A Survey on Mismatching and Aging of PV Modules: The Closed Loop

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***Abstract*—In this paper, the different aging mechanisms taking place in photovoltaic modules are discussed, and the cause–effect links, which exist among such mechanisms, are evidenced. It is also shown that a closed-loop link exists between aging and mismatching since aging (which is nonuniform by its nature) causes mismatching among cells, whereas mismatching, in turn, mainly due to its thermal effects, leads to nonuniform aging.**

***Index Terms*—Aging, mismatching, photovoltaic (PV) power systems, PV systems reliability.**

I. Introduction

A photovoltaic (PV) module is made up of many different components: PV cells, encapsulant, bypass diodes, junction box, wires, connectors, a protective glass for the front side of the module and different combinations of glass, and Tedlar/aluminium or polyethylene for the backsheet of the module [1], [2]. Each part of the PV module experiences its own degradation modes, which can be natural or induced, and can cause PV module failures, thus decreasing the reliability and the lifetime of the PV module.

As stated in [3], many years of testing of both cells and modules made clear that the encapsulant is the part of the PV module that is more frequently subjected to degradation phenomena. The encapsulant represents the structural support of the PV module; it ensures the isolation of the cells [4], and furthermore, it increases the surface emissivity, thus reducing the cells operating temperature [3]. As it will be clear in the following, the encapsulant can be subjected to many different failure mechanisms.

Examples of degradation phenomena related to the encapsulant are as follows: yellowing and browning, faster corrosion, delamination, and cracking. Moreover, even voltage breakdown, excessive leakage currents, increased soiling, or increased operating temperature can affect a PV module when the encapsulant fails to perform its expected job [3], [5]. The second source of faults in PV modules is the electrical circuit itself, due to the effect of mechanical stress of conductors, corrosion of the electrical terminals, photothermal degradation of connectors and cabling, broken solder joints, and thermal deformation of junction boxes.

Table I summarizes the results of a wide research focusing on the frequency of occurrence of different kinds of failures in field-aged crystalline-Si (c-Si) PV modules, for different module technologies, different tilt angles, and different years of field exposure [6].

The results of such a research have a quite general validity. As shown in Table I, the most frequent failure phenomenon in PV modules is related to the encapsulant degradation, mainly discoloration. The second most frequent failure mechanism is instead due to the solders degradation. Finally, PV cells are the most reliable parts of PV modules and hence of PV plants, as summarized in Table II. In particular, as shown in Table II, the failure rate of the PV cells is equal to 2%, on a total of 3500 faults detected in 27 months for 350 PV systems designed and installed by SunEdison in four continents [7]. However, many failure mechanisms can occur also in the cells, e.g., cell cracking or degradation of the antireflective (AR) coating. Modern advanced PV technologies and thin-film solar cells are not always able to achieve degrees of reliability, which are comparable with the one of c-Si cells [3], [8].

The aging of a PV generator is a continuous process, but several factors can influence its dynamics. In particular, environmental factors such as sulphur, acidic fumes, or other pollutants can speed up the degradation process [9]. Moreover, as it is clearly explained in the following, the operating conditions, such as humidity, temperature, and irradiance (incidence angle and intensity), strongly affect the degradation process and hence the reliability of each part of a PV module. The aging of PV modules causes the modification of the shape of the current versus voltage $(I-V)$ curve, as shown in Fig. 1. In such a figure, the $I-V$ curves of a module, which have been measured before and after many years of outdoor exposure, are shown. Such curves have been obtained by using data that have been presented and discussed in [9]. The change of the slope of the $I-V$ curve in the neighborhood of the short-circuit region is due to the decrease of the PV module shunt resistance, whereas the change of the slope of the $I-V$ curve in the neighborhood of the open-circuit region is due to the increase of the PV module series resistance. The reduction of the maximum power of the PV module and the decrease of the fill factor are clearly evident.

In the following sections, the various degradation mechanisms taking place in PV modules are reviewed, and the cause–effect links, which exist among such mechanisms, are also put into evidence. Moreover, another important aspect is

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TABLE I
OCCURRENCE VALUES OF FAILURE MODES IN FIELD-AGED MONOCRYSTALLINE-SI (MONO-SI) AND POLYCRYSTALLINE-SI (POLY-SI) PV MODULES. CNF/1000 REPRESENTS THE "CUMULATIVE NUMBER OF COMPONENT FAILURES PER 1000," AND IT IS EVALUATED AS THE CUMULATIVE PERCENT OF DEFECTS OF EACH FAILURE MODE DIVIDED BY 10 [6]

					Percent of Defects (%)								
PV module technology	Tracking	Construction*	No. of Modules	Years Fielded	Broken Cells	Encapsulant delamination	Encapsulant discoloration	Backsheet Warping or Detaching	Burn through Backsheet	Metallization or Busbar Discoloration	Solder failure	HotSpots	Diode failure
mono-Si	1-axis	G/P/FR	168	13.30			100				87.33	1.19	
mono-Si	Fixed Tilt	G/P/FR	216	18.00		1.39	100				80.73		
mono-Si	1-axis	G/P/FL	1155	13.30		0.17	99.83	54.55			7.61	0.61	
poly-Si	1-axis	G/P/FR	48	11.70			77.08				2.56	6.25	
mono-Si	1-axis	G/P/FR	50	11.70				66.00					
mono-Si	1-axis	G/P/FR	120	11.70				1.67	1.67	18.33	81.25	3.33	
mono-Si	1-axis	G/P/FR	2352	12.00		9.23	4.04	0.51	1.62	29.34	23.59	1.91	8.64
poly-Si	1-axis	G/G/FR	216	11.70	23.61	33.80	0.46	0.46		0.93	1.03	11.11	
Cumulative			4325	103.40	23.61	44.58	381.41	123.19	3.28	48.60	284.10	24.40	8.64
CNF/1000					2.36	4.46	38.14	12.32	0.33	4.86	28.41	2.44	0.86
CNF/1000 per operation time					0.02	0.04	0.37	0.12	0.00	0.05	0.27	0.02	0.04

*G = Glass; P = Polymer; FR = Framed; FL = Frameless

TABLE II
FAILURE RATE OF SUBSYSTEMS AND COMPONENTS OF A PV SYSTEM [7]

General Failure Area	Failure rate
Inverter	43%
AC Subsystem	14%
Support Structure	6%
DC Subsystem	6%
PV cells	2%
Other (Communication system, measuring system, weather station, etc)	29%

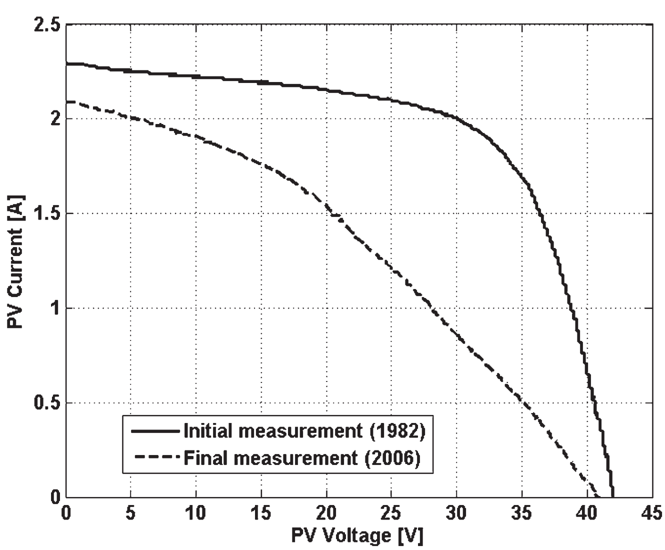

Fig. 1. $I-V$ curves of a c-Si module, which have been measured before and after 23 years of outdoor exposure [9].

also outlined. In fact, nearly all the aging phenomena, which will be analyzed in the following sections, lead to mismatching conditions, that is, they lead to nonuniform working conditions of the cells belonging to the same PV generator. In particular, it will be shown that a closed-loop link exists between aging and mismatching operating conditions. In fact, aging (which is nonuniform by its nature) causes mismatching among cells, whereas mismatching, in turn, mainly through its thermal effects, leads to nonuniform aging. This means that mismatching operating conditions are not only responsible for the waste of available energy [10] but that they also strongly affect the duration of life of the PV sources. Therefore, architectures and control techniques, which, up to now, have been designed only in order to face efficiency issues associated to mismatching [10], in the future will have, necessarily, to account also for the strong influence played by mismatching on the premature aging of PV modules. In fact, the PV industry needs PV modules that will perform for 20–25 years or longer in the field. This is necessary not only for warranty considerations but also in view of risks for financial stakeholders and overall economic viability, not to mention other issues such as key safety concerns. For example, for most PV products, there are many additional concerns, other than energy production, regarding what constitutes failure or unacceptable performance. After aging, safety is a critical concern to protect life and property. There may be also critical aesthetic concerns, such as with building-integrated PV systems (BIPV) products, which affect the viability (but not necessarily the power generation) of the product. If a module discolors in the Mojave Desert, no one may care, but if it discolors on a building facade, everyone may care, and the BIPV producer could be out of business due to cosmetic failure. Another important and strictly related aspect to consider is represented by the fact that PV modules are complex products and no current service life prediction test program can predict with 100% certainty that a module will properly perform in a specific environment for 25+ years. New and more reliable test methodologies taking into account also the relation between aging and mismatching, while still maintaining reasonable acceleration, are therefore still needed. In conclusion, this is a "state-of-the-art" survey paper on the relation existing between aging and mismatching.

The main objectives of this paper are two: the first one is to provide a current, accurate, and consistent information on aging and mismatching of PV modules; the second one is to put in evidence that, while the negative effect of aging as one cause of mismatching is well known, at least from the energetic efficiency point of view, instead, the effect of mismatching on nonuniform aging has not yet been discussed at all in the literature. In fact, to the best of the authors' knowledge, the existence of a feedback link between nonuniform aging and mismatching and its practical consequences have not yet been investigated in the literature.

II. Aging of PV Modules

Here, the main degradation mechanisms taking place in PV modules are reviewed.

A. Discoloration

Browning and yellowing of PV cells are mainly caused by the degradation of the encapsulant material, which is usually ethylene vinyl acetate (EVA). The aforementioned changes in the color of the encapsulant material produce a variation of the transmittance of the light reaching the solar cells and, as a consequence, a reduction of the power generated [9], [11]. In [12], a comparison of mechanisms of thermal and photothermal discoloration of EVA is carried out. The degradation related to thermal effects does not seem to be as critical as the one due to photothermal effects, i.e., ultraviolet (UV) exposure. Indeed, thermal degradation usually results in a light EVA yellowing, whereas photothermal degradation results in a dark EVA browning. In [13], a deep study on c-Si PV modules subjected to 22 years of outdoor natural aging and on c-Si PV modules subjected to 18 years of natural aging and then to several months of induced aging processes (caused by partial or total shading obtained by means of lumps of mortar) has been presented. The main conclusion reported in [13] is that modules subjected to both natural and induced aging exhibit browning rather than yellowing of the EVA. Authors of [14] put into evidence the shape of the discolored area: it is circular in circular cells and square in square cells. Furthermore, PV cells are mainly discolored in the central region. This is likely due to the heating effects since, during normal operation, the central part of the cell should be more heated than the border.

The encapsulation process and the hydrolysis of vinyl-acetate monomers are able to produce acetic acid, which facilitates a greater EVA discoloration [15]. In addition to the role played by the manufacturing of the EVA and the encapsulation processes, other phenomena affect the EVA discoloration rate. They are the UV light intensity and exposure [16], the UV-filtering effect of glass superstrates [14], [17], the permeability of the polymeric superstrates, and humidity [18]. In particular, the combination of UV rays and temperatures that are higher than 50 °C is shown to be the main cause of EVA discoloration. As an example, the aforementioned combination is one of the dominant aging modes under hot and dry desert climatic conditions in Arizona [6]. In addition, in [19], where the results of the analysis of 12-year field-aged polycrystalline silicon PV panels, which are located in Tunis, are presented, it is confirmed that the browning of the encapsulant is the main responsible for the PV modules degradation.

B. Delamination

The delamination consists of the loss of adherence among different layers of the PV module; as a consequence, the detachment of these layers takes place [20]. The main causes of delamination are the following: the movement of cells and cell interconnects due to environmental stresses, the expansion and the contraction of moisture and air that are trapped inside the layers of a PV module, the bond failure due to the combination of moisture and UV radiation, the cell overheating, and the consequent outgassing of the encapsulant [21]. In addition, physical aging processes related to the application of high temperatures could provoke delamination of a PV module, as shown in [22].

When delamination occurs, water can penetrate into the module. Furthermore, light decoupling with a subsequent increase of reflection phenomena also occurs. Even if the encapsulation process is made under vacuum, in order to prevent air inclusion in the adhesive, the nonzero viscosity of the adhesive does not allow a complete conformal coating. As a consequence, delamination cannot be completely avoided [23], leading to changes in the electrical performances of the PV module [24]. Moreover, humidity and high temperature increase the frequency of delamination [25]. Furthermore, delamination might cause ingress of humidity into the encapsulant and, as a consequence, corrosion. A discussion on delamination phenomena taking place in c-Si PV modules exposed to outdoor conditions for 22 years can be found in [2] and [26].

C. Bubbles

Chemical reactions that occur in the PV module, and are often related to thermal decomposition [12], can lead to the emission of gases. Bubbles can appear on both the back side or the front side of the module. They form an air chamber in which the gas temperature is lower than in the adjacent cells, as shown with thermographic images in [20]. Nevertheless, the air chamber worsens the heat dissipation capability of the nearby cell so that the latter overheats, exhibiting a temperature that is higher than in the adjacent cells [27]. Moreover, when bubbles appear on the front side, a reduction of the radiation reaching the PV cell occurs, thus creating a decoupling of light and increasing the reflection. Furthermore, bubbles can break, and hence, they can damage the back sealing surface, thus provoking humidity ingress [13].

D. AR Coating Degradation

The radiation received by AR coating during its lifetime could induce a change in its color, as shown in [20]. The change of colors is associated with a change in the properties of the

AR coating; hence, the amount of light that reaches the cells is strongly altered. This kind of degradation is related to the oxidation of the AR coating, because of a loss of adhesional strength between the cell and the encapsulant [28].

Moreover, the AR coating degradation can be accelerated if a voltage higher than 600 V (with respect to the ground) is applied to the cells. In [28] and [29], the visual effect of the AR coating degradation, i.e., a change of its color, is shown, putting into evidence the presence of such an aging effect upon all the outdoor field-aged PV modules under analysis.

E. Corrosion

One of the roles of the encapsulant is the protection of the modules from environmental corrosion. The natural corrosion in the absence of water is slow. The higher is the adhesive strength, avoiding the access of water to corrosion sites and the drift of acetic acid toward the corrosion sites, the strongest is the corrosion protection [15]. As a consequence, the rate and the degree of delamination, as well as its position, play a very strong role in the increase of the possibility of corrosion failures in metallic contacts. Thus, corrosion is strongly related to delamination; thus, the causes of delamination, e.g., the cell overheating, can be considered also as causes of corrosion. Even if the most used encapsulant is EVA, silicone materials also have been and are actually used as encapsulants for PV modules. In [30], the aging of modules with different encapsulants is analyzed by means of the damp heat (DH) test, since DH conditions (85°C and 85% relative humidity) create one of the best environments for corrosion reaction. Exposure of 1500 h of monocrystalline EVA-encapsulated modules and exposure of 3500 h of multicrystalline EVA-encapsulated modules show a decrease in fill factor and an increase in series resistance, which are very likely caused by corrosion. The same exposure provokes little or even no degradation in silicone-encapsulated modules. Silicone materials are also less sensible to photothermal effects [9], [31]; this property reduces the aging rate of the encapsulant and, as a consequence, the long-term power losses.

In [13], a severe degradation related to corrosion of busbars and contacts in cells that have been subjected to induced shading has been found. Such a severe corrosion is associated to the degradation of the encapsulant.

F. Crack in the Cells

Good adhesion is required for corrosion protection. On the other hand, a too strong adhesion can cause mechanical problems, particularly in the case of thin-film PV applications. Indeed, the stresses to which solar cells are subjected when a mechanical strain is applied to a PV module can cause a break of the silicon wafers [15], [32].

In addition to mechanical damages occurring during the PV module assembly, the shipping, the storage, the installation or maintenance, and the damage due to impacts, e.g., due to hail, as well as high-temperature thermal stresses of a cell and thermal cycling induced thermomechanical stresses, can produce the cell crack [21].

Microcracks of the cells can cause localized heatings [33]. They can also lead to isolated cells areas [34]. In such a case, the shape of the $I-V$ curve of the PV module is similar to the one of a partially shaded module since more than one knee may appear. A typical example is shown in Fig. 2, which has been obtained by using data that have been presented and discussed in [35]. The size of the isolated area is directly related to the amplitude of the step in the $I-V$ curve. Moreover, cell cracks entail many thermal effects, as discussed in the following.

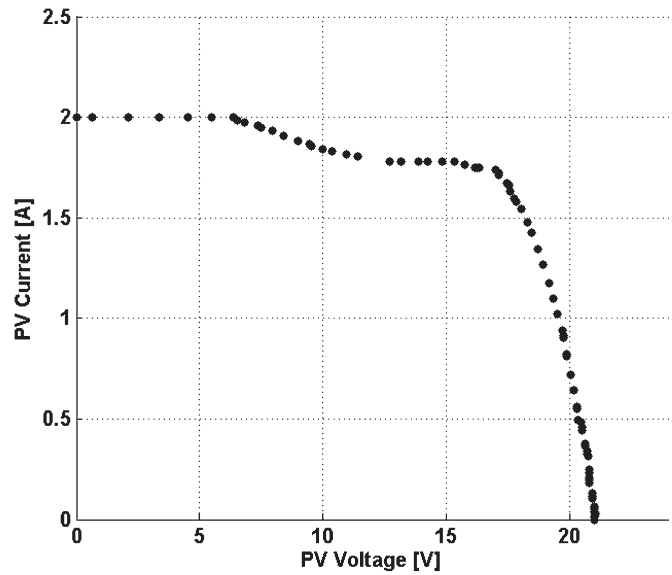

Fig. 2. $I-V$ curve of a PV module in which a cell crack has occurred. The curve has been obtained with the module subjected to uniform irradiance conditions. The break above 5 V is due to the cell crack. The curve has been obtained by using data that have been presented and discussed in [35].

G. Ribbon and Solder Bonds Degradation and Broken Interconnect

Continuous thermal cycling creates continuous expansion and contraction of solder bonds. As a consequence, the solder dissociates even more with time, resulting in a propensity of the ribbon and solder bonds to crack [20], [36]. In addition, excessive heating of a part of the cell can cause solder bond degradation, leading even to solder melting [37]. This aspect will be discussed in detail in Section II-K.

H. Dust and Soiling

Usually, there is a hazy or a dark appearance of the glass in correspondence of the lower edge of the PV modules. This type of glass soiling is the one examined in [28], where it is shown that all the modules of a 12-year field-aged PV generator exhibit such a defect, which, in practice, affects around 33% of the PV cells. The causes of glass soiling are mainly represented by the sedimentation of rainwater and by ion exchange between the alkalis in the glass and the H+ ions in the water [38]. Moreover, the soiling process is exacerbated by the water that is retained on the module edge from the PV module frame. The amount of retained water depends on the module structure, the weather conditions, and the module tilt angle [39], as well as on the degree of pollution [28].

The deposition of dust and the glass soiling provoke radiation losses and nonuniform operating conditions. Therefore, they increase the degradation rate and the losses of the PV generator [40], particularly in dry areas [41], and can generate localized heating phenomena (hot spots) [42].

I. PID

The high voltage taking place in PV systems may cause leakage currents between the solar cells and the module frame. Such currents cause power losses and are responsible for a degradation effect known as potential induced degradation (PID). Different types of PID exist. The dissolution of the AR coating, the degradation of metallization in c-Si solar panels [43], and the corrosion of the transparent conductive layer in thin-film PV modules [44] are just some examples of PID effects. However, the most frequently observed PID effect is the PID of the shunting type (PID-s), which can even lead to the total failure of the PV modules. Both silicon and thin-film solar cells can be affected by PID, and for both technologies, it has been demonstrated that the main role in the formation of PID-s is played by the Na migration [45], [46]. Na originated by the soda lime glass, usually used in the front and/or back sheets of a PV module, moves through the EVA. It concentrates at the interface between the AR coating and the active region (a Si bulk in a silicon PV cell), due to the high potential above the solar cell. The mechanisms occurring once Na reaches the semiconductor are not well known. One theory based on the microstructural analysis of solar cells subjected to PID states that if stacking faults are present in the structure of the solar cell, the Na decorates them, so that the stacking faults become conductive. When the Na ions enter the stacking faults, their charges are neutralized, and more Na drift is allowed from the glass to the bulk (shunting of the junction) [47], [48].

Moreover, both humidity and temperature affect the PID. In fact, the velocity of the positive charged ions is mainly influenced by the temperature, the humidity, and the applied voltage, as well as by the encapsulation material [43]. By increasing the operating temperature, the PID effect increases [49]; humidity has a huge impact on the leakage current [50].

J. Junction Box and Bypass Diodes Effects

Accelerated life tests show that heat exposure and humidity freeze cause junction box failures [51], [52]. Junction box failures can cause the corrosion of the electrical connectors [2], [20], [53], and the main negative effect is represented by the reduction of power output. In [26], the starting of corrosion into the junction box of a c-Si PV module is evidenced. Moreover, because of the lower browning degree and extent that appears in PV cells with improved EVA and better insulation in the junction box, in [26], it is concluded that a good insulation can slow down the degradation rate of the PV module in terms of discoloration. In [28], all the crystalline silicon PV modules analyzed after 12 years of operation in Southern Europe exhibited junction box defects. In particular, even if the PV modules were correctly working, the junction boxes were well attached to the backsheets, and silicone was in good conditions, all the PV modules exhibited a detachment of the internal connection board from the backsheet. Usually, junction boxes with better heat dissipation and improved adhesive do not exhibit such a kind of defect.

Furthermore, a bypass diode subjected to a long-term power dissipation, e.g., due to partial or full shading of a cell in the string of cells protected by the bypass diode itself, provokes overheating [54]. The resulting higher temperature of the bypass diode, of its junction box, and of the PV cell placed over such a junction box, can lead, in some cases, to failures ending with fire [55], [56]. The main causes of bypass diodes failures are the excessive current levels and improper or insufficient heat sinking [3]. The lack of any air flow in the junction box is crucial in the diode failures, particularly in the case of fast transitions shadow–sun–shadow [57].

Moreover, in the case of field-aged PV modules, the working temperature of the cell above the junction box is typically higher than that of the remaining cells. This may likely lead to a faster thermal degradation of such a cell with respect to the other cells of the PV module [28].

Finally, pollutants, such as sulphur and acidic fumes, stress both the encapsulant and the junction boxes [9].

K. Localized Heating Phenomena

Localized heating can be due to many phenomena such as shading, cracking, polarization, and soldering defects. In [34], the degradation observed in a 1.8-MWp PV plant made of 300 6-kWp units, each one mounted on a single axis azimuth tracker and coupled to the grid, is investigated. The heating phenomena have been studied by means of a thermal camera and visual inspection. Many blackened points in the Tedlar backsheet have been observed; they were located over the busbar tabs of the cells. It is worth noting that the busbars are connected in parallel, and thus, an increase in resistance of a busbar solder implies a reduction in its current flow with respect to the other busbar solders. Some of the blackened points were punctured, so that insulation failures were very likely [13]. In [34], it is found that not all the blackened points in the Tedlar are hot; on the other hand, not all the hot spots exhibit blackened points in the Tedlar. The analysis of the solderings in the cells, which are affected by localized heatings, proves that overheating affects the better solder joints rather than the weakest ones, since the latter are characterized by a higher resistance path for the current flow. Thus, the presence of weak solderings increases the probability of occurrence of localized heating phenomena [34]. As stated in Section II-F, cell microcracks also can create localized heating phenomena.

The in-depth analysis of the hot cells reveals that, often, they work in reverse bias, i.e., as loads, this being the cause of their higher temperature [58]. Cracked cells working in reverse bias can force the corresponding bypass diode to conduct or not, depending on the amount of the defect (the slighter is the defect, the lower is the probability that the related bypass diode conducts) and on the shape of the $I-V$ curve of the reverse biased cell in the second quadrant [59]–[61]. Weak solderings likely allow the bypass diodes to conduct, whereas cell microcracks unlikely provoke the bypass diode conduction.

Moreover, the localized heatings due to weak solderings may be destructive in the short term and may reduce the lifetime of the module in the long term, whereas the hot spots related to cell microcracks do not seem to worsen over time. Indeed, cell microcracks usually lead to working temperatures that are 10 °C–20 °C higher than the average temperature of the PV module, depending on ambient conditions. Such temperatures are not able to damage the Tedlar and hence to create short-term risks of module integrity degradation, but they obviously speed up the aging of the PV module [34].

In [62], PV modules burned areas, caused by hot spots, are analyzed. Even if hot spots are not likely to generate sustained fires, whole cells or significant cells portions can burn and break the glass.

In addition, partial or full shading of a cell can create hot areas [63], due to both high currents in the bypass diodes and reverse bias working of the shadowed PV cells. This aspect is analyzed in detail in Section III. In [35], it is shown that, by exposing an amorphous-Si (a-Si) module to light in a sun simulator and by causing a partial shadowing of the module, and hence the formation of hot spots, the following rule holds: the longer the duration of partial shade operating conditions of the modules, the bigger the areas of the hot spots. In addition, manufacturing processes can cause hot areas by creating shunting paths within cells. In [64] and [65], the direct correlation between areas containing high-impurity contaminants and hot spots in different samples of multicrystalline-Si (mc-Si) modules is studied. On the other hand, authors in [66] identified the etch pits as one of the main causes of the hot spots in mc-Si solar cells.

Irregular dust patterns on PV modules can also give rise to hot spots with temperatures that are more than 20° higher than the temperatures of the other cells [67]. Hence, they lead to large power losses of the PV generator and to extreme danger for the PV modules lifetime [68].

In [19], it is shown that field-aged polycristalline silicon solar cells develop low shunt resistances at the grain boundaries, which, in turn, provoke hot spots in case of local excitation by a laser beam on the surface. Indeed, the photocurrent, which is produced by the absorption of the laser light, is short circuited by the low shunt resistance [19]. Thus, aging can induce shunting paths in the PV cells, and such shunting paths can give rise to hot spots.

The analysis of the aging behavior and mechanisms of PV encapulsants presented in [69] and [70] shows that localized heating phenomena can also cause the deterioration of the encapsulant. Moreover, in case of inadequate module bypass and blocking protection, the degradation can be caused mainly by hot spots rather than by the browning of the encapsulant [71].

Hot spots are usually present in the connectors region, i.e., where the junction box is placed [72].

L. Detachment of the Frame

Not only the layers of the PV module can detach, leading to delamination (see Section II-B), but also the frame can separate from the rest of the module. In such a case, water is allowed to enter the module, and as a consequence, increased electrical risk and corrosion mechanisms occur. The detachment of the frame is mainly due to defects of sealant, typically silicone, snow or ice accumulation, or installation mistakes [20].

III. Closing the Loop: The Role of Mismatching in the Aging of the PV Modules

As discussed earlier, many aging phenomena, which are induced by many different causes, can affect a PV generator, leading to failures and to power losses, as shown in Table III. The interested reader can find in [73] a very wide and detailed description of PV module failures: their origin, statistics, and relevance for module power and safety are presented and discussed. Moreover, authors in [73] also dealt with follow-up failures, failures detection, and testing methods. From the analysis of the degradation mechanisms presented in the previous section, it is evident that the temperature has a huge impact on the aging of PV modules. Indeed, the higher the temperature, the higher the probability of EVA discoloration, module delamination, creation of bubbles and, as a consequence, corrosion. Moreover, also degradation of the ribbon and solder bonds and PID effect, as well as of cell cracks and failures of junction boxes and bypass diodes, are accelerated by higher working temperatures. In addition, localized heating phenomena can lead to very fast aging of PV modules and can cause their total failure. Nearly all the different aging mechanisms are tightly interconnected. It is evident, for example, that delamination speeds up corrosion and degradation of ribbon and solder bonds, which, in turn, create conditions for localized heating. Localized heating can provoke cell cracks, can exacerbate the PID effect, and can speed up the EVA discoloration, as well as the delamination and most of the aging mechanisms, which are typical of PV generators. In addition to the role of the temperature, another important common denominator of all the aging phenomena, which have been discussed in the previous sections, is represented by the fact that they cause nonuniform effects. That is, their effects are mainly concentrated in different regions of the PV modules instead of being uniformly distributed on all the cells of a PV generator. For example, damages and premature aging due to hot spots are particularly evident in the cells that are placed over the junction boxes. Instead, glass soiling usually occurs in correspondence of the lower edge of the PV modules and causes a consequent lower irradiation only for the cells that are adjacent to such an edge. Browning and yellowing of PV cells due to the degradation of the encapsulant usually take place in the central part of the cells only and not in their border. In any case, the discoloration is again more or less different (nonuniform) from cell to cell. Formation of bubbles, microcracks, or other unpredictable phenomena such as bird droppings or dust accumulations also affect only specific cells or group of cells rather than the whole PV module. In conclusion, aging phenomena affect the various cells of a given PV generator in a nonuniform way.

As a consequence, directly or indirectly, all the aging phenomena, which have been analyzed in the previous sections, unavoidably lead to nonuniform working conditions of the cells belonging to a given PV generator.

TABLE III
ON-FIELD PV MODULE DEGRADATION AROUND THE WORLD: SUMMARY OF SOME STUDIES

Location	Test duration (years)	Module technology	Average Maximum Power Degradation rate (%/year)	Comments	Reference
Malaga, Spain	12	c-Si	0.96		[28]
Manfredonia, South of Italy	10	mc-Si	1.87	With Anti-Reflecting Coating (ARC) layer	[14]
		c-Si	1.45	With ARC layer	
		mc-Si	2.16	With surface texture	
		c-Si	1.14	With surface texture	
Trinidad, California	20	c-Si	0.81		[83]
Patras, Greece	22	c-Si	0.96	Evaluated on two modules after 22 years of natural ageing	[13]
Hamamatsu, Japan	10	c-Si	0.62		[87]
Glendale, Arizona	12	c-Si	0.95	1-axis tracking	[88]

Nonuniform operating conditions are usually referred to as mismatching; they can lead to a significant drop in the energy produced by a PV field [10]. Mismatching occurs in PV applications when the PV cells work in different operating conditions because of one (or more) of the following reasons:

- nonuniform aging of PV cells belonging to the same PV generator;
- shadowing of a part of the PV generator;
- significant differences between the solar cells physical parameters, due to manufacturing tolerances, or defects;
- design and/or installation mistakes of the PV generator;
- different orientation of modules belonging to the same string with respect to the sun (it is quite common in BIPVS);
- erroneous or nonuniform wiring of the PV panels;
- dust and soiling;
- defects of the bypass diodes;

A PV module is usually made up of many cells, which are connected in series. For an ideal PV module, which is made up of exactly equal PV cells and which works in uniform conditions (i.e., all the cells are subjected to the same irradiance and operate at the same temperature), the $I-V$ characteristic can be obtained by stretching the one of a single cell. All the cells of such an ideal PV module operate at the same voltage, current, and temperature level. In mismatching conditions, however, the PV cells $I-V$ characteristics are not equal. As a consequence, the PV cells are characterized by different operating voltages, currents, and temperatures.

If a given cell C of a PV module, whichever the cause, generates a photocurrent that is lower with respect to the photocurrent of the other cells that belong to the same string, then C may be forced to operate in reverse bias conditions, that is, as a load. The shape of the $I-V$ curve in the second quadrant is not the same for all the cells. Thus, PV cells usually exhibit different breakdown voltages; in addition, such voltages strongly change depending on the time the cells have been working in reverse bias conditions [74]–[76]. As a consequence, the power that can be dissipated by a reverse biased cell usually changes from cell to cell. The higher is the dissipated power, the higher is the working temperature of the cell.

The hot spot effect is worse if only one cell in a string is partially shaded, as in the case of bird droppings, which often are not washed away even after heavy rains. In fact, such a single shaded cell must dissipate nearly the whole power, which is generated by the rest of cells, which are protected by the same bypass diode [77]. The greater the number of cells connected in series and protected by the same bypass diode, the higher the magnitude of the reverse voltage of C, which may be also subjected to breakdown [78].

As explained in the previous sections, different working temperatures lead to different degradation rates of the PV cells: the higher the temperature, the higher the degradation rate. Thus, mismatching affects aging mainly through its thermal effects; the magnitude of such effects depends on the degree of mismatching and on the characteristics of each cell. In order to prevent the reverse bias operation of mismatched cells and the hot spot formation, PV modules usually include one or more bypass diodes, with different possible configurations [79]–[81]. Nevertheless, if bypass diodes distribution is not correct (e.g., because of design mistakes due to the fact that the shape of the reverse bias $I-V$ curve is not correctly taken into account), mismatched cells may anyhow overheat [20], [81], [82]. Indeed, many long-term studies made on field-aged PV generators show that, even in presence of bypass diodes, reverse bias hot spots represent one of the main causes of PV module failures [26], [83].

In conclusion, it is possible to state that a closed-loop exists between nonuniform aging and mismatching. In fact, aging (which is nonuniform by its nature) causes mismatching among cells, whereas mismatching (whichever its cause indeed), in turn, leads to nonuniform aging. Mismatching influences aging mainly through thermal effects.

A simplified block diagram illustrating the main cause–effect links existing among PV modules degradation phenomena is shown in Fig. 3, where the closed-loop link connecting aging with mismatching is also clearly indicated.

To the best of the authors' knowledge, the strong closed-loop link existing between aging and mismatching has not yet been clearly and explicitly put into evidence so far in the literature.

In fact, a very huge number of papers dealing with mismatching can be found in the scientific literature. Such papers mainly focus their attention on architectures and control techniques that are able to limit what is believed to be the main negative drawback of mismatching, that is, the decrease of the energetic efficiency, which characterizes PV arrays that operate only in mismatching conditions [10]. Examples of

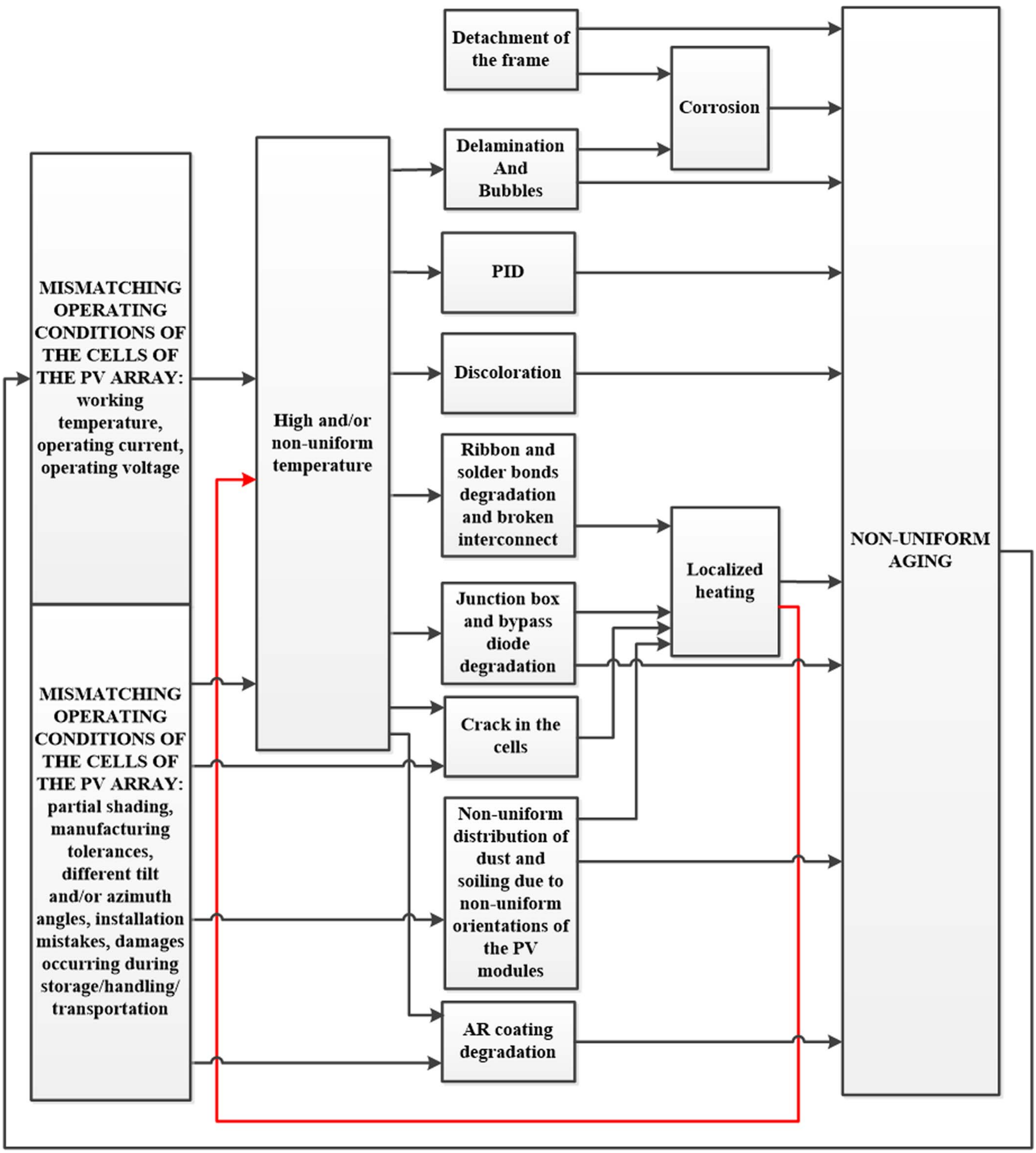

Fig. 3. Cause–effect links among PV modules degradation phenomena.

such architectures and control techniques are the distributed maximum power point tracking (DMPPT) architectures [84] or the PV array reconfiguration techniques [85]. Moreover, also particular static architectures such as the total cross-tied architecture, the honeycomb architecture, or the bridge-link architecture [86] have been investigated with the aim of increasing the energetic efficiency in presence of mismatching conditions. On the basis of the aforementioned considerations, it is clear that, in addition to the waste of available energy, mismatching is also responsible for nonuniform aging. What is lacking in the literature is a comprehensive analysis of the effects played on aging by architectures and control techniques that have been specifically designed to face the efficiency issues associated to mismatching. In particular, the following question arises: are DMPPT architectures [84] or PV array reconfiguration techniques [85] or particular static architectures [86] able not only to increase the energetic efficiency in mismatching conditions but also to enhance the duration of life of the PV generators? If the answer was yes for one or more of such architectures and techniques, this would undoubtedly represent a very important added value. Such an important aspect is of course beyond the objectives of this paper; it deserves major investigations and will be the subject of forthcoming papers. Only some brief considerations are provided here by way of example, but not of limitation with reference to PV array reconfiguration techniques. It is well known that if the $I-V$ characteristic of a string of modules contains more than one knee, then, depending on the value of the string current, one or more bypass diodes can start conducting and/or one or more cells or string of cells can become reverse biased. The bypass diodes conduction (particularly for prolonged times) and/or the reverse biasing of the PV cells represent dangerous operating conditions since they may lead to the premature aging and to the failures of the PV modules due to enhanced thermal stresses, as discussed earlier. In order to completely avoid bypass diodes conduction and cells reverse biasing, it is necessary to limit the string current below the lowest current value among the current values characterizing the knees of the $I-V$ string characteristic. This of course means that, nearly always, maximization of energy and absence of dangerous operating conditions are contrasting requirements. Therefore, the need exists for reconfiguration algorithms capable of providing configurations that represent a suitable compromise between such two contrasting requirements.

IV. Conclusion

In this paper, the different degradation mechanisms taking place in PV modules have been reviewed, and the cause–effect links, which exist among such mechanisms, have been put into evidence. It has also been shown that a kind of closed-loop link exists between nonuniform aging and mismatching. Therefore, in addition to the waste of available energy, mismatching is also responsible for the premature aging of PV modules. Further work is needed in order to clarify if existing architectures and control techniques that have been specifically designed in order to limit the waste of available energy due to mismatching operating conditions are also able to face the other important drawback associated to mismatching, that is, its acceleration effect on the aging of the PV modules.

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