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A scalable method for estimating rooftop solar irradiation potential over large regions

René Buffat*, Stefano Grassi, Martin Raubal

Institute of Cartography and Geoinformation, ETH Zurich, 8093 Zurich, Switzerland

HIGHLIGHTS

- Scalable method to estimate building rooftop solar irradiation potential.
- Validation of monthly energy production of 500 PV systems in Switzerland: $R^2 = 0.9$.
- Median error in July −0.55%, in December +28.08% (probably due to snow cover).
- The model shows for Switzerland a rooftop PV potential of 53.2 TW h.

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ABSTRACT

An estimate of solar irradiation potential over large regions requires the knowledge of the long-term spatio-temporal distribution of the solar radiation as well as the identification of the suitable surfaces where the photovoltaic (PV) installations can be built. These main components can be modelled in different ways and are thus affected by different sources of uncertainty. Thus, when estimating the exploitable potential over large regions, it is important to measure the accuracy of the entire process. In this work, we provide a generic method to estimate the solar irradiation potential of rooftops over large regions and an estimate of the corresponding uncertainties when calculating the long-term electricity generation of PV plants. This method uses satellite based solar radiation data covering a period of 22 years, with a temporal resolution of 30 min and a spatial resolution of 3.8–5.6 km. Suitable surfaces on rooftops are identified using Digital Surface Models combined with building footprints. This allows to determine the geometry of rooftops, such as slope, and orientation with a spatial resolution of 0.5 m. Finally, we calculated the electricity generation based on models which take into account all characteristics of PV system components. In order to estimate the accuracy of the model for electricity production, we compared the monthly generation of 500 PV plants in Switzerland consisting of different PV technologies (mono-crystalline, poly-crystalline and thin film) with the estimates. The validation results show a correlation coefficient (R^2) of 0.9 and a median monthly relative error between 0.28% (August) and 28.08% (December). The monthly estimates are more accurate during summer time, while spatially and technology-wise no significant differences are found.

1. Introduction

The modelling and prediction of the spatio-temporal solar irradiation is a challenging task due to the complexity and variability of the involved phenomena. The amount of solar irradiation reaching the surface of the Earth is subject to cloud cover and the composition of solar irradiation in the atmosphere [1], the slope and orientation of tilted surfaces, shadows due to local natural and anthropogenic objects [2] and the reflectance properties of the ground.

Photovoltaic (PV) systems transform the incoming solar irradiance to electricity and consist of several electrical components, such as PV modules and inverters whose performance is affected by multiple exogenous and endogenous factors. The transformation efficiency of such systems depends on the physical properties of the used components, such as the performance of the PV cell or the inverter, but also environmental properties such as dusting, external temperature and the level of solar irradiance [3]. For these reasons, when estimating the PV potential, the critical main aspects to consider are (1) the assessment of the accuracy of both the data of the solar radiation over the time and over the space and (2) the model transforming the solar radiation into electricity using PV systems.

Concerning the solar radiation, at present there are two main

* Corresponding author.
E-mail address: rbuffat@ethz.ch (R. Buffat).

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Nomenclature

α	orientation of inclined surface
α_{ISC}	temperature coefficient of short circuit current
β	slope of inclined surface
β_{VOC}	temperature coefficient of open circuit voltage
ρ	ground reflectance albedo
θ_h	solar elevation angle [rad]
θ_i	incidence angle on inclined surface [rad]
θ_z	solar zenith angle [rad]
θ_{hor}	horizon angle [rad]
a	diode ideality factor of the single-diode model
a_0	diode ideality factor of the single-diode model at NOCT conditions
A_{cell}	PV cell area
A_{panel}	PV panel area
E_g	energy gap
FF	fill factor
G	global horizontal solar irradiance $\left[\frac{\mathrm{W}}{\mathrm{m}^2}\right]$
G_B	direct horizontal solar irradiance $\left[\frac{\mathrm{W}}{\mathrm{m}^2}\right]$
G_D	diffuse horizontal solar irradiance $\left[\frac{\mathrm{W}}{\mathrm{m}^2}\right]$
$G_{\alpha,\beta}$	global solar irradiance on inclined surface $\left[\frac{\mathrm{W}}{\mathrm{m}^2}\right]$
$G_{B,\alpha,\beta}$	direct solar irradiance on inclined surface $\left[\frac{\mathrm{W}}{\mathrm{m}^2}\right]$
$G_{D,\alpha,\beta}$	diffuse solar irradiance on inclined surface $\left[\frac{\mathrm{W}}{\mathrm{m}^2}\right]$
$G_{R,\alpha,\beta}$	reflected solar irradiance on inclined surface $\left[\frac{\mathrm{W}}{\mathrm{m}^2}\right]$
I_m	solar irradiation of month m [W h]
I_s	diode saturation current of the single-diode model
I_{MP}	current at maximum power point
I_{ph0}	diode photo current of the single-diode model at NOCT conditions
I_{ph}	diode photo current of the single-diode model
I_{s0}	diode saturation current of the single-diode model at NOCT conditions
I_{SC}	current at short circuit condition
k	Boltzman constant
mono	mono-crystalline PV cell technology
N_p	number of cells of a PV module in parallel
N_s	number of cells of a PV module in series
NOCT	nominal operation cell temperature
poly	poly-crystalline PV cell technology
q	elementary charge
R_s	series resistance of the single-diode model
R_s0	series resistance of the single-diode model at NOCT conditions
R_{sh0}	shunt resistance of the single-diode model at NOCT conditions
R_{sh}	shunt resistance of the single-diode model
T_{ref}	nominal operating PV cell temperature
V_{MP}	voltage at maximum power point
V_{OC}	voltage at open circuit condition

sources of data: punctual measurements collected on the ground by weather stations and maps generated by devices installed on satellites. Ground mounted weather stations are sparsely distributed all over the world and measure the solar irradiation at ground level in a given location with different time resolutions (i.e. 10 min to 3 h or greater). Since the cost of the installation and maintenance of a ground based network are significant, the density and coverage in each country vary. On the other hand, devices installed on satellites can permanently scan the Earth's surface from different perspectives. Satellites record images of the earth at different wavelengths. These data are then used to estimate the cloud cover and the corresponding solar irradiation at ground level [4–6].

Both methods and technologies have advantages and downsides, leading to errors depending on the location and the boundary climate conditions, and for these reasons have been investigated in previous work in order to identify their main differences. Concerning the usage of ground-based measurements, researchers have recently evaluated and assessed interpolation methods using different time resolution, latitudes and elevations to identify the impact of different boundary conditions on the results.

First studies aiming at the generation of continuous maps of the solar radiation from ground-station measurements used different techniques such as spline functions, weighted average procedures or kriging [7–9]. The widely used r.sun [10] method is implemented in GRASS GIS and designed based on the equation of ESRA (European Solar Radiation Atlas) [11,12], which provided a significant contribution in terms of accuracy and progress compared to previous models. GIS-based models were implemented to estimate the spatial distribution of the solar radiation with monthly and daily temporal resolution in South Korea [13], Fujian Province with an annual temporal resolution [14], and Auckland, New Zealand [15] using ESRI's solar radiation analyst.

Unlike methods used at ground stations, satellite data and maps have the advantage to provide a large spatial and temporal resolution. In [16], the uncertainties when combining ground based measurements and satellite images are investigated. Five models converting satellite images into different radiation components (i.e. global and beam irradiance) were validated in [17] using the measurements collected in 2006 from 23 ground stations located in Europe at latitudes between 20° and 60°. The study shows that the global horizontal irradiance is retrieved with a mean bias of 1% $\left(\text{i.e. } 4\ \frac{\mathrm{W}}{\mathrm{m}^2}\right)$ and that an average standard deviation of 16% $\left(\text{i.e. } 55\ \frac{\mathrm{W}}{\mathrm{m}^2}\right)$ is achieved by the algorithm with best performance. The uncertainty of the generated maps was assessed using ground measurements from 27 meteorological stations available in Spain.

Previous work therefore demonstrated that satellite images of the solar radiation provide data in the form of continuous maps with different spatio-temporal resolution which must be validated (or complemented) using ground based measurements to quantify their accuracy. Nevertheless, despite these uncertainties, satellite or interpolated maps of the solar radiations are often used to determine the PV electricity generation with different time resolution and in different regions of the world such as Hong Kong [18], Greece [19], Piedmont [20] and the Canary Islands [21]. Despite differences in spatio-temporal resolution, satellite-derived data offer the unquestionable advantage to cover large areas and time periods, which is more reliable than extrapolating point measurements of ground based weather stations using statistical or geometrical approaches. For these reasons, satellite data offer a practical advantage when assessing the PV potential over large regions.

As aforementioned, the estimate of the PV potential on rooftops over large regions has multiple advantages and various approaches have been proposed combining GIS data and climate data. In order to quantify the PV potential over large regions, empirical methods were used to combine satellite images, building footprints and statistical data to quantify the available rooftop areas. The disadvantage of these methods concerns the large uncertainties when estimating the rooftop surfaces and thus the PV potential. Recent studies demonstrated that the use of LiDAR data significantly improves the identification of rooftop geometries [22–25,15] and thus estimate the PV electricity generation with a higher accuracy, the PV electricity generation [26–29]. Although these data allow for a significant increase in accuracy, one of the disadvantages of LiDAR data is the lack of large-scale availability. An alternative to LIDAR data are 3D city models [30–32].