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Economic Opportunities of Wind Power Generators in Italian Ancillary Services Market

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Abstract

Conventionally, operators of transmission system exploit the resources mainly provided by specified large thermal power plants connected to transmission networks in order to regulate the frequency of power system, maintain the energy balance and subsequently provide a high level of security. Thermal power plants are programmable and are able to easily modulate the production of energy. The increasing share of non-Programmable Renewable Energy Sources has a great impact on balancing of energy and consequently, security of power system and increases power system needs for energy regulation reserve.

Frequency control services are mainly traded in Ancillary Services Market, with the time span that ranges from one day up to couple of hours before delivery. In this market platform, the system operator is the only buyer of ancillary services to procure the system reserve needs. On the other hand, production units are the ancillary service providers and sell their assets by offering the quantity and price of the services. Increasing share of renewable energy sources requires these types of generation to increasingly participate in frequency control services provision. Increase in dispatching resources, possibility to increase financial opportunities for producers in conjunction with increase the competition among market participants are the motivations to reform the market in a non-discriminatory manner and allowing new actors to participate in frequency control service provision.

This work aims to assess the possibility and financial opportunities of non-programmable renewable sources (NP-RES) plants and aggregators to participate in Ancillary Services Market. To achieve this goal, an innovative analytical approach is presented through a mathematical model, compliant to Italian regulatory framework, providing the opportunity for NP-RES plants to optimally bid in ASM in order to maximize profit. Additionally the model is also used to evaluate the influence of different parameters on profit opportunities for NP-RES plants in ASM, based on current market situation and future evolution of energy sector.

In order to assess the results and effectiveness of the presented model, a simulation tool is created in MATLAB®. During the first phase of simulation, the optimal bidding quantities are generated for one year based on input data corresponding to year 2015. In the second phase of simulation, the generated bidding quantities are used to evaluate the influence of input parameters on change in annual cash flow. The outcome of this analysis and simulation reveals the favorable conditions in which the NP-RES plants can gain profit in ASM, as well as potential barriers which could be taken into consideration for further evolution of ASM policies.

Sommario

Tradizionalmente, l'operatore del sistema di trasmissione sfrutta le risorse fornite principalmente da grandi centrali termoelettriche collegate alla rete di trasmissione per regolare la frequenza del sistema elettrico, mantenere l'equilibrio energetico e, di conseguenza, garantire un elevato livello di sicurezza. Infatti, le centrali termoelettriche sono programmabili e sono in grado di modulare facilmente la produzione di energia. La quota crescente delle fonti di energia rinnovabili non programmabili ha un grande impatto sul bilanciamento dell'energia e, di conseguenza, sulla sicurezza del sistema elettrico; essa aumenta le necessità di riserva di regolazione.

I servizi di controllo della frequenza sono principalmente negoziati nel mercato dei servizi ancillari (MSD), con un intervallo di tempo compreso tra un giorno e un paio di ore prima della consegna. In questa piattaforma di mercato, l'operatore del sistema è l'unico acquirente di servizi ancillari, e soddisfa le esigenze di riserva del sistema. D'altra parte, le unità produttive sono i fornitori di servizi ancillari e vendono i loro beni offrendo servizi in termini di quantità e prezzo. L'aumento della quota di fonti energetiche rinnovabili richiede che questi tipi di generazione partecipino sempre più alla prestazione dei servizi di controllo della frequenza e di bilanciamento. L'aumento delle risorse di dispacciamento, le opportunità finanziarie per i produttori in combinazione con l'aumento della concorrenza tra i partecipanti al mercato sono le motivazioni per riformare il mercato in modo non discriminatorio e consentire ai nuovi attori di partecipare alla prestazione di servizi di bilanciamento.

Questo lavoro mira a valutare la possibilità e le opportunità finanziarie di impianti e aggregatori di fonti rinnovabili non programmabili (FER-NP) derivanti dalla partecipazione al mercato dei servizi di dispacciamento. Per raggiungere questo obiettivo, un approccio analitico innovativo viene presentato attraverso un modello matematico conforme al quadro normativo italiano, che determina la possibilità per FER-NP di offrire in maniera ottimale su MSD al fine di massimizzare il profitto. Inoltre, il modello è utilizzato anche per valutare l'influenza di diversi parametri sulle opportunità di profitto degli impianti FER-NP in MSD, sulla base della situazione attuale del mercato e della futura evoluzione del settore energetico.

Per valutare i risultati e l'efficacia del modello presentato, è stato creato uno strumento di simulazione MATLAB®. Durante la prima fase di simulazione, le quantità ottimali di offerta vengono generate per un intero anno in base ai dati di input corrispondenti (anno 2015). Nella seconda fase della simulazione, le quantità di offerta generate vengono utilizzate per valutare l'influenza dei parametri di input sulla variazione del flusso di cassa annuale. L'esito di questa analisi e simulazione evidenzia le condizioni favorevoli in cui le FER-NP possono guadagnare profitto in MSD, nonché potenziali barriere che potrebbero essere prese in considerazione per un'ulteriore evoluzione delle regole di funzionamento del medesimo mercato.

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Introduction

In modern phase of energy development planning, many countries around the word have established long term portfolios to develop their energy sector with the aim of supplying electricity in sustainable environmental and economical manner. In this regard, global and national targets are established such as 20-20-20 energy and climate package in European energy developing strategy. The sustainable approach, such as rapid decarbonisation target due to concerns about global warming and lowering the reliance on fossil fuels due to environmental and political issues, led the countries and legislators to turning their decisions toward developing renewable sources of energy. This rapid evolution in energy sector is not advantageous unless high security and quality of service is maintained in a high level.

In a national power system, electricity is generated from different sources of energy. Each of them has different characteristics from the other sources. Thermal plants are usually large in size and are programmable in generation of energy. Unless the fuel is available, they can operate at a different level of production. They can modulate their energy production to work at maximum capacity, or lower the production to zero or minimum allowed level of production. However, they may have restrictions on ramp rate to increase or decrease the production, due to thermal inertia of prime movers. NP-RES power plants generation are difficult to predict exactly due to variable and intermittent nature of primary sources such as solar and wind. These latter characteristics introduce challenges to maintain energy balance in power system, and increases the risk of frequency deviations and outages. These concerns require the system operator to increase the level of system reserve from programmable sources of power, known as Ancillary Services, to cope with renewable energy unpredictability and intermittent behaviors.

In general, power system faces different sources of imbalances between generation and consumption which is not only related to NP-RES production. These main causes can be mentioned as variation between forecasted and real time consumption, contingencies in transmission lines and loss of large production or consumption units. Therefore, without considering the penetration level of NP-RES, system operators always need to procure different types of reserves –known as dispatching resources- to confront system imbalances.

In order to sustainably develop the level of NP-RES in power system, beside utilization of free and clean source of energies to produce electricity, these type of generation should actively take part in different aspects of system operation and regulations. This subject will become more important when the share of NP-RES becomes significantly high and will gradually replace the conventional production units. In particular, NP-RES production units sell all of their produced energy as price taker participants, thanks to the zero price bidding in energy market. Furthermore, the imbalances resulted from unpredictability of primary sources are treated by the reserves coming from conventional power plants, which cause the increase in operational and reserve costs. It is clear that, if these kind of generations want to replace the conventional types of generation, it is mandatory to take more active roles in other aspects of system operation, such as participate in reserve provision

and competitively participate in free market. In order to realize this target, national regulatory frameworks, in countries with high penetration of NP-RES productions, recently focus on possibility to open ancillary services market to the new actors, such as NP-RES production units and aggregators with different size, to provide the frequency control services by participating in competitive and non-discriminatory market in order to amplify the availability of dispatching resources for system balance and frequency regulation as well as boost their financial opportunities by increase revenue from ancillary services provision.
In this regard, this project aims to introduce an analytical tool in order to assess the opportunity of wind plants to maximize their revenue by participating in ASM. This work will continue in next five chapters. In following, short summary of each chapter is introduced respectively.

In chapter 1, the evolution and current situation of energy in Italy is introduced. In the second part of the chapter, a full review of the support schemes and relevant statistics are presented. The role of GSE in supporting the renewable plants by providing trading services as well as the future trend of incentives are discussed at the end of the section. The value of incentives is a key element to be considered in model for financial opportunity, since according to current regulations, any preventing in generation in order to provide the reserve corresponds to loss of incentive components for that amount of energy.

Chapter 2 presents the national Italian electricity market and regulations concerning renewable energy sources. The first section, includes a full description of day ahead and intraday markets. A comprehensive review of ancillary services market structure and regulation is presented in this section. In the next section, the rules concerning imbalance settlements are introduced for different types of generation according to new updates published by regulatory. In particular, the introduction of *Single Price* and *Dual Price* mechanism is presented in this section. The review on priority of dispatch and energy curtailments in Italy and the method of remunerations are presented in the last section of this chapter.

In order to present the model fully in line with the national regulatory framework, the new reform with last updates concerning participation of new actors in ancillary services market is presented in chapter 3. In the first section of this chapter, all technical prescriptions to enabling units as well as the definition of new actors (Aggregators) providing ancillary services are investigated, to be considered in bidding strategy model. In next section, the necessity to introduce the new market model to implement the new reform and new role of DSO in procuring reserves from distributed generation units is presented.

In chapter 4, an analytical approach is introduced based on innovative mathematical model to optimally select bidding quantities with the aim of maximizing profit for each significant period based on market variables corresponding to that period, considering probability of acceptance of bidding price. Further, a method is introduced in order to estimate three new variables created by this new model, based on difference in market sessions gate closure times, and the mean value of forecast error for different time spans. In the last section, an algorithm is presented to evaluate the effectiveness of the presented model, by creating a simulation environment and bidding in one year. As a complementary part, the prescriptions about information exchange between transmission system operator and distributed generation units are presented in last section.
In chapter 5, methods to collect statistical data to be used as input variables of simulation are presented. In the first section, methods to create imbalance probability input vectors are presented

based on data provided by system operator. Methods to collect and analysis of data corresponding to market variables including market prices and wind plant's committed energy in energy market for one year is created. Vector of imbalance quantities is created based on generic wind plant's characteristics. In the third section, the methodology to create vectors associated to the ASM prices and probability of acceptance for reference week of each month are provided to be used in optimized bidding selection. In the last section, the methodology to create a simulation environment in MATLAB® is introduced. The simulation takes place in two phases. In the first phase, the vectors are used as input of the bidding model to generate bidding quantities and probability of acceptance based on the approach presented in chapter 5. In the second phase, the bidding quantities are used to calculate annual revenue and assess the financial opportunity by enabling to provide downward reserve and effectiveness of the model presented. The result of simulation is presented at the end of this section.

Chapter 1

Evolution of Energy Sector

1.1 Evolution of Renewable Energy in Italy

1.1.1 European and National Energy Target

During the recent years, many publications have been published related to European energy policy. The new objective was setting out in October 2014 and December 2015 [1] to set up a strategic framework for 2030. The strategy for a union's energy development supports three main historical pillars of European energy policy: Sustainability, security and competitiveness [06]. To achieve this frame, five dimensions are strongly integrated together:

- Energy security, solidarity and reliability
- A completely integrated energy market
- Energy efficiency
- Decarbonisation of the economy
- Research and development, innovation and competition

In this sense, the European council approved an outline of 2030 climate and energy. With the particular focus on greenhouse gas reduction, increase in renewable production and energy efficiency. In this new framework, the level of goal for increase in share of consumption from renewable sources of energy is set to 27% of total consumption in all sectors, showing 7% increase with respect to 2020 objectives.

In Italy, national renewable energy targets will be determined in "climatic and energy plan 2019[2]". As of now, national policies use incentives set by ministerial decrees as one of the main drivers, with the aim of accelerating parties toward the goal. The incentives mainly directs the producers of renewable energy and thermal producers to increase their efficiency through using renewable types of thermoelectric energy such as cogeneration, waste and biofuel units.

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[1] 21st conference of on climate change, 2015, Paris

[2] Piano Clima Energia del 2019

1.1.2 Consumption and Production of Renewable Energy in Italy

For many years, renewable energy sources have played a leading role in Italian energy consumption in three sectors of electricity, heat and transportation. By considering only the electricity sector, an approximately 700,000 plants with total power of 51.5 MW installed in on national territory in 2015. By that time, the contribution of renewable sources in electricity production measured has belonged respectively to hydro power plants (42% of total RES production), solar plants (21%), bioenergy (18%), wind (14%) and geothermal energy (6%). In 2015, the share of total consumption covered by RES reached to 17.5% which is a value higher than the target specified for Italy as 2020 plan, foreseen in European Directive 2009/28/CE [04]. In 2015, there was a slight increase in gross total electricity production in Italy (around 1%), in general, the economic crisis (after 2008) led to a noticeable decrease in consumption and despite a recovery on 2010-2011, the consumption has again declined since 2012 to the level observed in the first years of century.

In recent years, the use of fossil fuels has decreased in general. The share of renewables on gross electricity production was equal to 38.5% in 2015, quite higher than the quantity observed in 2009.

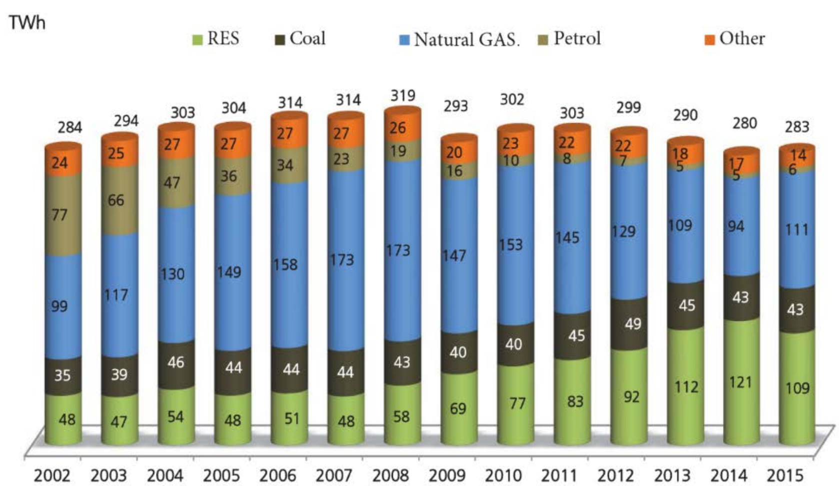

Figure 1-1: Evolution of electricity production in Italy [04]

From 2002 till 2015, the gross RES power installed in Italy increased form 19.3 MW to 51.5 MW, which shows annual growth rate equal to 7.9%. Only in 2015, 895 MW of new power installed has become into operation. In particular, among the renewable sources of energy, the evolution of installed hydro power was not considerable (0.8% annual average), while other renewable sources have grown considerably driven by various incentives to support the RES development.

Geographical distribution of renewable energy in Italian territory is based on natural potential of different types of renewables and has different characteristics from south to north. Figure 1-2 (left) illustrates the geographical distribution of RES in different regions, and distribution of wind power, in terms of installed capacity. In particular, *Lombardy* in north is the largest producer from renewable sources having 15.8% of total RES installed power in country. If we consider the country in three main macro zones, the north of Italy contributes with 53.7% of total RES production. Respectively south with 31.5% and center with 14.8% contribute in renewable energy production. In center, region of *Tuscany* is the major producer of geothermal energy in the country. Southern Italy has the largest number of wind farms installed at the end of 2015 (87.2% of total), *Puglia* has the first place in wind production, and *Basilicata* is placed next in production from wind. In northern part of Italy the spread of wind plants are very limited.

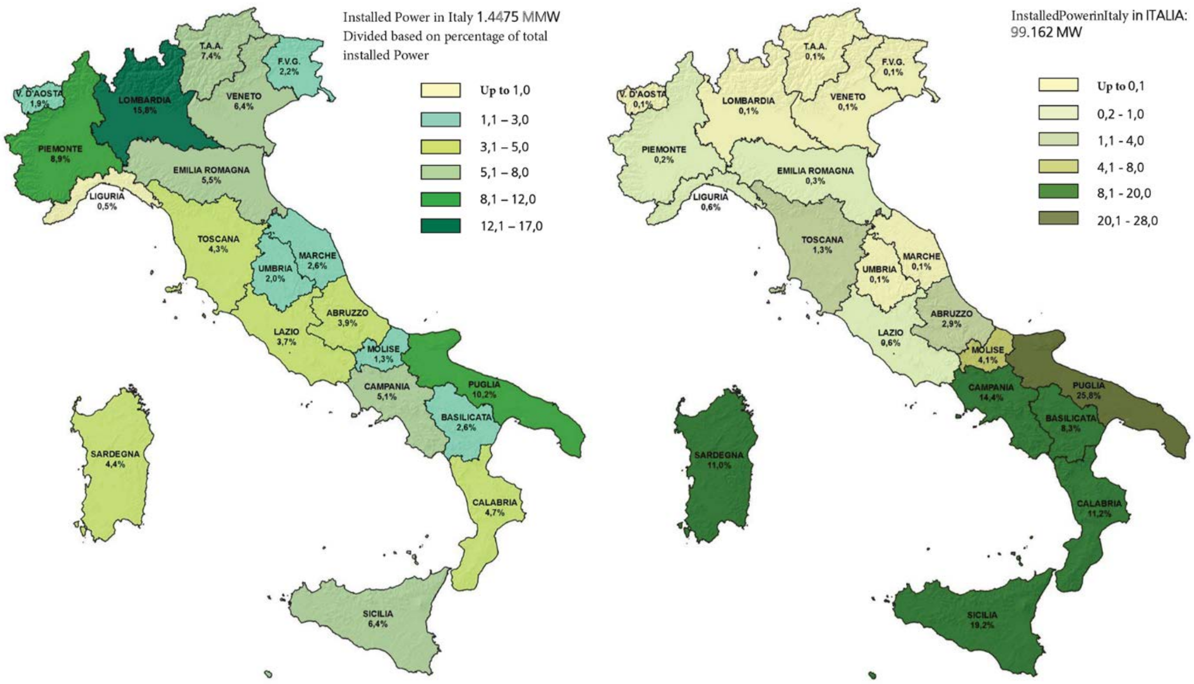

Figure 1-2: Geographical Distribution of RES and Wind in Italy

Figure below represents the percentage of plants number based on power (left), and wind utilization hours in Italy. Considering only the plants in operation in 2015, 50% of wind power plants managed to produce 1,395 equivalent hours show the reduction with respect to 2014. In the same year, average utilization hours were 1,683, reduced compared to 1,855 in 2012.

In terms of capacity, 75% of small wind farms have a power output less than 200 kW and 39.3% have a power output below 50 kW.

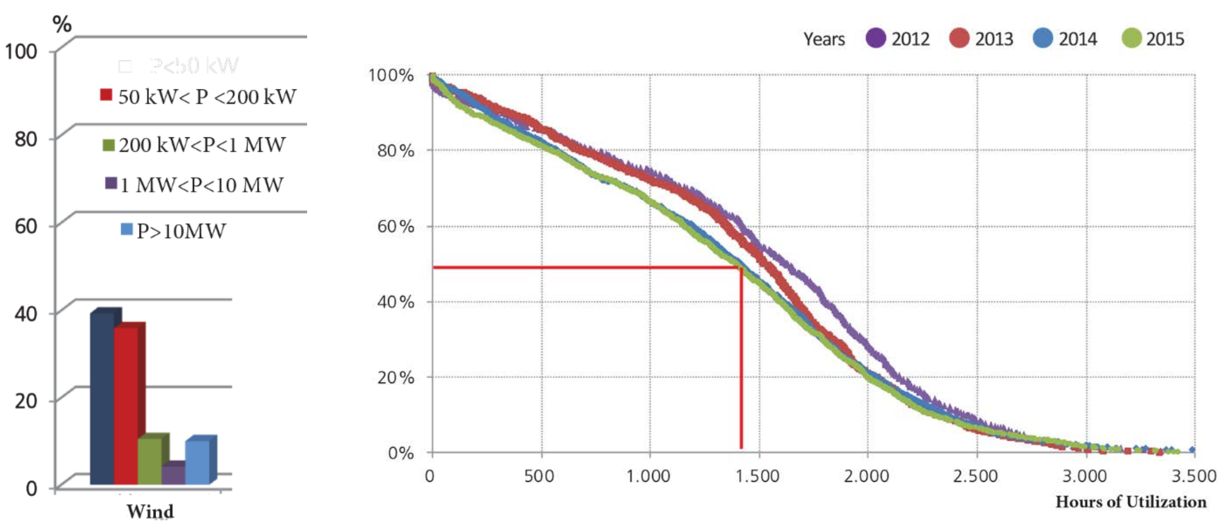

Figure 1-3: Number of Wind plants, Percentage of the number (left) and Utilization hours (right)

1.1.3 Future Trends and Resolutions

The new national energy strategy [37] aims to outline a sustainable growth path of renewable sources, ensuring security and stability for investors, ensuring their full integration into the system, enhancing existing infrastructure and assets, and focusing on technological, process and governance. In this framework, it is proposed to reach at a minimum penetration of 27% on final gross consumption by 2030. This target is reflected in 48% to 50% penetration for renewable Electricity, 28-30% for Renewable Heating and Cooling and 17-19% for Renewables in sector of transportation. This is particularly an ambitious target, even higher than what is required by European parameters. It remembers how the mid-term policy scenario identified the level needed to reach the binding European targets in 24% 39. On the other hand, even applying the same criteria used to set binding targets by 2020 (Directive 2009/28 / EC), Italy would fall to a 25% target by 2030. The objective that is proposed is defined as a minimum level to be achieved through allocative policies, and should not be understood as the capability of development opportunities. On the contrary, it is believed that achieving an economic and technical maturity of the sector will bring growth to even higher levels. The objective is therefore defined as part of a more comprehensive sustainability policy, which includes energy efficiency in the first place, and aims to decarbonise production in a combined manner with other policies of equal importance and gradual progress towards 2050.
In particular, current forms of support / incentives should be reviewed and gradually transformed into enabling mechanisms for the integration of renewables into the market, so that they acquire independence in contributing to environmental objectives.

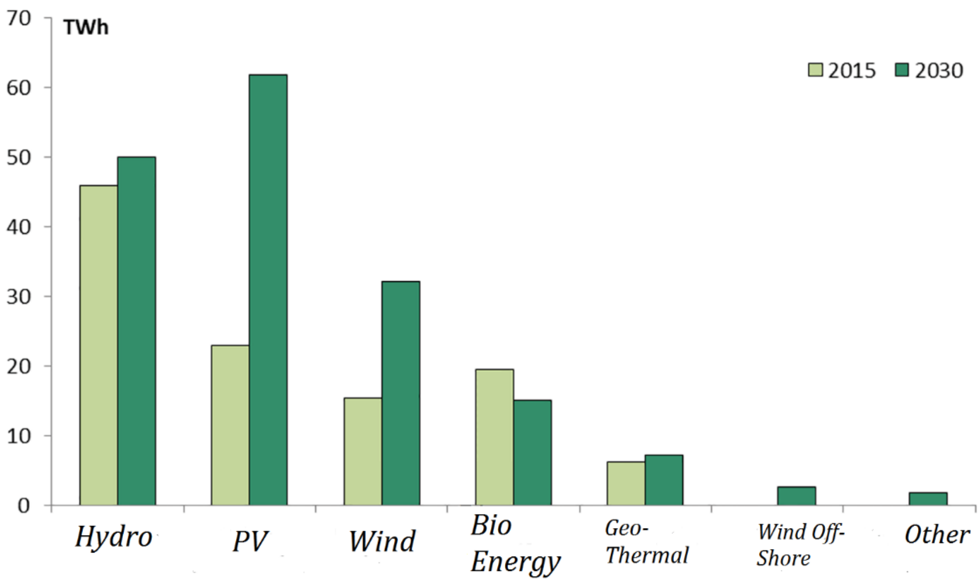

Figure 1-4: Evolution of renewable technology by 2030, separated by technology

1.2 Support Schemes for Wind Power Generation

The Italian system, with the aim of promotion and development of electricity produced from renewable sources is characterized by a variety of mechanisms that have evolved over the years in a logic of market orientation and progressive reduction of incentive level in line with decreasing of generation costs. In this section, a comprehensive discussion on each mechanism is provided, along with the data, based on reports provided in 2016 [02].

1.2.1 Incentives

1.2.1.1 Incentives based on DM 6/7/2012

This mechanism has introduced with the aim of substituting for the incentives corresponding to *Green Certificates* and *All-Inclusive tariffs*. This support mechanism was designed to incentivize the renewable sources of generation other than photovoltaic, which enter to the operation starting from 1° January of 2013, indicating of 5.8 billion EUR per year. This support scheme has provided the annual quota of energy to be incentivized based on source type, nominal power and the way the plants can access to the incentives as direct access for small plants, enrolment in registries for totally new[3] or renovated medium sized plants and participation in competitive auctions held by GSE for the plants exceeding a certain power threshold. In particular, generation units receive incentives based on the net energy injection to the grid. Plants with nominal power up to 1MW receive All-Inclusive tariffs, while plants with nominal power more than 1MW are incentivized equal to difference between a reference tariff and hourly zonal price of energy. The decree also regulates the manner for which plants that are already in operation, incentivized by the Ministerial Decree of 18 December 2008, will pass, from 2016, by the mechanism of Green Certificates to new incentive mechanisms. The typology of this incentive is presented in (2.4) and (2.5). For plants incentivized by All-Inclusive tariffs we have

$$T_O = T_b + P_r \tag{1.1}$$

For plants incentivized based on difference between base tariff and zonal price we have

$$T_O = T_b + P_r - P_z \tag{1.2}$$

In which T_b represents base tariff, P_z represents hourly zonal price and P_r represents the premium dedicated to plants with specific generation technologies. The plants with the output power lower than 1 MW, can choose or transfer among one of them (not more than twice for entire life of unit). In case of All-Inclusive Feed in Tariff, energy will be withdrawn by GSE. Plants with output power above 1 MW, can only opt with incentive only. The electricity produced by these plants remains in property of the plant. Table 1.1 represents the amount of base tariffs and premium for wind plants with different size.

According to the reports published by GSE [06] (last update on 31 December 2016), Table 1.1 provides the number and corresponding power of plants, as well as the evolution of plants (in terms of power and number) incentivized and eligible to access according to DM 6/7/2012.

[3] The definition of totally new, re-constructed and re-designed plants is given by DM 23/6/2016, Art. 2 in Italian

Table 1-1: Values of base tariff and premium dedicated to Wind plants according to DM 6/7/2012

Renewable Source	Capacity (kW)	Incentive Period (Year)	Base Tariff-T_b (€/MWh)	Premium-P_r (€/MWh)
Wind Onshore	1<P≤20	20	250	-
	20<P≤60	20	190	-
	60<P≤200	20	160	-
	200<P≤1000	20	140	-
	1000<P≤5000	20	130	-
	P>5000	20	110	-
Wind Offshore	1<P≤5000	-	-	40
	P>5000	25	165	40

Table 1-2: Method of access to the incentive for plants incentivized by DM 6/7/2012 [18]

Typology of Plant	Auction		Registry		Direct Access		Total	
	MW	n.	MW	n.	MW	n.	MW	n.
Wind Onshore	1239.2*	-	86.7*	-	65.2*	-	1391.1*	-
Total plants for all types	1358.4*	-	544*	-	116.6*	-	2019*	-

* These values do not take into account the excluded capacities due to renunciation, unrespect the rules of enter to operation, refusal from GSE in transitional periods from previous mechanism schemes (IAFR)

Table 1-3: Annual evolution of plants in operation with access to the incentive DM 6/7/2012

Typology of Plant	2013		2014		2015		2016	
	MW	n.	MW	n.	MW	n.	MW	n.
Wind Onshore	144.9	188	293.9	538	632	1194	974.1	1658
Total plants for all types	208.4	445	439.2	1011	950.6	2050	1462.8	2785

Besides the plants which are in operation at the end of 2016, 44 plants with total capacity of 417 MW are eligible to access to the mechanism, but still not in operation and expected to come into operation in subsequent periods.

1.2.1.2 **Incentives based on DM 23/6/2016**

The new decree is the updated version of DM 6/7/2012, introduced on 23 June 2016 with the aim of incentivizing RES-E producers other than photovoltaics entering into operation starting from 1° January 2013[06]. Similar to the previous support scheme, the power plants benefit from incentives only based on net energy injected to the grid. Power plants can access to this type of incentive depending on their nominal power. For wind plants, the access is direct for small plants lower than 60 kW. The bigger plants up to 5 MW should participate in registries with limited rankings. All type of plants above 5 MW, can access with competitive auctions if they are totally new, reactivated and can participate in registry if they are subjected to re-build.
The typology of incentives is similar to DM 6/7/2012. Plants will benefit from All-Inclusive tariff or the difference between base tariff and hourly zonal price according to (2.4) and (2.5). However, in this new decree, the maximum power of plants willing to access to the All-Inclusive tariff is reduced to 500 kW. Moreover, the value of base tariff will reduce in case of contribution in capital cost of plant as following

$$T_{br} = T_b \cdot (1 - R) \tag{1.3}$$

The value of R linearly changes between zero (no contribution in investments) up to 26% (in case of maximum 40% contribution in investments). In general, in new decree, the values of base tariffs are reduced for most type of producers. Table below shows the values in new mechanism in comparison with previous mechanism and the relative reduction.

Table 1-4: Base tariff of incentives in DM 23/6/2016 in comparison with DM 6/7/2012

		DM 6/7/2012			DM 23/6/2016			
Source of Power		Power (kW)	Incentive Period (Y_r)	Base Tariff-T_b (€/MWh)	Power (kW)	Incentive Period (Y_r)	Base Tariff-T_b (€/MWh)	% of variation
Wind	Onshore	1<P≤20	20	291	1<P≤20	20	250	-14%
		20<P≤200	20	268	20<P≤60	20	190	-29%
					60<P≤200	20	160	-40%
		200<P≤1000	20	149	200<P≤1000	20	140	-6%
		1000<P≤5000	20	135	1000<P≤5000	20	130	-4%
		P>5000	20	127	P>5000	20	110	-13%
	Offshore	1<P≤5000	25	176	1<P≤5000	-	-	-
		P>5000	25	165	P>5000	25	165	0%

In addition to the type of producers, the attribution of incentives and the values of tariffs according to both mechanisms can be summarized as

Mode of access according to DM 6/7/2012:

- Plants entered in a position as a result of the Auction Procedures and Register of DM 6 July 2012, incentivized by the tariffs indicated by DM 6/7/2012
- Plants eligible for directs access, which entered into operation between 31 May and 29 June 2016, provided that they have submitted or apply for access to incentives within 30 days of the date of entry into service , incentivized by the tariffs indicated by DM 6/7/2012

Mode of access according to DM 23/6/2016:

- Plants with direct access and registered to registry[4] procedure according to DM 23/6/2016, operational until 29/6/2017 and respected to the deadline for submitting the requests, incentivized by the tariffs indicated by DM 6/7/2012
- Plants with direct access and registered to registry procedure according to DM 23/6/2016, operational after 29/6/2017, incentivized by the tariffs indicated by DM 23/6/2016
- Plants awarded by the auction according to DM 23/6/2016 incentivized by tariffs indicated by DM 23/6/2016

According to the GSE report at the end of 2016, six month after introduction of the mechanism, wind plants with total power of 884 [MW] has been eligible to enter in operation by new mechanism. Among them, 21.7 MW have communicated to be in operation by that time. The maximum share of registration is for plants registered by auction. Table below shows the number and share of power divided by each type of registration

Table 1-5: Method of access to the incentive for plants incentivized by DM 6/7/2012 [06]

Typology of Plants	Auction		Registry		Direct access		Total	
	MW	n.	MW	n.	MW	n.	MW	n.
Wind onshore	800	38	66	71	17.8	-	883.8	-
Total plants for all types	870	41	330	407	24	-	1224	-

Among data reported by table 2.8, plants which requested to access to the incentive are as following

- Wind plants in operation, which by 31° December 2016 requested direct access to the incentive (17.8 MW)
- Wind plants which according to the results, by 31° December 2016, gained allowance to have access to the incentives through auction or registry. Among them, 3.9 MW of plants with registry access have been in operation

1.2.1.3 Green Certificates (CV) and Ex-CV

The incentive mechanism with *Green Certificates* works based on the obligation imposed on producers and importers on non-renewable sources of electricity, to contribute a minimum share of electricity produced by plants powered by renewable sources [02]. For each type of plants, the

[4] For detailed information on registries, auctions and the timing conditions, refer to DM 23/6/2016 "Titoli II e III" in Italian.

possession of green certificates means the fulfillment of this obligation. Each green certificate is conventionally attributed to the 1 MWh production of renewable energy. The fulfillment of obligation can be respected in two ways: generating electricity from renewable sources or purchasing green certificates from renewable energy producers.

Before 2016, for renewable producers and Non-renewable producers and importers which have obligation to buy green certificates, it was possible to trade the certificates through purchasing agreements or GC market induced by administrative obligation, at market price. However, by the evolution of renewable producers and reduction in obligations, the adequacy of the offers and obligations was not always sufficient to closing the market. In such case, GSE sets the additional mechanism particularly to intervene to closing the market. In this mechanism, the price for green certificates defined as a difference between a price cap and wholesale yearly average market price of one year before [32]. From 31 December 2007, GSE introduced a new rule to determine the value of green certificates by discriminating between technologies as following

$$I = k \cdot (180 - R_e) \cdot 0.78 \tag{1.4}$$

In (2.5), I represents the value of incentive, k is a factor which is different for various renewable generation technologies. In particular, this value is equal to 1 for wind plants over 200 kW. R_e represents the price for energy disposal and is determined annually by AEEG[5]. In particular for 2017, this value is equal to 42.38 €/MWh [33], meaning that for this year, based on (1.4), the calculated price of incentive equals to 107.34 €/MWh.
Starting from 2002, the values of obligation was determined yearly, as percentage of total non-renewable productions and imports, incremental up to 2013. From 2013, GSE started to phase out the obligations, and reduced to zero by 2016. Instead, from 2013, the issuance of Green Certificates took place from the measures transmitted monthly by the network operator. Figure 1.7 represents the evolution of GC market from 2002 to 2015.
As it is shown in figure 1.5, starting from 2006, difference between offers by producers and obligations has significantly increased. In this respect, starting from 2008, GSE upon the request of producers, withdrawn by June of each year, the green certificates which are in addition of supply the obligations for non-renewable producers and importers, at the reference price for the years before 2011, and withdraws quarterly in a year at reference price multiplied by 0.78 for the withdrawals after 2011. Figure 1.6 represents withdrawals of GCs by GSE.
Table 1.6 represents the total share of incentives according to GC mechanism particularly for wind plants by the end of 2016.

Table 1-6: Summary of Wind productions and economic attribution by GC mechanism

Generation Type	Power (MW)	n.	Energy (GWh)	Fees (mln €)
Wind Onshore	7923	564	293.9	538
Total	-	-	-	-

[5] Decreto legislativo 387/03

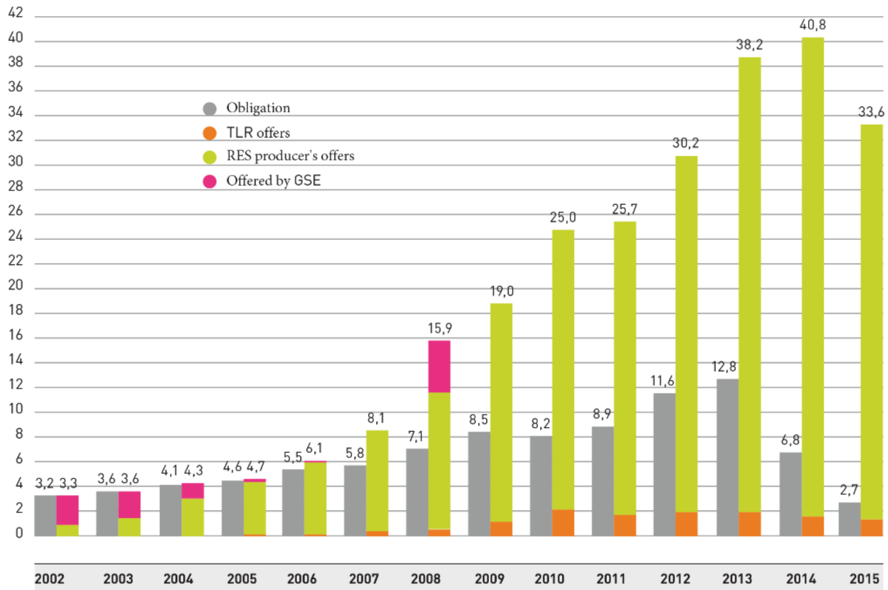

Figure 1-5: Evolution of GC market from 2002 to 2015 (Millions of GC) [06]

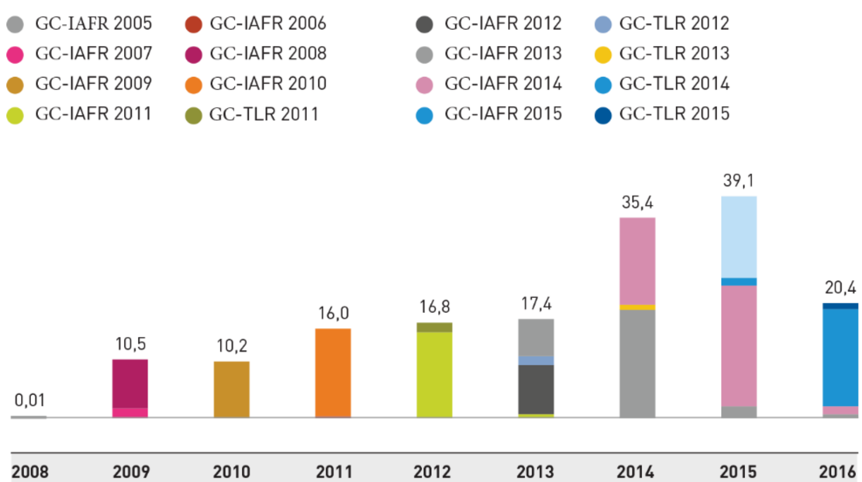

Figure 1-6: Withdrawals of GC by GSE

In general, for renewable plants incentivized by Green Certificate mechanism, the duration of incentive is 12 years for the plants entered into operation until 31° December 2007, and 15 year for the plants which are entered into operation starting from 1° January 2008.

1.2.1.4 **All-Inclusive tariffs**

This type of mechanism, alternative to green certificate, incentivizes the small power plants up to 200kW of wind, and 1 MW of other renewable plants for the duration equal to 15 years, which entered to the operation before 1° January 2013. Tariff which applies by this mechanism is constituted by two components, incentive and value of net energy injected to the electricity grid. Table 1.7 represents the value of incentives attributed to each type of generation.

Table 1-7: Values of incentives according to All-Inclusive mechanism

Generation Type	Incentive Tariff (€cent/kWh)
Wind up to 200 kW	30
Geothermal	20
Wave and Tidal	34
Hydro other than those introduced before	22
Biomass, Biogas, Bio Alcohol	28
Lnadfill gas, Residual gas from purification, Bio combustion liquid	18

Table 1.8 represents the share of All-Inclusive tariffs dedicated to Wind in comparison with total generation technologies ate the end of 2016.

Table 1-8: Quota of Wind producers in All-Inclusive tariff

Generation Type	n.	Power (MW)	Energy (GWh)	Fee (mln €)
Wind	368	22	24	7
Total	2874	1658	8764	2307

As we can see, the quota of wind producers from this mechanism is very little, only 1.3% of total incentivized capacity belongs to wind. This Quota is equal to 0.2% total incentivized energy by All-Inclusive tariffs. Figure 1.7 represents the evolution of this mechanism, in term of capacity.

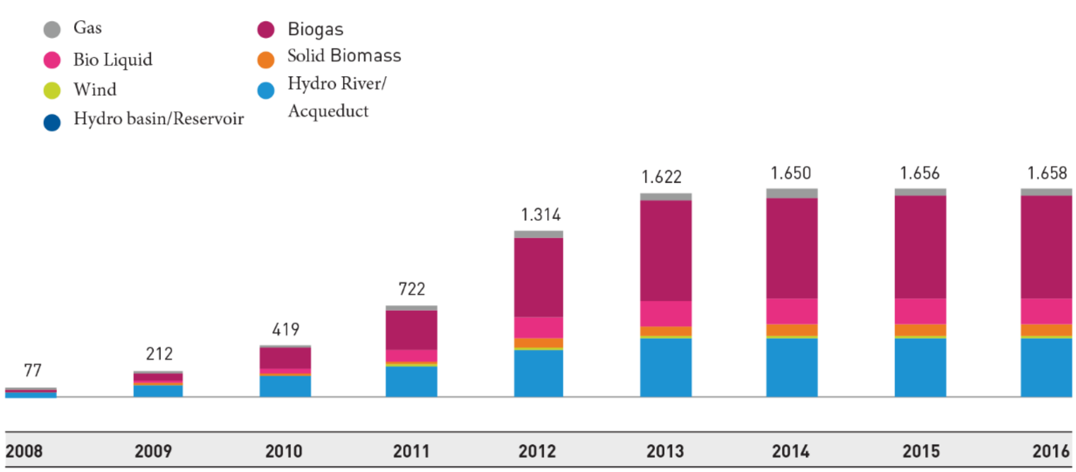

Figure 1-7: Evolution of All-Inclusive mechanism

1.2.1.5 **CIP-6/92**

For the plants up to 1 MW and wind plants up to 200 kW, entered into operation by 31° December 2012, it is a fixed tariff for withdrawal of energy injected into the grid. The tariff includes both incentive component and energy price. Table below shows the evolution of incentives and share of wind plants from this type of mechanism.

Table 1-9: Evolution of incentives, CIP6/92 and deliberation 81/99

	2007		2008		2009		2010		2011		2012		2013		2014		2015		2016	
	Wind	All	Wind	All	Wind	All	Wind	All	Wind	All	Wind	All	Wind	All	Wind	All	Wind	All	Wind	All
Capacity [MW]	810	7319	766	6358	6622	6124	498	5503	346	3620	161	2982	161	2293	150	1457	121	1369	21	12447
Energy [GWh]	1281	4580	1153	41733	878	36217	816	37702	465	26684	328	22441	199	15849	203	11535	168	9105	162	9185
Incentive [€/MWh]	134.8	179.9*	153.3	200.7*	126.9	183.6*	95.9	177.9*	102.5	180.7*	116	182.1*	112.9	186.7*	96.2	188*	91.7	182.2*	77.6	178.6*

** Values correspond to the average values of incentives for all renewable sources*

During the period between 2007 to 2016, it can be seen a gradual decrease in the volume of energy withdrawn by GSE (from about 47 TWh in 2007 to 9 TWh in 2016) due to the progressive expiry of the CIP6/92 convention, contracted power reduced from around 7,500 MW in 2007 to around 1,200 MW in 2016.

1.2.2 Withdrawal Services[6]; Trading Methods of Energy into Electricity Market

In general, RES plants can trade their net production into electricity network by directly sale through IPEX[7] into GME or sale via bilateral contracts to consumer parties. As another alternative, plants may choose GSE as a third party, to facilitate trade of energy into the market, particularly through *Dedicated Withdrawal* and *On-Spot Trading*. Next two section introduces two last mechanisms which is called *Withdrawal Services.*

1.2.2.1 Dedicated Withdrawals[8]

For NP-RES plants with any capacity of generation, this mechanism is an assisted mode of sale of electricity into the market. For plants with power less than 1 MW, GSE buys the first 1.5 million kWh of wind production from each producer at minimum guaranteed price[9] which is updated annually. For more production, and also for the plants with size greater than 1 MW, GSE calculates the price of energy according to average zonal price for each zone, each hourly phase and 12 month of the year. Table 1.10 represents monthly average zonal price for three hourly phase of energy sale, for

[6] *Servizi di Ritiro della Energia Elettrica*
[7] Italian Power Exchange
[8] In Italian *"Ritiro Dedicato"*
[9] Deliberation 618/2013/R/efr, modified deliberation n. 280/07

particular case of zone *SUD* in first semester of 2017. Minimum guaranteed price is presented for comparison. In case where the hourly zonal price is more advantageous than minimum guaranteed price, GSE calculates and pays the difference on behalf of the producer. Moreover, on behalf of producers, GSE transfers the fees of dispatching and transmission to DSO and TSO. Table 1.11 represents the evolution of energy withdrawn for particular case of wind plants from 2008 to 2016.

Table 1-10: Monthly average zonal price for each hourly phase and comparison with minimum guaranteed price for wind plants, zone SUD

Phase	Jan	Feb	Mar	Apr	May	June	P_{MG}
F1	63.83	51.50	39.75	42.16	44.96	38.32	49 €/MWh For first 1.5 million kWh
F2	57.85	50.16	40.89	41.77	41.68	36.59	
F3	50.17	47.28	39.95	34.48	31.53	33.32	

It is important to mention that this service is not compatible with FIT typology incentives (All mentioned in previous sections except Green Certificate) and *On-Spot trading* system.

Table 1-11: Evolution of energy withdrawn from wind plants under dedicated withdrawal mechanism

	2008	2009	2010	2011	2012	2013	2014	2015	2016
n.	117	143	188	251	373	372	345	297	203
Power (MW)	1653	2378	3200	4000	4622	4219	2930	2473	1008
Energy (GWh)	1650	2962	4783	5372	7446	6589	4975	3066	1414

1.2.2.2 On-Spot Trading[10]

SSP is a mechanism by which the injected energy is economically compensated by energy consumed by the same consumption-generation unit, at a time other than the consumption period. Units which are counterparty of energy purchase with the capacity up to 200 kW and units up to 500 kW which are entered into the operation starting from 1° January 2015 can access to this trading service, Table 1.12 represents data for units with wind production operating by *SSP* by the end of 2016.

Table 1-12: Share of wind plants with SSP, 2016

Generation Type	n. of conventions	Capacity (MW)	Inj. Energy (GWh)	Withdrawn (GWh)	Exch. Energy (GWh)
Wind	70	0.68	0.31	1.40	0.21
All	563214	4829	3100	7691	2109

[10] In Italian "*Scambio sul Posto*", regulated by deliberation 570/2012/R/efr

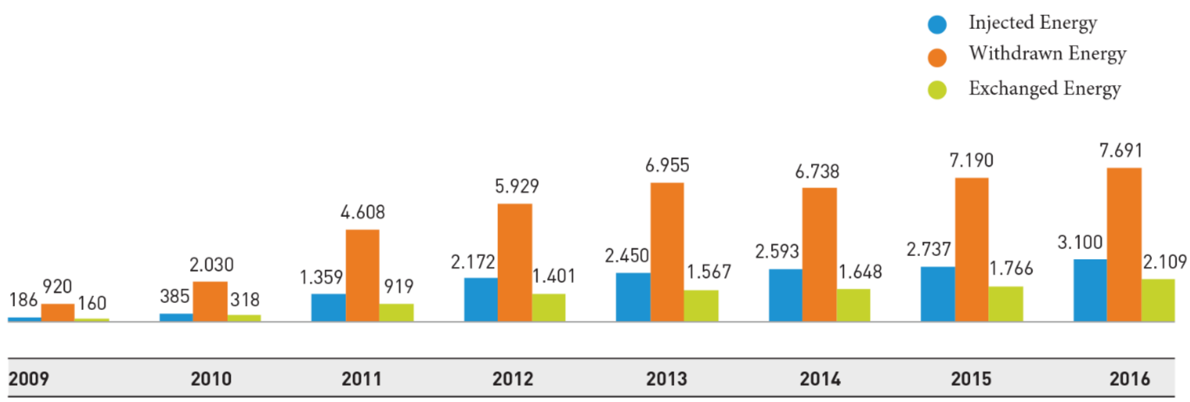

Figure 1-8: Evolution of SSP trading service

The share of *SSP* for units with wind production is very small. This share for photovoltaics is more than 99 percent. This mechanism is not compatible with dedicated withdrawals and FIT typology incentives. Figure 1.8 represents the evolution of this trading mechanism over the years.

1.2.3 Summary and Future of Incentives

In previous sections, it has been reviewed the typology and existing situation of different mechanisms and trading systems of renewable sources, with focus on wind power generation.

Table 1-13: Summary of incentives for RES-E no PV including Wind

Incentive Mechanism	Period of Access	Duration of Incentive	Plant Capacity	Incentive Typology	Valorization of Incentive	Incentivized Energy Type	Value of Inj. Energy
DM 23/6/2016 RES-E	From 2016	15-30 Years	≤ 500 kW	FIT	Constant Tariff	Injected	Included in Tariff
			> 500 kW	SFIP	Difference between base tariff and Zonal price	Injected	Market Price
DM 6/7/2012 RES-E	2013-2016	15-30 Years	≤ 1 MW	FIT	Constant Tariff	Injected	Included in Tariff
			> 1 MW	SFIP	Difference between base tariff and Zonal price	Injected	Market Price
All-Inclusive Tariff	2008-2012	15 Years	≤ 1 MW	FIT	Constant Tariff	Injected	Included in Tariff
Green Certificates and Ex-GC	2002-2012	8-15 Years	No limit	GC/SFIP	GC Market or GC withdrawal at energy price value/Tariff obtained from difference between the energy price	Produced	Market or Dedicated Withdrawal or On Spot Trading
CIP-6/92	1992-2001	8-15 Years	No limit	FIT	Price partially indexed for the fuel price	Injected	Included in Tariff

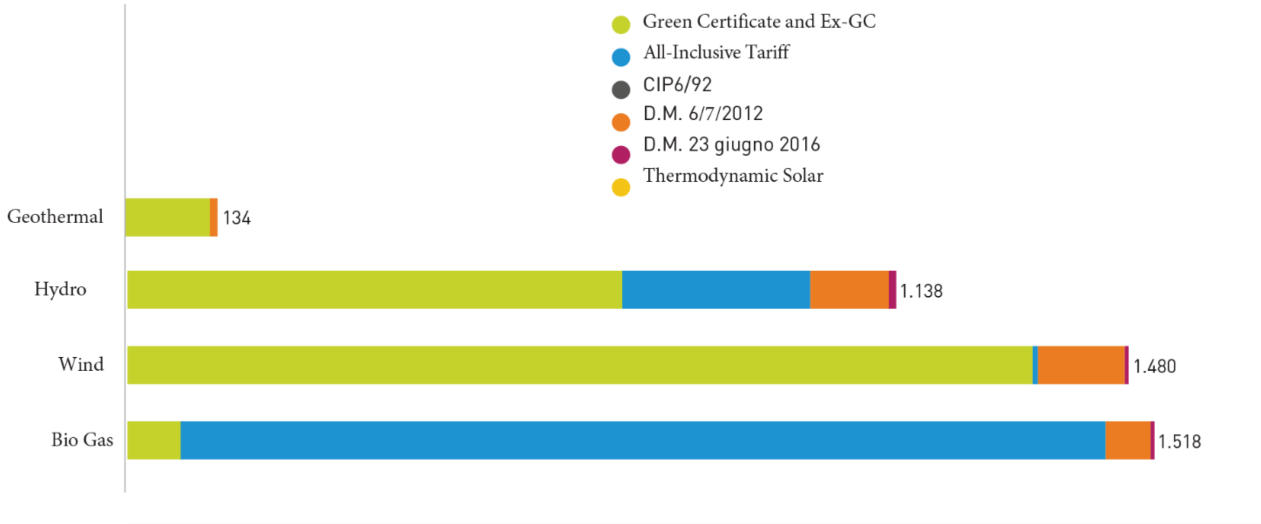

Figure 1-9: Share of incentives attributed to wind in comparison with some other RES producer, 2016

Beside the incentives which is still new and their economic effect should be exploited in future, such as DM 23/6/2016 and DM 6/7/2012, there are some mechanisms which the plants associated to them are close to their expiration of incentive period, such as CIP6/92 and part of the ex-CV. It is therefore important to figure up a long term scenario of the incentive requirements. The long term scenario is founded on the assumption of constant energy price equal to 46 €/MWh. A most persistent incentive supply is observed until 2023, followed by a progressive reduction, determined by different exit profiles of the existing mechanism

- Ex-CV and All-Inclusive, mainly from 2024 to 2028
- Conto Energia, associated with the photovoltaic production, with a very rapid decrease bringing total demand less than one billion Euros.

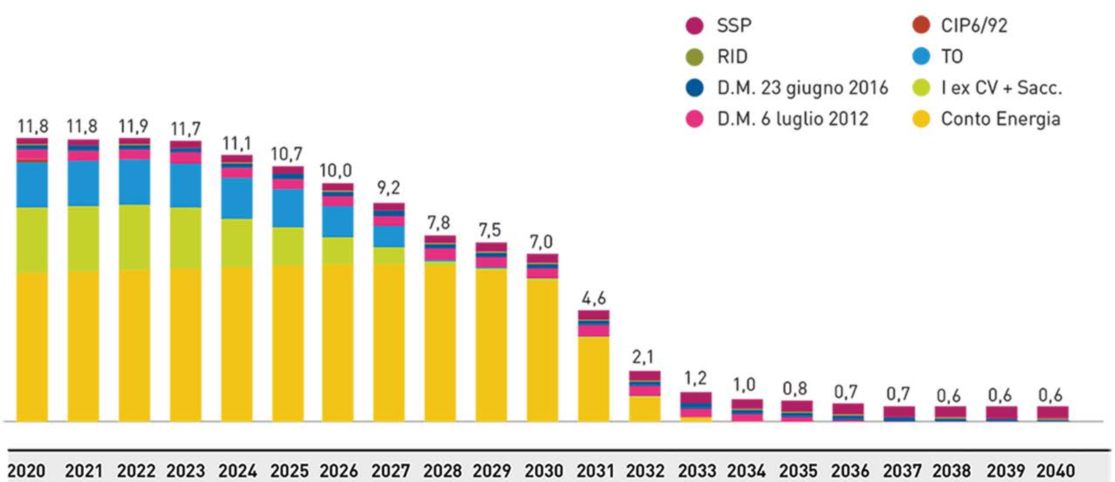

Figure 1-10: Future of Incentives in terms of billions of Euro

References:

[1] Gestore Mercati Elettrici; www.mercatoelettrico.org

[2] Gestore Servizi Energetici; www.gse.it

[3] *Decreti Ministeriali; DM 6/7/2012; DM 26/6/2016;*

[4] *Energia da fonti rinnovabili in Italia; Rapporto Statistico* 2015; GSE

[6] *Rapportao Attivita;* GSE; 2016

[7] *L'incentivazione delle Fonti Rinnovabili Elettriche: la situazione attuale e le prospettive a breve, alla luce del nuovo Decreto e delle Linee Guida europee; Seminario 1 Luglio 2016; Universita di Padov;*

[8] *Energie Rinnovabili al 2020; Scenari Tendenziali; GSE*

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[15] *Toward Smarter Grids: ENTSO-E Position Paper on Developing TSO and DSO Roles for the Benefit of Consumers (2015)*

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[22] *TERNA Grid Codes; Chapter 7*

[23] *Delibera n. 111/06 e Allegati*

[24] *TERNA website; www.terna.it*

[27] *"Regole techniche per il trsferimento delle partite economiche relative di sbilanciamento..."; GSE; Dec 2014*

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[30] *Partecipazione della domanda al mercato per il servizio di dispacciamento; Ai sensi della delibera 300/2017/R/eel; TERNA; 2017*

[32] *Lecture Notes of Smart Grids and Regulaions for RES;* Politecnico di Milano

[33] Deliberazione 31/2017/R/eel; Jan 2017

[34] *Position paper on priority dispatch of wind power;* EWEA; 2016

[35] Priority dispatch and curtailments; WindEurope

[36] *Delibera ARG/elt 5/10 e Allegato A*

[37] *Documento di consolazione; Strategia Energetica Nazional; June 20*

Chapter 2

Electricity Market and National Regulatory Framework

2.1 Structure of Italian Electricity Market

In Italy, the creation of new electricity market was initiated by the transition of national electricity sector, from vertically integrated monopoly structure to the liberalized form, initiated by directive 96/92/EC, transposed by decree n. 79, known as *Decreto Bersani* in 16 March 1999. This revolution in electricity market has been carried out with the aim of providing two main targets: (a) transparency, neutrality and competitiveness in electricity generation, sales and purchases and (b) ensuring the economic management of an adequate availability of ancillary services [01]. Figure 2.1 shows the revolution of electricity sector from vertical monopoly (ENEL, 1962 to 1999) to liberalized.

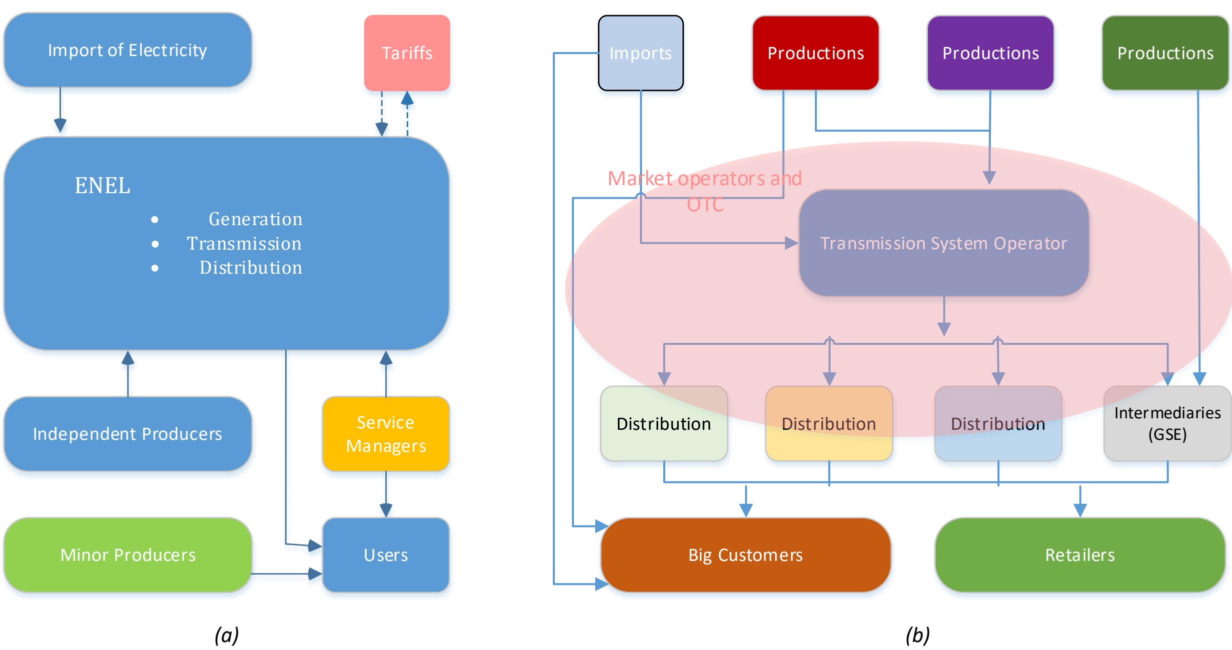

Figure 2-1: Revolution of electricity sector, (a) Vertical monopoly, (b) Liberalized

Italian electricity market (IEM) is operated by *Gestore Mercati Energetici* (GME). GME was initially set up by *Gestore Servizi Energetici* (GSE), which is owned by ministry of economy and finance. By now, GME carries out its activities in accordance with the guidelines given by the Ministry of Economic Development and the regulatory provisions issued by *Autorità per l'energia elettrica e il gas* (AEEG).

Electricity market is divided in two main parts, spot and forward electricity markets. Spot electricity market (MPE) consists of Day Ahead Market (MGP), Intra-Day Market (MI), Daily Products Market (MPEG) and Ancillary Services Market (MSD). Forward electricity market (MTE) is the venue where forward electricity contracts with delivery and withdrawal obligation are traded. Among various transactions in MTE, Base-Load and Peak-Load, with monthly, quarterly and yearly delivery periods and bilateral contracts can be mentioned as the important transactions. For the mentioned markets, GME provides power market platform, known as Italian Power Exchange (IPEX), on which producers and buyers sell and buy wholesale electricity. GME also operates the platform for transactions of Ancillary Services Market, which is managed by TERNA. Figure 2.4 shows the structure of Italian Electricity Market. In the next sections, the main parts of spot market are investigated more in details since it has more importance in this work.

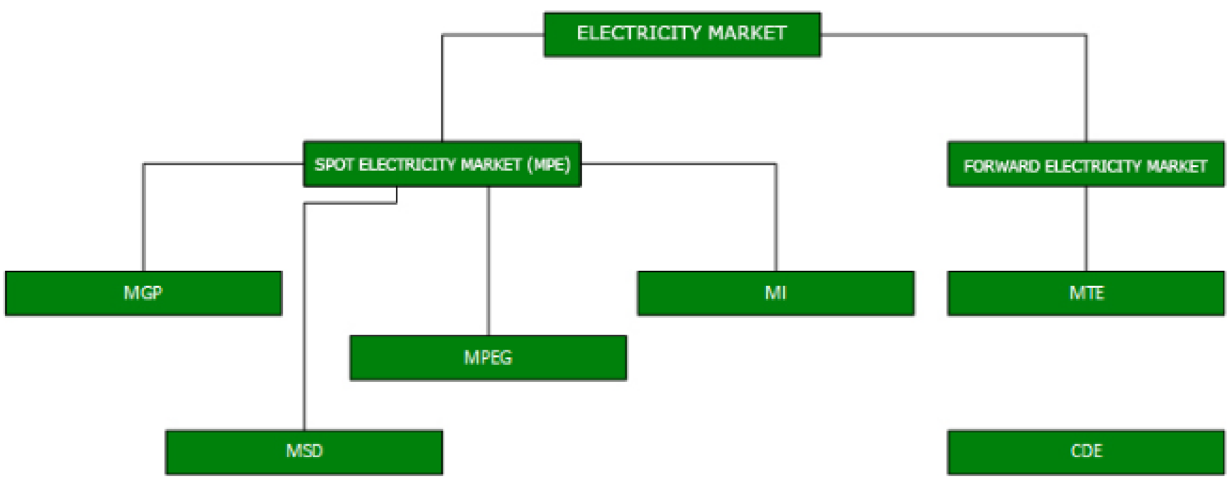

Figure 2-2:Structure of Italian Electricity Market

2.1.1 Market Zones

Italian system operator divides the operation of electricity system into zones based on portion of transmission network belonging to geographical classification and energy transfer limitations between areas [31]. By taking into account the developing plan of transmission network, system operator determines the zones according to following criteria

- The transfer capacity between zones must be limited to most frequent operational condition, based on observation, according to the security criteria considered during the operation of TN.
- Planned injection and withdrawal of energy, in general, should not cause the significant congestion to change injections and withdrawals inside each geographic zone with corresponding internal network and based on the security criteria mentioned in previous point.
- The location of injections and withdrawal points inside each zone, in general, should not have the significant influence on transfer capacity between zones.

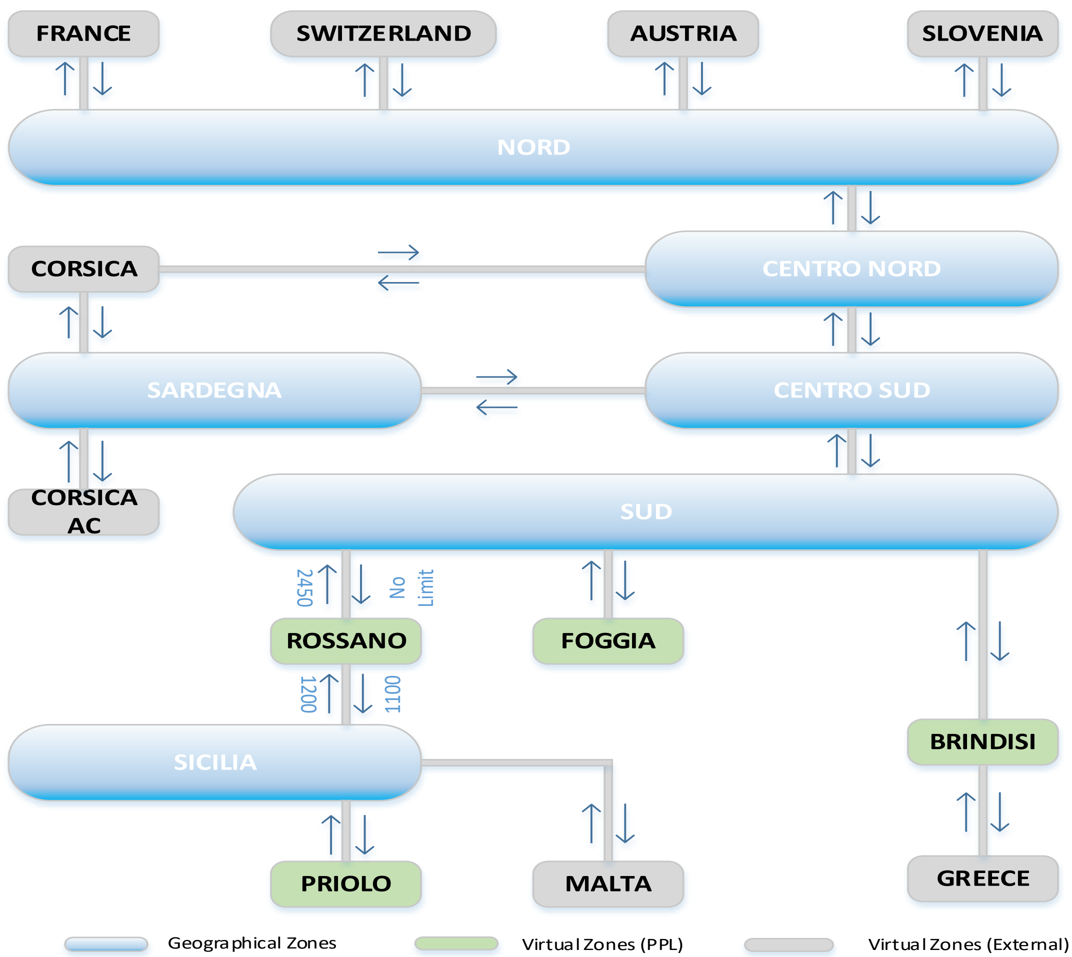

Figure 2-3: Relevant zones of Italian Transmission Network

The relevant zones of network could be corresponding to physical geographic areas, or virtual zones which are not directly corresponding to a physical zone, or corresponding to a limited production pole. The latter refers to virtual areas whose production is subject to constraints for the safe management of the electrical system. Figure 2.3 represents the market zones.

2.1.2 Day Ahead Market (MGP)

In day ahead market, the anticipated energy demand is procured by trade of energy blocks for each of every hours of the day of delivery, through auction based transactions between producers and purchasers. In this platform, producers offer the quantity of energy which they will provide with the price they will to sell. In other side, purchasers bid the quantities of demand with the minimum price they will to pay. At the end of session, market operator clears the result of auction by market clearing algorithm, in merit order basis, by considering transmission capacity limitations of market zones, and determines the quantity and price which the participant will exchange. The significance of this market is mainly due to the fact that the major share of electricity transactions carries out in this platform. In other words, the great share of generators and consumers plan their energy production or consumption based on the outcome of this market.
Participants of this market can bid their offers during the session which opens at 8 a.m. of the ninth day before the day of delivery and closes at 12 p.m of one day before delivery.

The results of the MGP are made known within 12.55 p.m. of the day before the day of delivery. Figure 2.4 illustrates the market clearing algorithm in Italian DAM for one hour of energy procurement. Market operator carries out the same clearing for every hour of the day, and make available the result, as clearing price and accepted quantities for each participants. Some other notable features of this market can be mentioned as following:

- RES plants participate in this market at zero price, first because of near zero marginal price of renewable sources of energy and second, in order to guarantee the acceptance of all renewable energy productions in energy market.
- Quantity of bilateral transactions (OTC) which has been exchanged in forward market, are included in this graph at zero price in order to ensure that they are considered in transmission capacity constraints.
- If there is no transmission congestions between zones, all participants pay or receive the same price, namely market clearing price (MCP). In case of congested transmission between zones, MCP will differ zone by zone and producers from different zones receive different price. But according to Italian rule, consumers in every zones pay the same price, equal to the average of MCP prices in each zone, namely *Prezzo Unico Nazionale (PUN)* calculated as

$$PUN = \frac{\sum {P^k}_z \cdot Q^k}{\sum Q^k} \tag{2.1}$$

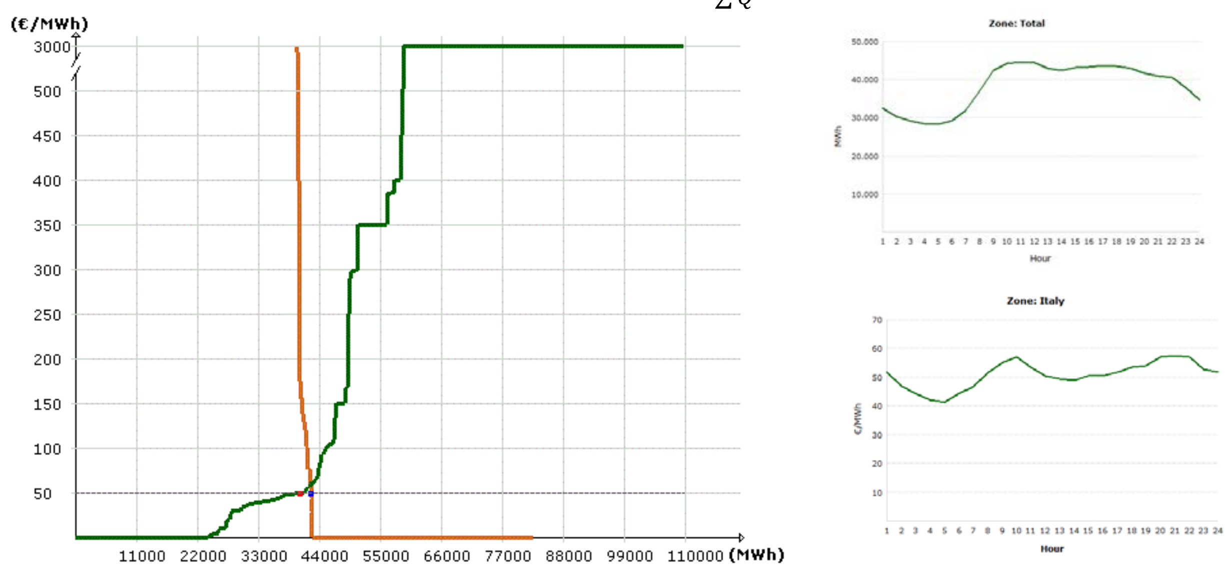

Figure 2-4: DAM clearing for one hour, Right: Cleared quantity and price for every hours of the day

2.1.3 Intra-Day Market (MI)

Participants who are scheduled in DAM, have the opportunity to modify their planned schedules by participating in intra-day market sessions. Generation plants may decide to change their planned production, before delivery, for many reasons. In particular, for thermal plants which are planned in DAM, but this plan does not conform their technical capability may choose to modify their generation plan comply with their constraints. Figure 2.5 (a) describes non-compliance scheduling of production with respect to unit ramp rate capability. For NP-RES plants, participation in MI will provide the opportunity to modify their planned generation according to more accurate weather forecast, more

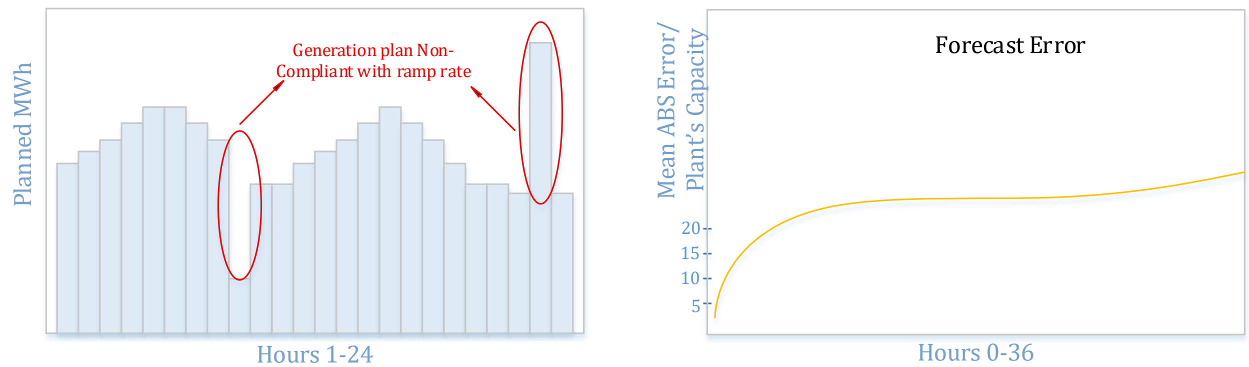

Figure 2-5: (a) non-compliant production plan of thermal plants, (b) increase in RES forecast error by time

close to real time. Figure 2.5 (b) illustrates increase in forecast error by increase time between forecasting and real generation. In current Italian market framework, MI sessions take place in seven sessions. The first session starts after the closing of MGP. The last session's gate closes at 3:45 PM of the delivery day. In general, for NP-RES plants, participation in MI session with gate closure time close to delivery time, significantly reduces the error in forecast and generation imbalance. Spot market sessions and gate closure time is provided in table 2.1, after introducing Ancillary Services Market.
In MI, Supply offers and demand bids are selected under the same criterion as the one described for the MGP except that unlike the MGP, accepted demand bids are valued at zonal price.

2.1.4 Ancillary Services Market

In Ancillary Services Market (in Italian, *Mercato Del Servizio di Dispacciamento)*, TSO procures the reserve needed to guarantee the security of the system. In other words, producers offer their quantity and price, and TSO as a single buyer, accepts the most favorable offers based on economic merit order criteria, transmission limit constraints, system reserve needs and others. In particular, TSO needs reserve in order to counteract to system contingencies, network congestions, imbalance between generation and production in real-time operation and create additional reserve to enhance the security of system.
Unlike previous energy markets presented in previous sections, which are almost using similar mechanism in different countries with liberalized electricity sector, Ancillary Services Market has more peculiarity and dispersity among different system operators in the world. In other words, different system operators mainly uses their own peculiar mechanisms to procure and remunerate the system reserves. In this regard, ENTSO-E[11], in accordance with ACER[12] and EC[13], started to establish the common rules and frameworks for National System Operators [35], in order to enhance the European Power System security and reserve adequacy in form of establishing more common structures and developing cross-border energy and reserve markets. In the following, we focus our attention to present the Italian ASM with its main characteristics, then we go one step further to briefly investigate about European directives and other nations behaviors in this subject.

[11] European Network of Transmission System Operators
[12] Agency for Cooperation of Energy Regulators
[13] European Commission

2.1.4.1 Introduction of Ancillary Services Market

TERNA, in order to securely operate the system, procures the system reserve needs in two reserve market framework:

- *MSD Ex-ante:* TERNA accepts bids/offers to plan the adequacy of reserve, create reserve margins and relieve system congestions in planning phase. These reserves are in the form of secondary and tertiary reserves. In current market framework, MSD transactions take place and update in six sessions. In particular, transactions in MSD_n corresponds to, or closes after MI_{n+1} sittings, therefore the congestions which rise in MI_{n+1}, are relieved by accepting bids/offers in MSD_n. Note that MSD_2 to MSD_6 uses the same bid/offers submitted in MSD_1 by dispatching units.
- *Balancing Market MB:* In this market, TERNA accepts bids/offers in order to solve congestions and imbalances which happen in real time of operation and are not planned before. Real time congestions and imbalances occurs mainly due to demand forecast errors and system contingencies such as loss of lines and other mains, NP-RES generation imbalances. Transactions in MB takes place and update in six sessions with the gate closure times distributed along the day of delivery. Table 2.1 contains the information regarding MGP, MI, MSD and MB sessions and gate closures. Note that MB_1 uses the bids/offers submitted in MSD_1, therefore participation in MSD_1 is necessary to be accepted in MB.

2.1.4.2 Dispatching Resources in Ancillary Services Market

Ancillary services which are traded in MSD are presented in the following:

- *Frequency Restoration Reserve:* This kind of reserve also is known as *Secondary Reserve (RS).* Units which offer this service are willing to change their binding programs after MGP or MI sessions to provide half band reserve in MSD. In real time, generation units put this reserve band under the control of TSO to control the production proportional to the level of control signal. If this service is not selected in MSD Ex-ante, unit may put this reserve band under the control of TSO by selecting in MB. As a technical obligation, this service must be able to be in operation for 15 minutes by receiving the dispatching order. In planning phase, TSO procures in MSD Ex-ante, the estimated amount of reserve for each zone of Sicily, Sardegna and Continent as (2.2). Then, this amount of reserve may be used in real time operation in case of need.

  $$RS = -150 + \sqrt{10 \cdot C + 150^2} \tag{2.2}$$

  In (2.2), *RS* represents the estimation of half-band secondary reserve. Note that the *Frequency Containment Reserve,* also known as *Primary Reserve,* is a compulsory service to be provided by eligible units in case of accidental frequency deviations and is not traded and paid in market. However, TSO uses secondary reserve in order to gradually restore the primary reserve bands.

Table 2-1: Timing of spot market sessions and gate closures

Reference Day	D - 1				D															
Market	MGP	MI1	MI2	MSD1	MB1	MI3	MSD2	MB2	MI4	MSD3	MB3	MI5	MSD4	MB4	MI6	MSD5	MB5	MI7	MSD6	MB6
Sitting Open	08:00 of D-9	12:55	12:55	12:55	°	17:30	°	22:30	17:30	°	22:30	17:30	°	22:30	17:30	°	22:30	17:30	°	22:30
Sitting Close	12:00	15:00	16:30	17:30	°	23:45 of D-1	°	03:00	03:45	°	07:00	07:45	°	11:00	11:15	°	15:00	15:45	°	19:00
Final Results	12:55	15:30	17:00	21:45	#	00:15	02:15	#	04:15	06:15	#	08:15	10:15	#	11:45	14:15	#	16:15	18:15	#

°Use bid of MSD1
Dispatching rules

- *Replacement Reserve:* Also Known as *Tertiary Reserve (GR).* Unlike secondary reserve, generation units activate tertiary reserve manually, manned, upon receiving dispatching order from TSO. Faster tertiary reserves are mainly utilized for restoring FRR, compensating the demand and NP-RES forecast errors, with activation time not more than 15 minutes. TSO also uses tertiary reserve as balancing resource. This reserve, namely *Replacement Reserve*, aims to re-establishing the tertiary reserve when a change in the cumulative programs of some units occurs and fully activates within 120 minutes from dispatching order, and can sustain in operation with no duration limits. Figure 2.6 illustrates the activation timing of dispatching services.

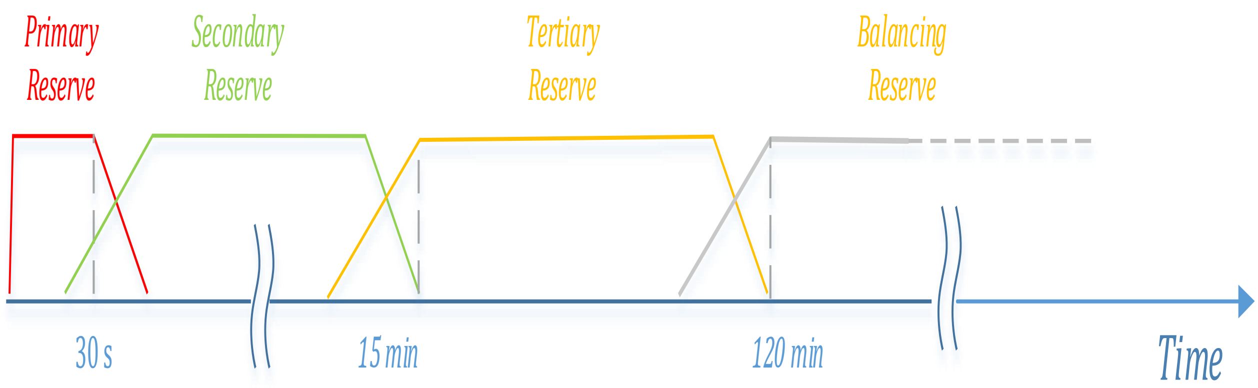

Figure 2-6: Activation timing of frequency control dispatching services

- *Participation in Recovery of Power System, and shut down:* Dispatching units can participate by bidding/offering of other dispatching services. These services include *Start-Up (AC), Minimum Operation or Shut down (AS)* services and *change of operating conditions (CA).* Eligible units can present in MSD one bid for Start-Up, valid for each hour of the day and one price (€/MWh) for offering minimum power starting from lower than a minimum value.

Moreover the services traded in MSD which are presented above, other dispatching resources which are not presented in MSD but considered as dispatching resources are presented as following

- *Frequency Containment Reserve:* Also known as *Primary Reserve* is a type of reserve which is activated instantaneously in case of sudden variations in frequency. FCR activates automatically, and it is independent of the location of imbalance's origin. In particular, all eligible generators[14] in synchronous area of European power system, provides, as uniform as possible, this frequency control service to keep the security of the system. According to ENTSO-E instructions, 3000 MW of mismatch between generation and demand leads to ±50 MHz deviation in frequency, which is activation band of FCR. As defined by system operator, the compulsory reserve band is ±1.5% of efficient power in mainland and ±10% in Sardegna.
- *Interruptible load:* System operator uses this type of frequency control service when the resources supplied on the MSD are insufficient to maintain the operational security of the system. This service agreement should be directly among TSO and final customers to take the responsibilities of load disconnection consequences. Participants which are required to provide this reserve are required to guarantee the disconnection in real time, within 200ms following receive of dispatching signal, or within 5 seconds in case of emergency conditions.
- *Reactive Power Regulation Services:* In Italy, services regarding Voltage-Reactive power controls are provided by eligible power plants and group of generators equipped with Autonomous System for Regulating Reactive Power and Voltage and telecommunication infrastructures to exchanging all

[14] In Italy, NP-RES units with nominal power more than 10 MVA are obliged to provide FCR.

required information with the Regional Voltage Regulator. This kind of service is mandatory for specified participants and is not remunerated as Power-Frequency control services. Basically, Reactive-Voltage control service are characterized as *Primary* and *Secondary* type of regulation.

- *Load Rejection:* The load rejection service for a generator group consists in remaining in a stable operating condition upon disconnection of that generator group from the grid, by powering its own ancillary services. This service is limited to the thermoelectric PUs under its ownership, including generator groups having a power greater than 100 MW, must be available to supply the service, with plants prepared and personnel properly trained.
- *Availability of use of Inter-tripping:* The availability to use the inter-tripping system consists in the availability to be subjected to the control of a device that, according to some specific events and conditions verified onto the network or to some orders sent by the TSO, can disconnect the UP from the grid. To supply the service of availability for inter-tripping, the PUs must be enabled for the balancing service and must be equipped with automatic devices that have the characteristics indicated in technical document indicated by TERNA. If, as a result of the energy market, several production units available for the inter-tripping service are dispatched in the same zone, and the Operator considers just one of these services sufficient, then the inter-tripping device will be made active on the production units that submitted the decreasing offer at the highest price on the MSD. If the offer prices are the same, the device will be made active on the production units that submitted the highest increasing offer on the MSD. If the result of the energy markets shows that there are no production units in service which are available for the inter-tripping service, the Operator may in any case select, if necessary for providing the resources for dispatching, such units on the MSD in order of economic merit of the offers submitted by the UD owning those units.

2.1.4.3 Bidding Structure in Ancillary Services Market

In previous section, the ancillary services which are traded in MSD were investigated. This section aims to present the way that the participants bid their products in MSD Ex-ante and MB.

***Bids in MSD*;** In general in operational planning phase, enabled units willing to participate in MSD Ex-ante must bid as following

- *Secondary Reserve (RS):* Is mandatory one price for upward reserve, and one price for downward reserve in form of (€/MWh), for each relevant period. Bid/offer for quantity is not mandatory in this case and will be automatically adjusted according to technical data of the plant.
- *Tertiary Reserve (GR)*: Is mandatory to bid/offer at least one price and one quantity for both downward and upward regulation. Units can optionally bids up to three pairs of price-quantity for this service. Note that in this case, unlike secondary reserve the quantity bidding is mandatory.
- *System Recovery Services* or *Shutdown Services*: Eligible units may bid one price for *Turn on (AC)* in form of (€), one price (€/MWh) for offering minimum power starting from a power lower than a specified minimum value or shut down *(AS)*, and one price (€) for providing *configuration change service*. The latter service remunerate all the configuration change operations referred to the ancillary service provision that are extra with respect to the number of configuration change operations resulting from the other Spot Markets. Note that the price is mandatory but the quantity will be automatically adjusted according to the technical data.

Bids in MB; The bids in balancing market have similar structure as in MSD. In case of bidding for *tertiary reserve,* units may bid up to four pairs of quantities and prices. Table 2.2 summarizes the structure of bidding in ancillary services market.

Table 2-2: Bidding structure of plants in MSD and MB

	MSD Ex-ante	MB
Secondary Reserve*	$[(P_{RS}^{+}\ Q_{RS}^{+*})\ (P_{RS}^{-}\ Q_{RS}^{-*})]$	$[(P_{RS}^{+}\ Q_{RS}^{+*})\ (P_{RS}^{-}\ Q_{RS}^{-*})]$
Other Services**	$\begin{bmatrix}(P_{GR}^{3+}\ Q_{GR}^{3+})\ (P_{GR}^{2+}\ Q_{GR}^{2+})\ (P_{GR}^{1+}\ Q_{GR}^{1+})\\ (P_{GR}^{1-}\ Q_{GR}^{1-})\ (P_{GR}^{2-}\ Q_{GR}^{2-})\ (P_{GR}^{3-}\ Q_{GR}^{3-})\end{bmatrix}$	$\begin{bmatrix}(P_{GR}^{4+}\ Q_{GR}^{4+})(P_{GR}^{3+}\ Q_{GR}^{3+})\ (P_{GR}^{2+}\ Q_{GR}^{2+})\ (P_{GR}^{1+}\ Q_{GR}^{1+})\\ (P_{GR}^{1-}\ Q_{GR}^{1-})\ (P_{GR}^{2-}\ Q_{GR}^{2-})\ (P_{GR}^{3-}\ Q_{GR}^{3-})(P_{GR}^{4-}\ Q_{GR}^{4-})\end{bmatrix}$
Turn on Service ***	P_{ACC}	P_{ACC}
Min or Shut Down Service	P_{AS}	P_{AS}
Change of Configuration	P_{CA}	P_{CA}

*Bidding of quantity in MSD is not mandatory and is adjusted based on plant's technical data
**Only first step of bid is mandatory in other services
***Turn on bid price is in (€)

Remuneration Mechanism: In Italian system, remuneration of regulations for any kind of services traded in ancillary services market is based on sold and purchased energy and pricing is according to *pay as bid* system.

Bidding Constraints in Ancillary Services Market: In bidding process of plants in ASM, there are constraints defined by TSO which must be respected. In particular, bidding quantities and prices are constrained to positive value. Bidding quantities and prices are constrained to follow the convexity trend. Figure 2.7 illustrates the convexity rule for pricing in MSD. In particular, in convexity constraint, the following items should be respected

- For each kind of services, the price of the bid to sell energy has to be higher or equal of the price used to buy the energy. Example: $(P^{1-}{}_{GR} \leq P_{GR}^{1+})$ or $(P^{-}{}_{RS} \leq P_{RS}^{+})$
- The price for the minimum production has to be lower or equal to the minimum selling price indicated in the other services bid. Example: $(P_{AS} \leq P_{GR}^{+})$
- The price to shut down the unit has to be lower or equal to the minimum buying price indicated in the other services bid. Example: $(P_{AS.SD} \leq P_{GR}^{3-})$
- Shut down price has to be equal to or higher than CAP define by the AEEG.

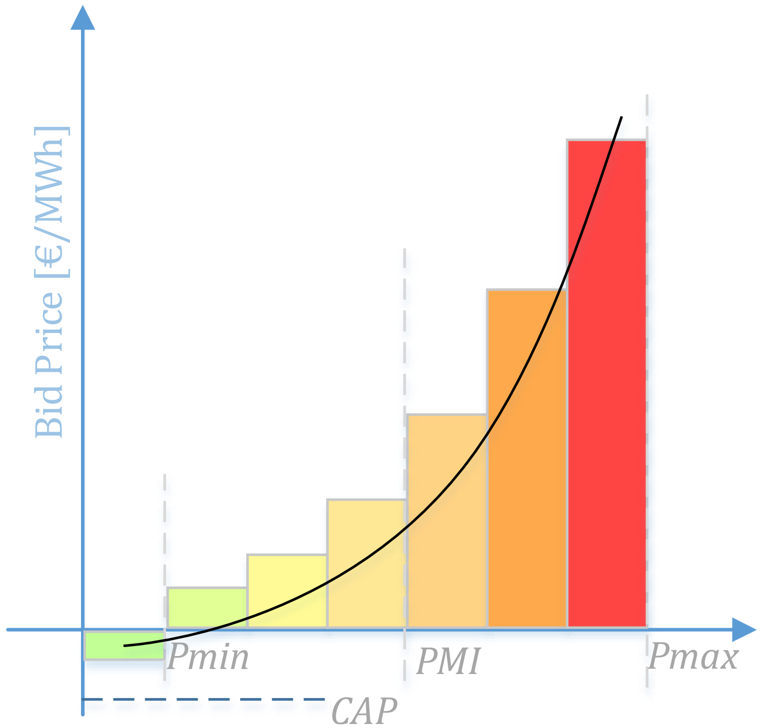

Figure 2-7: Illustration of convexity constraint on bidding prices

If this constrains are not respected at least for one of the price sets, TSO will adjust this price according to convexity rule. This rule is valid also for MB separately. There are existing constraints which participants in MB should respect with reference to bids in programming phase of MSD

- The price of Minimum (shut down) must not be higher (not lower) than the same price accepted in the programming phase.
- Selling (buying) price, separately for secondary reserve and Other Services, must be no more (not less) than the same price at which the offer has been accepted in the programming phase.
- The selling (buying) quantity for other services must be not less than the amount accepted in the programming phase.
- The selling (buying) quantity for other Services must be not less than the sum of the accepted quantity and the reserved quantity.

2.1.4.4 **Selection Procedure of Bids**

As introduced previously, TSO as the single buyer of ancillary services are responsible for buying reserves with the main objective of resolve transmission system congestions and build up secondary and tertiary margins. The selection of reserve bids and offers takes place in a manner to minimize the cost of procurement of services and meet the system security needs. In this regard, TSO minimizes the costs by solving *Unit Commitment Problem* by applying technical and economic constraints for each every quarter hour of the day, with the aim of optimizing generation resources to satisfy load demand at least cost, thereafter, for each relevant period, *Optimal Power Flow Problem* is solved to check the exceeding from constraints and solve congestions [32]. General form of UC by which TSO optimizes the cost can be written as

$$\min \sum_f \sum_h \sum_i \sum_o [(Q_{MSD\uparrow,fhio} \cdot P_{MSD\uparrow pb,fhi}) - (Q_{MSD\downarrow,fhio} \cdot P_{MSD\downarrow pb,fhi}) + C_{ACC,fhio} + C_{OFF,fhio}] \tag{2.3}$$

In which *f, h, i* and *o* represent dispatching unit, power plant belonging to dispatching unit, bus of the network and relevant period respectively. C_{ACC} and C_{OFF} are the bidding price of turn on and shut down. The result of this equation should respect the constraints grouped as balancing, transmission limit and generation constraints. These constraints can be mentioned as

- Hourly energy equality constraint (between generation and withdrawals) has to be respected.
- The selection procedure has to comply with the offered hourly quantities.
- The selection procedure has to comply with the half-band secondary reserve.
- Turn on and shut down bids cannot be partially accepted.
- Ramp rate limits for the generation units must be respected.
- Based on *total transfer capacity* calculated by TERNA for each selection periods, transmission limit between different market zones should be respected in UC problem. Subsequently, current limit on each line in *N* and *N-1* conditions in the OPF model should be respected.
- In particular for *secondary reserve*, each generating unit has to provide a band not higher than the band defined by the Grid Code

At the end of the selection procedure, the quantity of reserve provided by each selected unit is known separately for *secondary* and *tertiary* reserve, named as *reserved quantity.*
All the dispatching units are constrained to respect the program and accomplish all the operations required by the TSO, by considering the prescriptions of the Grid Code. Dispatching units are obliged to notify the TSO, by enough time prior to delivery period, any inability and inaccessibility to provide dispatching services. Plants which are selected but refuse to executing the dispatching orders with no prior notice, are subject to penalties and deprivations according to Grid Code prescriptions.

2.2 Imbalance Settlement

The present short-term power markets are designed for trading the energy in sessions which fix the transactions (Sell & Buy) of forecasted productions and consumptions, by clearing the market in a time span before the physical delivery. In particular in Italian power exchange framework, the time span between market clearing and physical delivery can vary between one to 36 hours [01]. Any deviation referred as imbalances, from the planned production and consumption are penalized due to technical and economical burdens for system operator and other production-consumption units to compensate these un-planned deviations. Among different types of producers, units powered by non-programmable renewable sources (mainly wind, solar and hydro-river) are more prone to imbalance penalties because of their high intermittent nature.

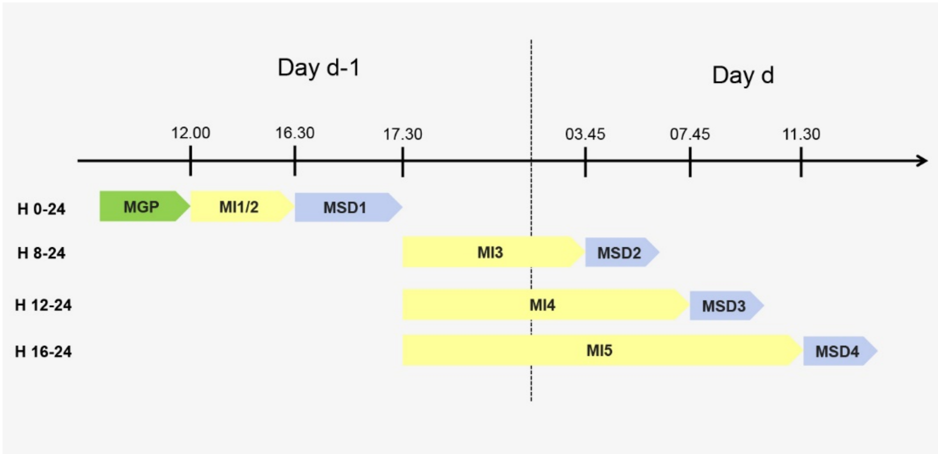

Figure 2-8: Day ahead market, intraday market, MSD sessions and gate closure times

The coordinated management of injections and withdrawals-known as dispatching services are carried out by TERNA (National transmission system operator) to ensure real-time balancing of power system. In particular, RES generating units in Italy can choose to directly trade in IPEX or contract with GSE as dispatching user in order to trade energy in market (or MSD) and receive dispatching orders from TSO. For the NP-RES units having mentioned dispatching contract, the GSE predicts and calculates the plan of production to be traded. Besides, for wind producers interconnected to national grid, corresponding to RID, DM 6/7/2012 and TO (DM 18 December 2008, exclusively for incentivized portion of electricity) financial mechanisms, GSE attributes higher revenues or charges resulting from imbalance fees allocation and participation in MI with the aim of reduction in imbalances [02].

2.2.1 Calculation of Imbalance

According to system-wide or local-wide classification, system operator considers two distinct form of imbalances in order to treat against imbalances.

- *Nodal Imbalance:* refers to the imbalance caused by effective behavior of single generator or set of generators connected to the single point of dispatching. The effective behavior refers to the difference between planned amount of generation based on MGP and MI session, or any modification implied by system operator in order to change the planned output, and the physical production in real time. The actual imbalance for each significant period is calculated as (2.4) [30]:

$$I_n = E_{inj} - E_{prog} \tag{2.5}$$

  For enabled units[15] the significant period equals to each quarter-hour, and is one hour for non-enabled units.

- *Zonal Imbalance:* refers to the algebraic summation of imbalances caused by production units belonging to the single macro zone[16]. Positive zonal imbalance refers to the excess of energy

[15] The term “Enabled Units” refers to the units enabled to participate in MSD

[16] Macro zones considered for calculation of imbalances defined by AEEG, Deliberazione n. 50/05 as: (A) corresponds to Nord and PPL of Turbigo-Roncovalgrande e di Monfalcone, (B) corresponds to Sicily and Calabria including PPL of priolo, (C) corresponds to Sardegna, and (D) corresponds to other zones of continent including othe PPLs not provided in other macro zones. This definitions are subject of changes. From 2015, the macro zones divided by two macro zones “SUD” and “NORD”

and TERNA should call the reserves to decrease their production according to MB↓. Instead, negative zonal imbalance refers to deficit of energy and TERNA should call the reserves in order to increase the production according to MB↑ in corresponding macro zone. In order to calculate imbalances, AEEG published the new resolution [28] proposing new method for calculation the sign and the amount of imbalances for each macro zone as

$$I_{mb,z} = \sum P_{mis} - \sum P_{prog} + \sum C_{prog} - \sum C_{mis} \tag{2.6}$$

The term "*Trans*" refers to the net import/export of the zone through transmission lines. TERNA presents on its portal an alternative way to calculate the imbalance sign based on the summation of accepted bids and offers in MSD and MB for each significant period:

$$I_{mb,z} = -(\sum Q_{MSD} + \sum Q_{MB}) \tag{2.7}$$

2.2.2 Calculation of Imbalance Prices

Under the European regulatory framework, ACER (Agency for the cooperation of energy regulators) presented the general framework of imbalance settlements to be followed by national regulators in [32]. In this regard, the new rules for treat against imbalances was introduced in Italian system starting from January 2013, by introducing the *Single Price Mechanism* to counteract against imbalances generated by NP-RES plants.
Currently, Italian system operator utilizes different mechanisms to financially deal with imbalances. The objective is to stimulate the production units at least to produce the amount as they planned in market, and to compensate the reserve charges which originated from the generation of imbalances. In particular, depending on different generation technologies, and being enabled to participate in MSD, dual price mechanism, single price mechanism and single price with discount mechanism will apply to the plants. Table 2.3 summarizes imbalance classification.

Table 2-3: Classification of imbalance settlement mechanisms in Italian system

	Enabled Generation units	Non-Enabled Generation units	
NP-RES	Dual Pricing	Single pricing	Single pricing with discount
Other than NP-RES	Dual Pricing	Single-Dual mix[17]	
Virtual Units (Aggregators)	Dual Pricing	Dual Pricing	

According to [21], the definition of Dual Pricing and Single pricing are provided as following

Dual Price mechanism: in this mechanism, the imbalance price simultaneously depends on the sign of the aggregate zoning imbalance and the sign of the actual imbalance of each dispatch point. In this context, with the same sign of the aggregate zoning imbalance, the positive and negative imbalances in each dispatch point are valued differently. Table 2.6 represents the pricing formula, for each Zonal-Nodal imbalance combinations

[17] With reference to Resolution 444/2016/R/EEL, Single price mechanism applies for the magnitude of imbalance lower than predefined band. For the magnitude of imbalance higher than this predefined band, Dual price mechanism applies.

Table 2-4: Dual price mechanism calculation for each combination of Zonal-Nodal imbalance

	Positive Nodal	Negative Nodal
Positive Zonal	$\lvert Q_{imb} \rvert \cdot Min(P_{MGP}; P_{MSD\uparrow Min})$	$\lvert Q_{imb} \rvert \cdot P_{MGP}$
Negative Zonal	$\lvert Q_{imb} \rvert \cdot P_{MGP}$	$\lvert Q_{imb} \rvert \cdot Max(P_{MGP}; P_{MSD\uparrow Max})$

Note that the price formula depends on sign of both zonal and nodal imbalance. In case of negative nodal, the unit pays back to the operator, while in case of positive nodal, the unit receives the compensation.
Single Price Mechanism: according to this mechanism, the price of imbalance depends, in each hour, only on the sign of the aggregated zonal imbalance. It is applied to both positive and negative imbalances. Table 2.5 represents the pricing formula, for each Zonal-Nodal imbalance combinations. Note that the price formula depends only on sign of zonal imbalance. In case of negative nodal, the unit pays back to the operator, while in case of positive nodal, the unit receives the amount attributed. The above formulation represents the case of single price with discount. The single price without discount could be obtained by simply considering the value of α equal to zero.

Table 2-5: Single price mechanism calculation for each combination of Zonal-Nodal imbalance

	Positive Nodal	Negative Nodal
Positive Zonal	$Max(\lvert Q_{imb}\rvert - \lvert\alpha \cdot Q_{CE}\rvert; 0) \cdot Min(P_{MGP}; P_{MSD\downarrow M}) + Min(\lvert\alpha \cdot Q_{CE}\rvert; Q_{imb}) \cdot P_{MGP}$	$Max(\lvert Q_{imb}\rvert - \lvert\alpha \cdot Q_{CE}\rvert; 0) \cdot Min(P_{MGP}; P_{MSD\downarrow M}) + Min(\lvert\alpha \cdot Q_{CE}\rvert; Q_{imb}) \cdot P_{MGP}$
Negative Zonal	$Max\left(\lvert Q_{imb\rvert} - \lvert\alpha \cdot Q_{CE}\rvert; 0\right) \cdot Max(P_{MGP}; P_{MSD\uparrow M}) + Min(\alpha \cdot Q_{CE}; Q_{imb}) \cdot P_{MGP}$	$Max\left(\lvert Q_{imb\rvert} - \lvert\alpha \cdot Q_{CE}\rvert; 0\right) \cdot Max(P_{MGP}; P_{MSD\uparrow M}) + Min(\alpha \cdot Q_{CE}; Q_{imb}) \cdot P_{MGP}$

By simply comparing two systems, in single pricing system, generation unit will be penalized when it deteriorates the system by generating the imbalance with the same sign of the zonal imbalance, while it gets profit when it helps the system by generating the imbalance with the opposite sign of zonal imbalance. In Dual pricing mechanism, there is no profit opportunity even in case of helping the system by imbalance, but the unit will be penalized by deteriorating the system. Graphical illustration of nodal imbalances are presented in Figure 2.9. The hatched area represents the portion of imbalance prone to discount, in case of using *single price discounted* mechanism.

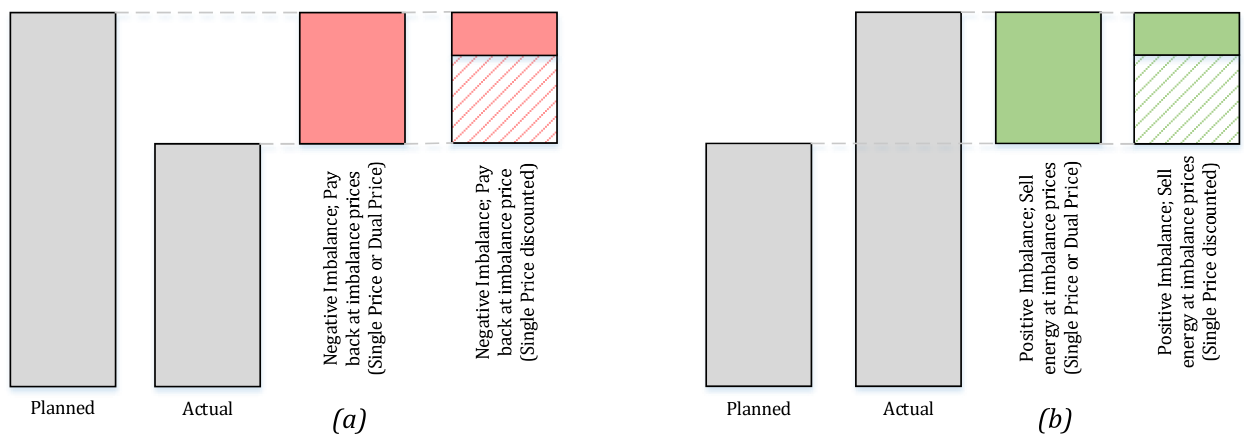

Figure 2-9: (a) Negative nodal imbalance and (b) positive nodal imbalance [31]

GSE transfers these contributions under different mechanisms to production units by applying aggregations among individual units in order to exploit maximum physical and economical compensation [27]. Table 2.6 shows the mechanisms for attribution and aggregation of NP-RES sub-divided by power output.

Table 2-6: GSE mechanisms of attribution and aggregation of UPNP

	Aggregation method	Attribution mechanism	
		Share of residual imbalance	Participation in MI
UPNP (≥ 10 MW)	Per Resource	Stabilization + Equalization	Equalization
UPNP (< 10 MW)	Per zone	Equalization + Pro quota misure	Equalization + Pro quota misure

The equalization mechanism aims to reduce the gap between the minimum and maximum value of the unbalanced residual quotas relative to the individual production units, meanwhile, the stabilization mechanism allows to parameterize the residual quota relative to each single unit of generation by taking into account of a predictability index represented by absolute imbalance of individual generation unit with respect to the total physical imbalance of all the production powered by the same primary source. More detail of this subject and the approach for the calculation can be investigated more in detail in [].

2.2.3 Overview of imbalances: real case in Italy

Zonal Imbalance: as introduced at the beginning of this section, Italian system operator, for each macro zone, and each significant period, calculates the zonal imbalance sign. According to (2.7) and definition of macro zones[2]. Using data available by TERNA [26], figure 2.10 represents the frequency ratio of positive and negative signs in particular for the *SUD* macro zone, for each month of the reference year. Once again, the significant period for enabled units is considered fifteen minutes, means that system operator assigns positive or negative sign for each quarter of an hour of the year. The graph shows highest frequency of positive imbalance in December and January, mainly because of high penetration of wind generation, and lowest frequency of positive imbalance in August and September.

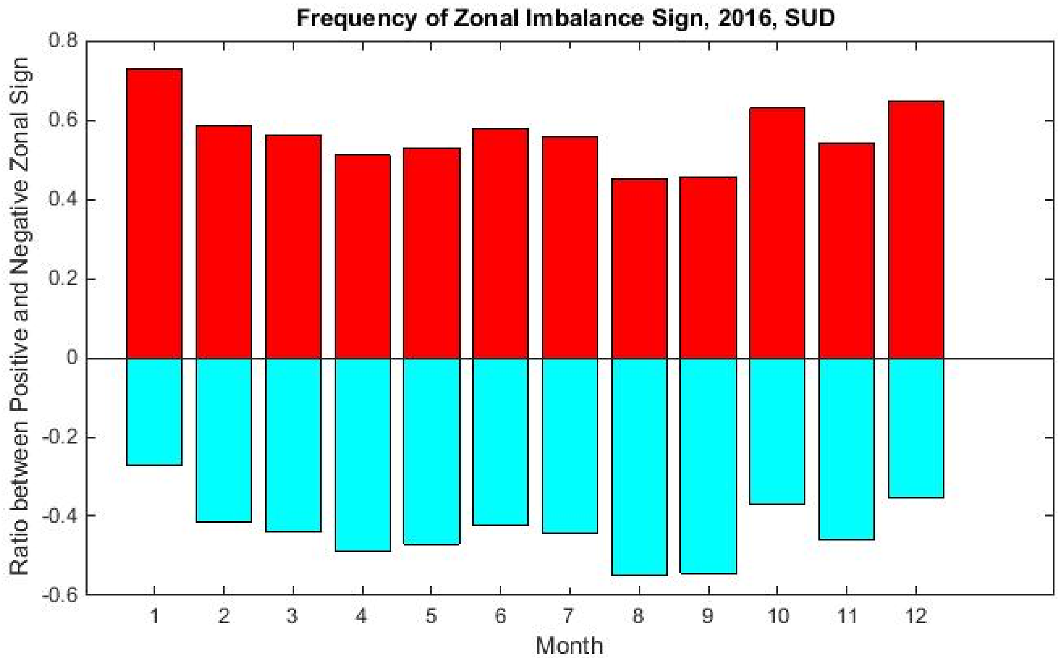

Figure 2-10: Ratio of positive and negative zonal sign in a year

Nodal Imbalance: Unlike the zonal imbalances which should be calculated based on system-wide parameters, the nodal imbalance generated by individual dispatching units highly depends on the production forecast, and unavailability to produce in real time or any retard and advance, in timing

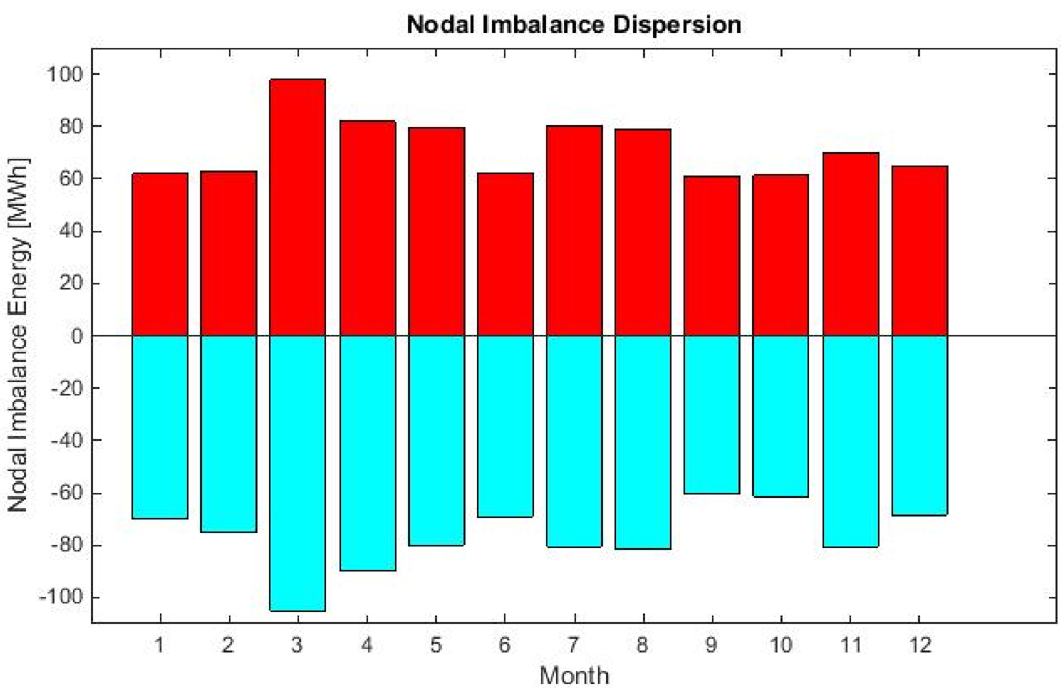

Figure 2-11: Ratio of nodal imbalance energy for a Wind plant

of energy production. In particular for wind generators, production forecast is carried out using Bayesian approach described in [33]. Figure 2.11 represents total nodal imbalance for a wind plant located in Sicily. According to this figure, for the wind plant, the net amount of imbalance for each month is negative. It is originated from the fact that, the wind velocity has Weibull distribution, and has a most probable value lower that the mean value. Therefore using Bayesian forecast method, wind forecasting has negative bias and is usually over estimated.

2.3 Priority of Dispatch and Energy Curtailments

2.3.1 Overview

Priority of dispatch has very important role in developing wind power generation, facilitating integration into the power system and protect this type of generation, in some extent, against market risks and investment uncertainties. In Europe, priority dispatch for renewable energy was introduced as a regulatory provision at EU level with the first RES-e Directive in 2001 and was further refined in Article 16(2) c of the 2009 RES Directive [34]. In particular, some development benefits of priority dispatch can be mentioned as [35]

- Maximizing the exploitation of wind energy and facilitating achievement of national and EU RES targets;
- Optimal development of the grid infrastructures necessary to integrate wind into power system;
- Incentivizing system operators in order to find technological solutions which help to reduce curtailments of renewable energy;
- Laying down a compensation schemes to reduce market risks for new market entrants, by providing transparent regulations on how the curtailment is treated among various technologies;

It is observed that this type of support mechanism impacts negatively both on operation of the power system and market functioning. Priority dispatch for wind creates additional challenges for system operators to manage grid security and stability that otherwise could be solved by direct curtailment of NP-RES generators, by first exhausting all other possible solutions. Moreover, priority dispatch impacts market functioning by making wind generators non-reactive to price signals from the market, thus undermining overall market efficiency. In particular, when electricity prices are above the marginal costs of wind energy generation, it is observed that priority dispatch privileges wind supply over conventional generation and causes the conventional generators to be pushed out of the market by wind generators.
Aforementioned operational threats and market distortions are often reduced by curtailing of power. Table 2.7 presents the summary of situations in which wind power is curtailed[18].

[18] Source: Jacobsen & Schröder, 2012

Table 2-7: Curtailment Reasons

Reason of Curtailment	Rationale
Network Constraints	Avoid over investment in transmission and distribution capacity, extension delays
Security	Reduce reserve capacity costs/dynamic reserve dependent on variable generation
Excess of Generation Relative to load levels	Highest marginal costs generators should be curtailed if market fails
Strategic Bidding	Profit from exercise of market power

In order to remove priority dispatch, it seems necessary to have liquid intra-day market with gate closure near real time, allowing to participate wind generators into balancing market, with separated up/down regulations, exposing all market parties to a transparent curtailment rules and congestion managements and have no priority dispatch for any other technology.
In systems with priority dispatch mechanism, wind energy curtailments is an economic issues which introduces challenge due to loss of free sources of renewable energy. From the generator's point of view, the effect of curtailment is independent from the underlying causes and represents forgone revenue. For generators, clear compensation mechanisms have to be defined in order to protect wind generators from discrimination and loss of investor's confidence. These compensation mechanisms should separate revenue streams to those taken into consideration in the calculation of support mechanisms based on energy output.
In order to mitigate the curtailments, several solutions are in place to increase the flexibility of the existing and new resources of the system, which can be mentioned as [35]:

- Improve short-term markets such as intraday and balancing, allowing access wind generators to balancing market, reducing gate closure time and enhancing participation to increase liquidity
- Integrating the storage systems to wind generation units
- Developing demand side response services
- Increasing the flexibility of conventional units to reduce the minimum must-run generations
- Aggregation of distributed generation and demand response
- Sector coupling through power to gas technologies and electrification of the transport and heating sectors
- Use of dynamic line rating technology to increase transmission capacity
- Close cooperation between DSOs and wind power producers to enhance flexibility by using wind farm capabilities

Among these, the first one is our case of interest and in this work, we are addressing to find the opportunities of wind generators in ancillary services market.

2.3.2 Wind Curtailment in Italy[19]

In order to ensure the security of national transmission network, in accordance with the priority of dispatch from renewable sources, TERNA has right to take any action in order to limit the injections

[19] Mancata di Produzione Eolica (MPE)

by sending dispatching orders close to or in real time to the units which are programmed to produce energy [26]. It is due to the fact that, the majority of wind farms which are located in southern area and connected to 150 kV network and far from demand locations, which is higher in northern area. In this regard, the congestion at transmission level occurs between South and North zone of country and due to limited capacity of transmission between zones, TSO curtails wind power generation in case of unbalances between generation and consumption.
The modality for remuneration of curtailed power due to the TERNA dispatching orders is presented in [36]. In this regard, dispatching users or in case of dedicated withdrawals, holders of one or more generation units may submit to GSE a request for remuneration of curtailed production.
GSE is responsible to calculate the curtailed energy for each units having active convention, based on transmitted data from TERNA, related to:

- General information and dispatching orders related to each production unit;
- Measurements of injected energy into national grid;
- Un-availabilities, provided by manufacturers;
- Forecasted and measured wind data, provided by manufacturers or GSE via satellite platform;

The estimation of curtailed energy is carried out according to the following formula:

$$MPE_{i,h} = \{max[0; E_{Producible,i,h} - \max(E_{inject,i,h}; E_{lim,i,h})]\} \cdot IA \tag{2.8}$$

In this equation, MPE represents the curtailed energy for plant i and period h, $E_{Producible,i,h}$ represents the available energy from primary source, $E_{inject,i,h}$ is the injected energy and $E_{lim,i,h}$ is the maximum allowed energy production based on TERNA dispatching order. IA is a reliability index which is calculated according to the criteria introduce in deliberation 112/10, art 1. The GSE within 12 weeks from the date of completion of the data provided by the operator will initialize the calculation model based on the data provided by the operator. The valorization of this energy is equal to the zonal price for the corresponding period of dispatching order[20]. The value of incentive which lost due to curtailment, is compensated by prolonging the duration of incentive plus 20%. Figure 2.12 represents the evolution of curtailment rates from 2010 to 2016, separated for each trading system. Net annual production of wind generators are provided beside each bar[21], in GWh. In particular in 2016, the curtailed energy calculated is equal to 1.3% of total annual production of wind plants.

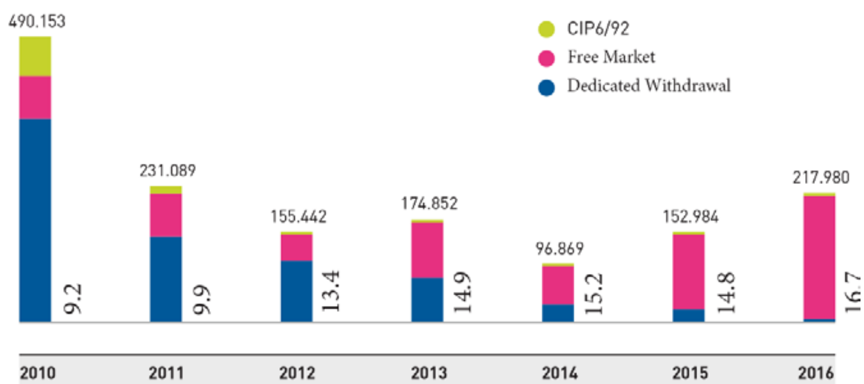

Figure 2-12: Evolution of curtailed wind energy [MWh]

[20]According to article 30, comma 30.4, lettera b, deliberation n. 111/06
[21] http:// www.Istat.it

Reduction of Distributed Generation in Emergency Condition of the National Electric System[22]: In case of emergency conditions originated form distributed generation connected to the medium voltage distribution grid, TERNA is allowed to reduce distributed generation in order to guarantee the security of electricity network [20]. The generation units subject to this regulation must be:

- Connected to the medium-voltage grid
- Fueled by renewable source of energy from Wind and PV-Solar
- With the capacity of at least 100 kW or higher

It should be noted that, since these plants are not part of dispatching services market, TERNA and distribution companies implement this service according to plan of *Uniform Distribution of Reductions* in accordance of national energy system operational and safety requirements.

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Chapter 3

New Actors in Ancillary Services Market

In last decade of energy evolution, European electricity sector is faced to rapid development of renewable energy sources, especially non-programmable ones such as solar and wind power generators. The large portion of NP-RES producers are planned to operate in medium and low voltage level of electricity network, which significantly changes the architecture of power system operation. In new architecture, distribution grids are gradually converting to active grids, allowing power to flow in reverse direction from MV to HV side. In this regard, with the aim of safe and proper management of power system, national regulatory framework is significantly subject to evolution and development of regulations in order to fulfill properly the hosting of these types of generation in national electricity network.
In general, ancillary services in power system have been provided and guaranteed by large synchronous conventional generators[23] normally connected to the transmission system. NP-RES generators were treated as negative loads which increase the active power reserve demand and system imbalance. By considering the increasing role of renewable and distributed generators, the regulations regarding ancillary services need to be adapted and revised in an economic and efficient way [01] [02]. In addition, TSO and DSO are needed to cooperate in a new manner, in order to facilitate the provision of ancillary services from new actors located on their networks. Following sections investigate issues regarding recently initiated reforms in Italian regulatory frameworks associated to ancillary services provision.

3.1 Reform of Ancillary Services Provision

Until recently, in Italian power system, the role of service provision has been carried out only by specified large units, with capacity equal or greater than 10 MVA, connected to transmission level of network and fueled by thermo-electric source of power, so called *relevant units*. These units are equipped with necessary devices in order to ensure their integration into the control system of TSO [12] and *enabling* them to receive dispatching orders.

[23] Relevant Units

The Italian energy authority[24] in 2015[25], has initiated the process of organized reform of the regulation of ancillary services in line with the measures undertaken regarding strategic framework of 2015 to 2018, and in line with European legislations[26] which are currently in the process of completion [08]. The guidelines for the first phase of dispatching reform (RDE[27]-1) is provided in 2016[28]. A pilot project has been initiated from 2017 with duration of two years, with the aim of allowing the units of consumption and production of any size and technology such as DG and NP-RES generation units to access to the ancillary services market through their dispatching users and necessary aggregations. In other words, with the first phase of the reform, the authority confirms its willingness to promote the ASM, firstly enlargement of the number of participants by removing quickly any unjustified discrimination between potential ancillary services providers and secondly, by taking into account of other national markets towards a harmonized European market. Authority advised that completion of market design requires an implementation time necessarily longer than two years which is foreseen for RDE-1.

3.1.1 Definitions

It is necessary to define the following terms which are considered as main parties in reformed market framework:

- *Enabled Units:* Refers to the allowed units to participate in ASM and equipped with the special instruments which allow to receive dispatching orders from TERNA
- *Relevant Units:* Refers to large production units equal or larger than 10 MVA connected to TN.
- *Enabled Virtual Units (UVA[29]):* Refers to the aggregated form of production and/or consumption units and are divided into:
    - Enabled Production Virtual Units (UVAP), characterized by the only non-relevant production units, whether programmable or non-programmable, including storage.
    - Enabled Consumption Virtual Units (UVAC), characterized by presence of only consumption units, as of now only non-relevant units.
    - Enabled Mixed Virtual Units (UVAM), characterized by presence of non-relevant consumption and production units (programmable, non-programmable) and storage.
    - Enabled Nodal Virtual Units (UVAN), characterized by presence of relevant production units subject to voluntary enabling and/or non-relevant, (whether programmable and non-programmable) as well as consumption units belonging to the same node of national transmission system.
- *Balancing Service Providers (BSP[30]):* Refers to the market participants which in form of aggregation provide balancing services to TSO, and is the only counterpart of TERNA.
- *Balancing Responsible Party:* Refers to the person/party responsible for paying actual imbalance fees.

[24] AEEG
[25] Deliberation 393/2015/R/eel
[26] "European Regulations on Electricity Balancing in Power System Operation" and "CACM Regulations" in activation phase.
[27] Riforma Dispacciamento Elettrico
[28] Documento per la consulazione 298/2016/R/eel
[29] In Italian "Unita Virtuale Abilitata"
[30] In Italian "Unita di Dispacciamento"

- *Single Buyer (AU[31]):* Refers to the party entrusted by law, which guarantees the purchase of energy at the most favorable conditions from producer which is not yet opted to participate free market, and sells to consumers or retailers or in free market.

In particular, in Italian market framework, GSE[32] acts as single buyer of energy with the conditions described in section 1.2. In cases in which the GSE acts as dispatching user to provide ancillary services to TSO, the document suggests more in depth study. In particular, for the case of *feed in tariff* incentive mechanism and *on-spot trading*[33] system, any action of GSE in MSD will have effects on incentives provided to producers as well as on accounts for new plants powered by RES and others attributed to the other forms of incentives. It could be allowed for the units with the access to *dedicated withdrawal*[34] mechanism to participate in ASM through GSE, since within this mechanism, there is no direct dedication of incentives to producers, or there is no any compensation for the account for new plants powered by renewable and assimilated sources. Another issue regarding participating through GSE in ASM is that the GSE has a significant share of producers, and may disturb immature market. Therefore, authority, during the first phase of reform excludes the participation of GSE in ASM, as well as excludes the units having contract to GSE or single buyer are exclude in ASM.

3.1.2 Authority's Guidelines

In order to timely opening of ASM to all technologies and resources of ancillary services, by means of amendments prepared by TERNA, the authority provides the general rules and guidelines by consultation document 298/2016/R/eel. The most important points of guideline are investigated as following. Once again we mention that the authority by opening the ASM to new actors intends to ensure the competition without discrimination between participants through the application of the same technical and economic conditions.

3.1.2.1 Enabling Process of Units to Participate in ASM

According to definition of dispatching resources which already investigated in section 2.1, for each resource the grid code provides the requirements to allow the production or consumption units to be enabled to supply their services into the market. If the unit requests to be enabled and possesses the condition of being enabled, it is obligatory to take part in ASM and receive dispatching orders from TERNA. This condition is important to be considered by NP-RES units, since by being enabled, the imbalance settlement rules transfer from *Single Pricing* to *Dual Pricing* mechanism.

Even during the first phase of reform, known as RDE-1, authority defined the steps to overcome the participation barriers. In the first place, the authority will require TERNA to eliminate the constraints regarding enabling of relevant production units powered by NP-RES. In second place, the authority will request from TERNA to grant the qualification of participation in ASM to set of non-relevant[35] production units including NP-RES or consumption units which comply with the appropriate geographic location criteria. In third place, the authority believes that RDE-1 should be characterized by a dual system of enabling, as voluntary system of participation and mandatory system of participation respectively. The mandatory regime would apply to all relevant units which, on the

[31] In Italian "Acquirente Unico"
[32] Gestore Servizi Energetici
[33] SSP-Scambio Sul Posto
[34] RID-Ritiro Dedicato
[35] Enabled Virtual Units (UVA)

basis of the abovementioned and current requirements, would be eligible for being required to submit bids in MSD. The voluntary scheme would instead attribute to the relevant production units powered by non-programmable renewable sources, non-relevant units (both production and consumption) and other relevant units that do not meet the technical requirements currently required for enabling.
Even for the units with access to the market on voluntary basis including virtual units, it is mandatory to be remotely controlled by dispatching users through physical control points, such as control rooms with the aim of fulfilling the requirements set by TERNA, being able to receive and implement dispatching orders. The modality of this interactions will be investigated in section 3.3.
It should be noted that in the first transitional phase, it is not allowed to enabling unprotected consumption and production units on hourly basis for the purpose of measurement (typically connected at low voltage and with a power output of less than or equal to 55 kW). Moreover, the consumption units having signed contract of interruptible loads or the contract for the super-interruptible services are not allowed to participate in this phase of market opening, since these types of services are traded outside ASM frame.
Regarding the first phase of reform, TERNA defines the new technical requirements that major production units and virtual units must be fulfill in order to be enabled in ASM. Such requirements, may differ depending on compulsory or voluntary regime of access to ASM. In particular:

- *ASM must allow the provision of only one of the services introduces as ancillary services presented in section 2.1, in accordance to the grid code.*
- *New users of dispatching should be allowed to provide the regulation only in one direction, up or down, which is called asymmetric services.*
- *TERNA may define a limit of capacity power of units, individual or aggregated, below which it is not possible to proceed to be enabled in ASM. This limit should be sufficiently low, in order not to restrict the participation of the large share of producers and aggregators in ASM. In the other hand, it should be high enough to ensure that the participation of the virtual units in ASM has a significant and measurable impact on the system. In particular, this limit is considered 5MW for virtual units as foreseen in documents [13]. The precise definition is however postponed to the Network Codes settled by TERNA.*
- *A procedure may run in order to pre-qualification of new users, which based on remote test and possibly on-site test of units should be provided to allow TERNA to verify the effective delivery of the requested service from the authorized unit.*

3.1.2.2 Aggregation Rules

The aggregation rules, refers to the definition of the modality by which the small size distributed single utilities can aggregate with the aim of constitution of one virtual unit with greater overall size able to provide useful share of dispatching resources. This mode of utilization of resources is considered as a key issues necessary to be addressed in development of the effective participation of the units in ancillary services market. It is possible to list the following advantages the aggregator will bring for the system

- *It allows the expansion of the communication channels and of the information exchanged across the network*
- *It allows validating preventively the services provided by the DG units and the loads, and required by the TSO and the DSO at a system and at a local level*
- *It facilitates the measurements and the gathering of all the technical parameters of the different units*

- *It allows the installation of actuators on the units ensuring a high reliability of the services provision*
- *It allows also improving the predictability of the different resources as a whole*

In some cases, wider aggregations on geographical basis provides more favorable conditions of participation in ancillary services market. On the other hand, it would be easier for dispatching users to aggregate the units in a unique dispatching point able to respond more reliably to dispatching orders. It should be considered that the aggregation rules which do not effectively consider the real constraints of network may become useless and increase the dispatching costs.
In order to achieve a satisfactory balance between these conflicting requirements it is believed that for the transitional phase, in continuity with the provisions of current regulation, the definition of the aggregation rules should continue to be carried out by TERNA at the level of the Network Code, based on criteria defined by the Authority. As of today, the following aggregation criteria for the RDE-1 transitional phase are identified:

- *The relevant production units cannot be aggregated and must participate in ASM individually. In such case, the dispatching point coincides to the injection point in which the single production unit is connected to.*
- *Non-relevant production units that requested for enabling can be aggregated with variety types of production including both programmable and non-programmable. In this sense, the perimeter of geographic aggregation cannot exceed the market area, but it does not have to necessarily coincide to it.*
- *The consumption units which requested to be enabled in ASM can be aggregated with any dispatching user, with the geographical criteria mentioned above.*
- *The consumption units without submission of enabling in ASM will continue to be aggregated on zonal basis for dispatching user.*
- *Although aggregation between production and consumption units is necessary to evolution of ancillary services provision, in RDE-1, this aggregation is not allowed in order to limit the complexity of managing of these units.*

According to the scheme described, a dispatching user (BSP), for each market zone, would be able to manage

- *One or more relevant production units, such as NP-RES units, some of which enabled to provide dispatching services.*
- *One or more enabled virtual production unit (UVA), which are the aggregation of non-relevant production units, containing programmable or non-programmable production units.*
- *One or more virtual production units which are the aggregation of non-relevant production units, containing programmable or non-programmable production units, but not enabled to participate in ASM.*

Participation in the energy and MSD markets should take place in relation to each aggregation. In particular, dispatching points of energy and MSD markets is required to necessarily be the same as foreseen by current regulations.

3.1.2.3 Revision of Selection Criteria

The criteria for selection of bids has been investigated in section 2.1. In this regard, TSO uses an objective function in order to minimize the cost of services according to merit order criteria. The introduction of new dispatching points requires a review of the priority criteria to be adopted in the presence of supply bids and offers with the same price. As an example, for some significant periods, there are many bids for regulation down services at zero price, which should be selected because of system needs. In this new revision, the plants presenting bids with the same price are selected according to

a) Offers from units essential for security of the power system, during the declared hours
b) Offers from NP-RES units other than those provided in point '*f*'.
c) Offers from programmable RES units other than those provided in point '*f*'.
d) Offers from high efficient cogeneration units.
e) Offers from CIP 6/92 production units and the production units with All-inclusive fixed tariff;
f) Offers from non-relevant plants powered by non-programmable renewable sources empowered to participate in MSD even if aggregated with different types of units.
g) Offers from the plants powered exclusively by indigenous primary energy fuel sources, to a maximum annual fee of no more than fifteen percent of the overall primary energy necessary to supply the consumption needs.
h) Other offers

3.1.2.4 Revision of Bidding Structure in ASM

In section 2.1, the general structure and the modality of bidding in ASM has been investigated. The introduction of new reform of ancillary services requires to take into account further considerations and revisions also for bidding structures. The new revisions for the first phase of reform are considered as following

a) For virtual units (UVA), *Switching On (AC)*, *Minimum Operation or Shutting down (AS)* services are not considered as services to be traded in ASM, since these units are mainly powered by free sources of energy.
b) The *Startup* offer will remain preserved for the relevant thermoelectric units enabled in MSD.
c) The offers for *change of operating conditions (CA)* remains preserved for the enabled relevant thermoelectric units, including combined cycles
d) Virtual units are allowed to offer in *asymmetric* mode, in other words, offering only for regulation up or regulation down services is allowed.

It is required for virtual units to be able to fulfill the order within 15 minutes after received from TERNA, with the duration of at least 3 hours.

3.1.3 Pilot Project

By 31 July 2017, TERNA proposed to the Authority a pilot project with the aim of the implementing participation of Distributed Generation units in ASM through the establishment of Virtual Power Production Units (UVAP) and published the details and the steps of qualification and legalization as well as the detailed technical procedure of pre-qualification tests for these units to participate at least in provision of one dispatching service. The definition of virtual unit is valid only to participate in ASM, and the participation of the same group of units in energy market is not valid.

3.1.3.1 Technical Statements

Following the qualification requirements presented by TERNA for the virtual units in order to provide dispatching services, the technical statements which must be fulfilled in real time is illustrated in figures 3.1 and 3.2.

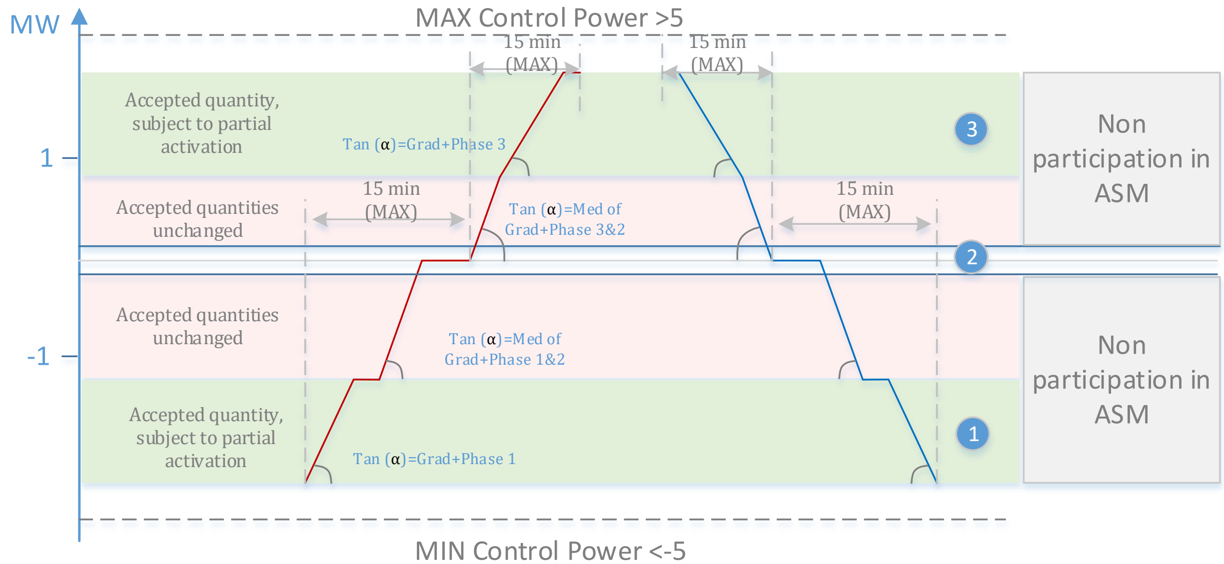

Figure 3-1: Technical prescription of UVA for provision of Up & Down regulations

In case the unit is enabled for both up and down regulation, the virtual unit will be divided to three phase of operation shown by three different color in figure. The grey one refers to the no participation, and justifies shows the fact that the participation in ASM is voluntary for UVA. The total expected production of the production facilities underlying the UVAP constitutes a profile so-called *Baseline.* This *Baseline* for production should be declared before each MSD Ex-ante session, by virtual unit for each quarter-hour of the delivery day. In case of lack of presentation of this *Baseline* even for one quarter-hour of the day, the *UVA* is not allowed to participate in ASM. For *Up* services, each *UVAP* must be able to increase its power at least 5 MW within 15 minutes from receiving TERNA's request and keep this level of generation for a period of at least three consecutive hours.
As previously mentioned, virtual units are allowed to provide the service in one direction only. If the *UVAP* has been modulated in one direction in the programming phase, TERNA may still re-modulate the *UVAP* in the opposite direction in the real-time management phase until the total modulation is canceled at the programming stage. Figure 3.2 illustrates this statement.

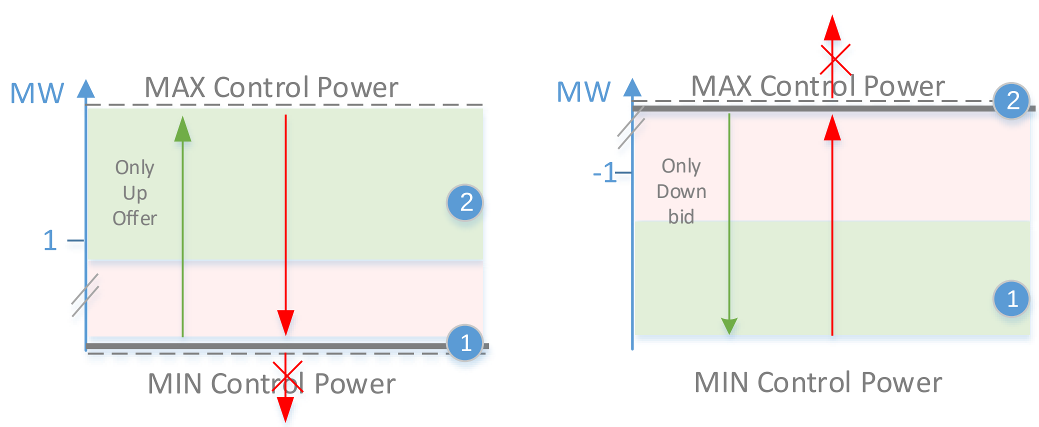

Figure 3-2: Technical prescription of UVA for provision asymmetric regulations

In this phase of reform, virtual units are allowed to provide different services depending on the ratio of the non-programmable power which the virtual unit is able to modulate. In particular, for the aggregator with modulable power from programmable sources lower than 80%, some services are not allowed. Table 3.1 represents the allowed participation based on share of non-programmable modulable share in aggregation.

Table 3-1: Allowed service for the virtual units with higher and lower 80% share of programmable

Dispatching resources	Share of programmable < 80%		Share of programmable ≥ 80%	
	Up	Down	Up	Down
Secondary Reserve	*No*	*No*	*No*	*No*
Tertiary Reserve	*No*	*Yes*	*Yes*	*Yes*
Congestion Management	*No*	*Yes*	*Yes*	*Yes*
Balancing Services	*Yes*	*Yes*	*Yes*	*Yes*

3.1.3.2 Economic Evaluation and Service Remunerations

As described in section 2.1, the remuneration of services are based on *pay as bid* system. For each quarter hour in which the unit fails to provide services following dispatching order, the virtual unit would be penalized. Separately for *up* and *down* services, this penalty is calculated based on following

$$MP_{sell} = \max\left[150\% \cdot \left(\frac{C}{Q_{MSD}}\right); P_{MGP}\right] \cdot [Q_{MSD}(i) + E_0(i) + E_{ne,mis}(i)] \quad (3.1)$$

$$MP_{buy} = \max\left[150\% \cdot \left(\frac{C}{Q_{MSD}}\right); P_{MGP}\right] \cdot [E_{ne,mis}(i) - (Q_{MSD}(i) + E_0(i))] \quad (3.2)$$

- Q_{MSD} represents the net quantity sold of accepted quantity.
- $E_{ne,mis}$ represents the injected energy in injection point corresponding to *UVAP*
- E_0 represents the programmed quantity of energy in injection point corresponding to *UVAP*
- *C* represents the overall valorization associated to accepting the offers
- P_{MGP} represents the zonal price in day ahead market
- i refers to i^{th} quarter hour

The holder is required to pay a penalty for failure to comply with the baseline

3.2 New Market Models

In conventional operation of power system, the frequency control services are provided mainly by large thermal power plants connected to transmission level. TERNA as the single operator of transmission network is responsible to procure the reserve to keep the frequency of the system always in normal operational range by sending dispatching orders to the specified large units connected to TN. Distribution companies always benefitted from these activities and will remain stable as long as the transmission system remains stable. On the other hand, distributed generation units are mainly connected to medium and low voltage level of power system, and are controlled by regional or local distribution system operators. Despite the change in architecture of power system resulting from increasing distributed generation units, TSO still remains the single part responsible to control the frequency of power system through management of reserves as system wide ancillary services. Considering this fact and at the same time taking into account the new reform in ancillary services provision by generation units connected to distribution level, it becomes necessary to define new dispatching models for the control of ancillary service providers based on local approach. In this regard, in order to provide ASM access for DG units, three new models presented by [10] defines a new role for DSO in provision of the ancillary services, including the incorporation of advanced information exchange between TSO, DSO and generation units [14].

3.2.1 Extended Central Dispatch

In this model, the market continues to be managed with the actual mechanism, enabling the new dispatching users to provide ancillary services according to the actual framework. In this case the TSO can purchase both during the planning phase and during the real time phase the resources it needs for what concerns the electric system as a whole; the contribution of the DG services for problems at a local level is not possible.
The DG and the RES plants can participate to the ASM thanks to an aggregator, which is a trader that acts as a dispatching user managing an adequate amount of generation capacity and that, on the basis of the data communicated by the generators, presents offers on the ASM.
This solution can be accompanied by two different ways to manage the distribution grid: the fit & forget logic, where the capacity of the distribution grid is increased so much that there is no way that new plants can cause any problem to the network; the smart logic, where the DSO can, when the security of the network is compromised, stop the injection of power and prevent a plant to participate to the ASM. According to the fit & forget approach currently in place, the DG could provide ancillary services directly in the ASM and through an aggregator without any technical problem: the grid will be able to host all the capacity that has been offered in the ASM. According instead to a smart approach, in order to guarantee a proper operation of the grid, the DSO should ensure some local

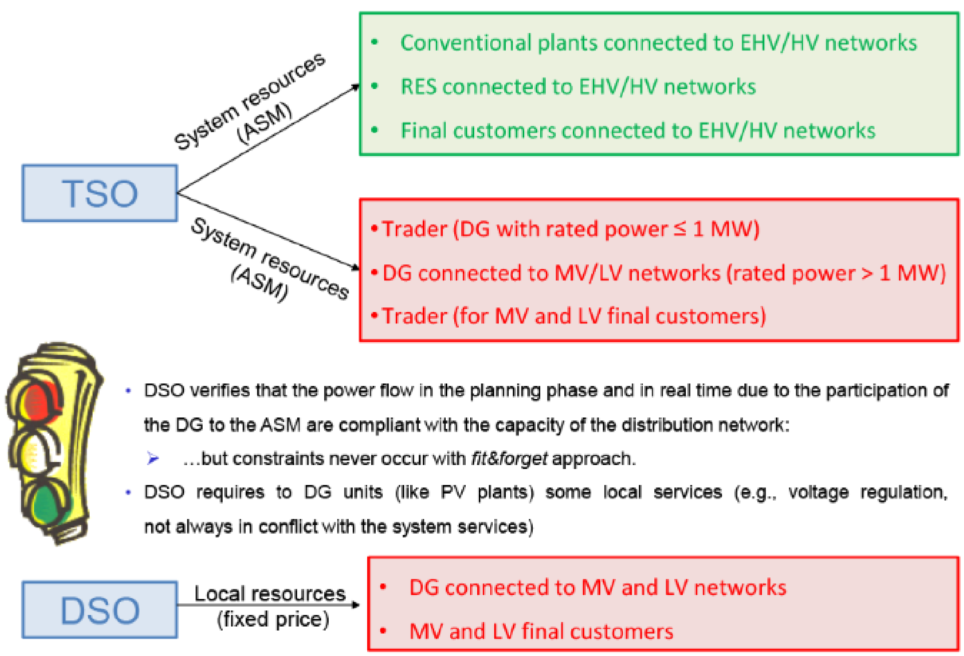

Figure 3-3: Illustration of extended central dispatch model

services that will be needed. As these services are correlated with local problems, characterizing a specific point of the network, only the few units near this point can ensure their provision, whereas the TSO is managing a system equilibrium and thus can purchase services all over the network. In this situation the DSO should verify the security of the grid during the planning phase and in real time, defining the compatibility of the participation of the DG to the ASM. This control by the DSO will be operated at the primary substations level, with the possibility for the DSO to directly use the DG in order to solve local issues. The scheme for this first model is reported in figure 3.3.

3.2.2 Local Dispatch by DSO

In this model both local and system services can be offered on the ASM; moreover this solution can be implemented only with a smart approach towards the development of the distribution grid.
The TSO can purchase the ancillary services directly from the plants connected at the transmission grid or from the DSOs; the DSO becomes hence a dispatching user and can identify and select the proper plants at distribution level in order to provide the required services.
This can occur through a D-ASM (Distribution ASM) where it acts like TERNA in the ASM. The plants can participate to this market as single units or in an aggregated form. The DSO purchases on the D-ASM some resources and makes them available at the primary substations level; the TSO can hence purchase on the ASM the services from a single primary substation (nodal dispatching) or from a set of primary substations (zonal dispatching). It is important to underline that, in this configuration, the DSO can buy on the D-ASM also those services which are needed at a local level, without presenting them to the TSO at the PS level. In this case the DSO could remunerate the local services on the market, but if they concern a specific point of the network (and can be solved only by certain units) it could remunerate these resources through an administrative price.

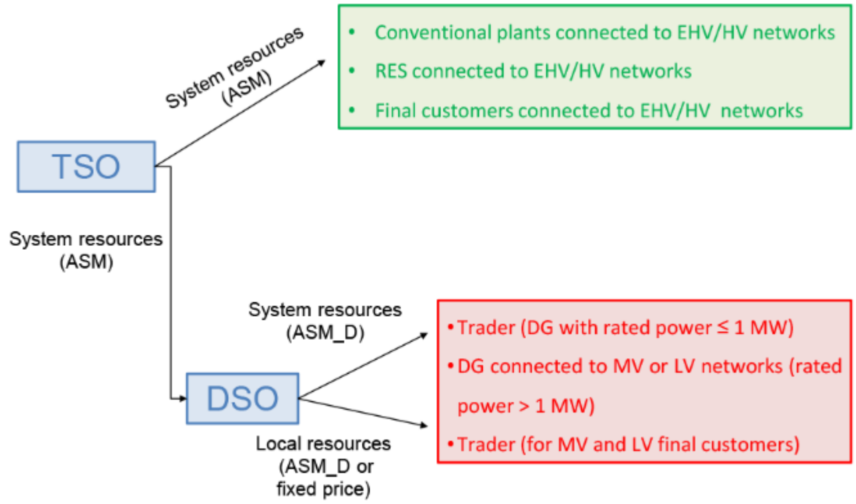

Figure 3-4: Illustration of local dispatch model

3.2.3 Scheduled Program at HV/MV Interface

In this last model the DSO is responsible towards the TSO for maintaining of a programmed profile for the energy exchanged at the PS level, both in the nodal and in the zonal form. The DSO, however, does not provide any service on the ASM which can be useful for the system management.
This kind of configuration leads to a lower impact of the variability introduced by the load and the generation connected at the distribution level, meaning that the amount of reserve and balancing capacity required to the TSO is reduced.
In order to fulfill the requirements at the PS interface, the DSO can select the proper resources on a D-ASM as for Model 2, and the plants can participate to the D-ASM market as single units or in an aggregated form. Figure 3.5 represents the scheme of this last model.

In any case the TSO will be responsible for the units connected to the transmission network. On the other hand the management of the DG units will be linked to the market model chosen. In particular, considering that the presence and the modulation of the DG units could bring to some problems along the distribution network, it is necessary to define some priorities between the activity of the TSO and the DSOs, beyond a communication system allowing the exchange of information in real time. This problem could be solved by the implementation of Model 2 or Model 3: in this models the DSO is responsible for the management of the resources at the distribution network level, hence it could control the network situation and at the same time (in Model 2) provide some dispatching resources to the TSO, but always checking first the security of its grid portion.
The DSO is the stakeholder that will be changed by the market evolution the most. Again, its role will be defined according to the market model chosen, but in any case its figure will be more and more important. On one side, according to Model 1, the DSO could be responsible for the verification, during and after the planning and the real time phase, of the compatibility between the participation of the DG and of the loads to the ASM, and the security of the local grid. This means that for every PS the DSO will check the exact amount of energy that can be provided to the TSO and will reserve a

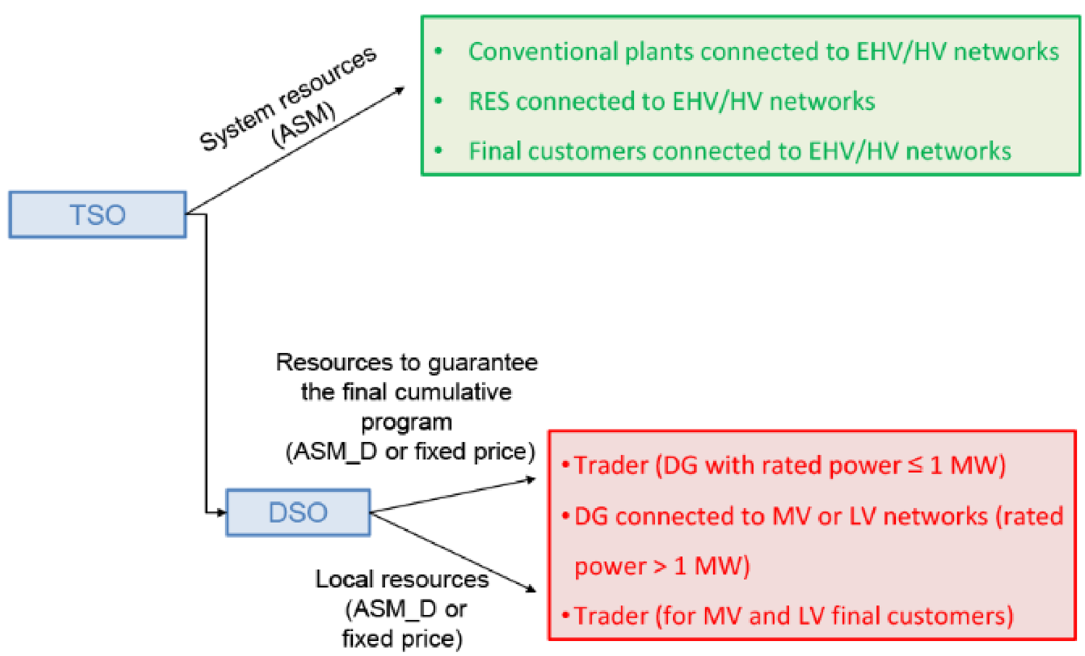

Figure 3-5: Illustration of third dispatch model

margin in order to face some local issues. On the other side, according to Model 2, the DSO keeps together two fundamental roles

- As a dispatching unit, it gathers the right and the obligation towards the TSO to inject or withdrawn into the network the quantity of energy resulting from the binding program modified and corrected.
- As a responsible of the D-ASM it purchases the resources necessary at a local and at a system level, acting as a counterpart for the negotiations at the distribution level. This last role would be covered by the DSO even for Model 3, where it would be responsible for the imbalance between the real and the binding program at the PS interface. In general the DSO could be in the future the figure which the TSO refers to in order to manage the DG units and the loads; this approach would have a great advantage in terms of reliability and security of the services provision, exploiting the already existing communication channels between TSO and DSOs and ensuring the coordination among all the local and system services.

3.3 Information Exchange and Connection Modes

As mentioned in previous section, an increased amount of penetration of non-programmable renewable sources connected to the distribution networks requires an increasingly close coordination between the operator of the transmission network, the managers of the distribution networks and aggregators of production units in order to ensure an adequate exchange of data and information related to management of the network. In this regard, recently with the resolution 646/2015/R/eel, the Authority has introduced premiums for network managers who act to develop innovative functionality called *observability of power flows and the state of resources* associated with the distributed generation units connected to the distribution networks in medium voltage level. This functionality is currently divided into two levels of complexity:

- *OSS-1*: Activities of distribution companies in this level refers to delivering to TERNA the real time measurement data from renewable generation units in continuous mode.
- *OSS-2*: Activities of distribution companies in this level refers to continuously delivering to TERNA, the accurate estimation of power injections by generation units as well as withdrawals of energy on distribution network.

On the other side, in the new context a central role will be taken by the aggregators or *BSPs* which facilitate the management of all the numerous small units connected to the distribution network, by procuring dispatching resources and placing in market and providing measurements and the verification of the services provided. The functionality of the aggregator is strictly linked to the implementation of communication systems between the different units aggregated and the central coordinator, in order to exchange the relevant data and to actuate the orders in real time. Figure 3.6 represents the general scheme of communication links between TSO, DSO, aggregators and DG units. In accordance with the deliberation 300/2017/R/eel, following the implementation of pilot project investigated in section 3.1.3, TERNA has indicated for this phase of reform, the possible modalities by which the *UVAP* can interact with the system, with two main targets of

- Trace and validate the execution of dispatching orders by *UVAP*
- Provide to TERNA in real time the amount of power available to be modulated

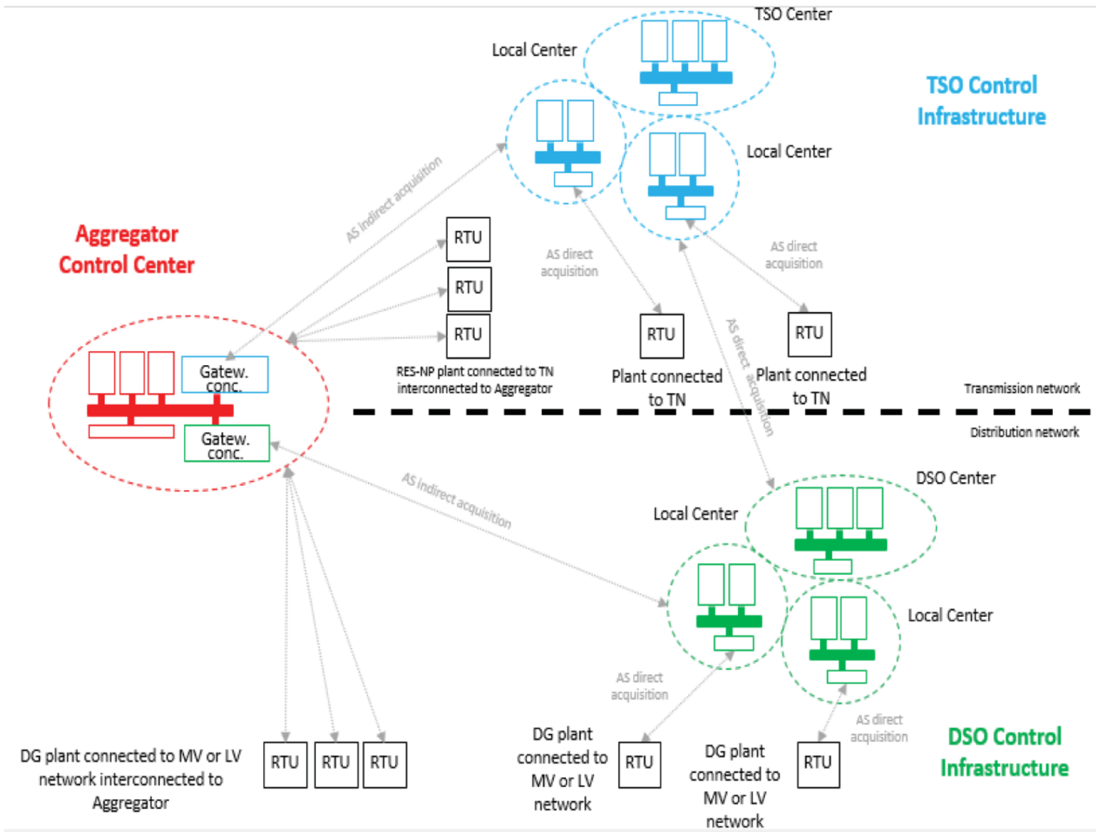

Figure 3-6: Communication architecture in new market reform

3.3.1 Characteristic of Measurements

The detailed technical prescriptions for the measurements is provided in corresponding grid codes[36]. This measurements mainly include the measurement of active power and total exchange between injection point and the power network. Measurement detection must be performed via an *UPMG*[37] or equivalent equipment such as RTU[38].

3.3.2 Connection Modes

In sense of information exchange between TERNA and *UVAP*, two modes of connection is foreseen in this phase of project

- Direct connection among *UPMG* and TERNA
- Indirect connection, through a *Concentrator*

In case in which the *UVAP* has already equipped with a telecommunication channel to TERNA, this channel can be utilized to attest a *UPMG* or a *Concentrator.* In general, four cases of connection exists ***Case (A)***: *UVAP* may directly connect to a site which already has data flow infrastructures to TERNA. In other words, if the *UVAP* is physically located on a site which is already equipped with protection

[36] TERNA Grid Codes Annexes A.41, A.42 and A.43
[37] Generation Monitoring Peripheral Unit
[38] Remote Terminal Unit

and control systems dedicate to TERNA, it is possible to exploit these dedicated infrastructures for the purpose of communication. Figure 3.7 represents the general scheme of this case.

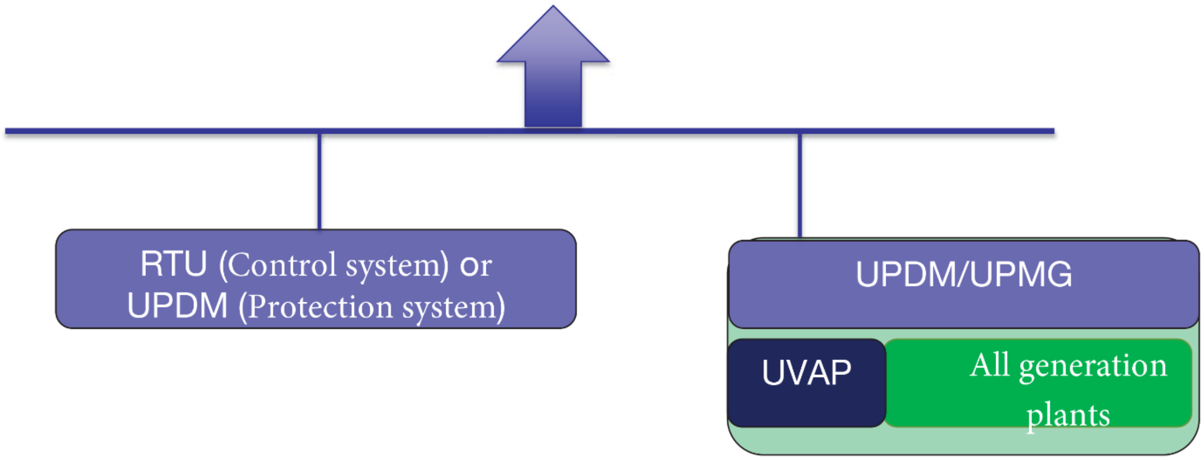

Figure 3-7: General architecture of connection under case A

Case (B): UVAP may directly connect to a site which is not equipped with TERNA communication infrastructures. In this particular case, it is necessary to establish the connection through two communication circuits. The technical prescriptions are foreseen in grid code.

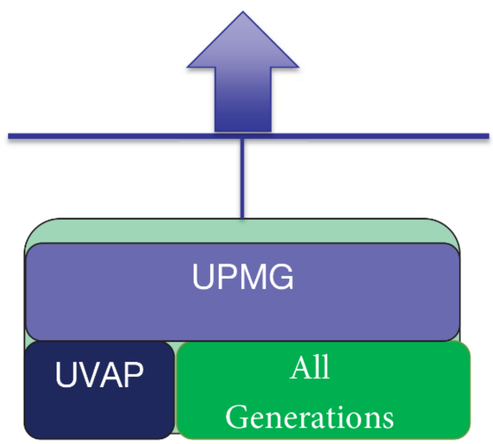

Figure 3-8: General architecture of connection under case B

Case (C): UVAP may indirectly connect through a *concentrator*. In this case, the only allowed connection for a concentrator is through two dedicated TLC circuits as provided. In general, the concentrator provides the following services to establish the data flow among *UVAP* and TERNA

- Collecting the measurements from UPMGs or equivalent units located in different sites
- To store all the measurement data from generation units and *UVAPs*
- Transfer the total data to TERNA

The connection of the devices installed at sites corresponding to the *UVAP* should be carried out by the Aggregator. Figure 3.8 represents the general scheme for this mode of connection.

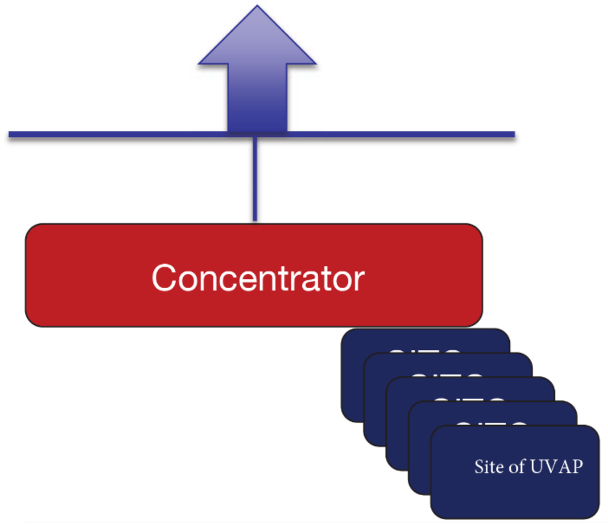

Figure 3-9: General architecture of connection through concentrator under case C

Case (D): In this case, similar to case (C), *UVAP* may connect through a concentrator, by using following communication infrastructures alternative to dedicated TLC circuits

- Exploiting the existing communication infrastructure of protection system
- Exploiting a pair of data lines already in use for data exchange with the TERNA Control System

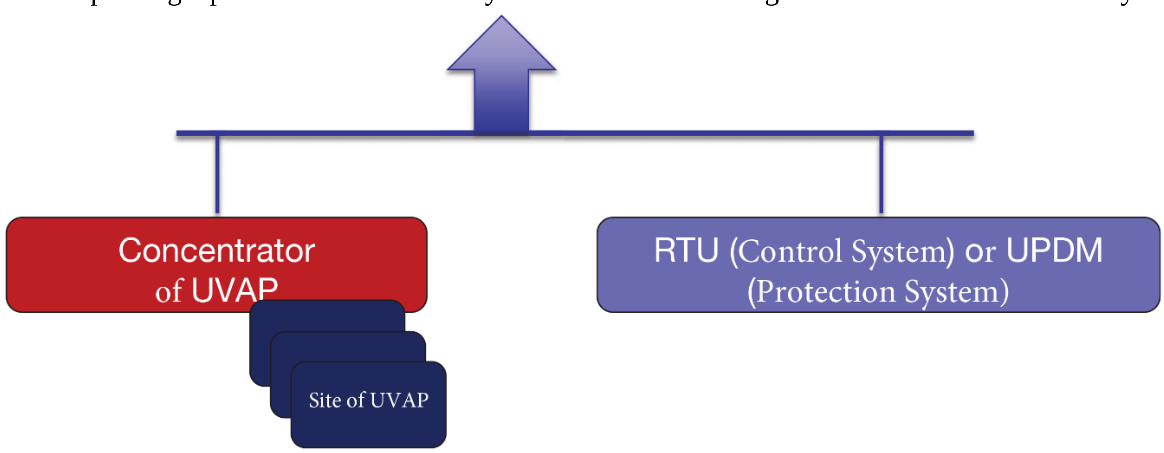

Figure 3-10: General architecture of connection through concentrator under case D

Both of these solutions require to access to a site which is already equipped with TERNA protection and control infrastructures. Among the infrastructures already installed on site to establish the communication with TERNA, the infrastructures dedicated for *RIGEDI* (Introduced in section 2.4) and / or remote interruptions of generation units can be mentioned. Through the *RIGEDI* procedure, TERNA has already installed the remote control infrastructures to be able to modulate or disconnect the DG connected to MV network in case of emergency conditions of network. More detailed technical information regarding *RIGEDI* can be found in [03].

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[4] *Norma CEI 0-16, Allegato M*

[5] *TERNA Grid Codes; Appendices A.58 & A72*

[6] *Documento per la consolazione 298/2016/R/EEL, AEEGSI; 2016*

[7] *Documento per la consolazione 557/2013/R/EEL, AEEGSI; 2013*

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[15] *REGOLAMENTO RECANTE LE MODALITÀ PER LA CREAZIONE, QUALIFICAZIONE E GESTIONE DI UNITÀ VIRTUALI DI PRODUZIONE ABILITATE AL MERCATO DEI SERVIZI DI DISPACCIAMENTO - REGOLAMENTO MSD; TERNA*

Chapter 4

Model Description; Wind Plant's Opportunity in ASM

The reason to provide optimal bidding strategy is to reduce the loss of revenues due to imbalance charges. Wind generation units may choose to sell all of their outputs in energy market. In current regulatory framework, the market operator accepts all the production due to the zero price offering of wind generators. Furthermore, any prevention in production in presence of available energy equals to an opportunity loss in revenue, because of the near zero production cost and financial incentives granted in charge of net energy injection to the grid. However, because of the high variability of wind plants, the units are exposed to significant penalties according to imbalance charge mechanisms. In this chapter, an optimal method of bidding is described with the aim of reducing the exposure to the imbalance penalties.
In particular, as introduced in section 2.2, depending on two mechanisms (Single price with or without discount) attributed to non-Programmable RES units, as well as positive or negative zonal and nodal imbalance, four combinations will occur in terms of imbalances, in which the generating unit loses or gains profit during real time operation. The net value of financial loss in comparison with the case of no penalty charges for each combination is provided in table 4.1 and 4.2, respectively for single price with or without discount mechanism. In order to simplify the equations, it can be assumed that $P_{MSD\uparrow M} \geq P_{MGP}$ and $P_{MSD\downarrow M} \leq P_{MGP}$.

Table 4-1: Net imbalance gains or loss in single price mechanism with no discount

	N+	N-
Z+	BRP loses $\alpha.E_p(P_{MGP} - P_{MSD\downarrow M})$	BRP gains $\alpha.E_p(P_{MSD\uparrow M} - P_{MGP})$
Z-	BRP gains $\alpha.E_p(P_{MSD\uparrow M} - P_{MGP})$	BRP loses $\alpha.Ep(P_{MSD\uparrow M} - P_{MGP})$

Table 4-2: Net imbalance gain or loss in single price mechanism with discount, Q_imb ≥ 49%

	N+	N-
Z+	BRP loses $(\alpha - 0.49)Ep * (P_{MGP} - P_{MSD\downarrow M})$	BRP gains $(\alpha - 0.49)Ep * (P_{MGP} - P_{MSD\downarrow M})$
Z-	BRP gains $(\alpha - 0.49)Ep * (P_{MSD\uparrow M} - P_{MGP})$	BRP loses $(\alpha - 0.49)Ep * (P_{MSD\uparrow M} - P_{MGP})$

Considering the discounted single price system, in particular for wind producers, the imbalance charges split for deviation lower and higher than 49% of planned generation. By this mechanism, for the imbalance lower than 49% of planned production, there is no penalty, in other words, the BSP only sells or rebuy the excess or deficit in its production at DAM price. For the deviation percentage higher than 49%, the application of imbalance charges is as presented in table 4.2.

4.1 Analysis of financial opportunities in ASM

According to the current regulatory framework, wind generators are profited by strong support mechanisms in charge of their net injections. They are easily accepted in energy market because of their zero bidding in DAM. Furthermore, any dispatching orders from TSO in terms of curtailment of production and subsequently loss in opportunity costs are calculated and compensated equal to available energy loss based on real time zonal market price and incentives, or prolonged support period. In this regard, and considering the fact that in Italy there is no mechanism to remunerate the reserve and only the energy sell or buy is subject to remuneration, any prevention of production in order to provide upward margin or curtailing energy for downward service, is equivalent to significant loss in revenue even if they sell such services with high prices compared to the conventional units.
As presented previously, there are different mechanisms which lay down the penalties to confront the deviations from planned production. Wind energy production, according to the nature of primary source, is the most variable among the other NP-RES producers which in some periods imposes heavy penalties and significant reduction in revenues during the plants life cycle. In this regard, and following the new modifications in regulatory framework discussed in chapter 3, in this chapter, a method is introduced to analysis the possible opportunities with the aim of reducing the imbalance effects and convert them to financial profits, by optimally bidding in ancillary services market and balancing market. In following sections, for *Single price mechanism with no discount*, financial opportunities regarding participation in upward reserve and downward reserve provision are discussed considering different combinations of zonal and nodal imbalances in case A to D In this phase of project, and Case E to H corresponding to *Single price with discount* would be the subject of future works. Table 4.3 presents the summary of cases which are investigated in following sections. General formulation is presented by considering the probability of nodal and zonal imbalances. Finally, a probabilistic approach is used to optimally select the bidding values to participate in reserve market.

Table 4-3: Summary of cases based on different imbalance combinations and imbalance mechanisms

Single Price mechanism no discount				Single Price Mechanism with Discount			
Positive zonal imbalance		Negative zonal imbalance		Positive zonal imbalance		Negative zonal imbalance	
Positive nodal imbalance	Negative nodal imbalance	Positive nodal imbalance	Negative nodal imbalance	Positive nodal imbalance	Negative nodal imbalance	Positive nodal imbalance	Negative nodal imbalance
Case C	Case A	Case D	Case B	Case E	Case F	Case G	Case H

4.1.1 Participation in upward regulation

In order to provide upward regulation, generation units must keep-no production-margin in order to be available to provide upward regulation in terms of energy [MWh]. When a generation unit participates in reserve market, its profit includes both profit from energy and reserve market. Depending on the type of reserve, market rules and national energy regulatory frameworks, the unit would be paid for its portion of only energy provided for regulation [EUR/MWh], reserve [EUR/MW], or both in order to make profit by providing such services [05]. These payment mechanisms for system services provision has a great impact on the units to plan their bidding strategy. Several unit commitment problems are presented to optimally select the bidding quantities in both energy and reserve markets, in order to gain maximum profit [01], [02], [03], [04]. Keeping upward reserve margin causes the generation units to lose the opportunity cost in exchange of the energy portion which could be sold in energy market. In particular, for the conventional units and wind plants participating in upward service provision, considering the incremental operating costs, the opportunity loss of upward regulation can be simply calculated by differentiating between possible revenue and operational costs. This subject is described in Figure 4.1.

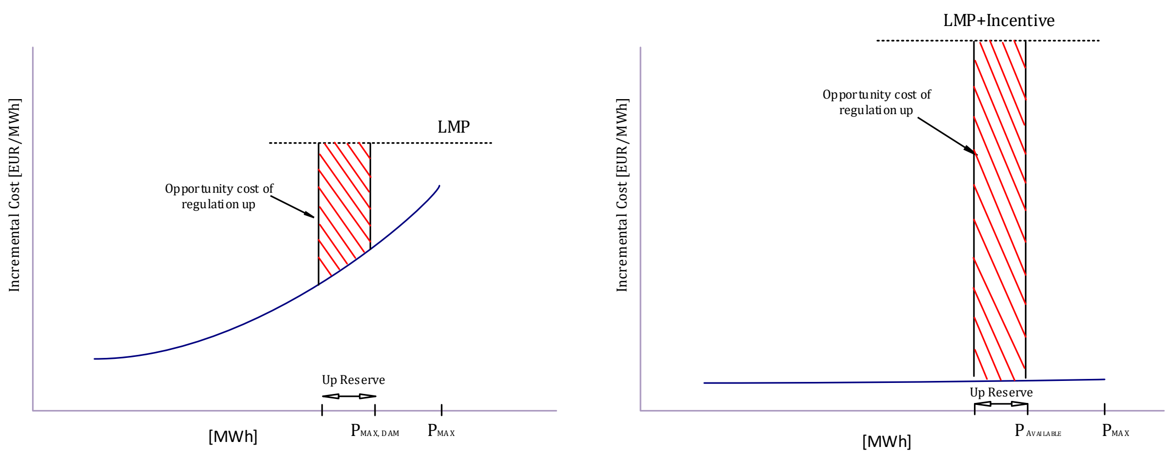


Figure 4-1: Loss in opportunity cost by upward reserve provision, (a) Conventional plants, (b) Wind plants

In particular, for the plants powered by non-programmable renewable sources, the loss in profit is much higher than the conventional units. This is due to the fact that RES plants have operational costs much lower than the conventional units because of free primary source. In addition, in many countries, RES plants are strongly incentivized for their net energy injection.

In order to compensate this loss in benefits, different system operators use different approaches to remunerate the regulation services. In some countries, this kind of reserve is paid in charge of capacity reserved plus the cost of energy, using marginal price mechanism. In some other countries, the remuneration is based on energy produced in order to provide regulation up, and using marginal pricing or pay-as-bid mechanism. Table 4.4 provides a short comparison of reserve remuneration mechanisms for different system operators in Europe.

In former case, producers may choose an optimization plan to strategically bid the quantity in multi-market participation according to the price signals available from the TSO for different time periods. In [02] a method is represented to optimally bid in multi-market, with particular attention on imbalance penalties. In latter case, in which the producer is remunerated in charge of energy [MWh] provided for upward regulation, the profitability of the upward reserve provision is highly correlated to the energy deployment of this non-production margin, by system operator. Since part of ancillary

Table 4-4: Ancillary services treatment in some EU countries

	Remuneration
Spain	FCR not remunerated, FRR remuneration for both energy (marginal price) and capacity (marginal). RR is energy remunerated by marginal price.
Denmark (DK1)	FCR remunerated by fixed price per MW per hour, paid as marginal price. Running the reserve is paid as ordinary imbalance. aFRR is both capacity (contract) and energy (marginal) remunerated.
Austria	FCR remunerated for the reserved capacity. aFRR remunerated for both energy and capacity. mFRR is only energy remunerated. Pay as bid system is adopted for all. mFRR is capacity and energy remunerated by marginal price

service procured may be deployed in real time, and the TSO needs to pay for this part in real time energy price, it is rational for producers to consider the probability and ratio of such anticipated deployment in real time.
Under the current Italian regulatory framework, which is the case of this project, production units get benefit in upward regulation for the deployment probability high enough, and bid prices higher than energy market marginal price, at least to cover the potential profit loss in energy market. In particular for the wind plants, with respect to the potential profit loss much higher than the conventional units, even in the case of considering imbalance charges, they will profit in situation in which the deployment ratio is near 100% and the bidding prices is high. By considering merit-order market clearing mechanisms, bidding at higher prices implies low probability of acceptance and high risk of potential profit losses. With reference to this fact, under the current national system circumstances presented in chapter 2, participation in upward regulation services is not fully expected to provide the profit opportunity for the wind plants and has very high risk of loss in opportunity. In this regard, and in following sections, we will spend all of our focus to find the financial opportunities of wind plants by only participating in downward reserve market, and postpone the analysis of upward reserve provision on future works.

4.1.2 Participation in Downward regulation

Figure 4.2 presents the steps of the analysis. In order to start the analysis, the financial opportunities by downward reserve provision in presence of imbalances are investigated case by case for single price imbalance mechanisms without discount. Note that for the units which are enabled to participate in ASM, TERNA applies dual price mechanism as introduced in section 2.5. Since the aim of the following analysis cases is to make a comparative study about financial opportunities by participation, and without participation in regulation downward services, the imbalance charges considered as imposed by TERNA for both cases, in other words, when the Wind plant is participating in service provision, is considered as enabled unit (4.1a). When the plant is not participating in bidding, it is considered as non-enabled units (4.2a). The analysis of profit opportunity is carried out individually for all combinations of zonal and nodal imbalances, then a super-ordinate formula is represented to integrate all cases in order to be used in model.

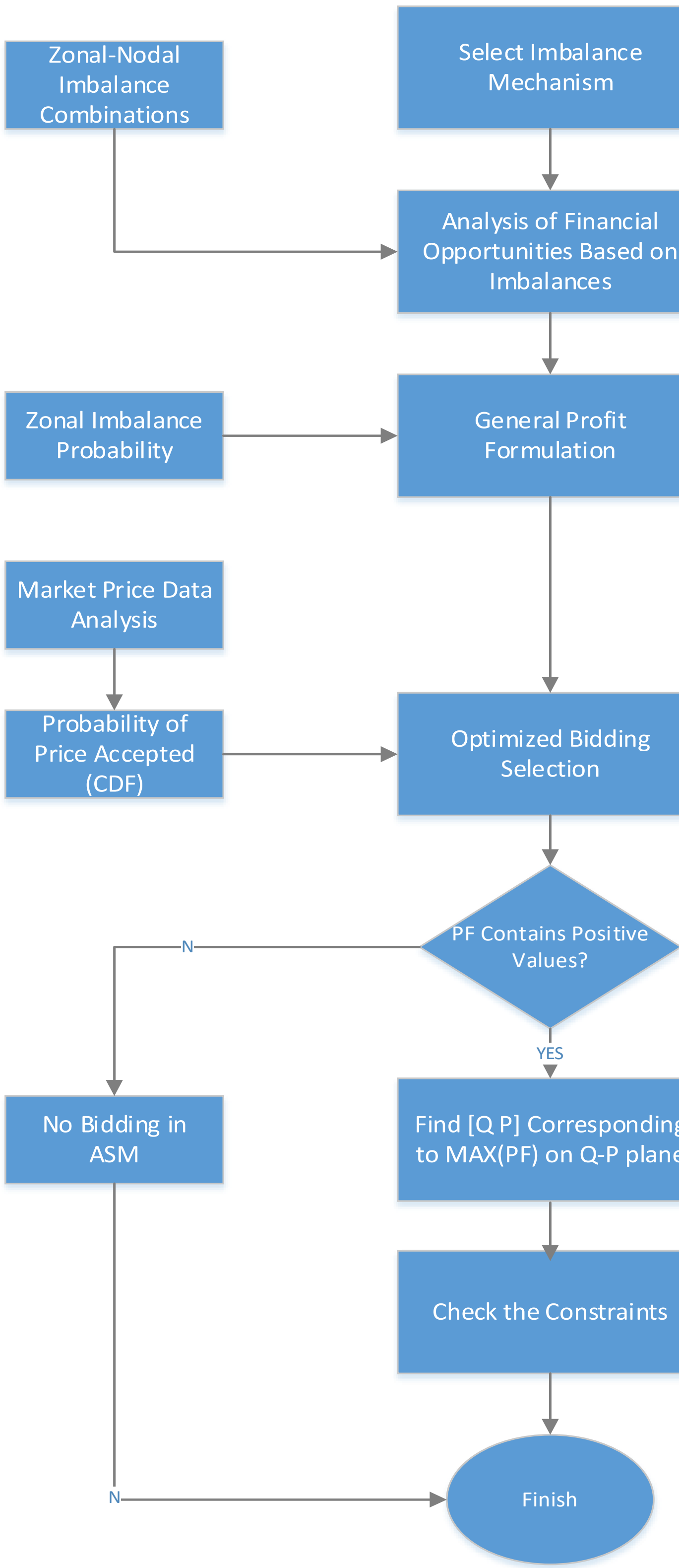


Figure 4-2: Algorithm to find optimal bidding in ASM, downward regulation, for a single hour

Case A: *Positive zonal imbalance, Negative nodal imbalance, Single price mechanism with no discount*

This case analyses revenue when the producer faces the negative imbalance, by considering certain quantity bid for downward reserve. The cost equation (4.1) splits into two regions, when $Q_{MB\downarrow} \leq Q_{imb}$ and $Q_{MB\downarrow} \geq Q_{imb}$. Figure 4.3 illustrates the portion of planned energy, imbalances and downward reserve activated in MSD or MB for the general case of negative nodal imbalance. Knowing about the temporal sequence of following quantities is important. In particular, Q_{CE} represents the committed energy to delivery after day-ahead or intra-day sessions, for a given delivery period, $Q_{MB\downarrow}$ is the bidding quantity for downward regulation after balancing market sessions with delivery period corresponding to the same period as day ahead or intra-day, and Q_{imb} is the imbalance quantity which occurs in real time, during the delivery period.

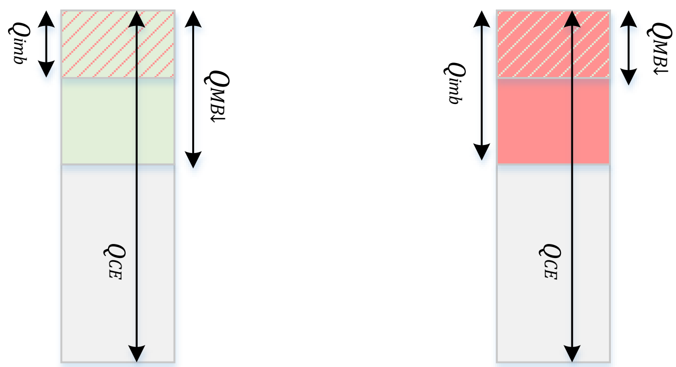


Figure 4-3: Quantity portion of committed energy, MB down and negative imbalance (left) Q_(MB↓)≥Q_imb and (right) Q_(MB↓)<Q_imb for the case of negative nodal imbalance

Equation (4.1a) and (4.1b) calculates the amount of revenue in case of provision of downward regulation, and with no provision of downward regulation respectively. The amount of profit gained by participation in reserve provision can be calculated by differentiating between two cases in (4.1c).

$$\forall\ Q_{MB\downarrow} < Q_{imb}$$

$$Revenue\ with\ reserve = Q_{CE}(P_{MGP} + Premium) - Q_{imb} \cdot P_{MGP} + Q_{MB\downarrow}\left(P_{MGP} - P_{MB\downarrow pb}\right) - Q_{imb} \cdot Premium \tag{4.1a}$$

$$Revenue\ without\ reserve = Q_{CE}(P_{MGP} + Premium) - Q_{imb} \cdot P_{MSD\downarrow M} - Q_{imb} \cdot Premium \tag{4.1b}$$

$$PF = Rev.\ with\ reserve - Rev.\ w.o\ reserve = Q_{MB\downarrow} \cdot \left(P_{MGP} - P_{MB\downarrow pb}\right) - Q_{imb}(P_{MGP} - P_{MSD\downarrow M}) \tag{4.1c}$$

$$\forall\ Q_{MB\downarrow} \geq Q_{imb}$$

$$Revenue\ with\ reserve = Q_{CE}(P_{MGP} + Premium) - Q_{MB\downarrow} \cdot Premium - Q_{MB\downarrow} \cdot P_{MB\downarrow pb} \tag{4.2a}$$

$$Revenue\ without\ reserve = Q_{CE}(P_{MGP} + Premium) - Q_{imb} \cdot P_{MSD\downarrow M} - Q_{imb} \cdot Premium \tag{4.2b}$$

$$PF = Rev.\ with\ reserve - Rev.\ w.o\ reserve = Q_{imb} \cdot P_{MSD\downarrow M} + Q_{imb} \cdot Premium - Q_{MB\downarrow} \cdot P_{MB\downarrow pb} - Q_{MB\downarrow} \cdot Premium \tag{4.2c}$$

Which are constrained to:

$$Q_{CE} - Q_{imb} - Q_{MB\downarrow} \geq 0$$

Note that Q_{imb} is a positive value, equal to the absolute value of the negative imbalance. Profit gained by participation in reserve market can be re-written as the following.

$$\frac{PF_{Z+,N-}}{Q_{imb}} = \begin{cases} \frac{Q_{MB\downarrow}}{Q_{imb}} \cdot (P_{MGP} - P_{MB\downarrow pb}) - (P_{MGP} - P_{MSD\downarrow M}) & \forall\ Q_{MB\downarrow} < Q_{imb} \\ P_{MSD\downarrow M} + Premium - \frac{Q_{MB\downarrow}}{Q_{imb}} \cdot P_{MB\downarrow pb} - \frac{Q_{MB\downarrow}}{Q_{imb}} \cdot Premium & \forall\ Q_{MB\downarrow} \geq Q_{imb} \end{cases} \quad (4.3)$$

It is important to note that at $Q_{imb} = Q_{MB\downarrow}$, the values of profit are the same for both cases, showing the continuity of the equation.

In order to illustrate the concept by numbers, a set of hypothetical input values are considered to show the outcome of formulations (4.1a) to (4.2). Table 4.5 represents this hypothetical values and the calculation results are provided in table 4.6 for the *Case A*. Note that in table 4.5, two values for $Q_{MB\downarrow}$ are presented to justify two cases in which the downward bids are higher and lower than imbalance quantity. In table 4.6, the value of net profit is calculated and the percentage of profit with respect to no reserve provision is calculated in last row. The same procedure is repeated for *Case B, Case C* and *Case D* separately, by considering the same input values as provided in table 4.5.

Table 4-5 : Hypothetical input values

Input Variable	Hypothetic Value	Unit	Input Variable	Hypothetic Value	Unit
P_{MGP}	*50*	*€/MWh*	$P_{MB\downarrow pb}$	*5*	*€/MWh*
$P_{MSD\uparrow M}$	*80*	*€/MWh*	Q_{CE}	*100*	*MWh*
$P_{MSD\downarrow M}$	*20*	*€/MWh*	Q_{imb}	*40*	*MWh*
$P_{MSD\uparrow MAX}$	*120*	*€/MWh*	$Q_{MB\downarrow}$	*45* *35*	*MWh*
$P_{MSD\downarrow MIN}$	*0*	*€/MWh*	*Premium*	*60*	*€/MWh*

Table 4-6: Calculation results for Case A

	$Q_{MB\downarrow} < Q_{imb}$	$Q_{MB\downarrow} > Q_{imb}$	$Q_{MB\downarrow} = Q_{imb}$
Revenue with reserve (€)	*8175*	*8075*	*8400*
Revenue without reserve (€)	*7800*	*7800*	*7800*
PF (€)	*375*	*275*	*600*
PF (%)	*4.8%*	*3.5%*	*7.6%*

The objective is to find the situations in which the profit values are positive and close to the maximum. In order to meet this objective, the parameters in (4.3) should be estimated using appropriate methods with minimum uncertainty. While the good estimation of values are provided, the optimal values of $P_{MB\downarrow pb}$ and $Q_{MB\downarrow}$ can be offered in order to achieve the maximum profit. Figure 4.6a graphically illustrates the concept of analysis resulted in (4.3). In this equation, the value of profit is substituted by profit factor, which is the net profit divided by real imbalance quantity. This profit factor is not intended to calculate the net profit in (€) according to input variables, rather it is only an indication which maximum value corresponds to the optimal bidding quantities. The figure shows that there is a region corresponding to (Q P) plane in which the value of profit factor is positive. From the plot, it can be perceived that the value of profit factor is maximum when the energy corresponding to downward regulation is equal to the real negative imbalance at zero price. The profit is still positive for the bid quantity lower than imbalance. For the bids greater than real imbalance, the profit tends to decrease fast to negative, means loss in opportunities due to avoid to sell of energy at market price and loss in incentives. In this region, the generating unit is exposed to the risk of high revenue loss. By estimation of Q_{imb}, the expected value of profit could be estimated for different values of $P_{MB\downarrow pb}$.

Case B: *Negative zonal imbalance, Negative nodal imbalance, Single price mechanism with no discount*

Similar to previous case, the cost equation (4.4) splits into two regions, when $Q_{MB\downarrow} < Q_{imb}$ and $Q_{MB\downarrow} \geq Q_{imb}$. The difference of this case is the amount of penalty which the unit must pay back when generates negative imbalance and deteriorates the balance of energy in system. The graphical illustration of this case is represented in Figure 4.6c. By considering table 4.1, and by comparison between two cases of positive and negative zonal imbalance, it shows that the generation unit is prone to penalty at negative nodal imbalance, while in previous case, it gains profit by producing negative imbalance since it helps the system balance. Equation (4.4a) and (4.4b) calculates the amount of revenue in case of provision of downward regulation, and without provision of downward regulation respectively. The amount of profit gained by participation in reserve provision can be calculated by differentiating between two cases (4.4c).

$$\forall\, Q_{MB\downarrow} < Q_{imb}$$

$$Revenue\ with\ reserve = Q_{CE}(P_{MGP} + Premium) - Q_{imb} \cdot P_{MSD\uparrow MAX} + Q_{MB\downarrow} \cdot \left(P_{MSD\uparrow MAX} - P_{MB\downarrow pb}\right) - Q_{imb} \cdot Premium \tag{4.4a}$$

$$Revenue\ without\ reserve = Q_{CE}(P_{MGP} + Premium) - Q_{imb} \cdot P_{MSD\uparrow M} - Q_{imb} \cdot Premium \tag{4.4b}$$

$$PF = Rev.\ with\ reserve - Rev.\ w.o\ reserve = Q_{MB\downarrow} \cdot \left(P_{MSD\uparrow MAX} - P_{MB\downarrow pb}\right) - Q_{imb} \cdot (P_{MSD\uparrow MAX} - P_{MSD\uparrow M}) \tag{4.4c}$$

$$\forall\, Q_{MB\downarrow} \geq Q_{imb}$$

$$Revenue\ with\ reserve = Q_{CE}(P_{MGP} + Premium) - Q_{MB\downarrow} \cdot (P_{MB\downarrow pb} + Premium) \tag{4.5a}$$

$$Revenue\ without\ reserve = Q_{CE}(P_{MGP} + Premium) - Q_{imb} \cdot P_{MSD\uparrow M} - Q_{imb} \cdot Premium \tag{4.5b}$$

$$PF = Rev.\ with\ reserve - Rev.\ w.o\ reserve = Q_{imb} \cdot P_{MSD\uparrow M} + Q_{imb} \cdot Premium - Q_{MB\downarrow} \cdot P_{MB\downarrow pb} - Q_{MB\downarrow} \cdot Premium \tag{4.5c}$$

Profit gained by participation in reserve market can be re-written as the following

$$\frac{PF_{Z-,N-}}{Q_{imb}} = \begin{cases} \dfrac{Q_{MB\downarrow}}{Q_{imb}} \cdot \left(P_{MSD\uparrow MAX} - P_{MB\downarrow pb}\right) - (P_{MSD\uparrow MAX} - P_{MSD\uparrow M}) & \forall\, Q_{MB\downarrow} < Q_{imb} \\ P_{MSD\uparrow M} + Premium - \dfrac{Q_{MB\downarrow}}{Q_{imb}} \cdot P_{MB\downarrow pb} - \dfrac{Q_{MB\downarrow}}{Q_{imb}} \cdot Premium & \forall\, Q_{MB\downarrow} \geq Q_{imb} \end{cases} \tag{4.6}$$

By comparing two cases, it can be noted that the only change in *Case B* is the substitution of $P_{MSD\downarrow M}$ by $P_{MSD\uparrow M}$ in negative zonal imbalance, which provides more opportunity to increase revenue with respect to positive zonal imbalance, and also $P_{MSD\uparrow MAX}$ due to application of dual price mechanism for enabled units in this case. In other words, bidding downward regulation in negative zonal imbalance provides higher opportunity to gain more revenue at lower risk, with respect to the positive zonal imbalance. Table 4.7 presents the calculation of net profits based on (4.4) and (4.5) and figure 4.5c graphically illustrates the concept of analysis resulted in (4.6).

Table 4-7: Calculation results for Case B

	$Q_{MB\downarrow} < Q_{imb}$	$Q_{MB\downarrow} > Q_{imb}$	$Q_{MB\downarrow} = Q_{imb}$
Revenue with reserve (€)	*7825*	*8075*	*8400*
Revenue without reserve (€)	*5400*	*5400*	*5400*
PF (€)	*2425*	*2675*	*3000*
PF (%)	*45%*	*49.5%*	*55.5%*

In this case, it is observed that the profit value is much higher than the previous case. This result is due to the fact that in case of negative zonal, negative nodal imbalance, according to the imbalance mechanism, plants would be penalized with high values of charges. Therefore by regulating down in this case, the large amount of penalty charges could be avoided which means higher profit.

Case C: *Positive zonal imbalance, Positive nodal imbalance, Single price mechanism with no discount*

This case represents the analysis of revenue when the producer faces the positive nodal imbalance, and provides downward regulation. Note that in cases of positive nodal imbalance, the cost equation (4.7) is not split into two regions, when $Q_{MB\downarrow} < Q_{imb}$ and $Q_{MB\downarrow} \geq Q_{imb}$. It is due to the fact that, according to TERNA regulations and grid codes, the quantity of downward regulation should be differentiated from Q_{CE} and is not subtracted from Q_{imb}. In other words, after dispatching order for regulation down, generation unit must set the operation point to a point determined by TERNA, not any operational point below the summation of Q_{CE} and Q_{imb}.

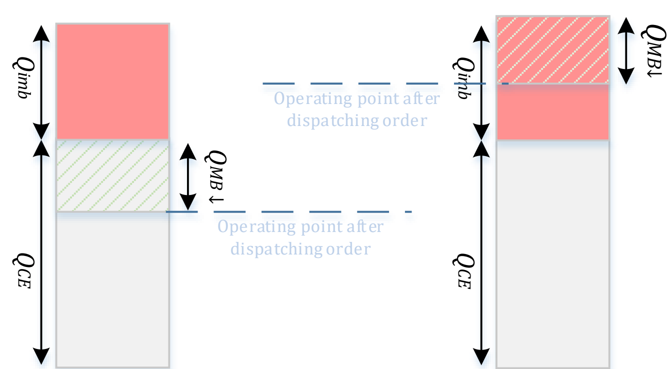


Figure 4-4: Quantity portion of committed energy, MB down and positive nodal imbalance (left) Real case of TERNA and (right) Alternative case

This fact is illustrated in figure 4.4 which presents the portion of planned energy, imbalances and downward reserve activated in MSD or MB for the general case of positive nodal imbalance. Note that according to TERNA rules, our calculation is based on the concept presented in figure 4.4 (left). It is clear that in this case, the real amount of energy which should be curtailed is higher than the amount of energy which is expected by TERNA. In other words, from the TERNA point of view, the curtailed energy is $Q_{MB\downarrow}$, while from the unit's point of view, this amount equals to $Q_{imb} + Q_{MB\downarrow}$. Equation (4.7a) and (4.7b) calculates the amount of revenue in case of provision of downward reserve, and without provision of downward reserve respectively. The amount of profit gained by participation in reserve provision can be calculated by differentiating between two cases (4.7c).

$$Revenue\ with\ reserve = Q_{CE}(P_{MGP} + Premium) - Q_{MB\downarrow} \cdot \left(Premium + P_{MB\downarrow pb}\right) \quad (4.7a)$$
$$Revenue\ without\ reserve = Q_{CE}(P_{MGP} + Premium) + Q_{imb} \cdot (P_{MSD\downarrow M} + Premium) \quad (4.7b)$$
$$PF = Rev.\ with\ reserve - Rev.\ w.o\ reserve = -Q_{MB\downarrow} \cdot \left(P_{MB\downarrow pb} + Premium\right) - Q_{imb} \cdot (P_{MSD\downarrow M} + Premium) \quad (4.7c)$$

Profit gained by participation in reserve market can be re-written as the following

$$\frac{PF_{z+,N+}}{Q_{imb}} = -\frac{Q_{MB\downarrow}}{Q_{imb}} \cdot \left(P_{MB\downarrow pb} + Premium\right) - (P_{MSD\downarrow M} + Premium) \quad (4.8)$$

Constrained to

$$Q_{CE} - Q_{MB\downarrow} \geq 0$$

Table 4.8 presents the calculation of net profits based on (4.7) and (4.8) and input values presented in table 4.5.

Table 4-8: Calculation results for Case C

	$Q_{MB\downarrow} = 35\ MWh$
Revenue with reserve (€)	*8725*
Revenue without reserve (€)	*13100*
PF (€)	*-4375*
PF (%)	*-33.3%*

As we can see in table, the loss of opportunity cost would be significant by providing downward regulation in case when the generation unit faces positive nodal imbalance. Figure 4.6b illustrates the trend of profit in presence of downward regulation. Note that the amount of profit by providing downward regulation is always negative and unlike the case of negative nodal imbalance, is strictly descending starting from zero by increasing the bidding quantity. This is due to the fact that the production unit is still positively remunerated when faces positive nodal imbalance, even when this positive nodal imbalance deteriorates the system balance.

Case D: *Negative zonal imbalance, Positive nodal imbalance, Single price mechanism with no discount*

Figure 4.6d illustrates the trend of profit in this case. Considering the imbalance mechanism applied to this case, the only difference with respect to previous case is the valorization of the penalty which the production unit receives in charge of imbalance in production. Therefore, this case can be written the same as *Case C* only by substituting $P_{MSD\downarrow MIN}$ by P_{MGP}. The profit equation can be presented as following

$$Revenue\ with\ reserve = Q_{CE}(P_{MGP} + Premium) - Q_{MB\downarrow} \cdot (Premium + P_{MB\downarrow pb}) \tag{4.9a}$$
$$Revenue\ without\ reserve = Q_{CE}(P_{MGP} + Premium) + Q_{imb} \cdot (P_{MGP} + Premium) \tag{4.9b}$$
$$PF = Rev.\ with\ reserve - Rev.\ w.o\ reserve = -Q_{MB\downarrow} \cdot (P_{MB\downarrow pb} + Premium) - Q_{imb} \cdot (P_{MGP} + Premium) \tag{4.9c}$$

$$\frac{PF_{z-,N+}}{Q_{imb}} = -\frac{Q_{MB\downarrow}}{Q_{imb}} \cdot (P_{MB\downarrow pb} + Premium) - (P_{MGP} + Premium) \tag{4.10}$$

Constrained to

$$Q_{CE} - Q_{MB\downarrow} \geq 0$$

Table 4.9 presents the calculation of net profits based on (4.9) and (4.10) and input values presented in table 4.5.

Table 4-9: Calculation results for Case D

	$Q_{MB\downarrow} = 35\ MWh$
Revenue with reserve (€)	*8725*
Revenue without reserve (€)	*14850*
PF (€)	*-6125*
PF (%)	*-41.2%*

Table 4.10 provides a summary of possible profit opportunity of reserve provision, sub-divided by each case as investigated above.

Table 4-10: Profit opportunity for each Z-N imbalance combinations, single price no discount system

	N+	N-
Z+	Full loss of opportunity	Profit opportunity in positive bidding region
Z-	Full loss of opportunity	Profit opportunity in positive bidding region

The analysis provided by each formula above, illustrates that in case when the unit is enabled and accepted for regulation down, but is not dispatched, it will lose money. It is perceived by considering $Q_{MB\downarrow} = 0$ in which the profit value becomes negative for each case. This situation originated from the fact that, by enabling units for participation in regulation, the imbalance fee is different for the case of non-enabled units. Therefore even if the unit is accepted, but not dispatched, it will lose profit equal to the difference between imbalance charges applied to enabled and non-enabled units.

4.2 General Profit Formulation

In order to determine the general form of bidding strategy, it should be determined how to use the profit analysis provided in previous sections. These formulations show the reserve market opportunities for each certain combination of zonal and nodal imbalances, based on stochastic input variables. However, since the occurrence of each combinations in each market bidding period is stochastic too, the super-ordinate equation is proposed to consider the probability of each imbalance combinations introduced as following

$$\frac{PF_{sup}}{Q_{imb}} = \begin{cases} (1-\rho)\cdot\frac{PF_{z-}}{Q_{imb}} + \rho\cdot\frac{PF_{z+}}{Q_{imb}} & \forall\, \gamma \geq \gamma_0 \\ 0 & \forall\, \gamma < \gamma_0 \end{cases} \quad (4.15)$$

Two new variables are presented to consider the probability of imbalance occurrence. In particular, ρ is the probability of positive zonal imbalance, and is presented as weighting factor to balance the risk corresponding to positive or negative zonal imbalance. The probability of negative nodal imbalance is named γ and acts as a decision variable to determine whether it is profitable to participate in reserve market or not.

Another approach to include the positive nodal imbalance occurrence is to generalize the super-ordinate equation by presenting the equations of positive nodal imbalance and use the γ multipliers directly in equation. The advantage of this approach is, there is no need to estimate the value of γ_0 by which the opportunity profit is positive, allowing generation unit to participate in reserve market. In order to more illustration, since the terms corresponding to positive nodal imbalances are strictly negative, the super-ordinate equation contains the positive values only for values of γ higher than certain percentage.

$$\frac{PF_{sup}}{Q_{imb}} = (1-\rho)\cdot\left[\gamma\frac{PF_{z-,N-}}{Q_{imb}} + (1-\gamma)\frac{PF_{z-,N+}}{Q_{imb}}\right] + \rho\cdot\left[\gamma\frac{PF_{z+,N-}}{Q_{imb}} + (1-\gamma)\frac{PF_{z+,N+}}{Q_{imb}}\right] \quad (4.16)$$

It should be noted that the equation (4.16) does not represent the net profit gained by the unit when offering in reserve market. This equation is considered as a criterion in which the maximum value determines optimal bidding variables, which can be selected by mapping on [Q P] plane. The real profit obtained using this bidding tool can be calculated by putting the results of the bidding algorithm into the appropriate simulation environment or assessed when using in real conditions. Figure 4.6e illustrates the effect of weighting factors in comparison with the use of only individual profit equations, for different values of probability of negative zonal imbalance. Note that for probabilities of negative nodal imbalance lower than γ_0, the maximum value of profit equation is equal to zero, the maximum value of the function occurs at zero in [Q P] plane, and subsequently the model automatically selects to bid at $Q_{MB\downarrow} = 0$, while for $\gamma \geq \gamma_0$, the tool optimizes the bidding at quantity and price corresponding to the maximum positive value of PF.

4.3 More Illustration of the Analysis; Example

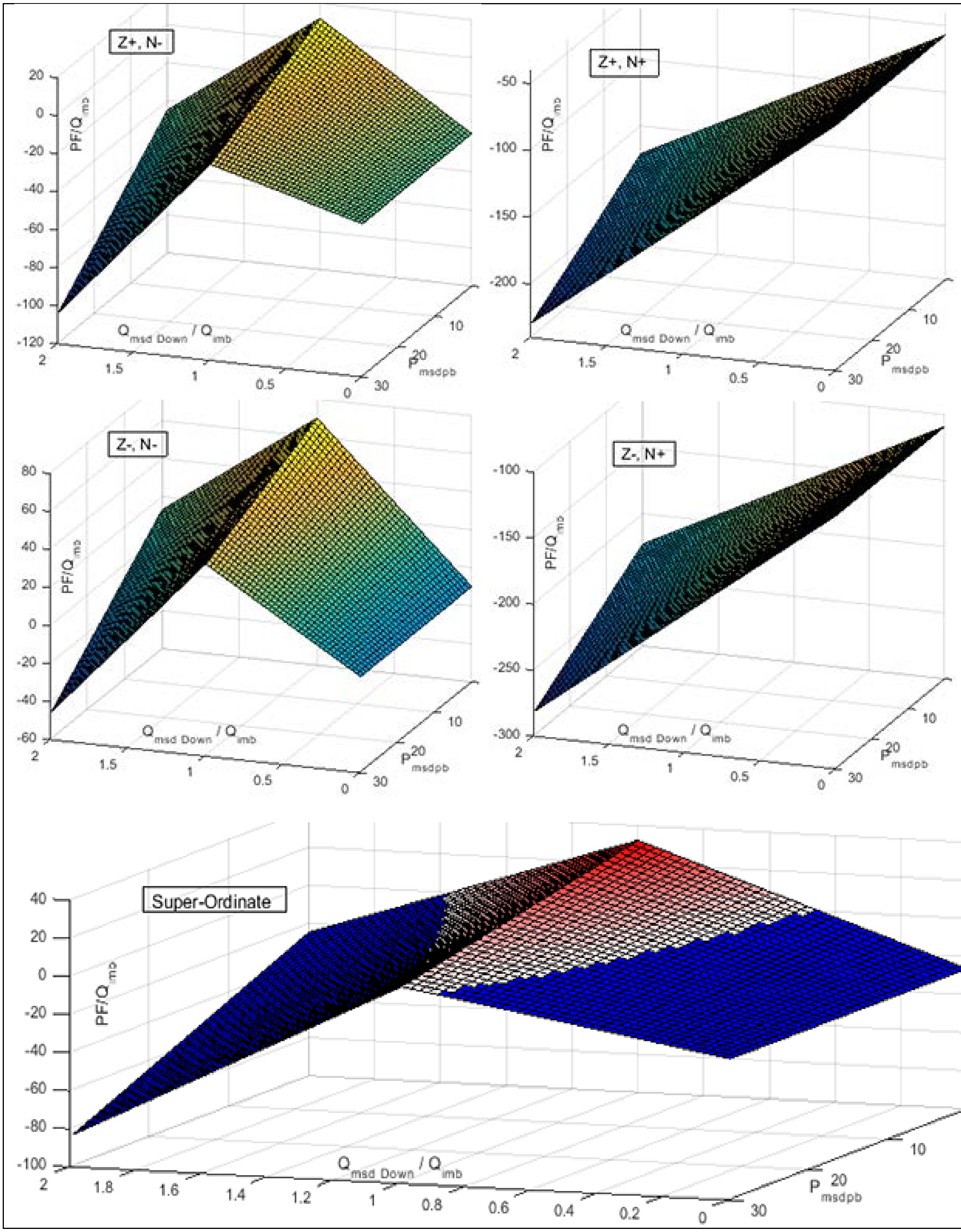
In this section, two examples are presented in order to illustrate better the concept and formulas presented in previous sections. In each example, a real set of input variables are considered corresponding to two different reference hours in 2016, and specified zone. Then, corresponding plots are represented to visually draw the formula presented above. Table 4.5 contains the list of input variables for two reference hours of the year.
In profit formulas, $\frac{Q_{MB\downarrow}}{Q_{imb}}$ and $P_{MB\downarrow pb}$ are the variable parameters correspond to X-Y plane. These two particular variables are the variables of interest, which are the subject of estimation by optimization tool. The output variable is $\frac{PF}{Q_{imb}}$, corresponding to Z-Axis, which is an indication for trend of profit by changing variables along X-Y plane, for each input variables presented in table 4.5.
Note that the values represented in table are only valid for one reference hour, and should be recalculated for other hours separately.

Figure 4-5: Summary of all input variables* used in profit formulas, zone SUD (4.1-16)

Input Variables	Description	Values (€/MWh) 08:00-02/02/2016	Values (€/MWh) 19:00-12/08/2016
P_{MGP}	Zonal DAM energy price	52	33
$P_{MSD\downarrow M}$	MSD↓ hourly average price	12	8
$Premium^{**}$	Incentive	58	76
$P_{MSD\uparrow MAX}$	MSD↑ hourly maximum price	80	91
$P_{MSD\uparrow M}$	MSD↑ hourly average price	70	86
$P_{MSD\downarrow MIN}$	MSD↓ hourly minimum price	0.00	0.00
ρ	Probability of positive zonal imbalance	0.3	0.3
γ	Probability of negative nodal imbalance	0.9	0.9

**Data provided by GME and TERNA*
*** According to DM 23/6/2016*

Figure 4.6 is graphical representation of formula (4-3), (4-6), (4-9) and (4-12) respectively. It can be seen that the opportunity of positive revenue, which is a region corresponding to positive value of each profit curve only exists in presence of negative nodal imbalance. In case where the nodal imbalance is positive, but the unit is dispatched down, the revenue opportunity is strictly negative, and once again it confirms the full loss of revenue. According to this figure, unit's revenue opportunity is higher when is dispatched down in presence of negative zonal, negative nodal imbalances. On the other side, it loses higher revenue opportunity when dispatched down in presence of negative zonal, positive nodal imbalances.


Z+, N-
Z+, N+
Z-, N-
Z-, N+
Super-Ordinate
PF/Q
Q msd Down / Q imb
P msdpb

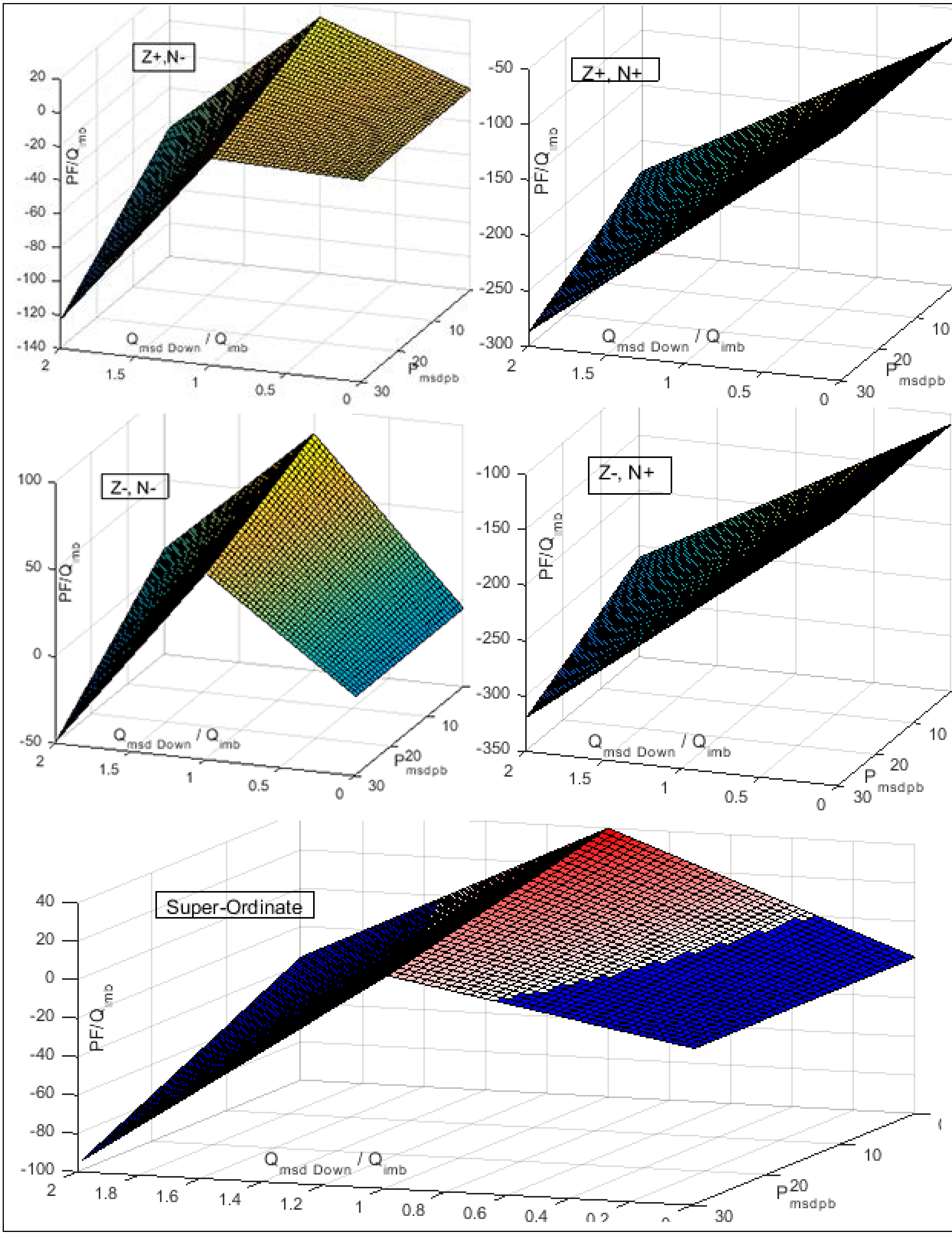


Figure 4-6 & Figure 4-7: Graphical representation of equations (4-1) to (4-16)

Figure *(4.6e)* graphically represents the general formulation of revenue opportunity, introduced in (4.16), considering the probability of each zonal nodal imbalances. In this plot, the region in which the unit has the opportunity of positive revenue, is indicated by color range from white to red. It can be realized that the maximum revenue is obtained when unit is dispatched down with the quantity equal to real time imbalance quantity ($Q_{MB\downarrow} = Q_{imb}$) and zero price ($P_{MSD\downarrow pb} = 0$). The region in which unit loses the revenue is indicated by color range from blue to black. Note that for the amount of regulation down quantities greater than imbalance quantity, generation unit will lose the revenue with higher rate. As it was mentioned before, region of negative revenue (blue), near and equal to the zero value of regulation down, can be justified by the fact that, even if the unit is accepted, but not dispatched, it will lose profit equal to the difference between imbalance charges applied to enabled and non-enabled units.
The example is repeated for the same mechanism, but different values of market parameters, provided in table 4.5. Results are depicted in figure 4.7. Note that keeping constant the probabilities (γ *and* ρ), different values of market parameters changes the region corresponding to positive revenue in each selected hour of the day.

4.4 Optimize the bidding values considering probability of acceptance

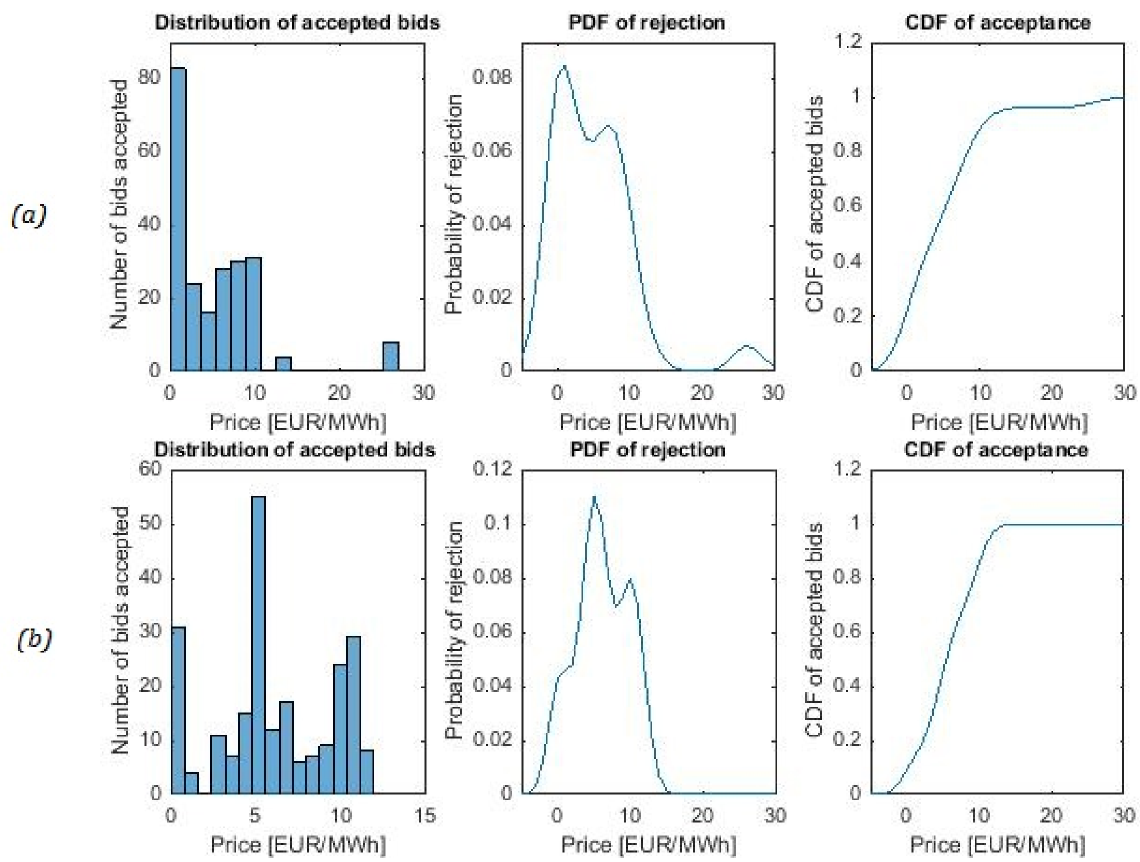


Figure 4-8: Distribution of accepted bids, PDF of prices and probability of acceptance

Considering the revenue analysis at previous section, it is clear that the generation unit gains maximum profit when buys back the regulation at the quantity equal to Q_{imb} at zero price. It is clear that this optimistic viewpoint about bidding at zero price may rarely provide the optimal profitability for the generating unit, since the probability of acceptance at zero price are low most of the times, bidding at higher price with higher probability of acceptance will increase the chance of profit by increase the frequency of acceptance in long term. In this regard, in order to optimally bidding in reserve market, the probability of acceptance should be considered in the model.
The methodology to analyze market data to find the probability of acceptance for whole the year will be introduced in the next chapter. However, in order to clarify the subject, the approach is described for the bids accepted in MB, at a certain hour for a certain reference week of the year.
In order to apply the effect of risk of rejection of bidding at low price, the histogram of number of accepted prices can be plotted based on the data available on market operator's portal. Once the distribution of accepted prices obtained, the probability density function and respectively the cumulative density function can be obtained using *Kernel Distribution Estimation* method, for each hour of the reference week. Figure 4.8 shows the distribution of accepted bids for the two sample periods presented in table 4.5.
Considering the cumulative density function of acceptance probability, once again, it can be emphasized that the probability of acceptance will increase univocally by increasing the bidding price for downward regulation.

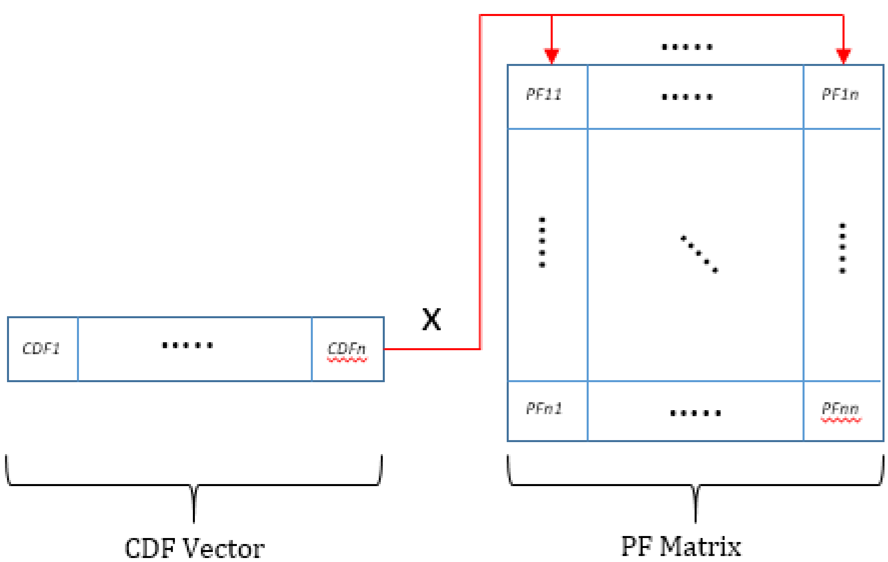
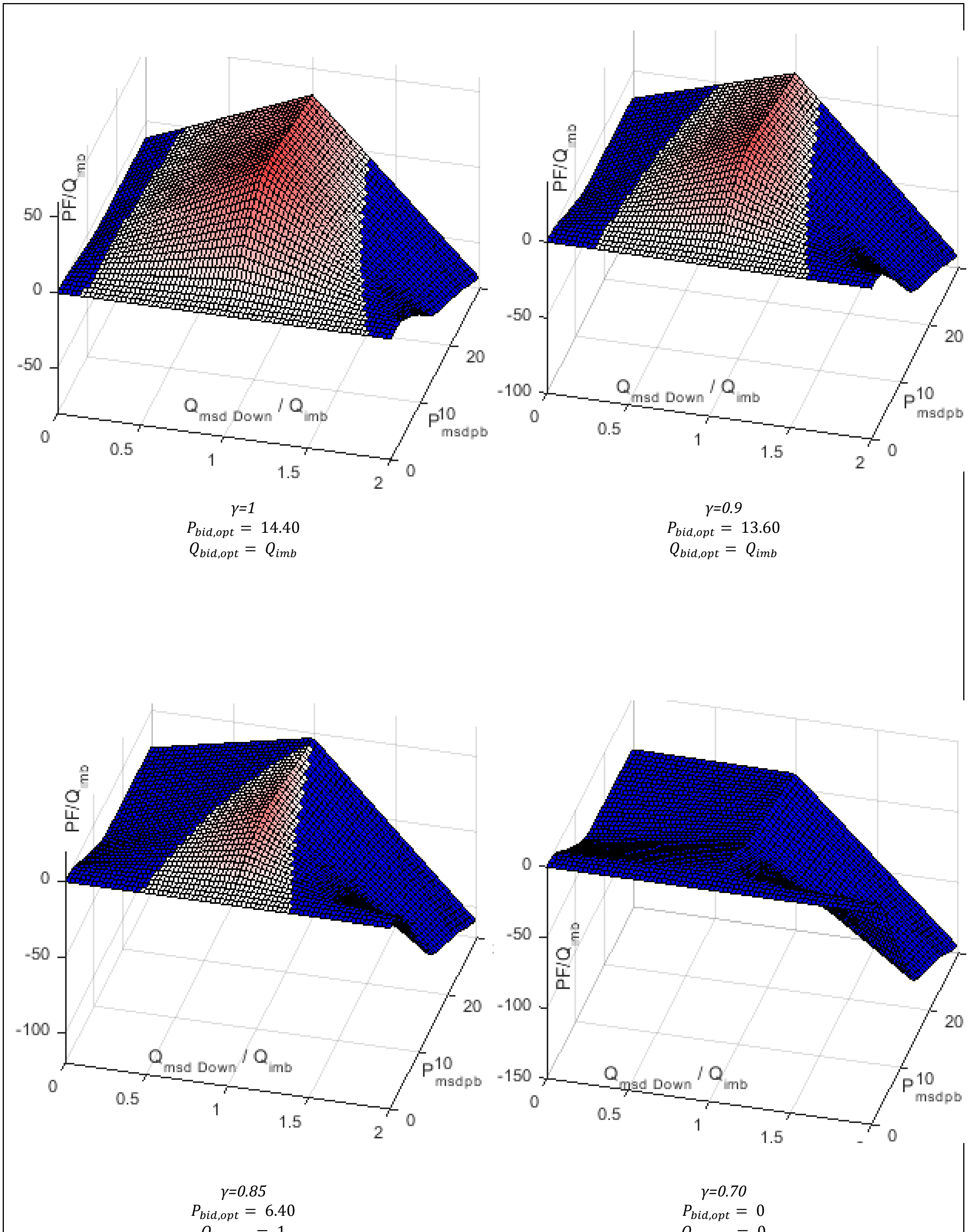


Figure 4-9: Illustration of elementwise multiplication of CDF vector to PF matrix columns

In order to apply the footprint of this probability function to the model, it is proposed to multiply element by element the CDF along with $P_{MB\downarrow pb}$ axis of the profit equation. Considering the values of PF in a $n \times n$ matrix, and considering the values of CDF in an $1 \times n$ vector, a loop function in MATLAB® is created to carry out this multiplication. Figure 4.9 illustrates the concept of this subject.
Since the CDF magnitude varies between [0 1], this multiplication keeps the sign of profit unchanged, and only diminishes the magnitude of profit in the areas in which the probability of acceptance is low. Note that the objective is to find the *maximum* value of the profit equation (4.16). Figure 4.10 shows the change in profit opportunity by applying probability of acceptance (CDF) along $P_{MSD\downarrow pb}$ axis.



$\gamma=1$
$P_{bid,opt} = 14.40$
$Q_{bid,opt} = Q_{imb}$

$\gamma=0.9$
$P_{bid,opt} = 13.60$
$Q_{bid,opt} = Q_{imb}$

$\gamma=0.85$
$P_{bid,opt} = 6.40$
$Q_{bid,opt} = 1$

$\gamma=0.70$
$P_{bid,opt} = 0$
$Q_{bid,opt} = 0$

Figure 4-10: Profit opportunity by applying probability of acceptance, for different values of γ

For different values of γ, this plot is depicted based on data provided in table 4.5 for a reference day in February.
According to the new plot, it is clear that by considering the risk of acceptance, the bidding strategy in order to gain maximum profit is not at zero price anymore. The point on [Q P] plane corresponding to the maximum value of Z-axis determines optimally the bidding of quantity and price, in order to participate in downward regulation. The bidding in market only realizes when the maximum value of profit is positive. In other words, in situations where the probability of nodal positive imbalance is high, the profit equation is negative for any values of [Q P] due to loss in opportunity costs (Figure4.10d). This condition is respected by including the probability of positive nodal imbalance in general equation (eq. 5.16).
In this case, it can be seen that the optimum value of price to be offered in reserve market which corresponds to the maximum value of PF function, is shifted from zero in previous case, to a higher value in positive profit region. For the particular numeric values used to plot this graph. This value of γ_0 which is an indication to determine the positive value of bidding formula, is variable based on different market periods.
In figure 4.10, the region of positive revenue is indicated by color range from white to red, while, the region in which the plant loses money is indicated by the color range from blue to black. Once the plant has the highest probability of being prone to negative imbalance ($\gamma = 1$, Figure 4.10a), the profit region is wider and the risk of losing opportunity by dispatching down is lower. This range gets narrow by decreasing the probability of negative nodal imbalance. In this particular case, for $\gamma \leq 0.66$, the values of Z-Axis are negative and there is no selection for bidding quantities. In other words, the maximum values of the graph occurs at $\frac{Q_{MSD}}{Q_{imb}} = 0$, which means the algorithm selects zero for the quantity of bidding, interpreted as no participation in downward regulation service.
The same procedure is carried out for another reference day in the year, based on data presented in table 4.5 for 19:00, date 12/08/2016. Similar to the previous case, the distribution of accepted prices corresponding to the new reference hour is obtained using data analysis. Then the probability density function and respectively, probability of acceptance is obtained from the cumulative distribution function. The results of bidding selection is provided in table 4.11 for both reference hours provided in table 4.5, for different values of γ.

Table 4-11: Summary of bidding based on market parameters and probability of acceptance, for different values of γ.

γ	*Bidding Price (€/MWh)*	
	(08:00)-02/02/2016	*(19:00)-12/08/2016*
1	14.40	15.20
0.95	13.60	15.20
0.90	13.60	14.40
0.85	12.80	14.40
0.80	10.40	12.80
0.75	6.40	8.80
0.70	2.40	1.60
0.65	-	-

By looking to the results, for lower probability of negative nodal imbalance, bidding algorithm selects the lower bidding price. In fact, one can say that the higher risk of rejection by bidding at lower price is in compromise with the risk of loss of opportunity due to lower probability of nodal negative imbalance. On the other side,

Note that the application of accepted price probability only affects the price of bid and does not have influence on the quantity. In this situation, the quantity still remained the same as previous cases and is selected optimal by offering at $Q_{MB\downarrow} = Q_{imb}$. In general, same procedure is not suggested to be utilized in order to optimize the selection of quantity of bids considering the probability of accepted quantity. It is due to the fact that unlike the bidding price, quantities offered in downward reserve are highly related to plant's capabilities and technical constraints, therefore analyzing the statistical data related to accepted quantities does not reflect effectively the probability of accepting the quantity. Another reason is that the awarded quantity is usually lower than the accepted quantities, therefore putting effort to find the optimum quantity value may have no significant effect on final results, and is proposed to be considered as $Q_{MB\downarrow} = Q_{imb}$ in current step of the work.

4.5 Gate closure time and forecast error in bidding strategy

Market sessions and gate closure times for day ahead, intraday and ancillary services market have been introduced in section 2.1. In this section we discuss about in which manner, these market sessions and gate closures associated with meteorological forecasts influences the bidding strategy in ancillary services regarding probability of imbalances [06].

In particular for Italian system, gate closure time for bidding in day-ahead market is around noon of day ahead (D-1) for all the 24 hours of the delivery day (D), meaning that the forecast time horizon is at least 12 to 36 hours before real time delivery. However, if we consider the arrival time of forecast data earlier than the bidding decision and gate closure, this forecast time horizon increases even much more. Longer forecast horizon results in larger forecast errors for the wind power producers and requires trading more energy in balance settlement [08], [09].

It is possible to correct the forecast errors in intra-day markets in which sessions open sequentially once the day-ahead market is closed, and held in multiple sessions with different opening and closure times. With the current intra-day market and balancing market, plants can bid in intra-day market around 5:15 minutes before starting of corresponding delivery period, while for balancing market this time span is two hours before periods of delivery. In other words, the binding programs of energy delivery is cleared at least 5:15 hours before the delivery hours, while it is possible for plants to assess their possible imbalances two hours before delivery in dispatching market. As shown before in previous sections, wind plants obtain the maximum profit by participating in regulation down services, when they face negative nodal imbalance, by bidding the quantity equal or very close to the imbalance quantities. Therefore this amount of imbalance can be determined two hours before dispatching in MB, and 3:15 hours after MI session. Table 4.12 illustrates the time span between gate closure times and delivery hours for intra-day market (MI) and balancing market (MB) in Italian market framework, according to the public data available in GME portal [07]. Note that, as previously indicated in table 2.1, for the day of delivery, MB(n) sessions closed after MI(n+1). As an example, delivery hours related to MB4, is corresponding to delivery hours for MI5.

Table 4-12: Time spans between gate closure times and relevant periods of delivery

Market	Gate Closure	Relevant Delivery Periods
MI1	15:00*	00:00 – 23:59
MI2	16:30*	00:00 – 23:59
MI3	23:45*	05:00 – 23:59
MI4	03:45	09:00 – 23:59
MI5	07:45	13:00 – 23:59
MI6	11:15	17:00 – 23:59
MI7	15:45	21:00 – 23:59
MB1	-	00:00 – 04:00
MB2	03:00	05:00 – 08:00
MB3	07:00	09:00 – 12:00
MB4	11:00	13:00 – 16:00
MB5	15:00	17:00 – 20:00
MB6	19:00	21:00 – 23:59

** Time relevant to day before delivery*

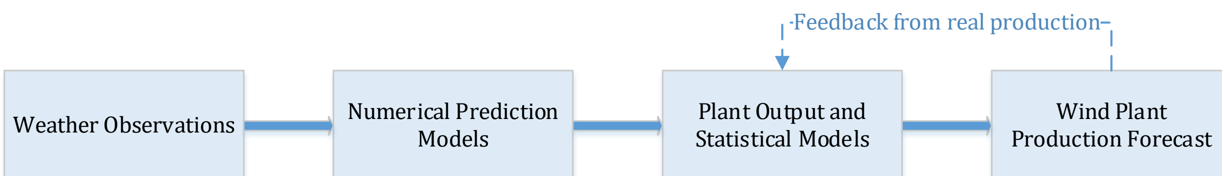


Figure 4-11: Steps of wind power forecasting [09]

Wind forecasting system can be generally introduced as the blocks presented in figure 4.11 [09]. The forecasting procedure initiates with the general weather observations, then it evolves by numerical weather prediction approaches. Statistical models convert wind to output power and correct for systematic biases and error patterns. In this level, the production forecast is provided based on the statistical models and feedback from actual productions to improve the statistical approaches. Forecast provides use many different ways to accomplish these steps or components.

Wind power forecast performance is typically evaluating by Mean Absolute Error (MAE) or Root Mean Square Error (RMSE), which are calculated based on (4.17) and (4.18) respectively considering few simplifying assumptions [10].

$$MAE = \frac{1}{n}\sum_{i=1}^{n} |\mathrm{e_i}| \tag{4.17}$$

$$RMSE = \sqrt{\frac{1}{n}\sum_{i=1}^{n} e_i^2} \tag{4.18}$$

In these equations, n represents number of samples observed based on measurement instruments on site, e_i is the error observed by i_{th} measurement. The differences and criteria for selection between each one is discussed in literatures [10] and [11] and is out of our work scope. In order to simply illustrate the concept, mean absolute forecast error is calculated based on hundreds of samples at a location of typical plant for time horizon from 1 to 36 hours, and is provided in figure 4.12.

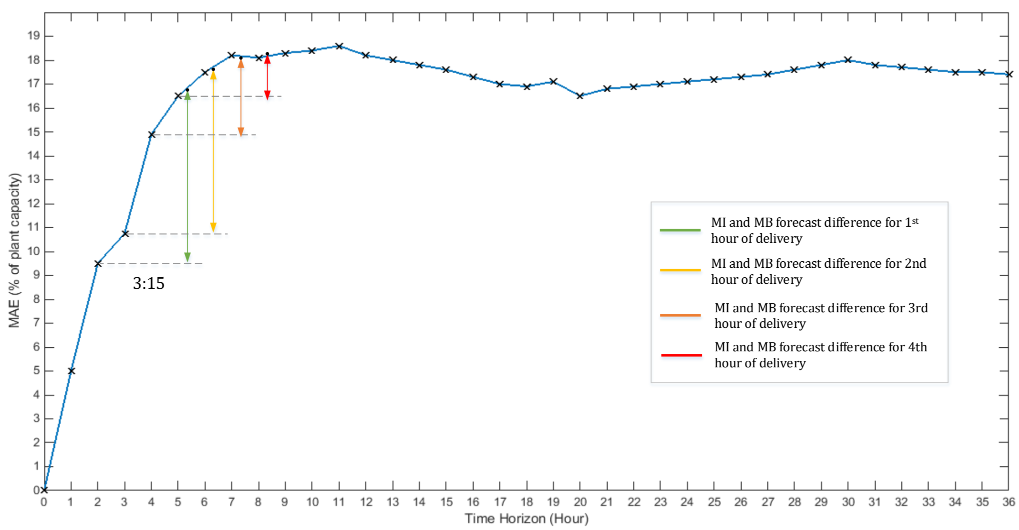


Figure 4-12: MAE with respect to time horizon of forecast

In this figure, the difference between forecast errors between MI gate closure and corresponding MB gate closure is shown by color arrows. In each MB session, the generation unit plans its service provision for four hours of delivery which begin from two hours to six hours after gate closure. In each MI session, generation unit plans its energy production for at least four hours of delivery which begins from $5\frac{1}{4}$ hours to $9\frac{1}{4}$ after gate closure.

As summary, wind plants can offer their best estimate of generation in MI closest to the period of delivery. Then according to the gate closure time difference between MI and MB, it is possible to bid their negative deviations of quantity from binding program in subsequent MB, with the optimized price as introduced based on algorithms described in previous sections. Once again, this possibility to estimating the deviation of binding production is due to the fact that the MB gate closure time is around 3:15 hour closer to delivery time, in comparison with the previous MI session, however the effectiveness of this approach is highly correlated to availability and ability of wind plants to essentially procure the appropriate meteorological data at the time corresponding to gate closure times.

4.6 Methodology to Find Imbalance Probabilities

As introduced in previous sections, based on the analysis model presented in this work to find the profit opportunities in ASM for wind power plants, the success of the model strongly depends on a good estimation of nodal and zonal imbalance probabilities. This probabilities are presented in equation (4.16) by γ and ρ respectively.

Section 4.5 introduced an approach, by which the wind generation units can estimate their imbalance based on difference between MI and MI gate closure times for a certain delivery period based on *Mean Absolute Error* of wind forecast on hourly time basis and bid this imbalance quantity in MB if this imbalance is negative. However the presented approach does not address explicitly about how to find the probability of this imbalance (γ) to be used in general formula presented by (4.16). In this section an approach will be introduced to estimate *Negative Nodal Imbalance Probability*.

As presented in previous section, according to table 4.12, MI gate closure time for a certain delivery time is at least 5:15 hours before delivery. For the same delivery period, MB gate colure time is 2 hours in advance which means 3:15 hour difference in gate closures. Based on figure 4.14, we assumed that according to updated meteorological data, wind production units can improve their forecast at the time of MB gate closure. Let us introduce the following variables to be used in analysis:

Table 4-13: Representation of quantities to be used in analysis

Variable	Description
$Q_{@MI,h}$	Forecasted quantity at MI gate closure time for h^{th} hour of delivery
$Q_{@MB,h}$	Forecasted quantity at MB gate closure time for h^{th} hour of delivery
Q_h	Real time energy delivery
MAE_n	Mean Absolute Error of n^{th} hour distance
δ_h	Forecast error standard deviation
f_h	Forecast error probability distribution function
F_h	Forecast error accumulative distribution function

As introduced in equation (4.17), the MAE for each time distance is obtained based on measuring *n* samples at corresponding time distance. It is clear that MAE is obtained by averaging this errors over the total number of samples. With reference to many works done on finding the distribution function of wind forecast, and wind power imbalance due to forecast errors, it can be assumed that wind forecast errors naturally follow a normal distribution shape. In this regard, MAE is presented as the mean value of this normal distribution function. Figure 4.13 represents the distribution function of imbalances for a generic wind plant. Knowing this distribution function is a key element to find the nodal imbalance probability presented in this section. It should be noted that the main characteristics of this distribution function is peculiar for each wind power plant located in different geographical zones. In the following, we start the stepwise approach in order to find a method to estimate the nodal imbalance probability based on numerical values presented in table 4.12 and figure 4.14. At the end a general formula presents in order to enable calculation for each plants with different numerical values.

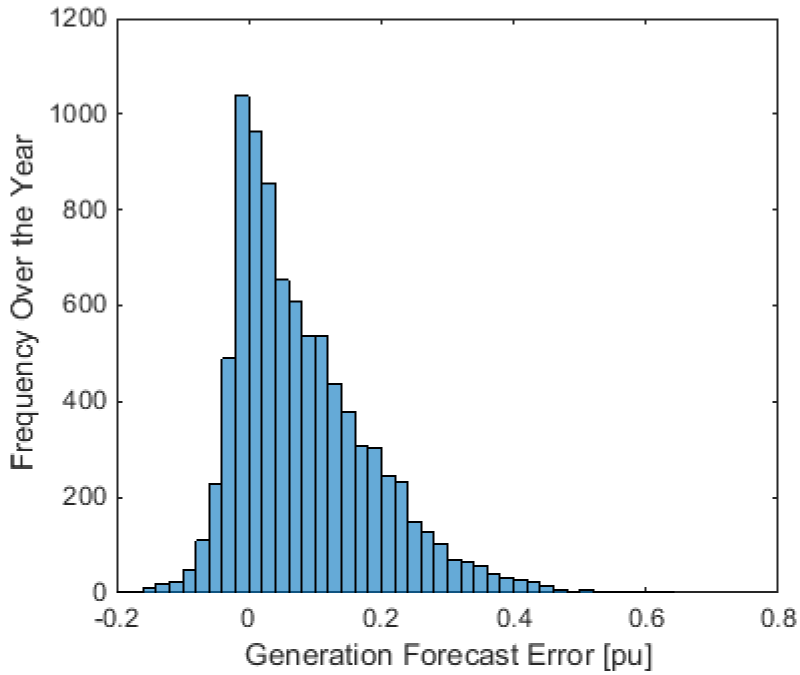


Figure 4-13: Distribution of forecast error measurements for a selected time horizon

We already assumed that the wind plant offers its best forecast at a MI gate closure closest to the first delivery hour ($Q_{@MI,h}$). According to 5:15 hour difference between MI gate closure and delivery time, the plant will face the forecast error with the mean value around 17% of plants capacity. Let's assume that at MB gate closure time for the same delivery period, which is 3:15 hour after MI gate closure, the best forecast reduces to 80% of the energy offered in MI ±9% of MAE. At this time, which is two hour before delivery, the plant's operator realizes that the plant will more probably faces the negative imbalance. Knowing that the latter MAE is the mean value of normally distributed errors for two hour time span, the probability of negative nodal imbalance can be obtained. Figure 4.14 graphically represents the concept of this approach, for particular case of $Q_{@MB,h} < Q_{@MI,h}$. In order to simplifying the illustration, the hypothetical numbers are used. MAE is assumed as percentage of offered forecast at MI for the sake of simplicity.

In this figure, two normal distribution functions represents distribution of forecast error around +MAE and −MAE. In this case only normal distribution function corresponding to +MAE is considered, in order to keep highest reliability margin. The shaded area represents the probability of positive imbalance, which can be calculated based on methods presented in probability reference books [12]. From the figure, it can be interpreted that the probability of nodal imbalance is also correlated to the variance of sampled forecast errors obtained by measurement. In other words, considering a certain value for MAE, measured sample errors with lower variance results in narrower normal shape, smaller shaded area therefore higher certainty to estimate the probability of negative or positive nodal imbalances. Following formulations, using normalization method is presented to calculate the probability of nodal imbalance individually for both cases when unit faces positive and negative nodal imbalance.

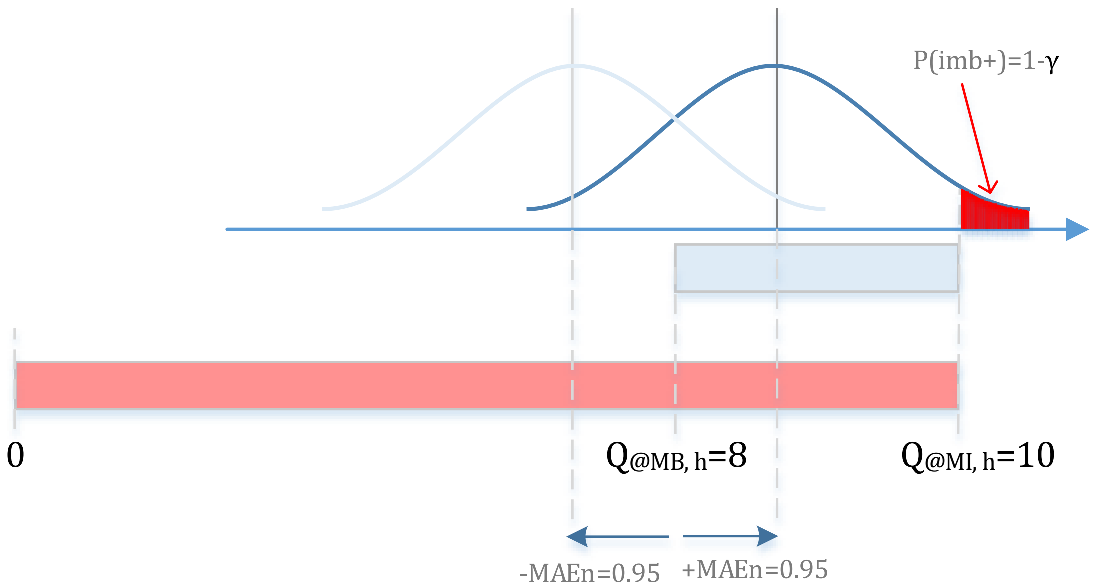


Figure 4-14: Illustration of concept to calculate nodal imbalance probability

$$\forall\ Q_{@MB,h} < Q_{@MI,h} \tag{4.19a}$$

$$\mu = Q_{@MB,h} + MAE_n \tag{4.19b}$$

$$\gamma = P\{Q_h < Q_{@MI,h}\} \simeq P\left\{\frac{Q_h - \mu}{\delta_h} < \frac{Q_{@MI,h} - \mu}{\delta_h}\right\} \simeq \phi(\frac{Q_{@MI,h} - \mu}{\delta_h}) \tag{4.19c}$$

In (4.19c), knowing standard deviation δ and mean value of normal distribution μ calculated based on (4.19b), ϕ can be easily calculated from the tables provided in handbooks. Equation (4.20) calculates the value of γ for the second case.

$$\forall\ Q_{@MB,h} > Q_{@MI,h} \tag{4.19a}$$

$$\mu = Q_{@MB,h} - MAE_n \tag{4.19b}$$

$$\gamma = P\{Q_h < Q_{@MI,h}\} \simeq P\left\{\frac{Q_h - \mu}{\delta_h} < \frac{Q_{@MI,h} - \mu}{\delta_h}\right\} \simeq \phi(\frac{Q_{@MI,h} - \mu}{\delta_h}) \tag{4.19c}$$

As an example for the first case, considering the hypothetical numeric values presented in figure 4.14, with standard deviations calculated for samples equal to $\delta = 0.713$, the probability obtained from table as $\gamma = 0.922$. Note that the value of probability will decrease by increasing standard deviation. As an example, by the samples with $\delta = 1.2$, the probability decreases to $\gamma = 0.807$. Table 5.8 presents the summary of numerical examples for both cases. The same procedure can be calculated for the second case. Note that in second case, the values inside parenthesis become negative. Therefore the probability value can be calculated from the table according to the following rule

$$\phi(-a) = 1 - \phi(a) \tag{4.19a}$$

By now, we discussed the calculation of nodal imbalance probability. For the zonal imbalance probability the scenario is completely different. Many works proposes to consider the correlation between zonal and nodal imbalance. However this correlation is strongly depend on how the geographical zones are defined, and the node is located in which part of zone. As an example, for the small zone with a single non-programmable generation unit located in the central node of zone, the correlation between zonal and nodal imbalance is very high. In particular, in Italian power system, the zone definition for calculation of imbalances is divided only by two macro zones, *SUD* and *NORD*.

On the other hand, the calculation of zonal imbalance is carrying out by TERNA, according to the criteria introduced in section 2.3. The calculation publishes by TERNA on monthly bases, at the end of each month. In this regard, using an analytical similar to the approach introduced to calculate nodal imbalance seems ineffective. On the other hand, considering the correlation between a single plant imbalance and zonal imbalance may not effectively meet our expectations. Based on these facts, it is proposed to calculate zonal imbalance probability based on the zonal imbalance sign[39] published by TERNA for each macro zone, for each hour of the day. The statistical approach used to calculate zonal imbalance probability (ρ) is mainly investigated in section 5.2. There are many factors affecting the zonal imbalance, some of them can briefly described as:

- *Definition of zones:* The geographical definition of zones has a great impact on zonal imbalance. Each geographical zone has a peculiar pattern of weather condition and energy consumption.
- *Load behavior*
- *Method of calculation:* Two different methods of calculation is introduced by TERNA, and represented in equations (2.6) and (2.7). By comparing data corresponding these two methods of calculation, for the same period, the difference can be detected.
- *Hour-Season:* The season of the year has a great impact on zonal imbalance according to weather condition and duration of the day. As an example, in summer, the effect of solar PV generation unit is high, causing higher probability of positive zonal imbalance during the day.
- *Network condition:* based on old method of imbalance calculation, congestions in network has a key influence on zonal imbalances. As an example, congestion in power transmission between zones *SUD* and *NORD,* in periods of high renewable penetration in *SUD* causes the excess of energy in zone *SUD.* Transmission network developing plans will reduce the effect of congestions.
- *Developing of NP-RES:* In particular, increasing penetration of these types of generation in a certain zone has direct impact to increase in zonal imbalances.

All of the factors presented above all subject to change, however, these changes will happens not instantaneously, but gradually over the years. Therefore finding the pattern of imbalances for each hour-month and including the local conditions and real time situations may help to effectively calculate the probability of zonal imbalance for each hour-month in order to be used in our model.

[39] Segno Sbilanciamento

4.7 Model Assessment

In order to assess the effectiveness of the model, the computer aided tools and programming techniques are required to generate the bidding variables (Q P) for all periods of the reference year (one hour for non-enabled units or quarter of an hour for enabled units participating in MB). This tool uses the estimated input variables provided for corresponding period, for whole the year. Once the results are provided and stored completely, the final outcome would be computed by an appropriate simulator. The outcome of this simulation will explain the effectiveness of the presented model and profitability of participating in ASM in terms of annual increase or decrease in revenue, comparing to the case of no participation in reserve market. Figure 4.15 illustrates the approach which will be discussed in details during the next chapter.

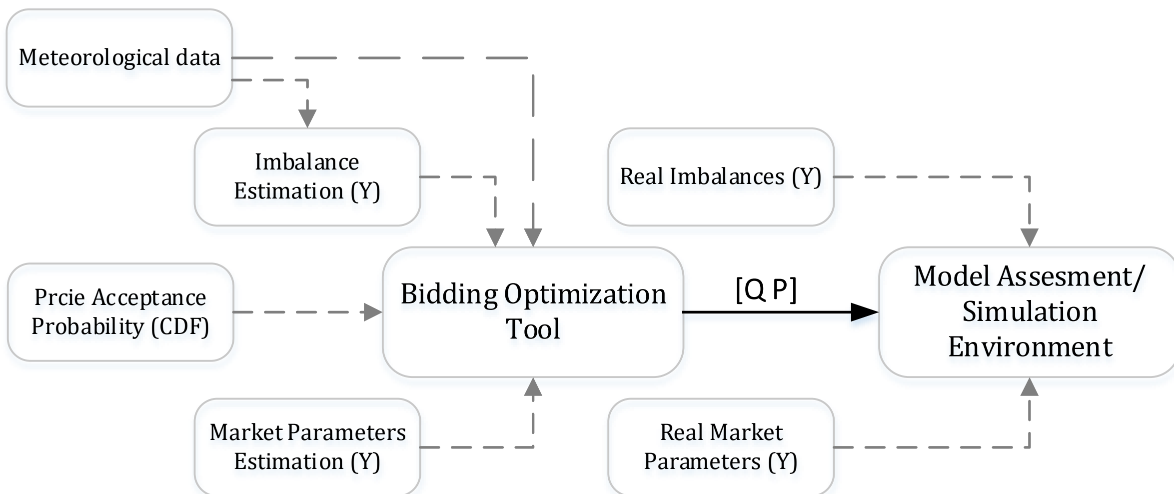


Figure 4-15: Algorithm for the assessment of optimization model

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Chapter 5

Simulation; Wind Plant's Opportunity in ASM

In the previous chapter, analytical methods to calculate the profit opportunity and bidding strategy for wind plants, based on Italian regulatory framework, have been investigated. The presented model is associated to various input parameters which must be estimated before real-time to calculate the bidding quantities to be offered in real time, in order to earn maximum financial profit by provision of regulation downward service in ASM. Clearly, the stochastic nature of inputs always exposes the generation unit to a certain amount of risk to lose money. In this regard, using the appropriate methods or instruments to fairly accurate estimation of input variables has key role to obtain high degree of success. Methodologies in order to estimate new input parameters which are introduced by this model, such as imbalance quantity, probability of zonal and nodal imbalances and probability of accepted price, have been investigated in previous chapter and will be more discussed further in this chapter. It can be shown that the sensitivity of final outcome varies for different input parameters. In other words, variation in some input parameters causes significant variation in final outputs, both in terms of selection of bidding quantities and final profit, meanwhile, these outcomes are less sensitive to the variation of some other parameters.

This chapter aims to provide a benchmark in order to utilize and assess the effectiveness of the instrument presented in previous chapter. In section 5.1 to 5.3 methods to collecting data as input variables are presented for one reference year. In section 5.4, the data collected are utilized to run the bidding strategy and estimate the profit opportunity in ASM, without considering the risk associated to errors in estimation of input parameters. For this purpose, data provided by TERNA© as transmission system operator as well as GME© as operator of electricity market are elaborated in MATLAB® [02] environment, and stored as input vectors and matrices for each single hour in the year. In section 5.4, the computer algorithm is created first to calculate the bidding quantities and probability of the acceptance of such quantities, and second to calculate the profit earned in one year by participation in ASM, considering different level of risk of estimation errors. Table 5.1 presents the list of variables presented by vectors to be calculated and used in next sections. It should be noted that in practice, the significant period for calculation of imbalance settlement is based on quarter of hour. However, in this chapter, for the sake of simplicity, a significant period for bidding in market and imbalance settlement is considered equal to one hour.

Table 5-1: List of input/output variables to be used in analysis

Variable	Type	Variable	Type
Q_{CE}	*Input*	γ	*Input*
Q_{imb^-}	*Input*	CDF	*Input*
P_{MGP}	*Input*	$Q_{MB\downarrow}$	*Output*
$P_{MSD\uparrow M}$	*Input*	$P_{MB\downarrow pb}$	*Output*
$P_{MSD\downarrow M}$	*Input*	*Zonal Imbalance Sign*	*Input*
$P_{MSD\uparrow MAX}$	*Input*	*Rev.WOR*	*Output*
$P_{MSD\downarrow MIN}$	*Input*	*Rev.WR*	*Output*
Premium	*Input*	*PF*	*Output*
ρ	*Input*	P_{acc}	*Output*

5.1 Probability of Imbalances

5.1.1 Probability of Zonal Imbalance

According to the model presented in this work, zonal imbalance probability (ρ) is considered as an input variable which has influence on bidding price selection. In the other words, fair estimation of this parameter helps to determine a more optimized bidding price. On the other hand, in the phase of simulation, the real hourly zonal imbalance sign is utilized to determine the revenue of the plant associated with that hour.

Zonal imbalance is a system wide parameter which is calculated by TERNA. This calculation previously was carrying out based on method presented by equation (2.6). Recently, TERNA carries out this calculation based on equation (2.7). In former case, the accepted quantities of bids and offers presented by market participants in ASM were considered as criteria to determine the value of zonal imbalance, which is correlated to ASM actors behavior. In latter case, the quantity and sign of zonal imbalance is calculated based on difference between measurements (real time injections and withdrawals) and programmed (injections and withdrawals) quantities of energy traded in specific zone. Knowing about this quantity for production units is usually out of access in real time. In fact, TERNA publishes data regarding hourly or quarter hourly of zonal imbalance on monthly basis, during the month after the period of corresponding imbalance. Currently, two macro zones *SUD* and *NORD* are considered for calculation of zonal imbalance, which means that each unit located in Italian territory belongs to one of these macro zones. If we assume that NP-RES power plants are the main cause of zonal imbalance, occurrence of positive or negative zonal imbalance is the result of total actor's behavior distributed in a vast geographical area, and the behavior of single actor alone, or few number of actors located in small area doesn't significantly alter the result. On the other hand, if the system operator defines the macro zones based on very small geographical area, the single plant or

a group of power plants behavior located in center of zone significantly influences the zonal imbalance, in other words, the correlation between zonal and nodal imbalance would be very high.
As described above, it is proposed to estimate zonal imbalance probability looking at the historical quantities of imbalances in conjunction with the influencing factors which can be observed close to real time. Some important influencing factors are already listed in section 4.6.
Based on data provided by TERNA [04], figure 5.1 represents the percentage of positive zonal imbalance of each single hour, during each month of three consecutive years, based on new method of imbalance calculation.
Another parameter which helps to improve the estimation of zonal imbalance probability is the range of variation of imbalance ratio on monthly basis. If we assume that the ratio of positive zonal imbalance can be called by ρ, the boxes in figure 4.2 represent the interquartile ranges (from 25^{th} to 75^{th} percentile) of the ρ for each month of each year. In particular for the year 2017, the interquartile ranges of each month show a narrower range. This narrower range increases the reliability of estimation.
In order to perform the calculation of bidding quantities for one year based on estimated probability of positive zonal imbalance, as well as calculation of profit based on real sign of zonal imbalance for each significant period (one hour in this case), the following procedures are introduced based on data provided by system operator

- *For calculating the bidding price quantity, the value of positive zonal imbalance probability (ρ) should be used as input variable. In this regard, a vector consistent of a number of elements equal to each hour of the year is created in MATLAB®, containing the estimated value of ρ for corresponding hour.*
- *For calculating the annual revenue and profit of generation unit, the actual sign of zonal imbalance should be used as input variable. In this regard, a vector consistent of a number of elements equal to each hour of the year is created, containing the actual sign of zonal imbalance for corresponding hour.*

The first variable which is based on estimation, is used in first phase of simulation in order to generate bidding variables and quantities. The second one, is determined by system operator and is used to calculate the profit obtained by bidding for corresponding hour of the year. According to zonal imbalance sign, TERNA indicates the price of imbalance energy to be applied to generating plant.

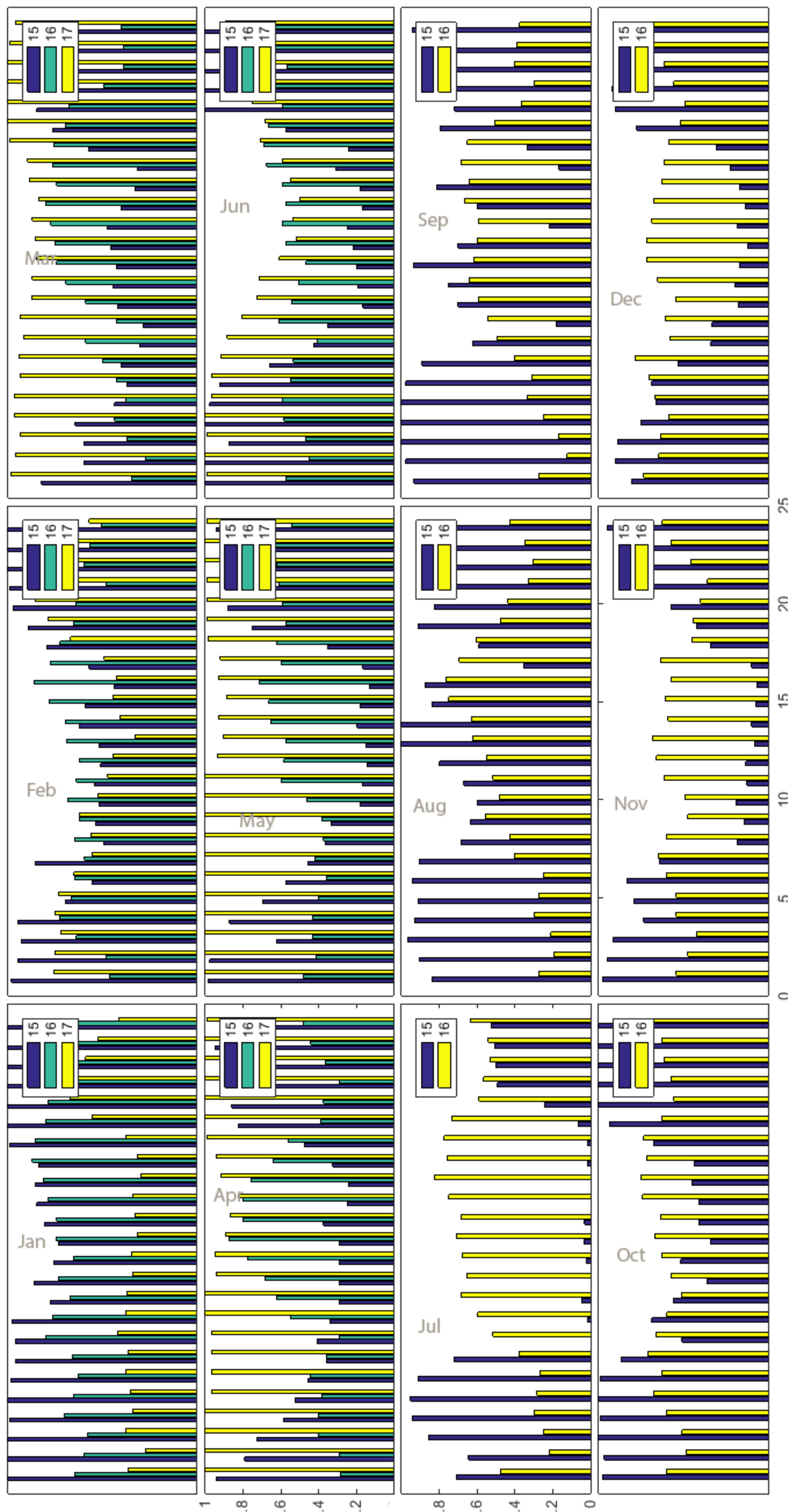

Figure 5-1: Probability of zonal imbalance, calculated based on real data

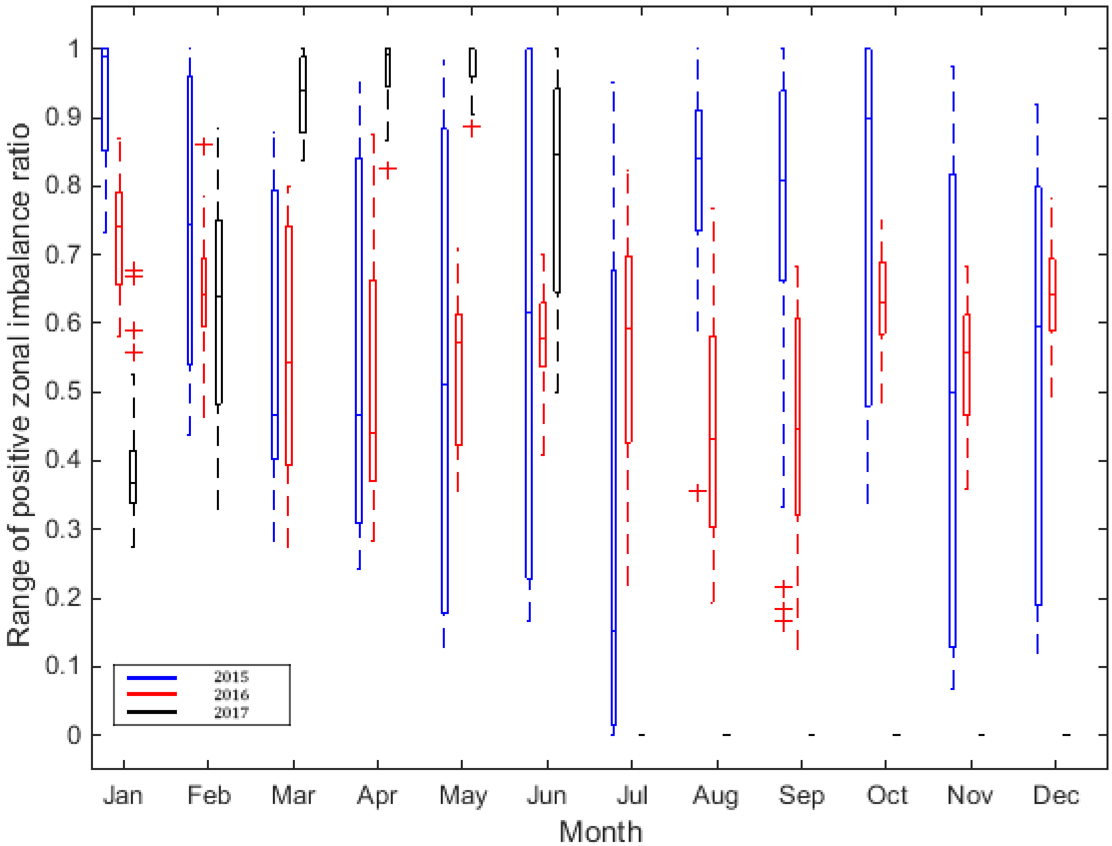

Figure 5-2: Box-Plot representing range of monthly positive zonal imbalance ratio

5.1.2 Probability of Nodal Imbalance

In section 4.6, statistical method to find the negative nodal imbalance probability (γ) to be used in bidding selection formula was introduced. In this method of calculation, the correlation between zonal imbalance and nodal imbalance is not considered. Unlike the estimation of positive zonal probability which is based on system wide behavior of numerous different actors, the calculation of negative nodal imbalance probability is completely based on plants individual behavior and plant's statistical data. In other words, the proposed method calculates γ based on forecast data and values of MAE close to real time of delivery.

In order to implement the analysis in this chapter, similar to the case of ρ, the value of γ should be used as input variable. As mentioned before, in order to create the values reflecting the real situation, for each individual plant, the statistical data for measured forecast errors samples and the values of MAE for different time spans as needed.

In this stage of the project, these real statistical data are not accessible from any private power plant, therefore a random statistical approach is used to create the vector of γ in MATLAB, to be used as the input of simulation. In this regard, assuming the generic power plant is located in the center of zone and the meteorological condition is the main influencing factor on imbalances, the zonal and nodal imbalance are considered correlated together. Therefore, in this work, the vector of γ is randomly generated based on vector of the ρ, with the random variation range equal to ±10% for i^{th} element of the vector. The function for calculation of γ is presented as following

$$\gamma(i) = randi([\max(0;\ \rho(i) - 10\%) \quad , \quad \min(\rho(i) + 10\%;\ 100)]) \tag{4.1}$$

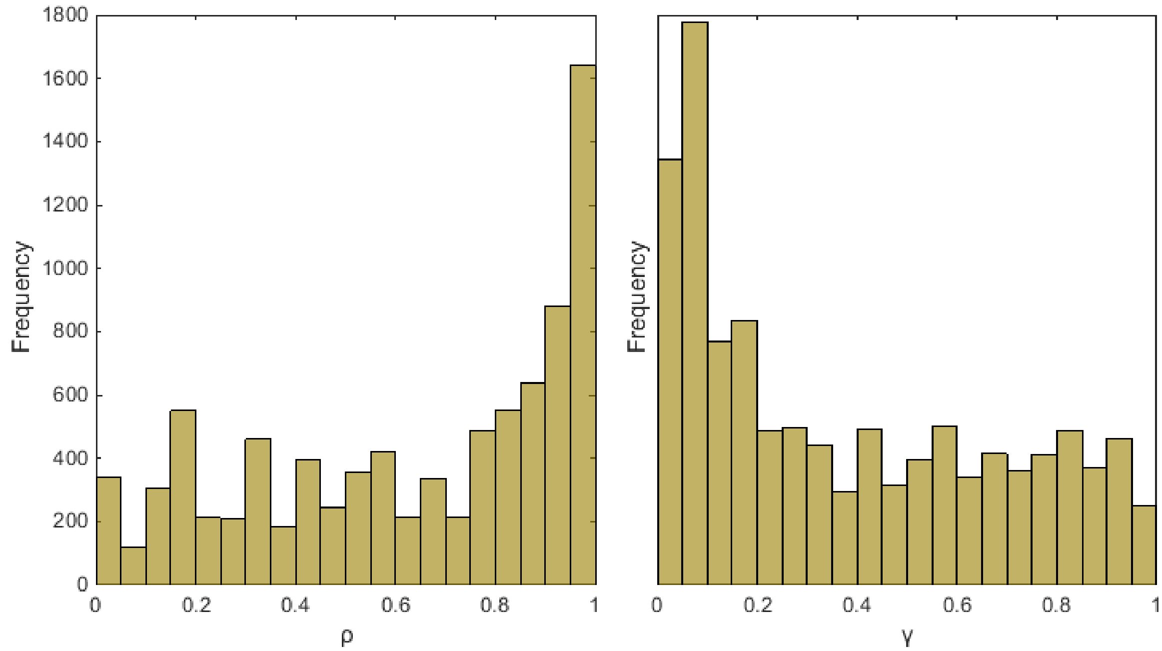

Figure 5-3: Distribution of ρ and γ over 8760 hours of the year

The distribution of ρ and γ vectors over 8760 hours of the year is presented in figure 5.3(left) and 5.3(right). It can be realized that ρ is mainly concentrated around one and in opposite, the γ is mainly concentrated around zero.

5.2 Market Variables

Market variables refer to the input variables which are imposed by market such as market prices presented in table 5.1. Among them, Q_{CE} will be investigated in this section since it represents the planned quantity to be sold in energy market and is independent from bidding strategy in ASM. $Q_{imb}$is not directly a market variable, however since the plants will be penalized according to this quantity, it will be addressed in this section. According to data provided by market operator [03] and system operator, these values are collected, refined and stored in vectors inside MATLAB in order to be utilized in simulation. In the following, the main points regarding generation of these input variables are investigated.

$\boldsymbol{P_{MGP}}$: This variable represents zonal market price, based on day ahead or intraday clearing sessions. The generated energy to be sold in market would be valued at this price. Furthermore, system operator uses this price to remunerate the imbalances in case of dual price mechanism applied to *Enabled* units. According to the data provided for each hour of the whole year 2015, the distribution of market prices for all single hours of 2015. The figure shows the prices are normally distributed around 49.56.

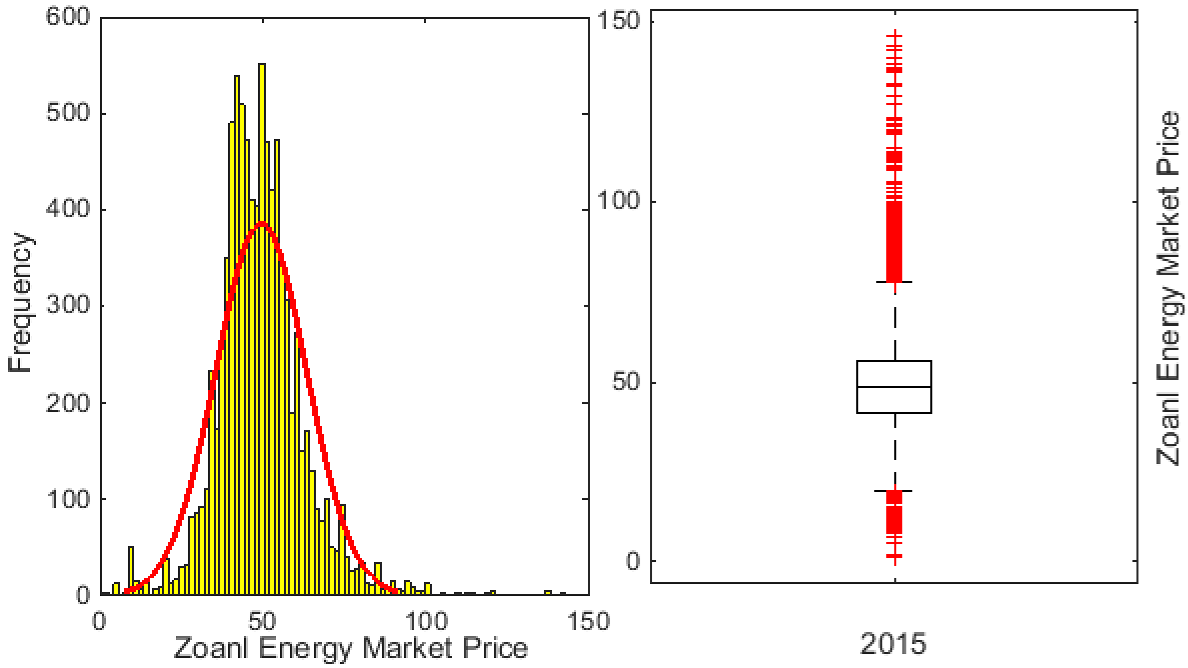

Figure 5-4: Distribution of zonal market price in 2015

***$P_{MSD\uparrow M}$, $P_{MSD\downarrow M}$, $P_{MSD\downarrow MAX}$ & $P_{MSD\uparrow MIN}$*:** These variables represent medium, minimum and maximum values of ASM accepted prices for each hour of the year. As investigated in section 2.2, the system operator uses these prices in order to apply imbalance charge for *single price* and *dual price* imbalance mechanism. The estimated values of these variables are used in optimization formulation for bidding selection. Besides, the real values of these variables are used in profit formulation since the profit is calculated as difference between revenues when the plant is participating in ASM and when is not participating in ASM respectively. For first case, the plant is enabled and its imbalances are treated by *dual price* mechanism, while in second case, the plant is not enabled and is treated by *single price* mechanism.

Figure 5.5 represents the distribution of ASM prices in a year based on data provided by system operator on hourly basis. In order to use these variables as input, for each variable, data corresponding to each single hour of the year are presented in a vector.

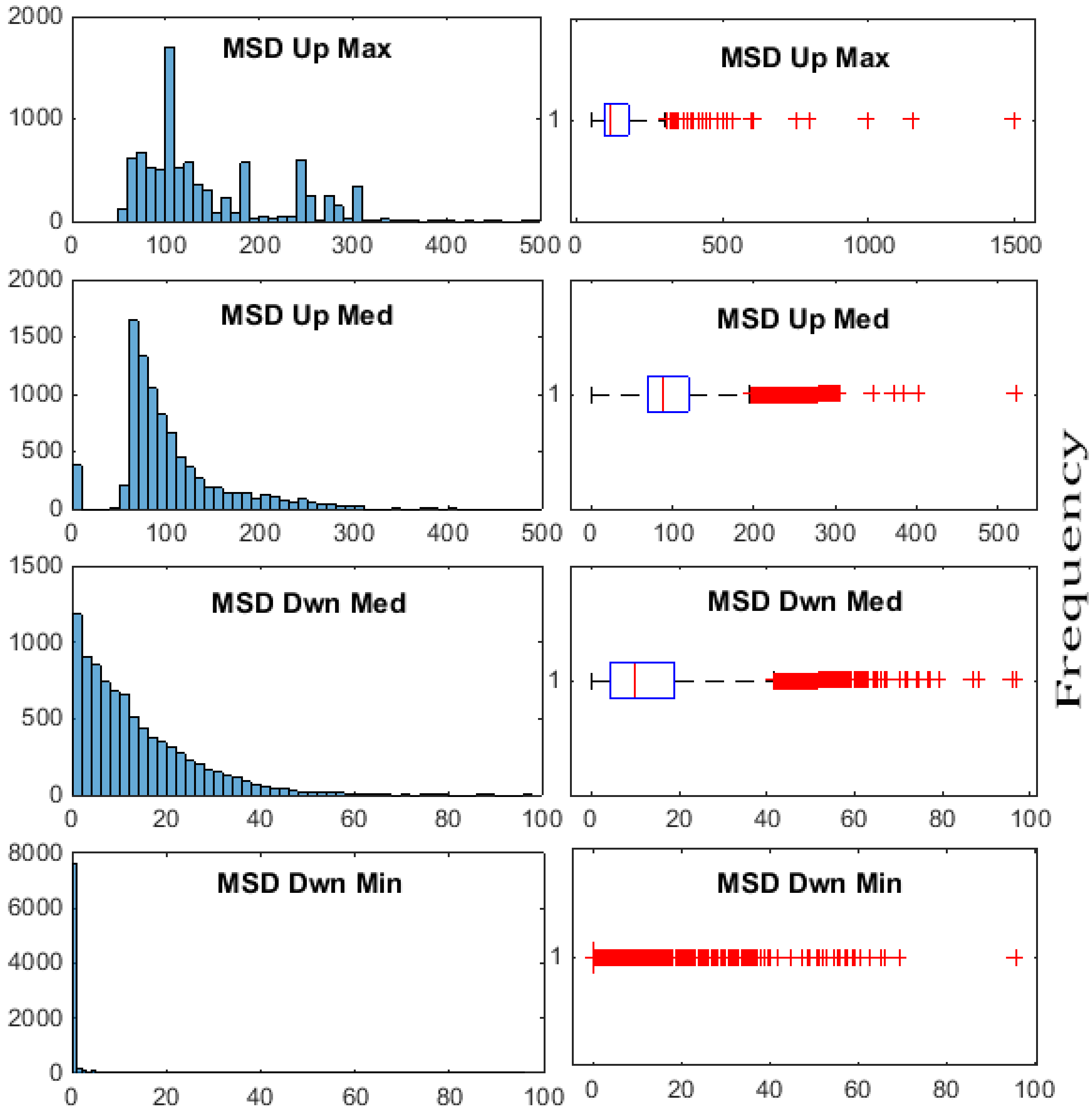

Figure 5-5: Distribution of ASM prices over 8760 hours of the year

$\boldsymbol{Q_{CE}}$: This variable represents the energy planned to be traded in energy market according to day ahead and intraday market sessions. In general, this planned energy is equal to all forecasted available energy of the plants. In current market conditions, mainly due to the zero price participation in energy market, wind plants offers are all accepted in energy market. Furthermore, plants receive incentives based on injection of energy to the network. Therefore, it is assumed that the plant offers its best forecast in energy market, and this offer will be fully accepted during the planning phase.

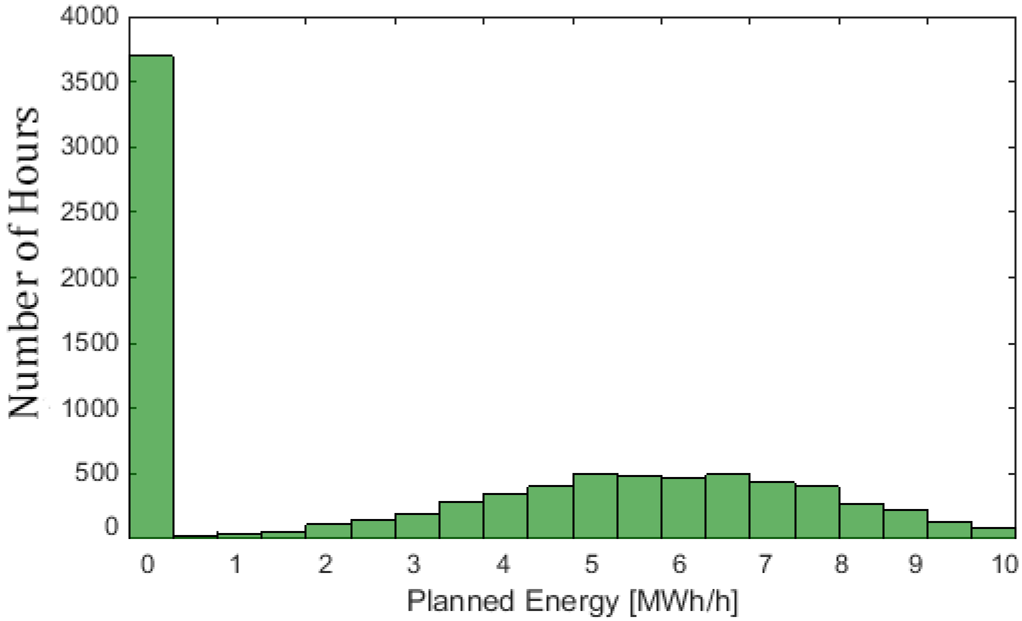

Figure 5-6: Distribution of Planned Energy in Energy Market over 8760 hours of the year

Figure 5.6 represents planned energy offered in energy market for a generic 10 MW wind plant. The annual production of the plant is equal to 29.897 GWh. The annual equivalent utilization hours of this generic plant equals to 2989 hours. According to this annual production information, plant is shut down for 3681 hours (42% of the times). In other hand, in 3472 hours of the year (40% of the times), wind plant's production is equal or greater than the half of the production capacity.
It should be noted that this energy quantity which is corresponding to sell of energy in energy market, constitutes the main component of total plant's revenue. In other hand, for 3681 hours of the year, wind plant is unable to participate in ASM market, since there is no production and subsequently no downward reserve to provide as ancillary services. Similar to previous steps, the quantity of planned energy for each hour is stored in a vector, to be utilized in revenue calculation.

$\boldsymbol{Q_{imb}}$: This variable refers to the imbalance quantity or deviation of the plant's production in real time with respect to the planned energy. The root cause of imbalance is forecasting error in time span between planning time and real time of delivery. Assuming that wind plant's accepted offers are according to best estimation, forecast error and subsequently imbalances would be random variable with normal distribution around mean value equal to zero. In some cases, producers may choose to strategically offer their production higher or lower than the best forecasted production. In these particular cases, the distribution of imbalances would not be normal anymore.
In order to include imbalance quantities in analysis, similar to previous steps, the values of imbalances must be generated and stored in a vector according to the following criteria:

- *It should comply with the values of MAE for the generic plant selected for the analysis. In this case, the value of MAE is considered equal to 20% for each different time spans between gate closure time and delivery hour*
- *It should have a distribution around* $\boldsymbol{Q_{CE}}$
- *Imbalance quantities for the hours corresponding to shutting down of plant is equal to zero*
- *The correlation between* $\boldsymbol{Q_{imb}}$ *and* γ *should be respected*
- *It should not violate the plant's capacity constraints, in particular for 10 MW power plant*

$$\begin{cases} Q_{CE,i} + Q_{imb,i} \geq 0 & \forall\ Q_{imb,i} < 0 \\ Q_{CE,i} + Q_{imb,i} \leq 10 & \forall\ Q_{imb,i} \geq 0 \end{cases}$$

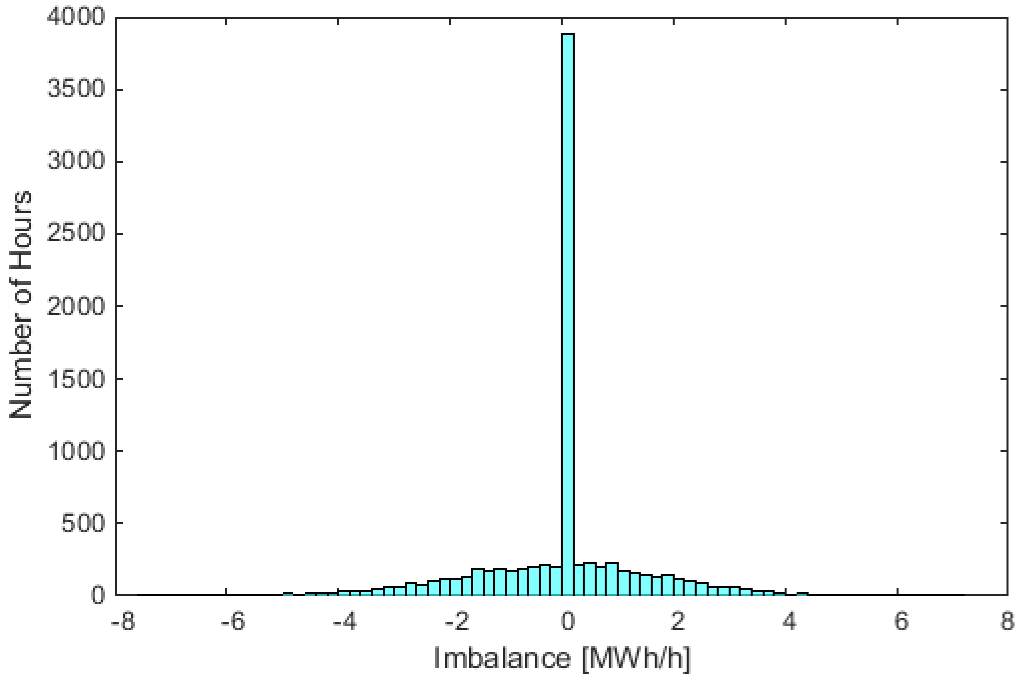

Figure 5-7: Distribution of Imbalance Quantity in Energy Market over 8760 hours of the year

Figure 5.7 represents the distribution of plant's imbalance quantity. Note that the high frequency of zero imbalance corresponds to the fact that, at zero generation hours, the quantity of imbalance is zero as well.

Premium: This variable represents the incentive which is paid in charge of each single MWh of energy injected into the grid. Different types of incentives and support schemes of wind power generation in Italy has been investigated in chapter 1. In particular, for generic large wind plants supported according to DM 23/6/2016, the value of incentive is calculated based on the difference between base tariff and market zonal price, for each hour of the year, and stored in a vector for further calculations.

5.3 Bidding Prices and Accepting Probabilities

As presented in previous chapter, in order to find the maximum opportunities in ASM, it is necessary to bid in an optimal way. Despite the fact that being accepted at zero-price brings the maximum profit for generation unit, it is accompanied with the lowest probability of acceptance and causes lowering down the annual profit by lowering the times which unit is accepted in service provision according to *merit-order* criteria. In this regard, section 4.3 has introduced a method to optimize the bidding price, thereafter the profit, by including the probability of acceptance in bidding algorithm. This has been done by applying the CDF vector along price axis of bidding price, for each significant period.

To do this, one vector of CDF, representing price and corresponding probability of acceptance, is needed for each significant period of bidding (one hour in this case) to be used in optimization.
This section presents the procedure that leads to this evaluation. This procedure was already described in [01] for upward reserve opportunities in ASM and the approach is used in this section in order to extend the method to the downward reserve. Data collected here refers to the zone *NORD* and in particular for MSD Ex-ante. The reason to do so is that at the present time of ASM operation, the bids and offers for this zone has a significant abundance with respect to the other zones and balancing market[40], which provides more advantages in terms of statistical analysis. This procedure is as following

- *Determination of the regulation services of interest in ASM*
- *Derivation of the reference data for the analysis*
- *Elaboration of collected data through statistical evaluation methods*
- *Create the price-probability vector for each hour of the year*

5.3.1 Collection and Organization of the Data

This analysis has been carried out on the data of the ASM provided by market operator [03]. The data collected from the market operator are divided and organized per month, and one reference week for each month. Then a statistical analysis with the aim of establishing a probability-price vector for each hour of the reference week is carried out. Using this approach, the bids related to *secondary reserve (RS)* and *tertiary reserve (AS)* can be subject of the analysis. It is assumed that the intra-zonal transmission capacity is not congested and the selection of bids are only affected by merit order criteria. For each month of the year, the data are grouped according to the day of the week to which they refer. It allows the creation of a weekly structure composed by 24x7=168 elements, each one referring to a single hour of the week. The first 24 elements report all the relevant bids of the given month presented on Monday, divided according to their reference hour; the elements from 25 to 48 report the bids of Tuesday, and so on for all the days of the week. For the days of other week, the same bids of the days belonging to reference week are used. In creation of the reference weekly structure, it is assumed that each month has its specific features and avoids to replicate for each week separately. Furthermore, by structuring data in a reference week, the general characteristics of prices are illustrated and the specific hours with the exceptions are not included. Using this approach, at the end, the bids grouped per month in a weekly reference structure are available.

[40] Mercato di Bilanciamento

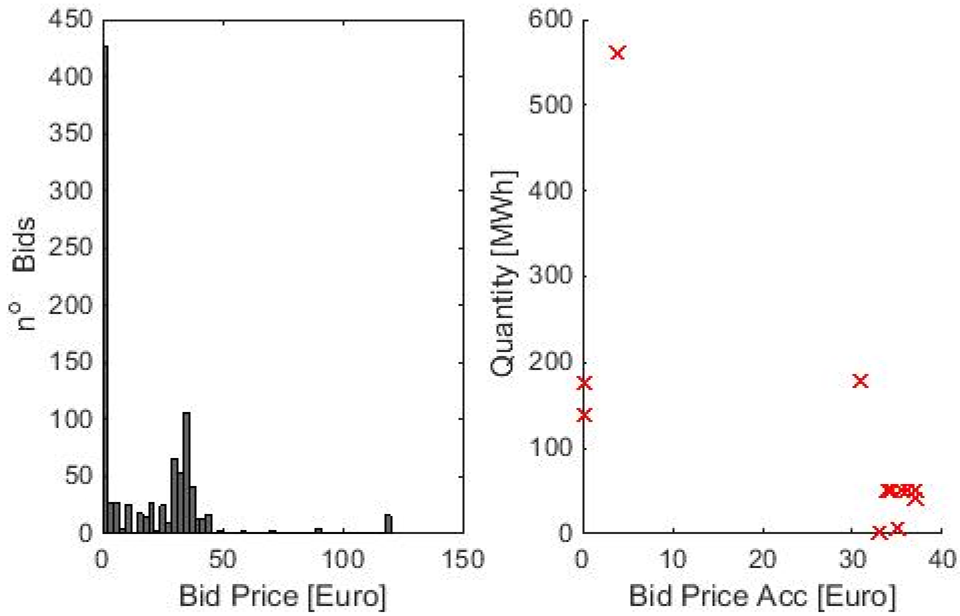

Figure 5-8: Presented (Left) and accepted (Right), 10:00, Monday of reference week, July

5.3.2 Statistical Features

The target of this section is associating the corresponding probability of acceptance of each price, for a given hour of the year and downward reserve bids through statistical analysis and probability distribution. Figure 5.8 represents distribution of presented bids (Left) and accepted bids (Right) for single hour of reference week.

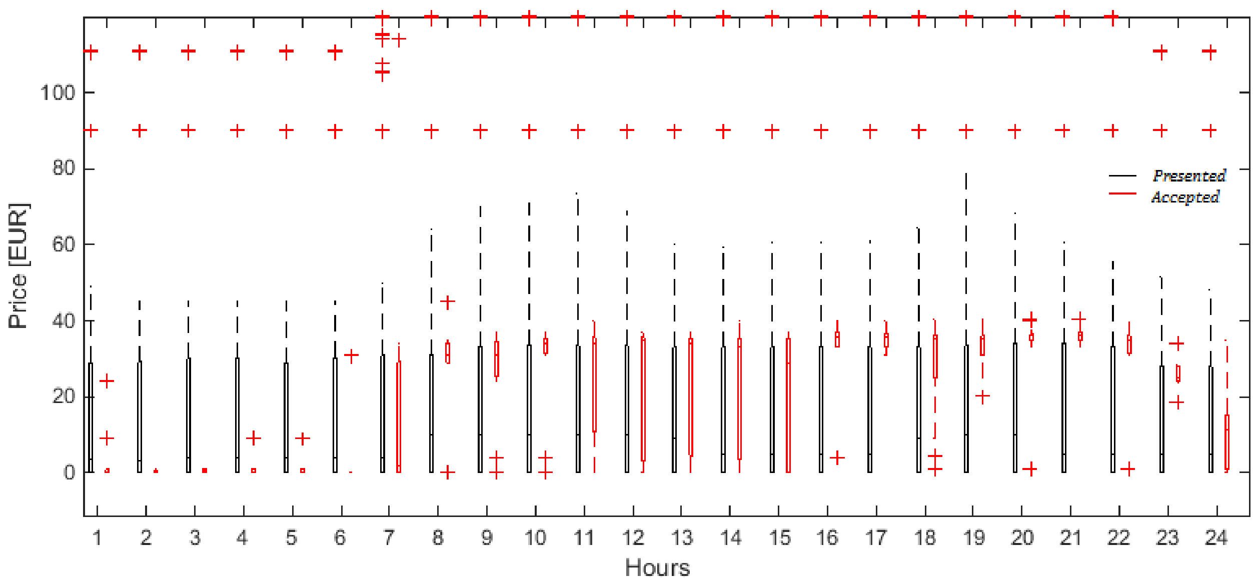

Figure 5-9: Presented prices vs accepted price during the day

Note that in accepted bids, each mark in plot corresponds to one bid. Note that among presented bids, highest frequency corresponds to the lower prices near zero and the bids are comprised between 0 €/MWh and 45 €/MWh. However, for the accepted bids, most prices are comprised between 30

€/MWh and 40 €/MWh. Figure 5.9 represents the behavior of presented bids along whole day of Monday in reference week of February.
A further data analysis describing the qualitative and quantitative behavior of ASM for any hours based on data collected is presented in [01], however, since this work is not fully intended to perform parametric analysis of the ASM, in this level we pay more focus to build a distribution function in order to evaluate the acceptance probability of downward reserve bids based on the presented prices in a non-parametric density estimation.
In this manner, this method proposes to use the histogram, by dividing the sample range into suitable number of bins. In this case, the height of bars represents the number of samples falling into the corresponding bin. Figure 5.10 (left) represents the histogram of accepted bids for the hour 10:00 of Monday of the reference week in February.
In order to find the distribution function of probability, the *Kernel Density Estimation (KDE)* method is proposed. In this method, the probability corresponding to a given value is calculated based on the ratio between number of samples and the interval in which the sample is falling into, and the product between the interval of samples and the total number of samples. Figure 5.10 (right) represents the probability density function obtained using KDE approach.

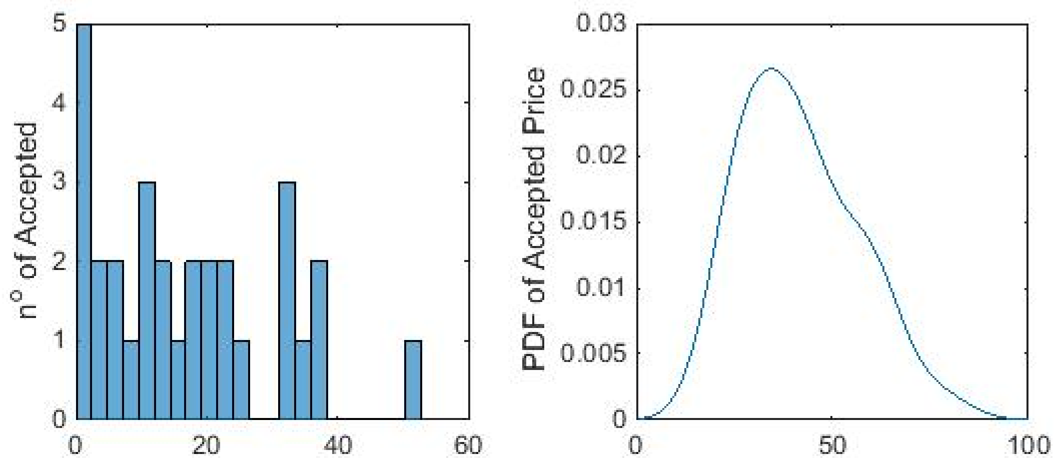

Figure 5-10 Histogram of Distribution (left) and PDF (right) of accepted bids

This function shows the estimated distribution of prices in terms of number of accepted bids. Based on merit order criteria and intuitive understanding of bidding selection, probability of accepting the bids should be increased by increasing bidding price. Considering this fact, the cumulative distribution function obtaining from probability distribution function can represent the probability of acceptance associated to each bidding price. Figure 5.11 represents the cumulative distribution function of price distribution. Note that the probability of acceptance is close to one for prices higher than 70 €/MWh.
In order to apply these probability vectors to the optimization model, it is required to store the probability-price function in each specific hour in year as an input matrix. By this motivation, a matrix with 8760 rows is created in MATLAB®. For each specific row which represents the hour number in year, the columns represents the value of probability. Therefore, for each hour of the year, the corresponding row of the matrix is applied to the optimization formula, as described in section 4.3.

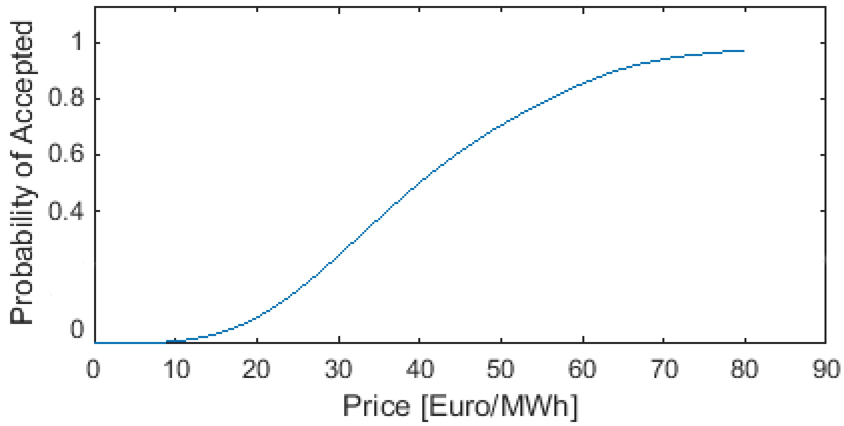

Figure 5-11: Cumulative distribution function, representing probability of acceptance

5.4 Simulation and Results

In previous sections, all input variables are collected based on real data provided by market operator and system operator as well as technical characteristics of wind plants and generation forecast. In this section, we aim to utilize these vectors as the input variables to simulate the outcomes of wind participation in ancillary services market, by only provide downward regulation. In this regard, all the calculations performed in this section are based on the concept, methodology and formula presented in chapter 4 in order to numerically analyze the wind plant opportunity in ancillary services market.

The simulation presented in this section is carried out in two main phases. In the first phase, an optimization tool is implemented in MATLAB to optimally generate the bidding quantities and probability of acceptance for one year by which the plant may participate in ASM. In the second phase, the generated bidding quantities are used in order to evaluate the economic effect of participation in ASM.

5.4.1 Selection of Bidding Quantities

The methodology of optimized bidding quantities for a single hour is introduced in chapter 4, based on equation 4.16 by applying input variables obtained in previous sections. Figure 5.12 represents the algorithm to determine bidding price for each hour of the year.

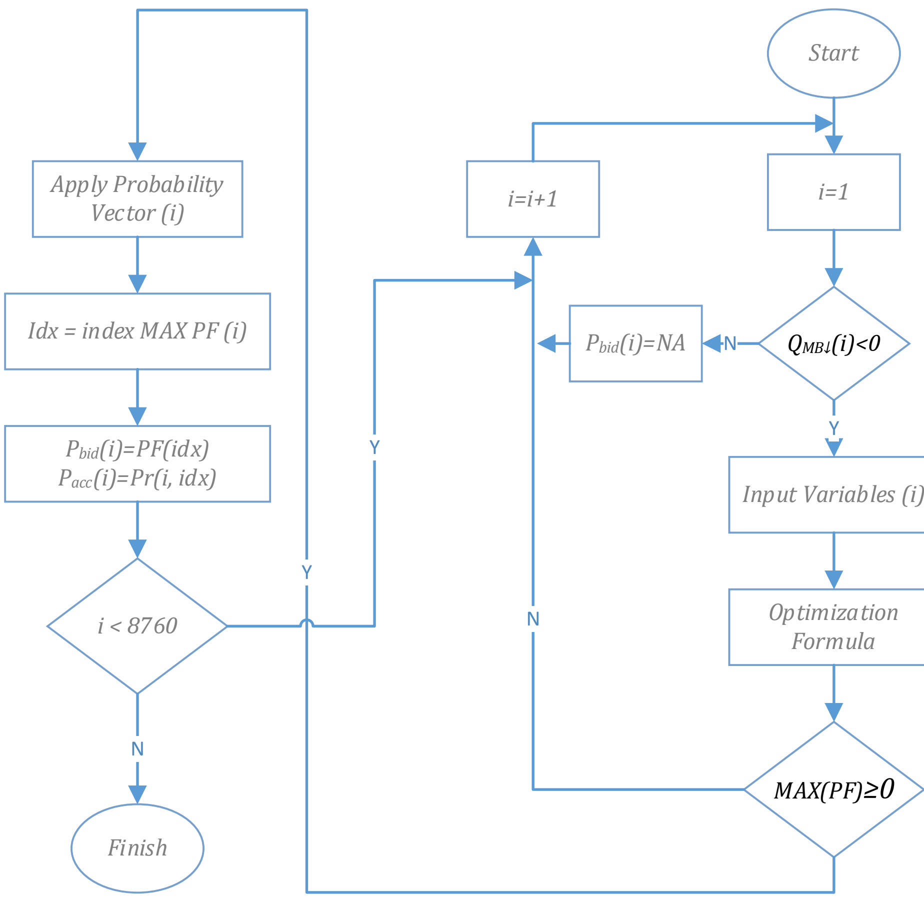

Figure 5-12: Algorithm of bidding price selection

Based on this method, the bidding in market only takes place when the imbalance quantity is negative. In other words, it is already investigated that for positive imbalance quantities there is no positive profit opportunity by providing downward reserve. Furthermore, the bidding in ASM is allowed when the maximum value of *Profit Equation* is positive. The value of this equation is only positive for sufficiently high probability of *Negative Nodal Imbalance (γ), meaning* lower risk of providing downward reserve when plant faces *Positive Nodal Imbalance*. At the end of this process, the vector of bidding prices and probability of acceptance corresponding to each price will be generated.

According to the results of bidding selection, the bids are generated only for 1870 hours of year, which is equal to 21% of the times. This is due to the fact that the plant is able to generate the power in 5709 hours of the year, and among them, for 2539 hours it faces negative nodal imbalance. Figure 5.13 represents the distribution of bidding prices over the hours of participation in ASM.

Table 5-2: Result of Bidding Selection Algorithm for a generic day in July

hour	Monday			Tuesday			Wednesday			Thursday			Friday			Saturday			Sunday		
	P_{bid}	P_{acc}	$Q_{MB\downarrow}$	P_{bid}	P_{acc}	$Q_{MB\downarrow}$	P_{bid}	P_{acc}	$Q_{MB\downarrow}$	P_{bid}	P_{acc}	$Q_{MB\downarrow}$	P_{bid}	P_{acc}	$Q_{MB\downarrow}$	P_{bid}	P_{acc}	$Q_{MB\downarrow}$	P_{bid}	P_{acc}	$Q_{MB\downarrow}$
0	NA	-	-0.82	NA	-	0	NA	-	-1.69	0	42	-3.43	NA	-	1.2	NA	-	0	NA	-	5.73
1	NA	-	0	NA	-	-2.46	NA	-	0	NA	-	1.5	NA	-	1.1	NA	-	0	NA	-	-1.10
2	NA	-	0.36	NA	-	1.13	NA	-	-1.01	NA	-	0	NA	-	-0.2	NA	-	0	NA	-	0
3	NA	-	1.51	NA	-	0	NA	-	0	NA	-	2.19	NA	-	0	NA	-	0	NA	-	0.7
4	NA	-	0	NA	-	0	NA	-	0	NA	-	0	NA	-	0	7.9	43	-0.77	NA	-	0
5	NA	-	2.44	NA	-	-2.78	NA	-	3.21	NA	-	1.01	NA	-	0	NA	-	1.21	40.6	88	-0.78
6	NA	-	0	NA	-	-2.35	NA	-	0	NA	-	0.1	NA	-	0	NA	-	0.56	NA	-	0
7	NA	-	2.34	NA	-	0	NA	-	-0.89	NA	-	1.7	NA	-	0.8	NA	-	0	NA	-	0.95
8	NA	-	-0.09	NA	-	0	NA	-	-1.46	NA	-	-2.89	NA	-	-4.01	NA	-	0	NA	-	0
9	NA	-	-1.50	NA	-	2.15	NA	-	-2.06	NA	-	0	NA	-	0.63	NA	-	0	NA	-	0
10	NA	-	-2.50	39.5	86	-1.96	39.8	85	-1.65	30.1	66	-03.	NA	-	-2.49	NA	-	0	5.4	37	-1.89
11	14.10	56	-0.1	10.5	50	-1.59	26.7	62	-0.48	31.6	67	2.1	NA	-	0	8.8	48	-2.66	NA	-	3.03
12	0	40	-1.5	7.20	47	0	15.5	52	-0.31	32.4	67	-1.23	NA	-	0.50	0	40	-1.31	NA	-	0
13	1.80	42	-2.5	15.30	53	0	NA	-	0	30.5	66	-2.88	NA	-	0.26	NA	-	2.31	5.6	46	-0.95
14	15.90	55	-0.1	23.80	60	-5.56	NA	-	3.43	0	40	-0.7	NA	-	-1.11	NA	-	0.61	15.2	53	-2.89
15	22.20	60	-0.21	1.60	42	-2.32	23.8	60	-1.5	16.8	55	1.2	NA	-	0.38	NA	-	0	NA	-	0
16	36.80	72	-0.1	0	40	0	14.7	52	0	21.3	59	0	NA	-	-1.34	NA	-	0	NA	-	0
17	26.40	65	-3.43	13.20	50	-3.40	26.2	62	2.19	38.7	72	0.31	NA	-	4.08	NA	-	0	NA	-	0
18	13.30	65	-2	5	44	0	NA	-	0	23.8	61	-2.1	0	40	-2.66	NA	-	0	NA	-	0
19	0	52	-0.25	14.5	53	-1.30	18.5	55	1.01	28.1	64	-1.88	NA	-	0.36	NA	-	-0.56	NA	-	1.89
20	5.40	40	-0.01	24.5	62	-3.89	4.9	44	-2.39	54.8	81	-0.1	NA	-	0	NA	-	-0.64	NA	-	0.18
21	12	45	-2.4	14.9	54	-0.25	0	38	-1.72	0	44	0.94	NA	-	0	NA	-	0	12.2	53	-0.21
22	0	52	-3.9	0	43	-1.625	0	41	-2.89	NA	-	2.31	NA	-	0	NA	-	1.21	NA	-	-0.8
23	NA	-	-1.8	NA	-	0	NA	-	2.1	NA	-	0	NA	-	0.61	0	21	-2.38	NA	-	0

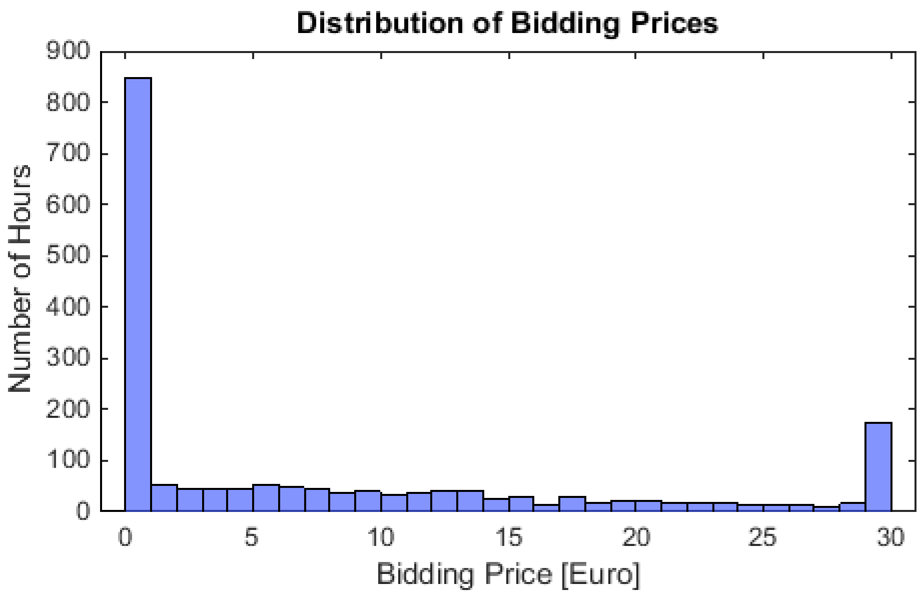

Figure 5-13: Distribution of Bidding Prices

5.4.2 Annual Revenue Calculation

With the aim of finding the influence of participation in ASM on annual revenue, a computer algorithm in MATLAB® is created in order to calculate the amount of change in annual revenue for a single plant by participating in energy and ancillary services market. This can be done by using the profit formula (4.3, 5.6, 5.8 and 5.10) introduced in chapter 4, it should be noted that for each hour, depending on the zonal-nodal imbalance sign, only one of these formulations should be utilized. These profit formulations are based on the difference between possible annual revenue by participation in both ASM and energy market by providing downward reserve, and possible annual revenue by only participating in energy market. In this approach, the calculation of first revenue formula is based on *Dual Price* imbalance mechanism, and the calculation of second revenue formula is based on *single price* imbalance mechanism. By this approach, it is possible to consider the change in revenue only due to the change of mechanism from *single price* (applied to non-enabled NP-RES plants) when transfers to *dual price* mechanism. It is shown that even if the plant is enabled but does not provide any regulation, the annual revenue will change due to the transition from one mechanism to another.

In first step of calculation, the simplified assumption is considered. It is assumed that there is no limit in transmission network and there is no congestion within a zone. Furthermore, it is assumed that the bids in ASM will be completely accepted. In further elaboration, it is possible to include other actor's behavior which influences the number of accepted bids

Once again, instead of directly using the profit formula, the annual revenue for each case can be calculated separately, then the profit can be obtained by simply differentiating between them and stored in a vector for the total hours of the year for further calculations. Table below summarizes these revenue vectors. These vectors are considered as *output* vectors, and the values are calculated using input vectors plus bidding vector generated in previous step. Table 5.3 represents the revenue vectors for the cases of reserve provision, no reserve provision with dual price, and finally the base case which is no provision of regulation with single price mechanism.

Table 5-3: Revenue vectors

Vector	Description	Size
Rev_WR_DP	Hourly revenue of the year, by providing reserve, Enabled unit with Dual price mechanism	*8760 x 1*
Rev_WOR_DP	Hourly revenue of the year, without providing reserve, Enabled unit with Dual price mechanism	*8760 x1*
Rev_WOR_SP	Hourly revenue of the year, without providing reserve, non-Enabled with Single price mechanism	*8760 x1*

In last two vectors, the revenue is calculated based on energy sold in market, incentives and the charges of imbalances. In case of reserve provision, the terms regarding energy rebought in order to provide downward regulation is included according to the criteria presented in chapter 4, based on *pay as bid* system. Figure 5.14 represents the algorithm for calculation of revenue vectors in MATLAB®. The results for the analysis is provided in table 5.4. According to the three revenue vectors, three vectors of profit are calculated with the aim of observing the opportunity of plant when the unit becomes *enabled* to provide downward regulation, with and without provision of reserve, compared to the case in which the unit is *non-enabled*.

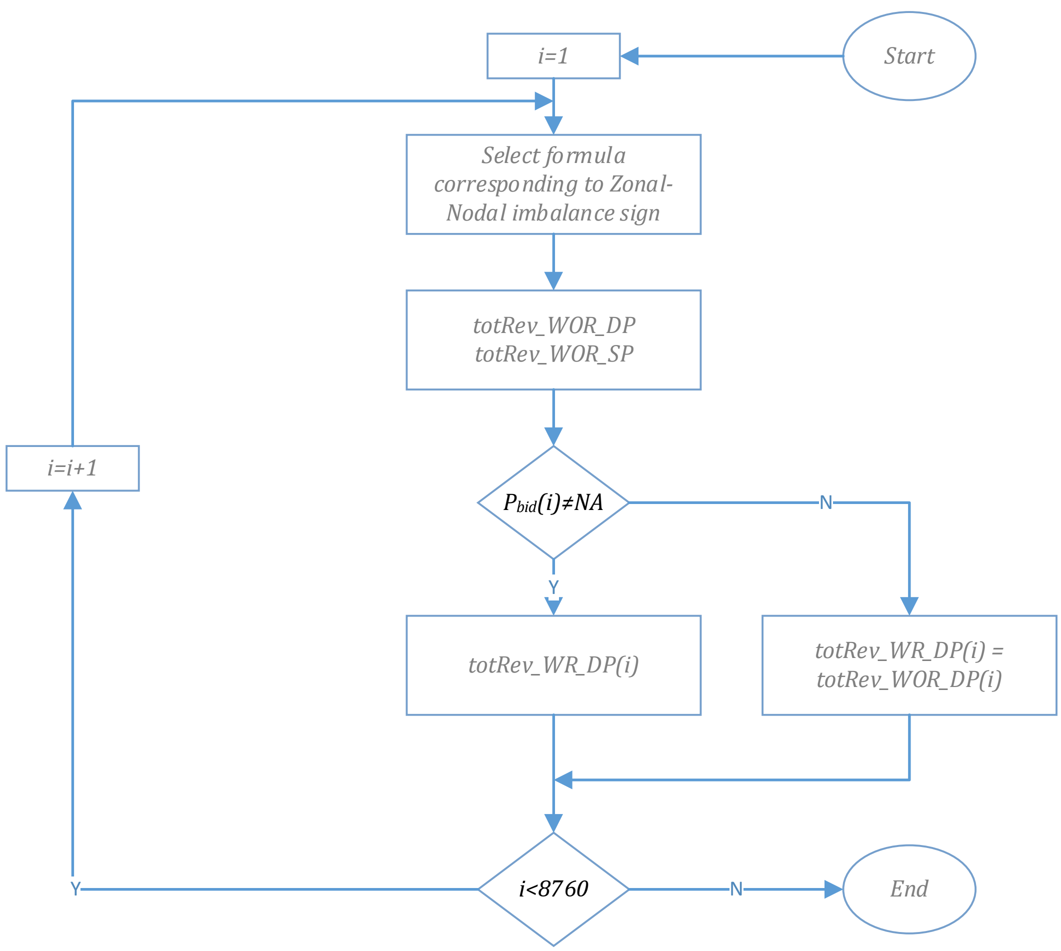

Figure 5-14: Algorithm to calculate revenue vectors

Table 5-4: Annual Profit Changes

Profit Vector	Description	Profit value	
		abs (M€)	%
PF_DPSP	*(Rev_WOR_DP) – (Rev_WOR_SP)*	-0.265	-9.21
PF_DP	*(Rev_WR_DP) – (Rev_WOR_DP)*	0.22	8.40
PF_SP	*(Rev_WR_DP) – (Rev_WOR_SP)*	-0.045	-1.5

The first term represents the change in annual cash flow when the unit moves to the dual price mechanism from single price mechanism, without providing any reserve. The second term presents the change in revenue, when the unit is enabled and provides regulation downward service, compared to the case of not providing regulation down. The last term represents the profit by providing reserve, compared to the case in which the unit is not enabled and does not participate to reserve provision. In this case, despite the profit is positive during the individual hours in which the unit provides downward regulation service, for the hours of not bidding in the market, the value of profit is negative since the unit loses money by transition to dual price mechanism. Figure 5.15 represents the distribution of profit for each case investigated in table 5.4.

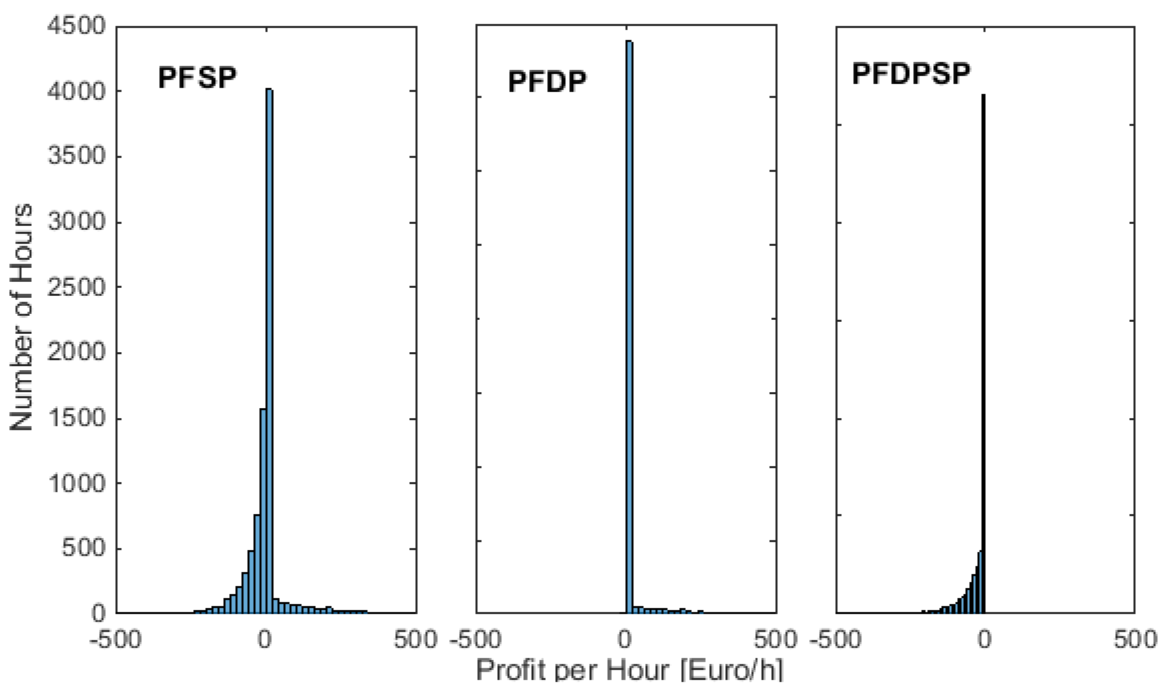

Figure 5-15: Illustration of number of hours with profit

Figure 5.15 (left), illustrates both loss in opportunity (negative values in x-axis) in hours in which there is no reserve provision. Positive values of x-axis corresponds to the hours in which plant provides downward regulation, and shows positive profit. Figure 5.15 (right) illustrates the negative profit considering only change in mechanism. In this case, despite the positive profit in the hours corresponding to reserve provision, the loss in opportunity cost in the hours corresponding to no-reserve provision is significant, which neutralizes the positive profit during downward reserve provision. These hours mainly are corresponding to the hours in which the plant faces positive imbalance and cannot offer in the market. In this regard, in order to exploit the remaining hours corresponding to positive imbalance, possibility of profit by providing upward regulation could be the subject of investigation in future works.

References:

[1] Filippo Bovera, *Optimization tool for the sizing of CHP plants in new energy market framework*, Politecnico di Milano, 2016

[2] MathWorks Inc., *Statistical toolbox for use with Matlab*: user's guide., 1999.

[3] Website of *Gestore Mercati Elettrici, http://www.mercatoelettrico.org*

[4] Website of *TERNA, http://www.TERNA.it*

Conclusion

In recent years, the number of RES generation units is grown considerably as instructed based on European directives such as 2009/28/EC and national energy developing plans. In particular, by considering the significant share of RES plants connected to distribution level, they are required to take more active roles and participate in system operation and management. However, realizing this action implies a major shift in regulations and operational practices, in order to properly integrate the new actors in markets, especially in ASM.

This thesis aimed to establish a general method to analyze NP-RES plant's profit opportunity in ASM, through detailed investigation of economic potentials and barriers, based on Italian regulatory framework and in line with the new reform of ancillary services market, with the focus on participation in downward service provision. The results obtained from this analysis can be used by operator of NP-RES generation units and aggregators during the planning phase of participation in ASM, and can be considered by regulatory authorities during the planning of next steps of the reform.

This work proposes a model to optimally find bidding strategies (quantity and price) to maximize the profit, by minimizing high negative imbalance charges through participation in ASM. The profit formula takes into account the economic consequences when the unit transfers to be *Enabled* in order to provide dispatching services in ASM. Based on the estimated input variables, the outcome of the optimization formula is a set of quantity-price values (region on a surface) by which the profit is positive. Therefore the optimal bidding values correspond to a pair of quantity-price by which the value of profit is maximum.

In earlier stage of analysis, it is found that the positive profit yields when

- The unit provides downward service when facing negative imbalance
- The accepted quantity of downward regulation is equal to the quantity of imbalance in real time

On the opposite side, it is found that the plant strongly loses the opportunity by providing downward reserve when faces positive imbalance. In order to avoid the high risk of loss in opportunity, the model selects the bidding quantity equal to zero, for the value of *negative nodal imbalance probability (γ)* lower than a certain value. This implies that for the periods in which the plant has high risk of providing downward service while it may face positive nodal imbalance, the bidding in market should be avoided. Further, a probabilistic method is introduced to estimate *(γ)* and negative imbalance quantity to be used in the optimization model based on gate closure time and mean values of forecast error for different time spans.

From the optimization model, it is found that

- Higher amount of incentives indicate lower positive profit by providing downward regulation, as it is corresponding to higher loss in opportunity.
- Lower amount of bidding price corresponds to higher profit, and profit reaches maximum for *zero price* bidding. However, bidding at zero price entails lowest probability of acceptance. In this regard, the model optimally selects the bidding price considering this compromise.

- Bidding quantity much higher than real time negative imbalance quantity implies high loss of revenue. For each significant period, the model indicates a range of bidding quantity by which the value of profit is positive (if exists), and is maximum when bidding quantity is equal to negative imbalance quantity. Therefore, to successfully bid the quantity, a fair estimation of real time imbalance quantity based on method introduced is crucial. Note that the bidding is based on different session market sessions and it is necessary for the plant to modify its bidding in different session of ancillary services to obtain a favorable outcome.
- Bidding in a period in which the zonal imbalance sign is positive provides lower opportunity in ASM. On the opposite, highest opportunity in ASM corresponds to bidding in a period when zonal imbalance sign is negative. This point resulted from the fact that the imbalance fees determined by system operator for each case of zonal imbalance is different.

The effectiveness of the model has been assessed by creating a simulation environment in two phases. In first phase, the bidding quantities are selected for one year, based on concepts and approaches presented by the model, using real input data and generic wind power plant's characteristics. Optimized bidding algorithm generated the bidding quantity for 1870 hours (22% of the times).

In second the phase of simulation, the bidding quantities, along with the probability of acceptance, generated in first phase, are exploited to calculate the annual cash flow. Results have shown that positive profit corresponds to the hours in which the unit provides downward regulation service. For the hours of non-provision of service, the unit faces negative profit due to transition to dual price mechanism. However, if the unit is treated by the same imbalance mechanism, before and after *Enabling*, the value of profit in terms of annual cash flow is expected to be positive. This finding is implied by 8% increase in cash flow, calculated based on *dual price mechanism*, before and after *Enabling*.

The tool presented in this work provides fair capability and flexibility to assess the profitability of participating in reserve provision for different conditions of the market. The conditions may change in terms of incentives, imbalance settlement, market prices, gate closure time, presence of negative prices and different scenarios about the trend of market's evolution. Similar to downward reserve, this method can be extended for the case of upward regulation.

In this project, downward reserve provision has been analyzed since it was simpler than upward reserve. In latter case, the unit sells all of its production in energy market, then on voluntary basis participates in ASM and buys back portion of its production. While in upward reserve provision, the unit should avoid to sell a portion of its production in order to keep upward margin which corresponds to loss of incentive and zonal energy price opportunity cost.

Annexes

ANNEX-1: MATLAB Codes (Available in .MAT File and Paper Verion)