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EVALUATION OF THE ECONOMIC POTENTIAL OF ENERGETIC AGGREGATION IN THE ITALIAN CONTEXT

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To my family and all the beloved ones who sustain me.

Thank you for being always by my side.

ABSTRACT (Italian)

L'aggregazione di risorse energetiche può facilitare significativamente l'integrazione di risorse non programmabili e/o distribuite, accrescere la flessibilità del sistema elettrico e ridurre la dipendenza dei piani energetici da costosi programmi di incentivazione.

Lo scopo di questo studio consiste nel fornire una valutazione del potenziale dell'aggregazione di risorse energetiche in Italia.

Nel dettaglio, e con riferimento alla normativa vigente nel nostro paese, le modalità di aggregazione oggetto di studio sono state due: l'aggregazione in una unità virtuale, o *virtual power plant (VPP)*, di sole risorse produttive (UVAP, unità virtuale abilitata di produzione); e l'aggregazione contemporanea in una unità virtuale sia di risorse produttive sia di unità di consumo (UVAM, unità virtuale abilitata mista).

Sottolineando la pertinenza del tema rispetto a problematiche attuali e il livello di flessibilità offerto dalle configurazioni virtuali, ciascun *VPP* è stato pensato in modo da comprendere solo risorse distribuite di piccola taglia – nello specifico: unità solari fotovoltaiche e batterie agli ioni di litio per quanto riguarda il lato produzione; unità di prelievo residenziali per quanto riguarda il lato consumi.

Nello svolgere la valutazione il primo passo effettuato è stato necessariamente quello di comprendere il funzionamento e la logica esistenti dietro il concetto di unità virtuale e, parallelamente, capire come tale concetto trovasse spazio in ambito regolatorio nel nostro paese. Il secondo passo è stato quello di costruire un adeguato modello di business e delle opportune casistiche per procedere secondo uno schema di valutazione investimento, talvolta anticipando sotto alcuni aspetti la regolazione esistente. Il terzo, fondamentale passo è stato infine quello di progettare un modello matematico che fosse in grado di simulare il comportamento delle unità virtuali ideate in ambiente di mercato, così da poterne valutare le potenzialità a livello economico.

I risultati ottenuti nell'insieme, nonostante l'alta variabilità dettata dalle diverse caratteristiche delle varie configurazioni analizzate, si dimostrano decisamente promettenti in prospettiva dei futuri sviluppi che seguiranno in ambito regolatorio, tecnologico e di modelli di business.

ABSTRACT (English)

The aggregation of energetic resources can considerably facilitate the integration of non-programmable and distributed energy sources, enhance system flexibility and reduce the reliance of energy strategies on costly incentive schemes.
The purpose of this study is to provide an evaluation of the potential of the aggregation of energetic resources in Italy.
More in detail, and with reference to the regulation in force in our country, two aggregation modalities have been put to the test: the aggregation into a virtual power plant (VPP) of production energy resources only (*UVAP, unità virtuale abilitata di produzione*); and the mixed aggregation into a virtual power plant of both production and consumption energy resources (*UVAM, unità virtuale abilitata mista*).
To underline the pertinence of the topic with respect to actual problematics and the level of flexibility that can be offered by virtual configurations, each VPP was thought to incorporate only small-sized DERs (distributed energy resources) – in the specific: solar photovoltaic and Li-ion batteries for what concerns the production side; residential units for what concerns the consumption side.
The first step conducted to perform the evaluation was necessarily to comprehend the functioning and the logic behind the concept of virtual power plants, but also, at the same time, to understand how much space was dedicated to that concept within Italian energy regulations. The second step was that of building up an adequate business model and a proper variety of casuistries to proceed according to an investment evaluation scheme, trying also to anticipate under certain aspects the regulation currently in force. The third, fundamental step was that of designing a mathematical model in order to simulate the behaviour of the virtual units on the markets, so to evaluate their economic potential.
The results obtained, in spite of their high variability resulting from the different characterization of the casuistries analysed, are interestingly promising in perspective of the future developments that will follow under the regulatory, technological and business model evolution points of views.

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Chapter 1

THE POWER SECTOR, FROM EUROPE TO ITALY

This opening chapter serves to introduce the work and the general energetic context in which the power sector, background of the case study that will be presented in the last chapter, will play a crucial role. Along the chapter, the discussion will retrace present and perspective outlooks and will gradually focus from the generalities of the European context to the specificities of the Italian situation, describing also the market scenario that has been chosen as the underlying context in building up the case study.

1.1. INTRODUCTION

Since the Nineties, when environmental and energetic issues started to raise the attention of leading world countries – starting with the UN conference held in Rio de Janeiro in 1992 and going on to the drafting of the Kyoto protocol in 1997 – a new model of environmentally sustainable growth, either industrial or economic, has been gradually defined [1] and put in the foreground by all major global economies. Although, the resilience of some influencing countries which based, and still do base today, their *supremacy* on traditional energetic resources – holding up their industrial economies and their public finances – somehow negatively affects the negotiations and the procedures to achieve common environmental and energetic targets to be pursued at worldwide level.

However, despite of the inertia and the scepticism of some *actors*, climate change and environmental sustainability have become questions of the utmost importance within the global energetic context [1]. The relationship between green-house gasses (GHG) emissions and global warming, climate change and human health, brought to raise questions about the sustainability and the greed of the industrialized world as it has developed since the first industrial revolution.

Here is the basis of the effort put by the global community in the recent past to raise awareness towards such matters, and the result is that nowadays the search for *energetic health* – a term through which it is intended here the achievement of adequate security of supply and competitive energy prices through the legacy of always less prominent traces in terms of carbon footprint – is followed with increasing interest and effort by all major economies, especially those which are exposed the most to scarcity of energetic resources and environmental issues.
To consolidate the progresses and the path designed at international level, it becomes fundamental to define strategies which are resilient to geopolitical changes (that still represent a strong influencing element) and to *downward* deviations of objectives [1].

1.2. IMPORTANCE OF THE POWER SECTOR IN THE GLOBAL ENERGETIC CONTEXT

In December 2015, with the achievement of the Paris Agreement, the countries participating to the conference unanimously renovated their commitment due more ambitious and legally binding objectives towards a cleaner and more environmentally responsible world. At the same time, the international community approved through the United Nations the Agenda 2030 for the sustainable development, setting up a new system of global governance to influence development policies [1].
To achieve the promised reduction of CO_2 emissions, to fight climate change and to reach the rest of the objectives foreseen by the most recent international agreements, countries all over the world cannot neglect a deep transformation of their energetic sectors.
In particular, the power sector is fundamental to this purpose because of its historical relationship with pollution generation and because there is no other sector that can be compared in terms of *speed of change* for what concerns the deployment of de-carbonization measures [2]. As a matter of facts, the changes already in place in some parts of the world, Europe ahead, highlight the potential of low-emission energy sources and give credibility to the implementation of effective actions against climate change: from the diffusion of clean energy sources to the increasing attention towards energy efficiency practices and the provision of lower amounts of subsidies to support fossil fuels consumptions [3].

Such measures become a key factor within the power sector also in sight of the expected increase of the share of electricity consumption within the overall growing energy demand trend: in 2040, the overall energy consumption is expected to increase by 30% with respect to today levels. And about 40% of the total energy needs is expected to be represented by demand for electricity [3]. This electrification of consumptions is supposed to be mainly driven by the further industrialization of *emerging* countries, the diffusion of electric vehicles, batteries and the effect of de-carbonization policies on the usage of fossil fuels [2].

Another important element that underlines the increasing relevance of the power sector within the overall energetic context at global level is that, in 2016, for the first time ever since the consolidation and the worldwide diffusion of traditional fossil fuels, global investments in the electricity sector overcame those sustained in the *oil-&-gas* one; a signal that underlines the cruciality of the power industry in its completeness and that the security of power supply has by now become a priority for governments [2].

Now, even though the role of traditional fossil fuels – at least oil and natural gas – is expected to remain fundamental in the energetic mix for decades yet to come, major improvements are expected from the continuous growth of renewable technologies. The rapid decrease of technological costs is going to make renewable energy sources (RES) economically competitive even without the support of incentive schemes, which will foster their ascent within the generation mix.

Considering then the limited impact of nuclear production and the expected drowning of coal demand – despite of the development of *carbon capture and storage* (CCS) technologies, it appears clearly not pursuant with de-carbonization strategies [1] – it is no wonder that the most realistic picture of the future electricity generation mix is characterized by the dominance of the duo gas-RES, and that an important re-allocation of investments is expected to take place in the next years [2]: as natural gas becomes the most important primary energy source – with most of the investments to be deployed within the *E&P* (exploration and perforation) and the LNG (liquefied natural gas) sectors – RES investments will come to boost green energy production, generating up to two third of the electricity in 2040 [3]. Moreover, the role of energy efficiency becomes definitely central in the *race* towards the achievement of environmental and economic objectives, as *EEMs* (energy efficiency measures)

become fundamental to reduce the pressure on the production side, to preserve energy sources, to favour emissions reduction and to diminish energetic intensity [2] [4].
Infrastructural investments will play a key role in driving the transition towards a low-carbon economy, too: the development and the diffusion of RES and smart technologies depends strongly on the adequacy of power networks to welcome them and to allow such technologies to fairly compete with traditional ones. This means that power networks must provide green technologies with the right level of flexibility; that grid infrastructures must be upgraded; that demand response and energy storage technologies must be really supported; and that rules and market mechanisms should be revised and harmonized and rightly drive the change [1] [3].

1.3. THE ENERGETIC TRANSITION IN EUROPE

1.3.1. Understanding the context

Europe is notoriously a region that depends a lot on the foreign supply of primary traditional energetic sources among industrialized economies. This is the principal reason why the European Union has been concentrating, for about the last twenty years, its efforts to draft forefront energy and environmental policies to solve the so-called *energy trilemma*: granting security of (energy) supply; strengthening the competitiveness of European economies through affordable energy prices; promoting environmental sustainability and preventing climate change [5]. As of today, the resolution of this *energy trilemma* seems to be linked to two fundamental objectives: the de-carbonization of the European economy and the realization of a unique European energetic market [4].
In the recent past, pushed by its exposure to energetic and environmental issues, Europe assumed a leading role in the *crusade* to stem GHG emissions.
The first important sign of the praiseworthy European commitment to the cause was given by the EU with the definition of the Climate-Energy Package, in 2008. The measures defined by the EU constituted a substantial *gear-change* to the achievement of continental de-carbonization goals and comprehended an ambitious set of actions and objectives to be achieved by 2020. The most important ones regarded: the reduction of GHG emissions of at least 20% with respect to 1990 levels; a contribution,

over final gross energy consumption, of at least 20% of RES energy and a 10% target established for bio-fuels; an improvement in the field of energy efficiency of at least 20% with respect to *business as usual* trends [4] [3] [6].

To give continuity to the message launched in 2008, the European Commission published in 2011 the first indications concerning the Roadmap 2050, the *final* de-carbonization plan through which European authorities wanted to achieve an 80% GHG emissions reduction target – with respect to 1990 levels – by 2050. Such ambitious target could be reached only by tightening currently in-force regulations and by deploying systems that continuously check for discrepancies between real and ideal trends. Likely, periodic adjustments, corrective actions, new short-term and medium-term objectives may be proposed and applied in progress. Following the rationale that early actions allow to save costs in the long run, it was commonly agreed that serious actions must be adopted from the first stages of deployment. As a matter of facts, the roadmap sets out a cost-efficient pathway to reach the 80% target by 2050 [7]: the European Commission put forward intermediate goals to be achieved by mean of domestic measures, of which the most important regarded the achievement of a 40% emissions reduction target by 2030 and a 60% figure by 2040 [8]. It is also to mention the review of the related 2020 target, that was increased to 25% on the wave of the promising results achieved by now in the ambit of the *20-20-20 Package* [7].

The path towards energetic independence and an always more carbon-free economy shall be made feasible and affordable through innovation and investments, so that all the sectors which are responsible for the high levels of continental emissions must contribute [7].

In particular, the state of the art of the progresses and the results achieved by 2030 will constitute the first important feedback in relation to the accomplishment of the roadmap designed.

Together with the already mentioned intermediate objective of reducing GHG emissions, in October 2014 the European Council defined the goals to 2030 even in terms of renewable energies and energy efficiency: the quota of RES energy over the total gross consumption and the improvement in the field of energy efficiency got both fixed to 27% – *at least* – so to give continuity to the previous Climate-Energy Package [7].

The Clean Energy Package, which reported legislative proposals related to the development and the penetration of renewable sources, the development of a

harmonized European electricity market and the development of energy efficiency support policies [1], was completed and promulgated definitely in 2016.
The European Commission reckoned that, to reach the targets, it would be necessary to adopt also the following measures: it will be necessary to improve and empower the interconnection capacity between member states, which would be prior to the constitution of an internal energy market (IEM). The completion of the IEM (that will surely require time) is seen as a key mean to enhance competitiveness and security of supply throughout the whole EU [9]; in perspective, the awaited reform of the European emission trading scheme (ETS), which remains a fundamental element for the transition to a low-carbon economy, will be necessary to make the market more liquid and more efficient.
It was also put forward a first idea for a new governance system based on national plans following a common European guideline [10] to come to pacts with the differences between the arrangements of the various member states and, at the same time, to provide standardized instructions.

1.3.2. Towards a more coordinated European power sector

One of the fulcrums of the European energetic renovation is represented by the harmonization of the mechanisms concerning the power sector. The basis of a true harmonization cannot neglect the presence of a common framework providing general guidelines to be respected by each country. The intention of European authorities was to aim for a much more nationally decentralized and a much more coordinated supranational organization. [1].
It was given mandate to ENTSO-E (the European Network of Transmission System Operators for the power sector) to properly draft common rules to facilitate the harmonization process, the integration and the efficiency of the European electricity market [11], under the guidance of the ACER – respectively, the two organization represent the coordinator of the various national transmission system operators (TSOs) and the Agency for the Cooperation of (national) Energy Regulators.
These common rules are contained in ten *network codes*, that constitute also an integral part of the drive towards the completion of the European internal energy market [11] and the achievement of 2020 and 2030 objectives. Network codes are

divided into three *families* regarding connection, operations and market issues and have reached full implementation with the approval and adoption of the codes concerning *Emergency and Restoration* and *Balancing* in December 2017. In particular, the new *Balancing Code* [12] represents one the last tassels towards the definition of an integrated electricity market model and it is a fundamental support to enhance security of supply and reduce system costs through the sharing of balancing resources with the creation of cross-border balancing markets – like it already happens for the simpler day-ahead market and (in the next future) for the infra-day market.

The new code was thought also to foster the integration of distributed generation and active demand with security of supply targets. Indeed, this is consistent with the progressive process of decentralization of the power generation [1] and the new paradigm that imagines the consumer as the engine of the energetic transition, in association also with innovative configurations including demand response, prosumers, aggregators and energy communities.

The new market design foresees also the total liberalization of retail markets, the equalization of the different generation sources according to a *level playing field approach* [1], the introduction of imbalance responsibilities for each market participant, the intensification of cross-border linkages and the redefinition of the duties of distribution system operators (DSOs).

Technological progress and common de-carbonization policies will drive then European countries towards an overall common characterization in terms of generation mix – as the progressive dismantling of nuclear facilities and phasing-out of carbon plants will make the way to the duo gas-RES, as it was aforementioned.

The need for reforming market rules originates thus because today's energy market rules are mainly designed to meet the needs of yesterday’s energetic systems, characterised by centralised fossil fuel plants with minimal levels of consumer participation [13].

The realization of an internal electricity market represents then a cornerstone for the re-design of the electricity market other than a remarkable element within the achievement of the objectives contained in the Clean Energy Package. On this purpose, the European Council, which agreed its position on IEM regulation in December 2017, focused the attention on a series of opportunities and challenges: bringing market transactions closer to real-time; establishing new rules about dispatching and balancing responsibilities; giving birth to a European entity representing DSOs;

defining clear principles to shape optimal bidding zones – electricity trading areas that should be sized so to grant stability over time; defining a new European adequacy assessment procedure for resources in association with the deployment of forward capacity allocation mechanisms [14].

1.4. FROM EUROPE TO ITALY

1.4.1. A new electricity market

The evolution of the power system, already in act at European and global level, is going to be strongly characterized by the evolution of de-carbonization policies and by technological changes. Since each country will be affected by the ferment of the transition, to promptly face the challenges and to catch the opportunities that were highlighted before, single member states must be ready to re-organize their attitudes in order to conform to the brand-new European common market design.
The latest Italian energy strategy, or *SEN* (*Strategia Energetica Nazionale*) *2017* (that has been already cited in the text) was adopted officially on December 10, 2017 by mean of a combined decree [1] of the Ministry for the Economic Development and the Ministry for the Environment and the Safeguard of the Territory and the Sea, and focuses significantly on the *hot topics* involving the power sector, posing questions concerning the effective level of non-programmable RES sustainable by the system, the entity of additional infrastructural investments and the measures to complete the liberalization process [15].
Here are resumed the topics that touched by the principal targets proposed through the *SEN 2017*:

- In the short-run: the complete qualification of RES plants to participate to the markets and the proper valorisation of the value added by active demand and other flexible resources (such as storage systems) and of the potential coming from the new aggregation and closed-system paradigms [1].
  The anticipated achievement of the national targets to be pursued within the *20-20-20 Package* underlines the primary role of renewable sources for our country [1]. The valorisation of the cost decrease of *ductile* green technologies

could be the key to foster RES investments in a smart and sustainable way, taking advantage of the socio-economic benefits that RES can be capable of.

- In the long-run: the introduction and the successive refining of new regulated contractual instruments for the forward transaction of energy products (like the brand-new capacity market) and of a different market model, foreseeing a major involvement of DSOs and distributed energy resources (DERs) [1].
  In perspective of a new market model, it would be also opportune to design proper methodologies and instruments to provide likely price signals on balancing and ancillary services markets, which are much more complex than traditional energy markets. This is to be considered essential in a long-term market vision, in what the actual Italian central-dispatch model is by now obsolete and inadequate to efficiently manage the increasing complexity of the power system [1].

In the *SEN 2017*, it is also specified that the deployment of principal reforms should be juxtaposed to another series of complementary interventions, such as: the realization of new efficient informative systems able to satisfy the necessity of more reliable and rapid information exchanges; new standards of observability and control; investments aiming at improving and empowering the current network infrastructure; measures aiming at improving the management of the market, pushing for an almost real-time configuration (which is a fundamental feature of the future European electricity market design).
Many of these issues are being faced by the national energetic authority, the ARERA (*Autorità di regolazione per energia, reti e ambiente*, previously named AEEGSI) and the Italian transmission system operator (TSO), Terna S.p.A, in the context of the project of reform of the electric dispatching (*riforma del dispacciamento elettrico, RDE*) [16] that will be discussed more in depth in the following chapters together with the national.
It is worth to underline that in the *SEN 2017*, a certain degree of optimism is shown about competitiveness-related improvement possibilities that the Italian economy may benefit from the harmonization of procedures, market models and generation mix. Indeed, the evolution of our market mechanisms towards a gate closure of wholesale transactions closer to real time, the thrust towards greener energy policies

and a renovated ETS market are supposed to drive the whole European power generation structure to converge towards RES and flexible gas-powered plants, a configuration which broadly corresponds already to the backbone of the Italian power infrastructure.

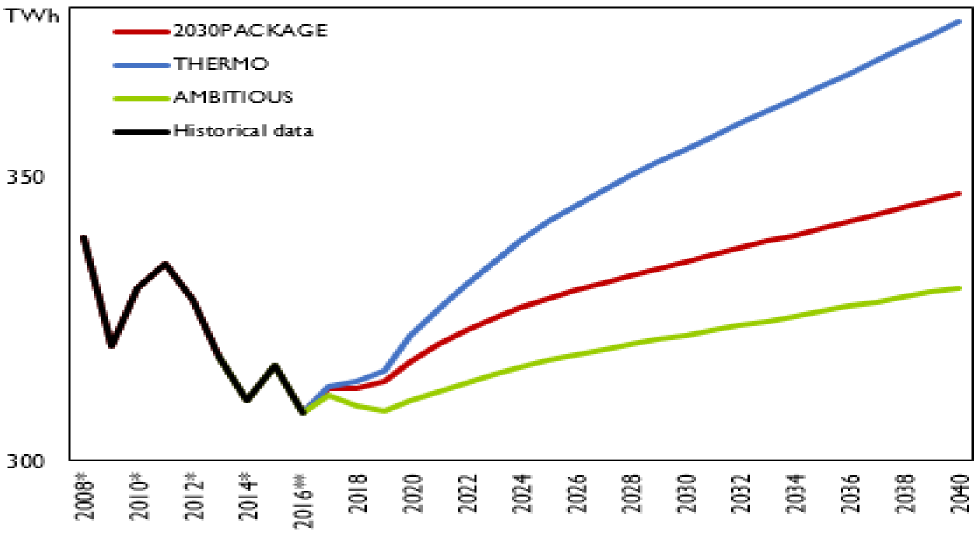
1.4.2. Perspective scenarios about the Italian electricity market

In a context where national strategies are supervised by common European guidelines and convey into a greater market design, the evolution of the Italian electricity market will be undoubtedly related to the decisions of supra-national European authorities.
The *SEN 2017*, like other national energetic strategies, incorporates this aspect in the targets proposed. However, the scenarios pictured within the *SEN 2017* may seem too *optimistic* under certain points of view.
Analysts at REF-E provided an independent prospective scenario which presents an underlying, substantial difference with respect to what is stated in the *SEN 2017*.
REF-E is an advisory company which has been operating in the Italian electricity market for almost twenty years. The company challenges independently the analysis of energy markets using proprietary models and databases. The principal activity of REF-E is the periodic release of perspective analyses concerning the evolution of the power sector, which are based on the current state of the art of the stance of market competition, impacting energy policies and technological aspects. The set of advisory services offered by REF-E ranges from the provision of strategical decision-making coaching for market players to the regulatory support to institutional authorities within the ambit of new policy-making.
Basing their evaluation on historical data, macro-economic and regulatory projections, according to the methodology that was described in the previous lines, the REF-E team defined their view about the future characterization of the Italian electricity market within the horizon 2017-2040.
Since their releases are always characterized by a triple perspective – a referential scenario, which is considered the most likely in terms of occurrence, is juxtaposed to a more optimistic and a more pessimistic view – here they will be all presented:

- Scenario *2030PACKAGE*: it sticks to the line traced by the EU with the objectives of the Energy and Climate Package, that is supposed to grant the realization of the achievements fixed with the Roadmap 2050. This is thought to be the most likely scenario.

- Scenario *THERMO*: it hypothesises the abandon of intense climatic and energetic policies due to failures in the achievement of further international agreements. It is characterized by higher consumptions, higher energy prices, lower CO_2 prices and less contribution from RES.

- Scenario *AMBITIOUS*: it is an optimistic scenario characterized by an intensified effort put in developing climate and energetic policies to reach advanced results in terms of GHG emissions reduction – 95% with respect to 1990 levels by 2050 instead of 80%. It is supposed to lead to opposite conclusions with respect to the second scenario.



Source: REF-E forecast, Terna development plan.
** historical data, ** provisional data*

FIGURE 1.1 *Historical and forecasted electric demand, data elaboration by REF-E*

According to REF-E, these perspective scenarios will be characterized by different factors according to the diverse time-period of reference within the whole horizon.
In the short-run (up to 2020), prices will be influenced and determined by the trend showed by the price of commodities (mainly oil and natural gas), and thus characterized by high variability.

Between 2020 and 2030, the market will be characterized by the progressive phasing-out of RES incentives and the new generations of renewable technologies will be supported also through a more compelling ETS mechanism, with a poorer clean spark spread (CCS) and a negative clean dark spread (CDS) – respectively, the profit realised by a power generator after the cost of gas/coal fuel and carbon allowances. In the very long-run instead, up to 2040, the market is supposed to reach an equilibrium given by the existence of complete RES market parity and a still viable economic sustainability of thermo-electric plants working as back-up systems to guarantee network security and a proper generation mix.

1.4.3. Scenario comparison: SEN 2017 and REF-E's 2030PACKAGE

The outline depicted within the *SEN 2017*, foresees a power demand boosted by the electrification of consumptions that covers up to 24% of the total internal energy gross consumption in 2030, with RES contributing for about 55% at aggregate level, on the wave of the phase-out of carbon-burning facilities expected by 2025 [1].
But what makes the targets posed by the *SEN 2017* resemble too optimistic is that it incorporates the effect of a series of new policies and tools to get to the targets it poses, which are not known today – other than the effect of still uncertain plans for the development of transportation and logistic infrastructures in energy-consuming industries and for sustainable and alternative mobility [1].
In the national strategy, energy efficiency also assumes a key role (42% improvement by 2030 with respect to the previous EU reference scenario 2007) [1]: through a capillary effect of energy efficiency policies, supposed to affect both energetic inputs and outputs at all levels of the energy production and consumption chain, the effect of the electrification of consumptions and of an increasing demand is almost completely mitigated. The result is a reduced energetic intensity of the Italian economy and a power demand forecast to 2030 which is in line with current levels (forecasted at 304 TWh) [1].
Expertise at REF-E rightly underlined the *ambitious* characterization of this scenario, and highlighted also the lack of adjusted estimations concerning the recent variations in the price of important commodities such as oil and gas.

Considering all these aspects, it could be questioned the real expectancy about such prospect, that might reveal misleading and excessively optimistic under certain points of view.

The reference scenario carried out by REF-E (*2030PACKAGE)*, instead, foresees a business-as-usual evolution based on current consolidated policies (and future developments as they are expectable today), with RES growth completely market driven coming to hit 49% of gross domestic consumptions by 2030 – against the 55% figure depicted in the *SEN 2017* – and 58% by 2040. This renewable result is mainly attributable to photovoltaics and particularly to small-scale, distributed units – REF-E accounts for a forecasted impact of DERs on the total amount of RES installations of about 45% by 2030, around 5% more than actual levels.

Here, it stands out that the differences in terms of demand (up to 2030) between the two views affect the output in terms of RES diffusion. In facts, the 55% RES figure depicted in the *SEN* scenario (based on a demand in line with current levels) would lead to a higher number of RES installations in the coming years, with respect to the 49% figure forecasted in the *2030PACKAGE* scenario (even though it is based on a higher level of demand). Again, the *SEN* target seems to presuppose the impact of a further boost to RES diffusion, which can be translated into a higher technological cost reduction and/or a higher impact of incentive schemes in favour of renewables with respect to what it is currently predictable.

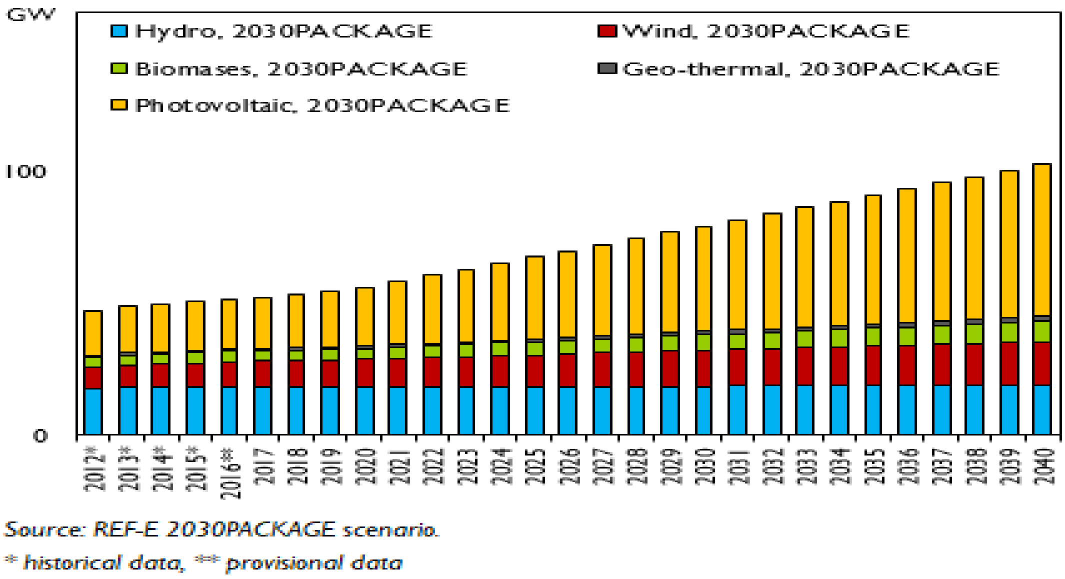


FIGURE 1.2 *RES evolution, data elaboration by REF-E*

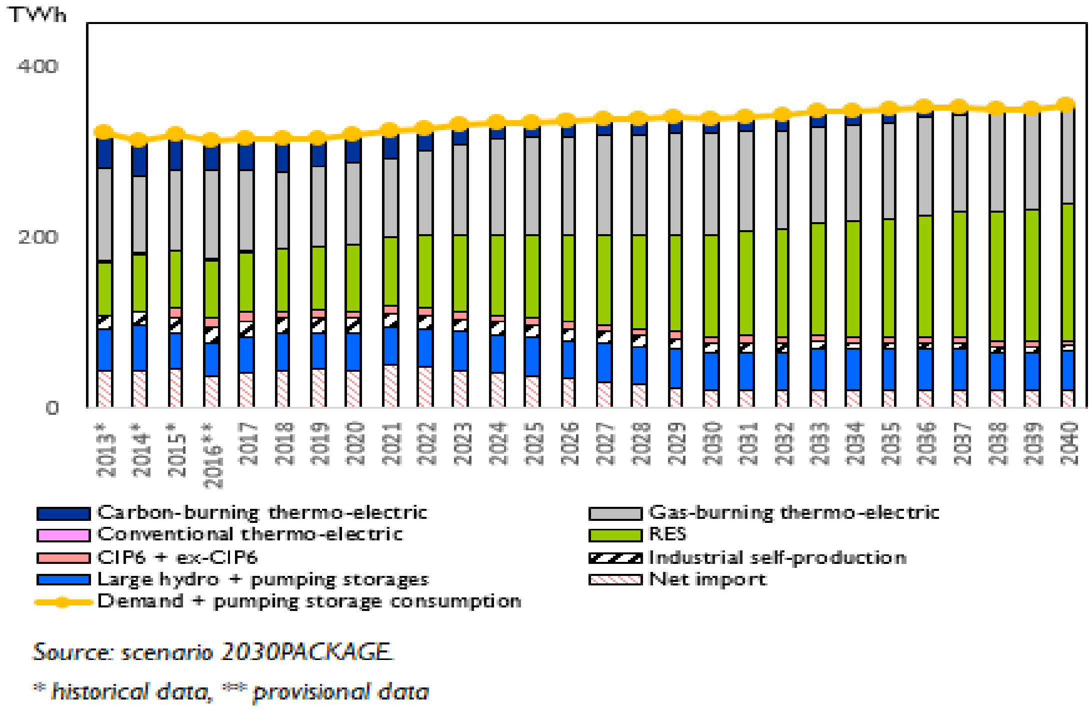


FIGURE 1.3 *Historical and forecasted electric balance, data elaboration by REF-E*

The considerations made above justify the choice of the more *prudent* view expressed within the REF-E *2030PACKAGE* scenario as the underlying *environmental* context at the basis of the evaluations made within the case study that presented in chapter 5.

Chapter 2

EVOLUTION OF THE ITALIAN REGULATORY FRAMEWORK WITHIN THE POWER SECTOR

This transition chapter wants to retrace the strategic regulatory path followed by Italian energy authorities up to 2018 and shed light on the general regulatory context in which the specific ambit of aggregation is included. Starting from the foundations of the last strategic plans deployed by the ARERA, the RDE reform will be introduced. The contents of the chapter are mainly referred to the following official documents: the deliberation 308/2012/A (strategic plan 2012-2014) and the deliberation 3/2015/A (strategic plan 2015-2018). For more technical explanations please refer to the original texts of the documents, which are cited in the below.

2.1. FOUNDATIONS OF THE LATEST STRATEGIC PLANS OF THE ITALIAN AUTHORITY FOR THE ENERGY

2.1.1. 2012-2014 Strategic Plan

The 2012-2014 plan [17] formulated by the Italian energy authority (from now on also referred to as the *Authority*), the ARERA (at that time still named AEEG, *Autorità per l'energia elettrica e il gas*) set sails focusing especially on two salient topics: the increasing decentralization of the power production and the rise of non-programmable RES plants.

The attention of the *Authority* was dedicated to grant the efficient operation – rationally, technically and economically – of the electric system, as well as of the electricity markets.

The challenge that loomed on the horizon mainly concerned how to properly integrate in the electric system the increasing share of intermittent RES capacity populating the upstream ring of the industry chain.
Among the principal ideas to be deployed in order to assure system safety and security of supply while facing the change, there were proposal involving the possible upgrade of grid infrastructures and the review of the market of ancillary services, the MSD.
In particular, consultations to reform the MSD on the wave of the increasing amount of distributed generation and intermittent RES officially began in 2013 with a public debate [18]. The document published by the *Authority* was accompanied by an attached study [19] carried out by the Department of Energy of the Politecnico di Milano. The study performed by the energetic department of the university offered a general overview of what was the situation of the MSD at that time and contained also a first proposal of innovative solutions for the renovation of the dispatching model – an exhaustive overview of this study can be found in *Appendix B*, at the end of the document.

2.1.2. 2015-2018 Strategic Plan

As time went by, the *RES revolution* and the continuous technological development got scenarios increasingly dynamic and made the impact of the change even more important in terms of both managerial complexity and market dynamics.
The latest strategic plan [20] (Autorità per l'Energia Elettrica, il Gas e il Sistema Idrico, 2015) formulated by the *Authority*, published at the beginning of 2015, was set to tackle these challenges and to grant continuity with respect to the actions undertaken and the themes treated in the previous plan.
The path was traced by mean of strategical objectives, coherently with the respect of sovereign European regulations (715/2009, 347/2013 and 1227/2011 among the others). Here is proposed a brief resume of the main points composing the backbone of the path identified by the *Authority*.

- The first point regarded the intention of giving birth to a more efficient, more flexible and safer electric market [20].

The principle moving the regulator was that every subject that could have a role in the dispatching system (from energy producers to consumers and *accumulators*) should have been given the possibility to be properly integrated with the rest of the network without any form of discrimination and contribute to its healthy operation.

This involved the necessity to push for sharper and more precise definitions of the services required by the national TSO, Terna S.p.A (from now on referred to as Terna), as well as for a re-design of the functioning of electricity markets. The objective was to eventually come to enhance flexibility and give the opportunity to market participants to adjust their commercial position as closer as possible to the real time. A scenario that would likely grant more coherency between forecasted and real injection profiles (especially in the case of non-programmable RES) and that could have beneficial effects even on the burdensome issue concerning the management of imbalances.

Specifically referring to the latter, it was also arranged to modify the way in which imbalance prices get computed, proposing a progressive shift towards nodal-based prices to better reflect the value of the electricity in real time and to get in line with the related European proposal [21]. The *Authority* also renewed its commitment to eventually come to put into operation a national *capacity market* – to this regard, the model proposed for our market [22] got finally approved in February 2018 by European authorities.

- A second purpose followed the principle of strengthening the integration between electric markets [20].

  The *Authority* expressed the will to extend the integration of the Italian day-ahead market with foreign ones – French, Austrian and also Greek markets, other than the already existing connection with Slovenia – and to expand this integration also to the market for balancing, pursuing the vision of a harmonized and interconnected European market design.

- A third point regarded the need to increase the competition within the retail market [20].

  In order to stem the inhomogeneities still existing in terms of competition in certain segments – especially in the residential one – the *Authority* proposed a review of the market regulation highlighting the exigency of taking into account also the impacts of the evolution enabled by technological progress: new kinds of players entering the market (from prosumers and energy service companies (ESCOs), to ICT companies and virtual aggregators)**;** differentiated offering (demand response services and energy efficiency interventions).

- The *Authority* underlined then the necessity to support the development of *smart technologies* in order to enhance smart grid and demand response practises. These practices cannot leave aside the real-time monitoring of energy flows. It becomes then extremely important that authorized market players and consumers are granted the possibility to access to injection/withdrawal data – in a non-discriminatory but privacy safeguarding manner [20] – so to be able to keep trace of their profiles and to understand whether a re-shaping of such profiles could bring economic improvements or not.

2.2. REFORM OF THE ELECTRIC DISPATCHING

2.2.1. Birth of the reform and beginning of the first phase

The first step towards an organic reform of the electric dispatching was advanced by the Authority within the last strategic plan but the first dedicated guidelines came officially to the public in 2015 with the deliberation 393/2015/R/eel.

The guidelines [23] gave indications about the review of the criteria according to which the TSO would have defined: each kind of ancillary service and the related remuneration; the extension of the fleet of resources participating to the provision of such services; the opportunity of evaluating the possibilities enabled in this sense by the new figure of the aggregator.

In the deliberation, the Authority underlined the impellent necessity to start a process for the reform of the electric dispatching comprehending in an organic way every element of the new regulatory framework so to lay the foundations of a stable market design [23].

This was the premise to the promotion of the multi-directional project for the reform of the electric dispatching, referred to as RDE (R*iforma del Dispacciamento Elettrico*).

The first phase of the reform, denominated RDE_1, officially began after the consultation opened in 2016 with the document for the consultation 298/2016/R/eel, which announced the beginning of the work for opening the MSD to non-programmable RES plants, distributed generation and the demand [24]. The scheme imagined by the Authority foresaw to officially begin operations with the beginning of 2017 and to make this first phase last at most two years.

As it was already declared, the RDE was thought to be juxtaposed to other important pieces of the comprehensive re-design of the electricity market – specific reference is to be made here to the announced reforms concerning the discipline of imbalances and the review of geographic zones.

As usual, dramatic reforms foresee a transitory period before coming completely into force, so to reduce sudden changes that could destabilize the market and the system. So, in this case, it was established to base the transitory period on pre-existing rules and algorithms [24]. The transitory period was also set up to adopt gradually innovative solutions to be tested, improved and perfectioned in time [24].

The reference market model that was selected by the Authority to begin the works is the first model proposed in the study carried out by the Department of Energy of Politecnico di Milano [19], that was mentioned before.

2.2.2. Overview of the principles related to the transition

The first element of interest was the qualification of RES plants to the provision of ancillary services. It was sanctioned that a distinction concerning the modalities of qualification should have been made between relevant plants (apparent power at least equal to 10 MVA) and non-relevant plants.

This distinction served also to introduce the already mentioned figure of the aggregator, a new subject supposed to regroup non-relevant units into virtual aggregates with the purpose of simulating the behaviour of larger units and to make them participate to the markets (MSD included).

The introduction of the figure of the aggregator brought then the regulator to question concerning the rules according to which aggregation would have been possible. The novelty of virtual units drove the *Authority* to propose also a new classification of the dispatching users.

Other important indications concerned again the different nature of the qualification to the MSD, voluntary or mandatory.

Without any discrimination about the nature of the qualification, it was however proposed that all the units getting the to participate to the MSD should have been remunerated according to current criteria (although substantial differences were in sight for what concerns the situation of virtual aggregates).

Other important hypotheses were made about the role of the GSE in the new MSD and the increased involvement of final customers into the markets.

Chapter 3

AGGREGATION IN ITALY

The intent of this chapter is to deepen the discussion about the current state of the art for what concerns the Italian regulation in terms of aggregation possibilities within the power sector. The chapter wants to clarify the process that brought to define the regulations currently in force and that define the referential regulatory context of the case study: starting from the first proposals made by the Authority (especially the DCO 298/2016/R/eel) and the discussion of the considerations made by the public within the open debate, it will be retraced and analysed the path that brought to the definition of the fundamental deliberation 300/2017/R/eel and of the first regulated pilot projects. This chapter serves also to identify the typologies of virtual power plants which behaviour will be tested during the case study. For more technical explanations please refer to the original texts of the documents which are cited in the below.

3.1. ANALYSIS OF THE DELIBERATION 300/2017/R/eel

With the deliberation 393/2015/R/eel and the *DCO* 298/2016/R/eel, it was referred for the first time in the history of Italian regulations to the figure of the *aggregator* and the concept of *aggregation*, that – as it will be more specifically described in the next chapter – regards the possibility to group energetic units to give birth to complex energetic compounds which comprehensive *relevance* or size would be such to *reproduce* the performance of larger units. In particular, inlaid units could be enabled to participate – as a whole – also to more remunerative markets, such as the one for ancillary services.

These energetic aggregates are namely referred to as *UVA* (*unità virtuali abilitate*). In May 2017, by mean of the deliberation titling the paragraph [25], the *Authority* formally regularized the terms, the obligations and the limitations involved in the creation of energetic aggregates.

3.1.1. Premises to aggregation: ARERA's guidelines

In the *DCO* 298/2016/R/eel, the *Authority* proposed a first series of guidelines concerning the interventions and the modifications to be performed in order to realize the intentions promoted with the *RDE*.
Among the most important concepts laying at the basis of the reform – the most influential one, for instance – regarded the necessity to increase the number of units that can offer ancillary services. It is rightly to this concept that is strongly related the theme of aggregation, which was introduced here through a series of early *instructions*.
The intention of the regulator was then to concede the qualification to operate on the MSD to: all relevant production units still resulting non-qualified, independently from the technology; non-relevant production units and consumption units which can be treated on hourly basis and that had not undergone any interruption-of-service contract.
As the regulator declared, this latter typology of units would be then allowed to participate to the MSD only through aggregation ploys. To this regard, it was also specified that production units could have inlaid into production aggregates and that consumption units could have grouped into consumption aggregates. It was denied the possibility of a mixed aggregation and also the possibility to comprehend relevant units in an aggregate.
In order to keep faith to the concept of technological neutrality, the regulator sustained that non-relevant units could be aggregated independently from the technology.
The *Authority* also proposed as general principle that the maximum perimeter of aggregation for the aforementioned units should be the market zone – but it gave mandate to Terna to better define aggregation criteria.
Another interesting point was moved by the *Authority* when it came to propose a distinction between voluntary and mandatory participation to the MSD. To make new resources available as soon as possible to the national TSO, the regulator proposed that all relevant units already respecting current technical requisites (independently

from their technology) should mandatorily participate to the MSD. All other categories of resources should instead be enabled to operate on the market after a voluntary request and a series of certifications.
Note that a mandatory participation translates into an obligation for the unit considered to present offerings on the market.
This meant that new requisites should have been identified for the qualification of new relevant plants and virtual aggregates. The *Authority* expressed the will to identify rules permitting the provision on the market of single typologies of services, in order to facilitate the participation of as many resources as possible, and that the participation of aggregates should be dependent on the respect of a minimum level of injection/withdrawal capacity.
With particular regard to aggregates, the ARERA (by then still named AEEGSI) also auspicated that, at least in the first phase of the reform, the counterparty of the TSO on the MSD should remain the BRP (the subject playing the role of economic counterparty for what concerns the discipline of imbalances, for each dispatching point (resource) it is responsible for) with the possibility in the future to distinguish between the figures of BRP and BSP (a subject that should be instead responsible only for what concerns the provision of ancillary services to the TSO, and not even for imbalances).
This is a very important element because the distinction between BRP and BSP would create the possibility of considering two potentially different entities referring to two different dispatching points (although related to the same unit) which would be valid on different markets – the point managed by the BSP would be relevant to ancillary markets purposes only, while the point managed by the BRP would be relevant for energy markets and for the imbalance position of the unit.
The argument became even more important in perspective of the definition of production and consumption aggregates, as the regulator also stated that even for *UVAs* the dispatching points related to the units afferent to the aggregates would have initially coincided for all the markets for the sake of simplicity.
A final comment about the participation to the MSD was made by the *Authority* on the limitations to be possibly imposed to plants receiving incentives under the control of the GSE. It was proposed that only plants accessing to the incentive scheme of *ritiro dedicato* [26] should be given the possibility to participate to the market for ancillary services, but this did not cancel the questionability of enabling a public entity like the

GSE to operate on the market: considered the particular position of the GSE and the amount of energy it transacts through the plants *controlled*, it could not be excluded the risk that its participation might have caused distortionary effects on the market.
With regards to imbalances instead, the *Authority* defined that effective imbalances should be evaluated according to the dual pricing rule for all dispatching points. It also expressed the will to confirm non-arbitraging coefficients and penalties for failures in fulfilling dispatching orders coming from the TSO.
The *Authority* gave then mandate to Terna to define proper modalities for *UVAs* to present offerings on the MSD, making sure that they can receive an equal treatment with respect to other resources.
It was then highlighted that the participation to the markets of the aggregates would inevitably cause the necessity for a review of the rules concerning dispatching priorities.
In connection to this last reflection, and without prejudice to what was declared before, the regulator expressed a doubt concerning whether *UVAs* should be granted some kinds of benefits because of the advantages they would supposedly bring to the system.
The most vivid example that was advanced concerned the idea that energy withdrawals carried out by *UVAs* on the MSD could be left free from the application of the *uplift* component – which basically reflects the costs Terna bears to procure resources to safely manage the system.
Referring to phases of the reform successive to the *RDE_1*, the ARERA underlined some other important exigencies.
First of all, the need for defining in a more precise way all the *products* that can be object of transaction on the MSD – firmly remaining the will to maintain whenever possible a central dispatching system configuration – so to define univocal technical requisites for the provision of each service focusing whenever possible on an output-based approach, respectful of the concept of technological neutrality.
In perspective, the precise definition of each service would have also served to determine different criteria of aggregation for *UVAs*, that could be allowed to form and qualify specifically for the provision of specific kinds of service.
The *Authority* also predicted a more active involvement of distributors in the management of local networks, given the expected increment of distributed energy resources connected to the grid and participating to the markets.

Certainly, the relationship and the dialogue among DSOs and distributed resources will be fundamental to the well-functioning of the whole system. Moreover, the regulator highlighted the importance of constituting proper informative interfaces permitting to all the subjects involved – the TSO, the DSOs, the aggregators and the owners/BRPs of the single aggregated units – to communicate and to share data to overcome information asymmetries and facilitating the management of the electric system.
Finally, the *Authority* figured out the intention to clearly define in the next future the role of the aggregators and the types of business models it would be better to develop or support.

3.1.2. Public response to the DCO 298/2016/R/eel

In the text of the deliberation 300/2017/R/eel, the measures disposed by the former AEEGSI were rightly preceded by a quite comprehensive recap not only of the concepts contained in the guidelines of the *DCO* 298/2016/R/eel, but also of the response coming from the public to that publication.
Opening debates concerning delicate or forward-looking topics is in general very useful for regulators since it allows to test the reaction of the public to proposals in draft form and gives the occasion to gather precious hints and suggestions coming from market participants and public institutions.
The consultation resulted in a large and active participation. Although the greater part of the proposals made by the *Authority* encountered the favour of the public, disfavours were expressed too and further considerations and suggestions were brought to the attention of the *Authority*.
About the first phase of the reform, a first question brought to the attention of the *Authority* came directly from the national TSO, Terna, that supported the idea of opening the gates of the MSD just to currently non-qualified but relevant production units in the very first place, postponing the qualification of virtual aggregates to avoid excessive complications.
The first observation coming from market participant concerned, on the opposite, the possibility to immediately aggregate relevant production units among themselves, relevant production units with non-relevant ones and consumption units with

generation units – none of these possibilities was allowed by the initial proposal of the *Authority*.

This latter request questioned the excessively static nature of the aggregation modalities defined by the *Authority* and confirmed the need to try and facilitate the participation to the MSD of small-size units.

Market participants also observed that in order to promote the participation to the MSD of incentivized RES plants, it could have been opportune to immediately introduce negative prices – producers would be given the possibility to pay consumers to withdraw their excess (imbalance) energy until it is more economically advantageous to shut down the plant. The rationale behind this proposal lays in the fact that incentivized RES plants receive incentives just for the energy they sell. In so doing, if a RES plant operated on the MSD it would be obliged to make available a certain quantity of energy without knowing if it will be eventually sold (upward service) or not. This would clearly represent a barrier to the participation of such players on the market. Negative prices would ideally cope with the incentive lost in case of unsold energy amounts – the energy would be sold at negative price, but since it gets sold the RES producer would get the incentive and still have a gain.

Another interesting suggestion regarded the opportunity to differentiate MSD qualification requisites basing on the technical characteristics of the units and of the typology of service considered. The *Authority* proposed that the new technical requisites should have been common to all units, but the considerations advanced by the public seemed effectively to represent a more practical solution: technologies may present big differences in terms of technical characteristics and establishing a unique set of technical requisites may eventually come to *discourage* the deployment of certain technologies, which would clearly go against the principle of technological neutrality. The public sustained hence that the new technical requirements should have been only service-based. This principle was awarded the utmost importance by the public, that asked for a prompt application from the very first stages of the reform.

The last observation concerning the first phase of the reform regarded the participation of the plants under *control* of the GSE to ancillary services market. As it was predictable, the public expressed a contrary opinion, either in case of controlled dispatching points being part of virtual power plants or in case of *stand-alone* generation units. The public agreed on the fact that the institutional nature of the subject and the huge level of energy transacted could cause distortionary effects on the market.

With reference to successive phases of the reform, there are a few other considerations worth mentioning.

One of these regarded the loudly request for defining as soon as possible the terms according to which storage systems (in all their forms) could become finally operative in the Italian system. The centrality that this topic acquired in recent years and the opportunities and benefits that this kind of technology can potentially disclose, represented obviously an incentive for market participants to push the *Authority* towards the study and the proposal of further regulations about the matter.

Many subjects requested then that the regulator took into account the possibility to consider as natural aggregates the so-called closed distribution systems, with special reference to *RIU* (*reti interne d'utenza*) systems [29]. It was in fact claimed that *internal user networks* asking for the qualification could be immediately considered as natural mixed aggregates on the basis of their nature. This represented certainly a quite interesting (although unexpected) request for the regulator, given also the importance that these kinds of systems are supposed to acquire in forthcoming years.

Another proposal coming from the majority of the participants to the debate concerned the quick adoption of measures to create a higher coordination between the day-ahead and infra-day markets and the MSD. It was rightly observed that the MGP and the MI markets are still too distant from the real time, which highlights a noticeable tardiness if compared to other European dispatching markets. The proposal of higher coordination practically translated into shifting the gate closure of the MI as much as possible towards the real time – an intention which was moreover declared by the *Authority* itself back in 2013 [28]. This would surely be a positive measure for all market participants, especially for less flexible technologies suffering from a more uncertain and difficult programming of their load profile, like RES plants.

Finally, everybody agreed on the opportunity to begin each step of the reform by mean of properly defined pilot projects under the supervision of Terna and the *Authority* itself, with the support of qualified market players.

3.1.3. Principal contents of the deliberation

In the formal text of the deliberation, the *Authority*, basing also on the contributions that came after the public debate, officially defined the principal aspects concerning the characteristics and the obligations of the new aggregates or *UVAs*.

The first clarification made by the *Authority* regarded the figure of the aggregator. It was established that this subject is to be identified with the BSP, i.e. the subject responsible for dispatching points in relation to the provision of ancillary services.

It was subsequently stated that a single aggregator-BSP can be responsible for more *UVAs* at the same time and that it is to be considered the unique counterparty of Terna for what concerns the procurement of dispatching resources afferent to the virtual power plants it is responsible for. Each aggregator-BSP was then authorized to modify the composition of the aggregates it controls on a monthly basis. This operation must be notified to the local DSO, that will have to verify the absence of contraindications and validate the modification.

A second important aspect clarified by the *Authority* regarded the forms of aggregation allowed and the requisites to respect to become part of a virtual aggregate. The regulator started with the confirmation of the initial forms of aggregation proposed for consumption units only and production units only, respectively named *UVAC* (*unità virtuali abilitate di consume*) and *UVAP* (*unità virtuali abilitate di produzione*). The news contained in the deliberation to this regard was that the *Authority* welcomed the request coming from the public and determined the possibility to give birth also to mixed aggregates or *UVAM* (*unità virtuali abilitate miste*) and to aggregates comprehending relevant units or *UVAN* (*unità virtuali abilitate nodali*).

With respect to the composition of the aggregates it was established that *UVAPs* and *UVACs* can include injection or withdrawal points related to non-relevant production or consumption units located in a unique geographic perimeter of aggregation, united by a common dispatching contract and that have formally made request for being enabled to participate to the MSD. Also, they must not have undergone any interruption-of-service contract.

The requisites for the units being part of mixed aggregates are basically the same as for *UVAPs* and *UVACs*, even though *UVAMs* will incorporate both kinds of unit at the same time. *UVANs* can instead include injection points related to relevant production units voluntarily participating to MSD and withdrawal points related to consumption units respecting the same limitations foreseen for *UVACs*, provided also that they are related to the very same node of the grid.

Obviously, the *Authority* came to define some basic rules that served to correctly identify qualified virtual aggregates. It was firstly determined that qualified *UVAs* will have to respect a minimum threshold concerning the *maximum control power* made available by the aggregate, that was set to a quota not inferior to 10 MW (active power).

Another important indication was given about aggregation perimeters, that in the view of the ARERA should be established by Terna consistently with what foreseen by the current procedure used by the algorithm selecting the offers on the MSD. It was advanced the possibility of identifying aggregation criteria differentiated on the basis of the kind of service offered and it was left to Terna the duty of investigating about the optimal dimension that *specialized* aggregates could be characterized by.

Another important clarification was made by the *Authority* about the participation of virtual aggregates to the markets. In particular, it was remarked how *UVACs* and *UVAPs* are relevant to MSD purposes only. For what concerns the participation to energy markets, the dispatching points of the single consumption and production units associated to them will remain in use. A different treatment will be applied instead to *UVAMs*, that will be provided with a new and unique dispatching point, valid for all the markets.

Consequently, the regulator underlined that for *UVAC* and *UVAP* aggregates it will be possible to appoint an aggregator subject (BSP) that may be different from the dispatching user(s) responsible for the valorisation of the imbalances (BRP(s)). In the case of *UVAM* aggregates, instead, the BSP and the BRP are subjects that will have inevitably to coincide since there is a unique dispatching point identifying the whole aggregate. The relationships between the aggregator-BSP and the various dispatching units belonging to a single VPP are supposed to be bi-laterally agreed but are to be noticed to the system operator in any case.

More specifically, about the participation to the MSD, the *Authority* declared that the modalities and the obligations for *UVAs* – and also for relevant plants voluntary participating to the market and not belonging to any VPP – to present offerings are the same as for currently qualified units. It was however stated that shut-down and ignition services remained reserved to thermo-electric units due to performance and reliability matters, at least in the short run. It was approved that *UVAs* and relevant production units voluntarily participating to the MSD can obtain the qualification even for the provision of a single type of service, which was auspicated by many market participants in the course of the public debate. Also to this purpose, the regulator ordered a review of the national *network code* (drafted by Terna) so to integrate measures defining the technical performances required by each single service to be negotiated on the MSD. It was also noticed that, having to respect the same obligations as for all other qualified units, *UVAs* will eventually incur into penalties each time a request of intervention demanded by the TSO is unsatisfied.

Another *tough* but important aspect highlighted in the deliberation pertains to the question of imbalances. The *Authority* defined that the effective imbalances of virtual aggregates – and also of other relevant plants voluntary participating to the market and not belonging to any VPP – will be generally managed according to the single pricing methodology. In the specific, for units being part of *UVAC* and *UVAP* virtual power plants, imbalances will be valorised referring to the dispatching points of the single non-relevant units composing them. For units belonging to *UVAMs* and *UVANs*, instead, the definition of the criteria for the valorisation of imbalances and the remuneration of ancillary services is delayed to special measures to be properly drafted in concomitance with the realization of the first *pilot projects*.

The *Authority* also disclosed that it will be possible for *UVAs* to inlay in their perimeter also energy storage systems (ESS) that can be assimilated to production units according to what is defined in the deliberation 574/2014/R/eel.

The concession of such possibility could represent a breakthrough point in perspective of future measures to de-frost the current transitory regulation concerning ESS [30] – the definition of more specific rules is likely delayed up to the moment in which the first *pilot projects* targeting the deployment of such systems on the markets will be realized – and it was also a way to keep faith to the concept of technological neutrality.

Lastly, it is interesting to report the decision from the *Authority* to reject the request of considering *RIU* systems as *natural aggregates*, even though it was allowed the chance of inlaying units belonging to closed system into a VPP.

3.2. THE FIRST PILOT PROJECTS

In the deliberation 300/2017/R/eel, the *Authority* positively welcomed the idea of gradually testing and introducing the arrangements of the reform by mean of pilot projects.

As it was previously said, the projects have to be identified by Terna with the help of qualified market players and have to be supervised by the *Authority* itself. The ARERA also underlined the need to identify and deploy pilot projects in a relatively short time, so to collect precious information and data for subsequent developments and improvements concerning the reform, prior to the drafting of the new *TIDE* (*Testo Integrato del Dispacciamento Elettrico*).

The new text will be committed to the new European balancing guidelines, that have just come to assume a consolidated aspect, and will be entrusted with the duty of defining the new general setup of the MSD, the procurement of services and the norms regarding the forward-looking discipline of effective imbalances basing on nodal prices.

With special reference to the theme of aggregation, the new TIDE is supposed to overcome the actual classification of consumption and production units stuck to the concept of *relevance*. This could represent a turning point in establishing new aggregation criteria basing on the spatial dimension of each dispatching service that the aggregate can provide: if, for example, a VPP is qualified to offer primary and secondary reserve services, it can be aggregated on a zonal basis; if, instead, it is also qualified to offer services concerning the resolution of infra-zonal congestions and other local issues, the aggregation could be limited to the competent node or to a restrained set of neighbouring nodes.

A negative aspect that could be highlighted in relation to this matter is that the regulator recommended these criteria to be defined trying to preserve, whenever possible, the central dispatch setting of the system.

Returning directly to the issue of pilot project, the regulator stated that pilot projects shall primarily target: the opening of the MSD to energy storage systems, consumption units and units currently not qualified in general; aggregation modalities; remuneration modalities for services currently not remunerated; forms of forward procurement of resources for the dispatching (like the well-known capacity market).

The admission of *pioneer* players to these pilot projects would be directly related to the fulfilment of basic requisites such as the availability of measuring data on hourly basis, the total independence from the GSE or the *single buyer* and the respect of the minimum technical requisites that will be defined case by case by the national TSO.
The deliberation also stated that no economic incentive will be provided to the units involved in the projects. Moreover, each project will be based on the actual classification of the units as well as on the concept of relevance, so to shorten the time needed to make them become operative.

3.2.1. Deliberation 372/2017/R/eel

With the deliberation 372/2017/R/eel, the *Authority* brought some simplifications and adjustments to the measures defined through the previous 300/17/R/eel, with the intent of making easier and quicker the start of the first pilot projects.
Moreover, as the document served also to approve the first ever Italian VPP project involving *UVACs*, one of the objectives of the new deliberation was to specifically simplify the modalities of aggregation, so facilitate the *collection* of the necessary DERs.
With the new rules, it was de facto cancelled the limit according to which all non-relevant units belonging to an *UVA* had to be united by the same type of dispatching contract. Other boundaries that got smoothed according to the same principles respectively regarded the minimum level of *control power* (lowered down from 10 MW to 5 MW) and the number of consequent hours of service supply (reduced from four hours to three hours between 2 p.m. and 8 p.m., from Monday to Friday), which is an obligation that all qualified units must normally respect.

UVAC pilot project

Entering the discussion of the first official Italian VPP project, it is opportune to clarify that rather than focusing on the technicalities concerning the requisites that each *UVAC* participating to the project had to respect, it was here preferred to analyse the *business-environment* characteristics of the pilot project, which was expected to

represent a good practice even in anticipation of the forthcoming organization of a *capacity market*.
The analogy with the capacity market is due to the particular system that was built to make the units involved participate to the market. In facts, it was established a dedicated system of auctions for the forward negotiation of ancillary services. VPPs joining the project were given the chance to present their offerings only for the supply of tertiary reserve and balancing services. Each *UVAC* was treated like a production unit, so that their load reduction could be assimilated to the provision of an upward service [31]. In the programming phase, the TSO was supposed to take into consideration all the offerings received to allocate upward tertiary reserve. Doing that served to give a measure of the availability to potentially offer an upward service in real time. In the balancing phase, instead, the TSO was given the right to ask to the units that presented availability offerings to really perform the service.
The remuneration fixed for the virtual power plants taking part to the experiment introduced an historic novelty in the Italian market framework that came to constitute a sort of precedent that could be allegedly repeated for similar applications in the next future, that is the remuneration of the simple availability to supply a service.
The principal economic remuneration for the units involved would have been, of course, the value at which the energy to be modulated in real time – when asked – was prized. The valorisation of such energy respected the usual *pay as bid* characterization foreseen on the MSD even though the regulator decided to put also a cap of 400 €/MWh on the variable market price.
But then, it was decided also to remunerate the forward availability demonstrated in offering the service – properly like it should happen in a capacity market. In this way, *UVACs* presenting offers that satisfied the minimum requirements (three subsequent hours of service supply) were given the possibility to additionally receive up to € 30.000 per MW per year. It was also given the possibility to see that cap incremented proportionally for each additional consequent hour of service supply offered after the mandatory three-hour period, up to the figure of € 60.000 per MW per year.

Considerations after the conclusion of the first phase of the UVAC pilot project

Citing a study [32] carried out by REF-E about the unwinding of the *UVAC* project, they are here reported some interesting considerations about the results of its first deployment phase.

The first comment worth mentioning is that, as it was expectable, none of the offerings presented by the units participating to the experiment was actually selected by Terna on the MSD ex-ante. In other words, the capacity allocated by the *UVACs* was incorporated by Terna in the amount of tertiary reserves available for deployment, but never got deployed in the end.

For what concerns the characterization of the offerings, their temporal evolution showed a progressive trend of stabilization: the first months of operations – June and July 2017 – served mainly to educate the participants, that progressively went to land their offerings –favoured also by more stable prices at the end of the summer.

It was also possible to identify a trend about the average offering price. Typically, prices used to be higher during those time windows in which presenting offerings was mandatory – from 2 p.m. to 8 p.m. – and during critical hours of the day in which there is usually a higher probability of seeing an offer accepted by Terna.

The initial set of auctions referred just to a small percentage of the total capacity made available by Terna, about one fifth on a total of 500 MW. As a matter of facts, the participation to the project has been unexpectedly poor: only six operators joined the project and not all of them gave continuity to their participation at the end of the first phase – which signed the end of the remuneration of the simple availability to provide services.

It could be hence complained that the reported comments may somehow lack of *resilience* and that a higher participation would have surely granted a better understanding of the possibilities and the dynamics related to the opening of the MSD to consumption units, but that it can be argued that things would not have gone much differently even in case of a higher participation.

A last interesting hint in conclusion to the analysis reported that, given the aforementioned likeness between the unwinding of this kind of forward-regulated ancillary service market approach and the *capacity market*, it would be better to pay attention to the interactions that may generate between these two markets in case of new future deployments [33]. The similarity between the two configurations may lead to misunderstandings and distortionary effects.

3.2.2. Deliberation 583/2017/R/eel

With the release of the deliberation 583/2017/R/eel, the *Authority* approved the general rules defined by Terna for the execution of the pilot project regarding the aggregation of non-relevant generation units into *UVAP aggregates* and gave also mandate to the TSO for evaluating the possibility to open up the doors of the MSD even to relevant RES production units by mean of aggregation into *UVANs*. Some considerations concerning the future development of project involving mixed aggregates were also provided.

UVAP pilot project

The characteristics defined for the *UVAP* pilot project were similar to those of the previous *UVAC* experiment. All the VPPs participating to the project were naturally advised to respect certain rules, such as the limits of the aggregation perimeters defined by Terna and the non-relevance of all the units afferent to them. As for *UVAC* pilot project, the *Authority* approved that for obtaining the qualification to provide upward and downward services, the minimum level of *maximum* and *minimum control power* necessary could be of 5 MW instead of 10 MW. All other technical and behavioural obligations remained the same as for the *UVAC* case.
Differently from what established for the first project, though, it was given the possibility to create a *UVAP* and to ask for the qualification to operate on the MSD to both the owners of the production plants that would become part of an aggregate and a third-party aggregator-BSP subject.
The system that Terna planned to put into force to control and coordinate MSD operations carried out by the virtual power plants is very similar to the one already used in the case of *UVACs*: the TSO will allocate tertiary reserve coming from the *UVAPs* during the sessions of the MSD ex-ante and will have the possibility to ask for the effective performance of the service in real time. This time, though, the TSO will not provide any remuneration for the availability to offer the service – i.e. for the

capacity allocated during the MSD ex-ante – because there will be no formal forward market established. Only the acceptance of the quantities offered – i.e. the performance of the service in real time – will generate a (variable) remuneration for the *UVAPs* participating to the experiment.

Hints about the relationships between UVAMs and closed distribution systems

With the deliberation, the *Authority* disposed also that Terna dealt with the drafting of a proposal for a pilot project concerning the aggregation of virtual mixed units (deadline set for April 2018). About that, an interesting pointer regarding the possibilities disclosed by mixed aggregation regards the particular situation of the already mentioned *RIU* systems. It is true, as it was explained before, that the request advanced within the public debate launched in 2016 of considering *RIU* systems as natural aggregates was rejected, but it is to be remembered also that the *Authority* established the possibility for the units belonging to this kind of closed distribution systems to become part of a virtual aggregate.

Without prejudice to what has been said in the lines above, it is now to be clarified that with the new regulation about closed distribution systems – the new *TISDC* (*Testo Integrato dei Sistemi di Distribuzione Chiusi*) – all the dispatching users organized according to *RIU* or similar systems will have to pay system charges on the quantity of energy measured at the connection point of their private grid [29]. This means that system charges will be paid even on the energy self-consumed that never gets into the public network.

Now, the pointer that was highlighted at the beginning of the paragraph lays in the fact that since each *UVAM* will dispose of a single dispatching point of new creation – and valid for all the markets – a consumption unit inlaid into a *RIU* which is also part of a mixed aggregate will have the possibility to *share* that connection point with other entities belonging to the aggregate itself. By so doing, system charges would be applied only to the net sum of injections and withdrawals recorded towards that connection point, meaning that they will end up being *shared* among all the units afferent to the *UVAM* without having (in theory) internal energy self-consumptions included in the count.

Chapter 4

VIRTUAL POWER PLANTS OVERVIEW

This chapter focuses the attention on the concepts of aggregator and virtual power plant and, through the right level of detail, wants to describe what a VPP practically is and how it is supposed to work. The description will start from the analysis of the main drivers behind aggregation and will touch both technical and organizational-strategic aspects. This is fundamental to fully understand both the potential and the complexity related to such energetic entities, but also the underlying rationale that is at the basis of the simulated behaviour of the VPPs object of the case study. A Canvas analysis of a generalist aggregator is also provided. With particular allusion to some technical aspects regarding the energy management system (EMS) of the VPP, it has been made reference to the architecture proposed by the team of the FENIX project (EU Horizon 2020 foundation).

4.1. INTRODUCTION TO VIRTUAL POWER PLANTS

4.1.1. General definition of the concept of virtual power plant and of aggregator

There are many definitions of virtual power plants (VPPs) in literature, starting from its early proposition in [34]. For example, in [35] virtual power plants are defined as flexible representations of a portfolio of DERs "that can be used to make contracts in the wholesale market and to offer services to the system operator", while in [36] VPPs are defined as clusters of "dispersed generation units, controllable loads and storage systems, aggregated in order to operate as a unique power plant" in which generation units make use of both fossil fuels and RES. According to the expertise of the Fenix project [37], the units becoming part of a virtual aggregate would "gain access and visibility across energy markets, benefit from VPP market intelligence and allow the creation of a single operating profile based on the peculiarities of the portfolio of DERs aggregated". This means that DERs would not be seen anymore as just stand-alone units with respect to the rest of the network, but as part of greater clusters able to provide a better, more efficient energetic performance.

There are also definitions highlighting the software component involved in the composition of the aggregate, like it happens in [38], where VPPs are defined as energetic entities that rely upon software systems "to remotely and automatically dispatch and optimize generation- or demand-side or storage resources in a single, secure web-connected system". Many other definitions and references to this regard can be found in [39].

Despite some differences, it is however possible to say that definitions seem to convey on the fact that VPPs are to be mainly identified with energetic compounds based on the aggregation of a portfolio of DERs, connected by mean of a proper ICT system, that act as single visible entity in the power system, as it is expressed in [40].

Each VPP can be seen then as a coalition of distributed energy resources that can comprehend intermittent RES, storage systems, flexible loads, small conventional plants and consumption units [41] with the intent of integrating them into power system operations – in the interest of the owners of the aggregated units, in that of the aggregator subject and also in that of network operators.

To identify instead the figure of the aggregator it is possible to take as reference the definition provided by the BestRES team [42], according to which they can be considered "legal entities that aggregate the load or generation of various demand and/or production units and aim at optimizing energy supply and consumption, either technically or economically".

In other words, these subjects could work as facilitators between the two sides of the electricity markets: on the one hand, they develop energy services for downstream industrial, commercial or domestic customers; on the other hand, they offer value to upstream market players such as DSOs, TSOs and energy suppliers.

4.1.2. Main drivers behind aggregation

According to the CEER (Council of European Energy Regulators), the benefits enabled by the aggregation regard security of supply, market integration, prosumer empowerment, CO_2 emissions reduction and innovation [43]. In what follows, it will be given a brief overview of the benefits deriving from aggregation with respect to the parties affected by its peculiarities.

Benefits for DERs' owners

The main goal of aggregation is that of giving also to distributed resources the possibility to actively participate to energy markets following the rationale that *unity is strength*.

The small-size of DERs makes their participation to energy markets troublesome and prohibitive today, not to mention that the *fit and forget* approach according to which they have been installed makes them hardly visible to system operators [44], especially in a centralized dispatching context.

But of course, there must be an incentive for *little aggregation services providers* to talk about aggregation as a viable solution. As a matter of facts, advantages are granted since VPPs allow afferent distributed units to exploit the augmented energetic performance generated by their aggregation to optimize their position and maximize their return opportunities [37].

In case of BRP applications, aggregation services could be also used for generating revenues from imbalances: with reduced and symmetric forecasting errors, the yearly balancing cost paid by the BRP could be potentially none [44].

DERs' owners could benefit also from lower energy bills and an increased value of their assets: enabling distributed resources to show their true potential could possibly make them become more interesting under both an economic and a competitive point of view than they are nowadays.

Benefits for network operators and the society

Aggregation services can reduce the need for peak generation capacity and favour the stability of the system, pulling it towards a framework in which there would be less need for big centralized generation units using fossil fuels and costly network investments [43].

The development of the VPP concept is possibly to be considered as a mean to learn to properly manage the increasing amount of DERs penetrating the market, with particular attention to non-programmable and less flexible resources, like RES. Nevertheless, the negative aspects of the increasing and uncoordinated penetration of distributed units are at the basis of the development of the concept of aggregation [42].

This would be surely a welcome ploy for network operators, that could be likely attracted by the possibility to reduce managerial complexity. The potential results could be identified in an increased security of supply and in a well-liked costs reduction – lower network investments and operational expenditures leading to lower network and system charges *on the rump* of households and other civilian users.

If the concept of VPP turned out to prove the convenience – economic, strategic and operational – of aggregated DERs, it would be possible to stimulate in an easier way the development and the diffusion of such kind of organization. This could bring to an improved and accelerated integration of non-programmable RES, with a consequent coverage of the energetic needs of the system through an always increasing share of existing distributed capacity [44], that would translate into higher resource efficiency and hence into a relevant reduction of emissions and a faster achievement of renewable and environmental targets.

Another point in favour of aggregation lays surely in the possibility to complement demand flexibility and decrease the reliance of the system on incentive schemes [3] – meaning again lower charges on the back of final users.

Market and technological benefits

At the beginning of the chapter, it was highlighted the strong digital component that characterizes the VPP paradigm and it is true that aggregation can be seen as a major driver to the digitalization of power systems [44]. The development of aggregation may in fact give a boost also to the development of innovative software solutions.

Moreover, given their flexible characteristics, VPPs cannot leave aside the integration with smart grid technologies, which represent the basis for faster communications, the interconnection of multiple energy carriers and higher technical efficiency for both prosumers and market operators.

Broadly thinking, the market of aggregated services could enable very interesting opportunities along the whole value chain of the power system, since almost all the categories of actors potentially involved (traders, utilities, technology providers, system operators) would theoretically benefit from the development of aggregation business models.

4.2. VIRTUAL POWER PLANT FRAMEWORK

Theory does not pose limits to the possibility of including in the same aggregate production units of whatever kind, energy storage systems, consumers and/or demand side response apparatuses. Anyway, regardless of their composition, VPPs would be responsible for managing the electricity flow not only within their clusters but also in exchange with the main grid. It was also said that virtual aggregates would be useful providers of ancillary and power quality services to network operators.

Here, given the complex variety of *functionalities* that has been described, it emerges the need for VPPs to integrate some specific digital instruments within their infrastructure.

As it was previously declared, a proper ICT structure would be needed: each VPP would need a *brain* in charge of harmonically connecting all the aggregated sub-parts. The main software applications would expectedly regard: the optimization of internal operations and of the activities of the aggregate on the market; the remote control of monitoring and safety apparatuses (from smart meters to control devices installed towards single units) to collect/provide data and command orders on a real-time basis.

4.2.1. VPP energy management system

Following the rationale proposed by the Fenix team in [37], under a practical point of view a VPP can be ideally split into two coordinated *entities*: the *technical* virtual power plant (TVPP) and the *commercial* virtual power plant (CVPP). In more practical terms these *entities* represent the two branches composing the energy management system (EMS) of the VPP. The need to properly define an EMS for a virtual power plants is expressed also in some definitions: it can be taken as example the aforementioned [36], according to which “the heart of a VPP is an EMS which coordinates the power flows coming from generators, controllable loads and storages”.

An energy management systems (EMS) can be identified as a set of computer-aided tools which are traditionally used by the operators of electric utility grids to monitor, control, and optimize the performance of the generation and/or transmission system [45].

This kind of technology can be also referred to as SCADA/EMS [45], where the first acronym stays for *supervisory control and data acquisition*. According to the International Organization for Standardisation, the purpose of an EMS is to enable an organization to follow a systematic approach in achieving continual improvement of energy performance, including energy efficiency, energy use and consumption, as it is expressed in the formulation of the related ISO 50001 [46].

However, the dimension of the final advantages that the deployment of an EMS will grant depends a lot on the ability of the *installer* to correctly exploit the functionalities of the system and the collections of data it captures.

With special reference to the topic faced in this chapter, the EMS of a VPP could operate according to several final optimization purposes [44]. Nonetheless, what is certain is that the *duty* of the system within the infrastructure of the VPP would be that to make rightly dialogue the two *souls* of the aggregate (the TVPP and the CVPP named before) and make them provide each other with feedbacks and information concerning, for example, production and consumption forecasts, the capacity addressable to each DER, the availability of controllable loads and other technicalities.

In what follows, a deeper investigation about the peculiarities of both the TVPP and the CVPP will be provided, pursuing the intention of highlighting the functions they take care of and the interaction existing between them.

4.2.2. Technical virtual power plant

The TVPP is responsible for the correct network integration of the DERs composing the VPP and also for the management of the energy movements taking place both inside the VPP and in exchange with the main grid [44]. It ensures that the power system is operated in an optimized and secure way considering physical constraints

and dispatching plans dictated by market binding programs or by orders coming from the competent system operator [44].
The TVPP is hence entrusted the duty to provide the following key functions [37] [44] [47] [48]: providing that ancillary services, whether they are voluntary or compulsory, are properly executed whenever necessary; collaborating with the competent DSO and TSO in order to guarantee the safe dispatching of the energy coming and withdrawn from DER units within the VPP; providing that the DERs belonging to the VPP are visible to the competent DSO and the TSO; communicating promptly to aggregated units every single change in terms of asset portfolio; managing the assets of the VPP under a technical point of view; facilitating the maintenance of the whole VPP infrastructure; helping to optimize the portfolio of units aggregated by carrying out periodical analyses and considering the real-time influence that the local network may have on the VPP aggregated profile; drafting an early scheduling of the operation to be potentially executed under a technical point of view, basing on both forecasted and historical data.

4.2.3. Commercial virtual power plant

The CVPP considers the DERs composing the VPP as commercial entities providing energy and services to be offered on electricity markets and tries to optimize the economical return of the overall VPP compound operating on such markets [48]. It is the mean through which DERs eventually access energy markets: distributed units contribute to compose the overall VPP offering profile/capacity and receive back a premium which is proportional to their contribution – that may vary offer by offer, according to resource availability or to optimization-driven choices.
The CVPP has therefore the task of allowing the following key functionalities [37] [44] [49]: providing production and consumption previsions basing on demand profiles, weather-based forecasts and propellants availability so to be always able to make early estimations of what can be offered to the markets; collecting the price curves as well as generation and withdrawal schedules of each DER – the impact of the distribution network is not considered in the aggregate CVPP profile; trading in the wholesale electricity markets and making offerings for the supply of ancillary services trying to identify the best possible bidding strategy basing on aggregated production/consumption previsions; balancing and/or trading portfolios and

reducing imbalance risk; sending specific injection/withdrawal schedules to each DER after the market has been cleared and after the comprehensive feasibility check concerning the dispatching of the VPP has been carried out by the competent DSO – at disaggregated level, with the help of the TVPP – and by the TSO – at aggregated level; submitting relevant information about DERs' operative and maintenance efficiency to the TVPP; modifying the injection/withdrawal profile in real-time whenever needed and making sure that each DER receives and executes modification orders within a proper pre-agreed time window.
Given the nature of its role, it could be observed that the functions of CVPP could be potentially entrusted to any BRP with market access – e.g. any existing utility or energy supplier.
Other duties demanded to the CVPP function may regard: the entertainment of relationships with the single BRPs related to each unit being part of the aggregate – BRPs can be seen as the *managers* (not necessarily the owners) of the single distributed units and are responsible for providing information concerning forecasted injection/withdrawal profiles and for imbalance-related issues; and the drafting of bilateral contracts with the units to be aggregated [44]. The importance of contracts is not to be underestimated because they may include constraints which will have to be taken into account by the EMS *brain* when executing daily operations.

4.2.4. Demonstrative architecture of a VPP

It will be here displayed how the theoretical VPP architecture described above should work in practice. The following architecture represents an equipment made of hardware and software components which allows the bi-directional, real-time communication between the subject aggregator responsible for the management of the VPP and the afferent DERs.
The scheme represented in the figure below will be helpful in understanding the interactions between TVPP, CVPP and the rest of the subjects involved.
In particular, the following scheme retraces the architecture proposed within the FENIX project [37], which represents a precious and influential landmark in terms VPP applications. This model foresees that the CVPP component is continuously in contact with a cloud server from which it receives information about the status of each DER and of the overall virtual system. The same happens between the CVPP and its

twin soul, the TVPP. In order to properly describe the process, let's now consider for simplicity the day-ahead market.

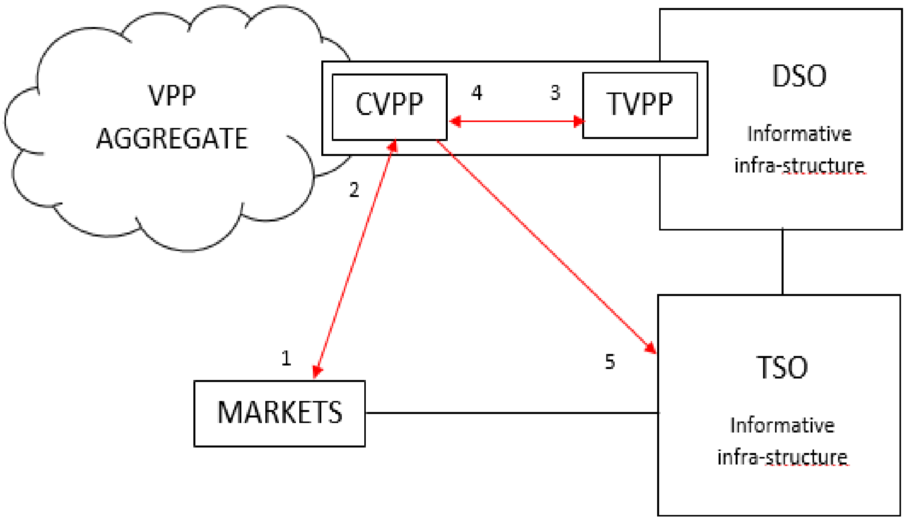


FIGURE 4.1. *Demonstrative architecture of a VPP, example of Fenix Box [37]*

1. Aggregated market offer presented by the CVPP on the market
2. Schedule clearance communicated to the CVPP after the market closure
3. Disaggregated schedule and bids to be checked by the *duo* TVPP-DSO
4. Disaggregated schedule and bids validated by the *duo* TVPP-DSO
5. Aggregated, corrected/confirmed, bids presented by the CVPP to the TSO

Let's say that the CVPP makes an offer on the day-ahead market and receives back the scheduling to be respected after the market has been cleared. The offer made and the scheduling received regard the aggregated offer of the VPP.
This is the moment in which the TVPP intervenes, because it is in charge of checking the technical internal viability of the disaggregated energy movements composing the aggregated offer presented by the CVPP.
According to this scheme the TVPP performs this activity in strict collaboration with the competent DSO to which the distribution network of usage belongs.
In case of technical problems or limitations, the TVPP elaborates and communicates to the CVPP a feasible dispatching strategy to be presented on the market.

As the TVPP and the DSO take care of disaggregated energy movements, all aggregated offerings (original or TVPP-corrected) presented by the CVPP must be finally approved by the TSO.
Once the scheduling program has been approved by all the subjects involved, the disaggregated hourly scheduling for the next day is automatically communicated to all the units of the VPP which have been involved.

The solution proposed by FENIX may disclose important advantages for distribution and transmission operators, as it was highlighted in previous paragraphs.
For example, the cooperation between the TVPP and the competent DSO could allow the latter to acknowledge the real-time production of each DER and to perform load rejection activities in case of need. Or again, benefiting from a higher visibility on DERs, the DSO could easily improve the management and the operation of its distribution grid since it would enjoy the possibility to deploy such units to cope with distribution network issues.
TSOs would instead benefit from a higher controllability and integration of DERs into the electric system and from the availability of new qualified resources to supply important services for the stability and the security of the system.

4.3. OVERVIEW OF AGGREGATION BUSINESS MODELS

In this paragraph, it will be provided a comprehensive description of the aggregation business models actually under development across Europe. What is reported below refers principally to the information gathered by the BestRES team in their research project [42] [43] [50]. Please refer to the very same documents for more detailed information.
The BestRES project was funded in 2016 within the ambit of the Horizon 2020 EU Research and Innovation programme in order to investigate current barriers to the development of aggregation business models and to understand the role of energy aggregators with respect to future market designs [42] [51].
The first stage of the project foresees properly to focus on the existing business models within Europe and investigate about the possible technical, social, environmental and

market benefits enabled by aggregation; a second phase will be instead devoted to the development of improved business models that can be replicated – hopefully – in all European countries [42].

The acknowledgements of this project will expectedly become an important milestone for the development of aggregation modalities across Europe as well as outside European borders.

The research performed within the first stage of the project provided interesting information concerning the current state of the art of aggregation business models across Europe. An interesting consideration within the study is that, among the business models developed within the BestRES *consortium* that were reckoned to be already good enough for implementation, a distinction was made between business models of aggregation foreseeing the combination of the role of the aggregator with other roles (that may derive from the performing of pre-existing business activities) and business models referring to pure aggregator subjects [50].

In what follows, an overview of the most relevant business model identified by the BestRES team [50] will be provided.

It is worth to premise that the BestRES report worked also as an important *source of inspiration* in the definition of the outline conditions for the case study object of this work.

4.3.1. Aggregators combining roles

TABLE 4.1. *Aggregators combining roles*

BUSINESS MODEL	DESCRIPTION	OBSERVATIONS
COMBINED AGGREGATOR-ENERGY SUPPLIER	Utility services and aggregation are offered as a package. There is a single BRP per connection point since the aggregator and the BRP are the same entity. *Retailers are in the best*	Reduced complexity; absence of financial settlements between suppliers and aggregators; few barriers to implementation.

	position to become aggregators because they already have connections with the market and existing relationships with the customers.	
COMBINED AGGREGATOR-BRP	There are two BRPs per connection point: the BRP-independent aggregator and the BRP-supplier. The aggregator puts under contract the consumers served by the supplier, which is compensated for imbalances and the energy sourced on the market.	Sourcing costs for the supplier to perform correct financial transfers unknown; major complexity when aggregators contract customers from different suppliers.

4.3.2. Independent aggregators

TABLE 4.2. *Independent aggregators*

BUSINESS MODEL	DESCRIPTION	OBSERVATIONS
INDEPENDENT AGGREGATOR SERVICE PROVIDER	The aggregator works as a service provider for one of the other market actors but has no balancing responsibility. This means that while the aggregator would gain full benefits from its actions, its counterparty would be fully exposed to price risk. This is the reason why the aggregator	The costs of the actions of the independent aggregator are not covered by any other player within the settlement function. They represent a loss to the whole system that would be covered eventually by grid users (or, with less

	and its counterparty should be engaged in a long-term relationship.	probability, by other BRPs).
INDEPENDENT DELEGATED AGGREGATOR	The aggregator sells at own risk to TSOs, BRPs, wholesales markets, ... The operations of the aggregators can have significant impacts on the balancing position of other market players, so their interactions should be properly formalized.	Complex system to realize; complexity is expected to increase as more independent aggregators enter the market.
PROSUMER AGGREGATOR	Commercial/industrial prosumers that choose to play the role of aggregator for their own portfolios.	Scale is a key factor; almost impossible scope to pursue for domestic prosumers.

According to the BestRES team, the typology of aggregators with the fairest possibilities to encounter a viable and forthcoming development is the first one [8]: they underline that since many European countries have not developed yet a clear framework that defines the role and the duties of aggregators – as well as the relationships among themselves or between them and other electricity market players – the lack of regulations will expectedly favour combined business models, as they appear also as the most compatible solution with respect to existing market structures.

Withal, c*ompatibility* represents a very welcomed feature to regulators when dealing with novelties since it can be translated into avoidance of drastic regulatory changes, at least in the short run.

The BestRES team also observes that combining roles seems to be the easiest way for companies to enter the business [50]: utilities/retailers would be able to expand easily their business to aggregation services, given their established market penetration;

natural aggregators would probably achieve results with rapidity if they tried to integrate their wealth of skills with, for example, ESCOs' functions.
In short, the keystone to succeed may be likely that of disposing of an adequate customer base to be potentially exploited for aggregation purposes.

Emerging alternatives

Other kinds of players identified by the BestRES team that may enter the aggregation business giving birth to alternative business models comprehended [50]:

- New suppliers: new electrical utilities that entered the market after the liberalization, which activities extend from the generation to the retail and supply of power coming mainly from subsidized RES plants.
  They try to diversify their portfolio through the provision of energy efficiency services flexibility.

- New flexibility companies: these subjects are independent from energy suppliers and are focused on providing flexibility to be sold on reserve/capacity markets.

- ICT companies: these are companies developing and selling informative and communication services, software and hardware infrastructures. To favour the diffusion and the improvement of their technologies, these companies use to cooperate with utilities.

4.3.3. Business Model Canvas analysis

Basing on what has been said until now, it is here proposed a brief analysis of a generalist aggregation business model through the well-known Business Model Canvas (BMC), a very useful strategic management template for the development of innovative business models or the documentation of existing ones [52] that was initially proposed by Alexander Osterwalder within his earliest work [53] – a similar analysis is also contained in [50].

The BMC is recognised as a blueprint for a strategy to be implemented though organizational structures, processes and systems [54].
The template provided by the Canvas is composed of nine building blocks that can be grouped into three main categories: the *value network*, the *value proposition* and the *economic model*.
The first category of building blocks describes how the business intends to create *marketable value* and comprehends the blocks referring to *key partners*, *key activities* and *key resources*. The second category describes how the business intends to transfer the value created to the market and regards the *value proposition* itself, the *channels* adopted, *customer relationships* and *customer segments*. The last category wants to clarify how the business would capture value from previous operations and takes into consideration the *cost structure* and the *revenue streams*.
In what follows, per each building block it will be given an outlook of what could be the content of the proposals with respect to a generalist aggregation business model.
First, a further clarification about the nine building blocks is given:

- Key partners: engaged stakeholders working with the organization to perform main activities.
- Key activities: fundamental actions/operations to performantly run the business.
- Key resources: group of assets needed to establish the business model.
- Value proposition: how the organization intends to satisfy the needs of the customers targeted.
- Channels: how the organization intends to communicate with customers to deliver its value proposition.
- Customer relationships: the kind of relationships that the organization intends to establish with each segment targeted.
- Customer segments: single or multiple customer segments served by the organization.
- Cost structure: the expenditures faced while running the business.

- Revenue streams: source of gain through which the organization reap revenue coming from the successful implementation of its value proposition.

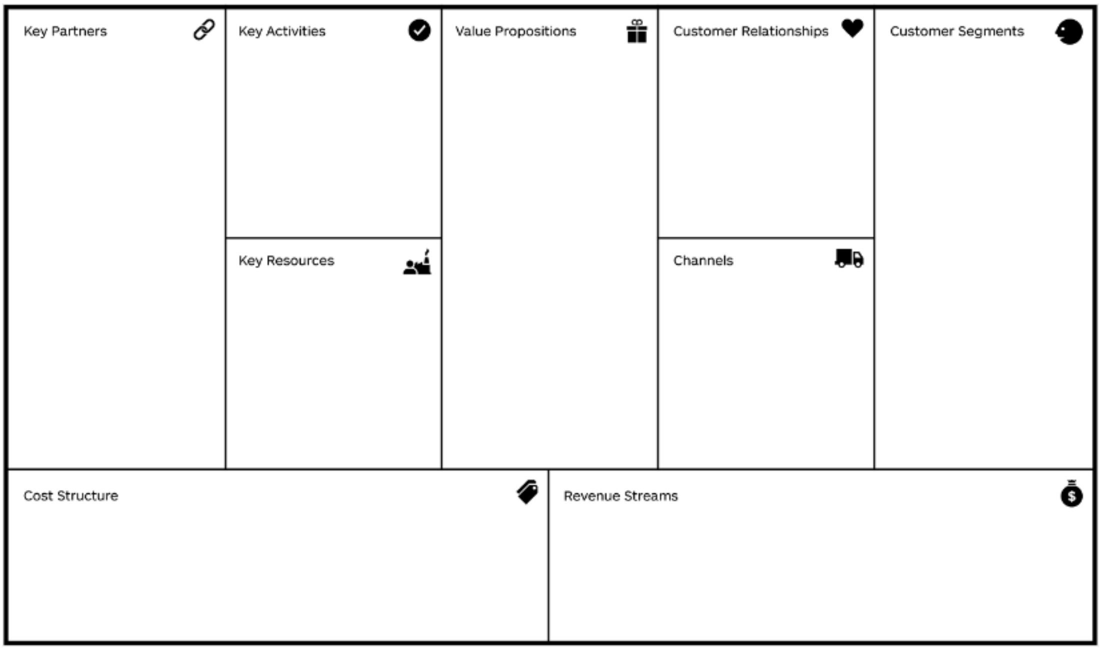


FIGURE 4.2. *Business Model Canvas template*

Key resources

Key resources in a VPP are represented by aggregated DERs, aggregated consumption and aggregated storages, if present.
It is also to be included the combination of software and hardware technologies needed to exchange data and to remotely dispatch distributed units.

Key partners

The most important – non-financial – stakeholders would be ICT companies and software providers, utilities/retailers and ESCOs. Of course, the support needed by the aggregator subject would be consistent with the level of its *independency* and on whether it is already involved in one or some of these businesses.

Key activities

Key activities can range over a large spectrum of possibilities: from the optimization of the gains coming from the participation to the markets, to the minimization of CO_2 emissions and energy waste, to the provision of local services to DSOs. It is something that should be expectedly evaluated case by case.

Channels and customer relationships

Combined aggregators-suppliers would leverage on their existing customer base to catch the opportunity to introduce them to aggregation. Independent aggregators would instead adopt a more aggressive channel strategy to make themselves a name and would probably be forced to rely on strategic partnerships to speed up the process, at least in the first stages of development.
However, it is possible to agree that the relationship with customers and VPP participants is to be characterized by a certain degree of direct dialogue.

Customer segments and value propositions

The value proposition must be put in relation with the kind of segments targeted. Here are some examples: portfolio optimization, imbalances containment and other trading options may be offered for BRP – or BSP – purposes; services such as congestion management and voltage control may be offered to network operators; prosumers and other VPP participants would be attracted by poorer energy bills, increased self-consumption and higher revenues deriving from the participation to energy markets.
Note that VPP participants could be considered as *customers* by the aggregator subject because it is rightly through their productive and consumptive capacity that the aggregation business model would work. According to this point of view, aggregators would have to convince them to join their virtual aggregates by demonstrating the advantages that aggregation can grant.

Cost structure

Main sources of cost would be: the remuneration for VPP participants, the cost of the EMS platform and in general of technologies to be outsourced, contracting and other transaction costs (TCs).

The remuneration of VPP participants translates into an *energy bill premium* for consumption units and in increased inflows for generation units. The costs of software technologies could be considered as fixed costs.

The direct dialogue between the VPP *manager* and afferent units mentioned before translates into bi-lateral contracts, that could be either case-specific or standardized according to the typology of unit. Contracting costs could be then a bulky item among the bundle of transaction costs at the beginning.

Other TCs would comprehend also costs related to open a trading position to operate on energy markets.

Revenue streams

Value would be created through a series of services and activities: from portfolio balancing and optimization to the supply of energy to selected consumers; from market operations to the provision of flexible energetic services. Aggregator could also benefit from brokerage fees and other similar contributions.

Flexibility would be surely the *trigger* for virtual aggregates to carve out an interesting share on the energy markets, especially for what concerns ancillary services – the perspective of higher inflows enabled by the participation to a wider range of markets and the supply of a wider range of services is one of the principal advantages that should convince small generators to join a VPP community.

4.4. BARRIERS TO IMPLEMENTATION

The revolutionary nature of the virtual power plant concept makes so that such kind of business model has to challenge the presence of a number of technical, economic and regulatory barriers within current European market frameworks.

Many of these barriers were identified years ago also by the FENIX team, that principally ascribed the tardiness in the implementation process of rules and regulations to the lack of integration of aggregation and related smart grid opportunities within national energy strategies [51].
Right below, an outlook of the main obstacles to the development of such kind of business model will be provided.

4.4.1. Aspects regarding network access and market participation

Defining proper conditions to enable DERs to participate to the provision of dispatching services is a necessary step for the evolution of the system towards an active management of distribution networks.
VPPs are a viable and adequate solution to pursue this intention in a gradual and secure way, but the slowness of the definition and implementation of delicate regulatory aspects such as authorization processes, technical rules and market participation [51], represents a main barrier to the development of aggregation business models because immobility only leaves space for uncertainty.
Markets mechanisms should be designed and mechanisms organized in a non-discriminatory way for VPPs [55]: in a level playing field perspective, products and services definitions should be adapted (where necessary) so that also VPPs are qualified to offer them and compete on equal terms with existing market actors.
Also, some markets or services which could be theoretically performed at best by VPPs (like flexibility markets) may still be developed [55]: – services do exist but are mandatory and/or not remunerated – or may not exist at all.

4.4.2. Technical aspects

The development of smart grids and proper control system technologies is fundamental to exploit the flexibility and the value added of DERs in structures like that of a VPP.
The absence of such interoperable solutions is clearly an obstacle to the development of VPPs [55]: new regulated standards for innovative metering solutions, faster bi-

directional communications, data transfer and elaboration are needed to make the management and the deployment of such kind of systems possible, secure and reliable.
The abatement of technical barriers would, for example, allow to extrapolate full flexibility from DERs and reduce the need to anticipate the gate closure time of market sessions, that could be shifted more closely to real-time.

4.4.3. Economic aspects

For parties operating DER units, joining a VPP has to be profitable over stand-alone generation [55]. The presence of RES incentive schemes inevitably influences the decision of DERs' owners in this sense: for example, the application of a feed-in tariff translates in DG units producing as much energy as possible without considering market and network needs [55]. Perceiving a very high incentive allows also DERs' owners not to miss the non-participation to traditionally more profitable markets, such as the one for ancillary services (where flexibility gets rewarded). The point is then that RES incentive schemes can make joining a VPP not interesting in many cases.
It could be proposed than to encourage the formation of aggregates through properly established support schemes or to organize a *preferred* or *protected* entry of VPPs in the markets through pilot projects.

4.4.4. Aspects concerning regulated system operators

The passage towards a decentralized network management needs some changes to be realized also in the attitudes of transmission and distribution operators.
In particular, it could be questioned to what extent DSOs should be responsible for managing the distribution grid and providing system services taking into account the high level of complexity that managing a rising number of DERs would take [55.].
To accelerate and favour the decentralization process, DSOs and TSOs should be incentivized to: avoid the delaying of the connection of new DG units to defer costs

[50]; and encourage investments into VPP-like systems, that would be really helpful in managing distributed resources and peripheral portions of the grid.

4.4.5. Specific aspects regarding the demand side

In recent years, possibilities related to demand-side response services provided by prosumers and pure consumption units are increasingly receiving the attention of regulators and system operators. To this regard, to reduce the need for demand profiling, the demand should be properly exposed to within-day price variations, and the provision of correct price signals is necessary to incentivize demand shifting purposes [50].

Chapter 5

CASE STUDY: EVALUATION OF AN INVESTMENT OPPORTUNITY IN A VIRTUAL POWER PLANT IN ITALY

In this chapter, which represents the core of the work, it will be presented the study object of the research. Starting from how the study has been set up and how it has been deployed, the chapter will go through the in-depth description of the mathematic models that have been designed, the main solving aspects and the final commentary of results, as it will be better clarified in the description of the methodology followed for the study. At the end of the chapter it is possible to find also a space dedicated to highlight future continuation opportunities and developments deriving from the acknowledgements of this work.

5.1. METHODOLOGY OF THE STUDY

The case study is organized according to the following methodology: first of all, the motivations and the main drivers behind the research will be presented; right after, it will follow an entire section dedicated to the description of the assumptions and of the boundary conditions that have been shaped to perform the study, starting from the general background to the definition of the main scenarios to be analyzed – *problem setting* phase; after that, it will succeed a section dedicated to the *problem solving* phase, that will be introduced with the description of the optimization models which have been designed to make the economic evaluation possible. Subsequently, it will be given explanation of the elements that have been specifically involved in the investment evaluation and the last paragraph of the *solving* section will be dedicated to the commentary of results and the comparison between the different casuistries that have been considered.

A resuming paragraph reporting final conclusions and the most important acknowledgments as well as proposals for further developments has been also prepared in conclusion to the study.
All along the explanation, it has been also paid attention in highlighting whenever necessary the differences between the diverse situations object of evaluation.

5.2. PURPOSE AND FOUNDATIONS OF THE STUDY

In this period of ferment, the electricity sector is being dotted with reformations. As it was deeply explained in the chapters above, the theme of virtual power plants has become of major interest under many points of view. So there lays the main foundation of this case study: it was reckoned of the utmost interest to conduct a research to investigate about the concreteness of the opportunities behind by the adoption of such kind of re-organization of the energetic resources. The objective that was set was precisely that to try to give an anticipation of those opportunities – if there was really any, at least in for what is known in this early stage of development – by carrying out a specific analysis: through a series of simulations made by mean of purposely designed mathematical models making use of real data about the perspective energetic scenario in Italy, and basing on the latest adjournments in terms of regulatory matters, the aim was that of reproducing the expected behavior of an aggregator subject on the Italian electricity market, to test the economic potential of aggregation in our country.

5.3. PROBLEM SETTING: FUNDAMENTAL ASSUMPTIONS

5.3.1. Background context

Indeed, given also the recent interest demonstrated by national energetic institutions, it was considered prior to carry out the evaluation to consider as experimental environment the still unexplored Italian context. Therefore, the virtual power plants

that have been ideated, have been *tested* on the Italian electricity market and have been designed in order to respect current Italian regulations on the matter.
For a better comprehension of the Italian electricity markets, which is a key requisite to fully understand what will follow, the general functioning of the IPEX and its markets is exhaustively described in *Appendix A*, at the end of the document.
Since the number of configurations to be potentially investigated in shaping up the structure of a virtual power plant appeared to be huge, it became clear the necessity to narrow down the research field. A specific point of view had to be assumed to properly clarify the scope and the boundaries of the study. It was thereby decided to structure the backbone of the VPPs object of the research focusing purely on renewable sources: since the main reforms currently on the run are referred to the proper integration of distributed RES within the existing network, it was reckoned appropriate to connect themes which will be likely put often in relation in the next future, adding also some more challenge to the study.
This choice led to the definition of the first fundamental assumptions of the study, that are the point of view to be assumed while performing the investment evaluation and the definition of the core power generation technology: it was hence decided to *play* the role of a pool of owners of non-relevant, non-incentivized photovoltaic plants evaluating the possibility of an aggregation.
The specific choice of photovoltaics among distributed RES is explained also by a particularly relevant fitting feature: non-relevant PV plants represent an ideal target for aggregation purposes since they represent an increasing amount of the distributed power generation in our country and still have no access to the most profitable electricity markets – i.e. those dedicated to ancillary services – and this makes them particularly predisposed to become object of a VPP *experiment*.
The opportunities considered in the study regard the aggregation of production units only (UVAP) and the combined aggregation of production and consumption units (UVAM). The general rules that have been considered as guidelines for aggregation are the ones promulgated until now by the ARERA about UVAs, the same that have been discussed in chapter 3.
Here are briefly reported those having a major impact in the definition of the casuistries which characterize the study: the configurations comprehending a power generation compound are basically two, the UVAP and the UVAM (leaving aside UVAN); there are minimum power thresholds to be respected when aggregating units

into UVAs, corresponding respectively to 5 MW for UVAP and 10 MW for UVAM; in both configurations it is allowed the presence of stand-alone energy storage systems, which are equalized to production units according to the deliberation 574/14/R/eel on ESS; as from their definition, UVAM must comprehend also consumption units.

5.3.2. Business model of aggregation

The aggregation business model applied to the case study was conceived while building up the scenarios for the investment evaluation and represents a very important theoretical pillar for all the subsequent work. Even though it was not formally inspired to the content of the aforementioned BestRES report about aggregation business models, it evidently shares similarities with some prototypes described in there.

Reasonably, the same business model has been applied to both UVAP and UVAM casuistries.

One of the hypotheses made while shaping the business model was that of excluding utilities, distributors or network operators from being directly involved in the investment. This because the idea was to test the results of the solution without considering the advantages that both private and public operators already heavily involved in the electricity business may bring to the cause.

It was then established that the aggregates protagonists of the various scenarios had to be all ideally managed – *managed, not owned* – by a third-party delegated aggregator that had to be ideally appointed by the group of investors previously defined. So, while the PV aggregate and the rest of the physical infrastructure composing the VPP *facility* remain under the property of the original pool of investors, the aggregator plays the role of a service provider entity.

What makes the difference with respect to the definitions of *delegated aggregator* and *independent service provider* given by the BestRES team – and somehow, what seems to combine the two roles, too – is that the aggregator subject imagined for this case study is also responsible for the correct execution of market operations, the effective provision of ancillary services and even for the imbalance position of the whole VPP.

In other words, this means that the aggregator is entrusted at the same time the roles of BRP and of BSP for the whole aggregate, in accordance with what declared by the recent Italian regulation concerning UVAM aggregates. The same ploy can be applied also to UVAP aggregates, although the separation between BRP and BSP is formally allowed by current regulations for them.
This aggregator subject would be named *delegated aggregator as service provider*.
The goodness of such business model is that the aggregator – which return is given by a share of the revenues made by the whole VPP – is incentivized in extrapolating always the optimal performance from the management of the VPP: even though it did not participate to the investment, it is exposed to market and operational risks the same way as the investors are and shall have no benefit in behaving opportunistically. The parcel that is recognized to the delegated aggregator is then as a cost for the investors that own the VPP *facility*, which is mainly composed by the generation infrastructure – that may comprehend also *upgrading technologies* such as storage systems.
The revenue stream can be composed by two different elements: the gains coming from market operations on the one hand, and the gains coming from the energy supplied to consumption units (only in case of UVAM) on the other hand. In facts, in case of UVAM scenarios, the VPP becomes the electricity supplier of the consumption units being part of the VPP itself. Hence, a source of the revenues for the UVAM is given properly by the remuneration that will be recognized for the energy supplied in this way.
It is opportune to clarify from the beginning that the consumption units of the UVAM are given exclusively by residential units accounting each for 3 kW in power.
To convince those consumers to join the aggregate according to the modalities that have been described above, the *new supplier* applies a discounted tariff on the energy component (*raw material*) of the electricity bill, that gets translated into a lower absolute contribution for consumers with respect to what they are used to pay to traditional energy suppliers. The effect of system charges and other components different from the pure energy one, are supposed to be reflected to consumers, as usually done by distributors.
It is supposed that residential users have already installed in their houses the necessary equipment needed to make them visible to the central brain of the VPP.

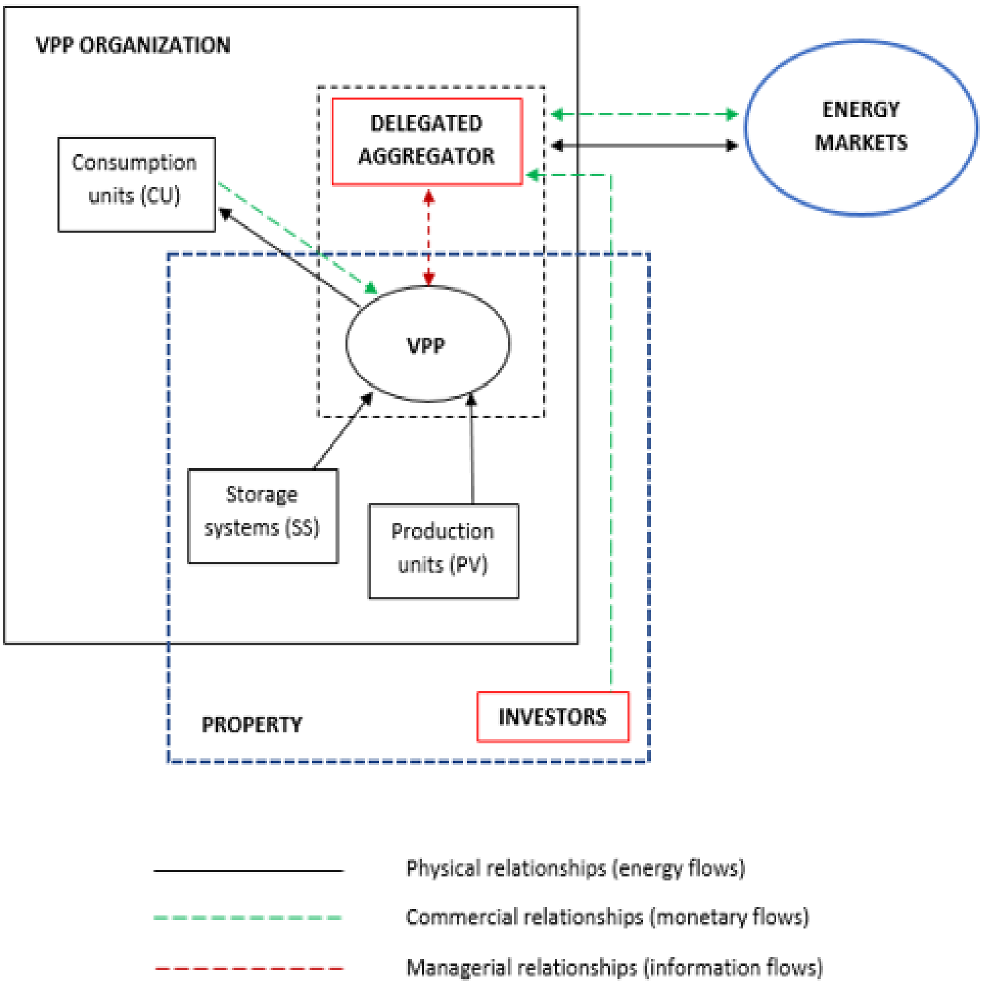


FIGURE 5.1. *Business model adopted, schematic representation*

5.3.3. Market participation and bidding strategy

Note that for what concerns the participation to electricity markets, it was decided to simulate a situation that is likely to occur in a more distant future: some actual barriers have been neglected and the participation of all the VPPs tested during simulations has been extended to all the markets making part of the Italian *MPE*.
So, each VPP is enabled to participate to day-ahead, infra-day, ancillary services and balancing markets – MGP, MI, MSD and MB. This choice is motivated by the intent of trying to capture a more genuine estimation of the real potential of such virtual power plants on the whole of electricity markets.

Of course, the participation of the VPPs to the market implicated the definition of a proper bidding strategy. In doing this, some differences were applied basing on the characteristics of the various markets: each VPP is *programmed* to behave as a price taker on the day-ahead and infra-day markets and to follow a more engaging strategy offering both upward and downward services at a very competitive price on the ancillary services (secondary reserve) and balancing markets (tertiary reserve), so to be sure to have all offerings accepted.

This differentiated strategy is consistent with the fact that the day-ahead and the infra-day markets (in which the product exchanged is pure electricity) are much more liquid that the remaining two (in which the products exchanged are services based on the *raw material* energy) and also with the typology and the specific characteristics of the power generation plants of which the VPPs tested during simulations endowed:

- On the day-ahead and the infra-day market, given the low variable costs associated with photovoltaics, the aggregator subject can ideally bid at a very low price to be sure to see its offerings accepted and remunerated anyhow at market price – of course the energy withdrawn from the grid to satisfy the energy needs of the consumption aggregate or to charge the storage compound (when present) will be valued at market price, too.

- On the other two markets, were the probability of being accepted at the *average* price is usually very low and market dynamics are more complicated, the restrained power (in comparison with other much bigger plants participating to these markets) of the VPPs can be an obstacle. For this reason, the deployment of a more aggressive strategy was thought necessary to maximize the probability of seeing both upward and downward offers always accepted. Therefore, each VPP is going to offer competitively-low prices for the provision of upward services and competitively-high prices for the provision of downward services – ideally a minimal quantity ε less and more, respectively, in comparison to averagely accepted bids.

5.3.4. Definition of scenarios: sizing, configurations, bidding strategy

Sizing guidelines of key VPP components

It was already mentioned that the case study has been built to analyze two different types of aggregates, UVAP and UVAM. It became useful then to understand, for modelling and simplification reasons, which characteristics could be shared by the two categories and which could not. Thus, apart from the adoption of the same business model, it was reckoned opportune to adopt the same criteria to size the power generation capacity and the eventual energy storage compound.
In doing this, the sum of the power of the small-size PV plants owned by the group of investors was univocally fixed at 7 MW. This figure was chosen to permit to cover the 5 MW limit imposed by the ARERA on UVAP aggregates and to reduce the number of consumption units to be included in the UVAM – thinking in perspective, gathering consumers could be a difficult task to be accomplished for the marketing branch of the VPP organization. The *specific* composition of the PV aggregate is not relevant: it could be either imagined as composed by seven identical plants of 1 MW each, for example, or by any other composition resulting in a total of 7 MW.
For what concerns the sizing of the eventual energy storage system, it was arbitrarily established that its size should have been equal to about the 30% of the total power of the aggregate, whether it being an UVAP or an UVAM.

UVAP and UVAM configurations differentiation

Once defined the rules to fix and determine some important parameters, it was necessary to define how the configurations of each virtual power plant typology should have been organized. Basically, three configurations have been organized: a first one foreseeing a simple aggregation; a second one foreseeing the inclusion of a stand-alone energy storage system; and a third one, representing an evolution of the second configuration, in which the energy storage system works according to a more complex arbitraging strategy. In the following tables there is a complete specification of the main cases defined.

TABLE 5.1. *UVAP configurations*

UVAP	
CONFGURATION 1	The group of investors decides to aggregate in order to obtain the possibility to participate also to the MSD and the MB. The total power of the aggregate is given by the sum of the power of the PV plants, hence 7 MW.
CONFGURATION 2	The group of investors chooses to aggregate making also an additional investment in a stand-alone storage compound. According to the generic rule that was mentioned before, the foreseen power size of the storage compound is set at 3 MW in this case.
CONFGURATION 3	In this configuration, the stand-alone storage compound purchased as additional investment is deployed according to an arbitraging strategy in order to try to maximize economic performances.

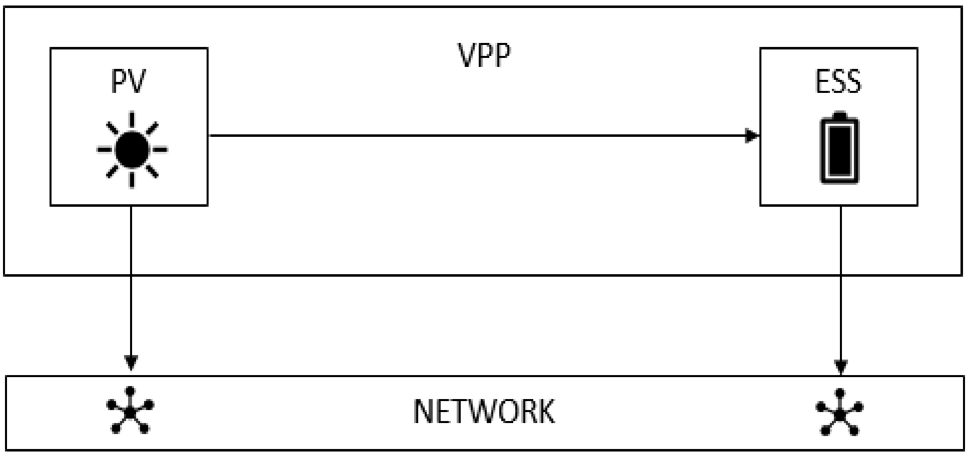


FIGURE 5.2. *UVAP, schematic representation*

TABLE 5.2. *UVAM configurations*

UVAM	
CONFIGURATION 1	The pool of PV owners decides to aggregate giving birth to a mixed UVA in order to participate also to the MSD and the MB. Since the PV generation capacity is fixed at 7 MW, investors need to aggregate a proper amount of consumption units, so to match the minimum required power of 10 MW. As it was specified before, the consumption aggregate will be composed of residential units accounting 3 kW each, meaning that it will have to comprehend 1000 units to cover the remaining 3 MW.
CONFIGURATION 2	The group of PV owners chooses to aggregate making also an additional investment in a stand-alone storage compound. According to the generic rule that was mentioned before, the foreseen power size of the storage compound is set at 4 MW.
CONFIGURATION 3	Similar to what happens for the UVAP, in this configuration the stand-alone storage compound purchased in addition is deployed according to an arbitraging strategy in order to try to maximize economic returns.

Each configuration will be analysed in three different contexts: in the first case, it is assumed that the capital costs associated with the PV plants of the investors are already completely covered and no other capital expenditure is going to be sustained within the time period coinciding with the horizon of the investment; in the second option, it is considered that there is still a 40% quota of PV CapEx to be covered; a the third case, it is assumed that it is necessary to undergo an investment to revamp the PV aggregate.

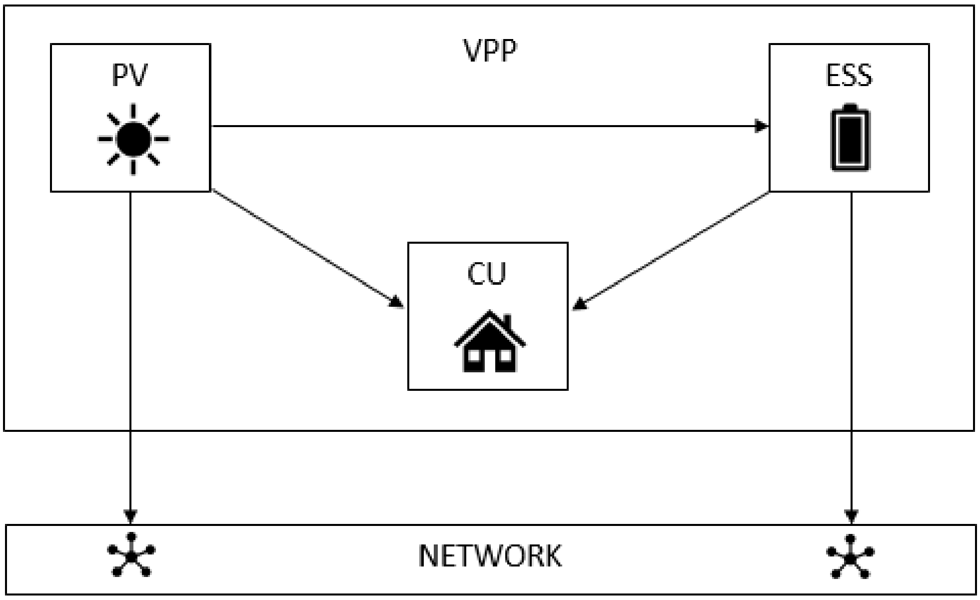


FIGURE 5.3. *UVAM, schematic representation*

The idea of testing the VPPs in three different initial cost-structure scenarios was born in order to measure the goodness of the economic results related to each aggregate and to each configuration with respect to different underlying financial situations at the basis of the investment.

Location of VPP components

It was previously explained that the regulation concerning UVAs foresees that all the component being part of an aggregate should belong to the same market zone. It was also said that the *Authority* gave mandate to Terna to establish stricter and more precise indications at this regard. So, to make sure that the situations depicted in the case study are respectful of even more limiting geographical boundaries, it was decided to locate all the components involved in each VPP configuration not only in the same market zone, but directly within the same provincial territory – i.e. the province of Pavia, in the market zone *Nord*.

5.3.5. Causal maps

During the setting phase, two causal maps [56] were drafted – one per each kind of aggregate, UVAP and UVAM. The advantage of drafting a causal map resides in the possibility to look at the problem in its entirely and so to have also the chance to better understand its key issues. Mapping the problem in this way is useful to help developing a comprehensive vision of the contribution of the main variables playing a role in the definition of the problem, giving simply the idea of the cause-effect relationships existing among them. To do that, it is needed to define three kinds of variables:

- *Decisional variables:* aspects of the decisional process that are under the control of the decision maker.

- *Exogenous variables:* variables affecting the decisional process on which the decision maker has no power because they are determined by external factors.

- *Endogenous variables:* usually they are the results or the consequences related to the effect that both decisional and exogenous variables manifest through their interaction on other parameters.

The map is to be drafted – and red – starting from the definition of the final objective, which is generally an endogenous variable. The rest of the map is to be carefully composed choosing the most important variables that it is worth showing.
Both maps refer to the most complete configurations described in the tables above.

Map legend

On the maps, decisional variables are written in red, exogenous variables in blue and endogenous variables in black. The plus and minus signs on the map serve to indicate the linear or inverse relationship linking an upstream variable to a downstream one. It is to note that the violet coloration adopted for the variable *VPP size* is to denote its

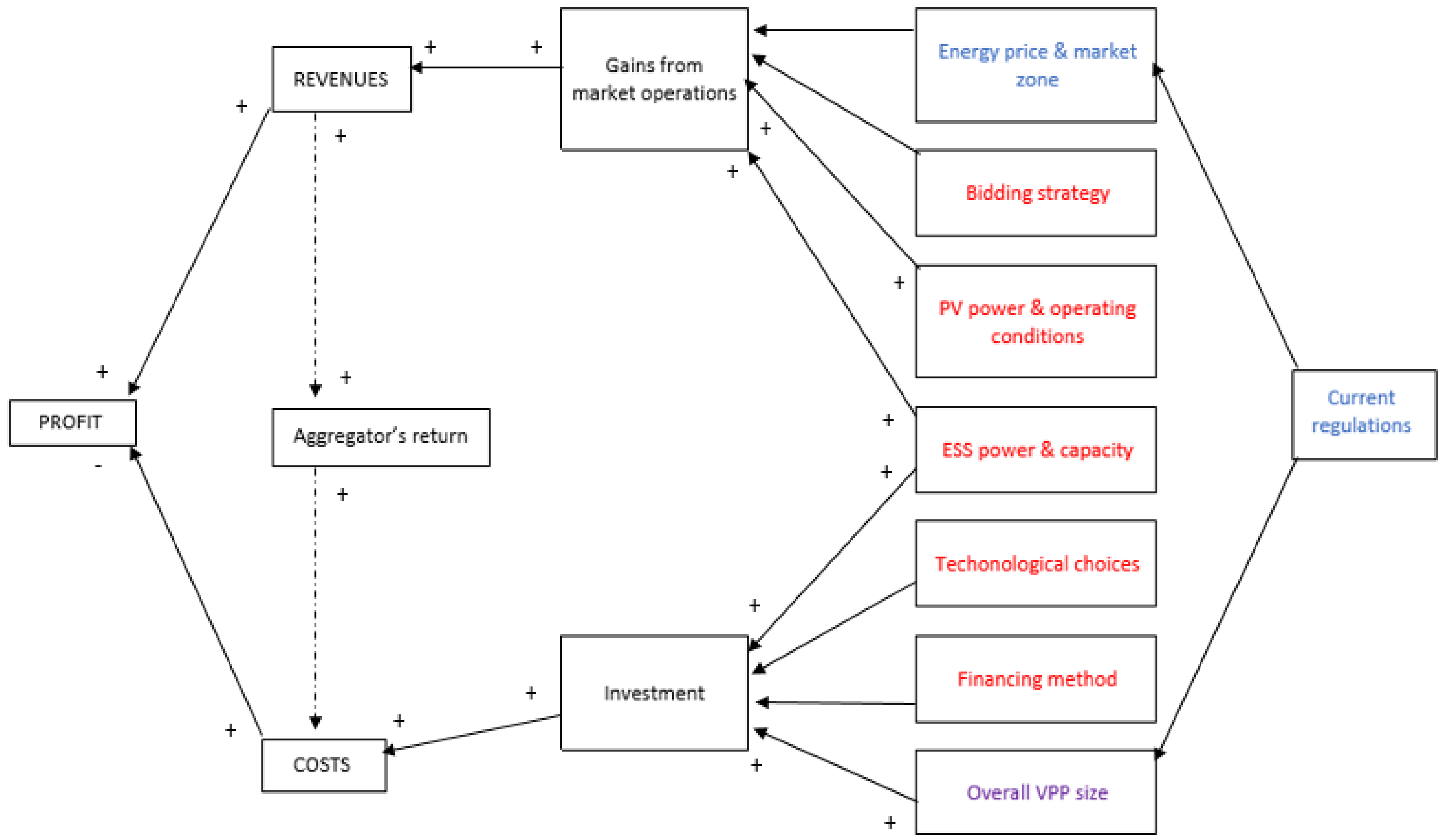


FIGURE 5.4. *Causal map, UVAP*

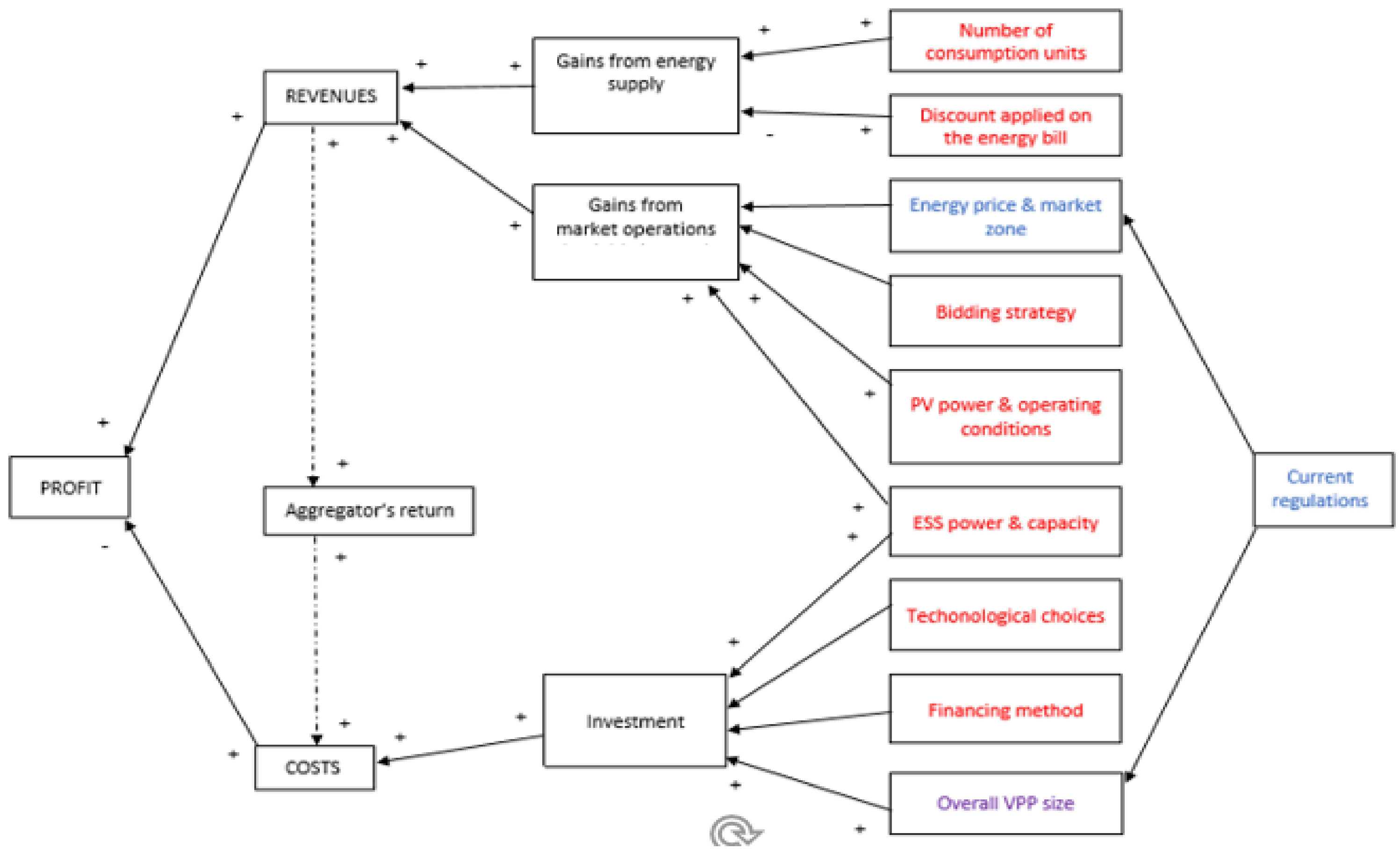


FIGURE 5.5. *Causal map, UVAM*

mixed nature, in some ways partially exogenous – due to the strong influence of regulations, environmental and bureaucratic aspects – and partially decisional.
It is to note also the presence of some variables for which it is not possible to distinctively clarify the impact by just putting plus and minus signs on the map. Here is a brief explanation:

- *Current regulations:* it is not easy to define precisely whether their overall impact is positive or negative because usually there are norms in favor of project developers and others which are not. However, their presence is fundamental in defining the boundaries of the project itself.

- *Financing method:* the method chosen to fund the project can have a strong impact on the final economic result of the investment. Basically, we would express the relation saying that the more *facilitating* is the debt contract for the borrower, the *lighter* would be its impact on the results of the investment.

- *Technological choices:* the choice of the technologies to be deployed may be very influencing in terms of performances but also in terms of costs. Generally, everybody would agree on the trade-off existing between the goodness of the performance desired and the price to be paid for it.

- *Bidding strategy:* this is a decisional variable which has obviously an important impact on the gains. It is possible to explain the relationship saying that the best results in terms of profit would be obtained in correspondence of a well-designed bidding strategy.

- *Energy price and market zone:* similar reasoning to the ones made above: the best economic results would be reached in correspondence of the best energy price situation. Nevertheless, the energy price is influenced by the location (the market zone) of injection and withdrawal points.

5.4. PROBLEM SOLVING: DESIGN OF THE MODELS

5.4.1. General description of the optimization models designed

Brief introduction to operations research and mathematical modelling

Prior to the description of the models, it is worth to briefly introduce the science behind the models themselves. Operations research is a discipline devoted to formulating and solving mathematic models which are involved in complex decisional processes [57]. Mathematic models are developed and used in a huge variety of contexts but they all share some fundamental characteristics. A model is a selective abstraction of a real system and is designed in order to analyse and comprehend the functioning of such concrete system from an abstract point of view [57]. The term *selective* is to underline that only the elements reckoned as relevant are modelled and this is important when it comes to associate problem solving with the concept of optimization. Optimization within complex decisional processes is used to determine the most advantageous solution, given a set of alternatives and a proper evaluation criterion [57]. Mathematic optimization is a fundamental part within the optimization theory. In mathematic optimization, evaluation criteria and the boundaries characterizing the problems are always expressed under the form of equations and inequalities [57]. Mathematical optimization problems can assume different forms according to the typology of system they want to model and to the typology of data of which they make use.

Here is the generic process at the basis of the development of a mathematical model. It is possible to schematize the development of a decisional mathematical model by mean of four main phases, as presented in [57].

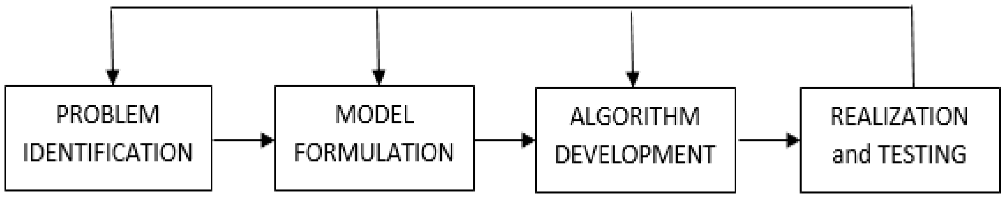


FIGURE 5.6. *Phases of development of a mathematical model*

The first phase is dedicated to the full comprehension of the problem in its concreteness, analysing relevant factors and trying to understand the causes and the main drivers at the basis of the problem or of the situation.
In the second step, the real situation analysed during phase one gets abstracted and modelled. This is the moment in which the main factors that will characterize the behaviour and the composition of the model itself – temporal horizon, decisional variables, constant parameters, mathematical relations, objective function – get defined.
Once the problem has been properly shaped, it comes the time to develop the algorithm/s necessary to solve the problem in order to get to the optimal solution. A generic algorithm should be designed in order to be efficient under both a temporal and an operational point of view – the resolution speed should be proportional to the complexity and adequate to application purposes.
In the last step deals with checking out the validity of the results obtained through the application of the model. It is to be investigated its behaviour in presence of extreme values of key parameters, the stability of the solution after minimal changes in the values of certain elements and the likelihood of the solutions obtained.
More detailed information about the theory behind the optimization forms that have been adopted to ideate the models that have been used in the case study – linear optimization, integer optimization, mixed integer-linear optimization – can be found in *Appendix C* at the end of the document.

Brief VPP optimization overview

In the last decade, literature got filled by a variety of theoretical examples concerning the methodologies and the models of optimization that could be adopted to deal with VPP structures.
A problem can be solved according to different optimization methodologies: from the usage of analytical methods to minimize power losses through the optimal placement of DG units like in [58] to the use of linear programming to face power optimization problems [59] or the enforcement of heuristic methods for optimal sizing and power allocation of of DERs like in [60].
Models can be also optimized according to different types and a different number of objectives. Generally, single objective problems can deal with direct objectives, such as the maximization of profits [61] [62] [63] [64], the minimization of costs [65] or of power losses [66]. Multi-objective formulations can be based on the weighted sum of individual objectives or on goal multi-objective indexes [44] and deal mainly with the combined optimal sizing and placement of dispersed energy units [67] [68].
A wide and interesting review of optimization methodologies can be found in [44].

Introduction to the models designed

The profit made through daily market operations by any agent participating to electricity markets depends on several factors. Each situation is to be considered agent-specific, because some factors are strictly connected to the peculiarities characterizing the agent itself: the amount of energy traded, the bidding strategy adopted, the management of imbalances, and so on. This is true even for the figure of the agent-aggregator that was pictured before. The models that are about to be described represent thus a mathematical ploy to come up modelling and simulating the economic behaviour of such aggregated system. Their execution allowed to gather precious and likely economic result that were fundamental to proceed with the investment evaluation.

Two models

Since the case study was constructed step by step, the rationale that brought to the development of the models was scalar. The first model was designed to reflect the market behaviour of the VPP and its basic components: a production aggregate composed by the agglomerate of photovoltaic plants (PV), a storage system compound (SS) whenever present and, in the case of UVAM, a consumption aggregate given by residential units (CU). Nevertheless, in spite of its successful implementation, it became evident that there was an unexploited potential coming from the storage component that this first model was not able to catch. There was a further portion of gains that remained unreachable due to the simplistic strategy – de facto a *non-strategy* – of deployment adopted for the energy storage system.
The goal of extrapolating the best possible performance from all the components of the VPP worked then as a driver towards the realization of a second, improved model. Basically, the improvement consisted in endowing the storage system with the ability to put in practice a more complicated arbitrage strategy.
In general, arbitrage is an economic operation which consists in purchasing a good or a financial product on a market in order to sell it on another market – at a higher price – so to benefit from the price differential among the two. The concept of arbitrage is not to be confused with that of speculation. The two strategies differ in what the first one is based mainly on the concept of *space*, while the second one is purely based on the concept of *time*: purchasing a product on a certain market and then re-selling it in a second moment, on a different market, is considered arbitrage; purchasing and re-selling the very same product on the very same market trying to capitalize just on the time differential between purchase and sale, is considered speculation.
In particular, arbitrage strategies on electricity markets – at least in the Italian case – are possible thanks to a mixture of temporal and spatial factors: the sequence of market sessions – reported in figure A.1 in *Appendix A* – makes so that the energy transacted within the various markets acquires economic value with the approaching of the real time – i.e. the moment in which the energy transacted must be physically delivered. This explains the increasing value of the energy and of the services exchanged on the ready-made markets as we move from the *earlier* sessions of the MGP and the MI to the *later* sessions of the MSD and MB. Thus, a market player that is qualified to operate on both energy and ancillary services markets can try, with the

right *instruments* – the right combination of hardware and software apparatuses – to capture full economic benefit from the incremental value of the products exchanged within time and across the various markets.

Premises

Here are reported the premises which are key to fully understand how the models behave and what it is to be expected from their application.
First of all, it is important to clarify that these are not to be considered as dispatching models. Their objective is to identify the optimal solution in terms of what energy movements shall be operated – and when, referring also to the various markets – to obtain the best economic performance, given certain limitations and forecasted or pre-defined parameters.
Secondly, both models were run basing on deterministic scenarios that simulated *typical* situations with respect to certain parameters. Specifically, the models are built to find the optimal economic result that can be obtained through market operations, in the *typical day* – i.e. 24-hour period – of a given month. The results must then be properly scaled to compose the expected profit of the whole month. The same procedure is to be repeated for each month of the year. Summing the results of each month obtained this way, it is possible to obtain the profit of a whole year.
The models are built on a sequence of time slots of one hour each (to follow the succession of market sessions), so all the basic input information have been arranged to be consistent with the dimension of the pre-set time slots.
Note also that the input data used for the two models are exactly the same. The results obtained with the two models change because of the different strategies adopted with regard to the deployment of the energy storage system. Relaxing arbitrage constraints, the second model would in fact behave exactly like the first one.
Lastly, not being neither of them a dispatching model, and being still unclear under a regulatory point of view how the situation will be managed in case of VPPs, no strategy to deal with imbalances was inserted in the models.

To point out the differences among the two models, it was judged appropriate to give a detailed explanation of both of them. The models are presented in their most complete form (all the components of the VPP are included). To cut a component out from the VPP and check for related results, it is sufficient to omit the boundaries concerning that component or, in some cases, to set null some parameters.

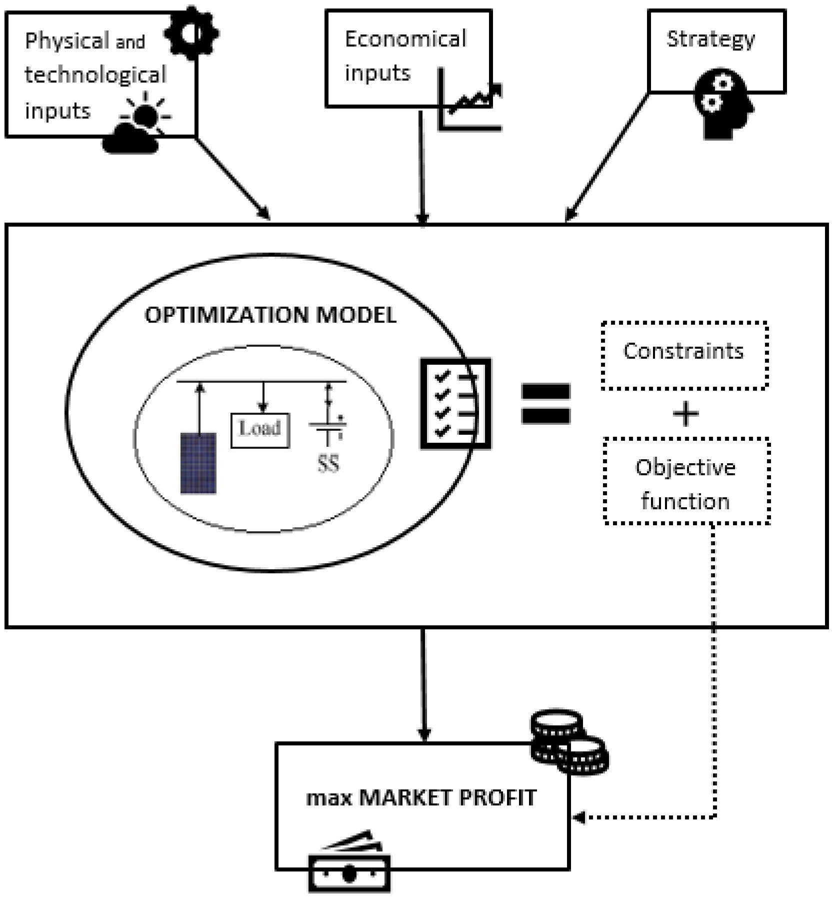


FIGURE 5.7. *Schematic functioning of the models*

- Physical and technological inputs: hourly expected aggregated photovoltaic production, hourly expected aggregated consumption loads, technological characteristics of the energy storage system (efficiency, charge/discharge limits, capacity).
- Economic inputs: hourly prices for each market session.
- Strategy: bidding strategy and deployment of the energy storage system

5.4.2. Model 1: optimizing the profit of the VPP considering a simple energy storage system operating strategy

The following model is a single objective, mixed integer-linear optimization model. Its purpose is the maximization of an objective function representing the expected market gain of the virtual power plant object of the investment evaluation under the assumption of a *non-strategic* deployment of the energy storage system.
The model has been run on GAMS software, version 23.2.1 (CPLEX solver), by mean of a 2.4 GHz Intel® Core™ i7-5500U processor with an average solving time of 0.4 seconds.
In what follows, it will be explained in detail how such model is composed and how it works. In this case, for the sake of clarity, it will be specifically described each variable/parameter involved.

Sets, parameters and variables

Sets and Indices

$h \in H$	Set of hours.
$I_h, K_h, J_h, Z_h \subset H$	Each hour is composed of four subsequent time slots that respectively refer to the transactions happening on the following markets: MGP, MI, MSD and MB.
$i \in I_h$	Set of MGP transactions time slot, within hour h.
$k \in K_h$	Set of MI transactions time slot, within hour h.
$j \in J_h$	Set of MSD transactions time slot, within hour h.
$z \in Z_h$	Set of MB transactions time slot, within hour h.

Parameters

$E_{PV}^{for}(h)$	Expected hourly energy produced by the PV aggregate.
$E_{CU}^{for}(h)$	Expected hourly energy demand coming from the consumption (CU) aggregate.
E_{SS}^{MAX}	Maximum level of energy that can be contained in the storage system.
E_{SS}^{MIN}	Minimum level of energy that must be present in the storage system to avoid malfunctions and damages.
$E_{SS}^{CH,MAX}$	Maximum amount of energy that can be charged at once in the storage system.
$E_{SS}^{DCH,MAX}$	Maximum amount of energy that can be discharged at once from the storage system.
η	Charge/discharge efficiency of the storage system.
$P_{MGP}(h)$	Hourly energy price, day-ahead market.
$P_{MI}(h)$	Hourly energy price, infra-day market.
$P_{MSD}^{UP}(h)$	Hourly upward ancillary services market price.
$P_{MB}^{UP}(h)$	Hourly upward balancing market price.
$P_{MSD}^{DW}(h)$	Hourly downward ancillary services market price.
$P_{MB}^{DW}(h)$	Hourly downward balancing market price.

Non-negative variables

$E_{PV\_CU}(h)$	Portion of energy produced by the PV aggregate used to satisfy the consumption needs of the CU aggregate, in hour h.

$E_{PV\_SS}(h)$	Portion of energy produced by the PV aggregate used to charge the storage system, in hour h.
$E_{PV\_N}(h)$	Portion of energy produced by the PV aggregate flowing to the network – sold on the markets, in hour h.
$E_{SS\_CU}(h)$	Portion of energy discharged by the storage system used to satisfy the consumption needs of the CU aggregate, in hour h.
$E_{SS\_N}(h)$	Portion of energy discharged by the storage system flowing to the network – sold on the markets – in hour h.
$E_{N\_CU}(h)$	Energy coming from the network – purchased on the markets – used to satisfy the consumptions needs of the CU aggregate, in hour h.
$E_{N\_SS}(h)$	Energy coming from the network – purchased on the markets – used to charge the storage system, in hour h.
$E_{SS}(h)$	Energy status of the storage system at the end of hour h.
$E_{SS}^{CH}(h)$	Total amount of energy charged in the storage system in hour h.
$E_{SS}^{DCH}(h)$	Total amount of energy discharged from the storage system in hour h.
$E_{PV_{MGP}}(h,i)$	Portion of energy produced by the PV aggregate which gets sold on the day-ahead market, in time-slot *i* within hour h.
$E_{PV_{MI}}(h,k)$	Portion of energy produced by the PV aggregate which gets sold on the infra-day market, in time-slot *k* within hour h.
$E_{PV_{MSD}}(h,j)$	Portion of energy produced by the PV aggregate which gets sold on the ancillary services market (upward services), in time-slot *j* within hour h.
$E_{PV_{MB}}(h,z)$	Portion of energy produced by the PV aggregate which gets sold on the balancing market (upward services), in time-slot *z* within hour h.
$E_{SS_{MGP}}(h,i)$	Portion of energy discharged by the storage system and sold on the day-ahead market, in time-slot *i* within hour h.

$E_{SS_{MI}}(h,k)$	Portion of energy discharged by the storage system and sold on the infra-day market, in time-slot *k* within hour h.
$E_{SS_{MSD}}(h,j)$	Portion of energy discharged by the storage system and sold on the ancillary services market (upward services), in time-slot *j* within hour h.
$E_{SS_{MB}}(h,z)$	Portion of energy discharged by the storage system and sold on the balancing market (upward services), in time-slot *z* within hour h.
$E_{MGP_{SS}}(h,i)$	Portion of energy purchased on the day-ahead market and used to charge the storage system, in time-slot *i* within hour h.
$E_{MI_{SS}}(h,k)$	Portion of energy purchased on the infra-day market and used to charge the storage system, in time-slot *k* within hour h.
$E_{MSD_{SS}}(h,j)$	Portion of energy purchased on the ancillary services market and used to charge the storage system (downward services), in time-slot *j* within hour h.
$E_{MB_{SS}}(h,z)$	Portion of energy purchased on the balancing market and used to charge the storage system (downward services), in time-slot *z* within hour h.
$E_{MGP_{CU}}(h,i)$	Portion of energy purchased on the day-ahead market and used to satisfy the consumption needs of the CU aggregate, in time-slot *i* within hour h.
$E_{MI_{CU}}(h,k)$	Portion of energy purchased on the infra-day market and used to satisfy the consumption needs of the CU aggregate, in time-slot *k* within hour h.
$E_{MSD_{CU}}(h,j)$	Portion of energy purchased on the ancillary services market and used to satisfy the consumption needs of the CU aggregate (downward services), in time-slot *j* within hour h.
$E_{MB_{CU}}(h,z)$	Portion of energy purchased on the balancing market and used to satisfy the consumption needs of the CU aggregate (downward services), in time-slot *z* within hour h.
$E_{MGP}^{INJ}(h)$	Total portion of energy injected into the network and sold on the day-ahead market, in hour h.

$E_{MI}^{INJ}(h)$	Total portion of energy injected into the network and sold on the infra-day market, in hour h.
$E_{MSD}^{INJ}(h)$	Total portion of energy injected into the network and sold on the ancillary services market (upward services), in hour h.
$E_{MB}^{INJ}(h)$	Total portion of energy injected into the network and sold on the balancing market (upward services), in hour h.
$E_{MGP}^{WTD}(h)$	Total portion of energy withdrawn from the network and purchased on the day-ahead market, in hour h.
$E_{MI}^{WTD}(h)$	Total portion of energy withdrawn from the network and purchased on the infra-day market, in hour h.
$E_{MSD}^{WTD}(h)$	Total portion of energy withdrawn from the network and purchased on the ancillary services market (downward services), in hour h.
$E_{MB}^{WTD}(h)$	Total portion of energy withdrawn from the network and purchased on the balancing market (downward services), in hour h.

Other variables

$\Phi_{SS}(h)$	Binary variable which assumes the value *1* in case of battery charging and the value *0* in case of battery discharging; there is no possibility to charge and discharge the storage system within a single hour h.
$E_{VPP}^{EXCH}(h)$	Total net amount of energy exchanged between the VPP and the network, in hour h.

Objective function and constraints

As it was declared before, the model aims for the maximization of an objective function representing the profit resulting from the operations carried out by the VPP on the said electricity markets. Here is the equation of the single-target objective function:

$$\pi = \sum_{h}^{H} P_{MGP}(h) \cdot [E_{MGP}^{INJ}(h) - E_{MGP}^{WTD}(h)] + \sum_{h}^{H} P_{MI}(h) \cdot [E_{MI}^{INJ}(h) - E_{MI}^{WTD}(h) \\ + \sum_{h}^{H} P_{MSD}^{UP}(h) \cdot E_{MSD}^{INJ}(h) + \sum_{h}^{H} P_{MB}^{UP}(h) \cdot E_{MB}^{INJ}(h) - \sum_{h}^{H} P_{MSD}^{DW}(h) \cdot E_{MSD}^{WTD} \\ - \sum_{h}^{H} P_{MB}^{DW}(h) \cdot E_{MB}^{WTD}(h) \tag{5.1}$$

The overall profit is given by the sum of different contributions, which are nothing but the result of the transactions the VPP made in each of the market-dedicated time slots showed above: the first contribution comes then from the results of the useful transactions made by the VPP in the MGP market sessions; the second one represents the same data referred to the second time interval, the one related to MI sessions; the third series of contributions makes reference instead to the results coming from the transactions happened in the sessions related to MSD and MB.

As it can be noticed, for the last two markets it was correctly considered the difference between upward and downward services.

$$E_{PV}^{for}(h) = E_{PV\_CU}(h) + E_{PV\_SS}(h) + E_{PV\_N}(h) \tag{5.2}$$

Equation 5.2 expresses the balance at the PV node within the internal VPP grid: the hourly energy produced by the PV compound – based on forecasted data – can reach to the network, to the consumption aggregate or to the storage facility.

$$E_{CU}^{for}(h) = E_{PV\_CU}(h) + E_{SS\_CU}(h) + E_{N\_CU}(h) \tag{5.3}$$

Equation 2.3 defines the balance at the CU node: the energy needed to satisfy the consumption can come from the PV aggregate, the network or the storage facility.

$$E_{SS}(h) = E_{SS}(h-1) + E_{SS}^{CH}(h) \cdot \eta - \frac{E_{SS}^{DCH}(h)}{\eta}, \qquad \forall h \tag{5.4}$$

$$E_{SS}^{MIN} \leq E_{SS}(h) \leq E_{SS}^{MAX}, \qquad \forall h \tag{5.5}$$

$$E_{SS}(h-1) = 1, \qquad if \;\; h = 1 \tag{5.6}$$

$$E_{SS}^{CH}(h) = E_{PV\_SS}(h) + E_{N\_SS}(h), \qquad \forall h \tag{5.7}$$

$$E_{SS}^{DCH}(h) = E_{SS\_CU}(h) + E_{SS\_N}(h), \qquad \forall h \tag{5.8}$$

$$E_{SS}^{CH}(h) \leq E_{SS}^{CH,MAX} \cdot \Phi_{SS}(h), \qquad \forall h \tag{5.9}$$

$$E_{SS}^{DCH}(h) \leq E_{SS}^{DCH,MAX} \cdot [1 - \Phi_{SS}(h)], \qquad \forall h \tag{5.10}$$

Equation 5.4 defines the energy balance of the storage system for each unit of time. The energy remaining within the battery at the end of hour t is given by the sum of the operations which have been made during the hour and thus it will be given by the quantity of energy already present from the previous time period plus an eventual charge, minus an eventual discharge.

Equation 5.5 defines the upper and lower bound of the energy level that can be stored in the storage system in the unit of time considered.

The purpose of equation 5.6 is that of initializing the model, making such that in the first hour, the quantity already present in the storage facility corresponds to the minimum allowed.

Equation 5.7 defines the provenience of the energy which will be used to charge the storage compound: that energy can come from the PV aggregate and from the network.

Equation 5.8 defines instead the possible destinations of the energy discharged by the storage system: the energy discharge can flow to the CU unit or to the markets.

Since the battery cannot contain more energy than the level defined by the upper bound parameter, the energy charging the SS must be properly limited (5.9). The same reasoning is valid for the opposite process of discharge (5.10).

$$E_{PV\_N}(h) = E_{PV_{MGP}}(h,i) + E_{PV_{MI}}(h,k) + E_{PV_{MSD}}(h,j) + E_{PV_{MB}}(h,z), \quad \forall h \tag{5.11}$$

$$E_{SS\_N}(h) = E_{SS_{MGP}}(h,i) + E_{SS_{MI}}(h,k) + E_{SS_{MSD}}(h,j) + E_{SS_{MB}}(h,z), \quad \forall h \tag{5.12}$$

$$E_{N\_SS}(h) = E_{MGP_{SS}}(h,i) + E_{MI_{SS}}(h,k) + E_{MSD_{SS}}(h,j) + E_{MB_{SS}}(h,z), \quad \forall h \tag{5.13}$$

$$E_{N\_CU}(h) = E_{MGP_{CU}}(h,i) + E_{MI_{CU}}(h,k) + E_{MSD_{CU}}(h,j) + E_{MB_{CU}}(h,z), \quad \forall h \tag{5.14}$$

This block of equations serves to specify that the energy injected into and withdrawn from the network can be destined to or coming from the four markets considered at the beginning: MGP, MI, MSD and MB. It is to remember that market sections are subsequent and that the movements of energy flows in each of them happen ideally in separate time windows.

Equation 5.11 defines this partition for the energy going from the PV aggregate to the network, while equation 5.12 expresses the same concept for the energy flowing to the network and discharged by the storage compound. Conversely, equations 5.13 and 5.14 express respectively the partition of the energy flow that goes from the network to the storage system and the consumption aggregate.

$$E_{MGP}^{INJ}(h) = E_{PV_{MGP}}(h,i) + E_{SS_{MGP}}(h,i), \quad \forall h \tag{5.15}$$

$$E_{MI}^{INJ}(h) = E_{PV_{MI}}(h,k) + E_{SS_{MI}}(h,k), \quad \forall h \tag{5.16}$$

$$E_{MSD}^{INJ}(h) = E_{PV_{MSD}}(h,j) + E_{SS_{MSD}}(h,j), \quad \forall h \tag{5.17}$$

$$E_{MB}^{INJ}(h) = E_{PV_{MB}}(h, z) + E_{SS_{MB}}(h, z), \quad \forall h \tag{5.18}$$

$$E_{MGP}^{WTD}(h) = E_{MGP_{SS}}(h, i) + E_{MGP_{CU}}(h, i), \quad \forall h \tag{5.19}$$

$$E_{MI}^{WTD}(h) = E_{MI_{SS}}(h, k) + E_{MI_{CU}}(h, k), \quad \forall h \tag{5.20}$$

$$E_{MSD}^{WTD}(h) = E_{MSD_{SS}}(h, j) + E_{MSD_{CU}}(h, j), \quad \forall h \tag{5.21}$$

$$E_{MB}^{WTD}(h) = E_{MB_{SS}}(h, z) + E_{MB_{CU}}(h, z), \quad \forall h \tag{5.22}$$

This block of equations is instead necessary to define the entity and the provenience of the energy injected into and withdrawn from each market.

Following this rationale, equation 5.15 defines the composition of the energy sold on the MGP. Equations 5.16, 5.17 and 5.18, in the same way, define the composition of the energy sold on the MI, the MSD and MB respectively. For the last two markets the energy injected into the network is identifiable with the provision of *upward services*.

The same happens for the withdrawals, with equations 5.19, 5.20, 5.21, and 5.22. The flows of equations 5.21 and 5.22 are identifiable with the provision of *downward services* on the MSD and the MB markets, respectively.

$$\begin{aligned} E_{VPP}^{EXCH}(h) = {} & E_{MGP}^{INJ}(h) + E_{MI}^{INJ}(h) + E_{MSD}^{INJ}(h) + E_{MB}^{INJ}(h) \\ & - E_{MGP}^{WTD}(h) - E_{MI}^{WTD}(h) - E_{MSD}^{WTD}(h) - E_{MB}^{WTD}(h), \quad \forall h \end{aligned} \tag{5.23}$$

Equation 5.23 represents the balance of the whole amount of energy exchanged by the VPP with the network in each hour – thus comprehending all the exchanges happened on the electricity markets within that hour – and it is obviously given by the sum of all injection contributions minus the sum of all withdrawals contribution.

$$E_{PV}^{for}(h) + E_{SS}^{DCH}(h) = E_{CU}^{for}(h) + E_{SS}^{CH}(h) + E_{VPP}^{EXCH}(h), \quad \forall h \tag{5.24}$$

This last equation represents the overall energetic balance of the virtual power plant. It basically states that all the energy which is supposed to come **from** VPP components must be equal to the energy flowing **towards** VPP components **plus the net** energy exchanged by the VPP with the main grid. It is a sort of security constraint that makes sure that the VPP balance is always confirmed, hour by hour.

5.4.3. Model 2: optimizing the profit of the VPP considering an arbitrage energy storage system operating strategy

Like the first one, the second model is a single objective, mixed integer linear optimization model. Its purpose is, in the same way, the maximization of an objective function representing the expected market gain of the virtual power plant. The substantial difference with the first model lays in what the storage system is *programmed* to follow a more complex arbitrage strategy, to furtherly increase market gains.
The model has been run on GAMS software, version 23.2.1 (CPLEX solver), by mean of a 2.4 GHz Intel® Core™ i7-5500U processor with an average solving time of 0.46 seconds.
The following description will recall the same structure used for describing the previous model, although a more restrained form has been adopted. Note also that the notation used is slightly different.

Sets, parameters and variables

Sets and Indices

$h \in H$ Set of hours.

$m \in M$	Set of markets – in the correct sequence MGP, MI, MSD and MB.

Parameters

$E_{PV}^{for}(h)$	Expected hourly energy produced by the all the PV aggregate.
$E_{CU}^{for}(h)$	Expected hourly energy demand coming from the CU aggregate.
E_{SS}^{MAX}	Maximum level of energy that can be contained in the storage system.
E_{SS}^{MIN}	Minimum level of energy that must be present in the storage system to avoid malfunctions and damages.
$E_{SS}^{CH,MAX}$	Maximum amount of energy that can be charged at once in the storage system.
$E_{SS}^{DCH,MAX}$	Maximum amount of energy that can be discharged at once from the storage system.
η	Charge/discharge efficiency of the storage system.
$P_{sell}(h,m)$	Price expected for market m in hour h, selling offerings.
$P_{buy}(h,m)$	Price expected for market m in hour h, purchase offerings.

Non-negative variables

$E_{PV\_CU}(h)$	Portion of energy produced by the PV aggregate used to satisfy the consumption needs of the CU aggregate, in hour h.
$E_{PV\_SS}(h)$	Portion of energy produced by the PV aggregate used to charge the storage system, in hour h.
$E_{PV_M}(h,m)$	Portion of energy produced by the PV aggregate sold on market m, in hour h.
$E_{SS\_CU}(h)$	Portion of energy discharged by the storage system used to satisfy the consumption needs of the CU aggregate, in hour h.
$E_{SS_M}(h,m)$	Portion of energy discharged by the storage system sold on market m, in hour h.

$E_{M_{CU}}(h,m)$ — Energy purchased on market m and used to satisfy the consumptions needs of the CU aggregate, in hour h.

$E_{M_{SS}}(h,m)$ — Energy purchased on market m and used to charge the storage system, in hour h.

$E_{SS}(h)$ — Energy status of the storage system at the end of hour h.

$E_{SS\_M}^{CH}(h)$ — Total amount of energy purchased on the markets and used to charge the storage system, in hour h.

$E_{SS\_M}^{DCH}(h)$ — Total amount of energy discharged from the storage system and sold on the markets in hour h.

$E_{SS_{hm}}(h,m)$ — Energy status of the storage system at the end of market m, in hour h.

Other variables

$\theta_{SS}(h)$ — Binary variable which assumes the value *1* in case of storage system charging and the value *0* in case of storage system discharging, in hour h; there is no possibility that at the end of the same hour h the storage system undergoes simultaneously a *net charge* and a *net discharge* in hour h.

$\lambda_{SS}(h,m)$ — Binary variable which assumes the value *1* in case of storage system charging and the value *0* in case of storage system discharging; there is no possibility to charge and discharge the storage system within the same market session m, in hour h.

Objective function and constraints

As for model one, the aim of this model remains the maximization of an objective function representing the profit resulting from the operations carried out by the VPP on the said electricity markets. In this case, however, the form of the equation representing the single-target objective function is different:

$$\pi = \sum_{h}^{H}\sum_{m}^{M} P_{sell}(h,m) \cdot [\, E_{PV_M}(h,m) \, + \, E_{SS_M}(h,m)] \\ - \sum_{h}^{H}\sum_{m}^{M} P_{buy}(h,m) \cdot [\, E_{M_{SS}}(h,m) \, + \, E_{M_{CU}}(h,m)] \tag{5.25}$$

The overall profit is given here by the delta between two main contributions. The first contribution is given by the sum, on the hours and then on the markets, of the product between the selling price referred to each subsequent market in each given hour and the total quantity of energy respectively sold on those markets in that given hour. For the second contribution, the reasoning remains the same, but the prices and the quantities are referred to purchases made on the markets, obviously.

$$E_{PV}^{for}(h) = E_{PV\_CU}(h) + E_{PV\_SS}(h) + \sum_{m}^{M} E_{PV_M}(h,m), \quad \forall h \tag{5.26}$$

$$E_{CU}^{for}(h) = E_{PV\_CU}(h) + E_{SS\_CU}(h) + \sum_{m}^{M} E_{M_{CU}}(h,m), \quad \forall h \tag{5.27}$$

Equations 5.26 and 5.27 are the equivalent of equations 5.2 and 5.3 of model one and express respectively the balance at the PV node and at the CU node. The difference is that the energy going from the PV aggregate to the markets and the energy going from the markets to the CU aggregate, are edited directly as the sum of the quantities that, in the given hour h, go to and come from the markets.

$$E_{SS}(h) = E_{SS}(h-1) + E_{M_{SS}}(h,m) \cdot \eta - \frac{E_{SS\_M}^{DCH}(h) + E_{SS\_CU}(h)}{\eta}, \qquad \forall h \tag{5.28}$$

$$E_{SS}^{MIN} \leq E_{SS}(h) \leq E_{SS}^{MAX}, \qquad \forall h \tag{5.29}$$

$$E_{SS}(h-1) = 1, \qquad if \;\; h = 1 \tag{5.30}$$

Equation 5.28 defines the status of the storage system in each given hour. The status at the end of hour h is given by the status at the end of the previous hour plus the eventual energy charged, minus the eventual energy discharged, adjusted through the efficiency parameter. The energy contained in the battery must respect upper and lower capacity limits, as stated by the constraint 5.29. It is also specified that the energy contained in the storage system at the beginning of the first hour is equal to the minimum level of capacity (5.30).

$$E_{SS_{hm}}(h,m) = E_{SS_{hm}}(h,m-1) + E_{M_{SS}}(h,m) \cdot \eta - \frac{E_{SS_M}(h,m)}{\eta}, \qquad \forall h, \forall m \tag{5.31}$$

$$E_{SS}^{MIN} \le E_{SS_{hm}}(h,m) \le E_{SS}^{MAX}, \qquad \forall h, \forall m \tag{5.32}$$

$$E_{M_{SS}}(h,m) \cdot \eta \le E_{SS}^{CH,MAX} \cdot \lambda_{SS}(h,m), \qquad \forall h, \forall m \tag{5.33}$$

$$\frac{E_{SS_M}(h,m)}{\eta} \le E_{SS}^{DCH,MAX} \cdot [1 - \lambda_{SS}(h,m)], \qquad \forall h, \forall m \tag{5.34}$$

$$E_{SS_{hm}}(h+1,m+1) = E_{SS}(h) + E_{M_{SS}}(h+1,m+1) \cdot \eta - \frac{E_{SS_M}(h+1,m+1)}{\eta}, \qquad \forall h, \forall m \tag{5.35}$$

Equation 5.31 is fundamental because is at the basis of the arbitrage strategy. It defines the status of the storage system between consequent markets within each given hour. With the arbitrage strategy, the storage system is allowed to ideally charge and discharge multiple times within the same hour to exploit the price differentials among the various markets. Of course, the market sequence cannot be upset: energy purchased on the MI market cannot be sold on the MGP, for example. So, the equation states that the level of energy contained in the storage system at the end of a certain market session *m* must be equal to the energy contained in the storage system at the end of the previous market session *m-1*, plus an eventual charge, minus an eventual discharge.

Note that the model assumes that the energy contained in the storage system at the beginning of the first market (MGP) in hour *1*, is equal to the lower capacity bound.

Equations 5.32 defines the upper and lower capacity boundaries that must be always respected not only within each hour h, but also within each market session m within hour h. Equations 5.33 and 5.34 define that the energy charged and discharged between market sessions must respect charge and discharge limits. Also, it can be noticed that charge and discharge cannot verify simultaneously.

Finally, equation 5.35 serves to properly link the status of the storage system at the end of the last market session (MB) of a given hour h, with the beginning of the first market session (MGP) of the subsequent hour h+1.

$$E_{SS_M}^{CH}(h) = \sum_{m}^{M} E_{M_{SS}}(h,m), \quad \forall h \tag{5.36}$$

$$E_{PV\_SS}(h) \cdot \eta \le E_{SS}^{CH,MAX} \cdot \theta_{SS}(h), \quad \forall h \tag{5.37}$$

$$\left[E_{SS_M}^{CH}(h) + E_{PV\_SS}(h)\right] \cdot \eta - \frac{E_{SS_M}^{DCH}(h)}{\eta} \le E_{SS}^{CH,MAX} \cdot \theta_{SS}(h), \quad \forall h \tag{5.38}$$

$$E_{SS_M}^{DCH}(h) = \sum_{m}^{M} E_{SS_M}(h,m), \quad \forall h \tag{5.39}$$

$$\frac{E_{SS\_CU}(h)}{\eta} \le E_{SS}^{DCH,MAX} \cdot [1 - \theta_{SS}(h)], \quad \forall h \tag{5.40}$$

$$\frac{\left[E_{SS_M}^{DCH}(h) + E_{SS\_CU}(h)\right]}{\eta} - E_{SS_M}^{CH}(h) \cdot \eta \le E_{SS}^{DCH,MAX} \cdot [1 - \theta_{SS}(h)], \quad \forall h \tag{5.41}$$

The set of equations from 5.36 to 5.41 defines the boundaries for the charge and the discharge of the storage system. These boundaries had to be modified with respect to the set of equations expressing the same concepts in model one in order to make the arbitrage strategy work as expected.

The expressions used to define that the storage system cannot end up being *net charged* and *net discharged* at the same time within a single hour *h*, are necessarily different and more complicated with respect to the equivalent expressions used to define the same concepts in the previous model.

The absence of the energy balance equation for the overall VPP is due to its proved superfluity with respect to the correct operation of the model and was thus omitted to relieve the model from some useless equation, following a reasoning that brought to exclude from this model every element or expression that was not explicitly functional.

5.4.4. Demonstration of the functioning of the models

It is here proposed a brief practical example to show how the models reason and pursue the goal declared through the objective function, which is the maximization of the market profit.
In particular, the example refers to the most complex and interesting of the two models, i.e. the one that deploys the storage system according to an arbitrage strategy.

Let's suppose to have a *day* which is composed by three hours only and let's suppose to have the expected photovoltaic energetic prooduction, the forecasted hourly market prices and the storage system features represented in the table below (note that the numbers used are fictitious and serve just to illustrative purposes). The energetic consumption of the aggregate was fixed to zero in each of the three hours for simplicity.

TABLE 5.3. *Demonstrative input data*

		HOUR 1	HOUR 2	HOUR 3
PV production	KWh	100	100	50
CU consumption	kWh	0	0	0
MGP	€/kWh	60	10	50
MI	€/kWh	50	70	40

MSD upward (sell)	€/kWh	15	10	30
MB upward (sell)	€/kWh	10	10	20
MSD downward (buy)	€/kWh	70	75	60
MB downward (buy)	€/kWh	80	5	80
		Max	**Min**	**Efficiency**
SS	kWh	285	60	95%

Let's now analyse the behaviour of the model (VPP) hour by hour. In the following tables are displayed the transactions happened in each hour in chronological market order (from the MGP to the MB). To ascertain that the model is behaving correctly we should:

- Not observe both charge and discharge operations executed in the same market session.

- Not observe charge operations if the capacity of the storage system is complete saturated; and not observe discharge operations if the storage system is at minimum capacity.

- Not observe selling operations involving a higher amount of energy that it is truly available at the moment of executing the transaction.
- Observe sales happening on the most profitable markets and purchases happening on the cheapest markets.

- Expect that the last discharge operation (in hour 3) reduces the capacity of the storage system at its minimum threshold, since there would be no reason to keep energy unsold *at stock*.

TABLE 5.4. *Demonstrative results of hour 1*

		Energy exchanged	Market of destination/origin
HOUR 1	PV send-out	100 kWh	To MGP
	CU load	-	-
	SS charge	11,842 kWh	From MI
	SS discharge	-	-
	SS final level	71,25 kWh	= 60 + 11,842*0,95

In the first hour, it is possible to notice that just two transactions happened: in the first one, the whole amount of energy produced by the PV has been sold on the most profitable market, the MGP; in the second one, the SS has charged a limited amount of energy purchasing it from the MI, the cheapest one.

The total level of energy present in the storage system at the end of the hour is to be computed taking into account that the efficiency in charging and discharging the SS is lower than 100%: so, for each amount of energy bought on the markets, it is to be considered that only the 95% will truly get to the replenish the storage facility and that, for each amount of energy sold to the markets, a higher amount of energy gets truly discharged from the storages.

In *hour 2* we see that there are two recharges operated by the SS: the first purchase happens on the MGP (the second cheapest market and the first cheap option to buy energy) and goes to completely fill up the capacity available in the storage facility; the second purchase happens instead on the MB (the cheapest market) through the execution of a downward service.

TABLE 5.5. *Demonstrative results of hour 2*

		Energy exchanged	Market of destination/origin
HOUR 2	SS charge 1	225 kWh	From MGP
	CU load	-	-
	PV send-out	100 kWh	To MI

	SS discharge	213,75 kWh	To MI
	SS charge 2	225 kWh	From MB
	SS final level	273,75 kWh	= 71,25 + 225*0,95 - 213,75/0,95 + 225*0,95

In between, the energy produced by the PV is sold on the MI (the most remunerative option) together with the energy charged within the storage system during the MGP session.
This is a perfect example of arbitrage strategy deployment. At the end of the hour, moreover, the net energy flow concerning the SS resulting from all the transactions is related to the provision of the downward service on the MB. This means that the operations made on the MGP and the MI could be ideally fictitious under a physical point of view. The implications of this observation will be better explained during the commentary of the results, at the end of the chapter.

In the third hour, the model opts to sell all the energy available on the MGP, which is rightly the most remunerative solution. The charge executed through the provision of the downward service on the MB during the previous hour, was again part of an arbitrage strategy aiming at selling that energy in a second, more economically advantageous, moment.
During the execution of the simulation all constraints have been respected and that the algorithm behaved exactly as expected. It can be also noticed that the final transaction performed by the SS is a discharge (to be considered a real energy flow) leaving the capacity at its minimum threshold.

TABLE 5.6. *Demonstrative results of hour 3*

		Energy exchanged	Market of destination/origin
HOUR 3	PV send-out	50 kWh	To MGP
	CU load	-	-
	SS charge	-	-
	SS discharge	203,062 kWh	To MGP

	SS final level	60 kWh	= 273,75 – 203,062/0,95

What clearly stands out from this exhibition is that the opportunity that the aggregation allows to exploit here, is that of making small-scale units capable of accessing more remunerative markets with respect to the past, and to provide them with a structure which is able to make them respect obligations (with respect to TSO services provision) and a strategy which allows them to fully capture the value of the price differential which gets formed day by day among the various markets.

5.5 INPUT DATA FOR THE MODELS

The key input variables of the models are regard the expected prices on the different markets, the expected PV production, the expected demand of the consumption units (in case of UVAM) and the parameters expressing the characteristics of the energy storage system, when present (charge and capacity limits, efficiency).

5.5.1. Definition of the production profile

Input data concerning the aggregated production profile of the set of PV plants, for the average day of each month of the year, was shaped basing on the following formula:

$$E = S * ME * (1 - SOL) * GI * 1h \qquad (5.42)$$

Prior to give an explanation about the parameters considered, it must be notified that it was assumed that all the small PV plants involved in the creation of the VPPs shared the same technological features described in the below. Basically, all the PV plants are based on the same mono-crystalline silicon technology – notably the most widespread, reliable and efficient in the field of photovoltaic panels, so far.
Note also that the indications and the numbers concerning technical PV parameters derive from real data gently provided by some distributors operating in the Italian market (V-Energy, Q-Cells, Sonepar, Tecnospot, AS Solar, Solar Frontier).

The formula states that the photovoltaic energy (E) produced by the PV aggregate in a single hour is given by the multiplication of the following series of parameters:

- *S:* it is the total *surface* occupied by the modules of all the PV plants. It was calculated considering that a single module occupies about 1.7 square meters and that each module has a peak power of 300 W. This means that, having to cover the equivalent of a 7 MW PV plant, the number of modules needed would be approximately 23.333 and that the total surface would be equal to about 39.667 square meters.

- *ME:* it is the *modules' efficiency*. The number officially used in the formula was 0.18, that was established taking into account the characteristic of the technology chosen.

- *GI:* it is the global irradiance, a parameter expressed in Watts over square meters that measures the power per unit of area received by the PV modules from the sunlight. These data were gathered with the use of a free online software sponsored by the European Commission called Photovoltaic Geographical Information System (*PVGIS*) [69]. Among the functions offered by the software there is one called *daily data* that allows the user to dispose of a 24-hour schedule showing the average historical values of global irradiance recorded for a given month, in a given location among the ones covered by the databases available.
  Multiplying the global irradiance for the time unit of 1 hour is a simple way to obtain a proper estimate of the global irradiation – which gives the same measure in terms of energy rather than power. The figure obtained can be then adjusted accordingly to the desired unit of measure, kWh or MWh.
  In the specific, global irradiance data come from the database *PVGIS-CMSAF* and the specific geographical location to which they are referred to is the countryside of the province of Pavia, as it was established in the setting phase of the case study. Namely, the coordinates used on the online software lead to the surroundings of the municipality of *Carbonara al Ticino*.

- *SOL:* it is a parameter that accounts for *system and other losses*. It was defined using default data provided again by the *PVGIS* software and comprehends a figure of 0.14 for what concerns *system losses* (naturally caused by physic imperfections) and a figure of 0.02 for what concerns instead the so-called *other losses* (shading, reflections and other similar phenomena), for a total loss figure of 0.16.

The graphs below report, for the average day of each month of the year, the level of global irradiance and the quantity of energy that can be produced by the 7 MW PV aggregate. The final total annual production capacity computed aggregating the production data has been of 9818 MWh.

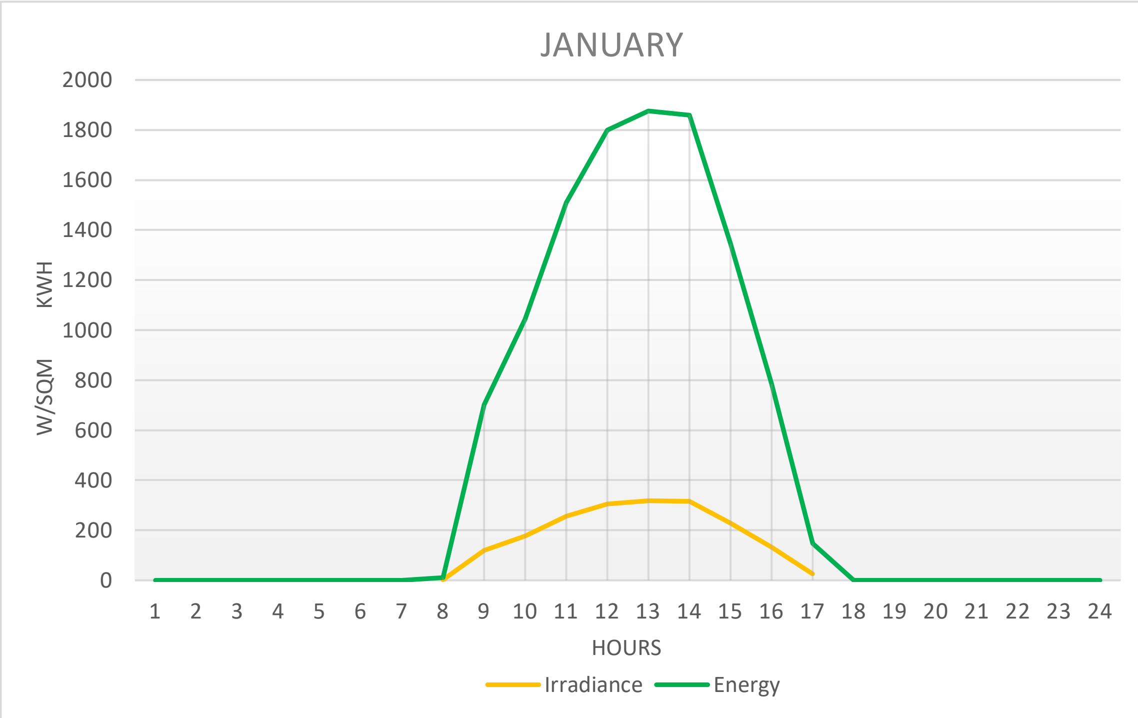


FIGURE 5.8. *Global irradiance and energy produced in a typical day of January*

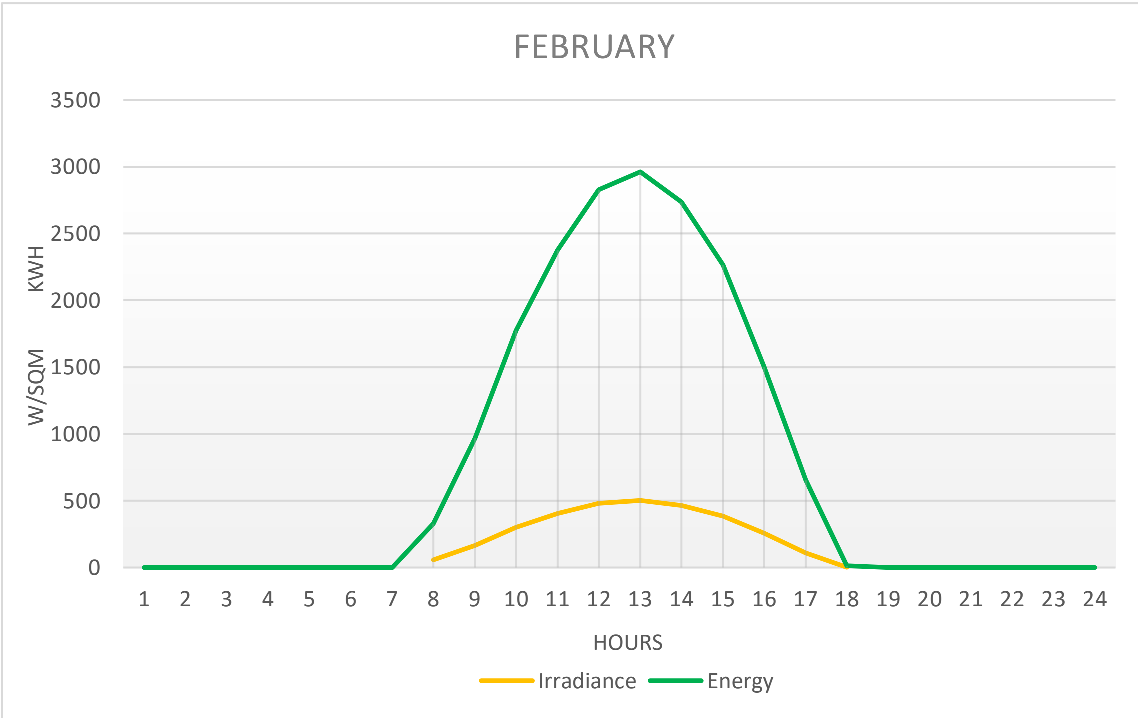


FIGURE 5.9. *Global irradiance and energy produced in a typical day of February*

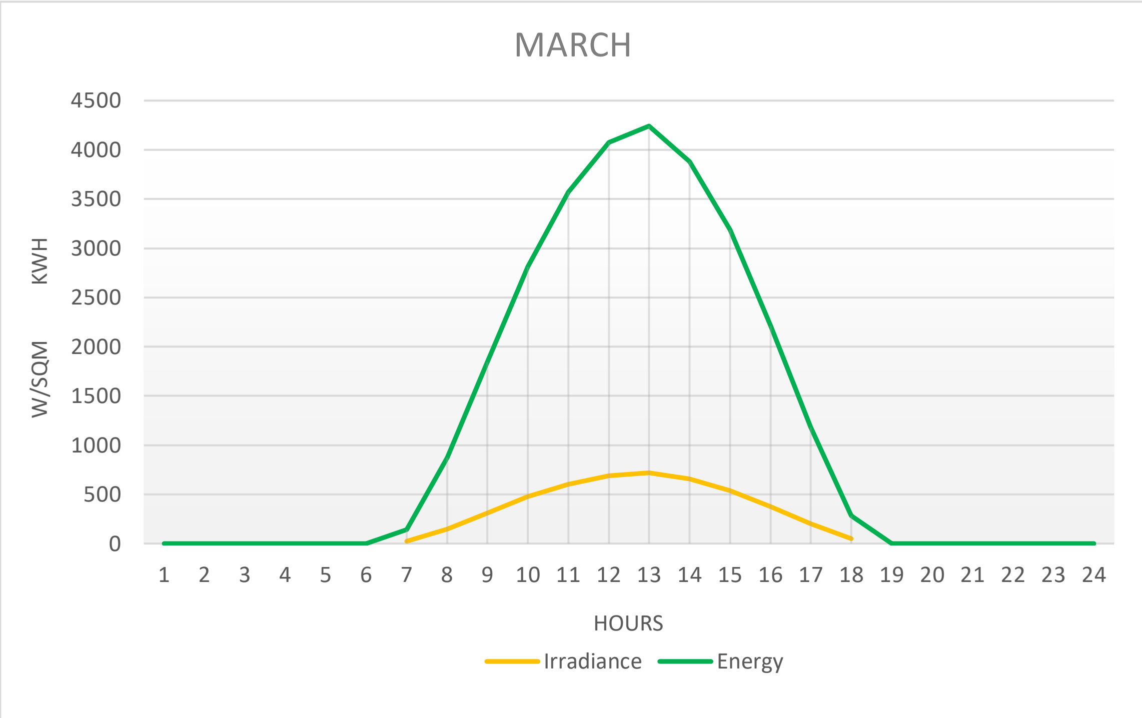


FIGURE 5.10. *Global irradiance and energy produced in a typical day of March*

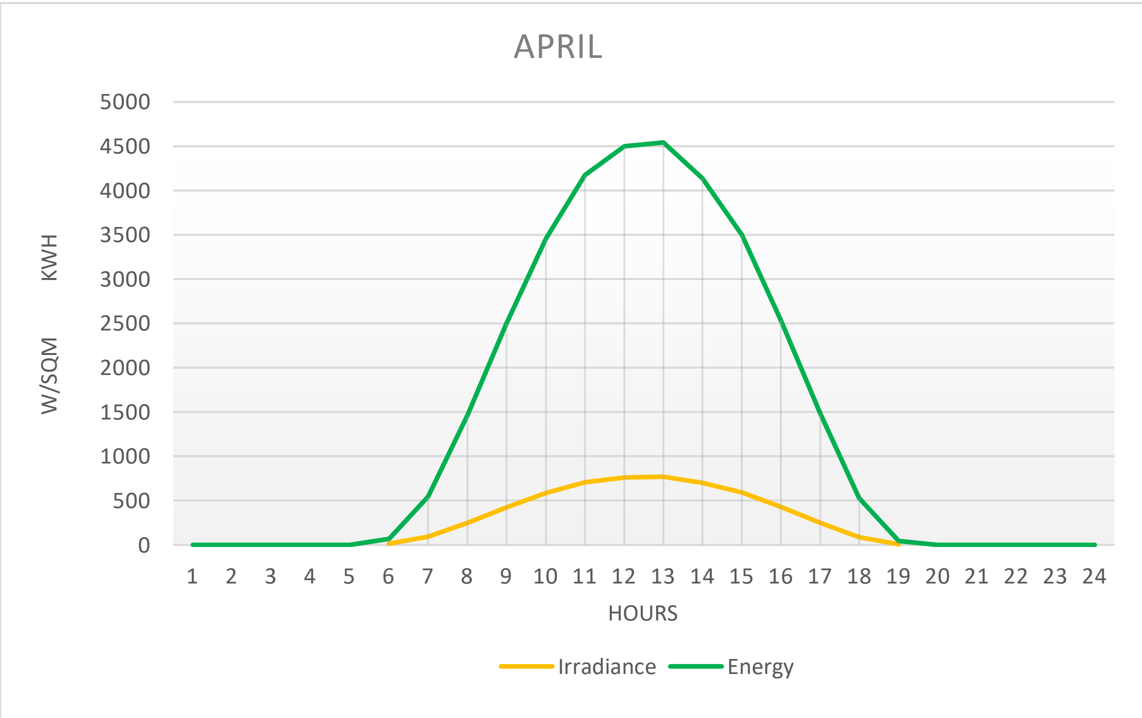


FIGURE 5.11. *Global irradiance and energy produced in a typical day of April*

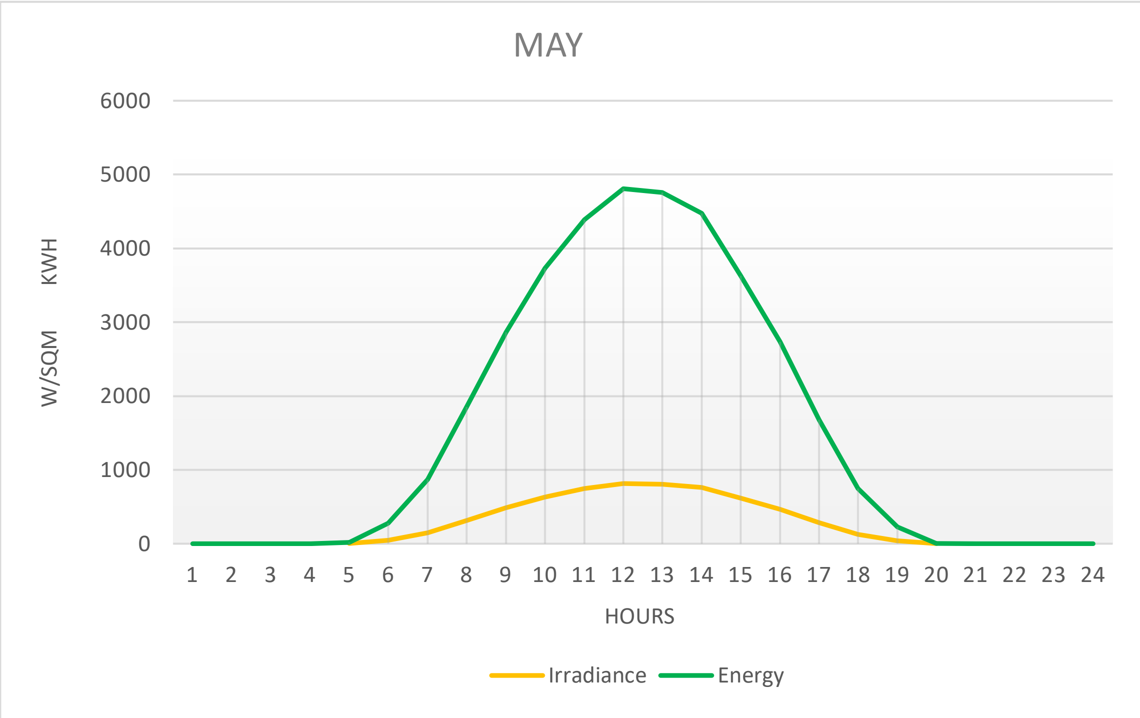


FIGURE 5.12. *Global irradiance and energy produced in a typical day of May*

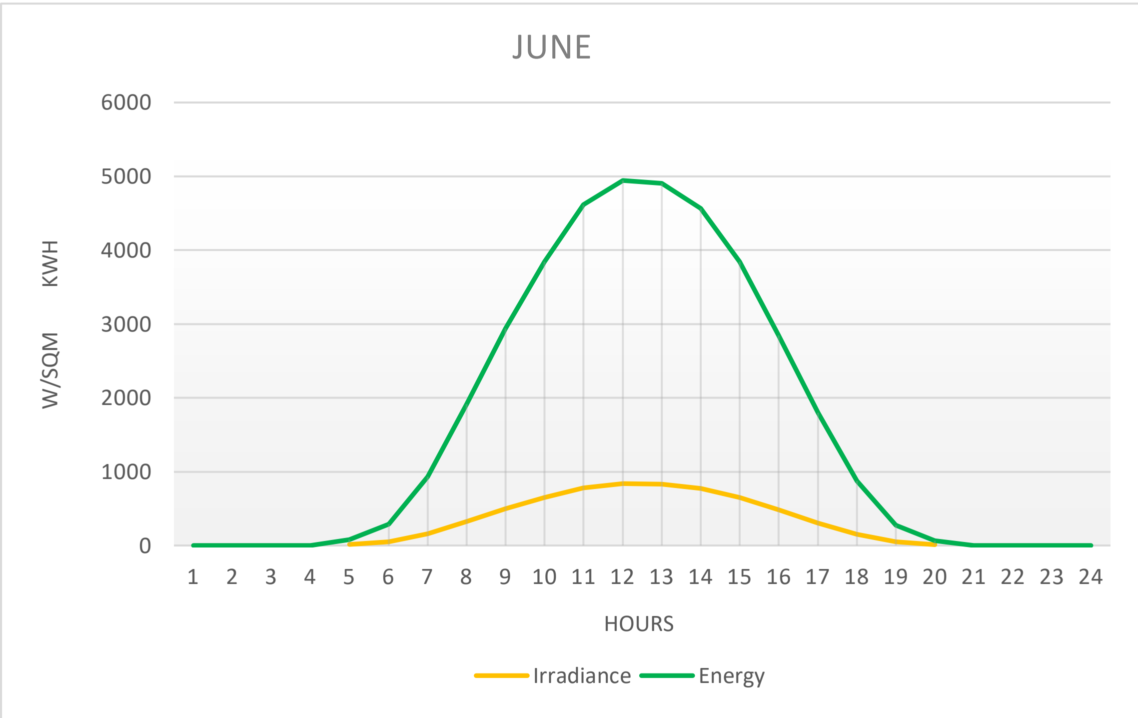


FIGURE 5.13. *Global irradiance and energy produced in a typical day of June*

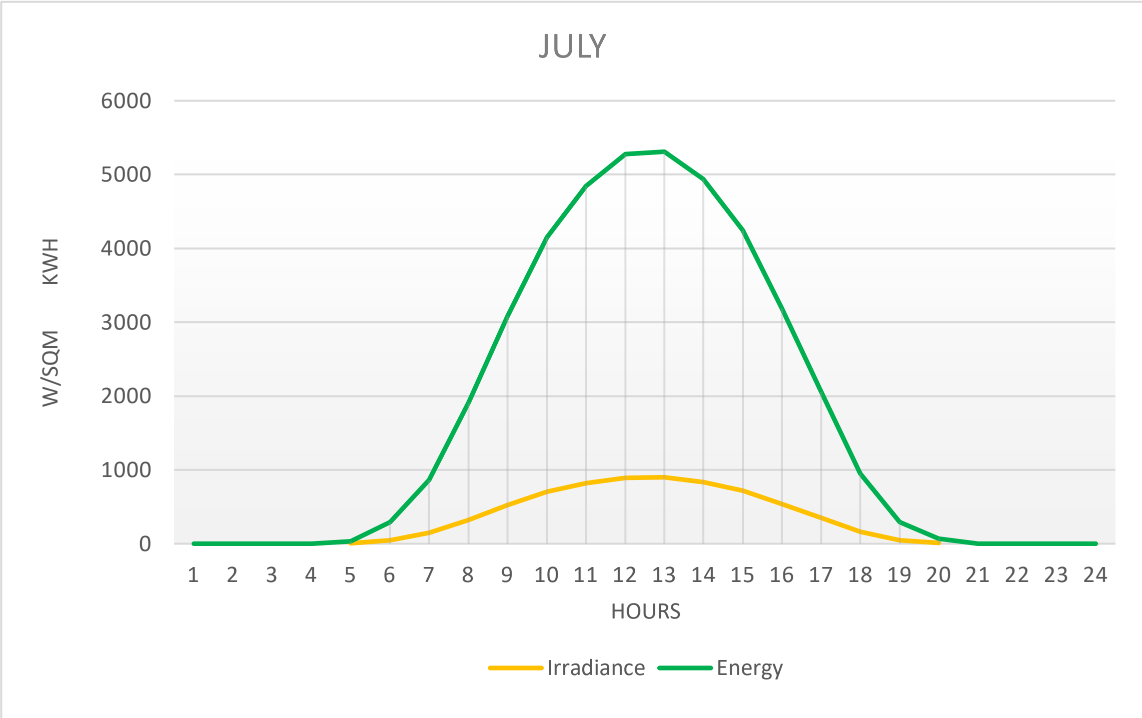


FIGURE 5.14. *Global irradiance and energy produced in a typical day of July*

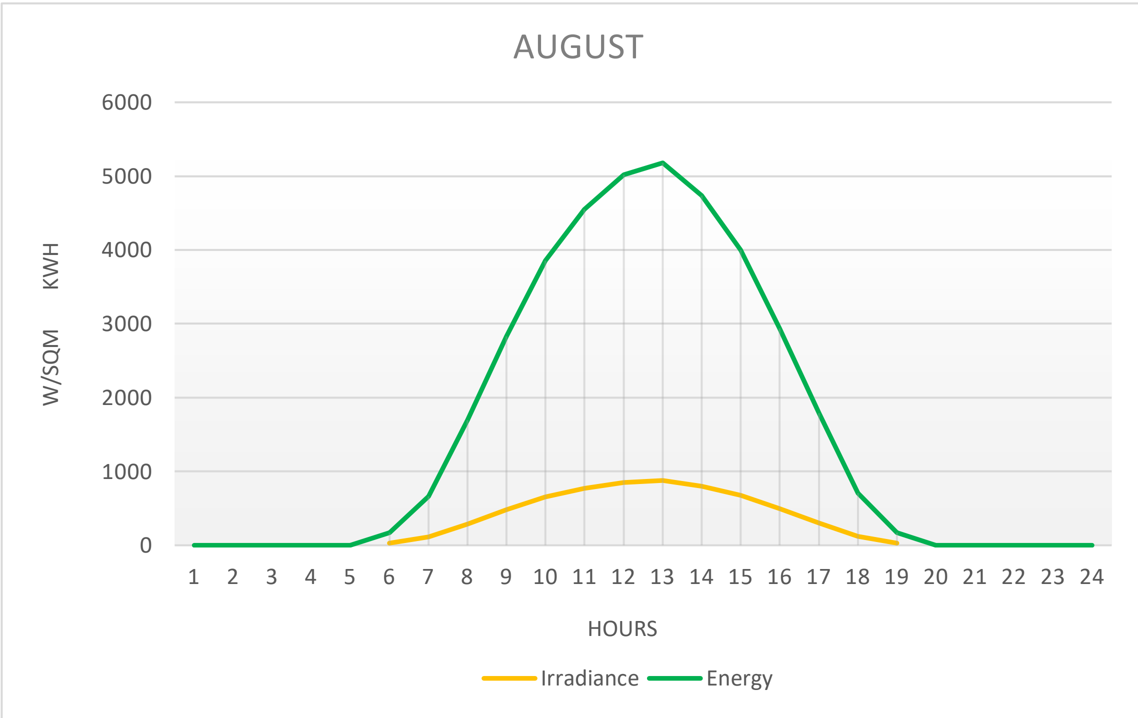


FIGURE 5.15. *Global irradiance and energy produced in a typical day of August*

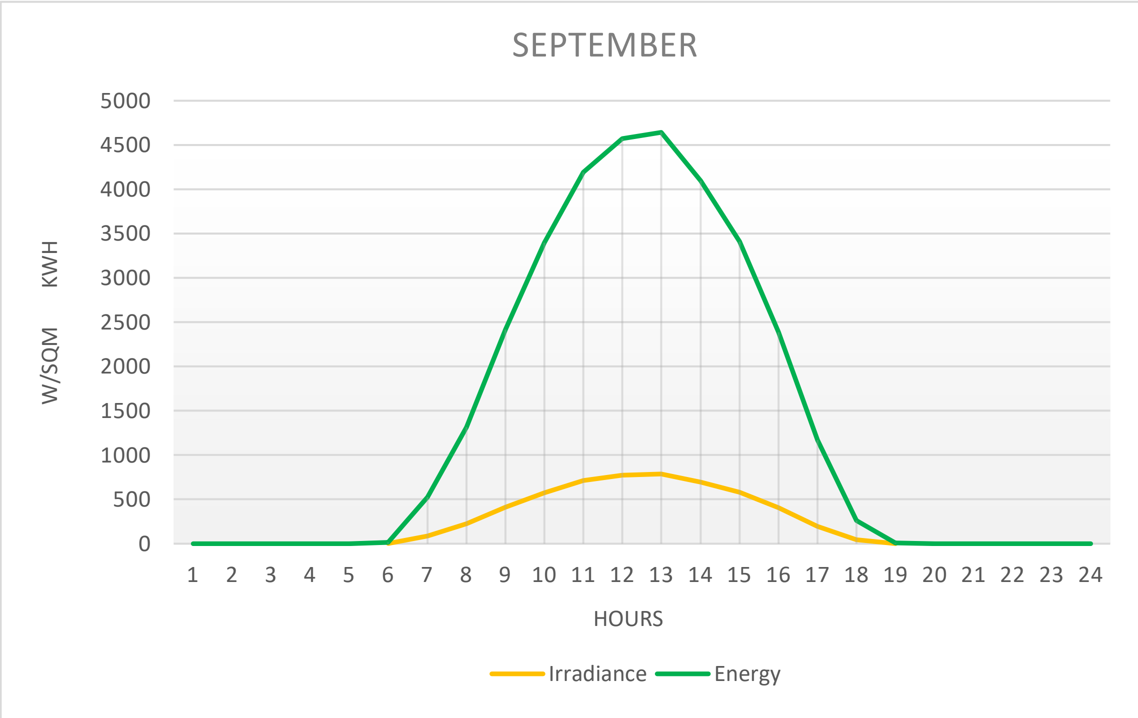


FIGURE 5.16. *Global irradiance and energy produced in a typical day of September*

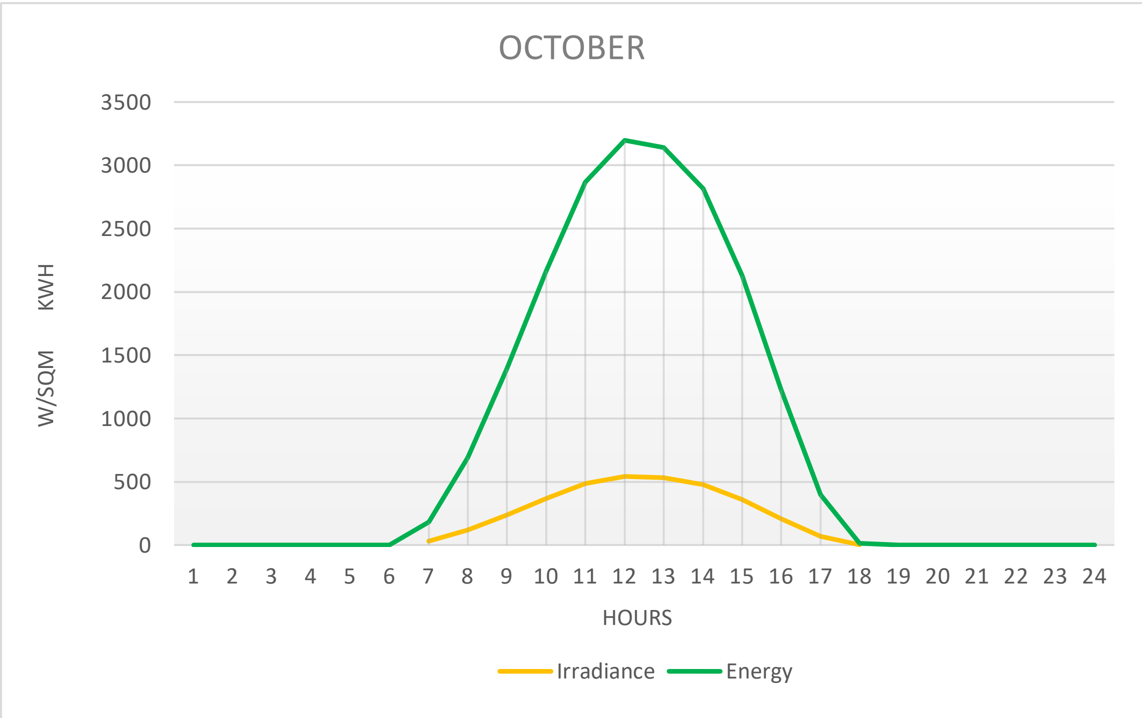


FIGURE 5.17. *Global irradiance and energy produced in a typical day of October*

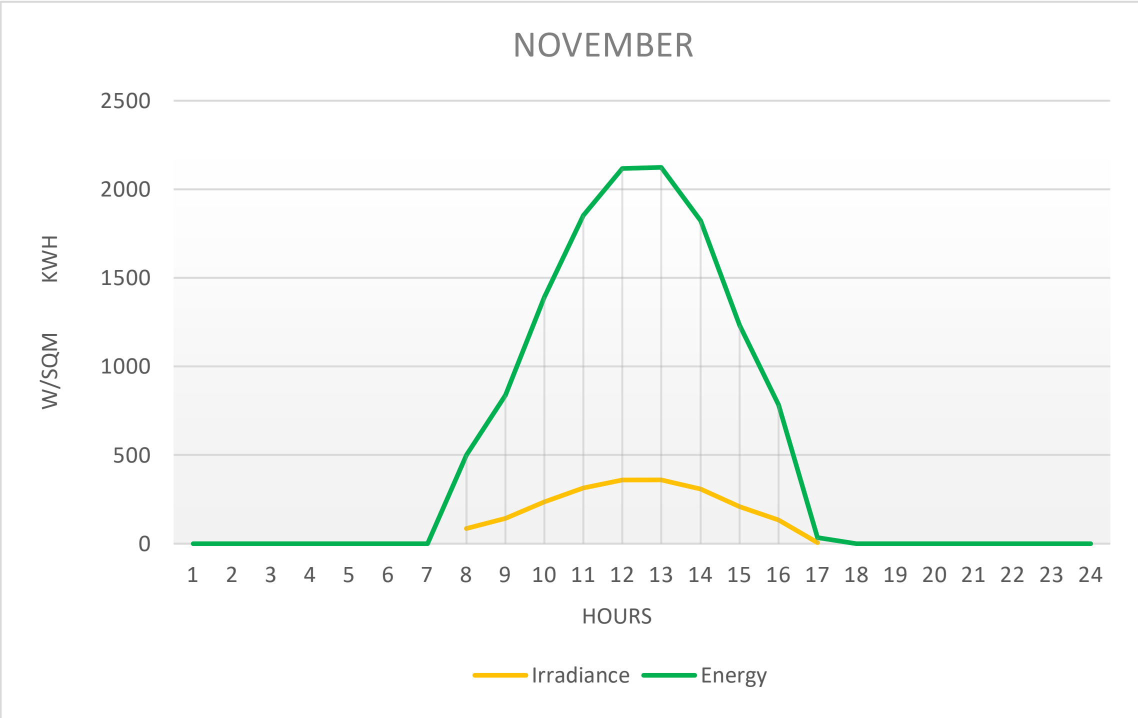


FIGURE 5.18. *Global irradiance and energy produced in a typical day of November*

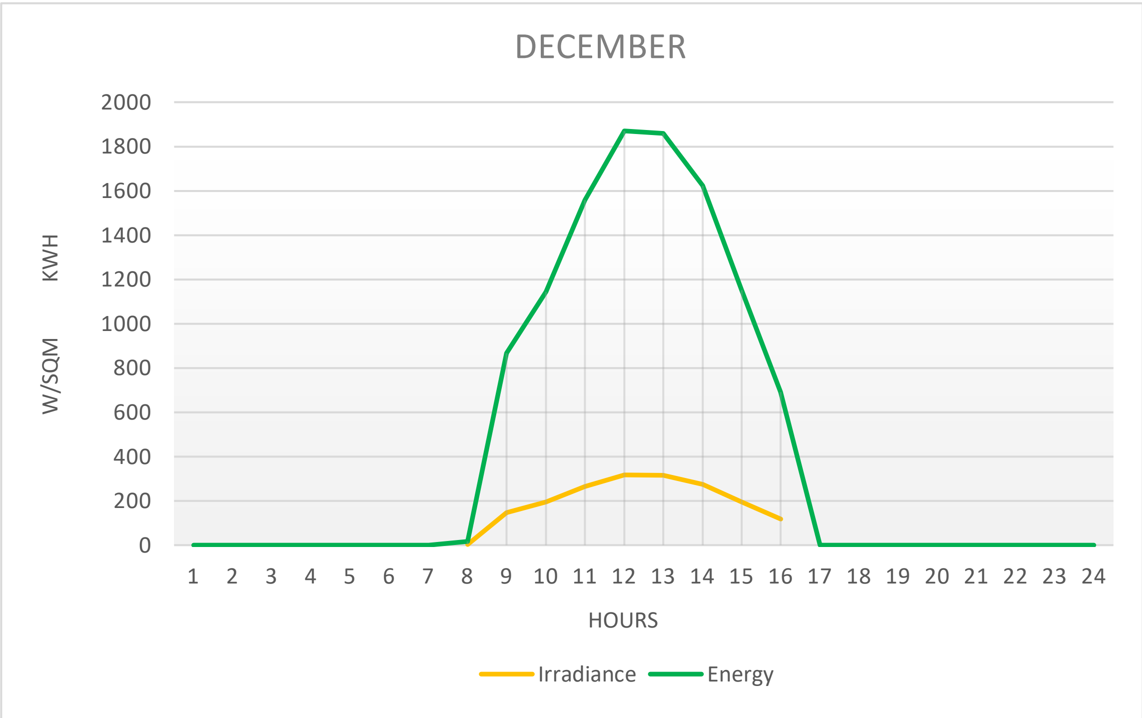


FIGURE 5.19. *Global irradiance and energy produced in a typical day of December*

5.5.2. Definition of the consumption profile

Input data concerning the aggregated consumption profile of the consumption units was shaped basing on data provided by REF-E and other data coming from [70]. Since the idea was to shape the average consumption profile of an aggregate of Italian households of the typical day of each month of the year, data have been organized in this way: it was first shaped a general consumption profile referred to the average weekday and holiday of the different seasons – summer, winter and mid-season; then it was computed the consumption of the average day of each month by considering: the average number of weekdays and holidays which are present in the given month, the positioning of the given month during the year in terms of season (some months are positioned in between two consecutive seasons); the eventual periods of vacation due to well-known festivities. The kind of residential application targeted, although being a basic household configuration – i.e. 3 kW of power, as it was already specified – is not to be precisely associated with the idea of standard Italian family as far as it is concerned by the Authority [71]. As a matter of fact, the global consumption level considered is higher due to the involvement of a non-standard electrical equipment during the hot season (air conditioning).

This is highlighted in the figures from 5.20 to 5.22, which are related to average seasonal consumptions: during winter and the mid-season, the consumption is given by standard electrical appliances and light, but during summer, the evident higher consumption is properly due to the usage of air-conditioning, which is not considered in the standardisations made by the Authority.

The figures coming next report instead the results concerning the average consumption of the typical day of each month, given all the specifications made above.

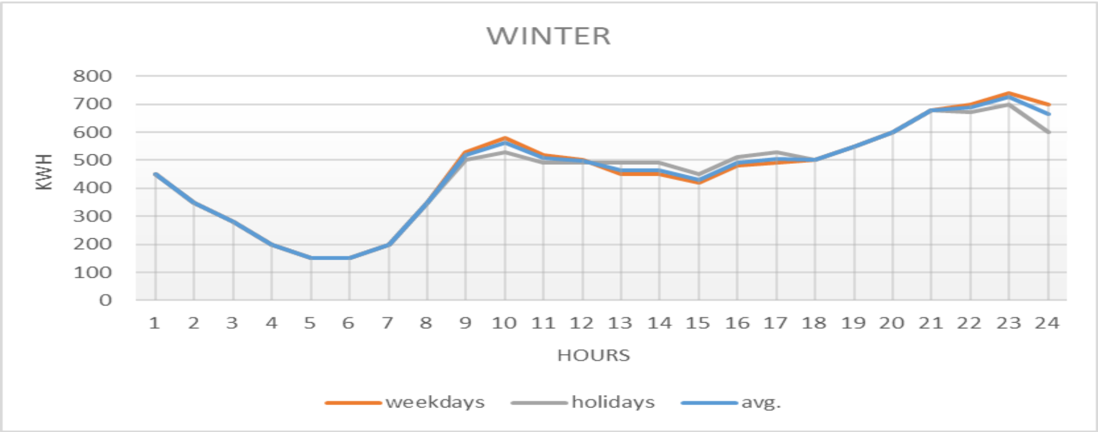


FIGURE 5.20. *Energy consumption during a typical winter day*

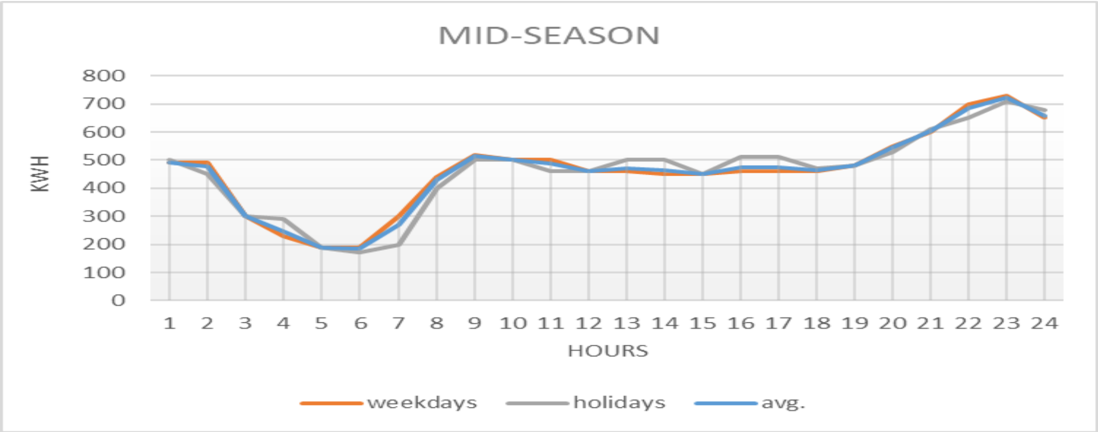


FIGURE 5.21. *Energy consumption during a typical mid-season day*

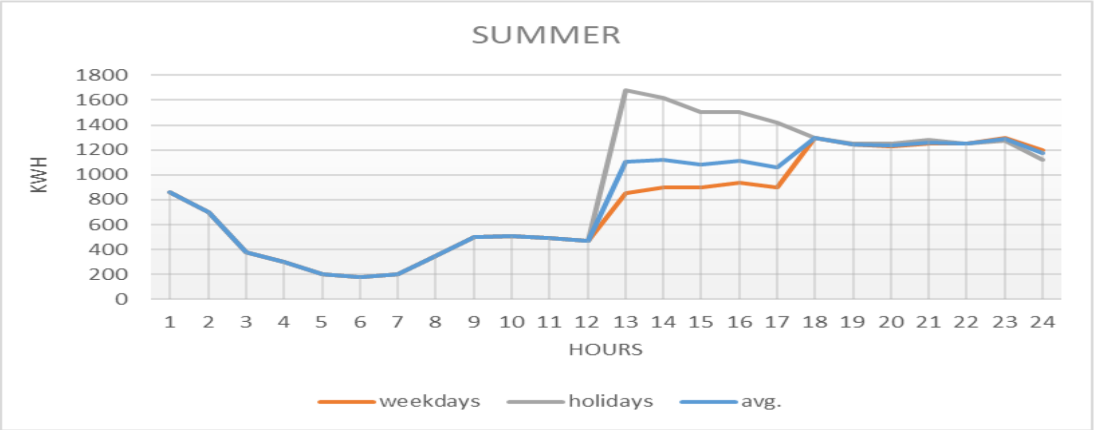


FIGURE 5.22. *Energy consumption during a typical summer day*

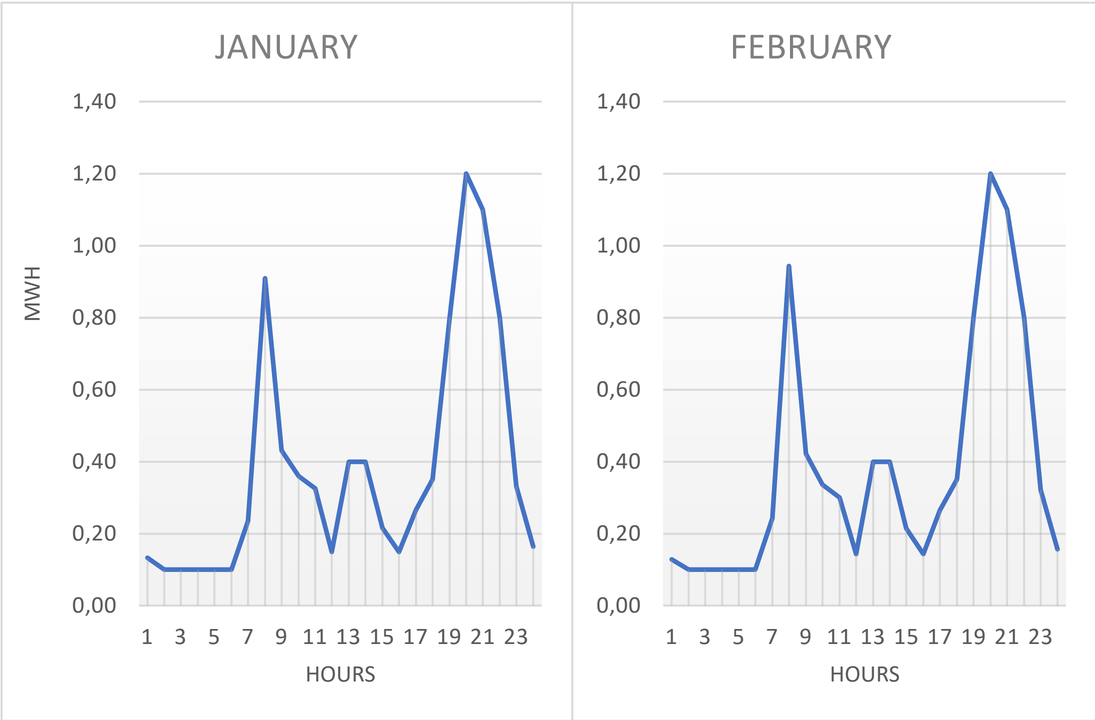


FIGURE 5.23. *Energy consumption in a typical day of January and February*

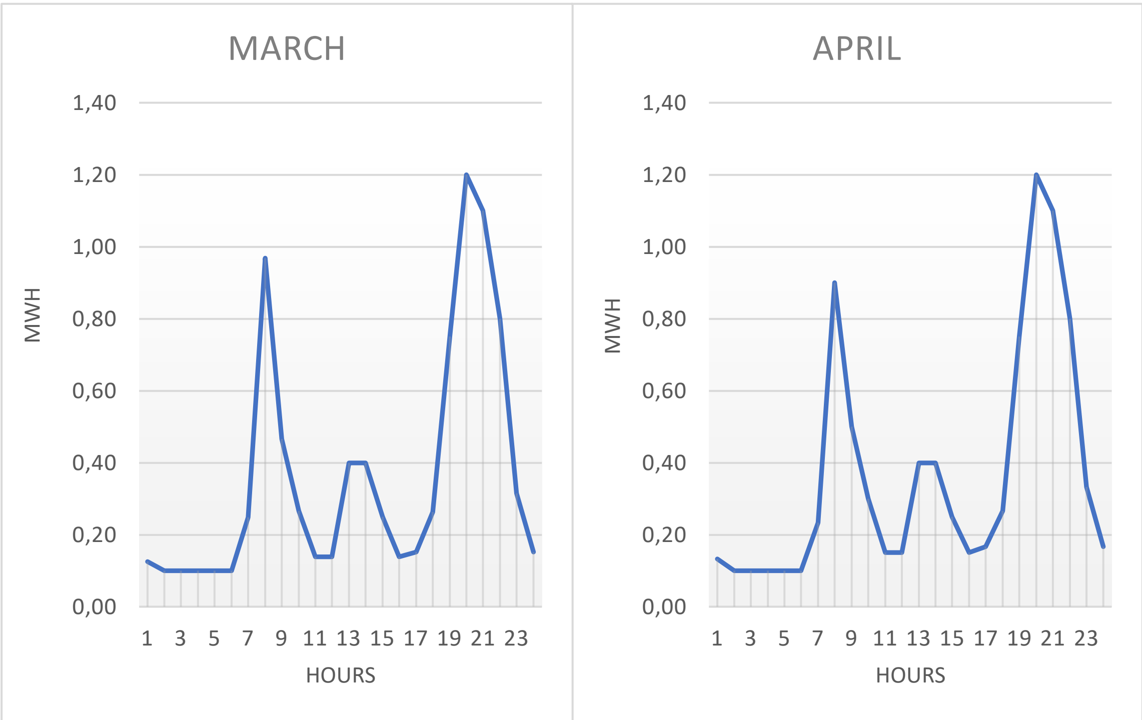


FIGURE 5.24. *Energy consumption in a typical day of March and April*

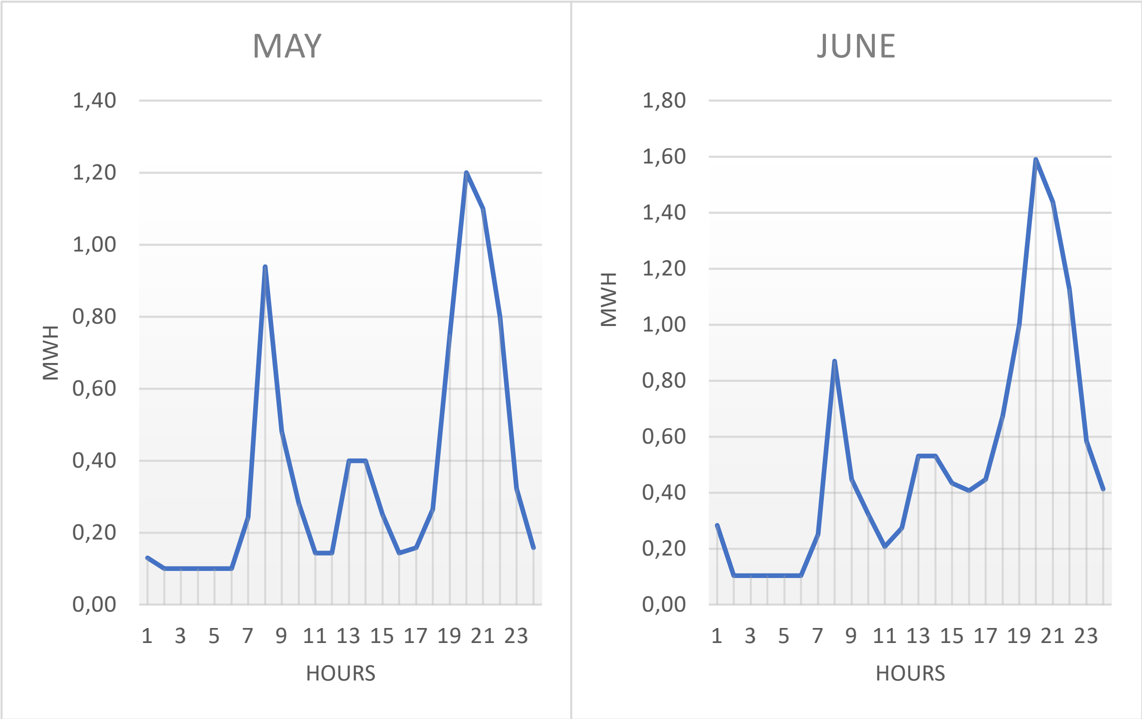


FIGURE 5.25. *Energy consumption in a typical day of May and June*

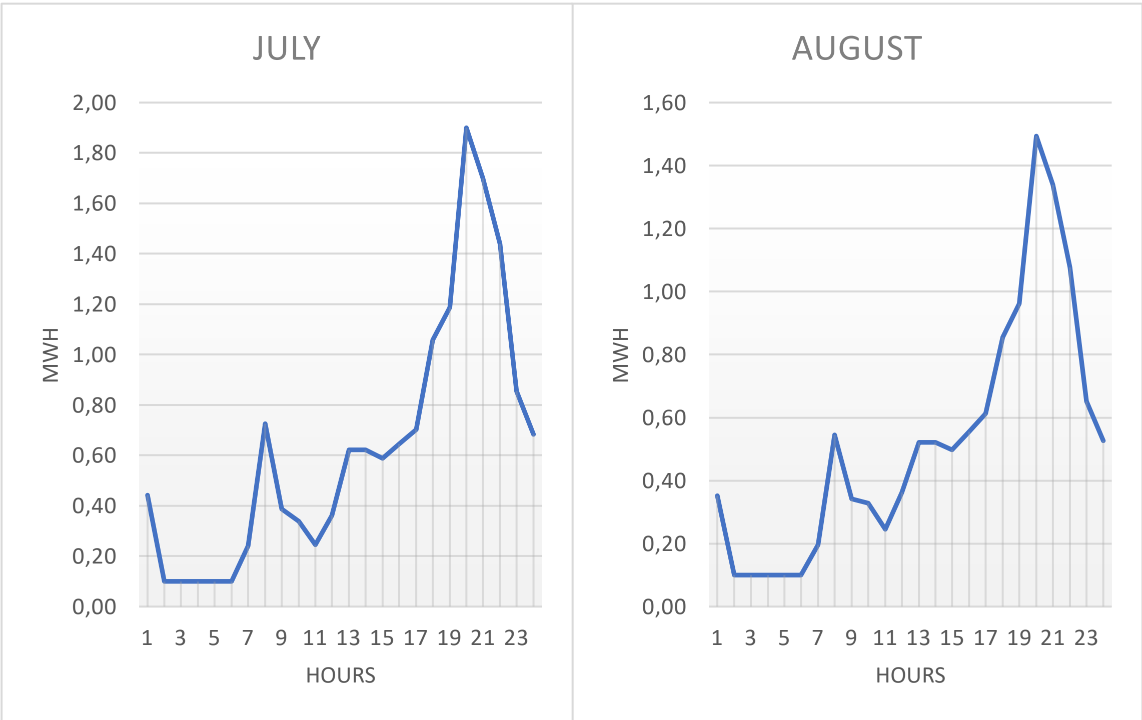


FIGURE 5.26. *Energy consumption in a typical day of July and August*

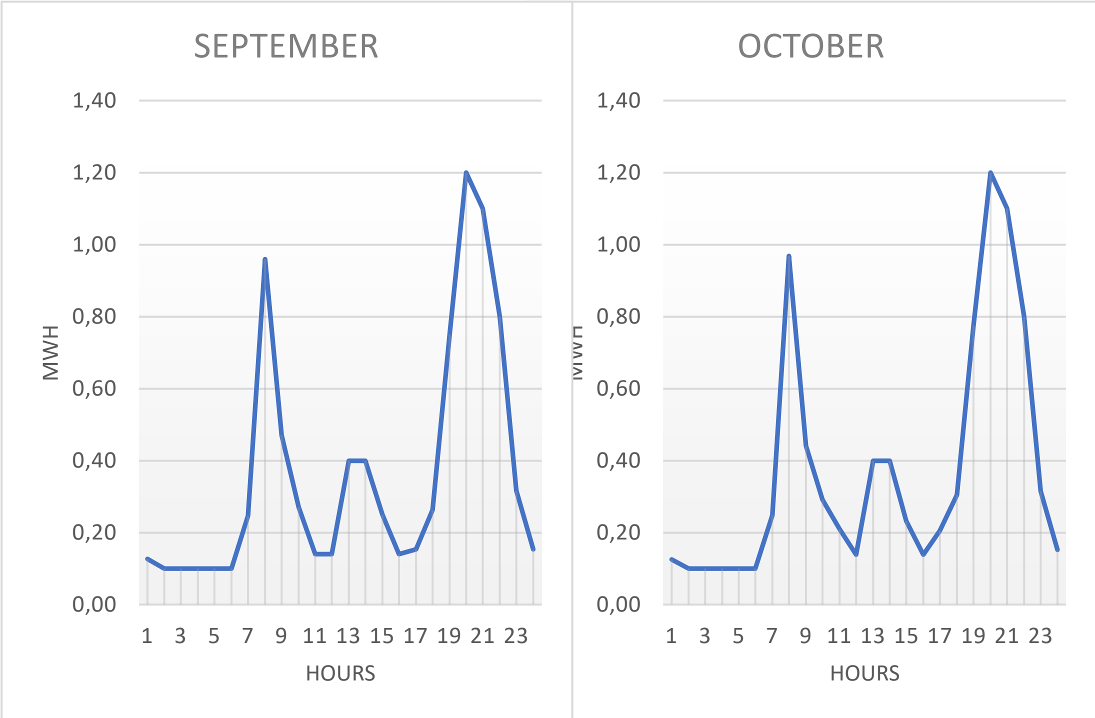


FIGURE 5.27. *Energy consumption in a typical day of September and October*

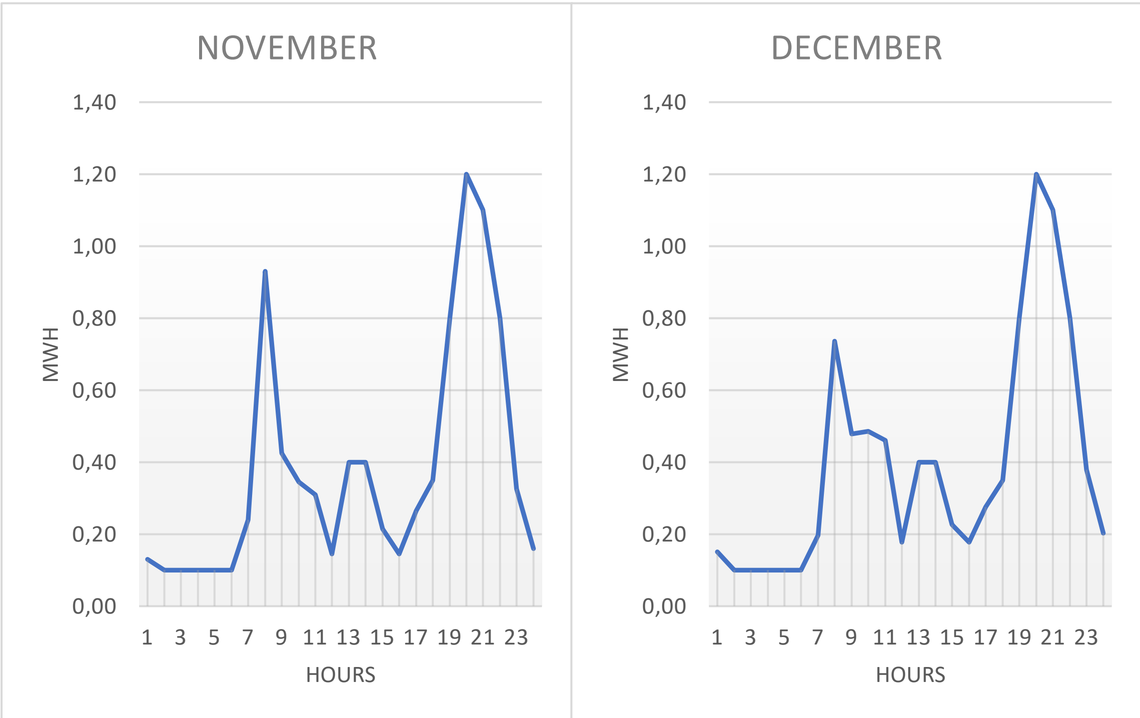


FIGURE 5.28. *Energy consumption in a typical day of November and December*

To know the consumption of the aggregated consumption unit (CU) it is sufficient to multiply these results for the desired number of families composing the consumption aggregate. If, for example, it is to be reached a total power of 3 MW, considering that each unit accounts for 3 kW, there would be needing to aggregate 1.000 families – the estimated total consumption would be in the order of 3600 kWh per annum.

5.5.3. Energy storage system

Among the various typologies of energy storage system that could serve the purpose, it was decided to entrust to a battery energy storage system (BESS) and more specifically to the well-known Li-ion technology.
This choice is motivated by the high adaptability of this kind of system in both energy and power applications and also by its advanced level of development in all market segments in comparison to other technologies.
Each scenario considered presents the very same BESS technical features. The referential characteristics of the BESS have been identified with the help of Ref-e and are here resumed:

- Energy-to-power ratio equal to 1, meaning that there is a perfect proportion between the nominal power and the nominal energy capacity. It may resemble an uncommon situation since generally the ratio is lower than one, but it is not impossible.

- Depth of discharge (DoD) equal to 80%, meaning that the minimum level of energy that must be always contained in the batteries to avoid damages is equal to 20% of the nominal capacity.

- Full charge limit equal to 95% of the nominal capacity to avoid overheating troubles.

- Charge/discharge efficiency equal to 95%.

- Useful life equal to 5.000 charge/discharge cycles. The formula used to account for how many cycles per year the batteries are subject to while in operations is the following:

$$\frac{Cycles}{Year} = \frac{tot.Energy\ Charged + tot.Energy\ Discharged}{Nominal\ Power * 2} \tag{5.43}$$

In the formula, data concerning the total energy charged and discharged by the batteries come from the simulations done with the optimization model.

Translating the useful life of the BESS in terms of years requires to make a distinction: since the amount of cycles completed is defined according to the physical flows of energy entering and exiting the batteries, there is a strong difference in the life-span of a group of batteries operated through the arbitrage strategy and a group which is not.
Taking a careful look at the output resulting from the simulations of the various cases, it was in fact recognised that, in case of arbitrage strategy, the greater part of the energy flows related to the BESS were *apparent* and not *physical*. If no strategy is applied then each energy flow involving the BESS is to be considered *real*.
So, the lower the *real* energy flows – those determining the effective level of energy contained in the batteries at the end of each hour – to be accounted to assess the number of cycles, the longer the useful life of the BESS.
In practical terms, the arbitrage strategy allows to better exploit the qualities of such technology, under both an economic and an operational point of view.

5.5.4. Prices

The prices that have been considered in the simulations have been gently provided by Ref-e and are the result of their forecasting model *ELFO++*. They come from the results of the *2030PACKAGE* scenario which was described in chapter 1. Note that even though the prices used during simulations refer to 2017, since they represent a product with a precious market value for the company, they will be only displayed in

a qualitative way with the help of some graphs due to understandable confidentiality matters.
Each of them will compare the trends of the prices considered for each market in the same context used during the simulations. Note that the graphs divide among *selling* and *purchasing* prices – while on the MGP and the MI the zonal price is considered for both sales and purchases, on the MSD and the MB it is needed to differentiate among upward and downward prices, which are usually very different since they refer to two different kinds of service.
It was already specified, but it is worth to remind it, that it was chosen to make the VPPs behave as price-taker agents on the MGP and the MI markets, while it was chosen to make them follow a more competitive strategy on the MSD and the MB markets.
In this way, given the strong characterization of the strategy followed on the latter markets, the acceptance of the offerings presented could be considered practically sure. So, the prices used in the simulations had not to be adjusted by mean of parameters expressing the probability of acceptance, because it was already taken into account.
Moreover, it is to be specified that the prices used for the MGP and the MI markets are zonal prices and refer to the market zone where the VPPs ideally belong (North zone). The prices considered for the MSD and the MB contain a *zonal characterization* as well.
Reasoning in terms of zonal prices got things easier because: it was possible to avoid considering the so-called *non-arbitraging coefficients* to be applied to the eventual differential between the PUN and the zonal price for offerings accepted on the MI [72]; it is not clear yet how the energy withdrawn from the markets by UVAs which are not namely pure consumption aggregates (UVAC) will be valorised at PUN or at zonal prices, so it was decided to opt for the second possibility for a matter of simplicity (also in the aftermath of the reason expressed in the lines right above).

In the graphs below, it is shown the trend of the prices in the typical day of each month, for each market. Even though the values are not explicitly shown on the vertical axis, prices are expressed in €/MWh.

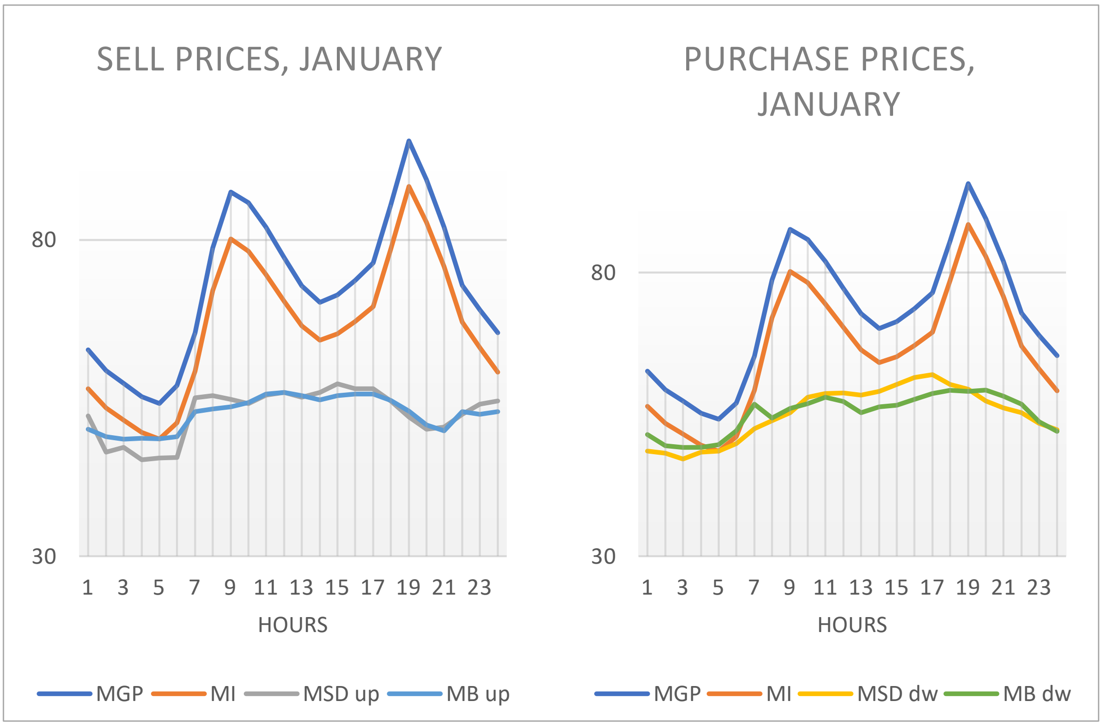


FIGURE 5.29. *Trend of selling and purchase prices, typical day of January, elaboration by REF-E*

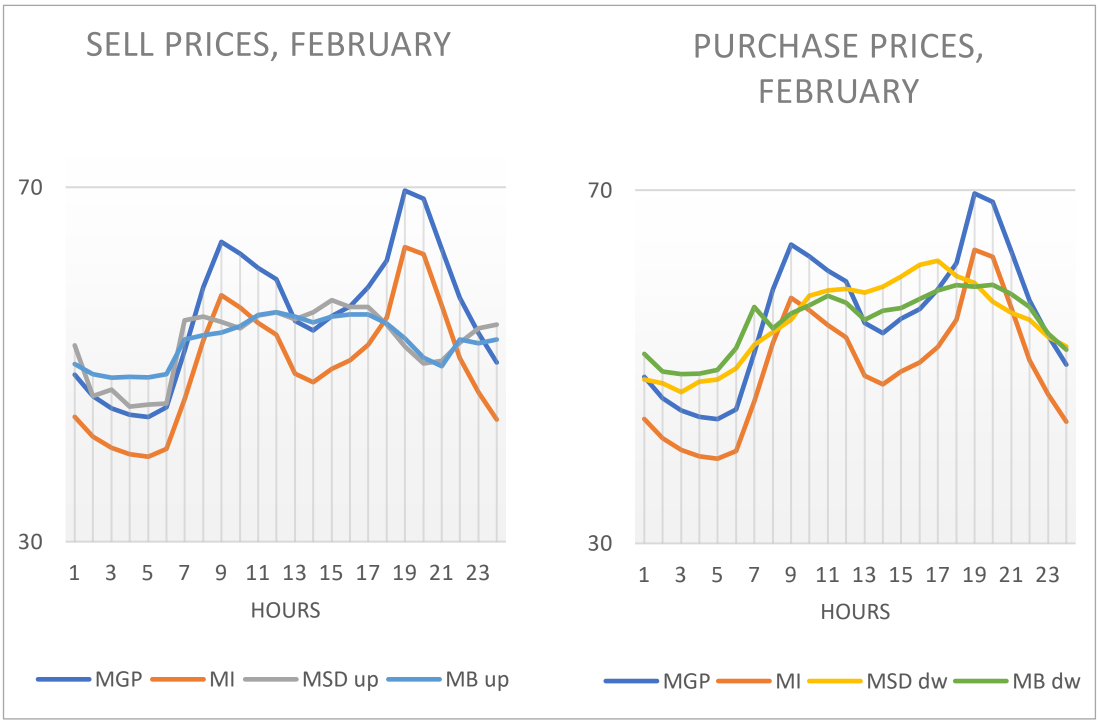


FIGURE 5.30. *Trend of selling and purchase prices, typical day of February, elaboration by REF-E*

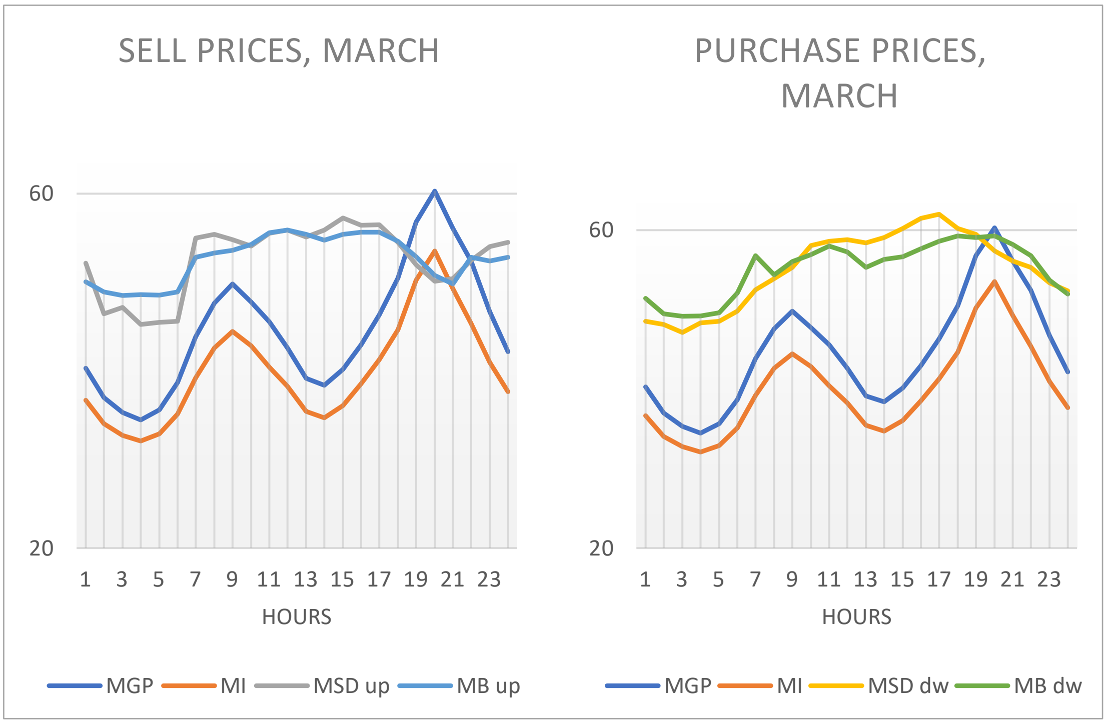


FIGURE 5.31. *Trend of selling and purchase prices, typical day of March, elaboration by REF-E*

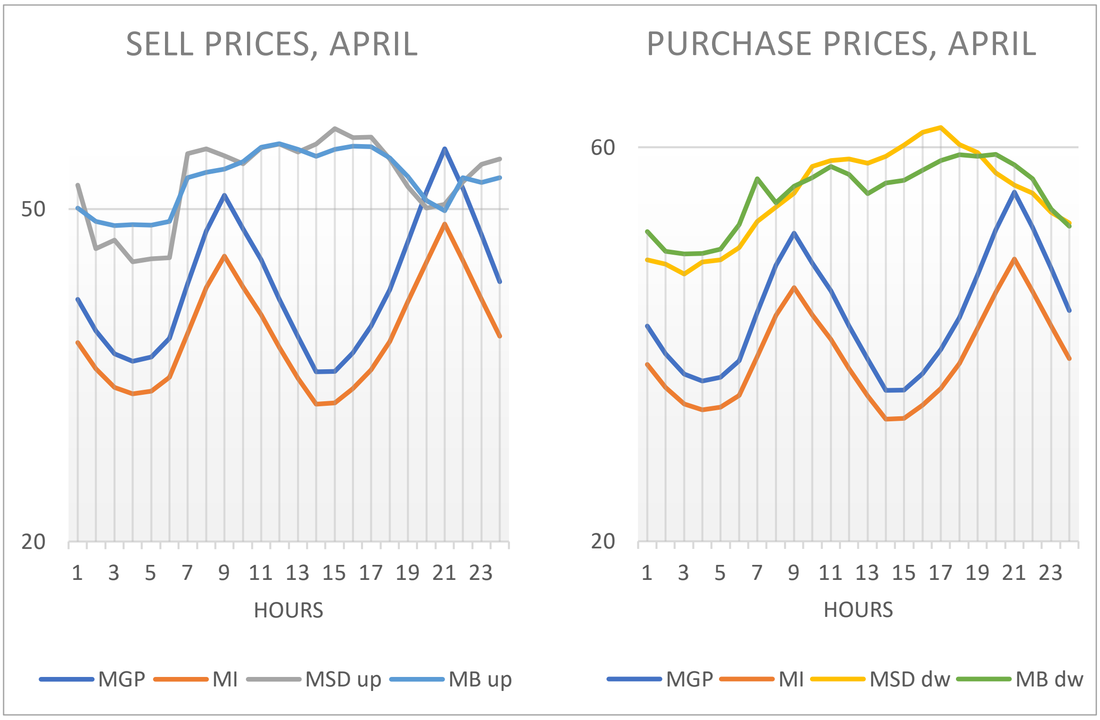


FIGURE 5.32. *Trend of selling and purchase prices, typical day of April, elaboration by REF-E*

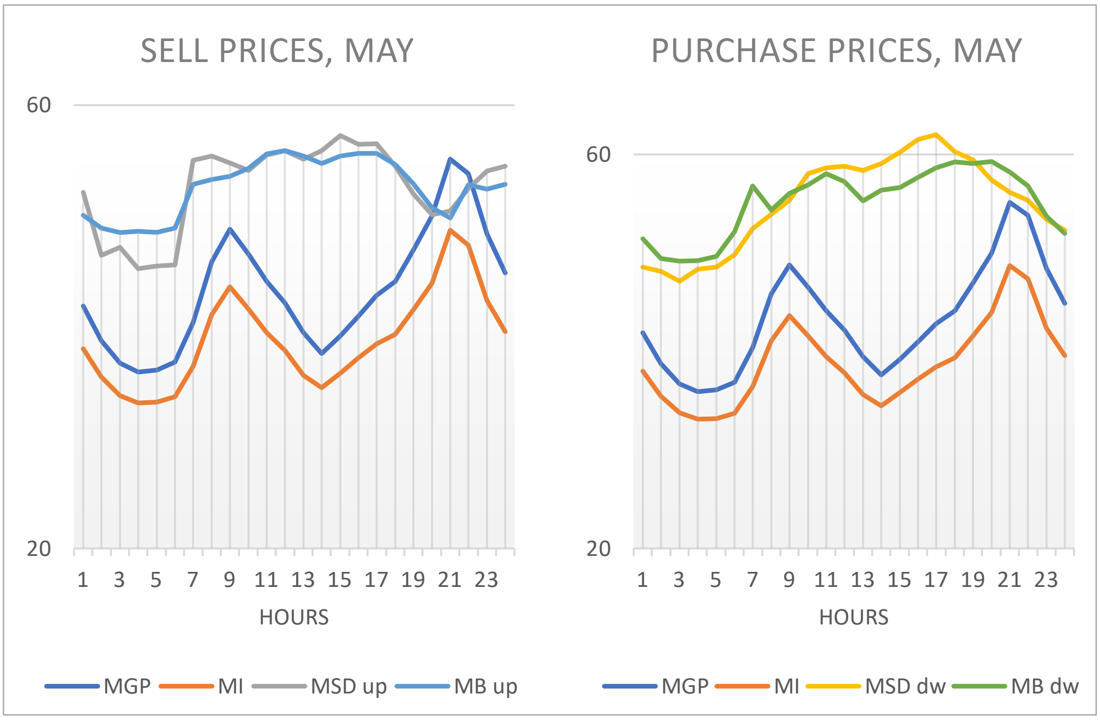


FIGURE 5.33. *Trend of selling and purchase prices, typical day of May, elaboration by REF-E*

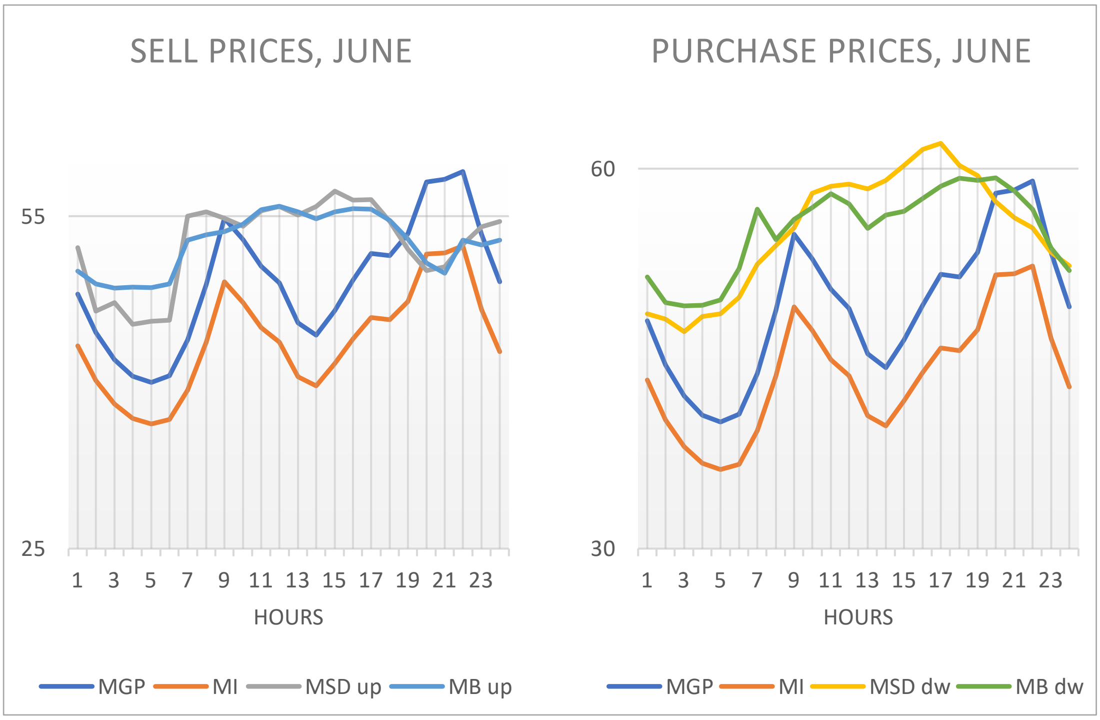


FIGURE 5.34. *Trend of selling and purchase prices, typical day of June, elaboration by REF-E*

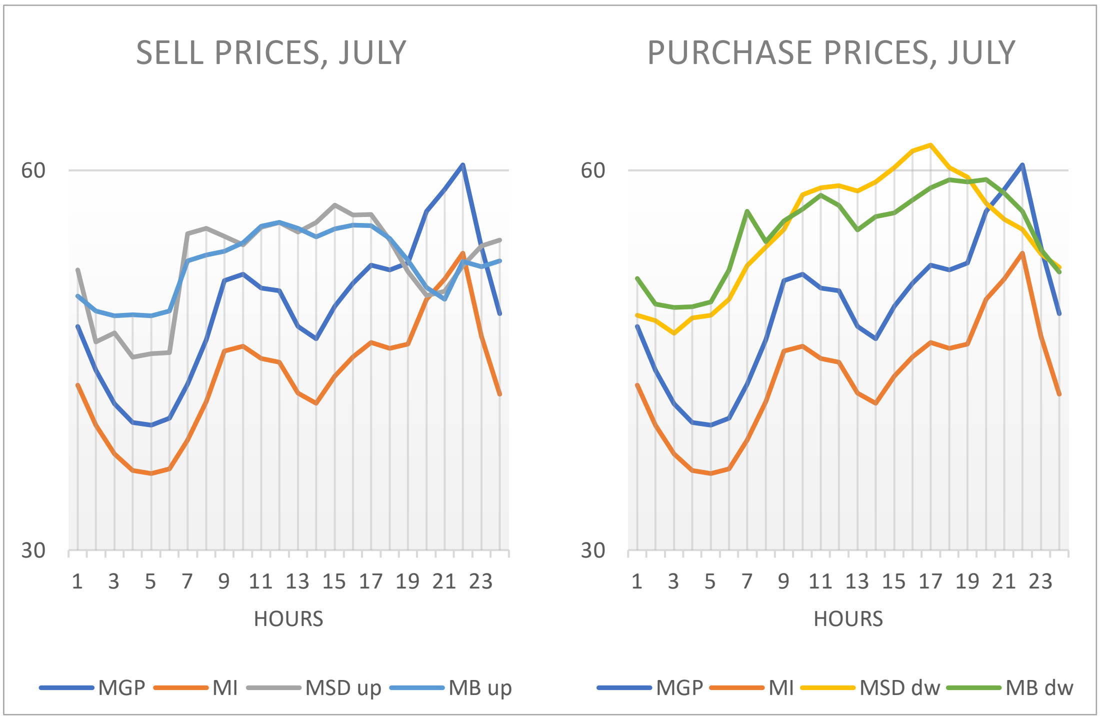


FIGURE 5.35. *Trend of selling and purchase prices, typical day of July, elaboration by REF-E*

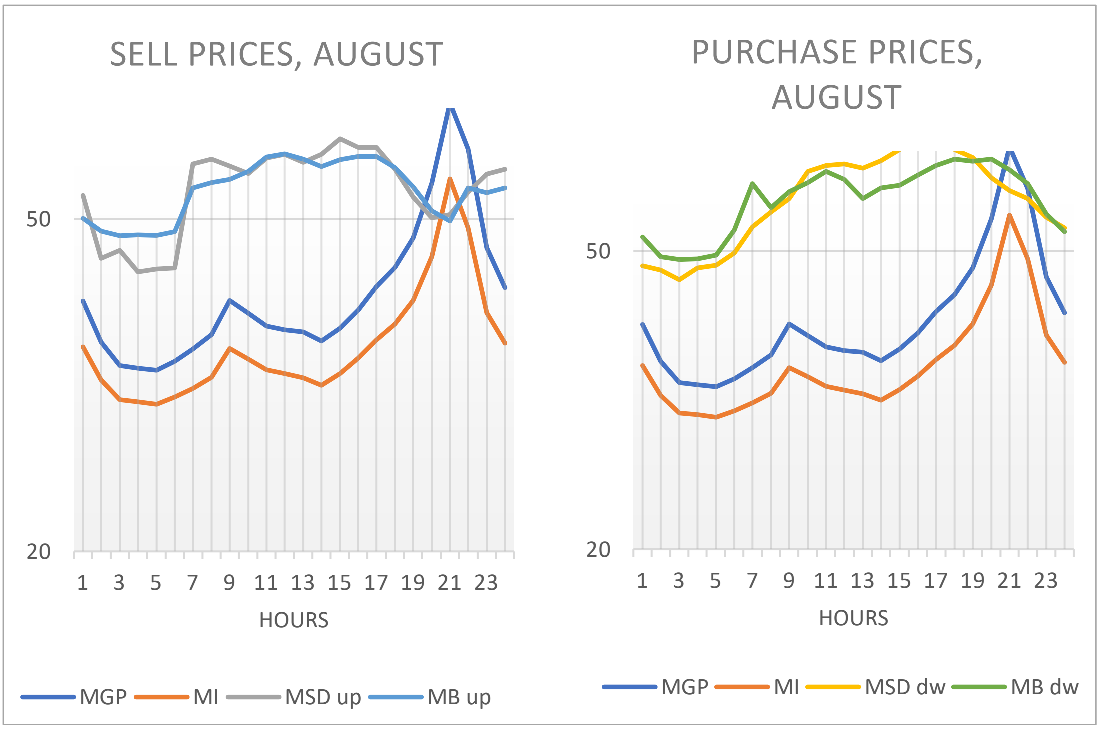


FIGURE 5.36. *Trend of selling and purchase prices, typical day of August, elaboration by REF-E*

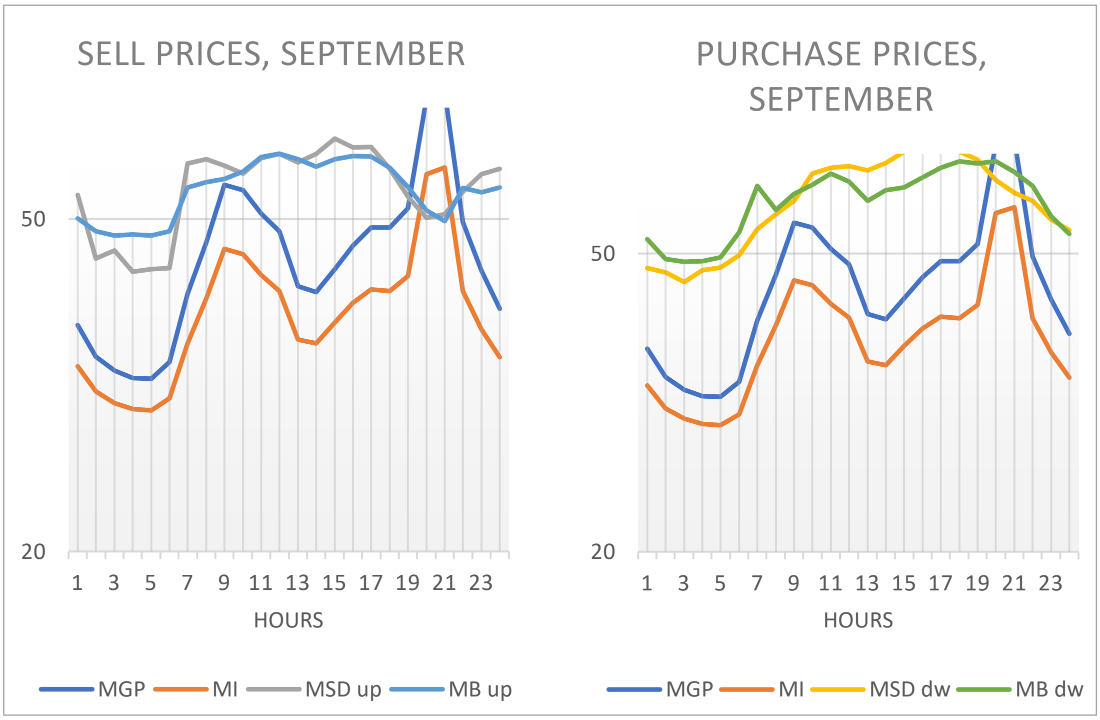


FIGURE 5.37. *Trend of selling and purchase prices, typical day of September, elaboration by REF-E*

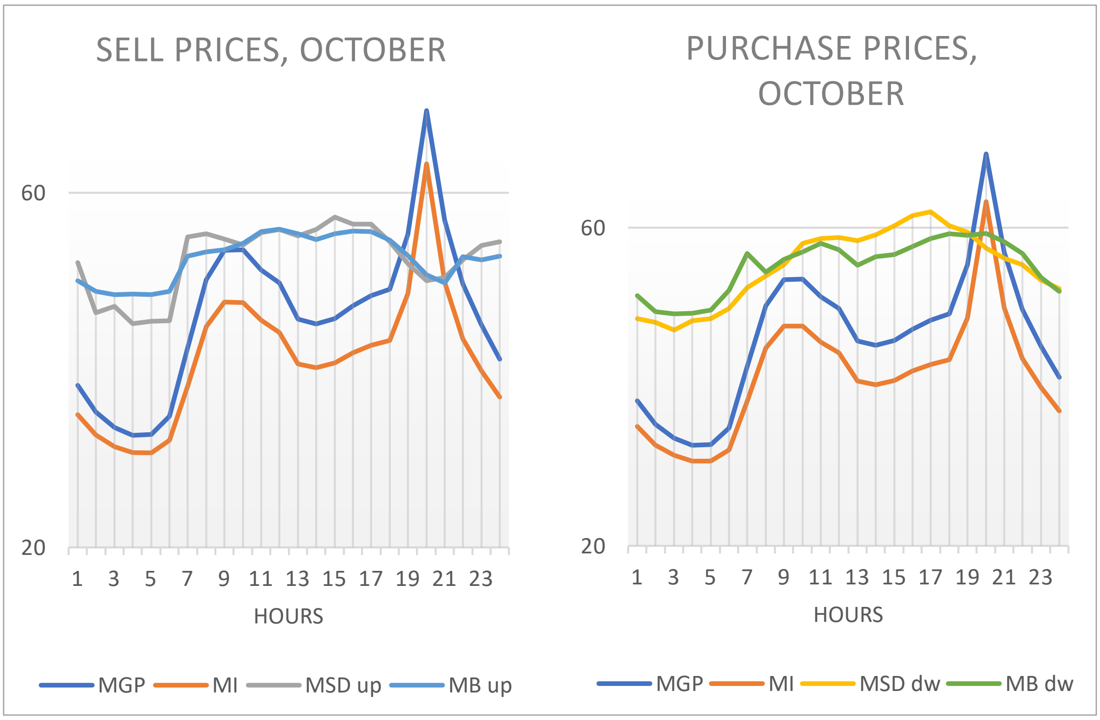


FIGURE 5.38. *Trend of selling and purchase prices, typical day of October, elaboration by REF-E*

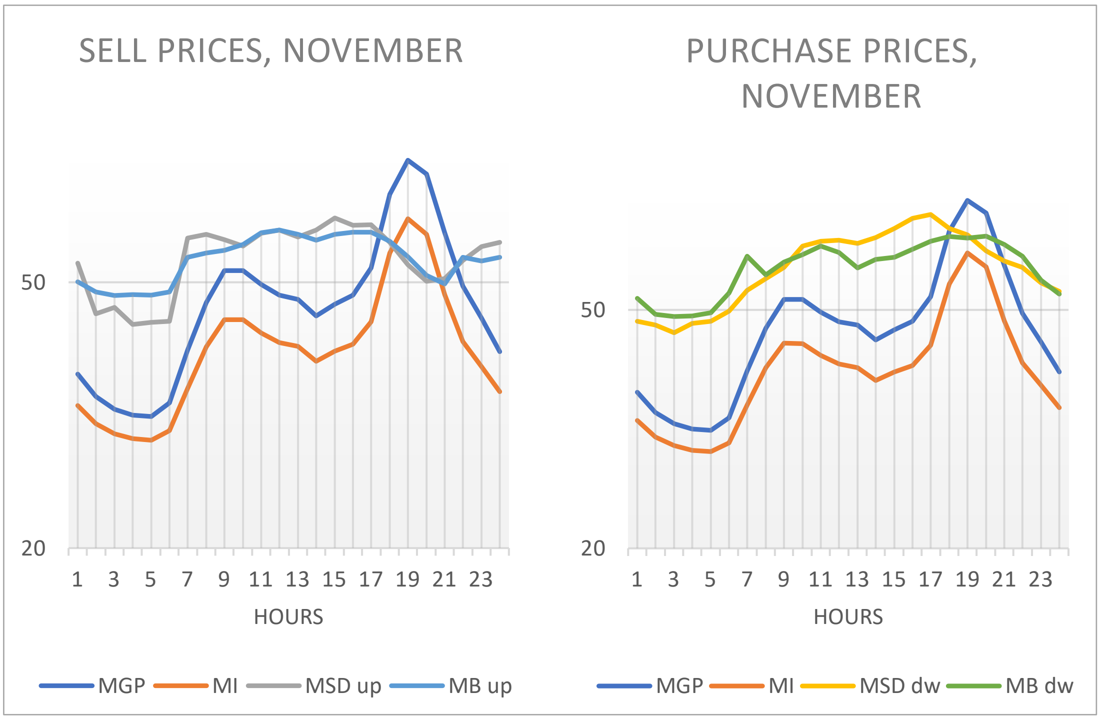


FIGURE 5.39. *Trend of selling and purchase prices, typical day of November, elaboration by REF-E*

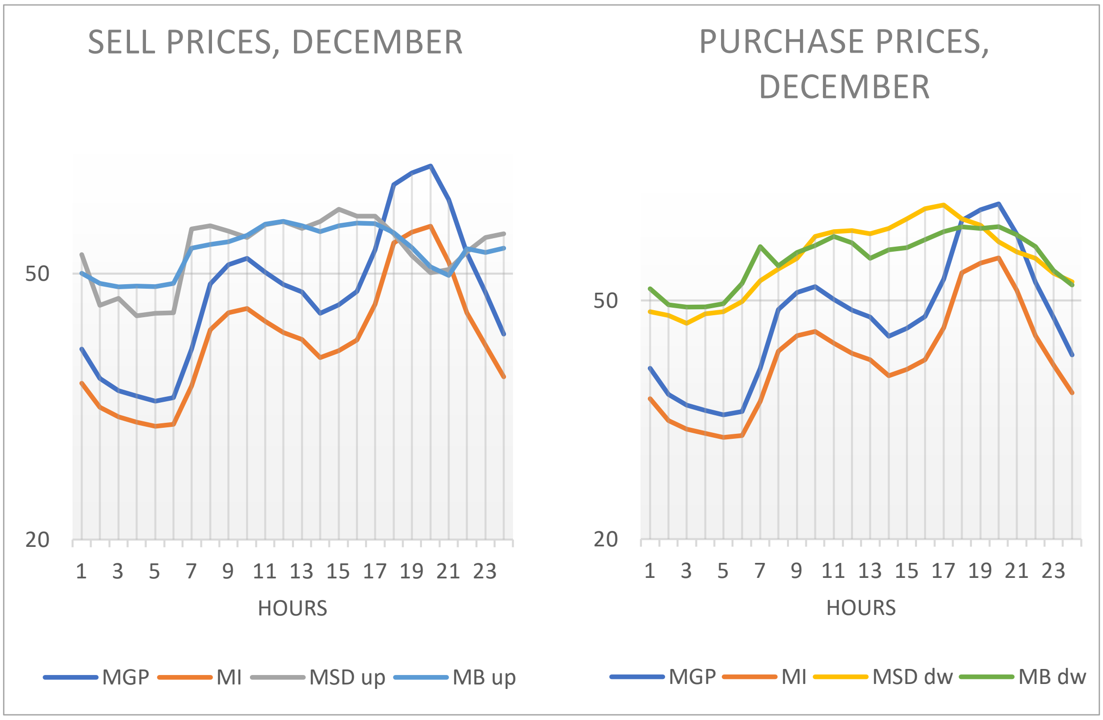


FIGURE 5.40. *Trend of selling and purchase prices, typical day of December, elaboration by REF-E*

5.6. PROBLEM SOLVING: DESING OF THE INVESTMENT EVALUATION

5.6.1. Financial indexes and time horizon

To evaluate the results of the various scenarios it was decided to entrust to traditional indicators such as *net present value* (NPV), *internal rate of return* (IRR) and *pay-back time* (PBT).

The time horizon foreseen for the investment is ten years: nine years of market operations plus the *year zero*. The first year of market operation coincides with the year 2017. The overall time period was defined basing on the duration in terms of useful life of some of the main structural components.

5.6.2. Description and assumptions about input data

Inflows

- Expected gains from market operations: this is the result of the maximization problem solved through the optimization algorithms previously described. Of course, it is case-specific.

- Expected gains from CU contractors: in case of UVAM, there is an additional revenue stream to be considered, that is the revenue stream coming from the provision of energy of the consumption units. This figure is obtained by multiplying the annual consumer fee applied and the number of CU contractors.

  The first parameter was arbitrary established in order to offer a discount of about 15% (in a first case) and of about 10% (in a second case) with respect to the average yearly price paid for the electricity by families corresponding to the category chosen. Given the amount of energy consumption recorded during the simulations and the price paid to buy it on the markets, it was computed a value for the energy consumed by a single household of about € 720 – that can be considered in line with a highly consuming 3 kW user (always considering the presence of consuming apparatuses like air-conditioning). The second parameter depends on the total power that must be reached by the consumption aggregate and is already known – i.e. 1.000 units.

- BESS CapEx: the cost of the batteries depends on the desired capacity of the whole compound and on the related price per kWh. Three different cost curves have been identified for Li-ion batteries in order to make some sensitivity. The reference *scenario* is inspired by data coming from [73], and considers an average cost of 500 €/kWh (in 2016) to be constantly reduced up to reach a 40% reduction in 2025. Basing on that, an *optimistic* and a *pessimistic* scenario have been designed: in the optimistic scenario the price reduction achieved in 2025 will be of 50%; in the pessimistic scenario the price reduction achieved in 2025 will be just of 25%. In both cases the price reduction is constant during the years. Building up cost curves was necessary to understand which price estimation should be applied to BESS purchases after the first one.

- BESS OpEx: to estimate yearly operation and maintenance costs, it was made reference to [73], [74]. It was finally concluded to consider BESS OPEX as a 5% figure of the total BESS capex.

- BESS connection cost: currently, Italian technical regulations about storage systems are not so well defined. As is the situation by now, stand-alone storage systems must be considered generation units belonging to the same category of RES and co-generation plants [30]. The connection cost is computed with a proxy of the formulas contained in an express document called *TICA* (*Testo Integrato delle Connessioni Attive)* and is directly related to the total power of the storage system. As a result, for a 3 MW compound, it was estimated a connection cost of € 133.000. For a 4 MW compound, the figure rose to € 175.000.

- Aggregator's return: as it is foreseen by the business model adopted, the VPP is managed by a third-party delegated aggregator. The return of this subject is obviously a cost for the pool of investors as it could be imagined as the prize for providing a VPP management service. To make some sensitivity, two levels of return were identified: 20% and 15% of the overall yearly revenues made by the VPP. Thus, it is a variable figure. It is worth remembering that in this way the aggregator will be incentivized in trying to get the best economic performance from the VPP, pursuing its own interests and those of the investors at the same time.

- PV revamping costs and residual CapEx: three different *financial* situations have been tested during the investment evaluation, as it was previously announced. In the first case, there are no remaining capital costs associated with the PV plants to aggregate; a second option considers the existence of a residual percentage of the initial CapEx to be covered yet; a third case foresees the need of a revamping investment.
  The residual CapEx quota was set equal to 40% of the total value of the PV aggregate – meaning that the costs are scaled to the proportion of a 7 MW plant – considering a total cost of supply of 850 €/kW (referring to an overall cost previous to 2015 quotations estimated with reference to the Politecnico di Milano university course *Management of Energy and Sustainability* reserved material and [75]).
  Revamping costs for a PV plant are instead usually associated with the substitution of the inverter, a fundamental component of the plant. These costs have been estimated in 0,08 €/W [76].

- PV OpEx: annual operating costs for the PV aggregate have been estimated in a quota equal to 3% of the overall capex.

- Imbalance compensation: since the models do not consider measures to deal with the imbalance position of the aggregates, it was thought to take somehow into account the possible negative effect of imbalances on market revenues through the application of a sort of *penalty* equal to 10 €/MWh – based on REF-E estimations – to be applied on the whole energy production of the aggregates and to be adjusted by a factor expressing the average unbalance probability of a PV plant in the northern market zone. This is a quite conservative figure with respect to the cost related to the imbalance risk which is generally transferred by traders to RES operators on the basis of actual rules, but it was chosen to be cautious on this aspect.

It is to remember that no cost for the equipment – reasonably, smart meters and similar technologies – needed to make the consumption units communicate with the central brain of the VPP has been considered. Also, PV connection costs have been considered as sunk costs (all the plants are reckoned already operational and connected to the grid at year zero).

General parameters

- Cost of capital: it was assumed a cost of capital of 10%, considering the pool of investors as the equivalent of a small-medium enterprise in healthy conditions (SME) [77].

- Fiscal pressure: the impact of taxes was set at 40%, trying to simulate the combined effect of IRES, IRAP and other minor contributions. It was left aside the effect of deductible interests.

- VAT: the VAT level was set at its current, non-subsidized value of 22%.

- Average electricity price: it is a proxy of the Italian average cost paid by households of the category chosen for a kWh of electricity. The figure applied, given the category of power and the level of energy consumed, was estimated basing on data coming from the AEEGSI website and is set at 0,19 €/kWh [78].

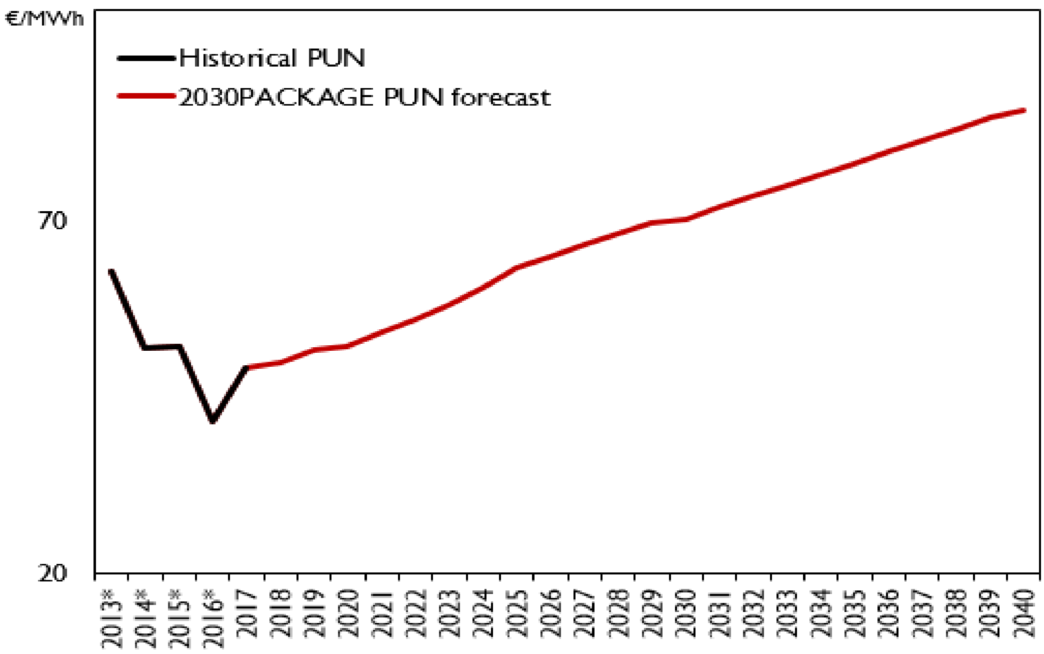
- Inflation rate and electricity price rate of growth: it was decided to distinguish between the general inflation rate and the specific rate of growth foreseen for the electricity price. The first value was set equal to the common value of 1,9%, constant in time and referred to the overall price level. The second one was instead derived from forecasted data provided by Ref-e. Since these data are reserved they will not be explicitly declared (a graphic progression is however provided in *Figure 5.41.*). However, this latter value

has been used to adjust year by year all those figures depending strictly on the variations of the electricity price rather than on the overall price level. It is worth underlining that no trend about future network and system charges has been considered due to lack of reasonable data.
Note also that this electricity price growth rate assumes that the spread between the prices of energy markets (MGP, MI) and of ancillary services markets (MSD, MB) remains constant in time. This consideration is justified by the extreme difficulty in defining a viable relationship among such prices that could additionally adjust the growth rate of the PUN that was used for making calculations, which is something that lies outside of the purposes of this study.

- BESS depreciation period: it was previously said that, depending on the strategy implemented, the useful life (measured in cycles) may change considerably. For this reason, the depreciation period of the BESS was set always equal to the expected useful life, according to case.

- Revamping investment and residual CapEx depreciation period: in both cases it was considered a depreciation period equal to the time horizon adopted for the investment evaluation.

- Discount on the energy component of consumers' bill: to convince consumers to join the aggregates, it was said that it would have been opportune to offer them a discount on their electricity bill. This discount had to be properly calculated so to grant the supplier still a positive gain from the provision of energy to the consumption units: using the results of the simulations made through the models designed, it was defined the average total cost paid for the energy bought on the markets and supplied to the consumption units and then, referring to the data made available by the *Authority* about the composition of the energy bill per each category of consumer, it was computed the quota related to the *raw material energy* (around 0,046 €/kWh). It is on that quota that the rebate is applied – two different levels of rebate were defined, 15% and 10%.



Source: REF-E 2030PACKAGE scenario

FIGURE 5.41. *Trend of electricity price (PUN) to 2040, data elaboration by REF-E*

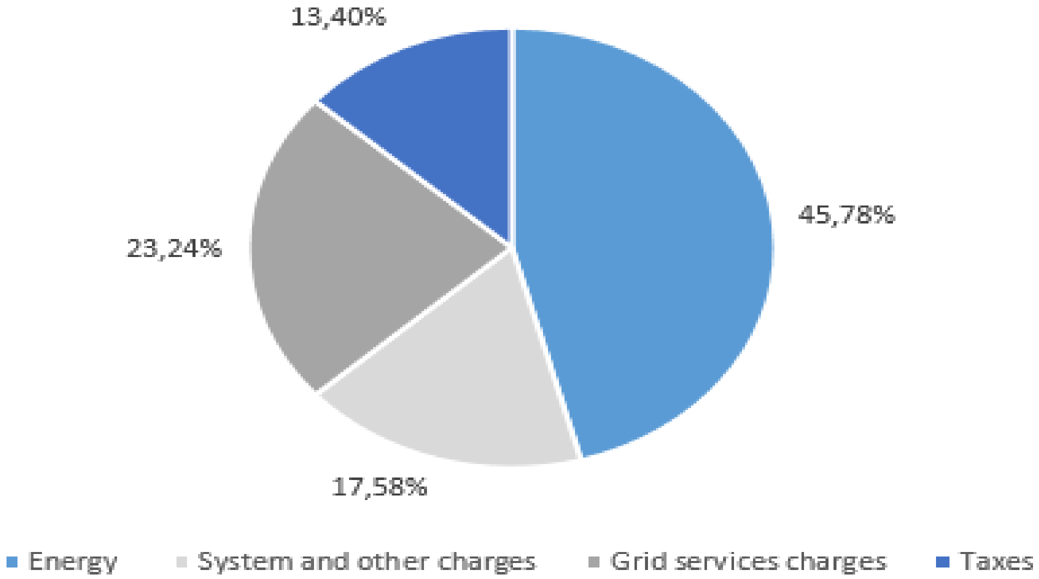


FIGURE 5.42. *Composition of energy bill for the residential segment, ARERA [71]*

Financial parameters

In doing this analysis it was supposed that the method of financing adopted by the investors is the traditional bank loan.

- Interest rate: assuming that the pool of investors can be considered as an overall *healthy investor*, it was applied a fair interest of 3,65% (fixed) for investments to be financed in year zero; for each subsequent purchased to be financed through external capital with respect to the investment made in *year zero*, an additional 0,5% was added to the initial interest rate. Note that these indications refer to real quotations provided by qualified personnel of BPM (Banca Popolare di Milano).

- Capital return: it was decided arbitrary to use the French rate method for computing the instalments to be paid to the bank. It was also estimated a down payment equal to 4% of the total loan amount to be deposited at the beginning to start the practice.

- Financed quota of the investments: it was defined a likely quota of participation of the bank in financing the investment equal to 70%.

- Financing period: the financing period is always equal to depreciation period, for simplicity.

5.7. PRESENTATION OF RESULTS

In this paragraph the main results of the investment evaluations concerning the various cases that have been previously described will be displayed and commented. It is to be communicated that it was fixed a minimum IRR requirement of 10% below which results would have been considered absolutely not satisfactory. Hence, for those cases which did not satisfy that minimum threshold, results will not be displayed in the detail of the tables. No restrictions were made about the other indicators. Results are shown by mean of a series of tables. Furthermore, in Appendix D it is showed the detail of the economic value and the volumes traded on the various markets for each VPP configuration.

5.7.1. Main acknowledgements

Before to present in the detail the results of the various cost-subcases and configurations, it is here provided a summary of the principal results. The intent is to clarify in a simple and direct way the fundamental concepts coming out from the analysis and to facilitate the reading and the comprehension of the detailed results coming next.
It is worth to anticipate that, as it becomes clear looking at the summaries presented below, some additional configurations (UVAM 4, UVAP 4 and UVAM 5) have been considered in the evaluation with respect to the initial three declared. Of course, the reasons behind this decision will be properly explained in the subsequent detailed presentation of results.

Note also that the attractiveness (last column of the following summaries) of each configuration was assessed basing on the following criterium: it was simply assigned a score from 1 to 5 to each typology of initial cost situation (no CapEx/revamping, PV CapEx, PV revamping, which will be indicated with the letters *a, b* and *c*) within each configuration (UVAP/UVAM 1, 2, ...) basing on the results achieved in terms of IRR. In doing this, all the possible solutions come out through sensitivity application – presented in detail in the subsequent tables – have been considered and the mean of such results is the figure which was adopted to make the assessment. As it can be easily understood, the overall attractiveness of the single business configuration is given by the average of the score reached in the three different initial cost situations. The scores have been set as follows:

1. Not sufficient: IRR < 10%
2. Just sufficient: 10% ≤ IRR < 15%
3. Acceptable: 15% ≤ IRR < 25%
4. Profitable: 25% ≤ IRR < 35%
5. Very profitable: IRR ≥ 35%

TABLE 5.7. *UVAP summary*

UVAP SUMMARY

CONFIGURATION		CONSIDERATIONS	ATTRACTIVENESS		
1	7 MW absent	Pure aggregation of small-scale PV units. The simplest, most suitable and actually mostly economic performing solution.	No CAPEX/REV.	5	4,33
			PV CAPEX	3	
			PV REVAMPING	5	
2	7 MW 3 MW (no arbitrage)	UVAP enriched through the addition of a battery energy storage system. The lack of a proper BESS deployment strategy leads to worst economic result.	No CAPEX/REV.	1	1
			PV CAPEX	1	
			PV REVAMPING	1	
3	7 MW 3 MW (arbitrage)	The strategic deployment of the BESS improves market performances but BESS costs are still scuttling the economy of the investment.	No CAPEX/REV.	2	1,33
			PV CAPEX	1	
			PV REVAMPING	1	
4	7 MW 2 MW (arbitrage)	Lower weight of BESS costs slightly affects market performances and strongly improves the economy of the investment.	No CAPEX/REV.	4	2,67
			PV CAPEX	1	
			PV REVAMPING	3	

TABLE 5.8. *UVAM summary*

UVAM SUMMARY

CONFIGURATION		CHARACTERISTICS	ATTRACTIVENESS		
1	7 MW	Mixed aggregation of small-scale production units and residential consumption units. The aggregation highlights the weight of the gains from energy supply and the achievement of the most interesting economic results.	No CAPEX/REV.	5	5
	3 MW		PV CAPEX	5	
	absent		PV REVAMPING	5	
2	7 MW	Production side enriched through the addition of a battery energy storage system. The lack of a proper BESS deployment strategy leads to worst economic result.	No CAPEX/REV.	1	1
	3 MW		PV CAPEX	1	
	4 MW (no arbitrage)		PV REVAMPING	1	
3	7 MW	The strategic deployment of the BESS improves market performances but BESS costs are still scuttling the economy of the investment.	No CAPEX/REV.	3	1,67
	3 MW		PV CAPEX	1	
	4 MW (arbitrage)		PV REVAMPING	1	
4	7 MW	Lower weight of BESS costs slightly affects market performances and strongly improves the economy of the investment.	No CAPEX/REV.	4	2,67
	3 MW		PV CAPEX	1	
	3 MW (arbitrage)		PV REVAMPING	3	

5	7 MW 7 MW 4 MW (arbitrage)	The increased participation of the consumption side weakens market profits but boost gains from energy supply and allows to reach better economic results.	No CAPEX/REV.	4	2,67
			PV CAPEX	1	
			PV REVAMPING	3	

5.7.2. Sensible variables

Before to proceed with the detailed presentation of the results, it is worth to highlight and recap the variables on which it was made some sensitivity:

- The return of the aggregator subject: according to the business model described in the problem setting phase, the third-party delegated aggregator is an entity which is basically offering a service to the investors. And it was also said that its remuneration is defined as a quota of the revenues made by the whole VPP. Basing on that, it was set an initial return quota of 15% and then a second, more generous, one of 20%.

- The rebate on the energy quota on the bill of the consumers joining the mixed aggregate (considered only for UVAM cases): it was said that, to convince the consumers to join the aggregate, it would have been reasonable to offer them an economic advantage. This translated into a discount of the energy component of their electricity bill.
  Therefore, two rebate quotas (15% and 10%) were defined in order to grant a less expense to the consumer while preserving an advantageous gain for the *VPP-energy supplier*.

- The cost of the BESS technology (if present): as it was said before, three different cost curves have been shaped to make some sensitivity with respect to the cost of Li-ion batteries. The first cost curve (CC1) is based on the analysis made by the Energy and Strategy Group of Politecnico di Milano and foresees a cost reduction to 2025 equal to 40% starting from an average 500 €/kWh level in 2016. The second cost curve (CC2) reflects an optimistic scenario in which, equal other conditions, the cost reduction to 2025 is increased to 50%.

Finally, the third cost curve (CC3) is based on a pessimistic scenario in which, equal other conditions, the cost reduction foreseen to 2025 reaches just 25%. The cost reduction per year is constant in each case.

- Presence of residual/revamping PV costs: although this cannot be specifically called a variable, it is an important element according to which sensitivity scenarios have been built. A first case foresees nor CapEx nor additional investment costs concerning the photovoltaics; a second case foresees the presence of a 40% quota of residual CapEx; a third option regards the presence of a revamping investment (inverter substitution).

It is worth to remember that the consumption aggregate associated with UVAM is composed of residential units accounting for 3 kW each which are not to be namely compared with the standard Italian family as intended by national authorities – yearly consumption of about 2700 kWh – because of non-standard home appliances (air-conditioning) concurring to the definition of the annual consumption level, which was estimated in the order of about 3600 kWh per family per annum.

A last information regards the *Δ market gains* datum inserted in the tables below. It expresses the difference between the revenues made through market operations by the VPP against the ones made by a 7 MW PV plant alone operating on the sole day-ahead market (basic case of comparison). That datum was also obtained through simulations carried out with the models designed – it was sufficient to change the parameters – and is very important for the definition of the viability of certain solutions.

5.7.3. UVAM basic configurations

UVAM 1

TABLE 5.9. *UVAM 1.a results*

UVAM 1.a	**No PV CAPEX or REVAMPING**
7 MW (PV) + 3 MW (CU)	

Δ market gains	- 80 k€	

Aggregator's return	CU rebate	IRR [%]	NPV [k€]	PBT [years]
20%	15%	+	1.518	0
	10%	+	1.573	0
15%	15%	+	1.635	0
	10%	+	1.694	0

TABLE 5.10. *UVAM 1.b results*

UVAM 1.b		**PV RESIDUAL CAPEX**		
7 MW (PV) + 3 MW (CU)				
Δ market gains	- 80 k€			
Aggregator's return	CU rebate	IRR [%]	NPV [k€]	PBT [years]
20%	15%	32,82	871	4
	10%	34,33	931	4
15%	15%	35,98	995	4
	10%	37,32	1.053	4

TABLE 5.11. *UVAM 1.c results*

UVAM 1.c		**PV REVAMPING**		
7 MW (PV) + 3 MW (CU)				
Δ market gains	- 80 k€			
Aggregator's return	CU rebate	IRR [%]	NPV [k€]	PBT [years]
20%	15%	91,37	1.294	2
	10%	94,70	1.349	2
15%	15%	99,25	1.411	2

	10%	102,78	1.470	2

In the first UVAM case, for all the possible scenarios, the results are extremely positive. Although the difference in market revenues with respect to the basic case is negative, the loss in variable returns is highly compensated by the additional income coming from the fees paid by the consumers making part of the VPP. Under these conditions, the solution implemented appears to be successful.

UVAM 2

In the second UVAM case, a group of Li-ion batteries accounting for 4 MW and following a non-strategic deployment program joins the aggregate. Although the difference in market gains with respect to the basic case is positive (+32 k€), investment results are strongly insufficient in each cost case *a, b* and *c*, thus the solution is not viable.

The main reason of this failure lays in the absence of a more engaging strategy of deployment for the BESS. Without an arbitrage strategy, all the transactions operated by the BESS translate into real energy movements. The stress suffered from the batteries in terms of charge/discharge cycles is quite relevant: 10 complete cycles per day on average (datum estimated analysing the behaviour of the BESS from models' outputs). In this way, considering a Li-ion BESS with a useful life of 5000 cycles and with all the characteristics reported before, a single battery compound would be substituted in less than two years, making the impact of BESS costs unsustainable for the economy of the investment.

UVAM 3

TABLE 5.12. *UVAM 3.a results*

UVAM 3		**No PV CAPEX or REVAMPING**
7 MW (PV) + 3 MW (CU) + 4 MW (BESS)		
Δ market gains	+ 133 k€	

Aggregator's return	CU rebate	BESS cost curve	IRR [%]	NPV [k€]	PBT [years]
20%	15%	CC1	13,01	171	10
		CC2	14,60	263	9
		CC3	10,72	41	10
	10%	CC1	14,49	256	9
		CC2	16,08	347	9
		CC3	12,21	125	10
15%	15%	CC1	17,32	413	8
		CC2	18,92	504	8
		CC3	15,02	282	9
	10%	CC1	18,90	502	8
		CC2	20,50	593	8
		CC3	16,60	371	9

With the introduction of the arbitrage strategy in the third UVAM case, results got improved. The first great change regards the market revenue, which is increased of more than 100.000 € with respect to the previous UVAM 2 configuration. The second fundamental difference regards instead the better efficiency with which the BESS is exploited. With the arbitrage strategy implemented, in facts, most of the transactions operated by the BESS do not translate into real energy movements. In this way, the stress suffered from the batteries is incredibly reduced: 2,5 complete charge/discharge cycles per day on average (slightly more than 900 cycles per year). Now, the same BESS considered before is able to last for more than five years (the useful life was rounded down to five years considering the negative effect of possible deterioration and damages). This translates into a considerable costs reduction with respect to the previous case. However, the results of the investment evaluation are satisfactory only in case there is no residual CapEx cost associated with the PV infrastructure, nor revamping expenses to be faced. Under the conditions depicted, the still high cost of the batteries added to other important capital costs would be such to kill the investment.

These considerations are true for all the cost situations *a, b* and *c*, although investment results improve at the point to become sustainable only in the lowest-cost case (*a*).

5.7.4. UVAP basic configurations

UVAP 1

TABLE 5.13. *UVAP 1.a results*

UVAP 1		**No PV CAPEX or REVAMPING**		
7 MW (PV)				
Δ market gains	+ 91 k€			
Aggregator's return		IRR [%]	NPV [k€]	PBT [years]
20%		+	1.128	0
15%		+	1.225	0

TABLE 5.14. *UVAP 1.b results*

UVAP 1		**PV RESIDUAL CAPEX**		
7 MW (PV)				
Δ market gains	+ 91 k€			
Aggregator's return		IRR [%]	NPV [k€]	PBT [years]
20%		19,76	369	7
15%		23,52	509	6

TABLE 5.15. *UVAP 1.c results*

UVAP 1		PV REVAMPING		
7 MW (PV)				
Δ market gains	+ 91 k€			
Aggregator's return		IRR [%]	NPV [k€]	PBT [years]
20%		67,87	904	2
15%		74,25	1.000	2

In the same way as for the UVAM 1 case, this first UVAP configuration shows very interesting results. The additional market gains are given by the fact that the VPP (which has no additional component with respect to a common 7 MW PV plant) is allowed to operate on all the markets, MSD and MB comprehended, and this permits to obtain a higher market margin. This organization could be addressed as a *no-cost solution* since there are no significant costs to be sustained by the investors to realize it, apart from paying the delegated aggregator. Nevertheless, to this regard, it is to be underlined that since there is no other source of revenue but market gains, the return of the aggregator must necessary account for a lower amount with respect to the additional market gains made by the VPP. For this reason, an aggregator's return of 20% produces a non-viable result.

UVAP 2

In the second UVAP case, the presence of a BESS – accounting for 3 MW – which is not programmed to operate according to a proper market strategy leads to an investment failure even though market gains are significantly improved (+174 k€). For this case, the considerations to be made reflect exactly those discussed in the previous UVAM 2 case.

UVAP 3

TABLE 5.16. *UVAP 3.a results*

UVAP 3		No PV CAPEX or REVAMPING		
7 MW (PV) + 3 MW (BESS)				
Δ market gains	+ 250 k€			
Aggregator's return	BESS cost curve	IRR [%]	NPV [k€]	PBT [years]
20%	CC1	12,42	105	10
	CC2	13,99	173	9
	CC3	10,16	7	10
15%	CC1	16,96	299	8
	CC2	18,55	367	8
	CC3	14,69	201	9

Again, for this UVAP 3 case, the same considerations made for the third UVAM case do hold. The arbitrage strategy allows a better exploitation of the BESS, which leads to increased market gains and a much longer useful life of the asset. This is however true only in case there are no other capital costs associated with the PV infrastructure (cost subcase *a*), otherwise the additional high cost of the BESS become too heavy to produce sufficient investment results (*b* and *c* initial cost subcases are stll unsustainable).

5.7.5. Additional cases

Apart from the basic configuration tested above, as it was announced at the beginning of the paragraph, three additional casuistries were created and put to the test to in order to better understand the impact of certain variables and explore the possibility to make further considerations about the conformation of the aggregates.

Decreased BESS capacity: UVAM 4 and UVAP 4

TABLE 5.17. *UVAM 4.a results*

UVAM 4			No PV CAPEX or REVAMPING		
7 MW (PV) + 3 MW (CU) + 3 MW (BESS)					
Δ market gains	+ 80 k€				
Aggregator's return	CU rebate	BESS cost curve	IRR [%]	NPV [k€]	PBT [years]
20%	15%	CC1	26,28	701	7
		CC2	27,84	770	6
		CC3	24,06	604	7
	10%	CC1	28,25	786	5
		CC2	29,81	854	5
		CC3	26,04	688	7
15%	15%	CC1	31,80	928	4
		CC2	33,37	996	4
		CC3	29,58	830	4
	10%	CC1	33,91	1.017	4
		CC2	35,48	1.085	4
		CC3	31,70	919	4

TABLE 5.18. *UVAM 4.c results*

UVAM 4			PV REVAMPING		
7 MW (PV) + 3 MW (CU) + 3 MW (BESS)					
Δ market gains	+ 80 k€				
Aggregator's return	CU rebate	BESS cost curve	IRR [%]	NPV [k€]	PBT [years]
20%	15%	CC1	13,93	222	9
		CC2	15,13	290	9
		CC3	12,20	124	10

	10%	CC1	15,42	307	9
		CC2	16,62	375	9
		CC3	13,70	209	9
15%	15%	CC1	18,01	449	8
		CC2	19,21	517	8
		CC3	16,28	351	9
	10%	CC1	19,60	538	8
		CC2	20,80	606	7
		CC3	17,87	440	8

UVAP 4

TABLE 5.19. *UVAP 4.a results*

UVAP 4		**No PV CAPEX or REVAMPING**		
7 MW (PV) + 2 MW (BESS)				
Δ market gains	+ 197 k€			
Aggregator's return	BESS cost curve	IRR [%]	NPV [k€]	PBT [years]
20%	CC1	31,54	633	4
	CC2	33,07	679	4
	CC3	29,38	568	5
15%	CC1	38,02	812	4
	CC2	39,40	851	4
	CC3	35,87	747	4

TABLE 5.20. *UVAP 4.c results*

UVAP 4		**PV REVAMPING**		
7 MW (PV) + 2 MW (BESS)				
Δ market gains	+ 197 k€			
Aggregator's return	BESS cost curve	IRR [%]	NPV [k€]	PBT [years]
20%	CC1	13,58	154	9
	CC2	14,64	199	9
	CC3	12,07	88	10
15%	CC1	17,83	333	8
	CC2	18,89	379	8
	CC3	16,31	268	8

In these two additional cases, it was arbitrarily reduced the size of the BESS by 1 MW for both the aggregates presented in cases UVAP 3 and the UVAM 3. What comes out from this variation in the composition of the VPPs is an improved economic result (excluding the case in which there is still a residual part of PV CAPEX to be covered). In facts, at the same time, while the reduced BESS size brings expectedly a lower amount of gains coming from market operations, the minor profit is more than recovered through the lower costs sustained for the acquisition of the BESS itself.
To give an idea of what this result means, we could say that – considering the level of BESS capacity defined for UVAP and UVAM cases that was defined through the rules explained in the setting phase – there was a negative differential between the *marginal benefit and the marginal costs of adding a unit of BESS capacity*.
Possibly, since no deeper/dedicated study was conducted to define how the cost structure of the BESS did impact on the economics of the VPP and the whole investment evaluation, the negative effect of additional costs over additional revenues when adding BESS capacity is to be principally ascribed to the first BESS purchase, which is characterized by the higher price per kWh and by the higher impact at expenditure level within the investment evaluation, given the fundamentals of the indicators that have been considered.

Increased number of consumption units: UVAM 5

TABLE 5.21. *UVAM 5.a results*

UVAM 5			No PV CAPEX or REVAMPING		
7 MW (PV) + 7 MW (CU) + 4 MW (BESS)					
Δ market gains	- 93 k€				
Aggregator's return	CU rebate	BESS cost curve	IRR [%]	NPV [k€]	PBT [years]
20%	15%	CC1	27,05	967	6
		CC2	28,63	1.058	5
		CC3	24,80	836	7
	10%	CC1	30,54	1.164	4
		CC2	32,12	1.255	4
		CC3	28,31	1.033	5
15%	15%	CC1	32,32	1.252	4
		CC2	33,90	1.343	4
		CC3	30,07	1.121	4
	10%	CC1	36,04	1.460	4
		CC2	37,63	1.551	4
		CC3	33,82	1.329	4

TABLE 5.22. *UVAM 5.c results*

UVAM 5			PV REVAMPING		
7 MW (PV) + 7 MW (CU) + 4 MW (BESS)					
Δ market gains	- 93 k€				
Aggregator's return	CU rebate	BESS cost curve	IRR [%]	NPV [k€]	PBT [years]
20%	15%	CC1	16,95	488	8
		CC2	18,24	579	8
		CC3	15,10	357	9

	10%	CC1	19,76	685	8
		CC2	21,04	775	7
		CC3	17,92	554	8
15%	15%	CC1	21,11	772	7
		CC2	22,40	864	7
		CC3	19,26	642	8
	10%	CC1	24,10	980	7
		CC2	25,39	1.071	6
		CC3	22,27	850	7

In this second additional configuration (dedicated to mixed aggregation only, for obvious reasons), it was arbitrarily decided to increase the total power of the consumption component of the UVAM aggregate to the same level of the production one, which implied the number of consumption units to rise from 1000 users to 2333 (accounting always for 3 kW each). This configuration, expectedly, lead to a lower income from market operations due to the higher level of energy to be supplied to satisfy internal consumes, but allowed at the same time to strongly increase the share of fixed revenues received by the investors. This translates into better economic performances at investment level (excluding the case in which PV CAPEX costs are not entirely covered yet). In this case results are even better than the ones resulting from the previous case UVAM 4, in which it was reduced the size of the BESS. Note that the average value of the energy supplied to the consumption units did not change with respect to the 1000-users case because of a proportional relationship between the consumption level and the number of consumers.

5.8. COMMENTARY OF THE RESULTS

In addition to the explanation given during the presentation of the numeric results, they are here summed up the main considerations concerning the results presented in the tables above and some cues to open the discussion about possible further developments on the theme. The comments will be schematically presented point by point for a matter of clarity and order.

- *A business that can work*

  The first thing that emerges by looking at results is that the aggregation business, at least in the form which was designed for this case study, can work. The principal driver boosting returns in UVAP cases is the possibility to access to all the markets, while in UVAM cases it seems to be the possibility to put under contract the consumption units becoming part of the VPP and to make profit *marking-up* the energy supplied to them. Obviously, the possibility to adopt an arbitrage strategy represents also a key element of profit optimization, in the cases in which it can be applied (besides of the cost of the technology that deploys it).

  Results can be then considered promising also in perspective of future developments in terms of regulatory, technological and business model development.

- *Which are the best solutions?*

  In the specific, and without surprises, *lowest-investment options* are the ones to be preferred: the simple aggregation (connection) of already existing elements which can dialogue by mean of already existing infrastructures is the quickest and most economically performing way to realize and bring into operation such kind of energetic system.

  No wonder also in noticing that the presence of high capital cost related to main components of the VPP strongly penalizes the economic performance of the investment.

- *UVAM better than UVAP*

  It is true that realizing a mixed aggregate would be more difficult than realizing a production-based aggregate, but results show that the mixed solution is to be preferred under a final and pure economic perspective – this is true at least within the business model and the cases object of this case study. The reason of the superior economic performance of UVAM aggregates is to address to the additional income deriving from the energy supplied to consumption units.

According to the business model implemented, the owner of the VPP can actually play the role of energy distributor for the consumers making part of the CU and make profits thanks to the application of a mark-up on the value of the energy supplied, as already explained. Even though there is a higher internal consumption penalizing market gains, the cost gets more than repaid by the fees received from the consumers.

Furthermore, what could be theoretically considered an advantage with respect to common distribution companies is that the economic value of the energy withdrawn from the markets to satisfy internal consumptions (or to charge the BESS, if present) gets mathematically minimized: the *brain* of the VPP is programmed to maximize market profits and always tries to purchase energy at the lowest cost. However, it is not said that such approach could be effectively implemented in a real situation where prices may significantly differ from day to day with respect to previsions and for multiple reasons (emergencies, unplanned outages, et cetera).

- *Impact of gains coming from energy supply in UVAM aggregates*

  As it was said in the lines above, the profit made by UVAM aggregates owes its *magnitude* mainly to the remuneration coming from the consumption units for the energy supplied. According to the results of the simulations, this component impacts a lot on the profitability of the VPP and varies between a minimum share of 33% of total income (UVAM 3) and a maximum share of 44% (UVAM 1) of total income. Indeed, the presence of the BESS (and of an arbitrage strategy to properly exploit it) causes a strong increase of market gains and makes decrease the incidence of contracts, while the total absence of the BESS causes the latter to maximize its incidence over total revenues. For obvious reasons, in the last UVAM 5 case, the incidence of the gains coming from the consumers was predominant, with a quota of nearly 65%.

  Leaving aside the negative influence of the BESS over the overall economic performance, these results (referring in particular to UVAM 1 and UVAM 5 cases) are very interesting because they prove that – at least for the business model adopted here – the idea of including consumption units within the VPP and providing them the energy they require can withstand: even though there are lower market gains with respect to UVAP cases consequently to major withdrawals, the fact that the cost of the energy bought on the market can be reflected with a mark-up on the consumers requiring it, still allows to make a good profit from it. Moreover, the idea to offer a discount could be easily supported even in a competitive perspective against traditional distributors, since these returns represent however a welcomed additional gain for the investors.

- *BESS inclusion*

  Results demonstrate that including a storage system into the VPP is generally inconvenient. Under the conditions and the hypotheses that have been considered to define the configurations put to the test through simulations, only the adoption of an arbitrage strategy within a *lowest-cost* environment produces positive results, which are anyway penalizing with respect to no-BESS solutions.

  Regardless from the type of energy storage system considered in this work, it is possible to say that the use of such apparatuses is to be optimized with respect to the physical characteristics of the system itself. And the same reasoning is true for what concerns any market deployment strategy: if the system considered is not able to grant certain characteristics in terms of speed of charge/discharge and reactiveness when it comes to inject or withdraw energy, it would probably be impossible to make it behave according to a strategy like the one that was designed for this work.

  It appears also evident that – even though no in-depth study was carried out to evaluate the optimal sizing of the BESS – the still high costs of batteries (at least for the first purchase) discourage the acquisition of *capacitive* systems, pushing for a downward revision of the optionable size.

- *Conservative results*

  It is to underline that the conditions fixed in the definition of the behaviour of the virtual power plant on the market, make the overall final results of the various investment evaluations kind of conservative. In facts, it could be pointed out that market gains become *limited* by the substantially passive behaviour of the VPP on the energy markets – the VPP essentially behaves like a price-taker agent – while, in reality, it could be more likely to see a more

aggressive strategy during the first years of operations since there would be few operators (or nobody else) with such characteristics on the markets and the additional possibility to deploy arbitrage strategies could potentially increase the probability of making very interesting returns.
Another element that makes results conservative is that, as the bidding strategy and the prices used were conceived, the spread between energy markets (MGP, MI) and ancillary services markets (MSD, MB) is minimum, and does not change in time (with reference to the time horizon considered for the investment evaluation): the more competitive strategy deployed on the latter markets – in consideration of the existing probability of acceptance, which must be necessarily taken into account – and the passive strategy adopted on the previous two, makes so that the potential spread existing between these markets is curtailed together with the final profit deriving from market operations.

5.9 CONCLUSION AND HINTS FOR FURTHER DEVELOPMENTS

The case study that was presented focused on a particular kind of business model that was purposely ideated to try to bring advantage to both the investors and the consumers (when present) and to try to respect and anticipate the regulations on the matter – an example is the extension of the participation of the VPPs to all the markets composing the Italian MPE.
However, this work represents just a first attempt to analyse the opportunities related to the aggregation world in our country, and wants to be a sort of manifest to rise the attention on a topic which really seems to be able to sign and to influence a whole new generation of energetic systems, which is perfectly in line also with the concepts of emissions reduction and of energy efficiency that have become so important at supra-national level.
To conclude, it was thought then to report some interesting cues about the further developments, opportunities and problematics that this work pushes forward. The comments will be schematically presented point by point as for the comments to results in the previous paragraph.

- *An opportunity for RES plants exiting from incentive schemes*

  The particular convenience of undertaking the investment in case of fully covered capital expenditures regarding the production component of the VPP, opens the door to a larger reasoning and a broader set of opportunities. The opportunity to make RES plants qualified to operate also on ancillary services markets, makes the VPP an ideal solution to refresh and support the economic returns of older plants (which capital costs were considerably higher with respect to more recent installations) which are about to exit the *comfort zone* of incentive schemes.

  As the situation is today, those plants – which are generally deployed on the sole day-ahead market adopting a price-taker behaviour – would never be interested in participating to ancillary services markets, even if they could, since the presence of incentives makes for them more attractive the maximization of the quantity of energy sold (which is the basis on which they receive the incentive) on energy markets.

- *Not only a thing for RES*

  It is to be underlined that even though the case study was focused on photovoltaics, the world of aggregates is open potentially to all kinds of production technologies, from other non-programmable RES to fossil fuel-burning plants.

  To this regard, it would be particularly interesting to investigate the possible benefits deriving from the interaction, within the same VPP, of renewables and traditional sources. For example, a thermo-electric facility, which is notoriously a flexible technology, could be possibly utilised to back up a RES plant and avoid the purchase of a flexible but costly storage system, in order to cover potential outages due to unpredicted weather conditions and imbalances.

  It could be brought to example for this specimen the generation structure of the VPP created in the ambit of the already cited Fenix project.

- *Imbalances*

Another topic that may have a relevant impact on the future of UVAs is rightly the definition of imbalance rules. By now, the generalities provided by the *Authority* on the matter (see C*hapter 3*) are just to be considered as indications and more concrete rules are expected to be defined with the full completion of pilot projects. It could be interesting then, to evaluate a proper solution to apply to the various typologies of VPP according to case.

- *More penetrating and relevant role of optimization methodologies*
  This work demonstrated how important was the contribution of mathematical optimization in estimating and defining certain key figures needed to perform the investment evaluation.
  A further development of the models that have been presented could be then really interesting in perspective of future applicative purposes. For example, it could be developed a model which aim is to optimize the real dispatching of the VPP including a strategy aiming at imbalance minimization; or a function able to perform a check-up of dispatching programs so to be able to reshape internal flows on the basis of the offers that have been accepted or refused on the markets; another interesting evolution could focus on the possibility to define the optimal size of each component of the VPP basing on a few fixed parameters (such as the size or the energy produced by an existing group of generation units), considering the impact of the costs and the benefits of increasing/decreasing the size or the capacity of each element directly in the optimization algorithm; or again, developing an algorithm which is able to create a VPP starting from scratch by picking up the most suitable units from a portfolio of available options.

- *BESS evolution*
  It was already said that the still high cost of the BESS significantly impacted on the economic performance of the investment in a negative way. However, it is also undeniable that the wise deployment of a flexible energy storage system – like the Li-ion set of batteries considered in this work – can give a precious contribution in boosting market returns.
  These considerations would lead supposedly to think that, as soon as costs will fall enough to make energy storage technologies (Li-ion in particular) more

attractive, a lot of market players could adopt them to try to increase market returns, to cover imbalances, to cut demand during peak hours and so on.
It could be surely interesting then, to investigate how the diffusion of such technologies and such practices would impact on the profitability related to these technologies and practices themselves – how much space there could be in the market and how much of it can be *occupied* by players before the market gets too crowded and profits fall?

- *Trade-off between aggregation diffusion and market profitability*
  Following the same reasoning as of the precedent point, another future study may regard the specific estimation of the market space that could be occupied by aggregates and aggregators. In the same way as the study could be carried out for energy storage systems deployed for market purposes, it would be interesting to understand how the profitability of virtual power plants could change as their number increases.

- *Social benefits*
  A final suggestion regards the deeper investigation of the social benefits that the business of aggregation could bring under many forms, for example: lower energy costs and lower costs for the system translating into lower energy expenditures for consumers; augmented energetic efficiency through the use of smart technologies and optimization approaches.

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Appendix A

ITALIAN ELECTRICITY MARKETS

This appendix wants to provide a sufficiently exhaustive explanation of how the Italian Power Exchange (IPEX) works – focusing on its ready-made markets branch – and to give an elucidation about the ancillary services currently defined in the network code drafted by Terna *[79]. Information concerning the functioning of the markets make reference to the latest version of the integrated text related to the electric market, or* TIME*, and to the information publicly available on the website [80] of the Italian market operator, the* GME (Gestore dei Mercati Energetici). *For any further explanation please refer to cited documents.*

A.1. THE ITALIAN POWER EXCHANGE

In Italy, the entity responsible for the management of the energy markets (electricity and gas) is the aforementioned GME, or *Gestore dei Mercati Energetici*. The company is completely owned by the larger GSE (*Gestore dei Servizi Energetici*), an organization controlled by the Italian Ministry of Economy and Finance (*MEF*) that was created after the liberalization of the electricity sector in 1999 [81] [82]. Today, it receives strategic and operating inputs also from the Ministry for the Economic Development (*MiSE*).
With reference to the electricity market, the GME is the market operator of the Italian Power Exchange (IPEX), also instituted in 1999. The IPEX is divided into two main branches: the MTE (*mercati a termine dell'energia*), which refers to the forward market; and the MPE (*mercati a pronti dell'energia*), which gathers instead the ready-made markets.

A.1.1. Forward market

The MTE platform dedicated to the forward market keeps record of all the bi-lateral transactions that take place day by day among participants. It is based on a continuous trading mechanism in which each contract concluded is characterized by delivery and withdrawal obligation. The contracts may refer to standard conditions of the delivery period – base-load contracts – or to specific hours of the delivery period – peak-load contracts. The market operator constantly updates an order book reporting the bids for each typology of contract, for each delivery period. In this way, transactions are concluded through the automatic matching of demand and supply requests.
Given the strict requirements needed to operate on the MTE, the platform is less liquid with respect to other trading platforms made available by private subjects. All the bi-lateral transactions taking place outside the MTE are indicated as *over-the-counter* (OCT). These transactions get recorded and approved by mean of another dedicated platform called PCE (*piattaforma conti energia*). The operators having an energy account on the PCE platform are also allowed to proceed to the physical delivery of energy flows transacted by mean of derivatives contracted on the IDEX, a segment of Borsa Italiana S.p.A. dedicated to the negotiation of derivative instruments concerning the energy world. Such kind of derivatives can be executed on a dedicated platform, the CDE (*consegna derivati energia*). The GME acts as counterparty for the operators and keeps trace of each transaction on the energy accounts of the operators before each physical delivery takes place.

A.1.2. Ready-made markets

The MPE is the platform dedicated to ready-made markets and represents the *core* of the IPEX. It is composed of three main sub-markets: the MGP, the MI and the MSD. Each of them will be discussed more in details right below.

Day-ahead market

The MGP (*mercato del giorno prima*) is the principal energy market within the *MPE*. On this market, energy transactions refer to hourly energy blocks to be exchanged the following day. Operators participate presenting offerings indicating the quantity of energy to be traded and the maximum/minimum price at which they are willing to buy/sell that quantity.

Even though the name suggests that all transactions take place exclusively during the day before the delivery day, the MGP – for a given delivery day – opens up in the morning of the ninth day before the delivery day. The last market session terminates at 12 p.m. of the day before the delivery day.

Market participants can present up to four different combinations of price and quantity for the same transaction period (one hour). The algorithm responsible for the market clearing works in order to maximize the gains in the trading period basing on economic merit and in respect of security constraints regarding the energy exchange limits existing among the various market zones – *Nord, Centro Nord, Centro Sud, Sud, Sicilia, Sardegna* – the so-called *limited production poles – Priolo, Rossano, Foggia, Brindisi, Monfalcone* – and the *virtual foreign zones* related to cross-border transactions and couplings. The algorithm also has to take into account the bilateral contracts concluded outside the MPE platform since they imply the utilization of part of the capacity of the transmission network.

Accepted offers are notified to market participants after the closure of the market session. Therefore, it is not granted that a certain offer is accepted on the MGP since it works basically as an auction market.

In each hour, if the transmission constraints are all respected, the algorithm identifies a unique market clearing prices, which is equal for all the market zones. In case it is impossible to respect some cross-zonal transition limits, the algorithm splits the market into two or more zones and computes an equilibrium price for each zone. The zonal price is applied to all selling offers coming from the referential zone and to purchase offers which are not referred to consumption units belonging to national zones. For all the other

casuistries, the reference price is the PUN (p*rezzo unico nazionale*), which is given by the weighted average of the zonal prices on the quantities demanded in each zone.
The central counterparty for all market participants is always represented by the market operator, the GME.

Infra-day market

The MI (*mercato infra-giornaliero*) gives the opportunity to market participants to modify injection/withdrawal programs defined during day-ahead sessions through seven *additional* sessions. For each market zone, the price applied during MI sessions is the same zonal price applied on the MGP.
In this way, there is no possibility for selling bidders on the MGP to behave opportunistically and exploit any spread between the price on the MGP and the price on the MI.
Even withdrawal bidders which have the energy purchased on the MGP valorised at PUN are discouraged by the possibility of making arbitrage thanks to the application of non-arbitraging coefficients [72].

Ancillary services market

The MSD (*mercato per il servizio di dispacciamento*) is the market through which Terna procures the resources which are needed to manage and control the system: infra-zonal congestion relief, energy reserve creation, real-time balancing. It is not properly an energy market since what gets exchanged is namely the provision of a service to the national TSO.
The MSD is by nature very complex: Terna seamlessly manages available resources through an optimization process taking into account limitations and constraints to be respected while trying to identify the best interventions to be possibly carried out.

The final injection/withdrawal program defined by the offerings accepted on the MSD is hence the result of the convergence of a multitude of inter-related variables and trying to identify the trigger point of each event is extremely difficult.
Offerings are accepted on the basis of economic merit in order to grant the correct and efficient functioning of the system. Terna plays the role of central counterparty for all market participants.
The MSD is structured in two main phases: the programming phase – MSD *ex-ante* – and the balancing phase – MB (*mercato del bilanciamento*).
The first phase is composed of six sub-phases and the offers presented by market participants must be presented in a unique session starting at 12.55 p.m. of the day preceding the delivery day and closing at 17.30 p.m. of the very same day. During the programming phase are accepted offerings for the purchase and selling of energy reserves – secondary and tertiary – and infra-zonal congestion relief services – structural congestions among different zones are solved through the market splitting mechanism on the day-ahead market. Accepted offerings are remunerated according to a pay-as-bid mechanism.
The balancing phase is composed of six sub-phases as well. For the first sub-phase, the *MB1*, Terna considers as valid the offerings presented in the first sub-phase on the MSD ex-ante (*MSD1*), while for all other sessions the opening is fixed at 22.30 p.m. of the day preceding the delivery day and the closing is fixed at one hour and a half before the first hour belonging to the session object of negotiation.
During the balancing phase are accepted offerings for the purchase and selling of secondary regulation services – *usage and refurbishment* – and of real-time balancing between injections and withdrawals on the grid. Accepted offerings are always remunerated according to a pay-as-bid mechanism. Prices accepted on the MB are used to define imbalance charges.
On both the MSD ex-ante and the MB markets, qualified participants must communicate the price to which they are willing to change the dispatching program previously defined through day-ahead and infra-day market sessions. Offerings may refer to different products: ignition/shutdown, secondary regulation (upward or downward adjustments

to be performed in few minutes) and other services (generally upward/downward adjustments to be performed within larger timeframes).

The offerings can be presented by dispatching users only and must respect a minimum informative content: identification code of the operator, of the market, of the specific session and of the dispatching point related to the offer; the relevant period; the typology of the offer; the quantity and the unitary price.

Only plants which are qualified for the supply of dispatching services are admitted on the MSD. Before the first phase of the *RDE* came into force, only relevant (generators with active power at least equal to 10 MVA) programmable plants were considered as qualified units. RES plants, due to their non-programmability, were excluded and the MSD was operated almost exclusively by conventional thermo-electric plants. But with the beginning of the *RDE_1*, the qualification was extended also to qualified RES plants and to non-relevant RES units that are part of virtual aggregates (although aggregates will initially be able to participate to IPEX markets only through a series of pilot projects promoted by Terna and the ARERA).

FIGURE A1. *Timing of ready-made markets' sessions as defined by the GME*

Reference day	D – 1				D															
	MGP	MI1	MI2	MSD1	MB1	MI3	MSD2	MB2	MI4	MSD3	MB3	MI5	MSD4	MB4	MI6	MSD5	MB5	MI7	MSD6	MB6
Preliminary info	11.30	15.00	16.30	-	-	23.45*	-	-	3.45	-	-	7.45	-	-	11.15	-	-	15.45	-	-
Opening	8.00**	12.55	12.55	12.55	°	17.30*	°	22.30*	17.30*	°	22.30*	17.30*	°	22.30*	17.30*	°	22.30*	17.30*	°	22.30
Closure	12.00	15.00	16.30	17.30	°	23.45*	°	3.00	3.45	°	7.00	7.45	°	11.00	11.15	°	15.00	15.45	°	19.00
Provisional results	12.40	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Definitive results	12.55	15.30	17.00	21.45	#	0.15	2.15	#	4.15	6.15	#	8.15	10.15	#	11.45	14.15	#	16.15	18.15	#

**	means that the hour is referred to the day D - 9
*	means that the hour is referred to the day D – 1
°	means that the offers considered are the ones presented in the section MSD1
#	means that the publication time window is defined by the dispatching discipline

A.2. ANCILLARY SERVICES CHARACTERIZATION

In the Italian *network code* drafted by Terna are defined the characteristics, the modalities of procurement and the obligations that suppliers must respect with reference to the resources needed to assure system safety and security of supply.

The network operator has the duty to assure these requisites in any condition and must therefore prevent the system from breaking down even though it is menaced by predictive errors, inefficiencies and system failures.

So, ancillary services are principally used by the system operator to generate energy *reserves* with the aim to preventively create sorts of *cushions* to be deployed in defence of the system.

The provision of ancillary services to the system operator is anyhow allowed only to units that have undergone a specific procedure organized by the TSO itself, so to test the adequacy and the respect of technical requirements.

In what follows, a description of each service defined by Terna in the network code will be given. Each service will be properly contextualized according to its voluntary or compulsory nature and to the purpose it serves.

A.2.1. Compulsory services

Primary reserve

Terna recurs to the primary reserve to correct instantaneous imbalances among production and withdrawals with respect to the whole European connected system. It is a basic service that all the units qualified to supply ancillary services must provide. The reserve is created through unused ranges of capacity that all the units must devote to the system operator. Terna can deploy the capacity range in a few seconds by mean of an automatized mechanism according to need. Units that, for any reason, are not available – temporarily or permanently – to provide primary reserve services must pay a *substitution fee* to the system operator. RES units are the only ones that may be awarded with a remuneration for the provision of this kind of services after the overcoming of certain thresholds, as declared in the *network code* [83].

Primary and secondary voltage regulation (reactive power)

Voltage regulation is performed through two tiers of reactive power *reserve*. Generation units supply this service by making their reactive power production subservient to an automatic regulation device. In this way, it is assured that for each alarming voltage differential recorded at the terminals of a single generation unit connected to the medium-voltage or to the high-voltage network, the reactive power is always adjusted instantaneously in defence of the system. The difference between primary and secondary voltage regulation lays in the fact that the second one is performed by units intervening in case alarming voltage differential concerns key nodes of the network, which are explicitly defined by Terna.

Primary regulation services are not remunerated. Secondary regulation services are more regulated but a practical remuneration has never been defined.

Load rejection

It foresees the disconnection of the considered units from the grid in case of external faults. Disconnected units cannot be shut down for a pre-defined period of time in order to be ready to be re-connected as soon as possible. This is a particular service which has to be mandatorily supplied by units with a power higher than 100 MW.

Participation to system recovery

Units adhering to the plan for the recovery of the electricity system must respect the requisites defined in [84]. The most important characteristics that these units must be able to provide are: the possibility of executing an autonomous ignition in absence of external propellant while granting the provision of voltage and frequency regulation services; the proper execution of the load rejection service.

Remote release

This service is performed through the help of automatic devices able to disconnect the afferent unit behind a real-time order coming from the system operator. Units supplying the service must respect precise technical requirements as defined in [85] and get selected simultaneously to the process of definition of binding programs.

A.2.2. Voluntary services

Interruptible load

This is a service contracted outside the market between Terna and final clients. The service provided consists in a temporary disconnection of the user from the network and is activated in case the resources procured by the system operator on the MSD resulted unable to cope with the issues affecting the system. The disconnection is demanded by Terna through a real-time request that is to be executed within a predefined time window. Users supplying the service receive an annual premium plus a positive or negative compensation depending on the number of interruptions correctively performed.

Congestion healing in the programming phase

It is a service transacted within the MSD on a daily basis and is used by the system operator to cope with congestion problems that verify after the update of cumulated injection/withdrawal programs. The resources procured by Terna offer their availability to undergo modifications to their own updated cumulated programs. The service is remunerated according to a pay as bid mechanism and qualified units are obliged to present offerings.

Secondary reserve

The TSO recurs to secondary power reserves in order to compensate the differences between system production and requirements and also in order to free primary reserves. Since the problems regarding national systems may generate also cross-border power exchange imbalances, these reserves intervene not only at national level but also to heal import/export imbalances.

Secondary reserves have to be activated within a few minutes from the reception of the request.

The service is daily negotiated on the MSD and remunerated according to a pay as bid mechanism. Qualified units are obliged to present offerings to the TSO.

Tertiary reserve

Tertiary reserves are generated to serve two purposes: to create margins with respect to the maximum and minimum power thresholds of the programs exiting from the MSD ex-ante; to substitute secondary reserves. There are two modalities according to which the service can be performed: the *upward* modality foresees resources to increase their power output; the *downward* modality foresees instead that resources decrease their power output. The provision of these services, independently from the modality, is demanded by Terna through real-time dispatching orders that must be executed within time windows that range between fifteen minutes and two hours.

Resources are procured by the system operator on a daily basis on the MSD and get remunerated according to a pay as bid mechanism. Again, qualified units are obliged to present offerings to the TSO.

Balancing services

Balancing services are required by the system operator to maintain injections and withdrawals in equilibrium, to manage congestions and to restore secondary reserves. Balancing services are deployed by Terna through the activation of tertiary reserves and through real-time procurement on the MB. Remuneration modalities are the same foreseen for the tertiary reserve.

Appendix B

INNOVATIVE DISPATCHING MODELS PROPOSED WITH THE STUDY PERFORMED BY THE DEPARTMENT OF ENERGY OF POLITECNICO DI MILANO ON BEHALF OF THE *AUTHORITY*

In this appendix, a more detailed overview about the innovative proposals contained in the study carried out by the Department of Energy of Politecnico di Milano *and attached to the* DCO *354/2013/R/eel will be given. References to everything is reported below can be found in the official text of the attachment [19]. Please refer to the very same document for a complete explanation.*

B.1. CENTRALIZED EXTENDED DISPATCHING

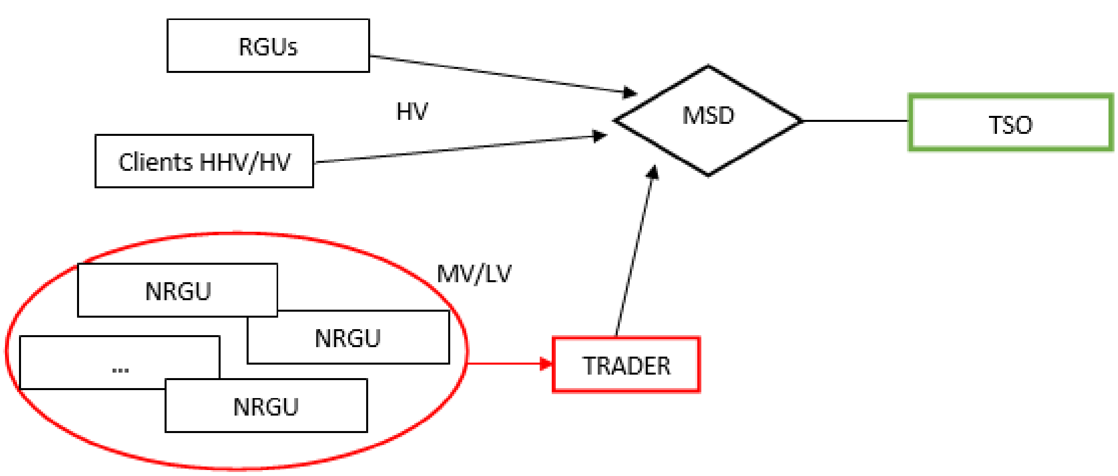

FIGURE B.1. *Model 1 - centralized extended dispatching*

The first model proposed within the study attached to the *DCO* is the one that was adopted as reference by the ARERA, formerly AEEGSI (*Autorità per l'energia elettrica, il gas e il sistema idrico*), in the aftermath of the public debate launched in 2013.
One of the main motives behind the choice of this model lays behind its central dispatching approach, meaning that no revolutionary change should be ideally applied in case of a hypothetic implementation. The interaction of distributed units with the network would are in facts managed in a centralized way by the TSO. Terna is seen also as the unique counterparty for all dispatching users. Each user is identifiable with both the figures of BRP (balancing responsible party) and the BSP (balancing service party), respectively defined as the subject responsible for imbalances and the subject responsible for the provision of ancillary services.
DSOs would have the opportunity to deploy distributed units for the supply of services related to local issues and would keep managing their networks according to a passive *fit&forget approach* – i.e. trying to limit the capacity of distributed units in order to avoid negative effects due to a high level of penetration.
For what concerns the access to the MSD, the creators of the model foresaw that all relevant generation units (RGUs) connected to the high voltage transmission grid would have been allowed to directly access the MSD, while non-relevant generation units (NRGUs) would have been allowed to do the same only if part of larger aggregations (and only via a specified trading figure). An exception to the necessity of interfacing the MSD mandatorily by mean of an intermediary was foreseen with respect to non-relevant units having a nominal active power higher than 1 MW.

The goodness of this approach lays in the already mentioned possibility to maintain unchanged the majority of current mechanisms and in the possibility to deploy distributed units to supply local services in favour of DSOs, if required.
The principal remark that can be done to this model concerns the managerial complexity related to its practical implementation: the huge number of units involved – that would be centrally managed – puts in evidence possible problems of measurement and verification of the quantities of energy to be effectively delivered, while another *limitation* could be potentially given by a *busier* MSD.

B.2. LOCAL DISPATCHING

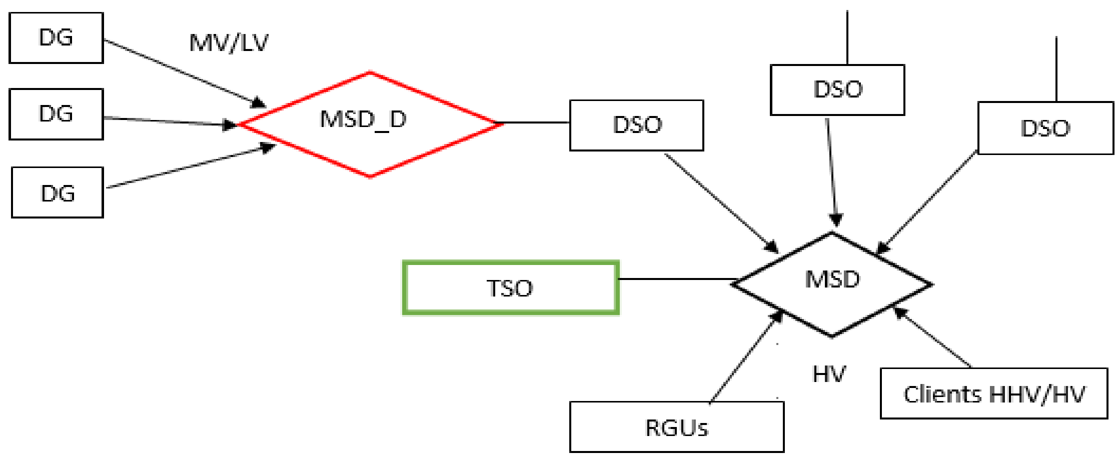

FIGURE B.2. *Model 2 – local dispatching*

The second model proposed in the attachment to the *DCO* was based on a radically different approach with respect to the first one and foresaw a much more active role of DSOs.

The interaction of the distributed generation (DG) with the network is now locally managed by distribution system operators, to which the creators gave also the duty of organizing special local markets (*MSD_D*) for dispatching services participated by DG units offering the supply of both local and system services and to be executed in between the sessions of the MGP/MI and those of the MSD. Single DSOs become then responsible for local dispatching but also for placing offerings on the MSD, becoming sort of *dispatching users* themselves.

Other duties for DSOs comprehend the verification of the respect of the constraints concerning their networks and the management of the conflicts between optimal distribution and transmission plans.

The model foresaw that, in case of zonal dimensioning, DG units could be allowed to gather into a unique dispatching point under the responsibility of a specified trading figure. Relevant plants are instead given the possibility to directly access the MSD.

Among the advantages deriving from the actuation of this model, it is possible to identify a *maximization* in the usage of resources and a probably better management of the conflicts between distribution and transmission programs.

It is however inevitable to question the real possibility to create a local market for dispatching service for each distribution network. Another problematic would regard, to this purpose, how to practically implement the local markets in terms of *timing*: the time window proposed is probably be too short in relation to the high number of expected participants.

B.3. ORGANIZED VOLTAGE EXCHANGE PROFILE

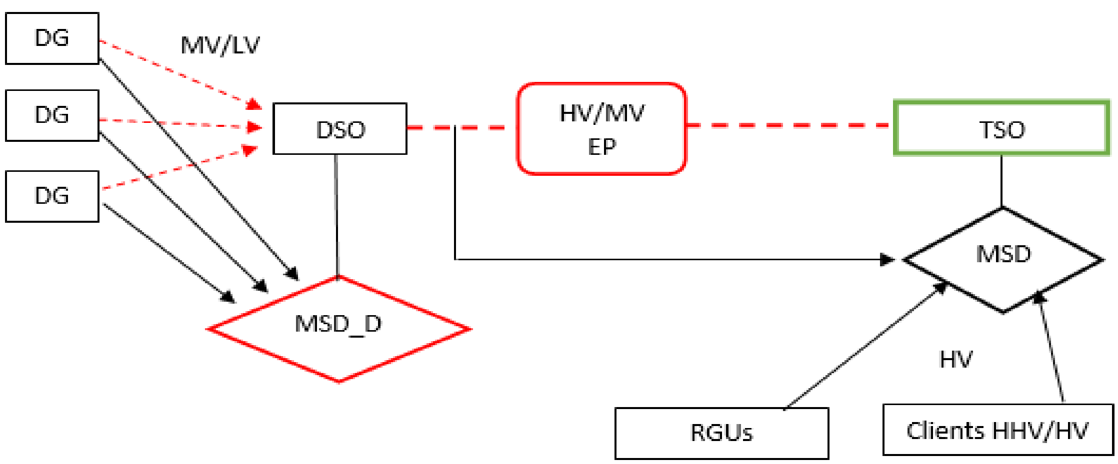

FIGURE B.3. *Model 3 – organized high-to-medium voltage exchange profile*

The third option contained in the attachment conceived a sort of variation of the situation depicted in the second model.

Systems connected to low or medium voltage grids are managed by DSOs on behalf of the national TSO, in an optic of centralized dispatching. The novelty consists in the fact that DSOs are supposed to manage resources in order to respect pre-established high- and medium-voltage exchange plans prepared by the TSO. DG units are thought here to provide only balancing services to DSOs at local level. Relevant generation units are allowed to directly access the MSD.

Even though it may seem strange, a deeper look at this configuration reveals that little would have to be physically changed with respect to the current situation to implement it. In the idea of the creators, it could also be appreciable the managerial fluency of distributed units.
A heavy disadvantage is to be identified in that DG units would not serve to the provision of network services, which is after all one of the main opportunities that the reform of the dispatching proposed to catch. Another constraint to this third model could be raised by questioning whether the number of distributed resources per single DSO could result to be scarce. In that case, there would probably be no other solution but furtherly investing into coping systems such as energy storage systems.

Appendix C

MATHEMATICAL OPTIMIZATION

In this appendix it is provided a more detailed explanation concerning the basics of mathematical programming models. The following content, of course, is not to be considered a complete overview. It is possible to refer to the documents cited in the text for further and more careful explanations. Note that the arguments treated in what follows refer to the forms of optimization encountered while designing the models described in Chapter 5.

C.1. OPTIMIZATION PROBLEMS

A general optimization problem can be represented in the following form:

Given a function $f : A \to \mathbb{R}$

Find: an element $x_0 \in A$ *s.t.* $f(x_0) \leq f(x)\ \forall x \in A$ in case of minimization

an element $x_0 \in A$ *s.t.* $f(x) \leq f(x_0)\ \forall x \in A$ in case of maximization

The subset $A \subseteq \mathbb{R}$ is called *search space* or *choice set* and is specified by a set of constraints, usually equalities and inequalities, that the elements of A must satisfy. The elements of A are called feasible solutions. The function f is generally called *objective function*. If it exists a feasible solution that minimizes – or maximizes, according to need – the objective function, then it is called an *optimal solution* [57].

C.2. MODELLING FRAMEWORK

The various forms of optimization that can be adopted to solve mathematical problems depend on the structure of the domain of the problem itself and on the proprieties of the objective function.
In the following sub-paragraphs, it will be given an overview of the most important theoretical concepts at the basis of the models realized.

C.2.1. Linear programming

Linear programming (LP) is a form of optimization in which the problem is represented just by **linear relationships**. This means that both the objective function and the constraints of the problem must be expressed through linear expressions.

Here is a general formulation of a linear programming problem:

$$\max k^T x \tag{C.1}$$

$$\text{s.t. } Ax \leq c \tag{C.2}$$

$$x \geq 0 \tag{C.3}$$

The decision variable in the problem is given by x, while k, A and c are known parameters.
Equation (C.1) is the objective function, equation (C.2) is the constraint on the decision variable x. Equation (C.3) is the non-negativity constraint on x. The constraints define the feasible set for the decision variable x.

A vector x for a linear programming problem is said to be feasible if it satisfies the corresponding constraints. A linear programming problem is said to be feasible if the constraint set is not empty; otherwise it is said to be infeasible [57]. The vector is optimal if it is feasible and is such that the objective function achieves its minimum or maximum value. The feasible region is a convex polytope, which is a set defined as the intersection of finitely many half spaces, each defined by a linear inequality [57]. A linear programming algorithm finds a point in the polyhedron search space where the objective function has the smallest – or largest – value, if such a point exists.

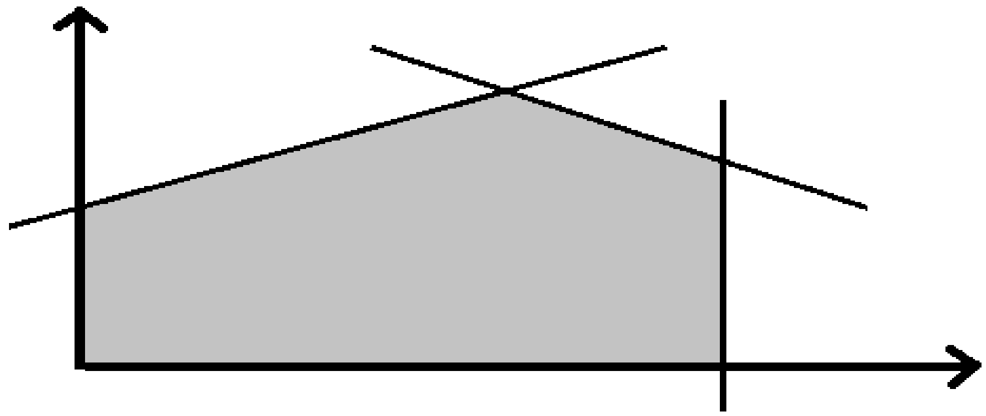

FIGURE C.1 *Example of convex bi-dimensional search space (linear optimization problem)*

A linear programming problem is usually solved with the simplex method. Developed by George Dantzig in 1947 [86][87], it has proved to be remarkably efficient and today it is used routinely to make computers solve huge problems. A description of how to solve a linear programming problem through the simplex method can be found in [88][89].

Dual problem

For each linear problem, or *primal problem*, there is a *dual problem* which is strictly connected to the first one. Given the standard form for the primal problem showed in before, the dual problem has the following form:

$$\min y^T c \tag{C.4}$$

$$\text{s.t. } Ay \geq k \tag{C.5}$$

$$y \geq 0 \tag{C.6}$$

The dual problem makes use of the very same parameters of the primal problem, but in different locations. An exhaustive explanation of the relationships between primal and dual problems can be found in [57].

C.2.2. Non-linear programming

For completeness, it is to be said that in case the objective function, the constraints, or both of them, contain non-linear terms, the problem is said *non-linear* (NLP). Solving this kind of problems is much harder than solving a traditional linear problem, and the optimal solution is not always guaranteed. Different methods and algorithms to solve a non-linear program are shown in [90].

C.2.3. Integer linear programming

In a LP problem, if the variables are Boolean or integer, the problem is said to be *integer linear* (IP). A general formulation is given by:

$$\max k^T x \tag{C.7}$$

$$\text{s.t. } Ax \leq c \tag{C.8}$$

$$x \in \mathbb{Z}_+^n \tag{C.9}$$

The feasible region now consists of a discrete set of points which is contained in the polytope defined by the constraints. The solution cannot be considered a convex set anymore. Consequently, the theory developed for LP cannot be directly applied to this class of problems.

C.2.4. Mixed integer linear programming

Operation research includes also a class of problems called *mixed integer linear* (MILP), that are basically linear problems in which only a subset of variables has integer values. Here is an example:

$$\max k^T x + w^T y \tag{C.10}$$

$$\text{s.t. } Ax + By \leq c \tag{C.11}$$

$$x \geq 0, \quad y \in \mathbb{Z}_+^n \tag{C.12}$$

There are different algorithms to find the solution of IP and MILP problems. One of the principals is the so-called *Branch and Bound* algorithm, initially proposed by A.H. Land and A.G. Doig in 1960, that uses linear programming relaxation to find the optimal solution [57]. It is the basic algorithm used by all commercial codes for solving IP and MILP problems. A description of how to solve a IP or MILP problems through the Branch and Bound method can be found in [57].

Appendix D

VOLUMES TRADED AND RELATED ECONOMIC VALUE

In this appendix it is provided a detailed outlook of the distribution of the energy volumes traded among the markets for each VPP configuration simulated with the optimization models. It is also reported the related economic value of the volumes.

D.1. UVAM

TABLE D.1. *Volumes transacted and related value - UVAM 1*

UVAM 1	**ECONOMIC VALUE [€]** (sold – purchased)	**VOLUMES [MWh]** (sold – purchased)
MGP	54.610 - 0	826 - 0
MI	0 - 146.721	0 - 3.274
MSD	234.870 - 15.854	4.184 - 285
MB	265.864 - 7.691	4.809 - 133
TOTAL TRANSACTED	725.610 €	13.511 MWh
MARKET GAINS	385.078 €	

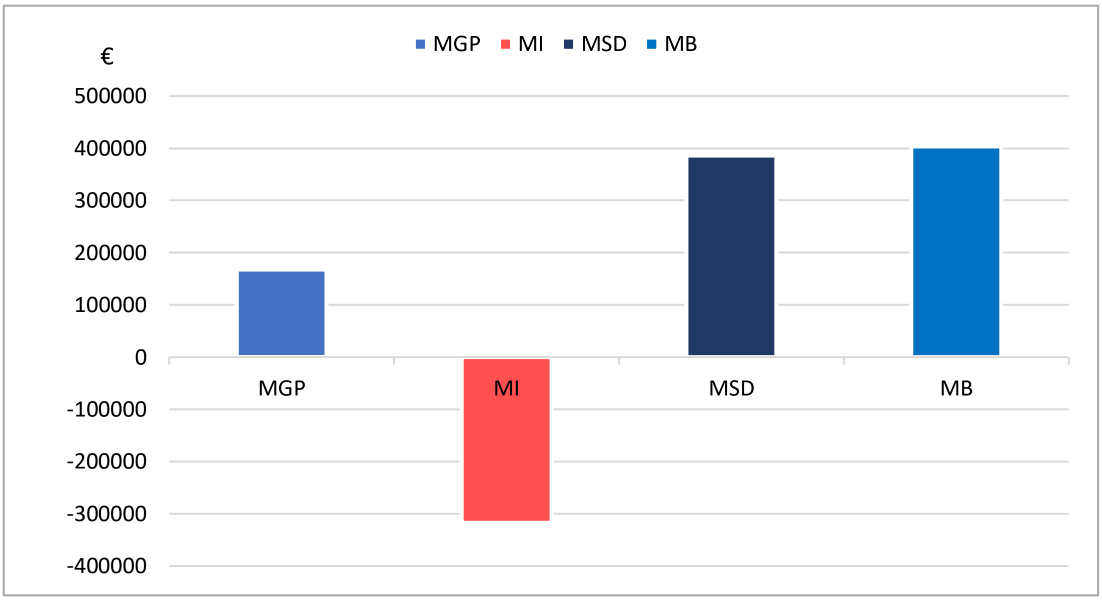

FIGURE D.1. *Distribution of net market gains – UVAM 1*

The UVAM has an internal aggregated consumption profile to be satisfied. As it can be denoted by the graph and the data reported in the table, the MI represented the preferred and only option chosen by the algorithm to execute purchases and at the same time the less profitable solution to sell the energy produced (not a single MWh of energy was sold on that market).

UVAM 1 is evidently induced to sell mainly on the MSD, attracted by the possibility of higher gains despite the *competitive price* strategy put into place. The MGP is marginally participated and never used to purchase energy.

TABLE D.2. *Volumes transacted and related value - UVAM 2*

UVAM 2	**ECONOMIC VALUE [€]** (sold – purchased)	**VOLUMES [MWh]** (sold – purchased)
MGP	205.151 - 0	3.088 - 0
MI	0 - 569.705	0 - 13.853
MSD	462.067 - 41.534	8.268 - 774
MB	477.390 - 35.825	8.894 - 622

TOTAL TRANSACTED	1.791.672 €	35.499 MWh

MARKET GAINS	497.542 €

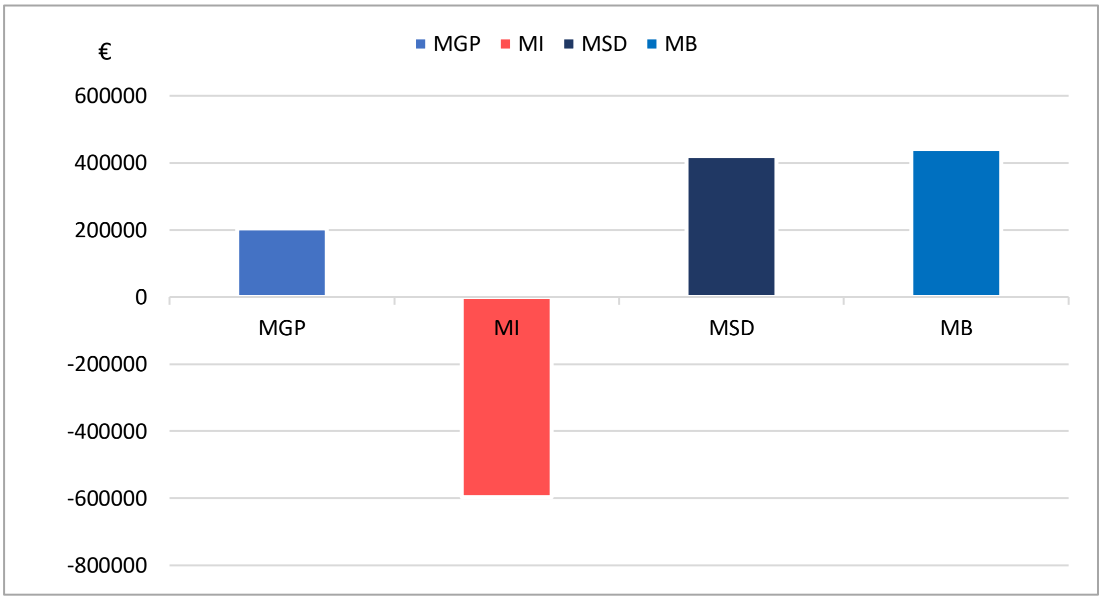

FIGURE D.2. *Distribution of net market gains – UVAM 2*

In this case, the presence of the BESS makes withdrawals increase a lot on the MI while: the energy purchased during one hour on the MI was sold under the form of a service during subsequent hours on the more profitable MSD and MB markets, in which injections increase significantly. Despite of the unsustainable costs related to this solution, BESS operations bring evidently more market gains to the VPP. The volumes transacted increase also on the day-ahead market.

TABLE D.3. *Volumes transacted and related value - UVAM 3*

UVAM 3	**ECONOMIC VALUE [€]** (sold – purchased)	**VOLUMES [MWh]** (sold – purchased)
MGP	352.628 - 32.494	5.344 - 773
MI	0 - 1.040.220	0 - 25.278

MSD	717.529 - 82.131	12.934 - 1.543
MB	752.067 - 69.047	14.196 - 1.200

TOTAL TRANSACTED	3.046.116 €	61.268 MWh

MARKET GAINS	598.332 €

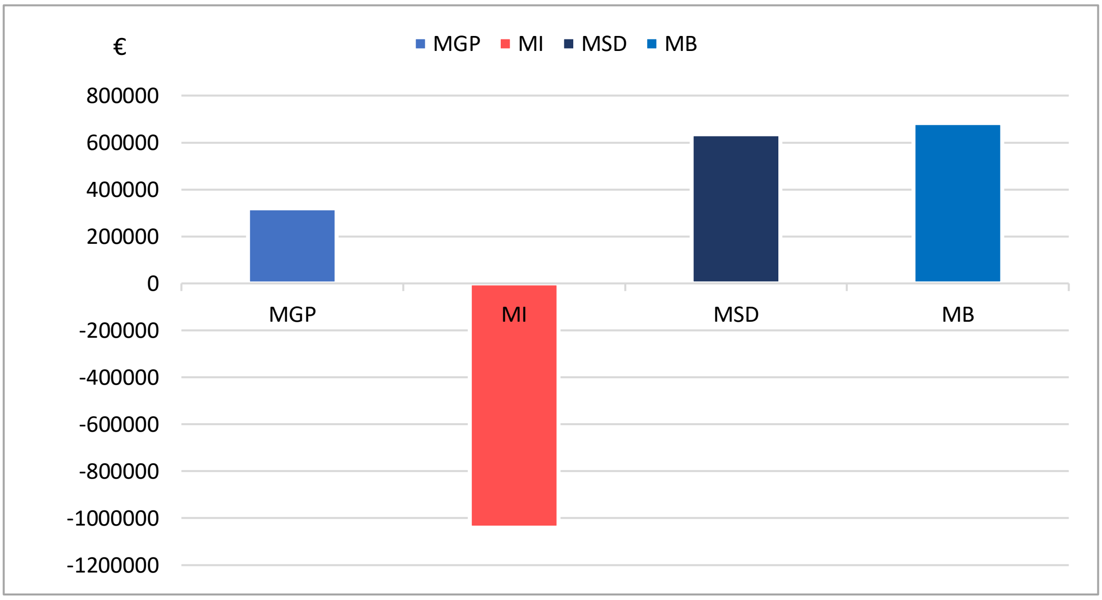

FIGURE D.3. *Distribution of net market gains – UVAM 3*

The effect of the arbitrage strategy deployed through the BESS makes volumes transacted increase even more with respect to the UVAM 2 case and brings higher market gains to the VPP. The arbitrage strategy allows to ideally execute multiple charges and discharges during a single hour so to purchase/sell energy on the energy markets and sell/purchase it back under the form of a service on the MSD and the MB markets even within the same hour.

Even the MGP is more participated; looking at the data reported in the table above it is possible to see also that more than 770 MWh have been withdrawn on that market (expectedly for arbitrage purposes).

TABLE D.4. *Volumes transacted and related value - UVAM 4*

UVAM 4	ECONOMIC VALUE [€] (sold – purchased)	VOLUMES [MWh] (sold – purchased)
MGP	278.124 - 24.371	4.214 - 580
MI	0 - 816.845	0 - 19.777
MSD	596.684 - 65.562	10.746 - 1.229
MB	630.517 - 53.708	11.849 - 934
TOTAL TRANSACTED	2.465.991 €	49.329 MWh
MARKET GAINS	545.019 €	

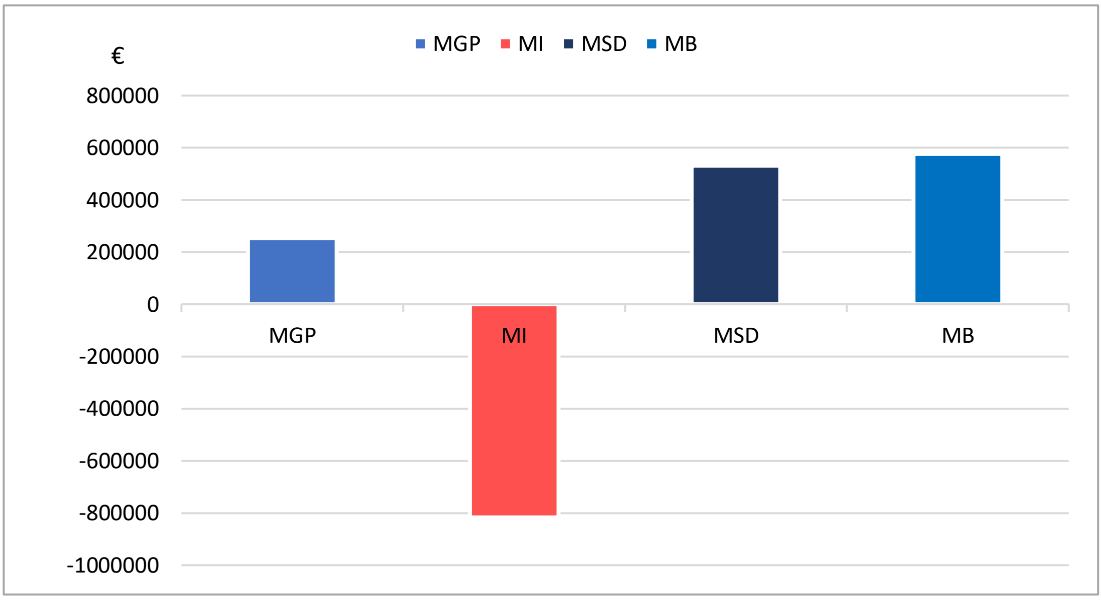

FIGURE D.4. *Distribution of net market gains – UVAM 4*

In this configuration the situation is totally similar to the situation depicted in the previous UVAM 3 case, the only difference is represented by the lower gains and volumes transacted due to the lower capacity of the BESS.

TABLE D.5. *Volumes transacted and related value - UVAM 5*

UVAM 5	ECONOMIC VALUE [€] (sold – purchased)	VOLUMES [MWh] (sold – purchased)
MGP	352.628 - 32.494	5.344 - 733
MI	0 - 1.235.799	0 - 29.642
MSD	717.529 - 103.265	12.934 - 1.923
MB	752.067 - 79.300	14.196 - 1.378
TOTAL TRANSACTED	3.273.082 €	66.190 MWh
MARKET GAINS	371.366 €	

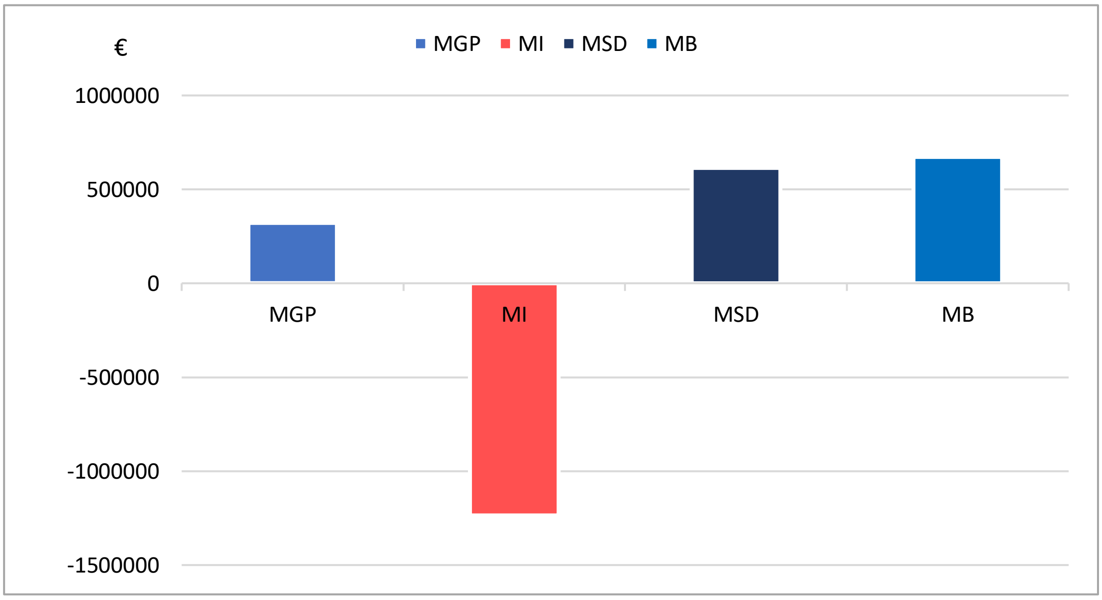

FIGURE D.5. *Distribution of net market gains – UVAM 5*

In this last UVAM configuration the volumes transacted on the MI furtherly increase because of the higher numeber of families joining the CU aggregate. Consequently, the higher consumption leads to an increased expenditure as the amount of energy withdrawn intesifies.

D.2. UVAP

TABLE D.6. *Volumes transacted and related value – UVAP 1*

UVAP 1	**ECONOMIC VALUE [€]** (sold – purchased)	**VOLUMES [MWh]** (sold – purchased)
MGP	54.610 - 0	826 - 0
MI	-	-
MSD	234.870 - 0	4.183 - 0
MB	265.864 - 0	4.809 - 0
TOTAL TRANSACTED	555.344 €	9.818 MWh
MARKET GAINS	555.344 €	

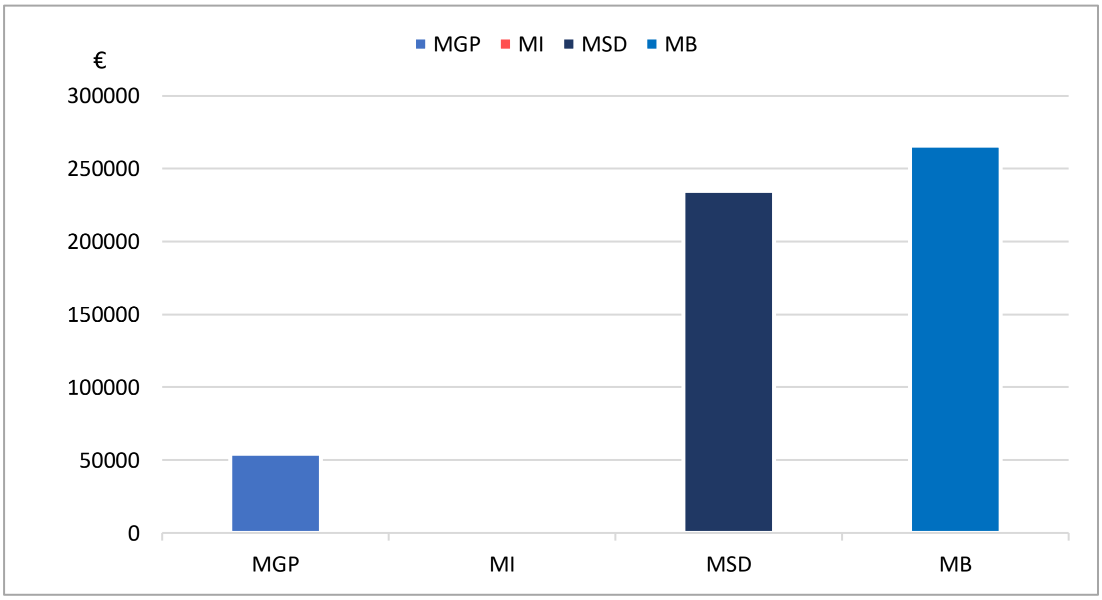

FIGURE D.6. *Distribution of net market gains – UVAP 1*

In case of UVAP aggregates there is no consumption profile to be satisfied, thus the only activity of the VPP on the markets concerns the sale of the energy it produces. Being this situation the equivalent of the one faced in the UVAM 1 case, the infra-day market ends up being totally *emarginated* from market transactions: the VPP is induced to operate mainly on the MSD and on the MB, attracted by the possibility of higher gains despite the *competitive price* strategy put in place, and – having no internal consume to satisfy – totally neglects the MI market. The MGP conserves a marginal role.

TABLE D.7. *Volumes transacted and related value – UVAP 2*

UVAP 2	**ECONOMIC VALUE [€]** (sold – purchased)	**VOLUMES [MWh]** (sold – purchased)
MGP	167.516 - 0	2.523 - 0
MI	0 - 317.238	0 - 7.934
MSD	405.268 - 19.259	7.246 - 367
MB	424.508 - 21.100	7.872 - 367
TOTAL TRANSACTED	1.354.889 €	26.309 MWh
MARKET GAINS	639.695 €	

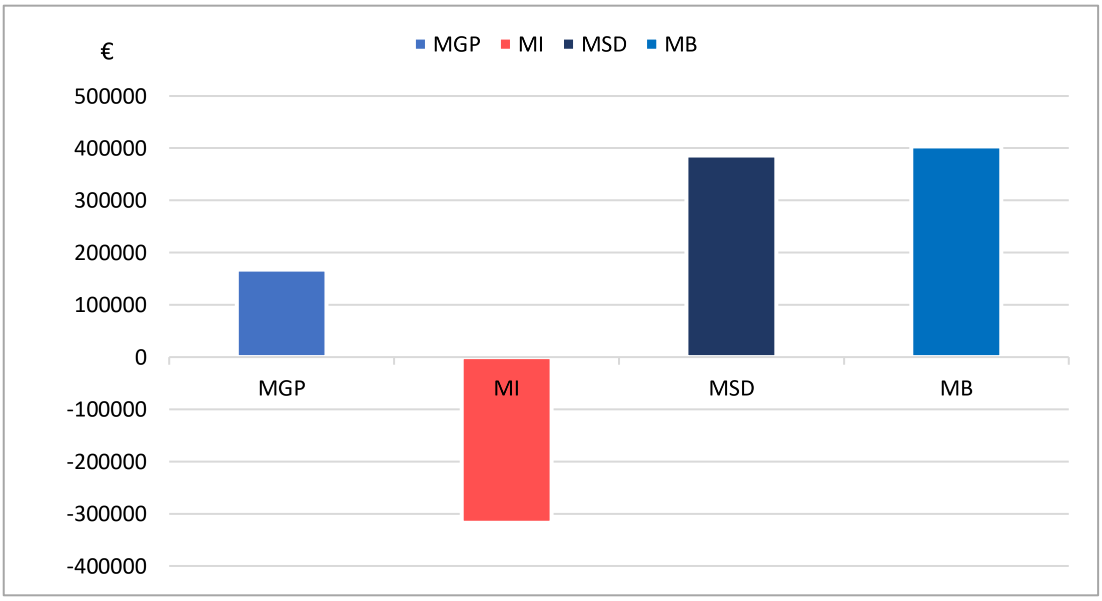

FIGURE D.7. *Distribution of net market gains – UVAP 2*

The energy withdrawals executed on the MI are due to the operations carried out by the BESS. As for the UVAM 2 case, the infra-day market remains the most convenient to purchase energy and the worst one on which to sell it. Again, the VPP is induced to offer performances mainly on the MSD and on the MB, attracted by higher margins. Unchanged also the role of the MGP market. The use of the BESS helps the VPP to improve market gains, despite of the unsustainable costs related to the solution.

TABLE D.8. *Volumes transacted and related value – UVAP 3*

UVAP 3	**ECONOMIC VALUE [€]** (sold – purchased)	**VOLUMES [MWh]** (sold – purchased)
MGP	278.124 - 24.371	4.214 - 580
MI	0 - 670.124	0 - 16.502
MSD	596.864 - 49.707	10.747 - 943
MB	630.516 - 46.016	11.850 - 800
TOTAL TRANSACTED	2.295.722 €	45.636 MWh
MARKET GAINS	715.286 €	

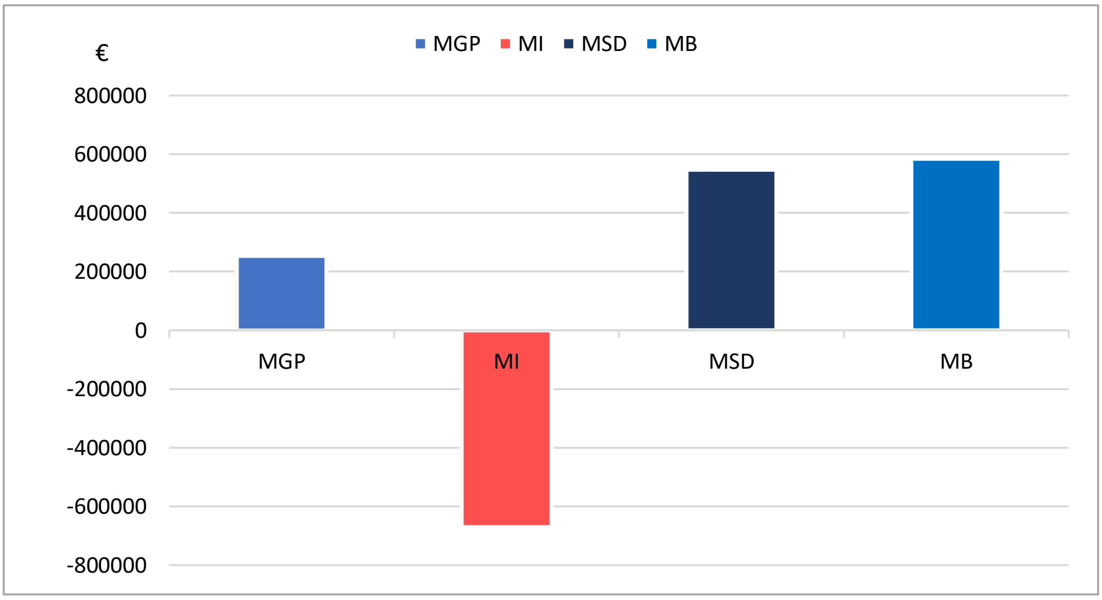

FIGURE D.8. *Distribution of net market gains – UVAP 3*

This situation is parallel to the one depicted for the UVAM 3 case: the increase in the level of volumes transacted and of profit made is due to the better deployment strategy undertaken to exploit the potentialities of the BESS.

TABLE D.9. *Volumes transacted and related value – UVAP 4*

UVAP 4	ECONOMIC VALUE [€] (sold – purchased)	VOLUMES [MWh] (sold – purchased)
MGP	203.619 - 16.247	3.085 - 386
MI	0 - 446.749	0 - 11.002
MSD	476.199 - 33.138	8.558 - 629
MB	508.966 - 30.677	9.503 - 533
TOTAL TRANSACTED	1.715.595 €	33.696 MWh
MARKET GAINS	661.973 €	

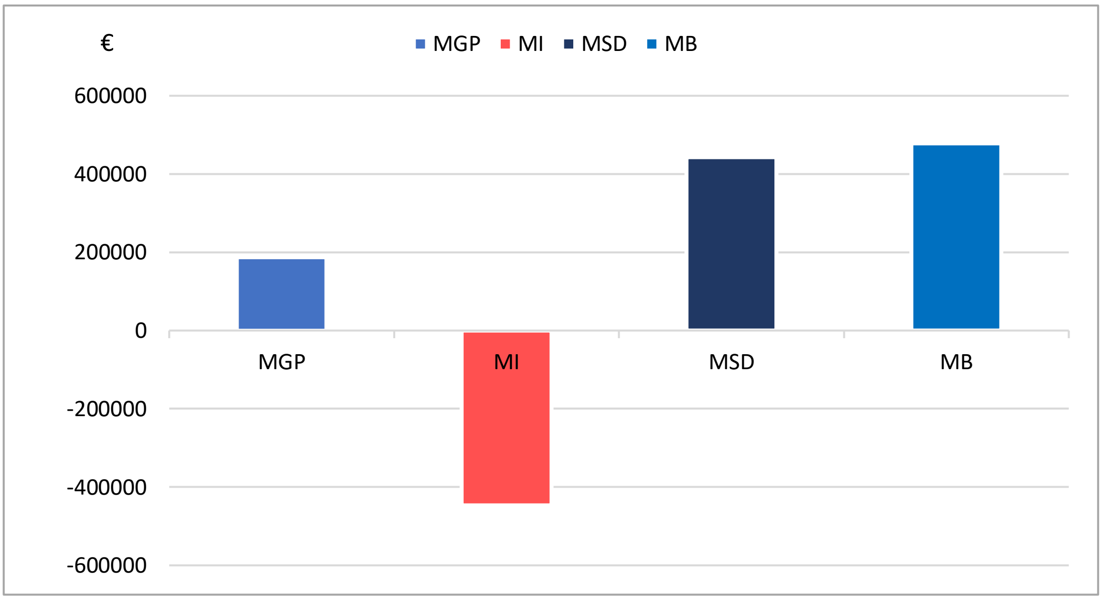

FIGURE D.9. *Distribution of net market gains – UVAP 4*

In this configuration the situation is totally similar to the situation depicted in the previous UVAP 3 case, with the only difference laying in the lower gains and volumes transacted due to the lower capacity of the BESS, that was reduced from 3 MW to 2 MW.