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"EVALUATING THE AGGREGATION OF DISTRIBUTED ENERGY RESOURCES IN THE ITALIAN ELECTRICITY MARKET"

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SUMMARY

Renewable generation is being widely adopted throughout the world, facing a dramatic increase along last decade. Nevertheless, the expansion of Renewable Energy Sources (RES), due to their intermittent and not-programmable production, and Distributed Generation (DG), due to market segmentation derived by its development, originates major difficulties in the alignment of electricity demand and supply, fundamental to ensure grid stability. This leads to major complications and inefficiencies in the management of the electric system, with higher costs for the TSO (Transmission System Operator), which shift on the community in the form of general system charges.

The introduction of Virtual Power Plants (VPP), aggregates of different production and/or consumption units, represents a possible solution to grid congestion. In this regard, Terna, the Italian TSO, is currently introducing new aggregation possibilities in the Italian power market, setting up the basis for an Italian Demand-Response (DR) market.

By the release of Resolution 300/17, the Italian Authority has put in place the foundations for a renewed power market, allowing for the participation of both demand and small-size producers in the ancillary service market (MSD – Mercato dei Servizi di Dispacciamento) as a single Aggregate of multiple units. The current regulation is addressed to both Consumption units (UVAC – Unità Virtuale Abilitata di Consumo), Producers (UVAP – Unità Virtuale Abilitata di Produzione) and Mix of them (UVAM – Unità Virtuale Abilitata Mista).

In order to clarify the economic opportunities of this new mechanism, the present thesis represents a critical review of the potential value of an UVAM participating in the MSD according to the current regulatory framework, defining the factors that is determining and will determine its value.

Therefore, in order to present an organic and complete overview of the new scenario that the Italian power market is going to challenge, the present thesis is structured in the following four chapters:

1. The first Chapter presents an introduction to the current market conditions, describing the recent energetic transition experienced in Italy, the complications derived from the spread of DG. It is introduced the mechanism of Demand-Response, highlighting its benefits in economic and operative terms.

2. The second Chapter describes the current framework for the Demand-Response Market, considering both the current European and Italian Regulatory Frameworks. It will be outlined the main participants to the market as well as possible market models for the figure of the Aggregator, and it will be clarified the main sources of flexibility.

3. The third Chapter focuses on the MSD Market, first illustrating the structure of the Italian power market and afterwards defining the MSD market and dispatchment services. It has been provided an analysis of market fundamentals and its evolution concerning the last 3 years of market outcomes as well as the first results of the Pilot Projects provided by Terna on the Italian power market.

4. The fourth Chapter presents a Case Study developed in order to estimate the value generated for an UVAM by the aggregation of different units and the participation to the MSD market, according to the current Italian Regulatory Framework and following the procedure provided by Terna regarding UVAM's pilot project. It will be also exposed a Price Analysis regarding the MSD to estimate the optimal offers to be presented on the market on the basis of current market conditions.

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1. POWER MARKET EVOLUTION

1.1 ENERGETIC TRANSITION – GROWTH OF RENEWABLE GENERATION IN ITALY

Along last decade, the Italian power system faced a dramatic energetic transition to Renewable Energy Sources (RES), due to the increase of investments in Renewable Generation (RG) following several legislative initiatives supported by both the European Union and the Italian governments (e.g. *"Conto Energia"*[1], *"Conto Termico"*[2]). Italy implemented generous incentive schemes to exploit the potential of renewable energy production. Its largest scheme incentivised solar PV production and led Italy from a low base of installed PV in 2010 to become the world's fourth largest country by installations by the end of 2014. Indeed, between 2007 and 2013, 28.587 MW of new renewable capacity was installed in Italy, more than doubling previous renewable installations (+234% of renewable capacity).

Solar energy production alone accounted for about the 8% of total electric production in the country in 2014, making Italy one of the countries with the highest contribution from solar energy in the world. Rapid growth in the deployment of solar, wind and bio energy in recent years led to Italy producing over 40% of its electricity from RES.

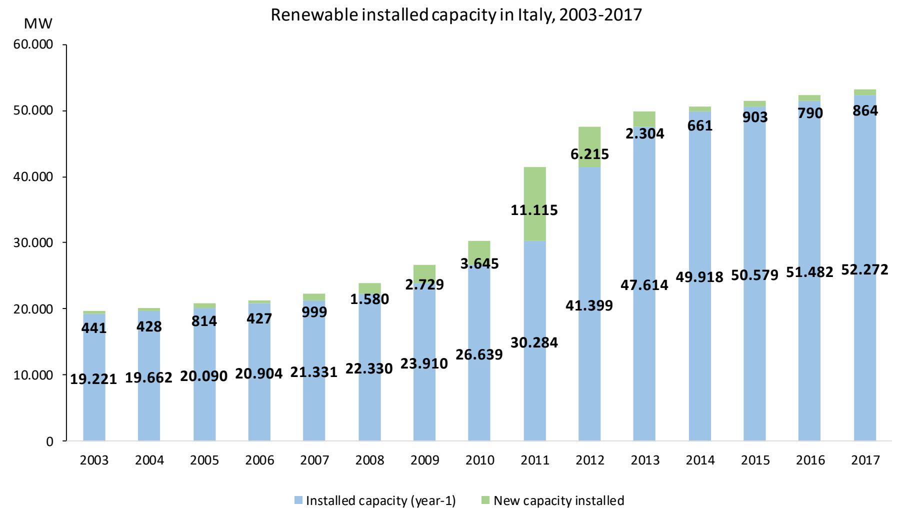


Figure 1. Renewable installed capacity in Italy, 2003-2017. Source: GSE, Osservatorio FER (Anie Rinnovabili)

[1] Italian Ministerial Decree of the 6th of February 2006.
[2] Italian Ministerial Decree of the 28th of December 2012.

Such impressive energetic transition has been pushed by three main international economic and social drivers:

- Purpose of reaching the energetic independence from fossil fuels, especially concerning country as Italy with limited reserves of hydrocarbon deposits, by consumptions' electrification and consequent increase in electricity production;
- Decreasing costs of RES investments. Photovoltaics' greenfield investment costs decreased by 75% from 2010 to 2017, as well as wind plants' costs, which decreased by 30% along the same reference period[3];
- Necessity of reducing pollution by substituting harmful sources to the environment (e.g. coal) with RES.

As previously mentioned, electric production by RES showed a steady increase (+16% yearly from 2009 to 2014) along last decade, facing a slight decreased caused by the shrink of hydroelectric production from 2015 to 2017 (-22%), although still showing an increase in the production by other sources. Such increase of RES production has been supported by the Italian authorities, through feed-in tariffs and fiscal benefits, as well as granting dispatchment priority to energy produced by RES in power markets.

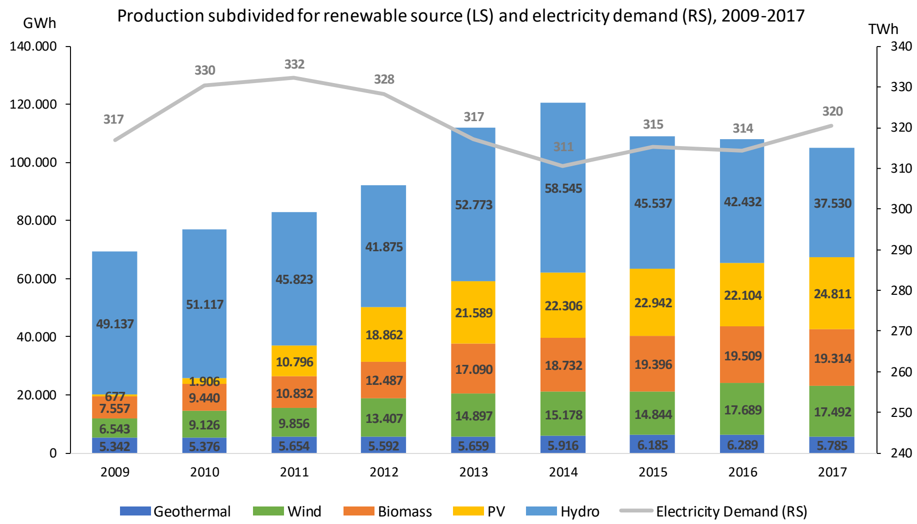


Figure 2. Production subdivided across RES and electricity demand, 2009-2017. Source: GSE and Terna

[3] IRENA (2018). Renewable power generation costs in 2017.

Still along years characterised by the decrease of electricity demand (from 2011 to 2014) RES production faced a regular growth, emphasising the transition from traditional power plants, which faced several shutdowns, no longer contributing to the supply of electricity demand.

1.1.1 SEN 2030 – New National Energy Strategy

By the release of SEN 2030, the ten-year National Energy Strategy, the Italian government provided new objectives in order to make the national energy system more competitive, more sustainable, and more secure.

Italy's National Energy Strategy 2017 lays down the actions to be achieved by 2030, in accordance with the long-term scenario drawn up in the EU Energy Roadmap 2050[4], which provides for a reduction of emissions by at least 80% from their 1990 levels.

The Strategy sets out measures to achieve sustainable growth and environmental targets, as envisaged by COP21[5], contributing in particular to a low-carbon economy and to the fight against climate change. Renewables (RES) and energy efficiency will contribute not only to environmental protection, but also to energy security (by reducing the dependence of the energy system) and cost-effectiveness (by favouring the reduction of costs and prices).

One of the targets highlighted by the Strategy is to remove every coal plant present on the Italian territory. In order to substitute coal's dependency, it has been targeted a dramatic increase in the percentage of electricity produced by RES up to 2030 both on electric and total consumptions.

To date, Italy has already achieved its RES targets by 2020, with a RES penetration of 17.5% in total energy consumption in 2015 vs. a 17% target to be reached by 2020. The objective for 2030 is to increase the percentage of RES generation on total consumptions by 6% on forecasted production, reaching the 28% of total consumptions derived from RES. Concerning electric consumptions, the objective of the Strategy is to achieve the 55% from RES, increasing by 17% the forecast for 2030.

Clearly, a significant amount of investments in RG will be necessary in order to overcome the trend, by granting incentives for power generation, placing more reliance on competitive

[4] Energy Roadmap 2050 (2012). European Commission
[5] COP21: 2015 United Nations Climate Change Conference, also known as the Paris Climate Conference (21st Session of the Parties to the United Nations Framework Convention on Climate Change (UNFCCC)).

auctions, taking a neutral approach to technologies with similar cost structures and levels, in order to stimulate competition and resorting to diversified support schemes for small-scale power generation and innovative technologies.

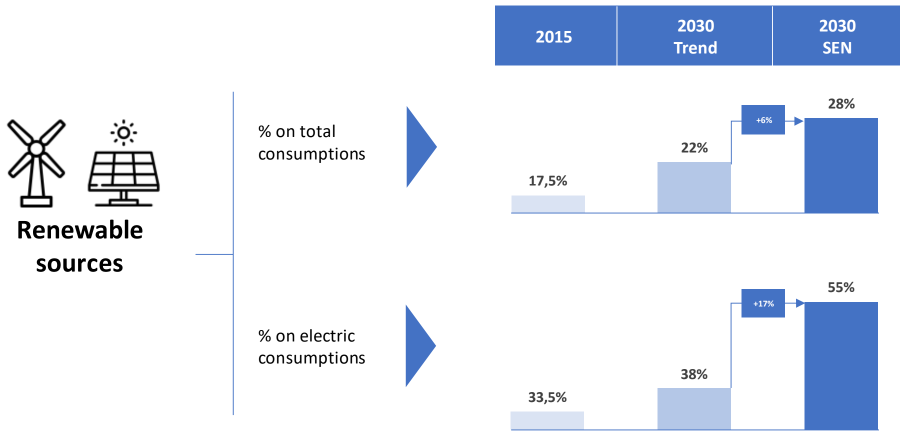


Figure 3. Targets of SEN (Strategia Energetica Nazionale) 2017. Source: Ministero dello Sviluppo Economico

Such increase in RG investments will lead to a greater segmentation of the Italian power market, increasing the share of DG and further worsening complications and costs that the system is currently facing.

1.2 Increasing complexity of the electric grid and management challenges for TSO

The recent expansion of intermittent RG (as solar and wind), which is predicted to continue its development with a steady growth during the following years, introduced several complications concerning short-term planning and management of the electric system. Decentralisation and decarbonisation are driving greater penetration of distributed and renewable energy systems and the subsequent need for greater system awareness, forecasting, and intelligence.

Actually, numerous programmable units powered by fossil sources (e.g. combined cycles), need to be shut down along many hours of the day because they are not anymore necessary in fulfilling the demand, due to the increase of feeding in of electricity by RES. Therefore, several programmable units are not profitable anymore, and consequently 13 GW of thermoelectric units have already been dismissed along last years.

On the other hand, programmable units powered by fossil sources, because of their characteristic of being able to vary rapidly and continuously the power fed into the grid, accomplish the fundamental task of providing balancing and adjustment services to the electric system. The electricity market operator makes use of these services in order to provide its balancing and congestion resolution services, guaranteeing safety and quality of power supply. The alignment of electricity demand and supply, fundamental to ensure grid stability, is indeed one of main objectives of marker operators.

The current reduction of programmable plants consequently reduces the available power for balancing services. Differently, minor predictability of the production by intermittent renewable energy generation, leads to higher necessity of balancing services.

Currently, massive concentration of RES power plants in areas characterised by low electric loads and inadequate grid infrastructures even lead to zonal congestions of the transmission system (in particular in Southern Italy). TSO thus faces the necessity of modulating the production of some traditional production units in order to balance the system and respect security constraints. Moreover, due to the significant volatility of RES production, TSO faces further complication in forecasting the residual loads on the system and it is thus constrained to acquire major dispatchment resources (with consequent higher charges) supplied by the so-called "qualified units" (generally represented by traditional thermoelectric power plants).

The main effects of intermittent RES generation on the safe operation of the national electric can be summarised as follows:

- Increase of reserve requirements: unpredictability of RES production leads to the increase of errors concerning residual load's forecast to be balanced in real-time and thus, an increased necessity of balancing power/tension, both upward and downward;
- Increase of plants' activations: the greater RES production, which reduces loads satisfied by traditional plants with balancing capacity, makes, all things being equal, technically more complex (and economically more expensive) the establishment of reserve's margins, necessary to guarantee the real-time balancing of the electric system. Consequently, the TSO is obliged to frequently request the activation of traditional plants otherwise shut down;
- Greater and different use of rapid reserves: concerning PV plants, being their production entirely concentrated along diurnal hours, the increase of such production gradually enhances the difference between minimum diurnal load and maximum evening load.

Such difference is linked by load/production ramps to be satisfied by rapid balancing's actions, traditionally supplied by programmable power plants with high possibility of modulation and quick response times.

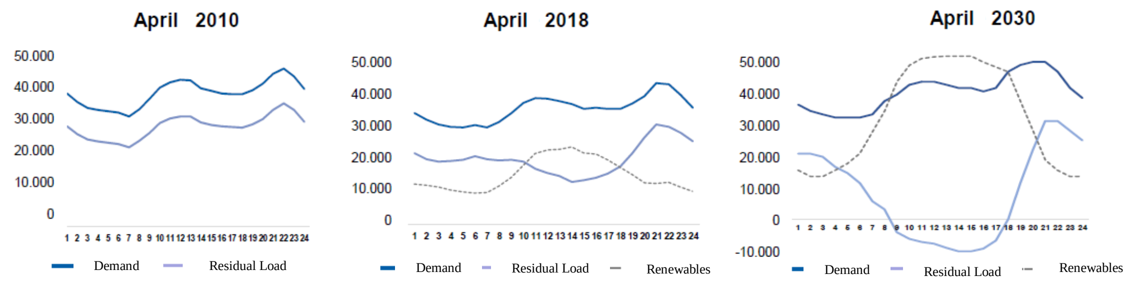


Figure 4. Demand and residual load. Source: Terna and GME

Because of the legislative schemes provided, and because of investment costs, the majority of investments in RG focused on little plants (< 1 MW), especially considering PV plants, whose 94% of total capacity is currently represented by residential plants with power lower than 50 kW. The same holds for wind plants, whose 81% of total capacity is constituted by plants with power lower than 200 kW. This confirms the substantial and rapid evolution of the national electricity system, which has shifted from few large-sized plants to a great deal of smaller facilities using widespread RES, leading to an electric system characterised by a significant amount of Distributed Energy Resource (DER), which in 2016 accounted for about the 22% of total national production and about the 26% of national installed capacity[6].

On the other hand, hydroelectric and biomass plants show the presence of significant capacity in high power plants, due to old plants installed before the beginning of the recent energetic transition. The same applies to geothermal plants, installed in previous decades.

[6] AEEGSI (2018) – Monitoraggio dello sviluppo degli impianti di generazione distribuita in Italia, per l'anno 2016

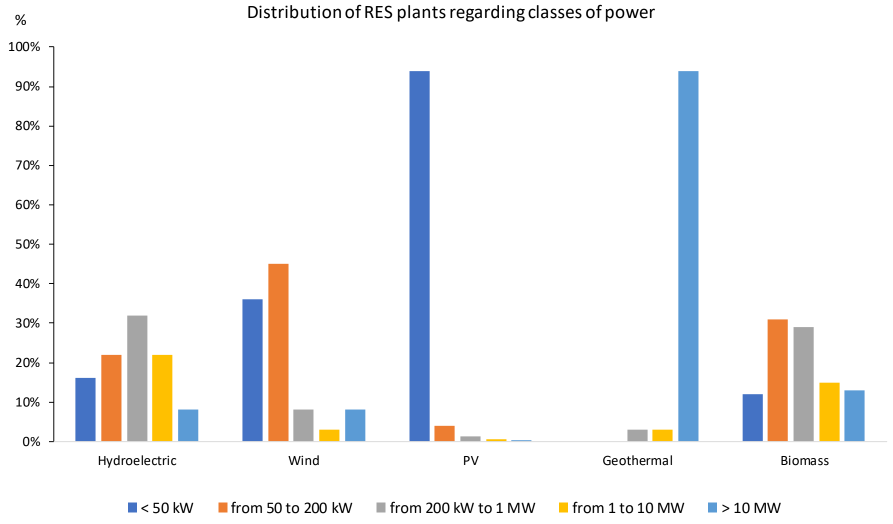


Figure 5. Distribution of plants powered RES subdivided by classes of power. Source: GSE

The reduction of generation units able to provide flexibility and balancing services has led to a steady increase of the costs faced by the system operator in the ancillary services market, due to the increase of demand of balancing services linked to a decrease of supply. These costs suddenly shift on the community in the form of general system charges, making the electric system inefficient along last years.

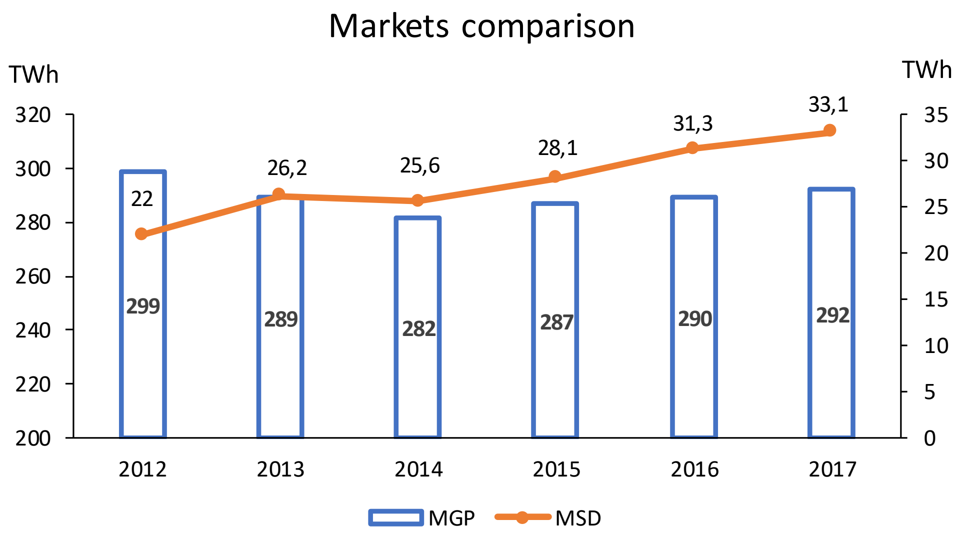


Figure 6. Volume’s comparison between MGP and MSD. Elaboration on Terna and GME data.

Along last six years, volumes of electricity traded on day-ahead market, MGP (Mercato del Giorno Prima) and ancillary services market, MSD (Mercato dei Servizi di Dispacciamento), showed a clearly different trend. In 2017 the volume of electricity traded on the MGP decreased by 2,3% with respect to 2012. Contrarily, volumes on the MSD faced a dramatic increase of about the 50,5% in the same period.

The effect of RES penetration in the Italian electricity market is also highlighted by the analysis of the average hourly PUN (Prezzo Unico Nazionale) on day-ahead market. The highlighted decrease in prices of electricity along the reference period (2012-2017) can be attributed, as well as to the slight decrease of electric demand and the slight decrease of commodities' prices, also to the increase of production from RES, which, facing null marginal costs and earning in most cases incentives for production, pushed for a reduction of prices[7].

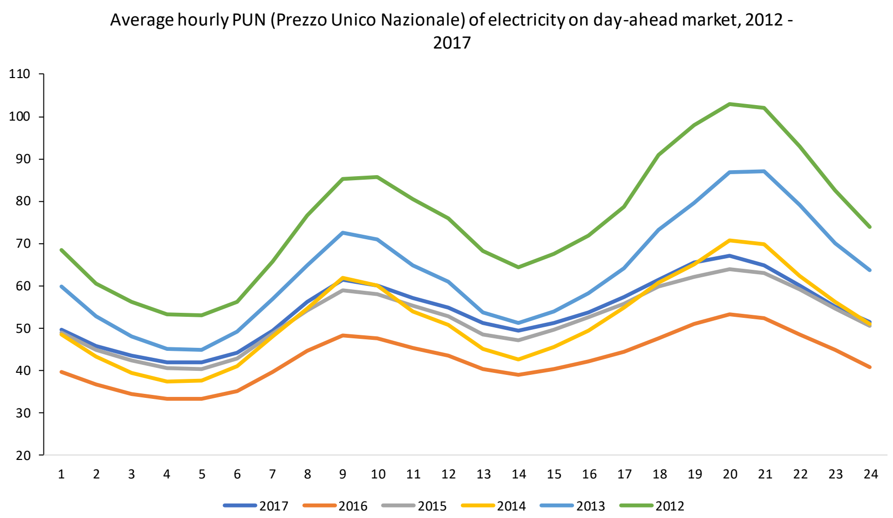


Figure 7. Average hourly PUN (Prezzo Unico Nazionale) of electricity on day-ahead market, 2012-2017. Elaboration on GME data

Thus, it is clear that the electric system requires new sources of flexibility, characterised by a steady and available disposability of varying flow of inputs and off-takes from the grid, to allow the balancing of the system.

1.3 DEMAND-RESPONSE

In the current context, the so-called "Demand-Response" mechanism is representing a possible solution to the mentioned complications of grid congestions.

[7] GSE (2017). Il valore dell'energia rinnovabile sul mercato elettrico

Demand-Response consists in the adjustment in power consumption of an electric utility customer to better align the demand for power with supply. Until recently, electricity could not be easily stored, and consequently demand and supply have traditionally been matched by regulating the production rate of power plants, taking generating units on or off line. Nevertheless, there are limits to what can be achieved on the supply side, because of the penetration of intermittent RES in the electric system, which present a low (almost null) degree of flexibility, or because some generating units can take a long time to come up to full power or may be very expensive to operate. Thus, Demand-Response seeks to adjust the demand for power instead of adjusting the supply.

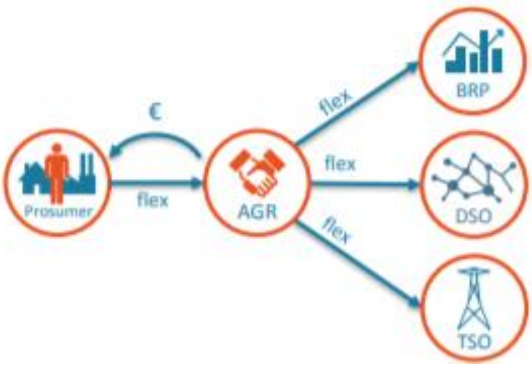
Currently, there is growing consensus that Demand-Response is a significant source for realising an efficient and sustainable electricity system at a reasonable cost. Demand-Response is indeed recognised as a critical facilitator of security of supply[8], renewables integration, improved market competition and consumer empowerment[9]. This understanding has been reflected within the European Energy Efficiency Directive and Network Codes in recent years and has led to the inclusion of Demand-Response in the European Commission’s legislative proposals on Electricity Market Design within the Clean Energy Package. In order to maximise the potentialities of this mechanism, participants shall converge in an aggregate of different generation/consumption resources, being the individual participation, although theoretically possible, highly impractical due to operative and regulatory barriers (e.g. Italian regulation provides that the minimum quantity to be hourly offered on the Italian dispatchment services market is equal to 1 MWh, more than 300 times a domestic unit’s consumption). Thus, the participation of Distributed Energy Generation (DER) resources currently requires the constitution of the so-called Virtual Power Plants (VPP).

To fulfil Europe’s energy goals, the full range of demand-side resources must be enabled, and all consumers must have the ability to benefit from their flexibility. This will require both Explicit and Implicit Demand-Response.

In Explicit Demand-Response schemes (called “incentive-based”) the aggregated demand-side resources are traded in the wholesale, balancing, and, where applicable, capacity mechanisms. Consumers gain direct payments in exchange of the variation of their consumption (or

[8] Petitet, M. (2015). Ensuring security of electricity supply: How capacity obligation impacts investments including demand response opportunities?
[9] Crampes, C., Waddams, C. (2017). Empowering electricity consumers in retail and wholesale markets

generation) patterns upon request, triggered by, for example, the activation of balancing energy. Consumers can earn from their consumption flexibility individually or by contracting with an aggregator, either a third-party providing the management of the aggregate of different consumption/production units.



Explicit DR:
- Aggregator bundles flexibility, optimizes and trades flexibility with BRP/DSO/TSO
- Prosumer is remunerated by the Aggregator

Figure 8. Explicit Demand-Response scheme. Source: USEF - Work stream on aggregator implementation models

In Implicit Demand-Response (called "price-based"), consumers autonomously react to dynamic market or network pricing signals.

It is important to highlight that neither form of Demand-Response is a replacement for the other: it is necessary to enable both Explicit and Implicit Demand-Response to accommodate different consumer preferences and to exploit the full spectrum of consumer and system benefits[10].

[10] SEDC (2018). Explicit Demand Response in Europe

Implicit DR:
- Prosumer is exposed to Time of Use tariffs by Supplier and/or DSO

Optionally:
- ESCo supports Prosumer to uses flexibility to optimize energy costs
- Prosumer pays ESCo for the service

Figure 9. Implicit Demand-Response scheme. Source: USEF - Work stream on aggregator implementation models

Demand-Response thus is ideally suited to accommodate three fundamental characteristics of electric power systems:

- Electricity cannot yet be stored economically, so its supply and demand must be maintained in balance in real time.
- Grid conditions can change significantly from day-to-day, hour-to-hour, and even within seconds. Generation and/or consumption levels can also change quite rapidly and unexpectedly, causing mismatches in supply and demand which can threaten the integrity of the grid within seconds.
- The electric system is highly capital-intensive, and generation and transmission system investments have long lead times and multi-decade economic lifetimes.

Demand-Response can increase the system's adequacy by substantially reducing the need for investment in peaking generation by shifting consumption away from times of extremely high demand. Crucially, it can act as a cost-effective balancing resource for variable renewable generation. Adding stability to the system, it lowers the need for must-run power plants that burn fuel continuously in order to be ready to supply power at short notice. It can decrease the need for local network investments, as it can shift consumption away from peak hours in regions with tight network capacity.

Apart from the indirect benefits that Demand-Response delivers to society by lowering the costs and optimising the efficiency of the electric systems and markets, it can also provide direct benefits to consumers by paying them directly for the value of their demand-side flexibility. Finally, it encourages market competition between different flexibility resources and market players, allowing the participation of independent service providers (the so called, Aggregators) and rewarding service-oriented retailers.

1.3.1 CONTEXT FOR AGGREGATION SERVICES

The implementation and development of Demand-Response services and, generally, aggregation services, is strictly linked to several different factor:

- Regulation

Regulation is the main driver for the development of aggregation services, due to the necessity of implementing new market models by the Authorities in order to permit the aggregation of different resources, which now presents regulatory barriers in most of the European countries. In recent years the EU Regulation is pushing for integration of aggregation services in energy markets and the recent Clean Energy Package encourages for the introduction of aggregators and active consumers in power markets as well as the development of further integration between TSO and DSO in the management of electric systems.

- Technology

Processes' digitalisation is currently allowing for the development of aggregation services, as well as the steady reduction in investments costs for new technologies and innovation. The increasing interest in smart grids development and real time management of production/consumption units is furthermore increasing the propensity for the introduction and development of new aggregation IT services worldwide.

- Markets

Growth of RES and DERs contributed to the development of new energy market contexts, which now require new balancing rules in order to guarantee the provision of the necessary balancing service on the grid. The introduction of new integrated markets as well as the optimisation of ancillary services are necessary for the development of new opportunities for aggregation services.

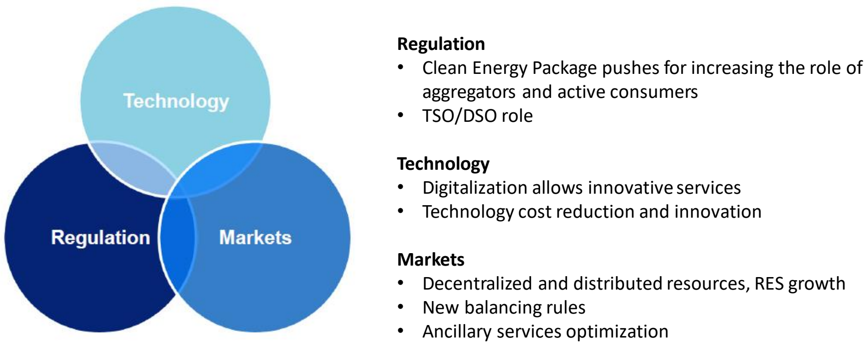


Figure 10. Main drivers for the development of aggregation services.

1.4 Benefits of Demand-Response aggregation

According to the definition of Burger, S., Chaves-Ávila, J. P., Batlle, C., and Pérez-Arriaga, I. J., aggregation is defined as the act of grouping distinct agents in a power system (i.e. consumers, producers, prosumers, or any mix thereof) to act as a single entity when engaging in power system markets (both wholesale and retail) or selling services to the system operator(s)[11].

As highlighted by the same authors, it can be distinguished between three different ways of creating value by the aggregation of DERs.

Firstly, aggregations create *"fundamental"* or "intrinsic" value, which do not depend on the specific regulations, level of market awareness of consumers, or technologies in place in the power system. It will be permanent or near permanent in time.

Aggregations can generate *"transitory"* value, contributing to a better functioning of the power system under the present and near-future conditions. However, the value of transitory aggregations may wane as technical, managerial or regulatory conditions improve.

Finally, aggregations with only *"opportunistic"* value emerge in response to regulatory or market design "flaws."

[11] Burger, S., Chaves-Ávila, J. P., Batlle, C., & Pérez-Arriaga, I. J. (2016). The value of aggregators in electricity systems. MIT Center for Energy and Environment Policy Research: Cambridge, MA, USA.

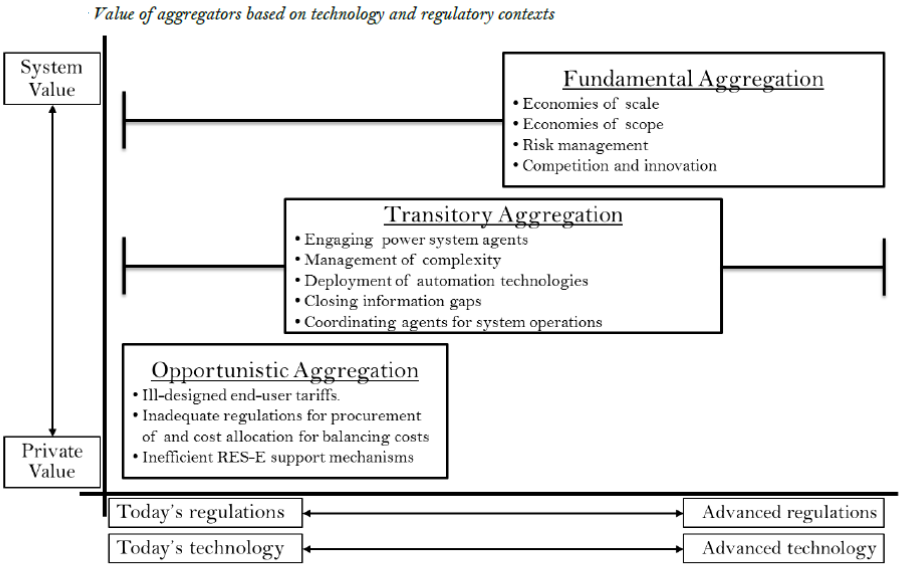


Figure 11.Value of aggregators based on technology and regulatory contexts. Source: Burger, S., Chaves-Ávila, J. P., Batlle, C., & Pérez-Arriaga, I. J. (2016). The value of aggregators in electricity systems.

Aggregation of DERs allows for economies of scale and scope, risk mitigation and joint access to the energy market and auxiliary services as a way to accelerate their penetration in the residential, commercial and industrial sectors. An appropriate regulatory framework is essential to define the technical, economic and administrative requirements needed and to specify the role of the various stakeholders. In such manner the consumer will be allowed to access flexibility markets and competition will be promoted between the various technical solutions to the simultaneous benefit of consumers and the sector as a whole. According to the Virtual Power Plants (VPP) operation context, some of the managed resources can be scheduled to support the participation of the VPP (and its aggregated resources) in the electricity markets. In this way, e.g., in the case of DR programs, the consumption reduction can be used to meet the demand's needs inside the network and also for the participation in the electricity market[12].

Firstly, aggregation cuts investment needs for single users, subdividing fixed costs across the aggregated users, while secondly it increases the revenue streams taking part in the energy and balancing markets. Aggregation also mitigates the economic, administrative and technical risks of DERs for stakeholders. This is a good way to speed up the deployment of distributed resources and to promote the participation of the consumer in the energy market. At the same

[12] Faria, P., Spínola, J., & Vale, Z. (2016). Aggregation and Remuneration of Electricity Consumers and Producers for the Definition of Demand-Response Programs

time, the electricity system can access reliable technologies to balance the system at a lower cost. Moreover, the presence of a single aggregate of potential market's participants allows for minor complications in the management of such units for the TSO. Reduction of potential overall transactions clearly represents one of the main advantages for the market operator. In order to achieve such improvement, aggregates of different units shall relate with the TSO by a single entity, named the Aggregator, who entitles the entire VPP and manages the flow of transactions, reducing the number of transactions and simplifying market conditions for all the stakeholders.

Regulation has to guarantee fair price signals to avoid any antitrust behaviour which raises the total cost of the energy system and so increases the proportionality of what the network charges to consumers[13].

Aggregators are needed to capture the flexibility from many small size sources. An aggregator is a service provider (BSP – Balance Service Provider) who operates, directly or indirectly, a set of demand facilities in order to sell the flexibility available from pools of electric consumers and/or producers as single units in electricity markets. The aggregator, a service provider who may or may not also be a retailer of electricity, represents a new role within European electricity markets. Most consumers do not have the means to trade directly into the energy markets and require the services of an aggregator to help them navigate the complexity and participate. Aggregators thus pool many different units of varying characteristics increasing the overall reliability of the aggregate and reducing risk for individual participants. Aggregation service providers are central players in creating vibrant demand-side participation and Demand-Response. They negotiate agreements with industrial, commercial and residential electricity consumers and producers to aggregate their capability to reduce (or increase) energy and/or shift loads on short notice. They create one "pool" of aggregated controllable units, made up of many smaller loads, and sell this as a single resource.

Aggregation can achieve performance levels that fulfil market requirements for reliability and can be comparable to, or better than, the performance of generation. The aggregation of diverse customers means that the system operator can use the aggregated demand-side capacity as a single, reliable resource. One of the key benefits of aggregation is the diversity of the aggregated portfolio (i.e. many small loads building one large resource), which ensures that the

[13] Rhys, J (2018). Cost Reflective Pricing in Energy Networks

committed capacity will be delivered by the Aggregator even when some individual consumers may not be able to perform.

Demand-Response potential typically amounts to around 15% of peak demand. The International Energy Agency (IEA) assessed that the potential could exceed 150 gigawatts (GW) by 2050 in the European Union[14], even though this capacity corresponds to different product definitions with regard to duration and frequency of response. Demand-Response can be deployed at four distinct levels, with an impact proportional to the scale of consumption:

- at the industrial level, when large manufacturing plants have the flexibility to adjust production processes to electricity prices to decrease their energy costs;
- at the services level, typically through automated solutions to manage air conditioning or lighting systems, also to decrease energy costs;
- at the residential level, with innovative commercial services offering consumers energy savings with minimal impacts on daily life, for example via smart appliances;
- at the transport level, with the deployment of electric vehicles.

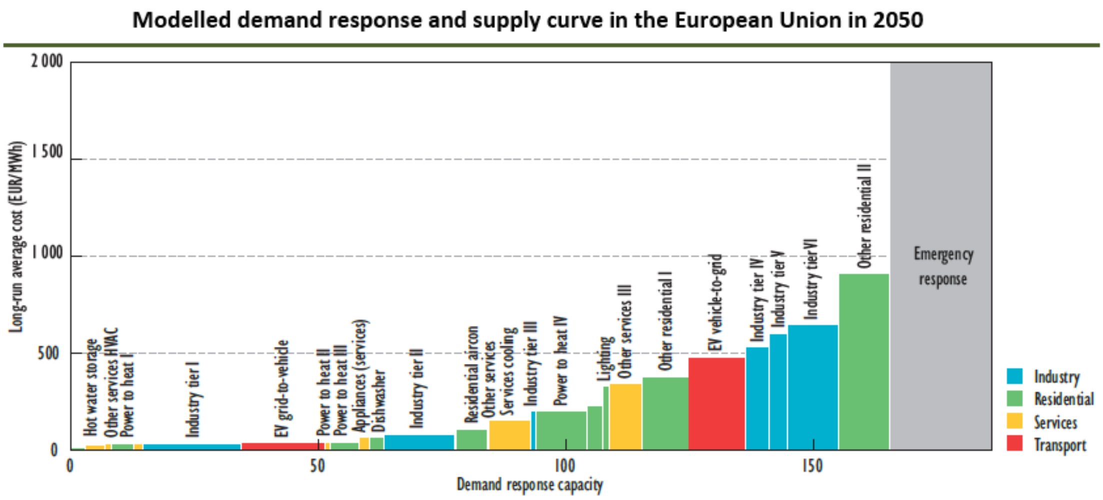


Figure 12. Demand-Response and supply curve in the European Union in 2050. Source: IEA

[14] IEA (2017). Digitalization and Energy 2017

2. DEMAND-RESPONSE MARKET

2.1 EUROPEAN REGULATORY FRAMEWORK

Over the past few years, there has been an overall increase of interest in enabling Demand-Response in several European countries. Various regulatory changes have been implemented or are planned in many countries. Notably, in countries where Demand-Response has traditionally been almost non-existent, such as Spain and Italy, there has been some regulatory interest in exploring its potential and providing a first execution by trial periods. The European countries that currently provide the most conducive framework for the development of Demand-Response are Switzerland, France, Belgium, Finland, Great Britain and Ireland. Nevertheless, there are still market design and regulatory issues that exist in these well-performing countries. Switzerland and France have detailed frameworks in place for independent aggregation, including standardised roles and responsibilities of market participants.

In France, a new draft decree reviewed by the *Conseil d'Etat* in early 2017[15] could provide for a new financial settlement framework whereby a significant portion of the payment to retailers with curtailed customers would be charged to retailers rather than to Demand-Response providers. However, issues persist around a standardised baseline methodology.

In both Belgium and Ireland upcoming legislation should help to increase the participation of Demand-Response[16]. New legislation addressing the role of the aggregator and independent aggregation will soon be put in place in Belgium, which will help to provide an equal footing for all market actors; a strong sign for the uptake of Demand-Response. However, there are still some issues regarding measurement and verification that inhibit the growth of Demand-Response. In Ireland, the new "*Integrated Single Electricity Market*" implemented in 2018, together with the DS3 programme, opens a range of markets for demand-side response, specifically the balancing market, and the wholesale market, as well as a newly designed Capacity Mechanism.

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[15] Deliberation N. 155 of June 2017
[16] SEDC (2018). Explicit Demand Response in Europe

Great Britain continues to have a range of markets open to demand-side participation. Independent Aggregators can directly access consumers for ancillary services and capacity products, and the country has recently started considering a framework for independent Aggregator access to the Balancing Mechanism. Yet, with relatively burdensome measurement and verification procedures in place for Demand-Response, it still has room to improve.

Finland stands out amongst the Nordic countries primarily as it allows independent aggregation in at least one of the programmes in the ancillary services, and due to its advanced provisions for measurement and verification. It will also be experimenting through pilot projects with independent aggregation in other parts of the balancing market.

Austria, Germany, Netherlands, Norway, and Sweden still present regulatory barriers which remain as an issue and hinder market growth. Although several markets in these countries are open to Demand-Response in principle, programme requirements continue to exist which are not adjusted to enable demand-side participation. Furthermore, a lack of clarity remains around roles and responsibilities of the different actors and their ability to participate in the markets. However, Germany, the Nordic countries and Austria have started processes to find a standard solution for the role of independent aggregation.

Concerning Germany, one of the notable improvements in the path of enabling Demand-Response is primarily due to the fact that product definitions have been updated or are about to be updated, and balancing reserve markets are about to be opened for independent aggregation.

Slovenia, Italy, and Poland are currently starting the process of enabling the Demand-Response market in their national markets. In Slovenia and Poland, nonetheless, no major regulatory changes have been made within the past couple of years that would have allowed for further Demand-Response participation.

Notably, Italy has slowly started to take the regulatory steps needed for a solid framework for Demand-Response. However, despite the gradual opening of markets, significant barriers still hinder customer participation. For example, major sections of the market are still closed off and they lack a viable regulatory framework for Demand-Response overall.

Spain and Portugal are thus currently still far from fully enabling Demand-Response in their electricity markets, because aggregated demand-side flexibility is either not accepted as a resource in any of the markets or it is not yet viable due to regulation.

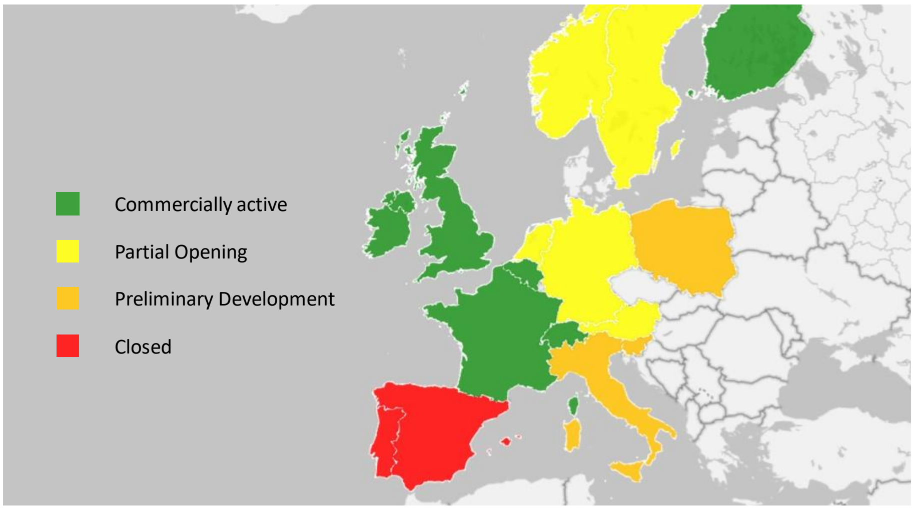

Figure 13. Enabling of Demand-Response in Europe. Source: SEDC – Explicit Demand-Response in Europe

European policy makers have demonstrated strong support for Demand-Response and this is reflected in several existing legislative texts.

The Electricity Directive – 2009/72/EC

The current Electricity Directive of the Third Energy Package already defined the concept of “energy efficiency/demand-side management”, acknowledging the positive impact on environment, on security of supply, on reducing primary energy consumption and peak loads. Article 25.7 requires network operators to consider Demand-Response and energy efficiency measures when planning system upgrades. Article 3.2 also states “In relation to security of supply, energy efficiency/demand-side management and for the fulfilment of environmental goals and goals for energy from renewable sources, [...] Member States may introduce the implementation of long-term planning, taking into account the possibility of third parties seeking access to the system”. This language was strengthened further within the Energy Efficiency Directive (EED).

The Network Codes – 2009/714/EC

The Network Codes are a set of rules drafted by European Network of Transmission System Operators for Electricity (ENTSO-E), with guidance from the Agency for the Cooperation of Energy Regulators (ACER) and the oversight of the European Commission, to facilitate the harmonisation, integration and efficiency of the European electricity market. These Codes, some of which are still in the final drafting phases, will be critical for the development of

Demand-Response, because they describe the terms and conditions under which demand-side flexibility providers will be able to participate in the electricity markets

The Energy Efficiency Directive (EED) – 2012/27/EU

The Energy Efficiency Directive (2012/27/EU) constitutes a major step towards the development of Demand-Response in Europe.

According to its Article 15.2, Member States were required to undertake an assessment of the energy efficiency potentials of their gas and electricity infrastructure, in particular regarding transmission, distribution, load management and interoperability, and identify concrete measures and investments for the introduction of cost-effective energy efficiency improvements in the network infrastructure, by 30 June 2015.

Furthermore, Article 15.4 requires Member States to:

- *"Ensure the removal of those incentives in transmission and distribution tariffs that are detrimental to the overall efficiency (including energy efficiency) of the generation, transmission, distribution and supply of electricity or those that might hamper participation of Demand Response, in balancing markets and ancillary services procurement".*
- *"Ensure that network operators are incentivised to improve efficiency in infrastructure design and operation, and, within the framework of Directive 2009/72/EC, that tariffs allow suppliers to improve consumer participation in system efficiency, including Demand Response, depending on national circumstances".*

The most important part of the Directive is Article 15.8, which establishes consumer access to the energy markets, either individually or through aggregation. In detail the Article states:

- *"Member States shall ensure that national regulatory authorities encourage demand side resources, such as Demand Response, to participate alongside supply in wholesale and retail markets."*
- *"Subject to technical constraints inherent in managing networks, Member States shall ensure that transmission system operators and distribution system operators, in meeting requirements for balancing and ancillary services, treat Demand Response providers, including aggregators, in a non-discriminatory manner, on the basis of their technical capabilities."*

- *“Member States shall promote access to and participation of Demand Response in balancing, reserves and other system services markets, inter alia by requiring national regulatory authorities […] in close cooperation with demand service providers and consumers, to define technical modalities for participation in these markets on the basis of the technical requirements of these markets and the capabilities of Demand Response. Such specifications shall include the participation of aggregators.”*

State aid Guidelines for Energy and Environment

In April 2014, the European Commission adopted new rules on public support for projects in the field of environmental protection and energy. Among other issues, the new Guidelines clarify under what conditions state aid to secure adequate electricity generation is permitted. This allows Member States to introduce so-called “capacity mechanisms”, for example to encourage producers to build new generation capacity or prevent them from shutting down existing plants or to reward consumers to reduce electricity consumption in peak hours. Although the text still refers to “generation adequacy”, it requests the primary consideration of “alternatives” to capacity mechanisms, such as Demand-Response. The rules state that, once set up, the capacity mechanisms must provide adequate incentives to existing and future generation, Demand-Response and storage. In detail, this is clarified in the following provisions:

- *(221) [...] Member States should therefore primarily consider alternative ways of achieving generation adequacy which do not have a negative impact on the objective of phasing out environmentally or economically harmful subsidies, such as facilitating demand side management and increasing interconnection capacity.*
- *(227) The measure should be open to and provide adequate incentives to both existing and future generators and to operators using substitutable technologies, such as demand-side response or storage solutions. [...]*
- *(232) The measure should be designed in a way so as to make it possible for any capacity which can effectively contribute to addressing the generation adequacy problem to participate in the measure, in particular, taking into account the following factors:*
- *(a) the participation of generators using different technologies and of operators offering measures with equivalent technical performance, for example demand side management, interconnectors and storage.*

Given that a number of Member States have already introduced, or are considering introducing or revising capacity mechanisms, these rules will be vital to create the solid legal basis needed to ensure that, when state aid is permitted for guaranteeing system adequacy, it should be provided in such a way that demand-side resources are not excluded, and so the lowest cost combination of resources can be acquired. However, the real value of these guidelines in creating a level playing field between the different technologies depends on the Commission's resolve to apply them.

New legislative proposals in the Clean Energy Package

The European Commission launched the Clean Energy Package in November 2016; a number of legislative proposals including, most importantly for Demand-Response, the revision of the Electricity Directive and of the Electricity Regulation. This could represent the most important change in the regulatory context ever seen in Europe, for Demand-Response. For example, the proposed text systematically includes Demand-Response as a resource in the provisions for all organised electricity markets, alongside storage and generation. It also requires that provisions for balancing and wholesale markets accommodate renewable energy sources and increasing demand responsiveness. Specific improvements of production definitions for balancing and wholesale markets are proposed, regarding procurement and minimum bid sizes respectively. Long-term hedging opportunities are also made tradable on exchange in an open and transparent manner and, where they exist, capacity mechanisms shall select capacity providers in a transparent, non-discriminatory and market-based process. Balancing and ancillary services, as well as dispatching, re-dispatch and curtailment, are generally to be market-based (exceptions are possible in some cases). In addition, the incentive structures for Distribution System Operators are to be adapted to encourage the market-based sourcing of system services at the DSO level. Eligible parties, including customers, retailers and aggregators, should be able to access relevant data based on the consumer's consent. Finally, the proposals include the obligation for all Member States to introduce a conducive legal framework for Demand-Response aggregators to foster market participation of DR, including through independent aggregators, enable their access to the market, and define relevant roles and responsibilities.

Among other important aspects in the legislative package, these key proposals for Explicit Demand-Response are complemented by further provisions essential to enabling Implicit Demand-Response. If accepted and adopted by the European Parliament and Council, and fully implemented across the EU, these overarching provisions will play a significant role in removing the different barriers currently still existing in some countries.

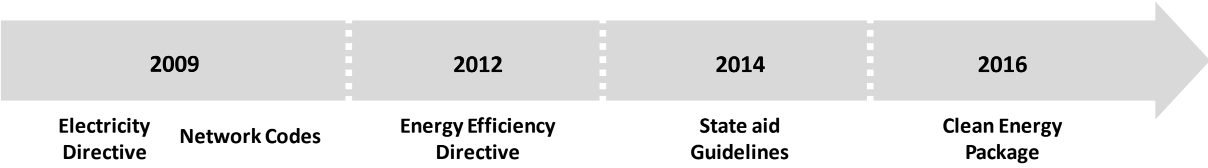

Figure 14. European regulation's timeline

2.2 Main roles in Demand-Response market

Prosumer

A Prosumer can be regarded as an end user that no longer only consumes energy, but also produces electricity.

BRP

A Balance Responsible Party (BRP) is responsible for actively balancing supply and demand for its portfolio of Producers, Aggregators, and Prosumers. A BRP is contracted by the Supplier. In principle, everyone connected to the grid is responsible for his individual balance position and hence must ensure that at each Program Time Unit the exact amount of energy consumed is somehow sourced in the system, or vice versa in case of energy production. The Prosumer's balance responsibility is generally transferred to the BRP, which is contracted by the Supplier. Hence the BRP holds the imbalance risk on each connection in its portfolio of Prosumers.

It will be distinguished between two possible figures of the BRP:

- BRP of the Supplier (BRP_{sup}): the supplier delegates to a BRP (named BRP_{sup}) the responsibility for the unbalancing of his portfolio of Prosumers;
- BRP of the Aggregator (BRP_{agr}): the Aggregator delegates to a BRP (named BRP_{agr}) the responsibility for the unbalancing generated by the activation of flexibility services. Indeed, the activation generates an unbalancing in the portfolio of the BRP_{sup} that must be "corrected" by an "energy transfer" between the BRP_{agr} and the BRP_{sup}.

DSO

The DSO is responsible for the active management of the distribution grid and introduces the system operation services. Flexibility obtained from the Aggregators on its network is purchased to execute its system operations tasks. The DSO is responsible for the cost-effective distribution of energy while maintaining grid stability in a given region.

Potentially, the DSO role could supersede the classical role of the DNO (Distribution Network Operator) to cost-effectively maintain the distribution network, but this does not necessarily have to be the case; one could think of business models where these roles are separate legal entities.

TSO

The role of the Transmission System Operator (TSO) is to transport energy in a given region from centralised Producers to dispersed industrial Prosumers and Distribution System Operators over its high-voltage grid. The TSO safeguards the system's long-term ability to meet electricity transmission demands. The TSO is responsible for keeping the system in balance by deploying regulating capacity, reserve capacity, and incidental emergency capacity. The role of the TSO remains unchanged, but flexibility services provides a new source of flexibility to the TSO as input for its system operation services. The TSO can purchase flexibility services indirectly via the BRP from the Aggregators active on its network.

Aggregator

The role of the Aggregator is to accumulate flexibility from Prosumers and their Active Demand & Supply and sell it to the BRP, the DSO, or (through the BRP) to the TSO. The Aggregator's goal is to maximise the value of flexibility by providing it to the services defined by the Authority. The Aggregator must cancel out the uncertainties of non-delivery from a single Prosumer so that the flexibility provided to the market can be guaranteed. This prevents Prosumers from being exposed to the risks involved in participating in the flexibility markets. The Aggregator is also responsible for the invoicing process associated with the delivery of flexibility. The Aggregator and its Prosumers agree on commercial terms and conditions for the procurement and control of flexibility.

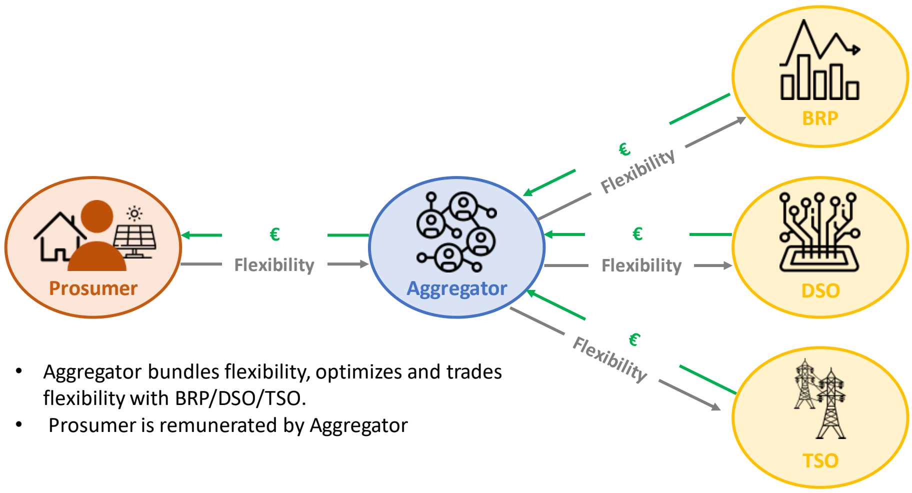

Figure 15. Main roles in Demand-Response market

2.2.1 THE AGGREGATOR

Adopting the definition of Aggregator promulgated by Ikäheimo, Evens, and Kärkkäinen, an "Aggregator is a company who acts as an intermediary between electricity end-users and DER owners and the power system participants who wish to serve these end-users or exploit the services provided by these DERs"[17].

In the current scenario, outlined by the new market models, the role of the Aggregator (BSP, according to the Commission Regulation (EU) 2017/2195) emerges as fundamental since responsible in the supply of flexibility services to the market by the different members of an UVA. Indeed, the involvement of DG and final users connected to the distribution grid in the management of the overall electric system leads to an increase of potential flexibility services implemented by the TSO. Nevertheless, on the other hand, this inclusion introduces more complexity in the management of several minor units (consumers and producers) by network operators, especially concerning the activities of metering and verifying of the supply of services (monitoring activities).

TSO must be able to depend on the supply of the requested services, which must be delivered with certainty and promptly, because also little differences between what is needed and what is offered could endanger system's security.

[17] Ikäheimo, J., Evens, C., & Kärkkäinen, S. (2010). DER Aggregator business: the Finnish case. Research Report, VTT-R-06961-09.

Analogously, DSO must ensure that services' supply by DG are developed respecting the operational limits of distribution grid's functioning (e.g. tension's limits). This implies the necessity of appropriate coordination, which must take place by adequate mechanisms and information exchange infrastructure, between the different actors involved in the energy exchanges, i.e. TSO, DSO and the Aggregator. Consequently, the figure of the Aggregator will assume a central role of interface with TSO and DSO in the supply of flexibility services by little units (producers or consumers) connected to the distribution grid, facilitating the creation of a significative resource for the TSO and thus the offers' selection by the latter.

The services offered would result in a higher quality, because more certain, and would amplify the management of the electric system making the metering of the resources offered more efficient. The Aggregator would have the perception of all the resources contemporarily underlying the same hub, with the concrete possibility of modulating injections and off-takes by all the consumers in his holdership depending on necessities.

Law Decree N.102 of the 4th of July 2014, implementation of EU Directive 2012/27/UE, defines the Aggregator as a "supplier of services who, on request, aggregates multiple consumer units, or consumer and production units, to sell them on energy organised markets". Its target is to enhance the value of active consumers, in a market that requires organisation in order to adapt to the new requirements that the current context calls for.

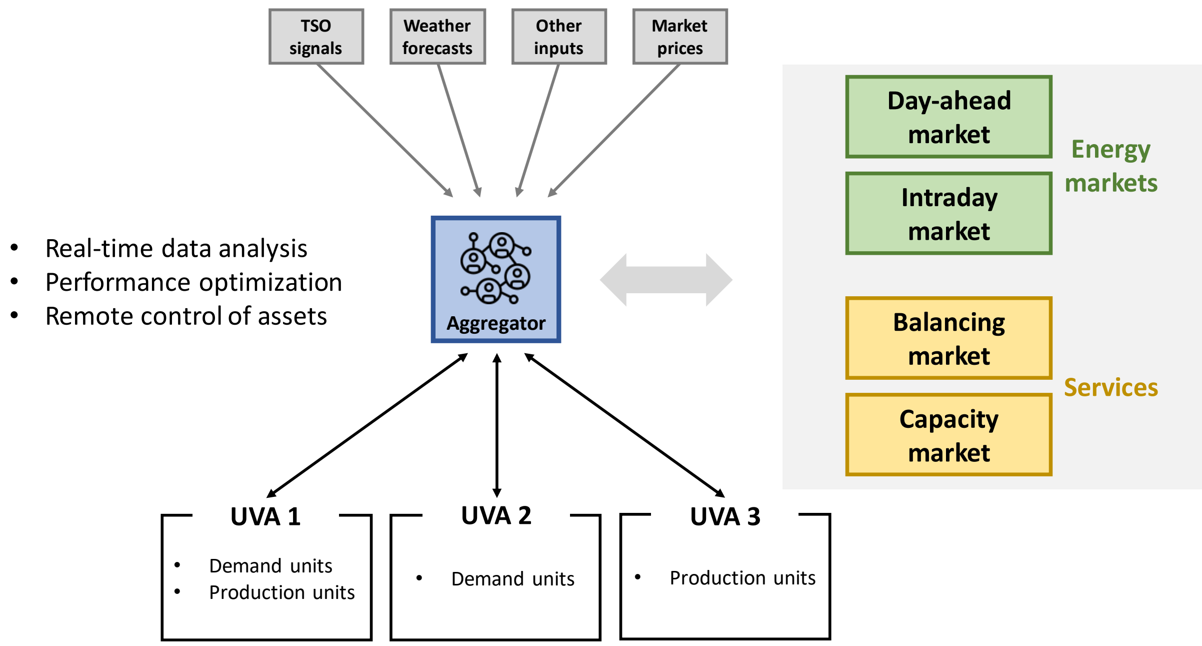

Figure 16. Aggregator's relationships

2.3 MARKET MODELS FOR AGGREGATOR

According to the USEF (Universal Smart Energy Framework)[18], there are several possible models in order to implement the role of the Aggregator in power markets, some of which are already been enabled in the European framework.

Integrated

In the "Integrated" model, the figures of Supplier and Aggregator coincide: it is thus not necessary any compensation between the two parties concerning the unbalancing generated by the activation of flexibility and the curtailment of energy supplied to Prosumer. It is also not necessary the presence of the BRP_{agr}.

The "Integrated" model is the most adopted in Scandinavian countries.

Broker

In the "Broker" model, which presents the absence of the BRP_{agr}, the Aggregator directly transfers the responsibility for the unbalancing, generated by the activation of flexibility services, to the BRP_{sup}. The compensation between the unbalancing generated by the flexibility and the curtailment of energy supplied is regulated by a specific contract stipulated between the Aggregator and the BRP_{sup}.

The "Broker" model is currently not adopted in Europe.

Contractual

In the "Contractual" model the Aggregator stipulates a contract with the BRP_{agr} to whom he delegates the responsibility of the unbalancing generated by the activation of flexibility services, as well as a contract with the supplier relative to the energy not supplied to the Prosumer with respect to the program.

BRP_{agr} and BRP_{sup}, in turn, stipulates a contract aimed to the "correction of the perimeter" of the BRP_{sup}. The Aggregator and the BRP_{agr} stipulate a contract with the BSP, relative to the supply of flexibility sources.

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[18] USEF - Work stream on aggregator implementation models

The “Contractual” model is adopted in Austria, Finland, France and Germany.

Uncorrected

In the “Uncorrected” model, presenting the absence of the BRP_{agr}, there is no “correction of the perimeter” of the BRP_{sup}. Contrarily, the BRP_{sup}’s unbalancing, generated by the activation of flexibility service of Prosumers by the Aggregator is ordinarily managed by the regulation on unbalancing. Since the unbalancing would support the system to rebalance, the unbalancing borne by the BRP_{sup} would typically have negative sign, representing a source of remuneration.

The “Uncorrected” model is adopted in Belgium, Ireland and UK.

Corrected

In the “Corrected” model the BRP_{agr} maintains the responsibility of the unbalancing generated by the activated flexibility service. Nevertheless, the measure of the off-takes by Prosumers is “corrected”, being curtailed of the activated flexibility (aiming to the Baseline’s value), thus removing the unbalancing of the BRP_{sup} and allowing the supplier to invoice as programmed. Consequently, the energy transfer directly involves the Prosumers, who are compensated by the Aggregator for the quantity of energy invoiced by the supplier, although not consumed.

The “Corrected” model is adopted in Belgium, France and Germany.

Central settlement

In the “Corrected” model the BRP_{agr} maintains the responsibility of the unbalancing generated by the activated flexibility service. The “correction of the perimeter” of BRP_{sup} and BRP_{agr} and the compensation of the supplier for the energy not supplied to Prosumer with respect to what programmed, is realised by a central subject named Allocation Responsible Party (ARP).

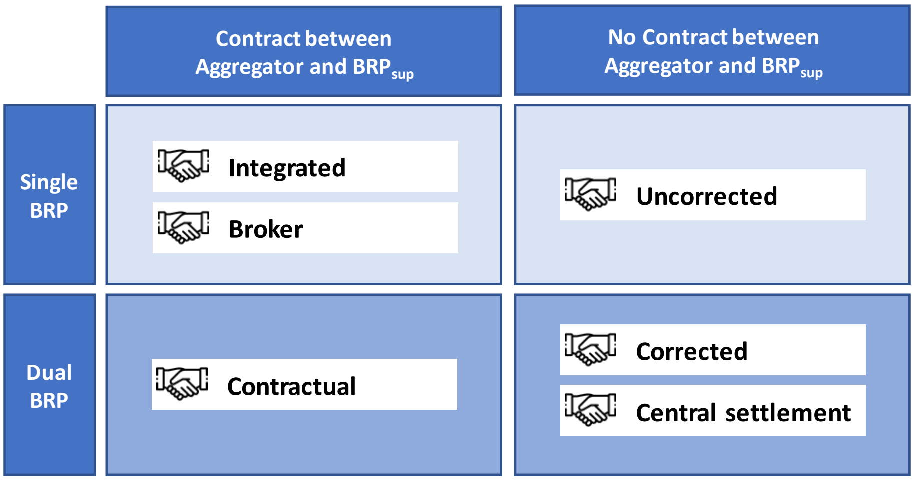

Figure 17. Aggregator model classification scheme. Source: USEF - Work stream on aggregator implementation models

2.4 Flexibility Services

2.4.1 Generation Flexibility

Concerning programmable production units until now excluded from the participation to the MSD because with size lower than 10 MVA, thermoelectric plants (as cogeneration plants, Combined Heat and Power, CHP, powered by fossil fuels as natural gas) or hydroelectric plants, already technically adequate and potentially able to offer flexibility services. The reduction of the minimum power size by the Regulator allows for the participation of this units to the MSD. Hence, they will contribute to fulfil the necessities of the national power system.

Concerning intermittent renewable units, once admitted in the MSD, they will have a different way of participating in the market. Since they are powered by an aleatory and extremely variable source, they will be able to supply flexibility services only when the source itself presents availability. Moreover, working always at the maximum power due to the absence of marginal cost of production and due to the priority of dispatchment granted to renewable sources, they would not have any margin to supply eventual increase of generation/injection at the current market conditions.

2.4.2 Storage Flexibility

Storage systems can be usefully implemented in order to reduce or even resolve some critical issues of the electric grid. For example, the energy's storage allows to optimise the usage of the existing grid, avoiding overloads during the hours of maximum production of intermittent renewable sources, via the storage of the energy not consumed, which can then be released when the production is not sufficient.

The effectiveness of a storage system is as much higher as it allows to minimise the energy produced by intermittent renewable sources which needs to be reduced in order to ensure grid stability. In this respect, storage systems shall provide a primary role in the integration of renewable sources, especially considering the ease and quickness of installation.

The possibility of installing storage systems on the most critical portions of the grid makes them crucial for the reduction of current and future congestions derived by a further development of renewable energy plants and Distributed Generation. In addition to the mitigation of the effects derived by the non-programmability of renewable generation, storage systems can also be implemented in order to weaken further necessities derived by the massive penetration of DG. Indeed, such systems can be implemented to provide energy reserve and to supply balancing resources for the electric system. Being able to in-take and off-take energy from the grid, storage systems represent one of the most efficient resources for reserve services both upward and downward: every MW installed potentially supplies the double of energy in terms of reserve and balancing.

On the other hand, it must be taken into consideration the temporal limit of the current storage systems, which are considered to be able to implement flexibility services for service-life of about 7 years. Differently from conventional plants, storage system’s functioning conditions its dimensioning, its service-life and its cost.

Storage systems allow to level out consumptions and relative peaks (peak shaving), storing energy in periods of low needs and releasing it in periods of higher needs (energy time-shift), avoiding the recourse to power plants with high variable costs. This kind of service can be helpful for an adequate management of pronounced loading ramps determined by renewable source production.

2.4.3 Demand Flexibility

Differently from what is attainable for production units or storage systems, it has to be highlighted that the use of loads (industrial, services, residential) as flexibility resources involves the possibility of using existing assets for another purpose and, in some cases, this presents ad advantage in terms of initial investment.

The possibility of modulating the off-take from the grid by consumption units depends on several factors which together describe the “flexibility” of consumption units, i.e. the capacity of supplying the so-called “Demand-Side Response Service”[19]. Indeed, the electricity off-taken from the grid depends on the characteristics of the process, the technology of transformation, the configuration of the plant, the installed capacity, etc.

Generally, a consumption unit can be considered “flexible” when the process underlying allows for the modulation of the off-take from the grid according to the technical specifications of the grid operator with no consequences for the final user. In this case the resource is potentially eligible for supplying flexibility services.

Moreover, beside the technical feasibility of the flexibility service by the consumption unit, the willingness of modulating his consumption by the operator has to be considered as a relevant variable. Consequently, beneficial remuneration/participation schemes are necessary.

In order to describe the flexibility of consumption units and their limits, some parameters are needed to be considered:

- **Response rate**: considering the characteristics of the underlying process and thus the usage of the electricity off-taken from the grid, the consumption unit can be suitable for a rapid activation (instantaneous activation or within seconds/minutes) or a slow activation (activation within hours). Furthermore, based on the response rate, other parameters can be considered, such as modularity of variation or range of variation.
  The presence of an Aggregator allows for the participation of “slower” units, which need longer terms than what is established by Terna by conveniently placing the interruption/reduction of a specific load in a sequence of interruptions/reductions with an activation timing in accordance with the disposition of Terna.
- **Duration**: according to the characteristics of the underlying process, the service supplied by a consumption unit can last for a defined term. Also in this case, the presence of an Aggregator allows for the participation of consumption units which can allow short-term flexibility services.

[19] European Commission (EC), Commission Regulation (EU) 2016/1388

- **Period**: according to the characteristics of the underlying processes, the provision of flexibility services by consumption units could be granted on hourly/daily/weekly/seasonal basis.
- **Substitution resources**: the reduction of the off-take from the grid by consumption units can be realised by a reduction of consumptions as well as by the substitution of energy source. For example, the substitution can be provided by:
  - Cogeneration units already installed on-site with margin of production generally not employed (as implemented in different UVAC);
  - Storage systems employed as a backup system for electric provision in case of black-out.
- **Plant's adaptation**: interruption/reduction of off-takes from the grid must not lead to disfunctions in plant's components or misuses along the production process (e.g. higher marginal costs). Consequently, investments aimed to adapt plants to the current framework could be needed and must be cost-efficient.
- **IT infrastructure**: in addition to technical feasibility related to the underlying process, it has to be considered the requirement of investments in monitoring, metering and communication devices.

2.5 ITALIAN REGULATORY FRAMEWORK

By Resolution 300/2017/R/eel "*Prima apertura del mercato per il servizio di dispacciamento (MSD)*" the Italian Authority defined the criteria to allow for the participation of consumption units and production units until now excluded (relevant, but intermittent renewables; not relevant) to the MSD in order to provide balancing services. Furthermore, the participation is also allowed for storage systems.

The Document provides that not-relevant, i.e. with power lower than 10 MVA, production and consumption units, together with relevant units (not aggregated) powered by RES, can be qualified for the MSD on aggregated basis, according to appropriate criteria of geographic localisation (*Perimetri di aggregazione*), constituting dispatchment points for *Unità Virtuali Abilitate* (UVA), thus setting up the first initiative to introduce the Demand-Response mechanism in the Italian power market.

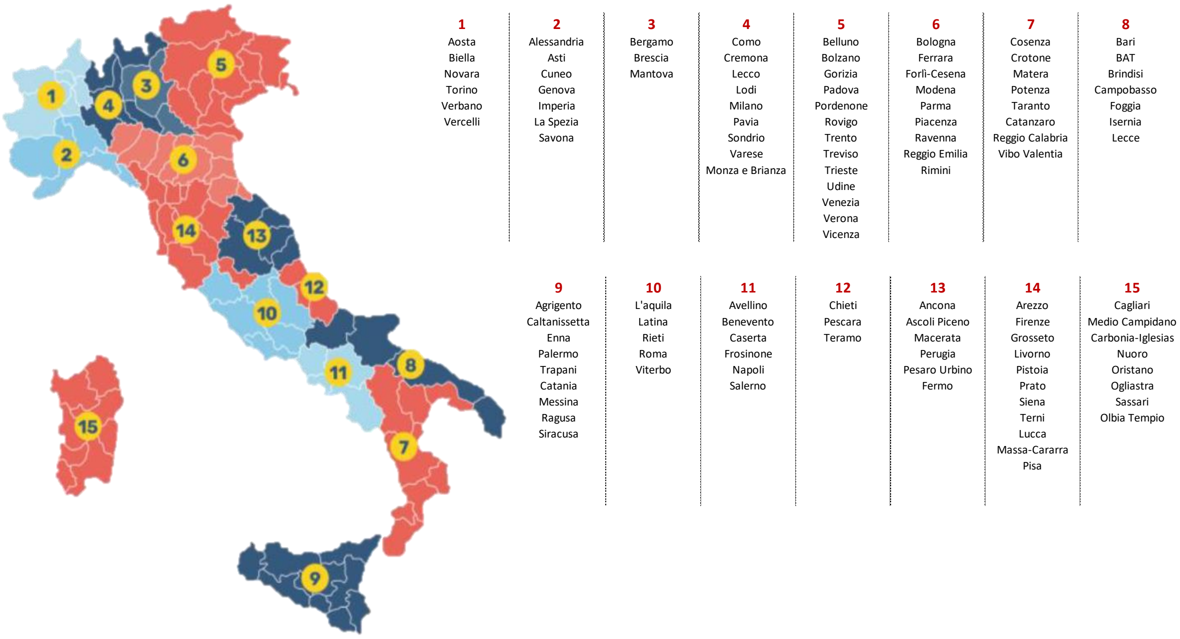

Figure 18. *"Perimetri di aggregazione"* according to Resolution 300/2017

The qualification to MSD is hence extended to new subjects: *Unità Virtuali Abilitate* which can be constituted by consumption units (UVAC – *Unità Virtuale Abilitata di Consumo*), production units (UVAP – *Unità Virtuale Abilitata di Produzione*) or made up of both categories (UVAM – *Unità Virtuale Abilitata Mista)* and finally, UVAN (*Unità Virtuale Abilitata Nodale*) is planned for next years.

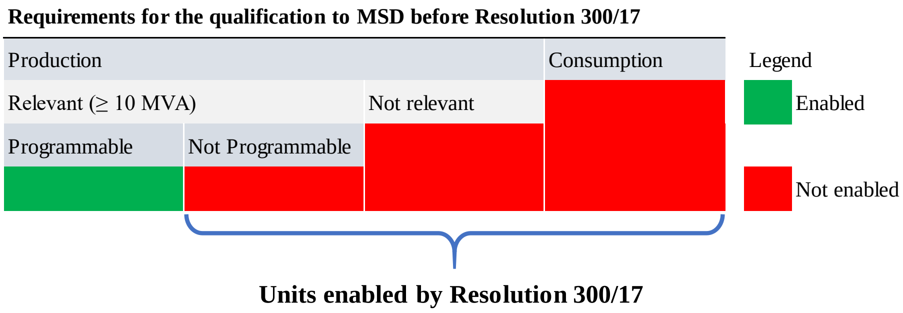

Figure 19. Requirements for the qualification to MSD before Resolution 300/17.

In particular, the Resolution provides as follows:

- The qualification to MSD is still mandatory for relevant production units respecting the requirements provided by the *Codice di rete*[20], whilst it is voluntary for the other relevant production units (powered by intermittent renewable sources) and for not-relevant production and consumption units;
- The qualification to MSD for consumption and production units not treated on hourly basis is still not allowed. Indeed, the participation of these units would lead to an arduous management by dispatchments users. This condition at the moment excludes all little users of the electric system from the trial;
- The service of interruptibility of consumption units is still not allowed for the participation to MSD, since it is a service negotiated outside the MSD;

Differently from what happens for relevant units, which participate as a single unit to both MGP and MSD (so BRP coincides with BSP), concerning UVAs the counterparty of Terna for the supply of dispatchment resources is the BSP, which could consequently be different from the dispatchment user.

A not-relevant production or consumption unit refers respectively to a Production Unit (UP) or Consumption Unit (UC) for the MGP market, whilst it refers to an UVA for the participation to MSD. It follows the coincidence or not between the figures of Dispatchment User (BRP – Balance Responsible Party, responsible for the unbalancing) and BSP (responsible for the implementation of dispatchment orders).

In case BSP and dispatchment user do not coincide, for every relevant period, Terna rewards to the BSP the product between the volume of electricity accepted on the MSD regarding the UVA and the price relative to the offer.

Assuming that the dispatchment order is not respected by the UVA, the BSP is obliged to remit a compensation of non-compliance to the TSO.

Modality and obligations concerning offer’s procedure are the same for both relevant production units and UVA as provided by the Codice di Rete for units currently qualified for the participation to MSD, except for the following specifications:

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[20] D.P.C.M. of the 11th of May 2004

- UVA do not apply for offers of minimum or shut-down;
- Offers of activation are reserved for qualified thermoelectric relevant production units;
- Offers of UVA and voluntarily qualified relevant production units can be presented "asymmetrically", i.e. just for one modality, upward or downward, according to the qualification obtained.

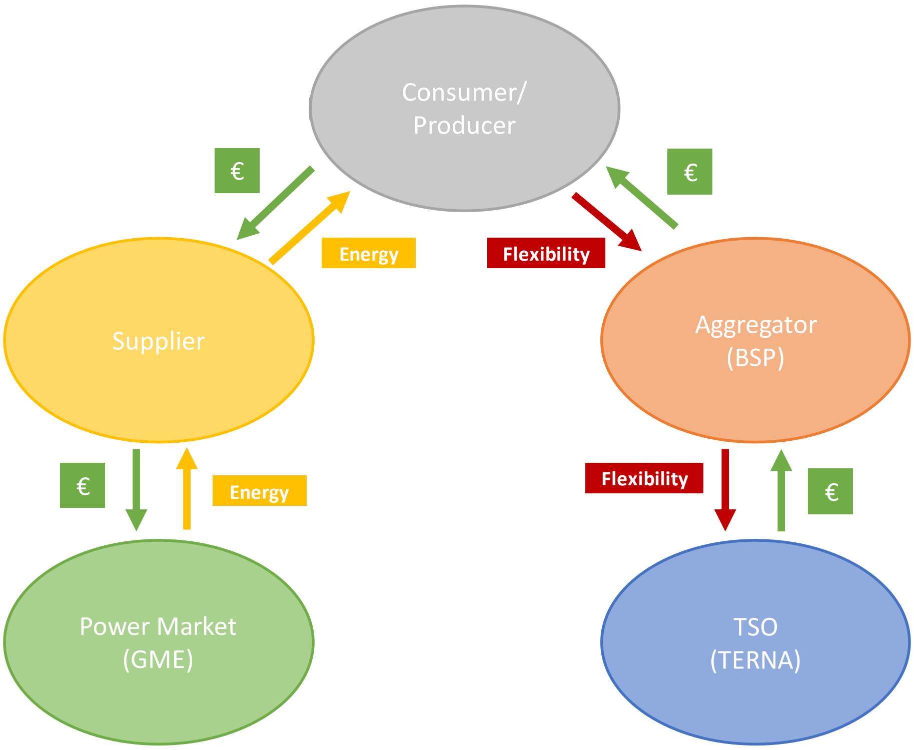


Figure 20. Main relationships from Demand-Response scheme in the Italian power market.

Following the Resolution 300/2017, the Italian Authority provided several Regulations and Procedures in order to clarify the mechanism of the different UVAs and activate them in the Italian power market as Pilot Projects.

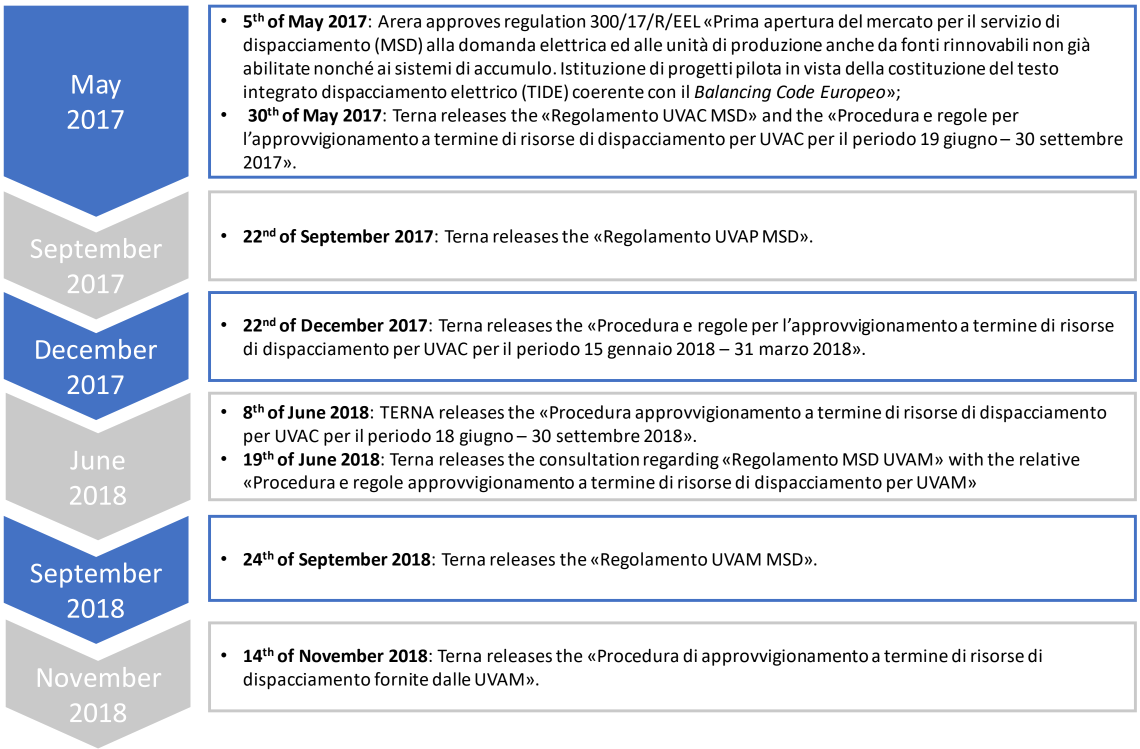


Figure 21. Italian's regulation timeline.

2.5.1 UVAC

By the release of "*Regolamento UVAC MSD*" on the 30th of May 2017, integrated by Terna via the "*Procedura e regole per l'approvvigionamento a termine di risorse di dispacciamento per l'UVAC per il periodo 18 giugno-30 settembre 2018*", the Italian Authority defined the characteristics of the UVAC (*Unità Virtuali Abilitate di Consumo*).

An UVAC consists in an aggregate composed exclusively by consumption units, resulting in the same dispatchment contract. They result as an aggregate just concerning the participation to the MSD, whilst in the participation the other power markets, and consequently in the determination of unbalancing, units included in an UVAC still remain allocated in the dispatchment points for consumption units existing today.

The counterparty of Terna for the supply of dispatchment services is the BSP, who can be distinct from the dispatchment user and is still responsible in case of non-compliance of dispatchment orders.

The figure of the BSP can be represented by:

- A subject characterised by the ownership of the consumption units aggregated in an UVAC;
- The dispatchment user (UdD) holder of the consumption facilities associated to the consumption units of the UVAC;
- A third aggregator party.

Services

An UVAC is entitled to offer services of flexibility concerning:

- Tertiary reserve upward;
- Balancing power upward.

Perimeters of aggregation

Concerning the geographic localisation of the UVAC, only units localised in the market zones NORD and CENTRO-NORD are entitled to aggregate as an UVAC and participate to the MSD. Concerning the "Perimetri di aggregazione" provided by Resolution 300/17, consumption units can be located in zones 1, 2, 3, 4, 5, 6, 13, 14.

Capacity allocation

The capacity allocated with regard to UVAC, has been set by the Authority by the release of "*Procedura e regole per l'approvvigionamento a termine di risorse di dispacciamento per l'UVAC per il periodo 18 giugno-30 settembre 2018*". The Procedure set a total of 500 MW of capacity for the Period of Validity, to be allocated by a "pay-as-bid" downward auction, during which every offer must be characterised by a couple quantity-price where:

- The quantity represents the capacity offered by the owner of an UVAC expressed in terms of power, not lower than 1 MW;
- The price represents the offered premium, expressed as €/MW, regarding the previous-mentioned quantity for the Period of Validity.

Remuneration

Concerning the remuneration for UVAC's capacity allocated by the auction procedure for "fixed-term" supply of dispatchment resources, it is composed by a fixed and a variable remuneration.

Fixed remuneration, determined as €/MW, has been defined at the conclusion of a "pay-as-bid" downward auction, from a unit price on annual basis equal to 30.000 €/MW, according to the remuneration for the supply of analogous service in EU.

Capacity remuneration has been introduced by Terna on the basis of possible criticalities derived by a lack of reserve during summer period, which could have been dangerous for the overall electric system.

Variable remuneration refers to the accepted quantities on the MSD in case of activation of flexibility resources, with a price not higher than a "strike price" provide by the Authority, equal to 400€/MWh.

Services' implementation

BSP is committed to present, as in the modalities defined by the Regulation of the MSD, in the Period of Validity, flexibility's offers upward (which in case of consumption units consists in the reduction of loads in order to guarantee more available energy to the system) concerning tertiary reserve and balancing within the planning phase of MSD and in the balancing market, with prices not higher than the strike price. The quantity of energy offered must be at least equal to the assigned capacity and the flexibility must last for at least three consecutive hours between 14:00 and 20:00 from Monday to Friday. Furthermore, the fixed remuneration is linearly incremented until a maximum value of 200% if the offer covers all the hours between 14:00 and 20:00.

In case the offer is accepted and the dispatchment order is not correctly executed, the owner of an UVAC shall be obliged to reimburse an amount equal to the product between the offered price on MSD (increased by 50%) and the quantity of energy not supplied.

2.5.2 UVAP

By the release of "*Regolamento UVAP MSD*" on the 22nd of September 2017, the Italian Authority defined the characteristics of the UVAP (*Unità Virtuali Abilitate di Produzione*).

An UVAP is characterised by the presence of only not-relevant production units (≤ 10 MVA, both programmable and not-programmable), including storage systems, involved in the same dispatchment contract. As in the case of UVAC, also UVAP result as an aggregate just concerning the participation to the MSD, whilst in the participation the other power markets, and consequently in the determination of unbalancing, units included in an UVAP still remain allocated in the dispatchment points for not-relevant production units existing today.

Every UVAP must guarantee certain values in terms of modulation upward and downward, named respectively "*Potenza Massima di Controllo*" (Maximum increase of injection that the UVAP can, in every condition, make available to Terna) and "*Potenza minima di Controllo Inferiore*" (Maximum decrease of injection that the UVAP can, in every condition, make available to Terna):

- If it has been requested the qualification to offer flexibility services both upward and downward, UVAP must guarantee a "*Potenza Massima di Controllo*" and a "*Potenza Minima di Controllo Inferiore*" not lower than 1 MW (in absolute terms);
- If it has been requested the qualification to offer flexibility services only upward, UVAP must guarantee a "*Potenza Massima di Controllo*" not lower than 1 MW and a "*Potenza Minima di Controllo Inferiore*" equal to 2 kW (in absolute terms);
- If it has been requested the qualification to offer flexibility services downward, UVAP must guarantee a "*Potenza Massima di Controllo*" equal to -2 kW and a "*Potenza Minima di Controllo Inferiore*" not lower than 1 MW (in absolute terms);

Differently from UVAC, because of characteristics of rapid modulation, UVAP must present on a daily basis, the so-called Baseline of production, representing the overall program of production for all the units/dispatchment points included in an UVAP.

Again, the counterparty of Terna for the supply of dispatchment services of UVAP is the BSP, who can be distinct from the dispatchment user. BSP is still responsible in case of non-compliance of dispatchment orders.

Services

An UVAP is entitled to offer services of flexibility concerning:

- Congestions resolution upward and/or downward;
- Tertiary reserve upward and/or downward;

- Balancing upward and/or downward.

Perimeters of aggregation

Differently from UVAC, concerning UVAP, the aggregated not-relevant production units can be localised in every macro-zone provided by the power market. Concerning the “*Perimetri di aggregazione*” provided by Resolution 300/17, not-relevant production units can be located in every perimeter.

Remuneration

Differently from the aggregation of consumption units, concerning UVAP it has not been provided any fixed remuneration based on the capacity made available to the system. Consequently, UVAP will follow the same rules applied for relevant production units, gaining a variable remuneration based on the acceptance of offers on the market. The same holds for the strike-price previously mentioned.

Services’ implementation

BSP has the faculty of presenting, as in the modality defined by the Regulation of the MSD, up to three (four) flexibility’s offers on MSD Ex-Ante (MB) upward (which in case of production units consists in the increase of production in order to guarantee more available energy to the system) and/or downward (which consists in the purchase of electricity from the grid in order to guarantee a decrease of the available energy in the system) concerning congestions resolution, tertiary reserve and balancing services. The offer, in case of acceptance, must last for three consecutive hours and flexibility resources must be activated within 15 minutes from the reception of the dispatchment order by Terna.

In case the offer is accepted and the dispatchment order is not correctly executed, the owner of an UVAP shall be obliged to reimburse an amount equal to the product between the offered price on MSD (increased by 50%) and the quantity of energy not supplied.

2.5.3 UVAM

By the release of “*Regolamento UVAM MSD*” on the 24th of September 2018, integrated by Terna via the “*Procedura di approvvigionamento a termine di risorse di dispacciamento fornite dalle UVAM*”, the Italian Authority defined the characteristics of the UVAM (*Unità Virtuali Abilitate Mista*).

According to the current Regulation, an UVAM can be represented by:

A. An aggregate composed by one or more of the following units:
   - Not-relevant production units;
   - Consumption units;
   - Storage systems, as defined in Regulation 574/2014/R/eel, “stand alone” or associated to not-relevant production units or consumption units;
   - One or more relevant production units not yet compulsorily obliged to the participation to MSD, that share the point of connection with one or more consumption units and eventually with one or more not-relevant production units and /or storage system, as long as the total power injected in the grid is lower than 10 MVA.

B. One or more relevant production units not yet compulsorily obliged to the participation to MSD, that share the point of connection with one or more consumption units and eventually with one or more not-relevant production units and /or storage system with total power injected in the grid higher than 10 MVA.
   - The average consumption of consumption units included in the UVAM must be at least equal to the 50% of energy produced by the units of the UVAM.

As in the case of UVAC and UVAP, also UVAM result as an aggregate just concerning the participation to the MSD.

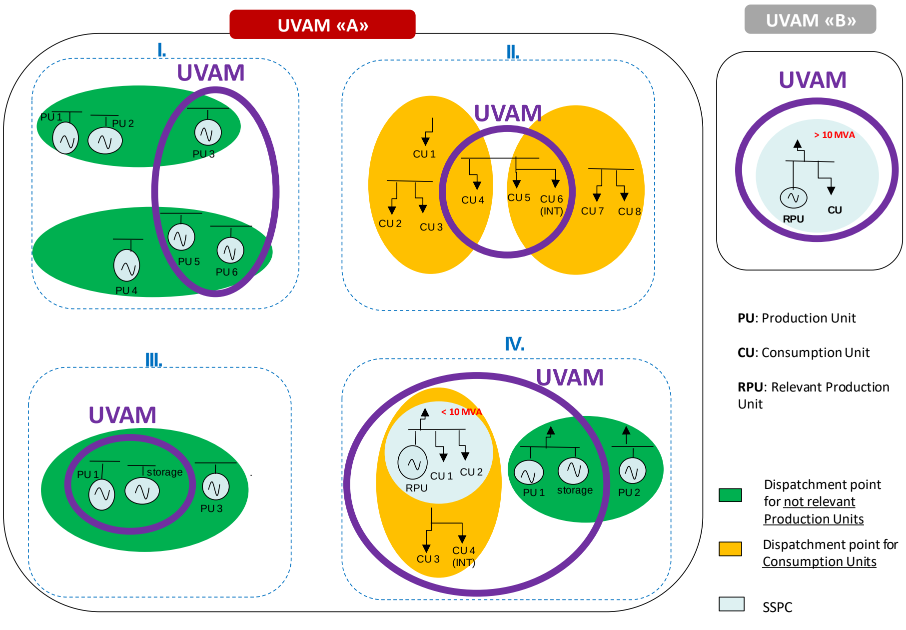


Figure 22. Possible aggregations according to UVAM’s regulation. Source: Terna

Like UVAP, also UVAM must guarantee certain values in terms of modulation upward and downward, named respectively "*Potenza Massima di Controllo*" and "*Potenza minima di Controllo Inferiore*", which present the same values provided for the UVAP.

An UVAM must present on a daily basis the so-called Baseline of injection, representing the overall program of injection and off-take by all the units (both production and consumption) included in the UVAM. Differently from the UVAP case, the Baseline of an UVAM can have negative values in case of majority of consumption rather than production.

Again, the counterparty of Terna for the supply of dispatchment services of UVAM is the BSP, who can be distinct from the dispatchment user. BSP is still responsible in case of non-compliance of dispatchment orders.

Concerning the possible composition of an UVAM, mostly the 40% of the entitled maximum power can be composed by not-programmable (RES) in case of entitling to Congestions resolution and Tertiary reserve upward. No limits of composition in term of programmable/not-programmable units are provided in case of downward services.

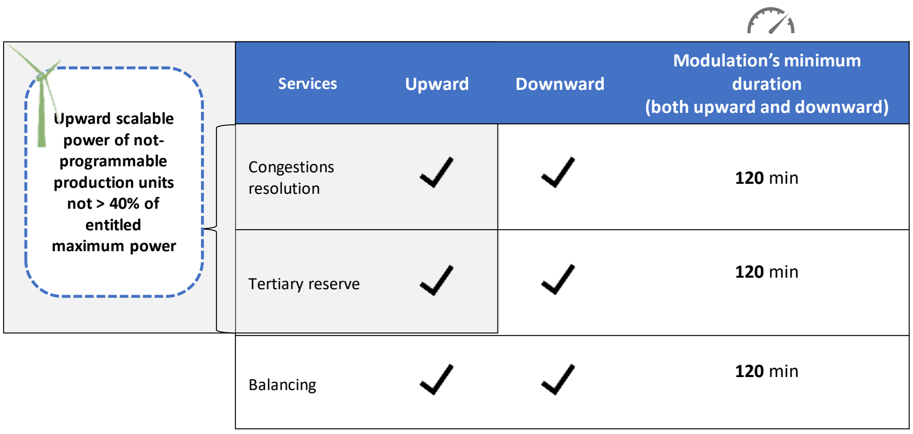


Figure 23. UVAM's composition, services and modulation's minimum duration

Services

Currently UVAM, according to "*Procedura di approvvigionamento a termine di risorse di dispacciamento fornite dalle UVAM*", is entitled to offer services of flexibility concerning:

- Congestions resolution upward (and/or downward according to "*Regolamento UVAM MSD*", contrarily from "*Procedura di approvvigionamento a termine di risorse di dispacciamento fornite dalle UVAM*");

- Tertiary reserve upward (and/or downward according to "*Regolamento UVAM MSD*", contrarily from "*Procedura di approvvigionamento a termine di risorse di dispacciamento fornite dalle UVAM*");
- Balancing upward (and/or downward according to "*Regolamento UVAM MSD*", contrarily from "*Procedura di approvvigionamento a termine di risorse di dispacciamento fornite dalle UVAM*").

Perimeters of aggregation

As in the case of UVAP, also for UVAM the aggregated units can be localised in every macro-zone provided by the power market. Concerning the "*Perimetri di aggregazione*" provided by Resolution 300/17, aggregated units can be located in every perimeter.

Capacity allocation

The capacity allocated with regard to UVAM has been set by the Authority by the release of "*Procedura per l'approvvigionamento a termine di risorse di dispacciamento fornite dalle UVAM*" for the entire 2019. Following the procedure, it will be allocated 1.000 MW of capacity for the Period of Validity subdivided in two main macro areas:

- 800 MW concerning market zones NORD and CENTRO-NORD (Macro area A);
- 200 MW concerning market zones CENTRO-SUD, SUD, SICILIA AND SARDEGNA (Macro area B).

Terna provides the following products:

1. Annual product, available from the 1st of January 2019 to the 31st of December 2019;
2. Three interim products, for every macro area, regarding the capacity eventually not allocated as annual products;
3. Twelve monthly products, for every macro area, regarding the capacity eventually not allocated as annual or interim products.

The capacity for the Period of Validity period will be allocated by a "pay-as-bid" downward auction, during which every offer must be characterised by a couple quantity-price where:

- The quantity represents the capacity offered by the owner of an UVAM expressed in terms of power, not lower than 1 MW;

- The price represents the offered premium, expressed as €/MW, regarding the previous-mentioned quantity for the Period of Validity.

Remuneration

Concerning the remuneration for UVAM's capacity allocated by the auction procedure for "fixed-term" supply of dispatchment resources, it is composed by a fixed and a variable remuneration.

Fixed remuneration, determined as €/MW, has been defined at the conclusion of a "pay-as-bid" downward auction, from a unit price on annual basis equal to 30.000 €/MW, according to the remuneration for the supply of analogous service in EU.

Variable remuneration refers to the accepted quantities on the MSD in case of activation of flexibility resources, with a price not higher than a "strike price" provide by the Authority, equal to 400€/MWh.

Services' implementation

BSP is committed to present, as in the modality defined by the Regulation of the MSD, in the Period of Validity, flexibility's offers upward (which in case of consumption units consists in the reduction of loads in order to guarantee more available energy to the system and in case of production units it consists in an increase of production) concerning congestions' resolution, tertiary reserve and balancing services within the planning phase of MSD and in the balancing market, with prices not higher than the strike price. The quantity of energy offered must be at least equal to the capacity assigned by Terna at the conclusion of the auction and the flexibility must last for at least four consecutive hours between 14:00 and 20:00 from Monday to Friday. Furthermore, the fixed remuneration is reduced by 50% if the offer covers just two consecutive hours.

In case the offer is accepted and the dispatchment order is not correctly executed, the owner of an UVAM shall be obliged to reimburse an amount equal to the product between the quantity of energy effectively not supplied and the maximum value between:

- The average weighted price, with respect to the corresponding quantities, of the bids accepted in relation to the UVAM;

- Accepted bids' highest price for other services in the macro zone in which the UVAM is localised.

Pilot Project	Minimum power threshold of the UVA	Services and mode
UVAC	From 10 MW to 1 MW	· Tertiary reserve upward · Balancing downward
UVAP	From 5 MW to 1 MW	· Congestions resolution upward and/or downward · Tertiary reserve upward and/or downward · Balancing upward and/or downward
UVAM	1 MW	· Congestions resolution upward · Tertiary reserve upward · Balancing upward

Table 1. Summary of UVAs' minimum power threshold and entitled services

Both UVAC and UVAP, as provided by Terna, will cease once the respective pilot projects will come to an end. Starting from 2019, both will converge in UVAM pilot projects, according to the Procedure provided by Terna. Moreover, UVAM pilot projects are entitled for just the year 2019, with, at the moment, no confirm concerning any possible prosecution for the following year.

3. MSD MARKET

3.1 THE STRUCTURE OF THE ITALIAN ELECTRICITY MARKET

Legislative Decree N.79 of the 16th of March 1999 (so-called "*Decreto Bersani*"), following the European Directive 96/92/CE, has put in place the foundations for a wholesale electricity market, known as "*Borsa Elettrica"*, otherwise IPEX (Italian Power Exchange), answering to two fundamental requirements:

i. To promote, according to criteria of neutrality, transparency and objectivity, competition in the activities of production and trade of electricity;
ii. To ensure the economic management of an adequate availability of dispatchment services.

The task of organising and managing the power market is assigned to the *Gestore dei Mercati Elettrici S.p.A* (GME) which, operating according to the previous-mentioned criteria, guarantees by its activity the security of power exchanges and the balancing between demand and supply of electricity in the system.

IPEX, as well as being the location for the virtual exchange where the final price of electricity (spot price) is determined by the match between demand and supply by operators qualified to the participation, is also the location where Terna S.p.A. (the supervisor of the national transmission system, TSO) procures the necessary resources to provide for the dispatchment of electricity on the national territory. Furthermore, such location represents the physical market where injection and off-take programs, to and from the grid, are defined.

It is specified that IPEX is not a mandatory market, since operators are allowed to negotiate trades of electricity also outside of it, by the so-called "bilateral agreements" or "Over the Counter OTC".

Market zones

The electric system is subdivided in portions of transmission's grid, defined as "zones", for whom there exist physical limits of transit for electricity, in order to guarantee system's security and efficiency.

Such limits are determined on the basis of the balance of power generation and consumption. The Italian electric system is thus subdivided in market zones, aggregates of real or “virtual” geographic zones, each characterised by its zonal price.

The national transmission network is functional to the management of transits along the territory and it is subdivided in twenty different market zones:

- 6 geographic zones (CENTRO-NORD, NORD, CENTRO-SUD, SUD, SICILIA, SARDEGNA);

Figure 24. Italian geographic market zones

- 8 virtual foreign zones (FRANCE, SWITZERLAND, AUSTRIA, SLOVENIA, BSP, CORSICA, CORSICA AC, GREECE);
- 4 virtual national zones which represent limited production hubs, i.e. zones constituted just by production units, whose interconnection’s capacity with the grid is lower than the power installed by the units itself (BRINDISI, FOGGIA, PRIOLO, ROSSANO).

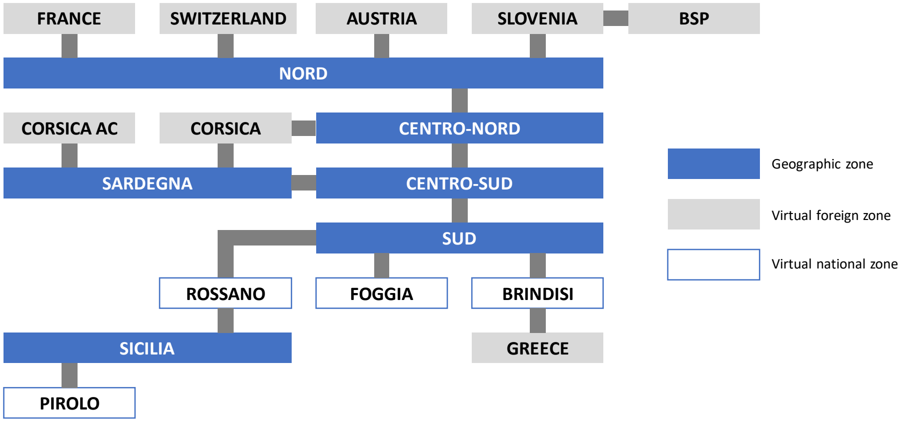


Figure 25. Italian market zones and interconnections. Source: GME

According to the TIDME (*Testo integrato della Disciplina del mercato elettrico*[21]), IPEX is subdivided in:

- Electricity Spot Market (MPE);
- Electricity forward market (MTE), with commitment of delivery and collection, concerning the supply of electricity on longer time horizons than what provided by MPE;
- Platform for the physical delivery of financial agreements traded on IDEX (Italian Derivatives Energy Exchange).

In particular, according to art.21 of TIDME, MPE is organised in:

- Day-ahead market (MGP - *Mercato del Giorno Prima*);
- Infraday market (MI - *Mercato Infragiornaliero*);
- Ancillary Services Market (MSD - *Mercato del Servizio di Dispacciamento*), furthermore subdivided in MSD ex-ante and Balancing Market (MB - *Mercato del Bilanciamento*).

The relevant period for all the above-mentioned markets is equal to the fixed hour.

[21] Legislative Decree 79/1999

3.1.1 DAY-AHEAD MARKET – MGP

The day-ahead market (MGP) is typically the most important market of IPEX, in terms of volumes of electricity traded and significance of resulting prices. The participation to the aforementioned market, as previously mentioned, is not mandatory, since operators are allowed to trade electricity by bilateral agreements outside of the market (OTC).

Within the MGP, producers, wholesalers and consumers can buy and sell electricity for every hour of the following day by presenting bids and offers along the relative market sessions. The relevant session for day D starts at 8:00 of day D-9 and ends at 12:00 of day D-1, i.e. the day ahead. Offers presented consist in a couple of values, quantity and price of electricity. In this market, as in the MI market, the transmission grid is expressed in terms of the previous-mentioned market zones, which subdivide the grid in different portions linked by corridors with electricity's transit limits provided by Terna. Such limits are determined by models based on the balance between generation and consumption in different scenarios, considering the impact of possible lack of production by some units, in order to guarantee the security of service.

Sell prices are determined by the mechanism of System Marginal Price, i.e. they correspond to the highest offer's price accepted on the market. Concerning bid price, it is always equal in all the market zones (PUN – *Prezzo Unico Nazionale*) and it corresponds to the average of zonal prices, weighted on the demand of every market zone. GME acts as central counterparty of market operator, thus guaranteeing transactions' outcome and eliminating counterparty risk.

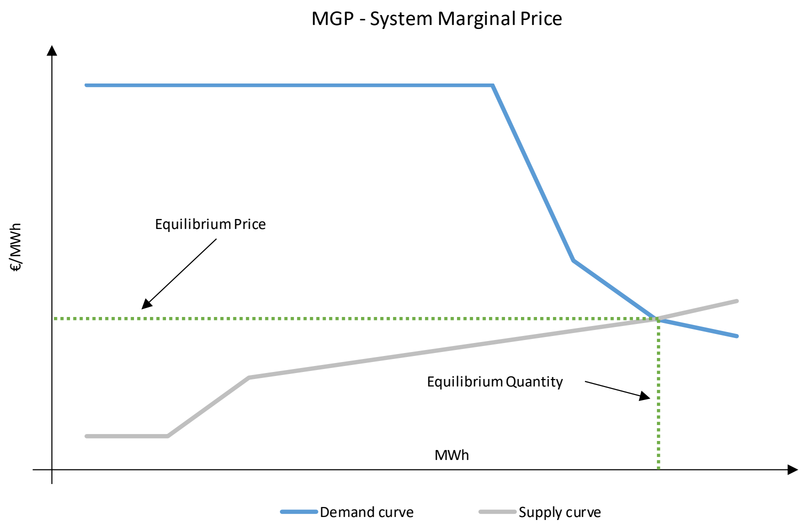


Figure 26. System Marginal Price determination on MGP

In particular, during sessions of MGP, organised according to criteria of economic merit order and valorisation of electricity at marginal offers, RES, characterised by almost null marginal costs, upset the supply curve of traditional power plants, contributing in reducing the electricity price on the market. This phenomenon, still present in other countries' markets and defined as "Merit Order Effect" (MOE), is becoming more evident because of the increase of RES participation in the national energetic production.

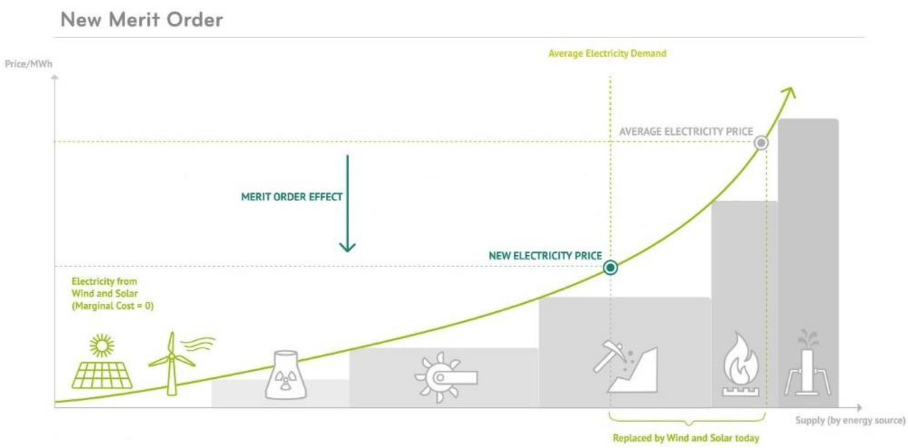


Figure 27. Merit Order Effect. Source: German Renewable Energies Agency

3.1.2 Intraday Market – MI

Infraday Market (MI) allows operators to modify their programs of injection/off-take defined in the MGP by further offers of sale or purchase. The adjustment is allowed in order to make programs compatible with plants' technical limits or to update them as a result of more accurate forecasts, since made approximately in real time. MI is subdivided in seven different market sessions and GME represents the counterparty of operators in stipulated contracts of sale or purchase.

Differently from what provided for the MGP, in the MI the PUN is not considered and all trades are valued at the zonal price.

According to art.52 of TIDME, in order to reflect on the MI the application of PUN to units belonging to different market zones, GME applies the so-called "not-arbitrage fee" to all the trades accepted on the market.

In particular, for every purchase transaction made on the MI relative to a dispatchment point belonging to a market zone, whenever, on the MGP, PUN was higher (or lower) than the relative zonal price, the operator shall pay (or receive) a “not-arbitrage fee”, equal to the difference between PUN and zonal price applied to every MWh object of the purchase transaction. The opposite applies for sale transactions.

As in the MGP, merit order criteria holds also concerning the Intraday Market, with the same effects of prices.

3.1.3 ANCILLARY SERVICES MARKET – MSD

The ancillary services market (MSD) is the instrument by which Terna provides the necessary resources in order to manage and control the overall power system (intrazonal congestions’ resolutions, backup electricity reserves, real time balancing).

Provision of electricity services must take place according to adequate standards of security, reliability, quality, continuity and efficiency by the action of the figure responsible of the management and control of transmission system, which must ensure the instantaneous match between load and generation, respecting operative limits also in case of large disturbances.

The MSD takes place after the conclusion of energy markets (MGP and MI), where operators offer sale (by production) or purchase (by consumption) of electricity for the following day. Such market is considered almost a “real time market” because it occurs close to the physical delivery of electricity and because it is needed by the TSO to guarantee the safe exercise of the national electric system, i.e. the match in every moment between demand and supply in every network node, which cannot be guaranteed at the conclusion of energy markets.

On the MSD Terna acts as central counterparty, and accepted offers are remunerated at the offered price (*pay-as-bid)* in case of necessity of resources and acceptance of the offer by Terna.

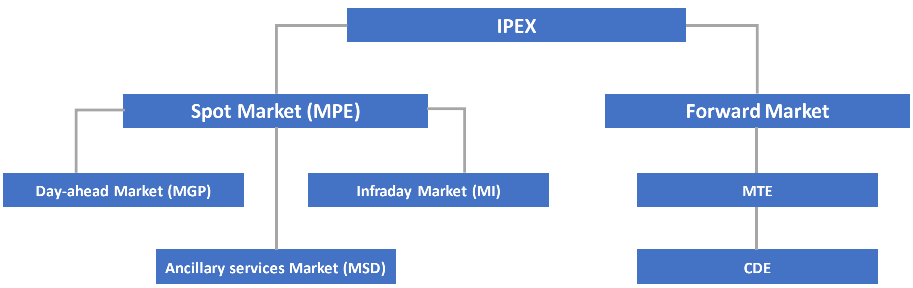


Figure 28. Italian electricity market’s structure

3.2 DEFINITION OF MSD MARKET AND DISPATCHMENT SERVICES

The MSD is subdivided in two different phases, MSD Ex-Ante (Programming phase) and Balancing Market (MB, Real Time phase). Both phases take place in six different sessions.

Concerning the MSD Ex-Ante consists of six programming phases: MSD1, MSD2, MSD3, MSD4, MSD5 and MSD6. It is provided a unique session for offers' presentation on the MSD Ex-Ante which starts at 12:55 of the day-ahead with respect to the day of physical delivery of electricity and it closes at 17:30 of the same day.

On the MB, Terna accepts offers of purchase and sale of electricity in order to operate the service of secondary regulation and to maintain the balancing, in real time, between injections and off-takes of electricity on the grid.

MB is subdivided in six different sessions (MB1, MB2, MB3, MB4, MB5 and MB6) during which Terna selects offers regarding different timeframes of the same day of the relative session. Concerning the first session, the offers considered are the valid offers presented by operators during the previous session on the MSD Ex-Ante. With regard to the other sessions of MB, the general term for offers' presentation open at 22:30 of the day-ahead the physical delivery of electricity (and anyhow not before the release of the outcomes of the previous session on the MSD Ex-Ante).

Reference Day	D-1	D										
	MSD1	MB1	MSD2	MB2	MSD3	MB3	MSD4	MB4	MSD5	MB5	MSD6	MB6
Session opening	12:55	°	°	22:30*	°	22:30*	°	22:30*	°	22:30*	°	22:30*
Session closing	17:30	°	°	03:00	°	07:00	°	11:00	°	15:00	°	19:00
Outcomes	21:45	#	02:15	#	06:15	#	10:15	#	14:15	#	18:15	#

° Offers presented on MSD1

* It refers to D-1

Dispatching discipline

Table 2. MSD market phases.

On the MSD there can be presented offers regarding secondary reserve, which, in real-time, are automatically accepted pro rata by the regulator of secondary reserve, and offers concerning other services, developed in order to create necessary reserve margins and to solve eventual intrazonal congestions.

In general, offers on the MSD must be referred only to entitled offers points and can be presented just by the respective dispatchment users. In particular, on the MSD Ex-Ante, users must present default offers, according to the procedures defined by the dispatchment discipline.

GME informs Terna about the received offers on the MSD for every offer point and for every relevant period, and later, Terna notifies GME the accepted offers.

At the conclusion of MSD phases, for every geographic zone and every hour, GME publishes the following data and information:

- Overall quantity subject of accepted upward and downward offers;
- Hourly average upward and downward accepted offers' prices, as well as the minimum downward offer's price and the maximum upward offer's price accepted;

Hence GME communicates:

- To every operator who presented offers, limited to such offers, the accepted ones, specifying the amount of electricity, final hourly programs of injection/off-take and every other information provided by the dispatchment regulation;
- To the dispatching user of each enabled offer point, the final cumulated hourly programs of injection/off-take.

Following, are presented the services currently requested by Terna to guarantee the secure balancing of the system, also in case of relevant accidents, on the basis of the subdivision between resources exchangeable on the MSD and off-market services.

Some of the following services are mandatory and automatically provided: being not acquired by Terna by the MSD are not remunerated. Other are acquired (and remunerated) on the MSD and provided by the units just in case of reception of a proper dispatchment order.

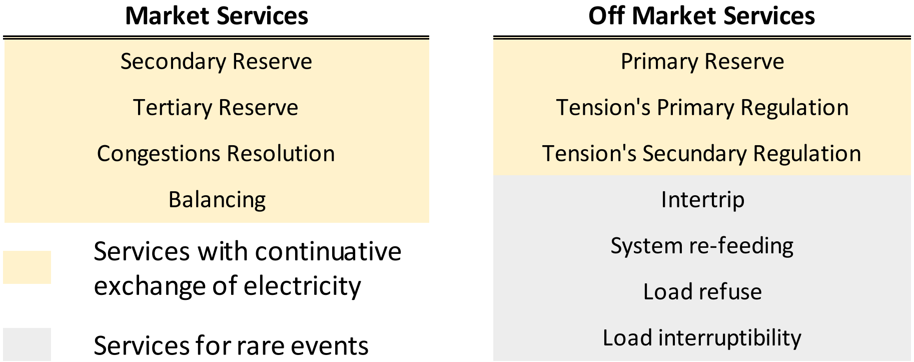


Figure 29. Services available on the MSD market.

In order to allow for a simpler management of the MSD, on both the programming phase (MSD Ex-Ante) and real-time phase (MB), dispatchment users present offers not regarding to every service, but only with respect to some macro-categories. Electricity supplied is further managed by Terna in order to solve the different issues of the system.

The offers that dispatchment user can present in order to supply flexibility services are:

- Sale offers (Upward);
- Purchase offers (Downward).

Separated for Secondary Reserve and Other Services.

Quantity and prices of sale and purchase offers on the MSD are to be intended as non-negative, with the exception of shutdown price, which can, potentially, assume values with negative sign and not lower than a floor price provided by the Authority (now equal to zero).

For every Production Unit and for every hourly period of the reference day, offers presented on the MSD Ex-Ante phase (MB phase) must be constituted by:

- If the unit is qualified to supply Secondary Reserve’s upward resources, 1 price (expressed in €/MWh) for the sale offer of Secondary Reserve, relative to the increase of injection for the eventual activation of flexibility resources;
- If the unit is qualified to supply Secondary Reserve’s downward resources, 1 price (expressed in €/MWh) for the purchase offer of Secondary Reserve, relative to the decrease of injection for the eventual activation of flexibility resources;

- At least 1 and until 3 (4 in MB) couples of quantities (expressed in MWh) and prices (expressed in €/MWh) for the sale offers for Other Services, relative to the increase of injection from the highest value between the Adjusted Cumulated Program and the Minimum Power, until the Maximum Power;
- At least 1 and until 3 (4 in MB) couples of quantities (expressed in MWh) and prices (expressed in €/MWh) for the purchase offers for Other Services, relative to the decrease of injection from the highest value between the Adjusted Cumulated Program and the Maximum Power, until the Minimum Power;

MSD is thus a more complex and articulated market compared to both MGP and MI. The activation of flexibility resources is indeed strictly linked to the eventual necessity, by the TSO, of higher (or minor) power and consequently it is not a matter of matching offer and supply with specific economic merit order as in power markets. Such necessities are mostly unpredictable, both in term of quantity and hour of the day, making the participation to the MSD unfeasible as the core business of any production unit.

Moreover, pay-as-bid methodology, with unique central counterparty, implies offer's price and quantity strategy and methodology, at a higher level compared to the necessities of participating to MGP.

3.3 MSD FUNDAMENTALS AND HISTORICAL DATA

In the following section it will be presented the market outcomes of the Italian ancillary services market (MSD), subdivided between the outcomes of the Ex-Ante phase and those of the Balancing Market phase. The last three years (2016-2018) of market flows were analysed in order to highlight volumes of both upward and downward traded electricity, average upward and downward prices and the spread between such prices and the relative zonal price on monthly basis. The following paragraphs will present the outcomes of market zone NORD, being the market zone in which the subsequent Case Study is geographically localised. Outcomes regarding the other geographic market zones will be presented in Appendix (Par. 1-2).

3.3.1 MSD Ex-Ante

Zone - NORD

Market zone NORD, concerning trades on the MSD Ex-Ante, represented the most active zone in terms of volumes along last three years, with an average monthly volume of traded electricity equal to 662 GWh (330 GWh upward and 332 GWh downward). The peak of monthly trades was observed in January 2017, with 1.277 GWh of electricity traded on the MSD Ex-Ante (823 GWh upward and 454 GWh downward), whilst the minimum was registered in February 2016, with 296 GWh of electricity traded (155 GWh upward and 141 GWh downward).

Concerning prices, the monthly average upward price registered between 2016 and 2018 was equal to 98,9 €/MWh, highlighting a maximum monthly average price equal to 144,6 €/MWh in January 2017 and a minimum monthly average price equal to 71,6 €/MWh in September 2016.

In the reference period, average upward prices and zonal prices (on MGP) showed a steady price's spread, with an average value equal to 46,8 €/MWh, showing a maximum spread of 89 €/MWh in April 2017 and a minimum spread of 23,7 €/MWh in August 2018. Furthermore, the two prices show a positive though weak correlation along last three years (Correlation coefficient equal to 0,54).

The average monthly downward price registered between 2016 and 2018 was equal to 26,1 €/MWh, highlighting a minimum monthly average price equal to 9,9 €/MWh in June 2016 and a maximum monthly average price equal to 42,7 €/MWh in November 2018. Downward price and zonal price showed a positive strong correlation along the reference period (Correlation coefficient equal to 0,72).

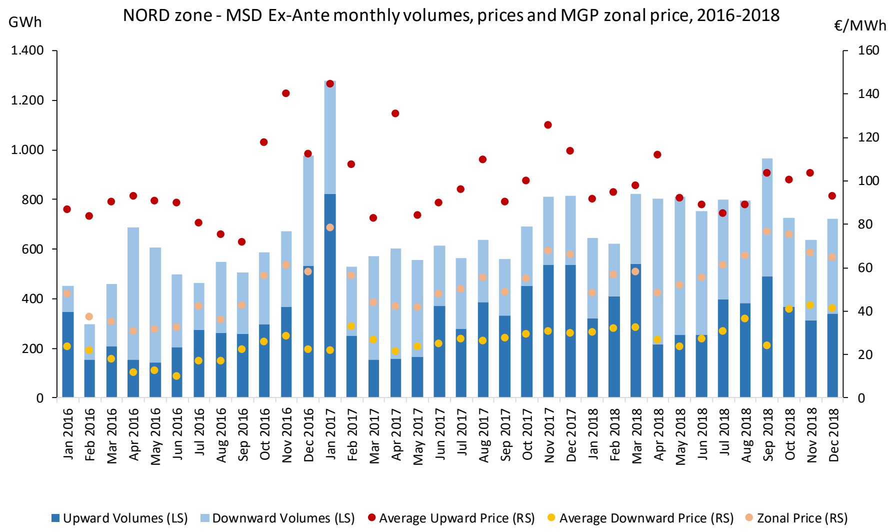


Figure 30. Upward and downward volumes and prices on the MSD Ex-Ante and Zonal Price in market zone NORD, 2016-2018. Source: GME

Overview

Concerning upward volumes, the Ex-Ante market showed a monthly average trade of electricity equal to about 932 GWh between 2016 and 2018, with the maximum monthly volume of trades equal to 1.447 GWh in January 2017 and the minimum equal to 637 GWh, registered in October 2016.

Most of the market is concentrated in market zone NORD which represents, on a monthly average, the 36% of market volumes (peak of 57% in January 2017). On the other hand, the least represented zone is SUD, with monthly average trades equal to about 1,3 GWh, representing the 0,1% of the overall market.

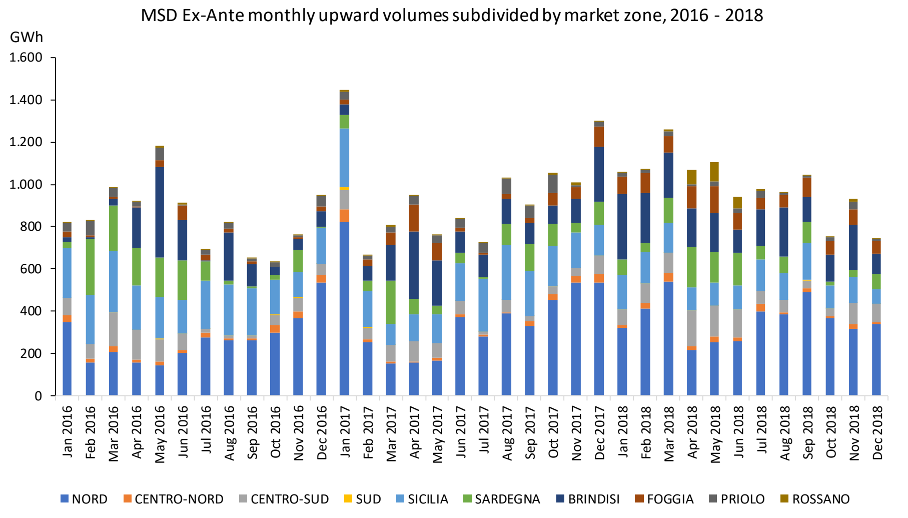


Figure 31. MSD Ex-Ante monthly upward volumes subdivide by market zone, 2016-2018. Source: GME

Concerning downward volumes, the Ex-Ante market showed a monthly average trade of electricity equal to about 554 GWh between 2016 and 2018, with the maximum monthly volume of trades equal to 1.008 GWh in April 2016 and the minimum equal to 357 GWh, registered in September 2017.

As in the upward volumes case, also regarding downward market, most of trades are concentrated in market zone NORD which represents, on a monthly average, the 62% of market volumes (peak of 85% in April 2018). Such concentration of trades is even more evident considering trades registered only in 2018, when market zone NORD represented about the 72% of the entire market. On the other hand, the least represented zone is SARDEGNA, with monthly average trades equal to about 0,4 GWh, representing the 0,1% of the overall market.

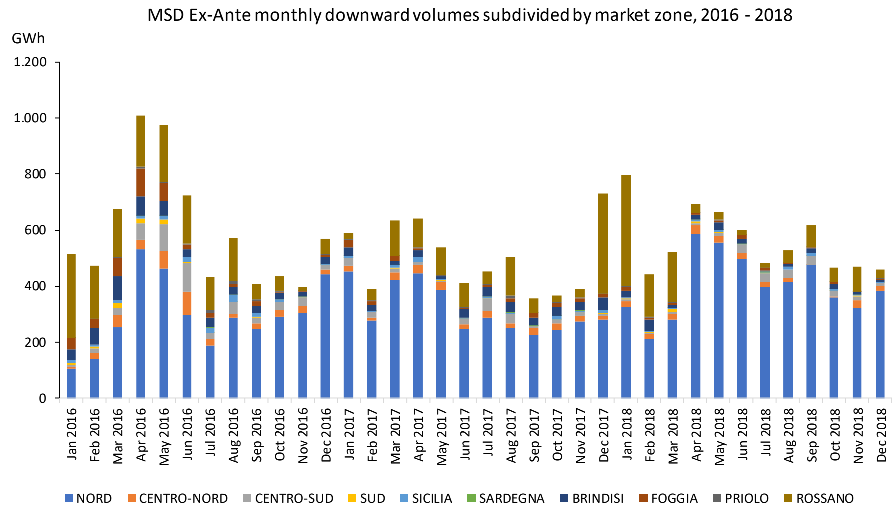


Figure 32. MSD Ex-Ante monthly downward volumes subdivide by market zone, 2016-2018. Source: GME

The overall Ex-Ante market value is about 1,3 billion €, obtained by multiplying the monthly upward trades on every market zone by the relative monthly average and then subtracting the product of monthly downward trades on every market zone by the relative monthly average price.

The market zone with the highest market value along the period of reference is represented by zone NORD, with a value of about 303 million €.

3.3.2 MB

Zone - NORD

Market zone NORD, concerning trades on the MB, represented the most active zone along last three years, with an average monthly volume of electricity traded equal to 669 GWh (165 GWh upward and 504 GWh downward). The peak of monthly trades was observed in June 2018, with 992 GWh of electricity traded on the MB (244 GWh upward and 748 GWh downward), whilst the minimum was registered in June 2016, with 478 GWh of electricity traded (131 GWh upward and 347 GWh downward).

Concerning prices, the monthly average upward price registered between 2016 and 2018 was equal to 111,3 €/MWh (+12,5% on the Ex-Ante), highlighting a maximum monthly average price equal to 170 €/MWh in January 2017 and a minimum monthly average price equal to 94,6 €/MWh in August 2016.

In the reference period, average upward prices and zonal prices (on MGP) showed a steady price's spread, with an average value equal to 58,7 €/MWh, showing a maximum spread of 91,8 €/MWh in January 2017 and a minimum spread of 29 €/MWh in September 2018. Furthermore, the two prices show a positive though weak correlation along last three years (Correlation equal to 0,47).

The average monthly downward price registered between 2016 and 2018 was equal to 27,1 €/MWh (+4% on Ex-Ante), highlighting a minimum monthly average price equal to 11,1 €/MWh in June 2016 and a maximum monthly average price equal to 43,7 €/MWh in September 2018. Downward prices and zonal prices showed a positive strong correlation along the reference period (Correlation equal to 0,94).

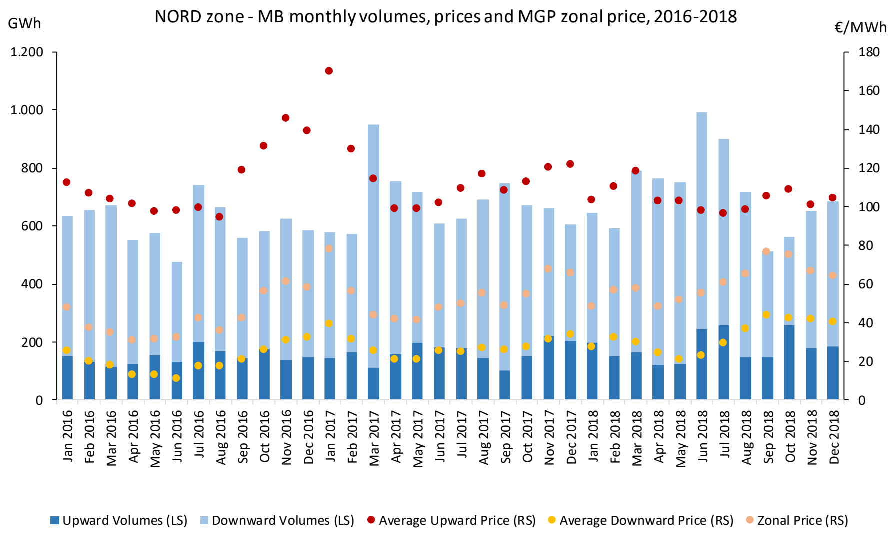


Figure 33. Upward and downward volumes and prices on the MB and Zonal Price in market zone NORD, 2016-2018. Source: GME

Overview

Concerning upward volumes, the MB market showed a monthly average trade of electricity equal to about 306 GWh between 2016 and 2018, with the maximum monthly volume of trades equal to 506 GWh in July 2018 and the minimum equal to 200 GWh, registered in September 2017.

Most of the market is concentrated in market zone NORD which represents, on a monthly average, the 54% of market volumes (peak of 68% in October 2018). On the other hand, the least represented zone is SUD, with monthly average trades equal to about 0,1 GWh.

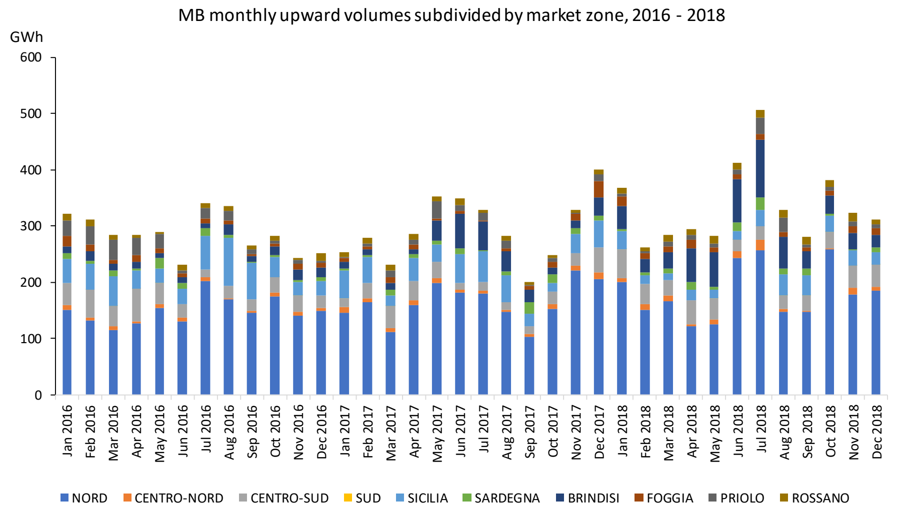


Figure 34. MB monthly upward volumes subdivide by market zone, 2016-2018. Source: GME

Concerning downward volumes, the MB market showed a monthly average trade of electricity equal to about 968 GWh between 2016 and 2018, with the maximum monthly volume of trades equal to 1.414 GWh in March 2017 and the minimum equal to 699 GWh, registered in September 2018.

As in the upward volumes case, also regarding downward market, most of trades are concentrated in market zone NORD which represents, on a monthly average, the 52% of market volumes (peak of 74% in June 2018). On the other hand, the least represented zone is SUD, with monthly average trades equal to about 0,3 GWh.

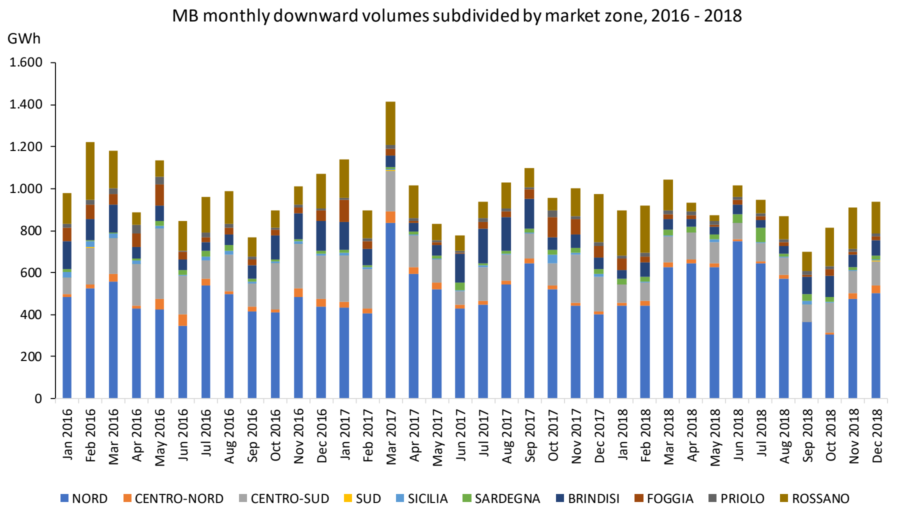


Figure 35. MB monthly downward volumes subdivide by market zone, 2016-2018. Source: GME

The overall MB market value is about 174 million €, obtained by the same procedure before mentioned for the Ex-Ante market.

3.4 First Outcomes from Italian pilot projects

UVAC

UVAC's market is currently composed by a complex of 422 MW of capacity, assigned by three distinct auction procedures organised by Terna. The overall capacity is subdivided in 40 UVAC, managed by 21 different BSPs and localised principally in the zone NORD (34 UVAC).

To date, UVAC highlighted a high degree of reliability, respecting the 75% of dispatchment orders (as percentual ratio between supplied and accepted quantities) received by Terna, on a total of 680,36 MWh of accepted offers. UVAC were activated only in real-time. Several UVAC are composed by consumption units whose off-takes' modulation are managed by the internal production's variation.

Flexibility services supplied by units composed just by consumption units increased between June 2017 and July 2018, representing at the end of reference period the 25% of the services supplied.

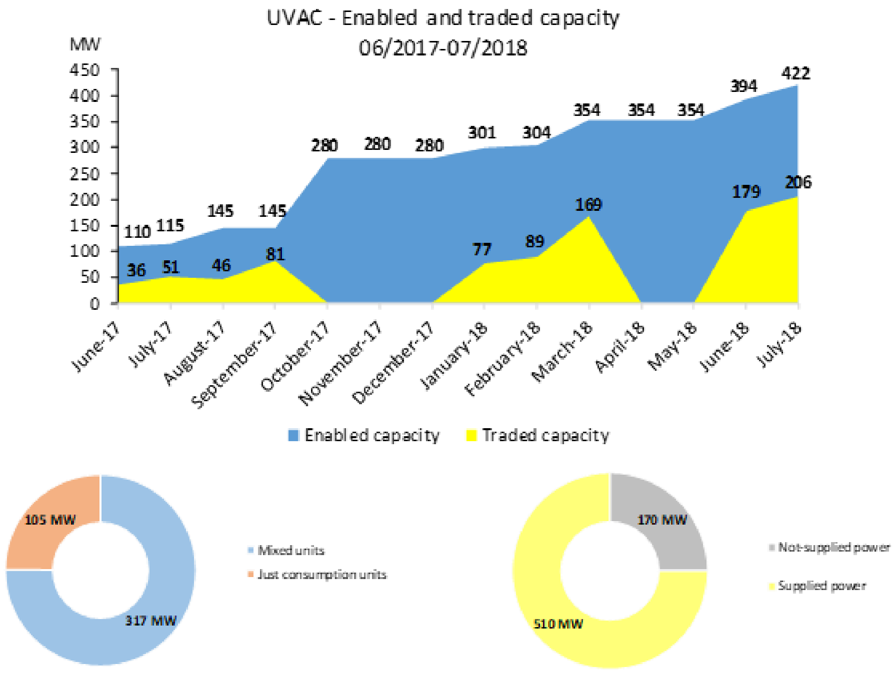


Figure 36. UVAC's enabled and traded capacity, composition of units enabled, supplied and not-supplied power. Elaboration on Terna data.

UVAP

UVAP's market is currently composed by a complex of 94 MW of assigned capacity, almost entirely represented by hydroelectric production units (93%). The overall capacity is subdivided in 15 UVAC, managed by 15 different BSP and localised principally in the zone NORD.

To date, UVAP highlighted a high degree of reliability, respecting the 76% of dispatchment orders (as percentual ratio between supplied and accepted quantities) received by Terna, on a total of 854,31 MWh of accepted offers upward and 25,59 MWh downward. UVAP were activated only in real-time.

27% of enabled capacity is attributable to units powered by intermittent renewable sources, "River hydroelectric".

The main source in the UVAP is represented by "Tank hydroelectric" (39%), while the least represented is the "Thermoelectric" (7%).

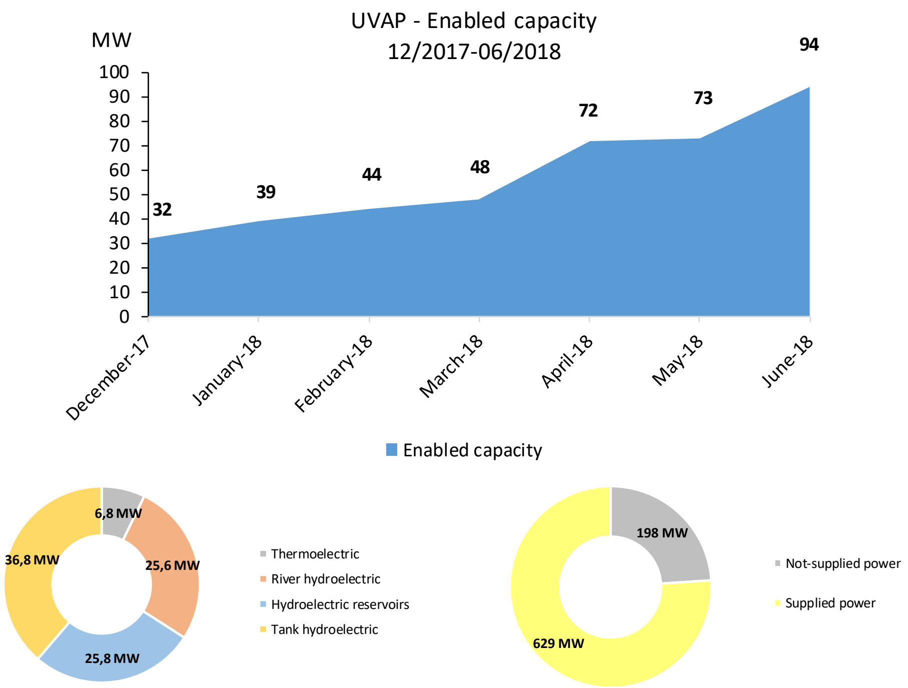


Figure 37. UVAP's enable capacity, composition of units enabled, supplied and not-supplied power. Elaboration on Terna data

UVAM

Concerning the procedure for term-based supply of dispatchment service by UVAM in 2019, which include aggregated production and consumption units, Terna assigned a total of 349,9 MW of capacity, mostly in NORD and CENTRO-NORD market zones, on the total 1.000 MW requested.

In particular, 332,8 MW over 800 MW of total capacity allocated was assigned to zone A to eleven different operators for a weighted average price of 29.979,7 €/MW/year, near the opening bid of 30.000 €/MW/year.

Other 17,1 MW over 200 MW of total capacity allocated were assigned to zone B to three different operators for a weighted average price of 29.999 €/MW/year.

Zone A

Operator	Assigned Capacity (MW)
Alpiq Energia Italia Spa	1
AXPO Italia Spa	8
Burgo Energia Srl	98
C.U.R.A. Consorzio	8
Edelweiss Energia Spa	2
EGO Trade Spa	29
Enel X Italia Spa	147,2
Engie Italia Spa	17,6
ENI Gas e Luce	2
EPQ Srl	14
HERA Trading Srl	6
TOTAL	**332,8**

Zone B

Operator	Assigned Capacity (MW)
Alpiq Energia Italia Spa	4,5
Enel X Italia Spa	9,7
EPQ Srl	2,9
TOTAL	**17,1**

Table 3. UVAM’s assigned capacity on first auction procedure

4. UVAM CASE STUDY

4.1 METHODOLOGICAL NOTE

The present Case Study aims to evaluate the economic benefit of the participation to the MSD market by an UVAM, according to the current regulation. The UVAM analysed in the present valuation is composed by the aggregation of 1 Production unit and 14 Consumption units relative to an Hospital localised in the North of Italy.

The UVAM presents a Production Unit composed by a cogeneration plant fuelled by natural gas, able to produce both electricity and heat, which currently procures the necessary resources for the 14 different Consumption Units, entirely in terms of heat and marginally in terms of electricity. Only the electrical production is functional to the participation by the UVAM to the MSD, therefore heat's production is not considered concerning market's participation.

The present UVAM is supposed to be assignee of 1 MW of capacity by the "pay-as-bid" downward auction provided by the *"Procedura per l'approvvigionamento a termine di risorse di dispacciamento fornite dalle UVAM"* for an annual product regarding the entire 2019. Such capacity is assumed to be assigned for the provided opening bid, equal to 30.000 €/MW/year.

Market Zone

The analysed UVAM is located in the North of Italy, and consequently the MSD market zone considered in the present Case Study is market zone NORD. According to the "*Perimetri di Aggregazione*" provided by the current regulation, the UVAM is located in perimeter 4.

Time horizon

Time horizon considered for the valuation is equal to 1 year, according to the before-mentioned "annual product" provided by Terna on the Italian power market by the "*Procedura per l'approvvigionamento a termine di risorse di dispacciamento fornite dalle UVAM*".

UVAM Market

Participation of UVAMs on the MSD is assumed as marginal with respect to the volumes expressed by the overall market and consequently not able to vary significantly both volumes and prices registered on the market along last years.

On the basis of this assumption, the simulated participation to the MSD market in 2019 has been conducted on the basis of the historical data analysed on both Ex-Ante and MB phases of MSD in 2018, in market zone NORD.

Such data, as plenty expressed along the Price Analysis in the following Paragraph, has been analysed on a monthly basis, assuming that all days of a specific month would present the same specific market conditions in terms of both quantities and prices.

It has not been assumed any difference between working days and holidays and between weekends and other days of the week.

Production

The Production Unit aggregated in the UVAM, as previously mentioned, consists of a cogeneration plant fuelled by natural gas, whose engine presents a Thermal Power of 1.505 kW_t and an Electric Power of 1.415 Kw_e with an overall efficiency of 85,6%. The subdivision of production between electricity and heat is fixed with a proportion of 0,88 kWh_e (electric kWh) for every kWh_t (thermal kWh) produced.

Plant's production currently provides the entire amount of heat necessary to the consumption units, and marginally provides the produced electricity to the same consumption units. Thus, currently plant's production is entirely self-consumed, since the production unit currently does not participate to any power market.

The following table highlights the "Actual" production regarding 2018 on monthly basis, subdivided between Electricity and Heat production. Moreover, it is presented the "Actual" Equivalent Hours of production and their percentage with respect to the possible overall production, equal to the total amount of yearly hours, i.e. 8.760 Eq. Hours.

	Actual Production											
	January	February	March	April	May	June	July	August	September	October	November	December
Electricity (MWh_e)	866,9	850,9	935,1	449,7	22,5	0,0	0,0	0,0	0,0	384,6	767,0	539,5
Heat (MWh_t)	983,0	964,8	1.060,3	509,9	25,5	0,0	0,0	0,0	0,0	436,1	869,7	611,7
Eq. H.	*633,5*	*621,8*	*683,4*	*328,6*	*16,5*	*0,0*	*0,0*	*0,0*	*0,0*	*281,1*	*560,5*	*394,2*
%	*85%*	*93%*	*92%*	*46%*	*2%*	*0%*	*0%*	*0%*	*0%*	*38%*	*78%*	*53%*

Table 4. UVAM's Actual Production of Electricity and Heat, 2018

Since current production strategy is aimed to maximise the production of heat on the basis of consumption units' necessities, and electricity's production is marginal, during summer months, in absence of heat's consumptions, plant is currently off. On the other hand, production is almost maximised along winter months.

Concerning the potentiality of production, the analysed production unit is assumed to be able to produce for a maximum of 8.500 yearly Eq. Hours (97% of total Eq. Hours) on the basis of maintenance's necessities. Such potential Eq. Hours has been proportionally subdivided along the analysed months.

The following table highlights the "Potential" production regarding 2019 on monthly basis, subdivided between Electricity and Heat production. Moreover, it is presented the "Potential" Equivalent Hours of production and their percentage with respect to the possible overall production and the consequent gas consumption.

	Potential Production											
	January	February	March	April	May	June	July	August	September	October	November	December
Electricity (MWh_e)	987,9	892,3	987,9	956,0	987,9	956,0	987,9	987,9	956,0	987,9	956,0	987,9
Heat (MWh_t)	1.120,1	1.011,7	1.120,1	1.084,0	1.120,1	1.084,0	1.120,1	1.120,1	1.084,0	1.120,1	1.084,0	1.120,1
Eq. H.	*721,9*	*652,1*	*721,9*	*698,6*	*721,9*	*698,6*	*721,9*	*721,9*	*698,6*	*721,9*	*698,6*	*721,9*
%	*97%*	*97%*	*97%*	*97%*	*97%*	*97%*	*97%*	*97%*	*97%*	*97%*	*97%*	*97%*
Gas Consumption (Smc)	*256.514*	*231.690*	*256.514*	*248.239*	*256.514*	*248.239*	*256.514*	*256.514*	*248.239*	*256.514*	*248.239*	*256.514*

Table 5. UVAM's potential production and relative gas consumptions, 2019

Cogeneration plant's gas consumptions have been esteemed from the historical data of production and consumption, assessing an hourly gas consumption equal to 355,32 m^3 of natural gas in case of full power production.

It is assumed that the cogeneration plant can provide an hourly production of electricity equal to about 1,33 MWh_e. Such production is considered equally distributed along all the analysed months and proportionally subdivided across all the days composing single months, not considering eventual variation due to external conditions (e.g. temperature).

In case heat is not necessary, especially during summer months, it is assumed that the present plant would have the possibility to entirely dissipate all the produced heat with no marginal costs and/or production inefficiencies.

Consumptions

It is assumed that the analysed UVAM would maintain the same consumptions registered in 2018. They have been considered on the basis of historical data of "Actual" consumption as presented in the following table regarding Electrical Consumptions deriving from the purchase of electricity from an external supplier for the share of electricity not produced by the cogeneration plant.

Actual Electricity Consumptions

MWh	January	February	March	April	May	June	July	August	September	October	November	December	Year
Hospital	185,5	131,4	119,4	606,1	1.189,4	1.318,0	1.519,7	1.333,0	1.106,5	603,7	290,0	643,1	**9.045,9**
Unit 1	9,1	8,7	10,0	7,8	9,0	12,6	19,1	15,2	8,0	9,6	10,3	10,6	**129,9**
Unit 2	16,2	14,7	16,6	17,1	16,8	14,2	15,2	16,2	15,5	12,4	13,7	14,9	**183,4**
Unit 3	1,8	1,5	1,3	1,7	1,4	1,5	3,4	1,8	1,4	2,0	1,7	1,8	**21,2**
Unit 4	1,7	1,5	1,5	1,5	1,5	1,7	2,0	1,8	1,6	1,6	1,6	1,7	**19,7**
Unit 5	6,2	5,4	5,2	5,0	5,1	5,0	5,8	4,8	4,8	5,2	5,3	5,7	**63,4**
Unit 6	1,7	1,5	1,6	1,4	1,3	2,0	3,4	2,4	1,5	1,5	1,6	1,6	**21,5**
Unit 7	3,3	3,1	3,5	3,4	6,3	9,5	12,4	8,9	5,2	3,5	3,6	3,8	**66,6**
Unit 8	0,1	0,1	0,1	0,1	0,1	0,1	0,1	0,1	0,1	0,1	0,1	0,1	**1,0**
Unit 9	8,9	8,1	8,9	8,6	2,0	3,9	5,0	5,0	2,8	2,5	2,4	2,9	**61,1**
Unit 10	5,5	4,9	5,4	5,2	5,2	4,9	5,3	5,0	5,0	5,5	5,3	5,6	**62,8**
Unit 11	0,5	0,5	0,6	0,6	0,3	0,2	1,3	0,5	0,2	0,3	0,3	0,7	**6,0**
Unit 12	0,5	0,5	0,5	1,0	1,1	1,7	4,1	3,2	2,2	2,6	3,6	0,1	**21,1**
Unit 13	5,8	5,8	5,8	3,2	2,7	3,0	8,9	7,8	5,4	4,5	5,4	8,3	**66,5**
TOTAL	**246,8**	**187,7**	**180,4**	**662,6**	**1.242,0**	**1.378,2**	**1.605,6**	**1.405,7**	**1.160,2**	**654,8**	**345,0**	**700,9**	**9.770,1**

Table 6. UVAM's Actual Electricity Consumptions (Purchase), 2018

As previously mentioned, if the production of electricity by the Production Unit is not sufficient to cover the full needs of electricity by the related Consumption Units, the remaining part of electricity is acquired.

Thus, overall electricity consumptions considered are a sum between electricity production and electricity purchase.

Overall Electricity Consumptions

MWh	January	February	March	April	May	June	July	August	September	October	November	December	Year
Purchase	246,8	187,7	180,4	662,6	1.242,0	1.378,2	1.605,6	1.405,7	1.160,2	654,8	345,0	700,9	**9.770,1**
Production	866,9	850,9	935,1	449,7	22,5	0,0	0,0	0,0	0,0	384,6	767,0	539,5	**4.816,4**
TOTAL	**1.113,8**	**1.038,7**	**1.115,6**	**1.112,3**	**1.264,6**	**1.378,2**	**1.605,6**	**1.405,7**	**1.160,2**	**1.039,4**	**1.112,0**	**1.240,4**	**14.586,5**

Table 7. UVAM's overall Electricity Consumptions

Such consumptions have been equally and constantly subdivided along all the days composing the reference months.

Market participation

It is assumed that the present UVAM is able to present upward offers for the entire 2019 on the MSD, in all the 365 days composing the year (from Monday to Sunday, weekly).

The UVAM is considered entitled, as provided by the regulation, to present upward offers on the MSD (both Ex-Ante and MB phase) for a minimum hourly capacity equal to the capacity assigned as a result of the pay-as-bid auction, corresponding to 1 MW.

Besides the obligation of offering at least the minimum quantity assigned, for 4 consecutive hours, between 14:00 and 20:00, it has been assumed that the UVAM would be able to present a total of 6 offers on a single day throughout the year. Such market participation has been supposed constant for all the months considered along 2019.

Revenues

Revenues considered in the present Case Study are subdivided between:

- Fixed Remuneration

Concerning the fixed remuneration provided by the current regulation in case of allocation of capacity according to the "*Procedura per l'approvvigionamento a termine di risorse di dispacciamento fornite dalle UVAM"*. It is considered equal to 30.000 €/MW/year and equally subdivided across all days composing the analysed year.

- Variable Remuneration

Relative to the remuneration of the flexibility resources offered on the MSD, according to dispatchment regulation, in case of acceptance of the offer by Terna. The evaluation of offer's value and consequent variable remuneration is largely presented in the following Price Analysis.

Costs

Costs considered in the present Case Study are subdivided between OpeX and CapEx as follows:

- OpEx
    - Electricity Purchase

Concerning costs faced by the UVAM in case of acquisition of electricity resources from external supplier. Such cost has been evaluated on the basis of the historical average monthly costs as shown in the following table.

Electricity Purchase Costs

€	January	February	March	April	May	June	July	August	September	October	November	December	Year
Hospital	38.625,6	30.039,0	26.789,4	110.036,9	199.871,7	215.115,1	210.443,2	244.042,9	182.123,2	99.441,9	52.715,4	109.846,9	**1.519.091,4**
Unit 1	1.967,6	1.855,5	2.094,2	1.610,7	1.903,4	2.692,3	4.146,7	3.269,1	1.680,9	1.886,2	2.027,4	2.016,8	**27.150,9**
Unit 2	3.377,2	3.060,1	3.355,3	3.404,0	3.282,4	2.769,9	2.689,6	3.328,1	2.387,8	2.931,2	2.627,7	2.804,9	**36.018,3**
Unit 3	414,4	394,2	313,5	384,0	308,0	344,1	348,4	809,9	304,3	446,0	428,7	344,1	**4.839,8**
Unit 4	439,5	400,5	386,9	372,8	374,4	420,5	486,0	425,9	379,5	396,2	383,6	402,2	**4.868,1**
Unit 5	1.355,1	1.205,9	1.096,5	1.144,6	1.052,2	1.040,8	1.013,6	1.183,1	975,4	1.052,8	1.052,6	1.200,1	**13.372,8**
Unit 6	427,9	387,0	384,1	342,5	323,5	452,3	726,3	518,3	362,9	360,1	375,7	370,2	**5.030,8**
Unit 7	759,6	702,4	955,8	944,7	976,0	1.993,9	2.599,3	1.839,4	1.113,6	744,0	675,8	859,3	**14.163,8**
Unit 8	44,9	44,3	44,3	44,2	44,0	43,8	44,3	43,9	43,9	44,4	44,2	44,4	**530,6**
Unit 9	1.924,6	1.737,9	1.924,6	1.862,3	440,7	844,8	1.072,9	1.072,9	610,2	537,7	528,6	451,3	**13.008,6**
Unit 10	1.217,8	1.084,5	1.157,1	1.103,6	1.075,1	1.018,1	984,4	1.119,6	1.018,1	1.103,8	1.088,6	1.055,2	**13.025,7**
Unit 11	123,1	112,0	117,1	107,5	203,6	83,0	94,8	344,8	87,2	90,4	90,0	172,0	**1.625,4**
Unit 12	132,9	132,9	132,9	245,5	257,7	409,2	1.002,1	772,7	528,7	634,4	885,0	812,6	**5.946,5**
Unit 13	1.266,7	1.266,7	1.266,7	708,4	584,4	649,4	1.950,9	1.717,3	1.188,5	989,5	1.184,5	1.742,0	**14.514,9**
TOTAL	**52.076,9**	**42.422,9**	**40.018,5**	**122.311,6**	**210.697,2**	**227.877,2**	**227.602,6**	**260.488,1**	**192.804,1**	**110.658,6**	**64.107,8**	**122.122,0**	**1.673.187,5**

€/MWh	January	February	March	April	May	June	July	August	September	October	November	December
Avg Cost	211,0	226,0	221,8	184,6	169,6	165,3	141,8	185,3	166,2	169,0	185,8	174,2

Table 8. UVAM's Actual Electricity Purchase costs (Purchase), 2018

Eventual costs of purchase of electricity faced due to the activation of flexibility resources has been linearly valuated at the relative average monthly cost.

- Gas Consumption

Relative to the production cost faced by the UVAM by the cogeneration plant. Such cost has been considered on the basis of the historical cost faced by the units composing the UVAM, equal to 0,3988 €/per cubic meter as shown in the following table.

Actual Gas Consumptions and Costs

	January	February	March	April	May	June	July	August	September	October	November	December	Year
Smc	225.109	220.955	242.821	116.768	5.851	0	0	0	0	99.866	199.162	140.084	**1.250.616**
€/Smc	0,3988	0,3988	0,3988	0,3988	0,3988	0,3988	0,3988	0,3988	0,3988	0,3988	0,3988	0,3988	0,3988
€	**89.773,5**	**88.116,9**	**96.837,0**	**46.567,1**	**2.333,4**	**0,0**	**0,0**	**0,0**	**0,0**	**39.826,6**	**79.425,8**	**55.865,5**	**498.746**

Table 9. UVAM's Actual Gas consumptions and Costs of Production, 2018

Eventual marginal costs of production faced due to the activation of flexibility resources has been linearly valuated at the previous-mentioned cost.

- Increased Maintenance

With reference to the assumption of the necessity of increased maintenance for the cogeneration plant, necessary due to the higher utilisation of the productive unit with respect to the current scenario. Such cost has been considered equal to 5.000 €/year on the basis of the average market costs and has been equally subdivided across all the months of the valuation.

- CapEx
    - Adjustment Costs

With reference to the assumption of the necessity of minor adjustments in the cogeneration plant in order to allow for higher variation of production flows with respect to the current scenario. The aforementioned adjustments are required to permit quick increase of production in case of the reception of dispatchment orders by Terna following the acceptance of an offer on the MSD. Such cost has been considered equal to 10.000 € on the basis of the average market costs and has been equally subdivided across all the months of the valuation.

- Control room setting up

With reference to the mandatory setting up of a control room as provided by the current regulation, in order to request the qualification to the MSD via the Pilot Projects. Such control room consists in a physical control point, i.e. a continually controlled emplacement by which receiving and carrying out dispatchment orders.

The cost of setting up the control room has been considered equal to 5.000 € on the basis of the average market costs and has been equally subdivided across all the months of the valuation.

4.2 MSD PRICE ANALYSIS

The objective of the present analysis is to identify the optimal offer’s price to be presented on the MSD by the UVAM object of the simulation, for every month of the yearly valuation.

The aim is to construct, on the basis of the accepted upward offers registered for every month in market zone NORD (localisation of the UVAM) in 2018, a distribution function to evaluate the probability of acceptance of an upward offer presented by the UVAM. Such problem is managed with a non-parametric statistical modelling approach.

Accepted upward offers in 2018 on both MSD Ex-Ante and MB were considered on monthly basis, with size, in terms of quantity (MW) offered, greater or equal to 1 MW. Concerning December, it has been considered only the MSD Ex-Ante because at the date of the analysis MB data were still not available.

The analysis is constructed on the assumption that, since, as previously mentioned, UVAM market is considered marginal with respect to MSD dynamics, the presentation of an offer with the same couple of price-quantity of offers accepted in 2018 would have the same probability of acceptance in 2019, reference year of the valuation.

It is assumed that offers with size equal to *N* MW are equivalent to *N* offers with size equal to 1 MW. Therefore, it is also assumed that the probability of acceptance of 1 offer with size equal to *N* MW has the same probability of acceptance of *N* offers with size equal to 1 MW. Consequently, it has been distinguished between “Offers” and “Standardised Offers”.

In the identification of the optimal offer, only “Standardised Offers” have been considered, for every month of 2018, from the minimum accepted price to the maximum accepted price on both market phases.

In the following table it is presented the number of upward accepted offers considered in the analysis for every month of 2018, distinguished between “Offers” and “Standardised Offers”.

Month	N. Offers	N. Standardised Offers
January	28.284	517.328
February	27.223	557.969
March	29.868	702.582
April	19.495	327.271
May	19.938	376.508
June	28.488	493.615
July	33.267	651.412
August	25.462	527.431
September	27.024	635.508
October	31.880	621.238
November	26.165	489.761
December*	5.533	340.201
TOTAL	**302.627**	**6.240.824**

*Only MSD Ex-Ante

Table 10. Number of Offers and Standardised Offers, market zone NORD, considered in Price Analysis. Source: *Offerte Pubbliche MSD - 2018*, GME

In the following figure are presented all the accepted upward Standardised Offers per price in January 2018 (including zeros), from the minimum accepted price (60 €/MWh) to the maximum accepted price (468 €/MWh).

Figure 38. Standardised Accepted Offers per Price (Including Zeros) – January 2018

Once data are modelled, it has to be considered that the lower the price, the higher the probability that an offer is accepted. Such consideration can be translated in a statistical valuation by using the cumulated density resulting from the data highlighted in the histogram of Figure 38.

Starting from the accepted offers' distribution, it can be defined a cumulative distribution function, and, from it, it has been defined a Probability Distribution Function by dividing the number of observations of every single price for the number of total observations.

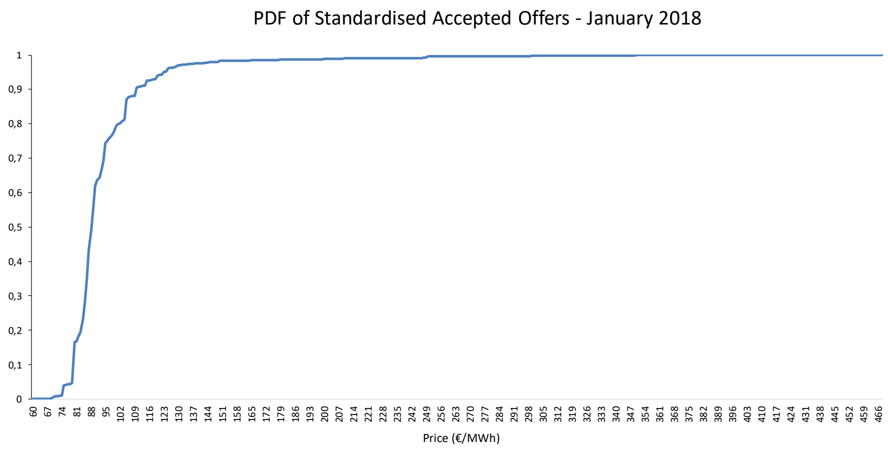


Figure 39. PDF of Standardised Accepted Offers – January 2018

The complement of the previous function is the function able to associate to every price the probability of acceptance for an offer corresponding to such price on the basis of the data registered on the MSD in 2018.

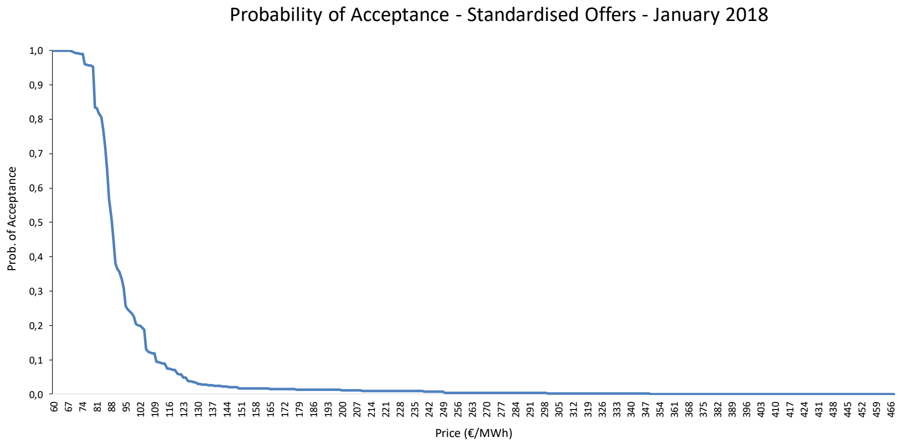


Figure 40. Complement of PDF, Probability of Acceptance for Standardised Offers – January 2018

It is noticeable how the probability of acceptance goes from 95% to 10% in a range of 30 €/MWh, from 79 €/MWh to 109 €/MWh because of the high frequency of offers in the mentioned interval.

Once obtained the probability associated to every price, it has been introduced the variable of the “Offer Cost”, intended as the cost derived by the activation of flexibility resources in case of acceptance of the offer on the MSD.

Such cost is a combination of the cost of purchasing further electricity (or the savings of purchasing fewer electricity), necessary to maintain a fixed level of consumption and present an upward offer, and the marginal cost of producing the necessary additional electricity. The Offer Cost largely varies along the year, because of the different actual flows of purchase of electricity and the different production’s intensity on monthly basis.

Winter months, characterised by a significant production intensity, present a high Offer Cost as a consequence of the necessity of acquiring large quantities of electricity at high price in order to present offers with size equal to 1 MW on the MSD. On the other hand, summer months, characterised by the current absence of production, present a low Offer Cost, as a result of minor acquisitions of electricity.

In the following table are presented the different Offer Costs associated to every month of 2018.

Offer Cost			
Month	Electricity Cost (€/MWh)	Production Cost (€/MWh)	**Offer Cost (€/MWh)**
January	211 €	104 €	**194 €**
February	226 €	104 €	**218 €**
March	222 €	104 €	**213 €**
April	185 €	104 €	**128 €**
May	170 €	104 €	**84 €**
June	165 €	104 €	**83 €**
July	142 €	104 €	**91 €**
August	185 €	104 €	**77 €**
September	166 €	104 €	**83 €**
October	169 €	104 €	**116 €**
November	186 €	104 €	**164 €**
December	174 €	104 €	**132 €**

Table 11. UVAM's Electricity (Purchase) cost, Production cost and resulting Opportunity Cost for every month of 2019

It has to be considered that Offer Cost is faced by the UVAM with the same frequency of the acceptance of the dispatchment offer on MSD, i.e. the probability of acceptance, since it is generated by the activation of flexibility resources formerly requested by Terna in case of acceptance, by its dispatchment order.

Moreover, offer's value is estimated as the product between its price and correspondent probability of acceptance. The same applies for the evaluation of Offer Cost.

$$\boldsymbol{Offer's\ value = Price * Prob.of\ Acceptance}$$

Consequently, the optimal offer's price to be presented on the MSD by the UVAM, is the one which maximises the difference between the product of offer's price and probability of acceptance and the product of Offer Cost and probability of acceptance.

$$\boldsymbol{Optimal\ price = Max\ (Price * Prob.of\ Acceptance - Offer\ Cost * Prob.of\ Acceptance)}$$

Such analysis has been provided for every month, highlighting the maximum value of the before-mentioned product, as shown in the following table concerning January 2018.

Results of the analysis regarding all months of 2019 are presented in Appendix (Par. 3).

P	Prob.	P*Prob.	Offer Cost	Offer Cost*Prob.	P*Prob.-Offer Cost*Prob.
243	0,82%	1,99	194	1,58	0,405
244	0,82%	1,99	194	1,58	0,413
245	0,82%	2,00	194	1,58	0,421
246	0,82%	2,01	194	1,58	0,429
247	0,82%	2,02	194	1,58	0,437
248	**0,81%**	**2,01**	**194**	**1,57**	**0,442**
249	0,78%	1,95	194	1,51	0,434
250	0,29%	0,72	194	0,56	0,163
251	0,29%	0,72	194	0,56	0,166
252	0,29%	0,73	194	0,56	0,169
253	0,29%	0,73	194	0,56	0,171

Table 12. UVAM’s maximum offer value – January

In the following table it is presented the optimal offer to be presented on the MSD and the associated probability of acceptance for every month.

Optimal Offer and Probability of Acceptance		
Month	Optimal Offer P (€/MWh)	Probability of Acceptance
January	248 €	0,81%
February	399 €	0,51%
March	348 €	0,41%
April	349 €	7,10%
May	348 €	1,98%
June	99 €	20,25%
July	99 €	13,64%
August	89 €	59,23%
September	104 €	61,48%
October	349 €	0,53%
November	349 €	0,21%
December	148 €	0,15%

Table 13. UVAM’s optimal Offer on MSD and Probability of Acceptance for every month of 2019

4.3 Hospital Case

The valuation of the economic benefit for the UVAM of participating to the MSD market, according to current regulation, has been conducted on a daily basis, supposing that all days of the reference month present the identical conditions in terms of both consumptions and production.

Moreover, all variables considered have been equally subdivided across single days on hourly basis, assuming that all 24 hours of a day present the same characteristics of production and consumptions.

Actual				
Hour	Production (MWh)		Purchase (MWh)	Electricity Consumptions (MWh)
	Heat	Electricity	Electricity	Total
1	1,32	1,17	0,33	1,5
2	1,32	1,17	0,33	1,5
3	1,32	1,17	0,33	1,5
4	1,32	1,17	0,33	1,5
5	1,32	1,17	0,33	1,5
6	1,32	1,17	0,33	1,5
7	1,32	1,17	0,33	1,5
8	1,32	1,17	0,33	1,5
9	1,32	1,17	0,33	1,5
10	1,32	1,17	0,33	1,5
11	1,32	1,17	0,33	1,5
12	1,32	1,17	0,33	1,5
13	1,32	1,17	0,33	1,5
14	1,32	1,17	0,33	1,5
15	1,32	1,17	0,33	1,5
16	1,32	1,17	0,33	1,5
17	1,32	1,17	0,33	1,5
18	1,32	1,17	0,33	1,5
19	1,32	1,17	0,33	1,5
20	1,32	1,17	0,33	1,5
21	1,32	1,17	0,33	1,5
22	1,32	1,17	0,33	1,5
23	1,32	1,17	0,33	1,5
24	1,32	1,17	0,33	1,5

Table 14. Subdivision of Actual daily Production, Electricity Purchase and Overall Electricity Consumptions on hourly basis –January 2019

As previously mentioned, it is assumed that UVAM is able to present 6 different upward offers daily, each one for 4 consecutive hours, with the same couple of price and size, as follows:

- Price as analysed in the previous section (MSD Price Analysis) on monthly basis;
- Size equal to 1 MWh hourly.

Such offer is assumed to be constant along the reference month.

UVAM			
Hour	Offer (MWh)	Offer (€/MWh)	Prob. Of
	MSD	MSD	Acceptance
1	1,0	248	0,8%
2	1,0	248	0,8%
3	1,0	248	0,8%
4	1,0	248	0,8%
5	1,0	248	0,8%
6	1,0	248	0,8%
7	1,0	248	0,8%
8	1,0	248	0,8%
9	1,0	248	0,8%
10	1,0	248	0,8%
11	1,0	248	0,8%
12	1,0	248	0,8%
13	1,0	248	0,8%
14	1,0	248	0,8%
15	1,0	248	0,8%
16	1,0	248	0,8%
17	1,0	248	0,8%
18	1,0	248	0,8%
19	1,0	248	0,8%
20	1,0	248	0,8%
21	1,0	248	0,8%
22	1,0	248	0,8%
23	1,0	248	0,8%
24	1,0	248	0,8%

Table 15. MSD upward offers on daily basis. Size, Price and Probability of Acceptance – January 2019

UVAM's electricity consumptions have been maintained equal to the historical data on monthly basis, both in case of acceptance of the presented offer on the MSD and in case of non-acceptance.

Thus, UVAM's MSD participation is constrained to the maintenance of the same hourly electricity consumptions as observed in 2018 for all days and months considered in the valuation.

Concerning the Production Unit, it is assumed that its production equals the same output observed in 2018 also in 2019, in terms of both heat and electricity in case of non-acceptance of the presented offer on the MSD. Eventual further production of electricity, necessary in order to accomplish dispatchment orders in case of acceptance of the offer presented on the MSD, is represented by the interval between the potential production and the actual production.

Such interval of additional potential production monthly varies on the basis of the actual consumptions and production. As presented in the following figure, indeed, months which in 2018 were characterised by intensive production, as winter months, present low potential upside of production (e.g. in January it is equal to 0,16 MWh_e hourly).

On the other hand, summer months, which in 2018 were characterised by low or null necessity of heat by the UVAM, and consequently low or null degree of production, present higher upsides of production (e.g. in April it is equal to 0,7 MWh_e hourly).

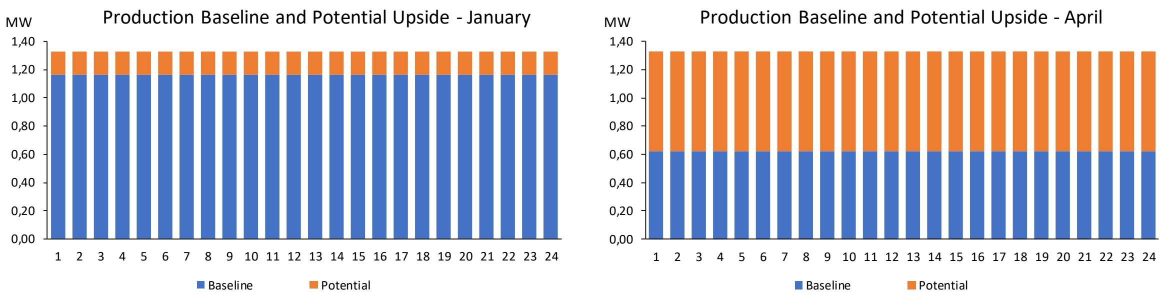


Figure 41. UVAM's production Baseline and potential upside – January and April 2019

Electricity dispatched on the MSD, in case of acceptance of the presented offer, is fully represented by the electricity produced by the cogeneration plant. Consequently, the activation of flexibility resources implies a reduction, in the overall consumed electricity, of the share of produced electricity, where present.

Hence, in order to maintain the same hourly electricity consumptions, it is assumed a shift between produced and purchased electricity to attain the overall hourly consumptions. Size and possibility of such variation varies along the months examined, depending on the historical data of both production and consumption.

Along winter months, characterised in 2018 by intensive production, it is observed the necessity to increase the acquisition of electricity from external supplier, allowing to dispatch produced electricity on the MSD.

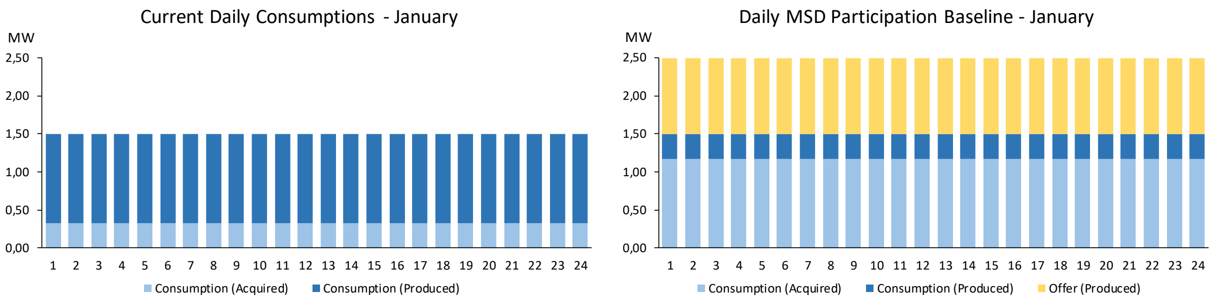


Figure 42. UVAM's overall Actual consumptions' Baseline (LS) and Overall Potential consumptions' Baseline and MSD offer (RS) – January 2019

On the other hand, along summer months, characterised by low/null production, it follows a decrease in the acquisition of electricity from external supplier, and a partial fulfil of electricity consumptions by the share of electricity produced and not dispatched on the MSD. The remaining share of production is available for being dispatched.

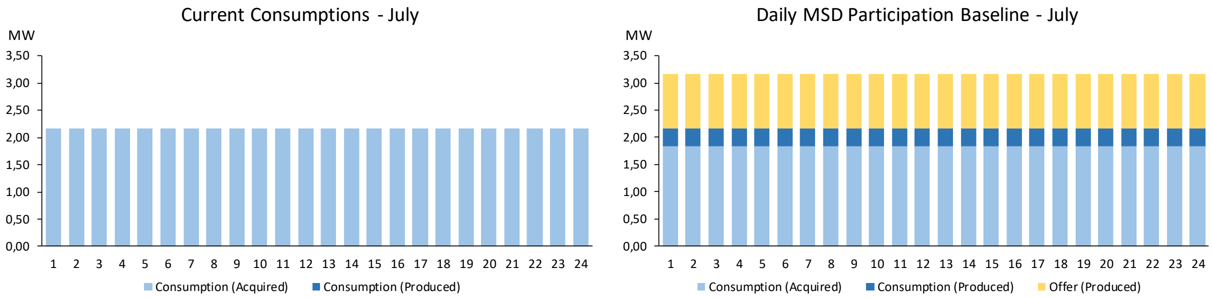


Figure 43. UVAM's overall Actual consumptions' Baseline (LS) and Overall Potential consumptions' Baseline and MSD offer (RS) – July 2019

Ultimately, the following tables present the overall differences between the Actual and the UVAM (potential) approach. Again, it is assumed that the increase of production and the shift in electricity consumption between purchased and produced electricity, determining an increase or decrease of Electricity purchase, depends on the acceptance of the upward offer presented on the MSD and consequent activation of flexibility resources, with the presented probability.

Actual				
Hour	Production (MWh)		Purchase (MWh)	Electricity Consumptions (MWh)
	Heat	Electricity	Electricity	Total
1	1,32	1,17	0,33	1,5
2	1,32	1,17	0,33	1,5
3	1,32	1,17	0,33	1,5
4	1,32	1,17	0,33	1,5
5	1,32	1,17	0,33	1,5
6	1,32	1,17	0,33	1,5
7	1,32	1,17	0,33	1,5
8	1,32	1,17	0,33	1,5
9	1,32	1,17	0,33	1,5
10	1,32	1,17	0,33	1,5
11	1,32	1,17	0,33	1,5
12	1,32	1,17	0,33	1,5
13	1,32	1,17	0,33	1,5
14	1,32	1,17	0,33	1,5
15	1,32	1,17	0,33	1,5
16	1,32	1,17	0,33	1,5
17	1,32	1,17	0,33	1,5
18	1,32	1,17	0,33	1,5
19	1,32	1,17	0,33	1,5
20	1,32	1,17	0,33	1,5
21	1,32	1,17	0,33	1,5
22	1,32	1,17	0,33	1,5
23	1,32	1,17	0,33	1,5
24	1,32	1,17	0,33	1,5

UVAM						
Hour	Production (MWh)		Purchase (MWh)	Electricity Consumptions (MWh)	Offer (MWh)	Prob. Of
	Heat	Electricity	Electricity	Total	MSD	Acceptance
1	1,51	1,33	1,17	1,5	1,0	0,8%
2	1,51	1,33	1,17	1,5	1,0	0,8%
3	1,51	1,33	1,17	1,5	1,0	0,8%
4	1,51	1,33	1,17	1,5	1,0	0,8%
5	1,51	1,33	1,17	1,5	1,0	0,8%
6	1,51	1,33	1,17	1,5	1,0	0,8%
7	1,51	1,33	1,17	1,5	1,0	0,8%
8	1,51	1,33	1,17	1,5	1,0	0,8%
9	1,51	1,33	1,17	1,5	1,0	0,8%
10	1,51	1,33	1,17	1,5	1,0	0,8%
11	1,51	1,33	1,17	1,5	1,0	0,8%
12	1,51	1,33	1,17	1,5	1,0	0,8%
13	1,51	1,33	1,17	1,5	1,0	0,8%
14	1,51	1,33	1,17	1,5	1,0	0,8%
15	1,51	1,33	1,17	1,5	1,0	0,8%
16	1,51	1,33	1,17	1,5	1,0	0,8%
17	1,51	1,33	1,17	1,5	1,0	0,8%
18	1,51	1,33	1,17	1,5	1,0	0,8%
19	1,51	1,33	1,17	1,5	1,0	0,8%
20	1,51	1,33	1,17	1,5	1,0	0,8%
21	1,51	1,33	1,17	1,5	1,0	0,8%
22	1,51	1,33	1,17	1,5	1,0	0,8%
23	1,51	1,33	1,17	1,5	1,0	0,8%
24	1,51	1,33	1,17	1,5	1,0	0,8%

Table 16. UVAM's Actual Production, Electricity Purchase and Electricity Consumptions (LS) and Potential Production, Electricity Purchase, Electricity Consumptions and MSD offer (RS) – January 2019

Finally, the economic benefit of participating to the MSD is valued on daily basis, as the difference between the resulting overall costs deriving from the UVAM approach and the Actual overall costs. Such benefit is considered as an upside in terms of minor costs faced by the UVAM.

In the Actual approach the only budget lines considered are represented by Operating Expenses (OpEx), in terms of:

- Production Costs, represented by the acquisition of Natural Gas for the cogeneration plant;
- Electricity Purchase, represented by the acquisition of electricity from a supplier to integrate produced electricity in total electricity consumptions.

Actual approach does not generate any revenue for the UVAM, and no Capital Expenditures (CapEx) are considered.

UVAM approach, on the other hand, presents two classes of revenues, determined as follows:

- MSD Revenues, representing the valorisation of UVAM's upward offers. Determined multiplying the daily overall electricity offered on the MSD by the offered price and by offers' probability of acceptance;

$$MSD\ Revenues = Electricity\ offered\ * Offered\ Price\ * Prob.of\ Acceptance$$

- Fixed Remuneration, determined subdividing the overall yearly Fixed Remuneration on daily basis.

Differently from Actual approach, Capital Expenditures are considered in the UVAM approach, regarding:

- Adjustment Costs, determined subdividing the overall adjustment costs regarding the cogeneration plant on daily basis;
- Control Room, determined subdividing the overall control room's setting up cost on daily basis.

Regarding Operating Expenses, UVAM approach presents an additional budget line compared to the Actual approach, represented by the Increased Maintenance relative to the cogeneration plant. Such cost is determined subdividing the overall yearly cost on daily basis.

OpEx previously outlined concerning the Actual approach, present daily differences compared to the UVAM approach, depending on the dispatchment of electricity on the MSD. As previously indicated, differences in the amount of these costs depend on the probability of acceptance of the offers on the MSD.

The overall higher production deriving from the optimisation of plant's production finalised to the participation to the MSD, leads to higher Production Costs in all months of the valuation on daily basis.

Variations between the two approaches relative to Electricity Purchase costs, differently, do not present a constant sign along the months analysed. Due to the shift between purchased and produced electricity, monthly varying on the basis of historical production and consumptions, Electricity Purchase costs are higher in UVAM approach along winter months. These months, indeed, are characterised by historical intensive production and necessity of purchasing electricity to participate to the MSD. Contrarily, summer months, characterised in the Actual approach by high amounts of Electricity Purchase, present lower expenses concerning this budget line in the UVAM approach.

Daily upside deriving from the participation to the MSD is then determined as the difference between the Net Costs faced by the UVAM in the Actual approach and the Net Costs faced by the aggregate in the UVAM approach, obtained as follows:

$$\boldsymbol{Net\ Costs = Total\ Revenues - Total\ CapEx - Total\ OpEx}$$

$$\boldsymbol{Upside = |"Actual"\ Net\ Costs| - |"UVAM"\ Net\ Costs|}$$

In the following table it is presented the daily upside for the standard day of January 2019.

January	**Actual**	**UVAM**
MSD Revenues	€ -	€ 48
Fixed Remuneration	€ -	€ 82
Total Revenues	**€ -**	**€ 130**
Adjustment Costs	€ -	(€ 27)
Control Room	€ -	(€ 14)
Total CapEx	**€ -**	**(€ 41)**
Production Costs	(€ 2.896)	(€ 2.899)
Electricity Purchase	(€ 1.680)	(€ 1.714)
Increased Maintenance	€ -	(€ 14)
Total OpEx	**(€ 4.576)**	**(€ 4.627)**
Total Costs	**(€ 4.576)**	**(€ 4.668)**
Net Costs	**(€ 4.576)**	**(€ 4.538)**
Upside		**€ 38**

Table 17. UVAM's daily Upside by the participation to the MSD – January 2019

The following figure presents the benefit of participating to the MSD for the UVAM on monthly basis, still in terms of minor costs faced, obtained supposing that all days composing the reference month present the same daily accounts. Thus, the previously exposed daily result has been simply multiplied for all the days of the month.

Furthermore, it is presented the monthly record of electricity production and consumptions. As previously mentioned, electricity consumptions have been maintained unchanged in both approaches. Concerning electricity production, it has been subdivided between the self-consumed production and the dispatched electricity on the MSD.

It is then presented the overall differences between the UVAM and the Actual approaches in terms of Revenues and Costs, whose difference leads to the monthly Upside.

UVAM	
January	
Production (MWh)	
Electricity	867,9
Consumed	861,9
Dispatched on the MSD	6,0
Purchase (MWh)	
Electricity	251,9
Total Consumptions (MWh)	
Electricity	1.113,8
Revenues (€)	
MSD	1.496,2
Fixed Remuneration	2.547,9
TOTAL	**4.044,1**
CapEx (€)	
Adjustment Costs	(849,3)
Control Room	(424,7)
TOTAL	**(1.274)**
OpEx (€)	
Natural Gas	(89.875)
Electricity	(53.143)
Increased Maintenance	(425)
TOTAL	**(143.442)**
Total Costs (€)	
TOTAL	**(144.716)**
Net Costs (€)	
TOTAL	**(140.672)**

Actual	
January	
Production (MWh)	
Electricity	866,9
Consumed	866,9
MSD	0,0
Purchase (MWh)	
Electricity	246,8
Total Consumptions (MWh)	
Electricity	1.113,8
OpEx (€)	
Natural Gas	(89.773)
Electricity	(52.077)
TOTAL	**(141.850)**
Total Costs (€)	
TOTAL	**(141.850)**
Δ Revenues	**4.044 €**
Δ Costs	**(2.866 €)**
Upside	**1.178 €**
Upside %	**0,84%**

Figure 44. UVAM's monthly Upside by the participation to the MSD – January 2019

4.4 Valuation

The overall yearly economic benefit for the UVAM deriving from the participation to the MSD, in terms of minor costs faced, resulted equal to 45.579€. Such outcome is the result of high varying monthly upsides, related to current mix of production and consumption and to MSD market conditions in terms of price of the offered electricity and offers' probability of acceptance.

Starting from the highlighted assumptions, April resulted as the most profitable month along 2019, with a monthly upside equal to 12.145 € (26,6% of total upside). Such result is determined by the high offer's price and relatively high probability of acceptance identified, as well as by the low Offer Cost considered. Also September (22,2% of total upside) showed high profitable results, due to the highest probability of acceptance considered (61,5%).

Being December's result influenced by the absence of MB's data, and consequently not being fully investigated with possibilities of underestimation, the least profitable month considered is November (2,4% of total upside). Such low profitability results from the lowest offer's probability of acceptance (0,21%), excluding December, and from a high Offer Cost.

As clear from the following figure, summer months present the highest monthly upsides (Q2-2019 represents the 44% of total upside, Q3-2019 represents the 40%) due to the higher potential of additional production and lower Offer Cost, leading to lower offers' prices and higher probabilities of acceptance.

On the other hand, winter months, characterised by a current intensive production and low margin for additional production, present high Offer Costs, and current market conditions generate low offers' probability of acceptance. As a consequence, both Q1-2019 and Q4-2019 represents about the 8% of total yearly upside generated for the UVAM by the participation to the MSD.

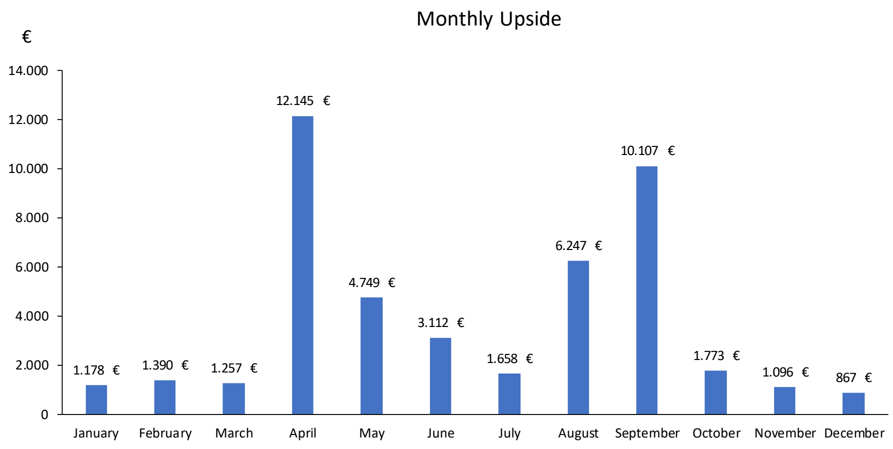


Figure 45. UVAM's monthly Upsides – 2019

On the basis of the previously exposed methodology, UVAM approach, compared to the Actual approach, presents the following differences and findings:

- Production

The UVAM approach presents an overall production of electricity significantly higher compared to the Actual approach (+32,4%), further subdivided between consumed electricity (only use of produced electricity in Actual approach) and Dispatched electricity on the MSD.

- Consumed electricity, equal to 5.162,8 MWh, +7,2% on the Actual approach (81% of produced electricity).
- Dispatched electricity on the MSD, equal to 1.215,6 MWh (19% of produced electricity), present only in the UVAM approach.

- Purchase of Electricity

The overall amount of purchased electricity is lower in the case of UVAM approach (-3,5% on the Actual approach), due to the increase of consumed electricity derived from the additional production.

- Total Consumptions

As previously mentioned, total consumptions in terms of electricity have been considered equal across the two analysed approaches.

- Revenues

As previously illustrated, total revenues in the UVAM approach are subdivided between the revenues derived from the dispatchment of electricity on the MSD (138.717,5 €, 82% of total revenues) and the Fixed Remuneration, provided by the current regulation, relative to the assigned and made available on the MSD capacity (30.000 €, 18% of total revenues). On the other hand, not being provided any market participation, Actual approach do not present any kind of revenue.

- CapEx

CapEx considered in the UVAM approach, relative to the cogeneration plant's adjustments and the setting up of a control room, amount to 15.000 €. No CapEx were considered in the Actual approach.

- OpEx

Total Operating Expenses in the UVAM approach amount to 2.280.072 € on yearly basis, with an increase of 108.138 € (+5% on Actual approach) compared to the Actual approach, due to the increase of natural gas consumptions' costs (+32,4%), compensated by a slight reduction in the overall cost of purchase of electricity from supplier (-3,5%), as predictable because of the reduction in the overall purchase of electricity previously exposed. Furthermore, UVAM approach present OpEx relative to the increased maintenance's costs, equal to 5.000 €, not taken into consideration in the Actual approach and contributing to the increase of total OpEx.

- Total Costs

The increase of total OpEx and the introduction of CapEx lead to an increase in total costs in the UVAM approach compared to the Actual approach. Such increase is equal to 123.138 € on yearly basis (+5,7% on Actual approach).

- Upside

The overall difference between the two approaches and resulting Upside in terms of minor costs faced by the UVAM, is thus equal to 45.579 € (-2,14% of costs on the Actual approach), resulting from the difference between the Net Costs in the Actual approach and Net Costs in the UVAM approach.

UVAM	
Full Year	
Production (MWh)	
Electricity	6.378,4
Consumed	5.162,8
Dispatched on the MSD	1.215,6
Purchase (MWh)	
Electricity	9.423,7
Total Consumptions (MWh)	
Electricity	14.586,5
Revenues (€)	
MSD	138.717,5
Fixed Remuneration	30.000,0
TOTAL	**168.717,5**
CapEx (€)	
Adjustment Costs	(10.000,0)
Control Room	(5.000,0)
TOTAL	**(15.000)**
OpEx (€)	
Natural Gas	(660.500,0)
Electricity	(1.614.571,6)
Increased Maintenance	(5.000,0)
TOTAL	**(2.280.072)**
Total Costs (€)	
TOTAL	**(2.295.072)**
Net Costs (€)	
TOTAL	**(2.126.354)**

Actual	
Full Year	
Production (MWh)	
Electricity	4.816,4
Consumed	4.816,4
MSD	0,0
Purchase (MWh)	
Electricity	9.770,1
Total Consumptions (MWh)	
Electricity	14.586,5
OpEx (€)	
Natural Gas	(498.745,7)
Electricity	(1.673.187,5)
TOTAL	**(2.171.933)**
Total Costs (€)	
TOTAL	**(2.171.933)**

Δ Revenues	**168.717 €**
Δ Costs	**(123.138 €)**
Upside	**45.579 €**
Upside %	**2,14%**

Figure 46. Yearly Upside by the participation to the MSD – 2019

Hence, even if the participation to the MSD for the analysed UVAM presents an economic benefit for the analysed aggregate of Production and Consumption units, it is considered as marginal in its management.

It has to be considered, indeed, the necessary subdivision of the value created across the units aggregated and the Aggregator, whose presence is considered as fundamental for the competitive participation of the aggregate on the MSD. Such breakdown would minimise the economic benefit for the stakeholders of the UVAM, grating minimum compensation, whatever is the approached model of value-sharing.

Being the maximum potential production lower than the overall electricity consumptions, with varying spreads across the different months analysed, the valuated UVAM cannot constantly guarantee a proper flexibility, given the constant necessity of providing electricity from external sources in case of dispatchment of production.

Hence, the relation between such necessity, the high costs faced by the UVAM both in terms of production and purchase of electricity, and the current MSD market conditions, do not allow for high profitability in the participation to the MSD.

Firstly because of the high production cost and Opportunity cost of shifting the produced electricity from consumptions to dispatchment, which lead the UVAM to require high compensation of dispatched electricity on the MSD, due to the significant price difference between purchase (from supplier) and sale of electricity (on the MSD) on the Italian power market.

Secondly, current MSD market, especially market zone NORD, highlights average upward prices which do not allow for a significant valorisation of the dispatched electricity in case of high price offers, which are related to remarkably low probabilities of acceptance for the presented offers.

In conclusion, to be significantly profitable and reasonably affect UVAM’s budget, the participation to the MSD for an aggregate requires the availability of a considerable share of production (or consumption) to be dispatched on the market. Such availability, indeed, provides low marginal costs to be faced and a truly competitive participation to the MSD, as observed in the present Case Study along summer months, characterised by higher potential upside of production.

CONCLUSIONS

The evolution of the Italian power market, challenged along last decade, introduced new grid's management issues concerning short-term planning and safe operation of the system. Decentralisation and decarbonisation are indeed driving greater penetration of Distributed and Renewable Energy Sources and the subsequent need for greater system awareness, forecasting, and intelligence, requiring the development of new flexibility services. As widely discussed, constant balancing between loads and generation has indeed become a critical issue for TSO in recent years and it is set to worsen due to the increasing penetration of Renewable Energy Sources, still disincentivised to supply dispatchment services because of their intermittent and not-predictable production. There consequently needs new resources to be employed in the ancillary services market.

The introduction of new market models and dynamics, as in the case of Demand-Response market, can represent a significant improvement in the current Italian power market scenario, leading to the inclusion of new subject in the market of flexibility services. Currently, there is growing consensus that Demand-Response is a significant source for realising an efficient and sustainable electricity system at a reasonable cost. Demand-Response is indeed recognised as a critical facilitator of security of supply, renewables integration, improved market competition and consumer empowerment.

By Resolution 300/2017/R/eel "*Prima apertura del mercato per il servizio di dispacciamento (MSD)*" the Italian Authority defined the criteria to allow for the participation of consumption units and production units until now excluded (i.e. not-relevant units, consumption units, relevant units powered by RES) to the MSD in order to provide balancing services.

Current regulatory barriers and market conditions, in order to maximise the potentialities of Demand-Response, requires participants to converge in an aggregate of different generation/consumption units, being the individual participation, although theoretically possible, highly impractical due to operative and regulatory barriers (e.g. Italian regulation provides a minimum quantity to be offered equal to 1 MW). Thus, the participation of Distributed Energy Generation (DER) resources currently requires the constitution of the so-called Virtual Power Plants (VPP).

Therefore, the participation to the ancillary services market is endorsed, by Resolution 300/17, on aggregated basis, by the constitution of the so-called *Unità Virtuali Abilitate* (UVA), setting up the first initiative to introduce the Demand-Response mechanism in the Italian power market. In particular UVAM (*Unità Virtuali Abilitate Miste*) represented the main object of analysis of the present thesis, because of the possibility, provided by the current regulation, of aggregating consumption and production units in the same Mixed aggregate for the dispatchment of flexibility services on the MSD market.

Once analysed the different potential flexibility resources, it has been examined the recently introduced mechanisms of new ancillary services' dispatchment, illustrating the roles of the different subjects included in the new framework. In particular, it has been analysed the figure of the Aggregator, fundamental for the aggregation of little production and consumption units and necessary for the maximisation of flexibility's value. The Aggregator will indeed assume a central role of interface with TSO and DSO in the supply of flexibility services by little units (producers or consumers) connected to the distribution grid, facilitating the creation of a significative resource for the TSO. By the Aggregator's intermediation, services offered would result in a higher quality, because more certain, and would amplify the management of the electric system making the metering of the resources offered more efficient.

Particular relevance, concerning the potential improvements in market participation, is represented by loads' inclusion in the dispatchment of flexibility services. Modulating loads, indeed, can lead to offer the same services currently offered by generating units, widening the quantity of possible participants to the ancillary services market and consequently the quantity of possible resources. Indeed, resources currently offered by generators can be put in place, with opposite sign, also by loads. Upward trades, which in case of generating units correspond to an increase of electricity's injection by an increase of production, in case of modulating loads correspond to a reduction of the off-takes from the grid, producing the same balancing effect. The opposite applies in case of downward trades. Consequently, loads and generation can be complementary on the MSD.

It the Case Study developed in the present thesis, it has been analysed the economic benefit deriving from the participation to the MSD for an UVAM, on the basis of current regulation. The analysed UVAM was composed by the aggregation of 1 Production Unit (a cogeneration plant) and 14 Consumption Units supplied by the aggregated plant.

The realised analysis presents low profitability from the participation to the MSD for the considered UVAM. Firstly because of the high costs faced by the UVAM in order to provide flexibility resources and secondly because of the highlighted current MSD market conditions, presenting average upward prices which currently do not allow for a significant valorisation of the dispatched electricity in case of high price offers, related to remarkably low probabilities of acceptance.

It has been stressed the necessity, in order to generate significant profits and reasonably affect UVAM's budget, of a considerable share of additional production to be dispatched on the market, exceeding the share of internal consumptions. Such availability, indeed, provides low marginal costs to be faced and a truly competitive participation to the MSD. The present necessity has been proven regarding cogeneration plants, but it holds for every kind of productive units.

Certainly, some regulatory barriers currently shrink the profitability of the new aggregate qualified to the MSD. Not being allowed the presentation of downward offers by UVAM, the full range of profits' potentialities cannot be reached by current Pilot Projects provided by Terna in case of mixed aggregates as provided by UVAM's regulation.

Nevertheless, the currently high system charges, which significantly increase the cost of acquisition of electricity, do not incentivise grid off-takes. In particular, in order to make grid off-takes economically convenient for downward balancing of consumptions, system charges should be excluded in case of activation of flexibility services, in order to equate both production and consumption units in every condition.

Moreover, current regulation does not incentivise the participation of RES to the MSD, both for regulatory (limits in RES participation in UVAM aggregates) and economic barriers. RES currently produce electricity at maximum productivity, because of null marginal costs of production and as a consequence of the economic merit order provided on the MGP, which guarantees dispatchment priority for RES (often RES production also gain fee-in tariffs). In case of participation to the MSD, the provision of upward flexibility services presupposes, for RES, a reduction of production in order to guarantee a potential upside in case of reception of dispatchment orders by Terna. Nonetheless, the uncertainty in the valorisation of offered electricity on the MSD due to the current offers' acceptation methodology, do not give any incentive in the provision of flexibility resources by RES. Further reduction in storage system costs, as well as the possibility of presenting downward offers with negative prices, could provide in the near future new incentive for the participation of RES in the ancillary services market.

To encourage a significant spread of the new aggregates participating to the ancillary services market, it is considered necessary to maintain the currently provided dual remuneration, with a fixed remuneration (for the availability of capacity) and a variable remuneration (for the activation of flexibility resources). Actually, the inclusion on the MSD market of new participants can be granted only by a certain remuneration for the capacity made available on the market. Such fixed remuneration would allow for the infrastructural investments necessary to allow major flexibility of both consumption and production units until now excluded from the dispatchment of such services. In absence of a capacity remuneration, new participants would consequently rely only on the possible remuneration of offered electricity, making the qualification and participation to the MSD riskier.

In conclusion, a considerable participation on the MSD market by the new qualified units and aggregates, besides supplying the necessary resources for the safe operation of the grid, can bring many advantages to the electric system. In particular, it could allow for a new implementation of resources already available and not sufficiently exploited due to current power market conditions. Indeed, not relevant traditional plants, currently not competitive on the MGP, could achieve renewed profitability by the participation to the MSD considering the new offered possibilities, considering their characteristic production's scalability. Additionally, a significant participation can mitigate management issues currently faced by the TSO and integrate, by additional legislative measures, RES within the view of forthcoming decarbonisation. Furthermore, an increase of flexibility resources on the MSD market, would increase market's competitivity by additional offer that can contribute in lowering current ancillary services' prices, with several benefits, as reducing the costs for system's management faced by the TSO and consequently lower system charges for the community.

APPENDIX

1. MSD EX-ANTE FUNDAMENTALS AND HISTORICAL DATA

Zone - CENTRO-NORD

Market zone CENTRO-NORD, concerning trades on the MSD Ex-Ante, represented the 3% of total trades along last three years, with an average monthly volume of traded electricity equal to 44 GWh (21 GWh upward and 23 GWh downward). The peak of monthly trades was observed in June 2016, with 96 GWh of electricity traded on the MSD Ex-Ante (14 GWh upward and 82 GWh downward), whilst the minimum was registered in October 2018, with 15 GWh of electricity traded (12 GWh upward and 3 GWh downward).

Concerning prices, the monthly average upward price registered between 2016 and 2018 was equal to 94,9 €/MWh, highlighting a maximum monthly average price equal to 164,2 €/MWh in January 2017 and a minimum monthly average price equal to 69,9 €/MWh in August 2016.

In the reference period, average upward prices and zonal prices (on MGP) showed a steady price’s spread, with an average value equal to 42,5 €/MWh, showing a maximum spread of 90,4 €/MWh in January 2017 and a minimum spread of 27,3 €/MWh in July 2018. Furthermore, the two prices show a positive strong correlation along last three years (Correlation coefficient equal to 0,73).

The average monthly downward price registered between 2016 and 2018 was equal to 25,7 €/MWh, highlighting a minimum monthly average price equal to 6,6 €/MWh in April 2016 and a maximum monthly average price equal to 43,3 €/MWh in December 2018. Downward price and zonal price showed a positive strong correlation along the reference period (Correlation coefficient equal to 0,77).

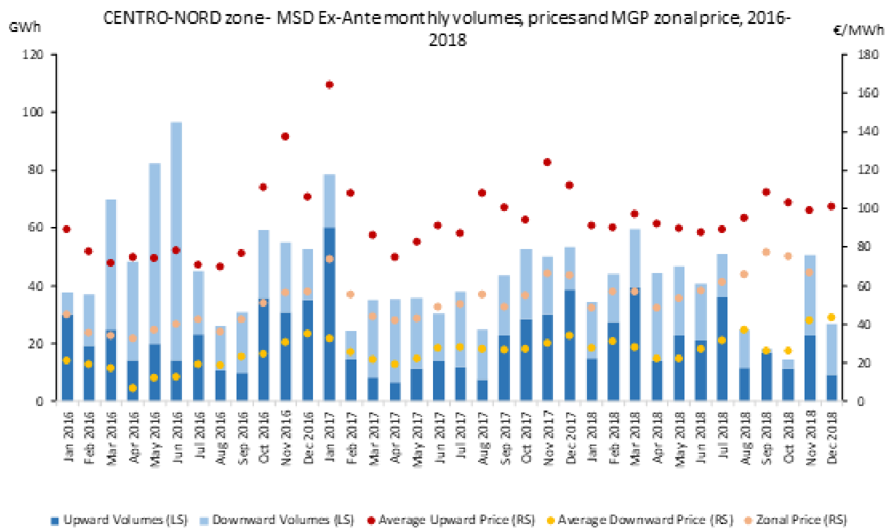


Figure 47. Upward and downward volumes and prices on the MSD Ex-Ante and Zonal Price in market zone CENTRO-NORD, 2016-2018. Source: GME

Zone - CENTRO-SUD

Market zone CENTRO-SUD, concerning trades on the MSD Ex-Ante, the 6,6% of total trades along last three years, with an average monthly volume of traded electricity equal to 98 GWh (73 GWh upward and 25 GWh downward). The peak of monthly trades was observed in April 2016, with 203 GWh of electricity traded on the MSD Ex-Ante (143 GWh upward and 60 GWh downward), whilst the minimum was registered in September 2017, with 28 GWh of electricity traded (21 GWh upward and 7 GWh downward).

Concerning prices, the monthly average upward price registered between 2016 and 2018 was equal to 184,1 €/MWh, highlighting a maximum monthly average price equal to 337,7 €/MWh in April 2018 and a minimum monthly average price equal to 80,2 €/MWh in July 2017.

In the reference period, average upward prices and zonal prices (on MGP) showed an irregular price’s spread, with an average value equal to 130,6 €/MWh, showing a maximum spread of 292,5 €/MWh in April 2017 and a minimum spread of 32,6 €/MWh in July 2017. Furthermore, the two prices show a positive though very weak correlation along last three years (Correlation coefficient equal to 0,17).

The average monthly downward price registered between 2016 and 2018 was equal to 20 €/MWh, highlighting a minimum monthly average price equal to 3,8 €/MWh in April 2018 and a maximum monthly average price equal to 48,8 €/MWh in September 2018. Downward price and zonal price showed a positive strong correlation along the reference period (Correlation coefficient equal to 0,83).

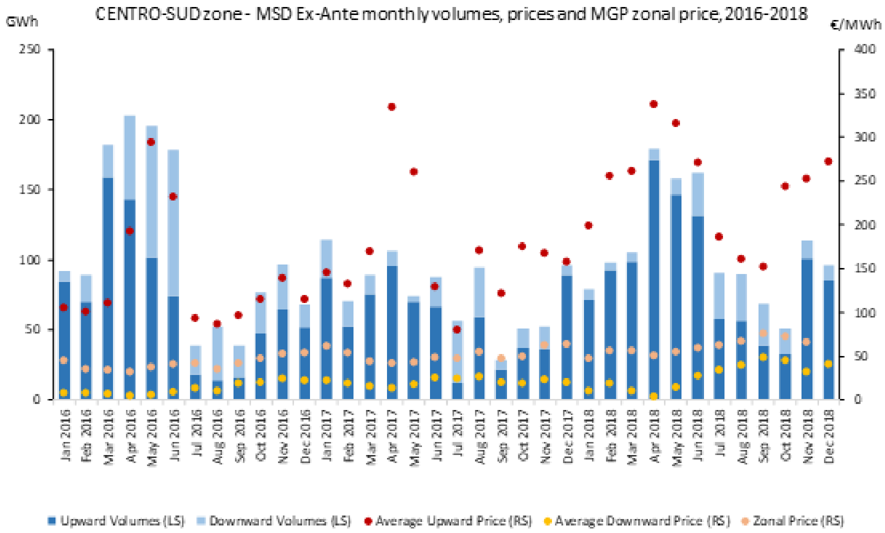


Figure 48. Upward and downward volumes and prices on the MSD Ex-Ante and Zonal Price in market zone CENTRO-SUD, 2016-2018. Source: GME

Zone – SUD

Market zone SUD, concerning trades on the MSD Ex-Ante, represented the 0,3% of total trades along last three years, with an average monthly volume of traded electricity equal to 5 GWh (1,5 GWh upward and 3,5 GWh downward). The peak of monthly trades was observed in May 2016, with 26 GWh of electricity traded on the MSD Ex-Ante (7 GWh upward and 19 GWh downward), whilst the minimum was registered in July 2017, with 0,1 GWh of electricity traded (0,05 GWh upward and 0,05 GWh downward).

Concerning prices, the monthly average upward price registered between 2016 and 2018 was equal to 165,4 €/MWh, highlighting a maximum monthly average price equal to 353 €/MWh in May 2017 and a minimum monthly average price equal to 85 €/MWh in February 2016.

In the reference period, average upward prices and zonal prices (on MGP) showed an irregular price's spread, with an average value equal to 117,4 €/MWh, showing a maximum spread of 310 €/MWh in May 2017 and a minimum spread of 37,8 €/MWh in August 2018. Furthermore, the two prices show almost null correlation along last three years (Correlation coefficient equal to 0,06).

The average monthly downward price registered between 2016 and 2018 was equal to 0,2 €/MWh, highlighting a minimum monthly average price equal to 0 €/MWh in different months along the reference period and a maximum monthly average price equal to 3,8 €/MWh in September 2018. Downward price and zonal price showed a positive tough weak correlation along the reference period (Correlation coefficient equal to 0,43).

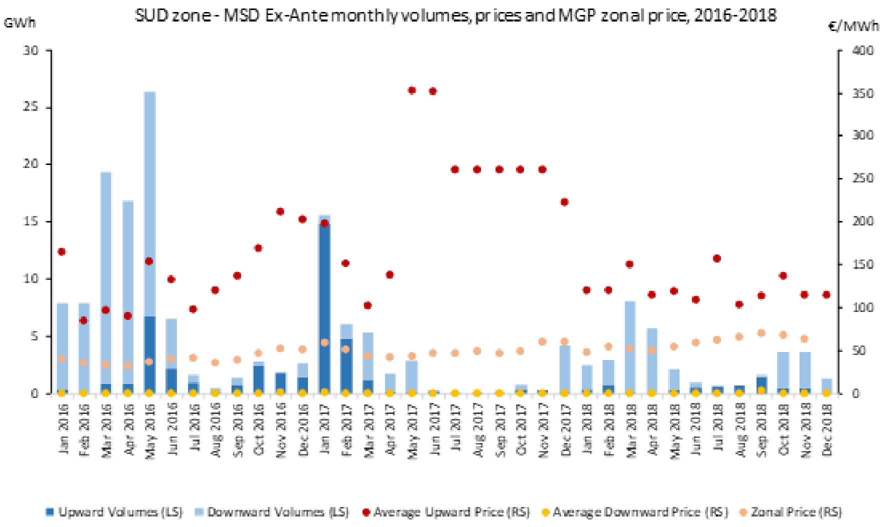


Figure 49. Upward and downward volumes and prices on the MSD Ex-Ante and Zonal Price in market zone SUD, 2016-2018. Source: GME

Zone – SICILIA

Market zone SICILIA, concerning trades on the MSD Ex-Ante, represented the 12,1% of total trades along last three years, with an average monthly volume of traded electricity equal to 180 GWh (172 GWh upward and 8 GWh downward). The peak of monthly trades was observed in March 2016, with 302 GWh of electricity traded on the MSD Ex-Ante (292 GWh upward and 10 GWh downward), whilst the minimum was registered in December 2018, with 70 GWh of electricity traded (69 GWh upward and 1 GWh downward).

Concerning prices, the monthly average upward price registered between 2016 and 2018 was equal to 107,7 €/MWh, highlighting a maximum monthly average price equal to 150,2 €/MWh in November 2018 and a minimum monthly average price equal to 47,2 €/MWh in April 2016.

In the reference period, average upward prices and zonal prices (on MGP) showed a steady price’s spread, with an average value equal to 48,1 €/MWh, showing a maximum spread of 90,7 €/MWh in July 2016 and a minimum spread of 8,7 €/MWh in January 2016. Furthermore, the two prices show a positive correlation along last three years (Correlation coefficient equal to 0,67).

The average monthly downward price registered between 2016 and 2018 was equal to 26,7 €/MWh, highlighting a minimum monthly average price equal to 9,5 €/MWh in May 2018 and a maximum monthly average price equal to 55,4 €/MWh in March 2016. Downward price and zonal price showed a negative correlation along the reference period (Correlation coefficient equal to -0,08).

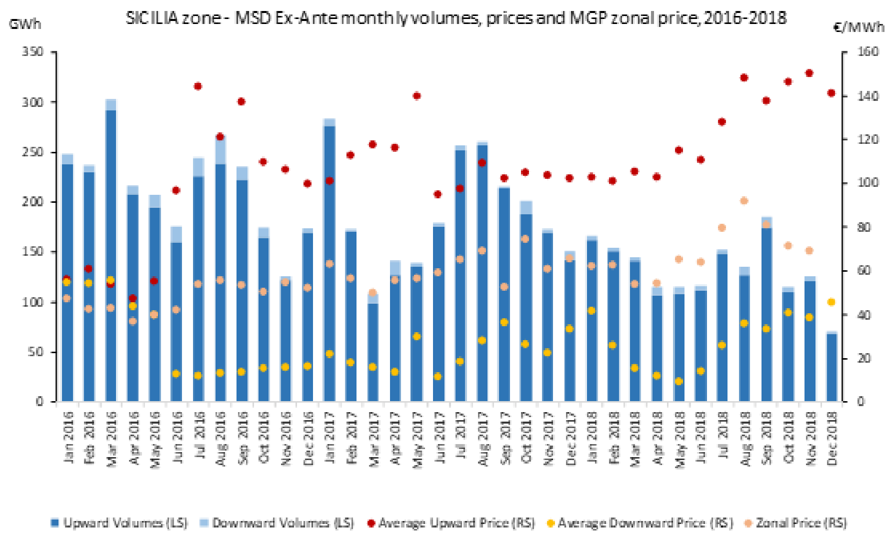


Figure 50. Upward and downward volumes and prices on the MSD Ex-Ante and Zonal Price in market zone SICILIA, 2016-2018. Source: GME

Zone – SARDEGNA

Market zone SARDEGNA, concerning trades on the MSD Ex-Ante, represented the 6,4% of total trades along last three years, with an average monthly volume of traded electricity equal to 95 GWh (94,5 GWh upward and 0,5 GWh downward). The peak of monthly trades was observed in February 2016, with 266,2 GWh of electricity traded on the MSD Ex-Ante, entirely upward, whilst the minimum was registered in December 2016, with 9 GWh of electricity traded, also in this case entirely upward.

Concerning prices, the monthly average upward price registered between 2016 and 2018 was equal to 115,2 €/MWh, highlighting a maximum monthly average price equal to 283,5 €/MWh in January 2016 and a minimum monthly average price equal to 56,6 €/MWh in January 2016.

Such impressive is attributable to arbitrage dynamics which took place in this market zone until June of 2016.

Consequently, in the reference period, average upward prices and zonal prices (on MGP) showed an irregular price’s spread, with an average value equal to 64,5 €/MWh, showing a maximum spread of 245,1 €/MWh in March 2016 and a minimum spread of 9,4 €/MWh in January 2016. Furthermore, the two prices show a negative correlation along last three years (Correlation coefficient equal to -0,42).

The average monthly downward price registered between 2016 and 2018 was equal to 26,7 €/MWh, highlighting a minimum monthly average price equal to 0 €/MWh in November 2016 and December 2017 and a maximum monthly average price equal to 71,3 €/MWh in October 2018. Downward price and zonal price showed a positive touch very weak correlation along the reference period (Correlation coefficient equal to 0,29).

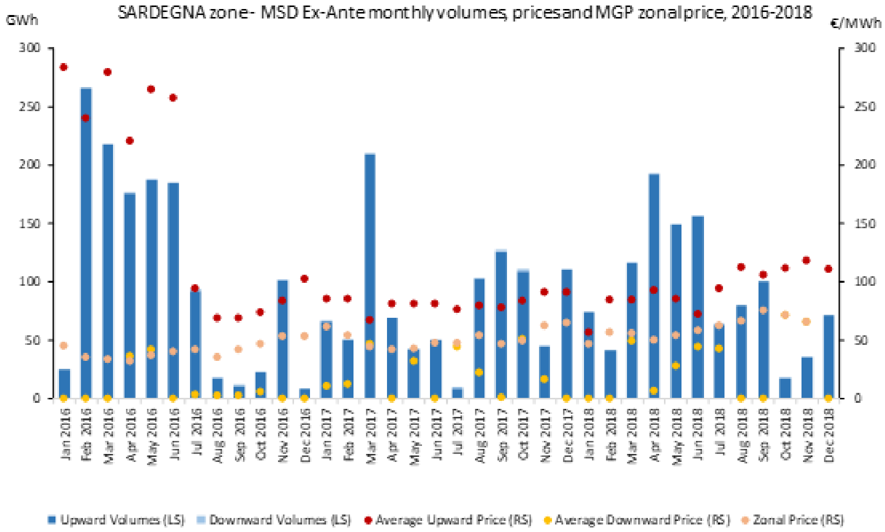


Figure 51. Upward and downward volumes and prices on the MSD Ex-Ante and Zonal Price in market zone SARDEGNA, 2016-2018. Source: GME

2. MB FUNDAMENTALS AND HISTORICAL DATA

Zone - CENTRO-NORD

Market zone CENTRO-NORD, concerning trades on the MB, represented the 2,5% of total trades along last three years, with an average monthly volume of electricity traded equal to 31 GWh (7 GWh upward and 24 GWh downward). The peak of monthly trades was observed in

March 2017, with 62 GWh of electricity traded on the MB (7 GWh upward and 55 GWh downward), whilst the minimum was registered in September 2018, with 4 GWh of electricity traded (1,5 GWh upward and 2,5 GWh downward).

Concerning prices, the monthly average upward price registered between 2016 and 2018 was equal to 104,2 €/MWh (+9,8% on the Ex-Ante), highlighting a maximum monthly average price equal to 174 €/MWh in November 2016 and a minimum monthly average price equal to 72 €/MWh in March 2016.

In the reference period, average upward prices and zonal prices (on MGP) showed a steady price's spread, with an average value equal to 51,8 €/MWh, showing a maximum spread of 117,6 €/MWh in November 2016 and a minimum spread of 29,8 €/MWh in September 2018. Furthermore, the two prices show a positive though weak correlation along last three years (Correlation equal to 0,57).

The average monthly downward price registered between 2016 and 2018 was equal to 26,3 €/MWh (+2,3% on Ex-Ante), highlighting a minimum monthly average price equal to 13,3 €/MWh in May 2016 and a maximum monthly average price equal to 44,8 €/MWh in October 2018. Downward prices and zonal prices showed a positive strong correlation along the reference period (Correlation equal to 0,87).

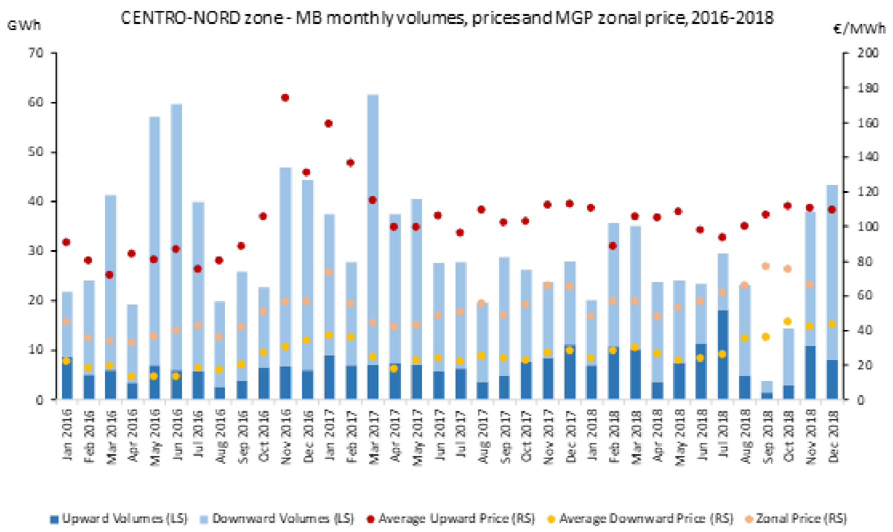


Figure 52. Upward and downward volumes and prices on the MB and Zonal Price in market zone CENTRO-NORD, 2016-2018. Source: GME

Zone - CENTRO-SUD

Market zone CENTRO-SUD, concerning trades on the MB, represented the 13,6% of total trades along last three years, with an average monthly volume of electricity traded equal to 174 GWh (30 GWh upward and 144 GWh downward). The peak of monthly trades was observed in May 2016, with 372 GWh of electricity traded on the MB (37 GWh upward and 335 GWh downward), whilst the minimum was registered in June 2017, with 74 GWh of electricity traded (12 GWh upward and 62 GWh downward).

Concerning prices, the monthly average upward price registered was equal to 213,5 €/MWh (+16% on the Ex-Ante), highlighting a maximum monthly average price equal to 352,7 €/MWh in April 2018 and a minimum equal to 120,6 €/MWh in August 2016.

In the reference period, average upward prices and zonal prices showed a steady price’s spread, with an average value equal to 160,5 €/MWh, showing a maximum spread of 302,1 €/MWh in April 2018 and a minimum spread of 80,2 €/MWh in January 2017. Furthermore, the two prices show almost null correlation along last three years (Correlation equal to 0,16).

The average monthly downward price registered between 2016 and 2018 was equal to 18,6 €/MWh (-7% on Ex-Ante), highlighting a minimum monthly average price equal to 5,5 €/MWh in May 2016 and a maximum monthly average price equal to 42,7 €/MWh in September 2018. Downward prices and zonal prices showed a positive strong correlation along the reference period (Correlation equal to 0,86).

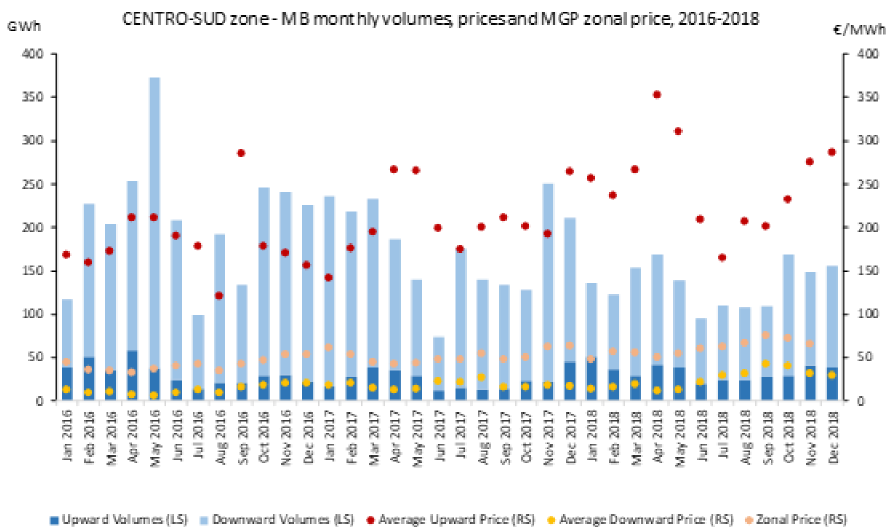


Figure 53. Upward and downward volumes and prices on the MB and Zonal Price in market zone CENTRO-SUD, 2016-2018. Source: GME

Zone – SUD

Market zone SUD presents a marginal amount of trades concerning the MB, representing less than the 0,1% of total trades last three years, with an average monthly volume of electricity traded equal to 0,4 GWh (0,1 GWh upward and 0,3 GWh downward), not presenting any trade in 16 months of the reference period.

Concerning prices, the monthly average upward price registered between 2016 and 2018 was equal to 110,4 €/MWh (-33% on the Ex-Ante), highlighting a maximum monthly average price equal to 260 €/MWh in December 2017 and a minimum monthly average price equal to 50 €/MWh in July 2018.

The average monthly downward price registered between 2016 and 2018 was equal to 4,5 €/MWh, highlighting a minimum monthly average price equal to 0,1 €/MWh in May 2017 and a maximum monthly average price equal to 40,2 €/MWh in December 2018.

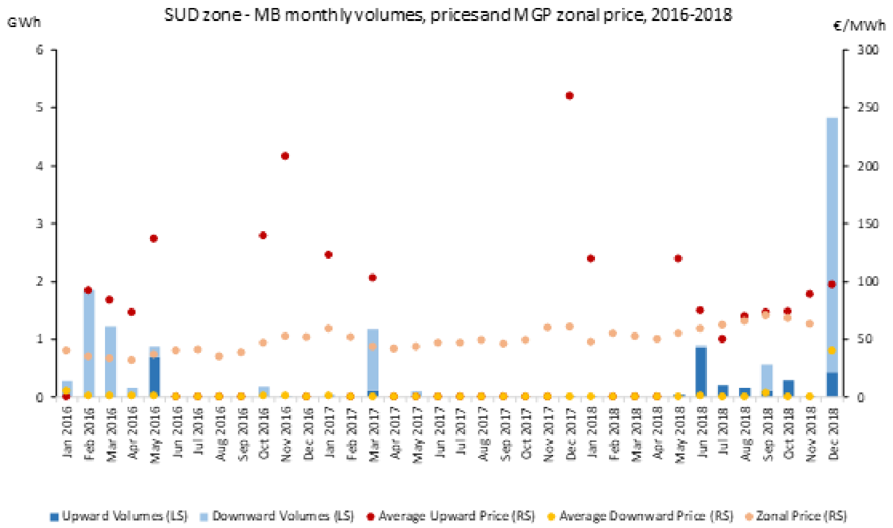


Figure 54. Upward and downward volumes and prices on the MB and Zonal Price in market zone SUD, 2016-2018. Source: GME

Zone – SICILIA

Market zone SICILIA, concerning trades on the MB, represented the 3,6% of total trades along last three years, with an average monthly volume of electricity traded equal to 46 GWh (35 GWh upward and 11 GWh downward). The peak of monthly trades was observed in August 2016, with 105 GWh of electricity traded on the MB (86 GWh upward and 19 GWh downward), whilst the minimum was registered in March 2018, with 15 GWh of electricity traded (11 GWh upward and 4 GWh downward).

Concerning prices, the monthly average upward price registered between 2016 and 2018 was equal to 102,1 €/MWh (-5,2% on the Ex-Ante), highlighting a maximum monthly average price equal to 177,6 €/MWh in September 2018 and a minimum monthly average price equal to 54,1 €/MWh in April 2016.

In the reference period, average upward prices and zonal prices (on MGP) showed an increasing price's spread, with an average value equal to 42,4 €/MWh, showing a maximum spread of 96,8 €/MWh in September 2018 and a minimum spread of 13,2 €/MWh in January 2016. Furthermore, the two prices show a positive strong correlation along last three years (Correlation equal to 0,80).

The average monthly downward price registered between 2016 and 2018 was equal to 31,6 €/MWh (+18% on Ex-Ante), highlighting a minimum monthly average price equal to 10,1 €/MWh in September 2016 and a maximum monthly average price equal to 49,1 €/MWh in March 2018. Downward prices and zonal prices showed a positive touch very weak correlation along the reference period (Correlation equal to 0,14).

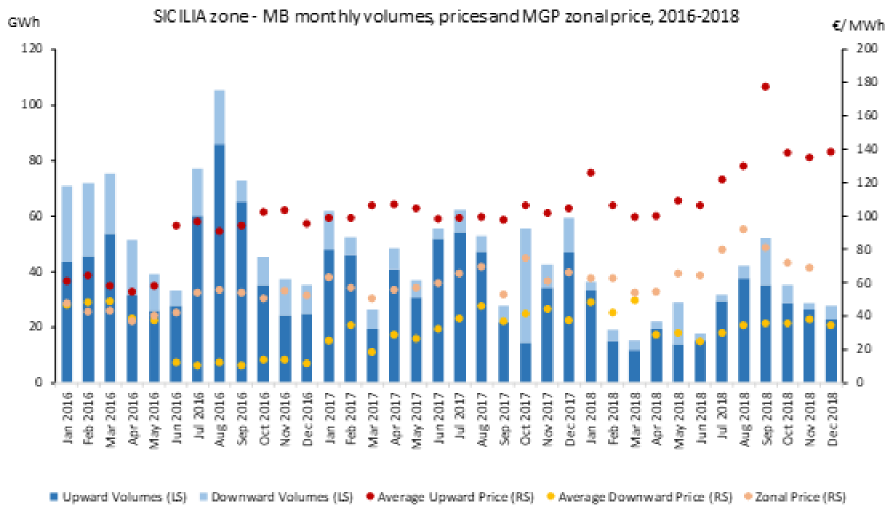


Figure 55.Upward and downward volumes and prices on the MB and Zonal Price in market zone SICILIA, 2016-2018. Source: GME

Zone – SARDEGNA

Market zone SARDEGNA, concerning trades on the MB, represented the 2,3% of total trades along last three years, with an average monthly volume of electricity traded equal to 29 GWh (9 GWh upward and 20 GWh downward). The peak of monthly trades was observed in July 2018, with 92 GWh of electricity traded on the MB (22 GWh upward and 69 GWh downward), whilst the minimum was registered in February 2016, with 11 GWh of electricity traded (5 GWh upward and 6 GWh downward).

Concerning prices, monthly average upward price registered between 2016 and 2018 was equal to 165,4 €/MWh (+44% on the Ex-Ante), highlighting a maximum monthly average price equal to 282,9 €/MWh in May 2016 and a minimum equal to 100,8 €/MWh in March 2016.

Concerning the relation between average upward prices and zonal prices, SARDEGNA market zone present the same controversy highlighted about the Ex-Ante market because of arbitrage issues. The maximum spread was equal to 245,5 €/MWh in May 2016 and the minimum was equal to of 46,8 €/MWh in December 2017.

The average monthly downward price registered between 2016 and 2018 was equal to 28,4 €/MWh (+6,4% on Ex-Ante), highlighting a minimum monthly average price equal to 6,5 €/MWh in August 2016 and a maximum monthly average price equal to 59,8 €/MWh in November 2018. Downward prices and zonal prices showed a positive correlation along the reference period (Correlation equal to 0,70).

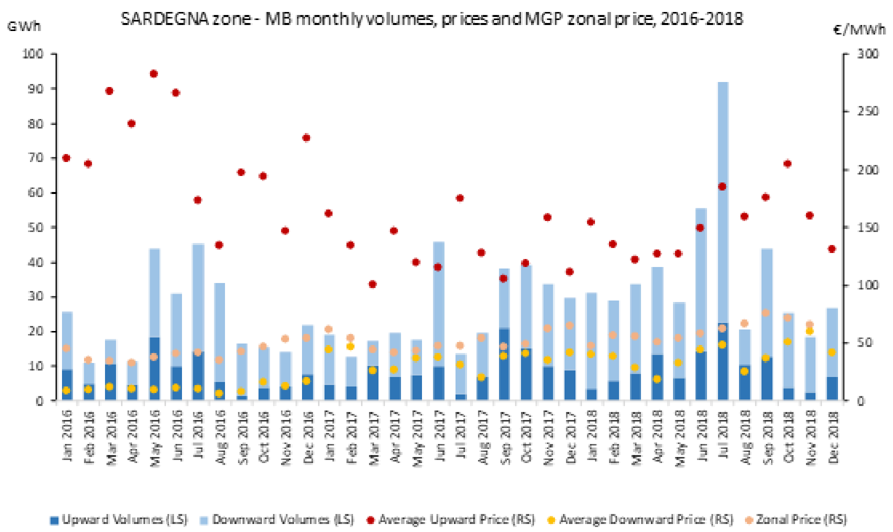


Figure 56. Upward and downward volumes and prices on the MB and Zonal Price in market zone SARDEGNA, 2016-2018. Source: GME

3. MSD Price Analysis

February

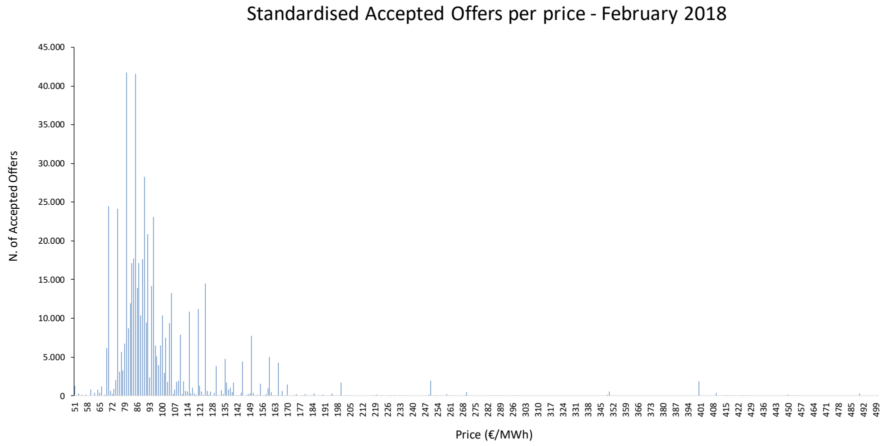


Figure 57. Standardised Accepted Offers per Price (Including Zeros) – February 2018

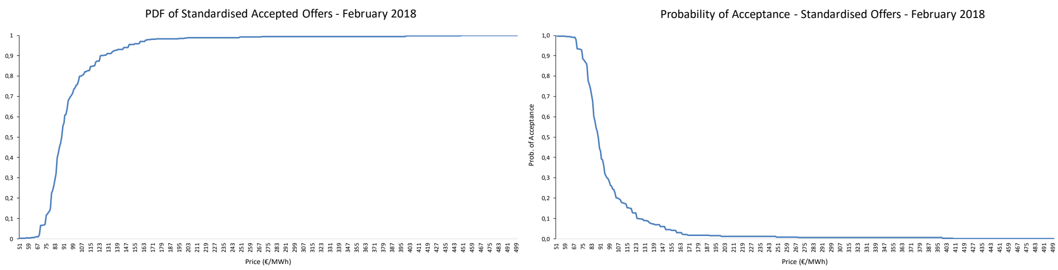


Figure 58. PDF of Standardised Accepted Offers (LS) and Probability of Acceptance (RS) – February 2018

P	Prob.	P*Prob.	Offer Cost	Offer Cost*Prob.	P*Prob.-Offer Cost*Prob.
394	0,51%	2,02	218	1,12	0,901
395	0,51%	2,03	218	1,12	0,906
396	0,51%	2,03	218	1,12	0,911
397	0,51%	2,04	218	1,12	0,917
398	0,51%	2,04	218	1,12	0,922
399	**0,51%**	**2,05**	**218**	**1,12**	**0,927**
400	0,18%	0,72	218	0,40	0,329
401	0,18%	0,73	218	0,40	0,330
402	0,18%	0,73	218	0,40	0,332
403	0,18%	0,73	218	0,40	0,334
404	0,18%	0,73	218	0,40	0,336

Table 18. Maximum offer value – February

March

Figure 59. Standardised Accepted Offers per Price (Including Zeros) – March 2018

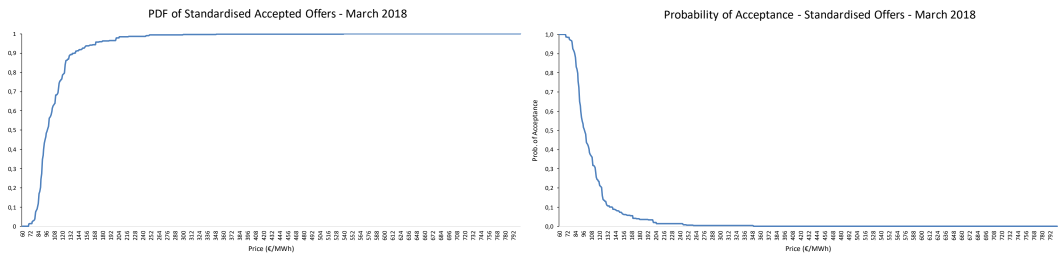


Figure 60. PDF of Standardised Accepted Offers (LS) and Probability of Acceptance (RS) – March 2018

P	Prob.	P*Prob.	Offer Cost	Offer Cost*Prob.	P*Prob.-Offer Cost*Prob.
343	0,41%	1,40	213	0,87	0,527
344	0,41%	1,40	213	0,87	0,531
345	0,41%	1,40	213	0,87	0,535
346	0,41%	1,41	213	0,87	0,539
347	0,41%	1,41	213	0,87	0,543
348	**0,41%**	**1,42**	**213**	**0,87**	**0,548**
349	0,40%	1,40	213	0,85	0,543
350	0,14%	0,48	213	0,29	0,188
351	0,14%	0,48	213	0,29	0,189
352	0,14%	0,48	213	0,29	0,191
353	0,14%	0,49	213	0,29	0,192

Table 19. Maximum offer value – March

April

Figure 61. Standardised Accepted Offers per Price (Including Zeros) – April 2018

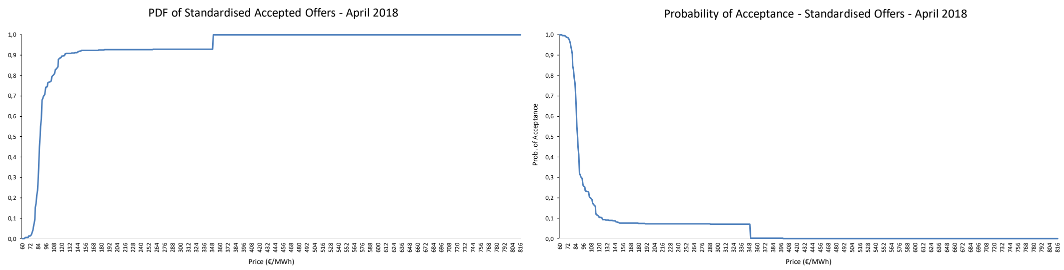


Figure 62. PDF of Standardised Accepted Offers (LS) and Probability of Acceptance (RS) – April 2018

P	Prob.	P*Prob.	Offer Cost	Offer Cost*Prob.	P*Prob.-Offer Cost*Prob.
344	7,10%	24,44	128	9,06	15,371
345	7,10%	24,51	128	9,06	15,443
346	7,10%	24,58	128	9,06	15,514
347	7,10%	24,65	128	9,06	15,585
348	7,10%	24,72	128	9,06	15,656
349	**7,10%**	**24,79**	**128**	**9,06**	**15,727**
350	0,08%	0,27	128	0,10	0,171
351	0,08%	0,27	128	0,10	0,171
352	0,08%	0,27	128	0,10	0,172
353	0,08%	0,27	128	0,10	0,173
354	0,08%	0,27	128	0,10	0,174

Table 20. Maximum offer value – April

May

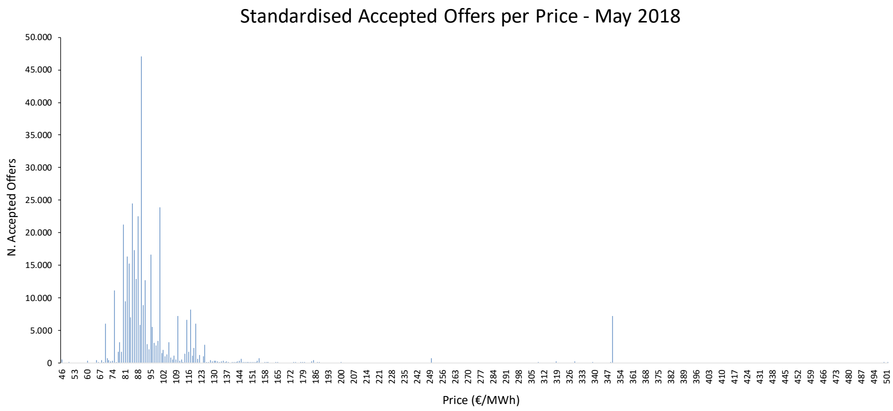


Figure 63. Standardised Accepted Offers per Price (Including Zeros) – May 2018

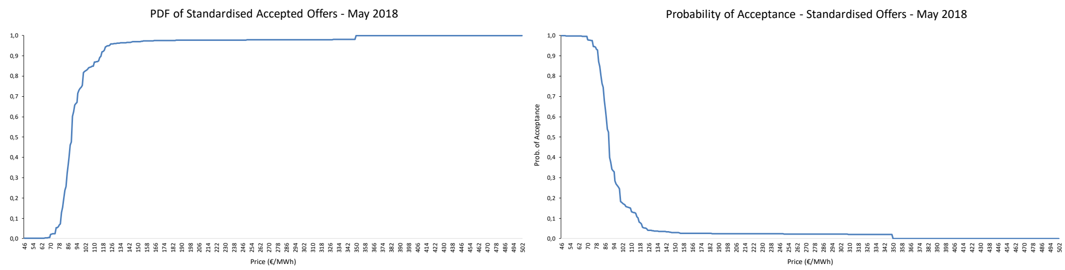


Figure 64. PDF of Standardised Accepted Offers (LS) and Probability of Acceptance (RS) – May 2018

P	Prob.	P*Prob.	Offer Cost	Offer Cost*Prob.	P*Prob.-Offer Cost*Prob.
343	1,98%	6,81	84	1,66	5,142
344	1,98%	6,83	84	1,66	5,162
345	1,98%	6,85	84	1,66	5,182
346	1,98%	6,87	84	1,66	5,202
347	1,98%	6,89	84	1,66	5,222
348	**1,98%**	**6,91**	**84**	**1,66**	**5,241**
349	1,95%	6,80	84	1,63	5,162
350	0,03%	0,11	84	0,03	0,083
351	0,03%	0,11	84	0,03	0,083
352	0,03%	0,11	84	0,03	0,083
353	0,03%	0,11	84	0,03	0,084

Table 21. Maximum offer value – May

June

Figure 65. Standardised Accepted Offers per Price (Including Zeros) – June 2018

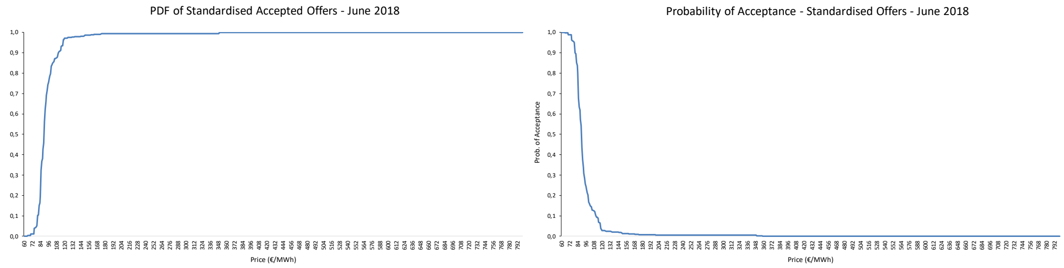


Figure 66. PDF of Standardised Accepted Offers (LS) and Probability of Acceptance (RS) – June 2018

P	Prob.	P*Prob.	Offer Cost	Offer Cost*Prob.	P*Prob.-Offer Cost*Prob.
94	28,58%	26,87	83	23,81	3,059
95	25,63%	24,35	83	21,35	2,999
96	24,35%	23,38	83	20,29	3,094
97	23,18%	22,49	83	19,31	3,177
98	21,34%	20,92	83	17,78	3,138
99	**20,25%**	**20,05**	**83**	**16,87**	**3,180**
100	16,66%	16,66	83	13,88	2,783
101	15,88%	16,04	83	13,23	2,811
102	15,36%	15,67	83	12,80	2,873
103	14,72%	15,17	83	12,26	2,901
104	14,41%	14,99	83	12,01	2,984

Table 22. Maximum offer value – June

July

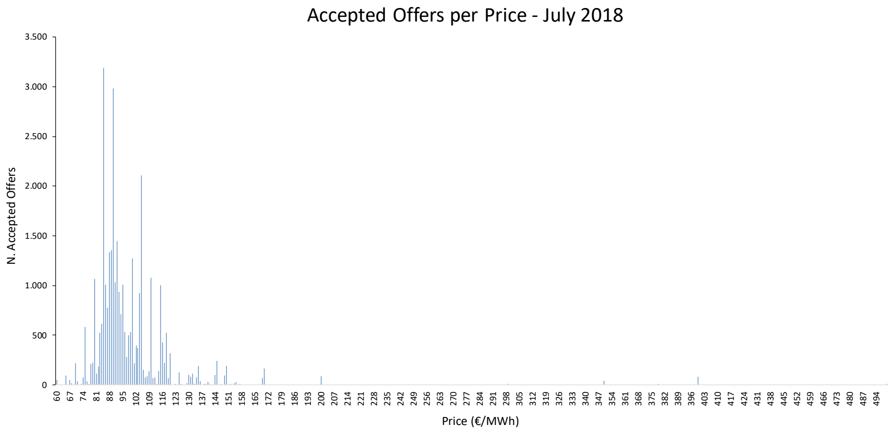
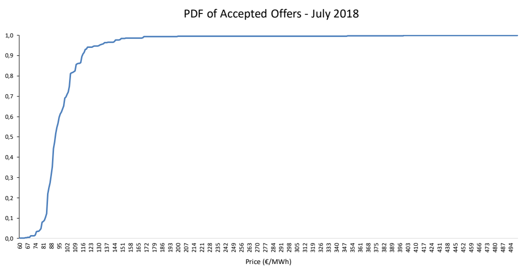


Figure 67. Standardised Accepted Offers per Price (Including Zeros) – July 2018



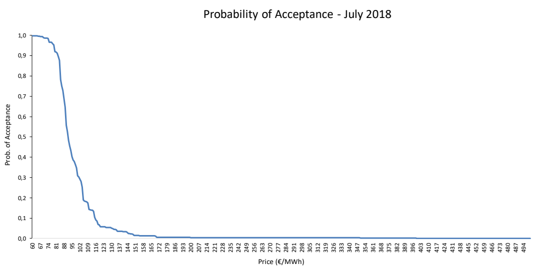


Figure 68. PDF of Standardised Accepted Offers (LS) and Probability of Acceptance (RS) – July 2018

P	Prob.	P*Prob.	Offer Cost	Offer Cost*Prob.	P*Prob.-Offer Cost*Prob.
94	20,49%	19,26	91	18,65	0,609
95	16,24%	15,43	91	14,78	0,645
96	15,32%	14,71	91	13,95	0,762
97	14,79%	14,34	91	13,46	0,883
98	14,21%	13,93	91	12,94	0,991
99	**13,64%**	**13,51**	**91**	**12,42**	**1,087**
100	10,14%	10,14	91	9,23	0,910
101	9,60%	9,70	91	8,74	0,957
102	9,22%	9,41	91	8,39	1,012
103	8,60%	8,86	91	7,83	1,030
104	7,81%	8,12	91	7,11	1,013

Table 23. Maximum offer value – July

August

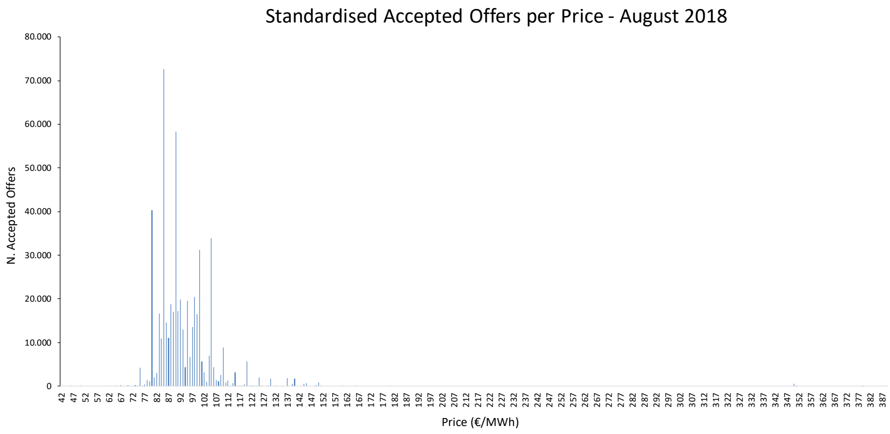


Figure 69. Standardised Accepted Offers per Price (Including Zeros) – August 2018

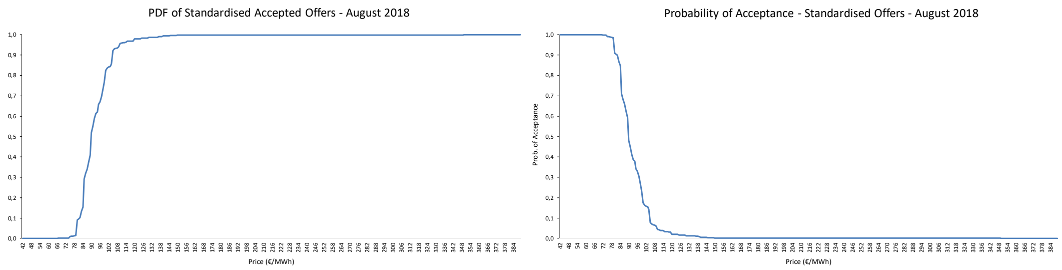


Figure 70. PDF of Standardised Accepted Offers (LS) and Probability of Acceptance (RS) – August 2018

P	Prob.	P*Prob.	Offer Cost	Offer Cost*Prob.	P*Prob.-Offer Cost*Prob.
84	84,66%	71,12	77	64,98	6,137
85	70,90%	60,27	77	54,42	5,849
86	68,13%	58,59	77	52,29	6,301
87	66,03%	57,45	77	50,68	6,768
88	62,47%	54,97	77	47,94	7,027
89	**59,23%**	**52,71**	**77**	**45,46**	**7,255**
90	48,17%	43,35	77	36,97	6,382
91	44,92%	40,88	77	34,48	6,401
92	41,16%	37,87	77	31,59	6,277
93	38,71%	36,00	77	29,71	6,291
94	37,89%	35,61	77	29,08	6,535

Table 24. Maximum offer value – August

September

Figure 71. Standardised Accepted Offers per Price (Including Zeros) – September 2018

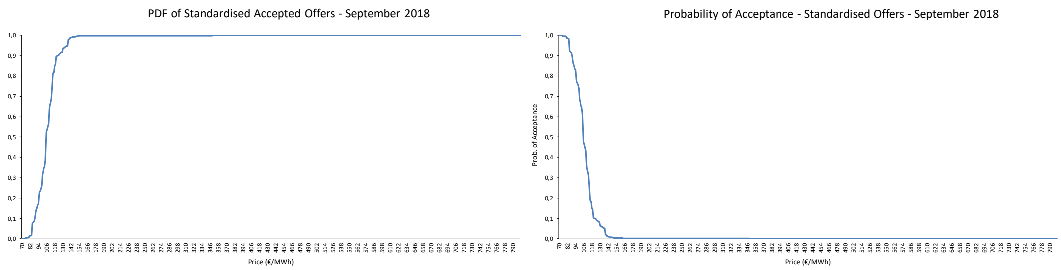


Figure 72. PDF of Standardised Accepted Offers (LS) and Probability of Acceptance (RS) – September 2018

P	Prob.	P*Prob.	Offer Cost	Offer Cost*Prob.	P*Prob.-Offer Cost*Prob.
99	73,79%	73,05	83	61,27	11,788
100	68,25%	68,25	83	56,67	11,586
101	67,73%	68,41	83	56,24	12,175
102	65,45%	66,76	83	54,34	12,420
103	64,52%	66,46	83	53,57	12,889
104	**61,48%**	**63,94**	**83**	**51,04**	**12,895**
105	52,13%	54,73	83	43,28	11,455
106	47,51%	50,36	83	39,44	10,915
107	46,28%	49,52	83	38,42	11,095
108	44,83%	48,42	83	37,22	11,197
109	43,36%	47,27	83	36,00	11,264

Table 25. Maximum offer value – September

October

Figure 73. Standardised Accepted Offers per Price (Including Zeros) – October 2018

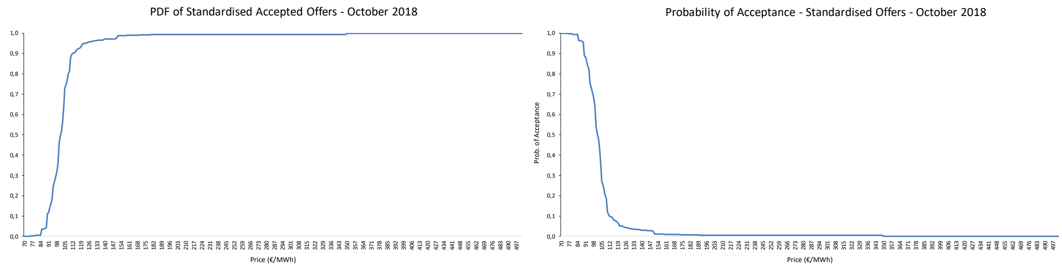


Figure 74. PDF of Standardised Accepted Offers (LS) and Probability of Acceptance (RS) – October 2018

P	Prob.	P*Prob.	Offer Cost	Offer Cost*Prob.	P*Prob.-Offer Cost*Prob.
344	0,53%	1,83	116	0,62	1,215
345	0,53%	1,84	116	0,62	1,221
346	0,53%	1,84	116	0,62	1,226
347	0,53%	1,85	116	0,62	1,231
348	0,53%	1,85	116	0,62	1,236
349	**0,53%**	**1,86**	**116**	**0,62**	**1,242**
350	0,02%	0,08	116	0,03	0,056
351	0,02%	0,08	116	0,03	0,056
352	0,02%	0,08	116	0,03	0,057
353	0,02%	0,08	116	0,03	0,057
354	0,02%	0,08	116	0,03	0,057

Table 26. Maximum offer value – October

November

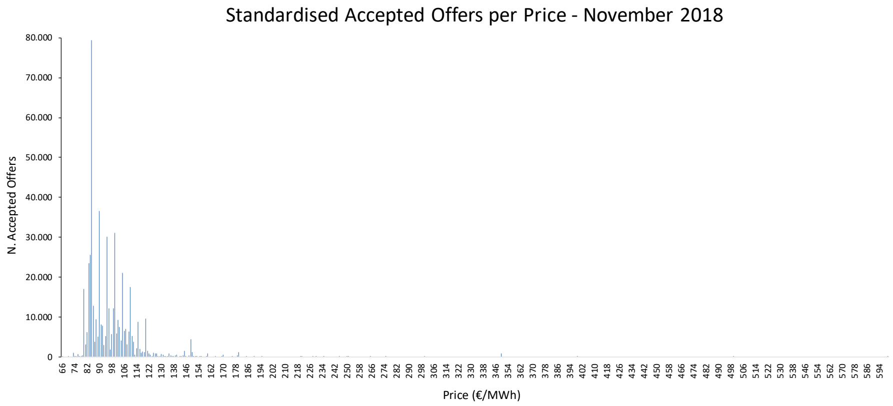


Figure 75. Standardised Accepted Offers per Price (Including Zeros) – November 2018

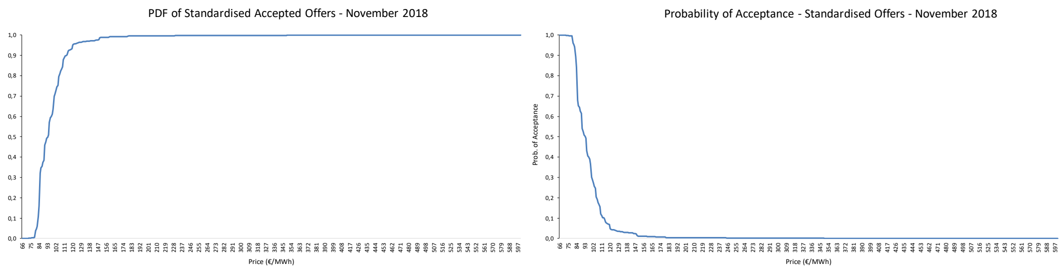


Figure 76. PDF of Standardised Accepted Offers (LS) and Probability of Acceptance (RS) – November 2018

P	Prob.	P*Prob.	Offer Cost	Offer Cost*Prob.	P*Prob.-Offer Cost*Prob.
344	0,21%	0,71	164	0,34	0,370
345	0,21%	0,71	164	0,34	0,372
346	0,21%	0,71	164	0,34	0,374
347	0,21%	0,71	164	0,34	0,377
348	0,21%	0,72	164	0,34	0,379
349	**0,21%**	**0,72**	**164**	**0,34**	**0,381**
350	0,03%	0,12	164	0,06	0,064
351	0,03%	0,12	164	0,06	0,065
352	0,03%	0,12	164	0,06	0,065
353	0,03%	0,12	164	0,06	0,066
354	0,03%	0,12	164	0,06	0,066

Table 27. Maximum offer value – November

December

Figure 77. Standardised Accepted Offers per Price (Including Zeros) – December 2018

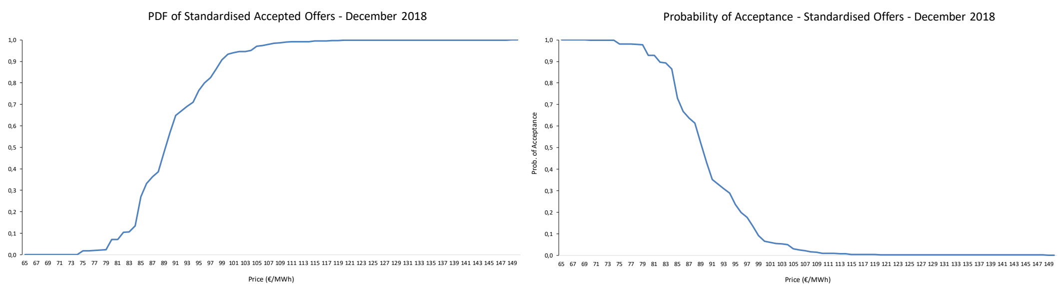


Figure 78. PDF of Standardised Accepted Offers (LS) and Probability of Acceptance (RS) – December 2018

P	Prob.	P*Prob.	Offer Cost	Offer Cost*Prob.	P*Prob.-Offer Cost*Prob.
143	0,15%	0,21	132	0,20	0,017
144	0,15%	0,22	132	0,20	0,018
145	0,15%	0,22	132	0,20	0,020
146	0,15%	0,22	132	0,20	0,021
147	0,15%	0,22	132	0,20	0,023
148	**0,15%**	**0,22**	**132**	**0,20**	**0,024**
149	0,00%	0,00	132	0,00	0,0001

Table 28. Maximum offer value – December

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