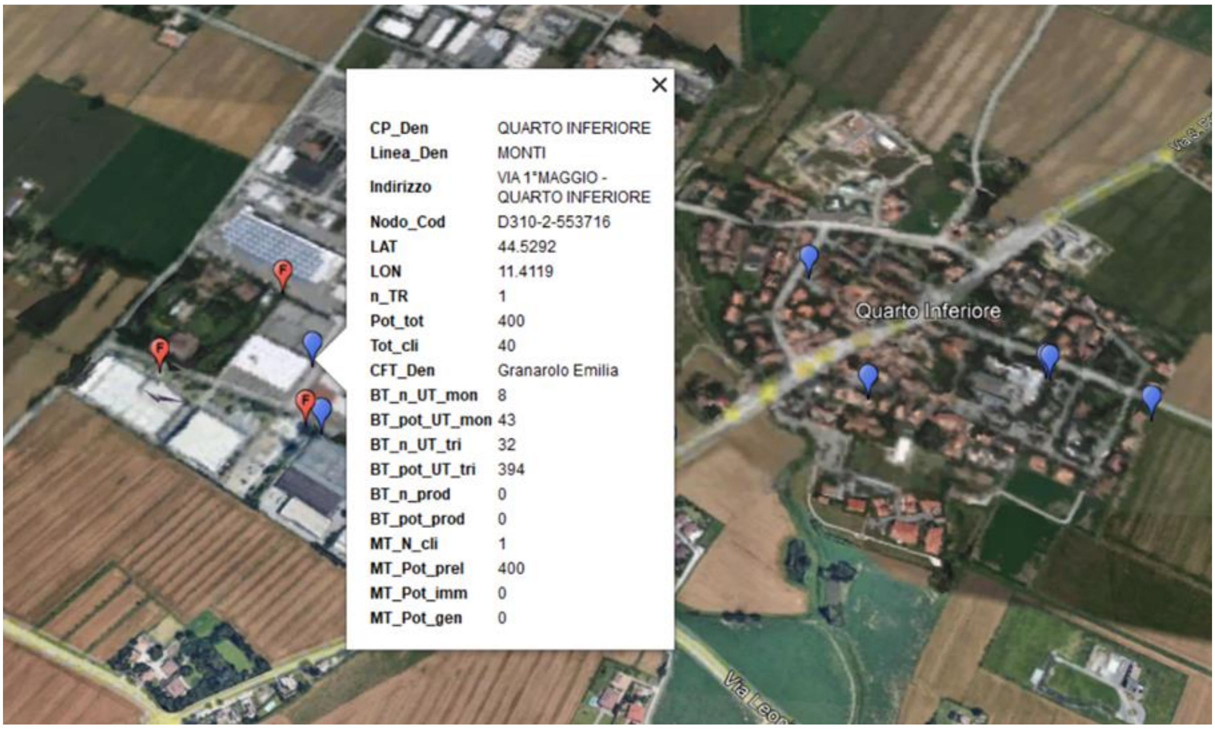


Figure 5.6 Secondary substation data in the interactive map

The data on the number of clients for each connection category (LV single-phase, LV three-phase or MV) and the respective power allow the estimation of the type of costumers connected to the substation: usually a large number of LV single-phase users means that the area is mostly residential with small offices; while a relevant number of three-phase LV users or even MT users usually identify an industrial-craft area or a business with a significant energy requirement.

Table 5.1 reports, per feeder, the data regarding number of clients and their power for each connection type, for both generation and consumption, of the costumers connected to the same feeder. Table 5.2 summarizes the data for each of the two substations.

Table 5.1 Installed power, contractual power and number of users, per feeder, connected to the two primary substation of the district

Primary Substation	Feeder	LV Single-phase power [kW]	n° of LV single-phase users	LV 3-phase power [kW]	n° of LV 3-phase users	LV Generation [kW]	n° of LV prosumer	MV power [kW]	n° of MT users	MV Generation [kW]	Tot. Power [kW]	Tot. Generation [kW]
QUARTO INF.	ALIM1	18	5	2671	55	1256	13	5249	14	4168	7938	5277
QUARTO INF.	ALIM2	193	57	3324	80	867	12	7114	18	4959	10630	5259
QUARTO INF.	CADRAN	522	152	563	30	76	14	186	2	1000	1271	1076
QUARTO INF.	ERRE	111	30	2410	59	489	11	1083	5	399	3604	889
QUARTO INF.	FIESSO	5775	1769	3450	186	759	87	419	2	16	9643	775
QUARTO INF.	FRULLO	473	151	827	29	6	1	1056	3	126	2356	132
QUARTO INF.	INCENE	0	0	0	0	0	0	5609	3	144	5609	142
QUARTO INF.	MONTI	2596	807	1979	141	86	24	3753	6	999	8328	1085
QUARTO INF.	NOVA	1290	400	5191	200	385	24	2248	4	2734	8729	2565
QUARTO INF.	POLIGR	39	8	815	14	90	1	4148	3	109	5002	189
QUARTO INF.	TELECO	208	64	1659	58	122	4	7066	4	2833	8933	504
S.DONATO	CAB1	968	337	3040	63	194	3	4097	12	291	8105	486
S.DONATO	CAB2	176	56	1204	12	0	0	1496	4	0	2875	0
S.DONATO	CARLIN	132	41	2520	50	210	4	5755	7	140	8407	350
S.DONATO	COLAMA	396	117	2127	66	44	4	1640	5	0	4163	44
S.DONATO	DATI	0	0	0	0	0	0	2000	1	0	2000	0
S.DONATO	FOSOLO	645	191	1577	60	96	9	2009	5	177	4230	288
S.DONATO	LARGA	878	260	3600	125	132	13	5765	15	1622	10243	1506
S.DONATO	MACELO	3807	1259	1228	118	0	0	445	1	0	5480	0
S.DONATO	PEEP	2609	809	2923	115	150	25	2701	4	0	8233	150
S.DONATO	PIANET	123	40	1706	58	166	6	3294	6	164	5123	331
S.DONATO	PILAST	4547	1482	3021	181	35	8	4026	5	264	11594	299
S.DONATO	ROVERI	671	186	5451	179	689	41	2637	11	0	8758	689

Table 5.2 Overall installed power, contractual power and number of users connected to the two primary substation of the district

Primary Substation Feeder	LV Single-phase power [kW]	n° of LV single-phase users	LV 3-phase power [kW]	n° of LV 3-phase users	LV Generation [kW]	n° of LV prosumer	MV power [kW]	n° of MT users	MV Generation [kW]	Tot. Power [kW]	Tot. Generation [kW]
Quarto Tot.	11224	3443	22888	852	4136	191	37931	64	17487	72042	17894
S. Donato Tot.	14950	4778	28396	1027	1717	113	35865	76	2660	79211	4142

The total load power is not uniformly distributed among feeders: feeders such as 'Alim 2' and 'Pilast' are one order of magnitude greater than feeder 'Cadran'. Also, the number of costumers is not uniformly distributed: feeders such as 'Pilast' or 'Fiesso' have almost two thousands of LV users while others such as 'Alim 1' or 'Poligr' have only few decades of LV users.

The feeders with the greatest generation are 'Alim 1' and 'Alim2', those feeders supply the CAAB-FICO area in which there are an intensive installation of PV plants: more than 10MW, which is almost the half of the total generation present in the district.

5.3.2 *Feeders power profile*

The power demand profiles of the most representative feeders is reported in the following. It should be highlighted that the real power demand shown in the following figures is different from the contractual power analysed in the previous paragraph: the contractual power is the maximum power available, but usually the real power consumed is lower.

The data collected regard voltages, currents and active power in each feeder with a time resolution of ten minutes from January 2019 to December 2020. In order to compare different feeders the same time windows has be analysed for all the considered feeders for both 2019 and 2020.

The following figures (from Figure 5.7 to Figure 5.10) show the power measured in each feeder during the second week of April for both 2019 and 2020 years. The time windows of the two years are slightly shifted in order to properly plot a week from Monday to Sunday. A time windows equal to the week allows the identification of the feeders that supply mostly industrial-craft customers which in the weekends day absorb less power (see feeder Monti, Figure 5.7).

The second week of April has been chosen to make a comparison between the power profiles during “normal” conditions (2019) and during the lockdown period (2020); the feeders which feed residential area or industry which have not been closed are not subjected to significant variations, such as Fiesso (see Figure 5.8).

Almost all of the power consumption measures are not bidirectional so the sign of power-flows cannot be identified, in most cases the reduced presence of generation implies that the power is absorbed; but analysing the feeders Alim 1 and Alim 2 in which there are 10 MW of PV plants is possible to see the power flow reverse. Regarding Alim 2 (Figure 5.9), in 2019 during the middle hours of the day is it possible to see the power request reduction duo to PV generation (seems a reversed bell curve); while during 2020, in which the power request was lower, is possible to see that the power profile in the morning goes to zero than rise up like a bell curve and then return to zero in the afternoon: the bell curve represent the PV production which is greater than load request so the power flow is from the feeder toward the primary substation. The effect is power flow reverse is more evident in feeder Alim 1 (Figure 5.10).

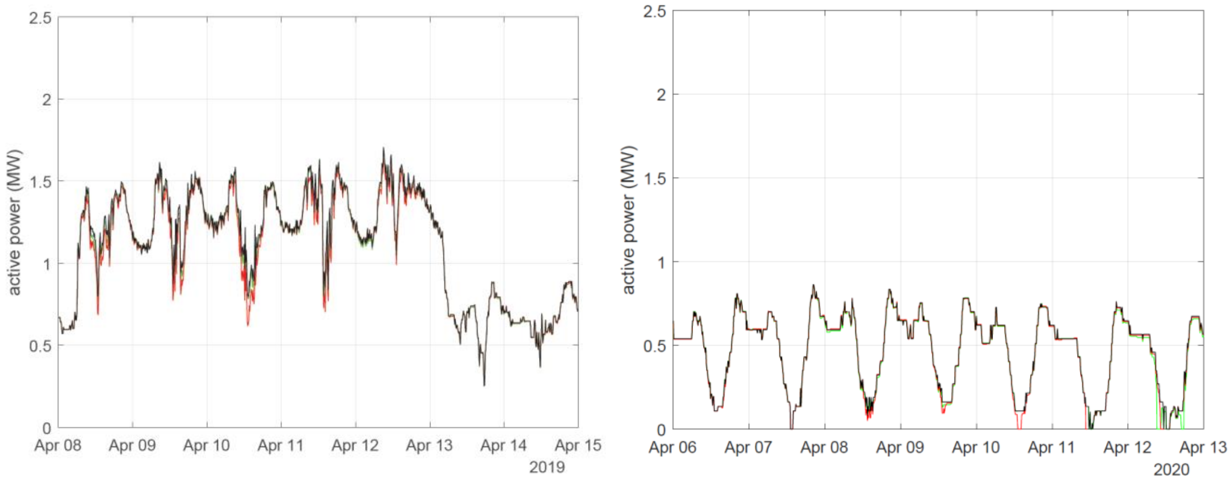


Figure 5.7 Feeder Monti power

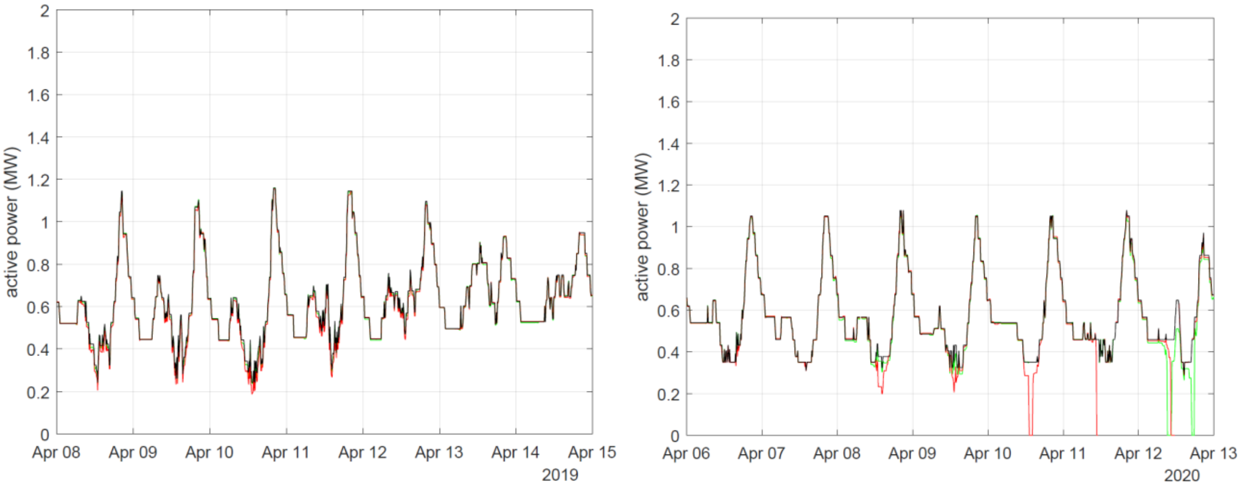


Figure 5.8 Feeder Fiesso power

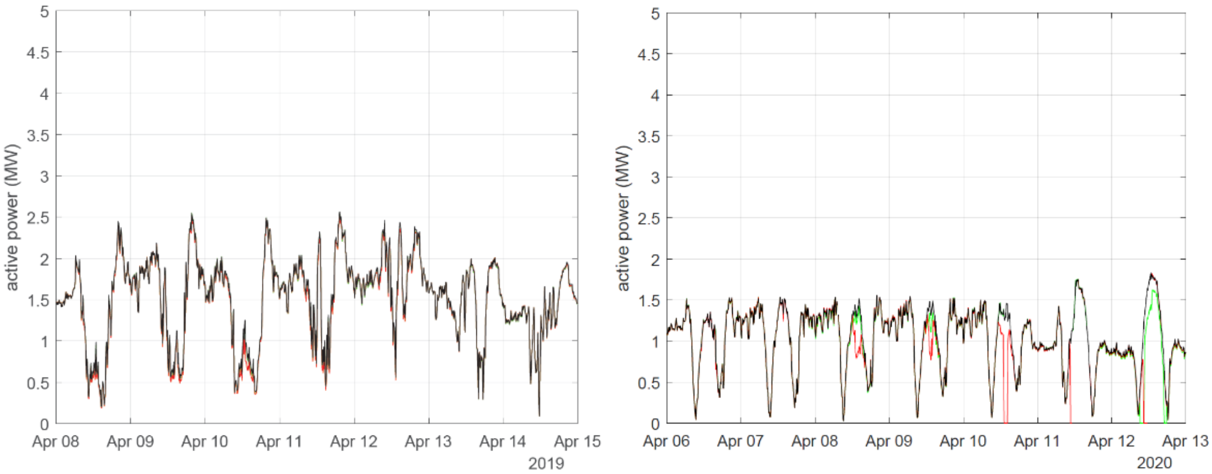


Figure 5.9 Feeder Alim 2 power

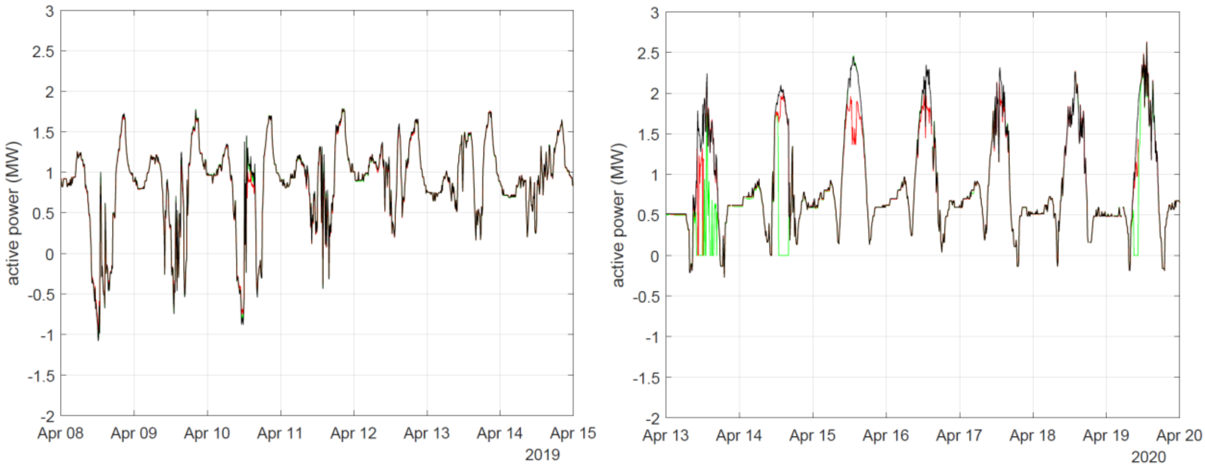


Figure 5.10 Feeder Alim 1 power

5.4 Load and profiles of CAAB

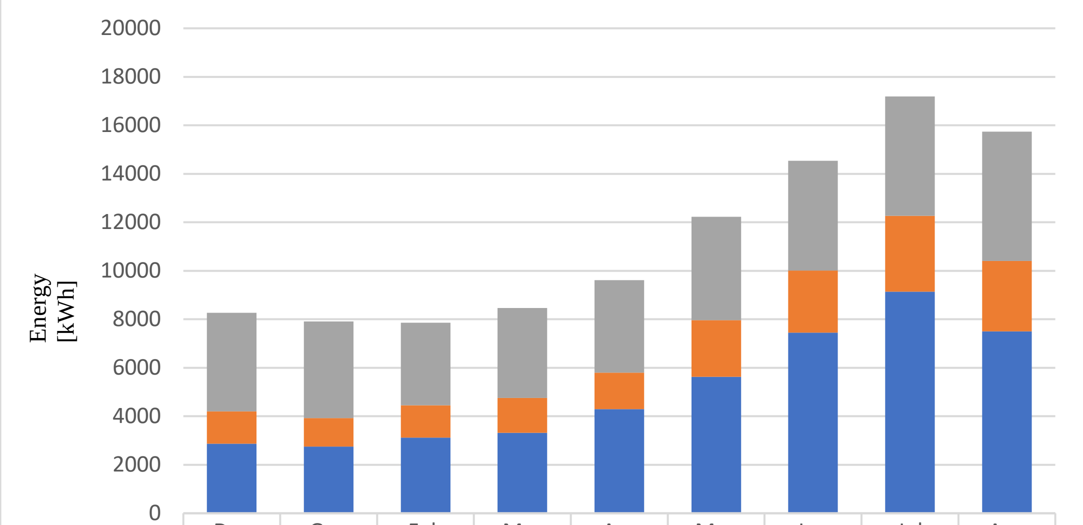
As already mentioned, CAAB is one of the most promising area for the creation of a renewable energy community in the GECO district; in that respect load and PV profiles of users/prosumers of CAAB area are presented in the following.

CAAB is a big and modern structure created to promote the wholesale trade food and food-related product, and its similarly specialized in the connected logistic services, it is located next to the 'FICO – Eataly world' park in the Roveri-Pilastro district. Within the CAAB's building there are many wholesale traders with offices and cold storages, each trader has its own POD (in some cases more than one), since they do not have any generation plant they can be classified as traditional consumers.

Since the area is occupied by costumers that have the same type of loads, a sample of wholesale traders has been used to estimate the energy behaviour of the area.

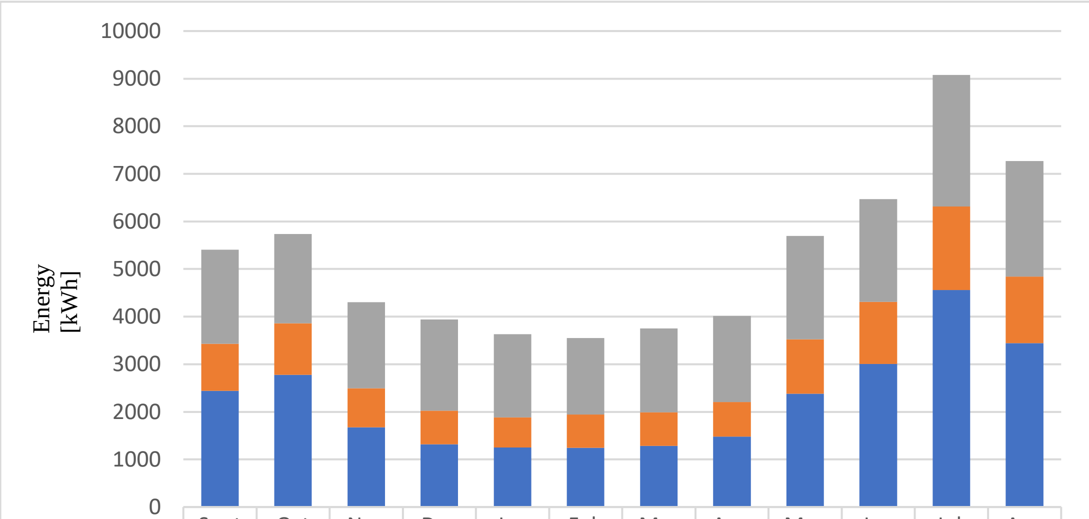
Figure 5.11-Figure 5.14 show the historical monthly energy consumption of some wholesale traders of CAAB, the costumers with cold-storage have a consumption trend which follows the external temperature trend: the peak of energy consumption is in summer while in winter the consumption in almost halved.

Figure 5.13 shows the consumption trend for Agribologna office; there are two peaks in the energy demand due to electric heating and cooling, corresponding to winter and summer, respectively.



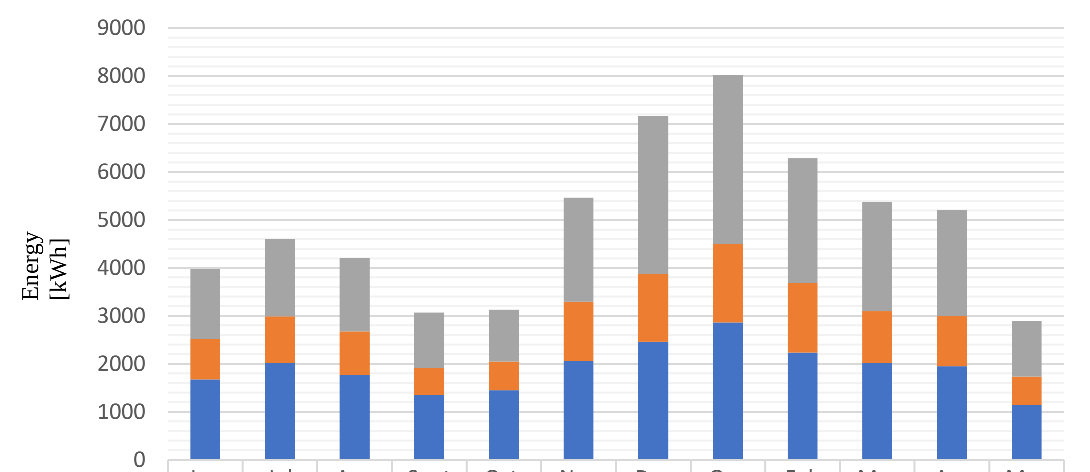
	Dec	Gen	Feb	Mar	Apr	May	Jun	Jul	Aug
F3	4062	3982	3411	3715	3816	4264	4524	4928	5334
F2	1331	1180	1322	1440	1496	2327	2559	3124	2903
F1	2872	2745	3125	3315	4297	5632	7452	9138	7507

Figure 5.11: Loffredo Stella energy consumption



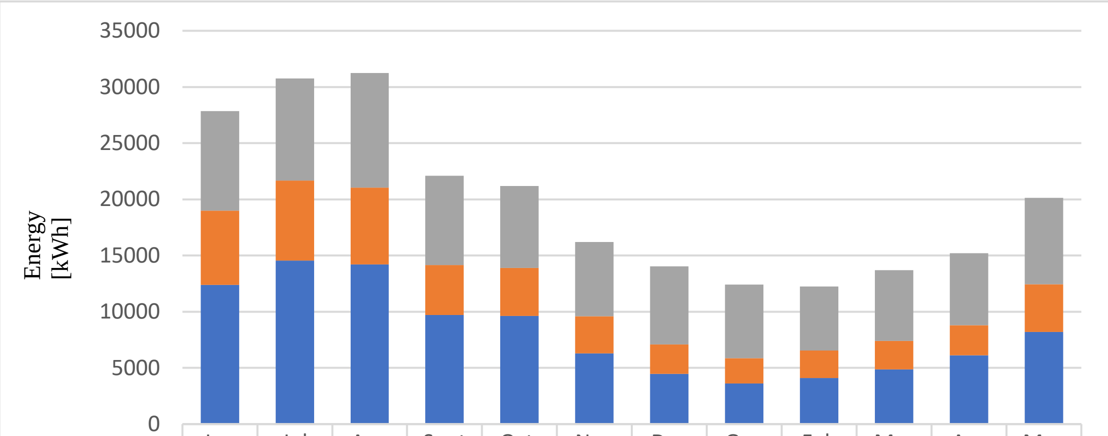
	Sept	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug
F3	1978	1875	1805	1916	1744	1609	1760	1814	2168	2163	2758	2425
F2	989	1083	823	702	634	701	707	724	1148	1300	1759	1404
F1	2441	2775	1673	1320	1252	1244	1287	1480	2379	3008	4558	3441

Figure 5.12: Frigogel energy consumption



	Jun	Jul	Aug	Sept	Oct	Nov	Dec	Gen	Feb	Mar	Apr	May
F3	1456	1614	1536	1154	1082	2172	3283	3532	2601	2282	2207	1149
F2	849	967	911	570	604	1236	1419	1635	1446	1082	1047	599
F1	1672	2024	1766	1348	1446	2058	2461	2861	2237	2014	1950	1139

Figure 5.13: Agribologna (office) energy consumption



	Jun	Jul	Aug	Sept	Oct	Nov	Dec	Gen	Feb	Mar	Apr	May
F3	8835	9086	10190	7930	7274	6626	6930	6549	5679	6283	6400	7705
F2	6613	7126	6826	4467	4270	3283	2640	2238	2469	2531	2679	4244
F1	12394	14548	14218	9697	9638	6301	4462	3622	4091	4881	6115	8192

Figure 5.14: Agribologna (storage) energy consumption

5.4.1 *Smart meters and experimental data*

In the CAAB area there is a strong presence of photovoltaic plant, most of them has a power larger than 200 kW (limit for renewable plants joining a REC – renewable energy community valid up to 8th November 2021) or connected at the Medium Voltage (MV) level (not allowed before 8th November 2021). Two plants, property of CAAB, are connected at Low Voltage (LV) level and have a power lower than 200kW (Muda of 94 kWp and Moden of 47.5 kWp). These plants are installed on the same roof of the other CAAB plants, monitoring their production with smart meters allows the estimation of all the other plants production.

To obtain detailed information on costumers' consumption and production smart meters have been used. The devices allow to collect real-time data from the appliances with a time resolution ranging from few seconds to few minutes according to the device type; data collected by smart meters are used for the creation of a database with historical information that can be used to perform planning decisions and load forecasting, moreover real-time data can be used by intra-day algorithm.

The installed metering devices belong to two different categories: the first one is called Users Devices (DU) while the second one is Non-Intrusive Load Monitoring (NILM). The following paragraphs report the details on the installation and data acquisition process for both the categories.

5.4.2 ***DU meters***

Users' Devices are second Generation (2G) meters equipped with Power Line Communication - Chain 2 (PLC-C), which allows the DU to communicate with the DSO fiscal meter. PLC-C provides a communication channel dedicated to users, and allows the comunication between the smart meter and the user's smart home devices, as shown in Figure 5.15. The 2G smart meters can measure the following quantities:

- Information about energy supplier;
- Istantaneous power peak;
- Mean value of the power in the last 15 minutes.

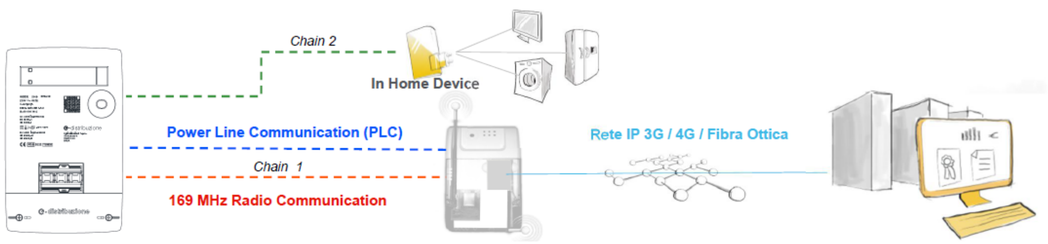


Figure 5.15: Metering data transmission chain (adapted from (E-distribuzione 2019))

The acquisition of the measures from DSO's meter by the DU device take place through the PLC-C channel: it consists in a signal injected in the electric plant at a frequency different from the 50Hz power frequency to establish a communication between fiscal meter and end user devices. To interface the smart meters with the fiscal meters a preliminary action by the manufacturer is necessary: once identified the costumers and their PODs the manufacturer upload on each smart meter a specific identifier which univocally bind the smart meter and the POD. Once the meters have been coded by the manufacturer, they should be connected in an electric socket to receive data from the DSO's meters; this process may face some problem especially if the socket is far from the fiscal meter or if in the electric plant there is strong noise (considering that the CAAB is a large industrial area this consideration is not negligible). The data collected by the user's device are upload in a database through a gateway provided by the manufacture together with the user's devices. The DU smart meters acquire data with a time resolution of 10 minutes.

The users' devices allowed to communicate with the smart meter through PLC-C must be compliant with CEI 13-82, CEI 13-83 and CEI 13-84 and certificated by accredited laboratory. From the list of accredited companies which produce devices compliant to former constrains, available on the E-Distribuzione website, the device produced by 'Tera s.r.l.' has been chosen.

As shown in Figure 5.16, the kit provided by Tera is composed of two devices: the 'Beeta Power' which perform the smart metering and the 'Beeta Box' which behaves as gateway.

The Beeta Power (on the left of Figure 5.16) is a plug and play device which has to be connected to a socket and it establish the communication with the fiscal meter. It acquires the measures of both consumption and production data performed by the DSO's meter and forward them to the Beeta Box. The resolution time of the measures is 10 minutes, as already mentioned.

The Beeta Box (on the right of Figure 5.16) acts as gateway of consumption measurements: it receives the measures from the Beeta Power and forward them via Wi-fi or Ethernet connection to upload and store all the measures of 10 minutes resolution in a database, as previously mentioned. Historical data can be also visualized through a dedicated app.

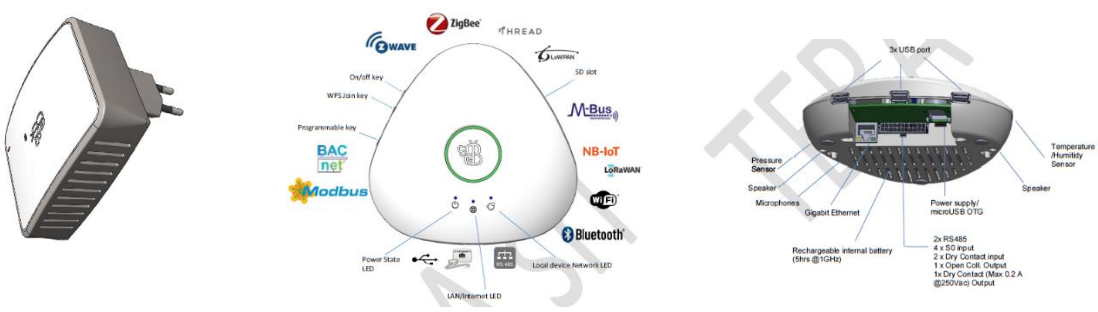


Figure 5.16 Beeta Power (adapted from (Tera 2020a) and Beeta Box (adapted from (Tera 2020b))

These devices have a very simple installation procedure, but the main disadvantage is related to the resolution range of the available information, which is limited to 10-15 minutes.

In the CAAB area two of these smart meters have been installed.

Figure 5.17 shows the power consumption of the Agribologna office, inside the CAAB area. The office is not equipped with photovoltaic power plant and the measures reported in Figure 5.17 are given by Tera's smart meter database. During the weekdays the consumption is greater; in Figure 5.17 some data are missed due to connection loss between smart meter and fiscal meter.

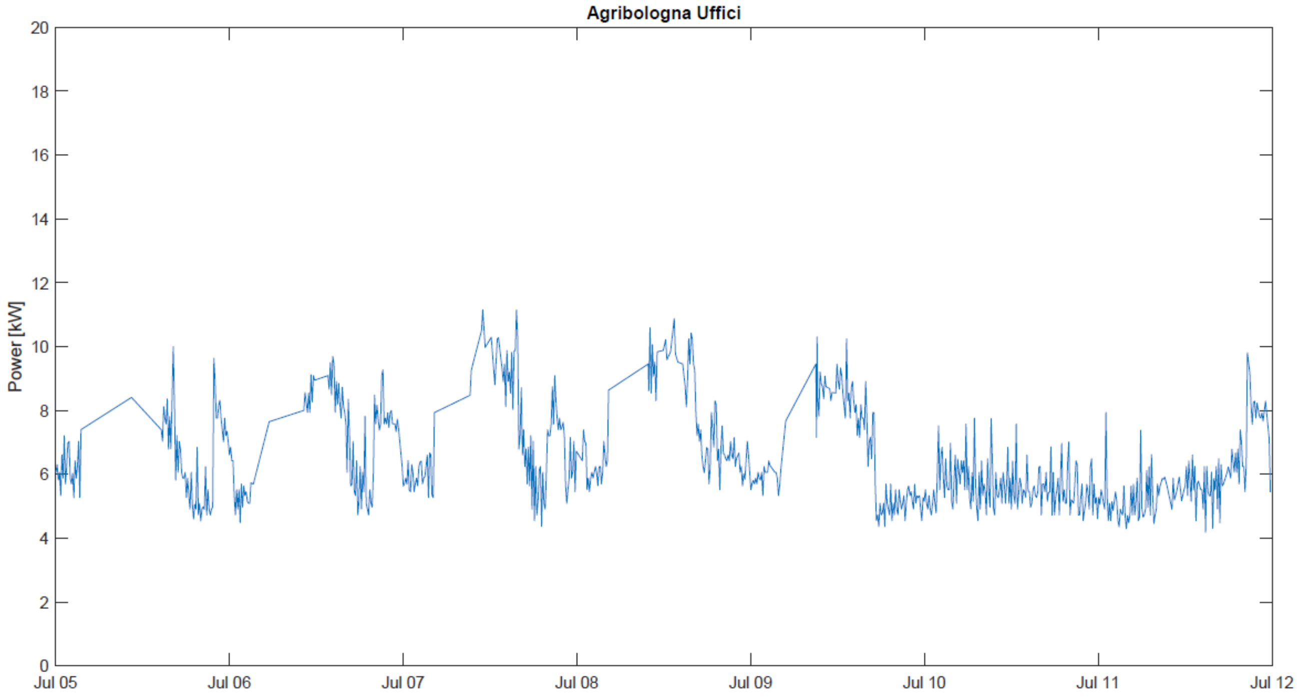


Figure 5.17 Consumption profile of Agribologna office (in CAAB area) not equipped with PV power plant

Figure 5.18 shows the power consumption of a cold room, namely Loffredo Stella. The power profile is acquired only during night hours because to this costumer is connected a photovoltaic plant of 96kWp (owned by another users) with a contract of exchange of electrical power on-site. Due to different PODs owners the smart meter cannot access to production data and cannot measure load consumption when the production is greater than load because no energy is taken from the grid.

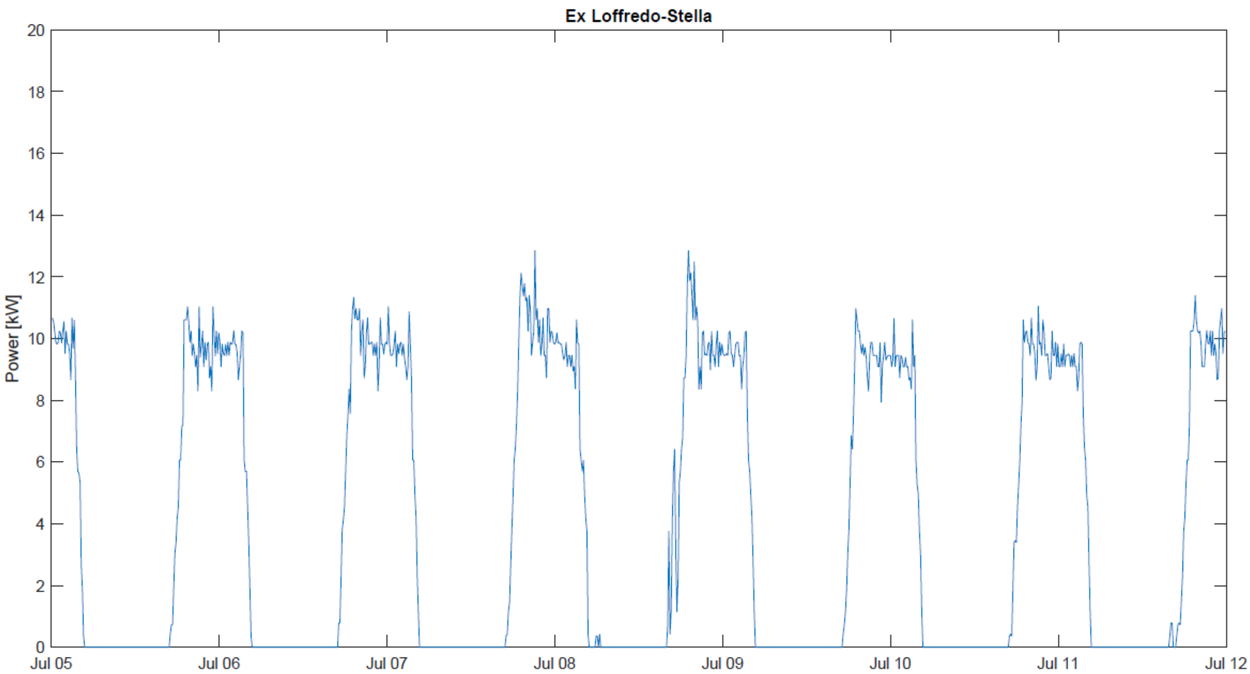


Figure 5.18 Consumption profile of Loffredo Stella (in CAAB area)

5.4.3 *NILM meters*

NILM meters involve the direct measure of the power. These metering devices should be physically installed in specific points of the users' electrical system. The measure is performed directly by the sensor, which can be a passthrough meter or an amperometric clamp Current Transformer (CT) depending on cable cross section: for small cable, up to 35 mm^2, both can be used but for grater sections only CT are suitable. The installation represents the main disadvantage of these devices: it requires operations on the electric plant, so it has been performed by a technician and in some cases the energy supply may be temporary interrupted. The energy information's resolution can reach up to 1 second.

Figure 5.19 RegalGrid smart metering device with internal or external current transformer; and SNOCU gateway (adapted from https://www.regalgrid.com)

The Smart Node Control Unit (SNOCU) and the controlled devices must be connected to the same physical network and belong to the same sub-network address. Moreover, for the controlled devices a static IP address is required.

The smart gateway of RegalGrid is the SNOCU shown in Figure 5.19 (on the right). The device should be interconnected to the NILM metering device, and it allows to connect and manage photovoltaic, storage, and consumption devices maximizing the self-consumption. The data collected by SNOCU can be stored in a cloud system.

The energy and power measurement are acquired with a time resolution of 1 second but the communication with the external database or cloud system take place with a larger time interval, which can be personalized according to the requirements and the application. Usually, the measured quantities are active power, reactive power and batteries state of charge.

To acquire real time data from devices an acquisition algorithm has been used, which is based on the Application Programmable Interface (API). The algorithm is continuously running on a workstation, every two seconds it sends a query to receive the meters' data (in this way there is a double read for each data).

Once the data is received it is stored for further elaborations. In case of connection failure the data are not lost: the algorithm can access to historical data once the failure is cleared; in case of historical data the time resolution is 5 minutes.

In the CAAB area five of these smart meters have been installed. Table 5.3 contains the details of the devices installed such as serial number, ID for API request, model and type of meter installed.

Table 5.3 Data, model, and location of installed devices

Serial SNOCU	Dev ID (API)	Model	User	Meter
FV18455F5FA5C-07	348	SNOCU DIN MONITOR 3P	Muda	CT 200/5A
FV18455F5FA74-07	335	SNOCU DIN CONSUMER BUSINESS 3P	Moden	Passthrough
FV18455F6032F-07	2080	SNOCU DIN CONSUMER BUSINESS 3P	Befer	CT 300/5A
FV18455F60BF6-07	2517	SNOCU DIN MONITOR 3P	Agribologna uff.	CT 150/5A
FV18455F60CB0-07	519	SNOCU DIN CONSUMER BUSINESS 3P	Deluca	CT 150/5A

Figure 5.20 and Figure 5.21 show the power consumption of two costumers with cold storage, the huge peaks correspond to the starting of cooling systems; both users have an available contractual power of 82 kW. In the following figures negative values represent power absorbed from the grid.

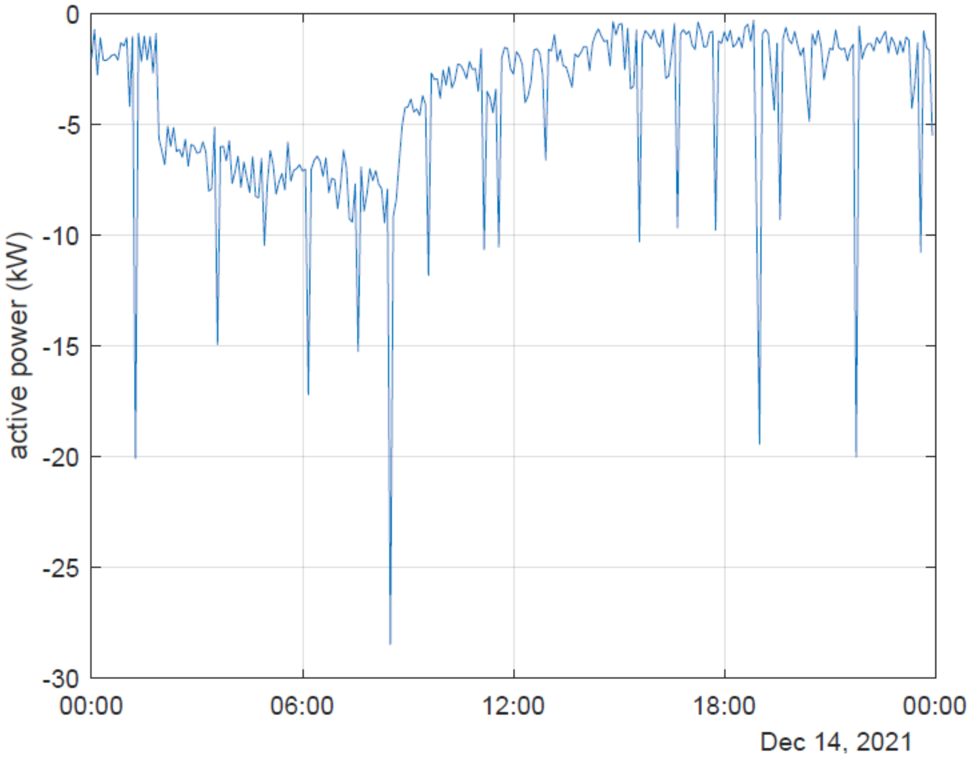


Figure 5.20 Deluca power consumption

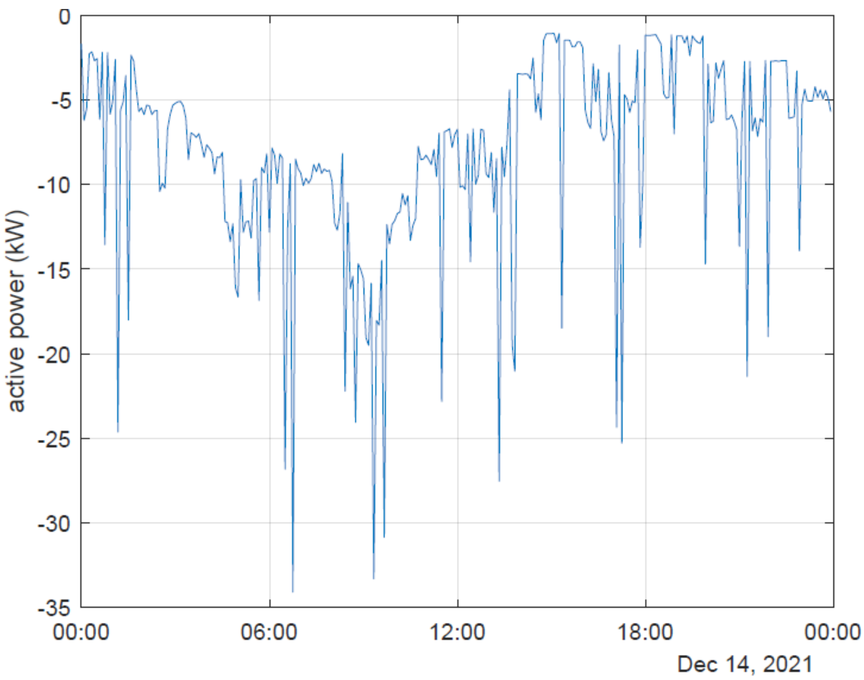


Figure 5.21 Befer power consumption

Figure 5.22 shows the power absorbed from the Agribologna office, the power request has smoothly variations during the day whose magnitude is much smaller than the ones generate by cold rooms.

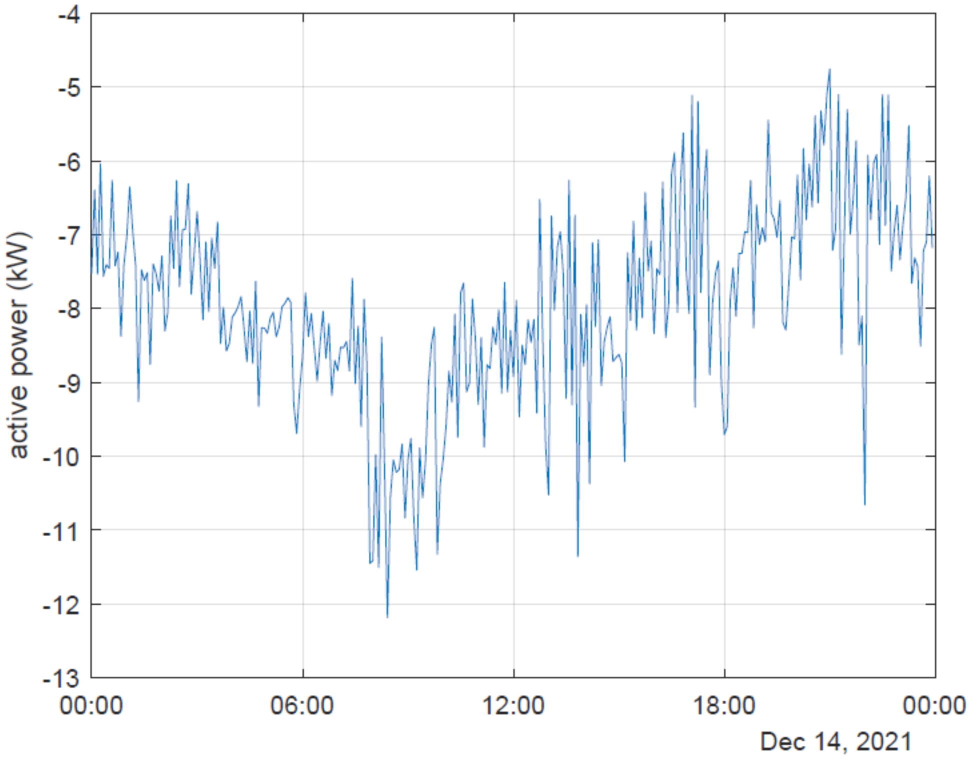


Figure 5.22. Agribologna (office) power consumption

Figure 5.23 shows the power exchanged with the grid by the costumer Moden; to this costumer is connected a 47.5kWp PV plant and a forklift charging station. During morning the forklifts are put on charge, they absorb more power than the PV production. In the late morning forklift are almost charged and the exceeding energy start to be injected into the grid. In the evening there is no PV production and the forklift are charged, there is only a small consumption by charge maintainer.

Figure 5.24 shows the load, production and exchanged power curves of costumer Muda. Muda has a 94 kWp PV plant and supplies many general service loads such as lighting and water pumps. In this appliance there are installed two sets of CT, one for the load and one for the PV production, the exchanged power is calculated as their difference.

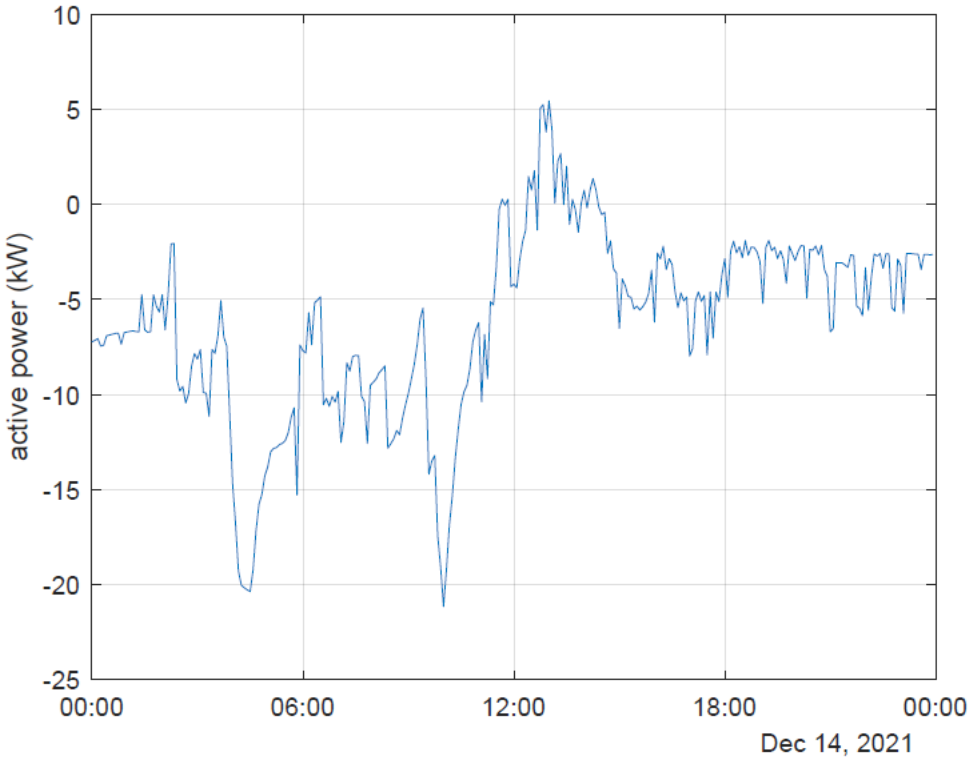


Figure 5.23. Moden power exchange

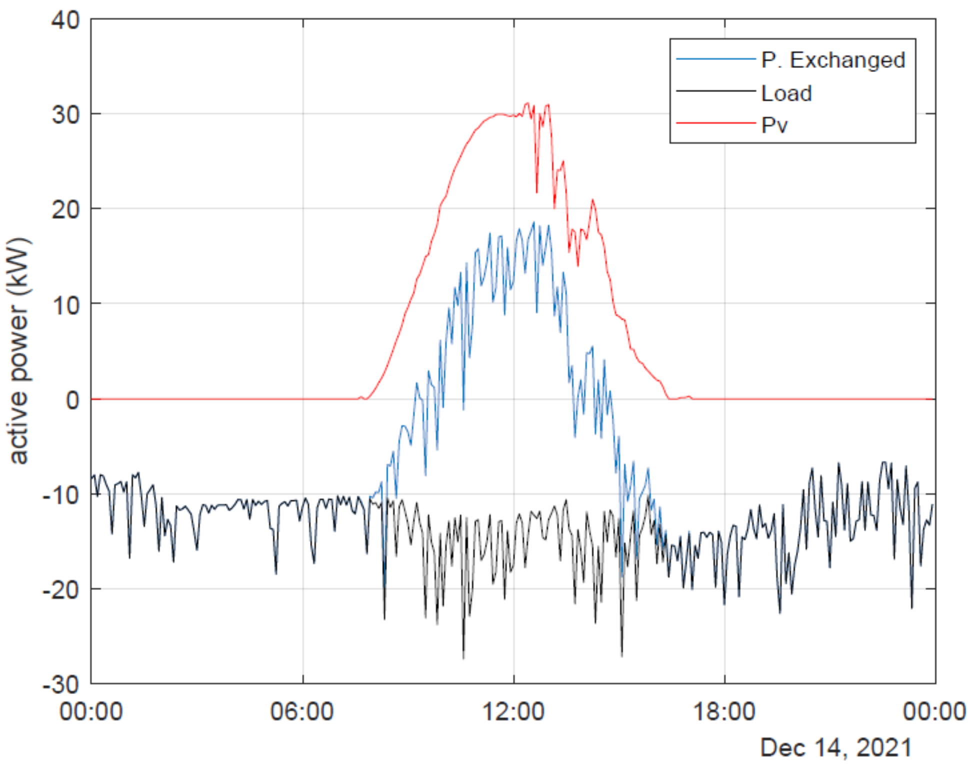


Figure 5.24. Muda power profile

5.5 Conclusions of the chapter

This chapter has been devoted to the description of the Climate-KIC GE.C.O project, aimed at the creation of the renewable energy community, contributing to the clean energy packet transposition into the national law framework.

Indeed, the present dissertation has been in part motivated by it, as the establishment of an energy community relies not only on the availability of generation units from renewable energy sources, of battery energy storage systems (planning problem), but also on the availability of an energy management system capable of optimally dispatching the energy flows among the prosumers and among the prosumers and the network, a point that in the present dissertation has been addressed limiting the focus to the day ahead dispatch.

In order to accomplish the above, data relevant to these energy flows need to be available and for this reason a number of suitable smart-meters has to be deployed at each customer/prosumer.

The available technologies have been presented and critically illustrated, and some selected smart meters have been installed at the GECO site also within the framework of the present dissertation. The power profiles of some prosumers of the district area of interest, gathered thanks to the installed smart meters have been reported. The instruments installed in the CAAB area have been eventually used both to implement an acquisition system and to create a profile of some of the characteristics loads present in the area. They are expected to be of great assistance in the management of the relevant energy communities as well as in the validation of the models.

Chapter 6. Concluding remarks

This dissertation has dealt with the planning and operation of power networks considering the presence of renewable energy sources (RES) and battery energy storage (BES) systems. Within this wide context, this thesis has addressed some technical issues relevant to the transmission grid – essentially concerning the expansion planning problems – and to the distribution one – concerning both planning and optimal dispatching of Renewable Energy Communities (RECs).

In particular, the first part of the thesis has been devoted to the expansion planning problem of transmission grids with high penetration of RES. Both stationary and transportable battery energy storage (BEST) systems have been considered in the planning model so to obtain the optimal set of BES, BEST and transmission lines that minimizes the total cost in a considered power network. First, a coordinated expansion planning model with fixed transportation cost for BEST devices has been presented and validated through the modified Garver's 6-node system. Then, the model has been extended to a planning formulation with a distance-dependent transportation cost for the BEST units, applied to a real regional grid with high RE penetration in China, and its tractability has been proved through a case study based on a 190-bus test system. The main improvement given by the more refined extended planning formulation relays on its applicability to any power systems, and not only to those where BEST fixed transportation cost could be a reasonable assumption. For both planning formulations, a single-stage approach has been considered as the investment decisions are obtained for a single year planning horizon.

The main contributions of the first part are the following:

- the accomplishment of long-term planning models with mobile storage units suitable for transmission system under high share of variable renewable energy, which differs for the allocation of the BEST transportation cost. We have indeed conceived the more refined model to be suitable for significantly large portions of power networks with large penetration of renewables. The relevant mathematical formulation, described in Chapter 2, makes also use of continuous variables, which allow for the evaluation of both the optimal size and location of stationary and transportable storage systems;
- an alternative mathematical approach implementation for the relevant vehicle scheduling problem suitable for transmission grids, which avoids the need of several complex constraints

involving a large number of binary variables that may cause numerical problems in the optimization. This is accomplished by the use of Number-of-nonzero (NZ) operator and an extremely limited number of constraints.

The second part of this thesis is then devoted first to the analysis of planning and management of renewable energy communities equipped with both variable renewable energy sources and dispatchable ones, biogas in particular, and BES systems.

First, the planning of photovoltaic (PV) and BES systems in a REC with an incentive-based remuneration scheme according to the Italian regulatory framework has been analysed and two planning models, according to a single-stage (static), or a multi-stage (dynamic) approach through which long term loads uncertainty and solar irradiation can be considered, have been proposed, so to provide the optimal set of BES and PV systems allowing to achieve the minimum energy procurement cost in a given REC. A comparative analysis of the two model formulations has been carried out; then, several cases differing by the value of discount rate, planning horizon, and by assuming or not a minimum BES investment for each prosumer, have been studied through the multi-stage planning approach. The obtained solutions have been compared to the case when the investment cost is zero, characterized by different operational costs and incomes, to quantify the effective benefits of the optimal planning scheme achieved.

The main contribution of the planning analysis of this part of the thesis are:

- the development of a single stage and of a multi stage planning models for the evaluation of the economic viability of new facilities such as PV and BES systems in a REC with the incentive-based mechanism foreseen by the Italian regulation framework;
- the obtained results showing that while within the considered assumptions the investment on PV systems is always convenient, while BES systems are not necessarily always included in the planning scheme. However, if each member of the community is forced to contribute with a minimum investment on BES systems – considered technically appropriate for a better handling of short term instability issues – the obtained results indicate that the optimal set of investments guarantees that the consequently increased saving and revenues achieved allow to pay back the larger initial investment in 5 or 6 years, which is interestingly not so different from the case when investing in PV systems only. In general, a higher discount rate leads to a lower initial investment in all the considered case studies;

- the fact that the proposed planning models could be suitable adapted also for other types of renewable energy communities, e.g. community where direct transactions between members are allowed.

Further, the optimal management of the available resources has been addressed along with the optimal scheduling of storage systems so to minimize the energy procurement cost for a considered community while fully exploiting the possible revenues foreseen. To this end, the last section of this second part of the thesis has been devoted to the study of the day-ahead scheduling of resources in renewable energy communities, by considering two types of REC. The first one, which has been referred to as “cooperative community”, allows direct energy transactions between members of the REC and aims to minimize the total energy procurement cost given by the energy exchanged with the external provider; the second type of REC considered, referred to as “incentive-based community” does not allow direct transactions between members but includes economic revenues for the community shared energy, which, according to the Italian regulation framework, is the minimum at each hour between the renewable energy fed into the electrical grid by the REC and the total energy demand required to the grid by the community. Moreover, dispatchable renewable energy generation has been considered by including producers equipped with biogas power plants in the community. Such analysis has allowed to quantify the contributions of all the components that build up the energy procurement cost for both types of REC. A comparative analysis with and without dispatchable generation units has been presented and discussed. The main contributions of the day ahead analysis of the second part are:

- the development of a model for day-ahead scheduling of RECs that takes into account not only the presence of BES units but also of biogas dispatchable renewable generation units for both cooperative communities and incentive-based ones;
- the obtained results showing that within the considered assumptiona, which include a constrained dynamics of the prices of the energy exchanged with the grid, the incentive mechanism approach adopted by the Italian regulation framework seems to be more profitable with respect to a cooperative community in which transactions between prosumers are allowed;
- the fact that although the daily procurement cost of a community incentivized according to the Italian regulation framework is much more dependent on the prices of the energy exchanged with the grid, by introducing producers equipped with biogas power plants in the community, a REC can reduce indeed its dependence from the utility grid and therefore its energy procurement cost.

Finally, the third and last part of this dissertation has illustrated the main scopes of the Climate-KIC GE.C.O project, which relies not only on the availability of PV units and of BES systems, but also on the availability of an energy management system capable of optimally dispatching the energy flows among the prosumers and among the prosumers and the network. In order to accomplish that, data relevant to these energy flows need to be available and for this reason the available smart metering technologies have been critically revised, and some selected smart meters have been installed at the GE.C.O site also within the framework of the present dissertation. The power profiles of some prosumers of the district area of interest, gathered thanks to the installed smart meters have been reported. The instruments installed in the CAAB area have been eventually used both to implement an acquisition system and to create a profile of some of the characteristics loads present in the area. They are expected to be of great support for the validation of the models.

The main contributions of this last part of the dissertation are:

- the critical analysis of available smart metering technologies, and the installation of the most appropriate of them at the GE.C.O site, which will be fundamental in the validation of the models
- the acquisition of the power profiles of some prosumers of the district area of interest, gathered thanks to the installed smart meters.

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Appendix A. ADMM

In this section, the scheduling of a community within a distributed optimization structure has been presented. Compared to the centralized approach discussed in section 4.1.1, the use of a distributed approach preserve the privacy and autonomy of each member of the community.

In the following, a distributed procedure based on the Alternating Direction Method of Multipliers (ADMM) algorithm has been introduced to solve the scheduling problem associated with the operation of the community. The formulation follows the proposed approach of (Orozco et al. 2019) and (Lilla et al. 2020), widely discussed in (C. Orozco 2021). The main inputs of the decisions of each participant in the community are the forecast of PV production and local load.

In the ADMM algorithm, *OF* (4.1) is decomposed into local subproblems, for each prosumer *i*, by means of the Lagrangian decomposition. The objective function for each prosumer *i* is given by

$$OF_i = \min_{\substack{P^t_{\text{buy\_Grid}\,i},\, P^t_{\text{sell\_Grid}\,i} \\ P^t_{\text{buy i},j},\, P^t_{\text{sell}\,i,j}}} \sum_{t \in T} \begin{bmatrix} \pi^t_{\text{buy}} P^t_{\text{buy\_Grid}\,i} \Delta t - \pi^t_{\text{sell}} P^t_{\text{sell\_Grid}\,i} \Delta t + \\ \sum_{\substack{j\in\Omega \\ j\neq i}} \lambda^t_j P^t_{\text{buy i},j} \Delta t - \lambda^t_i \sum_{\substack{j\in\Omega \\ j\neq i}} P^t_{\text{sell}\,i,j} \Delta t + \ell^t_i \end{bmatrix} \tag{0.1}$$

where

$$\ell^t_i = m \cdot \rho \cdot [\sum_{\substack{j\in\Omega \\ j\neq i}} (\hat{P}^t_{\text{buy}\,j,i} - P^t_{\text{sell}\,i,j})^2 + \sum_{\substack{j\in\Omega \\ j\neq i}} (P^t_{\text{buy}\,i,j} - \hat{P}^t_{\text{sell}\,j,i})^2] \tag{0.2}$$

Equation (0.1) represents the summation of three terms: costs and revenues associated with exchanges of energy with the external energy provider; costs and revenues for the energy transactions of prosumer *i* with the other prosumers, where λ^t_i and λ^t_j are the Lagrangian multipliers of the equilibrium between power sold and bought in each internal transaction; the squared norm of the imbalance of each energy transaction between prosumer *i* and every other prosumer *j*.

In this scheme, the prosumers' decisions are coordinated by means of a distributed procedure that iteratively updates the multipliers, and that only requires the information regarding energy exchanges between prosumers, as shown in (Lilla et al. 2020).

At the beginning of the procedure, Lagrange multipliers λ^t_i, penalization parameter ρ, and scale factor m are initialized. Then, at each iteration v, the local subproblem (0.1) is solved by each prosumer considering the set of constraints (4.3) - (4.11) and (4.14) - (4.16) (i.e., the set introduced for the operation model of the community in section 4.1.1). Constraint (4.2) (from the centralized model) is not present, since the problem has been decoupled by means of the augmented Lagrangian function in (0.1).

Subsequently, the prosumers communicate to each other values $P^t_{\mathrm{buy}\,i,j}$ and $P^t_{\mathrm{sell}\,i,j}$ obtained at the end of their own optimization problem. Then, each prosumer *i* updates the Lagrangian multipliers λ^t_i (i.e., the prices associated with the internal energy exchanges in the community) based on the imbalance between their local variables and the values communicated by the others prosumers, and denoted by a hat in (0.2), such that: parameters $\hat{P}^t_{\mathrm{buy\_Grid}\,i}$ and $\hat{P}^t_{\mathrm{sell\_Grid}\,i}$ are the values in the previous iteration of power bought and sold by prosumer *i* from and to the utility grid, respectively; parameters $\hat{P}^t_{\mathrm{buy}\,i,j}$ and $\hat{P}^t_{\mathrm{sell}\,i,j}$ are the values in the previous iteration of power exchange between prosumers *i* and *j* (i.e., bought and sold respectively). At each iteration, the corresponding imbalances will be reflected in the primal residual r^t_i.

Furthermore, the convergence of the ADMM procedure is improved by adding the following constraints, starting from the second iteration, as they provide a coordination between the selling and purchasing decisions of prosumer *i* with respect to those of the other prosumers:

$$P^t_{\mathrm{sell}\,i,j} \le \hat{P}^t_{\mathrm{buy\_Grid}\,j} + \sum_{\substack{i\in\Omega \\ k\neq j}} \hat{P}^t_{\mathrm{buy}\,j,k} \qquad j \text{ and } k \in \Omega \qquad (0.3)$$

$$P^t_{\mathrm{buy}\,i,j} \le \hat{P}^t_{\mathrm{sell\_Grid}\,j} + \sum_{\substack{i\in\Omega \\ k\neq j}} \hat{P}^t_{\mathrm{sell}\,j,k} \qquad j \text{ and } k \in \Omega \qquad (0.4)$$

In order to speed up the convergence of the distributed procedure, the value of penalization parameter ρ and scale factor *m* are adjusted at each iteration according to the iterative ADMM procedure.

In the case study included in this dissertation, the scale factor *m* is multiplied by 5 and 1.5 when the maximum value of the total mismatch $r^t = \sum_k \left|r^t_k\right|$ becomes less than 20 kW and 1 kW, respectively, and further by 5 when $\max\left(\left|r^t_k\right|\right) < 100\ \mathrm{W}$. These values are suitable to be adapted according to the case and the characteristics of the REC to accelerate the convergence of the algorithm.

Then, the distributed procedure is iteratively repeated until the absolute values of all residuals r^t_i are less than a small tolerance ε.

Once the procedure converges, ℓ_i^t tends to zero, and the value *OF* for the community is equal to the summations of the prosumer's objectives:

$$OF = \sum_{i \in \Omega} OF_i \tag{0.5}$$