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Comparative Analysis of Direct Inclined Irradiance Data Sources for Micro-Tracking Concentrator Photovoltaics

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Abstract: In recent years, the scientific community has intensified its efforts to develop a new type of concentrator photovoltaic module that is competitive with conventional modules. These modules are based on internal tracking systems, known as micro-tracking concentrator photovoltaic modules, which generate electrical energy proportional to the direct radiation on the inclined surface. There are several reviews, databases, and models for various components of solar radiation, particularly for global and direct normal radiation. However, readily available data on direct inclined irradiance remain scarce. This paper reviews several available sources of solar radiation data, finding that only the Photovoltaic Geographic Information System and Solar Radiation Database provide direct inclined irradiance data. A comparative statistical analysis was carried out, and a reasonable fit was obtained between both databases. In addition, direct inclined radiation data extracted from these databases were compared with the values calculated using a well-established mathematical model. In addition, worldwide maps were generated to determine areas of interest for this technology. Therefore, this paper presents an original comparative analysis of existing databases containing information on direct inclined irradiation. This information is of interest for the accurate design and performance analysis of micro-tracking concentrator modules.

Keywords: micro-tracking concentrator photovoltaic; direct inclined irradiance; solar radiation model



Academic Editor: Manoj Jamarkattel

Received: 29 April 2025

Revised: 1 June 2025

Accepted: 4 June 2025

Published: 5 June 2025

Citation: Perez-Higueras, P.; Ceballos, M.A.; Mouhib, E.; Bessa, J.G.; Montes-Romero, J.; Mata-Campos, R. Comparative Analysis of Direct Inclined Irradiance Data Sources for Micro-Tracking Concentrator Photovoltaics. *Electronics* **2025**, *14*, 2297. <https://doi.org/10.3390/electronics14112297>

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1. Introduction

An innovative and promising alternative in the field of solar energy and conventional photovoltaics (PVs) has materialized through concentrator photovoltaics (CPVs). This technology concentrates solar light onto small but highly efficient solar cells [1]. Although these cells are expensive, their cost is offset by the low cost of the concentrator optical elements used [2]. CPV systems have demonstrated their technical feasibility, obtaining CPV modules with a laboratory efficiency of 41.1% [3] and a commercial efficiency of 34% [4]. However, they have not been economically competitive with conventional PV systems [5]. This lack of competitiveness is mainly due to the need for costly tracking systems.

An accurate normal incidence of solar radiation on the module surface is essential for optimal performance in conventional CPV systems. This objective is achieved through the implementation of an external solar tracking device that follows the movement of

the Sun [6]. Nevertheless, its incorporation entails additional costs in terms of installation and annual maintenance, presenting an economic challenge for CPV technology. Furthermore, the weight and size of these trackers limit their installation in certain locations. In recent years, the scientific community has made significant efforts to make CPV technology competitive and integrate it into markets where it was previously excluded. To address this issue, a new type of CPV module has been developed [7,8], using small trackers—the so-called micro-tracking or tracking-integrated CPV (TICPV) modules. In this way, CPV systems are expected to become competitive, in terms of cost, with conventional PV systems.

A TICPV module is a static device with fixed azimuth and tilt, equipped with optical concentrator elements, high-efficiency solar cells, and an internal tracking system. It is an alternative to conventional trackers. The inclusion of tracking systems within a CPV module offers a distinctive approach to aligning the system with the solar trajectory. Rather than relying on conventional external devices, the CPV module itself performs this task autonomously by adjusting its components according to the movement of the Sun [9]. The concentrator module maintains a constant inclination, while its moving components allow it to track the angle of incidence as the Sun moves across the sky. Since the modules are fixed and contain concentrator elements, the energy generated by this type of module is proportional to the direct irradiance received in the plane of the outer surface or direct inclined irradiance (DII). This dependence on DII is the main difference compared to CPV modules, which depend on direct normal irradiance (DNI), and conventional FV modules, which depend on global tilt irradiance or global inclined irradiance (GII).

Regarding the relationship between DNI, DII, and direct horizontal irradiance (DHI), it can be observed that when the receptive surface is perpendicular to the solar rays, the power density on the surface equals the incident power density. However, as the angle between the Sun and the surface changes, the intensity on the surface decreases. As shown in Figure 1, the relationship between DII, DNI, and DHI is purely geometric:

$$DII = DNI \cos \theta_S \quad (1)$$

$$DHI = DNI \cos \theta_{ZS} \quad (2)$$

where θ_S is the angle of incidence of the beam radiation on the tilted surface or angle between the two vectors ($\vec{r}$ and $\vec{n}$), θ_{ZS} is the solar zenith angle, and $\vec{r}$ is the solar vector, also known as the unit vector, which points towards the Sun, and $\vec{n}$ is the normal vector or unit vector normal to the surface of the module. Thus, additional losses occur when the surface is not orthogonal to the sunlight, reducing the energy incident on the module surface due to cosine projection losses. These losses can significantly reduce the annual irradiance collected on a surface that is not permanently normal to the Sun.

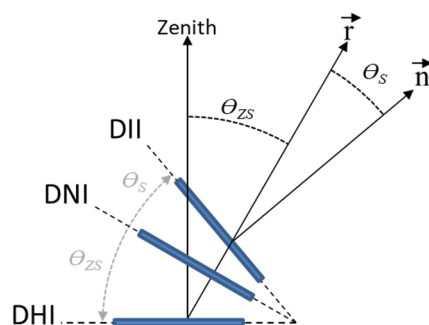


Figure 1. Relationship between angles and surfaces with different orientations.

Knowing the amount of DII available on the Earth's surface at a particular location is essential for engineers and scientists in designing TICPV systems. These DII datasets are imperative for estimating energy output, performing economic analysis, monitoring plan operation, and more.

There are two main methods for determining ground-level solar irradiance: direct measurements from ground solar monitoring stations and satellite-based models that attempt to predict the amount of ground-level solar irradiance based on images taken of the Earth and the amount of thermal reflectance from the Earth's surface.

Ground monitoring stations typically include two separate instruments to measure radiation components. A pyranometer typically measures global horizontal irradiance (GHI), and a pyrhelimeter measures DNI. These weather stations could measure DII using pyrhelimeters fixed at a certain tilt angle, but this type of measurement is not typically performed. Furthermore, most CPV laboratories measure DNI but not DII. In contrast, conventional PV research facilities and plants typically measure GII and GHI, but not DII.

Satellite-derived surface solar radiation estimates are an alternative to the solar radiation measured at ground solar monitoring stations. The advantage of satellite-derived solar radiation is its high spatial and temporal resolution compared with solar radiation derived from weather stations. Satellite-derived databases usually only offer GHI and DNI data; they usually do not offer DII data either.

Another way to obtain DII data is to calculate them using other measured meteorological variables. Given the absence of DII and the availability of DNI or GHI data, numerous models have been proposed with this aim in mind in the scientific literature. These models use irradiance measurements of global, diffuse, and direct irradiance components on the horizontal plane as input data. The objective of these models is to estimate the values of direct and diffuse irradiance components on surfaces at a specified inclination angle [10–13]. Most of these models exhibit complexity and/or possess limited applicability to specific geographic regions [14–16]. Additionally, within the existing body of literature, numerous models can be found for computing DNI based on diverse parameters. While certain models are straightforward [13,14], others are complex and challenging to implement, particularly due to the need for input data that are not readily available, such as measurements derived from satellite images [17–20].

The main objective of this work is to review radiation sources that offer suitable DII data for TICPV modules; in particular, the objective is to query the main satellite-derived spatial databases to determine which offer DII data and to make a comparative analysis. Furthermore, a secondary objective of this work is to compare the DII databases obtained by satellite with data obtained through a simple mathematical model. This will allow easy estimation of DII while exclusively using latitude and DNI as the input data. The model used is based on user-friendly equations proposed in several studies, which offer a reliable estimation covering a wide spectrum of latitudes with satisfactory accuracy for application in TICPV systems. The aim is to contribute to the advancement of TICPV technology and to provide tools that identify areas of interest and support decision-making by stakeholders in the energy system (politicians, companies, scientists, etc.). This is particularly valuable in a context where solar energy is emerging as a crucial source of sustainable energy worldwide.

2. Direct Inclined Irradiance Spatial Databases

To determine the energy generated by a PV system, it is advisable to use radiation data from a nearby location (with a spatial resolution of less than 10 km) and to have a long time series (greater than 10 years). If available, the typical meteorological year (TMY) for the location where the system will be located should preferably be used. These TMY datasets are derived from measurements taken at ground-based meteorological stations spanning

a ten-year period [21–23]. However, due to the associated expenses, such measurements are limited, and these data are only accessible at a small number of specific locations. To address this challenge, an alternative approach can be used: generating a spatial database using a model that derives radiation values from satellite data.

Satellite-derived estimates of surface solar radiation offer an alternative to ground-based solar monitoring station measurements. These satellite databases combine measured and modeled solar radiation data. The main advantage of satellite-derived solar radiation is its high spatial and temporal resolution compared to that from ground station data.

Several spatial databases offer radiation data for various geographical locations and time intervals. Among these databases are the EUMETSAT Satellite Application Facility on Climate Monitoring (CM-SAF) [24], NASA’s Surface Solar Radiation Data Set (SSE) [25], the NREL National Solar Radiation Database (NSRDB) [26], Meteornorm Worldwide Irradiation Data [27], Solcast NDV Company [28], Photovoltaic Geographical Information System (PVGIS) [29], Solar Radiation Data (SoDa) [30], Solargis Weather Data [31], and others. Table 1 presents the types of radiation data available in each database. All the databases analyzed provide GHI and DNI, while some also provide GII and DHI data. However, only two, the PVGIS and SoDa, offer DII data. Both offer annual, monthly, daily, and hourly values of DII. These databases will be described further in this section.

Table 1. Solar radiation data available (+) and not available (−) in different spatial databases.

	GHI	GI	DHI	DNI	DII
CM-SAF	+	−	+	+	−
SSE	+	+	−	+	−
NSRDB	+	−	+	+	−
Meteornorm	+	+	+	+	−
Solcast	+	−	+	+	−
PVGIS	+	+	+	+	+
SoDa	+	+	+	+	+
SolarGIS	+	+	−	+	−

PVGIS has been developed at the European Commission Joint Research Centre’s Ispra site in Italy since 2001. PVGIS focuses on research in solar resource assessment, PV performance studies, and the dissemination of knowledge and data about solar radiation and PV performance. The solar radiation databases have been developed by combining solar radiation models with interpolated ground observations. Methods for calculating solar radiation from satellites used in PVGIS data have been presented in several studies [32,33].

The SoDa service originated from a European project funded by the European Commission in 1999. Implemented in 2003 by Mines ParisTech and managed by the OIE (Observation, Impact, Energy Centre) research center of Mines ParisTech since 2013, it was acquired by Vaisala Oyj in 2023. SoDa is a web platform that facilitates the dissemination of solar radiation databases derived from HelioClim. These databases include irradiance measurements captured at the surface level, derived from the analysis of images captured by Meteosat satellites. The Heliostat-2 method allows for estimating radiation based on the analysis of 15 min Meteosat Second Generation (MSG) satellite images in the visible band. SoDa provides historical, real-time, and forecast meteorological and solar radiation data services. Table 2 lists this information.

The following sections analyze the worldwide annual DII values obtained from PVGIS and compare these values with the SoDa database for different locations.

Table 2. Key features of PVGIS and SoDa.

	PVGIS	DII
Spatial coverage	180° W to 180° E and 75° N to 65° S	66° W to 66° E and 66° N to 66° S
Spatial resolution	0.05° × 0.05°	0.05° × 0.05°
Temporal resolution	Hourly data	Hourly data
Availability period	2005 to 2020	2004 to 2024
Access to data	Open access	Open access only from 2004 to 2006

2.1. Worldwide Annual DII Data from PVGIS

Using the PVGIS Application Program Interface (API), annual DII values were obtained for 61,560 locations spanning latitudes from 85° S to 85° N and longitudes from 180° W to 180° E. The data have a spatial resolution of 1° and range from 2005 to 2014. Out of these locations, 46,063 values correspond to marine areas and 15,597 to terrestrial areas. Annual GHI and DNI values were also obtained for comparison with the DII values. To obtain the DII values, it was assumed that the inclination of the TICPV module is equal to the latitude of the location ($\beta = \varphi$) and that they are oriented towards the equator ($\alpha = 0$). All these values are presented in the histogram in Figure 2.

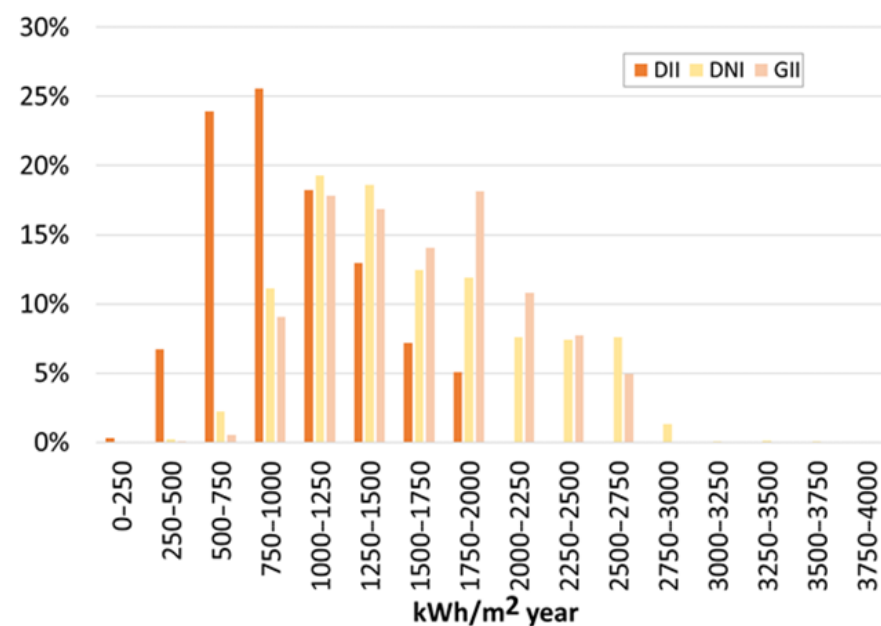


Figure 2. Annual irradiation histogram of DII, DNI, and GII. Data from PVGIS for 15,597 terrestrial locations from latitudes 85° S to 85° N and longitudes 180° W to 180° E. Data range from 2005 to 2014. It is assumed that the tilt is equal to the latitude of the location, and they are oriented towards the equator.

The annual DII values range from 99 to 2002 kWh/m²·year, with an average of 998 kWh/m²·year and a standard deviation of 385 kWh/m²·year. Most DII values fall between 750 and 1000 kWh/m²·year, with 81% of the values falling between 500 and 1500 kWh/m²·year. DNI and GHI values are higher than DII values, with maximum values of 3769 kWh/m²·year for DNI and 2693 kWh/m²·year for GHI. For DNI, 81% of the values range from 750 to 2250 kWh/m²·year, while for GHI, 87% of the values fall within the same range.

The acquired annual DII data are graphically depicted in Figure 3, using Surfer software developed by Golden Software (ver. 16) [34]. The map highlights areas of interest

for TICPV based on relatively high annual DNI values. Africa shows the highest annual DII, with maximum values exceeding $2000 \text{ kWh/m}^2 \cdot \text{year}$. The most remarkable regions in terms of DII values are the Sahara Desert and the Kalahari Desert. The Arabian Peninsula also exhibits high DII values, ranging from 1600 to $2000 \text{ kWh/m}^2 \cdot \text{year}$. In the Mediterranean, DII averages around $1200 \text{ kWh/m}^2 \cdot \text{year}$, representing the highest value in Europe. The Gobi Desert is another area of interest for TICPV due to its high DII values. In Oceania, north-western Australia shows DII values nearing $1400 \text{ kWh/m}^2 \cdot \text{year}$. In North America, the western regions of Mexico and the south-western USA, which encompass desert areas, also exhibit favorable conditions for TICPV, with values of around $2000 \text{ kWh/m}^2 \cdot \text{year}$. In South America, the Atacama Desert area and surrounding areas display some of the highest annual DII values, around $2000 \text{ kWh/m}^2 \cdot \text{year}$.

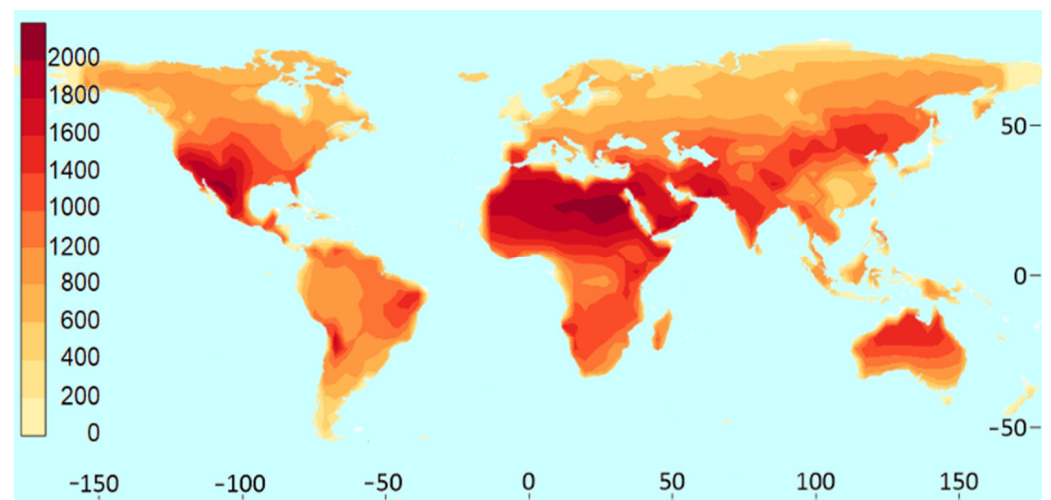


Figure 3. Annual DII ($\text{kWh/m}^2 \cdot \text{year}$). Data from PVGIS from latitudes 8° S to 8° N and longitudes 18° W to 18° E , with a spatial resolution of 1° . Data range from 2005 to 2014. It is assumed that the tilt is equal to the latitude of the location, and they are oriented towards the equator. © University of Jaen.

A TICPV system could have competitive advantages over CPV or conventional PV systems in geographic areas that simultaneously present a high DII value and a low DII reduction percentage compared to DNI or GII. Therefore, it is necessary to analyze the relationship between DII and DNI, as well as that between DII and GII.

The DII/DNI ratio versus latitude was analyzed to compare TICPV and CPV systems. However, when comparing TICPV with conventional PV, the DII/GII ratio versus latitude does not provide conclusive information. To address this, a detailed map WAS created to more precisely identify areas of interest. When comparing TICPV and CPV, it is critical to note that DNI is always higher than DII, meaning the ratio will be below 100%, and TICPV will always produce less energy than CPV. Nevertheless, TICPV systems can be more cost-effective than CPV systems due to their lower installation costs. To increase its competitiveness with CPV systems, the ratio for TICPV systems should be as high as possible, indicating high DII relative to DNI. As shown in Figure 4, latitudes between 2° S and 6° N have a DII/DNI ratio above 60%, making this range particularly relevant for TICPV systems.

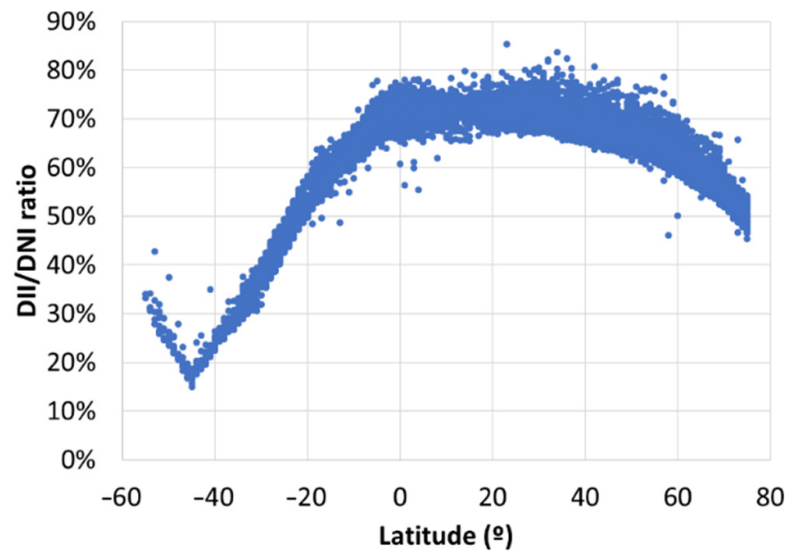


Figure 4. Ratio of DII/DNI versus latitude. Data from PVGIS for 15,597 terrestrial locations from latitudes 8° S to 8° N and longitudes 18° W to 18° E. Data range from 2005 to 2014. It is assumed that the tilt is equal to the latitude of the location, and they are oriented towards the equator.

In the comparison between TICPV and conventional PV systems, the same approach applies as in the previous case, but using GII instead of DNI. GII is always higher than DII; however, this does not imply that TICPV systems produce less energy than conventional PV systems, as more efficient cells are used ($\eta_{\text{cell}} > 45\%$).

Figure 5 is a map showing the percentage of reduction in annual DII with respect to GII. This is calculated using the following operation:

$$\Delta(\%) = \frac{\text{DII} - \text{GII}}{\text{GII}} \cdot 100 \quad (3)$$

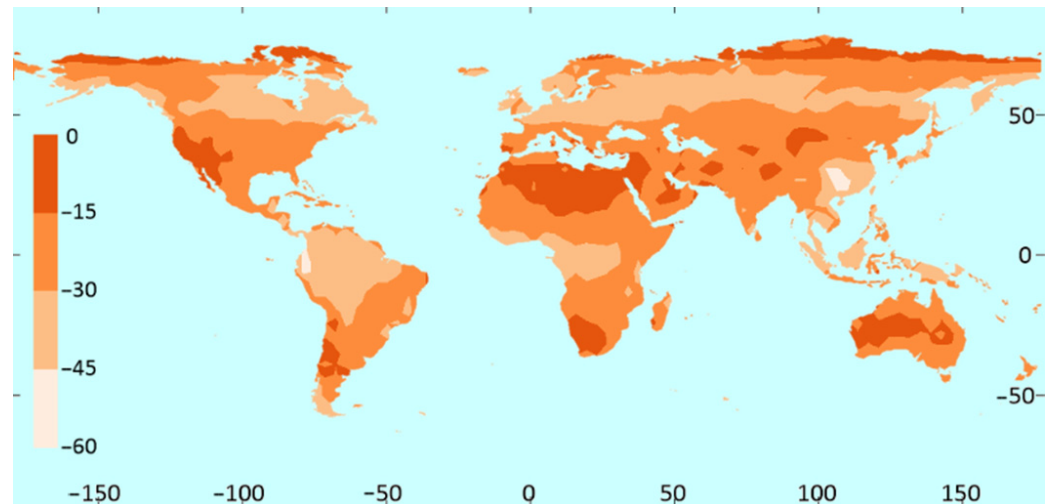


Figure 5. Relative difference between DII and GII in percentages: $\Delta(\%) = \frac{\text{DII} - \text{GII}}{\text{GII}} \cdot 100$. Data from latitudes 8° S to 8° N and longitudes 18° W to 18° E, with a spatial resolution of 1° and data ranging from 2005 to 2014. It is assumed that the tilt is equal to the latitude of the location, and they are oriented towards the equator. © University of Jaen.

By definition, a negative Δ ($\Delta < 0$) indicates a reduction in DII. The map areas with values close to zero (dark color) represent regions where the decrease in annual DII relative to GII is minimal. These locations are the most suitable for TICPV system deployment, enabling it to compete with conventional PV systems. As shown in Figure 5, the African

continent (both north and south) and Western Australia have the highest proportion of dark areas, indicating a maximum loss of 15%. South Asia also presents some regions with low losses. South America (especially in the southern region of Chile and Argentina) and North America (California, Nevada, and Arizona) also display a low percentage of DII reduction.

2.2. Comparison of Annual DII Data from PVGIS and SoDa

Selecting the correct data source and method to determine solar irradiance (W/m^2) at a specific geographic location is crucial for system design. A dataset that overestimates or underestimates the available solar irradiance at a specific location will affect the system's electrical performance, as real-world conditions may differ significantly from those assumed in the modeling process.

The spatial databases obtained from satellite data utilize a variety of input data, including satellite data and ground-based measurements. They also employ different methodologies to estimate DII values, obtaining different values in each database. Therefore, to investigate this uncertainty, a comparison was made between PVGIS and SoDa.

To perform this comparison, annual DII values were obtained for forty locations around the world for the years 2005 and 2006 from both databases (Data can be found in Supplementary Materials). The statistical metrics employed to compare the two databases were the relative mean absolute difference (MAD), the relative root mean square difference (RMSD), the coefficient of determination (R^2), the mean value of the difference (μ), and the standard deviation of the difference (σ). These metrics are defined as follows:

$$\text{MAD} = \sum_{i=1}^N \frac{(x_i - y_i)}{N} \quad (4)$$

$$\text{RMSD} = \sqrt{\sum_{i=1}^N \frac{(x_i - y_i)^2}{N}} \quad (5)$$

$$\mu = \frac{1}{N} \sum_{i=1}^N \frac{(x_i - y_i)}{x_i} \quad (6)$$

$$\sigma = \sqrt{\frac{1}{N} \sum_{i=1}^N \left(\frac{x_i - y_i}{x_i} \right)^2} \quad (7)$$

$$R^2 = \left(\frac{\sum_{i=1}^N (x_i - \bar{x})(y_i - \bar{y})}{\sqrt{\sum_{i=1}^N (x_i - \bar{x})^2 \sum_{i=1}^N (y_i - \bar{y})^2}} \right)^2 \quad (8)$$

where x_i and y_i are the values for the annual DII obtained from the SoDa and PVGIS databases, respectively, $\bar{x}$ and $\bar{y}$ are the mean values, and N is the number of locations analyzed ($N = 40$).

According to the definitions provided, the MAD measures the average magnitude of the difference without considering its direction, while the RMSD measures the squared difference between the two databases. The statistical μ and σ provide similar insights into the MAD and RMSD, respectively; however, μ reveals whether the average of the values in one database is greater or less than in the other, while σ quantifies the uncertainty between the values provided by the two databases. Finally, R^2 measures the linear fit between the two datasets.

Computation of the statistical indicators using the annual DII data of the forty locations studied (Table 3) found that the MAD is 8.21%, the RMSD is 9.94%, μ is 4.36%, and σ is 9.48%, and an R^2 value of 0.93 was obtained, as shown in Figure 6.

Table 3. Statistical indicators used to compare the annual DII values obtained from SoDa and PVGIS with those calculated using the mathematical model.

	N	MAD (%)	RMSD (%)	μ (%)	σ (%)	R ²
SoDa vs. PVGIS	40	8.21	9.94	4.36	9.48	0.93
SoDa vs. Mathematical model	40	1.74	2.17	0.57	2.07	0.99
PVGIS vs. Mathematical model	40	5.94	7.42	−5.22	4.65	0.98
PVGIS vs. Mathematical model	8000	6.08	6.89	−6.27	3.26	0.99

N: number of locations analyzed; MAD: relative mean absolute difference; RMSD: relative root mean square difference; R²: coefficient of determination; μ : mean value of the difference; σ : standard deviation of the difference.

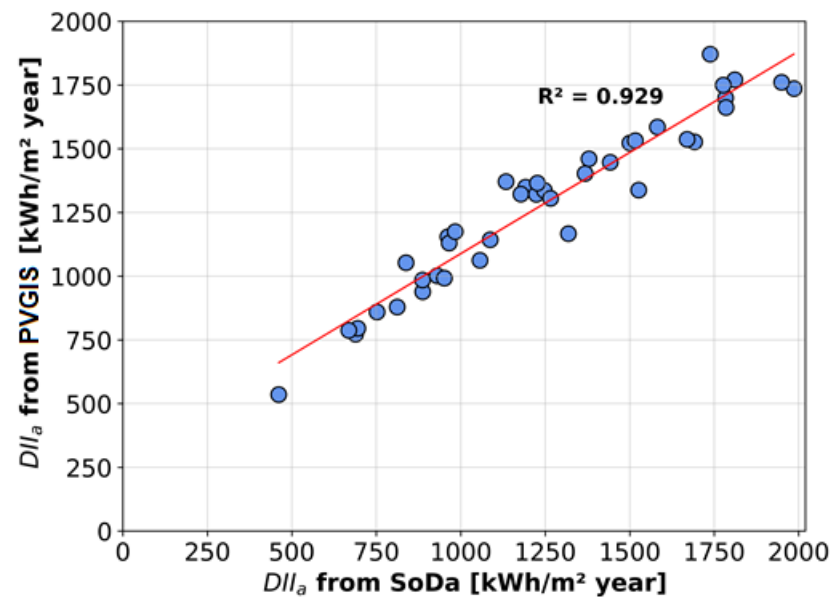


Figure 6. Annual DII (kWh/m²·year) from the SoDa database vs. that from the PVGIS database for 40 terrestrial locations, assuming the tilt is equal to the latitude of the location, and they are oriented towards the equator.

The values obtained for these statistics indicate that the average SoDa database value is slightly higher than the average of the PVGIS database. These statistical values also show some discrepancies between the data they provide, but there is a good fit for the studied locations.

Other studies have reported similar conclusions regarding the uncertainty of different types of radiation. *Suri et al.* [35] performed a cross-comparison of annual DNI maps from five databases providing solar resource and climate data information for Europe, obtaining an RMSD of up to 17%. *Harsarapama et al.* [36] compared and validated open-source satellite-derived solar resource databases for Indonesia, obtaining an MBD for GHI ranging from 3% to 7%. Similarly, *Marchand et al.* [37] compared several satellite-derived databases of surface solar radiation in Morocco and obtained an RMSD ranging between 12% and 21% for GHI.

The level of discrepancy observed highlights the need for improvements in both databases. Significant efforts have been made in this area, including the MESoR project [38], which is financially supported by the European Commission. This initiative aims to reduce uncertainty by establishing standardized benchmarking protocols and metrics to facilitate the comparison of databases. It also provides user guidance for employing resource data and offers unified access to diverse databases.

2.3. Comparison of DII Data from the Mathematical Model

In this section, the annual DII data provided by SoDa and PVGIS databases will be compared with data obtained using a well-established mathematical model.

In CPV systems, the temporal resolution and inherent uncertainty in radiation data have a multifaceted impact [39]. Nevertheless, some studies show that the complexity required for a solar radiation model in annual energy calculations is relatively minimal [40]. A set of twelve monthly mean solar irradiation values is sufficient for estimating annual values with negligible errors. Moreover, employing time resolutions shorter than hourly samples does not significantly improve energy estimation accuracy.

Therefore, the essential input parameters for the mathematical model calculations are the surface azimuth and tilt angle, site latitude, and the twelve-monthly average DNI. The outcome of the mathematical model is the annual DII. The model follows the sequence illustrated in Figure 7:

- I. Calculation of Solar Declination [41].
- II. Calculation of Sunrise Hour Angle [42].
- III. Direct Normal Irradiance Calculation from Irradiation [43].
- IV. Calculation of Angle of Incidence [44,45].
- V. Calculation of Hourly Direct Inclined Irradiance [46].
- VI. Calculation of Daily Direct Inclined Irradiation [46].
- VII. Calculation of Annual Direct Inclined Irradiation [46].

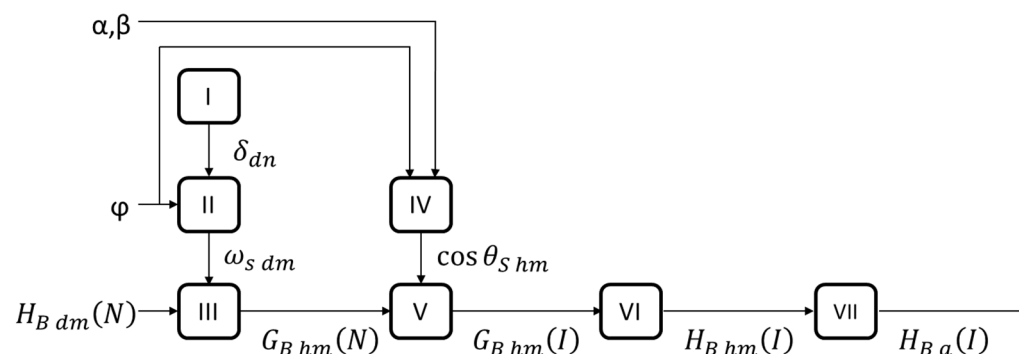


Figure 7. Flow diagram of the mathematical model for calculating DII from DNI, where α is the surface azimuth angle, β is the surface tilt angle, φ is the site latitude, $H_{B\,dm}(N)$ is the monthly average daily direct normal irradiation, δ_{dn} is the solar declination of the day at midday of every month, $\omega_{s\,dm}$ is the sunrise hour angle of the day at midday of each month, $\theta_{s\,hm}$ is the monthly average hourly angle of incidence, $G_{B\,hm}(N)$ is the monthly average hourly direct normal irradiance, $G_{B\,hm}(I)$ is the monthly average hourly direct inclined irradiance, $H_{B\,dm}(I)$ is the monthly average daily direct inclined irradiation, and $H_{B\,a}(I)$ is the annual direct inclined irradiation.

First, a comparison was made between the annual DII values calculated using the mathematical model and those provided by the SoDa database. To perform this comparison, the annual DII was calculated for each of the forty locations studied in Section 2.2 using a procedure involving two steps. This process began with directly obtaining the annual DII value for each location from the SoDa database. Subsequently, the twelve monthly DNI values for each location from the SoDa database were obtained and used as input for the mathematical model to calculate the annual DII value.

To facilitate a comparative analysis between both sets of DII values, the statistical indicators defined in Section 2.2 were applied. In this case, x_i and y_i are, respectively, the annual DII values obtained from SoDa and the DII values calculated by the model. It was found that the MAD is 1.74%, RMSD is 2.17%, μ is 0.57%, σ is 2.07%, and R^2 is 0.99. The values obtained for these statistics demonstrate a good fit between the SoDa database and

the mathematical model for the studied locations—an even better fit than that observed between SoDa and PVGIS.

Secondly, a comparison was made between the annual DII values calculated using the mathematical model and those provided by the PVGIS database. This process was similar to that previously performed with the SoDa database. In this case, the following results were obtained: $MAD = 5.94\%$; $RMSD = 7.42\%$; $\mu = -5.22\%$; $\sigma = 4.65\%$; and $R^2 = 0.98$. The statistical data show a good fit between the values obtained with the model and the PVGIS values for the studied locations, though this fit is not as strong as that obtained with SoDa; furthermore, in this case, the average PVGIS value is also lower than the average value calculated with the mathematical model.

Third, a comparison was conducted between the annual DII values calculated using the mathematical model and those provided by the PVGIS database from 8000 localities. The obtained results were as follows: $MAD = 6.08\%$; $RMSD = 6.89\%$; $\mu = -6.27\%$; $\sigma = 3.26\%$; and $R^2 = 0.99$. These values are quite similar to those obtained for the 40 localities.

Therefore, after analyzing the different comparisons, it can be concluded that this mathematical model can be used to obtain annual DII data with an acceptable level of precision.

3. Conclusions

In this work, several sources of inclined direct solar data for CPV systems were analyzed. Of all the spatial databases available, only PVGIS and SoDa provide DII data. Focusing on these two databases, TICPV systems were compared to conventional PV systems in terms of their effectiveness. The analysis in this study revealed that PVGIS offers extensive temporal coverage and global spatial data, making it a valuable resource for evaluating annual DII values. The data indicated significant variability in DII across different geographic regions, with the highest values observed in deserts such as the Sahara and the Atacama, suggesting that these areas are particularly advantageous for TICPV.

The comparison between the PVGIS and SoDa databases showed discrepancies in their DII values. These differences underscore the importance of selecting appropriate data sources for accurate system design and performance prediction.

The mathematical model applied to calculate DII from DNI values provides a practical alternative to using satellite databases. Compared to both SoDa and PVGIS data, the model achieves an acceptable level of accuracy, demonstrating that this approach can be a viable tool for estimating annual DII values.

Supplementary Materials: The following supporting information can be downloaded at: <https://www.mdpi.com/article/10.3390/electronics14112297/s1>, Annual direct inclined irradiation (DII) and monthly average daily direct normal irradiation (DNI) data for forty different locations.

Author Contributions: P.P.-H.: conceptualization, methodology, formal analysis, investigation, writing—original draft preparation, visualization, supervision. M.A.C.: writing—original draft, writing—review and editing, visualization, formal analysis. E.M.: writing—original draft, writing—review and editing, visualization, formal analysis. J.G.B.: writing—review and editing. J.M.-R.: writing—review and editing. R.M.-C.: software, writing—review and editing. All authors have read and agreed to the published version of the manuscript.

Funding: This work is part of the project WiT—CPV, grant number CNS2022—35288, funded by MICIU/AEI/10.13039/501100011033 and by the European Union NextGenerationEU/PRTR.

Data Availability Statement: Data can be made available upon request.

Conflicts of Interest: The authors declare no conflicts of interest.

Nomenclature

The following nomenclature is used in this manuscript:

Abbreviations

CPV	Concentrator photovoltaics
TICPV	Tracking-integrated CPV
PV	Photovoltaic
DHI	Direct horizontal irradiance (W/m^2) or irradiation (kWh/m^2)
DII	Direct inclined irradiance (W/m^2) or irradiation (kWh/m^2)
DNI	Direct normal irradiance (W/m^2) or irradiation (kWh/m^2)
GHI	Global horizontal irradiance (W/m^2) or irradiation (kWh/m^2)
GII	Global inclined irradiance (W/m^2) or irradiation (kWh/m^2)

Parameters

$G_{Bhm}(I)$	Monthly average hourly direct inclined irradiance (W/m^2)
$G_{Bhm}(N)$	Monthly average hourly direct normal irradiance (W/m^2)
$H_{Bdm}(I)$	Monthly average daily direct inclined irradiation (Wh/m^2)
$H_{Bdm}(N)$	Monthly average daily direct normal irradiation (Wh/m^2)
$H_{Ba}(S)$	Annual direct inclined irradiation (Wh/m^2)

Symbols

α	Surface azimuth angle (rad)
β	Surface tilt angle (rad)
δ_{dn}	Solar declination at midday of each month (rad)
φ	Latitude (rad)
$\omega_{s\,dm}$	Sunrise hour angle of the midday of each month (rad)
$\vec{r}$	Solar vector
$\vec{n}$	Normal vector to the surface of the module
θ_s	Angle of incidence of the beam radiation on the inclined surface (rad)
θ_{Shm}	Monthly average hourly angle of incidence (rad)
θ_{zs}	Solar zenith angle (rad)

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