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AGGREGATION OF RESIDENTIAL USERS: AN ITALIAN CASE STUDY

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Abstract

In recent years there was a big increase of renewable energy resources and many users installed photovoltaic panels and storage systems, becoming electricity producers. Renewable energy sources are typically non-programmable and non-dispatchable and this raises the issues of frequency and voltage variation in the grid. Starting from the deliberation 300/2017 issued by ARERA (the Italian authority for the regulation of energy), new entities can participate in the Ancillary Services Market (ASM), through the aggregation of renewable generations, loads and storage systems.

This thesis analyses the aggregation of residential users that are equipped with photovoltaic generations and storage systems, with the aim to offer services in the ASM. 399 residential users have been considered, each with a power consumption of 3 kW, located in Italy. Each user is equipped with a 30 kW photovoltaic plant and a storage systems. The power profile of the photovoltaic plants was assumed to be identical to the one measured in the laboratory of RSE (Ricerca sul Sistema Energetico).

A deterministic daily and annual optimization model was developed, evaluating the potential gain of the aggregator, given by the participation in ASM. Several simulations were made, changing the number of users and the size of the storage systems, in order to show how the aggregator's gain changes as function of aggregate characteristics. At the end of the thesis it is made an economic analysis, evaluating the additional gain due to the participation in ASM.

Sommario

Negli ultimi anni c'è stato un grande aumento delle fonti di energia rinnovabile e molti utenti hanno installato pannelli fotovoltaici e sistemi di accumulo, diventando produttori di energia. L'energia rinnovabile è non-programmabile e non regolabile, e questo causa variazioni di frequenza e tensione della rete. ARERA (Autorità di Regolazione per Energia Reti e Ambiente) ha emanato la delibera 300/2017, stabilendo che nuove entità possono partecipare al mercato di dispacciamento (MSD), attraverso l'aggregazione di generatori rinnovabili, carichi e sistemi di accumulo.

La tesi analizza l'aggregazione di utenze residenziali, dotate di impianto fotovoltaico e sistema di accumulo, con l'obiettivo di offrire servizi nel MSD. Sono stati considerati 399 utenti con una potenza disponibile di 3 kW, localizzati in Italia. Ogni utente è dotato di un impianto fotovoltaico da 30 kW e di un sistema di accumulo. Il profilo di potenza dell'impianto fotovoltaico è assunto identico a quello misurato nel laboratorio di RSE (Ricerca sul Sistema Energetico).

E' stato sviluppato un modello deterministico di ottimizzazione giornaliera e annuale, valutando il guadagno potenziale dell'aggregato, dato dalla partecipazione nel MSD. Sono state fatte varie simulazioni, cambiando il numero di utenti, la taglia del sistema di accumulo, per mostrare come il guadagno dell'aggregatore cambia in funzione delle caratteristiche dell'aggregato. Alla fine della tesi è stata fatta una analisi economica, valutando il guadagno dovuto alla partecipazione nel MSD.

INDEX

LIST OF FIGURES

1. INTRODUCTION

In recent years, we witnessed to an increase of production from renewable energy, in particular solar energy (photovoltaic panels) and wind energy (wind turbines), which made available new sources of energy. Up to now, most of the electrical plants in the world have been thermoelectric or nuclear plants. As a side effect, thermoelectric plants produce huge quantities of CO_2, while nuclear plants produce nuclear waste. An important economic factor is that the production of renewable energy decreases the usage of fossil fuel like gas and oil, with an obvious economic benefit, since Italy and Europe buy them abroad.
Renewable energy is non-dispatchable and non-programmable. Non-dispatchable means that such plants do not guarantee to deliver the exact quantity of energy required by the user, but they may provide less or more, so the remaining energy has to be requested or delivered from or to the grid. Non-programmable means that the production of these plants is uncertain, because it depends on weather and season conditions. Since many people installed photovoltaic panels in their houses or offices and they became electricity producers, the production of electricity is shifting from a centralized model to a distributed model.

The national grid has to be adjusted to this new scenario, in which there are many small prosumers (producers and consumers), who inject or absorb energy in the low- or medium- voltage grid. With the increase of renewable energy availability, some problems arise due to the variations of frequency and voltage, as an effect of non-dispatchability and non-programmability.

Frequency and voltage are controlled by ancillary services provided by power plants, with the aim to control grid frequency and voltage variations. Ancillary services include every operation of the electricity market that controls power setpoint for active and reactive energy. To allow the participation of small prosumers to ancillary services, the minimum power threshold had to be decreased below 10 MW. In this scenario, an important contribution is provided by storage systems. Many users that installed photovoltaic panels use also storage systems to increase self-consumption.

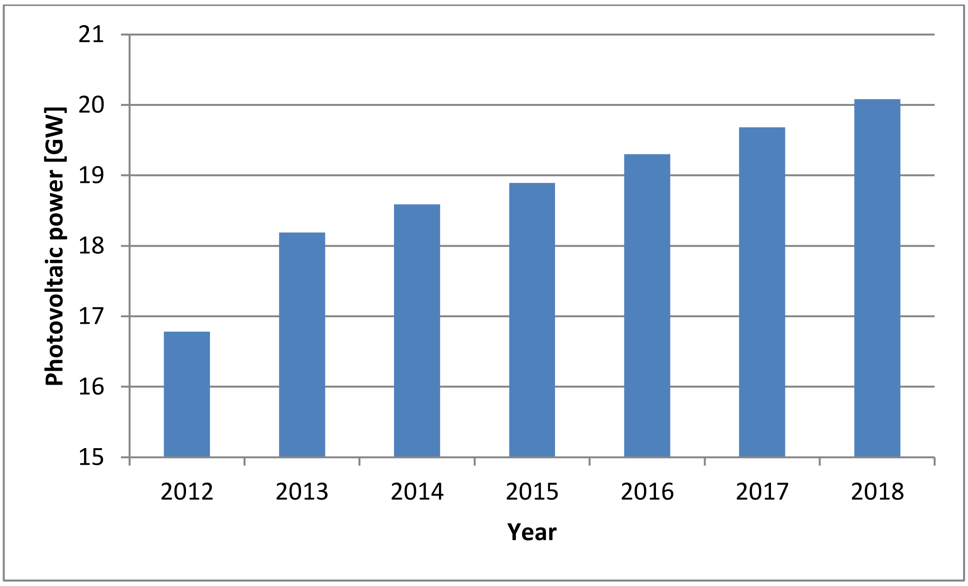

Figure 1 Photovoltaic power in Italy

From the diagram in figure 1, we can see that starting from 2012, there was a big increase of photovoltaic plants. In 2018 the installed power was 20 GW. The table below shows for each regions the number of photovoltaic plants and the power produced [1].

REGIONS	NUMBER	POWER [MW]
Piemonte	57114	1609.27
Valle d'Aosta	2342	23.79
Lombardia	124464	2296.91
Trentino Alto Adige	24850	427.64
Veneto	113483	1907.5
Friuli Venezia Giulia	33478	523.33
Liguria	8741	106.63
Emilia Romagna	84726	2028.38
Toscana	43024	810.69
Umbria	18594	478.52
Marche	27634	1078.37
Lazio	53991	1355.1
Abruzzo	20056	735.22
Molise	4033	173.72
Campania	32323	801.55
Puglia	48173	2653.24
Basilicata	8062	362.23
Calabria	24498	533.05
Sicilia	52461	1389.07
Sardegna	35947	783.81
TOTAL	817994	20078

Figure 2 Table of power produced in Italy by photovoltaic plants (MW) and number of plants for each region.

The total number of installed plants is equal to 817.994 and the total power is 20.078 MW. We can see that the highest number of photovoltaic plants is in Lombardia, i.e. 124.464. The highest installed capacity is in Puglia, i.e. 2653 MW.

The regulation of frequency and voltage in ASM have always been provided by medium and large-sized programmable plants, i.e. thermoelectric and hydroelectric plants. Due to the increase of renewable energy, today there are fewer thermoelectric and hydroelectric plants. Taking into account the new production scenario, ARERA, which is the Italian Authority for the regulation of energy, issued the resolution 300/2017, establishing that new entities can participate to the Ancillary Services Market (ASM). These new entities can be:

- Small producers, with power less than 10 MVA
- Consumers (loads)
- Storage systems
- Mixed entities (i.e. generators, loads and storage systems)

Following the regulation by ARERA, Terna which is the operator of the high voltage transmissions system in Italy, issued rules about the aggregation of users, with the aim to offer services in the ASM.

The thesis discusses the additional gain by residential users, who installed photovoltaic panels and storage systems in their houses, when they aggregate and participate in ASM.
A deterministic optimization model of this scenario is developed, and the daily and annual profits of the aggregator are evaluated when they participate in the ASM. The simulations performed have considered 399 users with a power consumption of 3 kW. The photovoltaic profile has been taken from a real photovoltaic plant of 30 kW installed in RSE (Ricerca sul Sistema Energetico). Several simulations were made, changing the number of users and the size of the storage systems, in order to show how the aggregator behaviour changes.

The thesis is divided into nine chapters:

- Second chapter: it describes the state of the art about the aggregation of residential users, starting from 2013 until now.
- Third chapter: it describes the electricity market in Italy

- Fourth chapter: it describes the main rules about the aggregation of users provided by Terna.
- Fifth chapter: it describes the uncertainty about load and photovoltaic forecasting.
- Sixth chapter: it describes the optimization model, from a mathematical point of view.
- Seventh chapter: it describes the daily optimization model.
- Eighth chapter: it describes the annual optimization model.
- Ninth chapter: it analyzes the economic benefits.
- Tenth chapter: conclusion and future developments.

2. State of the art of the residential user aggregation

In this chapter the state of the art of the residential users aggregation is surveyed.

2.1. Previous work without the participation in ASM

Section 2.1 reviews papers regarding the aggregation of residential users, equipped with photovoltaic generations and storage systems, with the aim to decrease the electricity bill, without the participation in ASM.

In 2013 L. Gkatzikis et al [2] developed a demand response model for residential users. They introduced a hierarchical market model for smart grids, where a set of competing aggregators act as intermediaries between the utility operator and home users. In the day-ahead market, users issue a cumulative load demand. A fixed price is charged for the consumption, independently of the period of the day. The operator seeks to compute the cumulative daily load profile that maximizes its revenue, which is given by the load demand minus the profile of the renewable energy and it can be solved through convex optimization. The cost of renewable energy is assumed to vary with time, due to the time-varying availability of supply. The cost is a strictly increasing and convex function. The aggregators compete to sell demand-response services to the operator and provide compensation to users, in order to modify their power consumption profile. The objective of the aggregator is to maximize its net profit, given by the reward received from the operator, minus the compensation provided to the users. In residential demand scheduling, users tend to move load out of peak consumption periods. The objective of each user is to maximize the difference between the power consumption pattern minus the dissatisfaction, due to the deviation from the reference consumption pattern. In order to evaluate the performance of this model, the dataset of the demand generator is taken from [3], considering 1000 users. They created one-minute resolution demand data, through the simulation of appliance use. The appliances in the model are configured using statistics, describing their mean total annual energy demand and associated power use characteristics, including steady state consumption or typical use cycles. To validate this model, they recorded electricity demand of 22 users , over the period of one year, in the East Midlands (UK).

In 2014 Adika and Wang [4] proposed an algorithm for the optimization of a single household, with photovoltaic generation ,without storage devices.

The strategy is to buy as little energy as possible from the grid, and export as much as possible without compromising its load energy requirements. Due to the intermittent nature of photovoltaic generation, a forecasting device has been installed in the household to provide expected hourly energy predictions. In order to be eligible for participation in the demand side program, the user is obliged to install at least 20 kW of photovoltaic generation. A smart scheduler (an intelligent device) is used to monitor a household's energy consumption pattern to ensure that the aggregate demand does not exceed the pre-defined limit. Based on the time series of use- pattern of the devices over the planning horizon, the scheduler computes the use probability of the appliances for each hour. This computation is done, based on the day of the week, weather conditions and the level of occupancy of the house, for a year. From these probabilities, the scheduler develops the probability of hourly profiles of each device. Using interpolation technique and past pricing and load data, the electricity prices of each hour are computed. Producers enjoy a cost-based price as compensation for the photovoltaic that they generate. It is considered that the utility company buys all the photovoltaic generated electricity from the user who in turn relies on the main grid to supply all its power requirements. The energy price for purchasing power from the grid is set lower than the price at which the user sells photovoltaic energy to the grid. The user gain is given by the energy sold to the grid, minus the energy bought from the grid. However, additional penalty charge is imposed on the consumer for submitting inaccurate photovoltaic energy forecasts to the utility company. Hence, the goal is to maximize the objective function, given by the difference between the gain of the user and the penalty charge.

In 2014 [5] Y. Zhou et al developed a robust optimization approach for household load scheduling, considering uncertainty in power output of a household photovoltaic system. The objective is to minimize the daily electricity cost, given by the load demand curve minus the photovoltaic generation. There is a strong randomness for the photovoltaic generation and it is assumed that it ranges in an interval. We are dealing with a non linear mixed integer programming model and it is adopted a genetic algorithm to solve it. The case study considers a house, in which a 10 kWp of photovoltaic power is installed ; the required power of the load and the real time price for users to buy electricity are assumed to be the same as that in [6].

In 2015 [7] Z. Zhu et al proposed a game-theoretic consumption scheduling framework based on the use of mixed integer programming. They described a mathematical optimization technique for scheduling daily energy consumption with the aim of reducing peak accumulated consumption and the cost of energy consumers. The total cost of energy consumption of all users is written as a quadratic function of the accumulated consumption of all consumers.

The household appliances are classified into two groups: shiftable appliances and non-shiftable appliances. Shiftable appliances means that the consumer can tolerate the shift of the operations of them. Non-shiftable appliances means that scheduling is not possible, since they have to operate continuously. The scheduler is able to draw energy optimally from either the main grid or renewable energy for every appliances. The objective is to minimize the electricity bill of each user, through optimum scheduling of energy consumption, using block-based time-of-use pricing. The optimization is a mixed integer problem, which can be solved using branch and bound method. In the game-theoretic approach, all consumers want to minimize their energy cost and they will be tempted to select the best strategy in response to the price plan and the other players' chosen strategy. The model covered one day, with time resolution of one hour, considering 10 users. The load curve has been obtained from [8]- [9].

2.2. Previous work about the participation in ASM

In literature there are many papers about users who bid in the energy markets, but the participation in ASM has not been addressed. In 2015, a model was developed to optimize the behaviour of an aggregator that participates in ASM.

In 2015 E. Heydarian-Forushami et al [10] developed a model based on the optimization of demand response aggregation with renewable energy resources. The aggregator aims to maximize its profit, by participating in day-ahead market, balancing and spinning reserve markets. A stochastic model has been developed, considering uncertainties of renewable energy and uncertainties on the prices of electricity market. In particular two major types of uncertainties have been considered: the uncertainties of market prices and the uncertainties from delivering energy while it is called by ISO (Independent System Operator).

Uncertainties of market prices have been characterized by log-normal distribution in each hour, modeled by the Roulette Wheel Mechanism (RWM) method [11]. Uncertainty from delivering energy while it is called by ISO is considered to be uniformly distributed between 0 and the offered amount by the aggregator, modeled by the RWM method. The objective function is given from the participation in electricity market and the gain coming from delivering energy while it is called by ISO, minus the cost that results from not delivering the energy to the grid and the cost of responsive demand. Furthermore they applied a risk measure for the aggregator, to specify the desirable weighting between expected profit and risk due to the uncertainty of customers' behaviour.

In 2017 K. Liu et al [12] developed an algorithm based on distributed batteries that are coordinated by an aggregator, which submits offers in the ASM to provide regulation. The objective function aims to achieve maximum profit in a given day. The gain is given by the revenue from the ancillary market service, minus the operation cost, the degradation cost and the maintenance cost of the battery. The operation cost is proportional to the amount of energy that is sold and bought from the grid. The battery degradation cost is closely related to battery characteristics. The maintenance cost is proportional to the maximum total power of all batteries, which is the sum of battery rated power. A certain battery can't be charged and discharged simultaneously. The aggregator can sell or buy at a specific time, typically for at least 15 minutes (time for the regulation service).The state of charge of the battery is between a minimum and a maximum value.

In 2018 [13] Arun and Selvan published a paper about the optimal sizing of renewable resources and energy storage devices, where they developed an algorithm for residential users. They assumed that a smart residential building is equipped with photovoltaic generation and a storage system. The prosumers can benefited by injecting power to the grid, which is limited by the utility manager to avoid stability issues. Consequently the power exported to the grid should be within the utility-defined limit. The power generated by renewable resources beyond the demand and export limit needs to be dissipated through dump loads to have power balance in the system. However, power dissipation through dump loads should be made as minimum as possible for better energy saving.
An optimal sizing of the photovoltaic system and of the battery is developed, to achieve a reduction in total investment cost. The size of each component should not exceed the consumer-defined maximum limit, which is decided based on the available space on the installation site. The objective of optimal sizing is to minimize the cost of energy, which is given by the sum of annualized capital cost of all components, the sum of replacement cost of the components, the sum of operation and maintenance cost, divided by the total energy delivered by renewable energy. This optimization problem is solved using genetic algorithm.
The data about the renewable resources needed for the estimation of power generation from renewable resources are measured at the National Institute of Technology in India.

From the previous survey, we can see that there are few papers about the participation in Ancillary Services, with both renewable energy and storage systems.

One of them developed a stochastic model, based on the uncertainties about renewable energy and electricity market; another one was concerned about the optimization of distributed batteries, and the third one proposed an algorithm about the optimal sizing of photovoltaic panels and batteries.
In the paper by Heydarian-Forushami [10], a stochastic model is developed with almost 500 users. A stochastic model is more computationally-intensive than a deterministic one, since probability distributions must be computed and the users' population has to be limited. Instead, the deterministic model proposed in the thesis allows to handle up to 4000 users that are equipped with photovoltaic panels and storage systems; it aims to maximize the aggregator's gain when offering services in the balancing market, according to the resolution 300/2017 issued by ARERA.

3. Electricity market in Italy

This chapter discusses the Italian electricity market, which is the context in which the ASM operates. The Italian electricity market is divided into four parts:

- Day-Ahead Market
- Intraday Market
- Daily Market
- Ancillary Market Services

During the **Day-Ahead Market** the producers and the buyers can sell/buy energy for the next day. The prices and the quantity of energy are defined. The session opens at 8.00 of the ninth day before the delivery day and it closes at 9.15 before the delivery day. The GME (Gestore del Mercato Elettrico) informs of the results within 10:45 before the delivery day. The offers are based on the pair quantity/price: the quantity of energy that can be sold/ bought, and the minimum/maximum price expressed in €/MWh. GME applies for each hour an algorithm that maximizes the value of the negotiation. The price is established from the intersection between the load curve and the offer curve.

Intraday Market allows producers and buyers to make some modifications about the delivery and absorption of power with respect to the results on the Day-Ahead Market. It is composed of seven sessions: MI1, MI2, MI3, MI4, MI5, MI6, MI7. They open at 12:55 of the previous day, before the delivering day and they close at 15:45 of the delivery day. Each session closes at a different time, so the producers can use more updated information about the values of energy of their plants.

During the **Daily Market** there is the negotiation of the daily products with the obligation to deliver the energy. The session will be held during the week-days:

- From 8:00 to 17:00 of two previous days before the delivery day (D-2). If D-2 is a holiday-day, the session will be from 8:00 to 17:00 of the previous day with respect to the delivery day.
- From 8-9 of the previous day with respect to the delivery day, only if D-1 is not a holiday-day. If it is a holiday-day , the session will be from 8 to 17 of the weekday, before the delivery day.

There are two kinds of loads: baseload and peakload.

- Baseload is needed every calendar day
- Peak load is needed from Monday to Friday

Ancillary Services Market (Mercato dei Servizi di Dispacciamento) is the market where Terna selects the ancillary services needed to manage and to control power system. All accepted offers are paid at the price at which they are submitted (pay as bid). There are two sessions:

- MSD Ex-ante: Terna buys energy with the aim to solve congestions problems and to build up reserves.

  It is divided into 6 sessions: MSD1,MSD2,MSD3,MSD4,MSD5,MSD6. There is only one session for submitting the offers. It opens at 12:55 before the delivery day and it closes at 17:30 of the same day.
- Balancing market: during this market offers are selected to sell and to purchase according to the secondary regulation and to keep the balancing between injection and withdrawal of power. It is divided into six sessions where Terna selects the offers divided into groups of hours of the same day. During the first session, the offers related to MSD-ex ante are considered. The other sessions open at 22:30 before the delivery day and close one hour and half before the offers can be sold [14] .

The remaining part of the thesis analyzes the additional gain obtained by participating in ASM, within the Italian electricity market.

4. Virtual Energy Storage System

A Virtual Energy Storage System (VESS) aggregates various controllable components of the power systems, which include: energy storage systems, flexible loads, distributed generators. It is able to vary its energy exchange with the power grid in response to external signals. While Virtual Power Plant (VPP) aggregates distributed energy generators to act as a single power plant, VESS aims to aggregate both generators, storage systems and loads like an equivalent big storage system.

The inclusion of distributed generation in the power system increases the flexibility of the grid, but it introduces a lot of difficulty in its management.
In a power system, the energy produced must be equal to the energy consumed, otherwise there will be frequency and voltage variations, which will bring to system instability or black out.

The possibility of offering flexibility services through VESS is promoted by Terna, through specific resolutions, issued by ARERA.

4.1. UVAC and UVAP

ARERA issued a resolution about the aggregation composed of loads (UVAC), resolution 372/2017 and the aggregation composed of generators (UVAP), resolution 583/2017.

UVAC (Unità Virtuale Abilitata al Consumo) can participate in the ASM with a minimum power of 1 MW.
In September 2018 the total power enabled was 516 MW.
UVAC had a gradual start: from June 2017 until September 2017, the use of UVAC was about 1%. In the same period, in 2018, there was an increase around 35,8%.

UVAP (Unità Virtuale Abilitata alla Produzione) are characterized by non relevant production units (i.e. power lower than 10 MVA) and storage systems. Until 2018 roughly 100 MW were enabled.

With the new resolution issued by ARERA 300/2017, if UVAC and UVAP will not be enabled as UVAM (see next section), they will not be allowed to participate in the ASM [15] .

4.1.1. Projects about virtual energy storage systems present in the world

Projects about VESS are present not only in Italy, but also around the world. There are roughly 197 projects. They are present in America (50,8%), in Asia (23,4%), in

Africa (10,7%), Europe (7,6%), Australia (6,6%), Antartide (1%). 74% of the projects are already activated and the other ones are in the construction phase. The 61% are powered both with renewable and traditional energy sources; instead the 34% are powered only by renewable sources, i.e. photovoltaic plants (63%), wind turbines (31%), hydroelectric plants (5%), biomass (1%) [15].

4.1.2. Example of a virtual energy storage system for residential users in Germany : Sonnen Community

Sonnen, which is a company that produces batteries, created in Germany in 2015 an aggregator composed of residential users, who installed photovoltaic panels and storage systems. The aggregator is composed of passive users (users without photovoltaic generation) or users with photovoltaic plants equipped with storage systems. For managing in real time the residential users, each user is equipped with a controller that acts as a gateway among the operator transmission system (TSO), the aggregator and the production/consumption plant.

Sonnen acts not only as an aggregator, but also as an utility for residential users; it withdraws the energy injected by the users that don't need it and it can inject power to its clients that need it [16].

4.1.3. Example of virtual energy storage system in Italy: Ego group

At the beginning, the virtual energy storage system was composed of UVAC and UVAP. Ego, which is an Italian group in the electricity market, partecipated in the Ancillary Services Market with UVAC. There were two grids: one in the north of Piedmont and the other one between the south of Piedmont and Liguria. The grids aggregated district heating plants, thermoelectric and cogeneration plants for a total of 45 MW.

Since Terna implemented the resolution ARERA 300/2017, UVAP and UVAC were replaced with UVAM. Terna made a call for the allocation of 1000 MW for UVAM of which 29 MW were awarded by Ego.

Ego met good results, fulfilling Terna's requirements [17].

4.2. UVAM

UVAM (Unità Virtuali Abilitate Miste) is a mix of non relevant generators, loads and storage systems, which can participate in the ASM with the resolution 300/2017 issued by ARERA.

The aggregator can offer services, providing upward power and downward power in:

- Congestion resolution

- Rotating tertiary reserve
- Replacement tertiary reserve
- Balancing

The power injected into the grid is assumed conventionally with positive sign, the power absorbed by the grid with negative sign.

UVAM must be able to supply maximum enabled power and minimum enabled power not less than 1 MW. The maximum enabled power is the maximum increase of power that UVAM can provide to Terna. The minimum enabled power is the maximum decrease of power that UVAM can provide to Terna.
In the case that Terna needs only upward flexibility (unidirectional service), the maximum enabled power must be equal at least to 1 MW and a minimum enabled power equal to 2 kW. If Terna needs only downward flexibility, the minimum enabled power must be equal at least to 1 MW and the maximum enabled power equal to -2 kW.

UVAM can provide upward flexibility and downward flexibility within 15 minutes from Terna's dispatching order for: congestion resolution, rotating tertiary reserve and balancing, for at least 2 hours.
For the replacement tertiary reserve UVAM can provide services within 120 minutes from the received order for at least 8 hours.

4.3. UVAM management

The BSP (Balance Service Provider), as UVAM owner, has to define a physical point in which it can receive dispatching orders, sent by Terna.
It must communicate to Terna the Baseline, based on the whole power that UVAM can provide, subtracting the load's consumption.
Every fifteen minutes, the BSP has to communicate how much power it can offer, to let Terna know the power that the aggregator can offer and make some modifications in the dispatching market. If UVAM doesn't declare how much power it can deliver, Terna will consider UVAM not available.
Terna can ask to the BSP to increase or decrease the power until it reaches the maximum power, but the increase or decrease in the grid has to satisfy the operating range. If the aggregator can't provide dispatching sources, it has to advise Terna [18].

4.4. Remuneration of the service and verification of compliance

Terna will accept the offer only if this condition is verified:

$|Q_{MSD}(\mathrm{i})| \geq \frac{0,5}{4}$ MWh   i is a quarter of an hour

where:

- Q_{MSD}(i)=$\sum q^{sell}_{EX-ante}$(i) - $\sum q^{buy}_{EX-ante}$(i) + $\sum q^{sell}_{MB}$(i) - $\sum q^{buy}_{MB}$(i)
- $\sum q^{sell}_{EX-ante}$(i) , $\sum q^{buy}_{EX-ante}$(i) represent the energy to sell and to buy in MSD Ex-ante.
- $\sum q^{sell}_{MB}$(i) ,$\sum q^{buy}_{MB}$(i) represent the acceptable energy increase or decrease in the balancing market.

The execution of the quantities accepted in each quarter of an hour i is considered fully respected if the following formulae are fulfilled :

- E_{tot}(i)≥ E_0(i)+ Q_{MSD}(i),   if Q_{MSD}(i)≥0 MWh
- E_{tot}(i)≤ E_0(i)+ Q_{MSD}(i),   if Q_{MSD}(i)≤0 MWh

where:

- E_{tot}(i) represents the total energy withdrawn/injected from the points in UVAM.
- E_0(i) represents the balance of the total energy programmed as injection and/or withdrawal by UVAM, which is computed as:

$$E_0(\mathrm{i}) = \frac{\mathrm{Baseline(i)} * 1\mathrm{h}}{4} + \Delta\ \mathrm{Baseline}$$

where:

- $\mathrm{Baseline(i)}$ is the baseline energy value, every fifteen minutes.
- Δ Baseline is the corrective factor that minimizes the risk for the TSO to pay as an excess or a defect of energy, with respect to the Baseline, resulting from an error of the BSP. For example, if the energy in output is higher than the predetermined one, then the baseline has to be corrected.

Δ Baseline can be computed as:

Δ Baseline= max {0; $\sum_{j=1}^{8}[\ E_{tot}(\mathrm{j}) - \mathrm{Baseline(j)}/4]/\mathrm{n}$ }   if Q_{MSD}(i)≥0 MWh

Δ Baseline=min{0; $\sum_{j=1}^{8}[\,E_{tot}(\mathrm{j}) - \mathrm{Baseline}(\mathrm{j})/4]/\mathrm{n}\,\}$ if Q_{MSD}(i)≤0 MWh

where:

- $[E_{tot}(\mathrm{j}) - \mathrm{Baseline}(\mathrm{j})/4]$ represents the difference between the energy effectively withdrawn/injected by the points inside UVAM and the energy withdrawn/injected programmed by the BSP.
- n represents the number of quarters of an hour before the hour in which the Baseline correction is made. Parameter n should not exceed eight.

If the conditions:

- E_{tot}(i)≥ E_0(i)+ Q_{MSD}(i), with Q_{MSD}(i)≥0 MWh
- E_{tot}(i)≤ E_0(i)+ Q_{MSD}(i), with Q_{MSD}(i)≤0 MWh

are not respected, Terna will apply a fee to the BSP.

Defining the quantity:

$Sbil_{UVAM}(\mathrm{i})$ =(E_{tot}(i) –[E_0(i)+ Q_{MSD}(i)])

we show how the fee is computed:

If Q_{MSD}(i)$>$ 0 and $Sbil_{UVAM}(\mathrm{i})$ <0, the fee is computed as:

$Fee = Sbil_{UVAM}(\mathrm{i})$*max($P_{MB}^{marg}$(i); P_{MSD}^{UVAM}(i))

where:

- P_{MB}^{marg}(i) represents the highest price of the accepted upward offers in the balancing market, in a quarter of an hour i.
- P_{MSD}^{UVAM}(i) represents the weighted average price for the accepted upward offers, with reference to UVAM in a quarter of an hour i.

if $Q_{MSD}(\mathrm{i}) < 0$ and $Sbil_{UVAM}(\mathrm{i}) > 0$, the fee is computed as:

$Fee = Sbil_{UVAM}(\mathrm{i})$*min($P_{MSD}^{marg}$(i); P_{MB}^{UVAM}(i))

where:

- P_{MB}^{marg}(i) represents the lowest price of the accepted downward offers, in the balancing market, in a quarter of an hour i.

- P_{MSD}^{UVAM}(i) represents the weighted average price, for the accepted downward offers, with reference to UVAM in the quarter of hour i [18].

5. Load and photovoltaic forecasting

In the thesis a deterministic model is developed, whose input data are from the real photovoltaic and load measures, taken in 2018. If we want to study a stochastic model, we have to take into account load and photovoltaic forecasting.
In this chapter we show how to take into account load and photovoltaic forecasting to predict the upward and downward services that the aggregator can provide.

5.1. Load forecasting

It is very important to know the uncertainty related to load forecasting to assess the precision of the model. Starting from measured load values (power) and forecast load values (power), the hourly mean error is computed: $\left|\frac{measured\ value - forecast\ value}{measured\ value}\right|$, dividing the year into seasons. Values are taken every 15 minutes, so in one day there are 96 measures. The values were measured in 2010 in the North of Italy.

Winter season

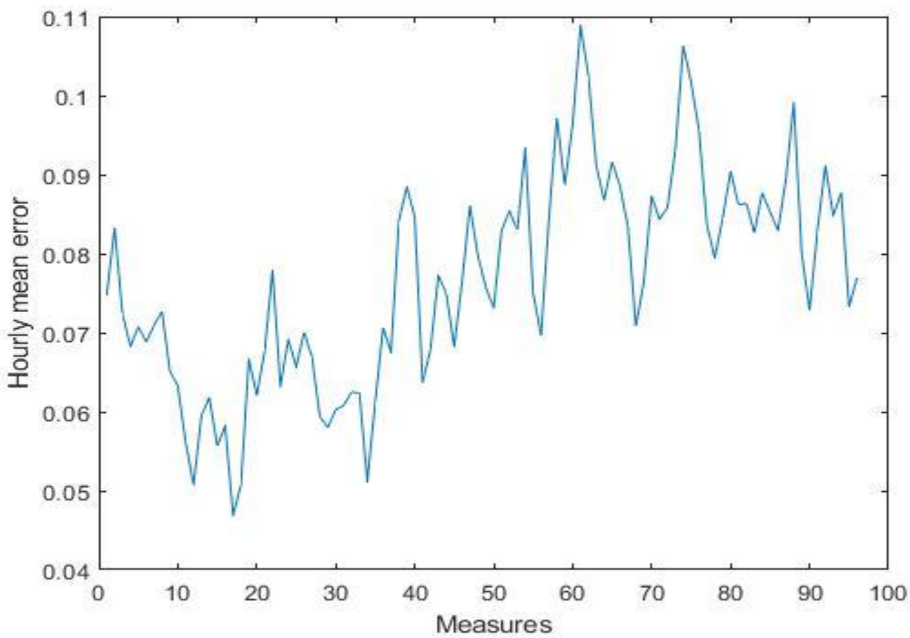

Figure 3 Hourly mean load error in Winter (y-axis) vs. measures (x-axis)

Spring season

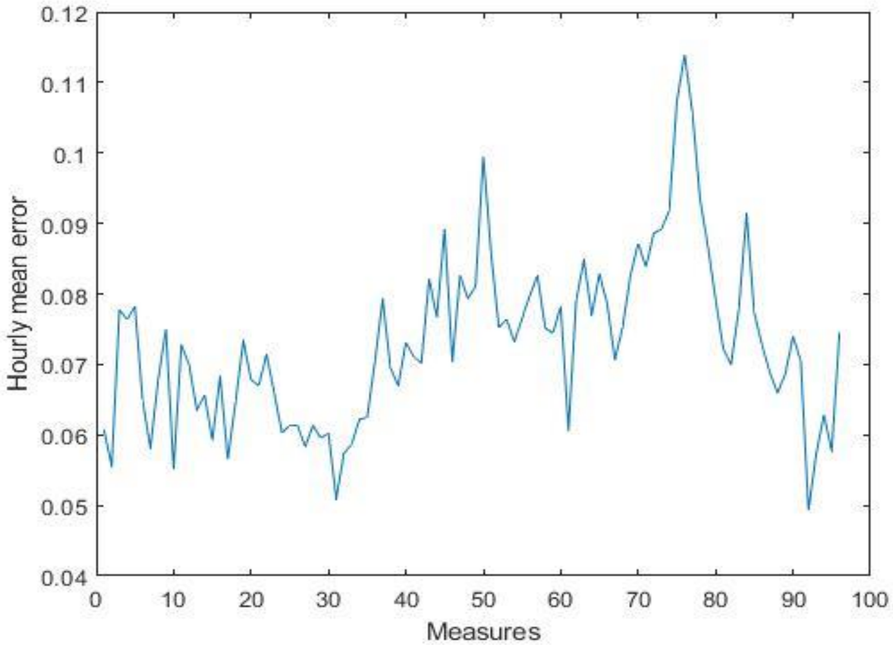

Figure 4 Hourly mean load error in Spring (y-axis) vs. measures (x-axis)

Summer season

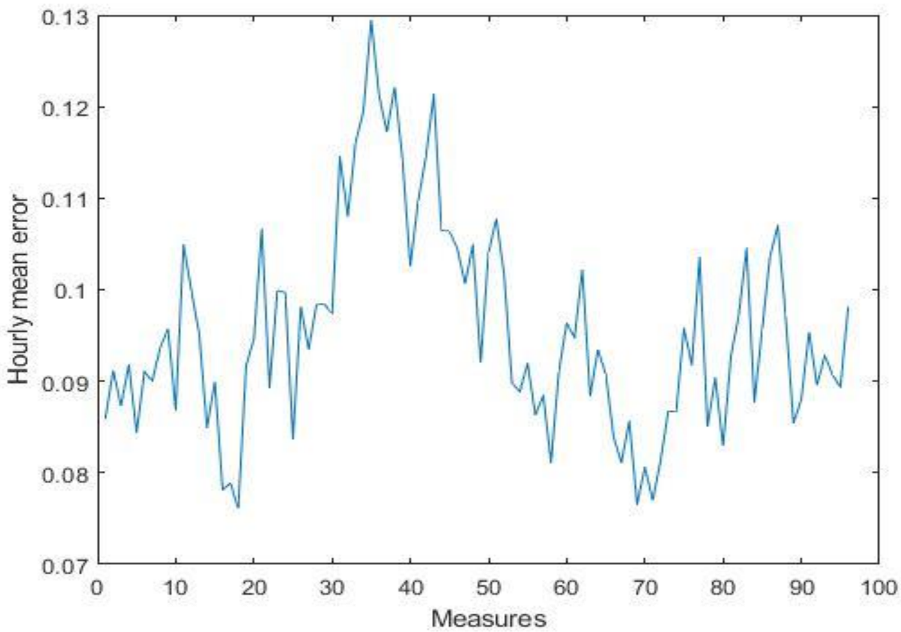

Figure 5 Hourly mean load error in Summer (y-axis) vs. measures (x-axis)

Autumn season

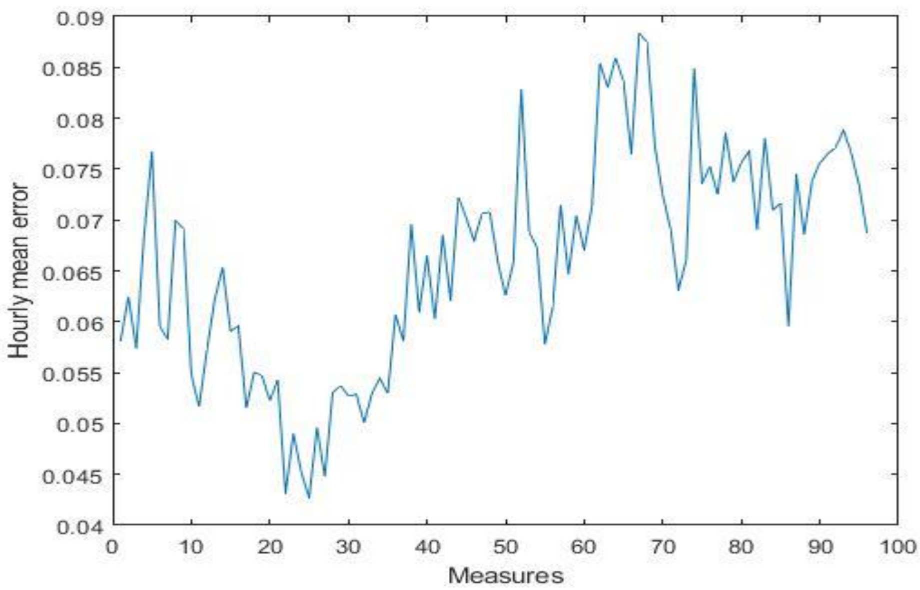

Figure 6 Hourly mean load error in Autumn (y-axis) vs. measures (x-axis)

The hourly load mean errors are reported according to the season from figure from 3 to figure 6. From the plots we can see that maximum error is in Summer and it is equal to 13%.

5.2. Photovoltaic forecasting

It is analyzed the uncertainty in photovoltaic forecasting.

The measures are taken in 2018 in Milan, in the Test Facility laboratory in RSE (Ricerca sul Sistema Energetico), which provides a low voltage microgrid that interconnects different generators (photovoltaic panels, wind turbines…) and storage systems.

Starting from measured photovoltaic values (power) and forecast photovoltaic values (power), I computed the hourly mean error: $\left|\frac{measured\ value - forecast\ value}{measured\ value}\right|$, dividing the year into seasons. Each value is taken every 15 minutes, so in one day there are 96 measures.

Winter season

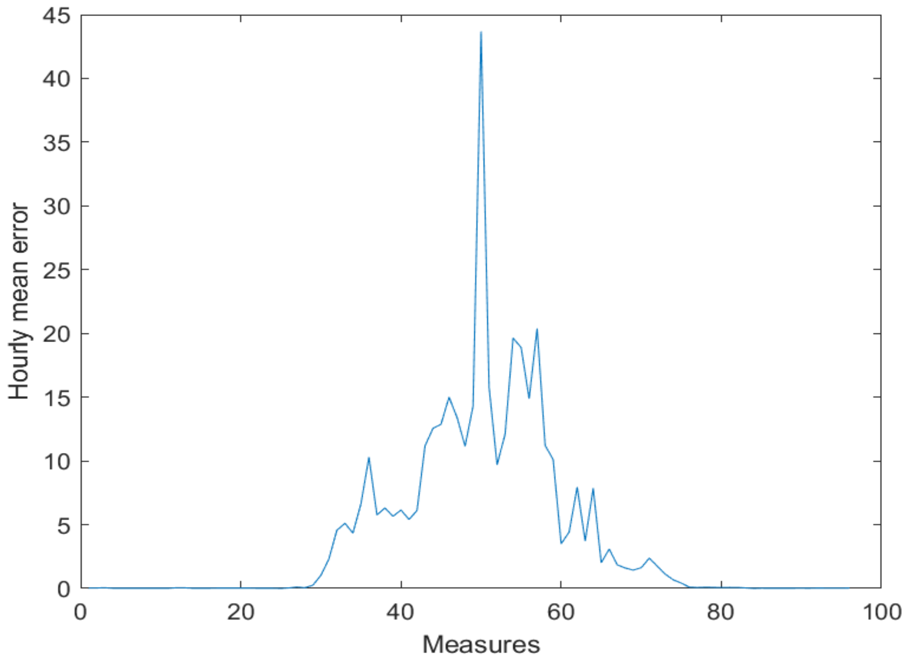

Figure 7 Hourly mean photovoltaic error in Winter (y-axis) vs. measures (x-axis)

Spring season

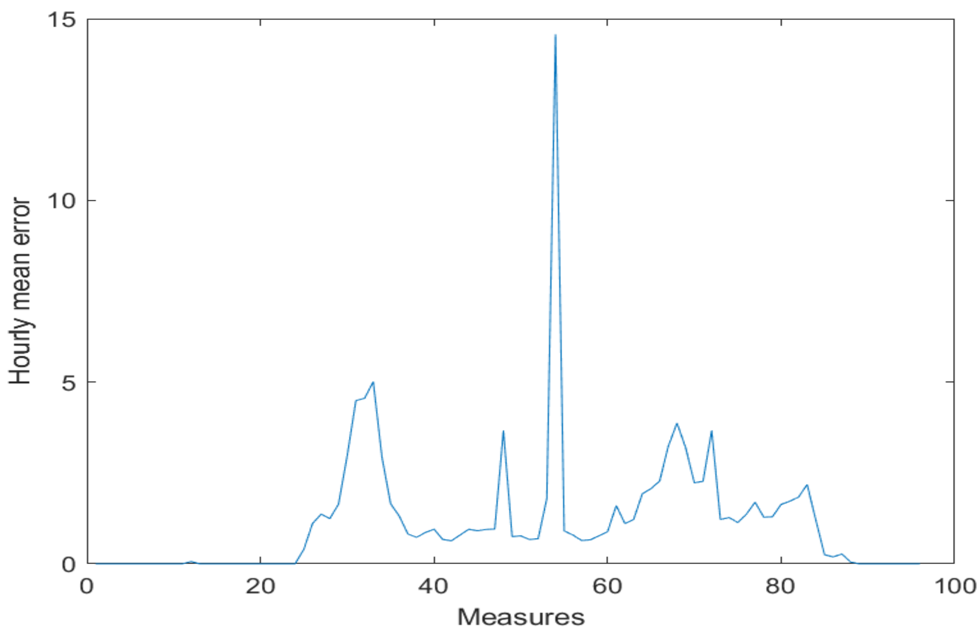

Figure 8 Hourly mean photovoltaic error in Spring (y-axis) vs. measures (x-axis)

Summer season

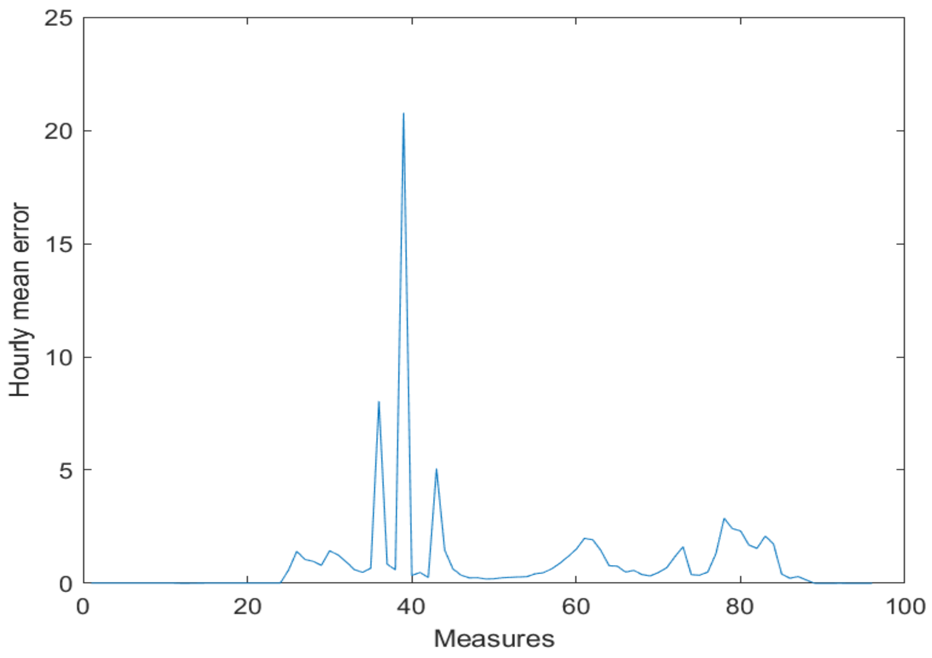

Figure 9 Hourly mean photovoltaic error in Summer (y-axis) vs. measures (x-axis)

Autumn season

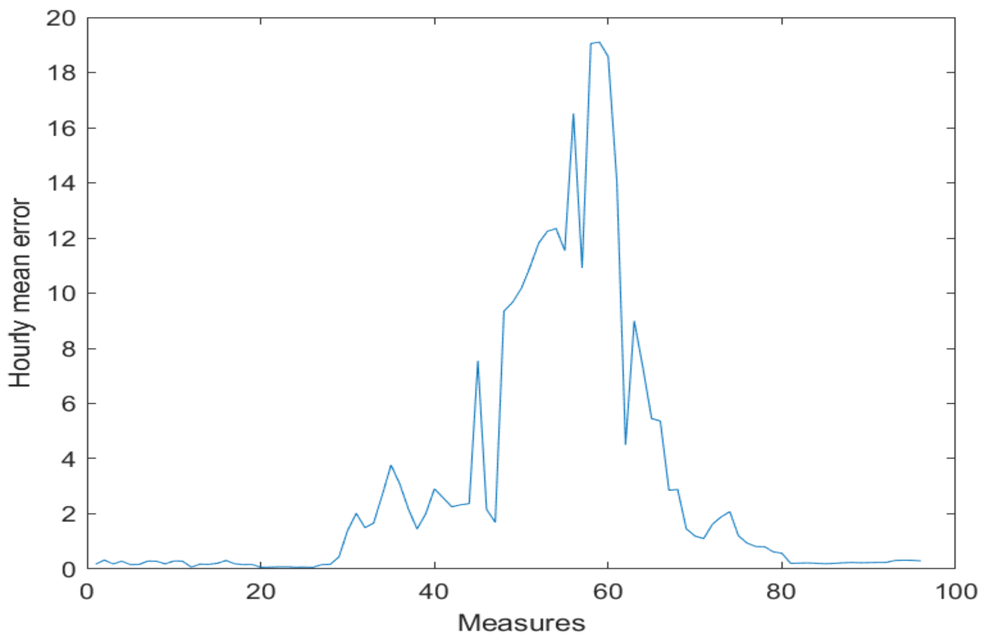

Figure 10 Hourly mean photovoltaic error in Autumn (y-axis) vs. measures (x-axis)

The hourly photovoltaic mean errors are reported according to the season from figure from 7 to figure 10.

6. Mathematical model of the optimization problem

This chapter describes the mathematical model of the optimization problem, whose aim is to maximize the gain of the aggregator, given by the participation in the electricity market.

6.1. Problem modelling

An optimization problem aims to maximize or minimize an objective function from all feasible solutions that satisfy a given set of constraints. A typical optimization problem includes: an objective function that we want to optimize, variables of the problem, constraints on the variables.

For example, we want to minimize the objective function $J(x)$:
$min_x \ J(x)$, such that $h(x) \geq 0$ and $g(x) = 0$, where x is the variable and $h(x)$ and $g(x)$ are the constraints.

We remind the following definitions from optimization theory:

- Feasibility set Ω={ x∈ R^n: $h(x) \geq 0, g(x) = 0$ } is the set of the values allowed by the constraints.
- Global minimizer x^*: $J(x^*)$≤ $J(x)$ ∀ x ∈ Ω is the only point inside the feasible set in which the objective function has the minimum value.

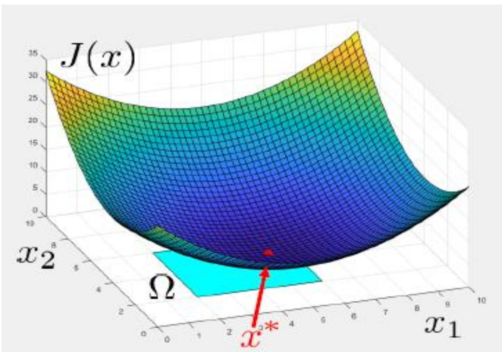

Figure 11 Global minimizer

- Local minimizer x^*: ∃ $N \ of \ x^*$: ∀x ∈ N ∩ Ω $J(x^*)$≥ $J(x)$ is the only point in its neighborhood and in the feasible set, in which the objective function has the minimum value, as shown in figure 11.

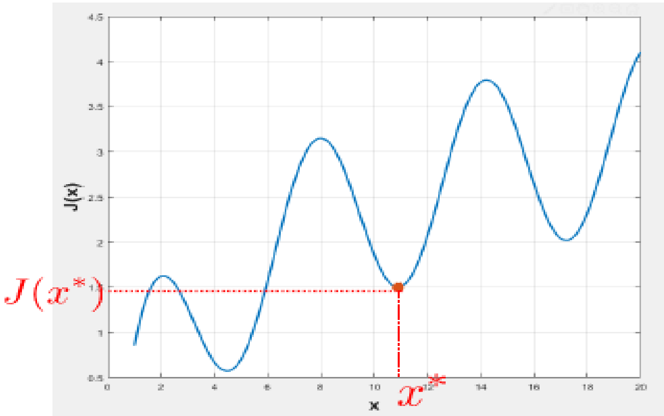

Figure 12 Local minimizer

To model an optimization problem we take into consideration the decision variables, the objective function and the constraints. The objective function and the constraints can be linear or non-linear; the decision variables can be continuous, discrete and mixed-integer.

An optimization problem can be convex or not convex. A function is convex if the line segment between any two points on the graph of the function lies above or on the graph, as shown in figure 13. A set is convex if each pair of points is connected by a segment fully inside the set, as shown in figure 14. An optimization problem is convex if both the function to be optimized and the constraints sets are convex. If an optimization problem is convex, than each local minimizer is also a global minimizer.

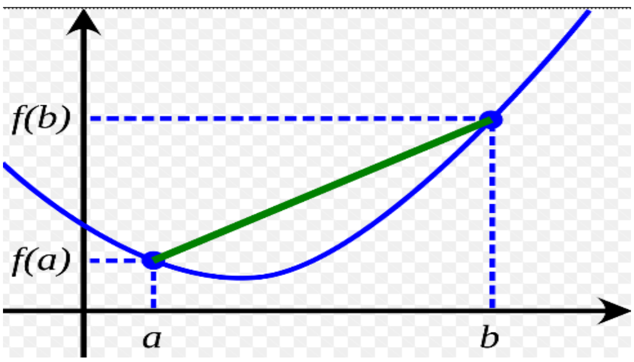

Figure 13 Convex function

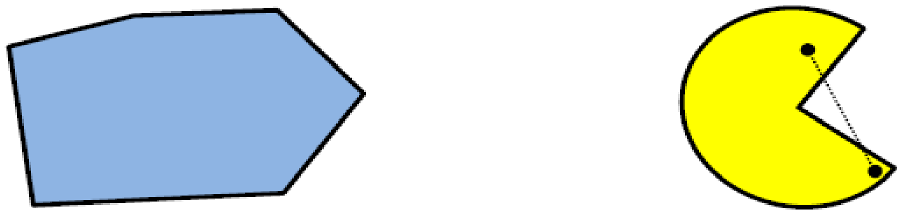

Figure 14 Convex and non convex figure

In the model of this thesis there are continuous constraints, a continuous objective function, continuous and discrete variables. This problem is classified as a MILP (Mixed- Integer-Linear-Programming), due to the presence of both continuous and discrete variables. In the following the canonical form of a mixed integer linear problem is described, where x are continuous variables and y are discrete variables:

$$\min_{x \in \mathbb{Z}^n,\ y \in \mathbb{R}^n} \ c^T x + \ d^T y$$

$$Ax + By + f \geq 0$$

$$Cx + Dy + g = 0$$

Since in MILP problems there are discrete binary variables that are used to model yes/no decisions, the optimization problem will be non-convex and more difficult to solve. Memory and computation time increase exponentially as more integer variables are added. The solution field is a n-dimensional space where n is the number of continuous and discrete variables.

6.2. Solutions of optimization problems

This section briefly introduces the techniques to solve an optimization problem. Consider the following LP (Linear Programming) problem whose solution space is shown in figure 15:

$$\max_{x_L,\ x_B} \ 3000x_L + 5000x_B$$

$$\begin{aligned} & x_L + x_B \leq 12 \\ & 7x_L \leq 70 \\ & 3x_B \leq 18 \\ & 10x_L + 20x_B \leq 160 \\ & x_L \geq 0 \\ & x_B \geq 0 \end{aligned}$$

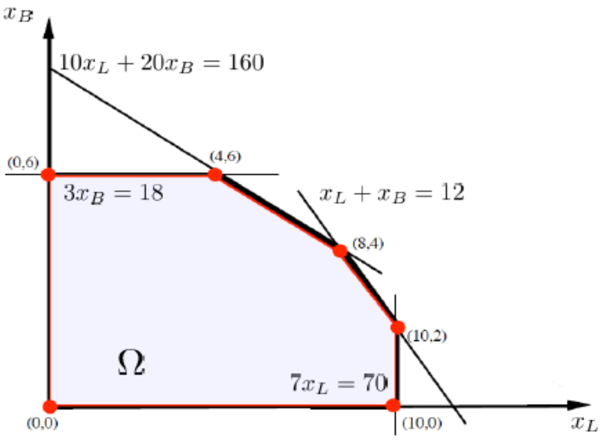

Figure 15 Example of two dimensional LP

In this LP problem, the objective function is a linear function with two continuous variables. The boundary of the solution field is represented by straight lines (i.e. constraints). The maximum of the function is obtained in one point of the feasible set, on one of the polygon's vertices:

- (0,6), J=30000;
- (4,6), J=42000;
- (8,4), J=44000;
- (10,2), J=40000;
- (10,0), J=30000;

The maximum is reached at the point (8,4).

If the problem has many variables, instead of exploring all the vertices of the polygon we can use the 'Simplex Algorithm' to reach quickly the optimum solution, moving in a smart way through the vertices.

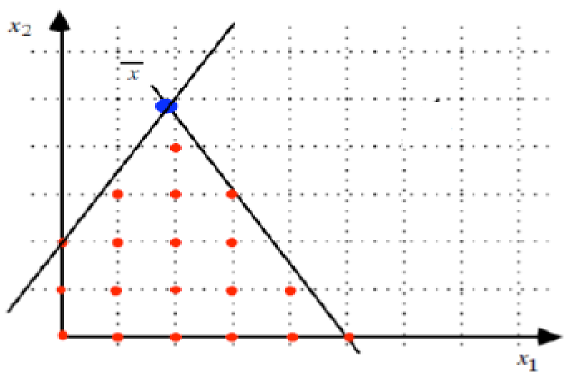

Figure 16 Example of a linear integer problem

Figure 16 shows a ILP (integer linear programming) problem, which is not convex, and whose hyperspace is a n-dimensional lattice made of discrete points. The optimum solution of an ILP problem is not necessarily on the vertex of the feasible set, so we can not use the simplex algorithm. To solve an ILP we can use two methods:

- Cutting planes
- Implicit enumeration

Implicit enumeration methods are based on applications of the Branch and Bound algorithm: it divides the problem into subproblems easier to be solved, fixing some variables values at different levels and creating branches of possible solutions. Analyzing each node some branches are removed, proving their non-optimality and adding sharpening constraints to the variables, reducing the number of solutions to be inspected.

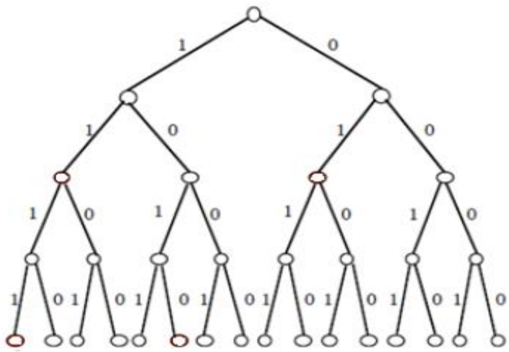

Figure 17 Branch and Bound method

The cutting planes method does not consider explicitly that variables are integer and solves the associated linear problem, to obtain a feasible solution. Geometrically this solution will be a vertex of the polytope of all feasible solutions. If this vertex is not an integer point, the method finds a hyperplane with the vertex on one side and all feasible integer points on the other. This is then added as a linear constraint to exclude the vertex found, creating a modified linear problem. The new problem is then solved and the process is repeated until an integer solution is found.

The Branch and bound method can be extended to solve a MILP problem [19].

6.3. Implementation of the model

The MILP model has been implemented and solved, by two Matlab procedures which call functions of the software interface YALMIP. The Matlab code allows the user to write the problem in a symbolic form, and then to translate it and make it understandable to the MILP solver CPLEX. Since our optimization problem involves a high number of variables and constraints, the solver CPLEX was chosen for its efficiency and robustness. CPLEX can solve linear and quadratic problems with continuous and integer variables and mixed integer linear problems.

7. Daily model of an aggregator

This chapter describes the mathematical model of an aggregator in the electricity market during a day. The input data, the decision variables, the constraints and the objective function are explained.

7.1. Input data

Input data are the load demand, the photovoltaic curve, the prices of the balancing market and the users' batteries characteristics.

The load inputs referred to 399 average users in Italy, with a power consumption of 3kW for each user. Each value is taken every 15 minutes, since upward power and downward power have to be offer within 15 minutes from the receipt of Terna dispatching order.

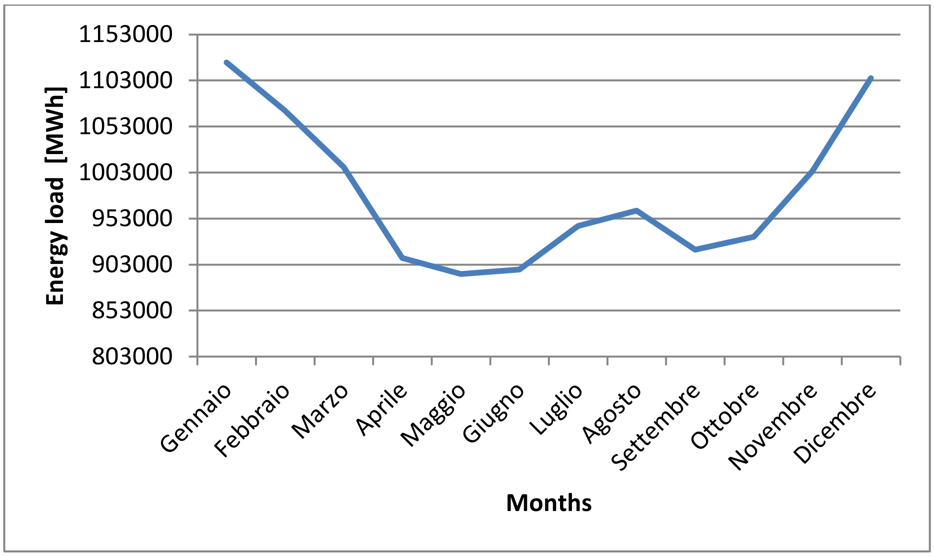

Figure 18 Energy load (y-axis) vs. months (x-axis)

Figure 18 shows the energy-load for each month of 399 users. From January to March the load curve reaches the peak, since there is an increase of electricity consumption due to an heavy use of electric appliances. In April the load curve decreases since the weather conditions improve and there is no need to use the electric heater. From June until September there is an increase in the load curve, since people use air-conditioning. From October to December the load curve increases.

The photovoltaic measures were taken in 2018 in Milan, in the photovoltaic plant (30 kW) of RSE (Ricerca sul Sistema Energetico). Each value is taken every 15 minutes.

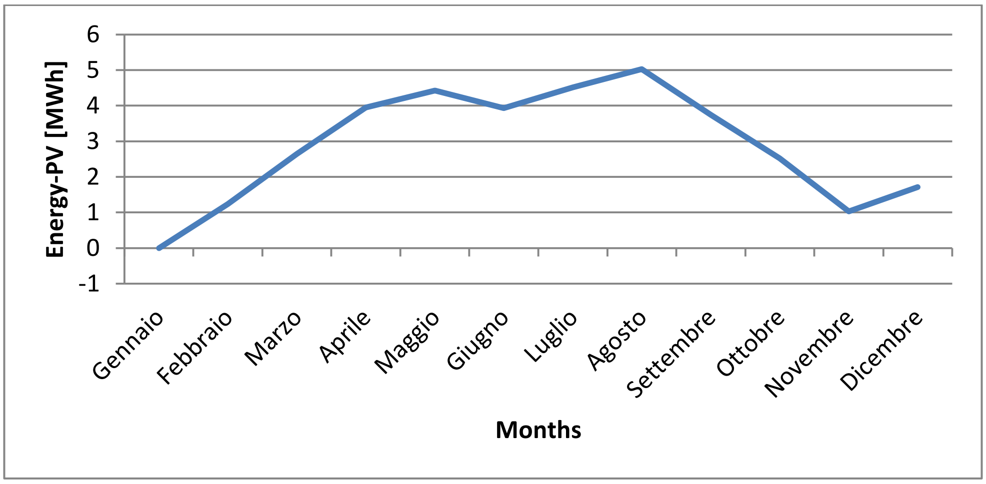

Figure 19 Photovoltaic energy (y-axis) vs. months (x-axis)

Figure 19 shows the photovoltaic curve. During January and February the photovoltaic curve is low since there is less sun radiation. Starting from March the curve increases, reaching a peak of 4,5 MWh in May. There is a little decrease in June and then the curve reaches another peak in August. Starting from September the photovoltaic curve decreases until December.

Figure 20 and figure 21 show upward prices and the downward prices accepted in 2018 in the balancing market [20].

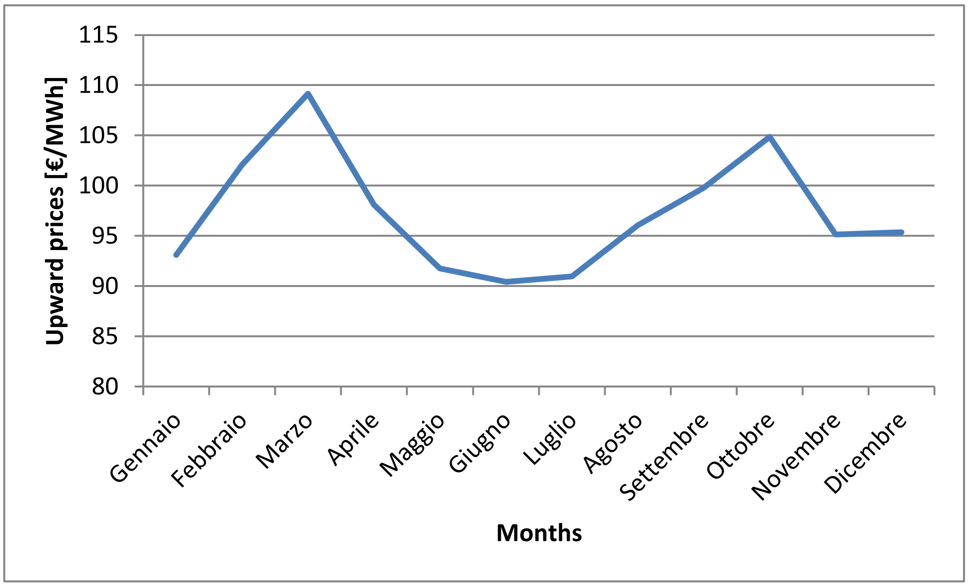

Figure 10 Upward prices (y-axis) vs. months (x-axis)

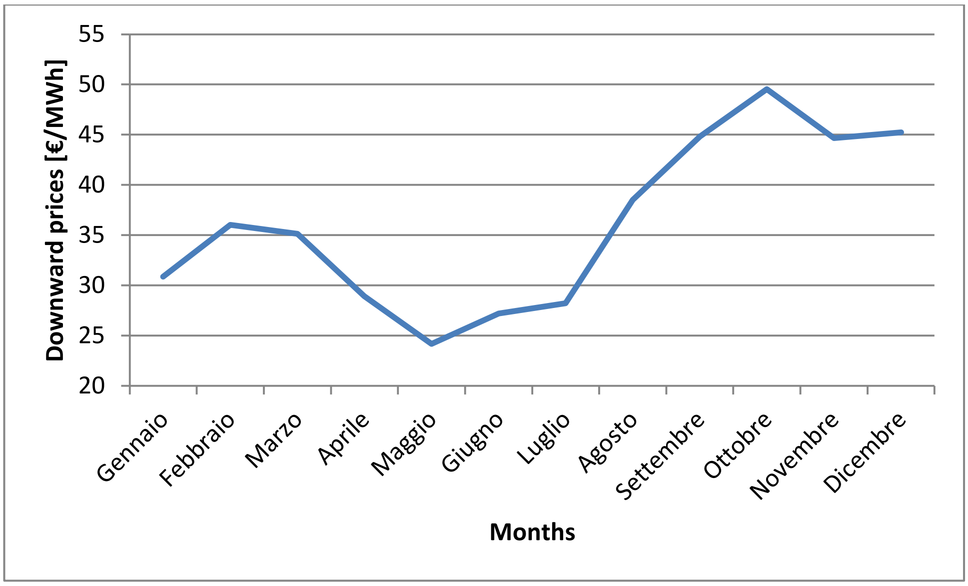

Figure 21 Downward prices (y-axis) vs. months (x-axis)

Figures 20 and 21 show the average upward prices and downward prices, during each month. Upward prices are greater then downward prices, since downward prices represent a repurchase of the amount of energy already sold in the previous market sessions. Upward offers will be submitted with a higher price that in the day-ahead market, with the aim to sell the quantity of energy not sold in the previous market sessions. Purchase offers are presented with a lower price than in the day-ahead market, with the aim to buy back the energy already remunerated at a higher price.

The daily optimization model has a discretization time of one hour. Starting from the load demand of 399 users, it is made an enlargement to 750 users of the population through a Gaussian Distribution, to see the variation of the aggregator's gain, with different simulations.

Input data are listed:

- Power load values, taken every 15 minutes, referred to 750 users
- Power photovoltaic values, taken every 15 minutes, referred to 750 users
- Storage system of each user, with size of 4 kWh. The total aggregator's maximum energy is $E_{max} = 4\ \mathrm{kWh} * n = 3\ MWh$, where n is the number of users
- Maximum charging and discharging power, equal to 2 kW for each user. The maximum aggregator's charging power is: $P_{max-ch} = -2\ \mathrm{kW} * n = -1{,}5\ \mathrm{MW}$

and the maximum aggregator's discharging power is: $P_{max-dh} = 2\text{ kW} * n = 1{,}5\text{ MW}$

- Hourly upward prices and downward prices of the balancing market, accepted in 2018

The power load value per unit is: $\frac{Ld}{n*3k}$

- Ld is the power load value sum of 750 users
- n is the number of users
- $3k$ is the consumption power of each user

It is supposed that each user is equipped with a photovoltaic plant, whose size is 30 kW. Each photovoltaic value (PV) is multiplied by the number of users, since the photovoltaic values refer to one plant, and is normalized per unit: $\frac{PV}{\max(PV)} * n$

- PV is the power photovoltaic value
- $\max(PV)$ is the maximum PV value of the year
- n is the number of users

7.2. Definitions

- $E(1)$ = initial state of charge of the battery = E_{max}*SOC_{start}
- E = energy in the battery = $E(1) + \int(-P_{baseline})* \, dt$
- PV = photovoltaic power
- Load = load power
- dt = time step
- E_{max}= maximum energy in the battery
- P_{max-ch} = maximum charging power
- P_{max-dh} = maximum discharging power
- SOC_{min}= minimum state of charge in the battery= 0,1
- SOC_{max}= maximum state of charge in the battery =0,9
- $P_{batteria} = P_{salire}+P_{scendere}+P_{baseline}$
- $E_{acquisto} = \int(P_{acquisto})* \, dt$
- $E_{vendita} = \int(P_{vendita})* \, dt$
- $Prezzi_{salire}$ = upward prices in the balancing market
- $Prezzi_{scendere}$ = downward prices in the balancing market
- prezzoE = 50 €/MWh. Price of the day-ahead market, about the energy sold to the grid, without participating in the balancing market

- costoE =200 €/MWh. Price of the day-ahead market, about the energy bought from the grid, with charges, without participating in the balancing market.

7.3. Decision variables

We describe a mixed integer linear problem (MILP), since there are discrete and continuous variables.

Continuous variables:

- SOC_{start}= initial state of charge of the battery
- P_{salire}= upward power that we sell in ASM
- $P_{scendere}$= downward power that we buy in ASM
- $P_{acquisto}$= power bought from the grid, without the participation in the balancing market
- $P_{vendita}$= power sold to the grid, without the participation in the balancing market
- $P_{baseline}$= $P_{batteria}$−P_{salire}−$P_{scendere}$

Discrete binary variables

- STATO_SALIRE is zero in case of upward power, otherwise it is equal to one.
- STATO_SCENDERE is zero in case of downward power, otherwise it is equal to one.
- STATO_VENDITA is one in case of power sold to the grid, otherwise it is zero.

7.4. Constraints

Batteries constraints are:

- E >=SOC_{min}*E_{max} and E <=SOC_{max}*E_{max}

The state of charge of the battery is between a minimum and a maximum value.

- $P_{batteria}$>=P_{max-ch} and $P_{batteria}$<=P_{max-dh}

The power battery depends on the maximum charging and discharging power.

- $|P_{baseline}|$<=$|\mathrm{Load} - \mathrm{PV}|$

The power baseline is less or equal than the absolute value of the difference of the power load minus the photovoltaic power.

- SOC_{start}>= 0,2 and SOC_{start}<=0,8

The initial state of charge of the battery is between 0,2 and 0,8.

- $P_{batteria}$=$P_{baseline}$+P_{salire}+$P_{scendere}$

The power battery is equal to the power baseline, plus upward power and downward power.

Offer constraints are:

- P_{salire}>=0
- $P_{scendere}$<=0

According to Terna's regulation, upward power must be positive and downward power must be negative.

Upward offer and downward offer cannot be submitted at the same time, so another constraint is added involving two binary variables, which specify if one of the two offers is present.

- STATO_SALIRE+ STATO_SCENDERE ≤ 1

According to the regulation issued by Terna, upward power and downward power must be equal at least respectively to 1 MW and -1 MW, otherwise, the offer is not accepted. This translates into the following constraints:

- STATO_SALIRE=0 $\leftrightarrow$ $P_{salire} \geq$ 1 MW
- STATO_SCENDERE=0 $\leftrightarrow$ $P_{scendere} \leq$-1 MW

Exchanged power constraints refer to the case of no participation in the ASM and they are:

- $P_{acquisto}$+$P_{vendita}$= $P_{batteria} + \mathrm{PV} - \mathrm{Load}$

The power bought and sold to the grid is equal to the power battery, plus photovoltaic power, minus load power.

- $P_{acquisto}$= STATO_VENDITA *($P_{batteria} + \mathrm{PV} - \mathrm{Load}$)
- $P_{vendita}$= 1-STATO_VENDITA *($P_{batteria} + \mathrm{PV} - \mathrm{Load}$)

It means that:

- STATO_VENDITA=1 $\leftrightarrow$ $P_{acquisto} = P_{batteria} + \text{PV} - \text{Load}$
- STATO_VENDITA=0 $\leftrightarrow$ $P_{acquisto} = 0$
- 1-STATO_VENDITA=1$\leftrightarrow$ $P_{vendita} = P_{batteria} + \text{PV} - \text{Load}$
- 1-STATO_VENDITA=0$\leftrightarrow$ $P_{vendita} = 0$

7.5. Big_M technique

To translate the logical constraints into inequalities readable from the interface, we use the Big_M technique. It is a method that translates logical relations into inequalities [21].

An example is shown:

δ=1 $\leftrightarrow$ $f(x)$ ≥0

This constraint can be rewritten in another form, by introducing the binary variable δ :

$$f(x) \geq m - m\delta$$

$$f(x) \leq M\delta$$

It means that:

δ=1→ $f(x) \geq 0$ and $f(x) \leq M$

δ=0→ $f(x) \geq m$ and $f(x) \leq 0$

where $m = min_x \; f(x)$ and $M = max_x \; f(x)$

The application of the Big_M technique in our model introduces the following constraints on the variables: STATO_SALIRE, STATO_SCENDERE , STATO_VENDITA.

- STATO_SALIRE=0 $\leftrightarrow$ $P_{salire} \geq$ 1 MW

  This constraint is translated by:

  1-M*STATO_SALIRE $\leq$ P_{salire} $\leq$ M-M*STATO_SALIRE

  If STATO_SALIRE=0 → 1 $\leq$ P_{salire} $\leq$ M

  If STATO_SALIRE=1 → 1-M $\leq$ P_{salire} $\leq$ 0

- STATO_SCENDERE=0 $\leftrightarrow$ $P_{scendere} \leq -1$ MW

This constraint is translated by:

M*STATO_SCENDERE - M $\leq$ $P_{scendere}$ $\leq$ M*STATO_SCENDERE-1

If STATO_SCENDERE=0 $\rightarrow$ - M $\leq$ $P_{scendere}$ $\leq$ -1

If STATO_SCENDERE=1 $\rightarrow$ 0 $\leq$ $P_{scendere}$ $\leq$ M -1

- $P_{acquisto}$= STATO_VENDITA *($P_{batteria} + \mathrm{PV} - \mathrm{Load}$)

This constraint is translated by:

$P_{acquisto} \leq$ M* STATO_VENDITA

$-P_{acquisto} \leq -(P_{batteria} + \mathrm{PV} - \mathrm{Load})$ + M*(1-STATO_VENDITA)

$-P_{acquisto} \leq$ m* STATO_VENDITA

$P_{acquisto} \leq (P_{batteria} + \mathrm{PV} - \mathrm{Load})$ – m*(1-STATO_VENDITA)

- $P_{vendita}$= 1-STATO_VENDITA *($P_{batteria} + \mathrm{PV} - \mathrm{Load}$)

This constraint is translated by:

$P_{vendita} \leq$ M* 1-STATO_VENDITA

$-P_{vendita} \leq$ -m* 1-STATO_VENDITA

$P_{vendita} \leq (P_{batteria} + \mathrm{PV} - \mathrm{Load})$ – m*(STATO_VENDITA)

$-P_{vendita} \leq -(P_{batteria} + \mathrm{PV} - \mathrm{Load})$ + M*(STATO_VENDITA)

7.6. Offer duration

According to the regulation issued by Terna, upward power and downward power must be provided for at least 2 hours in the balancing market.

- $P_{salire}(t_i) \geq P_{salire}(t_i - n) - P_{salire}(t_i - N)$
- $P_{scendere}(t_i) \leq P_{scendere}(t_i - n) - P_{scendere}(t_i - N)$

Considering in one day 96 intervals of time we have:

T=96, i=1,2…T, t_{min}= 2h, $N=\frac{t_{min}}{t_i}$, n= 1… N.

The first inequality means that the upward power must be equal or greater than the offered power in the previous interval of time, up to the previous eight intervals.

7.7. Time step

Load and photovoltaic data are given every 15 minutes, so there are 96 values in one day, which means 35040 values in the whole year. Since the resolution time grows exponentially with the increase of optimization variables, it is decided to optimize the model every hour, computing the mean of the values that are taken every 15 minutes. For example, in one hour there are 4 load and photovoltaic values, whose mean value is computed and then the cost function is optimized.

7.8. Objective function

Gain= $(((P_{salire} * Prezzi_{salire})+(P_{scendere} * Prezzi_{scendere})) * dt) + \quad (E_{venduta} * \text{prezzoE}) \quad - (E_{acquisto} * \text{costoE})$

The objective is to maximize the aggregator's gain, which is given by the upward offer and the downward offer, and the exchanged energy with the grid, without participating in the balancing market.

7.9. Report of the daily model

Figures 22 and 23 report the photovoltaic and load power of a sunny day, 25 August 2018, based on 96 measures, taken every 15 minutes.

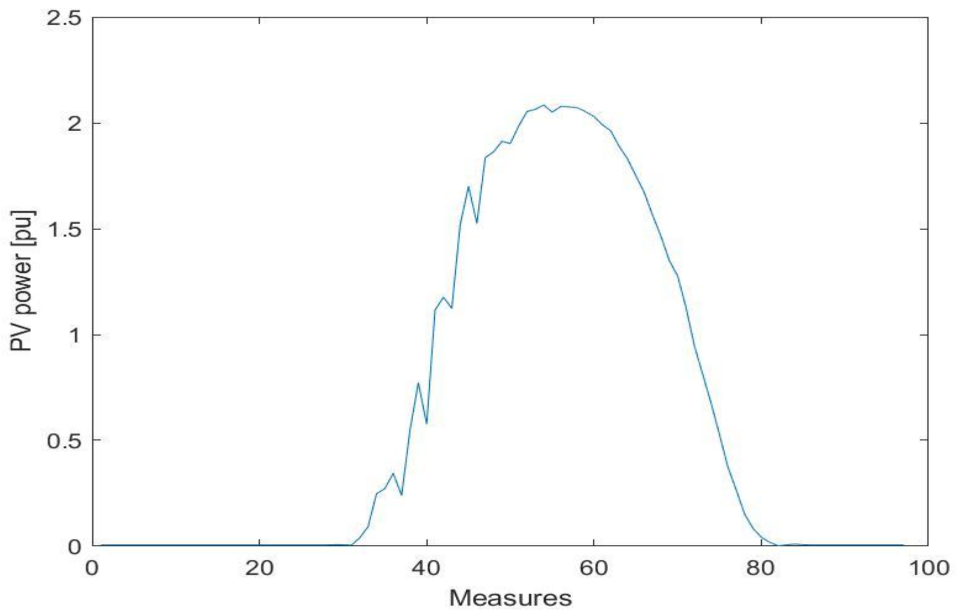

Figure 22 Photovoltaic power (y-axis) vs. measures (x-axis) of 750 users

Figure 22 shows the photovoltaic power in a sunny day. Photovoltaic power starts at 8 am, reaching the maximum value at 3 pm, since it is the hottest hour of the day. Then it decreases, reaching zero at 8 pm, because the sun goes down.

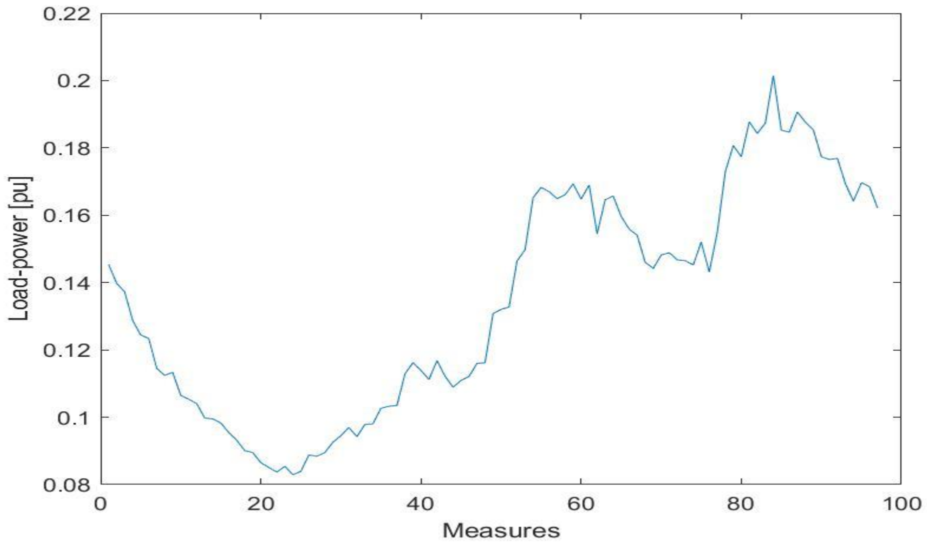

Figure 23 Load power (y-axis) vs. measures (x-axis) of 750 users

Figure 23 shows the load curve. Load power starts to decrease at midnight, reaching the minimum at around 4 am. At 6 am the curve increases because people wake up and use electric appliances. It reaches a peak at 3 pm, when most of the people are working and they need electricity. At 8 pm load power reaches the highest peak, since people came back to their houses and they need to use electric appliances.

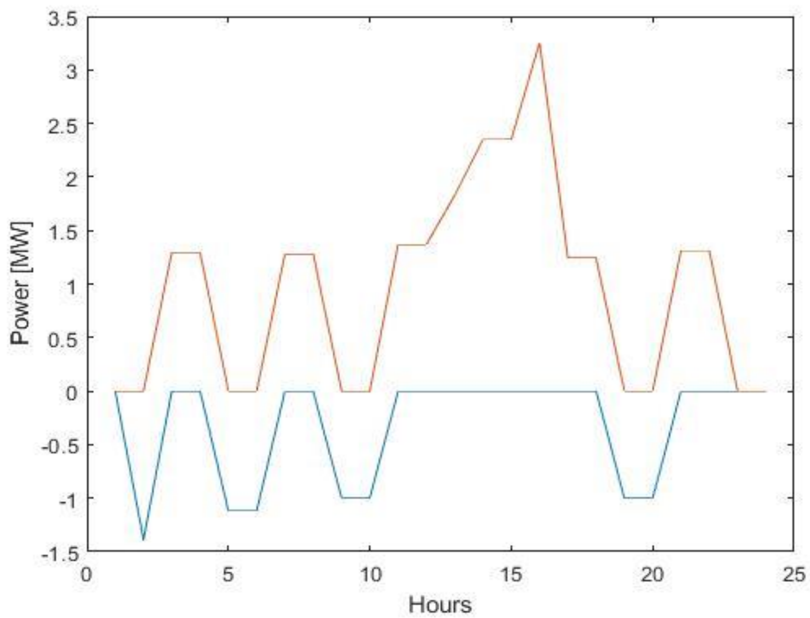

Figure 24 Upward power (blue color) and downward power (red color) (y-axis) vs. hours (x-axis) in a sunny day

Figure 24 shows the upward power and downward power at the same day. Starting from 3 am the power is bought from the grid and sold to the grid every two hours.

At 11 am, the photovoltaic values increase and the aggregator can sell more power to the grid, with a maximum of 3 MW at 3 pm. Then it sells less power, because the photovoltaic value decreases. The upward power and downward power are always respectively positive and negative and they are respectively greater than 1 MW and -1 MW, according to Terna' s rules.

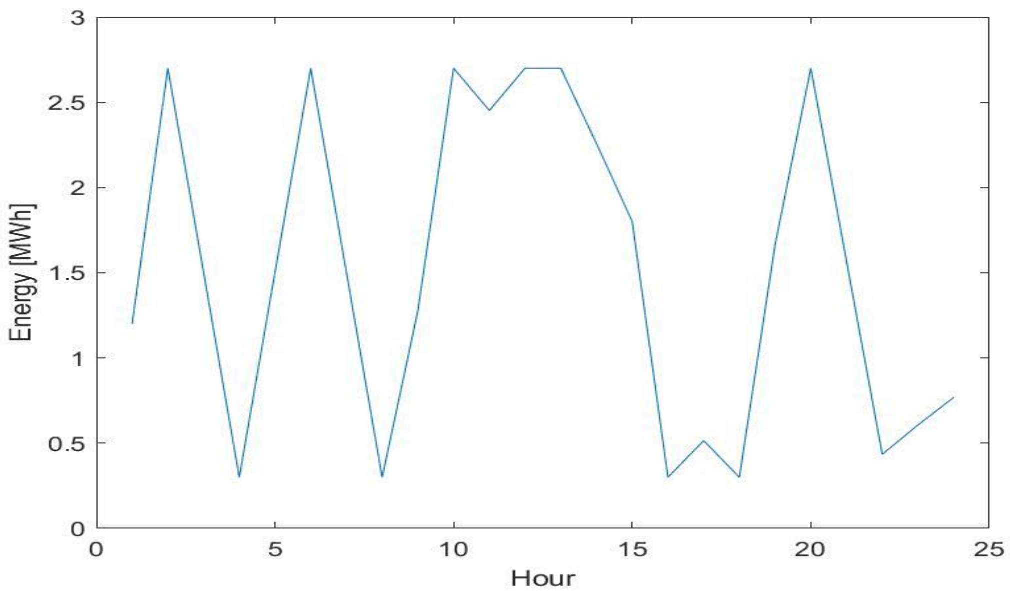

Figure 25 Energy (y-axis) vs. hours (x-axis) in a sunny day

Figure 25 shows the energy inside the battery. At the beginning, the virtual battery is charged and discharged. At around 10 am the battery is charged, reaching almost 3 MWh at 3 pm, which is the maximum energy that can be stored inside it. Then the battery is discharged. At 8 pm it is charged again, reaching another peak, then it is discharged.

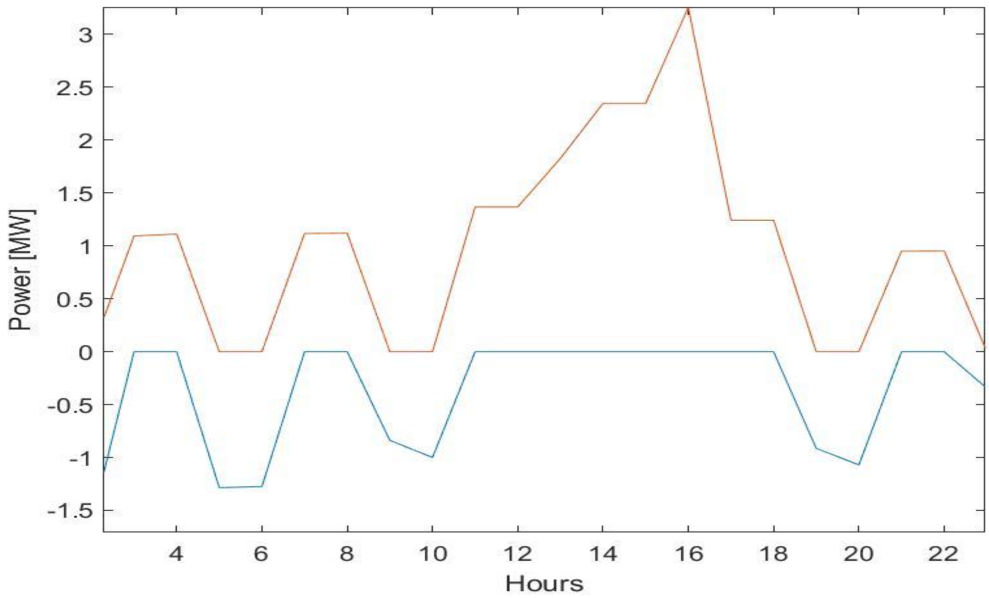

Figure 26 Power sold (red color) and power bought (blue color) (y-axis) vs. hours (x-axis) in a sunny day

Figure 26 shows the power bought and sold to the grid, without partecipation in the balancing market. From 1 am to 8 am, the power sold and bought are respectively 1 MW and -1 MW. From 11 am until 4 pm, a big quantity of power is sold to the grid, reaching 3 MW. Then, at 6 pm power is bought from the grid and at 9 pm power is sold to the grid.

Cloudy day

Figures 27 and 28 report the photovoltaic and load power of a cloudy day, 4 February 2018, based on 96 measures, taken every 15 minutes.

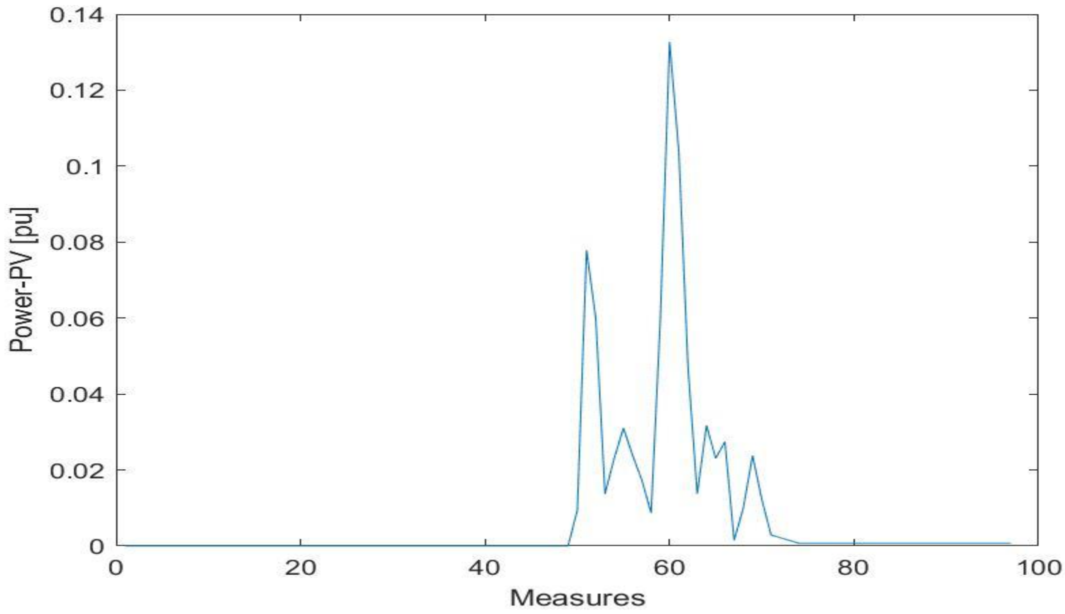

Figure 27 Power (y-axis) vs. measures (x-axis) in a cloudy day of 750 users

Figure 27 shows photovoltaic power in a cloudy day. Until 12 am the photovoltaic curve is zero. Then it increases, because the sun shows up. The highest peak is reached at 3 pm, since it is the hottest hour of the day. At around 6 pm the power curve reaches zero, because the sun goes down.

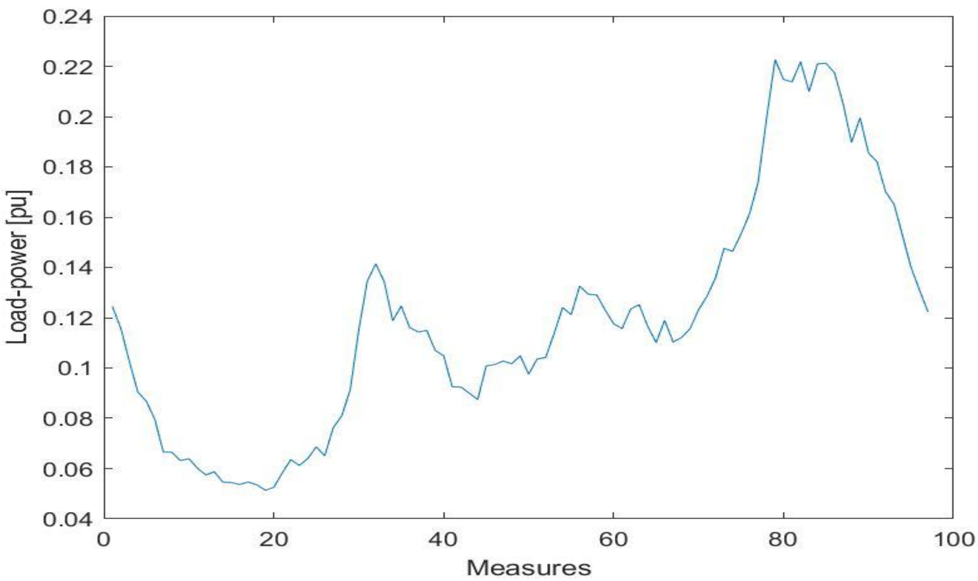

Figure 28 Load power (y-axis) vs. measures (x-axis) of 750 users in a cloudy day

Figure 28 shows the load power in a cloudy day. From midnight until 5 am the load curve decreases. At 5 am the curve increases since people start to wake up. At 8 am power values reach a peak, since most of the people are going out. At 6 pm power load increases, reaching the highest peak at 8 pm when people reached home. Then the curve starts to decrease.

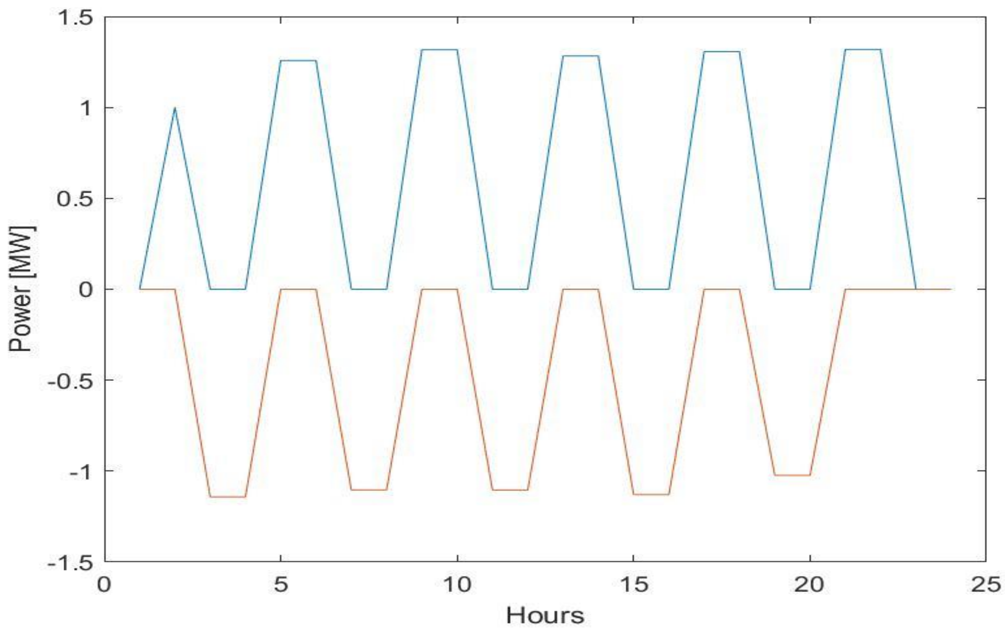

Figure 29 Upward power (blue color) and downward power (red color) (y-axis) vs. hours (x-axis) in a cloudy day

Figure 29 shows the upward power and downward power at the same day. There are many cycles of charging and discharging power. Starting from 3 am power is bought from the grid for two hours and then it is sold to the grid at 5 am. This cycle is repeated every two hours. Upward power and downward power is respectively positive and negative and the amount of power is greater than 1 MW (for upward power) and -1 MW (for downward power), according to Terna’s regulation.

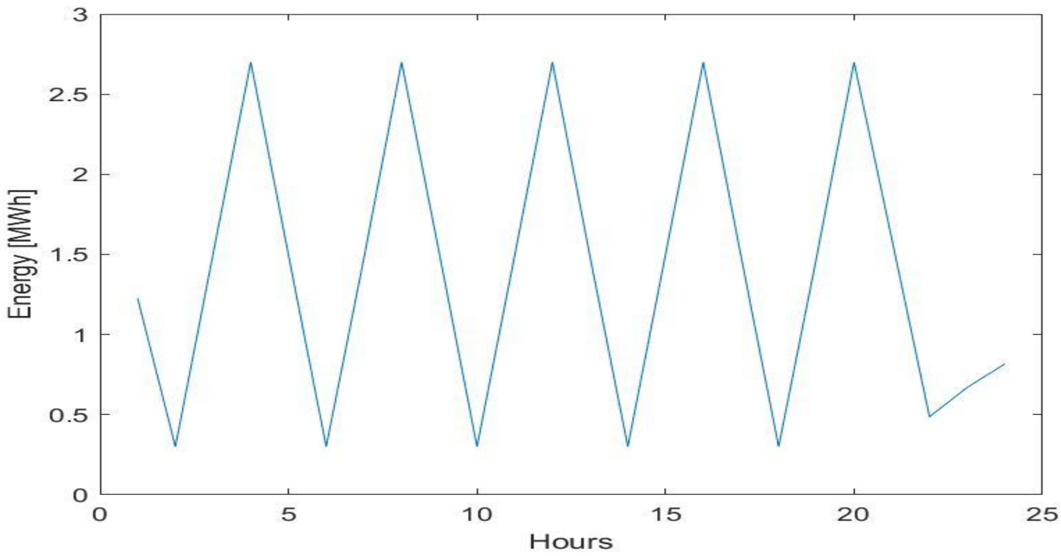

Figure 30 Energy (y-axis) vs. hours (x-axis) in a cloudy day

Figure 30 shows the virtual aggregator battery that is charged and discharged every two hours, reaching the peak value of 2,8 MWh. The maximum energy inside the battery is 3 MWh, so this constraint is respected.

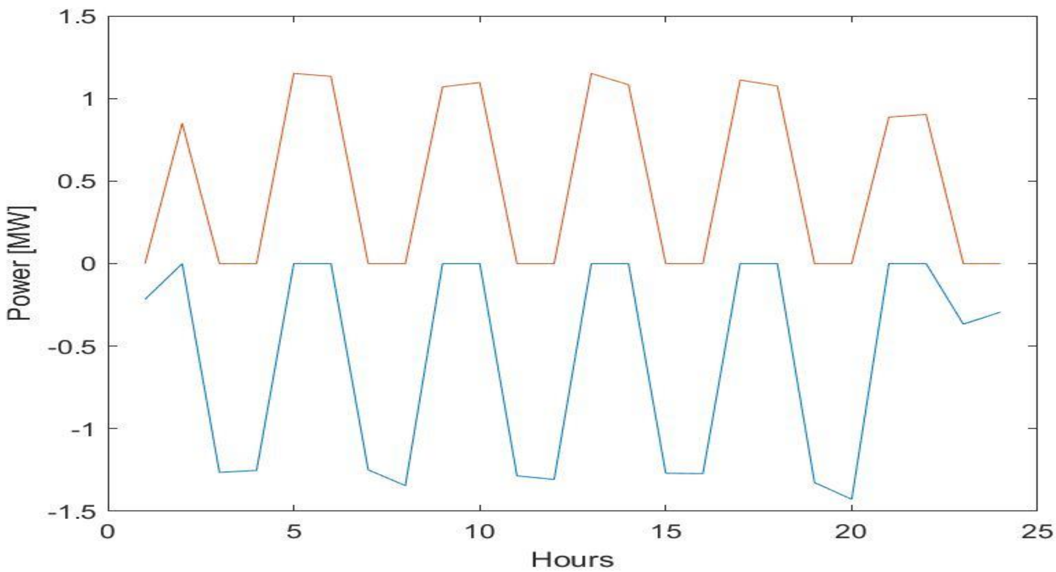

Figure 31 Power sold (red color) and power bought (blue color) (y-axis) vs. hours (x-axis) in a cloudy day

Figure 31 shows the power bought and sold to the grid, without participation in the balancing market. Starting from 3 am, power is bought from the grid. After 2 hours power is sold to the grid. This cycle is repeated in the whole day. Sold power does not have a big variation; it is almost equal to 1 MW. Bought power reaches a peak, equal to -1,5 MW at 8 pm.

8. Annual model of an aggregator

It is developed a deterministic annual model, optimizing the objective function every 4 hours, since the electricity market sessions are every 4 hours, with a time step of 15 minutes.

8.1. Input data

The input data are the same as in the daily model.

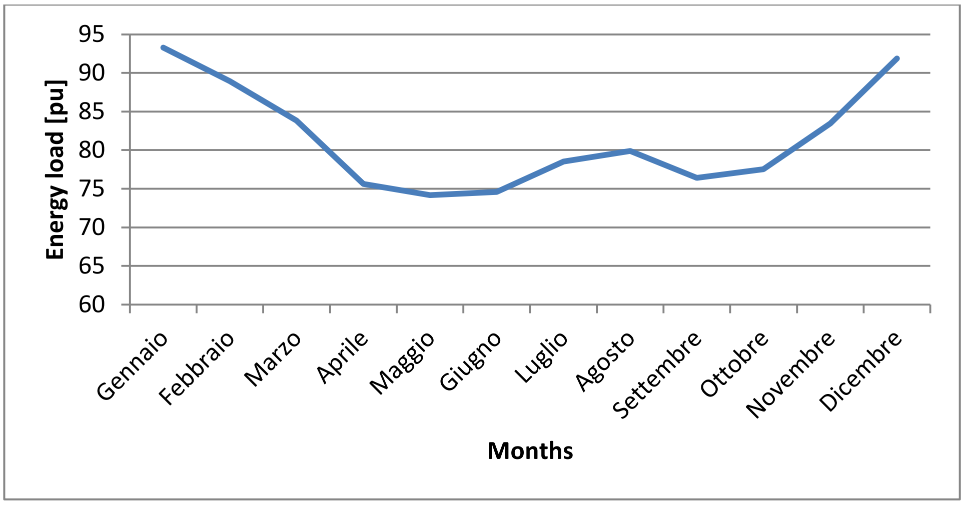

Figure 22 Energy load (y-axis) vs. months (x-axis) for 750 users

Figure 32 shows the load energy during the whole year for 750 users

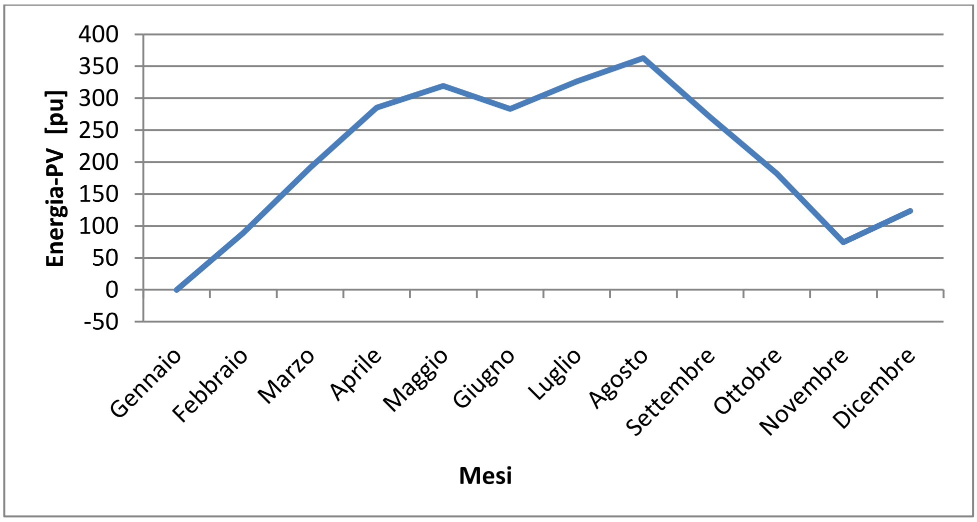

Figure 33 Energy PV (y-axis) vs. months (x-axis) for 750 users

Figure 33 shows the photovoltaic energy for 750 users during the whole year.

8.2. Constraints

The constraints are the same as in the daily mode, except for the state of charge of the battery.

- $SOC(i)_{start}$=$SOC(i-1)_{end}$

i is the number of optimizations, which are 6 per days times 365 days = 2190 optimizations.

This constraint means that, for each optimization, the initial state of charge of the battery is equal to the last state of charge of the previous optimization.

8.3. Sensitivity analysis

Sensitivity analysis is made, changing the number of users, the battery size of each user and the maximum charging and discharging power, specified as below.

Number of users :

- 750 users
- 1000 users
- 2000 users
- 4000 users

Storage system's size:

- E_{max} =4 kWh
- E_{max} =7 kWh

Maximum charging and discharging power:

- $P_{max-ch} = -\frac{E_{max}}{2}$
- $P_{max-dh} = \frac{E_{max}}{2}$
- $P_{max-ch} = -E_{max}$
- $P_{max-dh} = E_{max}$

We report in this chapter only four cases, each with the highest storage system's size and with the nominal power, while the number of users varies from 750 to 1000, 2000 and 4000. The remaining simulations are available in the Appendix 1.

First case:

- 750 users
- E_{max}= 7 kWh
- $P_{max-ch} = -7$ kW
- $P_{max-dh} = 7$ kW

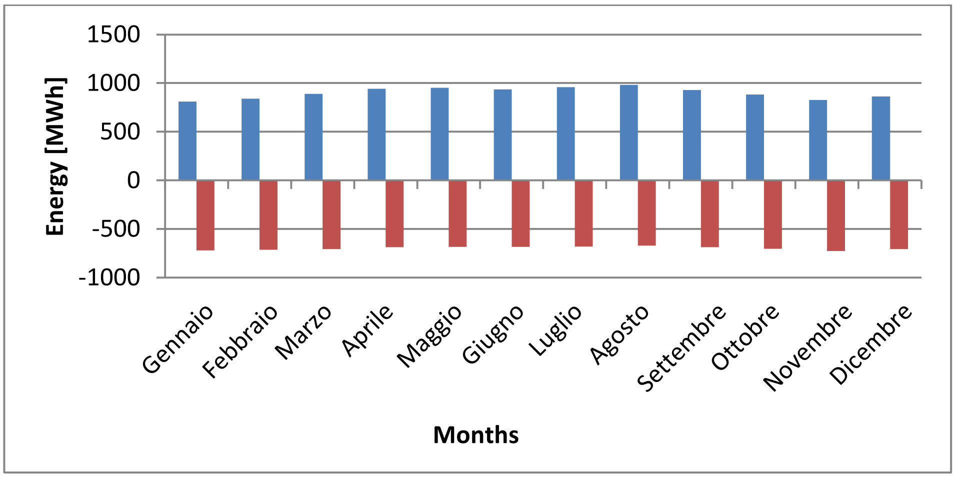

Figure 34 Upward energy (blue color) and downward energy (red color) (y-axis) vs. months (x-axis) in the first case

Figure 34 shows the upward and the downward energy during each month of the year in the first case. From April until August there is an increase of upward energy, reaching the maximum 980 MWh in August. The mean value of the downward energy is -680 MWh, which is almost constant during the year. From June until September there is a little decrease of downward energy, reaching -670 MWh.

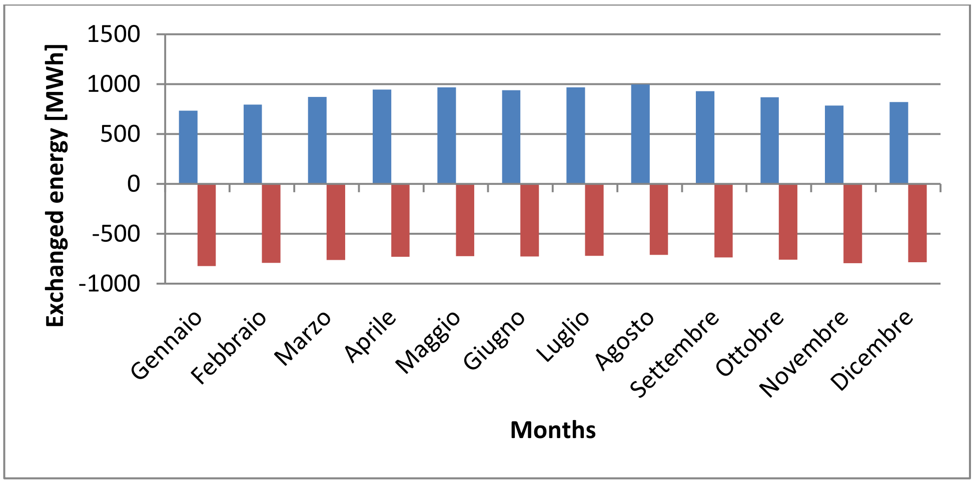

Figure 35 Energy sold (blue color) and energy bought (red color) (y-axis) vs. months (x-axis) in the first case

Figure 35 shows the energy sold to the grid and bought from the grid, without participating in the ASM during each month of the year, in the first case. The energy sold to the grid increases from April until August, reaching the peak value of 995 MWh. The energy bought decreases in summer months, reaching the minimum value of -710 MWh in August.

Second case:

- 1000 users
- E_{max}= 7 kWh
- $P_{max-ch} = -7$ kW
- $P_{max-dh} = 7$ kW

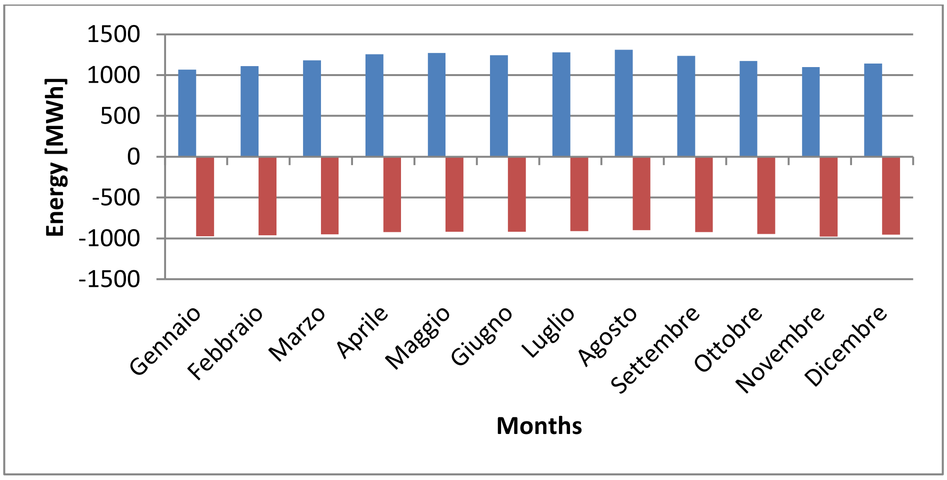

Figure 36 Upward energy (blue color) and downward energy (red color) (y-axis) vs. months (x-axis) in the second case

Figure 36 shows the upward and the downward energy during each month of the year in the second case. From April until August there is an increase of upward energy, reaching the maximum 1310 MWh in August. The mean value of the downward energy is -920 MWh, which is almost constant during the year. From June until September there is a little decrease of downward energy, reaching -899 MWh.

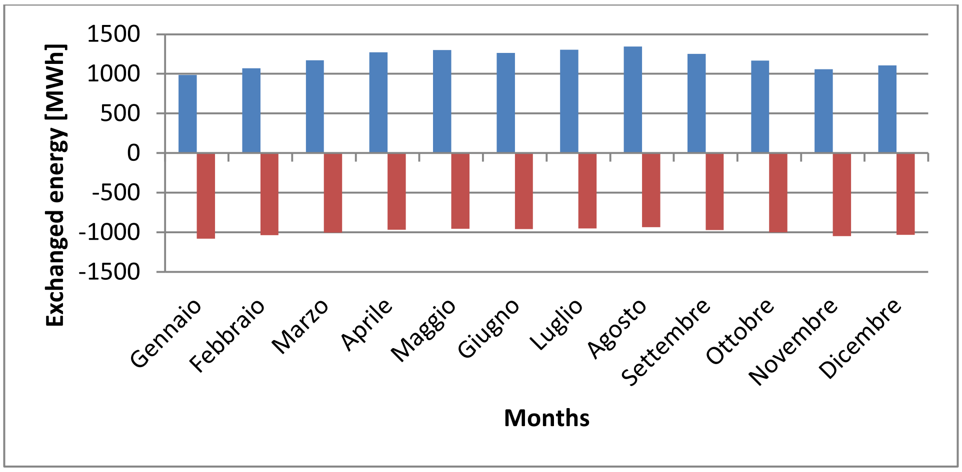

Figure 37 Energy sold (blue color) and energy bought (red color) (y-axis) vs. months (x-axis) in the second case

Figure 37 shows the energy sold to the grid and bought from the grid, without participating in the ASM during each month of the year, in the second case. The energy sold to the grid increases from April until August, reaching the peak value of 1342 MWh. The energy bought decreases in the summer months, reaching the minimum value of -936 MWh in August.

Third case:

- 2000 users
- E_{max}= 7 kWh
- $P_{max-ch} = -$ 3,5 kW
- $P_{max-dh} =$ 3,5 kW

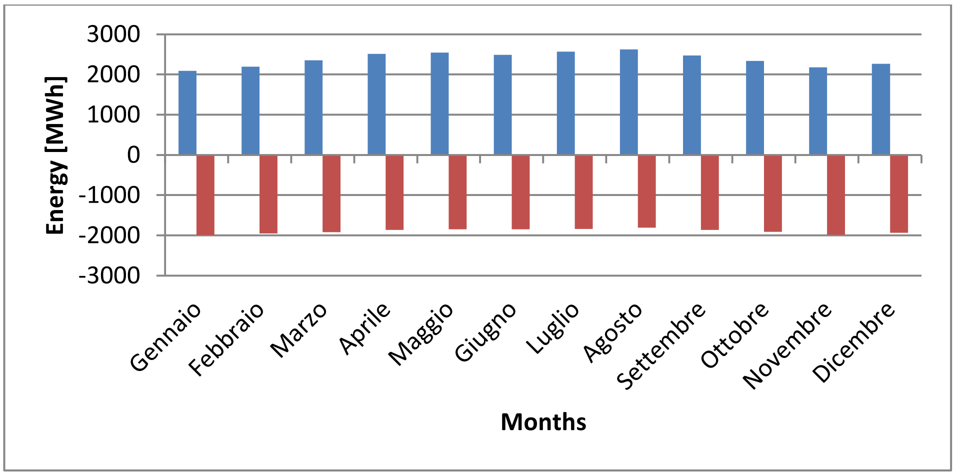

Figure 38 Upward energy (blue color) and downward energy (red color) (y-axis) vs. months (x-axis) in the third case

Figure 38 shows the upward and the downward energy during each month of the year in the third case. The maximum upward energy is 2624 MWh, reached in August. The mean downward energy is almost -1880 MWh. From June until September there is a little decrease of energy bought from the grid, since photovoltaic values increase and the minimum value is reached in August and it is equal to -1838 MWh.

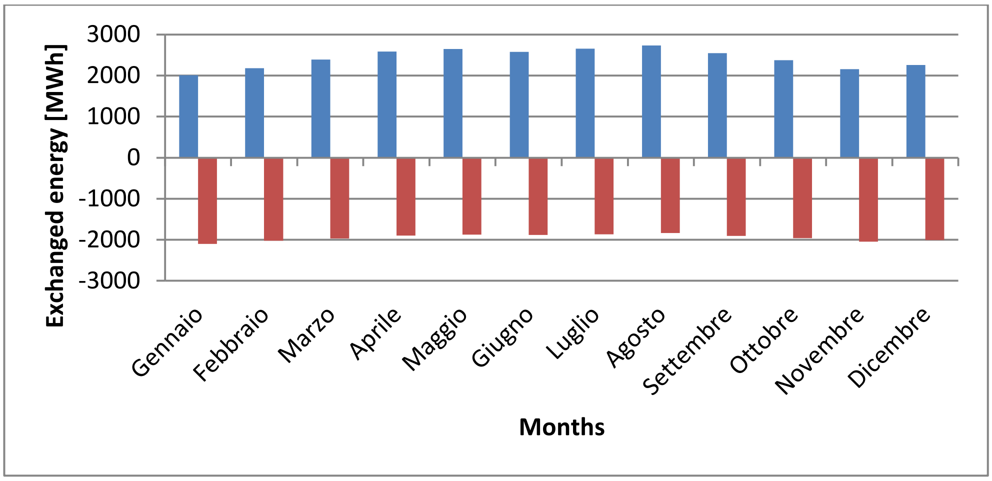

Figure 39 Energy sold (blue color) and energy bought (red color) (y-axis) vs. months (x-axis) in the third case

Figure 39 shows the energy sold to the grid and bought from the grid, without participating in the ASM during each month of the year, in the third case. The energy sold to the grid increases from April until August, reaching the peak value of 2730 MWh. The energy bought decreases in the summer months, reaching the minimum value of -1838 MWh in August.

Fourth case:

- 4000 users
- E_{max}= 7 kWh
- $P_{max-ch} = -$ 7 kW
- $P_{max-dh} =$ 7kW

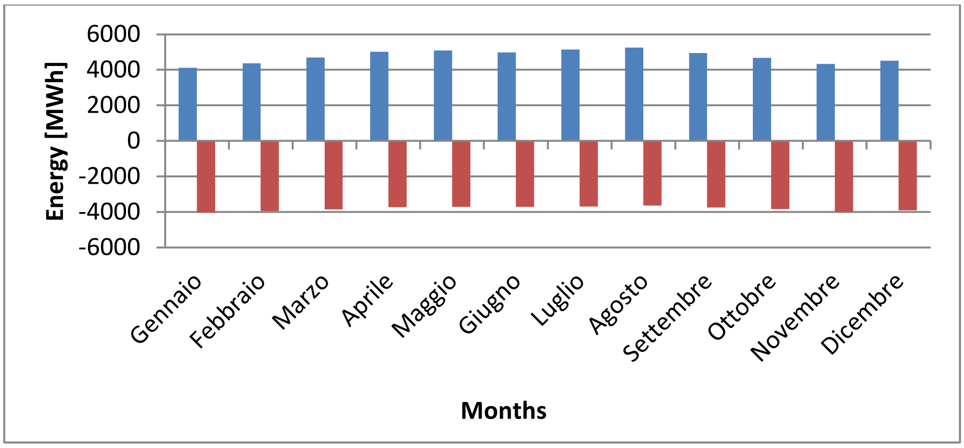

Figure 40 Upward energy (blue color) and downward energy (red color) (y-axis) vs. months (x-axis) in the fourth case

Figure 40 shows the upward and the downward energy during each month of the year in the fourth case. From April until September upward energy increases, reaching the maximum value of 5253 MWh. Downward energy decreases starting from May until September, reaching the minimum in August, which is equal to -3633 MWh.

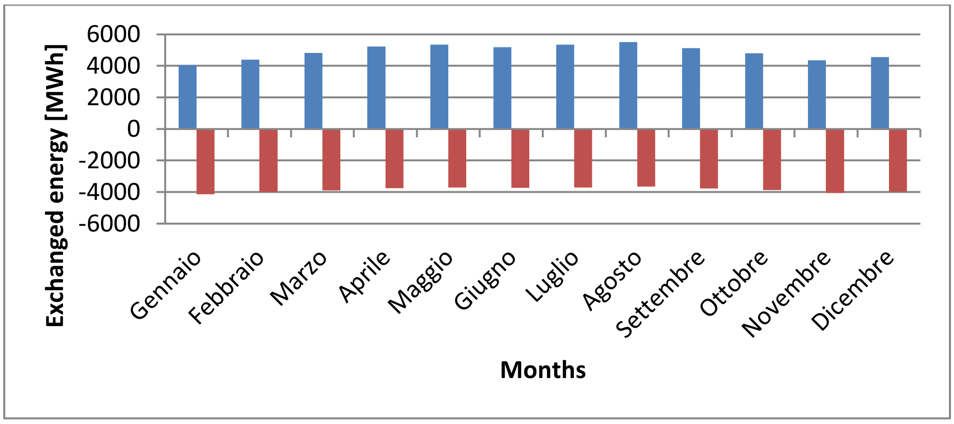

Figure 41 Energy sold (blue color) and energy bought (red color) (y-axis) vs. months (x-axis) in the fourth case

Figure 41 shows the energy sold to the grid and bought from the grid, without participating in the ASM during each month of the year, in the fourth case. The energy sold to the grid increases from April until August, reaching the peak value of 5500 MWh. The energy bought decreases in the summer months, reaching the minimum value of -3643 MWh in August.

9. Economic analysis of the experimental data

This chapter reports an economic analysis of the experiments, computing the gain that the aggregator can earn. In the model, fees were added only at the end of the results of the solution found by the optimizer and not before.

9.1. Input data

Input data are the prices set by ARERA, the Energy Authority in 2018 [22], assuming that each user chooses a the single-time slot.
We list the prices that change every three months.

1 January-31 March 2018	Energy_cost	Transportation_cost	System charges
Energy share [€/kWh]	0,08968	0,00786	0,065092
Fixed share [€/year]	34,79	19,32	0
Power share [€/kW/year]	0	21,29	0

1 April-31 June 2018	Energy_cost	Transportation_cost	System charges
Energy share [€/kWh]	0,07280	0,00786	0,069972
Fixed share [€/year]	34,79	19,32	0
Power share [€/kW/year]	0	21,29	0

1 July-30 September 2018	Energy_cost	Transportation_cost	System charges
Energy share [€/kWh]	0,09475	0,00786	0,055465
Fixed share [€/year]	34,79	19,32	0
Power share [€/kW/year]	0	21,29	0

1 October-31 December 2018	Energy_cost	Transportation_cost	System charges
Energy share [€/kWh]	0,10868	0,00786	0,055465
Fixed share [€/year]	34,79	19,32	0
Power share [€/kW/year]	0	21,29	0

- $Prezzi_{salire}$ = upward prices in the balancing market
- $Prezzi_{scendere}$ = downward prices in the balancing market
- prezzoE= 50 €/MWh, price of the day-ahead market
- $Excise_{tax}$ = 22,7 €/MWh
- Value Added Tax (VAT) = 10%
- $P_{Grid} = P_{acquisto} + P_{vendita} = P_{batteria} + \mathrm{PV} - \mathrm{Load}$
- $P_{Base} = P_{Grid} - P_{salire} - P_{scendere}$

Overall there are four cases:

- If $P_{Grid} > 0$ and $P_{Base} > 0$

Gain = $(P_{Base} * dt * \text{prezzoE}) + (P_{salire} * dt * Prezzi_{salire}) +$

$(P_{scendere} * dt * (\ Prezzi_{scendere} + \text{prezzoE}\ )\ )$

- If $P_{Grid} > 0$ and $P_{Base} < 0$

  Gain = $(P_{Base} * dt * \text{Energy\_cost}) + (P_{salire} * dt * Prezzi_{salire})$

- If $P_{Grid} < 0$ and $P_{Base} > 0$

  Gain= $(P_{scendere} * dt * Prezzi_{scendere}) +$
  $(P_{Base} * dt * (\text{Energy\_cost} + Transportation\_cost + Charges + Excise\_tax) * (1 +$
  $VAT))$

- If $P_{Grid} < 0$ and $P_{Base} < 0$

Gain= $(P_{Base} * dt * (\text{Energy}_{\text{cost}} + Transportation_{cost} + Charges + Excise_{tax}) *$
$(1 + VAT)) + (P_{scendere} * dt * Prezzi_{scendere}) + (P_{salire} * dt * (Prezzi_{salire} +$
$\text{Energy\_cost} + Transportation\_cost + Charges + Excise\_tax) * (1 + VAT))$

9.2. Results

In this section, we compare the economic gain when participating in the balancing market with respect to not participating, to answer the question if it is convenient for the aggregator to offer the service.

The following tables and figures refer to the experiments with 4 combinations of parameters discussed in the previous chapter. The remaining simulations are available in the Appendix 2. The red lines represent the aggregator gain without participating in the balancing market, the blue lines when participating in the balancing market. When the aggregator participates in the ASM the gain is always positive. Instead if it does not participate there is a loss, except from April until August. For each simulation the two scenarios are described, and the relative difference between the gain when participating in the ASM and not participating is computed as: Percentage_ gain =$\frac{Gain_{offer} - Gain\_no\_offer}{Gain_{offer}} * 100$.

Notice that the formula takes into account also the months in which there is a loss when not participating (e.g. first case: February, March), amplifying the gain in the case of participation.

First case

- 750 users
- E_{max}= 7 kWh
- $P_{max-ch} = -7$ kW
- $P_{max-dh} = 7$ kW

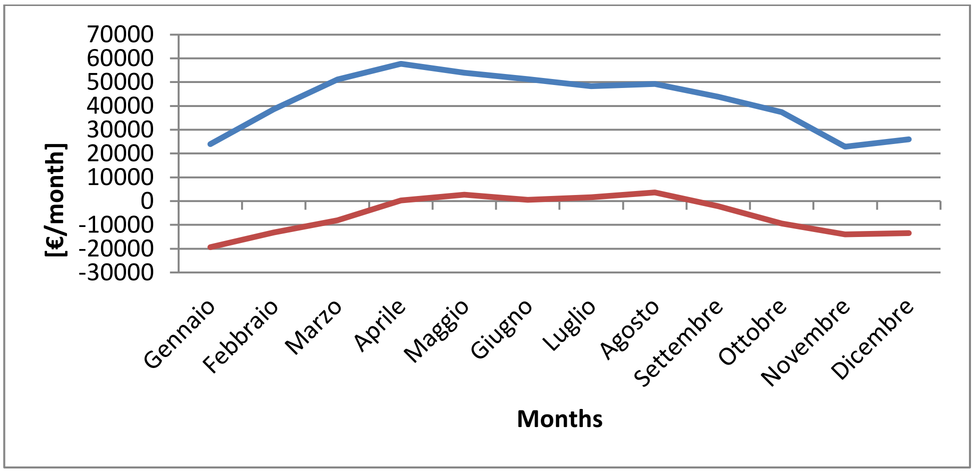

Figure 42 Participation in ASM (blue color) and no participation in ASM (red color) (y-axis) vs. months (x-axis) in the first case

Figure 42 shows the aggregator's gain in case of participation in the ASM, compared with the case of no participation in ASM in the first case. The blue curve reaches a peak in April, equal to 60000€, then it decreases and it reaches another peak in August. The red curve is negative from January until April. Then it becomes positive since the weather conditions improve and there are more sunny days, reaching a gain equal to 2727€ in August. Then it decreases until December. In the table below the percentage gain is shown.

Percentage gain:

Gennaio	180
Febbraio	134
Marzo	115
Aprile	99
Maggio	94
Giugno	98
Luglio	96
Agosto	92
Settembre	104
Ottobre	125
Novembre	160
Dicembre	151

Second case

- 1000 users
- E_{max}= 7 kWh
- $P_{max-ch} = -7$ kW
- $P_{max-dh} = 7$ kW

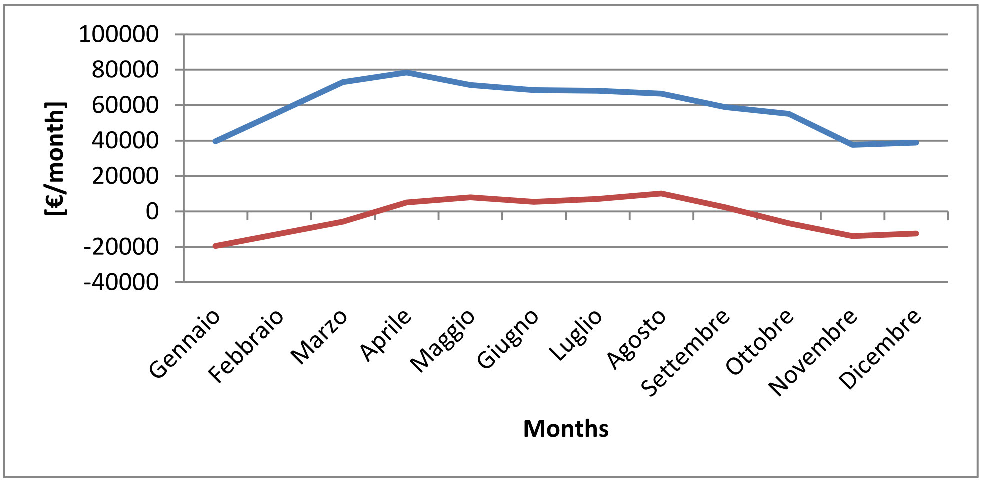

Figure 43 Participation in ASM (blue color) and no participation in ASM (red color) (y-axis) vs. months (x-axis) in the second case

Figure 43 shows the aggregator's gain in case of participation in the ASM, compared with the case of no participation in ASM in the second case. The blue curve reaches a peak in April equal to 80000€, then it decreases and it reaches another peak in August. The red curve is negative from January until March. Then it becomes positive since the weather conditions improve, reaching a gain equal to 10041€ in August. Then it decreases until December. In the table below the percentage gain is shown.

Percentage gain:

Gennaio	149
Febbraio	122
Marzo	107
Aprile	93
Maggio	88
Giugno	92
Luglio	89
Agosto	84
Settembre	95
Ottobre	112
Novembre	136
Dicembre	132

Third case

- 2000 users
- E_{max}= 7 kWh
- $P_{max-ch} = -7$ kW
- $P_{max-dh} = 7$ kW

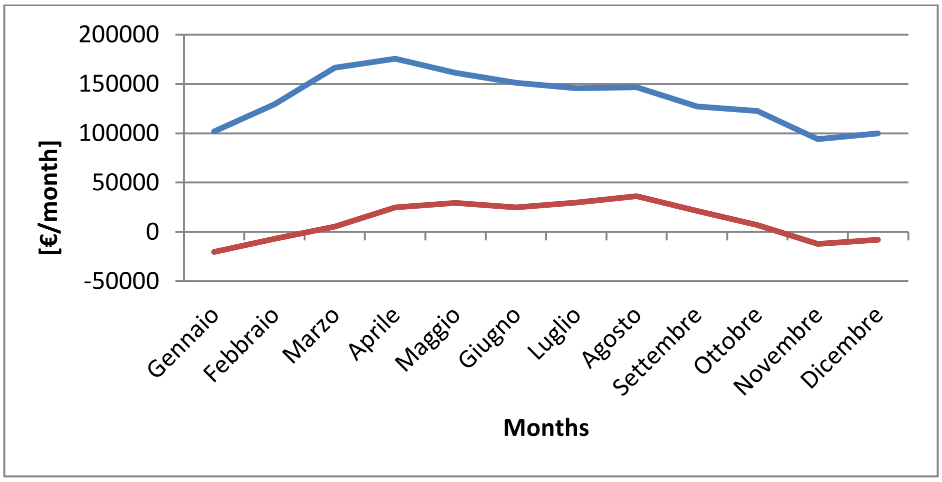

Figure 44 Participation in ASM (blue color) and no participation in ASM (red color) (y-axis) vs. months (x-axis) in the third case

Figure 44 shows the aggregator's gain in case of participation in the ASM, compared with the case of no participation in ASM in the third case. The blue curve reaches a peak in April equal to 170410€, then it decreases. The red curve is negative from January until February. Then it becomes positive since the weather conditions improve reaching a gain equal to 36057€ in August. Then it decreases, becoming negative in October. In the table below the percentage gain is shown.

Percentage gain:

Gennaio	120
Febbraio	105
Marzo	96
Aprile	85
Maggio	81
Giugno	83
Luglio	79
Agosto	75
Settembre	83
Ottobre	94
Novembre	112
Dicembre	107

Fourth case

- 4000 users
- E_{max}= 7 kWh
- $P_{max-ch} = -7$ kW
- $P_{max-dh} = 7$ kW

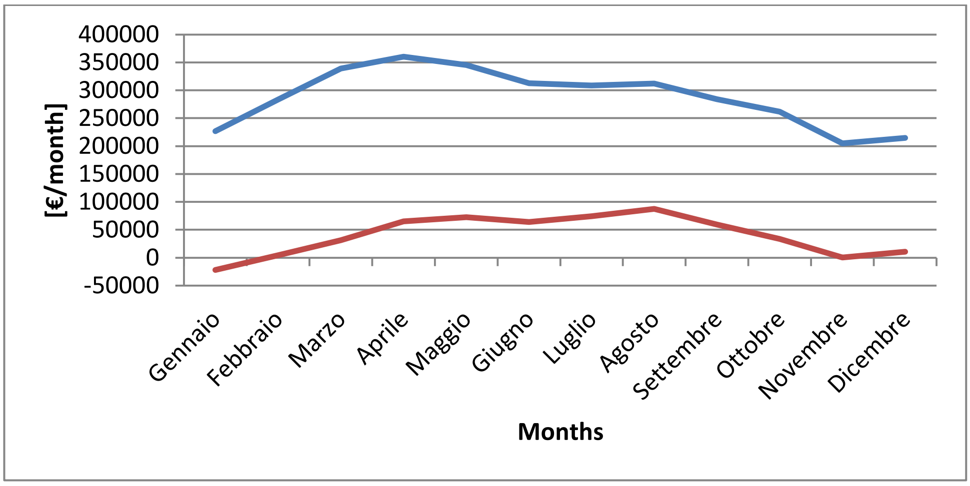

Figure 45 Participation in ASM (blue color) and no participation in ASM (red color) (y-axis) vs. months (x-axis) in the fourth case

Figure 45 shows the aggregator's gain in case of participation in the ASM, compared with the case of no participation in ASM in the fourth case. The blue curve reaches a peak in April equal to 360028€, then it decreases and it reaches another peak in August. The red curve is negative in January and February. Then it becomes positive since the weather conditions improve and there are more sunny days, reaching a gain equal to 37723€ and then it decreases. In the table below the percentage gain is shown.

Percentage gain:

Gennaio	109
Febbraio	98
Marzo	90
Aprile	81
Maggio	78
Giugno	79
Luglio	75
Agosto	71
Settembre	79
Ottobre	87
Novembre	99
Dicembre	95

9.3. Annual gain

If we want to compute the total annual electricity gain, we have to add the annual fixed share and the annual power share.

Each user has to pay the fixed share since it has an active delivery point and the power share, which depends on the power consumption of each user.

	Energy_cost	Transportation_cost	System charges
Fixed share [€/year]	34,79	19,32	0
Power share [€/kW/year]	0	21,29	0

In the total aggregator gain, we have to subtract the fixed share and the power share

Fixed_share=(Energy_cost+Transportation_cost)*n

Power_share= Transportation_cost*n*power_consumption

- n=number of users
- power_consumption=3 kW for each user

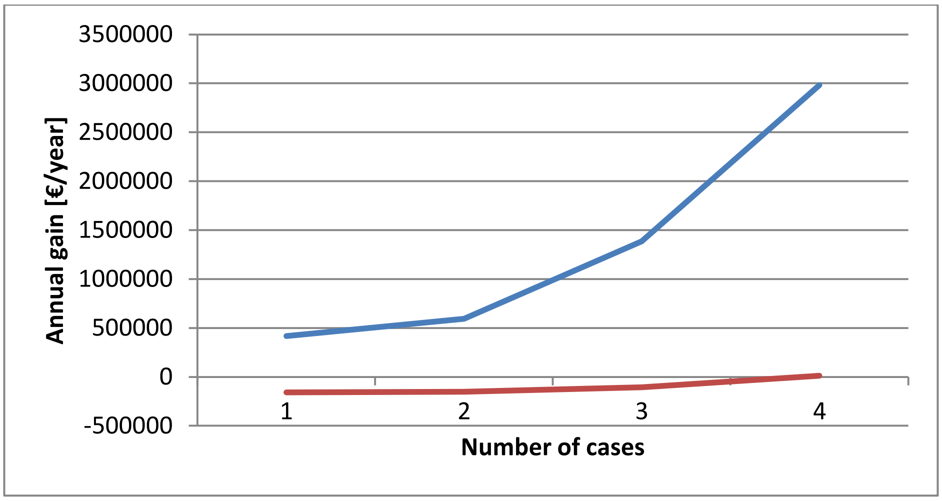

Figure 46 Participation in ASM (blue color) and no participation in ASM (red color) (y-axis) vs. number of cases (x-axis)

Figure 46 shows the aggregator annual gain during each simulation, considering the case of participation in ASM and the case of no participation. The blue line increases, as the number of users increases. The red line does not change too much in the different cases. It increases as the number of users increases, reaching a positive value when the number of users is maximum.

10. Conclusions and future developments

This thesis analyzes the aggregation of residential users, equipped with photovoltaic generations and storage systems, with the aim to offer services in the ASM, according to UVAM regulation. Several simulations are reported, changing the number of users, the battery size and the maximum charging and discharging power of the battery. From the simulations we can see that the participation in the ASM is economically convenient. As a general conclusion the aggregator gain increases, as the number of users increases. Considering the case with an aggregator composed of 4000 users, where each one is equipped with a battery size of 7 kWh and nominal power of 7 kW, the aggregator gain is 2 981 219 €/year. For each simulation it has been considered both the case in which the maximum charging and discharging power is equal to 2 kW and 4 kW (when the user is equipped with a battery size of 4 kWh), and the case in which the maximum charging and discharging power is equal to 3,5 kW and 7 kW (when the user is equipped with a battery size of 7 kWh). Comparing both cases, the annual gain increases around 20%.

As future work, the deterministic optimization model can be generalised into a stochastic model, which would allow to take into account also uncertainties about load and photovoltaic data. As a result the model would be more precise and it would produce more reliable solutions.

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Appendix N.1

This appendix reports further histograms related to the sensitivity analysis discussed in Chapter 8.3

Fifth case

- 750 users
- E_{max}= 4 kWh for each user
- $P_{max-ch} = -$ 2 kW for each battery
- $P_{max-dh} =$ 2 kW for each battery

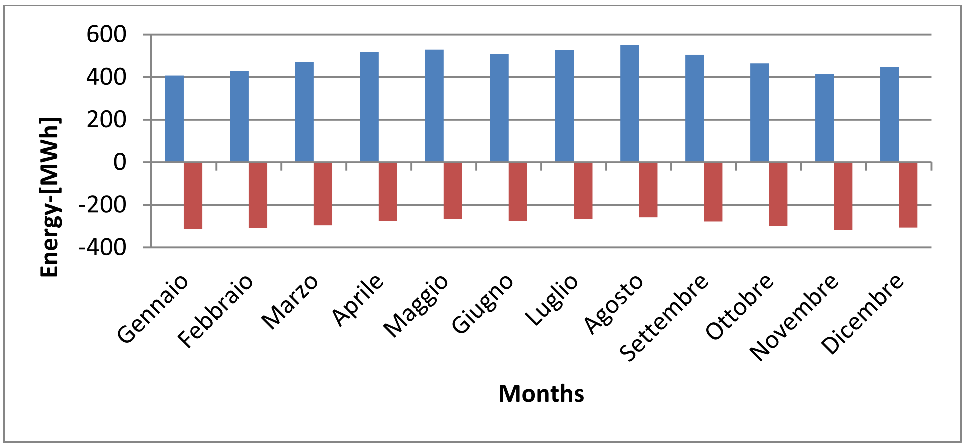

Figure 47 Upward energy (blue color) and downward energy (red color) (y-axis) vs. months (x-axis) in the fifth case

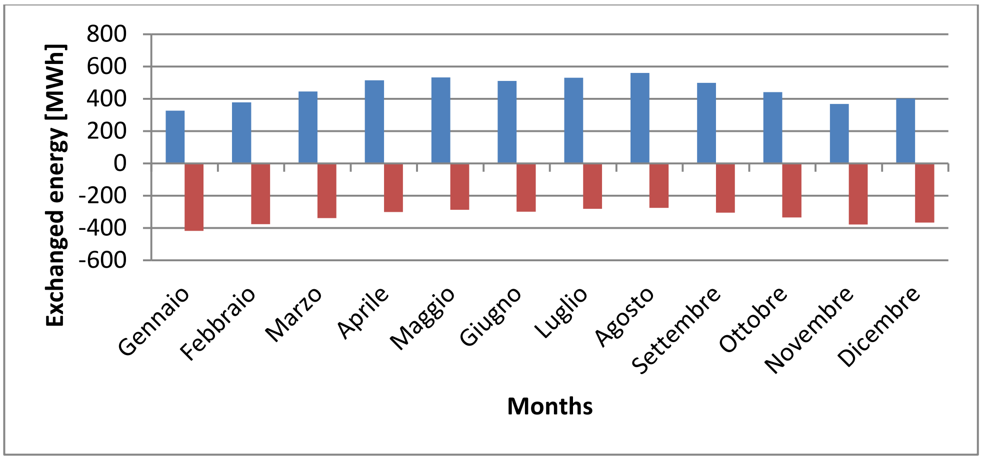

Figure 48 Energy sold (blue color) and energy bought (red color) (y-axis) vs. months (x-axis) in the fifth case

Sixth case

- 750 users
- E_{max}= 4 kWh
- $P_{max-ch} = -$ 4 kW
- $P_{max-dh} =$ 4 kW

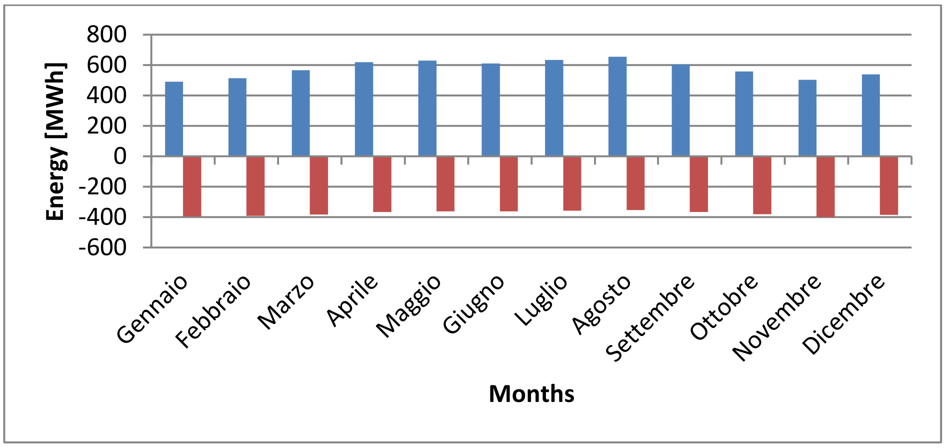

Figure 49 Upward energy (blue color) and downward energy (red color) (y-axis) vs. months (x-axis) in the sixth case

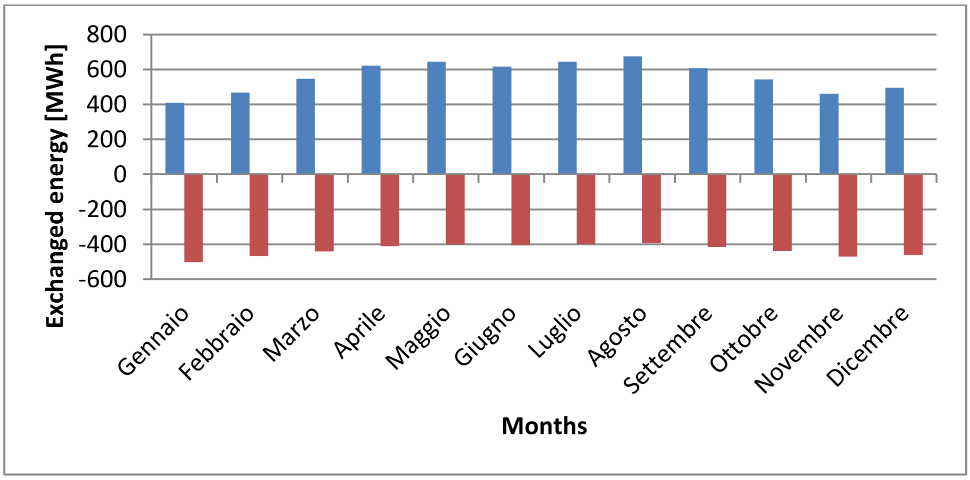

Figure 50 Energy sold (blue color) and energy bought (red color) (y-axis) vs. months (x-axis) in the sixth case

Seventh case:

- 750 users
- E_{max}= 7 kWh
- $P_{max-ch} = -$ 3,5 kW
- $P_{max-dh} =$ 3,5 kW

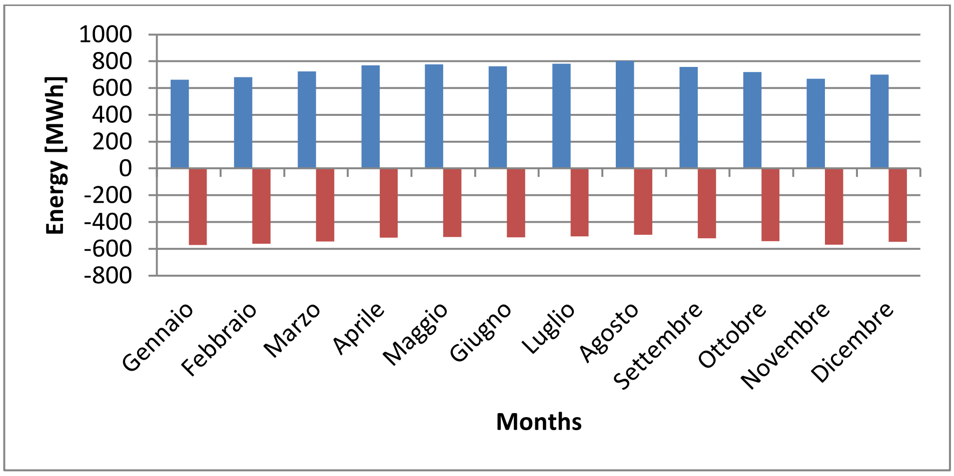

Figure 51 Upward energy (blue color) and downward energy (red color) (y-axis) vs. months (x-axis) in the seventh case

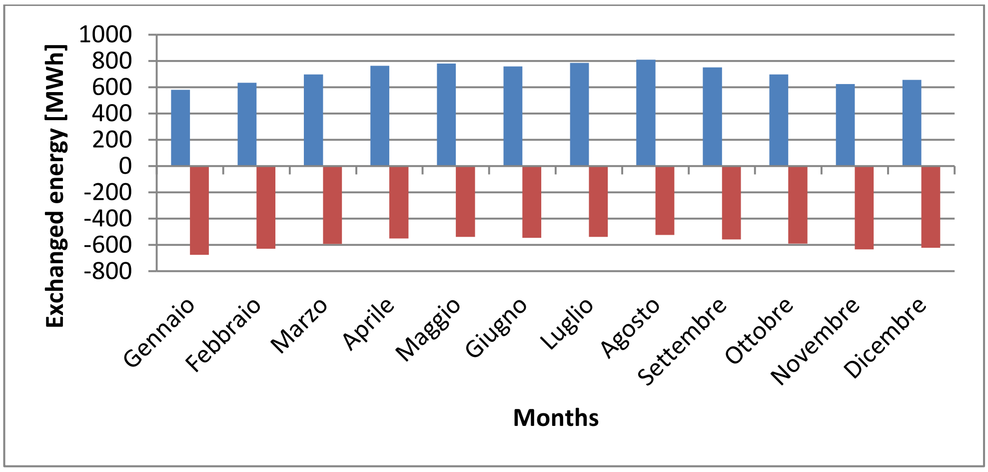

Figure 52 Energy sold (blue color) and energy bought (red color) (y-axis) vs. months (x-axis) in the seventh case

Eighth case:

- 1000 users
- E_{max}= 4 kWh
- $P_{max-ch} = -$ 3,5 kW
- $P_{max-dh} =$ 3,5 kW

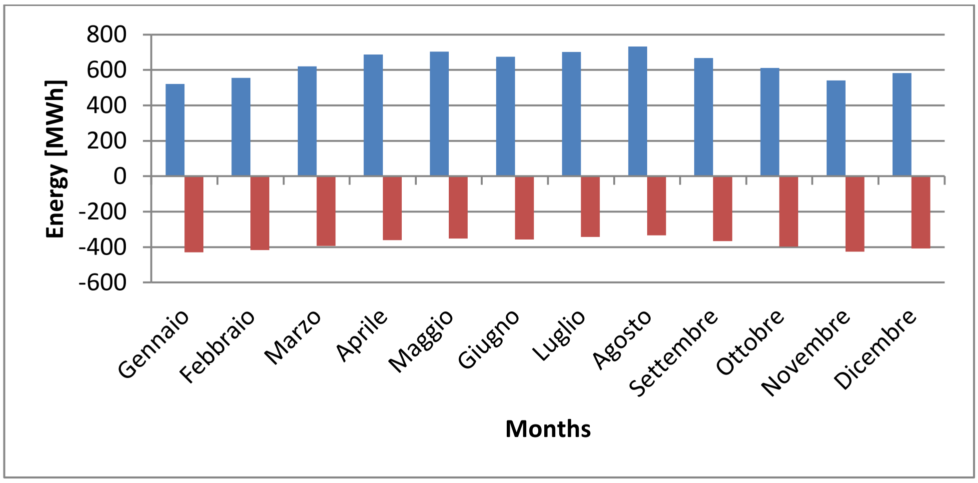

Figure 53 Upward energy (blue color) and downward energy (red color) (y-axis) vs. months (x-axis) in the eighth case

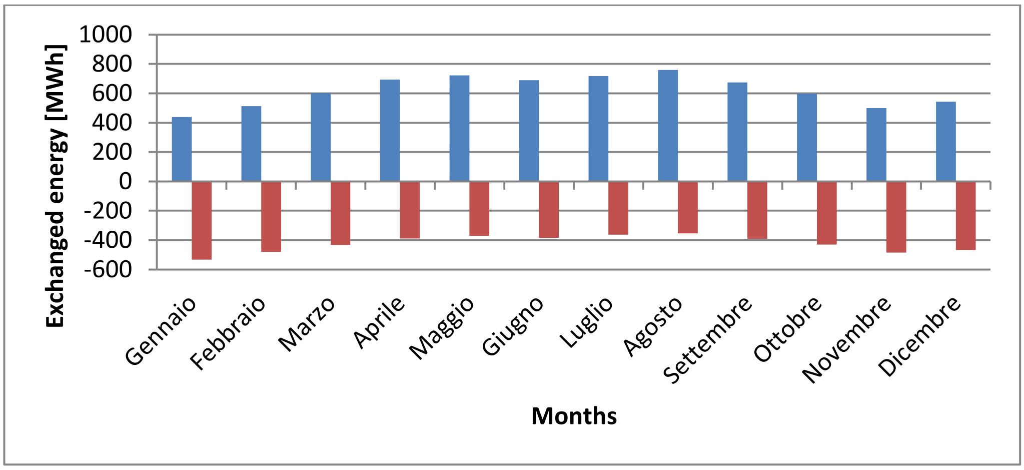

Figure 54 Energy sold (blue color) and energy bought (red color) (y-axis) vs. months (x-axis) in the eighth case

Ninth case:

- 1000 users
- E_{max}= 4 kWh
- $P_{max-ch} = -4$ kW
- $P_{max-dh} = 4$kW

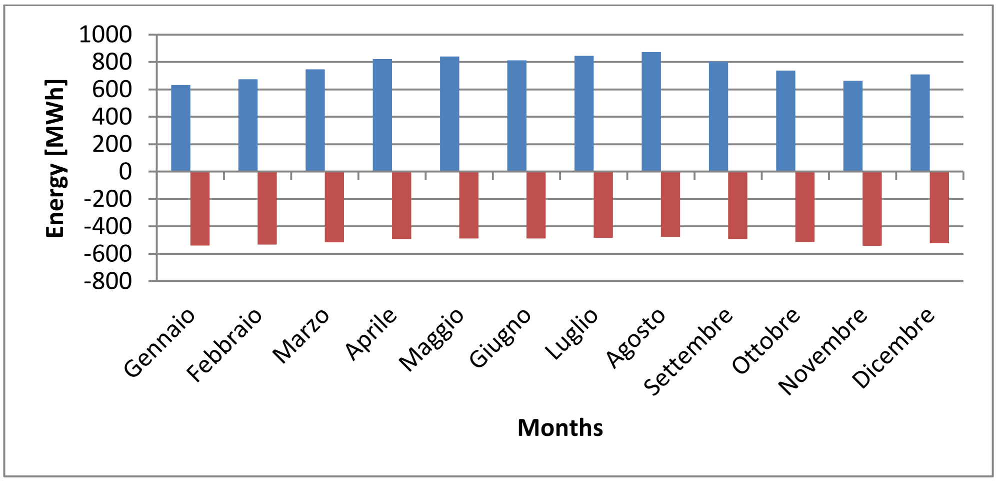

Figure 55 Upward energy (blue color) and downward energy (red color) (y-axis) vs. months (x-axis) in the ninth case

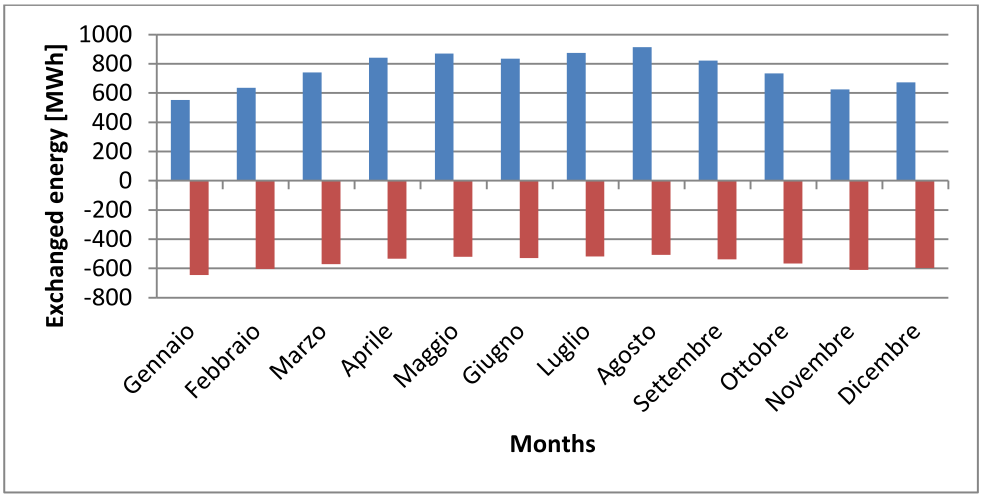

Figure 56 Energy sold (blue color) and energy bought (red color) (y-axis) vs. months (x-axis) in the ninth case

Tenth case:

- 1000 users
- E_{max}= 7 kWh
- $P_{max-ch} = -$ 3,5 kW
- $P_{max-dh} =$ 3,5 kW

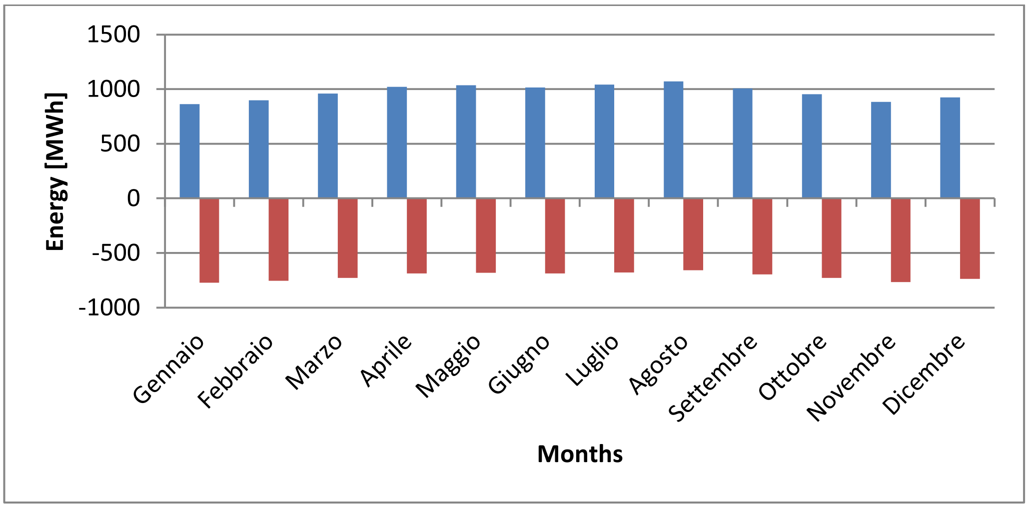

Figure 57 Upward energy (blue color) and downward energy (red color) (y-axis) vs. months (x-axis) in the tenth case

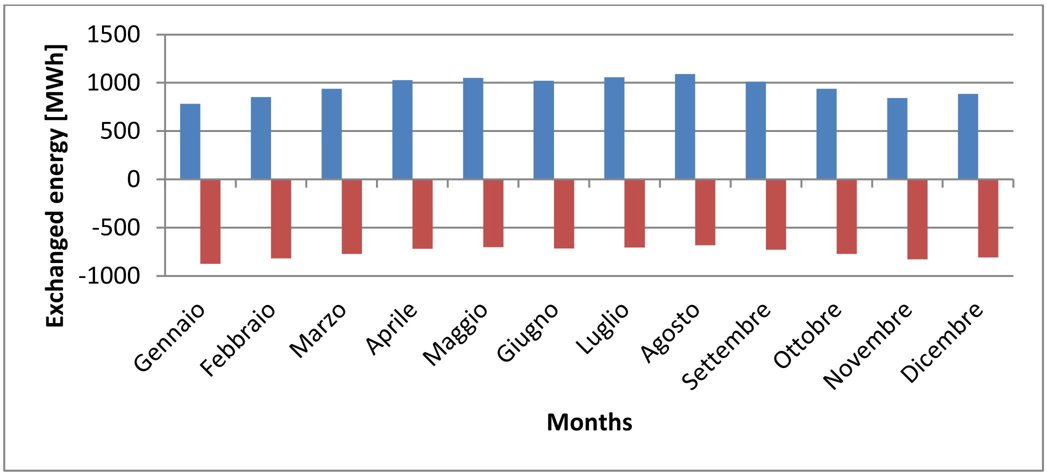

Figure 58 Energy sold (blue color) and energy bought (red color) (y-axis) vs. months (x-axis) in the tenth case

Eleventh case:

- 2000 users
- E_{max}= 4 kWh
- $P_{max-ch} = -2$ kW
- $P_{max-dh} = 2$ kW

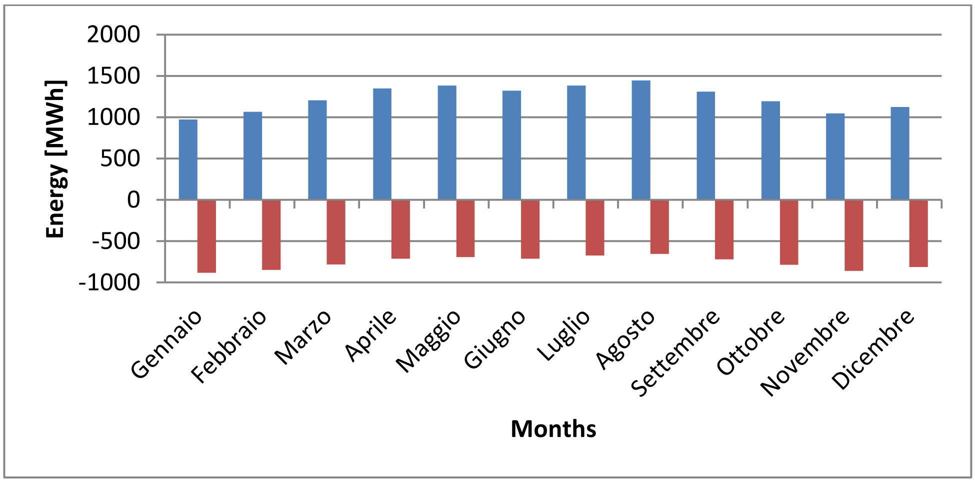

Figure 59 Upward energy (blue color) and downward energy (red color) (y-axis) vs. months (x-axis) in the eleventh case

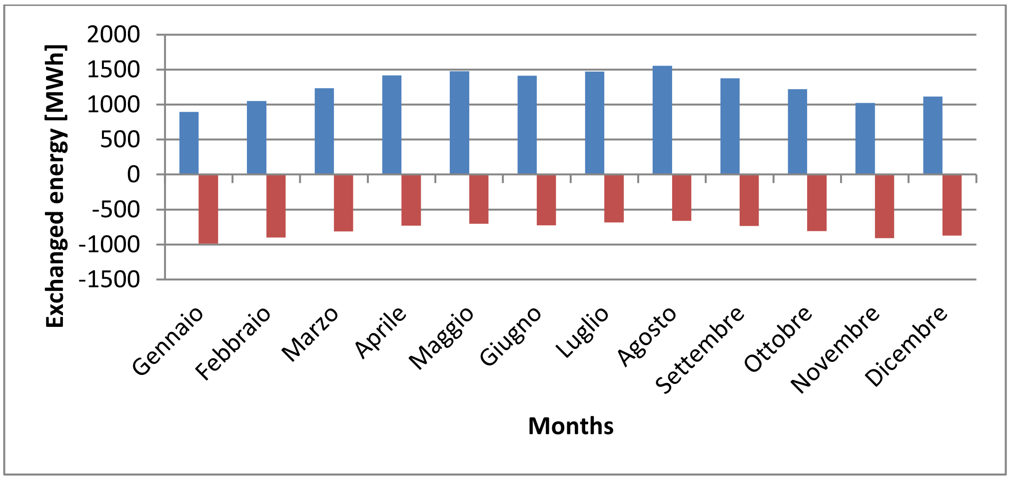

Figure 60 Energy sold (blue color) and energy bought (red color) (y-axis) vs. months (x-axis) in the twelfth case

Twelfth

- 2000 users
- E_{max}= 4 kWh
- P_{max-ch} $= -$ 4 kW
- P_{max-dh} $=$ 4 kW

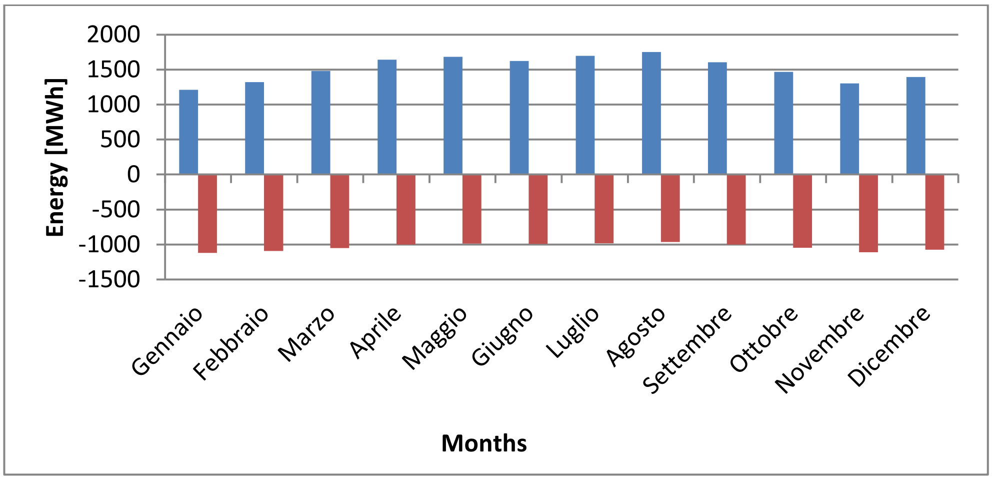

Figure 61 Upward energy (blue color) and downward energy (red color) (y-axis) vs. months (x-axis) in the twelfth case

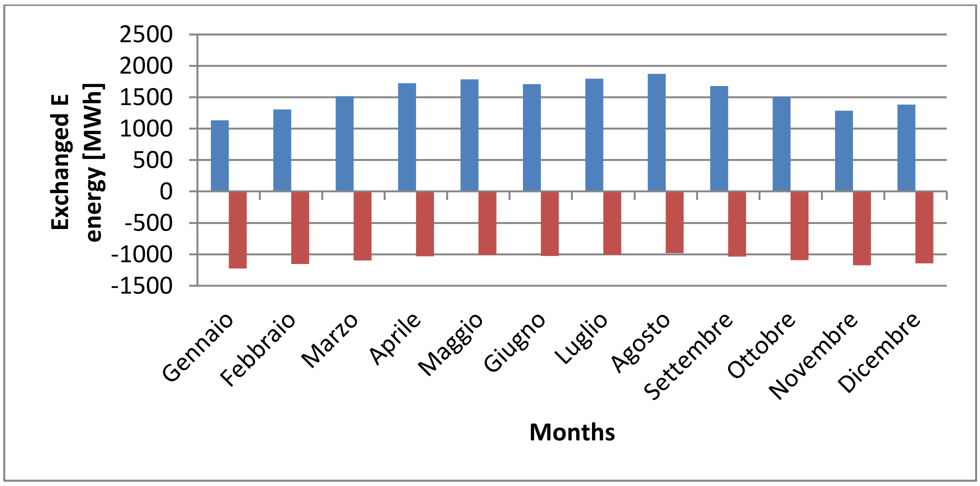

Figure 62 Energy sold (blue color) and energy bought (red color) (y-axis) vs. months (x-axis) in the twelfth case

Thirteenth case:

- 2000 users
- E_{max}= 7 kWh
- $P_{max-ch} = -$ 3,5 kW
- $P_{max-dh} =$ 3,5 kW

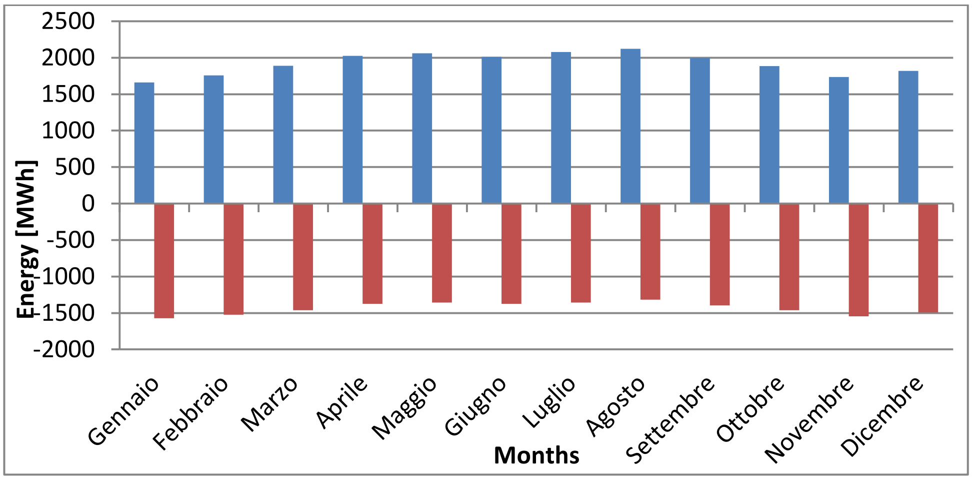

Figure 63 Upward energy (blue color) and downward energy (red color) (y-axis) vs. months (x-axis) in the thirteenth case

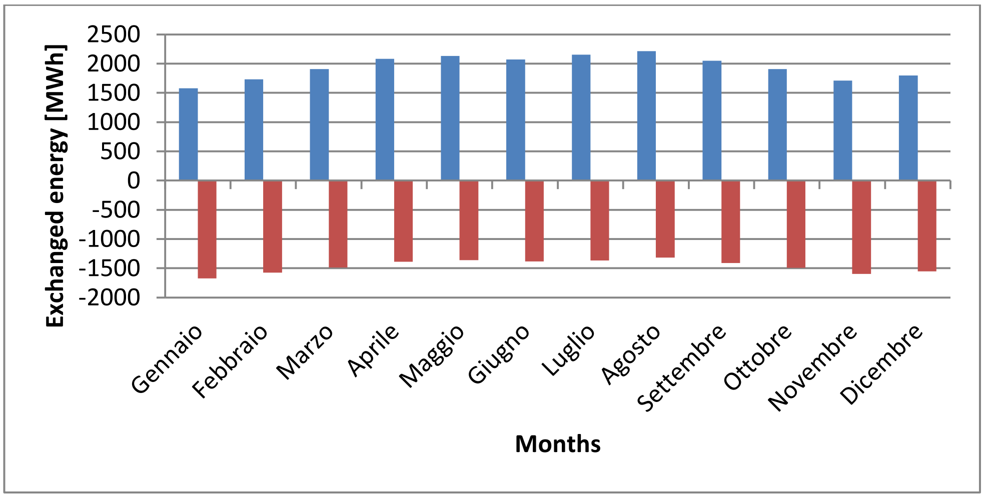

Figure 64 Energy sold (blue color) and energy bought (red color) (y-axis) vs. months (x-axis) in the thirteenth case

Fourteenth case:

- 4000 users
- E_{max}= 4 kWh
- P_{max-ch} $= -$ 2 kW
- P_{max-dh} $=$ 2 kW

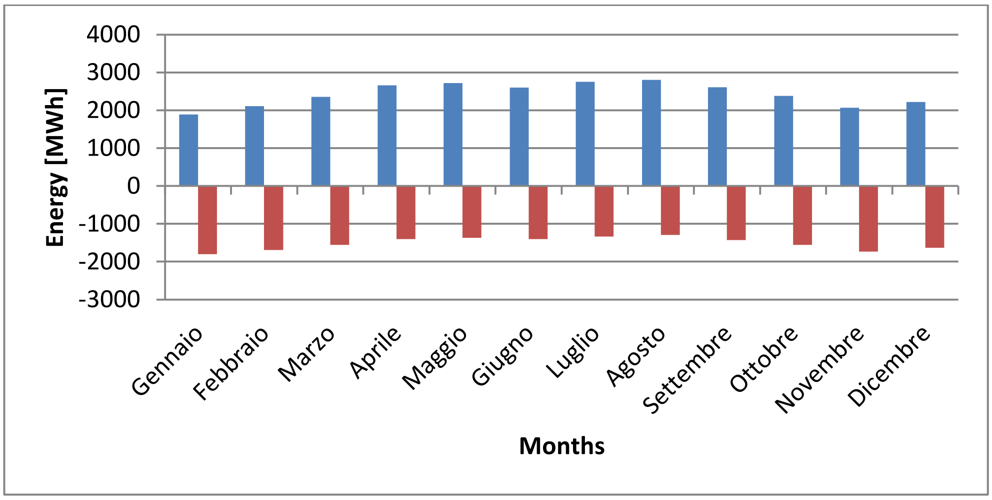

Figure 65 Upward energy (blue color) and downward energy (red color) (y-axis) vs. months (x-axis) in the fourteenth case

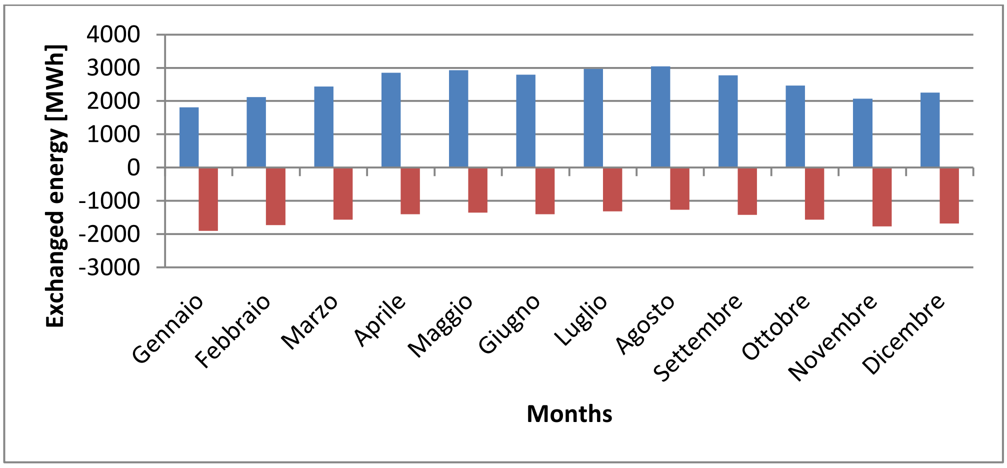

Figure 66 Energy sold (blue color) and energy bought (red color) (y-axis) vs. months (x-axis) in the fourteenth case

Fifteenth case:

- 2000 users
- E_{max}= 4 kWh
- $P_{max-ch} = -$ 4 kW
- $P_{max-dh} =$ 4 kW

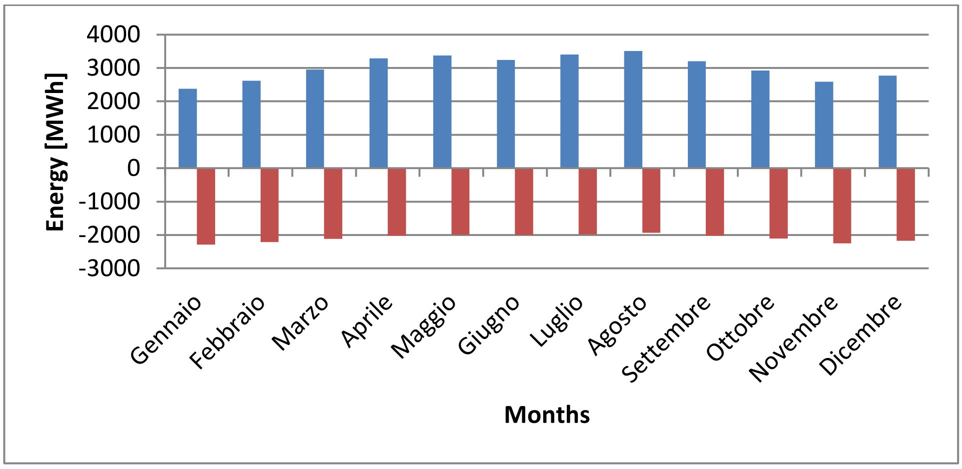

Figure 67 Upward energy (blue color) and downward energy (red color) (y-axis) vs. months (x-axis) in the fifteenth case

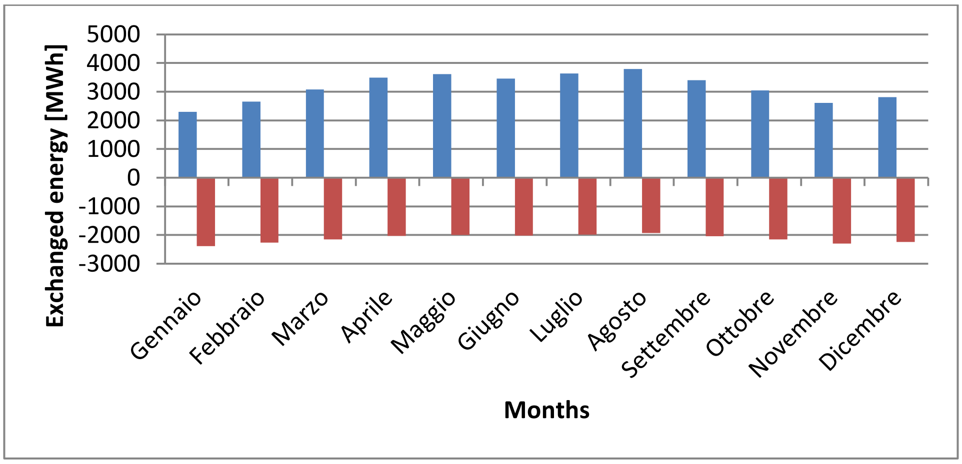

Figure 68 Energy sold (blue color) and energy bought (red color) (y-axis) vs. months (x-axis) in the fifteenth case

Sixteenth case

- 4000 users
- E_{max}= 7 kWh
- $P_{max-ch} = -$ 3,5 kW
- $P_{max-dh} =$ 3,5 kW

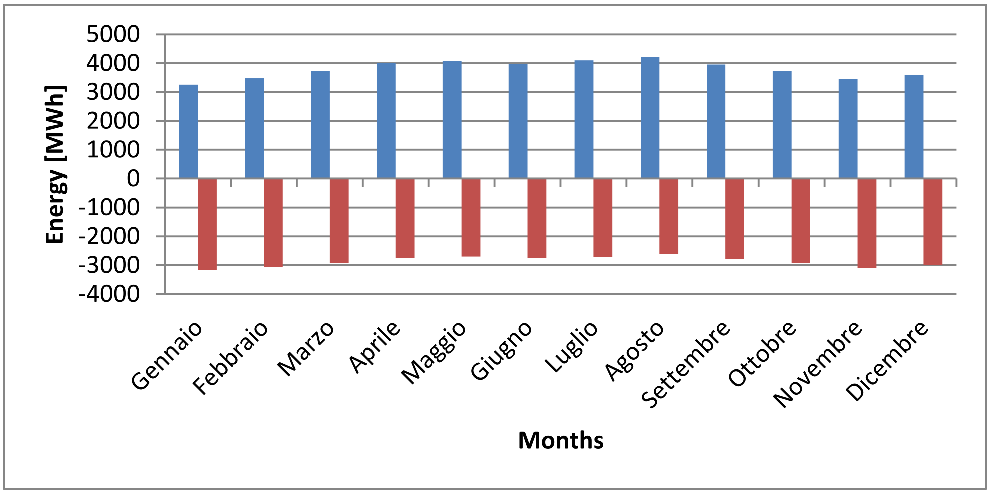

Figure 69 Upward energy (blue color) and downward energy (red color) (y-axis) vs. months (x-axis) in the sixteenth case

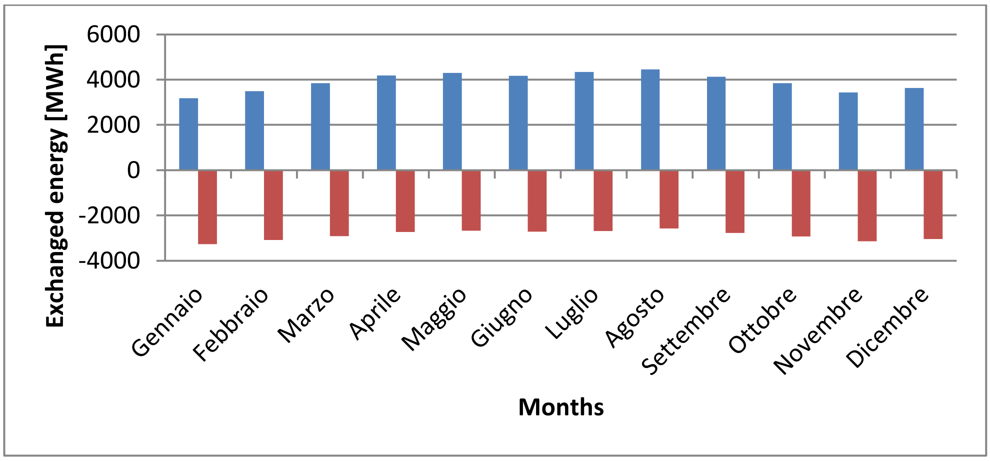

Figure 63 Energy sold (blue color) and energy bought (red color) (y-axis) vs. months (x-axis) in the sixteenth case

Appendix N.2

This appendix reports further diagrams related to the economic analysis discussed in Chapter 9.2.

Fifth case

- 750 users
- E_{max}= 4 kWh
- $P_{max-ch} = -2$ kW
- $P_{max-dh} = 2$ kW

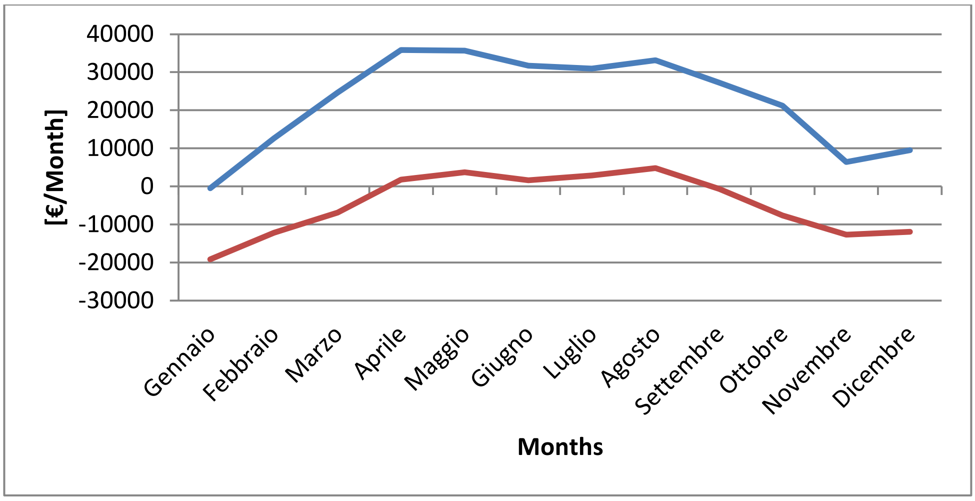

Figure 70 Participation in ASM (blue color) and no participation in ASM (red color) (y-axis) vs. months (x-axis) in the fifth case

Percentage gain:

Gennaio	35
Febbraio	196
Marzo	128
Aprile	94
Maggio	89
Giugno	95
Luglio	90
Agosto	85
Settembre	102
Ottobre	136
Novembre	297
Dicembre	224

Sixth case

- 750 users
- E_{max}= 4 kWh
- $P_{max-ch} = -$ 4 kW
- $P_{max-dh} =$ 4 kW

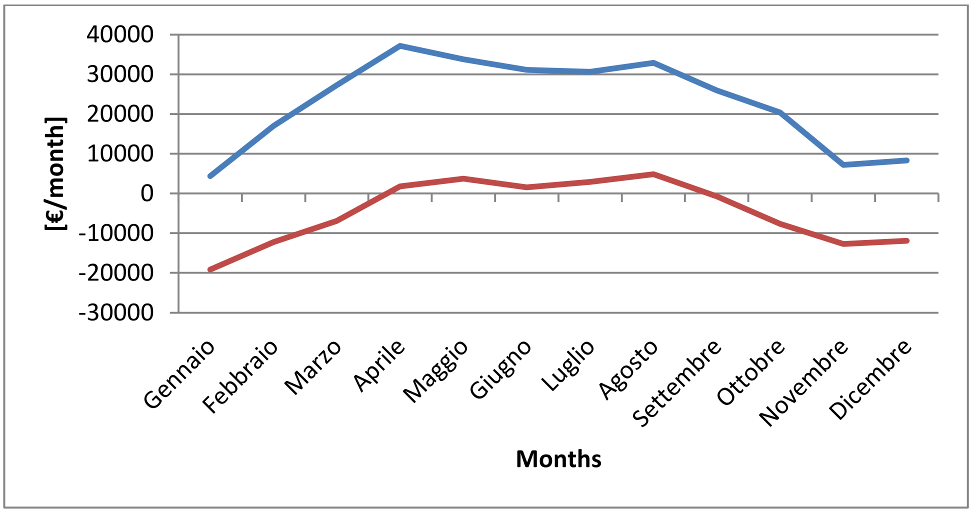

Figure 71 Participation in ASM (blue color) and no participation in ASM (red color) (y-axis) vs. months (x-axis) in the sixth case

Percentage gain:

Gennaio	542
Febbraio	171
Marzo	125
Aprile	95
Maggio	88
Giugno	94
Luglio	90
Agosto	85
Settembre	102
Ottobre	137
Novembre	277
Dicembre	243

Seventh case

- 750 users
- E_{max}= 7 kWh
- $P_{max-ch} = -$ 3,5 kW
- $P_{max-dh} =$ 3,5 kW

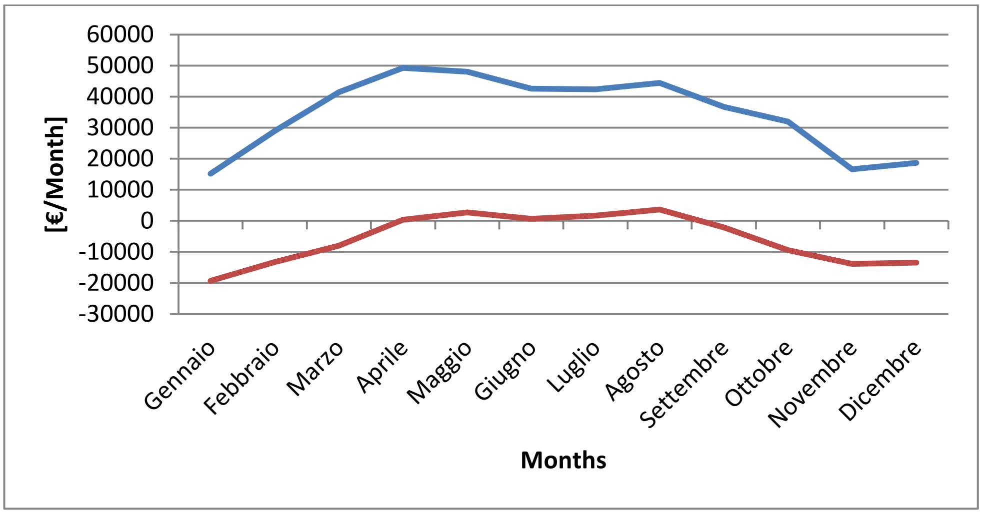

Figure 72 Participation in ASM (blue color) and no participation in ASM (red color) (y-axis) vs. months (x-axis) in the seventh case

Percentage gain:

Gennaio	228
Febbraio	145
Marzo	119
Aprile	99
Maggio	94
Giugno	98
Luglio	96
Agosto	91
Settembre	105
Ottobre	129
Novembre	183
Dicembre	172

Eighth case

- 1000 users
- E_{max}= 4 kWh
- P_{max-ch} $= -$ 2 kW
- P_{max-dh} $=$ 2 kW

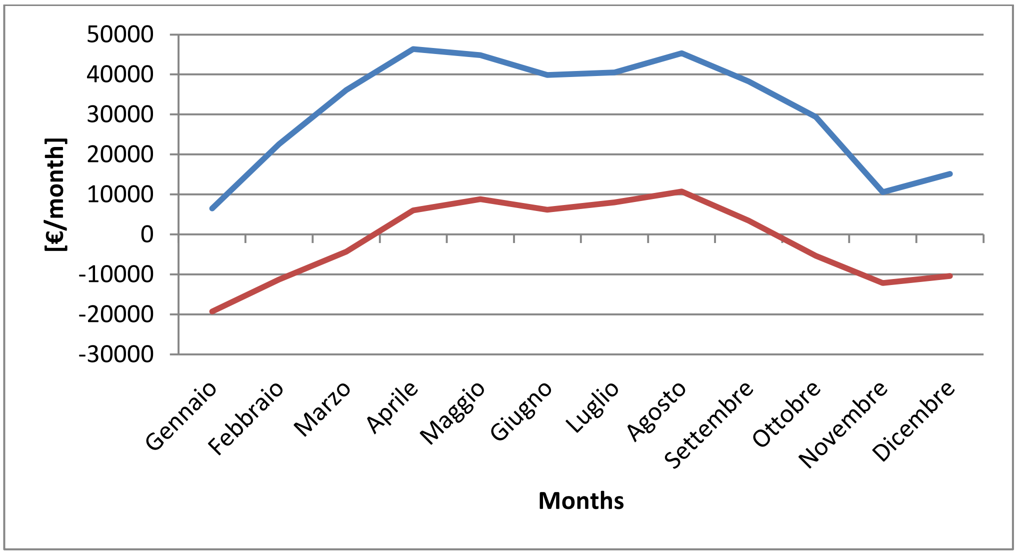

Figure 73 Participation in ASM (blue color) and no participation in ASM (red color) (y-axis) vs. months (x-axis) in the eighth case

Percentage gain:

Gennaio	397
Febbraio	149
Marzo	111
Aprile	86
Maggio	80
Giugno	84
Luglio	80
Agosto	76
Settembre	90
Ottobre	118
Novembre	214
Dicembre	168

Ninth case

- 1000 users
- E_{max}= 4 kWh
- $P_{max-ch} = -2$ kW
- $P_{max-dh} = 2$ kW

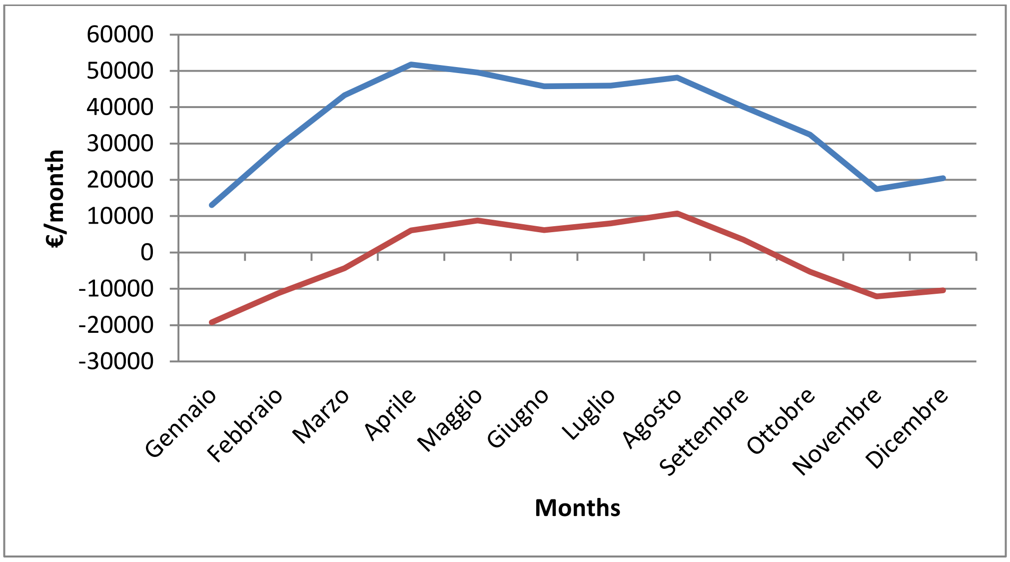

Figure 74 Participation in ASM (blue color) and no participation in ASM (red color) (y-axis) vs. months (x-axis) in the ninth case

Percentage gain:

Gennaio	248
Febbraio	138
Marzo	109
Aprile	88
Maggio	82
Giugno	86
Luglio	82.
Agosto	77
Settembre	91
Ottobre	116
Novembre	169
Dicembre	150

Tenth case

- 1000 users
- E_{max}= 7 kWh
- P_{max-ch} = − 3,5 kW
- P_{max-dh} = 3,5 kW

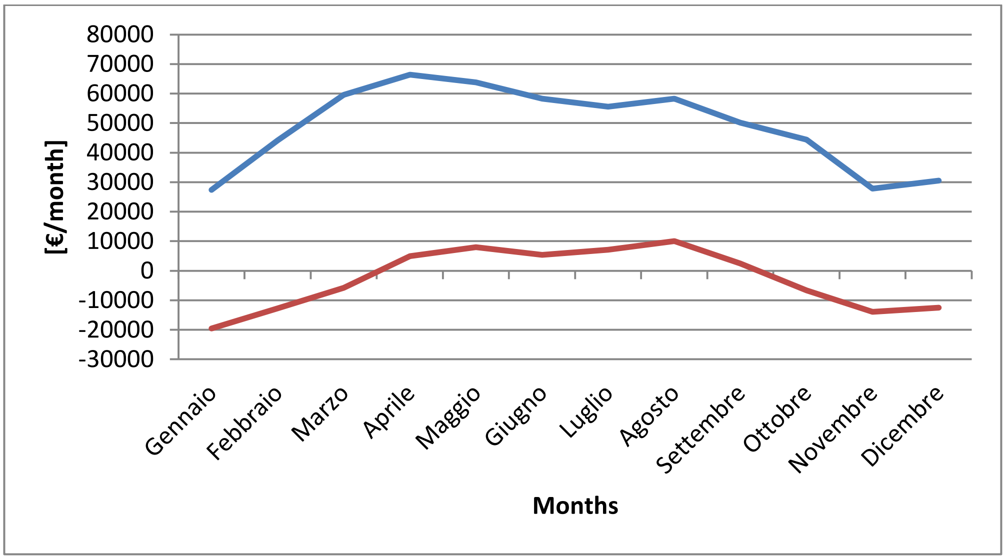

Figure 75 Participation in ASM (blue color) and no participation in ASM (red color) (y-axis) vs. months (x-axis) in the tenth case

Percentage gain:

Gennaio	171
Febbraio	128
Marzo	109
Aprile	92
Maggio	87
Giugno	90
Luglio	87
Agosto	82
Settembre	95
Ottobre	114
Novembre	149
Dicembre	140

Eleventh case

- 2000 users
- E_{max}= 4 kWh
- $P_{max-ch} = -2$ kW
- $P_{max-dh} =$ 2 kW

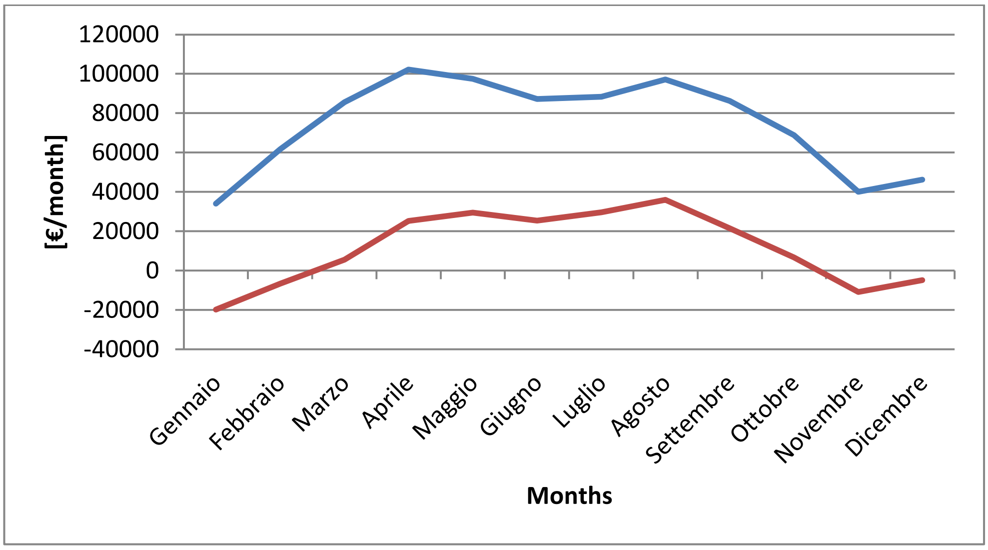

Figure 76 Participation in ASM (blue color) and no participation in ASM (red color) (y-axis) vs. months (x-axis) in the eleventh case

Percentage gain:

Gennaio	157
Febbraio	110
Marzo	93
Aprile	75
Maggio	69
Giugno	70
Luglio	66
Agosto	62
Settembre	75
Ottobre	90
Novembre	126
Dicembre	110

Twelfth case

- 2000 users
- E_{max}= 4 kWh
- $P_{max-ch} = -4$ kW
- $P_{max-dh} = 4$ kW

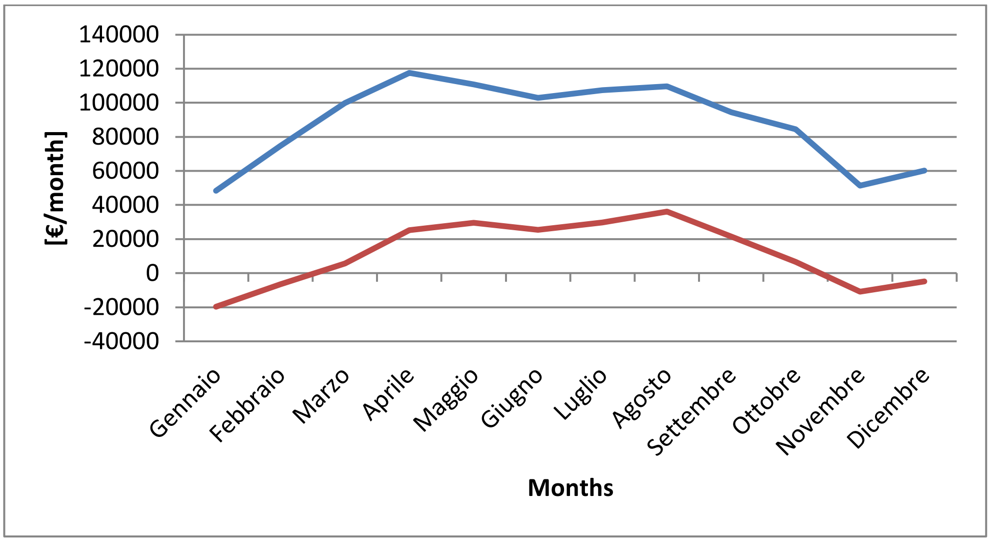

Figure 77 Participation in ASM (blue color) and no participation in ASM (red color) (y-axis) vs. months (x-axis) in the twelfth case

Percentage gain:

Gennaio	140
Febbraio	108
Marzo	94
Aprile	78
Maggio	73
Giugno	75
Luglio	72
Agosto	67
Settembre	77
Ottobre	92
Novembre	120
Dicembre	108

Thirteenth case

- 2000 users
- E_{max}= 7 kWh
- P_{max-ch} $= -$ 3,5 kW
- P_{max-dh} $=$ 3,5 kW

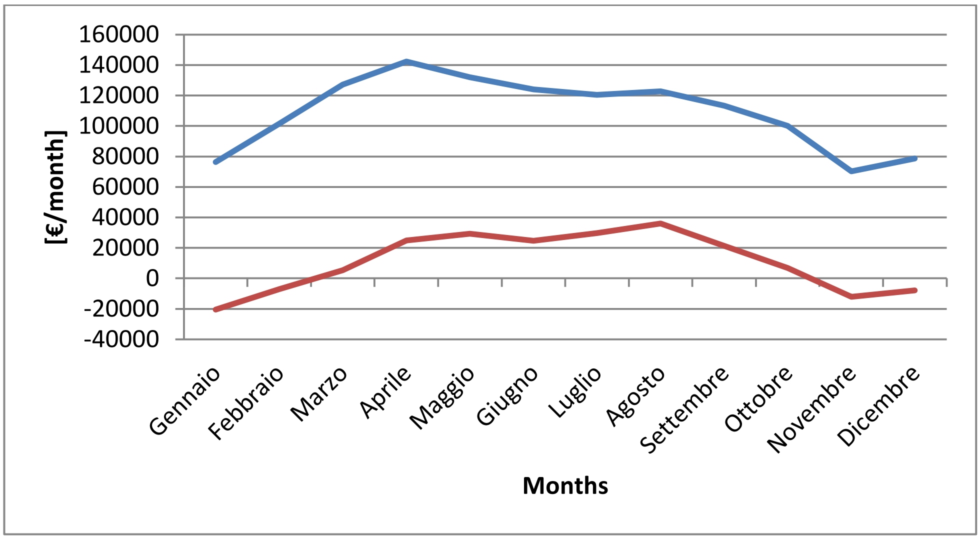

Figure 78 Participation in ASM (blue color) and no participation in ASM (red color) (y-axis) vs. months (x-axis) in the thirteenth case

Percentage gain:

Gennaio	126
Febbraio	106
Marzo	95
Aprile	82
Maggio	77
Giugno	80
Luglio	75
Agosto	70
Settembre	81
Ottobre	93
Novembre	117
Dicembre	110

Fourteenth case

- 4000 users
- E_{max}= 4 kWh
- $P_{max-ch} = -$ 2 kW
- $P_{max-dh} =$ 2 kW

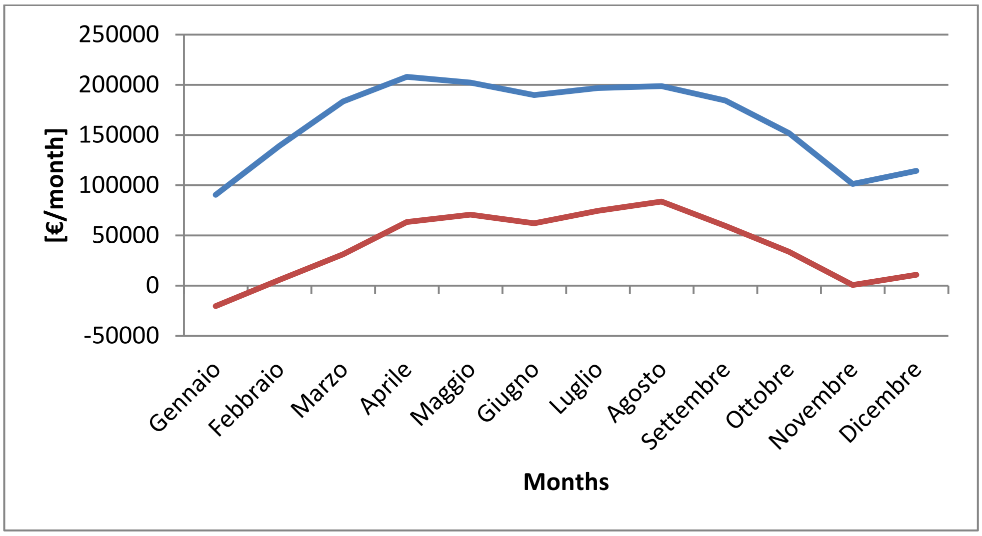

Figure 79 Participation in ASM (blue color) and no participation in ASM (red color) (y-axis) vs. months (x-axis) in the fourteenth case

Percentage gain:

Gennaio	122
Febbraio	96
Marzo	82
Aprile	69
Maggio	65
Giugno	67
Luglio	62
Agosto	57
Settembre	67
Ottobre	77
Novembre	99
Dicembre	90

Fifteenth case

- 4000 users
- E_{max}= 4 kWh
- $P_{max-ch} = -$ 4 kW
- $P_{max-dh} =$ 4 kW

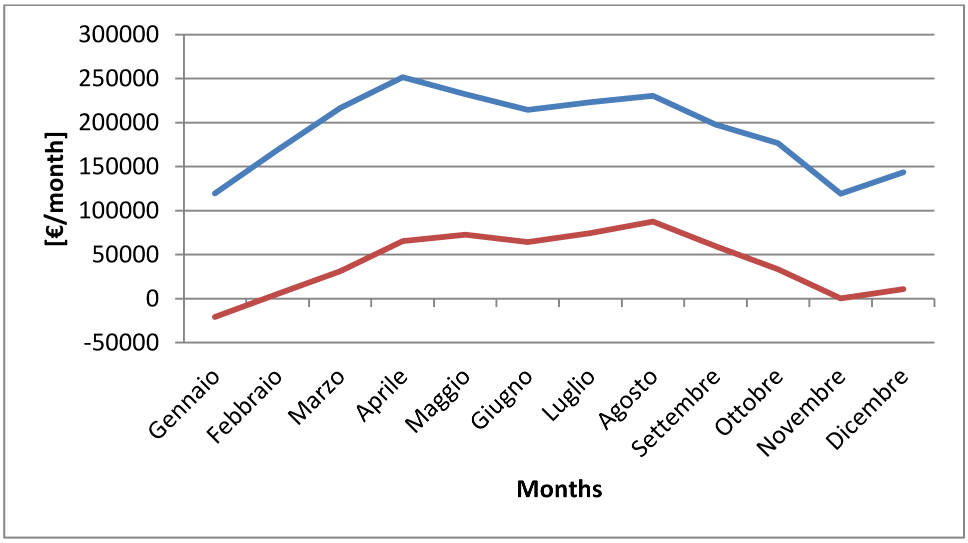

Figure 80 Participation in ASM (blue color) and no participation in ASM (red color) (y-axis) vs. months (x-axis) in the fifteenth case

Percentage gain:

Gennaio	117
Febbraio	96
Marzo	85
Aprile	74
Maggio	68
Giugno	70
Luglio	66
Agosto	61
Settembre	69
Ottobre	81
Novembre	99
Dicembre	92

Sixteenth case

- 4000 users
- E_{max}= 7 kWh
- $P_{max-ch} = -$ 3,5 kW
- $P_{max-dh} =$ 3,5 kW

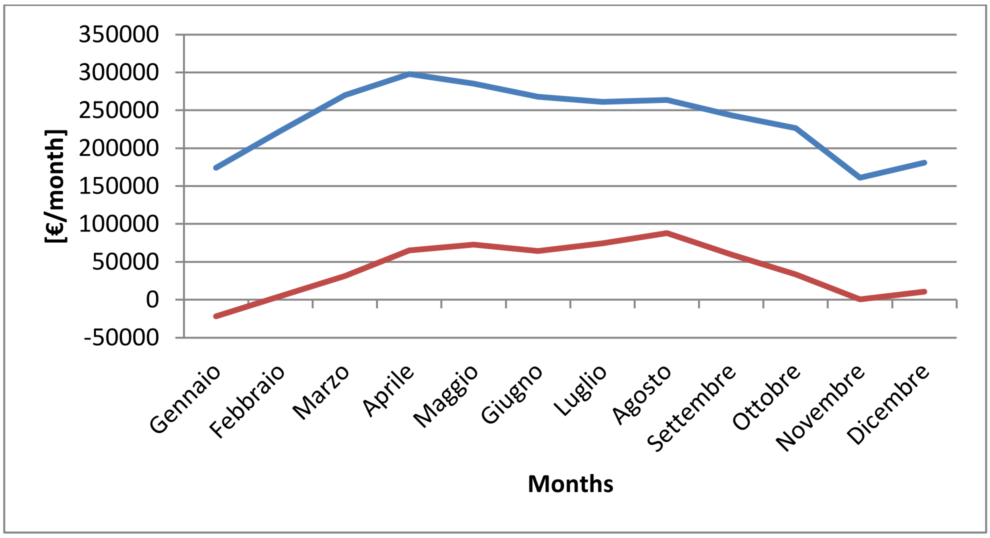

Figure 81 Participation in ASM (blue color) and no participation in ASM (red color) (y-axis) vs. months (x-axis) in the sixteenth case

Percentage gain:

Gennaio	112
Febbraio	97
Marzo	88
Aprile	78
Maggio	74
Giugno	76
Luglio	71
Agosto	66
Settembre	75
Ottobre	85
Novembre	99
Dicembre	94

Appendix N.3

This appendix reports MATLAB code.

```
%Strategia di offerta
clear all
close all
addpath(genpath('C:\Users\tiziano\Desktop\YALMIP-master'))
%input: previsione carico [tempo x utenti], previsione PV [tempo x utenti],
energia nominale batterie [utenti],
%potenza massima in carica e scarica [utenti], previsione prezzi servizio a
salire e
%scendere [tempo]

load ('Load2000utenti.mat');
Load=Pnew;

Load750=Load(3072:3168); % 2 febbraio
%Load750=Load(22752:22848);  %25 agosto
PV=xlsread('Fotovoltaico2000utenti.xlsx','A3072:A3168'); % 2 febbraio
Prezzi=xlsread('P2feb.xlsx'); % 2 febbraio
%PV=xlsread('Fotovoltaico750utenti.xlsx','A22752:A22848');  % 25 agosto
%Prezzi=xlsread('P25ago.xlsx'); % 25 agosto
%Load750=Load(8737:8832);

%PV=xlsread('Fotovoltaico750utenti.xlsx','A6937:A7032');
%Prezzi=xlsread('P2mar.xlsx');

%scale down
scale_down=4;  %parti di un'ora

%punto iniziale
start=1;    %prima ora della finestra temporale

%orizzonte ottimizzazione in ore
h=02;

%passo temporale in ore
dt=1;

%verifico fattibilità finestra temporale
if (start+h)*dt>length(Load750)/scale_down
    fprintf('La finestra temporale scelta è al di fuori dei dati disponibili in
input.\nPer ottimizzare cambiare ora iniziale o orizzonte temporale.\n')
    return
end

j=1;
for i=1:length(Load750)
    if i>=j*scale_down
        Load_s(j,1)=mean(Load750(i-scale_down+1:i,1));
        j=j+1;
    end
end

j=1;
for i=1:length(Load750)
    if i>=j*scale_down
        PV_s(j,1)=mean(PV(i-scale_down+1:i,1));
        j=j+1;
```

```
    end
end

%%
costoE=200 ; %Costo energia acquistata €/MWh
prezzoE=50; %prezzo vendita energia €/MWh
Emax=14;               %MWh
P_max_ch=-14;           %MW
P_max_dh=14;            %MW

%creo vettore prezzi al quarto d'ora
j=1;
for i=1:length(Load_s)
     Prezzi_salire(i)=Prezzi(j,1);
     Prezzi_scendere(i)=Prezzi(j,2);
     if mod(i,4)==0
         j=j+1;
     end
end
Prezzi_salire=Prezzi_salire';
Prezzi_scendere=Prezzi_scendere';


subplot(2,1,1)
plot(start:1:h/dt+start,-(Load_s(start:h/dt+start)-PV_s(start:h/dt+start)),'r')
hold on
plot(start:length(PV_s(start:h/dt+start)),P_max_ch,'+g')
plot(start:length(PV_s(start:h/dt+start)),P_max_dh,'+g')


tempo=1:h/dt+1;                                 %vettore tempo

%definizione variabili da ottimizzare
SoC_start=sdpvar(1,1);                                %SoC iniziale (da
ottimizzare)
% SoC_start=0.4;                                        %SoC iniziale
P_salire = sdpvar(length(tempo),1);                   %potenza offerta per i
servizi a salire (MW)
P_scendere = sdpvar(length(tempo),1);                 %potenza offerta per i
servizi a scendere (MW)
P_bs = sdpvar(length(tempo),1);                       %potenza baseline (MW)
P_acquisto=sdpvar(length(tempo),1);                   %potenza acquistata da rete
(MW)
P_vendita=sdpvar(length(tempo),1);                    %potenza venduta alla rete
(MW)
STATO_salire=binvar(length(tempo),1);                 %variabile di supporto
STATO_scendere=binvar(length(tempo),1);               %variabile di supporto
STATO_vendita=binvar(length(tempo),1);                %variabile di supporto



%%
%vincoli
% SoC_start=0.35;                                         %SoC iniziale di ogni
batteria (compreso nei due vincoli seguenti)
SoC_min=0.1;                                            %SoC minimo di ogni
batteria
SoC_max=0.9;                                            %SoC massimo di ogni
batteria
```

```
M=P_max_dh+2;
m=P_max_ch-2;

%vincoli tecnici batterie
P_sda = zeros(length(tempo),1);

E(1)=Emax*SoC_start;                                     %Stato di carica
iniziale
P_sda = P_bs +P_salire + P_scendere ;
E = E(1)+cumsum(-P_sda*dt);

Vincoli=[P_sda>= P_max_ch, P_sda<=P_max_dh];
for i=1:length(tempo)
    %Vincoli=[Vincoli,P_bs(i)<=Load_s(i)-PV_s(i), P_bs(i)>=-PV_s(i)+Load_s(i)];
    Vincoli=[Vincoli,abs(P_bs(i))<=abs(Load_s(i)-PV_s(i))];
end

Vincoli=[Vincoli, P_acquisto<=M*STATO_vendita, -P_acquisto<=-m*STATO_vendita,
P_acquisto<=(P_sda +PV_s(start:h/dt+start)-Load_s(start:h/dt+start))-m*(1-
STATO_vendita), -P_acquisto<=-(P_sda +PV_s(start:h/dt+start)-
Load_s(start:h/dt+start))+M*(1-STATO_vendita)];
Vincoli=[Vincoli, P_vendita<=M*(1-STATO_vendita), -P_vendita<=-m*(1-
STATO_vendita), P_vendita<=(P_sda +PV_s(start:h/dt+start)-
Load_s(start:h/dt+start))-m*(STATO_vendita), -P_vendita<=-(P_sda
+PV_s(start:h/dt+start)-Load_s(start:h/dt+start))+M*(STATO_vendita)];
Vincoli=[Vincoli, E>=SoC_min*Emax, E<=SoC_max*Emax];
Vincoli=[Vincoli, SoC_start>=0.2, SoC_start<=0.8];
Vincoli=[Vincoli, E(end)>=(SoC_start-0.1)*Emax, E(end)<=(SoC_start+0.1)*Emax];

Vincoli=[Vincoli, P_salire>=0, P_scendere<=0];



%aggiungo vincoli offerta
Vincoli=[Vincoli,P_salire<=M-M*STATO_salire];
Vincoli=[Vincoli,P_salire-1>=-M*STATO_salire];

Vincoli=[Vincoli,P_scendere>=M*STATO_scendere-M];
Vincoli=[Vincoli,P_scendere+1<=M*STATO_scendere];
Vincoli=[Vincoli,STATO_salire+STATO_scendere>=1];

% vincolo per offrire 2 ore consecutive

for i=max(int8(2/dt),1)+2:length(tempo)
     Vincoli=[Vincoli,P_salire(i)>=max(P_salire(i-max(int8(2/dt),1):i-1))-
P_salire(i-max(int8(2/dt),1))];
     Vincoli=[Vincoli,P_scendere(i)<=min(P_scendere(i-max(int8(2/dt),1):i-1))-
P_scendere(i-max(int8(2/dt),1))];
end


%vincoli autoconsumo
S1=binvar(length(tempo),1);          %variabile ausiliaria
S2=binvar(length(tempo),1);          %variabile ausiliaria
S3=binvar(length(tempo),1);          %variabile ausiliaria
S4=binvar(length(tempo),1);          %variabile ausiliaria
E_ss=cumsum(PV_s(start:h/dt+start)-Load_s(start:h/dt+start))*dt;        %Profilo
Energia senza offrire servizi
```

```
Vincoli=[Vincoli,E<=M-M*S1, E_ss>=M*S2-M,PV_s(start:h/dt+start)-
Load_s(start:h/dt+start)>=M*S3-M];
Vincoli=[Vincoli,S4-S1<=0, S4-S2<=0,S4-S3<=0, S1+S2+S3-S4<=2];

E_persa=cumsum(S4.*(PV_s(start:h/dt+start)-Load_s(start:h/dt+start)))*dt;
E_acquisto=cumsum(P_acquisto);
E_venduta=cumsum(P_vendita);

%vincoli simulazione
Vincoli=[Vincoli, P_salire(1)==0, P_scendere(1)==0, P_salire(end-
1:end)==0,P_scendere(end-1:end)==0];
%%
%funzione obiettivo
Guadagno=(P_salire'*Prezzi_salire(start:start+h/dt)+P_scendere'*Prezzi_scendere(
start:start+h/dt))*dt-E_persa(end)*costoE+E_venduta(end)*prezzoE-
E_acquisto(end)*costoE;

%%
%ottimizza
optimize(Vincoli,-Guadagno)


%%
%plot
Ev=double(E_venduta);
Ea=double(E_acquisto);
Pacq=double(P_acquisto);
Pven=double(P_vendita);
Off_salire_OPT = double(P_salire);
Off_scendere_OPT = double(P_scendere);
Psda=double(P_sda);
sv=double(STATO_vendita);
ss=double(STATO_salire);
sc=double(STATO_scendere);
plot(start:h/dt+start,Off_salire_OPT+Off_scendere_OPT, 'b')
xlabel('Hours')
ylabel('Power [MW]')
legend('Baseline: Load-PV','Limite massimo','Limite minimo','Offerta')

P_baseline=double(P_bs);

E_OPT=double(E);
subplot(2,1,2)
plot(E_OPT);
xlabel('Hours')
ylabel('Power [MW]')
double(Guadagno)




function [P_acquisto,P_vendita,E_acquisto,E_venduta,P_batt,SoC_out,
Off_salire_OPT, Off_scendere_OPT, Guadagno, Risultatott]=ottimizza(SoC_in,tempo,
Prezzi,Load_s,PV_s,scale_down,h,dt,start)

%Strategia di offerta

addpath(genpath('C:\Users\tiziano\Desktop\YALMIP-master'))
%input: previsione carico [tempo x utenti], previsione PV [tempo x utenti],
energia nominale batterie [utenti],
```

```
%potenza massima in carica e scarica [utenti], previsione prezzi servizio a
salire e
%scendere [tempo]

%%

costoE= 200 ; %Costo energia acquistata €/MWh
prezzoE=50; %prezzo vendita energia €/MWh


Emax=28;            %MWh
P_max_ch=-14;        %MW
P_max_dh=14;         %MW

%creo vettore prezzi al quarto d'ora
j=1;
for i=1:length(Prezzi)*scale_down
     Prezzi_salire(i)=Prezzi(j,1);
     Prezzi_scendere(i)=Prezzi(j,2);
    if mod(i,4)==0
        j=j+1;
     end
end




Prezzi_salire=Prezzi_salire';
Prezzi_scendere=Prezzi_scendere';


tempo=1:h/dt;                               %vettore tempo

%definizione variabili da ottimizzare
% SoC_start=sdpvar(1,1);
SoC_start=SoC_in;                                  %SoC iniziale
P_salire =sdpvar(length(tempo),1);                 %potenza offerta per i
servizi a salire (MW)

P_scendere = sdpvar(length(tempo),1);               %potenza offerta per i
servizi a scendere (MW)
P_acquisto=sdpvar(length(tempo),1);                %potenza acquistata da rete
(MW) senza offerte
P_vendita=sdpvar(length(tempo),1);                 %potenza venduta alla rete
(MW) senza offerte
STATO_salire=binvar(length(tempo),1);              %variabile di supporto
STATO_scendere=binvar(length(tempo),1);           %variabile di supporto
STATO_vendita=binvar(length(tempo),1);             %variabile di supporto
P_bs = sdpvar(length(tempo),1);


%%
%vincoli
% SoC_start=0.35;                                       %SoC iniziale di ogni
batteria (compreso nei due vincoli seguenti)
SoC_min=0.1;                                           %SoC minimo di ogni
batteria
SoC_max=0.9;                                           %SoC massimo di ogni
batteria
```

```
M=P_max_dh+2;
m=P_max_ch-2;

%vincoli tecnici batterie
P_sda = zeros(length(tempo),1);

E(1)=Emax*SoC_start; % stato di carica inizale
P_sda = P_bs +P_salire+P_scendere;
E = E(1)+cumsum(-P_sda*dt);
%%

Vincoli=[P_sda>= P_max_ch, P_sda>= P_max_ch];
for i=1:length(tempo)
%     Vincoli=[Vincoli,P_bs(i)<=Load_s(i)-PV_s(i), P_bs(i)>=-PV_s(i)+Load_s(i)];
    Vincoli=[Vincoli,abs(P_bs(i))<=abs(Load_s(i)-PV_s(i))];
end

Vincoli=[Vincoli, P_acquisto<=M*STATO_vendita, -P_acquisto<=-m*STATO_vendita,
P_acquisto<=(P_sda +PV_s(start:h/dt+start-1)-Load_s(start:h/dt+start-1))-m*(1-
STATO_vendita), -P_acquisto<=-(P_sda +PV_s(start:h/dt+start-1)-
Load_s(start:h/dt+start-1))+M*(1-STATO_vendita)];
Vincoli=[Vincoli, P_vendita<=M*(1-STATO_vendita), -P_vendita<=-m*(1-
STATO_vendita), P_vendita<=(P_sda +PV_s(start:h/dt+start-1)-
Load_s(start:h/dt+start-1))-m*(STATO_vendita), -P_vendita<=-(P_sda
+PV_s(start:h/dt+start-1)-Load_s(start:h/dt+start-1))+M*(STATO_vendita)];
Vincoli=[Vincoli, E>=SoC_min*Emax, E<=SoC_max*Emax];
% Vincoli=[Vincoli, SoC_start>=0.1, SoC_start<=0.9];

Vincoli=[Vincoli, E(end)>=(SoC_start-0.1)*Emax, E(end)<=(SoC_start+0.1)*Emax];

Vincoli=[Vincoli, P_salire>=0, P_scendere<=0];
%%

% vincolo per offrire 2 ore consecutive

for i=max(int8(2/dt),1)+2:length(tempo)
     Vincoli=[Vincoli,P_salire(i)>=max(P_salire(i-max(int8(2/dt),1):i-1))-
P_salire(i-max(int8(2/dt),1))];
     Vincoli=[Vincoli,P_scendere(i)<=min(P_scendere(i-max(int8(2/dt),1):i-1))-
P_scendere(i-max(int8(2/dt),1))];
end

%aggiungo vincoli offerta
Vincoli=[Vincoli,P_salire<=M-M*STATO_salire];
Vincoli=[Vincoli,P_salire-1>=-M*STATO_salire];

Vincoli=[Vincoli,P_scendere>=M*STATO_scendere-M];
Vincoli=[Vincoli,P_scendere+1<=M*STATO_scendere];
Vincoli=[Vincoli,STATO_salire+STATO_scendere>=1];


%%

%vincoli autoconsumo
% S1=binvar(length(tempo),1);         %variabile ausiliaria
% S2=binvar(length(tempo),1);         %variabile ausiliaria
% S3=binvar(length(tempo),1);         %variabile ausiliaria
% S4=binvar(length(tempo),1);         %variabile ausiliaria
```

```
% E_ss=cumsum(PV_s(start:h/dt+start-1)-Load_s(start:h/dt+start-1))*dt;
%Profilo Energia senza offrire servizi
% Vincoli=[Vincoli,E<=M-M*S1, E_ss>=M*S2-M,PV_s(start:h/dt+start-1)-
Load_s(start:h/dt+start-1)>=M*S3-M];
% Vincoli=[Vincoli,S4-S1<=0, S4-S2<=0,S4-S3<=0, S1+S2+S3-S4<=2];
%
% E_persa=cumsum(S4.*(PV_s(start:h/dt+start-1)-Load_s(start:h/dt+start-1)))*dt;
E_acquisto=cumsum(P_acquisto)*dt;
E_venduta=cumsum(P_vendita)*dt;

%vincoli simulazione
Vincoli=[Vincoli, P_salire(1)==0, P_scendere(1)==0, P_salire(end-
1:end)==0,P_scendere(end-1:end)==0];
%%
%funzione obiettivo
% Guadagno=(P_salire'*Prezzi_salire(start:start+h/dt-
1)+P_scendere'*Prezzi_scendere(start:start+h/dt-1))*dt-
E_persa(end)*costoE+E_venduta(end)*prezzoE-E_acquisto(end)*costoE;
Guadagno=(P_salire'*Prezzi_salire(start:start+h/dt-
1)+P_scendere'*Prezzi_scendere(start:start+h/dt-1))*dt+E_venduta(end)*prezzoE-
E_acquisto(end)*costoE;

%%
%ottimizza

RESULTS=optimize(Vincoli,-Guadagno)
Risultatott=RESULTS.problem

%%
%plot
Off_salire_OPT = double(P_salire);
Off_scendere_OPT = double(P_scendere);
SoC_out=double(E)/Emax;

Guadagno=double(Guadagno);
P_batt=double(P_sda);
E_acquisto=double(E_acquisto);
E_venduta=double(E_venduta);

E_acquisto=E_acquisto(end);
E_venduta=E_venduta(end);


P_acquisto=double(P_acquisto);
P_vendita=double(P_vendita);

E_OPT=double(E);
% subplot(2,1,2)
% plot(start:h/dt+start-1,E_OPT)
% xlabel('Tempo [hh]')
% ylabel('Energia [MWh]')
% legend('Energia disponibile VESS')


clear all
close all

load ('Load4000utenti.mat');
Load=Pnew;
```

```
PV=xlsread('Fotovoltaico4000utenti.xlsx');

Prezzi=xlsread('Ptot.xlsx');



%scale down
scale_down=4;  %parti di un'ora

%punto iniziale
start=1;    %prima ora della finestra temporale

%orizzonte ottimizzazione in ore
h=4;

%passo temporale in ore
dt=0.25;

%verifico fattibilità finestra temporale
if (start+h)*dt>length(Load)/scale_down
    fprintf('La finestra temporale scelta è al di fuori dei dati disponibili in
input.\nPer ottimizzare cambiare ora iniziale o orizzonte temporale.\n')
    return
end

SoC_in=0.4;
Load_s=zeros(h*scale_down,1);
PV_s=zeros(h*scale_down,1);

%creo vettore prezzi al quarto d'ora
j=1;
for i=1:length(Prezzi)*scale_down
     Prezzi_salire(i)=Prezzi(j,1);
     Prezzi_scendere(i)=Prezzi(j,2);
    if mod(i,4)==0
         j=j+1;
     end
end
Risultatott=zeros(0,1);


E_a=0;
E_v=0;
i=1;
while i<=length(Load)
% while i<=4*48
        Load_s=Load(i:i+scale_down*h-1,1);
        PV_s=PV(i:i+scale_down*h-1,1);
        [P_acq,P_ven,E_acq,E_ven,P_b,SoC_out, Psalire, Pscendere, Guadagno,
Risultatott(end+1,1)]=VESS_4h(SoC_in,i,Prezzi,Load_s,
PV_s,scale_down,h,dt,start);
        SoC_in=SoC_out(end);
        Psalire_anno(i:i+scale_down*h-1)=Psalire;
        Pscendere_anno(i:i+scale_down*h-1)=Pscendere;
        P_acq_t(i:i+scale_down*h-1)=P_acq;
        P_ven_t(i:i+scale_down*h-1)=P_ven;
        Psda(i:i+scale_down*h-1)=P_b;
        E_a=E_a+E_acq;
```

```
        E_v=E_v+E_ven;


        if i>=2
            Guadagno_anno(i:i+scale_down*h-1)=Guadagno_anno(scale_down*h-
1)+Guadagno;

        else
            Guadagno_anno(i:i+scale_down*h-1)=Guadagno;

        end

        SoC(i:i+scale_down*h-1)=SoC_out;
        i=i+scale_down*h;

end


clear all
close all
load ('RisultatiT15.mat');
% tariffe valide dal 1 gennaio 2018 al 31 marzo 2018
prezzo_energia=50; % €/MWh
costo_MateriaE=89.68; % €/MWh   considero una sola fascia oraria
costo_Trasposto_g=7.86; % €/MWh
oneri=65.092;  % €/MWh
accisa=22.7;  % €/MWh
IVA=0.1;   % percentuale  IVA
dt=0.25; % passo temporale

tempo=1:8640;
%load ('Load750utenti.mat');
Load=Pnew(1:8640);
%PV_P=xlsread('Fotovoltaico750utenti.xlsx','A1:A8640');
%Psda_1=Psda(1:8640);
Prezzi_salire_1=Prezzi_salire(1:8640);
Prezzi_scendere_1=Prezzi_scendere(1:8640);
Psalire_anno_1=Psalire_anno(1:8640);
Pscendere_anno_1=Pscendere_anno(1:8640);
P_acq_t_1=P_acq_t(1:8640);
P_ven_t_1=P_ven_t(1:8640);
P_sda=Psda(1:8640);
 for i=1:length(tempo)
     P_rete(i)=P_acq_t_1(i)+P_ven_t_1(i);
     P_Base(i)=P_rete(i)-Psalire_anno_1(i)-Pscendere_anno_1(i);
end
 for i=1:length(tempo)
    if P_rete(i)>0 && P_Base(i)>0

G(i)=(P_Base(i)*dt*prezzo_energia)+(Psalire_anno_1(i)*dt*Prezzi_salire_1(i))+(Ps
cendere_anno_1(i)*dt*(Prezzi_scendere_1(i)+prezzo_energia));
    elseif P_rete(i)>0 && P_Base(i)<0
        G(i)
=(P_Base(i)*dt*costo_MateriaE)+(Psalire_anno_1(i)*dt*Prezzi_salire_1(i));
    end

 if P_rete(i)<0 &&  P_Base(i)>0

G(i)=(Pscendere_anno_1(i)*dt*(Prezzi_scendere_1(i))+((P_Base(i))*dt*(costo_Mater
iaE+costo_Trasposto_g+oneri+accisa))*(1+IVA));
```

```
    elseif P_rete(i)<0 && P_Base(i)<0
         G(i)=
(P_Base(i)*dt*(costo_MateriaE+costo_Trasposto_g+oneri+accisa)*(1+IVA))+(Pscender
e_anno_1(i)*dt*(Prezzi_scendere_1(i)))+(Psalire_anno_1(i)*dt*Prezzi_salire_1(i))
+((Psalire_anno_1(i)*dt)*+(costo_MateriaE+costo_Trasposto_g+oneri+accisa))*(1+IV
A);
    end
end

somma=sum(G);
```