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Quantifying residential PV feed-in power in low voltage grids based on satellite-derived irradiance data with application to power flow calculations

Holger Ruf [a,c,*], Marion Schroedter-Homscheidt [b], Gerd Heilscher [a], Hans Georg Beyer [c]

[a] Ulm University of Applied Sciences, Institute of Energy and Drive Technologies, Eberhard-Finckh-Strasse 11, 89075 Ulm, Germany
[b] German Aerospace Center, German Remote Sensing Data Center, Oberpfaffenhofen, 82234 Wessling, Germany
[c] University of Agder, Department of Engineering Science, Jon Lilletunsvei 9, Grimstad, Norway

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ABSTRACT

A scheme using satellite-derived irradiance measurements to model the feed-in power of residential photovoltaic (PV) systems in a low voltage distribution grid is described. It is validated against smart meter measurements from a test site with 12 residential PV systems in the city of Ulm, Germany, during May 2013 to December 2014. The PV feed-in power is simulated in a 15-min time resolution based on irradiance data derived from Meteosat Second Generation satellite images by the physically based retrieval scheme Heliosat-4. The PV simulation is based on the nominal power and location of the PV systems as provided by the distribution system operator. Orientation angles are taken from high resolution aerial laser-scan data. The overall average mean error of PV feed-in power is 4.6% and the average root-mean-squared error is 12.3% for the individual systems. Relative values are given with respect to the total installed power of 152.3 kWp. Sensitivity studies discuss the need for knowing the exact orientation angles of each individual PV system or the usefulness of a single ground-based measurement as alternative to satellite observations. As an application of the scheme, the modelling of the effect of the power flow from the residential PV on the load flow of the low voltage distribution grid transformer is described and illustrates the advantage of the discussed approach for distribution system operators.

1. Introduction

In Germany, the majority of photovoltaic (PV) systems is installed in residential areas and connected to the low voltage distribution electricity grids. A major increase in the number of PV systems has been observed in recent years, causing new challenges for the electricity grid management (DGS, 2015).

Grid stability and power quality at the low voltage level is guaranteed by the distribution system operators (DSO). Nowadays the interconnections between the high and medium voltage grid are monitored widely in real time. Also, remote controllable devices exist to actuate the grid. On the other hand, at the interconnections between the medium and the low voltage grid only current meters with slave pointers are used. These only show the real-time readings but do not store or transmit the data for further analysis. Additionally, they allow monitoring the maximum apparent power at a transformer station which occurred since the last readout. Typically, the readout is only done manually once a year. In order to improve the monitoring capabilities a significant addition of controllable devices in the low voltage grid is currently foreseen (e.g. Agricola et al., 2014).

DSOs have to plan, operate, and maintain the grid to avoid voltage band violations and overloading of grid assets (EnWG, 2013). In doing so, their objective is to avoid unnecessary investments in *brute force* grid reinforcement. This may occur due to missing knowledge on the PV power contribution in different grid sections. There is a need for a cadaster of existing PV systems. DSOs require accurate information on distributed energy resources in the electric grid in order to fulfill their responsibility for grid operations (EnWG, 2013; NAV, 2006; TAB, 2009). On the other hand, solar surface irradiance time series over e.g. the last ten years and in 15-min temporal resolution are required to realistically simulate the recent PV feed-in power under the assumption of increasing solar shares. Having in mind that any expansion of the grid infrastructure will last over decades, the need for reliable planning data and simulation tools is obvious. Both, the potential maximum

* Corresponding author at: Ulm University of Applied Sciences, Institute of Energy and Drive Technologies, Eberhard-Finckh-Strasse 11, 89075 Ulm, Germany.
E-mail address: ruf@hs-ulm.de (H. Ruf).

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and the current feed-in active power of the grid-connected PV systems at any point in time in all their grid sections and at the transformer station level are required.

There is a gap between available methodologies for simulating and monitoring the individual PV system and the sum of PV feed-in power at the transformer station at low voltage level. Fig. 1 gives a schematic view of the factors affecting the load flow at the transformer. Besides the load in the low voltage grid segment, the variable PV generation needs to be simulated as a sum of the individual PV systems. The latter is a function of the respective PV system type and size as well as the irradiance on the module plane at each PV system.

The influence of distributed PV systems on the load flow in the distribution grid on both low and medium voltage levels has been described e.g. in Pardatscher et al. (2011). They derived the load flow for a total of 910 PV systems in a 12 km × 12 km area in southern Germany. However, the study was only for an assumed clear-sky day and another single day with large fluctuations as extreme cases. The day-to-day behavior remains an open question.

For realistic modelling of the real PV feed-in power, accurate measurements of irradiance conditions have to be available. Up to now, ground measured irradiances are used typically for the simulation of individual residential PV systems. Ueda et al. (2009) investigates the performance of 553 roof-mounted residential PV systems with various orientations by taking into account the local irradiance measured by a single pyranometer.

Such ground measurements are point measurements only and do not fully represent the natural spatial and temporal variability of a distributed PV fleet (Lave et al., 2013). In contrast, satellite-based irradiances provide the spatially distributed information, but with restrictions in the available spatial and temporal resolution. Typically, satellites have several km-sized pixels and 5 to 15-min temporal resolution. On the other hand, time series can be provided for more than 10 years. Satellite irradiance data may therefore fulfill the DSOs' needs for historical and spatially resolved information at 15-min time steps. This paper assesses the suitability of this approach.

PV simulation studies have been making use of satellite-based data to some extent. Leloux et al. (2012a,b) assessed the performance of more than 7000 residential PV systems in France and Belgium but using monthly irradiation only. Also they did not relate it to the load flow. The performance simulation and interaction of a PV fleet distributed over an area of 11 km × 15 km with 15-min irradiances derived from satellites is reported in Grossi et al. (2014). They assumed only a singular orientation for all systems. A similar approach was taken by Hoff and Perez (2012) for the determination of the variability of PV feed-in power on the macro scale area with a range from 10 km to 300 km. Bucher et al. (2012) used 15-min satellite data to derive statistical values for a given location to generate synthetic high resolution PV feed-in power profiles by Monte-Carlo simulations. These synthetic PV feed-in power profiles are used for the calculation of the hosting capacity for distributed PV systems in grids, taking into account various load profiles. However, only statistical reference grids are used instead of a real electric grid topology and a comparison against smart meter measurements is not provided. Rikos et al. (2008) have shown the suitability of using satellite-based irradiances to simulate the voltage at a substation for selected test cases in the island grid of Kythnos, Greece. Sky imagers are an alternative to satellite data and provide even higher spatial and temporal resolution, but sky imagers are only deployed in a few places and over short periods of time (Nguyen et al., 2016).

For the management of large scale transmission systems with a significant amount of PV penetration in Europe (Kühnert et al., 2014) and the U.S. (Renné, 2014), the use of satellite derived irradiation information is state-of-the-art. The information gap concerning the lack of monitoring individual PV systems with their orientation and system data, is virtually closed by using a lumped PV model, representing the average response of the PV fleet (Beyer et al., 2004). This requires that the number of PV systems covered is sufficiently large in order to average out the specific peculiarities of individual systems. Within this type of studies, details of planning and operation at the low voltage level are not handled.

A part of the information gap, especially the PV system orientation, can be closed with 3D data from geographical information systems. The combination of using both digital elevation models based on airborne laserscan data and solar irradiance data is state-of-the-art for the calculation of the received annual solar energy on tilted module planes. Fath et al. (2015) apply this approach by using irradiance data from the Meteonorm database (Meteotest, 2015). Jakubiec and Reinhart (2013) take 15-min irradiance data from a meteorological station nearby. Verso et al. (2015) use satellite-based time series of irradiances. However, all these studies focus on the theoretical solar potential on roofs in urban sites and not on the feed-in power of existing PV systems.

Normally, the DSO knows only the location of the connection point and the nominal power of the PV system, but not the individual orientation angles or the shadowing for each system due to obstacles in the neighborhood. Therefore, an objective of this study is to work with these imperfect limited data and not with all information available from a well-known test site as e.g. module and inverter types or PV mounting systems. Nevertheless, in order to quantify this information gap, the orientation angles of the

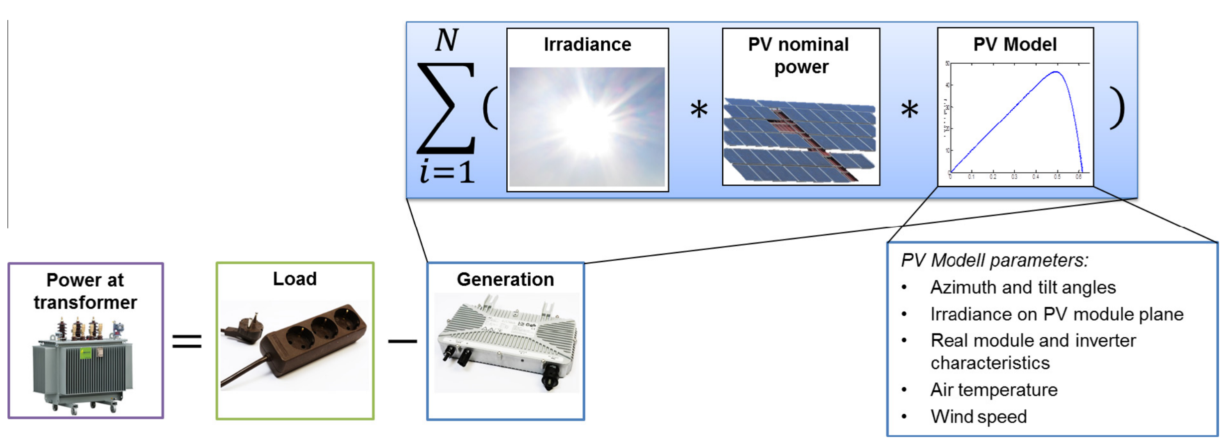

Fig. 1. Schematic study setup for simulation of the feed-in power of residential PV systems.