Solar Energy 174 (2018) 976–990

Contents lists available at ScienceDirect

Solar Energy

journal homepage: www.elsevier.com/locate/solener

Photovoltaic generation forecast for power transmission scheduling: A real case study

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ARTICLE INFO

Keywords:
Photovoltaic penetration
PV power forecast
Power transmission scheduling

ABSTRACT

The increased penetration of photovoltaic power introduces new challenges for the stability of the electrical grid, both at the local and national level. Many different effects are caused by high solar power injection into the electric grid. Among them, the increased risk of imbalance between the actual and scheduled power transmission is of particular relevance. The consequence is the need to exchange larger amounts of dispatchable power on the balancing energy market.

The aim of this work is to analyze and quantify the effects of PV penetration in a target region and to evaluate the energy and economic benefits of using day-ahead PV forecast for power transmission scheduling.

For this purpose, we developed several data-driven methods for transmission scheduling that include day-ahead PV power forecasts. We compared the resulting operational imbalances from these new models against two reference models currently used by the local grid operators.

In the case of no PV generation in the target area, the more accurate reference model leads to an imbalance of 3.6% of the peak power transmission while more accurate data-driven method reduces the imbalance to 3.2%. When the distributed PV capacity is not zero, the imbalance of the reference model grows from 5.15% (at the current penetration of 7%) to 9.8% (at the maximum planned regional penetration of 45%). When we apply the new scheduling model, imbalances are reduced to respectively 3.5% and 5.8% at 7% and 45% of penetration.

Since in Italy the costs of imbalances resulting from distributed PV are borne by ratepayers, these costs are estimated to be respectively 2.3% and 15% of the average electricity bill at 7% and 45% penetration if the reference scheduling is used. When applying the new model these costs are respectively reduced to 1.2% and 8.5%.

1. Introduction

The photovoltaic hosting capacity is the maximum capacity that can be integrated into the distribution grid with low impact on its stability, reliability and security (Ding et al., 2016; Dubey et al., 2015; Jothibasu et al., 2016). The residual electric demand (net-load), that should be covered by other non-intermittent energy sources, is the difference between the energy need (load) and the distributed PV generation. As PV penetration increases the net-load becomes increasingly dependent on meteorological conditions. This weather-induced net-load variability could potentially lead to electrical T&D issues such as voltage fluctuation and voltage flicker, generation uncertainty, lack of stabilizing inertia needed to maintain the system frequency, unintentional islanding, increasing of power ramps, as well as transmission availability and reliability, reverse power flow and energy imbalance problems (Kroposki et al., 2017; Stetz et al., 2015; Jothibasu et al., 2016; Denholm et al., 2016).

In 2015, the annual PV energy penetration in European countries was about 3%, with Italy leading at 8%. Different IEA scenarios anticipate this penetration to increase up to 10%-25% of the European Union electric energy demand (IEA, 2014a, 2014b, 2015). In Italy the National Energy Strategy (SEN) aims to triple the PV generation, passing from the actual 22.5 to 70 TWh per year in 2030 – corresponding to a PV penetration of 22% relative to the 2017 demand.

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https://doi.org/10.1016/j.solener.2018.09.054
Received 25 June 2018; Received in revised form 31 August 2018; Accepted 18 September 2018

Nomenclature

Acronym

DSO Distribution System Operator
TSO transmission system operator
NWP Numerical Weather Prediction
WRF Weather Research and Forecasting model
MOS model output statistic
DAEM day ahead energy market
BEM balancing energy market
P, SP persistence and smart persistence models used as reference to benchmark the forecast accuracy
PV NN upscaling method for regional PV generation forecast
ARI autoregressive model for transmission scheduling in the ideal case of no regional PV generation
ARIX autoregressive models with PV forecast exogenous inputs used for the transmission scheduling in case of high PV penetration (integrated method)
ARINN autoregressive models coupled with the PV forecast used for the transmission scheduling in case of high PV penetration (additive method)

Variables

P_{PV}^{actual}, P_{PV}^{NN} PV power generation (actual, predicted) normalized by the installed capacity (P_n) [MW/MWp]
$P_{TSO(noPV)}^{actual}$, $P_{TSO(noPV)}^{X}$ $P_{TSO\ (withPV)}^{actual}$, $P_{TSO\ (withPV)}^{X}$ Power transmission without and with PV generation (observed and scheduled by the model X) [MW]

Instantaneous ratios between the PV generation and the electric demand can be much higher than the annual energy penetration especially during summer. Thus, even with an apparently low annual penetration, the risk of negative impacts to the power grid cannot be excluded a priori.

Several strategies can be adopted by Transmission and Distribution System Operators (TSO and DSO) to mitigate the effects of high PV penetration and to increase the hosting capacity (Perez et al., 2016; Shivashankar et al., 2016; Emmanuel and Rayudu, 2017). Among these, regional PV power forecasting at different horizons is one of the first that can be implemented because it does not imply any change in grid configuration or any installation of new electrical devices, and it is already available at a small fraction of grid operations' costs. Hours and day ahead PV forecasting will become increasingly important to TSO and DSO to manage and balance the electric grid and to reduce the trading costs in energy markets.

In particular, solar prediction can be used for the transmission scheduling that DSOs have to provide to the TSOs. The TSO uses this scheduling to predict the day ahead power generation. Forecast can also be used directly by the DSO to prevent grid congestions in the connection between the transmission and the distribution grids and predict unintentional islanding or reverse power flow conditions.

The focus of the study is to calculate the day-ahead transmission scheduling for the TSO and to evaluate the errors that forecast of transmission (that would be necessary in case of no PV generation) and PV power add to this schedule and their imbalance and economical effects.

For these purposes:

1. We analyze the impact of PV penetration on grid balancing issues for a small area of the South Tirol region (North of Italy) under control of a local DSO. In 2015, the distributed PV generation provided almost the 7% of the annual electric load of the controlled area, very similar penetration to the one observed at national scale (8%). Furthermore, because solar is the only intermittent renewable energy source on this grid, the effects of the PV generation on the net-load and on the high voltage power that the TSO should supply to the local DSO to cover the electrical demand (i.e. power transmission) can be easily pointed out.
2. We evaluate the energy and economic benefit of applying PV power forecast in the day ahead scheduling of the power transmission in the controlled area. For this purpose, four different transmission scheduling models were developed. Two of them, used as reference models, are based on statistical persistence of the power profile regardless the PV generation. The two other models take into account the PV power prediction and are based on two different approaches: (1) an integrated approach where the PV forecast is the exogenous input of a seasonal autoregressive model, and (2) an additive approach consisting in subtracting the PV forecast to the scheduling of the power transmission in the case of no PV generation. For this reason, a model to scheduling the power transmission in the absence of PV was also built up. The PV generation forecast was obtained using an upscaling method described in Pierro et al. (2017). The power imbalance and its related costs obtained by the more accurate forecast and reference models were compared. In this way, the benefits of using scheduling models that include PV prediction with respect to simple statistical approach were quantified.
3. We simulate the effects on the power imbalance and its cost as a function of PV penetration in the controlled area. Since, in Italy the imbalance costs related to the errors in the distributed PV generation forecast are included into the electricity bills of the end-users, the economic gains for the community in using more accurate PV forecast was evaluated.

It should be remarked that the scheduling models proposed in this work could be used not only by the DSO but also by the TSO to predict directly the net load of the next day and consequently arrange the power generation. Thus this practical application of PV forecast could be useful to both DSOs and TSOs to better understand why and how solar forecasting should be integrated into their ancillary services. Indeed, as is explicitly mentioned in Zhang et al. (2015), there is a "lack of in-depth understanding about how forecast information may fit into the specific utility or ISO practices".

The paper is structured as follows:

- In Section 2, we report a short review on PV forecast application for grid managing issues, pointing out the novelty of this work with respect to literature.
- In Section 3, we describe the methods for day-ahead transmission scheduling.
- In Section 4, we describe the experimental data that are analyzed.
- In Section 5, we define the metrics adopted for forecast accuracy assessment.
- In Section 6, we describe the effects induced by PV generation on net-load and power transmission. We evaluate the impact of the PV forecast models and their accuracy on transmission scheduling. Finally, we evaluate the impact of PV penetration on power imbalances and related costs.

2. Background

Whereas there is an extensive body of literature on load forecasting (Alfares and Nazeeruddin, 2002; Hong and Fan, 2016), only recently did PV power predictions become included in these load forecast