POLITECNICO DI MILANO
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ANALYSIS OF EUROPEAN RES IMBALANCE CHARGES: THE IMPACT ON PV AND WIND PLANTS

POLO REGIONALE DI PIACENZA

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Abstract

The increasing share of Renewables Energy Sources (RES) on the energy market has had a great impact on the electricity market evolution. In particular, the high presence of non-programmable RES-E as photovoltaic (PV) and wind plants constitute one of the biggest turns that authorities and system operators have to deal with. The present work focused on the energy unbalance generated by photovoltaic and wind plants. In particular, it was studied the balancing obligation and the gate closure time unit in Germany, Italy and Spain. These three countries were chosen because of the high PV and wind plants penetration on their energy markets.

The Italian case was studied more thoroughly, in order to estimate some figures of the nodal and zonal unbalance and the different remuneration mechanism used to penalize the unbalance generators. To do so, a Matlab® model was written in order to estimate the photovoltaic and wind plants real and forecasted injections, as well as the forecasted and real load. Given the extent of the data that would be required to represent the whole Italy, it was decided to model just one of the six electric regions composing the country. In this sense, the Sicilian electric region was selected because of its high non-programmable RES penetration and the availability of meteorological data.

Additionally, the model was also used to estimate the effect of the gate closure time on the unbalance costs incurred by non-programmable RES-E and the real time balancing cost. To do so, it was required to relate the forecast error to the different gate closure intervals reported on the literature. Then the nodal and zonal unbalances were determined in order to estimate the cash flow of the Transmission System Operator (TSO, in Italy TERNA) and the plants generating the unbalance.

Finally, two additional scenarios were considered in order to take into consideration that the forecasting accuracy values might not correspond to the forecasting accuracy of the models used in Sicily. In this regard, both an optimist scenario and a conservative scenario were studied. The first one increases the forecasting model's accuracy, while the second one diminishes it.

Contents

List of Figures

List of Tables

Chapter 1

Introduction

The electrical system is evolving on an opposite way with respect to historical trend. There is a high increase share of Distributed Generation (DG) from biomass and PV, rather than from big conventional plants; an increasing generation of electricity in onshore and offshore wind plants, rather than near the principal inland demand centers; an increasing interchange of electricity with a wider European area [27]. This is a direct consequence of directive 2009/28/EC, which has set the share of renewable energy sources (RES) for each country of the EU-27. This objective shall be achieved by 2020. In order to do so, governments have put in place new regulations and incentives to foster and integrate RES into their energy market.

Integrating renewable energy technologies like biomass, geothermal and reservoir hydropower does not represent a major challenge than traditional technologies. On the other hand, integrating solar and wind plants is an ambitious task because these technologies are based on non-programmable fluctuating resources [6]. Given that solar radiation and wind are free of charge, these technologies are always on whenever their primary source is available. Then their goal is to fully exploit the primary source and avoid any waste regardless of the market price. However, the variability of these sources generates an energy unbalance, which requires other plants of the power system to change their output in order to maintain the balance between demand and supply. Balancing the system becomes increasingly difficult as the participation of non-programmable RES increases. Then the system security might be threatened if no regulations are put in place, given that photovoltaic cells (PV) and wind turbines are being strongly incentivized by some European governments, because they constitute a fundamental part of their plan to meet their 2020 goal.

Non-programmable RES have to be incentivized because of their high-investment costs. Even though these plants are characterized by low variable costs because their energy source is free of charge and only ordinary maintenance and employee costs are taken into account. Their fixed costs are quite high due to their high initial investment costs and the limited utilization hours, which render the total costs of these plants higher than traditional technologies.

All these facts have put a load on authorities to provide the conditions to integrate the rapid increasing share of RES into the energy market. To do so, a high capital cost is required due to the necessity of system expansion; balancing requirements due to non-programmable RES[1]; and the increasing use of open cycle gas turbines or other fast reacting plants to cover peak demand.

This thesis focuses on Germany, Italy and Spain, which have high non-programmable RES penetration on their electricity market (see figure 1.1 and 1.2). Then the policies used by these

[1] Additional upward and downward reserves are needed as non-programmable RES share increases

countries to integrate non-programmable renewables were studied. From which the main focus was given to the policies used to improve the system operation. More particularly it were studied the different practices used, by the mentioned countries, in order to deal with the energy unbalance. Additionally, a further analysis of the Italian unbalance regulations was performed, in order to evaluate more in detail the current unbalance policies. To do so, part of the Italian system was modeled, so that the impact of non-programmable RES units on the balancing market could be grossly quantified.

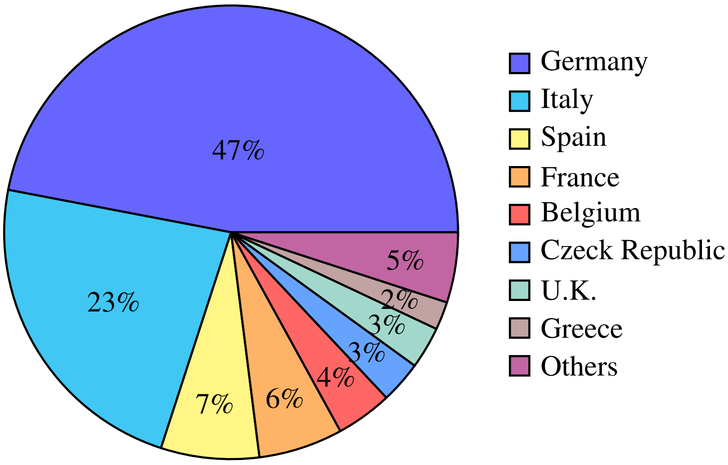

Figure 1.1: Distribution of the PV cumulative capacity (68GW) by late 2012 in Europe. Adapted from [2].

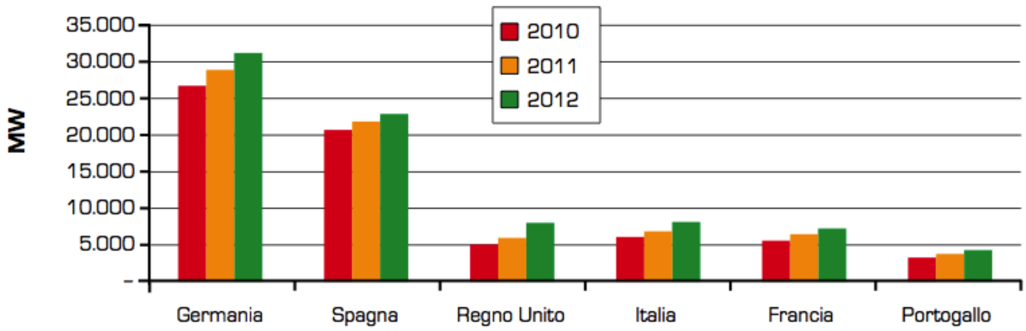

Figure 1.2: Distribution of the total wind cumulative capacity. Taken from [1].

1.1 Key factors bearing non-programmable RES-E

According to Cochran et al [27], there are five strategic areas to be covered in order to successfully integrate renewables on the energy market.

- Lead public engagement for planning new transmission, given that a two-way exchange of information is required when dealing with concerns over land use changes, environmental damage, decreased property values, or health concerns.
- Coordinate and integrate planning helps decision makers anticipate how non-programmable renewables might impact the grid and its operations, and what options would optimize costs across a system.
- Improve system operations like advanced forecasting techniques and changes to grid codes. Adequate forecasts reduce the amount of system flexibility needed to integrate non-programmable RES. Grid codes should be modified to oblige renewables to provide fault ride-through capabilities reactive power injection, voltage and frequency control.
- Expand access to diverse resources and geographic footprint of operations in order to reduce the weather vulnerability.
- Develop rules for market evolution that enable system hosting capacity like increasing transmission, or the addition of flexible resources to the system, such as more flexible generating units, storage, and demand response.

It is worth highlighting that there is no universal approach and each country uses its own combination of policies, market designs, and system operations.

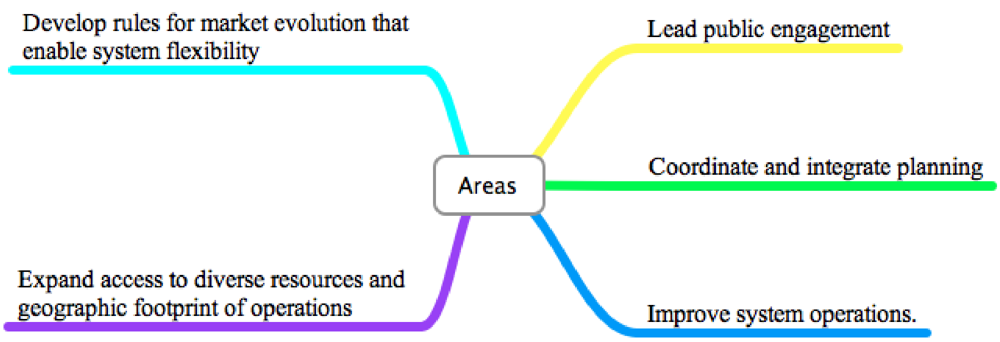

Figure 1.3: Key areas to properly integrate RES.

1.1.1 Concerns

Increasing the RES penetration on the electricity market brings with it the following concerns.

1. *Dispatching Priority*
   RES are dotted with dispatching priority, which make them participate on the energy market avoiding market signals. This, combined with an increasing penetration of RES on the energy market, has lead to a low residual load to be covered by conventional units. On figure 1.4, it can be seen that renewables significantly reduce the residual load, and such reduction varies

with the season and meteorological conditions. This diminishes the energy injections and operating hours of traditional plants, which compromises the system security because some reserve services can be provided only or mainly by operating plants. Then keeping reserves to comply with the system needs becomes more difficult as the residual load is lowered.

2. *Forecast Errors*
The intermittency of these sources causes a high forecasting error. This increases the total energy to be balanced in real time.

3. *Line Congestions*
The presence of significant inputs of electricity produced from non-programmable RES in recent years has contributed to a significant increase in management difficulties and risks to the security of the national electricity systems. The current congestion could worsen in the coming years in the absence of timely action aimed at ensuring a coordinated development at the local and national transmission system with that of the production capacity from non-programmable RES.

4. *Ride Through Fault*
When a fault occurs in the electric network, the supply voltage drops. In the case that it becomes lower than an admissible voltage, protection devices will isolate the faulty area from the rest of the network. During this interval, producers experience a voltage sag condition at their terminals. As a consequence of this disturbance, PV and wind plants may disconnect from the grid due to severe stability problems [30]. Then a huge amount of energy coming from PV and wind plants will disconnect generating a power deficit that can not be currently manage by the system. This is due to the fact regulations were set when these units were rare, and their disconnection meant no harm to the system security [33]. Thus, modern grid codes require these plants to continue their uninterrupted operation under various fault conditions according to given voltage time profiles.

5. *Interface Protection Systems*
Interface protection systems (IPS) are installed at the DG premises, and are designed to disconnect DG from the grid in particular network conditions (frequency variation due to a fault on distribution networks). The optimum range of operational frequencies varies according the concerned part. As mentioned above, TSOs want to widen the range to system stability and security (unwanted massive DG tripping for frequency transients on the transmission networks). On the other hand DSOs (Distribution System Operators) want to narrow the range to avoid unwanted islanding.

6. *Voltage Control*
Under normal operating conditions, excluding the periods with interruptions, supply voltage variations should not exceed $\pm$ 10% of the declared voltage Uc. A massive penetration of DG leads to problems on voltage regulation, because one or more DG units can bring the bus voltage at an excessive value higher than the allowed range.

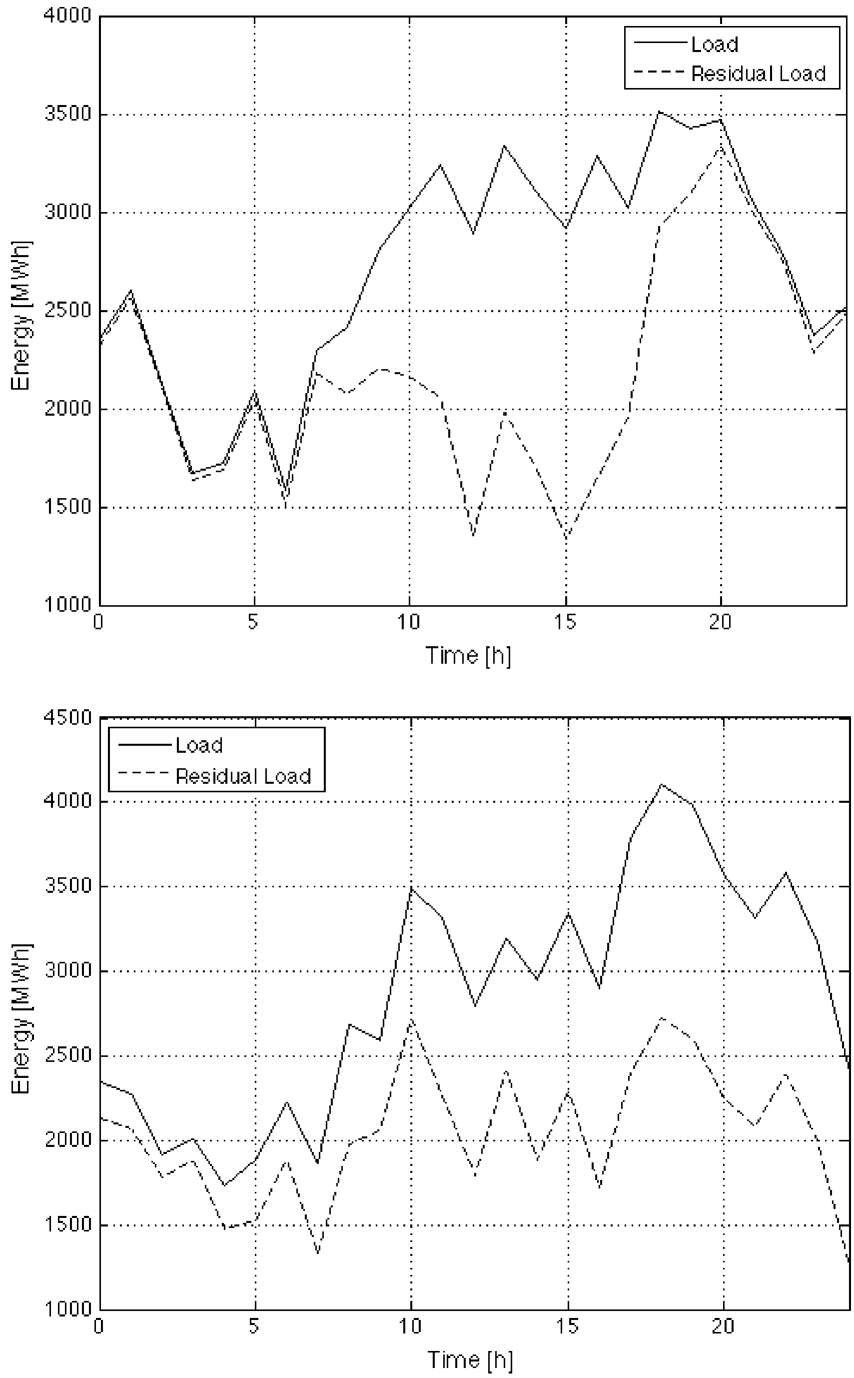

Figure 1.4: Non-programmable RES-E impact on the Sicilian energy demand during summer (up), and winter (down). Obtained from the developed model (see chapter 3).

Chapter 2

Energy Strategies and Regulations

2.1 General Objective

The aim of the work is to compare the RES imbalance charge regulations in force in Germany, Italy and Spain. The parameters to be considered are, among others: the nature of the balancing obligation, the settlement time unit, the number of prices and their impact on the imbalances magnitude and cost.

2.1.1 Specific objectives

- Compare the regulations put in place by Germany, Italy and Spain in order to integrate non-programmable RES-E on their energy markets.
- Compare the regulations put in place by Germany, Italy and Spain in order to deal with energy unbalance.
- Identify the costs for the system related to the unbalance of non-programmable RES plants on the Italian energy system.

The operation of an energy supply system where an increasing share of electricity is generated regardless the demand brings with it considerable challenges for the power market regulation. A successful integration of RES to the energy system requires tackling this challenges without compromising the system security and an affordable energy supply [31].

2.2 Germany

German national renewable energy action plan (NREAP[32]) proposed to accomplish a RES gross final energy consumption (GFEC) of 19.55% (448.418GWh / 38.557ktoe), which was above the 18% goal impose by the directive 2009/28/EC (see figure 2.1).

2.2.1 Incentives

German RES-E plants can choose between two different incentives. Plants can select to be incentivized under a feed in tariff or a feed in premium. Tariffs are paid during 20 years and incentives are

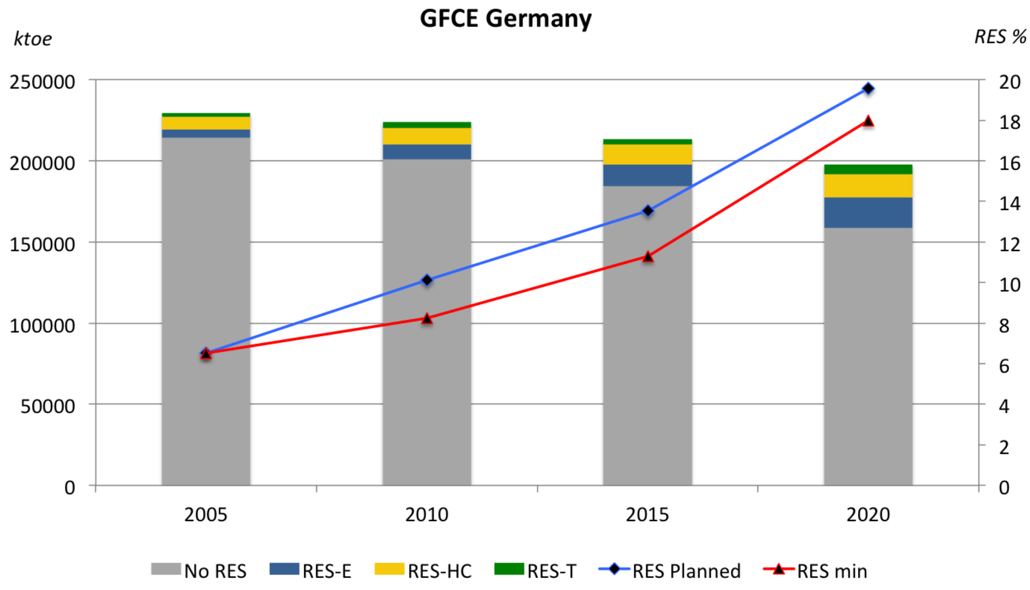

Figure 2.1: German renewable energy action plan

decrease a yearly known amount. Benefits and obligations vary depending on the incentive granted. In the case of the feed in tariff, energy is sold to the TSO, which is responsible for balancing their output. If the plant owner opts for a feed in premium, energy is sell at the market price plus the premium and the plant acquires balancing responsibilities. The market premium is defined as the difference between the technology specific feed-in tariff and the estimated average market value plus an additional incentive for participating on the market. Additionally, biomass plants can get an extra incentive (flexibility premium) by providing additional installed capacity[1] to participate on the balancing market [19], [24].

2.2.2 Concerns

Non-programmable RES-E have a high penetration on the German electricity system. The middle and northern part of the country has the majority of the wind farms, while PV plants are located mainly on the south part of the country. According to the framework of the Renewable Energy Sources Act EEG [24], grid system operators shall immediately and as a priority purchase, transmit and distribute the entire available quantity of electricity from renewable energy sources. The main concern is that wind generation is concentrated on rural areas with low consumption, which congest the transmission lines to transport it to urban areas where most of the consumption takes place. Additionally, the fast growing PV injections generate reverse flow of energy on distribution grids that were conceive to be passive [27].

2.2.3 Regulations already in place

German authority (EEG) has already put in place the following regulations.

[1]Increasing the installed capacity at least 0.2 times respect to the original capacity

- *Dispatching priority*
RES-E are granted with dispatching priority, unless other installations generating electricity must remain connected to the grid system in order to guarantee the safety and reliability of the electricity supply system. To control overloads, RES-E and CHP[2] units shall enable the technical facilities to allow the grid system operator, at any time, to reduce output by remote means [24].

- *Line congestions*
Upon the request of those interested in feeding in electricity, grid system operators shall immediately optimize, strengthen and expand their grid systems in accordance with the best available technology, if economically reasonable, in order to guarantee the dispatching priority of RES. Otherwise, those interested in feeding in electricity may demand compensation for the damage incurred [24].

- *Settlement time unit*
Day-ahead market gate closes at 12 pm. After that, intra day market runs every 15 minutes of the day. Section 5(2) of the Electric Network Access Ordinances allowed the injection schedule to be change with at least 45 minutes prior notice on every intraday market session. However, since December the 1st 2010, all German TSOs reduced the prior notice to 15 minutes. After the gate closure the four TSOs are responsible for the stability of the power system using the balancing capacity which they have acquired on the balancing market before [19, 44, 9]. In 2011 the average level of positive secondary balancing power was around 2,139 MW (2010: 2,425 MW) while the negative one was around 2,102 MW (2010: 2,219 MW) [9].

- *Balancing market*
To be eligible to participate on the balancing market, generators should comply with certain parameters. A minimum bid size of 1 MW and a tendering period of at least 1 weak are required to access the primary reserve. Bidders are allowed to make partnerships to accomplish the requirements, provided they are located within the same balancing area. A minimum bid size of 5 MW and a tendering period of 1 week are required to access both secondary and tertiary reserve. Partnerships are allowed to bid however they do not need to be located on the same balancing area [19]. This limits where lowered by the Bundesnetzagentur in 2011 to attract more technologies[3] to enter the balancing energy market [9].

- *Balancing obligation*
RES-E plants operating under the feed in tariff sell their energy to the TSO, which is responsible for the energy balance. On the other hand, plants under the feed in premium incentives have the balancing obligation. These plants are penalized under the single price mechanism.

  The German Federal Network Agency has made it a requirement that the uncertainties of wind forecasts are traded on the intraday market starting in 2011 at the latest. Then these plants can check the feasibility of producing the energy traded on the day-ahead market. If necessary, these plants can adjust their energy schedule until 15 minutes ahead of delivery. To do so, there is a continuous intraday spot market that facilitates the physical energy transactions necessary for those re-scheduling. As a result, the volume of the required balancing

[2] Combined heat and power
[3] Eg:. Interruptible consumption, storage facilities, etc.

capacity decreases and the liquidity in the intraday market increases [19]. Finally, the balancing energy mechanism distributes the cost of the reserve energy (balancing energy) among the originators of the unbalance [29].

- *Active power injection limits*
  In order to access the incentives, plants with an installed capacity over 100 kW should be able to reduce their output remotely in case the grid is overloaded. PV plants with a installed capacity lower than 30 kW shall perform this task and additionally limit their injection to 70% of their capacity. The operator shall receive a compensation for the lost revenues less the expenses saved. This cost can be allocated to the final consumer as a grid usage fee [24].

Wind plants

- *Ride through Fault*
  German Grid Code requests wind plants to remain connected even if a three-phase fault occurs with a voltage drop to zero for the maximum duration of 150 ms, followed by the voltage recovery to 0.9 PU in 1.5 s [30].

- *Frequency control*
  Wind plants IPS (Interface Protection Systems) should be set to remain connected to the grid in case of frequency variation between 47.5 and 51.0 Hz. In the case that available active power is greater than 50% of the plant capacity and frequency is higher than 50.2 Hz and lower than 51.0 Hz, the instantaneous active power shall be reduced 40% per Hz. Between 51.0 and 51.5 Hz wind plants shall disconnect from the network. Additionally, network operator can remotely block the automatic recoupling to the network upon request [34].

- *Voltage control*
  Given the high wind generation installed capacity (see figure 1.2), the German government has establish that plants installed after the 30th of June 2010 shall provide voltage and frequency stability. Wind plants installed before the 1st of January 2014 shall receive a bonus of 0.5 cents/kWh as compensation. Moreover, older wind power plants that retrofit are given an incentive of 0.7[4] cents/kWh for fulfilling fault ride through and frequency control obligations.

  The network operator shall specify to each wind power system one of the three different variants that determine the reactive power injection requirements. In all three cases, inverters shall be able to handle a constant K factor, which should be also adjustable between 0 and 10. The feed reactive power can fluctuate on an allowed margin of -10 to 20% of the rated current. In case voltage control becomes ineffective due to the distance between the wind unit and the grid connection point. The grid operator can required to the wind energy plant to inject reactive power as function of grid voltage [34].

PV plants & storage

- German government is fostering the installation of storage systems on PV plants with power capacity lower than 30 kW. Starting on may 2013, the State Bank KfW is paying 30% of the

[4] This additional incentive is granted for a five year period

cost incurred for the installation of the storage systems, together with low interest loans for this purpose. In order to be eligible, it is required that the plant was installed before 2012 and that the total energy delivered to the system does not exceed 60% of the total production. The objective is to encourage the installation of approximately 60 MWh of capacity accumulation, in order to lower the peak power on distribution system and increase the transport capacity of the national grid [2].

2.2.4 System balancing energy

All four German transmission system operators[5] participate on a single nationwide market for secondary and minute reserve (tertiary control reserve). The imbalances occurring on the different TSO control areas are netted so that only the remaining imbalance is solved by the secondary and minute reserves. This increases the system's efficiency to deal with the energy unbalance allowing a cost reduction [9].

2.3 Italy

Italian NREAP [23] proposed to accomplish a RES gross final energy consumption (GFEC) of 16.15% (249.928GWh / 21.490ktoe), which was below the 17% goal impose by the directive 2009/28/EC (see figure 2.2). However a big (unexpected) growth of photovoltaic, put in place with the incentive schemes set by *Quarto conto energia*, allow to surpass the PV power installed on 2011 (14.375GWh / 1.236 ktoe) respect to the one originally planned for 2020 (9.650GWh / 830ktoe). Figure 2.3 shows the difference between the planned PV installed capacity and the one predicted. Hence it is expected to produce a much higher share of PV on 2020 (50.000GWh / 4.299ktoe) respect to the originally planned on the NREAP. This extra installed capacity has increase the prediction for 2020, where it is now expected that the RES GFEC will be of about 19 - 20% [3].

2.3.1 Concerns

Nowadays, the Italian Energy Regulator is reviewing the dispatching rules taking into account the new market context. The integration of plants using non-programmable renewables and distributed generation in networks is a priority objective to be pursued due to the unexpected PV growth. In order to increase the penetration of these units on the electrical system, it becomes increasingly important to make sure that such plants provide services to network and participate actively in the management of electrical networks.

2.3.2 Regulations already in place

New dispatching rules are a real need because a significant and rapid diffusion of plants producing electricity from non-programmable RES can cause technical and economical problems. Italian authority has already react to some of these issues by implementing the following regulations:

[5] 50 Hertz, EnBW TNG, TenneT TSO, Amprion

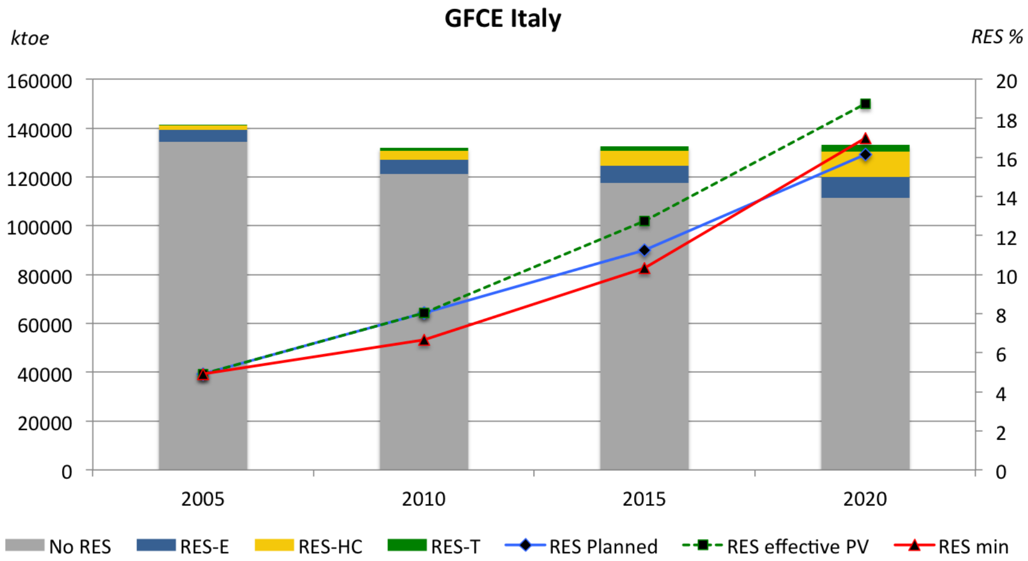

Figure 2.2: Italian renewable energy action plan

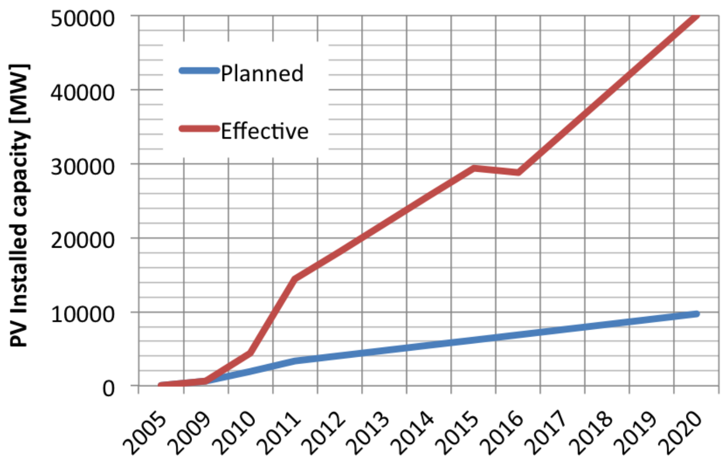

Figure 2.3: PV planned and Predicted installed capacity

- *Balancing obligation*
  Up to 2012 imbalances were not charged to non-programmable renewables but to final consumers. The AEEG regulation 281/2012/R/EFR [39] that took placed on July 5 defines the transitional provisions (from 1 January 2013) for the application of imbalance payments to non-programmable renewables power plants. The aim is to promote better forecasting of electricity fed into the grid from renewable sources avoiding the costs put on consumers due to poor predictability of these systems.

In order to ensure the required gradualness in the management of production facilities, from the period between 1 January 2013 and 30 June 2013, a forecast error of 20% should not be exceed; from the period between 1 July and 31 December, this amount should not exceed 10%. The energy unbalance overpassing the allowed error is penalized under the single price mechanism.This regulation has been partially cancelled by the "Consiglio di Stato" on September 11th due to the fact that it grants the same allowance to PV and wind plants, whose source uncertainty cannot be assume equal. The partial cancelation states that the allowed error should be raised once more to the value of 20%, while a new regulation is set.

- *Ride through fault*
  CEI 0-16 and CEI0-21[25] modified the dynamic behavior during voltage transients for PV and wind plants (on MV networks, CEI0-16, and on LV networks CEI0-21). Regulation requests PV ride-through capability for three-phase faults with the voltage drop to zero for the maximum duration of 200 ms, followed by the voltage recovery to 0.85 PU in 1.5 s. Wind power plants requirements are slightly different because it is required to be connected for 200 ms for a voltage drop to zero, then for other 200 ms at 0.3 PU, followed by the voltage recovery to 8.5 PU in 1.5 s and 0.9 PU in 180 ms (see figure 2.4).

- *Curtailments of RES production*
  Resolution ARG/elt 5/10 by AEEG[6] on its meeting of 25 January 2010 [36] has set the regulation for RES curtailment in case the safety of operation of electrical system is compromised. During year 2010 the loss wind production was equal to 470 GWh, that represents the 5,6% of wind energy on the Italian transmission system. This percentage was halved compared with its level in 2009 (10,7%).

  RIGEDI [45] is the procedure set by TERNA followed to curtail selected distributed generators. TERNA may request for the disconnection of some photovoltaic or wind power plants connected to the medium voltage networks, with power greater than or equal to 100 kW that inject into the grid their total production. The reduction applies only if there security of the national electricity system is at risks and no further actions are possible.

  Although it might seem contradictory, having the possibility to curtail plants remotely allows the network operator to decrease non-predictable RES-E curtailments. Then RES-E injections can be curtailed only when strictly needed.

- *Anti-islanding protection*
  In 2012 regulation 84/2012/R/EEL [37] by AEEG defined the qualities that inverters, or rotating machinery, and protective systems interface must have in order to be installed on new power plants to be connected in low and medium voltage, as well as detailed retrofit rules for existing plants with a power exceeding 50 kW connected to the medium voltage. These devices do not function solely to prevent the disconnection of distributed generation if the grid frequency remains within the range 47.5 to 51.5 Hz (instead of the range 49.7 to 50.3 Hz) but also to enable the provision of network services that may become relevant in view of future active networks (smart grids).

  The Italian system has found an innovative way to deal with unwanted islanding and nuisance tripping. In this way, IPS are able to recognize variations in frequency due to the local fault[7]

[6] Autorita' per l'Energia Electtrica e il Gas
[7] One, two and three phase faults to earth

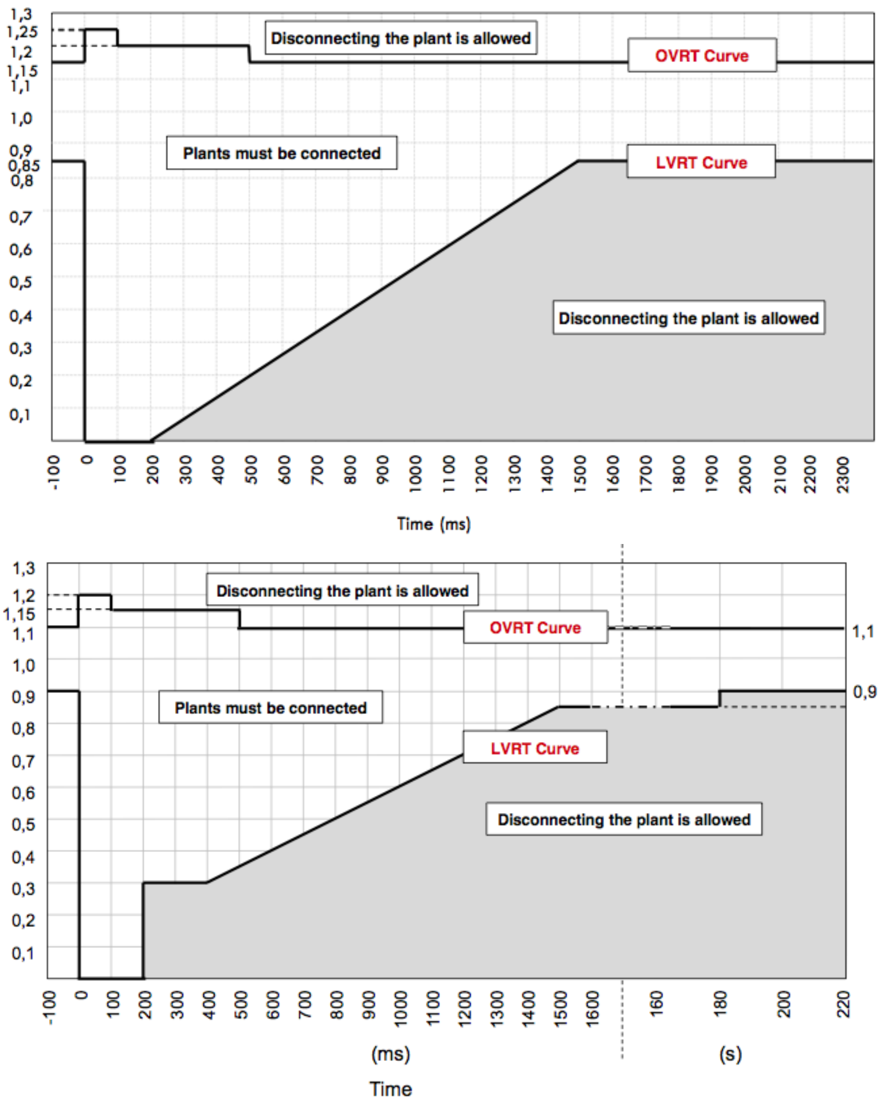

Figure 2.4: Dynamic behavior during disturbance Italian LVFRT curve for medium voltage PV plants (up); wind plants (down).

and to separate DG plants from network in a short time (before the first fast reclosing in order to avoid an out-of-synchronism reconnection). Additionally, a low sensitivity setting profile of voltage/frequency protections is enabled in the IPS (47.5-51.5 Hz), together with transfer trip, in order to disconnect DG only if an extreme transmission network incident occurs. This last configuration can be achieved provided that communication is active.

- *Voltage control*
  Regulation CEI 016 [25] established that all generation plants connected to the MV grid must be involved in voltage control through absorption and supply of reactive power. The absorption and supply of reactive power, in these cases, is intended to limit overvoltage/under-

voltage caused by the generator itself as a result of the input of active power. Regulation states that DG units should be equipped with the controls necessary to use the following alternatives in order to avoid retro fitting in the future.

1. Set and vary the power factor as function of active power ($cos\phi$ = f(P)). Which means that DG units are obliged to inject a reactive power proportional to their active power injection.
2. Supply/absorption of reactive power in accordance with adjustment functions under local logic based on the value of grid voltage read on the output terminals in accordance with characteristic curves ($Q = f(V)$).
3. Supply reactive power in accordance with a defined set-point by means of an external signal commanded by the DSO. The ability to supply reactive power in accordance with a defined set point by means of an external signal is required for all generating systems within the limits of their capability.

2.3.3 Network development

Italian authority (AEEG) is currently running demo projects on three areas, which are smart grids, electric vehicles recharge and electric storage on transmission and distribution grids. Given that those are considered innovative areas, there is not clarity on how to set the adequate regulation and incentives to held such approaches. Demo projects will be used to obtain concrete experiences on such areas, in order to get the required information to set adequate regulations that protecting the interest of users and consumers.

Storage

In some exceptional cases the development of networks may not be the most effective tool to manage the production of electricity from non-programmable renewable sources. In those cases the usage of energy storage systems (EES) might be more adequate. This type of systems are primarily aimed at reducing the curtailment of RES production, ensuring adequate capacity for regulating the balance and the safety of the electrical system in particular in areas with a strong presence of non-programmable renewable sources. Resolution 288/2012/R/EEL [38] has set the required objectives to evaluate pilot projects for testing storage systems using batteries on the Italian transmission grid. Regulation 66/2013/R/EEL [40] announced the approval of six pilot projects of 6MW and a nominal capacity of 40 MWh to be installed at the lines with high wind curtailments[8].

The main key features of the storage demo projects was to install the storage in a zone with high RESs penetration with temporal criticalities; to reduce the curtailment due to congestions for at least 150 charge-discharge cycles per year; manage the reactive power of the network for voltage regulation; and to provided primary frequency regulation. Six storage systems projects were eligible to be installed in south Italy, five of them with a storage capacity (power) of 40MWh (6 MW) each, and a sixth one of 32 MWh (4.8 MW).

Smart Grids

The smart grid demo project addressed active grids[9] in order to further integrate DG units to the

[8] The six projects are connected to the lines: Campobasso - Benevento 2 - Volturara - Celle San Vito and - Bisaccia 380

[9] Grids with at least 1% of yearly time with reverse power-flow from MV level to HV

network. Eight Projects were chosen taking into account many parameters among which, there is the amount of users connected to the impacted zone, the increase on the hosting capacity, project feasibility and replicability.

Electric vehicles
A demo project will held the installation of about 1000 electric vehicle recharging points in 9 Italian regions and cities. Six demo projects were chosen to provide the service. Three different approaches were chosen to achieve the task. On one of the approaches the DSO has direct contact with the client; on another one, there is a service provider which sells energy to the client; on the last one, the service provider is also the client because he owns the electric station.

2.3.4 Dealing with the unbalance

In order to deal with the energy unbalance, TERNA uses the ancillary services market (Mercato de Servizi di Dispacciamento, MSD) where producers offer their availability to modify their programmed injections. Only programmable plants can participate to the MSD, excepting cogeneration and biomass plants.

In case energy is in lacking TERNA demands more energy injections to power plants participating on the MSD. This energy is bought at a price fixed by the producer, which is usually higher than the day-ahead (and intraday) market. On the other hand, if energy is in excess TERNA orders a production decrease to the power plants participating on the MSD. Then producers have to buy back the energy previously sold in the day-ahead and intraday market. Once more, the producer fixes the downward price, which is usually lower than the day-ahead and intraday market price.

2.4 Spain

Spain's national renewable energy action plan (NREAP [17]) proposed to accomplish a RES gross final energy consumption (GFEC) of 22.7% (260.896 GWh / 22.433 ktoe), which was above the 20% goal impose by the directive 2009/28/EC (see figure 2.5). Wind energy will have the major share on achieving this goal, followed by solar plants [17].

CECRE
CECRE for its spanish acronym 'Centro de Control de Régimen Especial' was created in 2006 by Spain's TSO (REE[10]). It's role is to maximize renewables penetration on the energy market without compromising quality of service and system security.

CECRE receives on real time (every 12 s) active and reactive power injections and voltage measurements of RES-E with an installed capacity higher than 10 MW. Wind farms are obliged to additionally provide wind velocity, direction and ambient temperature. In the case system security is threaten by high wind production in low load periods, CECRE has the faculty to limit wind farms injections, provided that the order shall be complied within 15 minutes. CECRE regulates the energy injection of more than 800 wind farms, which correspond to around 98.6% of the wind installed capacity.

[10]Red Eléctrica de España

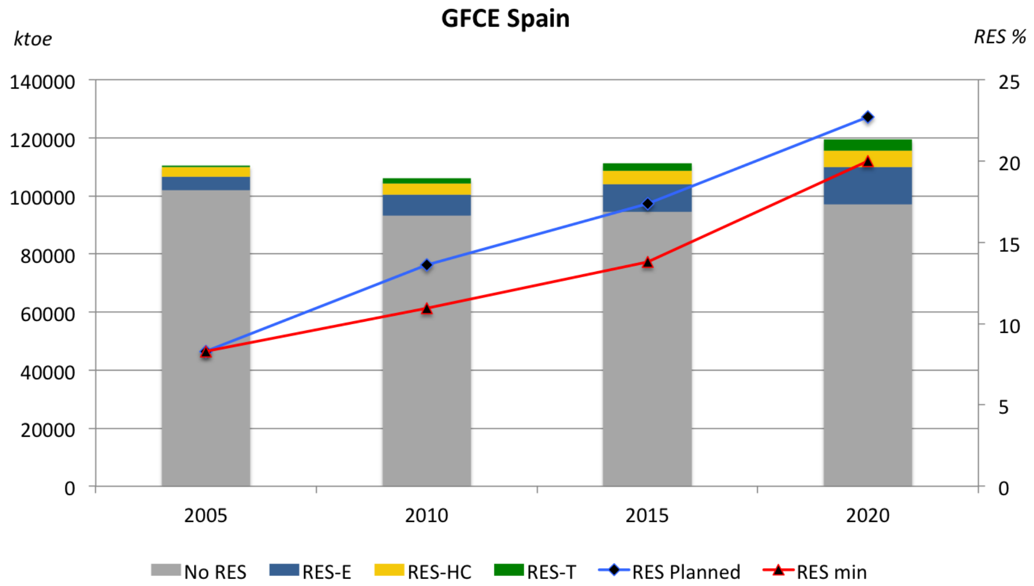

Figure 2.5: Spain's renewable energy action plan

2.4.1 Concerns

Spain has a low degree of interconnection with the European electric system. The relation between the importing energy and the installed capacity is bellow 5%, while the European commission mandated a minimum of 10% to be achieved in 2005. Interconnection lines allow exporting energy in low load and high non-programmable RES production situations. This helps compensating non-programmable RES variability and facilitates RES integration [28].

2.4.2 Regulations already in place

- *Market participation*
  Renewables can choose either to sell their energy by a regulated tariff (FIT[11]), or by participating directly on the energy market. Either option has to be the selling mechanism for periods not less than one year.

- *Balancing market*
  In order for RES-E to participate on the balancing market, the power plant has to sell their energy directly on the market. The minimum capacity to participate on the balancing market is 10 MW, which can be meet in consortium. Additionally, a manageability test, held by the Spanish System Operator, should be passed. Photovoltaic plants and wind farms are not eligible due to their high unpredictability. On the other hand, solar thermoelectric installations, mini-hydro and biomass plants are able to participate on the balancing market.

  The manageability test lasts 10 days in which the day-ahead production forecast and two updates should be sent. During the 10 days the system operator will send the order to reduce

[11]The tariff granted varies with the source of energy, installed power capacity and the date on which came into service

the injection to half of planned. This order should be achieved in no more than 15 minutes and should be maintained during four hours. Another instruction will ask for increasing the power of at least 60% of the reduced power with the decrease intervention. Up to the 1st of June 2011, 17 power plants passed the manageability test. Five hydraulic, three cogeneration, two WtE[12], seven thermo-solar. In total, 529 MW have obtained manageable condition, which makes up only 1.5% of installed capacity from renewable sources.

- *Imbalance*
  RES-E producers have balancing responsibilities. Penalization uses the dual pricing remuneration mechanism[13]. Then, only deviations that worsens the total system imbalance are charged to generators [19]. Up to 2007, the imbalance costs were estimated as follows:

  $$IC = 0.1 \cdot AP * \sum IM \tag{2.1}$$

  Where *IC* is the monthly imbalance cost, AP is the mean annual electricity cost and IM is the imbalance exceeding the tolerance level of deviations (20% for solar and wind, 5% for other technologies) [13].

  Nowadays, the imbalance cost fluctuates with hourly market prices. An upper limit is set by the regulator to reduce the risk imposed by balancing responsibility. Small producers sell their energy through intermediaries. The later ones keeps a large number of small generators on dispersed locations, which allows them to obtain enhance their prediction accuracy. This reduces small generators risk to balancing responsibility. At last, balancing cost does not represent a barrier to non-programmable RES-E thanks to the multiple intra day sessions, which limits the time between the gate closure and the delivery time [19].

- *Frequency control*
  Wind plants have the obligation to participate in the frequency containment reserve (primary reserve). Then a reserve margin of 1.5% is obliged. Given the high cost that this action represents to wind power plants, frequency control service can be contracted from any other source [22].

- *Ride Through Fault*
  Operational Plan (PO)[14] 12.3 [15] set the dynamic behavior during disturbance on voltage dips caused by one, two and three phase fault to ground for wind plants. This is a prerequisite wind plants had to achieve in order to be eligible for incentives. This regulation came into force the 1st of January 2008. Older wind plants were given a 3.8 Euro/MW bonus during five years if they retrofit before June 2011.

  The RD[15] 1565/2010 mandated PV whose installed capacity is higher than 2 MW to fulfill this requirement. PV plants installed before the 1st of July 2011 had to retrofit before the 1st of October 2011.

  A new regulation oblige ride-through capability for three-phase faults with the voltage drop to zero for the maximum duration of 150 ms, followed by the voltage recovery to 0.85 PU

[12] Waste to energy plants
[13] Penalization occurs when there is lower production than planned and higher consumption than planned, or vise versa
[14] In spanish 'Plan de operación'.
[15] 'Real decreto', which stands for Royal decree

in 1.5 s. Additionally, wind farms must also be fitted with a voltage control loop that injects reactive current during three phase faults [30].

- *Reactive power injection*
  All RES-E units will be given a bonus/penalization for injecting or consuming reactive power depending on the power factor and the load magnitude, which is differentiated between peak, intermediate or off-peak hours. The revenue obtained is estimated as a percentage of a pre-set value (78,441 Euro/MWh), which is reviewed annually. Additionally, Plants whose installed capacity is bigger than 10 MW can be asked to achieve a specific power factor. If the goal is achieved, the maximum bonus is granted. Otherwise the maximum penalization will be applied. Table 2.1 shows the bonus/penalization granted.

Type	Power Factor	Bonus (%)		
		Peak	Inter	off-peak
Inductive	<0,95	-4	-4	8
	$<$ 0,96 and $\geq$ 0,95	-3	0	6
	$<$ 0,97 and $\geq$ 0,96	-2	0	4
	$<$ 0,98 and $\geq$ 0,97	-1	0	2
	$<$ 1 and $\geq$ 0,98	0	2	0
	1	0	4	0
Capacitive	<1 and $\geq$ 0,98	0	2	0
	$<$ 0,98 and $\geq$ 0,97	2	0	-1
	$<$ 0,97 and $\geq$ 0,96	4	0	-2
	$<$ 0,96 and $\geq$ 0,95	6	0	-3
	$<$ 0,95	8	-4	-4

Table 2.1: Spain's reactive power bonus. Taken from [16].

2.4.3 Current situation

Spanish economical crisis has greatly impacted the renewable energy sector. The decree 1/2012 [14] made public the 27th of January 2012 has temporally suspended all incentives granted to new renewable energy technologies. According to this decree, with the Spain's current situation RES incentives are not essential to achieve the goal of directive 2009/28/EC.

There is a new decree ongoing, which regulates the energy self-consumed ('Balance neto'). In this way, Spain's government intends to foster distributed generation of small-scale plants.

2.5 Review and analysis

As can be seen from this chapter, each country uses its own combination of policies, market designs, and system operation rules in order to properly integrate non-programmable RES-E into their energy system. In particular it is interesting how each country decided its own particular way to deal with the energy unbalance.

- The German system is that renewable power plants can choose between a FIT and a FIP incentive. If the first one is chosen, the energy is sold to the TSO who becomes responsible for balancing their output. If the FIP mechanism is chosen, the plant owner is responsible for the energy unbalance and is penalized under the single price mechanism. However, they are granted an additional incentive for participating on the market. Under this scheme the plant owner has the possibility to make and extra profit and the corresponding TSO reduces the unbalance volume he is responsible of.

Another particularity of the German system is that the energy market (EPEX) operates under the day-ahead market mechanism, which closes every day at 12:00 pm. Additionally, intraday sessions are held every 15 minutes of the day, which opens the possibility to modify the injection profile up to 15 minutes prior the delivery[16]. As a result, the volume of the required balancing capacity in real time decreases, the liquidity in the intraday market increases, but the power reserve increases too [19].

- The Italian energy market (IPEX) operates under the day-ahead market mechanism, which closes at 9:00 am on the day before the energy delivery. There are four intraday sessions were power plants can modify their injections. RES unbalances is penalized following the single price mechanism, which implies that only unbalance worsening the global unbalance are penalized. In the case of non-programmable RES, penalization only occurs for the injections incurring into an error higher than the 20% with respect to the forecasted injections. This measurement reduces the risk incurred by the non-programmable RES units and fosters the development of more accurate forecasting models.

- Spain's energy market also operates under the day-ahead market mechanism, and it is provided with six intra-day sessions. In this case non-programmable RES have balancing responsibilities and penalization is done under the dual price mechanism. Penalization is paid at the market price, however an upper limit is set in order to protect producers. Additionally, Spain's TSO has an office (CECRE) that receives real time data and regulates the energy injection around 98.6% of the wind installed capacity. By doing so, a higher penetration of renewables can be achieve without compromising quality of service and system security.

Table 2.2 contains an small review that allows comparing the regulations adopted by Germany, Italy and Spain.

[16]This energy is not balanced and the surplus is extended to neighboring countries.

Measure	Germany	Italy	Spain
Frequency Control	Wind required (new plants) incentive (Retrofit)	Required	Wind required
Remotely limit active power injections	Required	Required	Wind plants $\geq$ 10 MW
Voltage Control	Wind required (new plants) Incentive (Retrofit)	Already in place at local level, but not exploited at central level.	–
Energy storage	PV incentive	Wind plants pilot projects	–
Supply of Reactive Power	Wind required (new plants)	Already in place, but not exploited	Incentive
Fault ride through	Required	Required	Required (new plants) Incentive (existing plants)
Islanding protection	–	Required	–
Plant operating in line with forecast	RES selling their energy on the market (FIP incentive)	Required	Required
Ancillary services	RES selling their energy on the market (FIP incentive)	–	RES participating on the market, that passed a manageability test
Settlement time unit	Day ahead market Infraday (15 mins before dispatching)	Day ahead market 4 infraday sessions	Day ahead market 6 infraday sessions

Table 2.2: Legislative framework in respect to grid integration of RES.

Chapter 3

Methodology

An increasing share of non-programmable RES makes the system security more vulnerable. In order to overpass this, regulation should oblige these power plants to contribute to system security by limiting the forecasting errors and participating on the frequency and voltage control. According to Bracale et al [4], an accurate forecasting method can be useful for optimizing power plants schedules, reducing the need for balancing energy and reserve power, and analyzing system steady-state conditions. It is worth mentioning that due to regulation stability, changes should be gradually set. In these sense regulation goals are fixed taking into account the best available technologies.

Wind energy production depends mainly on wind velocity and direction, which is characterized by a high uncertainty due to its random nature. On the other hand, solar energy production depends on solar irradiance at ground level, which mainly depends on two factors. The first one is solar position, which is a deterministic factor and can be calculated. The second one is cloud cover, which is a stochastic process difficult to model and predict. Then, the accuracy of both wind velocity and solar irradiance forecasting models depends mainly on the ability to predict their stochastic behavior.

The different forecasting methods are physical methods, statistical methods, artificial neural network methods and hybrid approaches.

- Physical methods are base on physical information[1] and weather conditions. These methods are complex methods with a high computational cost. On the other hand, these methods are accurate for long term forecasting (day ahead)
- Statistical methods are based on past data and can be further subdivided as point forecast and PDF[2] forecast methods. Both of them have a low computational cost. Nonetheless they are accurate for shorter periods (few hours predictions)
- Artificial neural networks are also based on past data, which is used as relation between wind/solar power and time series from the past. These methods are usually accurate for very short-term horizons (few hours predictions)
- Hybrid approaches use a combination of two or more methods.

The optimal method should be chosen taking into account the considered market characteristics, in particular the time in advance in which the forecast should be made (related to market gate

[1] Eg.: Height of turbine hubs for wind plants
[2] Probability density function

closure). In this way, medium time forecast (<48 hours) is useful for energy resource planning and scheduling whereas intraday forecast are profitable for reducing the real time balancing needs [10].

This thesis project will model the behavior of non-programmable RES-E on the Italian network, in order to compare different strategies that can be set by the National Energy Regulator (Autorita' per l'energia elettrica e il gas, AEEG) to further integrate these power plants on the electric system. A statistical method approach will be used, given that according to Bracale et al. [7], probabilistic approaches are able to represent the unavoidable time varying nature of wind speed and loads behavior on the distribution system. This chapter illustrates the series of steps followed to determine the nodal and zonal unbalance generated by PV and wind farms and the mechanisms used to charge the unbalanced plants.

3.1 Study case

The Italian electrical system is divided into zones for security reasons, geographical reasons and transmission limits. Zones represent a fraction of the national network and are defined by TERNA under the AEEG approval. Italian network is then composed by six geographical zones, which are north, center-north, center-south, south, Sicily and Sardinia. Figure 3.1 illustrates the geographical zones of the Italian network.

Zone divisions will be used to define a prediction algorithm for wind and PV taking into account the current geographically installed capacity (penetration) of non-programmable RES on one electric zone. Sicily was chosen as study case due to its high non-programmable RES penetration and availability of meteorological historical data. This zone was further divided into nine smaller sub areas that represent Sicily's provinces (see figure 3.5).

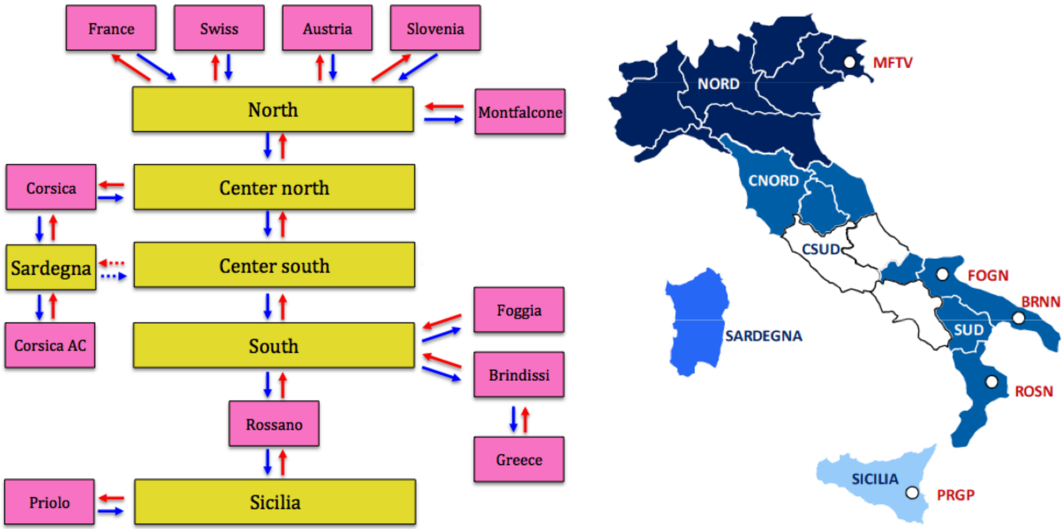

Figure 3.1: Italian geographical network zones

3.2 Weather data

Solar radiation and wind velocity were required to estimate PV and wind plants injections. Then the hourly solar radiation and wind velocity profile were required for each province, in order to obtain the injection of these plants during a period of one year. In this way, the injections of the total PV and wind plants located on the Sicilian region could be estimated on a hourly basis.

These data were obtained online from the "Comitato Termotecnico Italiano" webpage [26]. The data represents a typical year for the nine Sicilian provinces, and was provided by nine meteorological stations located on each province. Measurements were done under the UNI EN ISO 15927-4 norms. Given that the data does not represent a specific year, but a typical year, both solar radiation and wind velocity were further tested in order to check the accuracy of using these data to represent year 2012.

3.2.1 Solar radiation data

The accuracy of the radiation data was checked by contrasting it to the values given by GSE on the 2012 report [21]. In order to do so, it was required to obtain the typical day radiation on a monthly basis for each province. This was done by finding the average radiation each hour of the day month by month, province by province. By doing so, it was possible to obtain the typical day radiation profile per month.

Figure 3.2 contains both the typical day radiation on a monthly basis for the meteorological data and the values reported by GSE. In both cases the seasonal influence on solar radiation can be appreciated. It can be seen that the maximum solar radiation occurs in summer months around midday. In both cases, the maximum radiation is slightly lower than 900 W/m^2. There is a small, but still more notorious, difference for the winter months, where the maximum radiation reported by GSE is close to 300 W/m^2 while the same value for the meteorological data is around 400 W/m^2. This difference is attributed to the fact that GSE reports an average radiation for the whole country, while the meteorological data represents just a Sicilian province.

3.2.2 Wind velocity data

In the case of wind velocity, the only check performed was to confirm if the wind velocity was Weibull distributed, given that the forecast model operates under this assumption. To do so, the Matlab function *wblplot* was used. The purpose of this function is to graphically assess whether the data could come from a Weibull distribution, in which case the data obtained will be linear. From figure 3.3 and 3.4 it can be seen that wind velocity distribution can be approximated to a Weibull distribution. Then it can be said that the wind velocity can be properly represented by a Weibull distribution.

3.3 Provinces

The number of PV and wind plants with rated power and yearly energy production were defined for each province. Table 3.1 and figure 3.5 contain this data, which was obtained from GSE statistics reports [20, 21]. The installed capacity and energy production values were used to feed the model in order to estimate the hourly energy injections of PV plants and wind farms in Sicily.

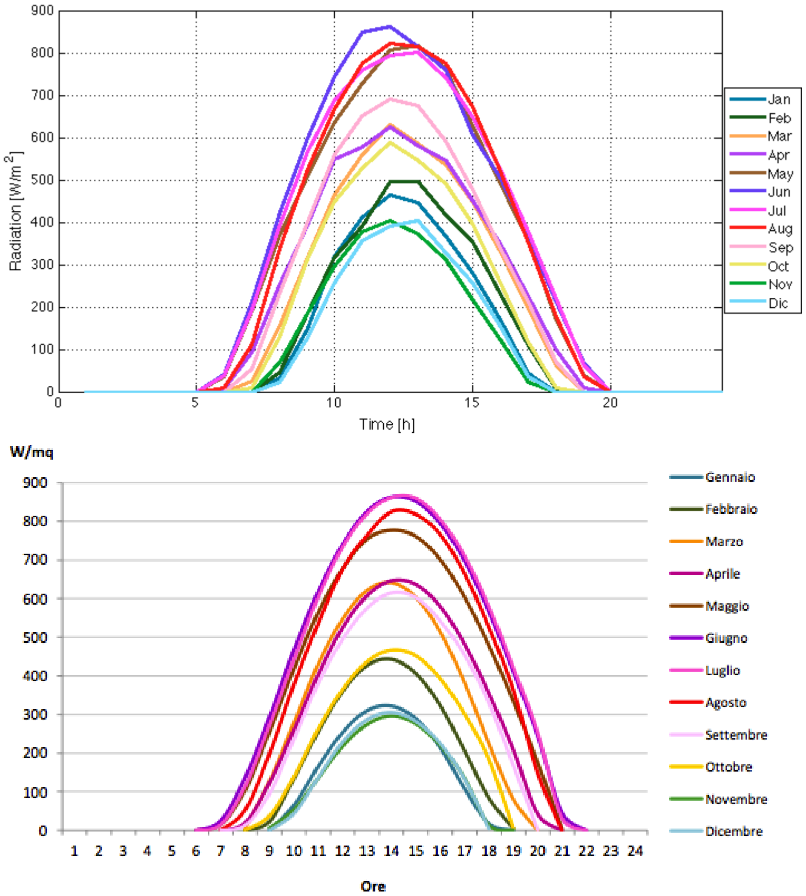

Figure 3.2: Monthly average radiation for the Enna province, obtained from the weather data [26] (up), obtained from GSE (down) [21].

It is worth mentioning that wind farms data refer to year 2011, while PV data refer to 2012. TERNA reported the wind farms energy production of 2012 in [46], with which wind data was scaled in order to feed the model with data corresponding to same year for both wind and PV plants. To do so, it was assumed that both the installed capacity and the energy production are proportional to the relation between the energy produced in 2012 and 2011 (see equation 3.1). Additionally it is assumed this relation is proportional in all the provinces of the region (see equation 3.2 - 3.3).

$$y = \frac{\sum EP_{2012}}{\sum EP_{2011}} = \frac{2995.9\ [GWh]}{2365.4\ [GWh]} = 1.27 \tag{3.1}$$

$$IC_{2012} = y * IC_{2011} \tag{3.2}$$

$$EP_{2012} = y * EP_{2011} \tag{3.3}$$

Where *y* is the scale parameter, *IC* the province installed capacity and *EP* the province energy production.

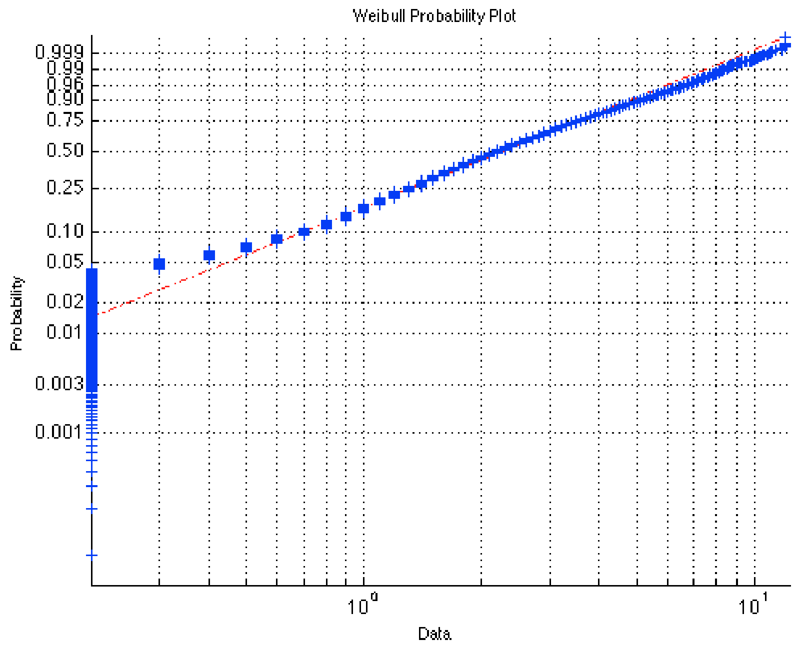

Figure 3.3: Weibull plot for a typical year Ragusa hourly wind velocity

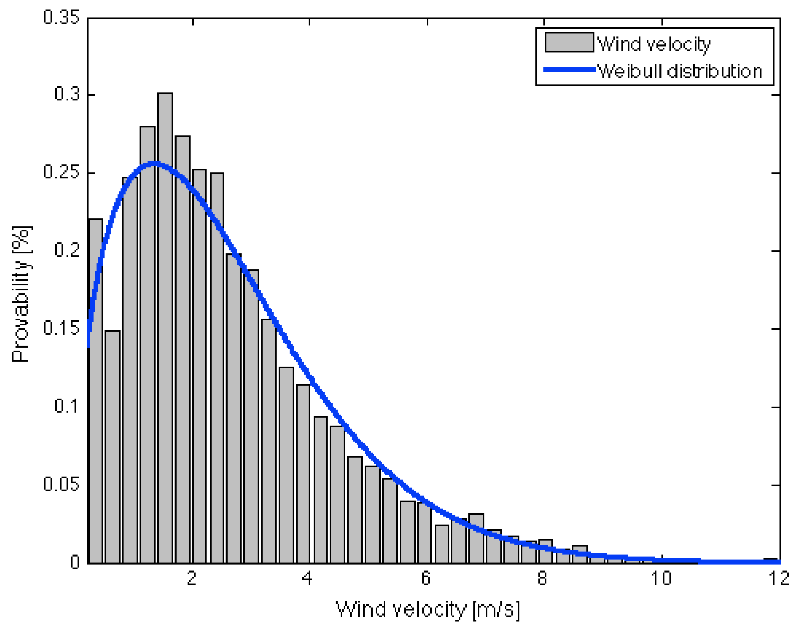

Figure 3.4: Wind velocity histogram and Weibull PDF for a typical year Ragusa hourly wind velocity

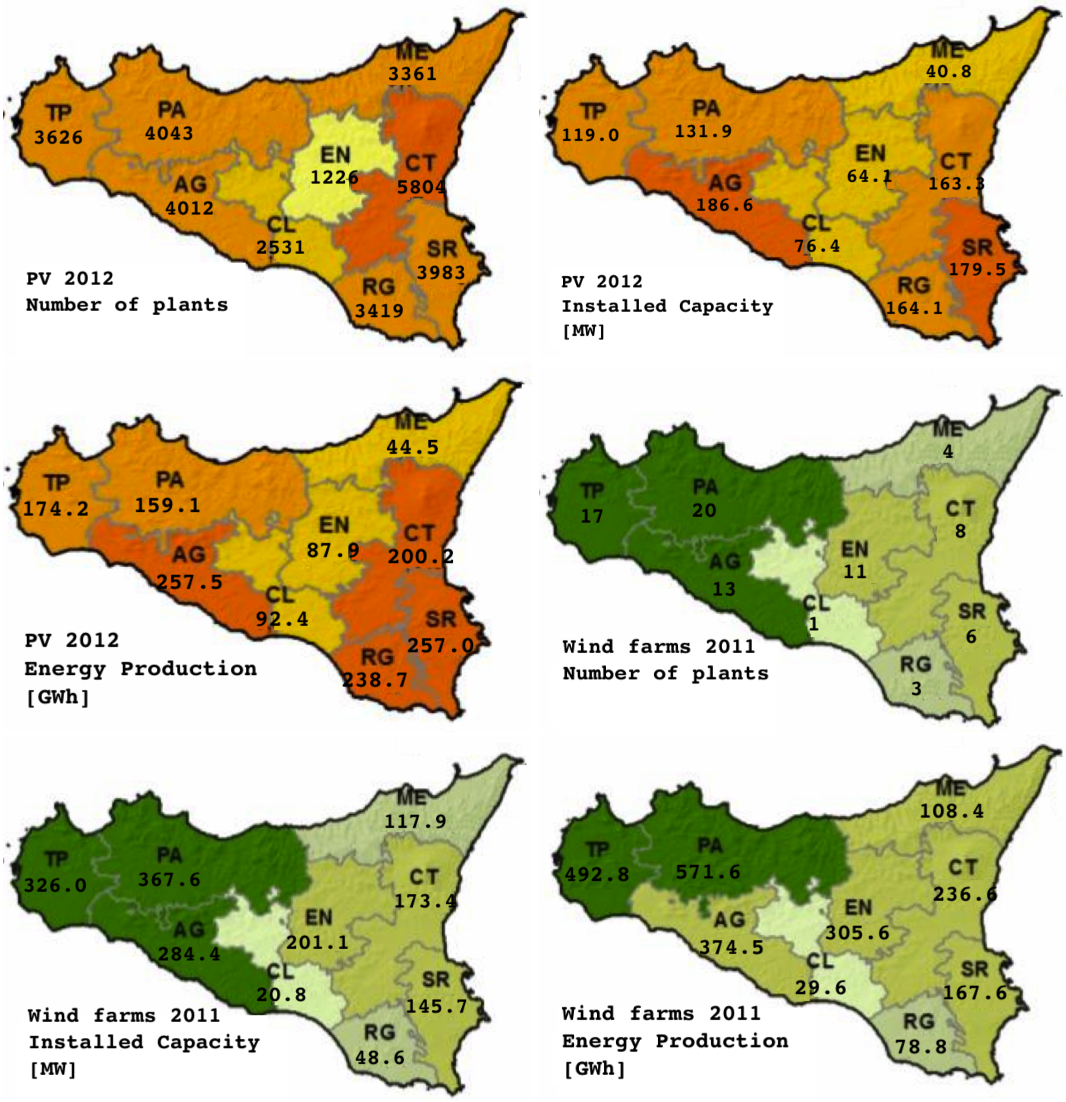

Figure 3.5: Province distribution of PV plants and wind farms in Sicili.

3.4 Conversion factor

At this point, the meteorological data[3], the installed capacity and energy production were known for each province. Such data were used to determine the conversion factor, which allows relating solar radiation and wind velocity to the amount of energy injected by PV and wind farms to the electric system. The relations obtained are describe in the following equations:

$$CF_{PV} = \frac{E_{PV}}{R \cdot C_{PV}} \tag{3.4}$$

[3] Solar radiation and wind velocity

Province	PV			Wind		
	No. Plants	Installed Capacity [MW]	Energy production [GWh]	No. Plants	Installed Capacity [MW]	Energy production [GWh]
Agrigento	4012	186.6	257.5	13	284.4	374.5
Caltanissetta	2531	76.4	92.4	1	20.8	29.6
Catania	5804	163.3	200.2	8	173.4	236.6
Enna	1226	64.1	87.9	11	201.1	305.6
Messina	3361	40.8	44.5	4	117.9	108.4
Palermo	4043	131.9	159.1	20	367.6	571.6
Ragusa	3419	164.1	238.7	3	48.6	78.8
Siracusa	3983	179.5	257.0	6	145.7	167.6
Trapani	3626	119.0	174.2	17	326.0	492.8
Sicily	32005	1125.7	1511.5	82	1685.4	2365.44

Table 3.1: Sicilian provinces PV and wind plants characteristics.

$$CF_W = \frac{E_W}{v^3 \cdot C_W} \tag{3.5}$$

Where CF is the conversion factor, E is the energy injected according to TERNA [46], R the solar radiation, v the wind velocity, C the installed capacity and the sub indices PV and W represents photovoltaic and wind farms respectively.

Wind velocity is elevated to the third power due to the fact that wind energy depends both on the wind kinetic energy ($\propto v^2$) and mass flow rate ($\propto v$). This makes wind farms injection forecast more challenging.

Equations 3.4 and 3.5 assume that all the considered power plants belonging to the nine provinces (either PV or wind) have the same efficiency. This implies that energy injections are proportional to solar radiation or to the third power of the wind velocity, regardless the PV panel or the wind turbine model and manufacturer. So one PV plant of a certain capacity will produce the same amount of energy in any province, when subjected to the same amount of solar radiation. The same applies to wind turbines located in any province subjected to the same wind velocity. Another assumption is that the meteorological data obtained for each province do represent the province as a whole, which means that any plant located within the same province is able to perceive the same solar radiation and wind velocity.

3.5 Forecast and real injections

The following section describes the methods used to obtain both the forecast and the real injections for PV and wind plants and for the Sicilian load. Each of the three procedures is based on literature and differ from each other due to the different nature of solar radiation, wind velocity and predictions on energy consumption.

3.5.1 Photovoltaics

As already mentioned, solar radiation is composed by both a deterministic and a stochastic behavior. The deterministic part was estimated as the monthly average radiation as described on section 3.2.1. A similar approach is done by the Royal Decree 661/2007 [16] for PV plants which do not provide an injection prevision in the Spanish system. Other authors as Marquez et al [43] chose the clear sky index as deterministic part. However under those circumstances the stochastic behavior could not be assumed to have a zero average, which is the case for this model.

The stochastic parameters were determined by subtracting the radiation obtained from the meteorological data to the monthly average (deterministic part) in the sun periods. This procedure was followed for each province by considering the total hours of the year. Equations 3.6 and 3.7 illustrate the way the mean and the deviation were obtained in order to generate the stochastic data.

$$\mu = \frac{\sum_{i=1}^{n}(M_{PV} - AV_{PV})}{n} \tag{3.6}$$

$$\sigma = \sqrt{\frac{\sum_{i=1}^{n}(M_{PV} - AV_{PV})^2}{n}} \tag{3.7}$$

Where μ is the stochastic component's mean, σ is the stochastic component's deviation, M_{PV} are the injections obtained by the meteorological data, AV_{PV} are the injections obtained by the monthly average radiation in sunny periods and n is the total number of hours considered. The mean and deviation obtained are 0 and 132.25 MWh (35.2%) respectively. This values represent the PV plants energy unbalanced mean and deviation for a period of one year for the Sicilian electric zone, and were used to generate the stochastic data in order to obtain the real injections, as reported on equation 3.8.

$$RI_{PV} = AV_{PV} + rnd(\mu, \sigma) \tag{3.8}$$

Where RI_{PV} is a column vector containing the whole year real injection on an hourly basis for one of the provinces[4], rnd is a Gauss distributed random column vector of the same size of RI_{PV}, whose mean and a deviation correspond to the estimated values from equation 3.6 and 3.7 and AV_{PV} is a column vector containing the typical day injections of the province considered by RI_{PV} on an hourly basis for a period of one year. Equation 3.8 is consider only for sunny hours, otherwise the random values could impose solar radiation on night periods.

Then forecasted injections were set as the deterministic data, while the real injections were estimated as the sum of both stochastic and deterministic values as described in equation 3.8. Figure 3.6 illustrates the described procedure in a flow chart. Once this was done, a final condition was imposed in order to check that the energy injections were always positive. This was done because for low radiation periods[5] the stochastic component, which can be negative, might have a higher magnitude than the deterministic one.

Correlation matrix

The stochastic behavior of solar radiation was modeled by an uncoupled Gauss distribution. This means there is no correlation between the stochastic value obtained on one province and its neighbors. However, this might not be true given the size and proximity of some provinces. Therefore it could be the case that two neighbor areas are passing through a cloudy day, while further regions are experiencing a clear sky. Hence it would not be illogic to think that solar radiation might be

[4] Thus the size of this vector is of 8760 x 1.

[5] Early in the morning or late at night

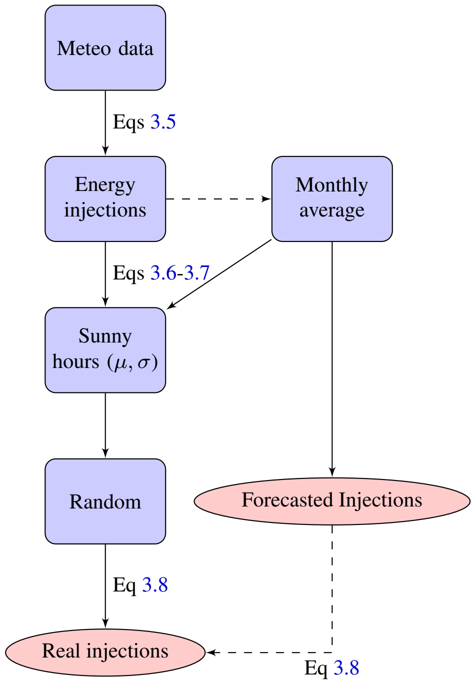

Figure 3.6: PV real injections flow chart

correlated among neighbor provinces, which will decrease differences on solar radiation variations among them, with respect to totally uncoupled data.

The flow chart 3.7 describes the procedure used in order to obtain the correlated solar radiation among neighbor provinces. First, a vector containing Gauss distributed random values whose mean and deviation correspond to the values found on equation 3.6 and 3.7 was generated for each province. The length of these vectors was of 8760, which corresponds to the number of hours in a year. Then, a matrix containing the nine uncopled vectors was assembled (B) and multiplied by the correlation matrix (C) in order to obtain a new matrix (B^*), which represents the correlated stochastic values of the nine provinces. This new matrix (B^*) contains the correlated value of each of the provinces in the same order as originally arranged on matrix (B). It is important to mention that the coefficients of the correlation matrix (C) were set in a way that the correlation didn't attenuate the original deviation of the data.

Equation 3.10 contains the correlation matrix. On it all neighbor connections, which are represented by Y values, were fixed constant. On the other hand, the self connection, which are represented with a X and a number on the C matrix, were varied until the standard deviation of the obtained data (b^*) was of the 35.2% as described in section 3.5.1.

$$b^* = C * b; \tag{3.9}$$

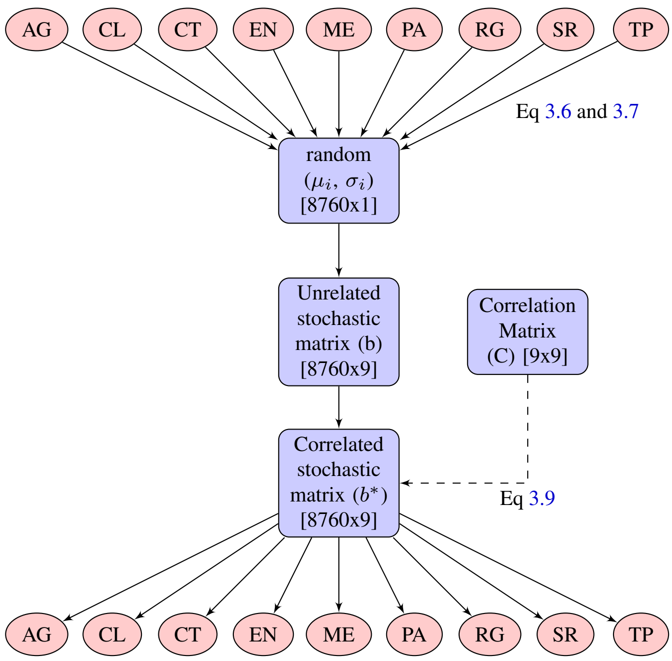

Figure 3.7: PV correlation

$$C = \begin{array}{c} \\ AG \\ CL \\ CT \\ EN \\ ME \\ PA \\ RG \\ SR \\ TP \end{array} \begin{array}{c} \begin{array}{ccccccccc} AG & CL & CT & EN & ME & PA & RG & SR & TP \end{array} \\ \begin{bmatrix} X1 & Y & 0 & 0 & 0 & Y & 0 & 0 & Y \\ Y & X2 & Y & Y & 0 & Y & Y & 0 & 0 \\ 0 & Y & X3 & Y & Y & 0 & Y & Y & 0 \\ 0 & Y & Y & X4 & Y & Y & 0 & 0 & 0 \\ 0 & 0 & Y & Y & X5 & Y & 0 & 0 & 0 \\ Y & Y & 0 & Y & Y & X6 & 0 & 0 & Y \\ 0 & Y & Y & 0 & 0 & 0 & X7 & Y & 0 \\ 0 & 0 & Y & 0 & 0 & 0 & Y & X8 & 0 \\ Y & 0 & 0 & 0 & 0 & Y & 0 & 0 & X9 \end{bmatrix} \end{array} \tag{3.10}$$

Table 3.2 contains an example of the random values obtained for one hour, before and after the correlation. From it, it can be seen that the difference between the values of neighbor provinces (see figure 3.5) is attenuated after the correlation, in comparison to the values before the correlation.

Correlation	Agrigento	Caltanissetta	Catania	Enna	Messina	Palermo	Ragusa	Siracusa	Trapani
Before	-0.1459	-0.1471	0.0613	-0.3474	-0.2360	0.0787	-0.6266	0.2935	-0.0595
After	-0.0960	-0.2303	-0.1494	-0.2090	-0.1554	-0.1202	-0.2828	0.0643	-0.0433

Table 3.2: Random values before and after using the correlation matrix.

Notwithstanding the correlation that might exist between neighboring provinces, the model should not perceive any difference between single unbalance generated with or without the correlation provided that the mean and deviation of the data are kept equal. However, the same cannot be said to the zonal unbalance produced with and without the correlation. Both correlated and uncorrelated data were used to feed the model in order to contrast these affirmations (see section 4.1.1).

3.5.2 Wind farms

Wind forecast was done by using the Bayesian approach described by Bracale et al [4]. This is a PDF method approach, which makes use of the Weibull probability function in an iterative process. Figure 3.9 illustrates the proceeding followed by the method. First it is required to take a sample of n consecutive data in order to determine the distribution mean (μ^t), scale (η^t) and shape parameter (β^t). After that, equation 3.11 is used in order lo correlate the sample mean (μ^t) with the second last value of the sample wind velocity (w_v^{t-1}). To do so, a Monte Carlo method is used to determine coefficients α_0 and α_1. Once this is done, the new mean (μ^{t+1}) is determined by using the equation 3.11, the α_0 and α_1 parameters and the last available wind velocity of the sample (w_v^t). The new mean (μ^{t+1}) and the original shape parameter (β^t) are used on equation 3.12 in order to obtain the new scale parameter (η^{t+1}). With both the scale and shape parameters one can find the wind velocity whose cumulative probability is 50% which is taken as the best estimative. Additionally a confidence interval was estimated by the wind velocities whose cumulative probability are 5.0 and 95.0% as illustrated on figure 3.8.

The Weibull scale parameter (η) represent how dispersed are the data. On the other hand, according to Ragusa et al. [5], the shape parameter (β) proportions direct information of the wind plant location. It reaches values of 1.6 for mountain areas, 2 for coastal areas and up to 3 for regions subjected to stationary or periodic winds. For a given average speed, a lower value of the shape parameter corresponds to higher energy availability, because the energy range is greater.

After that, the energy forecasted was obtained by using the wind conversion factor (see equation 3.5) and the wind velocity forecasted by the Bayesian method. The real energy injections were also determined by using the conversion factor and the meteorological data.

It is worth mentioning that for this method there is no need to correlate the data between provinces. This is due to the fact that the method uses the meteorological data of each province without introducing any deliberate variation as is the case for the PV model. Then the energy unbalance is caused by difference between the best estimative and the real wind velocity.

$$log(\mu^t) = \alpha_1 + \alpha_0 \cdot log_{10}(w_v^{t-1}) \tag{3.11}$$

$$\eta = \frac{\mu_{t+1}}{1 + \frac{1}{\beta}} \tag{3.12}$$

3.5.3 Load

The energy managed by Sicily at the day-ahead market was used to predict the zonal load requirements. Load was estimated for the whole electric zone (Sicily) and not on the province scale, because GME manages day-ahead market on a zonal scale. The estimated load was obtained from the 2012 day-ahead market provided by GME. Such data provides the hourly energy imports and exports of the Sicilian electric zone as forecasted on the day-ahead market. The Sicilian load was then estimated as the hourly energy needs plus the energy exported minus the energy imported from other zones (see equation 3.13).

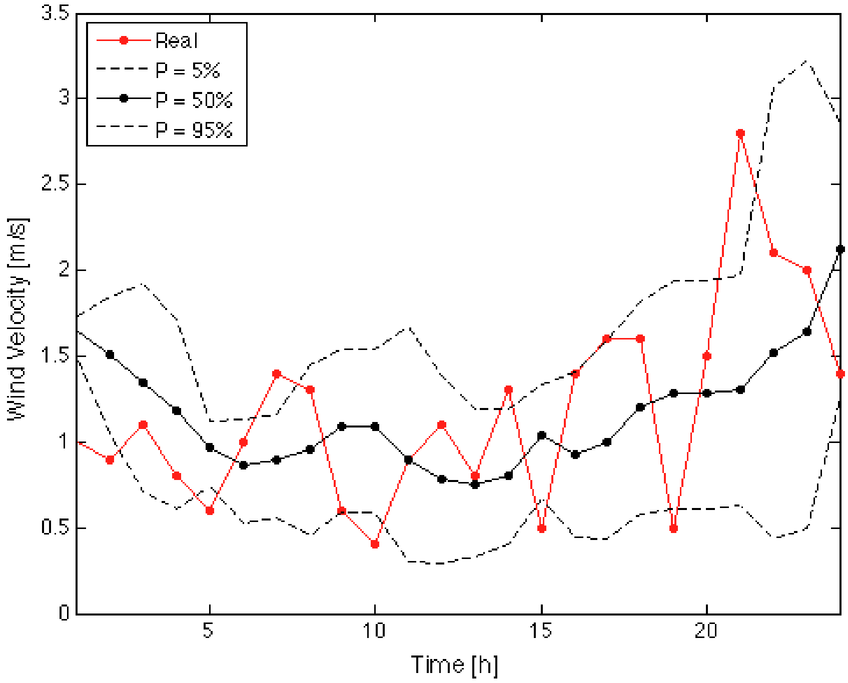

Figure 3.8: Wind forecast model

$$L_S = L_L + L_E - L_I \tag{3.13}$$

Where L_S is the hourly Sicilian load, L_L is the local load, L_E is the energy exported and L_I is the energy imported. It is important to mention that these parameters make reference to load on an hourly basis[6]. On the other hand, it was found that the Sicilian energy forecasted on the day ahead market for 2012 was slightly lower than the real energy consumption reported by TERNA in [46]. To cope with this, the energy forecasted on the day-ahead market was scale by using the consumption reported by TERNA as follows:

$$L_S^* = L_S \cdot \frac{EC_{2012}}{\sum L_S} \tag{3.14}$$

Where L_S^* is the Sicilian scaled load on and hourly basis, L_S is the day-ahead market Sicilian hourly load, $\sum L_S$ is the sum of the 2012 forecasted load on the day-ahead market and EC_{2012} is the energy consumed on 2012 according to the TERNA report.

[6]In order to find the load imbalance (see section 3.7.3) we considered only L_L because it was assumed that energy exports (L_E) and energy imports (L_I) do not contribute to the energy unbalance.

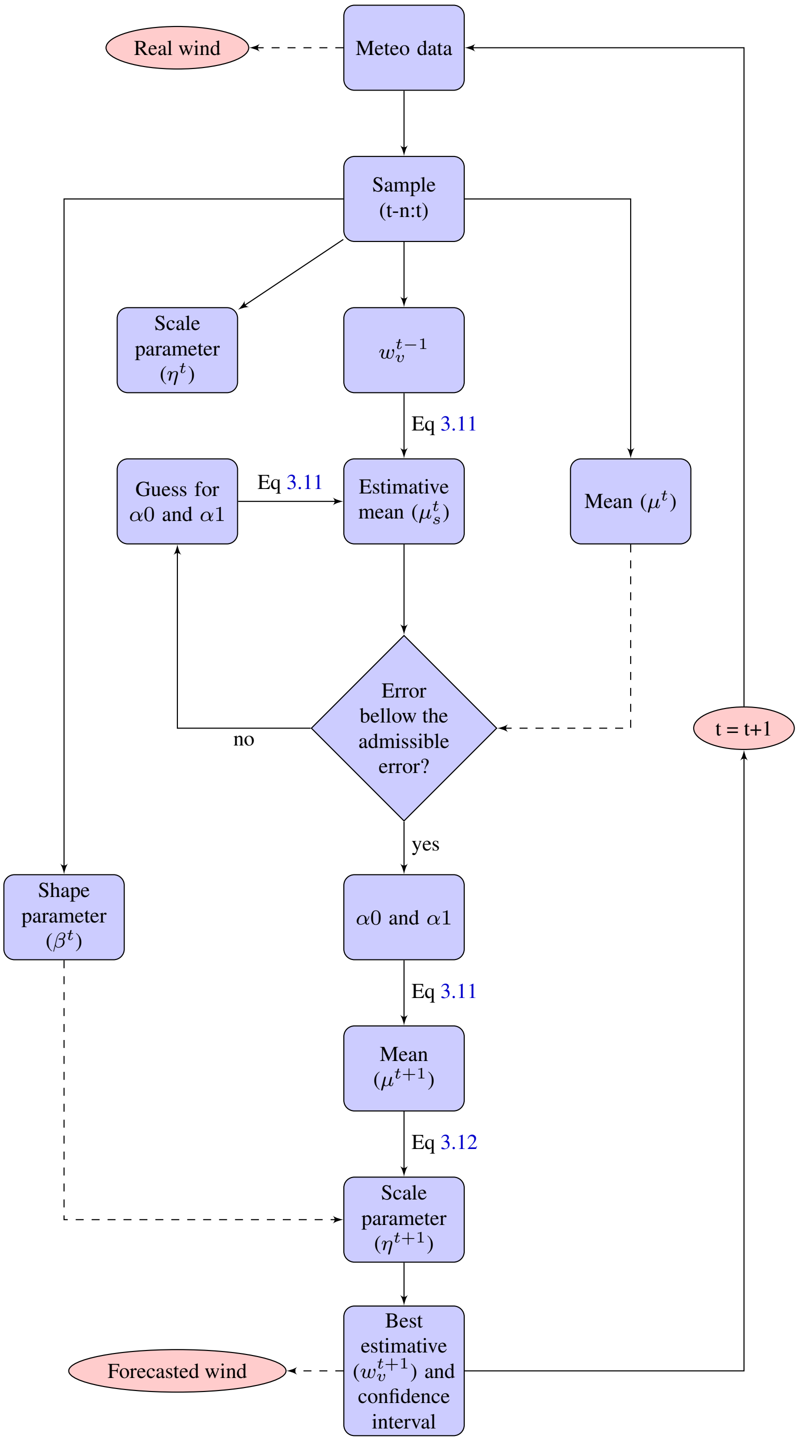

Figure 3.9: Bayesian method flow chart

3.6 Energy unbalance

3.6.1 Unbalance mechanisms

Energy unbalance is the difference between the energy injections planned on the day-ahead or intraday market and the real injections. For the purpose of this project, no unbalance was generated by traditional plants. Then the unbalance mechanism make reference only to PV and wind plants.

- *Nodal unbalance*
  Unbalance is computed on the basis of effective behavior[7] of each node (single unbalance). TERNA calculates the nodal marginal prices based on the offers of the balancing market (MB).

- *Zonal unbalance*
  Unbalance is computed on the basis of the zonal unbalance. The difference between the effective and planned production or consumption is compared with the zonal unbalance. The later refers to the the opposite sign[8] of the total electricity procured by TERNA for balancing purposes, in the market for dispatching services, with reference to the time period and a macro area issued.

Zonal unbalance

The Italian system operates under zonal unbalance mechanism. Then economic penalization takes into account the global unbalance, which can be either positive or negative.

Positive zonal unbalance
It refers to periods where energy is in excess, which occur when energy production is larger than planned or energy consumption is lower than planned. In this case, TERNA calls the programmable plants to lower their production.

- TERNA gets $MB_{\downarrow}$[9] prices from producers.
- TERNA pays unbalance price to unbalance operators.

Negative zonal unbalance
It refers to periods where energy is lacking, which occur when energy production is lower than planned or energy consumption is higher than planned. In this case, TERNA calls the programmable plants to increase their production.

- TERNA pays $MB_{\uparrow}$ prices to conventional plants.
- TERNA gets unbalance price from unbalance operators.

[7] Difference between the effective and planned production or consumption

[8] The energy bought by TERNA is count as negative, while the one sold is possitive

[9] MB stands for ”Mercato di bilanciamento” and makes reference to the ancillary service market in real time balance.

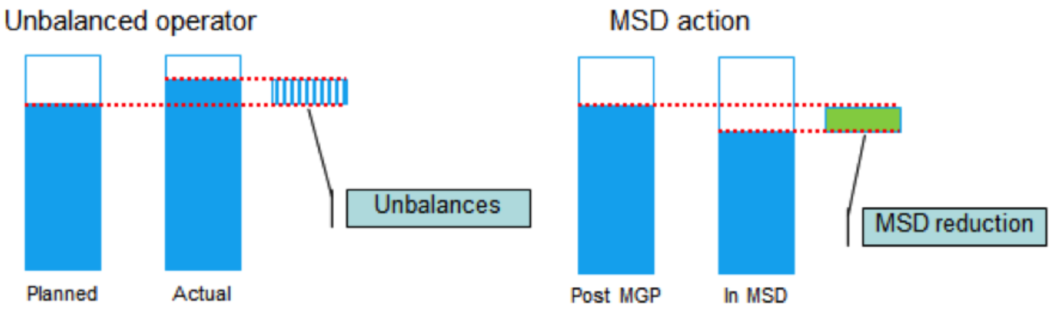

Figure 3.10: Positive zonal unbalance

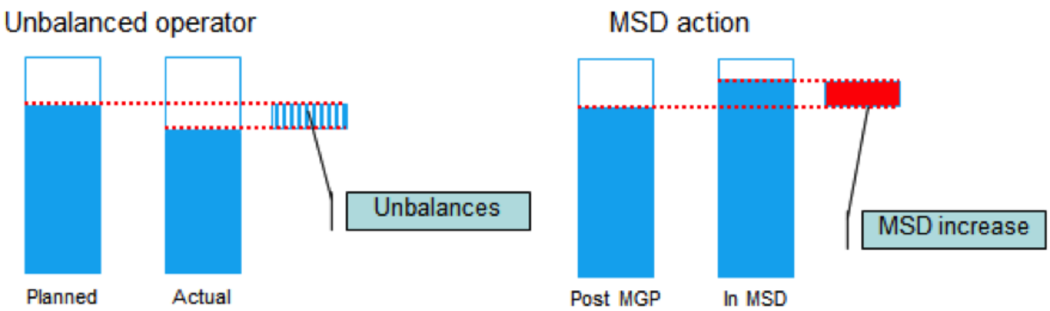

Figure 3.11: Negative zonal unbalance

Zonal unbalance remuneration

Zonal unbalance is paid under two different models.

1. *Dual pricing*
   In the dual price model, both single[10] and zonal[11] unbalance are considered. This mechanism has been kept in force for units authorized for the purposes of system security reasons. According to this mechanism, a power plant can never benefit from the imbalance even in cases where this ”aids” involuntarily TERNA to balance the system. The underlying logic is that of deter power plants from disregard their injection schedule, so that unbalance is never generated on purpose [35].

   In the case of a plant is generating a positive unbalance[12] the unbalance price can be estimated as follows.

   - In the case the zonal unbalance is positive, the unbalance prices is estimated as the minimum between:
     – the average price of the bids accepted in the market for the ancillary services for the purpose of real-time balancing, weighted by volume, in the same relevant period,

[10]Single unbalance is the unbalance of one power plant.
[11]Zonal unbalance is the sum of the unbalances of all power plants in one zone.
[12]Productions is higher than forecasted.

in the macro area where the dispatching point belongs;
- the price of the accepted supply offers in the day-ahead market (MGP) during the same period relevant in the area where is located the point of dispatching.

In the case of the plant generating a negative unbalance[13] the unbalance price can be estimated as follows.

- In the case the zonal unbalance is positive, the unbalance prices is estimated as the maximum between:
  - the average price of the bids accepted in the market for the ancillary services for the purpose of real-time balancing, weighted by volume, in the same relevant period, in the macro area where the dispatching point belongs;
  - The price of the accepted supply offers in the day-ahead market (MGP) during the same period relevant in the area where is located the point of dispatching.

Otherwise, in the case that the plant's unbalance opposes the zonal unbalance[14], the unbalanced energy is paid at day-ahead market price. So it is as if the unit has sold the unbalanced energy in the market.

	Positive unbalance	Negative unbalance
Positive zonal unbalance	Receive min(P_{MGP}, $P_{MB\downarrow}$)	Pay Day ahead price
Negative zonal unbalance	Receive Day ahead price	Pay max(P_{MGP},$P_{MB\uparrow}$))

Table 3.3: Dual pricing mechanism.

2. *Single pricing*
   In the single price model, only the zonal unbalance is considered.

   - *Positive zonal unbalance*
     The market zone is in over generation or under consumption.
   - *Negative zonal unbalance*
     The market zone is in under generation or over consumption.

	Positive unbalance	Negative unbalance
Positive zonal unbalance	Receive min(P_{MGP},media($P_{MB\downarrow}$))	Pay min(P_{MGP},media($P_{MB\downarrow}$))
Negative zonal unbalance	Receive max(P_{MGP},media($P_{MB\uparrow}$))	Pay max(P_{MGP},media($P_{MB\uparrow}$))

Table 3.4: Single pricing mechanism.

[13]Productions is lower than forecasted.
[14]The plant is producing more in an area in deficit or the plant is producing less in an area in excess.

3.7 Nodal unbalance estimation

The single unbalance produced by each PV plants and wind farm is the difference between real and forecasted injections. On the other hand, the load unbalance is estimated as the difference between the forecasted and the real load. The unbalance estimation will be explained differentiating the energy source.

3.7.1 PV unbalance

The PV unbalance was estimated by subtracting the real and the forecasted injections (see equation 3.15). This value corresponds to the stochastic term described on section 3.5.1. Figure 3.12 shows the unbalance obtained for Agrigento, which like other provinces can be assumed Gaussian distributed, with a mean value of 0 and a standard deviation of 35.2%.

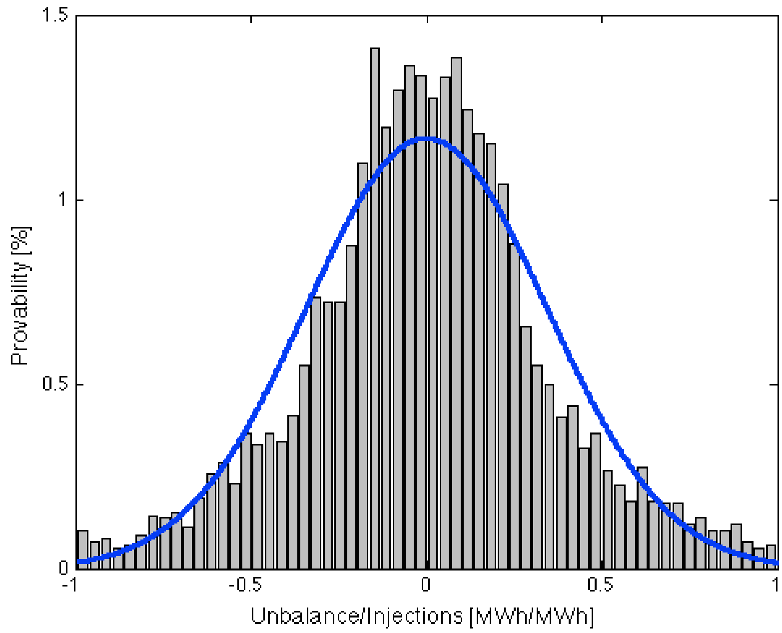

Figure 3.12: PV unbalance over the installed capacity histogram and probability density function for Agrigento

$$U_{PV} = R_{PV} - F_{PV} \tag{3.15}$$

Where F_{PV} is the forecasted PV plant injection, R_{PV} is the real PV plant injection and U_{PV} is the unbalance generated (see section 3.5.1).

3.7.2 Wind unbalance

Wind farms single unbalance was estimated with the meteorological data and forecast algorithm. The first one constitutes the real injections, while the second one represents the forecast injections. Equation 3.16 describes how the wind unbalance was estimated. Figure 3.13 illustrates the wind unbalance obtained for the province of Messina. It can be seen that the unbalance cannot be properly represented by a normal distribution or by a Weibull distribution because of the limitation of Weibull distribution referring to negative values. Other distributions as Rayleigh, extreme value and generalized extreme value distribution were also tested with no success due to their limitations and/or low fitness accuracy. This does not have any further implication on the methodology, given that wind farms unbalance was not generated by a PDF but by the Bayesian method described on section 3.5.2.

$$U_W = R_W - F_W \tag{3.16}$$

Where F_W is the forecasted wind plant injection, R_W is the real wind plant injection and U_W is the unbalance generated.

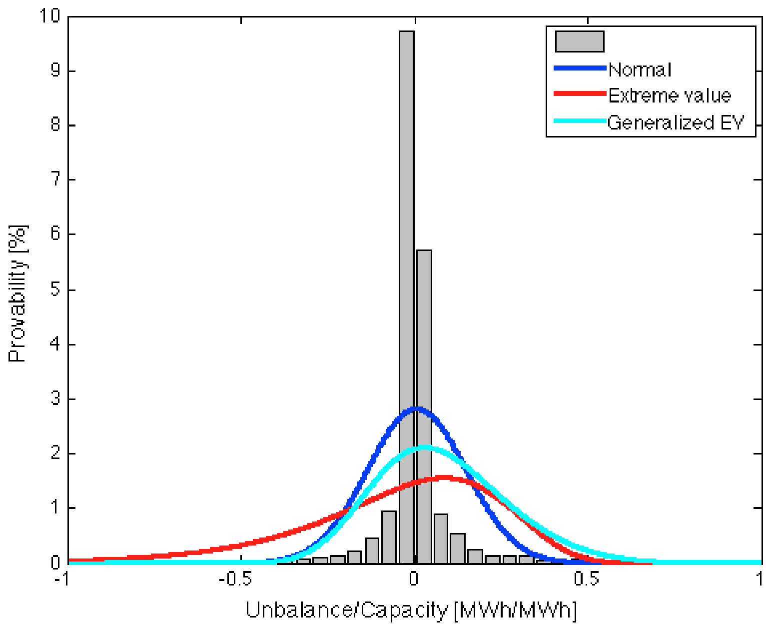

Figure 3.13: Histogram of the Messina's wind farms unbalance divided its installed capacity, together with different probability density functions.

3.7.3 Load unbalance

The forecasted load was obtained by adding a stochastic term to the energy needs. The stochastic term is a normal distribution with 0 mean and a 10% deviation as described by Bracale et al [4]. This term was just added to the local load (L_L) because it was assumed that energy exchange among zones (imports and exports) are not subjected to unbalance (see equation 3.13). Load unbalance was then calculated as reported on equation 3.17. Figure 3.14 contains the energy unbalance for the load, which as just mentioned is Gauss distributed.

$$U_L = F_L - R_L \tag{3.17}$$

Where U_L refers to the load unbalance, R_L is the real load and F_L is the forecasted load.

It was found that the Sicilian peak and base load are around 4.2 GWh and 0.9 GWh respectively. On the other hand, the maximum energy exported to the south region is 0.3 GWh while the maximum energy imported is 0.07 GWh. Finally, both the maximum positive and negative unbalance are 1.3 and 1.1 GWh respectively.

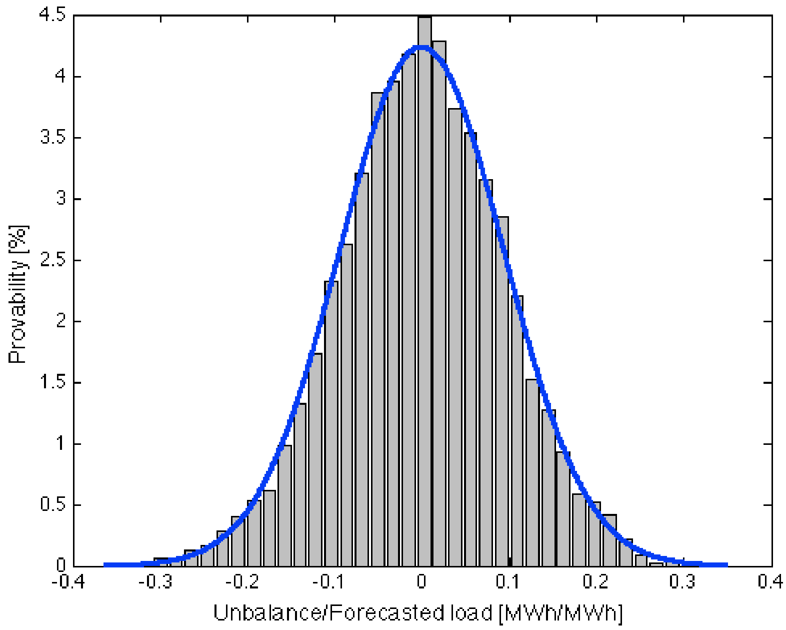

Figure 3.14: Load unbalance over forecasted load histogram and normal probability density functions for the whole Sicily

3.8 Zonal unbalance estimation

Figure 3.15 illustrates the real and forecasted energy injections and consumption on a day in Sicily. From it, it can be checked that PV plants only inject energy during the day period and that PV plants do generate energy unbalance due to the difference between the real (RI_{PV}) and the forecast energy injections (FI_{PV}). In the case of wind plants, it can be seen these plants inject energy all day long in case wind is present, and they also generate energy unbalance due to the difference between real (RI_W) and forecast (FI_W) injections. As for the load, it can be seen that load also generates energy unbalance due to forecast (L_f) and real (L_r) load difference. Then the zonal unbalance is the sum of the load unbalance and the PV and wind plants unbalance as illustrated on equation 3.18[15]. The zonal unbalance was calculated in order to obtain the unbalance quantity and sign, which mean to obtain the amount of the unbalance (zonal unbalance) and to check if energy is in excess or if it is in deficit. This information is required to calculate the amount of energy penalized by the single and dual pricing mechanism.

[15]For the sake of simplicity, it was assumed that conventional plants don't generate any unbalance.

$$U_Z = U_L + U_{PV} + U_W \tag{3.18}$$

Where U_Z refers to the zonal unbalance, U_L to the load unbalance, U_{PV} to the PV plants' unbalance and U_W the wind farms' unbalance. For the sake of simplicity, it was assumed that conventional plants unbalance is equal to zero.

Additionally, from figure 3.15 it can be seen that there are two peak loads which correspond to midday and early night. One concern exposed by this graph is that at midday the residual load[16] cover by conventional plants is reduced due to the high PV and wind plants injections. However at night PV plants cannot inject energy, so traditional plants should be ready to supply this demand. Additionally, it might be the case that wind plants injections are high early in the morning when energy load is low. This strongly reduces the residual load to be cover by traditional plants. However some of these plants cannot be shut down either for technologic limitation or to assure the system security. This constitutes one of the main concerns of integrating a high share of non-programmable RES-E on the energy system.

According to an AEEG report[41], the residual load variation produced by PV plants has a great impact on the day ahead market price. Then in hours where there is low or no PV production (1 - 10h and 17 - 24h), the day ahead market price (Prezzo Unico Nazionale, PUN) goes up. While in the periods of high solar radiation (11 - 16h) the day-ahead market price goes down.

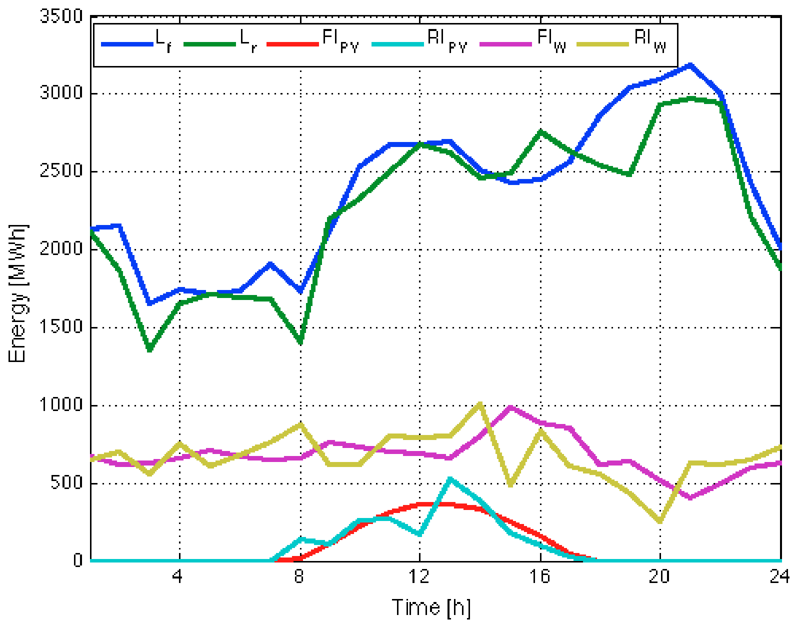

Figure 3.15: Planned and real injections for one day.

Figure 3.16 illustrates the yearly zonal unbalance, where it can be seen that zonal unbalance constantly varies from positive (energy is in excess) to negative (energy is lacking). Additionally it can be seen that both maximum and minimum unbalance values are close to 1.5 GWh. Finally, it was found that there is just 1 hour in the year when the PV plants and wind farms are able to cover

[16] Difference between consumption and the non-programmable RES-E injections

the whole Sicilian load plus the exports. TERNA cannot allow under any circumstance to cover the total demand of load with non-programmable RES-E, in order to guarantee the system security. In such scenario (or under a really high RES-E penetration), renewables are curtailed. Even though the model is not able to perform the energy curtailment, this does not represent any major threat due to the rare occurrence of this event.

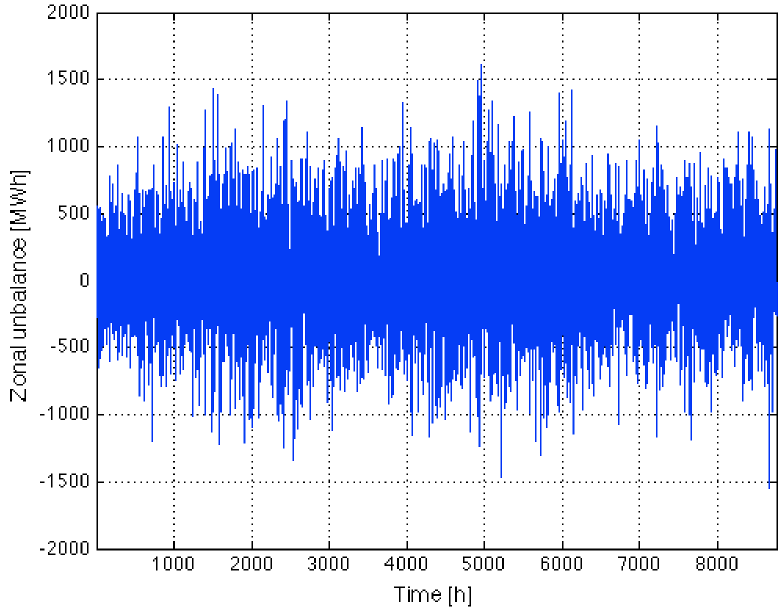

Figure 3.16: Yearly zonal unbalance

3.9 Unbalance remuneration

This section describes the remuneration mechanism used to deal with the energy unbalance. In this way, the different costs incurred by TERNA and the plant owners were obtained.

3.9.1 Single price mechanism

The Sicilian zonal unbalance was determined as described on equation 3.18. This was used to determine the hours that had positive and negative zonal unbalance. Then this information was used to penalize producers generating the unbalance. The revenues obtained by TERNA, under the single unbalance mechanism, were estimated as described by equation 3.19.

$$R_{TERNA}^{SP} = \sum_{plants} \sum_{hour} R - \sum_{plants} \sum_{hour} P \tag{3.19}$$

$$P = (U_{plant\downarrow} \cdot media(P_{MB\uparrow}))\forall U_{Z\downarrow} + (U_{plant\downarrow} \cdot media(P_{MB\downarrow}))\forall U_{Z\uparrow} \tag{3.20}$$

$$R = (U_{plant\uparrow} \cdot media(P_{MB\downarrow}))\forall U_{Z\uparrow} + (U_{plant\uparrow} \cdot media(P_{MB\uparrow}))\forall U_{Z\downarrow} \tag{3.21}$$

Where:

- R_{TERNA}^{SP} is the money collected by TERNA from the plants generating the unbalance under the single unbalance mechanism;
- $U_{plant\downarrow}$ and $U_{plant\uparrow}$ are the negative and positive plant unbalance;
- $MB_{\uparrow}$, $MB_{\downarrow}$ are the cost per MWh on the ancillary market for eligible plants to decrease or increase their energy injections respectively.

Then sign mitigation among different power plants is not taken into account, so the total unbalance volume dealt under this conditions is higher than the total zonal unbalance.

Without allowance

In the case that regulation states no unbalance allowance, all injections harming the system are penalized. Table 3.5 contains the energy penalized by province classified by source. Notice that the unbalance percentage is similar between provinces for the same source. This implies that the unbalance generated per MWh injected varies with the source and the forecasting method and not with the plant location[17]. It can also be seen that the forecast error obtained for wind plants is almost three times bigger than the one obtained for PV plants. This relation does judge the accuracy of the forecast methods used for the PV and wind injections[18], however it does not have any further implication on the real forecast accuracy.

Source	Penalization	Agrigento	Caltanissetta	Catania	Enna	Messina	Palermo	Ragusa	Siracusa	Trapani
PV	[GWh]	36.7	14.6	30.1	12.7	6.9	24.4	34.8	37.6	25.2
	[%]	13.9	15.5	14.8	14.2	15.1	14.9	14.3	14.4	14.1
Wind	[GWh]	198.0	17.4	120.6	170.5	41.3	368.4	22.9	108.6	203.9
	[%]	40.0	43.0	38.6	47.5	39.7	48.5	22.5	50.2	33.6

Table 3.5: Energy penalized without the allowance.

With allowance

The AEEG regulation 281/2012/R/EFR [39] and subsequent amendments and additions, state that from the period between 1 January 2013 and 30 June 2013, a forecast error of 20% should not be exceed; from the period between 1 July and 31 December, this amount should not exceed 10%. This regulation has been partially cancelled by the "Consiglio di Stato" on September 11th due to the fact that it grants the same allowance to PV and wind plants. The partial cancelation states that the allowed forecasted should be raised once more to the value of 20%. Then unbalance costs penalized under the dual price mechanism were estimated.

Table 3.6 contains the yearly energy penalized for both PV and Wind farms of each province. Once more, it can be notice that the unbalance percentage is similar between provinces. This implies that the unbalance generated per MWh injected varies with the source and the forecasting method and not with the plant location.

[17] Due to the proximity of the provinces.

[18] Even though the forecast method used for PV plants is simpler than the one used for wind plants, the results are better because wind velocity depends on wind speed to the third power. Then any forecast error is further magnified when converted from wind velocity to wind injections.

Source	Penalization	Agrigento	Caltanissetta	Catania	Enna	Messina	Palermo	Ragusa	Siracusa	Trapani
PV	[GWh]	23.6	9.7	19.8	8.3	4.6	16.0	22.8	24.6	16.6
	[%]	8.9	10.3	9.7	9.3	10.1	9.8	9.4	9.4	9.3
Wind	[GWh]	153.6	13.5	93.9	134.0	32.4	288.7	17.3	85.5	157.0
	[%]	31.0	33.4	30.1	37.3	31.1	38.0	17.0	39.5	25.9

Table 3.6: Energy penalized with a 20% allowance.

3.9.2 Dual price mechanism

Hours that had positive and negative unbalance were determined for the Sicilian load and for PV and wind plants single unbalance. Then this information was used to determine the hours in which non-programable RES-E unbalance harmed (or supported) the system. Hours in which the system was harmed were penalized, while a premium was granted for hours in which the unbalance aided the system. The revenues obtained by TERNA are estimated as described by equation 3.22.

$$R^{DP}_{TERNA} = \sum_{plants} \sum_{hour} R - \sum_{plants} \sum_{hour} P \tag{3.22}$$

$$P = (U_{plant\downarrow} \cdot P_{MB\uparrow}) \forall U_{Z\downarrow} + (U_{plant\uparrow} \cdot P_{MB\downarrow}) \forall U_{Z\uparrow} \tag{3.23}$$

$$R = (U_{plant\downarrow} \cdot P_{MGP}) \forall U_{Z\uparrow} + (U_{plant\uparrow} \cdot P_{MGP}) \forall U_{Z\downarrow} \tag{3.24}$$

Where:

- R^{DP}_{TERNA} is the money collected by TERNA from the plants generating the unbalance under the dual price mechanism;
- R and P are the revenues and payments obtained by unbalanced plants;
- $P_{MB\uparrow}$, $P_{MB\downarrow}$ are the cost per MWh on the ancillary market for eligible plants to decrease or increase their energy injections respectively;
- P_{MGP} is the day-ahead market price.

Notice that TERNA penalizes each plant from its own unbalance. Then sign mitigation among different power plants is not taken into account, so the total unbalance volume dealt under this condition is higher than the total zonal unbalance.

Without allowance

In the case that regulation states no unbalance allowance all injections harming the system are penalized. Table 3.5 contains the energy penalized by province classified by source. Notice that the unbalance considered doesn't depend on the remuneration mechanism but only on the power plants. So the difference between the single and dual price mechanism are the fees used to estimate the remuneration and not the energy penalized.

With allowance

The total energy unbalance penalized by this mechanism under a 20% allowance is listed on table 3.6. It is important to highlight that under the Italian regulation allowance is applied to single price, however this thesis project considered it also under the dual price mechanism as an estimation exercise.

3.9.3 TERNA's cash flow

Currently, TERNA pays/receives the difference between the costs paid to traditional power plants and the revenues obtained under the single price[19] mechanism with a 20% allowance. Given that the thesis project investigates the effect of different remuneration mechanism, TERNA's cash flow will be estimated not only for the mechanism currently in place, but for all mechanisms described in this chapter.

Traditional plants participating to the real time ancillary service market (MB) are paid to increase or lower their energy production in order to cope with the zonal unbalance. Then, to estimate TERNA's cash flow it is required to compute the revenues obtained by traditional plants balancing the system (see equation 3.25). Once done that, it was possible to estimate TERNA's cash flows as illustrated by equation 3.26.

$$C_{Traditional} = \left[\sum_{h=1}^{n} (U_{W+PV} \cdot MB_{\uparrow}\right] \forall_{U_Z<0} + \left[\sum_{h=1}^{n} U_{W+PV} \cdot MB_{\downarrow}\right] \forall_{U_Z>0} \tag{3.25}$$

$$C_{TERNA} = C_{Traditional} - RM \tag{3.26}$$

Where:

- $C_{Traditional}$ is the amount of money paid on the ancillary service market to traditional plants balancing the system;
- U_{PV}, U_W and U_Z are the PV, wind and zonal unbalances respectively;
- $MB_{\downarrow}$ and $MB_{\uparrow}$ are the cost per MWh paid by TERNA on the ancillary market for eligible plants to decrease or increase their energy injections respectively;
- n is the total number of hours in a year;
- m are the total number of plants;
- $\forall$ is the logical symbol "for all";
- C_{TERNA} is TERNA's cash flow;
- RM is the revenue obtained by TERNA through the mechanism to be studied[20].

[19]Traditional plants are penalized under the dual price mechanism without any allowance, not the single price.

[20]Single and dual price mechanism with and without allowance.

Notice that the magnitude of the load unbalance is not included in equation 3.25 because C_{TERNA} represents only the unbalance cash flow related to non-programmable RES-E. Load unbalance was just used to evaluate weather the zonal unbalance is positive or negative.

As a brief, to estimate TERNA's cash flow it is required to:

1. Find the quantity of energy unbalance and sign on each hour, for each power plant.
2. Estimate the zonal unbalance and sign.
3. Compute the cost incurred by unbalanced plants under the desired remuneration mechanism (single or dual price with or without allowance).
4. Determine the economic revenue obtained by traditional plants in order to cope with the zonal unbalance on real time.
5. Use both the values determined on the last two numerals to determine TERNA's cash flow.

Chapter 4

Results

4.1 Energy injections

A prediction algorithm for wind and PV plants was defined according to the geographic location of these power plants[1]. This allowed obtaining the forecasted and real generation curve on an hourly basis during a period of one year. Figure 4.1 contains the monthly equivalent operating hours. From it, the seasonal variation of solar radiation can be appreciated as on summer months the number of PV equivalent hours increases with respect to the equivalent hours during the winter period. Additionally, figure 4.1 reports that during year 2012 wind and PV plants operated during a total of 1777 and 1371 equivalent hours respectively. The GSE 2011 statistic report [20] stated that in 2011 the mean wind equivalent hours in Sicily was of 1779 hours[2]. Additionally the same source also reported that the mean value of the equivalent operation hours in Italy was 1325. The accuracy of these values can be attributed to the fact that the conversion factor used for PV and wind plants (see section 3.4) was estimated in order to obtain a total energy injection of 1544 and 2995.9 GWh for PV and wind plants respectively. This values correspond to the ones stated on TERNA's regional energy report [46].

Figure 4.2 contains the monthly injections for PV, wind and traditional plants in order to supply the load demand. It can be seen that both energy from renewables and load vary every month. Then the residual load remaining to traditional plants can increase or decrease depending on the weather conditions and load demand. The yearly Sicilian load was 24154 GWh, which closely corresponds to the value reported by TERNA's regional energy report [46]. With this value and the total PV and wind energy injections, it can be said that PV plants covered a 6.4% of the total load, while the share of wind plants corresponds to 12.4%. This makes a total of 18.8% of energy covered by non-programmable energy sources.

4.1.1 PV plants

In section 3.5.1 it was described that a correlation matrix was used in order to take into account that solar radiation might be correlated among neighbor provinces. Then it was required to test if such condition did modify the zonal injection profiles and unbalances. In order to do so, the energy injections, nodal and zonal unbalance were estimated for PV injections with and without the

[1] The location refers to the nine Sicilian provinces

[2] This number refers to plants installed up to 2010. Plants installed during 2011 were not taken into account because they did not operate during a complete year period

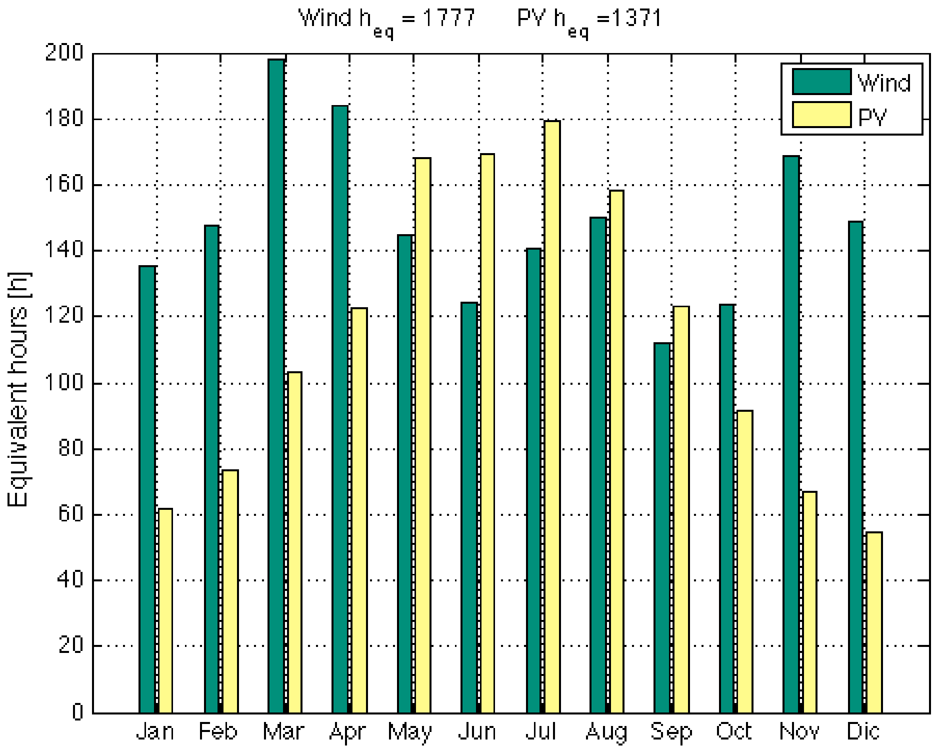

Figure 4.1: Non-programmable RES-E equivalent hours

correlation matrix. A third scenario was also modeled by assuming a strong correlation between provinces. In the case of no correlation, real radiation was obtained by adding uncorrelated random values (stochastic term) to the daily average radiation (deterministic term). On the other hand, the correlated stochastic term was obtained by multiplying the random values of each province by the correlation matrix (see section 3.5.1). Finally, a strongly correlated data was obtained by adding the same stochastic term to all the provinces. Physically, this implies that the entire region is affected by the same meteorological conditions, which means that all provinces perceive the same hour as a cloudy or sunny hour.

Figure 4.3 shows the monthly injections of the Sicilian PV plants without correlation and with the correlation obtained by the correlation matrix and the strong correlation. It can be seen that there is no remarkable difference between the three injection profiles. The total energy injections of PV with and without the correlation matrix are equal to 1540 GWh. Hence it can be said that in all the cases energy injections are practically the same.

Additionally, the nodal unbalance generated by the three data series was compared. In order to do so, the total energy unbalance generated for each province was estimated. As shown in table 4.1 the yearly province unbalance is almost equal for the three cases. The fact that both energy injections and unbalances are practically the same, for the different methods, occurs because a stochastic vector whose mean and standard deviation is of 0 and 35.2% respectively was used to generate both the data generated with and without the correlation. Up until here, it can be said that the model used is not able to perceive any difference between correlated and uncorrelated data

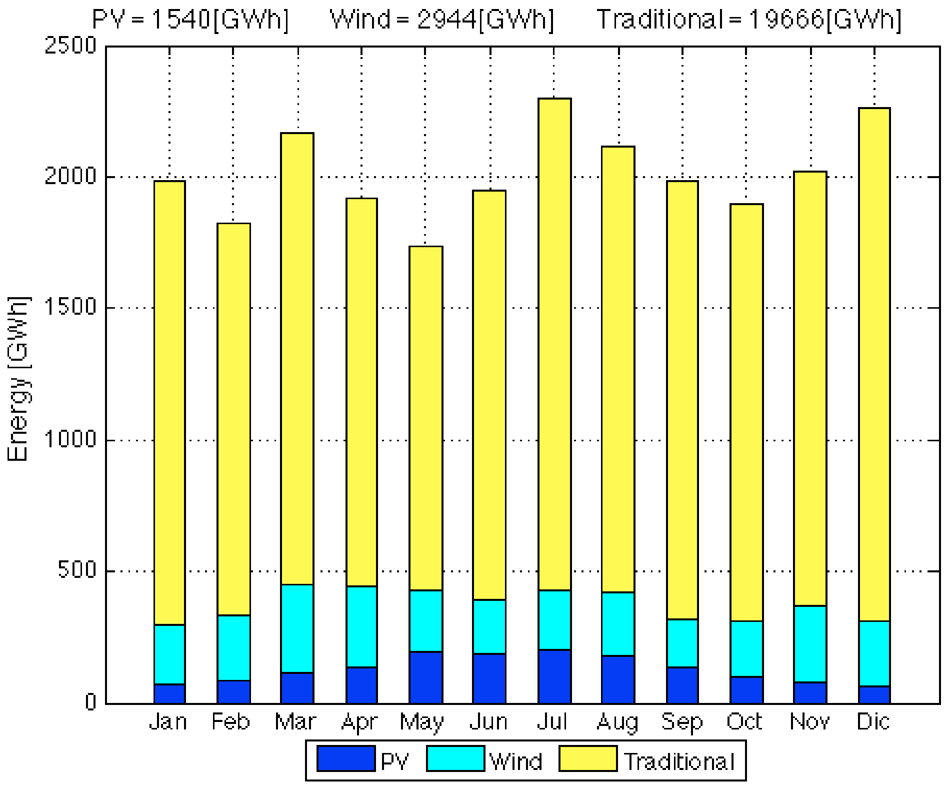

Figure 4.2: Monthly injections

provided that their mean and deviation are kept equal.

Correlation	Energy unbalance [GWh]								
	Agrigento	Caltanissetta	Catania	Enna	Messina	Palermo	Ragusa	Siracusa	Trapani
Without	64.73	25.68	50.99	22.77	12.64	42.92	63.75	68.41	46.42
With	64.66	25.00	53.00	22.76	12.68	43.26	63.31	68.15	46.85
Strong	64.65	25.11	52.07	22.70	12.66	43.24	62.14	67.16	46.39

Table 4.1: Yearly PV single unbalance for data generated with and without correlation.

The zonal unbalance generated under the three scenarios was measured in order to determine the effect of correlating the data. Table 4.2 contains the total zonal unbalance perceived under the different correlations studied. Even though in all three conditions the same nodal unbalance was generated, it can be observed that the total zonal unbalance does vary when correlating the data. In this way, it was obtained that forecasting PV injections without correlation generates the smallest zonal unbalance. This is attributed to the sign mitigation, that occurs on a greater extent when data is not correlated. On the other hand, imposing a strong weather correlation among provinces generates high zonal unbalance because, under this condition, there is no sign mitigation given that all plants are producing positive or negative unbalance at the same time. Despite the zonal unbalance increment, all the following calculations were done with the PV data obtained by the correlation matrix. This was done because it was considered that the correlated data represent

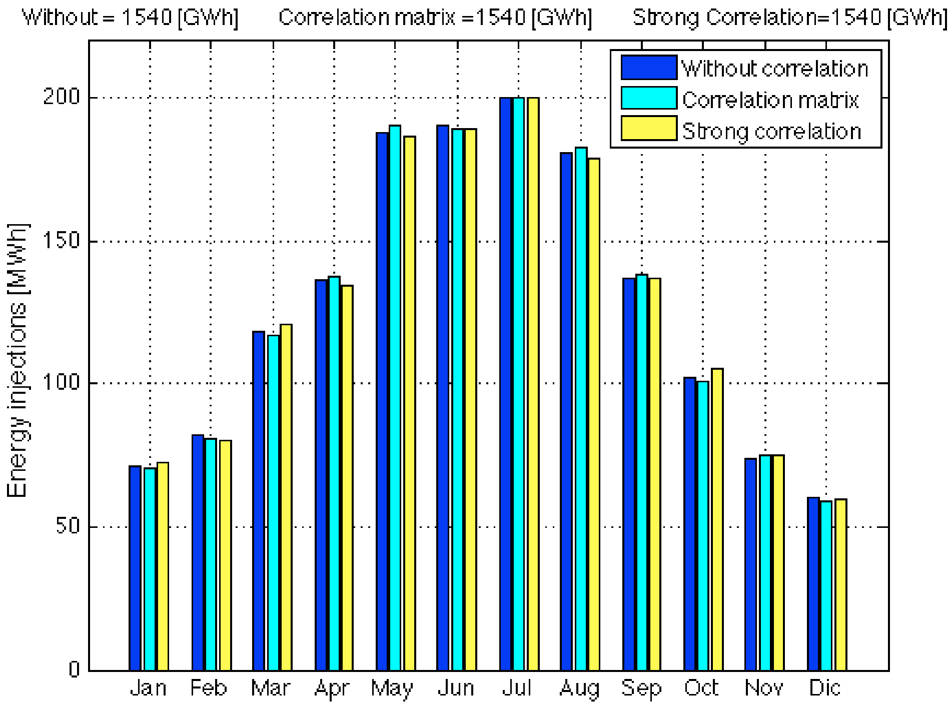

Figure 4.3: Monthly injections for PV plants with and without the correlation matrix

better the meteorological conditions.

PV Zonal unbalance	Without correlation	Correlation matrix	Strong correlation
+ [GWh/y]	95.09	138.64	219.70
- [GWh/y]	59.38	110.07	179.41

Table 4.2: Yearly PV zonal unbalance generated with and without correlation.

Finally, it is worth highlighting that correlation was performed only for PV plants and not for wind farms. In the case of PV plants such an action is required as the forecasting model uses a stochastic term which is deliberately imposed (see section 3.5.1) in order to determine the real injections. Then the correlation is done to bond the meteorological data on a spatial frame. On the other hand, the forecasting model used for wind plants adds no deliberate value and uses directly the meteorological data to create the forecast. Then, the spatial correlation is assumed to be implicit on the meteorological data. For this reason, no correlation was needed in the case of wind velocity.

4.2 Nodal unbalance

Once forecasted, real injections and forecasted and real loads were obtained, it was possible to estimate the unbalance produced by the load and the by sum of all PV and wind Sicilian plants. Figure 4.4, 4.5 and 4.6 contain the monthly unbalance generated by PV, wind plants and load due to forecasting errors.

PV unbalance

In the case of PV plants, it was found that the yearly positive and negative unbalance are 204.0 and 204.1 GWh respectively. This implies that the total energy unbalance constitutes a 26.0% of the total PV injections. From figure 4.4 it can be seen that the generated unbalance is symmetrical, given that, as already mentioned, the positive unbalance is equal to the negative one. This can be justified by looking at equation 3.8, where, in order to obtain the real injections, a stochastic value is added to every sunny hour. No bias is present, given that the stochastic mean (μ) is equal to zero.

Additionally, figure 4.4 can be used to see how dispersed is the data because it illustrates separately the imbalance whose deviation is lower than the 20% from the one higher. The positive and negative unbalance incurring an error higher than the 20% are 130.6 and 130.6 GWh respectively. This implies that for the case of PV unbalance, around 65.2% of the energy unbalance is caused by forecast errors higher than the 20%.

Finally, it is worth noticing that the energy unbalance exhibits a seasonal variation similar to the equivalent hours illustrated in figure 4.1. This is attributed to the fact that the induced error increases with the number of sunny hours, as one can see from equation 3.8, were a stochastic value is assigned to each sunny hour. The stochastic value represents the energy unbalance, so months with longer sunny periods will have higher unbalances.

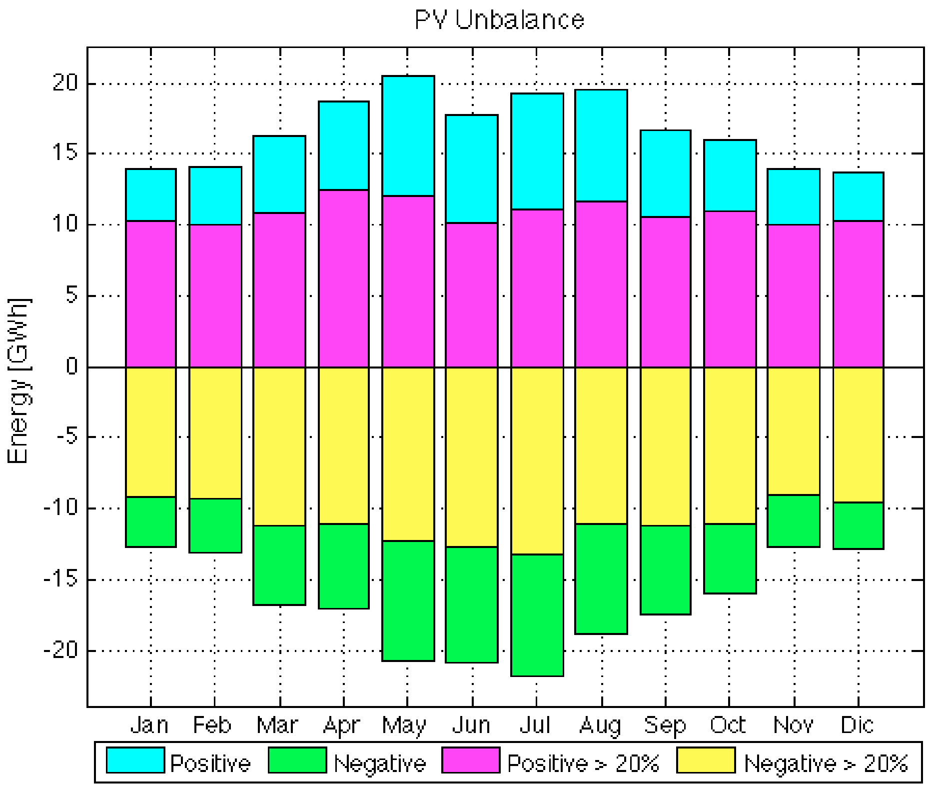

Figure 4.4: PV plants total nodal unbalance

Wind unbalance

In the case of wind plants, the yearly positive and negative unbalance are 875.6 and 926.8 GWh respectively. This implies that the total energy unbalance constitutes a 57.3% of the total wind injections. Notice that in this case, the positive unbalance is lower than the negative one. This is attributed to the fact that wind velocity is Weibull distributed and that one of the characteristics of this distribution is that the most probable value is always lower than mean value, which is the one used by the Bayesian method (see section 3.5.2). A similar observation was made by Di Piazza et al [5]. Then it can be said that the wind velocity forecasting model used has a negative bias, which implies that it tends to over estimate the energy production. An alternative solution would be to chose the most provable value as best estimate, in which case the unbalance bias might be reduced, however the energy unbalance would increase.

Furthermore, figure 4.5 can be used to see how dispersed is the data because it illustrates separately the imbalance whose deviation is lower than the 20% from the one higher. The positive and negative unbalance incur in on an error higher than the 20% are 681.5 and 722.4 GWh respectively. This implies that for the case of wind unbalance, around 77.9% of the energy unbalance is caused by forecast errors higher than the 20%. Then it can be said that, for the forecast methods used, wind unbalance is higher and more dispersed than PV unbalance. Finally, from figure 4.5 and 4.1 it can be seen that wind plants unbalance behaves in a similar way to the wind farms equivalent hours. This was attributed to the fact that wind plant's energy production is proportional to the velocity to the power of three, and then months with higher wind velocity have also higher uncertainties and forecast errors.

Load unbalance

From figure 4.6 it can be seen that, different from the wind unbalance, load unbalance is symmetric. The load unbalance was generated by a normal distribution with 0 mean and a 10% deviation as reported by Bracale et al [4] (see section 3.7.3); this is why the load unbalance is symmetric. Their yearly positive and negative unbalances are 909.8 and 908.4 GWh respectively. Then the total load unbalance (1817.8 GWh) corresponds to a 7.53% of the total load requirements.

Moreover, figure 4.6 can be used to check the dispersion range of the load unbalance. It was obtained that positive and negative unbalance, incurring in a forecast error higher than 20%, were of 91.16 and 90.53 GWh. Then just the 10% of the unbalance was greater than the mentioned value. Hence it can be stated that load unbalance is less dispersed than PV and wind plants whose reported value were much higher.

Total unbalance

As a final remark it can be said that the total positive and negative unbalance are 1985.8 and 2035.3 GWh per year. Then this adds an absolute total of 4021.1 GWh. From the total unbalance, PV plants are responsible of a 9.97%, wind plants of a 44.83% and the remaining 45.20% is attributed to load unbalance. Figure 4.7 illustrates this fractions on a pie diagram.

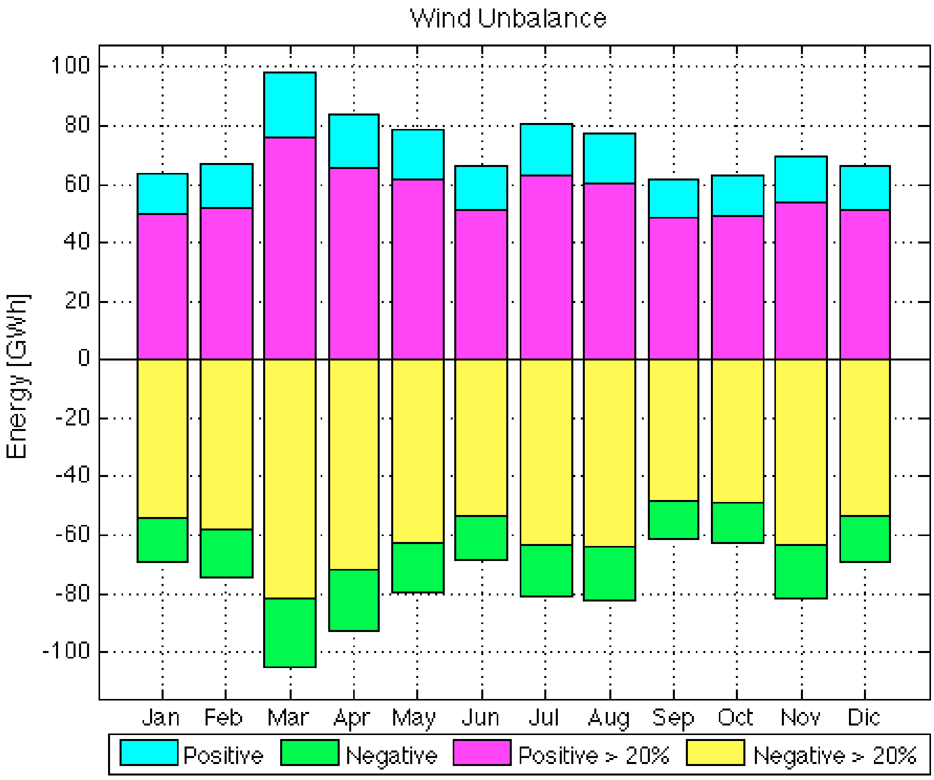

Figure 4.5: Wind plants total nodal unbalance

4.3 Zonal unbalance

As described in section 3.6, zonal unbalance takes into account both producers and customers unbalances. Then two different scenarios can be obtained, eather energy is in excess or it is in defect. Figure 4.8 illustrates the amount of unbalance energy that fits into the two scenarios on a monthly basis. Positive unbalance represents the case when energy is in excess, while negative unbalance represents the remaining one.

The yearly total positive and negative zonal unbalances are of 1151.8 and 1201.2 respectively. Both quantities correspond to a total zonal unbalance of 2353.0 GWh, which is significantly lower than the total nodal unbalance (4021.1 GWh) due to the unbalance mitigation among producers and consumers whose unbalances have different signs. It is important to mention that the positive unbalance is slightly lower than the negative one. This implies that in Sicily energy tends to be in defect rather that in excess. This is attributed to the fact that the forecasting models used for wind plants have a negative bias, which generally makes them over estimate the forecast energy injections as described section 4.2.

The unbalance generated by PV and wind plants can be classified under a different scheme, which determines if the unbalance is aiding or worsening the system balance. Unbalance helps the system balance when there is excess of production on a deficit zone or vice versa. On the other hand, it worsens the system balance when there is excess of production on an excess zone or deficit of production on a deficit zone. Figure 4.9 contains the amount of energy helping and worsening

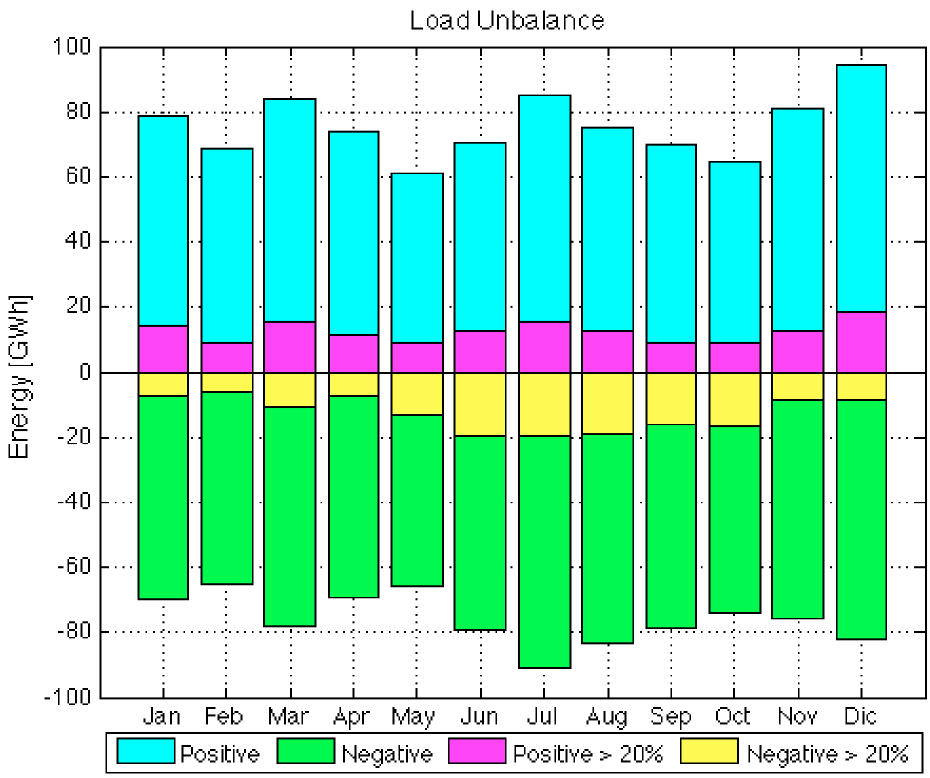

Figure 4.6: Load single unbalance

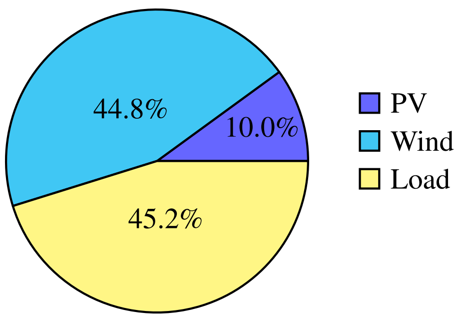

Figure 4.7: Distribution of the total energy unbalance in Sicily.

the zonal unbalance for both PV and wind plants. PV energy helping and harming the system are equal to 182.5 and 218.3 GWh respectively. While the same amounts for wind plants are 480.2 and 1322.3 GWh correspondingly. These make a total of 662.7 GWh helping the system and 1540.6 GWh aggravating the unbalance. It can be seen that, for PV and wind plants, the energy unbalance aggravating the system unbalance is higher than the one aiding it.

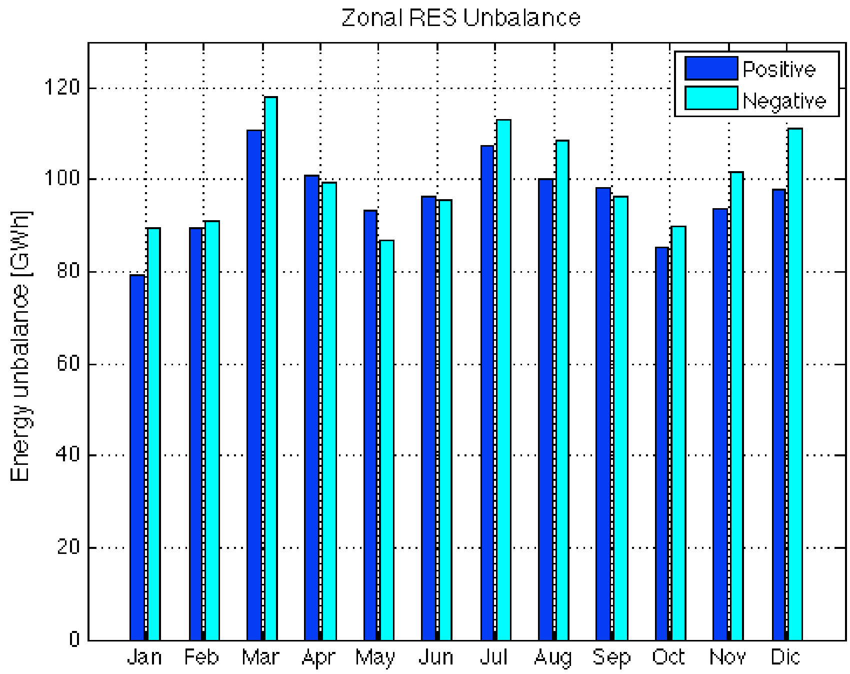

Figure 4.8: Total zonal unbalance

4.4 Unbalance remuneration

Once the nodal and zonal unbalance were estimated, it was possible to obtain the total energy penalized and awarded under the single and dual price mechanism. To do so, energy unbalances are separated under the four combinations obtained from positive and negative zonal unbalance and positive and negative plants unbalance as described in the previous section. Table 4.3 contains the PV and wind plants energy unbalances separated under these scenarios respectively. Additionally, table 4.4 contain the PV and wind plants energy unbalances penalized under a 20% error allowance.

Notice that the total positive and negative nodal unbalance, reported in tables 4.3 and 4.4, corresponds to the values reported in section 4.2 for both PV and wind plants. Then if in table 4.3 the positive and negative wind unbalance components are separately added, a total of 875.6 and 926.8 GWh will be obtained, which represents the total wind plants positive and negative unbalance respectively (see section 4.2). The same procedure can be applied for PV plants, and then to PV and wind plants with a 20% allowance.

It is important to mention that despite the penalization mechanism used, the energy unbalance does not vary, then values listed in table 4.3 can be used indistinctly to estimate the single and dual pricing remuneration. In the same way, table 4.4 can be used to estimate the single and dual pricing remuneration for PV and wind energy unbalance with a 20% allowance.

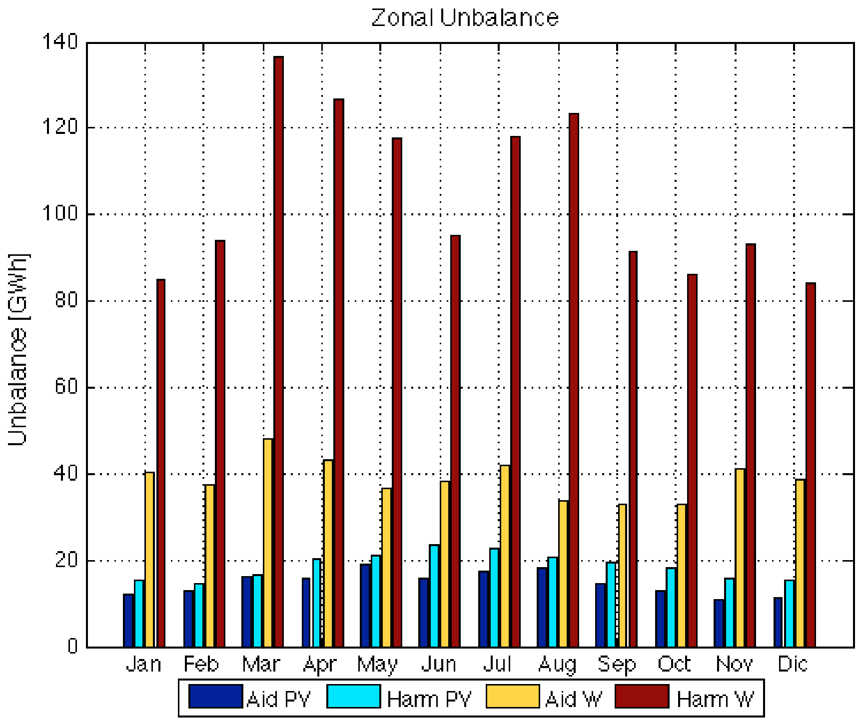

Figure 4.9: PV and Wind plants zonal unbalance treated

		PV nodal unbalance [GWh/y]		Wind nodal unbalance [GWh/y]	
		+	-	+	-
Zonal unbalance	+	120.6	-102.7	635.4	-240.0
	-	79.8	-97.7	240.2	-686.8

Table 4.3: Total PV and wind plant's unbalanced energy to be considered in the economic mechanisms without allowance.

		PV nodal unbalance (20%) [GWh/y]		Wind nodal unbalance (20%) [GWh/y]	
		+	-	+	-
Zonal unbalance	+	75.8	-60.5	497.7	-173.9
	-	54.8	-65.0	183.8	-525.9

Table 4.4: Total PV and wind plant's unbalanced energy to be considered in the economic mechanisms with a 20% allowance.

4.4.1 Single price

As described in section 3.6, the single price mechanism penalizes unbalance by just taking into account the zonal unbalance. Table 4.5 contains the fees used under this remuneration mechanism[3]. It is important to mention that only energy unbalance coming from PV and wind plants was used for the cost calculations. Load unbalance won't be taken into account in the unbalance magnitude, but only in the zonal sign. This can be justified by considering that it is required to estimate the extra cost incurred by PV and wind plants energy unbalance and not for the load unbalance.

		Nodal unbalance [Euro/MWh]	
		+	-
Zonal unbalance	+	23.1	23.1
	-	168.5	168.5

Table 4.5: Single pricing mechanism fees used.

PV and wind plant's cost without allowance

The total energy unbalance reported in tables 4.3 was used to determine the total cost paid for the energy unbalance under the fees reported in 4.5 (see equations 3.19 - 3.21). Table 4.6 summarizes the cost incurred by PV and wind plants under this mechanism. Additionally, table 4.6 contains the specific unbalance cost of PV and wind plants under this mechanism (see equation 4.1). The specific unbalance cost represents the share of money that imbalance producers pay to cover their unbalance per MWh injected.

$$c_{RES} = \frac{\sum_{month} C_{PV} + C_W}{\sum_{month} RI_{PV} + RI_W} \left[\frac{Euro \cdot month}{MWh \cdot month}\right] \tag{4.1}$$

Where c_{RES} is the specific PV and wind cost per month, C_{PV} and C_W are the monthly PV and wind cost calculated under the remuneration mechanism, and RI_{PV} and RI_W are the month real injections for PV and wind plants respectively.

From table 4.6 it can be seen that the total cost cover by this mechanism is 70.70 millions of Euro per year. PV plants pay the 3.8% of this value, while wind plants pay the remaining 96.2%. Then it can be said that, under the modeled conditions, the unbalance cost is much higher for wind plants than from PV plants. This is attributed to the fact that for wind plants unbalances constitutes 61.2% of their injections, while for PV plants this value corresponds to 26.0% of their injections. Additionally, wind plants unbalance is negatively biased, which means that wind plants tend to inject less energy than forecasted. Referring to the specific unbalance price, it was found out that in average 15.76 Euro are paid by PV and wind plants for every MWh injected.

PV and wind plant's cost with allowance

According to the current Italian regulation, only injections incurring an energy unbalance of more than 20% will be punished by the single price mechanism (see section 3.9.1). Then penalizations

[3] This values were obtained from a AEEG report [41].

Plants	Single price unbalance Cost [Million Euro/year]	Specific cost [Euro/MWh]
PV	2.68	1.74
Wind	68.02	23.10
Total	70.70	15.77

Table 4.6: Wind and PV economical penalization under the single price mechanism.

under this system were also estimated by using equations 3.19 - 3.21 for energy unbalance overpassing the 20% allowance. Table 4.4 contains the energy unbalance penalized under 20% allowance. With this data and the single price fees it was possible to determine the revenues collected by TERNA under this mechanism. From table 4.7 it can be seen that under a 20% allowance TERNA collects 53.11 millions of euro. From which the 2.7% are paid by PV plants while the remaining 97.3% are cover by wind plants. Additionally, it can be seen that in average 11.84 Euro are paid by PV and wind plants for every MWh injected. Equation 4.2 illustrates how to determine this last parameter.

$$c_{RES20\%} = \frac{\sum_{month} C_{PV} + C_W}{\sum_{month} RI_{PV} + RI_W} \forall \frac{U}{FI} > 20\% \left[\frac{Euro \cdot month}{MWh \cdot month}\right] \tag{4.2}$$

Where c_{RES} is the specific PV and wind cost per month, C_{PV} and C_W is the monthly PV and wind cost calculated with the desired remuneration mechanism, RI_{PV} and RI_W are the month real injections for PV and wind plants respectively, U is the nodal unbalance, FI the forecasted injections and $\forall$ the logic *for all* sign. Then only injections whose deviations are higher than the 20% are taken into account for this mechanism.

Plants	Single price unbalance Cost [Million Euro/year]	Specific cost [Euro/MWh]
PV	1.42	0.92
Wind	51.69	17.55
Total	53.11	11.84

Table 4.7: Wind and PV economical penalization under the single price mechanism with 20% allowance.

By contrasting the results of this mechanism with and without allowance, it can be obtained that the allowance diminishes the economic sanctions that arise from the energy unbalance. Therefore, this mechanism can be used to protect non-programmable RES-E from unbalance penalization.

4.4.2 Dual price

The dual price mechanism considers both nodal and zonal unbalance. By doing so, it charges plants producing a negative unbalance. On the other hand, plants whose unbalance is positive, receive a revenue for their energy. Table 4.8 contains the dual pricing fees used[4]. It is important to highlight that only the energy unbalance coming from PV and wind plants was used for the cost calculations. Load unbalance won't be taken into account in the unbalance magnitude, but in the zonal sign. Again, this can be justified by considering that it is required to estimate the extra cost incurred by PV and Wind energy unbalance and not for the load unbalance.

		Nodal unbalance [Euro/MWh]	
		+	-
Zonal unbalance	+	23.1	100
	-	100	168.5

Table 4.8: Dual pricing mechanism fees used.

PV and wind plant's cost without allowance

Plants unbalance are charged or receive a revenue under the dual price mechanism (see section 3.6). The amount of money paid by the plant owner is calculated as difference between the charges and the revenues (see equations 3.22 - 3.24). TERNA collects this in order to cover the expenses of balancing the zone on real time.

Table 4.9 summarizes the cost incurred by PV and wind plants under the dual price mechanism. It was found that the cost paid by the PV and wind plants adds a value of 120.5 millions of euro per year. From it, 13.7% comes from PV plants, while wind plant owners pay the remaining 86.3%. Additionally, table 4.9 contains the specific unbalance cost of PV and wind plants under this mechanism (see equation 4.1).

Plants	Dual price unbalance: Cost [Million Euro/year]	Dual price unbalance: Specific cost [Euro/MWh]
PV	16.49	10.71
Wind	104.03	35.33
Total	120.52	26.87

Table 4.9: Wind and PV economical penalization under the dual price mechanism.

It can be seen that this remuneration mechanism penalizes harder the unbalanced plants than the single price mechanism. Figure 4.10 illustrates the average specific cost variation (see equation 4.1) obtained for the different mechanisms.

PV and wind plant's cost with allowance

The current Italian regulation states that allowance is only applied for the single price mechanism. However, allowance was applied to the dual price mechanism as a study case. Table 4.10 sum-

[4]This values were obtained from a AEEG report [41].

marizes the cost incurred by PV and wind plants under the dual price mechanism with a 20% allowance. It was found that a total of 88.57 millions of euro are paid per year under this mechanism, which corresponds to an average of 19.75 Euro per MWh of PV and wind energy injected.

The dual price mechanism with 20% allowance penalizes more unbalanced plants than its single price equivalent. The same behavior was observed for this mechanism without allowance. This is attribute to the fact that under the dual price mechanism a plant can never benefit from the imbalance even in cases where this ”aids” involuntarily TERNA to balance the system.

Plants	20% allowance dual price unbalance	
	Cost [Million Euro/year]	Specific cost [Euro/MWh]
PV	10.10	6.56
Wind	75.47	26.65
Total	88.57	19.75

Table 4.10: Wind and PV economical penalization under the dual price mechanism and 20% allowance.

4.4.3 Comparison between the different mechanism

Figure 4.10 contains the average specific cost on a monthly basis for all the remuneration mechanisms studied. From it, it can be seen that price varies on a monthly basis and that from the different remuneration mechanism the price paid by single price mechanism with allowance is the lowest one, while the dual price mechanism is the highest. It can be observed that all mechanisms exhibit more or less the same behavior. This occurs because all of them deal with more or less the same energy unbalance or penalization fees. For instance dual price mechanism (DP) and single prince mechanism (SP) use exactly the same unbalance, however fees used on the penalization scheme are different. On the other hand, the dual pricing mechanism with and without allowance uses exactly the same penalization scheme but different unbalance volumes.

Balancing market cost

In order to grant the Italian electric system's security, TERNA deals with the energy unbalance in a zonal scale by using the single price mechanism for non-programmable RES-E[5]. Figure 4.8 illustrates the total zonal unbalance that TERNA has to deal with during the whole year. Once more, it is important to mention that this value considers only the zonal unbalance coming from PV and wind plants[6].

The zonal unbalance perceived by TERNA was classified under the four possible scenarios considering the nodal and zonal unbalance as reported on table 4.11. From it, one can obtain that TERNA deals with 1100.6 GWh per year. From which 527.3 GWh are bought from the downward reserve, while 573.3 GWh are bought from the upward reserve on the MSD. Notice that these values are lower than the sum of the nodal unbalance produce by PV and wind plants. This occurs

[5]TERNA uses the dual price mechanism without allowance to penalize traditional plants unbalancing the system.
[6]For the sake of simplicity it was assumed that traditional plants generate no energy unbalance.

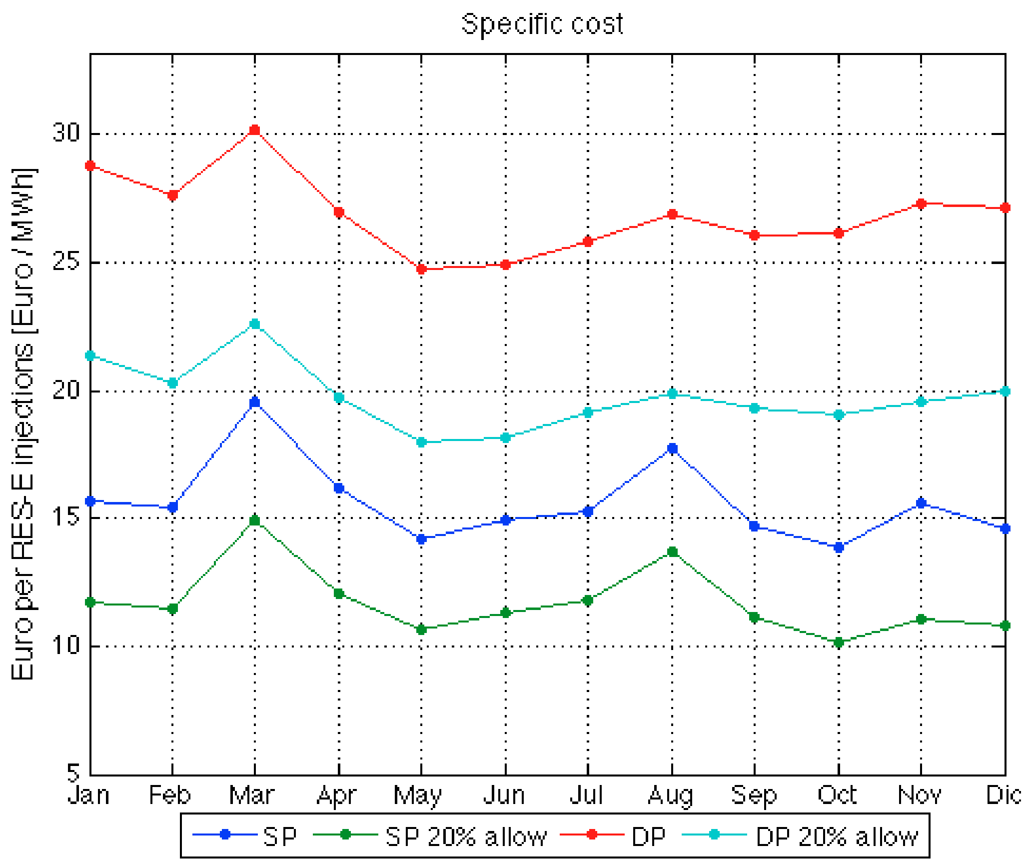

Figure 4.10: Monthly specific unbalance costs paid under the different remuneration mechanisms.

		Nodal unbalance [GWh/y]	
		+	-
Zonal unbalance	+	527.3	0
	-	0	-573.3

Table 4.11: Wind and PV zonal unbalance treated by TERNA.

because of the unbalance sign mitigation obtained when dealing with more that one plant at a time and because the produced unbalance might be aiding the zonal unbalance.

Table 4.12 summarizes the cost incurred on the real time balancing market in Sicily. It was obtained that under this conditions Sicily spends 108 million Euros per year on the real time balancing market. From this, 24.17 millions of Euros are used to balance PV plants, while the remaining 83.84 millions of Euros are used to balance wind plants. Once more, it was found that the specific cost of the unbalance is lower for PV plants that for wind farms. This implies that under the studied conditions, the electric system incurs a lower cost by introducing the PV plants energy than the wind farms energy.

Plants	Ballancing market Cost [Million Euro/year]	Specific cost [Euro/MWh]
PV	24.17	15.69
Wind	83.84	28.47
Total	108	24.08

Table 4.12: Balancing market expenses.

TERNA's cash flow

Once these values were found, it was possible to determine TERNA's cash flow. To do so, the total cost incurred on the balancing market and the revenue obtained by one of the remuneration mechanisms were subtracted as described on equation 3.26. Table 4.13 summarizes TERNA's cash flow to balance the system under the different remuneration mechanism. A positive value represents a cost, while a negative one represents a revenue. Then it can be said that charging unbalance plants under the dual price mechanism constitutes a revenue for TERNA, while using any other mechanism implies TERNA a cost. This entails that the revenue obtained under the dual price mechanism is higher than the cost incurred by TERNA on the real time ancillary service market. On the other hand, the revenues obtained under the other mechanism are not enough to cope with the balancing cost.

Remuneration Mechanism	TERNA's Cash flow [M Euro/y]	Specific cost [Euro/MWh]
Single price	37.30	8.31
Single price (20%)	54.89	12.24
Dual price	-12.51	-2.79
Dual price (20%)	19.43	4.33

Table 4.13: TERNA's cash flow.

Figure 4.11 illustrates TERNA's cash flow on a monthly basis. In can be observed that introducing an energy allowance increases the cost incurred by TERNA. This is attributed to the fact that the unbalance reduces the cost incurred by the unbalance plants, however the cost incurred to balance the system does not change. Then the cost reduction obtained by non-programmable RES is put on the shoulders of TERNA.

On the other hand, it can be seen that under the dual price mechanism without allowance TERNA's cash flow represents a monthly revenue. On the other hand, the dual price mechanism with a 20% allowance represents TERNA a monthly cost. So it can be said that there should be an intermediate allowance under which a cost effective mechanism is obtained. The same cannot be said for the single unbalance mechanism, which represents a cost to TERNA with and without allowance.

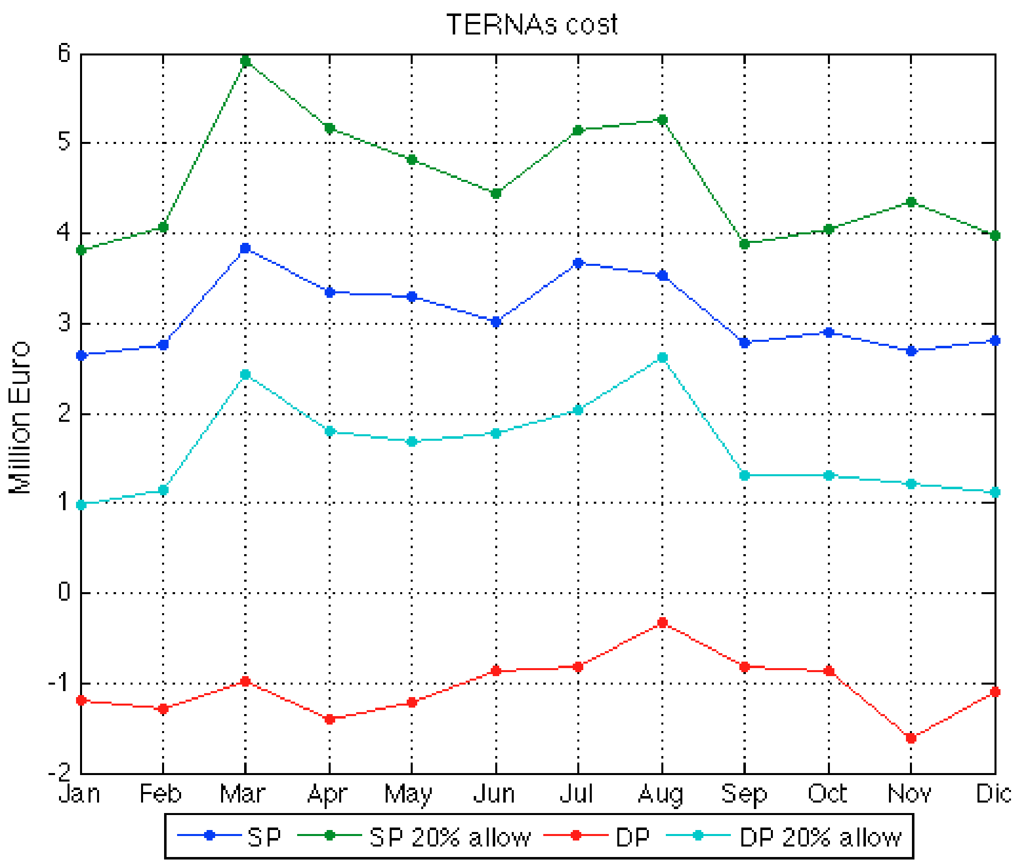

Figure 4.11: TERNA's cash flow on a monthly basis for the different remuneration mechanisms.

Chapter 5

Sensitivity Analysis

The Italian energy market (IPEX) operates under the day ahead marked figure, with four intra-day sessions. Given the gate closure time of the different intra-day session, injection schedule should be submitted from 6 to 21 hours ahead of the injection time [11][1]. Then non-programmable RES should forecast their energy injections in this horizon. The wide time horizon obtained is attributed to the fact that intra-day sessions were not original conceived to allow PV and wind plants update their energy injections, but to solve eventual problems that might arise in traditional plants to achieve the injection profile granted on the market.

This chapter describes the relation between the gate closure time and the unbalance magnitude and how this influences the unbalance costs. Reducing the time in advance, from which the energy injection should be forecasted, reduces the forecast uncertainties and with it the nodal unbalance generated. This has the same effect as increasing the forecasting accuracy. Then either the unbalance or the energy forecast can be varied in order to modify the models' accuracy, given that each time horizon is characterized by a model's forecasting error. Then it can be said that a model forecasting accuracy varies with the gate closure time. The models used to forecast PV and wind injections were modified in order to choose the desired error associated to the best available technology, so that the effect of different time horizons could be simulated.

5.1 Model accuracy parameters

5.1.1 Photovoltaics

In section 3.5.1, it was explained that PV real injections were determined by adding a stochastic term to the forecasted injections. This stochastic term represents the energy unbalance. In this case, the stochastic term is a Gauss distributed random vector with media 0 and deviation of 35.2%. Then, the unbalance deviation can be modified in order to simulate a variation on the gate closure time, so that its influence on the zonal and nodal unbalance magnitude and cost can be determined.

The errors associated to different time horizons were determined by using the accuracy of PV forecast models reported on literature. The results reported by Perez et al. [42] for the Goodwin Creek location were used to associated the solar radiation forecasting root mean square error (RMSE) obtained for the different gate closure times[2]. The RMSE parameter was chosen in order

[1]The time horizon of 21 hours refers to the second intra-day session (MI2) which closes at 15:00 of the day-ahead and foresees injections until midday of the dispatching day, when the third session (MI3) enters into force.

[2]Using the values report to other location or by other author might alter the associated error to each time horizon.

to relate the radiation standard deviation to the errors obtained by a real life model. In this way, it was possible to relate the gate closure time to the data deviation. The equation 5.1 shows the way RMSE values were estimated for the model data.

$$RMSE = \frac{\sum_{t=1}^{n}(r_t - f_t)^2}{n} \tag{5.1}$$

Where r and f are the real and the forecasted radiation respectively, t is the time corresponding to each observation and n is the total number of predictions.

Figure 5.1 and table 5.1 contain the error associated to the different forecasting time horizon (6 - 21 hours). Shorter forecasting horizons were considered just as an exercise to determine the cost incurred by TERNA and the unbalance plants under the hypothetical case of a regulation change that allows the schedule declarations closer to the delivery time. Notice that varying the gate closure time from 6 to 24 hours doesn't have any further effect on the solar radiation forecasting associated error. This is attributed to the characteristics of the model used by Perez et al. [42].

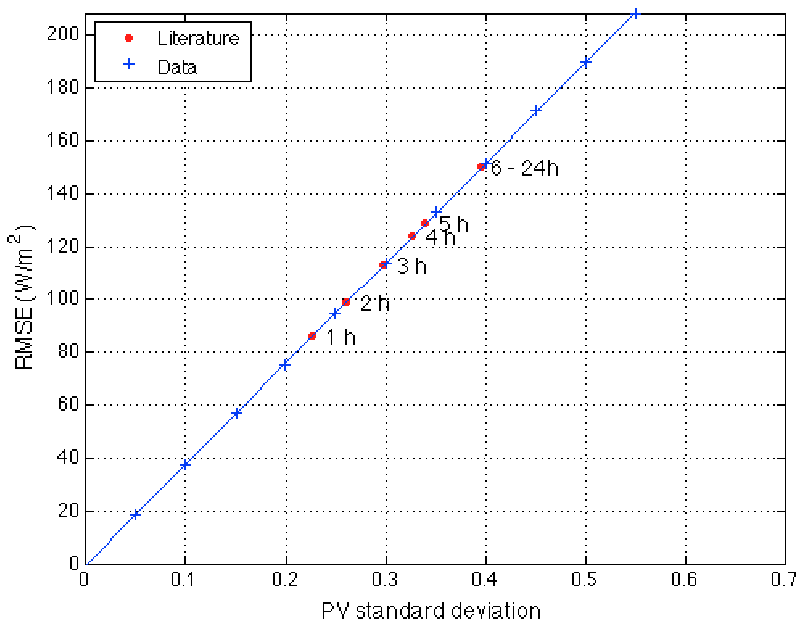

Figure 5.1: PV unbalance deviation evaluation

Model solar radiation	Forcast horizon							
	1 h	2 h	3 h	4 h	5 h	6 h	21 h	24 h
RMSE [W/m^2]	86	99	113	124	129	150	150	150
Associated deviation (%)	22.7	26.13	29.82	32.71	34.03	39.56	39.56	39.56

Table 5.1: Solar radiation forecasting error and standard deviation associated to different gate closure times.

5.1.2 Wind

In a similar way, wind forecast accuracy could be modified in order to simulate different gate closure scenarios. Wind forecast injections were obtained by the Bayesian approach described in section 3.5.2. In the case of wind farms, it results much difficult to modify the forecasting method than directly modifying the forecast obtained. To do so, a correction factor can be implemented in order to attenuate the unbalance (see equation 5.3).

$$U_W = F_W - R_W \tag{5.2}$$

$$F_W = F_W - x \cdot U_W \tag{5.3}$$

Where F_W is the forecasted wind, R_W is the real wind, U_W is the unbalance and x is the correction factor.

Wang et al [47] reviewed different wind power forecasting models commercially available, from were it was concluded that no single model performs best on all locations studied. From it, it was established that the mean absolute error (MAE) of a single wind farm forecasting ranges between 2-5% (of the nominal wind farm power) for a time horizon of one hour, 8-10% for 24 hours ahead and 10-15% for 48 hours ahead. This thesis project made use of the results reported by Boone et al. [8] , which roughly match the ranges set by Wang for a single wind plant located in Denmark. The mean absolute error represents the average unbalance produced. This value was used to evaluate the accuracy of a forecasting model and it was estimated as described on equation 5.4.

$$MAE = \sum_{i=1}^{n} \frac{abs\,[RI - FI]}{n} \tag{5.4}$$

Where MAE is the mean absolute error, RI are the real injections, FI the forecasted injections and N the number of data used, which in this case corresponds to the hours in a year.

Figure 5.2 illustrates the mean absolute error mitigation that can be obtained by the correlation factor. The continuous line represent the mean absolute error produced by each wind plant, while the red dots represent correction factors associated to the different gate closure times[3] as reported in [8]. Table 5.2 contains the error associated to the different forecasting time horizons. It can be seen that wind forecasting errors increase with the forecasting horizon. Once more, time horizons shorter than 6 hours were considered just as an exercise to determine the cost incurred by TERNA and the unbalance plants under the hypothetical case of a regulation change that allows the schedule injection closer to the delivery time.

Model wind velocity	Forcast horizon							
	1 h	2 h	3 h	4 h	5 h	6 h	21 h	24 h
MAE/Installed capacity (%)	3.38	5.88	6.14	6.33	6.40	6.56	6.96	7.37
Correction factor (X_W)	0.68	0.44	0.41	0.40	0.39	0.37	0.34	0.30

Table 5.2: Wind velocity forecasting error and correction factor associated to different gate closure times.

[3] The gate closure times studied are 1, 2, 3, 4, 5, 6, 21 and 24 hours.

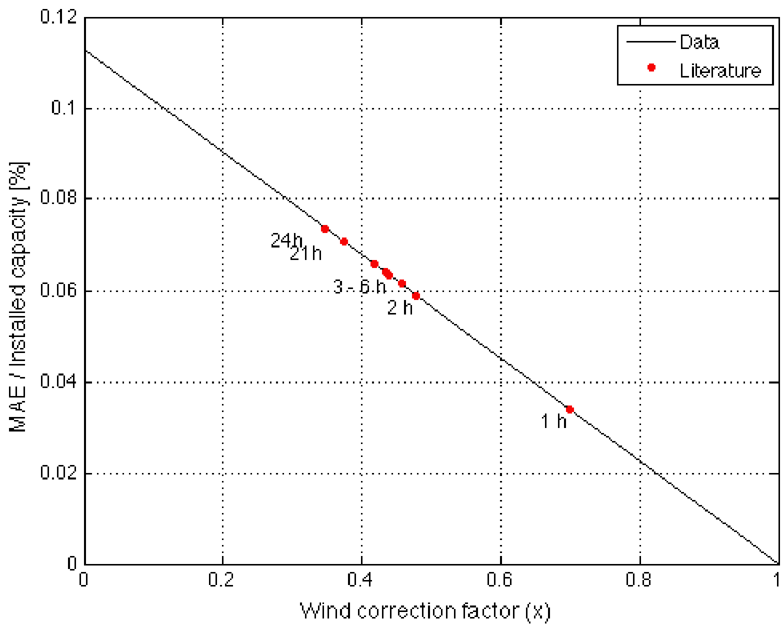

Figure 5.2: Correlation factor evaluation.

It is worth highlighting that the values corresponding to the different gate closure times are highly influenced by the model accuracy used to relate the data. This implies that using the accuracy prescribed by a different source might alter the values related to the different gate closure times, such as the unbalance volume and hence unbalance cost. Then these values can be used as an estimative exercise. Discretion is needed when judging this data because further validation is required in order to determine the accuracy of it.

5.1.3 Load

No modification was done for load forecast because it is out of the scope of this thesis project. This can be justified by taking into account that load unbalance was just used to determine the zonal unbalance sign and its magnitude was not further considered under any of the remuneration mechanisms.

5.2 Nodal unbalance

Table 5.3 contains the total nodal unbalance obtained for PV and wind plants under the different gate closure scenarios. It can be concluded that increasing the gate closure time increases the amount of energy unbalance. Physically, this is attributed to the fact that increasing the forecasting horizon implies forecasting with more anticipation, which increases the model uncertainties. Additionally, notice that the unbalance variation between two consecutive gate closure times decreases as the gate closure time increases. This characteristic strictly depends on the forecasting model and must be taken into account by policy makers intending to modify the energy unbalance by allowing non-programmable RES schedule variations in a time closer to delivery.

Unbalance Source	Yearly total unbalance							
	1h	2h	3h	4h	5h	6h	21h	24h
PV [GWh]	264.7	302.9	343.2	375.5	390.3	445.7	445.7	445.7
PV [% of injection]	16.76	19.18	21.73	23.78	24.72	28.23	28.23	28.23
Wind [GWh]	526.7	915.7	955.5	985.4	995-3	1021.0	1099.1	1146.1
Wind [% of injection]	17.58	30.57	31.90	32.89	33.23	34.08	36.69	38.26

Table 5.3: Energy unbalance under the different gate closure times.

5.3 Model accuracy variation

As an initial step, it was surveyed the unbalance cost behavior obtained by varying the model accuracy parameters. In this way, it was studied the effect produce on the PV and wind plants' specific cost under modifying separately the PV standard deviation and the wind correction factor. Then PV behavior was studied under the absence of wind unbalance, and the other way around for wind plants. The different remuneration mechanisms were studied following this procedure.

5.3.1 Photovoltaic plants

Figure 5.3 contains the PV plants costs under the studied mechanism as function of the PV unbalance deviation. It can be seen that under the studied mechanisms the cost incurred by PV plants can be positive or negative according to the penalization mechanism. This implies that, for PV plants, unbalance can constitute a cost or revenue. PV plants whose unbalance deviation is below 0.1 obtained small revenues for their unbalance under the single price mechanism with 20% allowance. This can be justified by taking into account that under the single price mechanism unbalance plants can make profit for unintentionally 'aiding' the zonal unbalance. On the other hand, the dual price mechanism was set in order to avoid this, so that traditional plants[4] cannot earn an extra revenue by deliberately modifying their schedule. Then under the dual price mechanism unbalance does always constitute a cost, which implies that the cost paid by unbalanced plants increases with their unbalanced energy injections.

Additionally, figure 5.3 contains some vertical lines that represent the standard deviation that characterizes different gate closure times. It can be observed that, for both single and dual price mechanisms the specific unbalance cost increases with the gate closure time. Then it can be stated that, under this mechanism, reducing the gate closure time generates a reduction in the unbalance costs, which occurs due to a reduction in the energy unbalance generated.

Notice that under the original deviation (35.2%) the unbalance specific costs reported in figure 5.3 are slightly higher than the values reported on section 4.4. This is attributed to the fact that the unbalance cost, and hence the specific unbalance costs, depend on the zonal unbalance, which in this case disregards the wind unbalance. The later one tended to be negative biased, which implies that in average wind plants energy injections tend to be lower than forecasted. This modifies the PV plants unbalance classification on the remuneration mechanism (see table 4.3). Then the values reported on figure 5.3 represent the unbalance costs incurred by PV plants in the case no wind plants are present, or in case wind plants forecasting mechanism is not biased.

[4] The current Italian regulation states that traditional plants are penalized under the dual price mechanism [35].

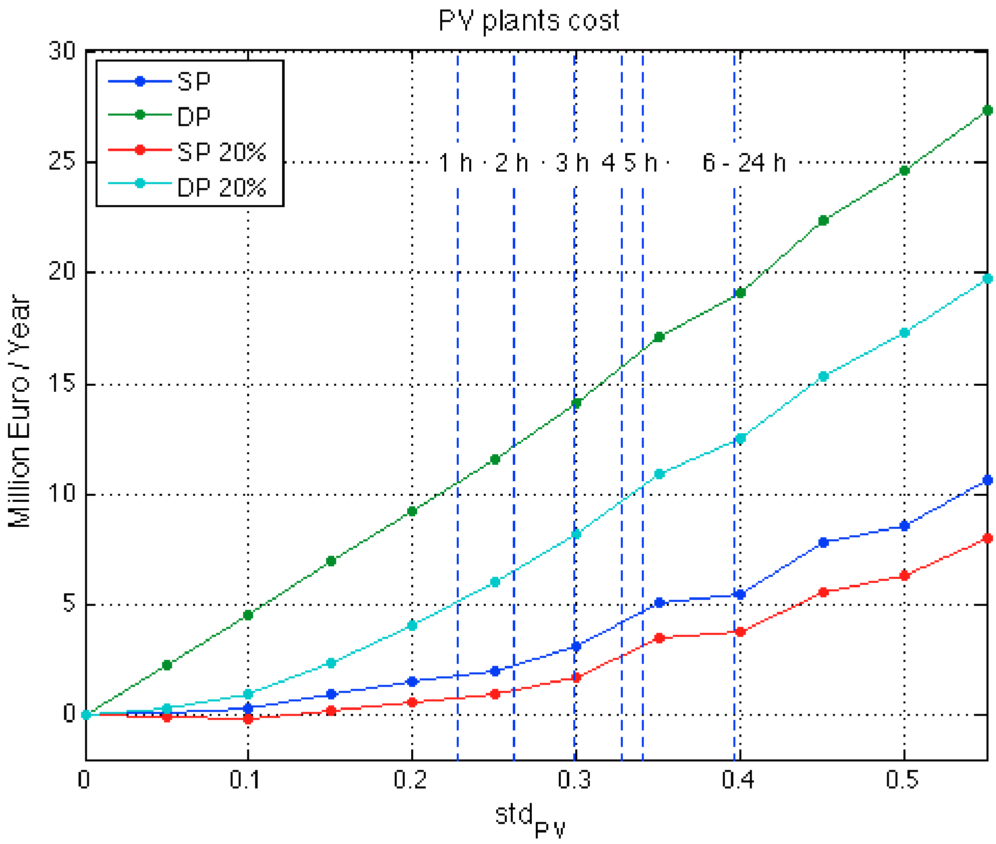

Figure 5.3: Unbalance cost for different PV forecasting accuracy under the different mechanism.

5.3.2 Wind plants

Figure 5.4 represents the remuneration under the studied mechanism for wind plants as function of the correction factor[5] disregarding the PV plants unbalance. It can be observed that, for both single and dual price mechanism, the specific unbalance cost increases with the gate closure time. Then it can be stated that, under this mechanism, reducing the gate closure time generates a reduction in the unbalance cost, which occurs due to a reduction in the energy unbalance generated.

Additionally, it can be seen that the dual price mechanism generates higher revenues that the single price mechanism. Further more, it can be observed that introducing allowances reduces the cost incurred by unbalance plants owners. This is attributed to the fact that allowances diminishes the total energy unbalance penalized; however it is important to keep in mind that this doesn't modifies the zonal unbalance, which means that TERNA perceives the same amount of energy unbalance with and without the allowance. Finally, the original model made no use of the correction factor, which means that X was equal to zero. It can be seen that this condition doesn't correspond to any of the time horizons considered. This means that error mitigation should be performed in order to properly represent the accuracy of the current wind velocity forecasting models.

[5]Notice that in figure 5.4, the abscissa (X axis) does not contain the correction factor, but one minus the correction factor.

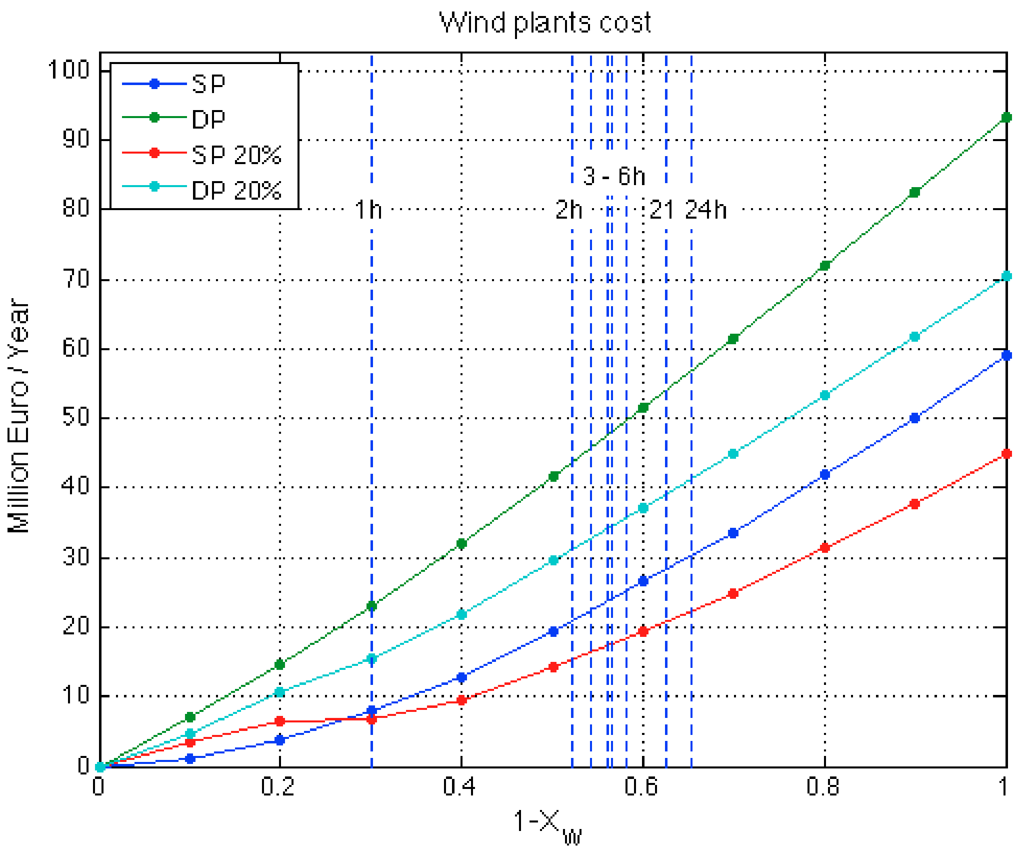

Figure 5.4: Unbalance cost for different wind forecasting accuracy under the different mechanism.

5.4 Remuneration mechanisms

This section investigates the relation between PV and wind forecasting accuracy and the unbalance costs under the different mechanism studied on chapter 4. To do so, the model accuracy was modified, as described in section 5.1, to vary the unbalance volume and the total costs incurred by TERNA on the balancing market and by the non-programmable RES-E plants unbalancing the system. However this time, both PV and wind forecasting accuracy were varied at the same time to represent the forecasting accuracy of these models under the forecasting horizons corresponding to the Italian market.

5.4.1 Single price mechanism

All the remuneration mechanisms were evaluated under the different time horizons. However, a special focus was given to the single price mechanism with 20% allowance because it's the one used to estimate TERNA's cash flow under the current Italian regulation

The single price mechanism with allowance was used to determine the penalization cost paid by unbalance plants. Figure 5.5 contains this value under a combination of different PV and wind forecast accuracy values. The abscissa (X axis) represents the wind error mitigation factor $(1 - X_W)$, the ordinate (Y axis) the PV standard deviation and the color represents the cost paid by unbalance plants under this mechanism[6]. Then on figure 5.5 moving right represents a wind velocity forecasting accuracy reduction, while moving up results in a solar radiation forecasting accuracy reduction. It can be observed that, for the considered time horizons, energy unbalance penalized under the single price mechanism does always constitute a cost that increases with the forecasting error, as expected from the results illustrated on figure 5.3 and 5.4.

Then it can be obtained that under the required time horizon (6 - 21 hours) the single price mechanism with a 20% allowance charges unbalance plants a total cost that varies between 20.01 to 22.17 millions of Euro per year, which correspond to an specific cost of 4.40 and 4.88 Euro per MWh of energy injected to PV and wind plants respectively. Moreover, it can be seen that the specific cost of the different gate closure times considered is lower than the same figure under the original model (53.11 [MEuro/y). This is attributed to the fact that the energy unbalance generated under the original wind velocity forecasting model is higher than the one expected in real life, according to the data used to related the gate closure time and the forecasting accuracy (see section 5.1).

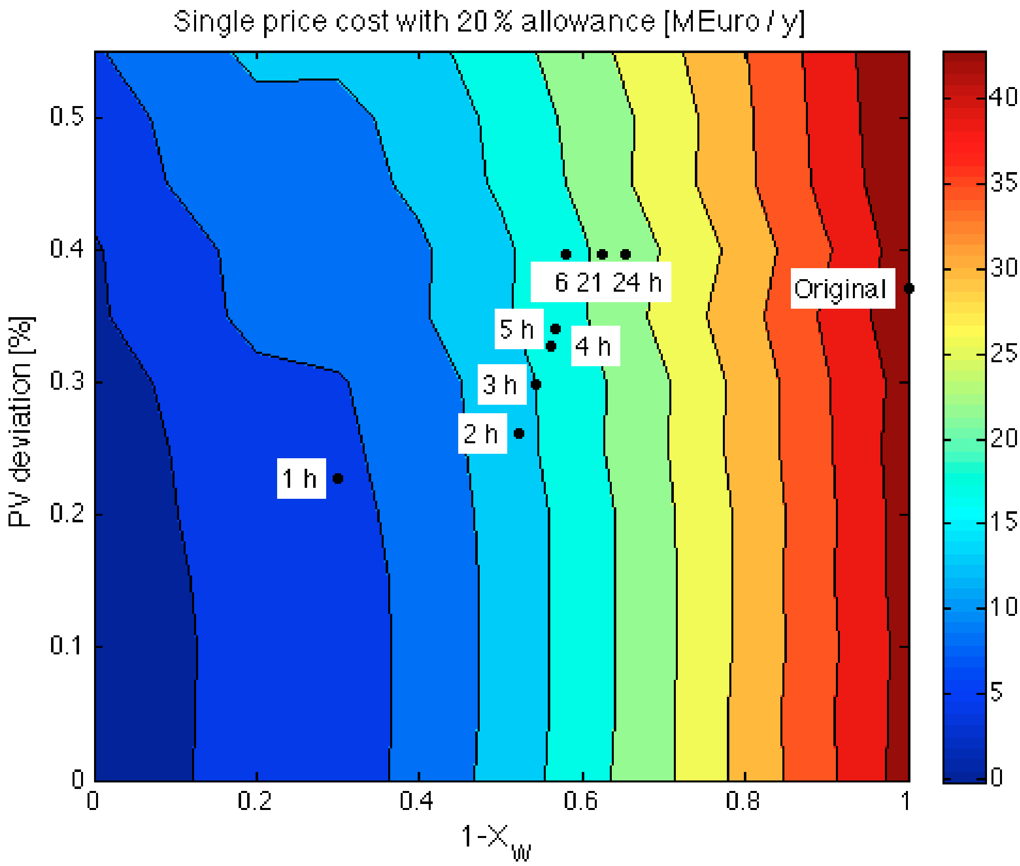

Figure 5.5: Single price cost with 20% allowance for different forecasting accuracy values.

[6]From red to cost incurred by unbalanced plants varies between -0.16 to 47.10 million euro per year respectively.

5.4.2 Balancing market

The cost incurred in the real time ancillary service market depends on the zonal unbalance. Then modifying the forecasting accuracy varies the zonal unbalance and hence the balancing cost. Table 5.4 summarizes the cost incurred in the zonal unbalance market to balance both PV and wind plants for the different time horizons. Then it can be obtained that under required time horizon (6 - 21 hours) the cost incurred in the balancing market varies between 54.47 and 58.85 millions of Euro per year.

Additionally it can be seen that under the different time horizons the specific cost of the energy coming from wind farms is higher than the one for PV plants. This is attributed to the fact that solar radiation is more regular than wind velocity, then wind forecasting has higher uncertainty and hence higher energy unbalances. Further more, wind plants unbalance is negative biased, which increases the amount of to be dealt by the upward reserved ($MB\uparrow$).

Unbalance	Forecasting time horizon							
Source	1h	2h	3h	4h	5h	6h	21h	24h
PV [MEuro/Year]	7.88	10.45	11.85	12.98	13.49	14.89	15.24	15.44
PV [Euro/MWh]	4.99	6.62	7.50	8.22	8.54	9.43	9.65	9.78
Wind [MEuro/Year]	18.12	36.41	37.86	39.09	39.46	39.58	43.61	46.10
Wind [Euro/MWh]	6.05	12.15	12.64	13.05	13.17	13.21	14.56	15.39
Total [MEuro/Year]	26.00	46.86	49.71	52.08	52.94	54.47	58.85	61.55
Total [Euro/MWh]	5.68	10.24	10.87	11.38	11.57	11.91	12.86	13.45

Table 5.4: Cost incurred on the balancing market for PV and wind plants under the different time horizons.

TERNA's cash flow

TERNA's cash flow depends on the amount of energy bought at the MB[7] and the remuneration received by the pertinent remuneration mechanism. Then, TERNA's unbalance cash flow was evaluated for the different remuneration mechanisms and the different PV and wind forecasting horizons. Figure 5.6 contains the yearly cost paid by TERNA under the single price mechanism with 20% allowance. On it, the abscissa (X axis) represents the wind forecasting error, the ordinate (Y axis) the PV forecasting error and the color represents TERNA's balancing cost. Moreover, figure 5.6 contains some labels that represent TERNA's cost under different gate closure times. In general, it can be observed that TERNA's cost increases with the closure time, which is attributed to the unbalance increment as reported in table 5.3.

It was found out that under the single price mechanism with 20% allowances, TERNA's incurred cost varies between 34.46 and 36.68 million of Euros per year, which means that the remuneration obtained under this mechanism is not high enough to cover the balancing market expenses. This implies that TERNA should spend 7.58 to 8.07 Euro per MWh of non-programmable RES injected to the net to deal with their energy unbalance. From figure 5.6, it can be seen that under the studied ranges, wind plants posses a higher influence on TERNA's cost.

Finally, it can be noticed that the values obtained for the different gate closure intervals are lower than the one obtained under the original model conditions (54.89 [Euro/MWh]). This is attributed to the fact that unbalance obtained under the original model is higher that the one expected

[7]'Mercato di bilanciamento' which stands for balancing market.

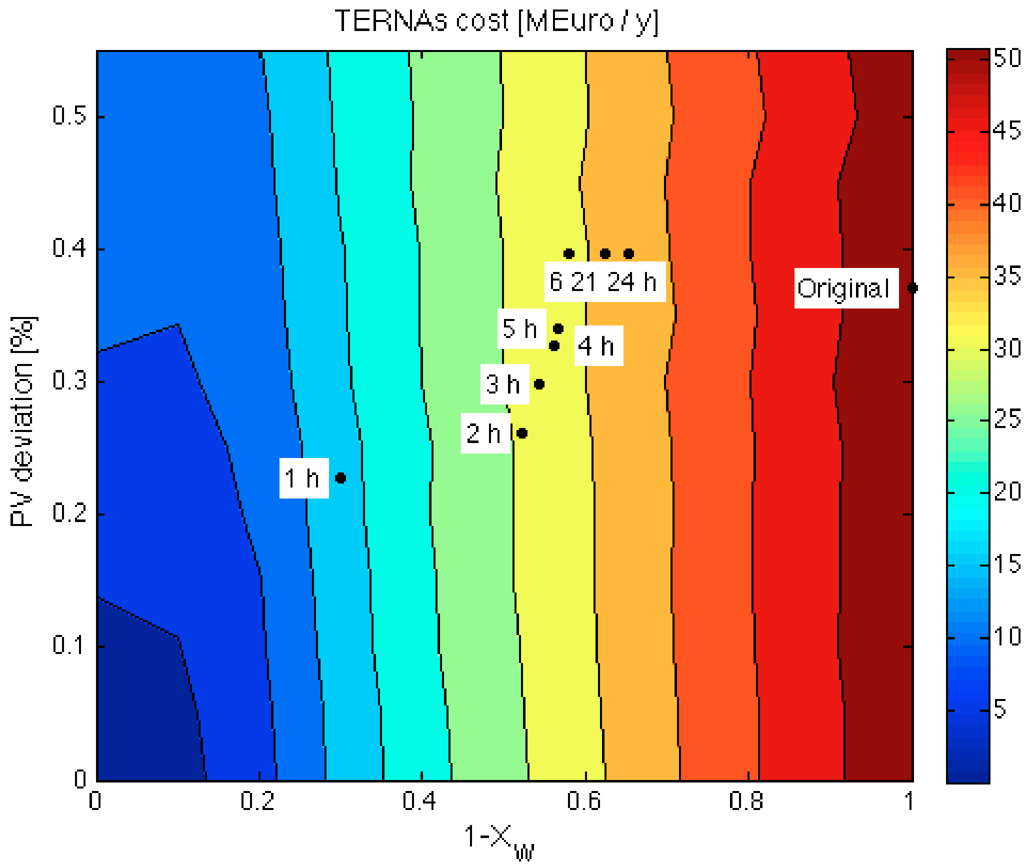

Figure 5.6: TERNA's unbalance cost for different forecasting accuracy values under the dual price mechanism with 20% allowance.

for the different gate closure scenarios, hence the cost incurred by TERNA under this non-cost effective mechanism decreases with the unbalance treated (see section 5.3).

5.5 Price analysis

The revenues obtained under the different remuneration mechanism and TERNA's cash flow were obtained for the different gate closure times. Table 5.5 summarizes the results obtained for the different time horizons studied.

- The cost incurred by PV and wind plants increases with the forecasting time horizon for all remuneration mechanisms. This is attributed to the fact that energy unbalance increases with the gate closure time. As a consequence, augmenting the time in advance for which the energy should be forecasted also increases the unbalance specific cost.
- It can be seen that the single price with 20% allowance is the mildest mechanism, while the dual price mechanism without allowance is the most severe. This implies that TERNA spends more on to balance the system under the single price mechanism with 20% allowance. On the

Remuneration Mechanism	Value	Forecasting time horizon							
		1h	2h	3h	4h	5h	6h	21h	24h
Single Price	Cost [MEuro/Y]	9.46	22.18	24.10	25.87	26.54	27.81	30.74	32.53
	Specific cost [Euro/MWh]	2.07	4.85	5.27	5.66	5.80	6.08	6.72	7.11
	TERNA's cost [MEuro/Y]	16.55	24.68	25.61	26.20	26.41	26.66	28.11	29.01
	TERNA's specific cost [Euro/MWh]	3.62	5.39	5.60	5.73	5.77	5.83	6.14	6.34
Single Price (20% allowance)	Cost [MEuro/Y]	7.44	15.83	17.06	18.58	19.18	20.01	22.17	23.52
	Specific cost [Euro/MWh]	1.63	3.46	3.73	4.06	4.19	4.37	4.85	5.14
	TERNA's cost [MEuro/Y]	18.57	31.03	32.64	33.50	33.77	34.46	36.68	38.03
	TERNA's specific cost [Euro/MWh]	4.06	6.78	7.14	7.32	7.38	7.53	8.02	8.31
Dual Price	Cost [MEuro/Y]	33.52	55.44	59.32	62.49	63.73	67.32	71.63	74.24
	Specific cost [Euro/MWh]	7.33	12.12	12.97	13.66	13.93	14.72	15.66	16.23
	TERNA's cost [MEuro/Y]	-7.51	-8.58	-9.61	-10.41	-10.78	-12.85	-12.78	-12.69
	TERNA's specific cost [Euro/MWh]	-1.64	-1.88	-2.10	-2.28	-2.36	-2.81	-2.79	-2.77
Dual Price (20% allowance)	Cost [MEuro/Y]	20.57	37.28	40.33	43.07	44.17	47.05	50.41	52.45
	Specific cost [Euro/MWh]	4.50	8.15	8.82	9.42	9.66	10.29	11.02	11.47
	TERNA's cost [MEuro/Y]	5.43	9.57	9.38	9.00	8.77	7.42	8.44	9.10
	TERNA's specific cost [Euro/MWh]	1.19	2.09	2.05	1.97	1.92	1.62	1.85	1.99

Table 5.5: Unbalance cost and mean specific cost for the different mechanism under different gate closure times.

other hand, the dual price mechanism is more favorable for TERNA's cash flow, because the amount charged to non-programmable RES-E for their unbalance is high enough to generate a profit.

- TERNA's cash flow increases with the gate closure time. This means that the total costs incurred by TERNA, under the single price mechanism with and without allowance and the dual price mechanism with allowance, increase by augmenting the forecasting time horizon. On a similar way, the revenue obtained by TERNA under the dual pricing mechanism also increases by increasing the gate closure time.

- Even though the costs incurred by non-programmable RES and TERNA increases monotonically under the different remuneration mechanism, the same does not occur for TERNA's specific cost under the dual price mechanism with and without allowance. It can be observed that in the case of the dual price mechanism without allowance the maximum revenue per MWh injected is obtained for a gate closure time of six hours, then deviating form it implies lower revenues per MWh, which doesn't mean that the same implications can be done for the total revenue. On the other hand, in the case of the dual price mechanism with 20% allowance the maximum specific cost incurred by TERNA is obtained for a gate closure time of two hours, then increasing the gate closure time increases the cost incurred by TERNA but decreases the cost allocated per MWh injected.

5.6 Sensitivity analysis

The fact that a time horizon is considered allows to obtain a range in which the real cost is expected to be. The simplicity obtained by these results allows compensating in certain way the simplifications and uncertainties of the model. Additionally, two more scenarios will be contemplated in order to take into consideration that the forecasting model accuracy used might not represent the forecasting models used in Sicily. Then forecasting accuracy will be further enhance on an optimistic scenario, while a more conservative scenario will lessen the forecasting accuracy. Figure 5.7 illustrates the influence of the different accuracy scenarios on the cost incurred on the balancing market. Both scenarios consider an error window of the same size of the original scenario, which means that the forecasting accuracy variation obtained for a forecasting horizon of 6 and 21 hours is constant. However, the accuracy obtained under a 6-hour horizon was modified. The optimistic scenario considers the error associated to a gate closure time of 5 hours. On the other hand, the conservative scenario considers that accuracy decreases by an equal magnitude that the accuracy increment obtained on the positive scenario.

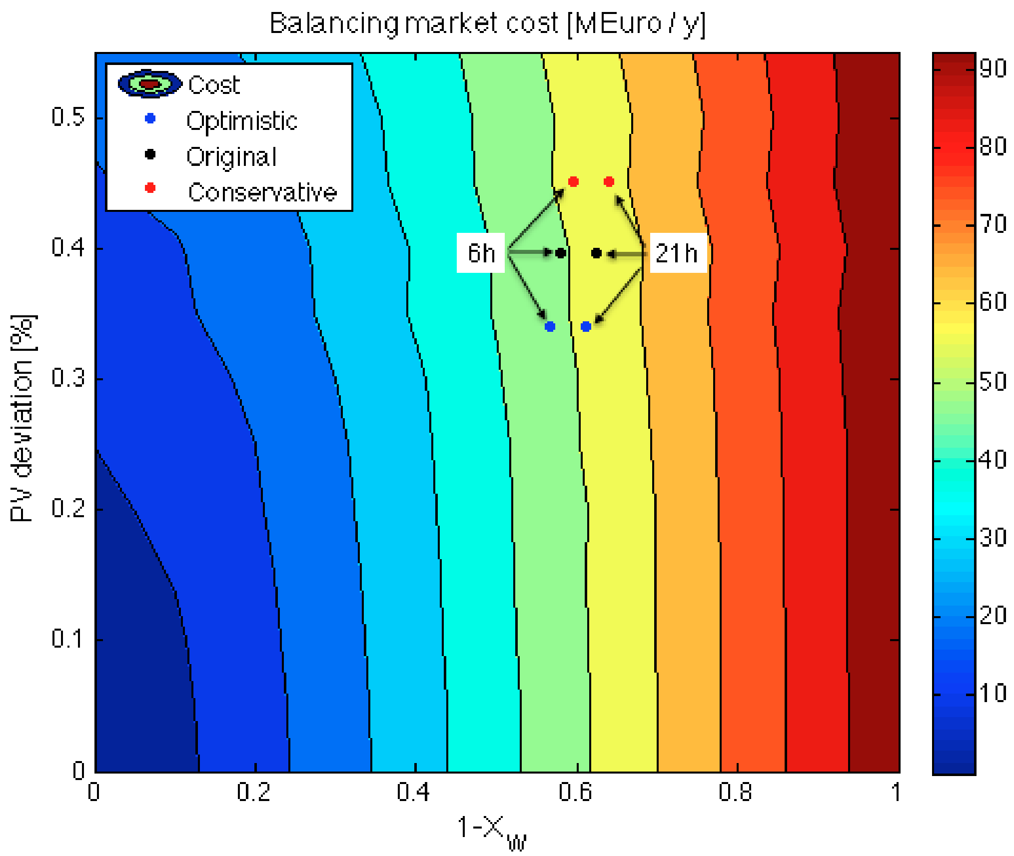

Figure 5.7: Accuracy variation for the different scenarios.

The accuracy delimitating this new scenarios are listed on table 5.6. Once the scenarios were defined, it was decided to evaluate the different remuneration mechanism under the forecasting accuracy of the new scenarios. In this way, the cost incurred by unbalanced plants and the cost of the balancing market was determined.

Under the optimistic scenario the zonal unbalance varies from 1.38 to 1.46 TWh per year. This constitutes a cost of 52.94 - 57.31 million of Euro per year on the balancing market, from which 24.78% corresponds to PV plants unbalance, while the remaining part corresponds to wind plants unbalance. On the other hand, the conservative scenario foresees a zonal unbalance that varies from 1.56 to 1.63 TWh. This implies a cost of 57.73 to 62.23 million of Euro per year on the balancing

Scenraio	Model	15h	39h
Optimistic	Solar radiation deviation (%)	34.06	34.06
	Wind correction factor (X_W)	0.434	0.389
Conservative	Solar radiation deviation (%)	45.15	45.15
	Wind correction factor (X_W)	0.404	0.360

Table 5.6: PV and wind plants forecast accuracy for the new scenarios.

market, from which 29.15% corresponds to PV plants unbalance, while the remaining part corresponds to wind plants unbalance. From this it can be said that under the conservative scenario the solar radiation forecasting accuracy was diminished more than the wind velocity accuracy. This can be concluded by comparing the fraction of the balancing cost coming from PV plants, which increases in the case of the conservative scenario. This was expected due to the fact that no forecasting accuracy variation was obtained under modifying the time horizon from 6 to 24 hour for solar radiation; however in the case of the conservative scenario, solar radiation forecasting accuracy was further decreased.

Table 5.7 summarizes the cost incurred by unbalanced plants under different remuneration mechanisms for the optimistic and conservative scenarios. From it, it can be concluded that the costs obtained under the optimistic scenario were lower than the ones under the original and the conservative scenario. This was expected because the optimistic scenario has a higher forecasting accuracy and therefore a lower remuneration cost. Additionally, it can be seen that the variation obtained for the optimistic scenario with regard to the original one is lower than the one obtained for the conservative scenario with respect to the original one. This implies that the accuracies selected for the optimistic scenarios are more close to the real scenario than the ones selected for the conservative one.

Scenraio	Parameter	SP	$SP_{20\%}$	DP	$DP_{20\%}$
Optimistic	Yearly cost [M Euro/y]	26.53 - 29.52	19.17 - 21.36	63.72 - 68.07	44.17 - 47.54
	Specific cost [Euro/MWh]	5.80 - 6.45	4.19 - 4.67	13.93 - 14.88	9.65 - 10.39
	Variation from the original value (%)	-4.26	-3.92	-5.15	-5.90
Conservative	Yearly cost [M Euro/y]	30.43 - 33.55	22.10 - 24.46	71.86 - 76.27	50.89 - 54.34
	Specific cost [Euro/MWh]	6.65 - 7.33	4.83 - 5.35	15.71 - 16.67	11.21 - 11.88
	Variation from the original value (%)	9.30	10.37	6.62	7.98

Table 5.7: Unbalance cost under the different mechanisms for the new scenarios.

Chapter 6

Conclusions

The amount of renewable energy sources is expected to grow considerably as mandated by the European directive 2009/28/EC. This proposed level of commitment to renewable energy generation diversifies the energy resources and reduces the greenhouse gas and particulates production. However, it implies a major shift in regulations and operational practices, in order to properly integrate renewable energy resources. Integrating technologies like biomass, geothermal and reservoir hydropower don't represent a major challenge than traditional technologies. On the other hand, integrating solar and wind plants is a harder task because these technologies are based on non-programmable fluctuating resources.

This thesis project focuses on assessing the cost incurred by the balancing of non-programmable RES in order to maintain the equilibrium between demand and supply in Italy. To do so, the Sicilian electric zone was modeled including the load demand and the PV and wind plants energy injections. The load was model by using the energy bought on the day ahead market, which was further scaled to obtain the total 2012 energy consumption reported by TERNA. On the other hand, PV and wind plants injections were modeled by using the meteorological data obtained from the *Comitato Termotecnico Italiano* [26] for each of the nine provinces representing the Sicilian region.

Additionally, the load variability was described by a stochastic Gauss distributed component with a deviation of the 10%. In a similar way, PV variability was described by a stochastic component, whose deviation was estimated by subtracting the hourly solar radiation to the corresponding monthly typical day radiation. From this, it was found that the unbalance produced is Gauss distributed with a deviation of the 35%. As it was found out that PV energy injections vary on a monthly basis as function of the season. Then summer months register higher energy injections and unbalance volumes than less sunny periods. Moreover the stochastic component was further modified in order to take into account the weather correlation that exist between neighbor provinces. However it was found that correlating the data increases the total zonal unbalance produced in comparison to totally uncorrelated data due to lower unbalance sign mitigation. Finally wind variability was obtained by subtracting the hourly wind velocity to the one forecasted by a PDF model. From this, it was found that windier months produce higher unbalance volume. Additionally, it was also found that wind plants generate higher energy unbalances than PV plants. This was attributed to the fact that wind velocity forecasting represents a bigger challenge than forecasting solar radiation, because of its non-periodical behavior and because wind velocity relates to the third power to wind energy production: any forecasting error is further magnified.

Once done this, the zonal unbalance was determined. It was found out that, under the specified conditions, the Sicilian zonal unbalance is negative biased. This means that energy tends to be in deficit rather than in excess. This was attributed to the wind velocity-forecasting model's characteristics. Thereupon the different remuneration mechanisms were used to determine the unbalance cost for the power plants generating the unbalance and the cost incurred on the balancing market. It was found that the dual price mechanism without allowance generates the highest unbalance remuneration, while the single unbalance mechanism with 20% allowance generates the lowest unbalance remunerations. Additionally, it was found that accepting a specific amount of energy coming from a wind plant into the energy market takes higher unbalance costs that accepting the same amount of energy coming from a PV plant. This is a direct consequence of the unbalanced energy related to each source, which in the case of wind plants is higher than PV plants.

Then it was found TERNA's cash flow to cover the cost incurred on the balancing market. To do so, the different remuneration mechanisms were contrasted. From where it was obtained that under the dual price mechanism TERNA makes a profit from the energy unbalance, while for the remaining mechanisms energy unbalance constitutes a cost for TERNA. This means that single price mechanism with and without allowance and the dual price mechanism with allowance aren't cost effective mechanisms, because the cost allocated to unbalance plants is lower than the one incurred by TERNA on the ancillary service market.

After that, different gate closure times were model by relating characteristic error of each gate closure time to an associated energy unbalance. Then the different remuneration mechanisms were tested, from where it was concluded that the unbalance cost diminishes with the gate closure time. This occurs because the energy unbalance diminishes with the forecasting time horizon. Once more, it was found that single price mechanism with and without allowance and dual price mechanism with allowance entail a cost to unbalanced plants which is lower than the cost incurred on the balancing market.

Additionally, two more scenarios were studied considering that the forecasting accuracy of the Sicilian plants was not fully represented by the described values. The first scenario studied was optimistic and on it the model's accuracy was enhanced. On the other hand, the second scenario was more conservative and on it the accuracy was lowered. Under the studied scenarios the cost incurred on the balancing market and the remuneration cost under the different mechanisms were studied. It was obtained that cost are lower under the optimistic scenario because on it forecasting accuracy is higher and hence lower energy unbalances are produced.

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Appendices

Appendix A

Model

This appendix contains the Matlab code lines used. The algorithms are classified by source. Additionally, an small description is done before the beginning of each algorithm.

A.1 PV

The following code was used to obtain and write on separate files the monthly average radiation (see figure 3.2) and the daily forecasted radiation. The later was referred as the deterministic part on section 3.5.1. Additionally, PV unbalance was estimated from subtracting the daily forecasted radiation and the real radiation. The mean and standard deviation were obtained and wrote on separate files.

```
clc
clear
close all

% PV DATA CHECK

%       Data Loading
h = load('moth_hours.csv'); %Vector containing the cummulative hours of ...
    a month

% Metheorological data
PI = load('Radiation_Sicili.csv'); % Solar radiation of the nine provinces

%      Monthly Average Radiation
AVI = zeros(24,12,9); % Matrix initialization

% Matrix filling
for j=1:9
    for i=1:31  % Months with 31 days
        AVI(1:24,1,j) = AVI(:,1,j) + PI(1+24*(i 1):24*i,j)/31;  %Jan
        AVI(1:24,3,j) = AVI(:,3,j) + PI(h(2)+1+24*(i 1):h(2)+24*i,j)/31; ...
             %Mar
        AVI(1:24,5,j) = AVI(:,5,j) + PI(h(4)+1+24*(i 1):h(4)+24*i,j)/31; ...
             %May
        AVI(1:24,7,j) = AVI(:,7,j) + PI(h(6)+1+24*(i 1):h(6)+24*i,j)/31; ...
             %Jul
```

```
        AVI(1:24,8,j) = AVI(:,8,j) + PI(h(7)+1+24*(i 1):h(7)+24*i,j)/31; ...
             %Aug
        AVI(1:24,10,j) = AVI(:,10,j) + ...
            PI(h(9)+1+24*(i 1):h(9)+24*i,j)/31;  %Oct
        AVI(1:24,12,j) = AVI(:,12,j) + ...
            PI(h(11)+1+24*(i 1):h(11)+24*i,j)/31;  %Dic
     end

    for i=1:30  % Months with 30 days
        AVI(1:24,4,j) = AVI(:,4,j) + PI(h(3)+1+24*(i 1):h(3)+24*i,j)/30; ...
             %Apr
        AVI(1:24,6,j) = AVI(:,6,j) + PI(h(5)+1+24*(i 1):h(5)+24*i,j)/30; ...
             %Jun
        AVI(1:24,9,j) = AVI(:,9,j) + PI(h(8)+1+24*(i 1):h(8)+24*i,j)/30; ...
             %Sep
        AVI(1:24,11,j) = AVI(:,11,j) + ...
            PI(h(10)+1+24*(i 1):h(10)+24*i,j)/30;  %Nov
    end

    for i=1:28  % Months with 28 days
        AVI(1:24,2,j) = AVI(:,2,j) + PI(h(1)+1+24*(i 1):h(1)+24*i,j)/28; ...
             %Feb
    end
end

%      Monthly average on a daily basis
pi = zeros(8760,9); % Matrix initialization

% Matrix filling
for j=1:9
    for i=1:31  % Months with 31 days
        pi(1+(i 1)*24:24+(i 1)*24,j) = AVI(:,1,j);  %Jan
        pi(1+(i 1)*24+h(2):24+(i 1)*24+h(2),j) = AVI(:,3,j);  %Mar
        pi(1+(i 1)*24+h(4):24+(i 1)*24+h(4),j) = AVI(:,5,j);  %May
        pi(1+(i 1)*24+h(6):24+(i 1)*24+h(6),j) = AVI(:,7,j);  %Jul
        pi(1+(i 1)*24+h(7):24+(i 1)*24+h(7),j) = AVI(:,8,j);  %Ago
        pi(1+(i 1)*24+h(9):24+(i 1)*24+h(9),j) = AVI(:,10,j);  %Oct
        pi(1+(i 1)*24+h(11):24+(i 1)*24+h(11),j) = AVI(:,12,j);  %Dic
    end

    for i=1:30 % Months with 30 days
        pi(1+(i 1)*24+h(3):24+(i 1)*24+h(3),j) = AVI(:,4,j);  %Abr
        pi(1+(i 1)*24+h(5):24+(i 1)*24+h(5),j) = AVI(:,6,j);  %Jun
        pi(1+(i 1)*24+h(8):24+(i 1)*24+h(8),j) = AVI(:,9,j);  %Sep
        pi(1+(i 1)*24+h(10):24+(i 1)*24+h(10),j) = AVI(:,11,j);  %Nov
    end

    for i=1:28 % Months with 28 days
        pi(1+(i 1)*24+h(1):24+(i 1)*24+h(1),j) = AVI(:,2,j);  %Feb
    end
end

%      Write matrices on files
dlmwrite('Average_injections.csv', AVI)
dlmwrite('Daily_Average_injections.csv', pi)
```

```
%       Monthly average radiation plots
bar3(AVI(:,:,1),'. ')
set(gca(gcf), 'xticklabel',{'Jan','Feb','Mar','Apr','May','Jun',...
    'Jul','Aug','Sep','Oct','Nov','Dic'},'FontSize',12)
xlabel('Months','FontSize',14)
ylabel('Hours','FontSize',14)
zlabel('Power [W/m^2]','FontSize',14)

T = AVI(:,:,4);

figure
h = plot(T,'linewidth',2);
set(gcf,'Color',[1,1,1])
set(h(1),'Color',[0.0 0.4 0.6])
set(h(2),'Color',[0.1 0.3 0.0])
set(h(3),'Color',[1.0 0.6 0.2])
set(h(4),'Color',[0.6 0.0 1.0])
set(h(5),'Color',[0.5 0.3 0.1])
set(h(6),'Color',[0.3 0.0 1.0])
set(h(7),'Color',[1.0 0.0 1.0])
set(h(8),'Color',[1.0 0.0 0.0])
set(h(9),'Color',[1.0 0.6 0.8])
set(h(10),'Color',[0.9 0.9 0.2])
set(h(11),'Color',[0.0 0.6 0.0])
set(h(12),'Color',[0.4 0.8 1.0])
set(gca,'fontsize',12)
xlabel('Time [h]','FontSize',14)
ylabel('Radiation [W/m^2]','FontSize',14)
legend('Jan','Feb','Mar','Apr','May','Jun',...
    'Jul','Aug','Sep','Oct','Nov','Dic')
xlim([0 24])
grid on

%       STATISTICS

% Data loading
PV = load('PV_Sicilia.csv'); % Energy produced in
PV(:,3) = PV(:,3)*1000; % Energy produced in MWh

% Stochastic mean and standar deviation
m = zeros(1,9);
s = zeros(1,9);

for i =1:9
    U = (pi(:,i)   PI(:,i));
    m(i) = mean(U(U /0));
    s(i) = std(U(U /0));
end

U = (pi   PI);
u = U(:,9);
u(u==0) = [];

% Normal distribution check
figure
h = normplot(u);
```

```

% Write the mean and deviation to a separate file
dlmwrite('Average_mean.csv', m)
dlmwrite('Average_deviation.csv', s)
```

This code illustrates the method used to vary the correlation matrix coefficients in order to obtained the required deviation.

```
clc
clear

% CORRELATION MATRIX

%       Data loading
C = load('C0_PV.csv');  % Matrix containing the neighbors
dv1 = load('Test_deviation.csv'); % Circular reference (Control value)

v = [0.51165 0.455 0.455 0.485 0.512 0.455 0.513 0.54 0.54];

% Change of the diagonal coefficients
for i=1:9
    C(i,i)= v(i);
end

% Deviation attenuation check
dv = 1.7*dv1;   % Original distribution
b = normrnd(0,dv,[9 1000000]);  % Random vector
d = C*b;    % Random vector after the correlation
std(d')     % New deviation
mean(std(d'))   % Mean value of the new deviation

% Write to file
dlmwrite('Coorrelation_PV.csv',C)
dlmwrite('dv_PV.csv',dv)
```

The next code was used to obtain both forecasted and real injections, based on the conversion factor (see equation 3.4), correlation matrix, daily forecasted radiation and the unbalance standard deviation already obtained. Additionally, it generates the histogram and provability density function of the unbalance error for each province (see figure 3.12).

```
clc
clear
close all

% STOCHASTIC AND DETERMINISTIC RADIATION INTO INJECTIONS

%       Data loading
% Radiation
ri = load('Daily_Average_injections.csv');  % Radiaiton Deterministic part
m = load('Average_mean.csv');        % Radiation unbalance Mean
s = load('Average_deviation.csv');  % Radiation unbalance Standard deviation
C = load('Coorrelation_PV_2.csv');     % Coorelation matrix

```

```
% Regional number of plants, installed capacity [MW] and energy produced ...
    [GWh]
PV = load('PV_Sicilia.csv');
PV(:,3) = PV(:,3)*1000; % Energy produced in MWh

% Hourly solar radiation [W/m^2]
R = load('Radiation_Sicili.csv');
R = R/1000000; % radiation in MW/m^2
ra = sum(R)'; % anual radiation

%       Average conversion factor (radiation to energy)
CF = PV(:,3)./(ra.*PV(:,2));

%       Stochastic and deterministic radiation vector
RI2 = zeros(size(R));  % Vector initialization

% Stochastic vector creation
e = 0.001;
for i=1:2000
    random = normrnd(0,1.7*mean(s),size(R))*C;
    if abs(mean(mean(random)))≤e
        i
        break
    end
end

random2 = normrnd(0,mean(s),size(R));
mean(std(random))
mean(std(random2))
std(random2)
%%

for i=1:9
    AV(:,i) = CF(i)*PV(i,2)*ri(:,i)/1000000;    % Deterministic ...
        raditaion to injections
    a = (AV(:,i) ≠0);   % Sun periods
    RI2(:,i) = ri(:,i) + a.*random(:,i);    % Deterministic + stochastic
    RI(:,i) = CF(i)*PV(i,2)*RI2(:,i)/1000000;   % Radiation to injections
    RI(RI(:,i)>PV(i,2),i) = PV(i,2);    % Maximum capacity check
    % No correlation matrix
    RI2s(:,i) = ri(:,i) + a.*random2(:,i);    % Deterministic + stochastic
    RIs(:,i) = CF(i)*PV(i,2)*RI2s(:,i)/1000000;   % Radiation to injections
    RIs(RIs(:,i)>PV(i,2),i) = PV(i,2);    % Maximum capacity check
    % No correlation matrix
    RI2sc(:,i) = ri(:,i) + a.*random2(:,4);    % Deterministic + stochastic
    RIsc(:,i) = CF(i)*PV(i,2)*RI2sc(:,i)/1000000;   % Radiation to ...
        injections
    RIsc(RIsc(:,i)>PV(i,2),i) = PV(i,2);    % Maximum capacity check
end

% No negative radiation check
RI(RI<0) = 0;   % Correlation matrix
RIs(RIs<0) = 0; % No correlation matrix
RIsc(RIsc<0) = 0; % Strong correlation matrix

% Histogram plot
```

```
for x=1:9
    U = (RI(:,x)   AV(:,x))./AV(:,x);     % Percentual unbalance
    U((any(isnan(U),2)|any(abs(U)≥1,2)|any(U==inf,2))) = []; % Remove no ...
        sun periods
    s2(x) = std(U);

    %       Histogram plot
    n = 60;
    [h1 x1] = hist(U,n);

    figure
    h = bar(x1,h1/length(U)/(x1(2) x1(1)));
    set(h,'FaceColor',[.7 .7 .7]);
    hold on
    X = min(U) + (1:1000)*(max(U) min(U))/1000;
    Y = normpdf(X,mean(U),std(U));
    plot(X,Y,'linewidth',2)
    set(gcf,'Color',[1,1,1])
    set(gca,'fontsize',12)
    xlabel('Unbalance/Injections [MWh/MWh]','FontSize',14)
    ylabel('Provability [%]','FontSize',14)

end

% Write to separete files
dlmwrite('Test_injections2_C2.csv', RI) % Real injections with ...
    correlation matrix
dlmwrite('Test_injections2s.csv', RIs) % Real injections no correlation ...
    matrix
dlmwrite('Test_injections2sc.csv', RIsc) % Real injections no ...
    correlation matrix
dlmwrite('Test_average.csv', AV)     % Forecasted injections
dlmwrite('Test_deviation.csv', mean(s2))     % Dviation
dlmwrite('CF_PV.csv', CF)     % Dviation

p = 1;
dv = linspace(0,.40,41);
Er = zeros(size(dv));
for i = 1:length(dv)
    RI = AV.*(normrnd(1,dv(i),size(AV)));
    RI(RI<0)=0;
    U = sum(RI,2)    sum(AV,2);
    Er(i) = mean(abs(RI(AV>0) AV(AV>0)))/mean(RI(AV>0));
end

figure
[r,m,b] = regression(dv,Er);
er = m*dv+b;
plot(dv*100,er,'k')
ylim([0 max(er)*1.1])
set(gcf,'Color',[1,1,1])
set(gca,'fontsize',12)
ylabel('Mean absolute error/Mean injections [MWh/MWh]','FontSize',14)
xlabel('Unbalance deviation [%]','FontSize',14)
grid on
```

A.2 Wind

The first code developed for wind plants is the Bayesian method described on section 3.5.2. Then it was used to determine the forecasted wind velocity. While keeping the meteorological data as the real wind velocity.

```
clc
clear
close all

% BAYESIAN APPROACH

%       Data Loading
WV = load('WV_Sicilia.csv'); % Hourly wind

%       Model Parameters
h = 8760; % Hours in a year
m = 3;  % Number of data used for the prediction
c = 8760   m; % Hours modelled
n = 20000; % Monte Carlo iterations
k = 1;  % Number of hours ahead of the injection
e_min = 1e 3;    % Min error allowed for Monte Carlo coefficients
err = zeros(1,9); % Error vector storage
err2 = zeros(1,9);% Error vector storage


for abc=1:9
    x = abc; % Province indicator

    U = zeros(h,1);     % Variable initialization
    U2 = zeros(h,1);     % Variable initialization
    Wn = zeros(h,1);     % Variable initialization
    Wp = zeros(h,4);     % Variable initialization
    A1 = zeros(h,1);     % Variable initialization
    A0 = zeros(h,1);     % Variable initialization
    E = zeros(h,1);     % Variable initialization
    Mu2 = zeros(h,1);     % Variable initialization
    a1 = zeros(1,n);     % Variable initialization
    a0 = zeros(1,n);     % Variable initialization
    e = zeros(1,n);     % Variable initialization
    mu1s = zeros(1,n);     % Variable initialization

    %       Bayes Method
    for i = 1:c
        Wn(i:m 1+i) = WV(i:m 1+i,x); % Sample
        [ab] = wblfit(Wn((i:m 1+i))); % size and shape parameters
        mu1 = mean(Wn(i:m 1+i)); % Original mean

        %       Monte Carlo Approach
        for j=1:n
            a1(j) = 2 4*rand(1,1); % Coefficient
            a0(j) = 2 4*rand(1,1); % Coefficient
            mu1s(j) = exp(a0(j)+a1(j)*log(Wn(m 2+i))); % Mean
            e(j) = (mu1 mu1s(j))/mu1; % Difference between the 2 means
            if abs(e(j)) < e_min % Error check
```

```
                mu2 = exp(a0(j)+a1(j)*log10(Wn(m 1+i))); % New mean
                n2 = mu2/(gamma(1+1/ab(2))); % New size parameter
                Wp(m+k+i 1,1) = wblinv(0.05,ab(1),ab(2)); %Confidence ...
                    parameter
                Wp(m+k+i 1,2) = wblinv(0.50,ab(1),ab(2)); %Best estimative
                Wp(m+k+i 1,3) = wblinv(0.95,ab(1),ab(2)); %Confidence ...
                    parameter
                % Test
                X = (1:100)*Wp(m+k+i 1,2)/100;
                Y = wblpdf(X,ab(1),ab(2));
                [no ind2] = max(Y);
                Wp(m+k+i 1,4) = X(ind2);
                % Unbalance
                U(m+k+i 1,1) = Wp(m+k+i 1,2)   WV(m+k+i 1,x); % Unbalance
                U2(m+k+i 1,1) = Wp(m+k+i 1,4)   WV(m+k+i 1,x); % ...
                    Unbalance for the test
                break
            elseif j == n % Check in case no Monte Carlo convergence
                i %Print the hour in which no convergence
                [em ind] = min(abs(e)); % Find parameters with minimum error
                mu2 = exp(a0(ind)+a1(ind)*log10(Wn(m 1+i))); % Same ...
                    procedure
                n2 = mu2/(gamma(1+1/ab(2)));
                Wp(m+k+i 1,1) = wblinv(0.05,ab(1),ab(2));
                Wp(m+k+i 1,2) = wblinv(0.50,ab(1),ab(2));
                Wp(m+k+i 1,3) = wblinv(0.95,ab(1),ab(2));

                X = (1:100)*Wp(m+k+i 1,2)/100;
                Y = wblpdf(X,ab(1),ab(2));
                [no ind2] = max(Y);
                Wp(m+k+i 1,4) = X(ind2);

                Wp(m+k+i 1,4) = wblinv(0.95,ab(1),ab(2));

                U(m+k+i 1,1) = Wp(m+k+i 1,2)   WV(m+k+i 1,x);
                U2(m+k+i 1,1) = Wp(m+k+i 1,4)   WV(m+k+i 1,x);
            end
        end
    end

    err(abc) = sum(abs(U(m+1:c+m)))/sum(WV(m+1:c+m,x)); % Error obtained
    err2(abc) = sum(abs(U2(m+1:c+m)))/sum(WV(m+1:c+m,x)); % Error ...
        obtained for the test

    %       Data to file
    dlmwrite(['W_P_WV_province' num2str(x) '_m' num2str(m) '_k' ...
       num2str(k) 'hours_base_e.csv'], Wp)
    %dlmwrite(['W_error_province' num2str(x) '_m' num2str(m)  '_k' ...
       %num2str(k) 'hours.csv'], err)
    abc % Province check
end
```

The second code was used to convert wind velocity into energy injection by using the wind conversion factor (see equation 3.5). Then it is used to obtain and write into separate files the energy injections and energy forecasts. Additionally, this code is equipped with the error mitigation described on section 3.7.2. Finally, it contains the step to obtain the figure 3.8.

```
clc
clear
close all

% WIND VELOCITY TO ENERGY INJECTIONS

% Regional number of plants, installed capacity [MW] and energy produced ... [GWh]
W = load('W_Sicilia.csv');
W(:,3) = W(:,3)*1000;   % Energy produced in MWh

WV = load('WV_Sicilia.csv');    % Hourly wind velocity (m/s)
wv3 = sum(WV.^3)';   % Energy is proportional to velocity at the power ... of 3

p = 7;
u = WV(:,p);
[h1 x1] = hist(u,40);
ab = wblfit(u);

wblplot(u)
set(gcf,'Color',[1,1,1])
set(gca,'fontsize',12)

figure
h = bar(x1,h1/length(u)/(x1(2) x1(1)));
set(h,'FaceColor',[.7 .7 .7]);
hold on
X = linspace(min(u),max(u),1001);
Y = wblpdf(X,ab(1),ab(2));
plot(X,Y,'b','linewidth',2)
xlim([min(u) max(u)])
legend('Wind velocity','Weibull distribution')
set(gcf,'Color',[1,1,1])
set(gca,'fontsize',12)
xlabel('Wind velocity [m/s]','FontSize',14)
ylabel('Provability [%]','FontSize',14)

% Forecast wind velocity
wf = zeros(8760,9,3);   % matrix initialization
WF05 = zeros(size(WV)); % matrix initialization
WF50 = zeros(size(WV)); % matrix initialization
WF95 = zeros(size(WV)); % matrix initialization
%WFmode = zeros(size(WV)); % matrix initialization

% Data loading
for i=1:9
    wf = load(['W_P_WV_province' num2str(i) '_m3_k1hours.csv']); % Data
    WF05(:,i) = wf(:,1); % Data 5 % prob
    WF50(:,i) = wf(:,2); % Data 50% prob
    WF95(:,i) = wf(:,3); % Data 95% prob
    %WFmode(:,i) = wf(:,4); % Data with the mode prob
end

%              Energy
WI = zeros(size(WV));   % matrix initialization
```

```
WR = zeros(size(WV));   % matrix initialization

% Conversion factor (wind velocity to energy)
CF = W(:,3)./(wv3.*W(:,2));   %

for i=1:9
    WR(:,i) = CF(i)*W(i,2)*(WV(:,i)).^3;% real injections
    WI(:,i) = CF(i)*W(i,2)*(WF95(:,i)).^3;% programmed injections ...
        knowing wind velocity
end

e = 2995900;    % Energy produced by wind on 2012
y = e/sum(sum(WR));% New plants installed on 2012
y2 = e/sum(sum(WI));% New plants installed on 2012
WR = WR*y;  % Scale parameter to obtain 2012 values
WI = WI*y2;  % Scale parameter to obtain 2012 values

close all

U = WR   WI;
sum(sum(abs(U)))
for i=1:9
    WR(WR(:,i)≥1.5*y*W(i,2),i) = 1.5*y*W(i,2); % Maximum injection check
    WI(WI(:,i)≥1.5*y2*W(i,2),i) = 1.5*y2*W(i,2); % Maximum injection check
end
sum(sum(WI))

U = WR   WI;
sum(sum(abs(U)))


dlmwrite(['PI_W_x_' num2str(0) '.csv'], WI) %Programed injections
dlmwrite('RI_W.csv', WR)    % Real injections

U = WR   WI;    % Energy unbalance
err = sum(abs((WR   WI)))./sum((WI)); %



p = 5;
u = (U(:,p))/(W(p,2)*y);
u(u==0) = [];
[h1 x1] = hist(u,40);
[ab(1) ab(2)] = normfit(u);
ab1 = evfit(u);
ab3 = gevfit(u);

figure
h = bar(x1,h1/length(u)/(x1(2) x1(1)));
set(h,'FaceColor',[.7 .7 .7]);
hold on
X = linspace(min(u),max(u),1001);
Y = normpdf(X,ab(1),ab(2));
Y2 = evpdf(X,ab1(1),ab1(2));
Y4 = gevpdf(X,ab3(1),ab3(2));
plot(X,Y,'b','linewidth',2)
```

```
plot(X,Y2,'r','linewidth',2)
plot(X,Y4,'c','linewidth',2)
legend('','Normal','Extreme value','Generalized EV')
set(gcf,'Color',[1,1,1])
set(gca,'fontsize',12)
xlabel('Unbalance/Capacity [MWh/MWh]','FontSize',14)
ylabel('Provability [%]','FontSize',14)

% Error mitigation
x = linspace(0,1,21);
Er_s = zeros(size(x));
for i=1:21

    WI_s = WI + x(i)*U;

    err_s = sum(abs((WR   WI_s)))./sum(WI_s); % Unbalance/total energy

    %U_w = sum(WR,2) sum(WI,2);
    U_ws = sum(WR,2) sum(WI_s,2);
    %Er = sum(abs(U_w))/sum(mean(WI))/length(U_w);
    Er_s(i) = mean(sum(abs(WR WI_s)/8760)./(W(:,2)'));
    %Er_s2(i) = mean(abs(sum(WR,2) sum(WI_s,2))/mean(sum(WI_s,2)));
end


[r,m,b] = regression(x,Er_s);
Y = .005 + [2.885 5.385 5.641 5.833 5.897 6.062 6.564 6.866]/100;
X = (Y b)/m;
%%
figure
plot(x,Er_s,'k')
hold on
%plot(x,Er_s2,' k')
plot(X,Y,'.r')
text(X,Y,['   1 h';'   2 h';'        ';'3   6 h';'        ';...
    '        ';'21h    ';'24h    ...
        '],'FontSize',12,'VerticalAlignment','top',...
    'HorizontalAlignment','right')
hold off
set(gcf,'Color',[1,1,1])
set(gca,'fontsize',12)
ylabel('MAE / Installed capacity [%]','FontSize',14)
xlabel('Wind correction factor (x)','FontSize',14)
title('Wind power error', 'FontSize', 14)
grid on
legend('Data','Literature')

dlmwrite('W_mean_abs_error.csv', Y) % Real RMSE values
dlmwrite('W_x_literature.csv', X) % X equivalent

%%

X = 0.2;
WI_s = WI + X*U;
%      Data to files

```

```


% Plot
x = 0;  % Mitigation factor
U2 = WF50   WV; % Unbalance
WF50 = WF50   x*U2; % Mitigation
WF05 = WF05   x*U2; % Mitigation
WF95 = WF95   x*U2; % Mitigation

WF05(WF05<0) = 0;   % Positive injections check

p = 4;  % Day to visualize
d = 1;  % Number of days to visualize

figure
plot(WV(d*24:24*(d+1),p),'. r')
hold on
plot(WF05(d*24:24*(d+1),p),'  k')
plot(WF50(d*24:24*(d+1),p),'. k')
plot(WF95(d*24:24*(d+1),p),'  k')
legend('Real','P = 5%','P = 50%','P = 95%',2)
set(gcf,'Color',[1,1,1])
xlim([1 24])
set(gca,'fontsize',12)
xlabel('Time [h]','FontSize',14)
ylabel('Wind Velocity [m/s]','FontSize',14)
```

A.3 Load

The following code contains the load real and forecasted injections. Additionally it imports both real and forecasted injections for PV and wind farms. Additionally, it is used to determine the zonal unbalance, the dual pricing both with and whit out the allowance, and the nodal pricing. Furthermore, it determines the number of hours in which PV and wind farms are able to cover the total load. Finally, this code contains the proceeding to generate all results and plots from chapter 4.

```
%clc
clear
close all

% ASK DELFANTI:
%   MAXIMUM AND MINIMUM LOAD WITH ri_mgp == 1
%   FEE CALCULATION

d = 1; % Days to see on the graph
d2 = 1;
ri_mgp = 1; % If 1 real injections, if 0 mgp values

%             Data loading
% Installed capacity by province
PVc = load('PV_Sicilia.csv');
Wc = load('W_Sicilia.csv');
```

```
% Sicili forecast and load
L_local = load('L_local.csv');
L_export = load('L_export.csv'); % Exports
L_f = load('L_f.csv');
L_r = load('L_r.csv');

U_L = L_f    L_r; % Load unbalance

u = U_L./L_f;
[h1 x1] = hist(u,40);
[ab(1) ab(2)] = normfit(u);

figure
h = bar(x1,h1/length(u)/(x1(2) x1(1)));
set(h,'FaceColor',[.7 .7 .7]);
hold on
X = linspace(min(u),max(u),1001);
Y = normpdf(X,ab(1),ab(2));
plot(X,Y,'b','linewidth',2)
set(gcf,'Color',[1,1,1])
set(gca,'fontsize',12)
xlabel('Unbalance/Forecasted load [MWh/MWh]','FontSize',14)
ylabel('Provability [%]','FontSize',14)

%              PV
% Data loading

fi_pv = load('Test_Average.csv');  % Forecast production

% Real injection for the uncorrelated and the correlated data
ri_pv = load('Test_injections2.csv');  % With correlation matrix
ri_pvs = load('Test_injections2s.csv');  % Without correlation matrix
ri_pvsc = load('Test_injections2sc.csv');  % With strong correlation

% Normalization
fi_pv = fi_pv*sum(sum(ri_pv))/sum(sum(fi_pv));
ri_pvs = ri_pvs*sum(sum(ri_pv))/sum(sum(ri_pvs));
ri_pvsc = ri_pvsc*sum(sum(ri_pv))/sum(sum(ri_pvsc));

% Energy unbalance
u_pv = ri_pv    fi_pv;       % Province unbalance
u_pvs = ri_pvs    fi_pv;       % Province unbalance
u_pvsc = ri_pvsc    fi_pv;       % Province unbalance

% Zonal injections and forecast and unbalances
FI_PV = sum(fi_pv,2); % Zonal PV forecast
RI_PV = sum(ri_pv,2); % Zonal PV real injections
RI_PVs = sum(ri_pvs,2); % Zonal PV real injections no correlation matrix
RI_PVsc = sum(ri_pvsc,2); % Zonal PV real injections STRONG correlation
U_PV = RI_PV    FI_PV; % PV total unbalance
U_PVs = RI_PVs    FI_PV; % PV total unbalance no correlation matrix
U_PVsc = RI_PVsc    FI_PV; % PV total unbalance strong correlation matrix

%             Wind
% Data loading
```

```
fi_w = load('PI_W_x_0.csv');  % Forecast production
ri_w = load('RI_W.csv');  % Real production

% Real injections normalization
y = 2995600/sum(sum(fi_w));
fi_w = fi_w*y;
ri_w = ri_w*y;

u_w = ri_w   fi_w;        % Province umbalance

% Zonal injections, forecast and unbalances
FI_W = sum(fi_w,2); % Zonal wind forecast
RI_W = sum(ri_w,2); % Zonal wind real injections
U_W = RI_W   FI_W;  % Wind total zonal unbalance

% Figure: Real and forecasting load and injections
L = [L_f L_r FI_PV RI_PV FI_W RI_W]; % Plot vector
figure
c = 28; % Day to be ploted
plot(L(24*c+1:24*(c+1)+1,:),'linewidth' ,2)
xlim([1 24])
legend('L_f', 'L_r', 'FI_P_V', 'RI_P_V', 'FI_W', 'RI_W','Location',...
    'BestOutside','Orientation','horizontal')
ylabel('Energy [MWh]','FontSize',14)
xlabel('Time [h]','FontSize',14)
set(gcf,'Color',[1,1,1])
set(gca,'fontsize',12)
grid on
set(gca,'XTick',0:4:24)

% Figure: RES injections and residual load
figure
X = [RI_PV, RI_PV+RI_W, L_r];
harea2 = area(X);
grid on
xlim([1 24*d2])
colormap summer
legend('PV','Wind','Traditional')
ylabel('Energy [MWh]','FontSize',14)
xlabel('Time [h]','FontSize',14)
set(gcf,'Color',[1,1,1])
set(gca,'fontsize',12)

% Figure: RES injections and residual load
d3 = 217; % ploted day
figure
t = 24*d3:24*(d3+1);
x1 = L_r(t);
x2 = L_r(t) RI_PV(t) RI_W(t);
t2 = 0:24;
plot(t2,x1,'k',t2,x2,'  k')
grid on
xlim([min(t2) max(t2)])
legend('Load','Residual Load','location','best')
ylabel('Energy [MWh]','FontSize',14)
xlabel('Time [h]','FontSize',14)
```

```
set(gcf,'Color',[1,1,1])
set(gca,'fontsize',12)

%         Zonal unbalance
%       MSD
msd_down = 23.1;  %MB downward price
msd_up = 168.5;   %MB upward price
PUN = 100;      %Day ahead marke price

U_z = U_PV + U_W + U_L;      % Zonal unbalance
U_zs = U_PVs + U_W + U_L;    % Unbalance check for PV without correlation
U_zsc = U_PVsc + U_W + U_L; % Unbalance check for PV with strong correlation

% Further check for the different PV correlations
%sum(U_PV(U_PV>0))
%sum(U_PV(U_PV<0))
%sum(U_PVs(U_PVs>0))
%sum(U_PVs(U_PVs<0))
%sum(U_PVsc(U_PVsc>0))
%sum(U_PVsc(U_PVsc<0))

% Positive and negative zonal unbalance vector
z1 = (U_z > 0);
z2 = (U_z < 0);

% Figure: yearly zonal unbalance
figure
plot(U_z(1:24*365))
set(gcf,'Color',[1,1,1])
set(gca,'fontsize',12)
ylabel('Zonal unbalance [MWh]','FontSize',14)
xlabel('Time [h]','FontSize',14)
xlim([1 8760])
grid on

%           Unbalance
% PV
% Energy in excess
p1_pv = (u_pv > 0);

% Energy is lacking
p2_pv = (u_pv < 0);

% Classification under the four combianations of nodal and zonal unbalance
e_11 = repmat(z1,1,9) + p1_pv;
e_11(e_11 < 2) = 0;
e_11 = e_11/2;

e_12 = repmat(z1,1,9) + p2_pv;
e_12(e_12 < 2) = 0;
e_12 = e_12/2;

e_21 = repmat(z2,1,9) + p1_pv;
e_21(e_21 < 2) = 0;
e_21 = e_21/2;
```

```
e_22 = repmat(z2,1,9) + p2_pv;
e_22(e_22 < 2) = 0;
e_22 = e_22/2;

% Wind
% Energy in excess
p1_w = (u_w > 0);

% Energy is lacking
p2_w = (u_w < 0);

% Classification under the four combianations of nodal and zonal unbalance
ew_11 = repmat(z1,1,9) + p1_w;
ew_11(ew_11 < 2) = 0;
ew_11 = ew_11/2;

ew_12 = repmat(z1,1,9) + p2_w;
ew_12(ew_12 < 2) = 0;
ew_12 = ew_12/2;

ew_21 = repmat(z2,1,9) + p1_w;
ew_21(ew_21 < 2) = 0;
ew_21 = ew_21/2;

ew_22 = repmat(z2,1,9) + p2_w;
ew_22(ew_22 < 2) = 0;
ew_22 = ew_22/2;

%       Energy unbalanced
U_pv(1,1) = sum(sum(u_pv.*e_11));
U_pv(1,2) = sum(sum(u_pv.*e_12));
U_pv(2,1) = sum(sum(u_pv.*e_21));
U_pv(2,2) = sum(sum(u_pv.*e_22));

U_w(1,1) = sum(sum(u_w.*ew_11));
U_w(1,2) = sum(sum(u_w.*ew_12));
U_w(2,1) = sum(sum(u_w.*ew_21));
U_w(2,2) = sum(sum(u_w.*ew_22));

%        Single price
m_sp = [min(msd_down,PUN) min(msd_down,PUN);
        max(msd_up,PUN)   max(msd_up,PUN)]; % Excess; lack

sp_w = U_w.*m_sp;
SP_W = sum(sp_w(:));     % Wind plants cost
sp_pv = U_pv.*m_sp;
SP_PV = sum(sp_pv(:));   % PV plants cost
SP = SP_PV + SP_W        % Total revenue under single price

%        Dual pricing
% Remuneration matrix
M_dp = [min(msd_down,PUN) PUN;
        PUN max(msd_up,PUN)];

dp_pv = M_dp.*U_pv;
DP_PV = sum(dp_pv(:));   % PV plants cost
```

```

% Wind
dp_w = M_dp.*U_w;
DP_W = sum(dp_w(:));     % Wind plants cost
DP = DP_PV + DP_W        % Total revenue under dual price

%         Single and Dual pricing with 10 or 20% allowance

a = 0.2;     % 10% or 20% allowance used

% PV
% Allowance condition
a_pv = (abs(u_pv)./fi_pv > a);

a_11 = e_11 + a_pv;
a_11(a_11 < 2) = 0;
a_11 = a_11/2;

a_12 = e_12 + a_pv;
a_12(a_12 < 2) = 0;
a_12 = a_12/2;

a_21 = e_21 + a_pv;
a_21(a_21 < 2) = 0;
a_21 = a_21/2;

a_22 = e_22 + a_pv;
a_22(a_22 < 2) = 0;
a_22 = a_22/2;

% Wind
% PV
% Allowance condition
w_a = .2;
a_w = (abs(u_w)./fi_w > w_a);

aw_11 = ew_11 + a_w;
aw_11(aw_11 < 2) = 0;
aw_11 = aw_11/2;

aw_12 = ew_12 + a_w;
aw_12(aw_12 < 2) = 0;
aw_12 = aw_12/2;

aw_21 = ew_21 + a_w;
aw_21(aw_21 < 2) = 0;
aw_21 = aw_21/2;

aw_22 = ew_22 + a_w;
aw_22(aw_22 < 2) = 0;
aw_22 = aw_22/2;

%       Energy unbalance
U_pv_a(1,1) = sum(sum((u_pv a*u_pv).*a_11));
U_pv_a(1,2) = sum(sum((u_pv a*u_pv).*a_12));
U_pv_a(2,1) = sum(sum((u_pv a*u_pv).*a_21));
```

```
U_pv_a(2,2) = sum(sum((u_pv a*u_pv).*a_22));

U_w_a(1,1) = sum(sum((u_w w_a*u_w).*aw_11));
U_w_a(1,2) = sum(sum((u_w w_a*u_w).*aw_12));
U_w_a(2,1) = sum(sum((u_w w_a*u_w).*aw_21));
U_w_a(2,2) = sum(sum((u_w w_a*u_w).*aw_22));

%       Single price
sp_pv_a = U_pv_a.*m_sp;
sp_w_a = U_w_a.*m_sp;

SP_W_a = sum(sp_w_a(:));     % Wind plants cost
SP_PV_a = sum(sp_pv_a(:));   % PV plants cost
SP_a = SP_PV_a + SP_W_a      % Total cost under Single price with allowance

%       Dual price
dp_pv_a = U_pv_a.*M_dp;
DP_PV_a = sum(dp_pv_a(:));   % PV plants cost

% Wind
dp_w_a = U_w_a.*M_dp;
DP_W_a = sum(dp_w_a(:));     % Wind plants cost
DP_a = DP_PV_a + DP_W_a      % Total remuneration under dual price with ...
    allowance

%       Cost cope by Terna
U_Tc1 = (U_W + U_PV).*z1;  % Energy is in excess
U_Tc2 = (U_W + U_PV).*z2;  % Energy is lacking

U_w_tc(1) = sum((U_W).*z1);  % Energy is in excess
U_w_tc(2) = sum((U_W).*z2);  % Energy is in lacking

C_T = zeros(2);
C_T(1,1) = sum(U_Tc1(U_Tc1>0));
C_T(1,2) = sum(U_Tc1(U_Tc1<0));
C_T(2,1) = sum(U_Tc2(U_Tc2>0));
C_T(2,2) = sum(U_Tc2(U_Tc2<0));

%        Cost incurred on the balancing market
R_trad(3) = sum(abs(diag(C_T))'*[msd_down; msd_up]);     % Total cost
R_trad(2) = abs(U_w_tc)*[msd_down; msd_up];      % Wind plants cost
R_trad(1) = R_trad(3)    R_trad(2)    % PV plants cost

CT = [SP SP_a DP DP_a] + R_trad(3)  % Cost incurred by TERNA under the ...
    diferent mechanisms
%dlmwrite('Cost_trad.csv', R_trad) % Real injections with correlation matrix

%        Total RES unbalance
U_PV_W = U_pv + U_w;
dlmwrite('Unbalance_matrix.csv', U_PV_W) % Real injections with ...
    correlation matrix

% Hours in which RES cover full load
n = L_r RI_PV    RI_W;
n2 = length(find(n ≤ 0));

```

```
%         Monthly values
% Data initialization
d = [0 31 28 31 30 31 30 31 31 30 31 30 31]; % Days per month
D = cumsum(d);
ub_p = zeros(12,1);
ub_n = zeros(12,1);
ub_p_a = zeros(12,1);
ub_n_a = zeros(12,1);

wb_p = zeros(12,1);
wb_n = zeros(12,1);
wb_p_a = zeros(12,1);
wb_n_a = zeros(12,1);

lb_p = zeros(12,1);
lb_n = zeros(12,1);
lb_p_a = zeros(12,1);
lb_n_a = zeros(12,1);

zb_p = zeros(12,1);
zb_n = zeros(12,1);
zb_p_s = zeros(12,1);
zb_n_s = zeros(12,1);
zb_p_sc = zeros(12,1);
zb_n_sc = zeros(12,1);

u_h_pv = zeros(12,1);
u_w_pv = zeros(12,1);

u_h_w = zeros(12,1);
u_w_w = zeros(12,1);

h_eq_pv = zeros(12,1);
h_eq_pvs = zeros(12,1);
h_eq_pvsc = zeros(12,1);
h_eq_w = zeros(12,1);

L_m = zeros(12,1);

r_trad = zeros(12,1);
DPC = zeros(12,1);
DPCA = zeros(12,1);
SPC = zeros(12,1);
SPCA = zeros(12,1);
NPC_1 = zeros(12,1);
NPC_2 = zeros(12,1);

%       Monthly values
for i=1:12
    t = (24*D(i)+1:24*D(i+1));

    ub_pv = u_pv(t,:);
    ub_p(i) = sum(ub_pv(ub_pv>0));
    ub_n(i) = sum(ub_pv(ub_pv<0));
    ub_p_a(i) = sum(ub_pv(ub_pv./fi_pv(t,:)>a)*(1 a));
    ub_n_a(i) = sum(ub_pv(ub_pv./fi_pv(t,:)<a)*(1 a));
```

```

    ub_w = u_w(t,:);
    wb_p(i) = sum(ub_w(ub_w>0));
    wb_n(i) = sum(ub_w(ub_w<0));
    wb_p_a(i) = sum(ub_w(ub_w./fi_w(t,:)>w_a)*(1 w_a));
    wb_n_a(i) = sum(ub_w(ub_w./fi_w(t,:)<w_a)*(1 w_a));

    ub_l = U_L(t);
    lb_p(i) = sum(ub_l(ub_l>0));
    lb_n(i) = sum(ub_l(ub_l<0));
    lb_p_a(i) = sum(ub_l(abs(ub_l./L_f(t))>a & ub_l>0));
    lb_n_a(i) = sum(ub_l(abs(ub_l./L_f(t))>a & ub_l<0));

    u_w_pv(i) = sum(sum((e_11(t,:)+e_22(t,:)).*abs(u_pv(t,:))));
    u_h_pv(i) = sum(sum((e_12(t,:)+e_21(t,:)).*abs(u_pv(t,:))));
    u_w_w(i) = sum(sum((ew_11(t,:)+ew_22(t,:)).*abs(u_w(t,:))));
    u_h_w(i) = sum(sum((ew_12(t,:)+ew_21(t,:)).*abs(u_w(t,:))));

    ub_z = U_z(t);
    ub_z_s = U_zs(t);
    ub_z_sc = U_zsc(t);

    zb_p(i) = sum(ub_z(ub_z>0));
    zb_n(i) = sum(ub_z(ub_z<0));
    zb_p_s(i) = sum(ub_z_s(ub_z_s>0));
    zb_n_s(i) = sum(ub_z_s(ub_z_s<0));
    zb_p_sc(i) = sum(ub_z_sc(ub_z_sc>0));
    zb_n_sc(i) = sum(ub_z_sc(ub_z_sc<0));

    h_eq_pv(i) = sum(RI_PV(t))/sum(PVc(:,2));
    h_eq_pvs(i) = sum(RI_PVs(t))/sum(PVc(:,2));
    h_eq_pvsc(i) = sum(RI_PVsc(t))/sum(PVc(:,2));
    h_eq_w(i) = sum(RI_W(t))/sum(Wc(:,2));

    L_m(i) = sum(L_r(t));

    % Since price
    spc(1,1) = sum(sum(e_11(t,:).*u_pv(t,:) + ...
        ew_11(t,:).*u_w(t,:)))*m_sp(1,1);
    spc(1,2) = sum(sum(e_12(t,:).*u_pv(t,:) + ...
        ew_12(t,:).*u_w(t,:)))*m_sp(1,2);
    spc(2,1) = sum(sum(e_21(t,:).*u_pv(t,:) + ...
        ew_21(t,:).*u_w(t,:)))*m_sp(2,1);
    spc(2,2) = sum(sum(e_22(t,:).*u_pv(t,:) + ...
        ew_22(t,:).*u_w(t,:)))*m_sp(2,2);

    SPC(i) = sum(spc(:));

    % Single price allowance
    spca(1,1) = sum(sum(a_11(t,:).*u_pv(t,:) + ...
        aw_11(t,:).*u_w(t,:)))*m_sp(1,1)*(1 a);
    spca(1,2) = sum(sum(a_12(t,:).*u_pv(t,:) + ...
        aw_12(t,:).*u_w(t,:)))*m_sp(1,2)*(1 a);
    spca(2,1) = sum(sum(a_21(t,:).*u_pv(t,:) + ...
        aw_21(t,:).*u_w(t,:)))*m_sp(2,1)*(1 a);
    spca(2,2) = sum(sum(a_22(t,:).*u_pv(t,:) + ...
```

```
        aw_22(t,:).*u_w(t,:)))*m_sp(2,2)*(1 a);

    SPCA(i) = sum(spca(:));

    % Dual price
    dpc(1,1) = sum(sum(e_11(t,:).*u_pv(t,:) + ...
        ew_11(t,:).*u_w(t,:)))*M_dp(1,1);
    dpc(1,2) = sum(sum(e_12(t,:).*u_pv(t,:) + ...
        ew_12(t,:).*u_w(t,:)))*M_dp(1,2);
    dpc(2,1) = sum(sum(e_21(t,:).*u_pv(t,:) + ...
        ew_21(t,:).*u_w(t,:)))*M_dp(2,1);
    dpc(2,2) = sum(sum(e_22(t,:).*u_pv(t,:) + ...
        ew_22(t,:).*u_w(t,:)))*M_dp(2,2);

    DPC(i) = sum(dpc(:));

    % Dual price allowance
    dpca(1,1) = sum(sum(a_11(t,:).*u_pv(t,:)*(1 a) + ...
        aw_11(t,:).*u_w(t,:)*(1 w_a)))*M_dp(1,1);
    dpca(1,2) = sum(sum(a_12(t,:).*u_pv(t,:)*(1 a) + ...
        aw_12(t,:).*u_w(t,:)*(1 w_a)))*M_dp(1,2);
    dpca(2,1) = sum(sum(a_21(t,:).*u_pv(t,:)*(1 a) + ...
        aw_21(t,:).*u_w(t,:)*(1 w_a)))*M_dp(2,1);
    dpca(2,2) = sum(sum(a_22(t,:).*u_pv(t,:)*(1 a) + ...
        aw_22(t,:).*u_w(t,:)*(1 w_a)))*M_dp(2,2);

    DPCA(i) = sum(dpca(:));

    % Terna cost
    U_T1 = (sum(ub_pv,2) + sum(ub_w,2)).*z1(t,:);  % Energy is in excess
    U_T2 = (sum(ub_pv,2) + sum(ub_w,2)).*z2(t,:);  % Energy is lacking

    c_t(1,1) = M_dp(1,1)*sum(U_T1(U_T1>0));
    c_t(1,2) = M_dp(1,2)*sum(U_T1(U_T1<0));
    c_t(2,1) = M_dp(2,1)*sum(U_T2(U_T2>0));
    c_t(2,2) = M_dp(2,2)*sum(U_T2(U_T2<0));

    r_trad(i) = c_t(1,1) + abs(c_t(2,2));%sum(c_t(:).*[2 1 1 0]');

    % New price
    npc_1(1,1) = sum(sum(e_11(t,:).*u_pv(t,:) + ...
        ew_11(t,:).*u_w(t,:)))*M_np_1(1,1);
    npc_1(1,2) = sum(sum(e_12(t,:).*u_pv(t,:) + ...
        ew_12(t,:).*u_w(t,:)))*M_np_1(1,2);
    npc_1(2,1) = sum(sum(e_21(t,:).*u_pv(t,:) + ...
        ew_21(t,:).*u_w(t,:)))*M_np_1(2,1);
    npc_1(2,2) = sum(sum(e_22(t,:).*u_pv(t,:) + ...
        ew_22(t,:).*u_w(t,:)))*M_np_1(2,2);

    NPC_1(i) = sum(npc_1(:));

    npc_2(1,1) = sum(sum(e_11(t,:).*u_pv(t,:) + ...
        ew_11(t,:).*u_w(t,:)))*M_np_2(1,1);
    npc_2(1,2) = sum(sum(e_12(t,:).*u_pv(t,:) + ...
        ew_12(t,:).*u_w(t,:)))*M_np_2(1,2);
    npc_2(2,1) = sum(sum(e_21(t,:).*u_pv(t,:) + ...
```

```
        ew_21(t,:).*u_w(t,:)))*M_np_2(2,1);
    npc_2(2,2) = sum(sum(e_22(t,:).*u_pv(t,:) + ...
        ew_22(t,:).*u_w(t,:)))*M_np_2(2,2);

    NPC_2(i) = sum(npc_2(:));
end
%        Data plotting

% Figure: PV nodal unbalance
bar(ub_p/1000,'c')
hold on
bar(ub_n/1000,'g')
bar(ub_p_a/1000,'m')
bar(ub_n_a/1000,'y')
xlim([0 13])
ylim([min(ub_n)*1.1 max(ub_p)*1.1]/1000)
legend('Positive','Negative','Positive > 20%','Negative > 20%'...
    ,'Location','BestOutside','Orientation','horizontal')
set(gca(gcf), 'xticklabel',{'Jan','Feb','Mar','Apr','May','Jun',...
    'Jul','Aug','Sep','Oct','Nov','Dic'},'FontSize',12)
ylabel('Energy [GWh]','FontSize',14)
title('PV Unbalance','FontSize',14)
set(gcf,'Color',[1,1,1])
set(gca,'fontsize',12)
grid on

figure % Figure: Wind nodal unbalance
bar(wb_p/1000,'c')
hold on
bar(wb_n/1000,'g')
bar(wb_p_a/1000,'m')
bar(wb_n_a/1000,'y')
xlim([0 13])
ylim([min(wb_n)*1.1 max(wb_p)*1.1]/1000)
legend('Positive','Negative','Positive > 20%','Negative > 20%'...
    ,'Location','BestOutside','Orientation','horizontal')
set(gca(gcf), 'xticklabel',{'Jan','Feb','Mar','Apr','May','Jun',...
    'Jul','Aug','Sep','Oct','Nov','Dic'},'FontSize',12)
ylabel('Energy [GWh]','FontSize',14)
title('Wind Unbalance','FontSize',14)
set(gcf,'Color',[1,1,1])
set(gca,'fontsize',12)
grid on

figure % Figure: load unbalance
bar(lb_p/1000,'c')
hold on
bar(lb_n/1000,'g')
bar(lb_p_a/1000,'m')
bar(lb_n_a/1000,'y')
xlim([0 13])
ylim([ 100 100])
legend('Positive','Negative','Positive > 20%','Negative > 20%'...
    ,'Location','BestOutside','Orientation','horizontal')
set(gca(gcf), 'xticklabel',{'Jan','Feb','Mar','Apr','May','Jun',...
    'Jul','Aug','Sep','Oct','Nov','Dic'},'FontSize',12)
```

```
ylabel('Energy [GWh]','FontSize',14)
title('Load Unbalance','FontSize',14)
set(gcf,'Color',[1,1,1])
set(gca,'fontsize',12)
grid on

figure % Figure: zonal unbalance
Zb1 = [zb_p  zb_n]/1000;
bar(Zb1)
colormap jet(2)
xlim([0 13])
ylim([0 max(Zb1(:))]*1.1)
legend('Positive','Negative',1)
set(gca(gcf), 'xticklabel',{'Jan','Feb','Mar','Apr','May','Jun',...
    'Jul','Aug','Sep','Oct','Nov','Dic'},'FontSize',12)
ylabel('Energy unbalance [GWh]','FontSize',14)
title('Zonal RES Unbalance','FontSize',14)
set(gcf,'Color',[1,1,1])
set(gca,'fontsize',12)
grid on

figure % Figure: Unbalance aiding and worsening the zonal unbalance
u_w_h = [u_h_pv, u_w_pv, u_h_w, u_w_w]/1000;
bar(u_w_h)
colormap jet % Change the color scheme
grid on
xlim([0 13])
legend('Aid PV','Harm PV','Aid W','Harm ...
    W','Location','BestOutside','Orientation','horizontal')
set(gca(gcf), 'xticklabel',{'Jan','Feb','Mar','Apr','May','Jun',...
    'Jul','Aug','Sep','Oct','Nov','Dic'},'FontSize',12)
ylabel('Unbalance [GWh]','FontSize',14)
title('Zonal Unbalance','FontSize',14)
set(gcf,'Color',[1,1,1])
set(gca,'fontsize',12)

figure % Figure: Energy injections for PV plants with and without ...
    correlation
PV_injection = [h_eq_pvs, h_eq_pv, h_eq_pvsc]*sum(PVc(:,2))/1000;
bar(PV_injection)
colormap jet(3)% Change the color scheme
grid on
xlim([0 13])
ylim([0 max(PV_injection(:))*1.1])
legend('Without correlation','Correlation matrix','Strong correlation')
set(gca(gcf), 'xticklabel',{'Jan','Feb','Mar','Apr','May','Jun',...
    'Jul','Aug','Sep','Oct','Nov','Dic'},'FontSize',12)
ylabel('Energy injections [MWh]','FontSize',14)
title(['Without = ' num2str(round(sum(PV_injection(:,1))))...
    ' [GWh]       Correlation matrix =' ...
        num2str(round(sum(PV_injection(:,2))))...
    ' [GWh]       Strong Correlation=' ...
        num2str(round(sum(PV_injection(:,3))))...
    ' [GWh]'])
set(gcf,'Color',[1,1,1])
set(gca,'fontsize',12)
```

```

figure % Figure: PV and wind plants equivalent hours
h_eq = [h_eq_w, h_eq_pv];
bar(h_eq)
colormap summer(3)% Change the color scheme
grid on
xlim([0 13])
legend('Wind','PV')
set(gca(gcf), 'xticklabel',{'Jan','Feb','Mar','Apr','May','Jun',...
    'Jul','Aug','Sep','Oct','Nov','Dic'},'FontSize',12)
ylabel('Equivalent hours [h]','FontSize',14)
title(['Wind h_e_q = ' num2str(round(sum(h_eq_w)))...
    '        PV h_e_q =' num2str(round(sum(h_eq_pv)))])
set(gcf,'Color',[1,1,1])
set(gca,'fontsize',12)

% Equivalent hours to energy injections
pv_bar = h_eq_pv*sum(PVc(:,2));
w_bar = h_eq_w*sum(Wc(:,2));

figure % Figure: PV, Wind and traditional plants injections
bar(1:12, [pv_bar, w_bar L_m pv_bar w_bar]/1000, 0.5, 'stack')
colormap jet(3) % Change the color scheme
grid on
xlim([0 13])
legend('PV','Wind','Traditional','Location','BestOutside','Orientation','horizontal')
set(gca(gcf), 'xticklabel',{'Jan','Feb','Mar','Apr','May','Jun',...
    'Jul','Aug','Sep','Oct','Nov','Dic'},'FontSize',12)
ylabel('Energy [GWh]','FontSize',14)
title(['PV = ' num2str(round(sum(pv_bar)/1000))...
    '[GWh]       Wind = ' num2str(round(sum(w_bar)/1000))...
    '[GWh]       Traditional = ' ...
        num2str(round(sum(L_m pv_bar w_bar)/1000))...
    '[GWh]'],'FontSize',14)
set(gcf,'Color',[1,1,1])
set(gca,'fontsize',12)

figure % Figure: Specific cost remuneration mechanism
price = [ SPC, SPCA, DPC, DPCA]/(pv_bar+w_bar);
plot(price,'. ')
grid on
xlim([1 12])
ylim([5 max(price(:))*1.1])
legend('SP','SP 20% allow','DP','DP 20% allow','Location','BestOutside',...
    'Orientation','horizontal')
set(gca,'XTick',1:1:12)
set(gca(gcf), 'xticklabel',{'Jan','Feb','Mar','Apr','May','Jun',...
    'Jul','Aug','Sep','Oct','Nov','Dic'},'FontSize',12)
ylabel('Euro per RES E injections [Euro / MWh]','FontSize',14)
title('Specific cost','FontSize',14)
set(gcf,'Color',[1,1,1])
set(gca,'fontsize',12)

figure % Figure: TERNA's cash flow for the remuneration mechanisms
price = repmat(r_trad,1,4) +[SPC,SPCA,DPC,DPCA];
plot(price/1e6,'. ')
```

```
grid on
xlim([1 12])
legend('SP','SP 20% allow','DP','DP 20% allow','Location','BestOutside',...
    'Orientation','horizontal')
set(gca,'XTick',1:1:12)
set(gca(gcf), 'xticklabel',{'Jan','Feb','Mar','Apr','May','Jun',...
    'Jul','Aug','Sep','Oct','Nov','Dic'},'FontSize',12)
ylabel('Million Euro','FontSize',14)
title('TERNAs cost','FontSize',14)
set(gcf,'Color',[1,1,1])
set(gca,'fontsize',12)
```

A.4 Sensitivity

Finally, the following code was written to perform the sensibility analysis. Then it contains al the proceedings, results and plots from chapter 5.

```
clc
clear
close all

%       Data loading

PVc = load('PV_data/PV_Sicilia.csv');
Wc = load('W_data/W_Sicilia.csv');

% Sicili forecast and load
L_local = load('L_data/L_local.csv');
L_export = load('L_data/L_export.csv'); % Exports
L_f = load('L_data/L_f.csv');
L_r = load('L_data/L_r.csv');

U_L = L_f   L_r; % Load unbalance

% PV data
dv_pv = load('PV_data/dv_pv.csv');
dv_pv2 = load('PV_data/dv_literature.csv');
RMSE = load('PV_data/RMSE_data.csv'); % RMSE equivalent to dv_pv
RMSE2 = load('PV_data/RMSE_literature.csv'); % RMSE for 1,2,3,4,5,6 and 24h
fi_pv = load('PV_data/Test_Average.csv');

% Wind data
fi_r_w = load('W_data/PI_W_x_02.csv');  % Real forecast production
ri_w = load('W_data/RI_W2.csv');  % Real production
fi_r_w = fi_r_w*2995600/sum(sum(fi_r_w));
ri_w = ri_w*2995600/sum(sum(ri_w));


W_mae = load('W_data/W_mean_abs_error.csv');
X_lit = load('W_data/W_x_literature.csv');
u_r_w = ri_w   fi_r_w;  % Real unbalance
x = linspace(0,1,11);

```

```
y = 2995.9/sum(Wc(:,3))*sum(Wc(:,2)); % Max capacity 2012

%       Constants
msd_down = 23.1;
msd_up = 168.5;
PUN = 100;

% Single pricing fees
M_sp = [min(msd_down,PUN) min(msd_down,PUN);
        max(msd_up,PUN)   max(msd_up,PUN)]; % Excess; lack
% Dual pricing fees
M_dp = [min(msd_down,PUN) PUN;
        PUN max(msd_up,PUN)];

% New price fees
np = load('NP.csv');
M_np = [np(1) np(1); np(2) np(2)];

FI_PV = sum(fi_pv,2);
RI_W = sum(ri_w,2); % Zonal wind real injections


%       Matrix and vector creation
u_pv_11 = zeros(length(dv_pv),length(x));
u_pv_12 = zeros(size(u_pv_11));
u_pv_21 = zeros(size(u_pv_11));
u_pv_22 = zeros(size(u_pv_11));

u_pv_a_11 = zeros(length(dv_pv),length(x));
u_pv_a_12 = zeros(size(u_pv_11));
u_pv_a_21 = zeros(size(u_pv_11));
u_pv_a_22 = zeros(size(u_pv_11));

u_w_11 = zeros(size(u_pv_11));
u_w_12 = zeros(size(u_pv_11));
u_w_21 = zeros(size(u_pv_11));
u_w_22 = zeros(size(u_pv_11));

u_w_a_11 = zeros(size(u_pv_11));
u_w_a_12 = zeros(size(u_pv_11));
u_w_a_21 = zeros(size(u_pv_11));
u_w_a_22 = zeros(size(u_pv_11));

DP = zeros(size(u_pv_11));
SP = zeros(size(u_pv_11));
s_dp = zeros(size(u_pv_11));
s_sp = zeros(size(u_pv_11));

DP_a = zeros(size(u_pv_11));
SP_a = zeros(size(u_pv_11));
s_dp_a = zeros(size(u_pv_11));
s_sp_a = zeros(size(u_pv_11));

U_res = zeros(size(u_pv_11));
U_res_pv = zeros(size(u_pv_11));
U_res_w = zeros(size(u_pv_11));
```

```
U_res_a = zeros(size(u_pv_11));

s_sp_pv = zeros(size(dv_pv));
s_dp_pv = zeros(size(dv_pv));
s_sp_w = zeros(size(x));
s_dp_w = zeros(size(x));

sp_pv = zeros(size(dv_pv));
dp_pv = zeros(size(dv_pv));
sp_w = zeros(size(x));
dp_w = zeros(size(x));

s_sp_pv_a = zeros(size(dv_pv));
s_dp_pv_a = zeros(size(dv_pv));
s_sp_w_a = zeros(size(x));
s_dp_w_a = zeros(size(x));

sp_pv_a = zeros(size(dv_pv));
dp_pv_a = zeros(size(dv_pv));
sp_w_a = zeros(size(x));
dp_w_a = zeros(size(x));

CT = zeros(size(u_pv_11));
s_ct = zeros(size(u_pv_11));
s_ct1 = zeros(size(dv_pv));
ct1 = zeros(size(dv_pv));
s_ct2 = zeros(size(x));
ct2 = zeros(size(x));

R_trad = zeros(size(u_pv_11));
R_trad_pv = zeros(size(u_pv_11));
R_trad_w = zeros(size(u_pv_11));

er_pv = zeros(size(dv_pv));
er_w = zeros(size(x));

V_pv_w_11 = zeros(size(u_pv_11));
V_pv_w_12 = zeros(size(u_pv_11));
V_pv_w_21 = zeros(size(u_pv_11));
V_pv_w_22 = zeros(size(u_pv_11));

m_u_pv = zeros(size(u_pv_11));
m_u_w = zeros(size(u_pv_11));


for i = 1:length(dv_pv)
    % PV real injections (for the different deviations)
    ri_pv = load(['PV_data/RI_PV_dev' num2str(dv_pv(i)) '.csv']);
    fi_pv = fi_pv*sum(sum(ri_pv))/sum(sum(fi_pv));  % Forecast injections
    %FI_PV = sum(fi_pv,2);
    RI_PV = sum(ri_pv,2);   % PV zonal real injections
    u_pv = ri_pv   fi_pv;
    U_PV = RI_PV   FI_PV;

    for j = 1:length(x)
        % Wind forecasted injections (with correction factor)
```

```
        fi_w = fi_r_w + x(j)*u_r_w; % Nodal forecast
        FI_W = sum(fi_w,2); % Zonal forecast
        % Wind unbalance
        u_w = ri_w   fi_w;  % Wind nodal unbalance
        U_W = RI_W   FI_W;  % Wind zonal unbalance

        % Sicilian zonal unbalance
        U_z = U_PV + U_W + U_L; % Zonal unbalance
        z1 = (U_z > 0); % Energy excess
        z2 = (U_z < 0); % Energy lack

        %           Unbalance
        % PV
        % Energy in excess
        p1_pv = (u_pv > 0);

        % Energy is lacking
        p2_pv = (u_pv < 0);

        e_11 = repmat(z1,1,9) + p1_pv;
        e_11(e_11 < 2) = 0;
        e_11 = e_11/2;

        e_12 = repmat(z1,1,9) + p2_pv;
        e_12(e_12 < 2) = 0;
        e_12 = e_12/2;

        e_21 = repmat(z2,1,9) + p1_pv;
        e_21(e_21 < 2) = 0;
        e_21 = e_21/2;

        e_22 = repmat(z2,1,9) + p2_pv;
        e_22(e_22 < 2) = 0;
        e_22 = e_22/2;

        u_pv_11(i,j) = sum(sum(e_11.*u_pv));
        u_pv_12(i,j) = sum(sum(e_12.*u_pv));
        u_pv_21(i,j) = sum(sum(e_21.*u_pv));
        u_pv_22(i,j) = sum(sum(e_22.*u_pv));

        M_u_pv = [u_pv_11(i,j), u_pv_12(i,j);
                 u_pv_21(i,j), u_pv_22(i,j)]; %PV unbalance

        m_u_pv(i,j) = sum(abs(M_u_pv(:)));

        % Wind
        % Energy in excess
        p1_w = (u_w > 0);

        % Energy is lacking
        p2_w = (u_w < 0);

        ew_11 = repmat(z1,1,9) + p1_w;
        ew_11(ew_11 < 2) = 0;
        ew_11 = ew_11/2;
```

```
        ew_12 = repmat(z1,1,9) + p2_w;
        ew_12(ew_12 < 2) = 0;
        ew_12 = ew_12/2;

        ew_21 = repmat(z2,1,9) + p1_w;
        ew_21(ew_21 < 2) = 0;
        ew_21 = ew_21/2;

        ew_22 = repmat(z2,1,9) + p2_w;
        ew_22(ew_22 < 2) = 0;
        ew_22 = ew_22/2;

        u_w_11(i,j) = sum(sum(ew_11.*u_w));
        u_w_12(i,j) = sum(sum(ew_12.*u_w));
        u_w_21(i,j) = sum(sum(ew_21.*u_w));
        u_w_22(i,j) = sum(sum(ew_22.*u_w));

        M_u_w = [u_w_11(i,j), u_w_12(i,j);
                 u_w_21(i,j), u_w_22(i,j)]; %Wind unbalance

        m_u_w(i,j) = sum(abs(M_u_w(:)));

        % Allowance
        %        Single and Dual pricing with 10 or 20% allowance

        a = 0.2;    % 10% or 20% allowance used

        % PV
        % Allowance condition
        a_pv = (abs(u_pv)./fi_pv > a);

        a_11 = e_11 + a_pv;
        a_11(a_11 < 2) = 0;
        a_11 = a_11/2;

        a_12 = e_12 + a_pv;
        a_12(a_12 < 2) = 0;
        a_12 = a_12/2;

        a_21 = e_21 + a_pv;
        a_21(a_21 < 2) = 0;
        a_21 = a_21/2;

        a_22 = e_22 + a_pv;
        a_22(a_22 < 2) = 0;
        a_22 = a_22/2;

        u_pv_a_11(i,j) = sum(sum((a_11 a*a_11).*u_pv));
        u_pv_a_12(i,j) = sum(sum((a_12 a*a_12).*u_pv));
        u_pv_a_21(i,j) = sum(sum((a_21 a*a_21).*u_pv));
        u_pv_a_22(i,j) = sum(sum((a_22 a*a_22).*u_pv));

        M_u_pv_a = [u_pv_a_11(i,j), u_pv_a_12(i,j);
                 u_pv_a_21(i,j), u_pv_a_22(i,j)];   % PV unbalance with ...
                     allow

```

```
        % Wind
        % PV
        % Allowance condition
        w_a = .2;
        a_w = (abs(u_w)./fi_w > w_a);

        aw_11 = ew_11 + a_w;
        aw_11(aw_11 < 2) = 0;
        aw_11 = aw_11/2;

        aw_12 = ew_12 + a_w;
        aw_12(aw_12 < 2) = 0;
        aw_12 = aw_12/2;

        aw_21 = ew_21 + a_w;
        aw_21(aw_21 < 2) = 0;
        aw_21 = aw_21/2;

        aw_22 = ew_22 + a_w;
        aw_22(aw_22 < 2) = 0;
        aw_22 = aw_22/2;

        u_w_a_11(i,j) = sum(sum((aw_11  w_a*aw_11).*u_w));
        u_w_a_12(i,j) = sum(sum((aw_12  w_a*aw_12).*u_w));
        u_w_a_21(i,j) = sum(sum((aw_21  w_a*aw_21).*u_w));
        u_w_a_22(i,j) = sum(sum((aw_22  w_a*aw_22).*u_w));

        M_u_w_a = [u_w_a_11(i,j), u_w_a_12(i,j);
                 u_w_a_21(i,j), u_w_a_22(i,j)]; % Wind unbalance with allow

        U_res(i,j) = sum(sum(abs(M_u_pv+M_u_w)));   % Total zonal unbalance
        U_res_pv(i,j) = sum(sum(abs(M_u_pv)));  % Total PV zonal unbalance
        U_res_w(i,j) = sum(sum(abs(M_u_w)));    % Total wind zonal unbalance

        %      Single Price
        SP_PV = M_sp.* M_u_pv;
        SP_W = M_sp.* M_u_w;
        SP(i,j) = sum(SP_PV(:)) + sum(SP_W(:));
        s_sp(i,j) =  SP(i,j)/sum(sum((ri_pv+ri_w)));% Specific sp

        %      Single Price with allowance
        SP_PV_a = M_sp.* M_u_pv_a;
        SP_W_a = M_sp.* M_u_w_a;
        SP_a(i,j) = sum(SP_PV_a(:)) + sum(SP_W_a(:));
        s_sp_a(i,j) =  SP_a(i,j)/sum(sum((ri_pv+ri_w)));% Specific sp

        %      Dual Pricing
        DP_PV = M_dp.* M_u_pv;
        DP_W = M_dp.* M_u_w;
        DP(i,j) = sum(DP_PV(:)) + sum(DP_W(:));
        s_dp(i,j) =  DP(i,j)/sum(sum((ri_pv+ri_w)));% Specific dp

        V_pv_w_11(i,j) = M_u_pv(1,1) + M_u_w(1,1);
        V_pv_w_12(i,j) = M_u_pv(1,2) + M_u_w(1,2);
        V_pv_w_21(i,j) = M_u_pv(2,1) + M_u_w(2,1);
        V_pv_w_22(i,j) = M_u_pv(2,2) + M_u_w(2,2);
```

```

        %       Dual Pricing allowance
        DP_PV_a = M_dp.* M_u_pv_a;
        DP_W_a = M_dp.* M_u_w_a;
        DP_a(i,j) = sum(DP_PV_a(:)) + sum(DP_W_a(:));
        s_dp_a(i,j) =  DP_a(i,j)/sum(sum((ri_pv+ri_w)));% Specific dp

        %       New Price mechanism
        NP_PV = M_np.* M_u_pv;
        NP_W = M_np.* M_u_w;
        NP(i,j) = sum(NP_PV(:)) + sum(NP_W(:));
        s_np(i,j) =  NP(i,j)/sum(sum((ri_pv+ri_w)));% Specific dp

        %       Cost Terna
        % Cost cope by Terna
        U_T1 = (U_PV + U_W).*z1;  % Energy is in excess
        U_T2 = (U_PV + U_W).*z2;  % Energy is lacking

        M_u_t(1,1) = sum(U_T1(U_T1>0));
        M_u_t(1,2) = sum(U_T1(U_T1<0));
        M_u_t(2,1) = sum(U_T2(U_T2>0));
        M_u_t(2,2) = sum(U_T2(U_T2<0));

        % Balancing market cost
        R_trad(i,j) = abs(diag(M_u_t))'*[msd_down; msd_up];
        R_trad_pv(i,j) = R_trad(i,j)*sum(abs(U_PV))/sum(abs(U_PV)+abs(U_W));
        R_trad_w(i,j) = R_trad(i,j)   R_trad_pv(i,j);

        % Terna's cost for single price with allowance
        C_T = SP_a(i,j) + R_trad(i,j);%M_u_t.*M_dp;
        CT(i,j) = C_T(:);
        s_ct(i,j) =  CT(i,j)/(sum(RI_PV)+sum(RI_W));

        if x(j) == 1    % No wind unbalance
            dp_pv(i) =  sum(sum(DP_PV));
            sp_pv(i) =  sum(sum(SP_PV));
            s_dp_pv(i) = dp_pv(i)/sum(sum(ri_pv));% Specific dp PV
            s_sp_pv(i) = sp_pv(i)/sum(sum(ri_pv));% Specific sp PV
            % allowance
            dp_pv_a(i) =  sum(sum(DP_PV_a));
            sp_pv_a(i) =  sum(sum(SP_PV_a));
            s_dp_pv_a(i) = dp_pv_a(i)/sum(sum(ri_pv));% Specific dp PV
            s_sp_pv_a(i) = sp_pv_a(i)/sum(sum(ri_pv));% Specific sp PV
            % Terna
            ct1(i) = CT(i,j);
            s_ct1(i) = s_ct(i,j);

            er_pv(i) = mean(abs(ri_pv(fi_pv>0)  fi_pv(fi_pv>0)))/...
                mean(ri_pv(fi_pv>0));
        end
        if dv_pv(i) == 0     % No PV unbalance
            dp_w(j) =  sum(sum(DP_W));
            sp_w(j) =  sum(sum(SP_W));
            s_dp_w(j) =  dp_w(j)/sum(sum(ri_w));% Specific dp PV
            s_sp_w(j) =  sp_w(j)/sum(sum(ri_w));% Specific sp PV
            %s_np_w(j) =   sum(sum(NP_W))/sum(sum(ri_w));% Specific sp PV
```

```
            % allowance
            dp_w_a(j) =  sum(sum(DP_W_a));
            sp_w_a(j) =  sum(sum(SP_W_a));
            s_dp_w_a(j) =  dp_w_a(j)/sum(sum(ri_w));% Specific dp PV
            s_sp_w_a(j) =  sp_w_a(j)/sum(sum(ri_w));% Specific sp PV
            % Terna
            s_ct2(j) = s_ct(i,j);
            ct2(j) = CT(i,j);

            er_w(j) = mean(sum(abs(ri_w fi_w)/length(ri_w))./(Wc(:,2)'));
        end

    end
end

% Write to file
dlmwrite('Cost_Terna.csv', CT)  % TERNA's cost
dlmwrite('Accuracy_PV.csv', RMSE) % PV RMSE error
dlmwrite('Accuracy_W.csv', er_w)    % Wind MAE error
dlmwrite('U_T_11.csv', V_pv_w_11)   % Total zonal unbalance +,+
dlmwrite('U_T_12.csv', V_pv_w_12)   % +,
dlmwrite('U_T_21.csv', V_pv_w_21)   %  ,+
dlmwrite('U_T_22.csv', V_pv_w_22)   %  ,

% Interest zone for the different scenarios
sq = [1 X_lit(end 2), dv_pv2(end 2), X_lit(end 2) X_lit(end 1),...
    dv_pv2(end) dv_pv2(end 3)]; % Original scenario
sq2 = [1 X_lit(end 3), dv_pv2(end 3), X_lit(end 2) X_lit(end 1),...
    dv_pv2(end) dv_pv2(end 3)]; % Optimistic scenario
sq3 = [1 X_lit(end 1), dv_pv2(end 1), X_lit(end 2) X_lit(end 1),...
    dv_pv2(end) dv_pv2(end 3)]; % Conservative scenario

% Interest zone for the original scenario
x_lit = [X_lit(6) X_lit(7)];
dv_pv3 = [dv_pv2(6) 2*dv_pv2(end) dv_pv2(end 3)];

%     Gate closure values
% Specific unbalance cost
V_u_pv = interp2(1 x,dv_pv,m_u_pv,1 X_lit,dv_pv2);
V_u_w = interp2(1 x,dv_pv,m_u_w,1 X_lit,dv_pv2);

% Specific unbalance cost
V_s_dp = interp2(1 x,dv_pv,s_dp,1 X_lit,dv_pv2);
V_s_dp_a = interp2(1 x,dv_pv,s_dp_a,1 X_lit,dv_pv2);
V_s_sp = interp2(1 x,dv_pv,s_sp,1 X_lit,dv_pv2);
V_s_sp_a = interp2(1 x,dv_pv,s_sp_a,1 X_lit,dv_pv2);
V_s_ct = interp2(1 x,dv_pv,s_ct,1 X_lit,dv_pv2);
V_s_np = interp2(1 x,dv_pv,s_np,1 X_lit,dv_pv2);

% Unbalance cost
V_dp = interp2(1 x,dv_pv,DP,1 X_lit,dv_pv2);
V_dp_a = interp2(1 x,dv_pv,DP_a,1 X_lit,dv_pv2);
V_sp = interp2(1 x,dv_pv,SP,1 X_lit,dv_pv2);
V_sp_a = interp2(1 x,dv_pv,SP_a,1 X_lit,dv_pv2);
V_ct = interp2(1 x,dv_pv,CT,1 X_lit,dv_pv2);
V_np = interp2(1 x,dv_pv,NP,1 X_lit,dv_pv2);
```

```

% Single total unbalance
V_res_pv = interp2(1 x,dv_pv,U_res_pv,1 X_lit,dv_pv2);
V_res_w = interp2(1 x,dv_pv,U_res_w,1 X_lit,dv_pv2);
V_trad = interp2(1 x,dv_pv,R_trad,1 X_lit,dv_pv2);
V_trad_pv = interp2(1 x,dv_pv,R_trad_pv,1 X_lit,dv_pv2);
V_trad_w = interp2(1 x,dv_pv,R_trad_w,1 X_lit,dv_pv2);

% Optimistic scenario
X_sc2 = [X_lit(5) X_lit(5) (X_lit(6) X_lit(7))];
Y_sc2 = [dv_pv2(5) dv_pv2(5)];

% Conservative scenario
X_sc3 = [ X_lit(5)+2*X_lit(6)  X_lit(5)+2*X_lit(6) (X_lit(6) X_lit(7))];
Y_sc3 = 2*dv_pv2(6) dv_pv2(5)*[1 1];

% Gate closrue values for the different scenarios
V_dp2 = interp2(1 x,dv_pv,DP,1 [X_sc2, X_sc3],[Y_sc2, Y_sc3]);
V_dp2_a = interp2(1 x,dv_pv,DP_a,1 [X_sc2, X_sc3],[Y_sc2, Y_sc3]);
V_sp2 = interp2(1 x,dv_pv,SP,1 [X_sc2, X_sc3],[Y_sc2, Y_sc3]);
V_sp2_a = interp2(1 x,dv_pv,SP_a,1 [X_sc2, X_sc3],[Y_sc2, Y_sc3]);
V_ct2 = interp2(1 x,dv_pv,CT,1 [X_sc2, X_sc3],[Y_sc2, Y_sc3]);
V_res_pv2 = interp2(1 x,dv_pv,U_res_pv,1 [X_sc2, X_sc3],[Y_sc2, Y_sc3]);
V_res_w2 = interp2(1 x,dv_pv,U_res_w,1 [X_sc2, X_sc3],[Y_sc2, Y_sc3]);
V_trad2 = interp2(1 x,dv_pv,R_trad,1 [X_sc2, X_sc3],[Y_sc2, Y_sc3]);
V_trad_pv2 = interp2(1 x,dv_pv,R_trad_pv,1 [X_sc2, X_sc3],[Y_sc2, Y_sc3]);
V_trad_w2 = interp2(1 x,dv_pv,R_trad_w,1 [X_sc2, X_sc3],[Y_sc2, Y_sc3]);

% Results plotting
figure  % Figure: Revenue from single price with allowance
contourf(1 x,dv_pv, SP_a/1e6,10)
colorbar
title('Single price cost with 20% allowance [MEuro / y]','FontSize',14)
xlabel('1 X_W','FontSize',14)
ylabel('PV deviation [%]','FontSize',14)
set(gcf,'Color',[1,1,1])
set(gca,'fontsize',12)
hold on
h = text(.98 [X_lit(1),X_lit(2),X_lit(3),X_lit(4) .1,X_lit(5)],...
    [dv_pv2(1),dv_pv2(2),dv_pv2(3),dv_pv2(4),dv_pv2(5)],...
    ['1 h';'2 h';'3 h';'4 h';'5 h'],...
    'FontSize',12,'HorizontalAlignment','right');
set(h,'BackgroundColor',[1 1 1])
h = text(1 X_lit(7),dv_pv2(7) 0.02,'   6 21 24 ...
    h','FontSize',12,'HorizontalAlignment','center');
set(h,'BackgroundColor',[1 1 1])
h = ...
    text(0.92,dv_pv2(5)+.03,'Original','FontSize',12,'HorizontalAlignment','center');
set(h,'BackgroundColor',[1 1 1])
plot(1 [X_lit, 0],[dv_pv2, dv_pv2(5)+.03],'.k', 'MarkerSize', 10)

figure  % Figure: TERNA's cost estimated with SP with allowance
contourf(1 x,dv_pv,CT/1e6,10)
colorbar
title('TERNAs cost [MEuro / y]','FontSize',14)
xlabel('1 X_W','FontSize',14)
```

```
ylabel('PV deviation [%]','FontSize',14)
set(gcf,'Color',[1,1,1])
set(gca,'fontsize',12)
hold on
h = text(.98 [X_lit(1),X_lit(2),X_lit(3),X_lit(4) .1,X_lit(5)],...
     [dv_pv2(1),dv_pv2(2),dv_pv2(3),dv_pv2(4),dv_pv2(5)],...
     ['1 h';'2 h';'3 h';'4 h';'5 h'],...
     'FontSize',12,'HorizontalAlignment','right');
set(h,'BackgroundColor',[1 1 1])
h = text(1 X_lit(7),dv_pv2(7) 0.02,'6 21 24 ...
     h','FontSize',12,'HorizontalAlignment','center');
set(h,'BackgroundColor',[1 1 1])
h = ...
     text(0.92,dv_pv2(5)+.03,'Original','FontSize',12,'HorizontalAlignment','center');
set(h,'BackgroundColor',[1 1 1])
plot(1 [X_lit, 0],[dv_pv2, dv_pv2(5)+.03],'.k', 'MarkerSize', 10)

figure  % Figure: PV cost under no Wind unbalance
plot(dv_pv,sp_pv/1e6,'. ',dv_pv,dp_pv/1e6,'. ',dv_pv,sp_pv_a/1e6,'. ',...
     dv_pv,dp_pv_a/1e6,'. ')
hold on
plot([dv_pv2(1) dv_pv2(1)],[2 10]*1.1*max(ct1),'  ')
plot([dv_pv2(2) dv_pv2(2)],[2 10]*1.1*max(ct1),'  ')
plot([dv_pv2(3) dv_pv2(3)],[2 10]*1.1*max(ct1),'  ')
plot([dv_pv2(4) dv_pv2(4)],[2 10]*1.1*max(ct1),'  ')
plot([dv_pv2(5) dv_pv2(5)],[2 10]*1.1*max(ct1),'  ')
plot([dv_pv2(6) dv_pv2(6)],[2 10]*1.1*max(ct1),'  ')
plot([dv_pv2(7) dv_pv2(7)],[2 10]*1.1*max(ct1),'  ')
plot([dv_pv2(8) dv_pv2(8)],[2 10]*1.1*max(ct1),'  ')
h = text(dv_pv2(1:5),2.5e7/1e6*ones(1,5),['1 h';'2 h';'3 h';'4 h';'5 h'],...
     'FontSize',12,'HorizontalAlignment','center');
set(h,'BackgroundColor',[1 1 1])
h = text(dv_pv2(6),2.5e7/1e6,'    6   24 h',...
     'FontSize',12,'HorizontalAlignment','center');
set(h,'BackgroundColor',[1 1 1])
title('PV plants cost','FontSize',14)
ylim([2 1.1*max(dp_pv/1e6)])
xlim([0 .55])
xlabel('std_P_V','FontSize',14)
ylabel('Million Euro / Year','FontSize',14)
grid on
set(gcf,'Color',[1,1,1])
set(gca,'fontsize',12)
legend('SP','DP','SP 20%','DP 20%',2)

figure % Figure: Wind cost under no PV unbalance
plot(1 x,sp_w/1e6,'. ',1 x,dp_w/1e6,'. ',1 x,sp_w_a/1e6,'. ',1 x,dp_w_a/1e6,...
     '. ')
hold on
plot((1 X_lit(1))*[1 1],[0 15]*1e7,'  ')
plot((1 X_lit(2))*[1 1],[0 15]*1e7,'  ')
plot((1 X_lit(3))*[1 1],[0 15]*1e7,'  ')
plot((1 X_lit(4))*[1 1],[0 15]*1e7,'  ')
plot((1 X_lit(5))*[1 1],[0 15]*1e7,'  ')
plot((1 X_lit(6))*[1 1],[0 15]*1e7,'  ')
plot((1 X_lit(7))*[1 1],[0 15]*1e7,'  ')
```

```
plot((1 X_lit(8))*[1 1],[0 15]*1e7,'  ')
ylim([0 max(dp_w/1e6)*1.1])
ylabel('Million Euro / Year','FontSize',14)
xlabel('1 X_W','FontSize',14)
title('Wind plants cost','FontSize',14)
set(gca,'fontsize',12)
grid on
legend('SP','DP','SP 20%','DP 20%',2)
set(gcf,'Color',[1,1,1])
h = ...
    text([1 X_lit(1) ,1 X_lit(2)],20*[4,4],['1h';'2h'],'FontSize',12,'HorizontalAlignment','c
set(h,'BackgroundColor',[1 1 1])
h = text(1 X_lit(3) .01,85,'3   ...
    6h','FontSize',12,'HorizontalAlignment','left');
set(h,'BackgroundColor',[1 1 1])
h = text(1 X_lit(8),80,'21 ...
    24h','FontSize',12,'HorizontalAlignment','center');
set(h,'BackgroundColor',[1 1 1])

figure  % Figure: Balancing market cost
contourf(1 x,dv_pv,R_trad/1e6,10)
colorbar
title('Balancing market cost [MEuro / y]','FontSize',14)
xlabel('1 X_W','FontSize',14)
ylabel('PV deviation [%]','FontSize',14)
set(gcf,'Color',[1,1,1])
set(gca,'fontsize',12)
hold on
plot(1 X_sc2,Y_sc2,'.b');
plot(1 X_lit(6:7),dv_pv2(6:7),'.k')
plot(1 X_sc3,Y_sc3,'.r')
h = text(1 X_lit(6:7)+[0.1, 0.1],[dv_pv2(6:7)],[' 6h';'21h'],...
    'FontSize',12,'HorizontalAlignment','center');
set(h,'BackgroundColor',[1 1 1])
legend('Cost','Optimistic','Original','Conservative',2)
```