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Potential measurement techniques for photovoltaic module failure diagnosis: A review

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ABSTRACT

Various characterization methods are used for the detection of PV (photovoltaic) module defects. However, these methods yield different results with varying uncertainties, depending on the measuring apparatus, data acquisition system, and filtering standards. This imposes the risk of accurately estimating the location and influence of defects of a PV module. The immediate identification and quantification of degraded solar panels have the direct cost-benefit of preventing PV module failure. The replacement of a PV system could cost far more than the cost of the module itself. Therefore, the challenges involved with solar panel defect detection techniques are discussed along with a summary of the conventional and emerging characterization technologies that enable accurate identification of the degradation source and extension of PV modules' useful lifetime. One hundred and twenty-six studies are reviewed, of which 60% deal with indoor, 40% outdoor, and 7% cover both indoor and outdoor defect detection techniques. Cell-cracks (23%) and hotspots (18%) are the most reported sources of PV module defects. The reviewed publications provide strong support for the claims that the I–V curve measurement is more handy, cost-effective, and provides instant feedback to verify the PV module condition. Simultaneously, the clustering-based computation method is relatively new and imposes several challenges, such as providing reliable predefined data with clusters optimization. Therefore, in this paper, the primary factors that degrade PV systems are investigated. The current best techniques for characterizing defects in PV systems are then overviewed, and their advantages and limitations are discussed.

1. Introduction

Recent advances in PV module defect detection methods have accelerated PV systems' commercial productions and installations, offering numerous economic, social, and environmental benefits. An imaging-based technique to extract spatially resolved information to diagnose photovoltaic (PV) module defects have been widely used in research and industrial applications. The negative environmental impacts, which have been gaining increasing attention to the photovoltaic community, suggest that when solar panels useful life expires, they need to be disposed to reduce the possible harmful effects to the environment [145]. Recently, feasibility analyses of PV modules have been conducted considering their environmental impacts [1] and financial risk [2]. Under real operating conditions [3], it has been reported that solar energy can only be economical if they efficiently and reliably operate for 25–30 years in outdoor environments [4]; however, these might varies depending on the geographical locations. Thus, assessing the PV modules' reliability through accelerated testing can be an essential method to predict their long-term performance in the field (accelerated testing is necessary because waiting twenty years for performance assessment is impractical).

PV module failure in the field can stem from material issues, fundamental product design flaws, or failure in quality control during the manufacturing process. Three key mechanisms responsible for a PV module's failure are typically considered, namely, infant mortalities, mid-life failures (i.e., random failures), and wear-out failure. Fig. 1 shows a typical bathtub curve generated by mapping the rate of early "infant mortality" PV module failures when first occurred, then the rate of "random failures" during its "normal operation period," and finally, the rate of "wear out" failures after its end-of-life date.

As shown in Fig. 1, the risk of failure is high during the commissioning period or start-up period, commonly known as infant mortality. That risk comes down very rapidly during the normal operation period,

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Nomenclature

ASTM	american society for testing and materials
CBC	clustering-based computation
CCD	charge-coupled device
CdTe	cadmium telluride
EBIC	electron beam induced current
EDFAS	electronic device failure analysis society
EDX	energy dispersive x-ray
EL	electroluminescence
EQE	external quantum efficiency
EVA	ethylene-vinyl acetate
FF	fill-factor
IR	infrared
ISO	international organization for standardization
IEC	international electrotechnical commission
J_{ph}	photocurrent
J_L	load current
HITL	heterojunction with an intrinsic thin layer
I_{sc}	short circuit current
I_m	maximum current
I_T	cell current
I–V	current-voltage
K_B	Boltzmann constant
LBIC	laser beam induced current
MPP	maximum power point
NREL	national renewable energy laboratory
n_1	ideality factor
P_{max}	maximum power
PL	photoluminescence
PR	performance ratio
PV	photovoltaic
R_s	series resistance
SEM	scanning electron microscope
STEM	scanning transmission electron microscope
T	temperature
UVF	ultraviolet fluorescence
V_{oc}	open-circuit voltage
V_m	maximum voltage

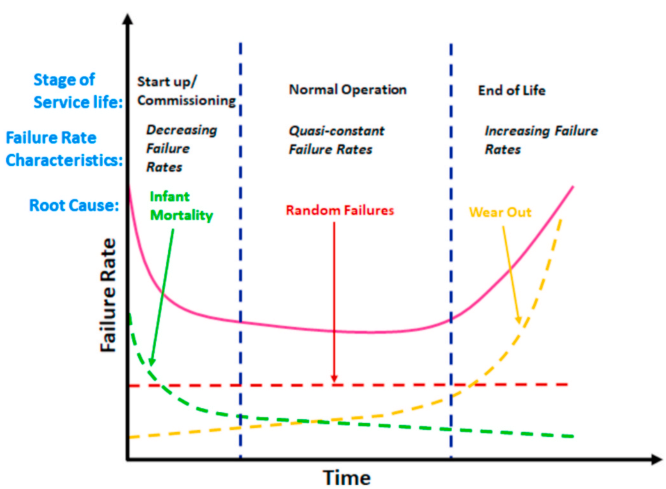

Fig. 1. Typical "Bathtub curve" of PV module failure, modified from Ref. [3].

where the failure rate is almost constant. However, at the end of the PV module's lifetime, the probability of failure increases due to wear out.

Early detection of defects using accurate characterization techniques could increase solar panels' lifespan, reducing the PV module wastage. Thus, this paper has discussed the various potential and widely used PV module failure and fault diagnosis methods, including visual inspection, I–V curve measurement, IR thermography, EBIC, SEM, EL, and UV-F imaging.

Due to the high PV installation capacity in European countries, the demand for accurate performance degradation measurement techniques has significantly increased among manufacturers, distributors, and PV plant owners. Imaging-based methods have recently received widespread attention in the production process, driven by the recent advancement in solar energy technologies. For example, in Spain Munoz et al. (2011) have conducted an experiment based on visual inspections, I–V curve field measurements, infrared (IR) imaging, and Electroluminescence imaging techniques and detected hidden defects that initiate during the manufacturing process. Nevertheless, some faults still could not be detected using reliability tests (IEC61215 or IEC61646) in different operating conditions [4].

Imaging-based solar panel defect detection techniques' complexity restricts their use, both indoor and outdoor. Michl et al. (2014) suggested an indoor/outdoor testing approach based on combining photoluminescence (PL) imaging, infrared (IR) thermography, and electron-beam induced current (EBIC) imaging, respectively for a better understanding of the PV cell degradation sources [5]. In addition to that, various test methods such as electroluminescence (EL), electron beam induced current (EBIC), scanning transmission electron microscope (STEM) are combined to evaluate the degradation sources in PV modules [6]. Sulas et al. (2019) have recently compared several imaging methods, including scanning-laser illumination, contactless electroluminescence, and pattern-illuminated photoluminescence in solar panel defect detection [7]. On-site based PV cell defect detection methods based on conventional PV degradation models in conjunction with machine learning algorithms to predict solar panels' lifetime and failure modes have also been reported [8,9].

However, no studies published to date have claimed a PV module defect detection technique using a single imaging method to the best of our knowledge. This is due to the complexity of imaging-based defect detection techniques. For example, the bulky experimental setup and the need for accurate output image interpretation have hindered the scientific progress towards developing cost-effective and user-friendly imaging-based PV module defect detection techniques for indoor and outdoor applications. While it is unlikely that such a universal approach will be available soon, further progress in defect-specific and defect-generic measurement methods for optimization can be expected, though. This study reports on the measurement methods to follow up those issues, which allow the detection, characterization, and diagnosis of the PV module defects. This type of comparative analysis of the measurement methods is rarely seen in the literature.

Moreover, to generalize the PV cell defect detection methods, this paper divide them into (i) imaging-based techniques, (ii) rapid visual inspection methods, and (iii) I–V curve measurements, which are the most powerful diagnostic tools for field-level testing. This paper also explain the corresponding experimental setup, best contemporary practice, and each defect detection method's pros and cons. This paper suggests using essential techniques to monitor the PV plants online to see if some deterioration phenomena are developing or if some faults exist. Then examine PV modules in the laboratory to understand deeply the type of degradation that is happening.

Even though researchers have discussed many different PV diagnosis methods separately, none of them have conducted a comparative analysis between methods. Therefore, this study attempts to close this gap in the literature. The novelty of this work is threefold: first, it compares the most widely used PV panel's fault diagnosis methods through a systematic, simplified, and scientific manner; second, it highlights the critical challenges and benefits associated with the discussed methods; finally, it indicates future research direction of PV panel's defect characterization towards developing the future International Standards. Hence, this study provides a comprehensive comparative analysis of the key PV diagnosis methods, which is lacking in the literature.

The rest of the article is organized as follows: Section 2 discusses the prior studies about degradation sources and defect detection. Section 3 describes the degradation effects on I–V characteristics. Section 4 explains the methodology used for this work. Section 5 defines the basic methods of fault detection for PV modules and highlights their advantages and limitations. Section 6 discusses the findings of this study. The final section concludes the article.

2. Prior studies

A PV module's lifetime may vary due to geographical locations, where variations in temperature, humidity, and solar irradiation can be significant. For example, Asian countries have higher humidity, which may degrade the performance of a PV module. Thus, it is essential to identify frequently occurring defects in a PV module to understand better and interpret the changes in its electrical performance parameters. A comprehensive test in Indian climatic conditions has been conducted using visual inspection, IR, and I–V characteristic measurements. Non-uniform single-cell browning and junction box failure, hotspots, disconnected PV cells, and string interconnect ribbons were identified, with peak power degradation quantified following the International Electro-technical Commission (IEC) standards. Three modules showed 50% degradation, while the remaining seven modules showed only 0.6–2.5% degradation in peak power after 2.5 years [10].

On the other hand, in tropical climatic conditions, it was found that the I–V characteristics degrade differently. For example, in Senegal, a mid-life PV module experienced the highest loss in maximum power ($P_{\max}$) (0.22%/year to 2.96%/year), while its open-circuit voltage (V_{oc}) remained undegraded [11], and this unexpected behavior needs to be further investigated over a longer time period in order to fully understand the long-term electrical performance degradation of photovoltaic modules functioning in tropical climatic conditions. In desert conditions, cracked cells and some unusual physical material defects have been detected, resulting in PV module degradation of up to 12% compared to the initial performance [12]. Therefore, it is crucial to use accurate measurement methods that can precisely predict the key factors affecting PV module performance degradation in particular climate conditions.

A PV module's output power also predominantly depends on the installation type (rooftop, floating, etc.). For example, evaporation (or high humidity) has a higher impact on the efficiency, reliability, and degradation of the floating PV module. The performance of PV modules based on the use of heterojunction with an intrinsic thin layer (HITL) and Poly-Si on the water surface is found to be 0.4% and 2.7% lower than that of land-based counterparts, respectively. In contrast, a CdTe PV module's performance on a water surface is found to be 3.1% higher than that of a land-based module [13].

Furthermore, the accuracy of the measurements plays a critical role in determining solar panel lifetime. Fezzani et al. (2017) have proposed a method of uncertainty to improve the degradation measurement procedure in desert environments [14]. Note that the output power of crystalline-silicon based solar panels decreases heavily due to soiling in desert [15], e.g., the output power could drop up to 40% in Saudi Arabia and around 65% in Kuwait climatic conditions due to soiling [16]. Typically, the lifetime of a solar panel decreases due to aging in the field conditions. This type of degradation can be identified using EL [17] and I–V characterization [18]. As discussed earlier, the temperature coefficient is another critical factor that affects a solar panel's performance. Typically, the temperature coefficient depends on the PV module type [19]. For instance, different PV module technologies have been trialed in the field to measure their temperature coefficients [20]. It has been found that the thin-film solar panels, such as Cadmium Telluride (CdTe) PV modules, are more tolerant to temperature changes, displaying a temperature coefficient of $-0.172\%/^{\circ}$C, which is more than 60% less than that of a polycrystalline solar panel [21]. Data from previous studies have suggested that dust on the solar panel's surface can reduce its efficiency by 35% in the Bangladeshi environment [22], and 50% in the Malaysian climate [23]. Several studies have focused on understanding the causes, categories, and the overall influence of dust on solar panels' conversion efficiency [24], in the Middle East and North Africa, which have the worst dust accumulation zones globally [25]. The root cause of soiling is a cementation process leaving behind a glass that cannot be cleaned [26].

The accurate estimation of degradation rates must be known to predict power delivery and calculate the PV modules' payback period. Sayyah et al. (2014) reported a precise method for determining dust-induced mechanical stress [27] in different parts of the world, which helps forecast the module output power and payback period. According to NREL, damp heat, humidity, and thermal stress are responsible for PV module failures [28], directly impacting the PV module's lifetime. For example, PV module manufacturers typically guarantee that a solar panel can degrade on average at a rate of 1% each year in the field due to UV light exposure and thermal cycling. Thus, the outdoor field degradation measurement technique could play a vital role in quantifying PV modules' long-term behavior for a better return on investment by accurately predicting the decrease in panel efficiency.

Various other factors are also responsible for PV modules' low efficiency and early failure, predominantly due to the losses arising from multiple phenomena, degrading the PV module performance. The earlier detection of those losses has a positive impact on solar panel efficiency improvement. A list of these losses is shown in Table 1 [29]. While most losses are internal, many external factors are also essential, including dust accumulation, partial shading, moisture content, crack formation, interconnection problems, physical damages, and installation failures that can significantly reduce the solar panel lifetime.

Factors affecting PV panels' performance could be categorized into "ecological" and "PV module specifications" factors. The main ecological factors are solar irradiation and temperature. All the other factors, such as wind velocity, the accumulation of dust particles, and humidity, would indirectly affect either the two main ecological factors (solar irradiation and cell temperature) or influence the PV system specifications. For instance, the accumulation of dust on the surface of PV panels increases the cell temperature. It decreases the received solar irradiation, thus reducing the PV panel's maximum output power and increasing the risk of a hot spot occurrence, which leads to panel failure.

Table 1
A list of external factors to efficiency reduction in PV modules (Data source [29]).

Sl. No.	Causes for the losses	Percentage of loss (Approximate)
1	Excess photon energy	33 %
2	Photon energy less than a bandgap	23 %
3	Voltage factor	20 %
4	Additional curve factor	5 %
5	Curve factor	4 %
6	Top surface contact obstruction	3 %
7	Reflection at the top surface	1 %
8	Quantum efficiency	0.4 %
9	Series resistance	0.3 %
10	Shunt resistance	0.1 %

3. Degradation effects on I–V characteristics

Determining the degradation rate of a PV module is essential to measure its critical electrical characteristics parameter, namely, the open-circuit voltage (V_{oc}), short circuit current (I_{sc}), maximum current (I_m), maximum voltage (V_m), and fill-factor (FF), which can be obtained from the I–V curve. A simplified equivalent circuit of a PV cell is shown in Fig. 2 to calculate the solar panel performance's electrical parameters.

I–V relationship for a solar cell's single-diode model can be expressed as [30]:

$$I = J_{ph} - J_{o1}\left(exp\left[\frac{q(V_L + J_L \times R_s)}{n_1 K_B T}\right] - 1\right) - \frac{q(V_L + J_L \times R_s)}{R_P} \tag{1}$$

where R_s is the series resistance, n_1 is the ideality factor, T is the temperature, K_B is the Boltzmann constant, J_{ph} and J_L are the photocurrent and load current, respectively.

The above single-diode approach is commonly used to predict the solar cell current for experimental outdoor and indoor operating conditions. However, the single diode I–V model has several limitations. For instance, if the I–V curve analysis is performed inside a laboratory, the soiling and shading problems cannot be investigated. For outdoor experiments, the measured I–V characteristics are usually compared with mathematical models. In this regard, the circuital model shown in Fig. 2 (single diode model) cannot be used for accurate diagnostic purposes as only the value of shunt resistance provides information about the PV module degradation, where the change in shunt resistance enables some defects to be found [31]. For more accurate modeling of the PV cell, the single diode model shown in Fig. 2 can be upgraded by adding a parallel diode to the circuit, resulting in a double-diode model (Fig. 3).

Compared to the simplified single-diode model, the modified double-diode model introduces another diode in parallel to take into account the effect of carrier recombination. A parasitic shunt resistance is also added, leading to the following expression of the I–V characteristics [33].

$$I = J_{ph} - J_{o1}\left(exp\left[\frac{q(V_L + J_L \times R_s)}{n_1 K_B T}\right] - 1\right) - J_{o2}\left(exp\left[\frac{q(V_L + J_L \times R_s)}{n_1 K_B T}\right] - 1\right) - \frac{q(V_L + J_L \times R_s)}{R_P} \tag{2}$$

where R_p is the shunt resistance.

There are five primary factors that affect a PV module's performance, namely, series losses, shunt losses, mismatch losses, reduced current, and reduced voltage. The series losses show up in the I–V curve as a decreased slope of the curve near V_{oc}. This effect is equivalent to adding a single external resistance in series with the PV module. The series resistance losses can be internal in a PV module, e.g., due to broken internal interconnections, or external, e.g., due to wiring, where corrosion or poor connection of PV modules increases the series resistance. Shunt losses due to shunt resistance, which is typically caused by resistive paths between the front and back surfaces of the PV cell, increases the slope of the I–V curve near the short circuit current, thus reducing the output power of the PV module. Therefore, the I–V curve can be used for troubleshooting when the system performs lower than expected. Mismatch in PV modules occurs when the PV cell's electrical parameters are dissimilar, thus increasing the power losses, especially because typically, the current of a PV module is determined by the current of the solar cell that has the lowest current. Reduction in the output current of a PV module is mainly due to the shading of a single or multiple PV modules, thus preventing unshaded cells from operating at their maximum current (or power). Therefore, even insignificant shading over a large PV array can significantly reduce a PV system's output current. Note that, to overcome shading, PV modules can be connected in parallel; however, bypass diodes must be used so that the higher current of unshaded cell strings can flow around the shaded PV modules. Bypass diodes, however, increase the electrical losses of the PV array. Shading also reduced the output voltage of a PV panel; however, this voltage reduction is typically insignificant compared to a current decrease. For example, for a-Si PV panel operating at a Maximum Power Point (MPP) voltage of 33 V, the maximum open-circuit voltage drops from 43 V to only 38 V when the solar irradiance drops from 1000 W/m^2 to 200 W/m^2, respectively. A list of the commonly used methods to detect the various degradation factors is shown in Table 2 and Fig. 4

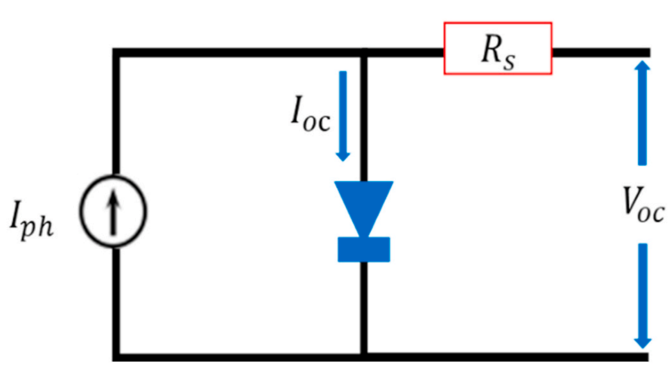

Fig. 2. A simplified equivalent circuit of a typical solar cell's single diode model.

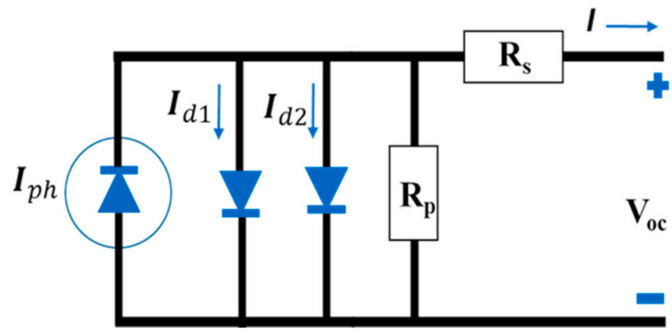

Fig. 3. A double-diode equivalent circuit of a solar cell [32].

Table 2
A comparison of basic techniques for photovoltaic module failure used in the literature.

Studies/ References	Used Method	Investigated For
[18,34–42]	I–V Characteristic	Electrical parameters of the PV module to detect uniform dust faults, hot spot, dark current, shunt resistance, partial shading faults, ageing, and short circuit faults.
[43–47], [45,48, 49] [50,51]	EL imaging	Cell breakage, solar cell cracks, deteriorated areas, intrinsic defects, dislocations, shunts or other process failures, interrupted contacts
[52–60]	IR imaging	Deficient soldier joints, short-circuited cells, bypassed substrings, encapsulant discoloration, defective bypass diodes, hot area
[61–63]	UV-F imaging	Micro-cracks in the cells, hotspots, glass breakage, mechanical rupture, yellowing effect, polymer degradation, mismatched cells
[58,64–66],	SEM imaging	Hotspots, shunts, p-n junction properties, material defects, the surface morphology of hot spots
[67–71]	EBIC imaging	Pre-breakdown phenomena, leakage currents, sub-surface defects, diffusion length, recombination centers, shunt defects, grain boundaries defects

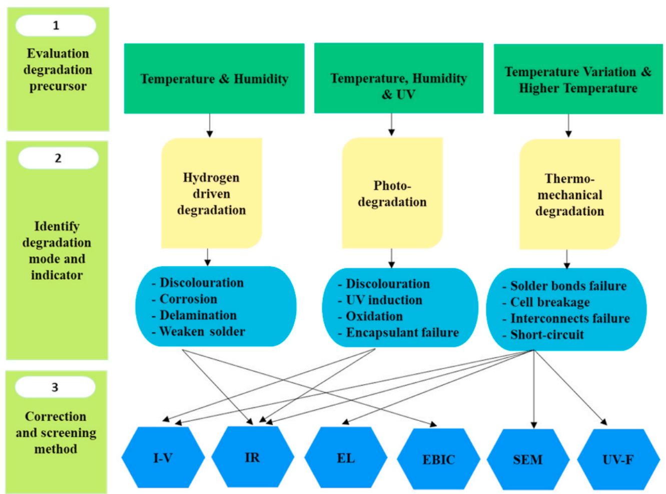

Fig. 4. A flowchart showing the steps used to identify a PV module's degradation sources, modified from Ref. [72].

shows the steps used for the detection of defects of a PV module.

According to Kaaya et al. (2019), most of the degradation measurements are conducted for specific degradation modes using controlled test conditions and validated based on indoor measurements from accelerated tests [72]. Since a PV module in outdoor operation experiences numerous climatic loads, which, in turn, might lead to different degradation modes, combined stress models are a prerequisite to estimate PV module degradation. Thus, the most critical step is to select the defect detection technique. For example, measuring the I–V characteristics can check whether the solar panel's performance has been degraded. It is assumed that it is crucial to first assess the impact of various stresses in controlled conditions using accelerated tests [72]. Thus, the effects of stress can be evaluated to check whether degradation is due to aging or defects. This is needed to correlate the power degradation to specific degradation modes using other characterization methods. It also helps to understand the physics of failure of the different degradation modes. However, the uncertainties associated with a technology-specific measurement method make it difficult to identify the geography-specific degradation rates and extract accurate module parameters. Some errors may occur due to random malfunctions of data acquisition and improper instrument handling. Note that inaccurately identifying the cause of PV module degradation may lead to financial hazards and significant warranty risk [73]. Therefore, the next question would be: what steps should be taken to rectify the problem? For better measurement accuracy and precision, International Standard test procedures need to be followed during failures analysis using different defect detection techniques. For example, IEC61215 or IEC61730 are the standard test procedures used to measure the solar panel quality in the manufacturing industry [45]. The objective of the IEC6125 standards is to determine the electrical and thermal characteristics of the terrestrial photovoltaic module, especially for crystalline silicon terrestrial flat PV modules under long-term operation in an open-air climate [74]. At the same time, IEC61730 specifies the PV module's fundamental construction requirements to provide a safe electrical and mechanical operation, such as electrical shock, fire hazards, and personal injury due to mechanical and environmental stresses [75]. However, sometimes all the latest findings regarding different failure tests are not included in the IEC61215 standard [74]. Therefore, it is recommended to conduct an additional bypass diode test (IEC 62979, IEC/TS 62916).

4. Methodology

A scoping review reported in Ref. [76] is adopted, based on mapping the peer-reviewed journal articles and conference papers on PV module degradation monitoring approaches. Many databases containing scientific reports are available; however, it is a daunting task to determine the best database relevant to our interests. We began the review process using Edith Cowan University's (ECU) library search engine ECU Worldsearch, Australia, using relevant keywords [77]. The keywords used for the search were: Solar panel defect detection; PV module degradation; PV module fault detection, PV module degradation measurement methods, and techniques; Solar cell degradation detection technique; PV module, Solar panel performance measurement, PV module wastage, and its environmental effect, and PV module fault diagnosis. While searching, either the word 'PV' or 'Solar' was kept constant as the review is focused on PV/Solar panel defect detection only. The search resulted in 200 studies; during the selection process, 74 studies were not directly associated with the PV module defect diagnosis and removed from the analysis, leaving 126 studies that have been considered for this review. After completing the review process, findings have been analyzed and summarized, all these steps are shown in Fig. 5.

At the start of the search, the following steps have used to determine the search terms/words:

- Sorting the chosen topic as a question or several questions
- Identifying and defining the main concepts in our chosen question(s)
- Creating a list of keywords for searching
- Deciding whether we need to be comprehensive or selective
- Defining the scope of our search

5. Basic techniques for failure diagnosis

PV module undergoes several standard quality tests before it is supplied to customers. Those tests' primary objective is to determine the possible factors that cause a breakdown of the solar panel, which is the heart of a PV system. However, measuring the mechanical characteristics is not enough for testing the reliability and stability of the PV system. For example, those test includes thermal imaging of the interlayer adhesive material used to encapsulate the PV module and protect it from the environment and mechanical impairments, thermo-mechanical, and photo-induced effects checked before and after panel installation. There are various methods to detect a PV module's defects and determine the causes behind this defect. Each of these methods has advantages and disadvantages, which are covered separately in several previous studies.

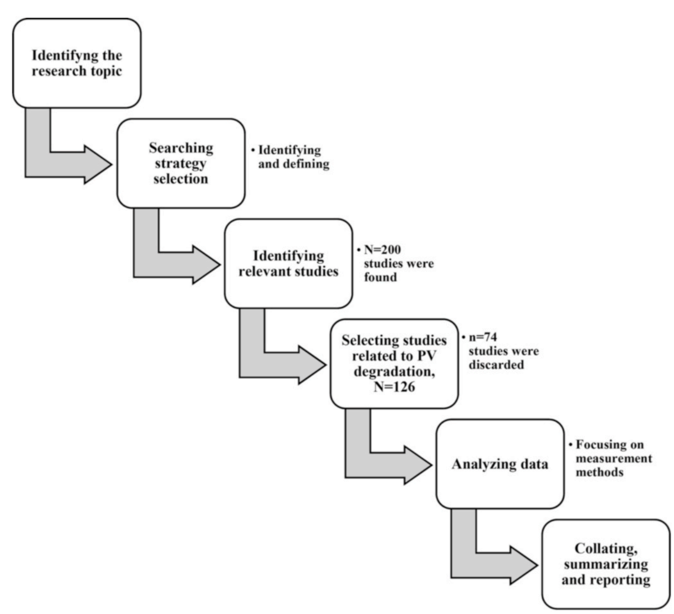

Fig. 5. Steps are illustrating the methodology used for this study to search for PV module defect detection approaches.

For instance, a 'review of infrared and electroluminescence imaging for photovoltaic field applications' has been conducted [78]. However, a comparative analysis of widely used methods has rarely been seen in the literature. Thus, this study focuses on addressing the PV module characterization methodologies (e.g., power vs. efficiency, temperature, etc.) better to meet the PV manufacturers and the end-user's needs. A complete schematic of the characterization techniques used in this study has shown in Fig. 6. A PV module's performance mainly depends on the smart management of the PV system configurations, thermal conditions, water, and dust ingression. This study has reviewed scientific reports, books, book chapters, and articles, which covered different methods for identifying PV module defects. It has taken various defect detection methods to depict a comparative picture and highlight its key features.

5.1. *Visual inspection technique*

Various types of methods are used to identify defects and failure modes in PV modules. However, visual inspection is the quickest and convenient way to detect defects in a solar panel [79] by directly looking at the PV cell using a naked eye or a magnifying glass. Fig. 7 shows examples of visible defects due to weathering.

The visual inspection method is usually accomplished before and after exposing the solar panel to evaluate the environmental, mechanical, and electrical stress, such as thermal cycling and UV irradiation. Moreover, visually inspected PV module defects, such as panel browning, delamination, and cell damage, provide a good indication of their correlation with the measured I–V curve. The visual inspection method should be carried out following the international standard test procedures, such as IEC61215, IEC61646. Note that the test results of visual inspection, such as the image, position, and size of defects, should be documented to compare its recent findings.

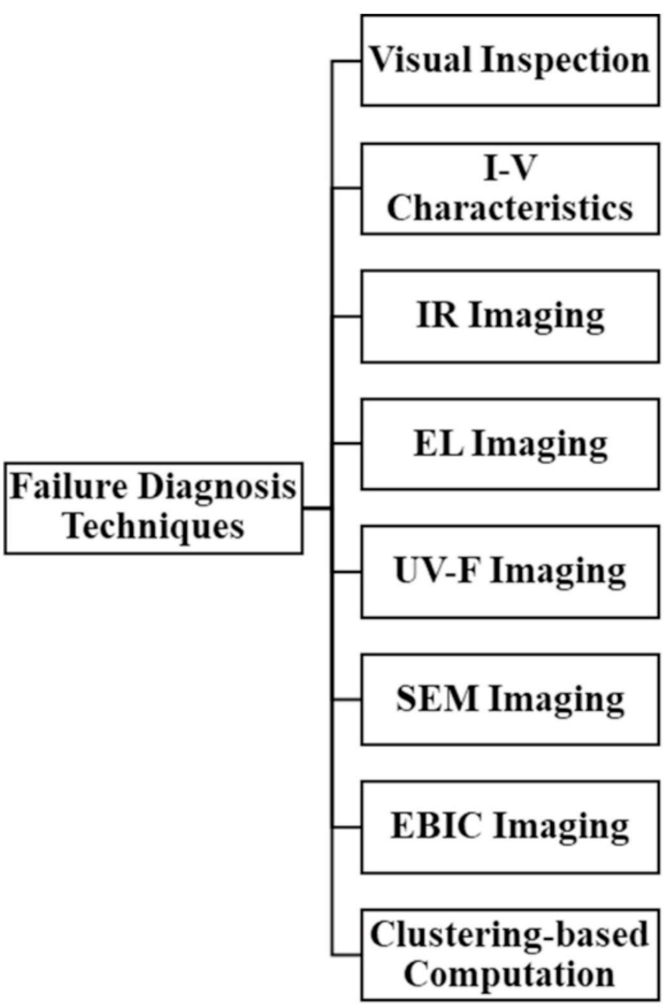

Fig. 6. Standard methods/techniques considered for this study.

Advantages of the visual inspection technique:

- Visual inspection is an inexpensive method that is simple to collect an aged PV panel's physical defect information.
- The primary defects, such as delamination, junction box failure, and encapsulant yellowing, can be identified quickly, thus minimizing the utilization of expensive human resources.

Disadvantages of the visual inspection technique:

- It provides information about the surface only, not more in-depth into the cell.
- It can't detect smaller indiscretions (limited to the detection of massive flaws).
- It does not provide precise measurements, especially on a microscopic scale.
- Difficult to identify the key factors responsible for identified defects.

5.2. *I–V characteristic technique*

Measuring the current-voltage (I–V) curve has been the most effective method for investigating a solar panel's electrical performance. The output power degradation is identified through the PV module's fill factor reduction. The reduction of fill factor is attributed to increases in series and shunt resistance and non-uniform discoloration of the PV module's encapsulant. The I–V curve of a PV module typically changes if operated under outdoor conditions [81]. For example, moisture ingression effectively reduces the active area of the solar panel [82], thus decreasing the solar panel conversion efficiency and increasing the degradation rate (above the typical 0.5 %/year rate) of flat plate terrestrial panels [28], and 1.8 % per year for crystalline silicon panels [83].

In addition to predicting the electrical degradation, the I–V curve of the PV module can be used to detect chemically-induced degradation, such as ethylene-vinyl acetate (EVA) discoloration, by measuring the I_{sc} and cell efficiency of the PV module, i.e., observing a steeper (i.e., less flat) I–V curve [84]. Chemical ingression can be severe, as it typically affects the junction box's resistances and metallic contacts of the PV cells. PV module cracks and hotspots can also be identified using the I–V curve method (as with EL and IR thermography) via detecting the increase in R_{shunt} (shunt resistance) and decrease in fill-factor (*FF*) of the PV panel [85].

A standard I–V curve measurement setup comprises a sun-simulator, a test bench, a light power sensor, and a data acquisition system. The homogenous distribution of light should be kept as constant as possible [86]. The experimental design is shown in Fig. 8 [87], which usually includes a silicon module [Kyocera LU181C58A] and a digital meter [Keithley 2420 Digital Meter] [88] as the starting sample and measuring instrument. From the measurement setup, the maximum power of a PV module specimen can be evaluated.

According to EN/IEC 61215 standard test, every module must successfully pass the defect test [58]. Therefore, for accurate PV module defect detection, a typical measurement procedure must be conducted following the IEC61215 standards by measuring the I–V curves under standard irradiation scenarios [89]. Besides, a light sensor is usually used as a solar reference device for evaluating global irradiance following the IEC60891 standards [90,91], and the ISO 17025 standards [92]. Standardized PV module accelerated aging tests and qualification tests are performed to ensure the module's stability, lifetime, and performance. The voltage, current, and power can be recorded by varying the load resistance, and hence the maximum power can be measured based on the ASTM standard E1036-08 [93]. Note that the short circuit

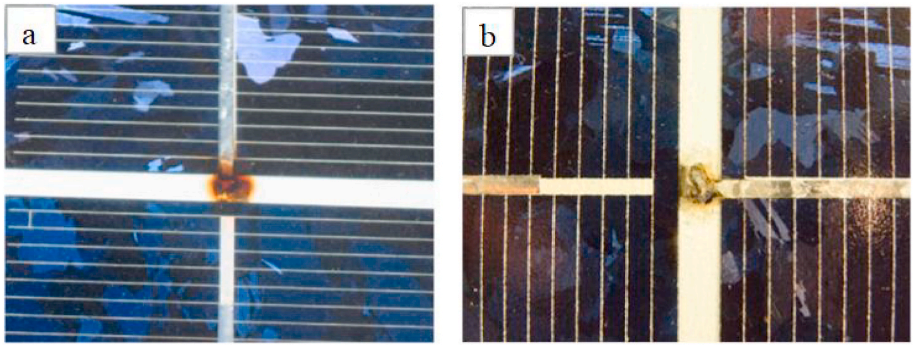

Fig. 7. Examples of PV module failures that are easily detectable in the field using visual inspection, such as; (a) broken interconnecting cell ribbons and (b) degraded soldering bonds. Reprint from Ref. [80]. Copyright, 2016, Elsevier.

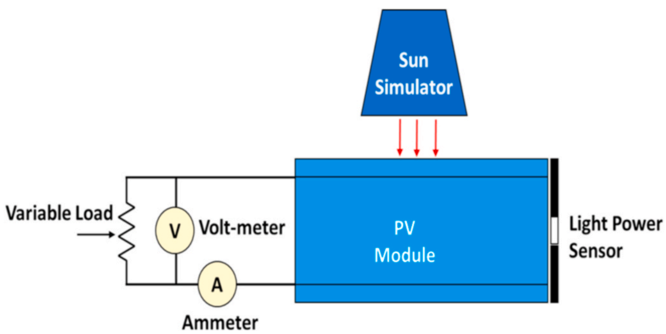

Fig. 8. A simplified schematic diagram is used to measure the current-voltage (I–V) curve of a PV module [87].

current (I_{sc}) depends on the solar cell material's irradiation level and quality. Fig. 9 shows a simple example of an experimental graph's variation with a shorted bypass diode and without a shorted bypass diode. A small instrumental error may lead to a severe problem in interpreting the I–V curve. The I–V curve acquisition method needs to be calibrated [94] to improve the measurement accuracy, which is usually conducted according to the IEC 60904 [95] standards [88].

Different types of faults caused by dust, short-circuit, partial shading, and aging can be identified using the I–V characteristic method [38]. These faults could be detected by observing the changes in I–V characteristic curve, as follows [96]:

- A low short-circuit current may initiate glass cover corrosion and discoloration of the PV module's encapsulation.

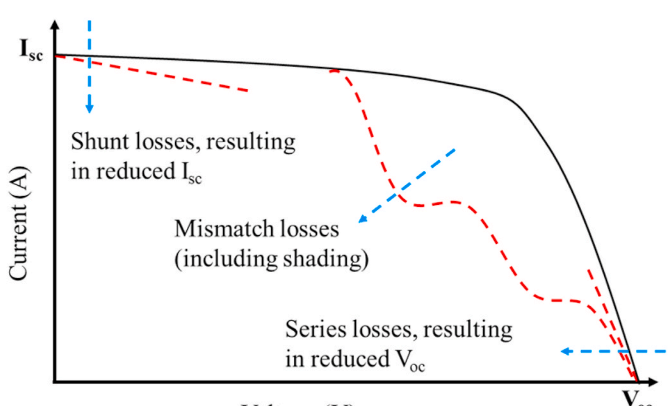

Fig. 9. A simplified I–V characteristic curve of a PV panel illustrating the shunt-, series- and mismatch-related losses.

- I–V curve turns into a stepped shape due to damaged PV cells, module shading, and dust (partial shading) [38].
- Due to the shorted bypass diode and light-induced degradation, the open-circuit voltage decreases.
- The slope near the short-circuit current increases due to the development of a shunt path.
- The I–V curve slope near the open-circuit voltage reduces due to oxidation, increased wiring resistance, and damaged intercell ribbons.

When part of a PV module is shaded, the unshaded cells will force the shaded cells to pass more current than their lower short circuit current. The only way the shaded cells can operate at a current higher than their short circuit current is to operate with a negative voltage, causing a net voltage loss to the system. The shaded cells will dissipate power as heat, thus causing "hot spots". Therefore, the shaded PV cells drag down the overall I–V curve of the group of PV cells. This effect of shading on the I–V curve's shape typically depends on how the module is being shaded. As discussed earlier, one way to minimize the impact of shading (or PV module performance degradation) is to use bypass diodes in the junction box.

The key advantages and disadvantages of the I–V characteristic method are as follows:

Advantages of the I–V characteristic technique [97]:

- Solar cell I–V characteristic curves provide a detailed description of the power conversion efficiency of the PV module.
- I–V curves provide the information required to configure a PV system to operate as close to its optimal peak power point (MPP) as possible.
- The I–V curve shape or profile provides a highly effective visual indication of PV modules or strings' performance.
- An assessment of the I–V curve during the installation or commissioning, or as part of the periodic inspection and test of a system, can help verify that all the modules are healthy and performing at a consistent level in line with their specified parameters.

Disadvantages of the I–V characteristic technique [97]:

- The measurement accuracy reduces with the slight differences in the curve shape and change in fill-factor.
- The expected I–V curve could be hampered due to soiling and shading

5.3. IR-thermography imaging technique

"Thermography is a safe, non-contact measurement method to check groups of circuits and solar panels. The thermal irregularities are apparent on the camera's screen, and dual images can be saved to the report" [98]. Thermography or infrared (IR) imaging was first introduced in 1990 as a robust solar panel defect diagnosis tool [99]. A typical thermography setup comprises an excitation source and an infrared (IR) camera that identifies the hot spot of a PV module placed in between them [55], as illustrated in Fig. 10.

Thermally-induced degradations of a solar panel induced by short circuits, shunt resistance, and moisture can be detected by IR thermography [55]. Large temperature variations could be experienced if the solar cell is short-circuited or have any defects [101]. Higher solar irradiation causes inhomogeneous temperature distribution throughout the section, typically creates hotspots in the solar cell [93]. The hotspots in the solar cell can be detected by IR thermography tests [80]. Fig. 11 shows the thermography images of the field-aged silicon solar panel.

Fig. 11 shows that the hotter cell in a solar panel (by looking into the color index, where yellow represents the hotter place) appears yellow due to defect formation and cell fracture. Even a patchwork pattern can be detected on the IR image due to bypass diodes, which later can heat the strings of cells and degrade the solar cell performance [54]. The solar panel would become less efficient once the temperature rises. This means the output of the solar panel would decrease, thus produces less electricity [102]. Some of these heating defects can cause solar cells to break down. Thermal imaging is one of the best solutions to find these problems before failure [56].

Although thermal imaging offers many advantages, such as being a non-destructive technique, some common measurement errors occur due to a very shallow viewing angle, partial shadowing, reflections, and solar irradiance change over time [103]. Some typical thermal-imaging-related errors are listed in Table 3.

Four main requirements must be met for accurate defect detection by using IR thermography, namely (i) the thermal sensitivity of the camera needs to be adjusted, (ii) sufficient solar irradiance (above 700 W/m^2 is recommended) must be maintained, (iii) the imaging angle should be between 5 and 60° and (iv) any shadowing should be avoided. In addition to that, when the PV modules and plants are under operation, outdoor IR inspection should be conducted according to IEC TS 62446–3:2017(E) defined guidelines [104].

J.L Beaudoin proposed lock-in thermography in 1986 [105,106], which is a qualitative technique to identify solar cell defects [107]. In contrast, dark-thermography has been used for detecting the flaws of a thin-film-based solar cell for quality control [108]. According to EDFAS (2011), the inferior contact defects of a solar panel could behave like a heat-dissipating resistor (hotspot) [109]. Consequently, heating, in conjunction with defects, can cause the PV module failure [56]. The key advantages and disadvantages of thermography imaging are as follows:

Advantages of the IR-thermography imaging technique [110,111]:

- The devices used for IR imaging, e.g., non-contact thermometers, are not in contact with the source of heat. In this way, the temperature of hot solar panels can be measured safely, keeping the user out of danger and makes it a safe and sound technique for indoor and outdoor applications.

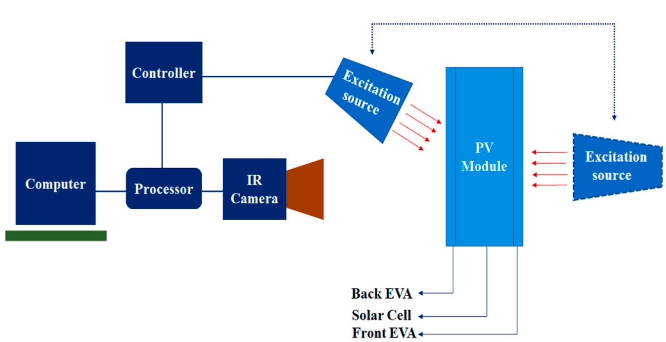

Fig. 10. A simplified schematic diagram of IR-thermography for PV module defect detection [100].

- By employing IR measurements, cells' thermal behavior in a module, as well as several defects (e.g., short circuits in PV cells, shunts, inactive cell parts, moisture, and defective bypass diodes), can be determined.
- IR imaging is a real-time measurement technique, enabling a rapid scan of large-surface PV panels, thus saving time and money.
- Faults can be identified at an early stage [112] due to faster measurements and the ability to compare two-dimensional thermal images of target PV areas.
- IR imaging is a non-destructive technique that emits harmless radiation, unlike X-ray imaging. Thus, it does not affect the tested target's performance, making it convenient for prolonged and repeated use.

Disadvantages of the IR-thermography imaging technique [111]:

- Obtaining high accuracy images can be difficult due to varying emissivity of the different materials, reflections from other surfaces, and other characteristics. Moreover, image interpretation requires particular experience and knowledge.
- In IR imaging, it is necessary to view the electrical components being scanned directly; thus, covers have to be removed, which can be hazardous.

5.4. Ultraviolet fluorescence (UV–F) imaging technique

UV-F imaging is a valuable non-destructive characterization tool for failure analysis and defect detection of PV systems. The UV-F imaging relies on the fluorescence effects of the polymeric lamination material in a PV module. This is typically ethylene vinyl acetate (EVA) added with various additives such as oxidation stabilizers, UV absorbers, and crosslinker [113]. In addition to the PV module's material-specific properties, module failure sources within the module, such as (micro)-cracks in the cells, hotspots, or glass breakage, can be detected through fluorescence footprints. In this technique, the UV-F measurements are conducted in the absence of incident illumination. A photographic camera [e.g., Olympus OMD] [61], equipped with a high pass filter that blocks specific UV irradiation, is used to detect changes in fluorescence emission. The measurement place should be isolated from external light sources. Thus, field measurements are possible at night or at least during twilight. The setup comprises a UV-light source [LED 380 or 365 nm; or Laser 400 nm], an optical fiber [Ocean optics QR600-7-SR 125 BX], and a spectrometer [Ocean Optics, MAYA 2000 Pro (200–1100 nm)] [61] as shown in Fig. 12.

For this technique, only 20–30 s is required to get a well-contrasted UV fluorescence from a solar panel [43]. However, it is challenging to detect cell cracks near the interconnects using UV-F imaging [62]. During UV-F imaging, the excitation is carried out using LED light sources. The higher intensity source lamp is used to illuminate a PV module [114]. Fig. 13 shows the solar panel distributed crack formation, which is identified through UV-F imaging.

The key advantages and disadvantages of UV-F imaging are as follows:

Advantages of the UV-F imaging technique [115]:

- One of the significant advantages of UV-F imaging is that the age of cell cracks can be determined. The cracks show up on the UV image as a dark area, which becomes more pronounced as the defect ages.
- UV-F provides spatial information, which is non-destructive compared to SEM.
- It has a wide range of selectivity and contrast; even tiny single molecules can be visible [116].
- It could be combined with EL imaging for a more accurate PV module quality assessment.

Disadvantages of the UV-F imaging technique [115]:

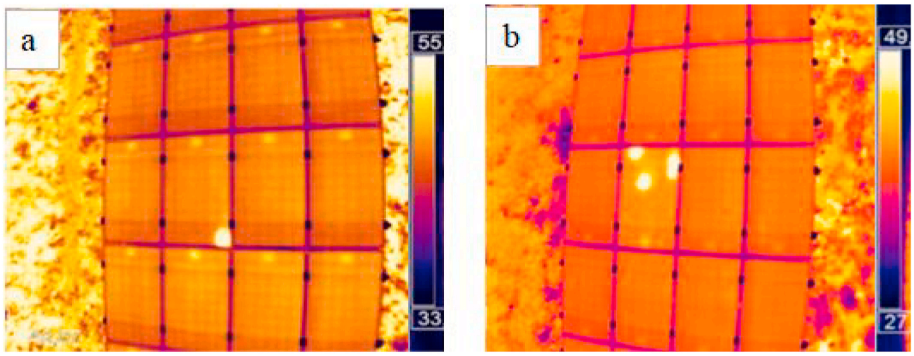

Fig. 11. IR thermography image of solar panels showing the hot area at the front side of the (a) defective solar panel and (b) cracked solar panel. Reprint from Ref. [80]. Copyright, 2016, Elsevier.

Table 3
A list of typical module errors that might detect during thermal imaging (Source [54,103]).

Error/Problem Types	Example	Thermal Image
Manufacturing/ Processing induced defects	i) Impurities and gas pockets ii) Cracks in cells	i) A hot or cold spot ii) Cell heating
Damage	i) Cracks ii) Cracks in cells	i) Cell heating ii) A portion of the section appears hotter
Shading (Temporary)	Pollution, bird droppings, humidity	Hot spots
Defective bypass diode	Not applicable	A 'patchwork pattern.'
Faulty/bad interconnection	Module or string of modules are not connected	A module or string of modules appear consistently hotter

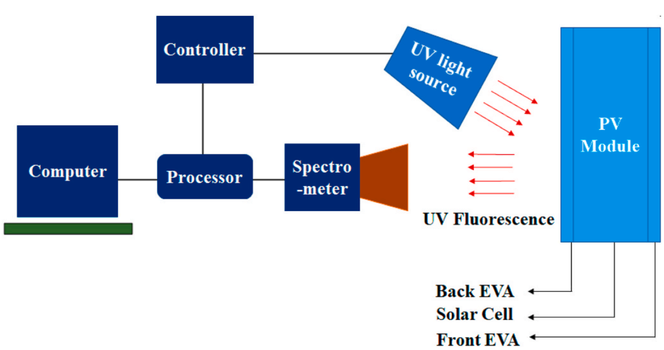

Fig. 12. A simplified schematic diagram of UV-F imaging for PV module defect detection [61].

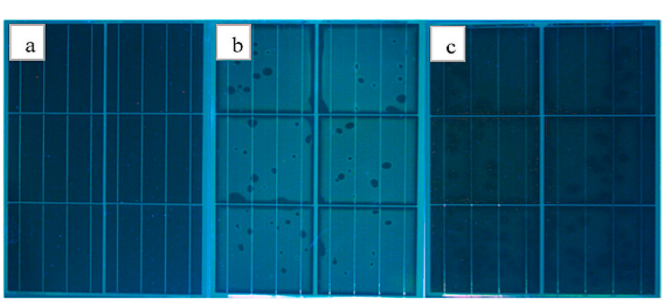

Fig. 13. The UV-F image of three test modules with micro-cracks; a) a module with its original state; b) a module after exposure to sunlight for 1000 h, and c) the module after natural storage for 1.5 years, adopted from Ref. [43].

- Fluorescence is not evident in the UV imaging of glass-glass modules or when high transmission EVA is used.
- This method requires an extensive area of the PV sample to be illuminated, and this becomes troublesome if the fluorescence tends to fade quickly.
- It requires an expensive high-pass filter before the CCD camera to stop the UV light below 400 nm.

5.5. Electroluminescence (EL) imaging technique

"*Electroluminescence (EL) is an optical and electrical phenomenon in which a material emits light in response to the passage of an electric current or a strong electric field. When investigating PV modules, the current is fed into a solar cell/module, and radiative recombination of carriers causes light emission.*" [45]. A direct current is supplied to the EL methods, which stimulates radiative emission in the PV module [117]. The stimulating emission is captured by a 1-megapixel scientific-grade multiple CCD cameras [Andor model, Luca-R] and a 640 × 480 pixel-based scientific-grade InGaAs camera array [Sinfrared Model, Xeva 1.7–760] [118]. The whole EL imaging arrangement is placed in a dark atmosphere because the PV cell's emitted radiation is lower than the background lighting. A filter needs to be employed before the camera, as illustrated in Fig. 14. In the EL imaging setup, the specimen (PV cell) is directly connected to a power supply. Simultaneously, the CCD camera captures the image and is later stored into a hard disk under the IEC63202-2 ED1 [119] standard test procedure.

This technique is typically used to identify defects in a PV module, such as structural defects that may arise from imperfect semiconductor processes, unmatched crystalline lattices, or faulty electrical connections [44]. In addition to that, solar panel characterization [120], micro-cracks [10], and even the diffusion length of a solar cell [121] can

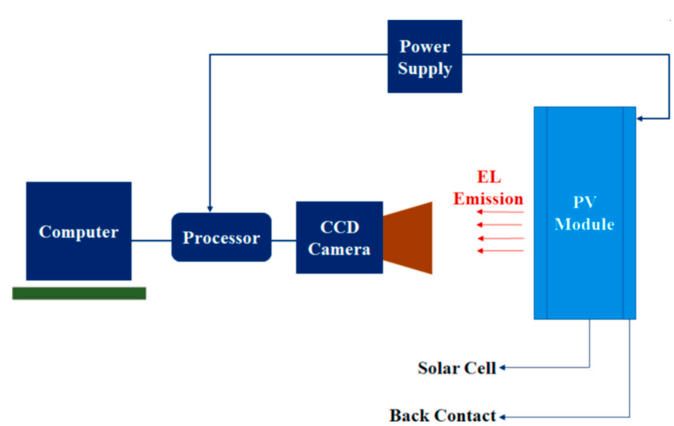

Fig. 14. A simplified schematic diagram of the experimental electroluminescence setup for PV module defect detection [118].

be measured using the EL imaging technique. Interestingly, the EL imaging technique is the only one that can visualize cracks. Note that any other method cannot detect nonelectrical active cracks. In rare cases, a misinterpretation of a grain boundary can happen. However, no other method can go to this limit. To make it short: EL is the gold standard for crack detection without any competition or doubt. Typically, the camera resolution should be fair enough (640 × 480 pixel) to visualize the defects of the PV cell. This problem can be resolved quickly by using a low-resolution camera in conjunction with a lock-in technique. Fuyuki et al. (2005) first presented this method under forwarding biasing [44]. Another similar form of luminescence imaging is photoluminescence. In photoluminescence, the illumination is conducted using smaller sources of wavelength [122].

Mochizuki et al. (2016) has proposed an open circuit voltage technique for analyzing PV module degradation [123]. This technique can help distinguish between the increment of series resistance and shunt resistance [124]. However, a combination of IR and EL based imaging techniques enables more accurate identification of PV module degradation sources. Fig. 15 shows the EL image of the cracked solar panel.

The key advantages and disadvantages of the EL imaging technique are as follows:

Advantages of the EL imaging technique [111]:

- EL has proven to be a useful high-resolution tool for investigating electrical inhomogeneities caused by intrinsic defects (e.g., grain boundaries, dislocations, shunts, or other process failures) and extrinsic defects (e.g., cell cracks, corrosion, or interrupted contacts)
- The high resolution of EL imaging enables resolving some defects more precisely than IR imaging.
- Less expensive method compared to UV-F imaging [45].
- This is a standard practice in determining solar cell cracks [125,126].
- It can detect untraceable and hidden defects that cannot be found with other techniques, such as infrared (IR) imaging or the I–V characteristic method.

Disadvantages of the EL imaging technique [111]:

- While EL imaging is a useful technique of fault detection, it is expensive due to the camera sensor technologies used, such as thermally stabilized charge-coupled devices (CCD) and Indium–Gallium-Arsenide sensors.
- In this technique, electrical contact is necessary, making it a time-consuming approach compared to other methods.
- The silicon detector (CCD camera) has an inadequate response beyond 1000 nm wavelengths and challenging to determine the influence of defects on cell/module performance.
- The captured image is subjected to interference from external light sources, and the origin of a defect might not be identifiable.

5.6. Scanning electron microscopy (SEM) imaging technique

Scanning electron microscopy (SEM) imaging is a beneficial technique to examine a solar cell's material properties following the international IEC61215 standards [127]. For instance, cell features at micron and sub-micron scales cannot be obtained using conventional optical microscopy. In SEM, an electron beam is focused on a spot and scanned over a specific solar cell area. During scanning, the electron beam interacts with the sample and generates signals through reflections, which reveal the PV sample's local properties. In this way, an image of an area of the PV sample is formed for analyzing the surface topography, layer structure, material composition, and electrical properties [128]. The primary beam current (I_P) and PV cell current (I_T) are measured using a Faraday cup and a programmable Keithley 6517 A electrometer [129], as shown in Fig. 16.

Fig. 17 illustrates information about the SEM image of the affected and non-affected PV sample. The image reveals the surface damage, which attributes to the hot spot formation (the model's chemical composition can be found from the EDX measurement, coupled with the SEM system).

The key advantages and disadvantages of the SEM imaging technique are as follows:

Advantages of the SEM imaging technique [131]:

- Scanning electron microscope (SEM) pictures are useful for examining the fine structure of solar cells. For example, even in large areas commercial devices, and SEM photographs can show the depth of the rear surface aluminum alloyed layer.
- With an electron microscope, it is possible to have the whole device in focus at once.

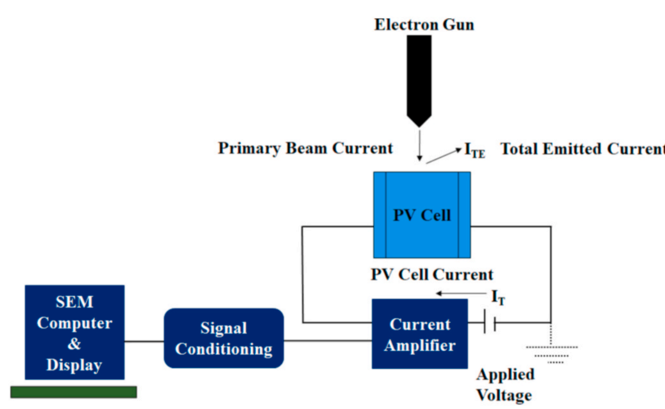

Fig. 16. A simplified schematic diagram of an SEM imaging experimental setup for PV cell defect detection [130].

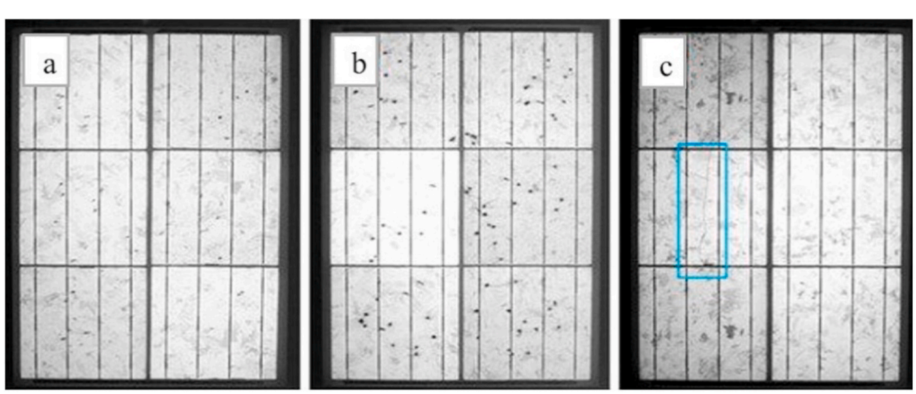

Fig. 15. Measurement of Electroluminescence (EL) images with a) few numbers of cracks, b) many numbers of micro-cracks, and c) with only cell crack, adopted from Ref. [43].

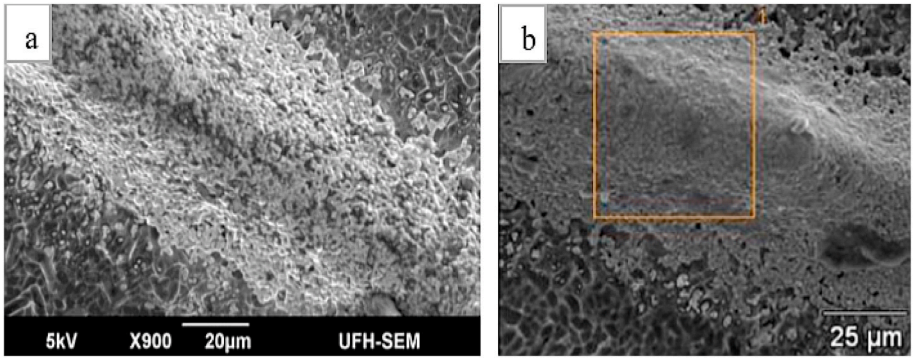

Fig. 17. SEM can scan the grain boundary of a silicon solar cell, such as a) the affected solar cell can be seen differently compared to, b) non-affected section at the micro-level, using SEM micrography images, adopted from Ref. [58].

- An additional advantage of an electron microscope is its higher depth of field.
- SEM can be offered at nanoscale resolution, making it versatile tool for textural examination [132].
- Three-dimensional and topographical images can be obtained [133].

Disadvantages of the SEM imaging technique:

- The SEM system is expensive and large.
- Maintenance of the SEM system is cumbersome and time-consuming.
- Sample preparation can initiate artifacts.
- Special training is required to operate and prepare samples.

5.7. Electron beam induced current (EBIC) imaging technique

Electron beam-induced current (EBIC) measurement is a reliable technique that identifies electronic abnormalities and physical characterization of a PV cell, including the electron-hole recombination dependence on the shunt resistance and cell temperature. It also helps to investigate PV cell pre-breakdown phenomena. "Electron Beam Induced Current (EBIC) is a technique for measuring currents that flow in a semiconductor that is exposed to an electron beam. When the electron beam strikes a semiconductor, electron-hole pairs are created. If these pairs diffuse into a region with a built-in electric field, the electrons and holes will be separated, and a current will flow. This is similar to how a solar cell works except that an electron beam instead of light generate the electron-hole pairs." [134].

EBIC is a powerful PV defect detection instrument whereby an electron-hole pair is created on the PV cell surface to measure its carrier collection efficiency [135]. With the EBIC technique, the electron beam applied on the PV cell surface to generate a current between the cell's front and back contacts, enabling its external quantum efficiency (EQE) curve to be measured following the international standard test procedure, such as IEC TS 62804–1 [136]. This current contains a convolution of three factors: local recombination rate, electron-hole generation rate, and collection efficiency [135]. A similar method, known as the laser beam induced current (LBIC), can also be used, in which a laser beam induces the current in the PV cell [122].

Electronic irregularities, shunts, and residues have been monitored through the EBIC imaging technique [67]. The typical measurement setup of the EBIC is illustrated in Fig. 18. EBIC imaging can be conducted in two different ways: top-view EBIC and cross-sectional EBIC. In top-view EBIC imaging, the electron beam is measured after penetrating the front contact layers before reaching the absorber layer. On the other hand, in cross-sectional EBIC imaging, the absorber layer is directly exposed to the electron beam. Note that EBIC techniques are incorporated with SEM, where the electron beam source is used for analysis purposes. When an electron beam from the SEM strikes the PV cell's surface, it generates electron-hole pairs within beam interaction volume

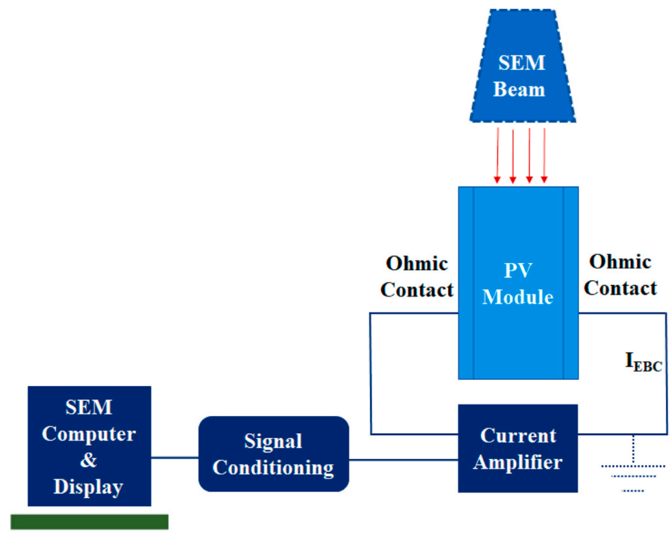

Fig. 18. A simplified schematic diagram of an electron beam-induced current (EBIC) imaging system [122].

over the section. A typical EBIC imaging system comprises an SEM, low noise current amplifier, signal conditioning circuitry, and a computer unit [122], as shown in Fig. 18.

The bright regions in EBIC images signify the collected electron, while uncollected electrons remain dark. The defected areas of the PV cell cannot collect electrons since they enhance the electron-hole recombination. Thus, the images related to the areas with defects will look darker, while other regions where no physical defects exist remain brighter. The current variation across the active part of the PV cell could be generated due to variation in defects density.

Fig. 19 shows the EBIC image of the thermal stress sample.

EBIC has also been used for material characterization, e.g., measuring the diffusion length [138]. While scanning electron microscopy can be used to investigate material-related properties like texture, grain structure, and layer structure. Complementary information on the p-n junction properties can be obtained by high-resolution EBIC imaging [139]. The key advantages and disadvantages of the EBIC imaging technique are as follows:

Advantages of the EBIC imaging technique [131,138]:

- A useful technique for showing the electrically active areas of a PV device. An electron beam is swept across the sample to create an EBIC image, and the output current of the device is measured. Those electrons collected by the junction show up as bright regions while uncollected electrons represent the dark regions. It is common to

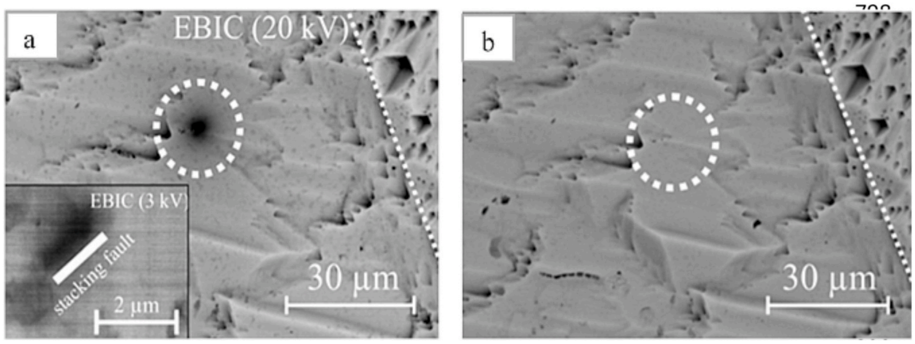

Fig. 19. The EBIC imaging at shunt location, a) before, and b) after a thermal recovery process. Reprint from Ref. [137]. Copyright, 2014, Elsevier.

superimpose the EBIC images on SEM images to show active areas' locations clearly.

- It can be used to (i) analyze the PV cell's uniformity during fabrication, (ii) detect and locate the faults very quickly, and (iii) measure the minority carrier's diffusion length.
- It can be used for material characterization. Altering the beam's energy changes the depth and volume of electrical excitation, which can characterize defects. By sweeping the beam across the surface of the PV device, it is possible to identify electrically inactive areas, such as grain boundaries.

Disadvantages of the EBIC imaging technique:

- It requires the leakage current to be very small, in the order of microampere. Otherwise, the measured data would be too noisy for accurate analysis.

5.8. Clustering-based computation (CBC) technique

The clustering-based computation (CBC) technique requires no physical inspection of the modules on-site. Thus, this technique speeds up the inspection process without further delay by using previous meteorological data only. "The degradation rate is the decline in power output for the same input conditions over a while and is a crucial parameter that reflects the performance of the (solar PV) plant" [140]. This degradation rate can be measured through the clustering-based computation (CBC) method. This unsupervised PV module degradation rate measurement technique requires only previous meteorological data. A pattern-recognition way must use to obtain similar input conditions, in conjunction with this technique, to distinguish different clusters. The necessary steps involved in the clustering-based computation method are illustrated in Fig. 20.

In the first step, meteorological data needs to be collected, and interpolation should be conducted to generate the dataset's missing values. And if necessary, data normalization could be completed at this stage. In the second step, the clustering of input data needs to be obtained through a standard method, such as a K-means clustering algorithm. The input data typically includes meteorological data such as wind speed, temperature, dew point, humidity, pressure, irradiance, and sunshine hours. In the third step, common clusters must be identified. In the fourth step, cluster separation should be conducted following the chosen timeframe, such as weekly, fortnightly, or monthly.

In the fifth step, the performance ratio (PR) is calculated. The following information is required to calculate the PR of a PV module:

- Analysis period (typically in years)
- PV module area
- The efficiency of the PV module
- Actual measured output of the PV module
- Nominal PV output
- Incident solar irradiation

By using this information, the PR can be calculated using the following formula;

$$Performance\ Ratio\ (PR) = \frac{Actual\ reading\ of\ the\ PV\ output\ in\ kWh\ per\ annum}{Calculated,\ nominal\ PV\ output\ in\ kWh\ per\ annum} \tag{3}$$

where Nominal PV output = Annual incident solar irradiation at the generator surface of the PV × relative efficiency of the PV module. In the final step, the obtained performance ratio calculates the degradation rate, typically using the standard least-square regression method. The slope of the regression line obtained from the PR curve indicates the degradation rate [see Equation (3)] [140].

For example, solar PV degradation analysis using performance ratio measurement is presented in Ref. [140]. Few other factors influence the performance ratio, such as environmental factors, including the PV module's temperature [141]. The 'weather-corrected performance ratio' proposed by National Renewable Energy Laboratory (NREL) should be used to avoid the temperature effect. For further detail, see Ref. [142].

The key advantages and disadvantages of the CBC technique are as follows:

Advantages of the CBC technique:

- Physical inspection of the PV module is not required.
- Real-time degradation estimation can be possible.

Disadvantages of the CBC technique:

- It requires previous meteorological data, which is sometimes challenging to collect. For example, to collect data, it is necessary to visit the PV site physically.
- This technique typically depends on many factors, such as solar irradiance and PV module area.

6. Discussion and comparative analysis

The solar panel defects can be classified as optical and electrical-mismatch-related degradation, such as discoloration of the encapsulant, front cover glass breakage, delamination, shading, cell fracture snail trails, poor soldering, broken interconnection ribbons, and short-circuited cells [80]. In addition to that, some non-classified incidents lead to PV module failures, such as open-circuited submodules and short-circuited bypass diodes. All these solar panel defects can be assessed through the various methods summarized in Table 4.

Measuring the PV module's I–V curve has been the primary method used to investigate degradation sources, such as uniform dust, partial shading, aging, and short circuit [34]. However, a slight difference in the curve shape changes the fill factor, which reduces the measurement accuracy.

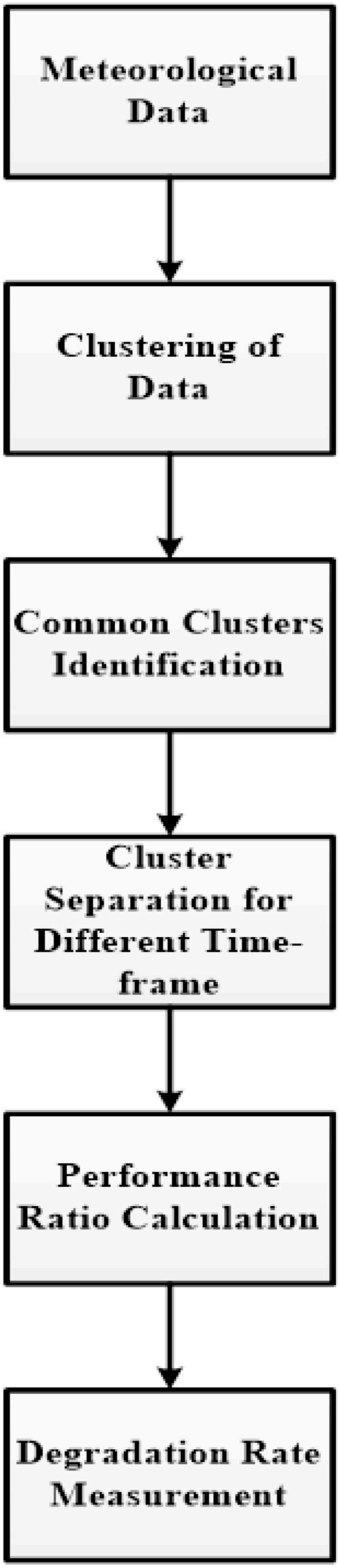

Fig. 20. Steps involved in the clustering-based computation method for PV cell characterization [140].

Table 4
Summary of a solar panel fault diagnosis considered in this study.

Characterization Techniques	Type of Faults/Characteristics
I–V curve	Discoloration, uniform dust faults, partial shading faults, short circuit faults, aging
Thermography (IR)	Interconnection problems, short-circuited cells, cracks in cells, encapsulant discoloration, delamination, defective bypass diodes, hot area and moisture.
Ultraviolet fluorescence (UV–F) imaging	Micro-cracks in the cells, prolonged overheating of cells and junction boxes, glass breakage, mechanical rupture and yellowing effect.
Electroluminescence (EL) imaging	Cell breakage, disconnected cell regions, shunts and interrupted contacts.
Scanning electron microscopy (SEM) imaging	P–N junction properties, material defects, and surface morphology of hot spots.
Electron beam induced current (EBIC) imaging	Pre-breakdown phenomena, electronic irregularities, leakage currents, recombination centers, shunt, and grain boundary defects
Clustering-based computation method	Power output for the same input conditions over a specific period

Visual inspection is the most inexpensive method, also considered as a primary method for defect detection. However, it can only provide information about the surface, not the in-depth of the cell. Among the other imaging-based defect detection methods, IR thermography is considered the most widely used way. This technique has been used for the relative and accurate quantification of a solar panel's thermal behavior and defects. For example, IR thermography can identify hot-spots' exact location in a solar panel during operation [143]. However, experts must perform IR imaging to analyze the qualitative information about the PV modules' conditions.

EL methods provide similar results to IR thermography or UV-F imaging techniques. However, the EL imaging technique is more expensive compared to IR thermography. It is still cheaper than the UV-F imaging method [45] and can detect intrinsic defects, dislocations, cell breakage, deteriorated areas, interrupted contacts, shunts, and other process failures. In general, the EL test provides more accurate information about PV modules' state of health. However, EL-based diagnosis has a significant limitation [80]. Namely, it cannot be performed during PV module operation (due to PV module removal and offline testing setup), making it unpopular in outdoor measurement.

UV-F is a less commonly used technique in solar panel defect detection. Characterization results obtained from the UV-F imaging technique show that micro-cracks in the solar panel, hotspots, glass breakage, mechanical rupture, yellowing effect, polymer degradation, and mismatched cells further contribute to the reduction of the PV module power output [61]. However, this method is based on expanding a UV beam to illuminate an extensive area of the PV sample, making it troublesome as fluorescence signal (typically small) tends to fade quickly.

The least used solar panel defect detection method is the scanning electron microscopy (SEM) imaging technique. The spatially resolved images can be obtained from the SEM image, which provides qualitative information about the surface morphology of hot spots caused by imperfect p-n junction properties and material defects [58]. Besides, SEM imaging could be employed if detailed information regarding the cause of the degradation, such as the material composition of a PV cell, is required. However, special training is needed to operate an SEM and prepare the PV samples, making this method expensive and time-consuming.

On the other hand, complementary information on the p-n junction pre-breakdown phenomena, leakage currents, recombination centers, sub-surface, and grain boundaries defects can be obtained using the electron-beam-induced current (EBIC) imaging method. This technique can be performed in conjunction with an SEM or a scanning transmission electron microscope (STEM) [68]. This method has some limitations too. For example, the leakage current must be minimal, in the order of microampere. Otherwise, the measured data would be too noisy. Hence, the analysis would be inaccurate.

The clustering-based computation (CBC) method provides qualitative and quantitative information about solar panel degradation, which does not require any physical inspection and imaging [140]. Due to ease in operations, faster processing time, and reliability, this technique can be widely employed for PV modules inspection. However, the CBC technique requires previous meteorological data, which is sometimes challenging to collect.

The primary defect detection alternative to image analysis is the I–V curve measurement. The main difference between the I–V curve measurement method and the IR, EL, UV-F, SEM, EBIC, and CBC imaging methods is that the I–V scan provides quantitative information about the condition and health of the PV modules by observing the changes in I–V characteristic curve as follows [96]:

- Low short circuit current may cause glass cover corrosion and discoloration of the encapsulation of the PV module.
- I–V curve turns into stepped-shaped due to damaged cells, shading, dust, and partial shading on the PV module [38].
- Due to bypass diode shorted and light-induced degradation, the open-circuit voltage decreases.

Breitenstein et al. (2008) have found that "*combined application of EBIC and EL may deliver useful information on the presence and the physical properties of crystal defects in silicon solar cells*" [67]. In a recent study, Appiah et al. (2019) have recommended four criteria to evaluate different defect detection techniques, such as (i) degradation detection and classification capability, (ii) real-time detection, (iii) degradation localization, and (iv) degradation isolation [78]. Therefore, it can be argued that there is not a single degradation detection and diagnosis method that can meet all the four criteria. Thus, combining two or more strategies would be a suitable approach in determining the PV modules' degradation rate (using the I–V characterization technique in conjunction with any other imaging technique).

The primary PV module defect diagnosis methods that have been identified in this review are shown in Fig. 21. The I–V curve measurement was the dominant technique for analyzing the PV module degradation, accounting for about 33%. This is because this technique is fast and reliable and also provides instant feedback for fault diagnosis. For example, by measuring the I–V curve of a PV module and compare to the expected response, one can locate the exact electrical problem of the PV module.

After the I–V curve measurement technique, IR imaging, EL imaging, EBIC imaging, visual inspection (VI) method, and CBC method represented 19%, 17%, 10%, 5%, and 2% of the reviewed PV module defect detection technique, respectively. On the other hand, collectively, SEM imaging and UV-F imaging accounted for only 7% of the reviewed PV

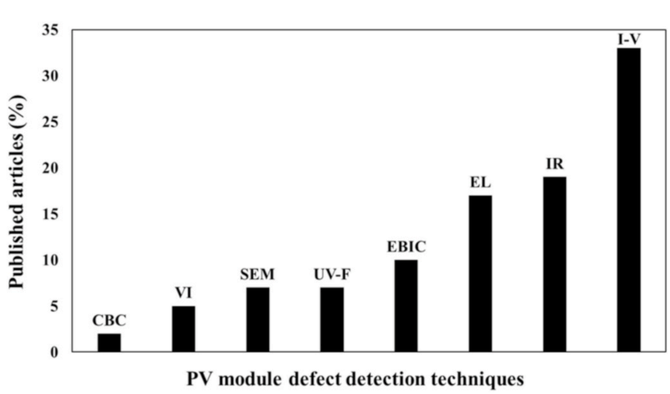

Fig. 21. Summary of the literature review (in percentage) shows the relative fractions of the literature sources analyzed per method type.

module defect detection techniques. The I–V technique is the most used method for in-the-field PV module inspection, whereas the CBC technique allows for online PV module performance monitoring. Despite the many benefits of the CBC technique, such as cost-effectiveness and fastness. This technique has not been widely used, possibly because (i) it is relatively new, and (ii) an optimal CBC algorithm based on reliable data has not been fully developed yet.

The non-destructive and in-situ characterization techniques, such as X-ray scanning and ultrasonic inspection, can also be used for PV module defect detection. However, they are not as widely used as the above-discussed techniques. It is expected that the above-discussed PV module defect detection technique will continue to be widely used for the detection of material defects, such as impurities, which affect the conversion efficiency, thus helps to reduce the module's early failure. It is predicted that the relationship between the measurement technique and material characteristics will become more understood in the future. Thus, the challenges to choosing suitable defect detection methods, scientific tools, data collection procedures, and analyzing techniques relevant for the specific problem will be gradually overcome through quantitative correlation of the actual PV module performance with the data collected from the various PV defect detection technique. This will require collecting data from different PV installations around the world to be centralized and shared by the global PV community, thus creating a central database that enables real-time (i) finding of root causes of failures, issues, and defects in PV modules/systems, (ii) evaluating risk portfolios and (iii) predicting costly PV system operational failures before they occur. Note that a PV module's spectral response is also critical in determining solar panel lifetime [144]. It is anticipated that spectral characterization techniques might be introduced in the future for use in conjunction with the above-discussed methods for the PV module defect detection.

7. Conclusion

The deployment of imaging techniques is rising worldwide due to the exponential increase in PV installations. Therefore, many solar panel manufacturers, policymakers, and solar energy distributors invest in novel approaches for useful and accurate solar panel defect detection. As more PV technologies continue to emerge with unspecified durability, the efficient identification of the PV module performance degradation sources is a reasonable step for maximizing the performance of PV modules and systems throughout their lifetimes. This paper has shown that the primary sources of PV module degradation identified in the literature are discoloration, delamination, corrosion, and breakage. This can be directly quantified using Infrared (IR) thermography and I–V curve measurement, in addition to environmental parameters such as temperature, humidity, and UV radiation. In this review, significant progress has been made towards understanding the underlying principles of the degradation sources that reduce the PV module efficiency and the critical techniques used to identify them. The characterization techniques presented in this review are also suitable for examining the next-generation PV technologies. They can be deployed in PV manufacturing facilities, production lines, and laboratories. Materials and device performances have to be evaluated before mass production to attain high yields and manufacture cost-effectiveness.

The work presented in this paper predominantly covers widely used imaging-based techniques for PV module defect detection, and it excludes unique methods, such as electrical techniques based on statistical and signals processing, reflectometry-based, and machine learning-based techniques. A significant number of techniques are currently available to detect the PV module defect either in labs or outdoors. However, there is a need to develop a methodology that can support solar panel defect detection from the surface level to the micro-level during field operation. Overall, understanding the underlying principle of PV module defect detection techniques could help address PV module performance degradation's economic and environmental impact, especially in large-scale PV installations that do not carefully consider environmental conditions, such as climate change. Indeed, significant challenges to the widespread deployment of PV module defect detection methods remain in a dark loop.

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Declaration of competing interest

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