Article

The value of PV power forecast and the paradox of the "single pricing" scheme: the Italian case study

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Abstract: One of the major problem of photovoltaic grid integration is limiting the solar-induced imbalances since these can undermine the security and stability of the electrical system. Improving the forecast accuracy of photovoltaic generation is becoming essential to allow a massive solar penetration. In particular, improving the forecast accuracy of large solar farms generation is important both for the producers/traders to minimize the imbalance costs and for the Transmission System Operators to insure stability. In this article, we provide a benchmark for the day-ahead forecast accuracy of utility scale PV plants in 1325 locations spanning the country of Italy. We then use these benchmarked forecasts and real energy prices to compute the economic value of forecast accuracy and accuracy improvement in the context of the Italian energy market regulatory framework. Through this study, we further point out some several important criticisms of the Italian "single pricing" system that brings to paradoxical and counterproductive effects regarding the need to reduce the imbalance volumes. Finally, we propose a new market-pricing rule and innovative actions to overcome these undesired effects of the current dispatching regulations.

Keywords: Photovoltaic power forecast, energy markets, solar imbalance.

1. Introduction

In Italy, in 20 years, the electric mix evolved from 20% to 35% worth of renewable energy (RE) generation and in only 10 years, solar became the second RE source after Hydropower (Figure 1a). According to the 2030 climate & energy framework, adopted by the European Council in October 2014, the Italian National Energy Strategy (SEN) [1] and the Integrated National Plan for Energy and Climate (PNEC or PNIEC)[1] [2] prescribe 55% of the electricity demand to come from RE sources and define how this target can be reached in Italy (Figure 1a). Solar and wind are the two RE technologies with enough growth potential to achieve this objective: under this protocol, solar generation should increase from the current 24.4 TWh/yr to 74.5 TWh/yr and wind from 17.2 TWh/yr to 40 TWh/yr (Figure 1b). Therefore, by 2030, solar will become the first Italian RE source and the PV energy penetration (i.e. the fraction of annual demand covered by solar generation), which is already one of the highest in Europe [3] and the third in the word [4], will increase from 8% to 22%.

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[1] Both the acronyms can be found in literature
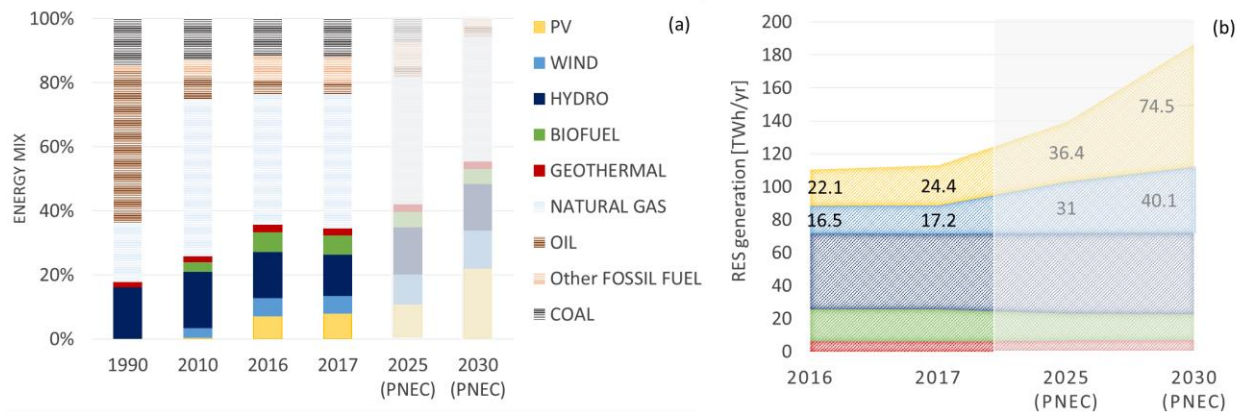
Figure 1. Evolution and PNEC scenario of the Italian energy mix (a); PNEC scenario for RES generation (b) (elaboration from [2, 5]).

Nevertheless, large share of photovoltaic generation imposes new challenge for the national energy system. One of the major problems related to PV grid integration is the increase of the imbalances between supply and demand due to the intrinsic solar intermittency and stochastic variability. Indeed, since PV generation is not programmable and if distributed mainly locally produced/consumed, the supply of programmable energy sources needed to fulfil the residual electric demand becomes much more difficult to predict. As result, the growth of the PV penetration will increase dramatically the solar-induced imbalances and a higher amount of flexible and dispatchable capacity (reserves) would have to be held to ensure the security and stability of the national grid.

Figure 2 shows an example of the impact of the forecast errors on the imbalance and the energy volumes that must be exchanged on the Balancing Energy Market (BEM) to resolve this imbalance. In this case, a clear sky day was erroneously predicted so that the Italian TSO had to purchase on BEM a remarkable amount of energy for upward regulation to compensate this under prediction.
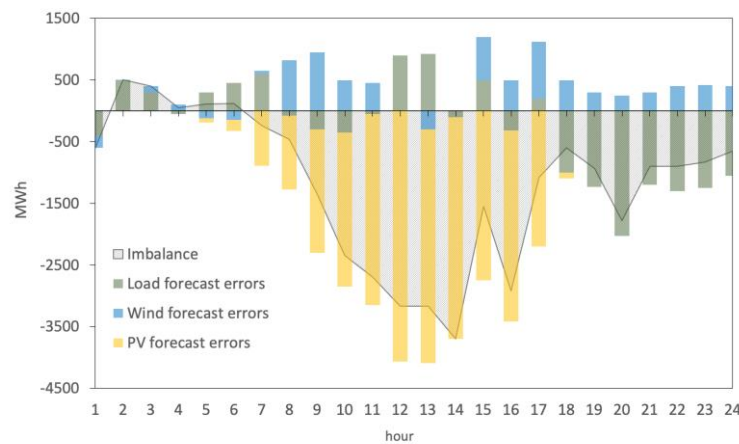
Figure 2. Load, PV and wind day-ahead forecast errors and the resulting system imbalance during a day of August 2015 in Italy. Source: the Italian TSO (Terna) [6].

For this reason, the PNEC explicitly states that, with the achievement of the 2030 VRES objectives, "*the high quantity of non-programmable renewable sources will force to keep available a significant portion of thermoelectric generation capacity, in order to guarantee the necessary reserve margins for the safe operation of the system*".

In Italy, there is only one TSO (Terna Spa) that manages the 72,900 km of transmission grid. Terna is the largest transmission system operator in Europe and is in charge of the security and the stability of the national transmission grid. Currently, only large photovoltaic producers that manage

plant with a capacity greater or equal to 10 MW have to deliver their day-ahead power forecast to Terna and, according to the "single pricing" rule, are subject to penalties for the imbalance between their real and scheduled generation. In contrast, Terna manages the remaining distributed PV [customer-sited] plants in an aggregate manner and the imbalance costs are borne to ratepayers. Even if, nowadays, the majority of the solar generation comes from the distribute PV fleet, the improvement of the forecast accuracy of large solar farms it is important for two main reasons:

1. The objective of the PNIEC by 2030 will inevitably require to increase the capacity of utility scale PV plants with respect to the distributed one and in fact, we have now tenders to cover this part although at the moment only wind projects are presented to problems in getting building permits for PV plants;

2. To predict the day-ahead supply and reserves, Terna need to forecast the whole Italian PV generation. The forecast model is strongly based on the large plant generation scheduling: "*Terna receives the forecast from several external suppliers, subject to a pre-qualification process and continuous performance monitoring, who make their own forecasts … Before the execution of each sub-stage of the planning phase, the individual forecasts are then processed, together with the final photovoltaic production … by a statistical algorithm of "meta-forecasting", which provides the best combination of the different forecasts, in order to minimize the overall forecast error*" [7].

Therefore, in order to achieve the 2030 solar generation target, it is necessary not only to implement policies to promote a rapid increase of photovoltaic installations (centralized and distributed) but also to ensure proper economic incentives to improve the forecast accuracy of the generation of large photovoltaic farms.

The first aim of this work is to benchmark the forecast accuracy of the generations of large PV farms, their related imbalance values and the value of the accuracy improvement in 1325 locations all over Italy. The second aim is to assess the effectiveness of the current energy market framework to boost large solar producers/traders to increase the performance of their forecast and hence to reduce their solar-induced imbalances. Therefore, this study is important, not only for the owners of solar farms to understand the value of accurate solar predictions but also for the Italian TSO and policy makers (Italian Authority for Energy/Minister of Economic Development) to understand the limits of the current energy market regulation framework.

The paper is organized as following:

- In section 2, we report the novelty of work with respect to the existing literature;
- In section 3, we summarize the main features of the Italian energy market and of the solar imbalance regulation framework;
- In section 4, we present the satellite and numerical weather prediction data employed to estimate and forecast the generation of utility scale PV plants all over Italy.
- In section 5, we describe the methodology used to carry out our study;
- In section 6, we report the main accuracy and economic metrics used to assess the forecast performance and its related imbalance economic value for large solar producers/traders;
- In section 7, we discuss the results emerging from our investigation. We show the forecast accuracy of the photovoltaic generation of utility scale solar plants on 1325 locations in Italy and we compute the imbalance values of their forecasts. These values are compared with the one obtained with a baseline forecast to evaluate also the economic advantage of forecast accuracy improvements.
- In section 8, we suggest a possible market regulation revision.
- In section 9, conclusions are reported.

2. Existing literature and novelty of the work

In the last years several works have centered on assessing the value of PV power forecasting and forecast accuracy improvement both from the point of view of transmission and distribution systems operators (regional fleet forecasts) and from producers/traders point of view (single plant forecasts).

Zhang et al. [8] studied the economic benefits of improving the forecast accuracy of the regional solar generation for the Independent System Operator–New England (ISO-NE) and for the California–ISO (CAISO). They found that, according to the local balancing energy markets (BEMs), with more accurate forecast the two different ISO can achieve 25% of reserve costs reduction. Brancucci et al. [9] analyzed the costs for ISO-NE under multipole aspects: operational electricity generation, electricity generation from the fast start and lower efficiency power plants, ramping of all generators, start and shutdown costs, and solar power curtailment. From this analysis, they derived the economic impact of solar power generation at different grid penetration and the values of forecast accuracy improvement. Wu et al. [10] estimated the economic impact on energy reserves of wind and solar uncertainty and variability for the Arizona Public Service Company utility in the southwestern United States. Joos at al. [11] analyzed wind and solar integration costs due to grid congestion management and balancing for Germany and the UK. Joos et al. also investigated possible reforms in balancing systems in both countries than can lead to an imbalance costs reduction.

Pierro et al. in [12, 13] evaluate the energy and economic benefit for a local distribution system operator in the north of Italy in improving their TSO transmission scheduling and reducing the reserves by the use of accurate probabilistic PV generation forecast. In [14], Pierro et al. extend these studies to the Italian national scale, proposing an innovative strategy to reduce the imbalance and its related costs. The authors, first, assess the value of improving PV power prediction accuracy by the use of "state of the art" forecast models and the enlargement of the forecast-controlled area. Afterward, they propose the use of a new kind of solar systems, called 'flexible' PV plants, able to provide dispatching services for solar-induced imbalance regulation by proactive curtailment and battery storage additional power. These studies [12, 13, 14] were conducted considering current and future solar penetration at regional and national levels. Perez et al. [15, 16] showed how flexible plants can be used at first to provide a "perfect forecast" removing the prediction uncertainty and then to provide a full dispatchable, firm PV generation 24/365 removing solar intermittency, for several US states. The costs of turning all the PV fleet into flexible systems depend essentially on the size of the battery energy storage systems and will be economically affordable in the near future. Fonseca et al. [17] explored the advantages of a perfect forecast instead of a simple day-ahead forecast to limit PV curtailment in Japan. However, their perfect forecast was purely theoretical (using actual production data in lieu of forecasts) so that neither the capacity nor the cost of BESS were considered.

At single site level, Kaur et al. in [18], quantified the forecast value for the owner of a one MW PV farm in the Western Interconnection dispatch energy mark. [19] and [20] reported the imbalance costs or revenues that can be achieved by the Italian "single pricing" rule by the owners of a 960 kWp PV and 3.6 MW wind farms. Nevertheless, in [19], De Giorgi, et al. assumed the energy markets prices to be constant during the year; therefore the resulting economic evaluation is rather limited. In [20], Bignucolo et al. focused their attention more on the benefit of using battery energy storage systems to reduce wind imbalance and maximize the revenues on the dispatching market. It is worth noting that, in [15], Perez et al. also evaluate the value of "perfect forecast" achievable by pro-active curtailment and battery energy storage at PV site level in climatically distinct individual US locations. Furthermore, the authors analyzed the differences between the standard accuracy metric and a new operational metric that quantifies the lowest cost of operationally achieving "perfect forecasts".

Antonanzas et al. [21], analyzed the imbalance economic valorization and the values of forecast improvement of a 1.86 MWp PV plant derived from the "dual pricing" rule on the Iberian balancing energy market. The authors used different PV power forecast methods, and as in [15], they pointed out the discrepancies between the standard accuracy metrics and economic metric for choosing the best prediction method.

Finally, a comparison between the "single pricing" and the "dual pricing" mechanisms in the Italian market zone of Sicily, can be found in [22]. Even if many simplified assumptions are assumed

and a simple forecast model is used, the relative comparison between the imbalance costs achievable by the two market rules can be considered an interesting result.

First, unlike the works [8]- [17], the present study is addressed to quantify the forecast accuracy and its economic value for PV producers/traders that manage utility scale PV farms. However, the reported results are important both for the Italian TSO and for the Italian Authority for Energy/Minister of Economic Development in charge of the energy market regulation framework. Moreover, differently from [15, 20], we consider the imbalance only of traditional solar farms that do not make use of any battery energy storage.

The first novelty of this work is to provide an accurate benchmark of the day-ahead PV power imbalance (forecast accuracy) and of its related cost on the energy market all over Italy with a resolution of 12x12 km. As far as the authors know, this kind of study is novel and does not exist for any country in Europe.

While, in [22] the impact of "single" and "dual" pricing mechanism on the PV imbalance costs are analyzed, in this paper we consider only the current "single" pricing market role. In contrast, our results are much more reliable since we use accurate forecast method and real hourly market prices of the periods 2014-2016.

Among the cited works, the one of Antonanzas et al. [21] presents more similarities to our investigation. In [21], the authors assess the values of different forecast methods while we test just one PV prediction model. In contrast, they performed their study on a single location and for a small period (half year), while we conduct the analysis on 1325 different locations for tree different years (2014-2016). Therefore, our results not only are more statistically meaningful but also allow pointing out more critical features of the current markets regulatory framework: the second major contribution of the study.

3. Spot market structure and imbalance regulatory framework for production units in Italy

3.1. Spot market structure

To ensure the security of the Italian electricity system, the 20 Italian regions have been aggregated into six areas defined by physical energy transit limits of the national transition grid [23]: North (NORD); Center-North (CNOR); Center-South (CSUD); South (SUD); Sicily (SICI) and Sardinia (SARD) (Figure 3). These areas each feature a spot energy market in which most of the energy needed to fulfill the national demand is exchanged.

The spot market is organized into tree main energy submarkets: day-ahead market (DAM), intra-day market (IDM) and balancing energy market (BEM). The BEM is divided in two: the market of the dispatching services (MSD ex-ante) and the real time balancing market (BM). Each submarket is characterized by different functions, gate open/closure time, number of sections, and different energy price formation rules.

- The DAM is the place of negotiation of the bulk supply/purchase electricity bids for each hour of the delivery day. All electrical operators can participate in the DAM. The bids are accepted by the Italian Energy Services Manager (GME) according to the "Merit Order" rule that will define the energy price i.e. the equilibrium price between supply/purchase bids. If accepted, the energy of the supply bid is remunerated at the zonal price (P_Z^{DA}) while the energy of the purchased bid at the single national price (PUN). The PUN is the average zonal price weighted over the relative amount of exchanged energy. Accepted bids determine the preliminary scheduling for the energy supply and withdrawal of each grid connection point for the day of delivery. The zonal prices depend on the transit capacity limits between the market zones according to the Italian TSO (Terna) requirement [24].

- The IDM is the place of negotiation of the supply/purchase electricity exchange for each hour of the current day, with the purpose of adjusting the injection/withdrawal scheduling defined by the DA market.

- The BEM is the place of negotiation of bids for the supply/purchase of dispatching services, used by Terna for the resolution of intra-zonal congestions, for the supply of the reserves and for the

balancing in real time between demand/supply. BEM is divided in two: the market of the dispatching service (MSD ex-ante) and the real time balancing market (MB). On MSD ex-ante, Terna defines the reserves margin and acquires/sells the energy needed to compensate the day-ahead imbalance and to resolve congestions. On MB, Terna acquires/sells in real time (by sending dispatching orders) the energy needed to correct the imbalance due to unpredictable events or errors in the reserve estimation.

On the BEM, Terna acquires/sell dispatchable energy following the "Pay as Bid" role i.e. bids are accepted based on simple economic merit. On the balancing energy market, two different prices appear: an upward regulation price ($P_Z^{B\uparrow}$) in case of less supply than predicted (negative zonal imbalance) and a downward regulation price ($P_Z^{B\downarrow}$) in case of more supply than predicted (positive zonal imbalance). The first price is equal or higher than the DA price with no upper limit while the second is equal or lower than the DA price with zero as lower limit These energy prices are the average zonal prices of the accepted bids weighted with the corresponding exchanged energy and they are defined ex-post the day after the day of balancing energy delivering [24].
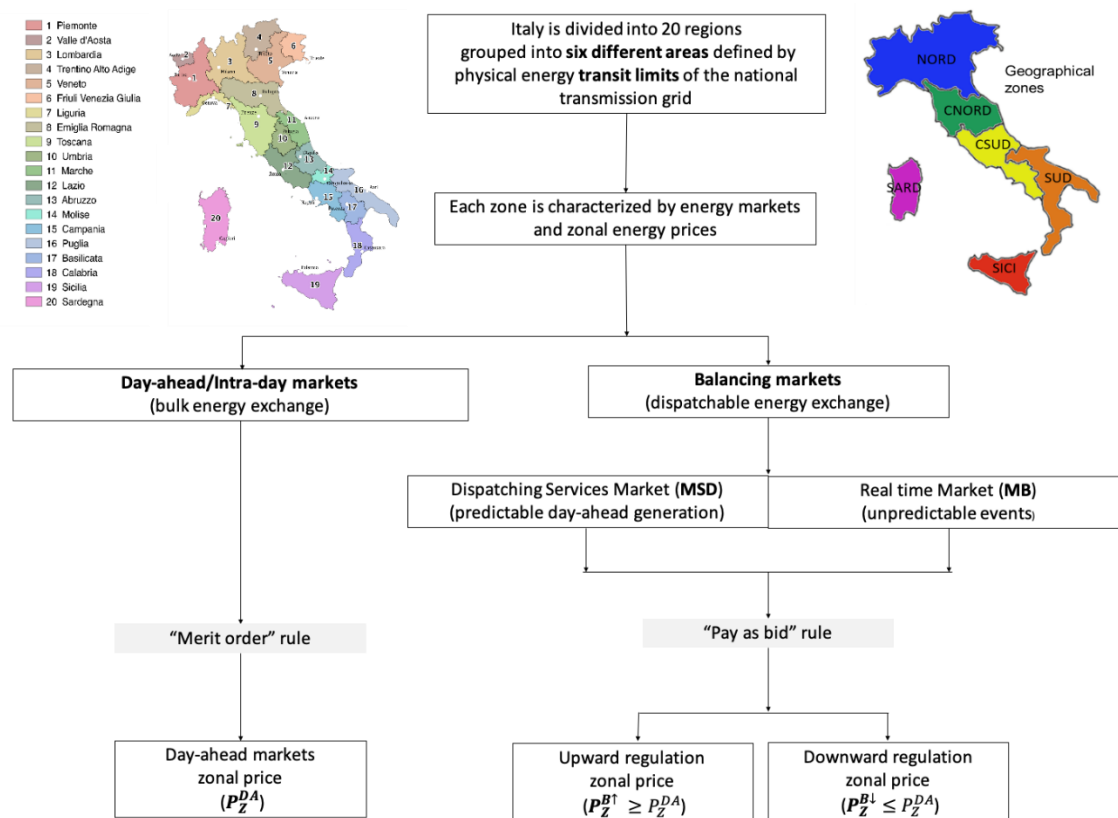

Figure 3. Spot markets in Italy.

3.2 Production unit imbalance and economic valorization on MSD

According to the regulatory framework 281/2012/R/efr, 525/2014/R/EEL, 419/2017/R/eel of the Italian Authority for Electricity and Gas and the dispatch guidelines of Terna [25], the production units (UP) are divided into: relevant or non-relevant. The relevant UP are single plants or aggregated plants of the same type in a given zone (virtual production units) with a total capacity greater than 10 MW.

Only "relevant " UPs have to deliver to the TSO the day-ahead generation scheduling and will incur in penalties for the imbalances with respect to their scheduled profile. The generation imbalance is defined as:

$$E_{imb}^{MSD}(UP,h) = E_{generation}^{current}(UP,h) - E_{generation}^{forecast}(UP,h) \ , \tag{1}$$

where $E_{generation}^{current}$ and $E_{generation}^{forecast}$ are the real and day-ahead scheduled generation of the UP at the delivery hour (h).

Therefore, UP negative imbalance means under production with respect to the scheduling while positive imbalance means over production.

To define the energy price of the relevant UP imbalance, Terna divided the Italy in two macro zones (

Table 1). The first is the North market zone and the second is the remaining part of Italy.

Table 1. BEM "single pricing" imbalance valorization scheme for Relevant Production Units not allowed to provides dispatching services (P_Z^{DA} is the DAM zonal price; $P_Z^{B\downarrow}$ and $P_Z^{B\uparrow}$ are the MSD ex-ante purchase/sale zonal prices).

<table>
<tr>
<td rowspan="2" colspan="2"></td>
<td colspan="2">Sign of the imbalance of Relevant Production Unit (market zone Z)</td>
</tr>
<tr>
<td>Over generation with respect the day-ahead scheduling
 ($E_{imb}^{MSD}(UP, h) > 0$)

 (+)</td>
<td>Under generation with respect the day-ahead scheduling
 ($E_{imb}^{MSD}(UP, h) < 0$)

 (-)</td>
</tr>
<tr>
<td rowspan="2">Sign of Macro zonal imbalance</td>
<td>Over generation (+)</td>
<td>UP <u>sells</u> to TSO their imbalance at minimum MSD price

 $V_Z^B =\min \{P_Z^{DA} \,,\, P_Z^{B\downarrow}\}.$

 Negative imbalance value (cost)

 $E_{imb}^{MSD}(UP, h) * (V_Z^B - P_Z^{DA}) \leq 0$</td>
<td>UP <u>purchases</u> from TSO their imbalance at minimum MSD price

 $V_Z^B =\min \{P_Z^{DA} \,,\, P_Z^{B\downarrow}\}.$

 Positive imbalance value (revenue)

 $E_{imb}^{MSD}(UP, h) * (V_Z^B - P_Z^{DA}) \geq 0$</td>
</tr>
<tr>
<td>Under generation (-)</td>
<td>UP <u>sells</u> to TSO their imbalance at maximum MSD price

 $V_Z^B =\max \{ P_Z^{DA} \,,\, P_Z^{B\uparrow}\}$

 Positive imbalance value (revenue)

 $E_{imb}^{MSD}(UP, h) * (V_Z^B - P_Z^{DA}) \geq 0$</td>
<td>UP purchases from TSO their imbalance at maximum MSD price

 $V_Z^B =\max \{ P_Z^{DA} \,,\, P_Z^{B\uparrow}\}$

 Negative imbalance value (cost)

 $E_{imb}^{MSD}(UP, h) * (V_Z^B - P_Z^{DA}) \leq 0$</td>
</tr>
</table>

The price of the generation imbalance of the relevant UPs depends on the sign of the regional imbalance of the macro zone in which the UP is located: negative zonal imbalance means less supply than needed while positive zonal imbalance occur when supply exceed the demand. The macro-zones sign is computed by Terna ex-post (after the supply) so that also the price of the "relevant" UPs imbalance is known ex-post.

A subset of the relevant production units are enabled to participate on the dispatching market depending on the flexibility and programmability of their power generation (balancing system operators – BSO-) [25]. In particular, variable renewable power plant such as wind and solar are not allowed to provide dispatching services. The imbalance price for these variable energy plants is defined by the "single pricing" rule. i.e. the price on the BEM depends only on the sign of macro zonal imbalance (

Table **1**). This rule has been designed to take into account the effect of the imbalance of the single 'relevant' UP on the overall imbalance of the macro-zone (in which the UPR is located).

- If the signs of the imbalance are the same, the day-ahead generation scheduling errors of the "relevant" solar farm contribute to increase the imbalance of the macro-zone. In this case, the imbalance value will be negative i.e. a cost for the producer.
- If the imbalance signs are different, the scheduling errors contribute to reduce the macro-zone imbalance and the imbalance value will be positive i.e. a revenue for the producer.

Figure 4 shows the main statistical values (mean, one and two std and out-layers) of the DA and MSD prices during 2014-2016 together with the imbalance price resulting from the "single pricing" rule. It is worth noting that the mean imbalance price is similar to the mean day-ahead price but the range of variability is much wider reaching values up to 1000 €/MWh for critical upward regulation hour.
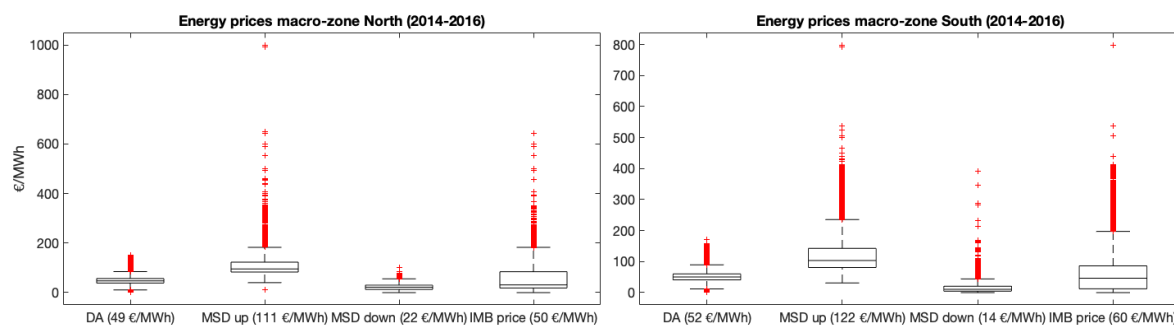

Figure 4. Energy prices in the two macro-zones during the year 2014-2016: DA price (P_Z^{DA}), MSD prices for upward and downward regulations ($P_Z^{B\uparrow}$ and $P_Z^{B\downarrow}$) and the imbalance price resulting from the "single pricing" rule (V_Z^B). In brackets are reported the average values.

Figure 5 summarizes the whole process to compute the UP imbalance values.

It is important to specify that the imbalance cost borne by "relevant" UPs allowed to provide ancillary services (BSO) is defined by the "dual pricing" market scheme in which the imbalance price depends on both the zonal and UP imbalance signs (dual), this scheme is well explained in [26, 21]. In contrast with the "single pricing", this rule cannot produce revenues for Balancing System Operators.
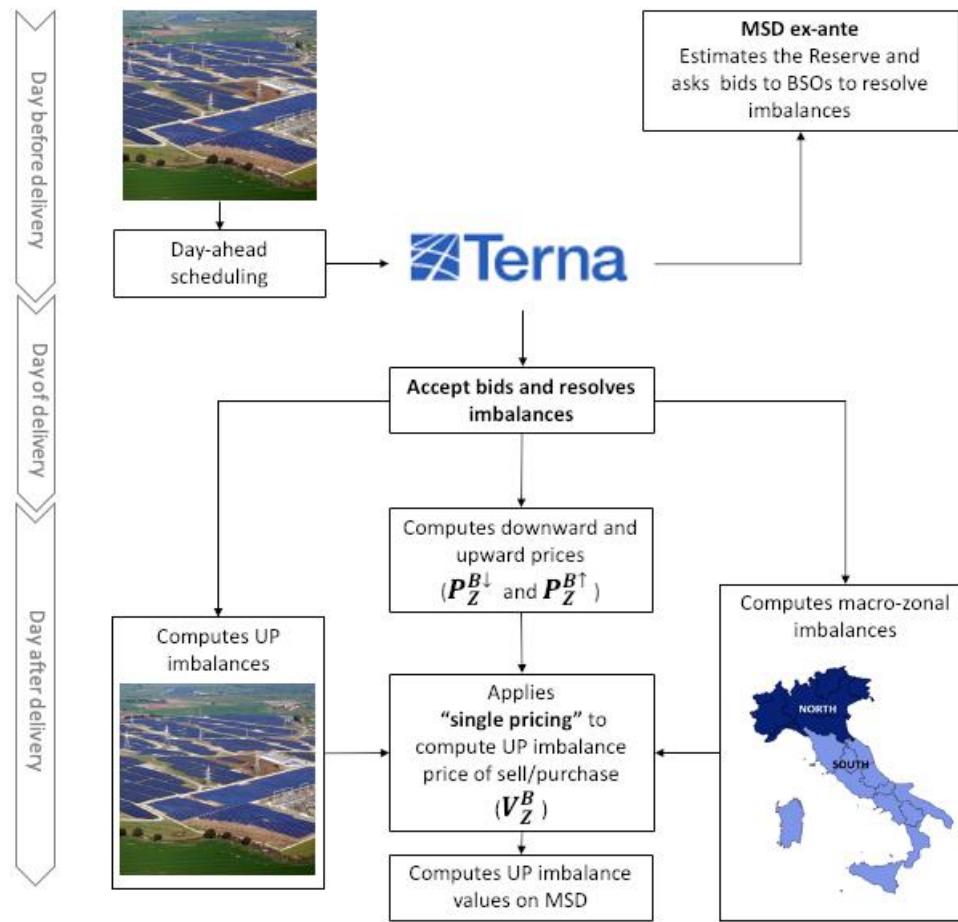
Figure 5. Process to compute the UP imbalance values.

4. Satellite and Numerical Weather Prediction data

The satellite and numerical weather prediction data have been provided by the forecast provider Ideam Srl.   A brief description of these data is reported below.

4.1 Satellite derived data

The satellite derived irradiance (GHI) used for power estimation comes from the Geostationary radiative fluxes products, under Météo-France responsibility. It was obtained by OSI SAF SSI algorithm applied to the satellite images provided by METEOSAT-9 (MSG-3) at 0° longitude, covering 60S-60N and 60W-60E, at 0.05° latitude-longitude. The data have an hourly granularity and a spatial resolution of 12 km x 12 km -- amounting to 1325 grid points for the entire country.

A particularity of the Météo-France data is to report GHI equal to zero at sun elevation lower than 10°. Thus, to reduce this error the data were post-processed with a cubic extrapolation of the clear sky index for low sun elevation angles. Each of the 1325 time series covers the period 2014-2017 (Figure 6b).

4.2 Numerical Weather Prediction forecast data

The GHI and T_{air} prediction, used as forecast models input, were generated by the Weather Research and Forecasting model (WRF–ARW 3.8) [27] with an initialization at 12 UTC, analyzing the 24 hours forecasts starting from the following 00 UTC:

1. Initial contour data for model initialization comes from GFS model output with a spatial resolution of 12 km x 12 km (Figure 6);
2. Radiation scheme: "Rapid Radiative Transfer Model";
3. Forecast horizon: 24 hour / Temporal output resolution: 1 hour /Spatial resolution 12 km x 12 km covering all the country (1325 points);
4. Each of the 1325 daily hindcasts time series covered the period 2014-2017.
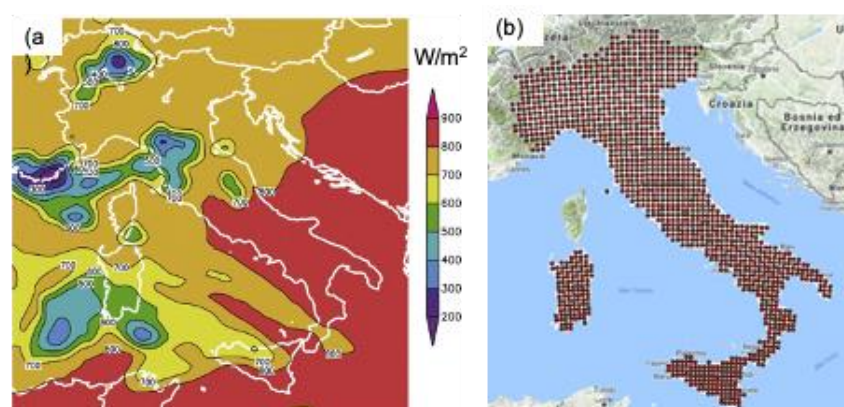
Figure 6. Short wave radiation in the WRF model domain (a), 1325 points irradiance satellite/forecast points computed on a grid of 12x12 km (b).

Importantly, we observed that the WRF irradiance predictions exhibited considerable bias errors. Indeed, in most of radiation schemes used by the WRF model, GHI is sensibly reduced only if one or more vertical model levels present water vapor content at the saturation level. In cases where the forecasted relative humidity of the entire column is very close to, but not at the saturation point, the modeled GHI reduction is very weak. This ignores that in real atmospheres, there is almost certainly condensation of the water vapor at some height, with a consequent GHI reduction at the surface [28]. Moreover, other factors limit the capabilities of the radiation scheme. For instance, in our case, aerosols and gas concentrations are set by tables that only take into account time of year and location. Consequently, the variation of diffuse and direct components due to these aspects is rigid and predefined. For these reasons, we had to correct the irradiance prediction obtained by WRF with an original Model Output Statistic method based on a deterministic and neural network models chain similar to the one we had previously developed and described in [29]. However, the description of this method is out of the scope of this work.

4. Materials and Methods

In order to benchmark the economic value of the solar energy trading on the MSD ex-ante and DA energy markets and to verify the effectiveness of the current market regulation in encouraging PV producers to reduce their imbalances, we adopted the following methodology (Figure 7):

1. We mapped the satellite and the NWP irradiance into the generation of nominal PV plants placed on an optimal plane of array (30° tilted and south oriented) by a deterministic PV power method described in subsection 4.1. Nominal PV production was simulated for each of the 1,325 grid points covering Italy using four years of hourly data: 2014-2017 (see **Figure 6**b). PV geometry was chosen taking into account that "relevant" solar farms (PV systems with capacity ≥ 10 MWp) are all optimally tilted and oriented;

2. We computed the energy imbalance between the current satellite derived PV generation and the day-ahead scheduled production for each point;

3.   We evaluated the PV forecast economic value for each single "relevant" solar producer, by the DA and MSD ex-ante energy prices and the macro-zone imbalance signs related to the years 2014-2016. These energy price data were archived by Terna Spa, they are of public domain and downloadable from the TSO website [30].
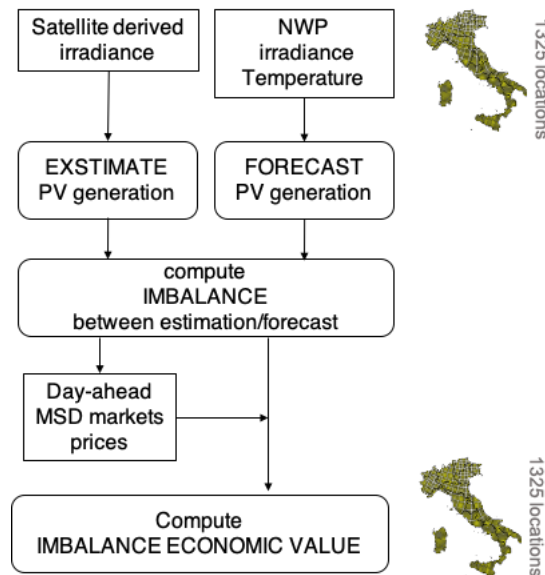

Figure 7. Methodology diagram.

5.1 PV power estimation/forecast method

To estimate and predict the PV generation of "relevant" solar farm we used a deterministic "physical-based" method consisting in a chain of three semi-empirical models (Figure 8):

1.   A decomposition model to retrieve the direct normal irradiance (DNI) and the diffuse irradiance (DHI) from the GHI data. In this case, the direct insolation simulation code model (DISC) has been applied [31, 32, 33]. DISC is very simple model that provides the DNI using only the global horizontal and the extraterrestrial direct normal irradiance [34]. The DHI is then simply computed from the GHI and the estimated DNI.

2.   A transposition model to retrieve the global irradiance on the plane of array, i.e., the tilted irradiance (GTI). Here, we use the isotropic model developed by Liu–Jordan [35]. This is one of the most common methods that can be used when only DNI, DHI, and albedo are available.

3.   Last step is given by a power estimation model that maps the incident irradiance into PV generation. For this purpose, we selected the Sandia array performance model (SAPM) developed in [36]. This is one of the most accurate PV simulation models because it takes into account all of the main performance losses that affect PV performance in real operating conditions [37, 38] .
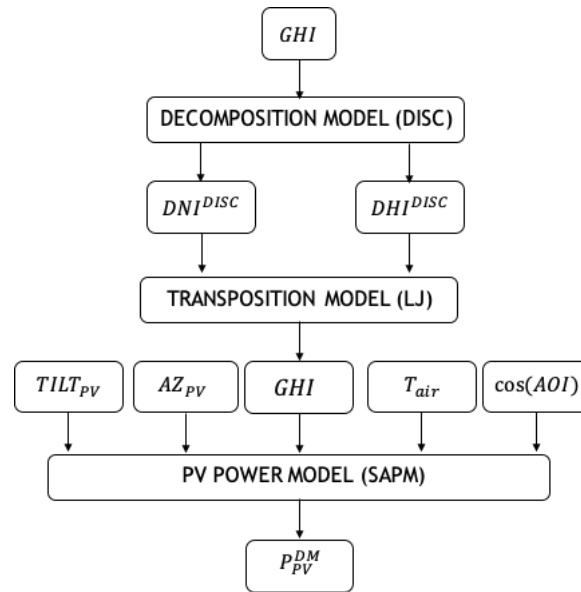
Figure 8. Site PV power estimation/forecast method diagram.

Therefore, the model inputs are the tilt and the orientation of the PV plant ($TILT_{PV}$, AZ_{PV}) that in our case are 30° and 0° South, the GHI forecast (GHI^{SAT} or GHI^{FOR}), the air temperature forecast (T_{air}^{FOR}) and the Angle of Incidence (AOI) while the model output is the PV plant generation forecast per unit of installed capacity (P_{PV}^{DM}) expressed in MW/MWp.

We compare the forecast accuracy and its economic value with the one obtained by a simple persistence forecast (that is the reference model most used in forecast literature):

$$P_{PV}^{P}(h + H|dd, h) = P_{PV}(h, dd) \quad with\ H = 24 \ , \tag{2}$$

where, dd is the current day and h is the hour of the day, P_{PV}^{P} is the simple persistence PV power forecast.

6. Metrics to evaluate accuracy and economic imbalance value

Table 2 reports two of the main metrics used in forecast literature to evaluate the accuracy of non-probabilistic predictions, where X is the variable that should be predicted, n is the number of yearly sun hours.

The RMSE accentuates the largest forecasting errors (i.e., outliers) while Skill Score is exactly the accuracy improvement of the developed forecast method with respect a baseline reference model (in our case, the Persistence Model). The RMSE is usually expressed in W/m² in case of irradiance or in MW or in % of peak power in case of PV power forecast (since DSO and TSO usually adopt this unit), whereas, SS is a dimensionless index.

The computation of imbalance value for a single relevant solar plant has been explained in section 3 and Table 2 also reports the main economic metrics. We just mention that the net-imbalance value (NIV_{MSD}) is simply the hourly sum of the UP imbalance ($e_h(UP_Z)$) time the difference between the imbalance price on MSD ex-ante (V_Z^B) and the energy price on the DA (P_Z^{DA}). It represents the value of the forecast with respect to the value of a "perfect" forecast i.e. the total incomes on the MSD and DA achieved by the provided PV power forecast ($EIV_{DA\&MSD}^{forecast}$) net of the "ideal" incomes that could be achieved on the DA market with no imbalance (EV_{DA}). In our case, the imbalance price V_Z^B is defined by the "single pricing" rule.

Table 2. Metrics for economic imbalance valorization.

| Name	Acronym and formulae
Forecast error [W/m² or MW - % of peak power]	$e'_h = \left(X^{for}(h) - X^{obs}(h) \right)$
Root mean square error [W/m² or MW - % of peak power]	$RMSE = \sqrt{\dfrac{\sum_{h=1}^{n} {e'_h}^2}{n}}$
Skill score [%]	$SS = 100 \left(1 - \dfrac{RMSE^{forecast\ model}}{RMSE^{reference\ model}} \right)$
Current and scheduled PV generation [MW/MWp]	$P_{PV}^{obs},\ P_{PV}^{for}$
UP Imbalance [MW or % of peak power]	$e_h(UP) = \left(P_{PV}^{obs}(UP, h) - P_{PV}^{for}(UP, h) \right)$
UP absolute energy imbalance [MWh/yr per MWp]	$AEI = \sum_{h=1}^{n} |e_h(UP)|$
UP net-imbalance value [k€/yr]	$NIV = \sum_{h=1}^{n} (V_Z^B(h) - P_Z^{DA}(h))\, e_h(UP)$
UP energy income on DA [k€/yr]	$EV_{DA}^{forecast} = \sum_{h=1}^{n} P_Z^{DA}(h) * P_{PV}^{for}(UP, h)$
UP imbalance value on MSD [k€/yr]	$EIV_{MSD}^{forecast} = \sum_{h=1}^{n} V_Z^B(h)\, e_h(UP)$
UP total energy income [k€/yr]	$EIV_{DA\&MSD}^{forecast} = EV_{DA}^{forecast} + EIV_{MSD}^{forecast}$
UP energy income on DA with perfect scheduling (no imbalance) [k€/yr]	$EV_{DA} = \sum_{h=1}^{n} P_Z^{DA}(h) * P_{PV}^{obs}(UP, h)$

3. Results

3.1 Forecast results

The observed 2014-17 mean horizontal radiation ranged from a minimum of 990 kWh/m² in the North Alpine region to a maximum of 1900 kWh/m² in the very South (Sicily). The country's mean radiation was 1533 kWh/m² per year (Figure 9).

It follows that the minimum Italian generation rate of "relevant" solar farms is around 1000 MWh/MWp in the North alpine space, while the maximum is around 2000 MWh/MWp in the very South. The average generation rate of an optimal tilted and oriented PV system is around 1671 MWh/MWp   (Figure 9).
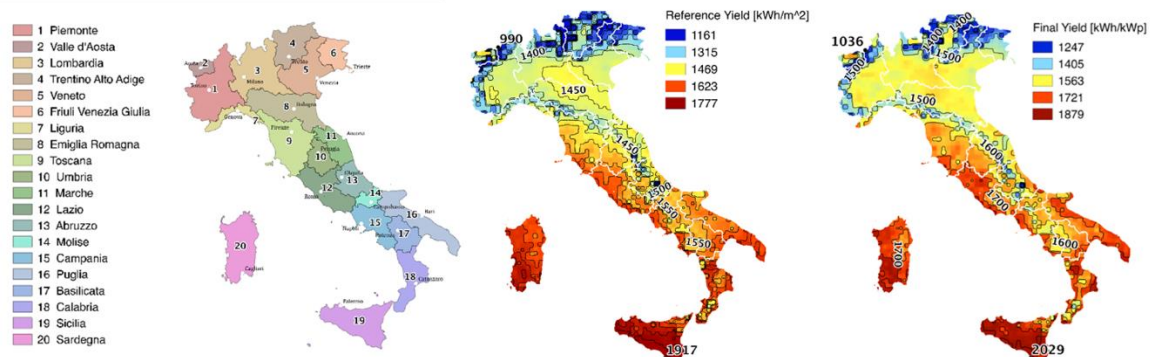
Figure 9. Maps of Italy: Italian Regions, Reference Yield (global horizontal annual radiation) and Final Yield (annual energy rate). Average values of satellite derived radiation and power estimation over the years 2014-2017.

Figure 10a reports the RMSE of our GHI forecast model plotted against the RMSE of the persistence model. Each point in this figure corresponds to one of the 1325 gridded locations. Our forecast errors ranges between 85.6 and 118.8 W/m2 depending on the location, while the persistence errors are between 131.7 and 179.2 W/m2. The Skill Score of the GHI forecasts range from 20% to 45%. Figure 10a also displays the error range a day-ahead irradiance forecast benchmarks in four site of four different EU countries from five or four different forecasting methods depending on location, Lorenz et al. [39]. The bars, report the maximum, mean and minimum RMSE of the five/four day-ahead predictions in each EU site provided by the different forecasting methods. It is worth noting that our RMSE is near or below the fit of the best accuracy values obtained in the work of Lorenz et al. Our forecasts can be thus considered to be representative of "state of the art" forecasts. We also have to note that Lorenz et al. compared forecasts against ground measurements while here, we compare forecasts against satellite-retrieved irradiances. Nevertheless, it has been shown that satellite data are an acceptable, if not in many case preferable ground measurement proxy to both train and test forecast models [40, 41, 42, 43, 44, 45].
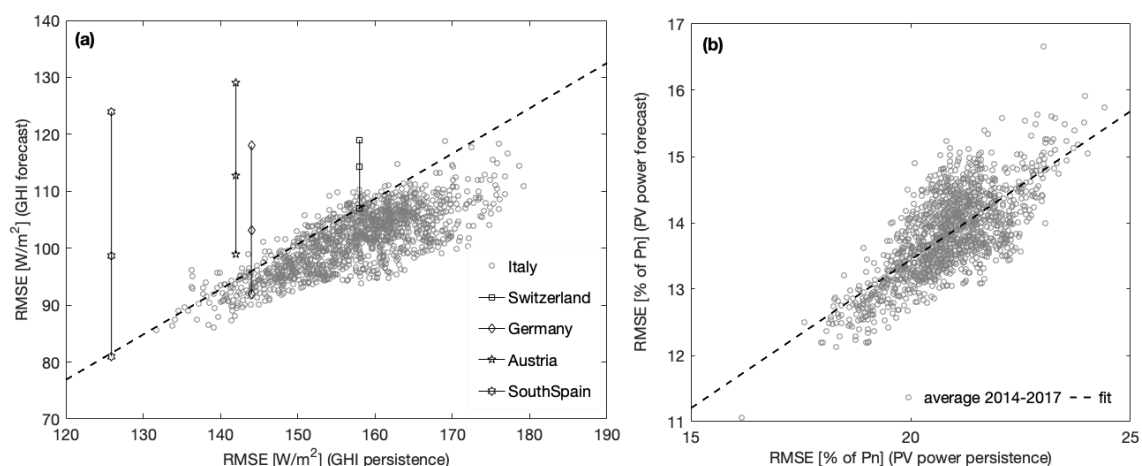

Figure 10. RMSE of the irradiance forecast vs RMSE of persistence (average values over the years 2014-2017) and comparison with the forecasting errors resulting from different forecasting methods

in four EU locations [39] (the dashed line is the fit of the accuracy of the outperforming forecasts) (a); RMSE of the PV power forecast vs RMSE of persistence (b).

Figure 10b plots the RMSE of our PV power forecast against the RMSE of the persistence. Our forecast errors ranges between 11 and 16.7% of PV capacity (Pn) while the persistence errors are between 16.2 and 24.4 % of Pn. Skill scores range from 25.7% to 39.7% with a mean value of 33.6%.

We observe the highest regional RMSEs in Val d'Aosta, Liguria and Abruzzo owing to variable conditions due to the mountains. The lowest RMSEs are observed in Sardinia and Sicily islands (see Figure 11). The best skill scores occur in the north regions Piemonte and Val d'Aosta, while the worst ones are observed in Abruzzo (due to the high weather variability) and in Puglia (due highly persistent weather and the relatively good performance of persistence).
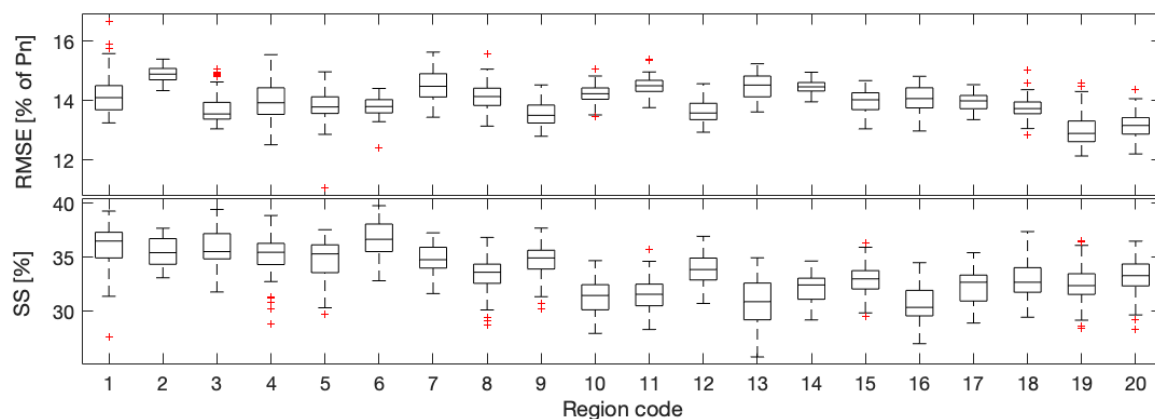
Figure 11. Regional RMSE and Skill Score of the PV generation forecast (averaged over the years 2014-2017).

From the PV power forecasts at each of the 1325 Italian locations, we computed the annual imbalance costs/revenues for "relevant" PV producers or traders. We also computed the economic valorization of the forecast with respect the persistence i.e. the economic value of using predictions that are more accurate.

The benchmark of the imbalance economic value has been carried on using the years 2014-2016 according to the hourly DA and MSE ex-ante energy prices available on the Terna database (Figure 4).

Through this benchmark, we evaluate the effectiveness of the "single pricing" rule in promoting solar imbalance reduction, pointing out some important shortcomings of the Italian regulatory framework.

7.2 Benchmarking the economic value of the imbalance of "relevant" PV plants

Figure 12a shows the imbalance valorization on the MSD in different locations/years using our deterministic PV generation forecast. As reported in section 3, the "single pricing" rule can produce, for "relevant" PV production units, positive (revenues) or negative (costs) imbalance values that, in this case range, from 5 to -5 k€ per MWp of PV capacity per year. There is a notable difference between the imbalances values obtained in different years. During 2014 and 2016, for the majority of the locations of the North, the imbalance is a cost (regions from 1 to 12) while in the South, it is mainly a profits (regions from 13 to 20). In 2015, however, energy imbalance generated a revenue almost everywhere in Italy.
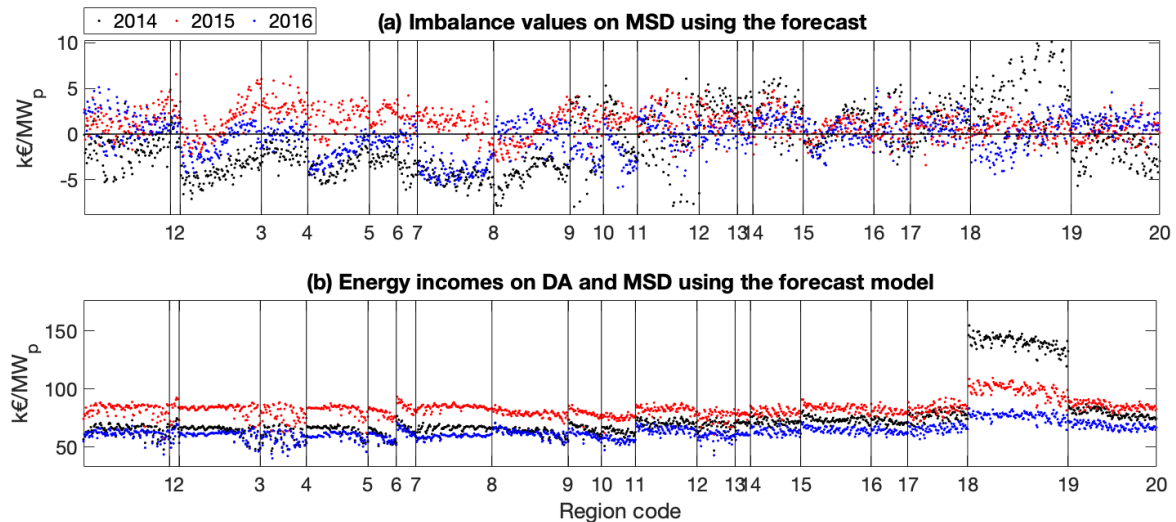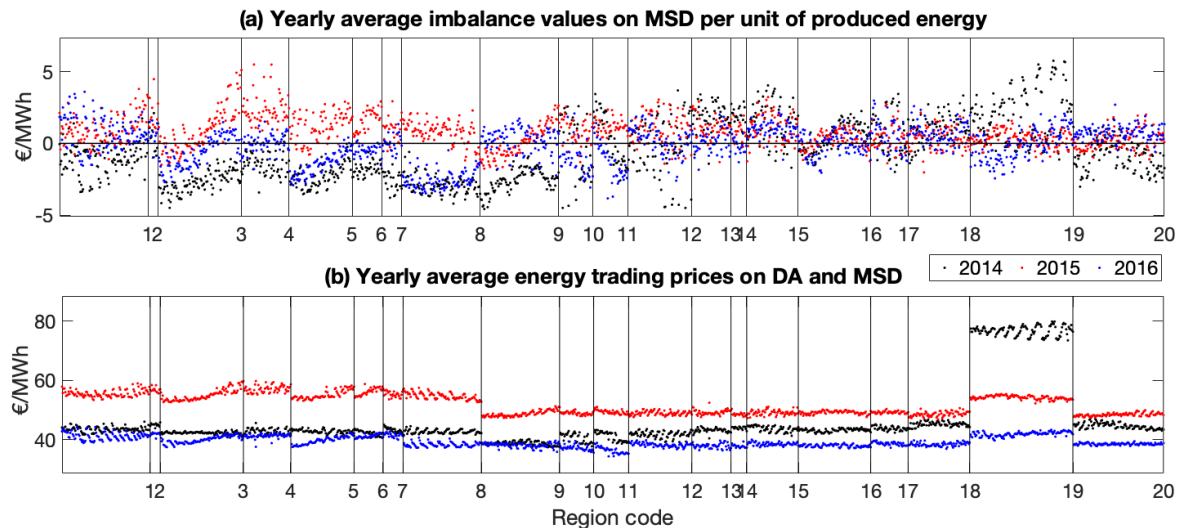
Figure 12. Imbalance values on MSD ex-ante resulting from the PV generation forecast model (a); energy incomes on DA and MSD ex-ante resulting from the PV generation forecast (b). Positive value are revenues while negative are economic costs. Each point on the graphs is the annual energy value achievable in one of the 1325 locations (wider Regions imply more points).

Figure 12b shows the total energy incomes (on DA and MSD markets) for "relevant" PV producers in different locations/years. These incomes range from 50 to 150 €/MWp per year and in this case, the higher incomes were obtained during the year 2015 with the only exception of Sicily.

Indeed, in Sicily, during the year 2014, the zonal energy market was affected by a high speculations level due to the grid bottleneck that does not allow the flow of additional cheaper power from the land. In addition, the "single pricing" market rule provides penalties/premium for solar imbalances according to the imbalance sign of the macro-zones in which the PV production unit is located. Therefore, as we will show later, energy traders can predict the imbalance macro-zonal sign to maximize their profits on the MSD market. Up to 2014, Sicily was itself a macro-zone, so that local PV producers could easily predict the macro-zonal imbalance sign increasing their profits also on the MSD. In order to reduce these trading speculations, after 2014, Terna improved the grid connection between the island and the land and incorporated Sicily and Sardinia into the South macro-zone increasing difficulties in the prediction of the macro-zonal imbalances.

Figure 13 reports the yearly average (weighted with the corresponding exchanged energy) of the imbalance values on MSD and of energy trading values on DA and MSD markets, per unit of produced energy. The average imbalance values range between -5 and 5 €/MWh while the total values on the energy markets ranges between 37.5 and 80 €/MWh. Therefore, thanks to the "single pricing" system, the solar imbalance unitary values is more than ten times lower than the total trading values.

Figure 13. Yearly average imbalance values on MSD ex-ante per unit of produced energy (a); yearly average trading values on DA and MSD ex-ante (b).

The annual economic loss/gain due to the errors in the PV generation scheduling is the value of the PV forecast i.e the net imbalance value (Table 2) and it can be computed as the difference between the total energy incomes on DA - MSD markets and the energy revenues that could be realized with a perfect forecast (no imbalance).

The net imbalance values are costs in all the Italian regions with the exception of Lazio, Campania, Calabria and Sardinia where there are some locations in which the imbalance could even bring to profits (Figure 14a).
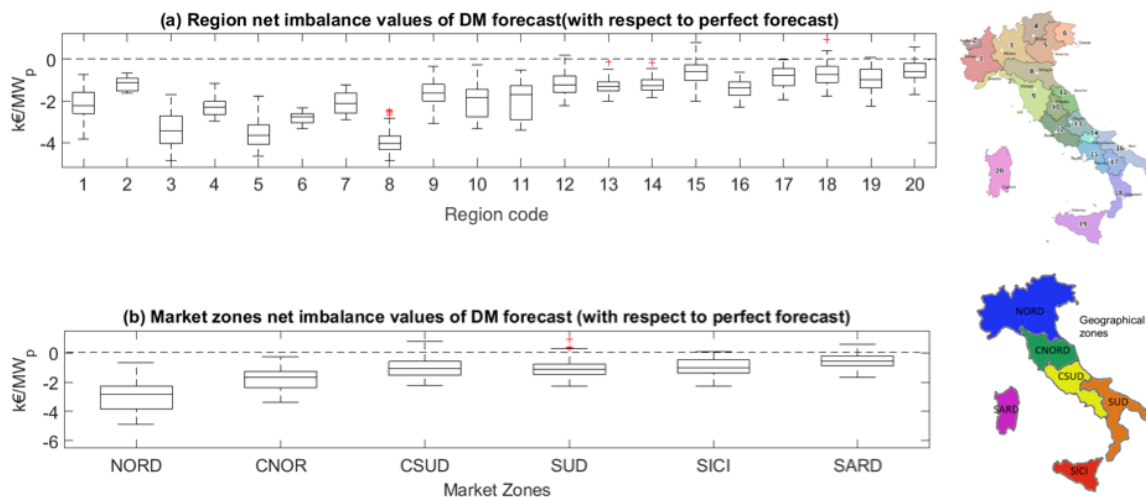
Figure 14. Net imbalance values aggregated by regions and market zones.

The maximum economic losses are in the North zone with a zonal average of -2.8 k€/MWp and a range of -4.9/-0.7 k€/MWp while the minimum losses are in Sardinia with zonal average of -0.6 k€/MWp and a range of -1.7/0.5 k€/MWp (Figure 14b).

Antonanzas et al. in [21] found a net imbalance value of a single plant on the Iberian energy markets under the "dual pricing" mechanism that range between -2.6 and -3.3 k€/MWp depending on the forecast accuracy.

It is worth noting that the net-Imbalance values should be always a cost (negative) but there are some locations in which it is a revenue (positive) therefore with "single pricing" rule, imperfect forecast could be more profitable than "perfect" forecasts. Moreover, the net-Imbalance values (that range between -5 and 0.6 k€/MWp), are quite small if compared with the total energy incomes (that

range between 50 and 150 k€/MWp - Figure 12b -), hence with "single pricing" rule the imbalances have a small impact on the total energy revenues of PV producers.

From Figure 15a it can be observed that the imbalance values obtained using our forecast method (DM) are almost everywhere higher than the ones obtained using the persistence predictions (average on the years 2014-2016). In particular, the persistence predictions lead always to negative values i.e. economic losses for producers.

The economic gains of DM forecast with respect to persistence on MSD can be computed as:

$$Gains_{MSD}(DM, P) = \begin{cases} |EIV_{MSD}^P| - |EIV_{MSD}^{DM}| & if \; sign(EIV_{MSD}^P * EIV_{MSD}^{DM}) > 0 \\ |EIV_{MSD}^P| + |EIV_{MSD}^{DM}| & if \; EIV_{MSD}^P < 0 \; and \; EIV_{MSD}^{DM} > 0 \\ -(|EIV_{MSD}^P| + |EIV_{MSD}^{DM}|) & if \; EIV_{MSD}^P > 0 \; and \; EIV_{MSD}^{DM} < 0 \end{cases} , \qquad (3)$$

where EIV_{MSD}^P and EIV_{MSD}^{DM} are the energy imbalance value produced by the persistence and the DM forecast.
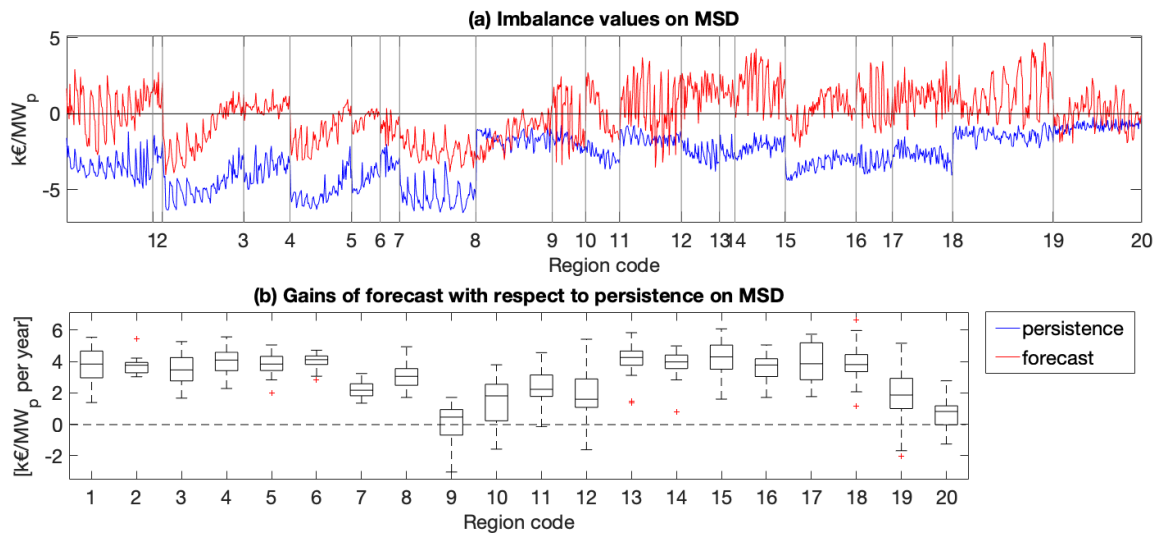
Figure 15. Imbalance values on MSD ex-ante per unit of PV capacity resulting from the use of persistence and our forecast models (average 2014-2016) (a); MSD ex-ante gains per unit of PV capacity resulting from the use of our PV generation forecast instead of the persistence prediction, aggregated by regions (b). Negative gains are losses.

Figure 15(b) shows that the mean regional imbalance gains are positive in all the regions and the increase of the forecast accuracy could produce benefits that ranges from 1 to 6 k€ per MWp of PV capacity per year. This considerably more than the cost of a high quality solar generation forecast.

The annual day-ahead market gains of our forecast (DM) with respect to persistence (P) can be computed as follows:

$$Gains_{DA}(DM, P) = EV_{DA}^{DM} - EV_{DA}^P =$$
$$= (EV_{DA} - EV_{DA}^P) - (EV_{DA} - EV_{DA}^{DM}) = [\sum_{h=1}^n P_Z^{DA}(h) * e_h^P(UP)] - [\sum_{h=1}^n P_Z^{DA}(h) * e_h^{DM}(UP)], \quad (4)$$

where EV_{DA}^{DM} and EV_{DA}^P are the annual energy values on DA market obtained by the DM and persistence scheduling (Figure 16b), P_Z^{DA} is the energy price on the day-ahead market and e_h^{DM}, e_h^P are the prediction imbalances (Table 2).

It worth noting that: $\sum_{h=1}^n P_Z^{DA}(h) * e_h^P(UP)$ is always very small since persistence forecasts are almost always unbiased ($\sum_{h=1}^n e_h^P(UP) \cong 0$) so that, when our DM forecast model provides an annual under-prediction ($\sum_{h=1}^n e_h^{DM}(UP) > 0$) there will be an high probability that the day-ahead market gains will be negative while when the model provides an over-prediction ($\sum_{h=1}^n e_h^{DM}(UP) < 0$) the gains are likely to be positive. In this case, since our model provides a slight under prediction almost everywhere (Figure 17), the DA gains are mainly negative ranging between -4.5 and 0.5 k€ per MWp (Figure 16b). Therefore, our forecasts produce economic losses on DA market with respect to the trivial persistence predictions.
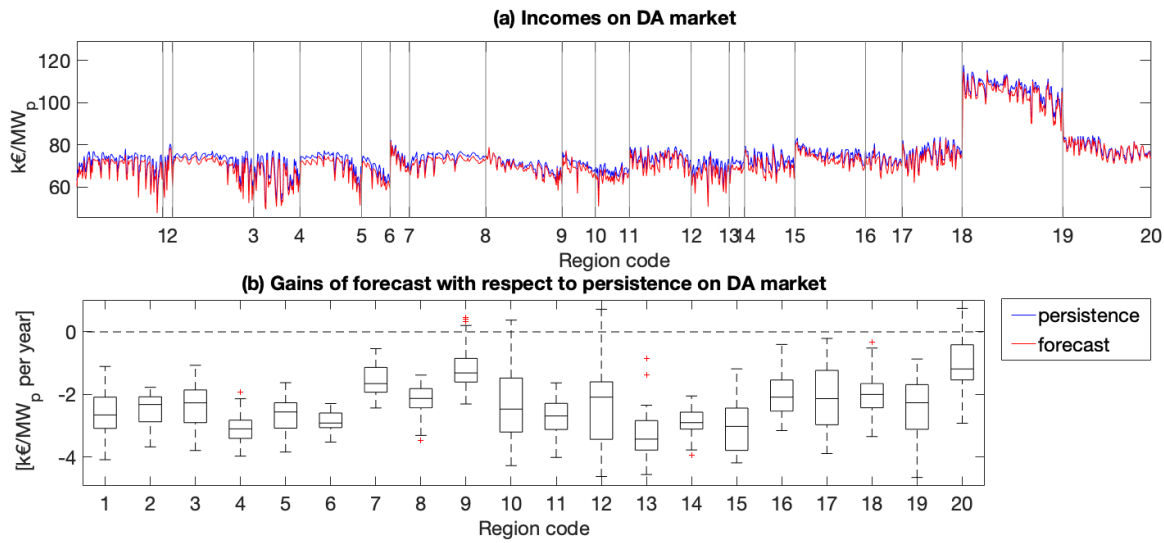
Figure 16. Energy trading incomes on DA market per unit of PV capacity resulting from the use of persistence and our forecast models (average 2014-2016) (a); Gains on DA market per unit of PV capacity resulting from the use of our PV generation forecast instead of the persistence prediction, aggregated by region (b). Negative gains are losses.

It had to be pointed out that under-forecast produces lower income on the DA market but higher/lower revenue/cost on the MSD since it mainly implies energy exchanges for downward regulations (at lowest dispatching prices) and vice versa.
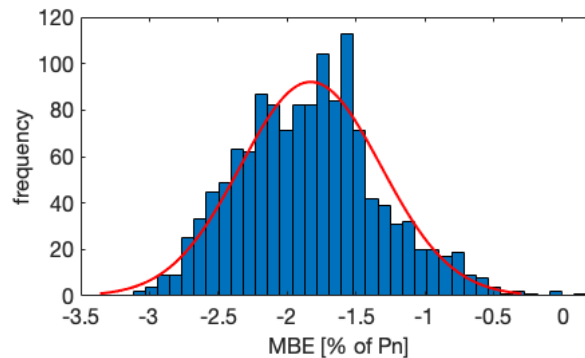
Figure 17. Frequency of the forecast Mean Bias Errors. It has to be remind that $\sum_{h=1}^{n} e_h^{DM}(UP) = -nMBE$.

Figure 18 summarizes all the results, reporting the total gains on both DA and MSD markets obtained by our accurate forecast with respect the persistence, i.e. the value of the accuracy improvement:

$$Gains_{DA\&MSD}(DM, P) = EV_{DA\&MSD}^{DM} - EV_{DA\&MSD}^{P}, \tag{5}$$

where $EV_{DA\&MSD}^{DM}$ and $EV_{DA\&MSD}^{P}$ are the annual energy incomes on DA and MSD markets obtained by the DM and persistence forecasts.

Figure 18a shows that the economic gains of DM forecast on the MSD market ($Gains_{MSD}(DM, P)$) are positive almost everywhere in Italy (since our forecast is more accurate than persistence), while the gains on the DA market ($Gains_{DA}(DM, P)$) are negative (since our forecast is slightly negative biased while persistence is almost unbiased). As results, the total gains are strongly reduced or even cancelled out.   Small benefit from using a more accurate forecast can be obtained in the North (NORD), Centre-South (CSUD), South (SUD) and Sicily (SICI) regions with an average zonal values of 1.1, 0.4, 1.6 and 0.3 k€/MWp per year (Figure 18b). In contrast, negative gains appear

in the Centre-North and Sardinia with average zonal values of -0.5 and -0.3 k€/MWp per year, hence, from an economic point of view, in these zones the persistence model should be preferred to our more accurate forecasting method.

The "single pricing" system not only allows revenues from solar imbalances reducing the net-imbalance values of the forecast but also reduces or cancel the economic benefits of using a more accurate forecast instead of the simple persistence.

When the forecasts are biased low, it is much more difficult to obtain this paradoxical result when the "dual pricing" system is used since no revenues can be achieved on MSD. Nicolas Ibagon et al. [22] showed that the imbalance cost resulting from the "dual pricing" are almost twice as large as costs resulting from the "single pricing" rule. Antonanzas et al. in [21] found a value of the forecast improvement with respect to persistence between 0.46 and 1.2 k€/MWp depending on the forecast accuracy. Nevertheless, the authors still found that less accurate forecast could produce higher benefits than more accurate ones. For this reason, they stated that standard error metrics are not sufficient to evaluate the economic impact of the forecast. We add that this discrepancy between accuracy and economic metrics is due to the dependence of the imbalance value on stochastic variables, viz. zonal imbalance sign and upward and downward regulation prices. Indeed, using both "single" and "dual" pricing rules, is always possible that a poor forecasts but with imbalances frequently in favor of the system (negative match between the zonal and UP imbalance signs) produces lower imbalance cost than a better forecast but with an imbalance frequently against the system (positive match between the imbalance signs). Therefore, as we will demonstrate in the next section, in order to reward always the better forecasts, the market rules to compute imbalance values should not depend anymore on these random variables.
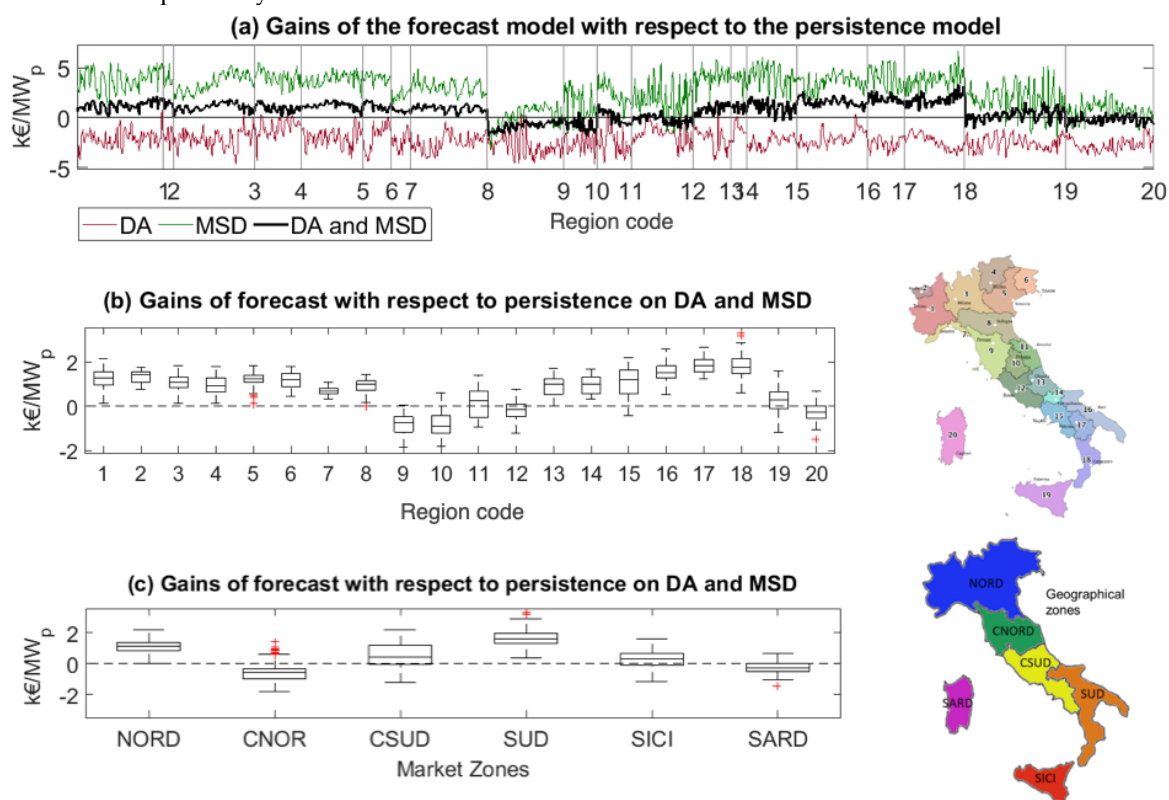
Figure 18. Energy trading gains on DA, MSD ex-ante and on both the markets per unit of PV capacity resulting from the use of our DM forecast instead of the persistence prediction (average 2014-2016) (a); Gains on DA and MSD ex-ante per unit of PV capacity resulting from the use of our DM forecast instead of the persistence prediction, aggregated by region and market zones (b and c). Negative gains are losses.

We further point out another important shortcoming of the current imbalance market regulatory framework. The "single pricing" system produces negative imbalance valorization (penalty) if the

signs of the imbalances of the solar production unit (UP) and of the Macro Zone (in which the UP is located) are the same and positive valorization (premium) if the UP and Macro Zone imbalance signs do not match. Indeed, the incorrect solar generation scheduling, in the first case, increases the zonal imbalance while in the second case, helps to reduce the imbalance of the macro zone. Even if this rule appears reasonable, it leads to another counterproductive effect regarding the need to reduce the imbalance volumes.

The imbalance values on MSD ($EIV_{MSD}^{forecast}$) can be decomposed in two factors:

$$EIV_{MSD}^{forecast} = \langle V_Z^B \rangle * AEI, \qquad (6)$$

where, $\langle V_Z^B \rangle$ is the average imbalance unitary value (€/MWh) and AEI is the imbalance volume (MWh/MWp per year) i.e. the accuracy of the forecast.

The value $\langle V_Z^B \rangle$ embeds both the MSD energy prices (for upward or downward regulation) and the match between the UP and the Macro Zonal imbalance signs.

Figure 19 shows that the imbalance values on the MSD market are much more correlated with the average imbalance unitary values than with the imbalance volumes.

This means that, for energy producers/traders under "single price" rule, it is much more important to predict the right sign of macro-zone imbalance and thus to provide Terna an adequate under/over forecast rather than to deliver the most accurate forecast minimizing the volume of solar imbalance. In 2014, for this reason, the Italian TSO enlarged the size of the imbalance zones passing from four macro-zones to the current two. In this way, Terna increased difficulties in predicting the macro-zonal sign, reducing the arbitrage activities on the imbalance market (see the imbalance valorization in Sicily during 2014 reported in Figure 13).
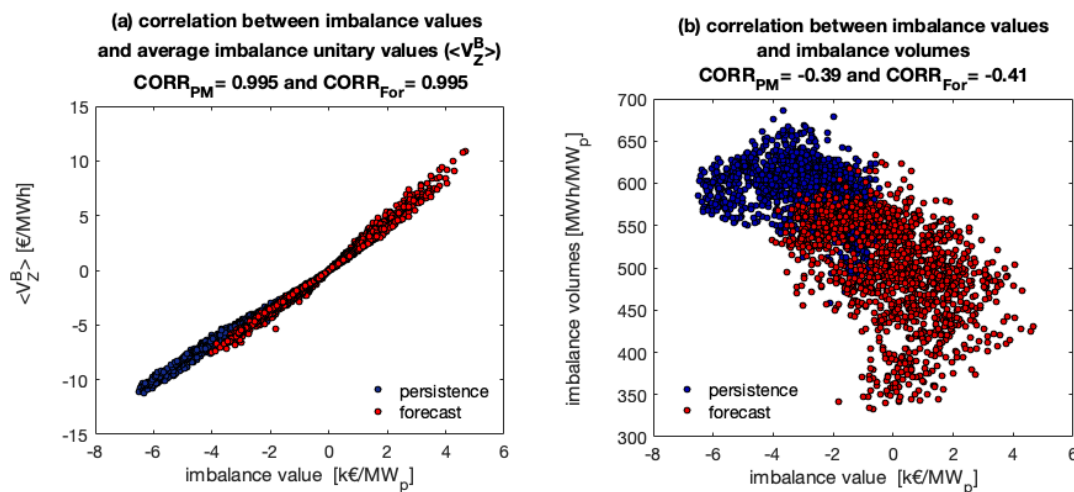
Figure 19. Scatter plot of the average imbalance unitary values on MSD ex-ante vs the imbalance values per unit of PV capacity (a); scatter plot of the imbalance volumes per unit of PV capacity vs the imbalance values per unit of PV capacity (b).

In contrast, Antonanzas et al. in [21] demonstrated that this kind of market speculation and fraudulent activities are strongly limited by the "dual pricing". They showed that there is a much higher correlation between the imbalance values and the imbalance volume with a well-fitted linear relation between these two quantities. Nevertheless, small deviation from linearity can still give rise to lower economic benefits of the outperforming forecast (as previously discussed).

Clo' and Fumagalli [26], in their study on the Italian shift of the settlement rules of consumption sites from a "single" to a "dual" pricing scheme, arrived at the same conclusion on the effectiveness of "dual pricing" in reducing the system imbalances.

From Figure 19, it is also worth noting that our DM forecasts not only provides a lower imbalance volume with respect to persistence but also a higher average imbalance unitary values i.e. a more profitable match between the UP and macro-zonal imbalance signs.

This could indicate that the majority of the solar producers use the persistence model to predict their PV generation. Indeed, for instance, if the majority of the "relevant" PV producers inside a Macro Zone delivers a persistence over-forecast of their solar generation, Terna will predict a lower generation supply than needed; hence there will be a negative imbalance of the Macro Zone. At the same time, if a PV producer that, using another forecast model (for example our DM method), provided to Terna an under-forecast, he would supply more solar energy than expected, thus helping Terna to reduce the zonal-imbalance. Therefore, this PV producer will have an economic premium while all the others will pay penalties for their imbalances. If this situation occurs many times during a year, it will result in a higher average imbalance unitary value for the producer that uses state-of-the-art forecasts than for all the others that use the persistence prediction. In other words, as stated in [46], the forecasts with lower correlation with the TSO prediction (driven by the forecast of all the market agents) would have a higher probability of being in favor with the needs of the system and thus, to avoid penalties or earn rewards.

It is important to understand that the increase of the average imbalance unitary values depends only on the sign of the forecast error generated by one model (for instance our method) with respect to the imbalance sign obtained by the most used prediction model (persistence model in this case), independently from the imbalance volumes that they generate with their predictions i.e. from the forecast accuracy.

8. Proposed revision to dispatching market regulatory framework

The "single pricing" rule was introduced to reduce imbalance penalties for variable renewable energy plants characterized by unprogrammable generation. Nowadays, PV generation has reached grid parity. It is the cheapest source of electrical energy (at least on an unconstrained kWh basis) [1]. Therefore, the rule to compute the imbalance prices should be appropriately revised for all the new plants coming online to avoid the undesired effects mentioned above.

The simplest rule revision could be to shift from the "single" to the "dual" pricing schemes so that, as was demonstrated in [21, 26], the best forecasts would be more probably rewarded and market arbitrage actions would be strongly reduced.

However, we suggest a more radical regulatory reform.

First, we showed in [14] that solar imbalance can be halved just operating proactive curtailment in all the case of under-forecasting i.e. all the energy generated that exceeds the prediction is curtailed by smart inverters and control systems so that the grid injection will be the scheduled value.

Since the energy that should be curtailed is exactly the energy imbalance:

$e_h(UP) = E_{generation}^{real} - E_{generation}^{forecast} = E_{generation}^{forecast} + E_{generation}^{curtaiment} - E_{generation}^{forecast} = E_{generation}^{curtaiment}$, the costs for the producers of the curtailed energy is exactly equal to the net Imbalance costs, regardless of the market-pricing rule. Therefore, for the producers, it is economically the same to pay for the imbalance or to curtail the energy above the forecast (in effect, delivering a "perfect" forecast). Considering that all the new plants employ smart inverters, proactive curtailment should be mandatory. In this way, solar flexibility would be improved and the downward regulation due to solar-induced imbalance would be avoided.

In addition, we suggest overcoming both the "single" and "dual" pricing mechanisms by removing any dependency from the zonal imbalance sign. The MSD imbalance price, in case of negative imbalance (under-forecast), can be higher than the DA market price (P_Z^{DA}) by a fixed daily amount: ($\Delta P_Z^{B\uparrow}(d) = \langle P_Z^{B\uparrow}(h) - P_Z^{DA}(h)\rangle_d$) and the imbalance value can be calculated as: $V_Z^B(h) = P_Z^{DA}(h) + \Delta P_Z^{B\uparrow}$. The additional price $\Delta P_Z^{B\uparrow}(d)$ on MSD is the daily mean (sun hour only) of the differences between the zonal upward regulation price and the day-ahead price (computed ex-post).

With this simple rule change and proactive curtailment in case of over-forecast, not only would the daily net-imbalance value always be negative (i.e., a cost for the plant owners) but also it would be directly proportional to the daily upward imbalance volumes. Indeed the daily net-imbalance value would become:

$$NIV(d) = \sum_{h=1}^{24}(V_Z^B(h) - P_Z^{DA}(h)) \, e_h(UP) = -\Delta P_Z^{B\uparrow}(d) \sum_{h=1}^{n_{up}} |e_h(UP)|, \qquad (7)$$

where n_up is the number of hours of the day (d) during which the plant generated less than the scheduled (negative imbalance).

The imbalance costs for the producers would be higher than the one obtained by "dual" pricing scheme, in case of upward regulation since they would pay for the under-scheduling regardless the zonal imbalance sign. To reduce these penalties, the producers could either improve their forecasts or use systematic under-forecasts and over-curtail. In both the case, it would result in lower solar-induced imbalance.

With this pricing scheme the most appropriate physical metric to assess the forecast quality becomes the yearly average of the daily mean absolute imbalance errors:

$$\langle MAE(d)\rangle_{year} = \langle \frac{1}{n\_up}\sum_{h=1}^{n\_up} |e_h(UP)|\rangle_{year}, \tag{8}$$

Nevertheless, there remains a discrepancy between the economic metric: $\langle NIV(d)\rangle_{year}$ and the physical metric $\langle MAE(d)\rangle_{year}$ induced by the stochastic variability of the daily additional prices: $\Delta P_Z^{B\uparrow}(d)$. However, at high solar penetration, higher MSD additional prices $\Delta P_Z^{B\uparrow}(d)$ would naturally appear during days with irradiance more difficult to predict. Therefore the forecasts with lower $\langle MAE(d)\rangle_{year}$ will most likely produce the lowest annual imbalance costs ($\langle NIV(d)\rangle_{year}$). In addition, any market arbitrage based on the forecasting of the zonal imbalance sign would be eliminated.

It is worth recalling that, full solar flexibility could be reached by equipping the PV systems with battery energy storage systems (BESS) so that they can provide not only proactive curtailment in case of under-forecast but also additional power supply in case of over-forecast. This kind of systems that we called: "flexible" PV plants are able to reduce their imbalance as well as to eventually provide a perfect predictable generation [14].

In [14], we also proved that solar-induced imbalance of the whole Italian PV fleet can be limited by the use of "relevant" "flexible" solar plants that provides ancillary services. The costs of this solar regulation can be lower than current imbalance costs if these flexible plants are under the control of the Italian TSO that use them to correct the forecast error of the whole Italian generation. Thus, we suggest to economically supporting solar producers that install such flexible plants leaving their control to the national TSO. This support could consist in paying all the generated energy and the additional BESS power at day-ahead market prices adding a suitable amount to pay back the BESS' capital and operating costs (CapEx & OpEx). In this way, producers would maximize their revenues (since no imbalance cost would be charged) and improve the value of their plants with full flexibility without additional cost for BESS installation and O&M. As we showed in [14], this economic incentive for flexible PV farms employed for solar regulation could be paid for by the saving in national imbalance costs.

In [47], we further show how solar regulation applied to forecast certainty is the first logistic step to gradually reach ultra-high PV penetration in Italy (achieving over 92% RE energy contribution).

9. Conclusions

We first showed that the accuracy of our irradiance forecasts could be considered "state of the art" in Italy. We then applied a deterministic method to convert predicted irradiances into PV production from optimally oriented and tilted solar plants. We thus provided a benchmark of the forecast accuracy of the "relevant" PV plants generation in 1325 locations in Italy. We found that the RMSE of the day-ahead predictions ranged from 12% and 16% of PV nominal capacity with a skill score ranging between 25% and 40% depending on location.

We used the PV power forecast results to provide a benchmark of the net imbalance values of "relevant" PV plants i.e. the energy values on the DA and MSD markets net of the ideal incomes that could be obtained on DA market with no imbalance (i.e., perfect forecast). We found these values to be mainly negative (economic losses) and, on regional average, decreasing from the North to the South of the country, passing from -2.8 k€/MWp to -0.6 k€/MWp.

We also compared the energy values on the MSD and DA markets that could be achieved by the use of our forecasts to the energy values obtainable by a simple persistence prediction. Almost

everywhere in the country, our forecast produces lower economic losses or higher revenues than persistence on the MSD market place. The benefits of our forecast with respect to the persistence prediction ranges from 1 to 6 k€ per MW of PV capacity per years. This is considerably more than the cost of a high quality solar power forecasts. Nevertheless, we showed that these benefits were strongly reduced or even cancelled if we also considered the energy incomes obtainable by the PV generation scheduling on the DA market. Indeed, in some regions, the persistence prediction could produce even more profits than a much more accurate forecast on the DA and MSD markets.

We highlighted several important shortcomings of the Italian "single pricing" system that brings to paradoxical and counterproductive effects regarding the need to reduce the solar induced imbalance volumes.

1. The net imbalance absolute values (that ranges from -5 to 5 k€/MWp per year) are very small if compared with the total energy incomes on the DA and MSD markets (that ranges from 50 to 150 k€/MWp per year) hence with the current market rules the imbalances have a small impact on the total energy revenues of the PV producers/traders.
2. The net imbalance values that should be always negative (economic losses for producers) in some locations can be also positive (economic revenues). Hence, poorly predicted PV generation could even lead to higher profits than an "ideal" perfectly predictable generation (that will not produce solar-induced imbalance).
3. Not only the benefit of using more accurate forecast with respect to a simple persistence is very small but in some regions persistence predictions produce even higher revenues. Therefore, in these regions, there is no economic need to improve the forecast accuracy reducing the solar imbalance volumes.
4. For energy producer/traders, it is much more important, in order to maximize revenues, to predict the right macro-zonal imbalance sign and then deliver to Terna a suitable under/over PV generation forecast than provide Terna the most accurate power prediction.

Therefore, we demonstrated that, in Italy, the current market regulation framework is in complete disagreement with the physical need of reducing imbalances and hence it requires a significant revision to allow a higher PV penetration.

Finally, we suggested a simple revision of dispatching market regulatory frameworks that would avoid all the undesired effects of the "single pricing" scheme, forcing the solar producers to be balanced.

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