A Case Study on the Performance Degradation of a Photovoltaic System Module in Tripoli, Libya

Albashir K. Elfaqih*‡, Abdurazaq Elbaz*, Milad A. Bashiri**

* Department of Solar Cells, The Libyan Center for Solar Energy Research and Studies, Tripoli, Libya

**Libyan Center for Plasma Research, Tripoli, Libya

(b_elfaqih@csers.ly, abdalrazaklabz@gmail.com, bashiri2013@gmail.com)

‡ Corresponding Author; Albashir K. Elfaqih, Tel: +218926680575, b_elfaqih@csers.ly

Received: 30.09.2023 Accepted:26.10.2023

Abstract- The degradation of used modules in photovoltaic (PV) systems is a major problem for module manufacturers, owners, and researchers due to their exposure to different climatic conditions, which leads to their degradation, regardless of the type and composition of the module. Therefore, this paper aimed to study a real case to calculate the degradation rate of the modules of a PV system connected to the grid, which was established in the year 2012, which is approximately 11 years ago, and is located in the Libyan Center for Solar Energy Research and Studies (LCSERS) in the city of Tripoli. This study was performed through the methodology of visual inspection of the system, measuring maximum power (P_{max}) and other electrical characteristics through indoor and outdoor test devices, and thermography. The results showed that the PV system is operating in good condition and that the P_{max} degradation rate of the PV module ranges between 13.95% and 16.75%.

Keywords: Solar energy, photovoltaic, degradation, module, thermography.

1. Introduction

With increasing population density and sustainable development around the world, energy demand is expected to grow to 60% of global primary energy by 2030 [1]. Some of this demand is likely to come from renewable energy sources (RES) as an alternative to fossil energy sources. It has a negative impact on the environment [2], [3]. Therefore, photovoltaic (PV) system technology which is a solar energy source plays an important role, present and future, in the global energy landscape [4]. And to have a leading role in renewable energy technologies in 2050 [5]. And Silicon technologies dominate with a large share, accounting for about 95% of the market [6]. But the phenomenon of degradation of PV modules is one of the negative factors in this system, especially with the passage of years of the life of the system, and therefore it must be studied, treated, and limit this degradation in order to reduce the efficiency of the panels as well as increase the operational life of them [7]. PV module degradation has been detected since the early 1970s. In 2017 the National Renewable Energy Laboratory (NREL) classified the most common terms for module degradation after a ten-year study, categorizing them according to their occurrence rates, as in Fig. 1 [8].

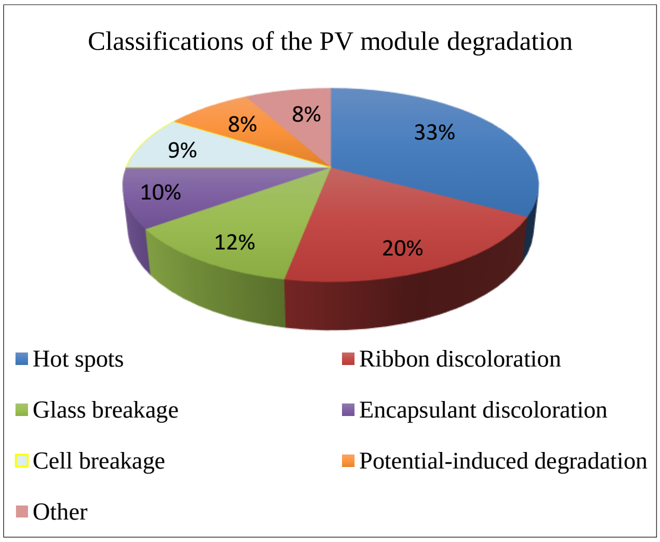


Fig. 1. The most common classifications of PV module degradation.

There are many studies conducted around the world on the degradation and reliability of the modules in the photovoltaic systems. Where a study was conducted in the city of Islamabad, Pakistan on the number of four different types of PV modules whose operating ages range from 10 to 35 years, and the tests conducted on them proved that there is degradation for some of these types after years of work, a decrease in the value of the maximum power (P_{max}) was observed ranging between 22.2 - 28.7%, as well as the colour of EVA turning to brown, the presence of cracks and discoloration in the backsheet and defects in the junction box, as well as corrosion in Bars and copper wires, but with all this degradation in performance, the modules were still being produced and the situation is not catastrophic [9]. In a study conducted at Kwame Nkrumah University (KNUST) in Ghana [10], on 14 polycrystalline silicon module after 19 years of their operational life, and they were examined visually, and by the maximum power testing (I-V characteristics), and by means of Infrared imaging. The results were the presence of some bubbles, erosion and discoloration, and the degradation rate was 1.3 % year. Four modules of two different technologies, one monocrystalline silicon (mc-Si) and the other polycrystalline silicon (pc-Si), were installed at the University of Dakar, Senegal [11], to assess degradation after 1.3 - 4 years of operation in the Equatorially environment, the results show that maximum power (P_{max}), short circuit current (I_{sc}), maximum current (I_{max}), and fill factor (FF), are the most degraded performance characteristics of all modules. The maximum power degradation (P_{max}) ranged from 0.22% - 2.96% per year. A study was conducted to find out the rate of degradation in PV modules over a period of ten years from six different locations located in the United Kingdom and Australia, to find out the extent to which photovoltaic modules are affected by cold weather conditions in the United Kingdom, and the extent to which modules are affected by hot weather conditions in Australia, and the study was carried out by imaging test by using thermal imaging camera (FLIR E4) .The results showed that the rate of degradation in the United Kingdom was lower than that in Australia, where the rate was about 1.05 - 1.16%, while in Australia it ranged between 1.35 - 1.46% [12]. In a study conducted in Libya in the year 2010 on a number of photovoltaic modules of the crystalline silicon type to see the extent of the rate of degradation after used for a long time in the Libyan desert for more than 30 years, as they were installed in 1979. The results showed through visual inspection that the modules are still in Good condition, and the results also proved through the outdoor and indoor measurements of the modules that the rate of degradation was about 13.8%, so the study concluded that the modules can operate for a period more than 40 years [13].

In this study, we will study the performance of the photovoltaic (On-Grid) system modules installed in the city of Tripoli with a capacity of 5 kilowatts and the extent of degradation occurring in its modules through visual inspection, power measurement (I-V characteristics), and Thermography.

2. Degradation Study Methodology

Numerous studies, experiments and tests have been conducted to know and understand the nature of the phenomenon of degradation and failure of modules in PV systems. Whereas, the manufacturers consider the PV module to be degraded if its power reaches a level less than 80% of its initial capacity [14]. Therefore, various methods of studying degradation have been found to help improve manufacturing processes and extend their life. There is also an international standard (IEC61215) that specifies design qualification requirements of terrestrial PV modules suitable for long-term operation in outdoor climates. These main methods are categorized as follows: [2], [4]:

2.1. Visual Inspection

In the process of evaluating the performance of the degradation of modules, a visual inspection is first carried out on the system, and it is considered an important tool in order to detect and identify the various defects that can be observed visually. The most common of these defects that are observed on modules are:

2.1.1. Breakages and cracks

The presence of breakages and cracks in the PV modules is one of the reasons for the degradation of these modules, which may cause the separation of the cell parts and thus reduce the production of its energy and also cause a mismatch in the electrical characteristics, which leads to an irregular distribution of temperatures throughout the modules. These breakages and cracks occur as a result of pressures and mechanical loads such as environmental conditions such as strong winds and snow storms [15], as well as during the manufacturing phase where cracks can occur during welding, during transportation and installation of modules and other factors [16], [17].

2.1.2. Discoloration

One of the most common defects in the photovoltaic module is the colour change in the module, which can be detected visually, and it is a colour change in the adhesive (encapsulation unit) EVA, or from the glue between the solar cell and the glass, where the colour of the material changes to brown or yellow on the surface of the PV modules. One of the main causes of discoloration is the quality of the product, exposed to ultraviolet (UV) radiation, the high temperatures, and humidity [18].

2.1.3. Delamination

Delamination is the appearance of spots, often called a “milky pattern,” that appear on large areas above the solar cells, mainly on the sides of the cell and appear less frequently in the middle. This occurs as a result of the loss of adhesion between the polymeric packaging material such as EVA and the solar cell, or between the solar cell and the Infront glass. The adhesive loses its strength due to high humidity and high temperatures as well as increased exposure to sunlight and water penetration into the module structure [19].

2.1.4. Bubbles

The shape of the bubbles often resembles the shape of the lamination process, and they are found at the front and back of the module, and are mostly located in the middle or corner of the solar cell. These bubbles occur as a result of a chemical reaction that releases a gas or due to the weakening of cell bonds. These bubbles make It is difficult for the cells to dissipate heat and this will lead to overheating, degradation and shortened life of the module [20].

2.1.5. Corrosion

Corrosion of some parts of PV modules, especially the metal connections, is one of the most common problems in PV systems. One of its problems is that it causes the colour of the metal strip in the modules to change, which results in degradation and problems in the modules electrical circuit and loss of its performance. Corrosion also occurs at the module’s outer frame. And also, in the junction box. Moisture that enters from the edges of the module is one of the causes of corrosion [14]. Peter Hacke et al. [21] studied the effect of humidity and temperature on the degradation of the PV module, and they discovered that corrosion appeared after 1,000 hours of exposure of the PV module to a temperature below 85 C^0 with a relative humidity rate of 85%.

There are several other reasons that lead to the phenomenon of degradation in the performance of photovoltaic modules, which can be detected visually, such as the accumulation of sand, dust, or mud on the modules, which forms a barrier to sunlight falling on them, and thus leads to a decrease in energy production and a significant decrease in the module’s performance [22].

2.2. Indoor and Outdoor Power Measurement (I-V curve)

The power measurements of the photovoltaic modules are one of the main ways to know the quality of the product, as well as to know the extent of degradation in it after a period of operation years. The current - voltage (I-V) curve is considered one of the most important measurements for evaluating the performance of the photovoltaic module, as through this curve we can know the electrical characteristics of the module such as short circuit current (I_{sc}), open circuit voltage (V_{oc}), maximum current (I_{max}), maximum voltage (V_{max}), maximum power point (P_{max}), and fill factor (FF) [18][23].

This test to calculate the I-V curve to infer the maximum power and other electrical parameters of the PV module, (indoor) in a solar simulator or (outdoor) under exposure to sunlight through the field device. It is preferable for this test to be under standard conditions (STC), at radiation equal to 1000 W/m^3 and a temperature of 25 C^0, but these conditions cannot be provided in the outdoor test, but they can be available in the internal test, with the occasional increase in temperature or not shedding enough light on the unit as a result of its dispersion. It has therefore been suggested that the test should be different from standard conditions (STC) and should be repeated, so that the results are more realistic [24].

2.3. Thermography (Infrared Imaging)

The thermography test is the most used method for determining the location of the degradation occurring in photovoltaic energy module that cannot be detected by visual inspection [25], as this test works to detect cells with higher levels of temperature than the rest of the cells, which are known as (Hot spots), It is where the temperature difference between these levels exceeds 20 C^0. This test is performed by a device Portable thermal camera with Infrared sensor with a range of 3 - 15 micrometers. This method relies on the property of each material to emit electromagnetic radiation whose wavelength and relative maximum are related to the temperature of the material. This test is performed on the front and backsheet of the photovoltaic panel to locate the hotspots when the system is running on load condition [26], [27].

2.4. Ultrasonic Inspection

This technique is used to detect cracks and small cracks in solar cells, as it depends on the analysis of ultrasound waves resulting from vibrations by two ways; pulse-echo method and transmission method, and it has been proven that the resonant frequency in the low frequency bandwidth increases when there is a crack in the cell [24].

2.5. Electroluminescence (EL) and Photoluminescence (PL) Imaging

Electroluminescence (EL) imaging is the most popular analysis technique for characterizing the health of photovoltaic cells in recent years. This process is done by applying a forward bias current to the modules, and the result of radiative recombination emits infrared light, which is captured using a camera with silicon-coupled device (CCD) sensor features. The captured images will present thick dark parts that reflect the defective regions that contribute to the unit energy loss (the defective cell part will appear darker because the detached parts will not irradiate). Additionally, some have used it to characterize defects including browning and lamination of the coating on crystalline silicon modules resulting from aging from years of external exposure [28].

Photoluminescence (PL) imaging is similar to EL imaging and is used to analyse the conditions of a photovoltaic module by providing information regarding the identification of quality, performance, and defects. By means of radiation signals emitted by cell materials when charge carriers recombine from radiation excitation, the difference between the two techniques is that EL can detect various decay modes which include cell cracks, PID, electrical mismatch etc. whereas in PL the carrier lifetime can be detected Minority and series resistance [29], [30].

3. Description of the PV System Location

A grid-connected PV system with a capacity of 5 kilowatts is located in the yard of the Libyan Center for Solar Energy Research and Studies (LCSERS) in the Tajoura region, in the city of Tripoli, Libya, as in Fig. 2. According to the coordinates (32.814°N, 13.438°E). This system was created as a research project approximately eleven years ago.

Fig. 2. PV (On-Grid) system at the LCSERS.

The commercial manufacturer of the module is Sollatek, model of SP-75, according to the specifications mentioned in Table 1. This module is from Monocrystalline silicon (mc-Si) cell type. These modules are designed by the manufacturer to operate optimally in a wide ambient temperature range from 40~85 C°. The thermal properties engineered into these panels contribute to their long-term performance and make them an ideal choice for regions with multiple climatic characteristics.

Table 1. Specification of PV initial module

	Value	Unit
Rated power	75	Watt
Rated voltage	17.0	Volt
Rated current	4.4	Amp
Open circuit voltage	21.0	Volt
Short circuit current	4.8	Amp
Maximum Open circuit voltage	600	Volt

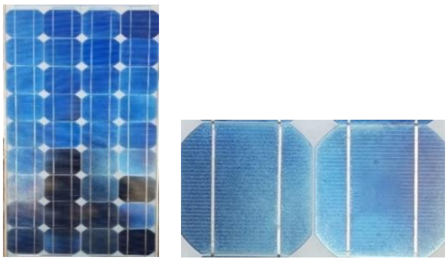
4. Results and Discussion

4.1. Visual Inspection

Through visual inspection of the entire system, it was found that there is an accumulation of dust on the front of the PV modules, especially on the sides of the module, as shown in Fig. 3. The reason for this presence is likely the dust due to a failure to clean these modules, as well as the presence of an obvious protrusion in the surface frame on the front side. This helped the accumulation of this dust, and this is what we see as a defect in the quality of the product itself.

Fig. 3. Accumulation of dust on the side of the module frame.

Also, through visual inspection, it was observed that there was a phenomenon of dark discoloration in many cells in the PV modules, as shown in Fig. 4 (a), and this change because is change in the adhesive material in the encapsulation unit. It is likely a result of the deterioration of the adhesive material as a result of its poor quality as well as its exposure to high temperatures and UV radiation, especially in the summer. There is also a delamination phenomenon in most of the cells in the modules, which appear in light Gray areas at the edges of the cells as in Fig. 4 (b).



(a) (b)

Fig. 4. (a) Discoloration & (b) Delamination phenomenon of PV system modules.

In general, and through visual inspection, no major visually noticeable defects were seen, such as breakages and cracks on the front glass or in the backsheet, there is any damage to the wires and connectors, as well as no corrosion or damage to the junction boxes and frames. Also, there is no discoloration or bubbles in the backsheet.

4.2. Power Measurement

4.2.1. Indoor test

In indoor measurement test, the Pulsed Solar Simulator (PSS 8-3) was used to find the electrical parameters of the PV module using a setup that simulates solar energy intensity, this simulator is located at the LCSERS in Tripoli. A used PV module from a 5 KW system was tested under standard conditions and at several levels of different solar radiations, as in Fig. 5. These data for the parameters obtained were compared with the data for the initial module to evaluate the degradation in performance parameters resulting from failure modes. Table 2 shows the measured values of the used module as well as the percentage decrease for each parameter.

It is noted from the results of this test that the measured values of the electrical parameters of the used module decreased compared to the values of the initial module, in the standard conditions at solar radiation 1000 W/m^2, where the P_{max} value of the used module 63.76 W, compared to the P_{max} value of the initial module, which is 75 W, meaning it had a degraded of 14.98%, which is shown by the I-V curve in Fig. 6 of the used and initial module.

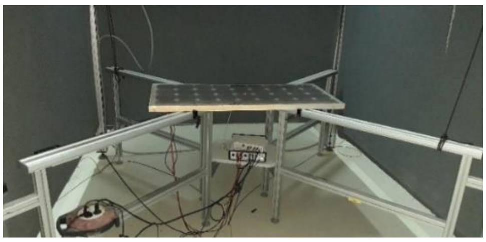


Fig. 5. Used module test in pulsed solar simulator.

Table 2. Measured values of the used module and percentages of decrease in indoor measurement test

Parameters (Unit)	Initial values	Measurement values				Percentages of decrease %				
Solar Radiation (W/m^2)		516	720	842	962	516	720	842	962	Average
I_{sc} (A)	4.8 A	4.72	4.74	4.74	4.74	-1.66	-1.25	-1.25	-1.25	-1.35
V_{oc} (V)	21 V	19.58	20.03	20.20	20.82	-6.76	-4.61	-3.8	-0.85	-4.00
I_{mpp} (A)	4.4 A	4.04	4.052	4.12	4.05	-8.18	-7.9	-6.36	-7.95	-7.59
V_{mpp} (V)	17	15.15	15.43	15.25	15.55	-10.88	-9.23	-10.29	-8.5	-9.72
P_{max} (W)	75	61.28	62.52	62.69	63.11	-18.29	-16.45	-16.41	-15.85	-16.75

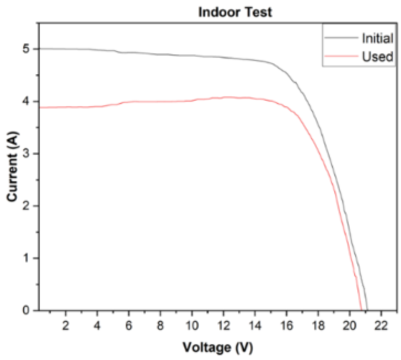


Fig. 6. I-V Curve in indoor measurement test of used & initial module at 1000 W/m^2.

From Table 2 we find that the average degradation rate of P_{max} for the used module at different radiation levels was 16.75%, Which will be taken as a result of this test. Also, the measured values of other electrical characteristics of the used module at radiation levels of 516, 720, 842 and 962 W/m^2 were also degraded compared to the initial module, as shown in the I-V curves in Fig. 7. Where the average relative rate of degradation for I_{sc}, V_{oc}, I_{mpp} and P_{max} were 1.35 %, 4 %, 7.59 %, and 16.75 %, respectively.

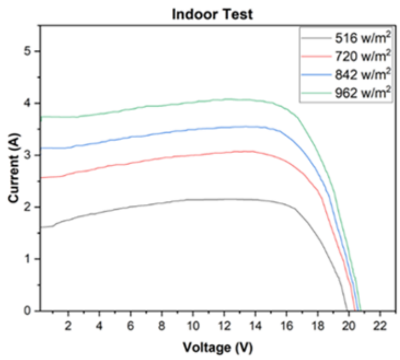


Fig. 7. I-V Curves in indoor measurement test of used module at several levels of solar radiations.

4.2.2. Outdoor test

The outdoor measurement test is the same as the indoor measurement test and aims to calculate the electrical parameters of the PV module by exposing the module to sunlight. The field-testing device for PV modules, model of (PVPM 1000C) was used as in Fig. 8. It is located at the LCSERS in Tripoli. The same used module that was tested in the indoor measurement was tested. The readings were taken at different levels of solar radiation. Table 3 shows the measured values of the used module as well as the percentage of decrease for each parameter.

Fig. 8. Outdoor testing device (PVPM 1000C)

It is noted from the results of this test in Table 3 that the measured values of all electrical parameters of the used module decreased compared to the values of the initial module when the solar radiation increased, which when the test was conducted reached a value of 800 W/m^2, and this is due to the increase in the module's temperatures. The P_{max} value for the used module was 61 W, which means that it degraded by 18.66%, which is shown by the I-V curve in Fig. 9 for the used and initial module at the solar radiation value of 800 W/m^2. While the P_{max} value for the used module was 68.7 W at the lowest recorded solar radiation value, which was 520 W/m^2, that is, a degradation rate of 8.4%. Therefore, we will take the average recorded value of P_{max} at all recorded radiation levels, which is 64.8 W, and thus the average percentage of degradation rate in this test is 13.59%.

Table 3. Measured values of the used module and percentages of decrease in outdoor measurement test

Parameters (Unit)	Initial values	Measurement values				Percentage change %				
Solar radiation (W/m^2)		520	613	739	800	520	613	739	800	Average
I_{sc} (A)	4.8 A	4.42	4.39	4.33	4.31	-7.916	-8.541	-10.854	-10.2	-9.377
V_{oc} (V)	21 V	23.7	23.4	22.4	22.1	-12.85	-11.42	-6.667	-5.238	-9.04
I_{mpp} (A)	4.4 A	3.78	3.76	3.7	3.68	-14.09	-14.54	-15.9	-16.36	-15.22
V_{mpp} (V)	17	18.2	17.8	16.9	16.6	-7.05	-4.705	-0.58	-2.35	-3.67
P_{max} (W)	75	68.7	66.9	62.6	61	-8.4	-10.8	-16.5	-18.66	-13.59

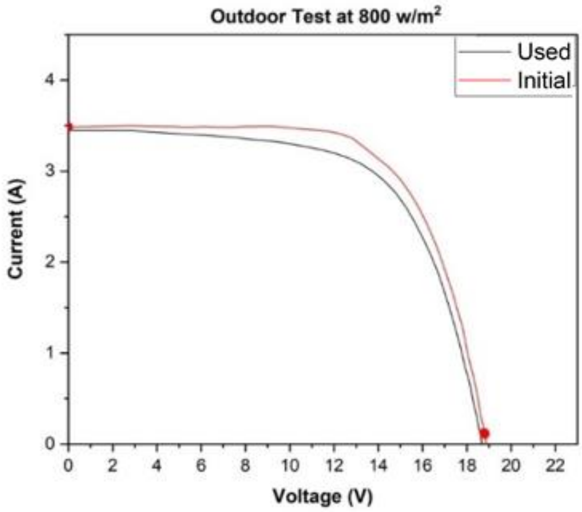


Fig. 9. I-V curve in outdoor measurement test of initial & used module at 800 W/m^2.

While the measured values of other electrical characteristics of the used module at radiation levels of 520, 613, 739 and 800 W/m^2 were also degraded compared to the initial module, as shown in the I-V curves in Fig.10. where the average relative rate of the degradation for I_{sc}, V_{oc}, and I_{mpp}, were 9.37%, 9.47%, and 15.22%, respectively.

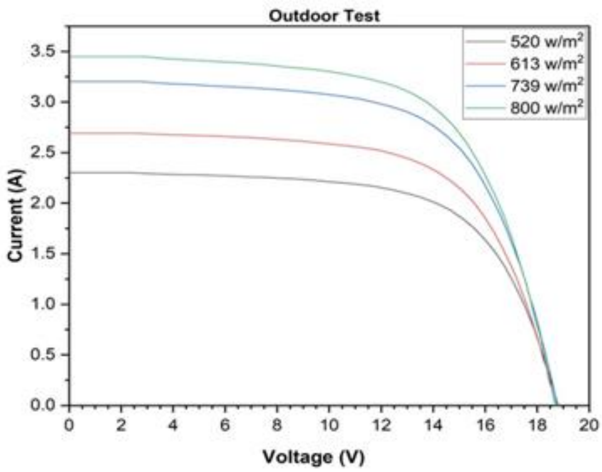
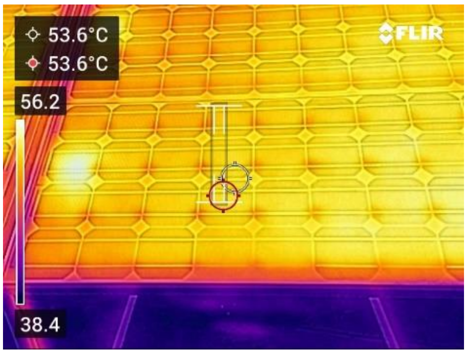


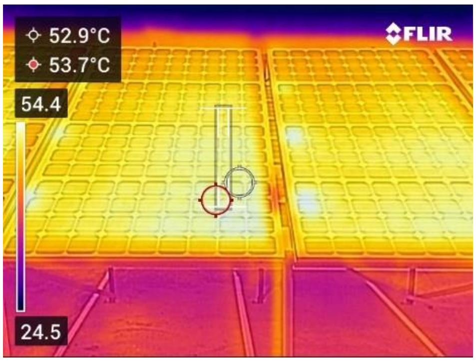
Fig. 10. I-V curve in outdoor measurement test of used module at several levels of solar radiations.

4.2.3. Thermography

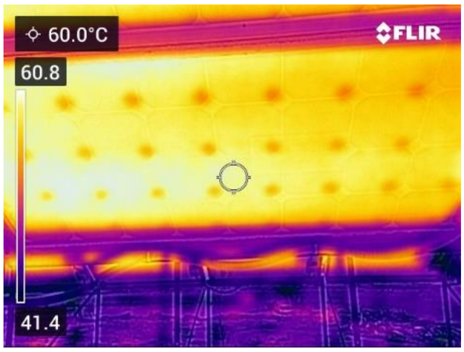
The photovoltaic system was detected by thermography at noon, at an atmospheric temperature of 35 C^0, using a FLIR C5.1.1 thermal imaging camera. Thermography showed a mostly homogeneous distribution of temperatures over all modules and there are no hot spots, as Fig. 11 (a), (b) shows that the temperature difference between the cells on the front surface of the modules does not exceed 3 C^0, and Fig. 11 (c), (d) shows that the temperature does not exceed 5 C^0 in the backsheet of the modules and at the junction boxes.



(a)



(b)



(c)

(d)

Fig. 11. Thermography test of the PV system; (a) Infront the module, (b) strings of PV modules, (c) backsheet of the module, and (d) junction box.

5. Conclusion

As a result of the rapid growth of the PV module industry and the increased demand for it, studies and research on the rate of degradation of these modules have also increased, in order to increase the reliability and operational life of these modules. Therefore, this paper aimed to study the rate of degradation occurring in the PV system connected to the grid with a capacity of 5 kilowatts, which was established in the year 2012 at the Libyan Center for Solar Energy Research and Studies in the city of Tripoli. This study was based on three methods: visual inspection, measuring electrical characteristics through indoor & outdoor test devices, and thermography. The results showed the following:

- Through visual inspection of the modules and the entire PV system, it was found that there was dust accumulation on the front of the PV modules. The phenomena of discoloration and delamination were also observed. There are also no breakages, cracks, corrosion, or any other visible phenomena.
- In the indoor measurement test, the degradation rate of the maximum power (P_{max}) value was 16.75%, while in the outdoor measurement test, the degradation rate of the maximum power value was 13.59%. Therefore, the annual degradation rate of P_{max} in this study ranges between 1.23 - 1.52%.
- The results of the degradation rate measurements in the other important electrical characteristics I_{sc}, V_{oc}, and I_{mpp} in indoor and outdoor test devices of used module were good and not bad compared to the results of previous studies, as the average degradation rate for I_{sc}, V_{oc}, and I_{mpp} in the indoor test was 1.35, 4, and 7.59%, respectively. While in the outdoor test, the average values were slightly larger, reaching 9.37, 9.07, and 15.22%, respectively.
- The results of the Thermography test show that there are no hot spots, that the temperature distribution is homogeneous across all modules of the PV system, and that the temperature differences of the cells on the modules do not exceed 5 C^0.
- From the results of this study, it is clear that the modules are still in good condition. It is capable of operating for another ten years, so if we assume from the results of the two tests that the average of P_{max} degradation rate for the past eleven years was 15.17%, then the expected rate of degradation after the next ten years will be about 28.9%, meaning that the system's productivity will reach approximately 3.55 KW. This expected rate of degradation is considered closer to the results of some previous studies, which proved that the systems are still operating over many years despite the significant degradation occurring in them.

References

[1] T. T. E. Vo, H. Ko, J. H. Huh and N. Park, "Overview of solar energy for aquaculture: The potential and future trends", Energies, vol. 14, no. 21, 2021.

[2] M. Kumar and A. Kumar, "Performance assessment and degradation analysis of solar photovoltaic technologies: A review", Renewable and Sustainable Energy Reviews, vol. 78, no. November 2016, pp. 554–587, 2017.

[3] M. Venkatesh, "A review on the estimate solar PV cell variables for efficient photovoltaic systems", International Journal of Smart Grid (ijSmartGrid), vol. 7, no. 3, pp. 154–159, 2023.

[4] S. A. Alves dos Santos, J. P. N. Torres, C. A. F. Fernandes, and R. A. Marques Lameirinhas, "The impact of aging of solar cells on the performance of photovoltaic panels", Energy Conversion and Management: X, vol. 10, p. 100082, 2021.

[5] E. Muñoz-Cerón, J. C. Osorio-Aravena, F. J. Rodríguez-Segura, M. Frolova, and A. Ruano-Quesada, "Floating photovoltaics systems on water irrigation ponds: Technical potential and multi-benefits analysis", Energy, vol. 271, p. 127039, 2023.

[6] G. Brito-Santos, B. Gil-Hernández, C. Hernández-Rodríguez, B. González-Díaz, R. Guerrero-Lemus, and J. Sanchiz, "Degradation analysis of highly UV-resistant down-shifting layers for silicon-based PV module applications", Materials Science and Engineering: B, vol. 288, p. 116207, 2023.

[7] M. Aghaei, A. Fairbrother, A. Gok, S. Ahmad, S. Kazim, K. Lobato, G. Oreski, A. Reinders, J. Schmitz, M. Theelen, P. Yilmaz, and J. Kettle "Review of degradation and failure phenomena in photovoltaic modules", Renewable and Sustainable Energy Reviews, vol. 159, p. 112160, 2022.

[8] D. C. Jordan, T. J. Silverman, J. H. Wohlgemuth, S. R. Kurtz, and K. T. VanSant, "Photovoltaic failure and degradation modes", Progress in Photovoltaics: Research and Applications, vol. 25, no. 4, pp. 318–326, 2017.

[9] M. Noman, Tu, Shanshan, Ahmad, Shahab, Zafar, Fahad Ullah, Khan, Haseeb Ahmad, Rehman, adaqat Ur Waqas, Muhammad Khan, Adnan Daud Rehman, and Obaid ur, "Assessing the reliability and degradation of 10–35 years field-aged PV modules", PLOS ONE, vol. 17, no. 1, pp. 1–16, 2022.

[10] D. A. Quansah, M. S. Adaramola, G. Takyi, and I. A. Edwin, "Reliability and Degradation of Solar PV Modules—Case Study of 19-Year-Old Polycrystalline Modules in Ghana", Technologies, vol. 5, no. 2, 2017.

[11] A. Ndiaye, C. M. F. Kébé, A. Charki, P. A. Ndiaye, V. Sambou, and A. Kobi, "Degradation evaluation of crystalline-silicon photovoltaic modules after a few operation years in a tropical environment", Solar Energy, vol. 103, pp. 70–77, 2014.

[12] M. Dhimish and A. Alrashidi, "Photovoltaic Degradation Rate Affected by Different Weather Conditions: A Case Study Based on PV Systems in the UK and Australia", Electronics, vol. 9, no. 4, 2020

[13] M. A. S. Alshushan and I. M. Saleh, "Power degradation and performance evaluation of PV modules after 31 years of work", in 2013 IEEE 39th Photovoltaic Specialists Conference (PVSC), 2013, pp. 2977–2982.

[14] A. Ndiaye, A. Charki, A. Kobi, C. M. F. Kébé, P. A. Ndiaye, and V. Sambou, "Degradations of silicon photovoltaic modules: A literature review", Solar Energy, vol. 96, pp. 140–151, 2013.

[15] J. Solis, A. Råberg, J. André, and M. Nilsson, "Analyzing the effect of snow in PV regulator response in a PV solar park", in 2021 9th International Conference on Smart Grid (icSmartGrid), 2021, pp. 72–75.

[16] R. Dubey, A. Kottantharayil, N. Shiradkar, and J. Vasi, "Effect of Mechanical Loading Cycle Parameters on Crack Generation and Power Loss in PV Modules", in 2021 IEEE 48th Photovoltaic Specialists Conference (PVSC), 2021, pp. 799–802.

[17] H. Mohammed Niyaz, R. Meena, and R. Gupta, "Impact of cracks on crystalline silicon photovoltaic modules temperature distribution", Solar Energy, vol. 225, pp. 148–161, 2021.

[18] S. Gyamfi, B. Aboagye, F. Peprah, and M. Obeng, "Degradation analysis of polycrystalline silicon modules from different manufacturers under the same climatic conditions", Energy Conversion and Management: X, vol. 20, p. 100403, 2023.

[19] L. Lillo-Sánchez, G. López-Lara, J. Vera-Medina, E. Pérez-Aparicio, and I. Lillo-Bravo, "Degradation analysis of photovoltaic modules after operating for 22 years. A case study with comparisons", Solar Energy, vol. 222, pp. 84–94, 2021.

[20] J. Kim, M. Rabelo, S. P. Padi, H. Yousuf, E.-C. Cho, and J. Yi, "A Review of the Degradation of Photovoltaic Modules for Life Expectancy", Energies, vol. 14, no. 14, p. 4278, 2021.

[21] P. Hacke et al., "Accelerated Testing and Modeling of Potential-Induced Degradation as a Function of Temperature and Relative Humidity", IEEE Journal of Photovoltaics, vol. 5, no. 6, pp. 1549–1553, 2015.

[22] M. Idara, M. Ndiaye, and W. Nkounga, "Correlation between Dirt on The Photovoltaic Module Surface and Climatic Parameters in the Dakar Region, Senegal", in 2018 7th International Conference on Renewable Energy Research and Applications (ICRERA), 2018, pp. 517–521.

[23] A. H. El Khateb, N. A. Rahim, and B. W. Williams, "Impact of fill factor on input current ripple of photovoltaic system", 2015 International Conference on Renewable Energy Research and Applications, ICRERA 2015, vol. 5, no. 3, pp. 120–123, 2015.

[24] M. A. Munoz, M. C. Alonso-García, N. Vela, and F. Chenlo, "Early degradation of silicon PV modules and guaranty conditions", Solar Energy, vol. 85, no. 9, pp. 2264–2274, 2011.

[25] O. Mesbahi, M. Tlemçani, F. M. Janeiro, and A. Hajjaji, "A Modified Nelder-Mead Algorithm for Photovoltaic Parameters Identification", International Journal of Smart grid, vol. 4, no. 1, 2020.

[26] E. Kaplani, "Detection of Degradation Effects in Field-Aged c-Si Solar Cells through IR Thermography and Digital Image Processing", International Journal of Photoenergy, vol. 2012, p. 396792, 2012.

[27] V. Sharma and S. S. Chandel, "Performance and degradation analysis for long term reliability of solar photovoltaic systems: A review", Renewable and Sustainable Energy Reviews, vol. 27, pp. 753–767, 2013.

[28] O. A. Alimi, E. L. Meyer, and O. I. Olayiwola, "Solar Photovoltaic Modules’ Performance Reliability and Degradation Analysis—A Review", Energies, vol. 15, no. 16, 2022.

[29] R. Bhoopathy, O. Kunz, M. Juhl, T. Trupke, and Z. Hameiri, "Inspecting series resistance effects and bypass diode failure using contactless outdoor photoluminescence imaging", in 2018 IEEE 7th World Conference on Photovoltaic Energy Conversion (WCPEC) (A Joint Conference of 45th IEEE PVSC, 28th PVSEC & 34th EU PVSEC), 2018, pp. 377–380.

[30] M. K. da Silva, M. S. Gul, and H. Chaudhry, "Review on the Sources of Power Loss in Monofacial and Bifacial Photovoltaic Technologies", Energies, vol. 14, no. 23, 2021.