Abstract: The validation of the potential energy yield of bifacial PV systems of various configurations at low latitudes under West African climatic conditions is critical for evaluating performance and for promoting market expansion of the technology since validation has mostly occurred in high-latitude regions. In this paper, the potential energy yield from an inclined south-facing bifacial PV module and a vertically mounted east–west bifacial PV module are compared to an inclined south-facing monofacial PV module using an analytical model, field-measured data, and simulations. For measured/modelled and PVsyst/modelled monofacial systems, the model predicts RMSE values of 1.49 and 9.02, respectively. An inclined bifacial PV system has RMSEs of 1.88 and 7.97 for measured/modelled and PVsyst/modelled, respectively, and a vertically installed system has RMSEs of 10.03 for measured/modelled and 3.76 for PVsyst/modelled. Monthly energy yield is predicted by the model, with deviations from measured data ranging from 0.08% to 1.41% for monofacial systems, from 0.05% to 4.06% for inclined bifacial systems, and from 4.63% to 9.61% for vertical bifacial systems. The average bifacial gains from the modelled, measured, and simulated data of an inclined south-facing stand-alone bifacial PV system over an inclined south-facing stand-alone monofacial system are 9.05%, 10.15%, and 5.65%. Finally, at 0.25 albedo, the inclined monofacial PV system outperforms and yields more energy than the vertically installed bifacial PV system.

Keywords: energy yield; bifacial PV module; monofacial PV module; solar radiation; bifacial energy gain

1. Introduction

A viable technology for the future growth of photovoltaics (PVs) is the bifacial solar photovoltaic module. This is because bifacial solar cells absorb incident solar radiation from the sun on the front side while also collecting light falling on the backside, making use of direct, diffuse, and albedo radiation from the ground to generate more power per area than the conventional (monofacial) modules [1–5]. When compared to the conventional modules, bifacial PV can significantly increase energy yield while lowering the levelized cost of energy (LCOE) of photovoltaic modules [6–8]. The following articles reiterated that the use of bifacial PV modules can reduce the levelized cost of energy. For places with high land costs, such as Seattle, optimizing the bifacial system can significantly decrease the LCOE by 23% [9]. While for high latitudes with high module costs, optimizing the tilt angle between 10–15% higher is required, which can result in a 2–6% reduction in LCOE [10]. Depending on the location for latitudes below 40°, a bifacial PV system with an albedo range of 0.12–0.30 can become more cost-effective than a monofacial system [11]. Extensive research is being conducted to evaluate the technology’s performance from a stand-alone system [12] to a solar farm [10,13] as the manufacturing cost difference between bifacial
and monofacial modules has declined substantially. In the 13th edition of the International Technology Roadmap for Photovoltaics (ITRPV) publication, bifacial PV cells have been tipped to have a market share of 85% by 2032 over conventional (monofacial) cells [14].

Some studies have examined the performance of the bifacial PV technology using simulations [15,16], analytical and numerical approaches [17,18], experimental approaches [2,4,19], and a combination of any of the three [12,20,21]. The performance of the bifacial solar PV system is found to be location dependent in all analysis, with variables such as albedo (ratio of the ground reflectance to global horizontal irradiance) [22], radiation intensity [23], shading [24], non-uniformity of back irradiance [25,26], diffuse fraction, ground clearance height, tilt angle, ambient temperature, pitch, elevation angle [27,28], and latitude affecting the energy yield from the system. The addition of a diode to a solar cell model has been found to improve the performance of a solar module [29,30].

Over the years, comparative studies on the performance of bifacial PV systems and monofacial systems have been reported. Guo et al. [22] performed a global analysis of an equator-oriented monofacial and a vertically mounted (east–west) bifacial photovoltaic system. The authors discovered that the performance of vertically mounted bifacial PV systems with a bifaciality of one over monofacial PV systems is highly dependent on albedo, which varies from region to region. Khan et al. [31] also stated that at an albedo of 0.5, vertically mounted bifacial PV modules can achieve a higher energy yield than monofacial PV systems. Yusufoglu et al. [18] demonstrated that under an albedo coefficient of 0.5, a bifacial gain of up to 25% can be achieved from an inclined south-facing bifacial PV module when compared to a monofacial PV module. Wang et al. [13] established the importance of ground clearance height, demonstrating that increasing ground clearance height from 0 to 1 m increases bifacial gain from 4.6% to 10.4%. Shoukry et al. [12] also studied the performance of bifacial PV modules over monofacial for a stand-alone system and a solar farm. The stand-alone system achieved a bifacial gain of 33.9%; when integrated into a solar farm, the gain drops to 31.4%. The decrease in gain is caused by the surrounding modules casting shadows and blocking reflected irradiance. Sun et al. [32] demonstrated that bifacial PV modules oriented towards the equator have a bifacial gain of 10% worldwide, which can be increased to 30% with an albedo of 0.5. Annual bifacial gains of 21% were observed in the arctic region for south-facing bifacial modules. The annual production of vertical east–west bifacial modules was found to be the same as that of south-facing latitude tilt bifacial modules [33]. The integration of a bifacial PV module with a string inverter and a micro-inverter over a monofacial PV system resulted in the monthly energy output of a bifacial module being slightly 4.03% higher than that of a monofacial for microinverter PV system and a 3.21% higher than that of a monofacial for string inverter PV system [34]. In an outdoor experiment of bifacial PV modules, Wei Q. et al. [35] observed a power gain of 15% and 30% on sand and snow, respectively.

While the energy generated by bifacial PV modules varies greatly depending on the deployment scenario and environmental conditions [36], most studies conducted so far through model validation, simulation, and the total current installed capacity of bifacial PV systems are all located in higher latitudes regions [37–39]. This is a limitation because the performance of a bifacial PV system in the high-latitude region cannot be used to justify performance in the low-latitude region. A comprehensive study addressing the performance of bifacial PV systems in various deployment scenarios in low-latitude regions under West African climatic conditions is required for wide adoption, market penetration, and expansion.

In this paper, the performances of a stand-alone bifacial PV system with two configurations—inclined south-facing and vertically mounted east–west—and an inclined south-facing monofacial system under West African climatic condition are investigated. The results for the modelled and measured single-day in-plane solar radiation for each configuration and predicted monthly potential energy yield from the modelled, measured, and simulated data are presented. This research work contributes to the body of knowledge, demonstrating that bifacial PV modules have the potential to produce significantly more energy than
monofacial PV modules under West African climatic conditions. The findings of this study provide an understanding of the performance of bifacial PV modules of various deployments in low latitudes under West African climatic conditions not only to the PV research communities but also to PV installation companies and governments interested in expanding solar energy projects in the region.

The paper is laid out as follows. Section 1 introduces bifacial PV technology and the reasons for the paradigm shift toward the technology, followed by a literature review that includes the methods used to examine performance, variables influencing energy yield, and bifacial gain reported across various regions, research gaps, and contributions. Section 2 then presents the mathematical equation for the analytical model of the location’s global horizontal radiation, incident irradiance on the modules, energy yield, bifacial gain, field data to validate the model, and simulated data. In Section 3, we present the results of the modelled and measured single-day in-plane irradiance and compared the predicted potential energy yield, bifacial gain, deviation, and root mean squared error for various configurations, and finally, in Section 4, we summarize the results and highlight the impact of the research.

2. Materials and Methods

The analytical model used in this study is developed to validate the performance of three solar PV configurations in a Microsoft Excel environment:

i. An inclined stand-alone monofacial PV system oriented towards the south;
ii. An inclined bifacial PV system oriented towards the south;
iii. A vertically installed east–west stand-alone bifacial PV system.

2.1. Theoretical Framework

To model the output of a bifacial solar photovoltaic module for the various stand-alone PV systems, the irradiance, which is the power of the sunlight per area (W/m\(^2\)), for the location on any particular day must be determined. Then, the plane of array of irradiance incident on the modules, and lastly, through the physics-based model, the power output of the insolation is calculated.

To begin with, the solar path and intensity of sunlight are required to calculate a location’s temporal solar irradiance data [40]. At any particular time during the day, the extraterrestrial irradiance and solar path, which are functions of zenith \(\theta_Z\) and azimuth \(\alpha_S\) angle, and elevation angle [24] are determined for the geographical location [22], in this case, Navrongo (10.89\(^\circ\) N, 1.09\(^\circ\) W). To calculate the global horizontal irradiance (GHI), the sun position data were fed into five clear sky models, namely the Haurwitz model, the Berger–Duffie (BD) model, the Robledo–Soler (RS) model, the Adnot–Bourges–Campana–Gicquel (ABCG) model, and the Kasten–Czeplak (KC) model from [40,41]. The hourly global horizontal irradiance (GHI) generated was compared, and the Kasten–Czeplak (KC) clear sky model was chosen because its values are the closest to those obtained from the ground weather station data at Navrongo.

\[
E_{\text{GHI}} = 910 \cos z - 30
\]

where \(z\) is the zenith angle of the sun.

2.1.1. GHI Decomposition into DNI and DHI

The global horizontal irradiance (GHI) is composed of two components: direct normal irradiance (DNI) and diffuse horizontal irradiance (DHI). Their relationship is expressed as follows:

\[
E_{\text{GHI}} = E_{\text{DNI}} \cos z + E_{\text{DHI}}
\]

GHI must be decomposed from the equation into the variables that make up the value. The diffuse fraction \(K_D\) is determined using the hourly sky clearness index \(K_T\) when implemented in the Reindle model [42,43], and the clearness index is the ratio of GHI to
extraterrestrial irradiance. The DHI is then estimated through the relationship between diffuse fraction and GHI. Finally, from Equation (1), DNI can then be calculated. Since GHI is already determined, based on the day of the year, $I_0$, I can be computed analytically.

$$K_T = \frac{GHI}{I_0 \cos z}$$

(3)

In the literature, there are various empirical models for decomposing GHI. On average, a reasonable agreement has been established amongst these models [31]. The Hay and Davies model [44,45] is used for DHI transposition on the plane of the array. The diffuse circumsolar irradiance surrounding the DNI is accounted for using the model. This ensures that the anisotropic nature of the diffuse irradiance is properly considered as the circumsolar diffuse irradiance is superimposed on the isotropic model, lowering the model’s overestimation of energy yield PV modules.

2.1.2. Estimation of the Angle of Incidence (AOI) for the Optimally Tilted and Vertically Installed Stand-Alone Bifacial Module

The angle of incidence (AOI) at the front/back surface of the two oriented panels must be determined to assess the contribution of direct normal irradiance (DNI) for both stand-alone optimally inclined north–south and vertically installed east–west orientation. The angle of incidence (AOI) is a function of the zenith angle $\theta_Z$, tilt angle $\tau$, the azimuth angle of the sun, and the module expressed as $\alpha_S$ and $\alpha_M$. The angle of incidence (AOI) for the north–south-oriented inclined panel can be expressed as follows [10,32,46]:

$$\cos \text{AOI}_\text{front} = \cos \theta_Z \cos \tau + \sin \theta_Z \sin \tau \cos (\alpha_S - \alpha_M)$$

(4)

$$\cos \text{AOI}_\text{rear} = \cos \theta_Z \cos (180 - \tau_{\text{front}}) + \sin \theta_Z \sin (180 - \tau_{\text{front}}) \cos \left(\alpha_S - \left(\alpha_M + 180\right)\right)$$

(5)

The angle of Incidence (AOI) for the vertically installed east–west orientation is given as follows [31]:

$$\cos \text{AOI}_{\text{front}} = \sin \theta_Z \cos (\alpha_S - \pi/2)$$

(6)

$$\cos \text{AOI}_{\text{back}} = \sin \theta_Z \cos (\alpha_S + \pi/2)$$

(7)

2.2. Optical Collection Model on the Panel

Based on the orientation of the module, the amount of irradiance incident on the surface of a panel can be estimated. This may be divided into irradiance hitting the front surface $E_f \text{W/m}^2$ and irradiance at the rear surface $E_r \text{W/m}^2$ for the monofacial and bifacial module configurations. The total irradiance at the front side of the module is given as follows [17]:

$$E_f = E_{DNI}^f + E_{\text{DIFF}}^f + E_{\text{GREF}}^f$$

(8)

These are the direct, the diffuse, and the reflected irradiances in W/m$^2$.

2.2.1. Direct Irradiance

The equation for the proportion of direct normal irradiance (DNI) incident on the module is as follows [11,32]:

$$E_{\text{DNI(front/rear)}} = E_{\text{DNI}} \cos \text{AOI}_{\text{front/rear}} (1 - AL(\text{AOI}))$$

(9)

$AL$ is the angular losses in PV modules, the angle of incidence (AOI) influences the angular losses of direct normal irradiance to the module surface [47], and the model proposed to compute these losses is as follows:

$$AL_{\text{DNI(AOI)}} = 1 - \left[\frac{1 - e^{(-1 - \text{AOI}/a_r)}}{1 - e^{(-1/a_r)}}\right]$$

(10)
where \( ar \) is the angular loss coefficient considered to be 0.16 in this study. This value falls between the normal \( ar \) values for commercial C-si modules \[47\].

### 2.2.2. Diffuse Irradiance

Because of the anisotropic nature of the diffuse radiation, accounting for diffuse radiation on a tilted module is challenging when compared to direct irradiance. The transposition model performance analysis of diffuse irradiance has been conducted by Yang et al. and Xie et al. \[45,48\]. The author of \[45\] concluded that there is no universal model after analyzing the performance of 26 transposition models against 18 datasets throughout the world. The author identified the Hay and Davies transposition model, which includes two components, as one of the best with two components. The model is used for the hourly in-plane diffuse irradiance. The isotropic component of diffuse radiation is thought to be homogeneous across the sky globe. The circumsolar component radiates from the Sun’s immediate surroundings \[24\]. Each of these components has a unique method for estimating the optical plane of array radiation on the solar module. This is given as follows:

\[
E_{diff}(iso) = (1 - AL_{diff})E_{diff(iso)}svf
\]

\[
E_{diff(cir)} = (1 - AL_{DNI(AOI)})E_{diff(c)} \cos(AOI_{cir})
\]

\[
E_{DIFF front/rear} = E_{diff(iso)} + E_{diff(cir)}
\]

where \( svf \) is the sky view factor from the module to the sky, \( AL_{diff} \) is the diffuse angular loss \[24,47,49\], and the angle of incidence of circumsolar \( AOI_{cir} \) is the same as that of the direct irradiance \[32\]. The integration of the two components gives the total radiation on the front and the rear side of the module.

### 2.2.3. Ground Albedo Irradiance

The methodology for calculating the front and back sides of the reflected ground is divided into two parts. The ground reflected irradiance for the front surface is calculated assuming that global radiation is isotropic; that is, the radiation is uniform and independent of the direction and it is given as follows \[11,24,50\]:

\[
E_{GREF front} = (1 - AL_{gref})\rho_{GHIgvf}
\]

where \( gvf = \frac{1 - \cos \tau}{2} \) is the ground view factor, \( AL_{gref} \) is the ground angular losses \[47,49\], and \( GHI \) is the global horizontal irradiance in W/m\(^2\). For the calculation of the rear-side ground reflected irradiance, the radiation attenuation caused by the module’s resulting shadow on the ground is accounted for using the equation from \[51\]. Only diffuse radiation is received by the shaded area, whereas ground horizontal radiation is received by the unshaded area. Thus, the method used by Shoukry et al. \[12\], Sun et al. \[32\], and Appelbaum \[50\] for the rear-side plane of module radiation was adopted.

\[
E_{GREF rear} = (1 - AL_{gref})[\rho DHIgvf F_{rsgd} + (\rho GHIgvf F_{msgd} - F_{rsgd})]
\]

\( F_{rsgd} \) and \( F_{msgd} \) represent the shaded area and the non-shaded area of the rear side. The total irradiance at the rear side of the module is given as follows:

\[
E_r = E_{DNIrear} + E_{DIFFrear} + E_{GREFrear}
\]

Note that the height of the panel is 1 m and the elevation of the panel from the ground is 1 m; a low ground albedo of 0.25 is considered as it corresponds to vegetation/soil ground, as reported by \[15,32\].
2.3. Power Conversion Efficiency Model

A single-point power model is used to convert the light incident on the modules to electrical power output \([32,52]\), which is written as follows:

\[
P_{PV} = E^f A \times \eta^f + E^r A \times \eta^r
\]  

(17)

where the \(E^f\) and \(E^r\) are the sum of the front- and rear-side in-plane irradiance on the panel, \(A\) is the area of the PV module, \(\eta^f\) and \(\eta^r\) are the efficiencies of the front and rear sides of the PV module, and \(P_{PV}\) is total power output. The bifaciality is given as \(\eta_{rear(STC)}/\eta_{front(STC)}\) \([32]\). The rear-side efficiency is determined as the bifaciality, and the front side efficiency is given by the module manufacturer.

The potential energy is given as follows:

\[
Y_{PV} = \int_0^t P_{PV} dT
\]  

(18)

\[Bifacial\ gain\ (BG) = \left(\frac{Y_{bifacial}}{Y_{monofacial}} - 1\right) \times 100\% \]  

(19)

where \(Y_{bifacial}\) represents the energy yield in the bifacial PV module and \(Y_{monofacial}\) is the monofacial energy yield.

2.4. Field Data

Methodology for Validation of the Model with Field Data

The model results were validated against the field data for Navrongo (10.89° N, 1.09° W) in Ghana. The site installation includes a reference inclined monofacial PV module, as well as two stand-alone bifacial PV modules, one inclined and oriented south and the other vertically mounted and oriented east–west (see Figure 1). Hourly on-site global horizontal irradiance (GHI), front in-plane irradiance, and rear-side in-plane irradiance measurements are available for November 2020 to June 2021. The instrumentation for measuring and recording field data consisted of Campbell CMP-1 and SP-421 Apogee Pyranometer for measuring the global horizontal irradiance and the in-plane irradiance, a Microstep BIM205 intelligent solar charger, 12 V DC battery, load, and a Campbell CR300 logger. Each of the modules was connected to a single solar charger with MPPT function, which in turn is connected to the battery, load, and data logger. Tables 1 and 2 show the electrical properties of the PV modules (JA Solar JAM72S09-385/PR and LG NeoN2 Bifacial LG335N1T-V5) as well as the system parameters installed at the location. To obtain the optimum performance on the yield, the inclined south-facing PV system is tilted at an optimum angle of 14° while the vertically mounted east–west is at 90°.

2.5. Simulation Data

To determine the energy yield for each configuration, the stand-alone system was simulated in PVsyst version 7.2 with a jinkosolar product (JKM335M-60H-BDVP-BIFACIAL and JKM335M-60H-TV) under the same system parameter conditions. The electrical characteristics of the module are presented in Table 3.
Figure 1. Site installation at Navrongo, Ghana [Inclined Monofacial PV module (Panel A), Inclined Bifacial PV module (Panel B), and Vertically mounted Bifacial PV module (Panel C)].

Table 1. Electrical characteristics of the experimental setup at Navrongo.

| Electrical Parameters at STC | Monofacial (Panel A) | Bifacial (Panel B) | Bifacial (Panel C) |
|-----------------------------|----------------------|--------------------|--------------------|
| Peak Power [W]              | 385                  | 335                | 335                |
| Open Circuit Voltage, Voc [V]| 49.04                | 40.7               | 40.7               |
| Max. Power Voltage, Vmp [V] | 39.9                 | 34.1               | 34.1               |
| Short Circuit Current, Isc [A]| 10.17              | 10.34              | 10.34              |
| Max. Power Current, Imp [A]  | 9.65                 | 9.83               | 9.83               |
| Module Efficiency, STC [%]  | 19.3                 | 19.6               | 19.6               |
| Pmax Bifaciality coefficient [%] | -                   | 70 ± 5             | 70 ± 5             |
| Pmax temp coefficient [%/°C] | -0.37                | -0.36              | -0.36              |
| Fill Factor                 | 0.7720               | 0.7970             | 0.7970             |
| Dimensions (L × W × H) [mm] | 1979 × 996 × 40      | 1686 × 1016 × 40   | 1686 × 1016 × 40   |
| PV cells Type               | Monocrystalline/n-type | Monocrystalline/n-type | Monocrystalline/n-type |

Table 2. System parameters.

| Parameters         | Values |
|--------------------|--------|
| Albedo             | 0.25   |
| Tilt Angle         | 14°    |
| Module elevation   | 1.04 m |
| Front efficiency   | 19.60% |
| Rear efficiency    | 13.72% |

Table 3. Electrical characteristics of the simulated system.

|                                | Monofacial PV Module | Bifacial PV Module |
|--------------------------------|----------------------|--------------------|
| Peak Power [W]                 | 334.0                | 334.37             |
| Open Circuit Voltage, Voc [V]  | 40.46                | 41.24              |
| Max. Power Voltage, Vmp [V]    | 33.40                | 34.40              |
| Short Circuit Current, Isc [A] | 10.34                | 10.23              |
| Max. Power Current, Imp [A]    | 10.00                | 9.72               |
| Fill Factor                    | 0.79                 | 0.79               |
| Bifaciality [%]                | 70                   |                    |
| Dimensions (L × W × H) [mm]    | 1704 × 1008 × 35     | 1704 × 1008 × 30   |
3. Results and Discussions

The radiation received by each configuration can be calculated using the model presented in Section 2. Figure 2 depicts the in-plane radiation received by each configuration on the 21st of March, June, and December. The model output result is compared to the measured data from the field (Navrongo, 10.89° N, 1.09° W). The south-facing bifacial PV module tilted at 14° receives the most in-plane radiation in a single day, as shown in Table 4. The model in-plane irradiance values are higher than the experimental values. Though models are ideal, the disparity in value with the measured can be due to the inaccuracy in the orientation of the module, daily diurnal variation, and site climatic conditions.

The in-plane radiation of monofacial and bifacial PV modules oriented towards the south has one peak period at noon. A bifacial PV module oriented east–west and tilted at 90° has two peak periods during which the in-plane radiation received by the module is at its highest: morning and evening. In the global analysis of a vertically installed bifacial PV module by Guo et al. [22], a similar pattern of in-plane irradiance received by the module was reported. The output power curve for vertically mounted bifacial PV modules shown by Sun et al. [32] and Thomas et al. [53] has the same pattern of two peak periods. These dual peak periods have been discovered to be advantageous in network integration because they aid in improving power network efficiency as well as matching the daily power generated and the load profile [54–56].

3.1. Estimation of Energy Yield by Different Solar PV Configurations

The accuracy of the model for each PV module configuration is examined in this section. The analysis is based on the potential energy yield from the previous year’s field data (November 2020–June 2021) and energy output simulated with PVsyst 7.2. Figures 3–5 represent the potential monthly energy yield from various solar PV configurations. The calculated values are compared to the measured results and PVsyst simulation values. Tables 5 and 6 show the deviation between the measured data, PVsyst data, and modelled data and the root mean square error of the systems. This aids in determining how well the model can predict the energy yield of the systems. In Figures 3 and 4, the potential energy yield predicted by PVsyst is greater than both the modelled and measured energy yield for inclined monofacial and bifacial PV systems. The modelled and measured potential energy yields for the two systems are in more agreement, with deviation ranges of 0.08–1.41% for the monofacial system and 0.05–4.06% for the inclined bifacial PV system. The two systems’ average deviation values are 0.75% and 1.01%, and the root mean square errors for the modelled and the measured potential yield are 1.49 and 1.88, respectively. This indicates that the proposed model for estimating monthly energy yield is suitable for the system [57].

As shown in Figure 5, the potential energy yield for the PVsyst simulation results and the modelled data in a vertically installed system are in more agreement and are higher than that of the measured data. While the model assumed equal radiation intensity before and afternoon (morning and evening), resulting in an overestimation of potential energy yield, there is a variation in radiation intensity, with in-plane radiation being slightly lower toward in the evening period [53]. The average deviation between the modelled and measured potential energy yields is 6.86%, while the deviation between the PVsyst and the modelled potential energy yield is 2.47%. It is worth noting that the PVsyst software for the simulation adopted the Perez model that accounts for the horizon diffusion which was not considered by the model. The variation in a system’s model, measured, and simulated potential energy output can be linked to uncertainties in the measuring equipment, local weather interannual variation, and simulation software inefficiency [58,59].

3.2. Comparison of the Model Energy Output of the Two Bifacial PV Systems

Based on the model data, the annual energy output of both bifacial PV systems (tilted south-facing and vertically mounted east–west) is compared. The tilted bifacial PV module system, as shown in Figure 6, generated more energy throughout the year. The annual average relative difference between the two configurations in energy output is 18.09%.
Figure 2. (a) Single-day analysis of in-plane radiation of the various solar PV; 21 March; (b) single-day analysis of in-plane radiation of the various solar PV; 21 June; (c) single-day analysis of in-plane radiation of the various solar PV; 21 December.
Table 4. Single-day in-plane radiation.

|                  | Tilted Monofacial (Wh) | Tilted Bifacial (Wh) | Vertical Bifacial (Wh) |
|------------------|------------------------|----------------------|------------------------|
| Modelled (March) | 6440.2                 | 7948.9               | 6818.0                 |
| Measured (March) | 5920.7                 | 7239.4               | 6191.6                 |
| Modelled (June)  | 6902.4                 | 8475.8               | 6685.0                 |
| Measured (June)  | 6089.4                 | 7268.2               | 5385.4                 |
| Modelled (December) | 5742.2                 | 6960.0               | 5687.6                 |
| Measured (December) | 5633.0                 | 7001.0               | 5271.7                 |

Figure 3. Measured, modelled, and PVsyst monthly energy yield of the tilted monofacial PV system.

Figure 4. Measured, modelled, and PVsyst monthly energy yield of the tilted bifacial PV system.
3.3. Inclined Bifacial Energy Gain over the Monofacial System (Bifacial Gain)

The monthly bifacial gain from the measured, modelled, and PVsyst simulated energy output of an inclined bifacial system over a monofacial system is shown in Figure 7 and Table 7. From the field data (November 2020–June 2021), the bifacial gain from monthly measured data of an inclined bifacial system over a monofacial system ranges between 7.08 and 10.27%; however, a higher bifacial gain of 6.64–12.44% is observed in the modelled system. Meanwhile, the PVsyst simulated gain observed is less than the measured and modelled bifacial gains. Interestingly, the average bifacial gain under vegetation or soil (albedo: 0.20–0.25) of an inclined bifacial system over a monofacial system from measured, modelled, and simulated data aligns with what other authors have reported for latitudes below 30° [12,32].
Table 5. Monthly potential energy yield deviation (November 2020–June 2021 field data).

| Months       | Deviation (%) | Deviation (%) | Deviation (%) | Deviation (%) | Deviation (%) |
|--------------|---------------|---------------|---------------|---------------|---------------|
|              | Modelled/Measured (Inclined Monofacial) | PVsyst/Modelled/Measured (Inclined Monofacial) | Deviation (%) | Modelled/Measured (Inclined Bifacial) | PVsyst/Modelled/Measured (Inclined Bifacial) | Deviation (%) |
| November 2020 | 0.22          | 5.60          | 0.07          | 6.28          | 4.63          | 3.39          | 1.26          |
| December 2020 | 0.38          | 5.77          | 0.47          | 5.32          | 5.76          | 4.17          | 1.76          |
| January 2021 | 0.25          | 6.79          | 0.28          | 5.79          | 5.02          | 3.67          | 1.35          |
| February 2021 | 0.55          | 5.18          | 0.05          | 4.08          | 6.28          | 4.49          | 3.99          |
| March 2021   | 0.68          | 5.57          | 0.25          | 4.55          | 6.42          | 4.55          | 3.53          |
| April 2021   | 0.08          | 5.73          | 0.16          | 4.95          | 7.59          | 5.54          | 2.09          |
| May 2022     | 1.41          | 3.74          | 2.76          | 4.03          | 9.61          | 6.89          | 3.41          |
| June 2021    | 1.41          | 3.36          | 4.06          | 4.06          | 9.61          | 7.08          | 2.37          |
| Average      | 0.75          | 5.22          | 1.01          | 4.91          | 6.86          | 4.97          | 2.47          |

Table 6. Root mean square error of monthly potential energy output.

| Measured/Modelled Incl Monofacial PV | Measured/PVsyst Incl Monofacial | PVsyst/Modelled Incl Monofacial | Measured/Modelled Incl Bifacial PV | Measured/PVsyst Incl Bifacial | PVsyst/Modelled Vertical Bifacial | Measured/Modelled Vertical Bifacial | Measured/PVsyst Vertical Bifacial | PVsyst/Modelled Vertical Bifacial |
|--------------------------------------|----------------------------------|---------------------------------|-----------------------------------|---------------------------------|-----------------------------------|-----------------------------------|---------------------------------|----------------------------------|
| 1.49                                 | 9.27                             | 9.02                            | 1.88                              | 8.55                            | 7.97                              | 10.03                            | 6.62                            | 3.76                             |
3.4. Stand-Alone Vertically Mounted Bifacial Energy Loss over Monofacial PV System

Table 8 shows the performance of a vertically installed bifacial PV system on natural vegetation with an albedo of 0.25. Regardless of the method adopted to determine the energy yield, the monofacial PV system outperforms the vertically installed bifacial system at Navrongo. Though a vertically installed bifacial PV system has the advantage of shifting peak power generation to dawn and dusk, system optimization is required to improve the energy yield. Khan et al. [31] reported that globally, the albedo of a vertically installed bifacial PV module should be increased to 0.5 to outperform a monofacial system. Guo et al. [22] reported that the performance of a vertically installed bifacial PV system over a monofacial PV system is dependent on albedo and that it varies from location to location. This viewpoint is supported by research conducted by Shoukry et al. [12], who discovered that at an albedo of 0.2 at El Gouna (Egypt) and Constance (Germany), a monofacial system outperforms a vertically installed bifacial system. Increasing the albedo to 0.5 at both locations resulted in an annual energy gain of 15.77% at Constance and a loss of −5.99% at El Gouna. Hence, for an installation of a vertically mounted east–west bifacial PV system in this location, the albedo will have to be optimized to boost the energy yield over the monofacial PV system.
Table 8. Monthly vertical bifacial PV loss over monofacial PV system.

| Months   | Measured | Modelled | PVsyst |
|----------|----------|----------|--------|
| November | −27.92   | −11.27   | −32.84 |
| December | −31.10   | −8.84    | −34.27 |
| January  | −28.41   | −7.84    | −34.85 |
| February | −29.23   | −1.29    | −35.78 |
| March    | −29.64   | −4.43    | −34.43 |
| April    | −30.85   | −2.28    | −28.87 |
| May      | −33.79   | −3.82    | −25.19 |
| June     | −35.51   | −7.15    | −21.94 |

4. Conclusions

An analytical model was used in this study to determine the potential energy yield of a south-facing bifacial PV stand-alone system and a vertically installed east–west bifacial PV stand-alone system in comparison to a monofacial system at low latitude in Navrongo, northern Ghana. The model considers important system parameters such as albedo, module elevation, and module self-shading, all of which can influence the potential energy yield. The model was validated using in-plane field irradiance data (Navrongo, Ghana) from November 2020 to June 2021, as well as PVsyst.

The results from Figures 3–5 show that the proposed model has a higher accuracy in predicting the output of the potential energy yield for a south-facing-inclined bifacial PV system than for a vertically installed east–west bifacial PV system. The model predicts RMSE values of 1.49 and 9.02 for measured/modelled and PVsyst/modelled monofacial systems. For an inclined bifacial PV system, RMSE values of 1.88 and 7.97 are obtained for measured/modelled and PVsyst/modelled, and lastly, for a vertically installed system, RMSE values of 10.03 for measured/modelled and 3.76 for PVsyst/modelled were predicted. The model predicts monthly energy yield, with a deviation from measured data ranging from 0.08% to 1.41% for monofacial systems, from 0.05% to 4.06% for inclined bifacial systems, and from 4.63% to 9.61% for inclined bifacial systems. Taking this into consideration, this model is useful in predicting the potential energy yield for various configurations at this location, and depending on the system configuration and parameters, the model can be applied anywhere in the world in the absence of measured data to determine the energy yield. The technical assessment of a bifacial PV module under West African climatic conditions revealed an average bifacial gain of between 5.65% and 10.15%. Conducting a technoeconomic assessment to determine financial viability will make scaling up the system easier.

Author Contributions: Conceptualization, R.O.Y., L.D.M., D.A.Q. and M.S.A.; methodology, R.O.Y. and M.T.A.; validation, R.O.Y.; formal analysis, R.O.Y.; investigation, R.O.Y. and M.T.A.; resources, L.D.M. and M.S.A.; data curation, R.O.Y. and M.T.A.; writing—original draft preparation, R.O.Y. and M.T.A.; writing—review and editing, M.S.A., L.D.M. and D.A.Q.; supervision, L.D.M., D.A.Q. and M.S.A. All authors have read and agreed to the published version of the manuscript.

Funding: This research received no external funding.

Data Availability Statement: Not applicable.

Acknowledgments: Rahimat O. Yakubu acknowledges and appreciates the PhD scholarship support by the Kwame Nkrumah University of Science (KNUST), Kumasi, Ghana, through ‘KNUST Engineering Education Project (KEEP)’, an Africa Center of Excellence (ACE) impact project funded by the Government of Ghana as part of the World Bank ACE for Development Impact Project. Maame T. Ankoh acknowledges and appreciates the PhD scholarship support by the Kwame Nkrumah University of Science (KNUST), Kumasi, Ghana, through ‘Upgrading Education and Research Capacity in Renewable Energy Technologies at Kwame Nkrumah University of Science and Technology (KNUST) Kumasi Ghana’, a collaborative project between KNUST and Norwegian University of Life Sciences, Ås Norway, which is funded by the Norwegian Agency for Development Cooperation (Norad) through the Energy and Petroleum (EnPe) programme. Furthermore, the authors acknowledge the
financial support of the EnPe project for the establishment of the experimental facilities used in this study. Additionally, the authors appreciate the support from the Faculty of Environmental Sciences and Natural Resources Management, Norwegian University of Life Sciences, Ås, Norway.

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

Nomenclature

\[ E_{\text{GHI}} (\text{W/m}^2) \]  
Global Horizontal Irradiance

\[ Z (\circ) \]  
Zenith Angle of the Sun

\[ E_{\text{DNI}} (\text{W/m}^2) \]  
Direct Normal Irradiance

\[ E_{\text{DHI}} (\text{W/m}^2) \]  
Diffuse Horizontal Irradiance

\[ K_d \]  
Diffuse Fraction

\[ K_T \]  
Clearness Index

\[ AOI (\circ) \]  
Angle of Incidence

\[ E_f (\text{W/m}^2) \]  
Total Incident Irradiance at the Front of the Module

\[ E_r (\text{W/m}^2) \]  
Total Incident Irradiance at the Rear Side of the Module

\[ \Delta \text{L} \]  
Angular Losses

\[ g_{\text{ef}} \]  
Ground View Factor

\[ P_{\text{PV}} (\text{W}) \]  
Electrical Power Output from the Incident Irradiance

\[ \eta \]  
Efficiency

\[ Y_{\text{PV}} (\text{Wh}) \]  
Potential Energy Yield

\[ F_{\text{sh}} (\text{m}) \]  
Shaded Area

\[ F_{\text{nsh}} (\text{m}) \]  
Non-Shaded Area

\[ \text{BG} \]  
Bifacial Gain

References

1. Lamers, M.; Özkalay, E.; Gali, R.; Janssen, G.; Weeber, A.; Romijn, I.; Van Aken, B. Temperature effects of bifacial modules: Hotter or cooler? Sol. Energy. Mater. Sol. Cells 2018, 185, 192–197. [CrossRef]

2. Leonardi, M.; Corso, R.; Milazzo, R.G.; Connelli, C.; Foti, M.; Gerardi, C.; Bizzarri, F.; Privitera, S.M.S.; Lombardo, S.A. The Effects of Module Temperature on the Energy Yield of Bifacial Photovoltaics: Data and Model. Energies 2021, 15, 22. [CrossRef]

3. Berrian, D.; Libal, J.; Klenk, M.; Nussbaumer, H.; Kopecek, R. Performance of Bifacial PV Arrays With Fixed Tilt and Horizontal Single-Axis Tracking: Comparison of Simulated and Measured Data. IEEE J. Photovolt. 2019, 9, 1583–1589. [CrossRef]

4. Lamers, M.; Ozkalay, E.; Gali, R.; Janssen, G.; Weeber, A.; Romijn, I.; Van Aken, B. Temperature effects of bifacial modules: Hotter or cooler? Sol. Energy. Mater. Sol. Cells 2018, 185, 192–197. [CrossRef]

5. Mesquita, D.D.B.; Silva, J.L.D.S.; Moreira, H.S.; Kitayama, M.; Villalva, M.G. A review and analysis of technologies applied in PV modules. In Proceedings of the 2019 IEEE PES Innovative Smart Grid Technologies Conference - Latin America (ISGT Latin America), Gramado, Brazil, 15–18 September 2019. [CrossRef]

6. Leonard, M.; Corso, R.; Milazzo, R.G.; Connelli, C.; Foti, M.; Gerardi, C.; Bizzarri, F.; Privitera, S.M.S.; Lombardo, S.A. The Effects of Module Temperature on the Energy Yield of Bifacial Photovoltaics: Data and Model. Energies 2021, 15, 22. [CrossRef]

7. Berrian, D.; Libal, J.; Klenk, M.; Nussbaumer, H.; Kopecek, R. Performance of Bifacial PV Arrays With Fixed Tilt and Horizontal Single-Axis Tracking: Comparison of Simulated and Measured Data. IEEE J. Photovolt. 2019, 9, 1583–1589. [CrossRef]

8. Wang, S.; Shen, Y.; Zhou, J.; Li, C.; Ma, L. Efficiency Enhancement of Tilted Bifacial Photovoltaic Modules with Horizontal Single-Axis Tracking—The Bifacial Companion Method. Energies 2022, 15, 1262. [CrossRef]

9. Tillmann, P.; Jäger, K.; Becker, C. Minimising the levelised cost of electricity for bifacial solar panel arrays using Bayesian optimisation. Sustain. Energy Fuels 2019, 4, 254–264. [CrossRef]

10. Patel, M.T.; Khan, M.R.; Sun, X.; Alam, M.A. A worldwide cost-based design and optimization of tilted bifacial solar farms. Appl. Energy 2019, 247, 467–479. [CrossRef]

11. Rodriguez-Gallegos, C.D.; Bieri, M.; Gandhi, O.; Singh, J.P.; Reindl, T.; Panda, S. Monofacial vs bifacial Si-based PV modules: Which one is more cost-effective? Sol. Energy 2018, 176, 412–438. [CrossRef]

12. Appelbaum, J. Bifacial photovoltaic panels field. Renew. Energy 2016, 85, 338–343. [CrossRef]

13. Shoukry, I.; Libal, J.; Kopecek, R.; Wehringhaus, E.; Werner, J. Modelling of Bifacial Gain for Stand-alone and in-field Installed Bifacial PV Modules. Energy Procedia 2016, 92, 600–608. [CrossRef]

14. Wang, S.; Wilkie, O.; Lam, J.; Steeman, R.; Zhang, W.; Kkoo, K.S.; Siong, S.C.; Rostan, H. Bifacial Photovoltaic Systems Energy Yield Modelling. Energy Procedia 2015, 77, 428–433. [CrossRef]

15. ITRPV-VDMA. International Technology Roadmap for Photovoltaics (ITRPV) 2021 Results; VDMA: Frankfurt, Germany, 2022.

16. Appelbaum, J. Bifacial photovoltaic panels field. Renew. Energy 2016, 85, 338–343. [CrossRef]

17. Pat, M.T.; Khan, M.R.; Sun, X.; Alam, M.A. A worldwide cost-based design and optimization of tilted bifacial solar farms. Appl. Energy 2019, 247, 467–479. [CrossRef]

18. Rodríguez-Gallegos, C.D.; Bieri, M.; Gandhi, O.; Singh, J.P.; Reindl, T.; Panda, S. Monofacial vs bifacial Si-based PV modules: Which one is more cost-effective? Sol. Energy 2018, 176, 412–438. [CrossRef]

19. Shoukry, I.; Libal, J.; Kopecek, R.; Wehringhaus, E.; Werner, J. Modelling of Bifacial Gain for Stand-alone and in-field Installed Bifacial PV Modules. Energy Procedia 2016, 92, 600–608. [CrossRef]

20. Wang, S.; Wilkie, O.; Lam, J.; Steeman, R.; Zhang, W.; Kkoo, K.S.; Siong, S.C.; Rostan, H. Bifacial Photovoltaic Systems Energy Yield Modelling. Energy Procedia 2015, 77, 428–433. [CrossRef]

21. ITRPV-VDMA. International Technology Roadmap for Photovoltaics (ITRPV) 2021 Results; VDMA: Frankfurt, Germany, 2022.
18. Yusufoglu, U.A.; Pletzer, T.M.; Koduvelikutathu, L.J.; Comparotto, C.; Kopecak, R.; Kurz, H. Analysis of the Annual Performance of Bifacial Modules and Optimization Methods. *IEEE J. Photovolt.* 2015, 5, 320–328. [CrossRef]

19. Castillo-Aguilera, J.E.; Hauser, P.S. Multi-Variable Bifacial Photovoltaic Module Test Results and Best-Fit Annual Bifacial Energy Yield Model. *IEEE Access* 2016, 4, 498–506. [CrossRef]

20. Asgharzadeh, A.; Toor, F.; Bourne, B.; Anoma, M.A.; Hoffman, A.; Chaudhari, C.; Bapat, S.; Perkins, R.; Cohen, D.; Kimball, G.M.; et al. A Benchmark and Validation of Bifacial PV Irradiance Models. In Proceedings of the 2019 IEEE 46th Photovoltaic Specialists Conference (PVSC), Chicago, IL, USA, 16–21 June 2019; pp. 3281–3287. [CrossRef]

21. Pelaez, S.A.; Deline, C.; MacAlpine, S.M.; Marion, B.; Stein, J.S.; Kostuk, R.K. Comparison of Bifacial Solar Irradiance Model Predictions With Field Validation. *IEEE J. Photovolt.* 2019, 9, 82–88. [CrossRef]

22. Guo, S.; Walsh, T.M.; Peters, M. Vertically mounted bifacial photovoltaic modules: A global analysis. *Energy* 2013, 61, 447–454. [CrossRef]

23. Lloyd, M.A.; Bishop, D.; McCandless, B.E.; Birkmire, R. Zinc Selenide Surface Passivation Layer for Single-Crystalline CZTSe Solar Cells. In Proceedings of the 2017 IEEE 44th Photovoltaic Specialist Conference (PVSC), Washington, DC, USA, 25–30 June 2017; pp. 726–729. [CrossRef]

24. Varga, N.; Mayer, M.J. Model-based analysis of shading losses in ground-mounted photovoltaic power plants. *Sol. Energy* 2021, 216, 428–438. [CrossRef]

25. Wang, L.; Liu, F.; Yu, S.; Quan, P.; Zhang, Z. The Study on Micromismatch Losses of the Bifacial PV Modules Due to the Irradiance Nonuniformity on Its Backside Surface. *IEEE J. Photovolt.* 2019, 10, 135–143. [CrossRef]

26. Ayala Pelaez, S.; Deline, C.; MacAlpine, S.; Olalla, C. Bifacial PV System Mismatch Loss Estimation. 6th BifiPV Work. Amsterdam, NL, no. October, p. 1. 2019. Available online: https://www.nrel.gov/docs/fy19osti/74831.pdf (accessed on 25 March 2022).

27. Asgharzadeh, A.; Marion, B.; Deline, C.; Hansen, C.; Stein, J.S.; Toor, F. A Sensitivity Study of the Impact of Installation Parameters and System Configuration on the Performance of Bifacial PV Arrays. *IEEE J. Photovolt.* 2018, 8, 798–805. [CrossRef]

28. Asgharzadeh, A.; Lubenow, T.; Sink, J.; Marion, B.; Deline, C.; Hansen, C.; Stein, J.; Toor, F. Analysis of the Impact of Installation Parameters and System Size on Bifacial Gain and Energy Yield of PV Systems. In Proceedings of the 2017 IEEE 44th Photovoltaic Specialist Conference (PVSC), Washington, DC, USA, 25–30 June 2017; pp. 3333–3338. [CrossRef]

29. Al-Shabi, M.; Ghenai, C.; Bettayeb, M.; Ahmad, F.F.; Assad, M.E.H. Estimating PV models using multi-group salp swarm algorithm. *IAES Int. J. Artif. Intell.* 2021, 10, 398–406. [CrossRef]

30. AlShabi, M.; Ghenai, C.; Bettayeb, M.; Ahmad, F.F.; Assad, M.E.H. Multi-group grey wolf optimizer (MG-GWO) for estimating photovoltaic solar cell model. *J. Therm. Anal.* 2020, 144, 1655–1670. [CrossRef]

31. Khan, M.R.; Hanna, A.; Sun, X.; Alam, M.A. Vertical bifacial solar farms: Physics, design, and global optimization. *Appl. Energy* 2017, 206, 240–248. [CrossRef]

32. Sun, X.; Khan, M.R.; Deline, C.; Alam, M.A. Optimization and performance of bifacial solar modules: A global perspective. *Appl. Energy* 2018, 212, 1601–1610. [CrossRef]

33. Pike, C.; Whitney, E.; Wilber, M.; Stein, J. Field Performance of South-Facing and East-West Facing Bifacial Modules in the Arctic. *Energies* 2021, 14, 1210. [CrossRef]

34. Yu, B.; Song, D.; Sun, Z.; Liu, K.; Zhang, Y.; Rong, D.; Liu, L. A study on electrical performance of N-type bifacial PV modules. *Sol. Energy* 2016, 137, 129–133. [CrossRef]

35. Wei, Q.; Wu, C.; Liu, X.; Zhang, S.; Qian, F.; Lu, J.; Lian, W.; Ni, P. The Glass-glass Module Using n-type Bifacial Solar Cell with PERT Structure and its Performance. *Energy Procedia* 2016, 92, 750–754. [CrossRef]

36. Deline, C.; MacAlpine, S.; Marion, B.; Toor, F.; Asgharzadeh, A.; Stein, J.S. Evaluation and field assessment of bifacial photovoltaic module power rating methodologies. In Proceedings of the 2016 IEEE 43rd Photovoltaic Specialists Conference (PVSC), Portland, OR, USA, 5–10 June 2016; pp. 1–6. [CrossRef]

37. Kopecak, R.; Libal, J. Bifacial Photovoltaics 2021: Status, Opportunities and Challenges. *Energies* 2021, 14, 2076. [CrossRef]

38. Oleczak, P.; Olek, M.; Matuszewska, D.; Dyczko, A.; Mania, T. Monofacial and Bifacial Micro PV Installation as Element of Energy Transition—The Case of Poland. *Energies* 2021, 14, 499. [CrossRef]

39. Ishikawa, N.; Nishiyama, S. World First Large Scale 1.25MW Bifacial PV Power Plant on Snowy Area in Japan. In Proceedings of the 2018 45th IEEE Photovoltaic Specialists Conference (PVSC), Portland, OR, USA, 5–10 June 2018; pp. 129–133. [CrossRef]

40. Reno, M.J.; Hansen, C. Global Horizontal Irradiance Clear Sky Models: Implementation and Analysis Global Horizontal Irradiance Clear Sky Models: Implementation and Analysis. Sandia Rep., No. January. 2014. Available online: http://www.osti.gov/servlets/purl/1039404/ (accessed on 15 February 2022).

41. Mabasa, B.; Lysko, M.; Tavzinga, H.; Zwane, N.; Moloi, S. The Performance Assessment of Six Global Horizontal Irradiance Clear Sky Models in Six Climatological Regions in South Africa. *Energies* 2021, 14, 2583. [CrossRef]

42. Lave, M.; Hayes, W.; Pohl, A.; Hansen, C.W. Evaluation of Global Horizontal Irradiance to Plane-of-Array Irradiance Models at Locations Across the United States. *IEEE J. Photovolt.* 2015, 5, 597–606. [CrossRef]

43. Lopez, T.C. PV Performance Modeling Collaborative | Piecewise Decomposition Models. 9 August 2014. Available online: https://pvpmc.sandia.gov/modeling-steps/1-weight-design-inputs/irradiance-and-insolation-2/direct-normal-irradiance_piecewise_decomps/models/ (accessed on 30 March 2022).
44. Lopez, T.C. PV Performance Modeling Collaborative|Hay and Davies Sky Diffuse Model. 9 August 2014. Available online: https://pvpmc.sandia.gov/modeling-steps/1-weather-design-inputs/plane-of-array-poa-irradiance/calculating-poa-irradiance/poa-sky-diffuse/hay-sky-diffuse-model/ (accessed on 30 March 2022).

45. Yang, D. Solar radiation on inclined surfaces: Corrections and benchmarks. Sol. Energy 2016, 136, 288-302. [CrossRef]

46. Duffie, A.J.; Beckman, W.A. Solar Engineering of Thermal Processes; John Wiley & Sons: Hoboken, NJ, USA, 2013; Volume 3.

47. Martin, N.; Ruiz, J.M. Annual angular reflection losses in PV modules. Prog. Photovolt. Res. Appl. 2005, 13, 75–84. [CrossRef]

48. Xie, J.; Sengupta, M. Performance Analysis of Transposition Models Simulating Solar Radiation on Inclined Surfaces. Eur. PV Sol. Conf. Exhib. (EU PVSEC) 2016, 18302, 66573.

49. Marion, B.; Macalpine, S.; Deline, C.; Riley, D.; Stein, J.; Hansen, C. A Practical Irradiance Model for Bifacial PV Modules. In Proceedings of the 2017 IEEE 44th Photovoltaic Specialist Conference (PVSC), Washington, DC, USA, 25–30 June 2017.

50. Yusufoglu, U.A.; Lee, T.H.; Pletzer, T.M.; Halm, A.; Koduvelikutluthu, L.J.; Comparotto, C.; Kopeczek, R.; Kurz, H. Simulation of Energy Production by Bifacial Modules with Revision of Ground Reflection. Energy Procedia 2014, 55, 389–395. [CrossRef]

51. Appelbaum, J. The role of view factors in solar photovoltaic fields. Renew. Sustain. Energy Rev. 2017, 81, 161–171. [CrossRef]

52. Gu, W.; Ma, T.; Ahmed, S.; Zhang, Y.; Peng, J. A comprehensive review and outlook of bifacial photovoltaic (bPV) technology. Energy Convers. Manag. 2020, 223, 113283. [CrossRef]

53. Baumann, T.; Nussbaumer, H.; Klenk, M.; Dreisiebner, A.; Carigiet, F.; Baumgartner, F. Photovoltaic systems with vertically mounted bifacial PV modules in combination with green roofs. Sol. Energy 2020, 190, 139–146. [CrossRef]

54. Jouttiärvi, S.; Lobaccaro, G.; Kampíntunen, A.; Miettunen, K. Benefits of bifacial solar cells combined with low voltage power grids at high latitudes. Renew. Sustain. Energy Rev. 2022, 161, 112354. [CrossRef]

55. Baumann, T.; Fabian, C.; Raphael, K.; Markus, K.; Andreas, D.; Hartmut, N. Performance Analysis of Vertically Mounted Bifacial PV Modules on Green Roof System. In Proceedings of the 35th European Photovoltaic Solar Energy Conference and Exhibition (EU PVSEC), Brussels, Belgium, 24–27 September 2018.

56. Meyer, C. Vertical bifacial: Grid-friendly and competitive agrophotovoltaic concept: New project of Dirmingen. Agrovoltaics Fr. Ger., No. October, 2018. Available online: https://energie-fr-de.eu/fr/manifestations/lecteur/seminaire-sur-lagrivoltaisme-en-france-et-en-allemande.html (accessed on 16 April 2022).

57. Fernández, E.F.; Pérez-Higuera, P.; Almonacid, F.; Ruiz-Arias, J.; Rodrigo, P.; Fernandez, J.; Luque-Heredia, I. Model for estimating the energy yield of a high concentrator photovoltaic system. Energy 2015, 87, 77–85. [CrossRef]

58. Mahachi, T. Energy yield analysis and evaluation of solar irradiance models for a utility scale solar PV plant in South Africa. Master Eng. (Electrical Electron. Fac. Eng. Stellenbosch Univ., vol. 1, no. 12, 2016. Available online: https://scholar.sun.ac.za (accessed on 31 January 2022).

59. Caballero, P.; Srinivasan, G. How to Calculate P90 (or Other Px) PV Energy Yield Estimates|Solargis. 2018. Available online: https://solargis.com/blog/best-practices/how-to-calculate-p90-or-other-pxx-pv-energy-yield-estimates (accessed on 26 May 2022).