THE INTERNATIONAL JOURNAL OF SCIENCE & TECHNOLEDGE

Power Degradation and Its Climatic Correlation in Field-Aged Photovoltaic Modules Operating in Kenya

Macben Makenzi
Lecturer, Mechatronic Department, Jomo Kenyatta University of Agriculture and Technology, Kenya
Timonah Nelson
Lecturer, Physics Department, Jomo Kenyatta University of Agriculture and Technology, Kenya
Benedict Mutua
Dean, Faculty of Engineering and Technology, Egerton University, Kenya
Ismael Abisai
Quality Manager, Ubbink East Africa Ltd., Kenya

Abstract:
Photovoltaic (PV) modules deployed outdoors usually degrade physically due to exposure to the various elements such as UV light, a range of fluctuating temperatures and humidity and variations in operating currents and voltages. In this paper, physical degradation of a PV module was found to have a corresponding effect on the power characteristics. Research was carried out to investigate the relationship between the maximum power output of field-aged PV panels and the climatic conditions under which they have been operating. Identification and analysis of modules that had been deployed in various locations in Kenya, and had been in operation for more than 8 years was carried out. The current power at the maximum power point (P_{MPP}) was determined for each panel and this was compared to the original manufacturer's specifications. The results indicated that field aged PV modules experience power loss which directly corresponds to the level of physical degradation of the module. Power degradation is higher in older panel and experienced at a greater level by panels operating in areas experiencing high temperature and precipitation
.

Keywords: *Degradation, photovoltaic module, field-aged, maximum power point*

1. Introduction

Solar modules are usually assigned their nameplate ratings by the manufacturer. This information is determined at standard test condition (STC) which is 25˚C, 1000 W/m^2, and air mass 1.5. These conditions are rarely the same as the operating conditions experienced by modules deployed outdoors, and this result in either temporary (reversible) derating of module performance or non-reversible permanent degradation changes due to weathering. Research on the physical degradation exhibited by a PV module and the power being generated by the same, gives insight into how modules have degraded and how modules are affected by physical degradations.

PV manufacturers assign key parameters that are used for specifying a PV module. These include short circuit current (I_{SC}), open circuit voltage (V_{OC}), maximum power (P_{MPP}), current at maximum power (I_{MP}) and voltage at maximum power (V_{MP}). Each of this has an influence on the operations and the overall installation setup of a solar home system. The power produced by the cell in Watts is usually derived along the I-V curve sweep. At the I_{SC} and V_{OC} points, the power will be zero and the maximum value for power will occur between the two. As such power measurement is a good variable to use in determining the overall condition of the PV panel.

Degradation of PV modules is caused by ambient temperature and humidity; moreover, these factors can accelerate the rate degradation. Technically, degradation mechanisms can lead to complete failure of a PV module [1].

A clear understanding of power decline over time by PV modules is important to all stakeholders including private consumers and PV manufacturers. It is not well known how long modules last after their installation. Manufacturer warranties often guarantee 80% maximum power for 25 years; however relatively few PV modules have been in use for that long. As a result, there is a limited amount of data on PV module power production over time.

Different methodologies have been used to study power degradation. Photovoltaic module manufacturers usually make efforts to eliminate the impact of short-term and long-term environment-induced degradation, but the difficulty in correlating indoor with outdoor testing at local conditions, poses a great challenge. Degradation studies are more often than not based on various scientific studies that are typically grounded on general conditions. Manufacturers usually expose their products to accelerated tests which rarely depict the actual environment that the panel will eventually end up operating in after outdoor deployment.

There exists a huge knowledge gap on the degradation forms on a PV module and their relationship between the climate under which they operate and the power production. A larger gap tending towards almost total exclusion of this knowledge, for the Kenyan environment, does exist. The present article presents an empirical study of PV panels, in their natural operating environments and having been in operation over an extended period, to investigate the above stated relationships.

2. Research Approach

Solar panels sample were sourced from various regions in Kenya that experience varied climatic conditions. The PV panels also varied in age with the oldest panel having been in operation for 27 years whilst and the youngest having an operation lifetime of 9 years as at the time of analysis.

Precipitation and temperature data for each of the locations from where the samples have been in operation was obtained. Table 1 outlines the zoning classifications created in order to group panels under common climate areas.

Temperature zone	Annual Temperature Range(˚C)	Precipitation Zone	Annual Precipitation Range (mm)
Zone 1	≤17	Zone 1	>1000
Zone 2	<21, >17	Zone 3	< 1000
Zone 3	≥ 21		

Table 1: Sample's location temperature and precipitation zoning

An industrial sun simulator and an IV-Curve tracer was used for measuring the maximum power output of each panel at STC.

3. Results and Discussion

A brief description of the PV-module samples used in the investigation in terms of location, age and climate is outlined in Table 2 below.

Module I.D	Installation Location	Age (Years)	Temperature Zone	Rain Zone
S 1	Bunyore	27	Zone 2	zone 1
S 2	Tala	23	Zone 2	Zone 3
S3	Sultan Hamud	21	Zone 3	Zone 3
S 4	Voi	17	Zone 3	Zone 3
S 5	Homa Bay	17	Zone 2	Zone 1
S 6	Kisii	20	Zone 2	Zone 1
S 7	Kisii	22	Zone 2	Zone 1
S 8	Migori	15	zone 3	zone 1
S 9	Uasin Gishu	10	zone 1	Zone 1
S 10	Nanyuki	11	Zone 1	Zone 3
S 11	Nakuru	13	Zone 1	Zone 1
S 12	Nakuru	9	Zone 1	Zone 1
S 13	Nairobi	12	zone 2	Zone 3
S 14	Kapsabet	12	Zone 1	Zone 1
S 15	Kericho	21	Zone 2	Zone 1
S 16	Kericho	11	Zone 2	Zone 1
S 17	Mwingi	20	Zone 3	Zone 3

Table 2: Information on Solar Modules Samples

Table 3 outlines the results obtained after the measurements of the actual power being produced by each panel in comparison to the manufacturer's rated power output of the PV module.

Module I.D.	Rated Power (W)	Actual Power (W)	Derating (%)
S 1	240	21.39	91.000
S 2	50	31.50	36.958
S 3	20	17.41	12.920
S4	10	0.00	100.000
S 5	20	27.00	14.340
S6	25	27.00	5.916
S 7	15	7.28	51.460
S 8	32	0.00	100.000
S 9	60	27.00	4.761
S 10	5	27.00	20.660
S 11	55	0.00	100.000
S 12	60	27.00	0.645
S 13	60	27.00	1.973
S 14	70	0.00	100.000
S15	53	0.00	100.000
S16	55	27.00	6.562
S17	64	27.00	12.500

Table 3: Output analysis of Solar Modules Samples

Various forms of degradation do exist and these have a direct impact on the power production of the module.

3.1. Power Derating VS Age

Figure 1 shows the relationship between the various age groupings of the sampled panels and the group's average power derating.

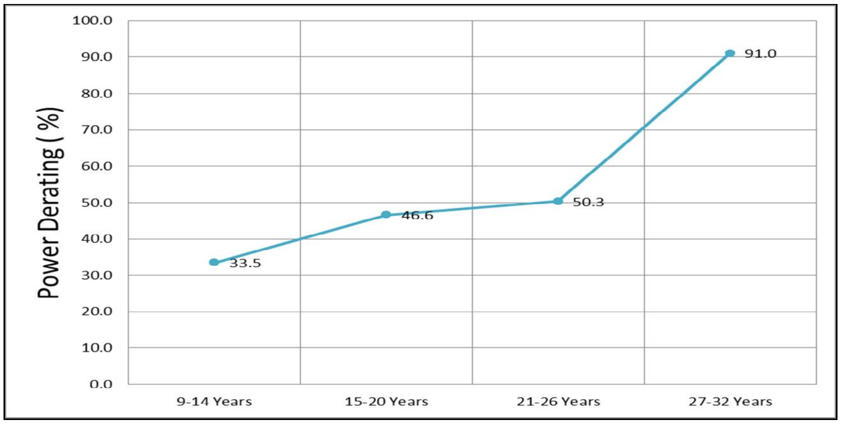

Figure 1: Power derating as a function of module age

It is seen in general that the power derating is higher in older panels as compared to younger panels. Power derating is the direct result of the various forms of degradation acting on the solar modules, with each form contributing some percentage to the overall deration,

3.2. Power Derating VS Temperature

Figure 2 shows the relationship observed between the average power derating of the panels operating in the three temperature zones.

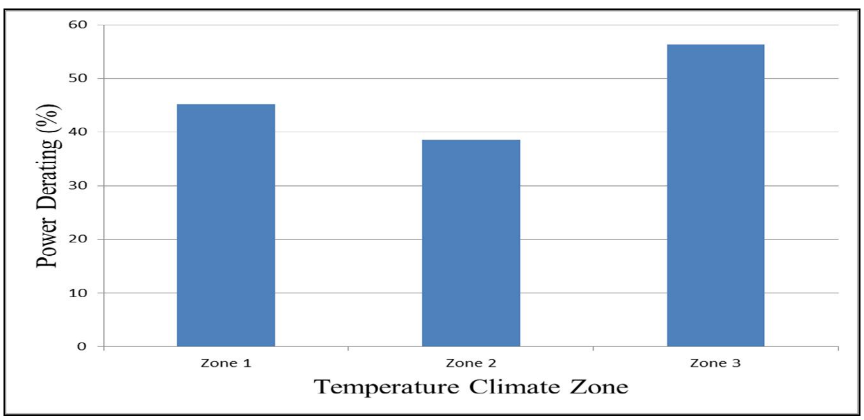

Figure 2: Power derating Vs Temperature

The highest power derating was observed from panels which had been in operation in temperature zone 3 (Areas with annual temperature exceeding 21˚C). Two modules which did not give any power output fall in the temperature zone 1 and these tend to give a misleading higher power deration to that group as compared to zone 2 (Areas with annual temperature below 21˚C and above 21˚C).

The high temperatures contribute to commencement and acceleration of several forms of degradation. Cell discoloration may result from degradation of the anti-reflective (AR) coating. AR degradation can be caused by humidity, temperature, and voltage and reduces the amount of light a cell can absorb and thus the current and power produced by the PV cell [2]. The severity of this discoloration ranges from having little or no effect to reducing the performance by as much as 50% [3].

3.3 Power Derating VS Precipitation

Figure 3 shows the relationship observed between the average power derating of the panels operating in the two precipitation zones. Zone 1 regions experience annual precipitation exceeding 1000mm while Zone 3 regions experience annual precipitation of less than a 1000mm.

It is observed that panels operating in Zone 1 experienced higher power deration as compared to those operating in zone 3. This is expected as high moisture and humidity levels contribute highly to initialization and accelerating various forms of degradation, which in turn reduce the power output of the panels.

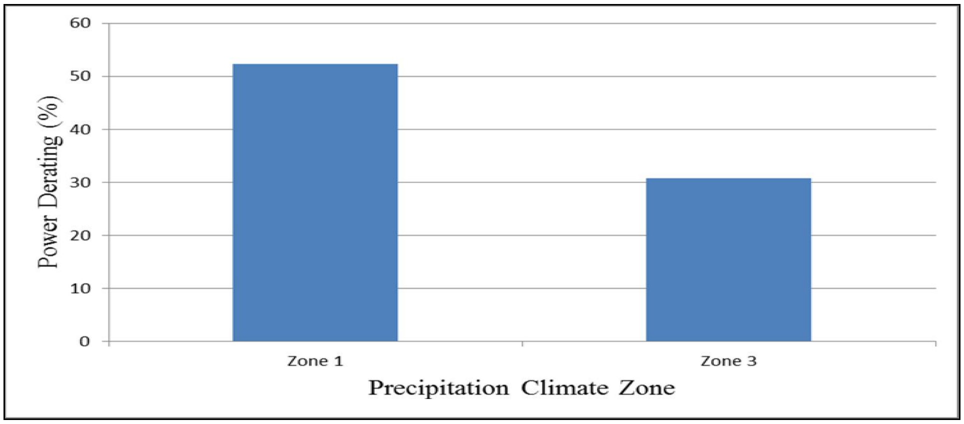

Figure 3: Power derating Vs Precipitation

Moisture can diffuse into PV modules through their breathable back sheets or their ethylene vinyl acetate (EVA) encapsulant sheets [4]. When in service in hot and humid climates, PV modules experience changes in the moisture content, the overall history of which is correlated with the degradation of the module performance [4]. If moisture begins to penetrate the polymer and reaches the solar cell, it can weaken the interfacial adhesive bonds, resulting in delamination [5]. Delamination is a common problem and occurs more frequently and more severely in hot and humid climates [6]. It reduces heat transfer from the surface of the cells where the delamination occurs, and it reduces the amount of light incident on the PV cell surface which affects the amount of current the module produces [7]. It also fosters an environment in the module for moisture to enter and settle, and upon reaching the edge of the module it may even pose a safety threat in the electrical insulation properties of the module [8].

Moisture also leads to an increased numbers of ingress paths, loss of passivation [9], and corrosion of solder joints [10, 11]. Of these possibilities, the occurrence of corrosion has one of the highest frequencies in outdoor-exposed PV modules [12]. Significant losses in PV module performance are caused by the corrosion of the cell itself [13, 14].

Electrochemical Corrosion (EC) also referred to as the electrochemical delamination of the transparent conductive oxide (TCO) layer from the front glass surface, affects modules on glass substrates which corrode as a result of moisture ingress and reverse bias. Modules experiencing EC operate at a lower efficiency as compared to their nameplate efficiency. EC in modules increases the series resistance by limiting the quality of the TCO [15].

4. Conclusion

An investigation into the power output of field-aged PV modules operating in various climatic conditions in Kenya has been presented in this paper.

The results of the study clearly indicate that power derating in PV modules is seen to be higher in modules operating in regions of elevated temperatures. PV modules operating in regions of higher precipitation and humidity also exhibit higher power loss as compared to those in areas of less precipitation and humidity.

The cause of the power loss is mainly destruction and /or degradation of the solar modules. Research shows that degradation in PV modules is initiated and accelerated by exposure of the modules to elevated levels of moisture and temperature. It should be noted that other degradation forms are not necessarily related to climate e.g. hotspots. However, they affect the physical properties of the module and as such they also contribute to the power loss experienced by field-aged modules.

5. Acknowledgment

The authors acknowledge the various individuals who provided PV module samples to be investigated in this research.

6. References

1. L. Escobar and W. Meeker, Statistical Methods for Reliability Data. Jo. John Wiley & Sons: New York, 1998.
2. J. M. Kuitche, G. TamizhMani and R. Pan, “Failure modes effects and criticality analysis (FMECA) approach to the crystalline silicon photovoltaic module reliability assessment," Proc. of SPIE Vol. 8112, 81120L, Reliability of Photovoltaic Cells, Modules, Components, and Systems, 2011.
3. E. L. Meyer and E. E. V. Dyk, “Assessing the reliability and degradation of photovoltaic module performance parameters," IEEE Transaction on Reliability, Vol. 53, No. 1, March, 2004.
4. M. D. Kempe, “Modeling of rates of moisture ingress into photovoltaic modules," Solar Energy Materials and Solar Cells, vol. 90, no. 16, p. 27202738, 2006.
5. K. Morita T. Inoue, H. Kato I. Tsuda, and Y. Hishikawa, “Degradation factor analysis of crystalline-Si PV modules through long-term field exposure test," in Proceedings of the 3rd World Conference on Photovoltaic Energy Conversion, p. 19481951, 2003.
6. N.Dhere, N.Raravikar, A. Mikonowicz and C. Cording, “Effect of glass Na content on adhesional strength of PV modules," Proceedings of the 29th IEEE Photovoltaic Specialists Conference, New Orleans, LA, 2002.
7. M. A. Quintana, D. L. King, T. J. McMahon and C. R. Osterwald, “Commonly observed degradation in field-aged photovoltaic modules,” Sandia National Laboratories, Albuquerque, NM, 1.

8. M. Kontges, V. Jung, and U. Eitner, “Requirements on metallization schemes on solar cells with focus on photovoltaic modules,” in Proceedings of the 2nd Workshop on Metallization of Crystalline Silicon Solar Cells, 2010.
9. E. E. van Dyk, J. B. Chamel, and A. R. Gxasheka, “Investigation of delamination in an edge-defined film-fed growth photovoltaic module,” Solar Energy Materials and Solar Cells, vol. 88, no. 4, p. 403411, 2005.
10. N. G. Dhere and N. R. Raravikar, “Adhesional shear strength and surface analysis of a PV module deployed in harsh coastal climate,” Solar Energy Materials and Solar Cells, vol. 67, no. 1-4, pp. 363-367, 2001.
11. X. Han, Y.Wang, L. Zhu, H. Xiang and H. Zhang, “Mechanism study of the electrical performance change of silicon concentrator solar cells immersed in de-ionized water,” Energy Conversion and Management, vol. 53, no. 1, pp. 1-10, 2012.
12. D. Polverini, M. Field, E. Dunlop, and W. Zaaiman, “polycrystalline silicon PV modules performance and degradation over 20 years,” Progress in Photovoltaics: Research and Applications, vol. 21, no. 5, pp. 1004-1015, 2013.
13. M. Kontges, V. Jung, and U. Eitner, “Requirements on metallization schemes on solar cells with focus on photovoltaic modules," in Proceedings of the 2nd Workshop on Metallization of Crystalline Silicon Solar Cells, 2010.
14. C. Dechthummarong, B. Wiengmoon, D. C. aand C. Jivacate, and K. Kirtikara, “Physical deterioration of encapsulation and electrical insulation properties of PV modules after long term operation in thailand,” Solar Energy Materials and Solar Cells, vol. 94, no. 9, pp. 1437{1440, 2010.