Long-Term Performance and Shade Detection in Building Integrated Photovoltaic Systems

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Building integrated photovoltaics (BIPV) operate in a unique environment compared with field-mounted systems and may experience elevated temperatures and recurrent or persistent shading. These stresses are expected to accelerate degradation, but there are few performance reports for true BIPV systems as defined in IEC 63092-1. Herein, the long-term performance (over 5–10 years) of 55 BIPV systems in Switzerland is reported. Using a year-on-year (YOT) performance loss rate (PLR) analysis, the median degradation rate of all systems together (fleet-wide) is determined to be 0.06% per year (i.e., essentially no degradation), though there is a large spread of rates. Visual inspection of the systems indicated that some are shaded at times, so a fault detection and diagnosis algorithm (FDDA) is developed to estimate the shading severity of the systems using their daily production profiles. The fraction of time in shading fault presents a linear trend for the upper limit of PLRs, though by itself it is not a strong predictor of system performance. On average, the degree of shading is found to increase in newer systems, and decrease in larger capacity systems. These results highlight the importance of alleviating shading stresses through innovative BIPV module and system design.

1. Introduction

Building integrated photovoltaics (BIPV) are a rapidly growing segment of the photovoltaic (PV) market, especially in areas where intensive land use limits deployment of utility-scale PV and building/energy policies support construction or retrofitting of low and net-zero energy consumption buildings. While there are several studies on the long-term performance of utility-scale PV systems, there are very few for BIPV. This is problematic because it is known that BIPV systems can be subjected to higher operating temperatures and near-field shading stresses compared with field-mounted modules.[1–4] Moreover, the term “BIPV” has been and is still often used to describe residential and commercial systems that utilize conventional PV modules attached onto pre-existing roof and façade structures, though these are more appropriately classified as building applied PV (BAPV) systems.[5–7] BIPV modules are defined as a building product in IEC 63092-1, and the majority of “BIPV” systems in published reports do not satisfy this strict classification. BIPV modules are intended to fulfill one or more functional requirements of the building envelope,[8] and if removed they must be replaced by an appropriate building product. Thus, BIPV systems form an integral part of the building itself, and are quite distinct from field-mounted PV and BAPV systems in terms of construction, function, and operational environment.

PV module and system lifetimes are determined by their degradation of performance loss rate (PLR), which is the change in power output over time. Many environmental and operational stress factors drive degradation, including continuous and cyclic exposure to heat/cold, sunlight, and moisture. To calculate PLR, the performance ratio (PR) of a system is plotted as a function of time, ideally over many years.[9,10] The PR is the ratio of actual yield (kWh/kW) and reference yield, the latter of which is calculated using meteorological inputs and nominal system capacity.[11] Once PRs are calculated, PLRs can be determined using various methods. One of the most comprehensive reports on long-term PV system performance showed median PLR values around −0.5% per year for c-Si modules,[5] whereas a more recent report analyzing mostly residential BAPV systems showed median PLRs of −1.0% per year.[7] Note that, negative PLR values denote performance loss and positive values signify performance gain, in accordance with a recent report by IEA PVPS Task 13 experts on performance analysis.[12]
In BIPV systems, it is expected that temperature- and shaded-induced degradation will be more prevalent.[14] In fact, IEC TS 63126 addresses the first, and describes modifications to typical module qualification and safety tests (MQT and MST) to account for applications for which high temperatures are expected, such as in BIPV and hot climates.13,14 Shade-induced degradation is less well understood. Modules typically contain two or more sub-strings of solar cells, each protected by a bypass diode (BPD) that helps mitigate the effect of partial shading conditions by allowing current to bypass the shaded or bad cell or cells in a string. For a conventional PV, module and system partial shading is usually a temporary event caused by soiling or partly cloudy weather. However, in a BIPV system, shading events may be routine or continuous throughout the day because of building elements such as overhangs, dormers (windows), chimneys, or multiple roof and façade orientations, and even external elements such as nearby buildings, trees, or other structures. This extended use of BPDs, including regular and excessive current excursions, is not anticipated in their design. In fact, the main qualification test for module BPDs (MQT 18.1 in IEC 61215-2) is only conducted for 1 h, with a possible extension to 5 h if diode temperature does not stabilize.[14] While in operation, BPDs dissipate heat that over time can damage the diodes and nearby components, thus reducing their functionality and ultimately the module performance.[15–17]

The immediate effect of partial shading can be seen in module and string output, including voltage, current, and power, thus shade detection is in principle possible from analysis of plant production data.[18–21] Several studies have examined these effects, which are highly dependent on factors including shading pattern and heaviness, cell string layout and module design, and PV system layout (e.g., electrical connections).[22–24] Typically measured and simulated plant production are compared, and then deviations are assigned to shading or other electrical faults. Different approaches have been taken to quantify the shading severity or factor, for example, on the basis of geometric (\(A_{\text{shaded}}/A_{\text{total}}\)), irradiance (\(G_{\text{shaded}}/G_{\text{unshaded}}\)), or yield metrics (\(Y_{\text{shaded}}/Y_{\text{unshaded}}\)).[1,23,25] Most of these analyses are applied to single modules or systems, and few trends or general conclusions can be made in relation to partial shading effects on the performance of fleets of PV systems, in particular in the long term.

This work reports the PLRs and shading factors of more than 55 rooftop BIPV systems with 5–10 years of operation. All were located in central Switzerland, and median system capacity was 17 kWp. The systems were all constructed with modules from a single manufacturer, and included 252 strings that were monitored and analyzed individually. The fleet average PLR was essentially zero, but a large spread of rates existed and a closer examination of some poorly performing systems showed that shading was apparent by visual inspection or due to clear deviations from an ideal production profile. This manual method of shading evaluation was a labor intensive and subjective process, so as a next step a fault detection and diagnosis algorithm (FDDA) to identify shading and classify its severity was developed. As inputs it used meteorological conditions (irradiance, temperature, and wind speed) as well as measured and single-diode (SD)-modeled direct current (DC) production (voltage, current, and power) to classify fault cases. The main causes of these faults were linked to partial shading, so the proportion of time in a fault state was defined as the shading factor of a string/system. The shading factor was found to delineate an upper limit on the PLRs of the BIPV systems. Moreover, average shading factors were found to increase in newer systems, and decrease in larger capacity systems. Further developments of the PLR and FDDA analyses are discussed, including validation. Finally, improvements to BIPV module and system design are discussed, which could mitigate shaded-induced performance losses.

2. Results and Discussion

2.1. BIPV System Characteristics

A total of 55 BIPV rooftop systems were under investigation in this work, all constructed with MegaSlate II modules manufactured by 3S Solar Plus AG and installed by Baur AG. The modules were made with monocrystalline silicon solar cells and have a glass/backsheet construction. The systems were located in central Switzerland, which has a temperate warm summer climate (Cfb Köppen-Geiger classification), and at elevations between 500 and 600 meters above sea level. They were installed between 2010 and 2015, thereby giving 5–10 years of operational data for these analyses. The median system capacity was 17 kWp, with the smallest being 6 kWp and largest being 148 kWp. Power production from the systems was monitored at the string level, of which there were 252 in total. Some plants contained a single string, and the largest had 18 strings. System orientations covered all cardinal directions with the majority oriented between east–south–west, whereas the average system tilt was 25° (range of 10°–55°).

2.2. PLR Analysis

PRs were calculated using system capacity and satellite-derived meteorological data (Solcast) as inputs. Then using monthly aggregation, PLRs were calculated using the year-on-year (YOY) methodology. The methods for PR and PLR calculation

![Figure 1. PLRs [% year\(^{-1}\)] for 55 BIPV systems (252 module strings) by installation year showing mean, median, confidence intervals (CI, 25–75% and 5–95%), and outliers.](image-url)
are described in more detail in Experimental Section and in the study by Özkalay et al.\cite{10}. Figure 1 and Table 1 show the annual PLRs for the 55 rooftop BIPV systems by installation year. Many systems had multiple strings and inverters, so in total 252 PLRs were calculated. The median fleet-wide PLR, which considers all systems together, was 0.06% per year, indicating essentially no performance change over time, though there was a large spread of positive and negative values. No trend by installation year was identified, and no systems exhibited obviously nonlinear performance loss behavior. Note that, here, a negative value denotes performance loss, whereas a positive value signifies performance gain, the same convention adopted in a recent IEA PVPS Task 13 framework report.\cite{12} In spite of the harsher operating environment for BIPV modules, many of the systems have degraded less than the average values between −0.5% and −1.0% per year reported for utility-scale and BAPV systems.\cite{5–7} While there is some uncertainty inherent in PLR calculation, this could be a result of different type and quality of module materials, designs, and processes.

The spread between the best- and worst-performing BIPV strings was very large, 1.20% per year versus −1.47% per year. A closer look at a well-performing and poorly performing system is shown in Figure 2. The well-performing system (Figure 2a) had no apparent near-field shading elements and its production profile followed a smooth and continuous path throughout the day, mirroring the daily irradiance profile. In contrast, the poorly performing system (Figure 2b) was characterized by several shading elements, namely nearby chimneys and trees. Moreover, the daily production profile of the system showed several clear drops and other characteristics that were attributable to shading events.\cite{1,15,22,25,26} It is suspected that module operation under routine or continuous shading accelerated degradation of the BPDs and cells.\cite{15–17,26} This subjective examination of a well-performing and poorly performing system highlighted the deleterious effect of shading on long-term performance, and motivated the development of a FDDA to better measure the severity of shading.

![Figure 2](image_url). Photographs and daily production profiles for a) a well performing and b) poorly performing BIPV systems. The profile of the b) poorly performing system showed signs of several shading events during the day due to chimneys and nearby trees.

| Installation year | Mean | Median | Lower CI [95%] | Upper CI [95%] | Number of systems | Number of strings |
|-------------------|------|--------|----------------|----------------|-------------------|------------------|
| 2010              | −0.03| −0.05  | −0.26          | 0.21           | 1                 | 6                |
| 2011              | 0.42 | 0.43   | 0.32           | 0.52           | 6                 | 25               |
| 2012              | 0.14 | 0.13   | 0.06           | 0.23           | 7                 | 45               |
| 2013              | −0.03| 0.00   | −0.08          | 0.02           | 14                | 96               |
| 2014              | 0.01 | 0.01   | −0.13          | 0.15           | 13                | 39               |
| 2015              | 0.05 | −0.05  | −0.07          | 0.17           | 14                | 41               |
| Fleet             | 0.07 | 0.06   | 0.03           | 0.11           | 55                | 252              |
Table 2. Fault classification and potential causes in the shading FDDA.

| Fault | Fault effect | Potential causes                  |
|-------|--------------|-----------------------------------|
| F0    | Normal       | –                                 |
| F1    | Cloudy       | Cloudy weather                    |
| F2    | Low V, low I | Partial shading, connection fault, MPPT fault |
| F3    | Low V        | Partial shading with BPD activation, short-circuited BPD, connection fault |
| F4    | High V, low I| Temperature drop due to shading, MPPT fault |
| F5    | High V       | Temperature drop due to shading, MPPT fault |
| F*    | Other        | Open-circuit fault, soiling, hot spot, potential-induced fault, ground fault, soldering, discoloration, cracks, delamination |

2.3. Shade Detection Analysis

A more quantitative analysis of the shading in the BIPV systems was achieved using a FDDA, described in detail in Experimental Section. In brief, it compared the measured DC inputs (voltage, current, and power) with simulated SD values calculated using satellite-derived meteorological data. When the DC inputs passed predefined thresholds, the system was classified as in fault, with the fault types shown in Table 2 by their effect. F0 is in fact not a fault, but refers to normal system operation where measured DC inputs are within expected ranges. F1 denotes operation in mostly cloudy weather, defined by a cloud opacity above 40%, where there is uniform shading across the whole system.

Faults F2–F5 have a variety of potential and even overlapping causes, and precise classification is difficult because the impact of partial shading is heavily dependent on partial shading pattern, heaviness, and module string layout.[22] To improve the FDDA, optimization of the fault detection thresholds and validation of the fault classifications should be carried out on a test system with intentional shading elements. Regardless, the root cause of each of these faults can reasonably be attributed to partial shading events, especially if they are recurrent at specific times of the day or visual inspection of the system indicates the presence of nearby shading elements. F2 (low voltage, low current) can be attributed to partial shading without BPD activation. F3 (low voltage) is most likely partial shading with BPD operation, in which case module or string voltage is reduced in proportion to the number of BPDs in operation.[22,23,27] The high voltage faults (F4 and F5) may be due to temperature effects or maximum power point tracking (MPPT) errors. As for temperature effects, if shading is sufficient to lower module temperature, then the voltage would increase, while current may decrease.[28,29] A similar effect that is not due to shading is observable during the comparatively cool morning and evening hours, when voltage is correspondingly higher. As for MPPT errors, when one or more BPDs are activated, it creates two or more maxima in the power–voltage curve.[22,27,30,31] In the optimal case of global maximum power, the voltage is lower (e.g., an F3 fault), however, if there is an MPPT error the module or string may be stuck in a local maximum at higher voltage, but lower overall power. Finally, F* refers to other module and system faults not detected with the algorithm. These faults can be assessed by onsite inspection or other types algorithms.[32]

To illustrate the classification, Figure 3 shows examples of the FDDA applied to three BIPV systems, in which the DC current and voltage were compared with the SD simulations and their respective thresholds. The fault-type heat maps on the bottom exemplifies the fault detection procedure. The unshaded BIPV system (Figure 3a) showed no faults, with both voltage and current within the simulated boundaries throughout the course of the day. The higher current in the morning and afternoon were not indicative of faults, just of higher performance than the SD model. The other two systems were shaded by building elements, as confirmed by onsite inspection. The first shaded system (Figure 3b) exhibited a recurring low voltage fault (F3) in the mornings and afternoons. The second shaded system (Figure 3c) and had a high voltage, low current fault (F4) occurring in the afternoons.

The FDDA can also be applied over an extended time period to identify seasonal and long-term patterns, for example, by fixed elements (e.g., a chimney) or changing elements (e.g., tree growth/seasonal leaf loss). Figure 4 shows full year outputs of the algorithm for one unshaded and one shaded system string in 2020 as heat maps of the fault detection and diagnosis where one can visualize the distribution of faults in time. The unshaded system showed no signs of recurring shading events, whereas...
recurring faults were readily observed in the shaded system. By extending this analysis over the operational life of a system a shading factor can be computed, which is defined as the time shading fault divided by the time in operation (excluding nighttime).

2.4. Shading and Trends in BIPV Systems

The FDDA was applied to the 55 rooftop BIPV systems (252 module strings) to calculate shading factors, which were then plotted with the PLRs, as shown in Figure 5. The shading factor alone was not a strong predictor of PLR, as in fact there are a variety of factors that contribute to system degradation besides shading.\[^{12,33}\] In particular, there is likely to be some variation in the substructure of the roofs, which would affect heat transfer of the modules, and thereby their temperature.\[^{34,35}\] In addition, the type of shading fault might have an influence on PLR. Here, faults F2–F5 were all grouped together to determine the shading factor, so further analyses should be made with a breakdown of fault types. In spite of these limitations, the shading factor did appear to present an upper limit or threshold of the PLRs, shown by the dashed line in Figure 5. This would indicate that shading limits the maximum achievable long-term performance of BIPV systems. The figure also indicates the installation year of the systems, though no clear trends within the fleet were observed.

Two other trends were observed for shading factor of the BIPV systems, shown in Figure 6. The first is a moderate increase in shading in newer systems (Figure 6a). This trend is consistent from 2010 to 2014, and may be due to installation of BIPV on less ideally exposed rooftops. The best exposed roofs would offer the highest return on investment, but as systems costs have come down dramatically, even a less exposed rooftop can be viable investment. Moreover, support schemes and incentives sometimes encourage installation of PV systems without regard to local exposure (insolation) conditions.\[^{36}\] Another reason may be the increasing use of customized module sizes and shapes to fully cover roof areas, especially around shading elements. Analysis of more and newer systems (2015 to present) would help to determine if this is a real and continuing trend.

The second trend observed is a shading factor decrease with system capacity (Figure 6b). This is most noticeable for small capacity systems, below 30 kWp. The reason for this is likely because larger systems tend to be on large roofs, for example, warehouses, barns, or other commercial buildings, which would have fewer shading elements with respect to their size and be located in larger and more open land parcels. Smaller systems, on the other hand, are mostly on residential buildings, including single family homes, for which the number of potential shading elements is greater compared with the roof size.

2.5. Continuing Development of the Performance and Shading Analyses

Some limitations of the PLR and FDDA analyses have already been mentioned earlier, and improvements are ongoing. First, the analyses are being applied to an even larger fleet of BIPV systems within the same geographical area. This will provide many other data points in the analysis, so that other factors affecting them can be examined with greater confidence, including potential effects due to orientation, tilt, DC/AC ratio, and inverter selection.

Second, the roof substructures are not identical between each of these systems, and the ventilation area and rafter length and...
spacing can vary widely. This would have a noticeable effect on operating temperature, another stressor that drives module degradation.[34,35] To resolve this confounding factor in understanding, the relationship between shading and long-term performance some large systems with multiple strings are undergoing deeper analysis. The assumption is that for a single BIPV system, the substructure and local environment would be identical for all strings, so trends might be easier to identify.

Third, in this work, all shading fault types (F2–F5) were grouped together to determine the shading factor. However, it cannot be assumed that each type of shading fault has the same effect on performance. So further analyses will breakdown fault types to assess their impact.

Finally, the shade detection algorithm is undergoing continuous optimization, including adjustment of thresholds for fault detection and more precise identification of fault causes. To this end, a BIPV test stand has been built to validate the fault classifications, both their cause and effect.

### 2.6. Applications and Mitigation of Shade-Induced Degradation

The FDDA can be applied to any type of BIPV or even conventional PV system with intraday monitoring data to detect shading and determine its severity. Problematic modules and strings can be identified and then removed or modified to minimize the effect of shading on the entire system. Because shading may be a contributing factor to performance loss, if a poorly performing system ultimately results in a warranty claim (e.g., $P_{\text{max}} < 80\% P_{\text{nom}}$ in the 25 year warranty period, or a PLR $< -0.8\%$ per year), the FDDA can assist attribution of responsibility, e.g., to the module manufacturer or system designer and installer.

Both parties can undertake action to mitigate the effect of shade-induced degradation, some of which include: 1) Design of more shade resistant modules, e.g., by installation of additional BPDs or diodes with higher ratings into modules.[36,37] 2) Improved education and training for system designers concerning the weaknesses and limitations of PV module design for specific applications. 3) More precise assessment of the local boundary conditions in the building envelope and surroundings to identify heavily shaded areas. 4) Optimization of the electrical layout of strings, or installation of DC/DC power optimizers and microinverters (instead of string or central inverters) so that fewer modules are affected by shading.[38,39] 5) Installation of more shade resistant modules or dummy panels in areas expected to experience heavy shading.

BIPV constitutes a small segment of the PV market, and there is still a learning curve to be climbed to optimize system performance.[4] Moreover, this work focused on rooftop BIPV systems. Façade BIPV systems are another growing segment, and have greater risk for shading than rooftops. Utility-scale PV systems had a similar learning curve in the early 2000s as capacity began to grow exponentially. There were numerous examples of poor system design that resulted in nonoptimal performance or early failure, such as widespread installation damage from mishandling or vertical module orientation resulting in strong losses due to inter-row shading during winter.[25,40] Experience from the early days of PV expansion have shown steadily improving performance of PV systems, and demonstrated that there is plenty of room for improvement.

### 3. Conclusions

The long-term performance of BIPV modules is an open question for the sector, as most reports are for field-mounted PV or BAPV systems. This lack of data is especially concerning because of the increased risk factors for BIPV systems, including elevated operating temperatures and regular shading events. In that regard, this work is one of the first studies on long-term performances of true BIPV systems as defined in IEC 63092-1. The median PLR of 55 rooftop BIPV systems (252 module strings) in Switzerland was found to be 0.06% per year, indicating an essentially stable performance over 5–10 years of operation. However, within the fleet a large spread of PLRs was identified, and faster degrading systems were found to be more heavily shaded. A FDDA was developed to identify deviations in DC voltage and current that were indicative of shading events. By applying the FDDA over the operational life of each string and system,
a shading factor or fraction of time in shading fault was calculated. The shading factor alone was not a strong predictor of PLR, but it presented an upper boundary, effectively limiting maximum achievable performance. Shading severity was found to increase in newer systems, and decrease in larger capacity systems. Further improvements to the shading analysis are expected to better establish the relationship between shading and long-term performance. These results highlight shading as a major risk factor for BIPV that has potential to accelerate system degradation. Moreover, they provide valuable insights to BIPV module manufacturers and installers, allowing them to better design products and systems to mitigate the effect of shading within BIPV and other integrated PV systems.

4. Experimental Section

PR and PLR Calculation: In this work, the PRs and PLRs of 55 rooftop BIPV systems in Switzerland were calculated. All systems utilized the same type of module (3S Solar Plus MegaSlate II) and were installed between 2010 and 2015, resulting in 5–10 years of production data per system. Each PV plant had a monitoring system for string and inverter yield down to 10 min frequency. Global horizontal and diffuse irradiance were derived from satellite-based measurements (Solcast), and then translated to plane-of-array irradiance for each system.[32] Three filters were applied to improve data quality. First, an irradiance filter removed very low (<200 W m⁻²) and very high irradiance conditions (>1250 W m⁻²). A second filter, a power filter, removed very low measured power (<1% \( P_{\text{nom}} \)), and very high measured power (>120% \( P_{\text{nom}} \)). And for the last filter, the relation between the measured power and irradiance was used. Instantaneously calculated PR (in this case, 10 min) values were filtered using 0.3 and 1.2 as lower and higher thresholds, respectively. Monthly PR was calculated as a function of measured yield and reference yield, using methods described by Jordan et al. and Özkalay et al.[9,10] Then PLRs were calculated using the YOY methodology. This compares the PR of 1 month with the same month in subsequent years, and results in a distribution of PLR values for all months and years. From this, degradation statistics of the system were determined. Values reported here are median PLRs for each string or system. None of the systems exhibited obviously nonlinear performance loss behavior, so a linear rate was assumed. Some analyses use nonlinear or multistep models for PLR,[41] but these methods are still being developed and not widely used.

Shading Factor Calculation (FDDA): The degree of shading was estimated by comparing the actual yield and idealized (unshaded) yield, enabling identification of faulty operation in the system due to shading events. To accomplish this, a FDDA was developed to identify and...
Table 3. List of terms and abbreviations in the FDDA.

| BIPV system inputs          | Meteorological inputs          | Simulated inputs          | Defined thresholds          | Calculated outputs          |
|-----------------------------|--------------------------------|---------------------------|----------------------------|----------------------------|
| $V_{dc}$ DC voltage [V]     | $G_{hi}$ Global horizontal irradiance [W m$^{-2}$] | $V_{id}$ SD voltage [V]   | $V_{th\_low}$ Low voltage [V] | Time (fraction)            |
| $I_{dc}$ DC current [A]     | $D_{ni}$ Diffuse horizontal irradiance [W m$^{-2}$] | $I_{id}$ SD current [A]   | $V_{th\_high}$ High voltage [V] | F0 Normal operation        |
| $P_{dc}$ DC power [W]       | $D_{hi}$ Direct horizontal irradiance [W m$^{-2}$] | $P_{id}$ SD power [W]     | $I_{th\_low}$ Low current [A] | F1 Cloudy weather          |
|                            | $T_{amb}$ Ambient temperature [$^\circ$C]        |                            |                            | F2 Low voltage, low current |
|                            | $W_s$ Wind speed [m s$^{-1}$]                   |                            |                            | F3 Low voltage              |
|                            | – Cloud opacity                                |                            |                            | F4 High voltage, low current|
|                            |                                                |                            |                            | F5 High voltage             |
|                            |                                                |                            |                            |                            |

categorize faults, as shown in the flowchart of Figure 7 and with terms shown in Table 3.

At the first level, the algorithm collects DC system data as the main inputs—voltage, current, and power—from the system inverters at string level, resampled at 10 min frequency. Metadata was also collected from the systems, specifically, the location, DC capacity, orientation, and tilt. Meteorological data were then extracted for the location of each system from Solcast historical time series,[42,43] which provides satellite-based weather data at 10 min frequency, including ambient temperature, wind speed, cloud opacity (cloudiness), and global, direct, and diffuse horizontal irradiances. Plane-of-array irradiance was calculated using a transposition function based on system orientation and tilt.[32]

At the second level, using the pvlib-python library, the SD model was applied to simulate PV system outputs using the meteorological data as input.[44] Specifically, the parameter values for the SD equation at effective irradiance and cell temperature were evaluated using the De Soto et al. model,[45] with cell temperature calculated using the sandia array performance model.[46] The maximum power point values of the SD model were then scaled to the string output level, giving SD simulated values for voltage, current, and power. By comparing the measured and simulated values the relative power loss can be calculated.

The third step in the FDDA was the definition of statistical threshold values for the voltage and current, which were used as baselines to detect faults. To do so, the daily standard deviations of voltage and current outputs were computed, $\sigma_V$ and $\sigma_I$, respectively. Through iterative optimization as well as literature review,[18,19,47] the following thresholds were found to be suitable to detect faults and minimize false alarms for voltage (1, 2) and current (3).

$$V_{th\_low} = V_{id} - 2 \cdot \sigma_V$$  \hspace{1cm} (1)

$$V_{th\_high} = V_{id}$$ \hspace{1cm} (2)

$$I_{th\_low} = I_{id} - 0.5 \cdot \sigma_I$$ \hspace{1cm} (3)

In short, the higher factor applied to the voltage threshold reflects the lower variability of DC voltage in a given day, while a lower factor was applied to current as the daily standard deviation was inherently higher (linked directly to the irradiation variations during the day). Moreover, given the scaling of simulated values, the standard deviations were only applied for the lower thresholds. For current, only a lower boundary was applied as values higher than simulated outputs do not indicate potential faults, but rather higher performance than the SD model.[40] In terms of voltage however, deviations above or below the defined threshold indicate faulty behaviors, such as BPD operation and changes in the maximum power point of the module or string.[41]

In the next level, once the thresholds were defined the FDDA sorted out the signal by fault type, as shown in Table 2 by their effects on DC voltage and current. The possible classifications include normal operation (F0) if the signal is within the daily defined boundaries. Given the possibility of faults occurring due to cloudy or overcast weather (F1), a filter is applied to remove these faults. In this study, a cloud opacity threshold of 40% was used to identify these faults, which represents a 400 W m$^{-2}$ drop from AM1.5 irradiance. This level of opacity corresponds to thin stratus cloud coverage.[46] Because the Solcast irradiance data already adjusts for cloud opacity, the cloud coverage filter could be considered redundant in this case. If a voltage fault is not identified as being due to cloudy weather, the FDDA categorizes the faults further.

Faults F2–F5 have a variety of potential causes, but can reasonably be attributed to partial shading of the systems. Potential causes of F2 faults are not obvious—BPD activation (lower voltage) should theoretically not lower the current of the string, so partial shading, connection faults, or MPPT errors are likely explanations.[20] F3 faults are clear shading faults; when the voltage decreases and the current remains within acceptable ranges, it is a clear indication of BPD activation due to shading.[39,50] Considering the two standard deviation thresholds around the voltage fault detection, the identified voltage drops are significant and are therefore due to modules or half-modules being bypassed in the studied string. For F4, when the voltage increases and current is below the defined threshold, the behavior is indicative of shading without BPD activation; the current is lower due to lower irradiance reaching the shaded modules, and the voltage increases due to its temperature dependence (lower temperatures in shade would increase the voltage) and/or to adjustments in the MPPT, which should correct to the highest MPP.[22] The F5 faults with higher voltages and no current drop are explained by the small mismatches in the current and voltage thresholds of the FDDA—these faults are often observed to be coupled with F4, and therefore have the same probable causes.

The final step of the shading analysis is the quantification of the degree of shading identified using the FDDA. This is achieved through the definition of a shading factor (SF) (4), in this case, the percentage of time during which a system experiences shaded or faulted conditions. For a given power-producing time period $T_{period}$ (s), e.g., a full year of data, the total amount of time while shaded $T_{shaded}$ (s) is identified through the FDDA by considering the fault types F2–F5 for partial shading, and the SF is computed as

$$SF = \frac{T_{shaded}}{T_{period}}$$ \hspace{1cm} (4)

Nighttime is excluded from this computation as the DC outputs are close to zero, and this is achieved by filtering out values before the sunrise and after sunset.

Optimization of the FDDA is ongoing, including modification of the thresholds and classifications. Validation of the shading analysis is being
made with a BIPV test system incorporating intentional shading elements. In addition, deeper analysis of BIPV systems by breaking down shading faults can be made, i.e., examining F2–F5 faults separately instead of together to determine the shading factor.

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**Conflict of Interest**

H.Q. and P.W. are affiliated with 3S, the manufacturer of the modules used in the BIPV systems analyzed. 3S has not had access to the raw data, or influenced analysis in any way that might be considered inappropriate.

**Data Availability Statement**

Research data are not shared.

**Keywords**

building integrated photovoltaics, bypass diodes, degradation rates, fault detection and diagnosis algorithm, performances, reliability, shadings

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