Performance degradation of photovoltaic modules at different sites

A Hadj Arab\textsuperscript{1a}, I Hadj Mahammed\textsuperscript{2}, S Ould Amrouche\textsuperscript{1}, B. Taghezouit\textsuperscript{1} and N. Yassaa\textsuperscript{1}

\textsuperscript{1}Centre de Développement des Energies Renouvelables, CDER, 16340, Algiers, Algeria  
\textsuperscript{2} Unité de Recherche Appliquée en Energies Renouvelables, URAER, Centre de Développement des Energies Renouvelables, CDER, 47133, Ghardaïa, Algeria  
\textsuperscript{a} E-mail: a.hadjarab@ceder.dz

Abstract. In this work are presented results of electrical performance measurements of 120 crystalline silicon PV modules following long-term outdoor measurements. A set of 90 PV modules represent the first grid-connected photovoltaic (PV) system in Algeria, installed at the level of the “Centre de Développement des Energies Renouvelables” (CDER) site (Mediterranean coast), Bouzareah. The other 30 PV modules were undertaken in an arid area of the desert region of Ghardaïa site, about 600 km south of Algiers, with measurements collected from different applications. Following different characterization tests, we noticed that the all tested PV modules kept their power-generating rate except a slight reduction. Therefore, a mathematical model has been used to carry out PV module testing at different irradiance and temperature levels. Hence, different PV module parameters have been calculated from the recorded values of the open-circuit voltage, the short-circuit current, the voltage and current at maximum power point. The electrical measurements have indicated different degradations of current-voltage parameters. All the PV modules stated a decrease in the nominal power, which is variable from one module to another.

1. Introduction
The decrease in the cost of crystalline silicon photovoltaic (PV) modules is noticeable and embraces a great promising future. However, it raises the question of whether weather conditions can these PV modules sustain.

The manufacturers deploy efforts in order to increase the PV modules lifetime, even under harsh operating conditions. Therefore, the accelerated and qualification tests procedures have been used to anticipate the aging mechanisms, and to establish a realistic standard quality. When a PV-module is bought, it is often accompanied with a warranty of more than 20 years, which is based on a type certification IEC 61215 and proceeded with a number of accelerated lifetime tests. Therefore, it is recommended to support the accelerated tests data with data from field-testing, in order to prove the users that a warranty of more than 20 years is valid. Substantial progress has been achieved, but more research is needed and then manufacturers will have to establish serious standard quality control in order to fulfill the long-term goals. Hence, to predict lifetime, mainly in remote areas, it is necessary to study the aging of the PV modules in various climatic areas.

Jordan and Kurtz examined degradation rates of flat-plate terrestrial modules and systems, from field-testing throughout the last 40 years. Approximately 2000 degradation rates, measured on individual modules or entire systems have been collected from and show a mean degradation rate of 0.8%/year
and an average value of 0.5%/year. The majority, 78% of all data, stated a degradation rate of <1%/year. This cumulative field experience may now support long-term warranties [1]. Kichou et al. [2] have studied the degradation of the micro-morph Thin Film Photovoltaic (TFPV) modules in a relatively dry and sunny inland site with a Continental-Mediterranean climate in Jaén, Spain. They have noted the reduction of the DC output power of about 12.51% after the first month of exposure under outdoor conditions. Furthermore, the stabilization period was observed to start after four months of operation with a total reduction of the PV array DC output power of 16.66%.

Kahoul et al. [3] have studied the electrical performance degradation of local manufacturing PV modules (UDTS-50), in Algeria. Results reveal the degradation of some PV modules up to 12% compared to their original state. Jordan et al. found that median degradation for x-Si technologies in the 0.5–0.6%/year range with the average range of 0.8–0.9%/year. Hetero-interface technology (HIT) and microcrystalline silicon (μ-Si) technologies even though are not as abundant, exhibit degradation around 1%/year and resemble thin-film products more closely than x-Si. On the other hand, they mentioned that nonlinearities for some products have been documented in some studies for the worst performing modules and are influenced by a number of factors. Modeling these nonlinearities, whether they take place at the beginning-of-life or end-of-life in the PV life cycle, has a significant effect on the LCOE [4].

A first study dealing with the measurements of electrical performance of crystalline silicon PV modules following long-term outdoor continue exposure was carried out by Hadj Arab et al. [5]. They noticed that all the modules presented a decrease of the nominal power.

In our case, we aim at evaluating the degradation of the electrical characteristics of 120 PV modules, tested at different sites. 90 PV modules of monocrystalline silicon technology operating, at CDER, Bouzareah with a Mediterranean climate condition, and 30 modules of monocrystalline at Ghardaïa site of arid climate. The period of exposure of these modules are from June 2004 for the PV system of Bouzareah site and from July 2008 for the site of Ghardaïa.

2. Photovoltaic array

The total number of the PV modules previously mentioned forming the two PV generators (PVG1 and PVG2) and operating for different applications have been tested according to the type of use, as follows:

2.1. Photovoltaic array PVG1

The PVG1 array consists of 90 PV modules; it was installed on a horizontal roof at the CDER building (Algiers). This system was acquired within the CIEMAT cooperation (Spain). The station's latitude is 36.8°. The unique tilt angle considered of the PV array is 25°, which favors energy production in the summer time. Note that Algiers is near the sea and is affected by the seasons [6]. Due to the excessive use of air conditioners, the peak loads occur on summer afternoons in Algeria.

| Parameter                      | Value |
|-------------------------------|-------|
| Width (mm)                    | 654   |
| Length (mm)                   | 1310  |
| Weight (kg)                   | 11.5  |
| Number of cells in series     | 36    |
| Number of cells in parallel   | 2     |
| Maximum Power (Wp)            | 106   |
| Short-circuit current (A)     | 6.54  |
| Current at Maximum Power Point (A) | 6.10 |
| Open circuit voltage (V)      | 21.6  |
| Voltage at Maximum Power Point (V) | 17.4 |
The PV array consists of 90 PV 106 Wp crystalline silicon modules (see table 1). It is composed of three sub-arrays of 30 modules each. The sub-array configuration is 15Sx2P. Each sub-array is connected to a 2.5 kVA inverter [7].

2.2. Photovoltaic array PVG2
Similar to the PVG1, the current PVG2 array, which consists of 30 PV modules of the same technology, was installed on a roof at URAER (Applied Research Unit for Renewable Energy) building (Ghardaïa), located at a latitude of 32.4 °. The common tilt angle was close to the latitude angle of Ghardaïa. Huge irradiances and temperatures characterize this site.

The PV array consists of the two following sub systems:
- Subsystem 1 consists of 10 PV modules of 100 Wp, connected in (1Sx10P) configuration (see table 2).
- The subsystem 2 consists of 20 PV modules of 50 Wp configured in (2Sx10P).

| Parameter                | First sub PVG2 | Second sub PVG2 |
|--------------------------|----------------|-----------------|
| Width (mm)               | 654            | 340             |
| Length (mm)              | 1310           | 1304            |
| Weight (kg)              | 11.5           | 5.5             |
| Number of cells in series| 36             | 36              |
| Number of cells in parallel | 2             | 1               |
| Maximum Power (Wp)       | 100            | 50              |
| Short-circuit current (A)| 3.27           | 3.27            |
| Current at Maximum Power Point (A) | 2.87 | 2.87 |
| Open circuit voltage (V) | 43.2           | 21.6            |
| Voltage at Maximum Power Point (V) | 34.8 | 17.4 |

All the subsystems are connected to a 2 kVA inverter and supply a stand-alone PV system. Table 2 gives technical characteristics of these two subsystems respectively.

3. Modeling of PV module
A PV array is a nonlinear power source. At a given irradiance, the current-voltage (I-V) relationship is illustrated by:

\[ I = I_{ph} - I_s \left[ \exp \left( \frac{V + R_s I}{mV_t} \right) - 1 \right] - \frac{V + R_s I}{R_{sh}} \]  \hspace{1cm} (1)

Where \( V_t = \frac{kT}{e} \)

\( I_{ph} \) is the photocurrent, \( I \) the saturation current, \( R_s \) the series resistance, \( m \) the diode quality factor, \( R_{sh} \) the shunt resistance, \( V_t \) the thermal voltage, \( k \) the Boltzmann’s constant, \( T \) the temperature of the solar cell (K) and \( e \) the charge of the electron.

The analytical five-parameter method has been used to measure the PV array performances at different irradiance and temperature conditions [8].

At a particular temperature and illumination, the five parameters \( I_{ph}, I_s, R_s, R_{sh} \) and \( m \) can be computed from the open-circuit voltage (\( V_{oc} \)), the short-circuit current (\( I_{sc} \)), the voltage and current at maximum power point (\( V_m, I_m \), \( R_{s0} \) and \( R_{sh0} \)).

\[ \frac{dV}{dI} \bigg|_{V=V_m} = -R_{s0} \] \hspace{1cm} (2)

\[ \frac{dI}{dV} \bigg|_{I=I_m} = -R_{sh0} \] \hspace{1cm} (3)
Where: $R_{s0}$ and $R_{sh0}$ are reciprocal of slope at open circuit point and reciprocal of slope at short circuit point respectively. The obtained equations are:

$$m = \frac{V_s + I_s R_{s0} - V_{oc}}{V_s \ln(I_{sc} - \frac{V_{oc}}{R_{sh}} - I_s) - \ln(I_{sc} - \frac{V_{oc}}{R_{s0}})}$$  \hspace{1cm} (4)$$

$$I_s = \left(I_{sc} - \frac{V_{oc}}{R_{sh}}\right) \exp\left(-\frac{V_{oc}}{m V_t}\right)$$  \hspace{1cm} (5)$$

$$R_s = R_{s0} - \frac{m V_t}{I_s} \exp\left(-\frac{V_{oc}}{m V_t}\right)$$  \hspace{1cm} (6)$$

$$I_{ph} = I_{sc}\left(1 + \frac{R_s}{R_{sh}}\right) + I_s \left(\exp\left(\frac{I_{sc} R_s}{m V_t}\right) - 1\right)$$  \hspace{1cm} (7)$$

$$R_{sh} = R_{sh0}$$  \hspace{1cm} (8)$$

Equations (4)-(8) have been used to estimate the five parameters $I_{ph}$, $I_s$, $R_s$, $R_{sh}$ and $m$ that are necessary to apply equation (1). In order to show how accurately the model works, measured current-voltage curves for a (Si) module are compared with modelled curves. The measured and simulated curves have been found to agree well [5].

The curve of equation 1 is only applicable at one particular irradiance ($G_1$) and temperature ($T_1$). A model is used to translate this curve to other irradiance ($G_2$) and temperature ($T_2$) according to (9)-(14):

$$I_{sc2}(G_2, T_2) = I_{sc1}(G_1, T_1) \frac{G_2}{G_1} + \alpha(T_2 - T_1)$$  \hspace{1cm} (9)$$

$$V_{oc2}(G_2, T_2) = V_{oc1}(G_1, T_1) + m V_t \ln\left(\frac{G_2}{G_1}\right) + \beta(T_2 - T_1)$$  \hspace{1cm} (10)$$

$$I_2 = I_1 + \Delta I_{sc}$$  \hspace{1cm} (11)$$

$$V_2 = V_1 + \Delta V_{oc}$$  \hspace{1cm} (12)$$

$$\Delta I_{sc} = I_{sc2} - I_{sc1}$$  \hspace{1cm} (13)$$

$$\Delta V_{oc} = V_{oc2} - V_{oc1}$$  \hspace{1cm} (14)$$

Where $\alpha$ is temperature coefficient of current (A/K) and $\beta$ is temperature coefficients of voltage (V/K). In order to evaluate this model, we have compared measured I-V curves at a variety of ambient conditions, with the curves defined by equations 1 to 14. A good fit between the measurement and simulation is obtained.

4. Degradation rate

In order to determine the degradation rate (DR) of the maximum power output ($P_{max}$) of the PV modules, measured standardized values are matched to data of the PV module given by the manufacturer. The difference in percentage represents the reduction of the parameter. The degradation rate of parameters is given respectively by the following equation [9]:

$$DR(\%) = \left(\frac{P_{max0} - P_{max}}{P_{max0}}\right) \times 100$$  \hspace{1cm} (15)$$
Where: \( P_{\text{max}}^0 \) and \( P_{\text{max}} \) are respectively the maximum power given by the manufacturer and the maximum measured power

5. Results and discussions

5.1. Photovoltaic array PVG2

The PVPM2540C device (figure 1.a) provide the I-V curve measurement with 101 samples in 2 seconds for photovoltaic modules and small strings up to 250V and 40Adc, the device measure the irradiance and PV cell temperature using sensors box (figure 1.b).

Each PV module was washed to eliminate the dirt and the sand gathered on the front glass due to long-term field exposure.

Figures 2 illustrates the degradation of each PV module of the three sub-arrays. These degradations are divided into three sets:

- moderate degradation: 0.5-5% /year
- average degradation: 5-10% /year
- high degradation: \( \geq 10\% /\text{year} \)

Figure 2.a shows the degradation of sub-array G1 with 3.92 % /year of DR. It can be seen that the majority have moderate degradation. Only 30% of this sub-array present an average degradation, particularly in the second string (S2). Unlike G1, the sub-array G2 holds the poorest performance between the three sub arrays (Figure 2.b), with 8.52% of DG /year. G2 contains the worst DR 13.75% /year for a module situated in string 2 due to the clear crack of one cell in the PV module.

The next figure 3 presents a detailed estimation of modules degradation for the three sub arrays.
Table 3 summarizes the minimum, average and maximum performance of all modules of the installed grid-connected PV system. It provides the maximum power modules for different performances reported at STC conditions: their degradation rates and their positions in the PV generators. Thus, the best performance is assigned to a module from the sub array1; also, the medium to one module of the third sub array3 and the worst performance belongs to the second sub array2.

Table 3. Performance of all modules of the installed grid connected PV system PVG1

| Parameters | Minimal Performance | Average performance | Maximal performance |
|------------|---------------------|---------------------|---------------------|
| Pmax (W)   | 91.43               | 99.54               | 105.44              |
| DR (%)     | 13.75               | 6.10                | 0.53                |
| Position   | G2; S2; M3          | G3; S2; M6          | G1; S1; M10         |

5.2. Results for PVG 2

Figure 4.a presents the degradation of the sub array1 of GPV2 with 7.52 % /year of DR. It can be seen that the majority have moderate degradation, except for one module of this array, which has high degradation with 16.25 % /year of DR. However, 90% of this array has average degradation between 5.07% and 8.32 % of DR /year. (See table 4).

![Figure 4](image1)

Figure 4. The degradation rates of PVG2 sub-arrays: a) Sub1, b) Sub2

The degradation of the sub-array 2 of GPV2 is presented in Figure 4.b. 7.19 % /year of DR is observed. This degradation can be divided into three categories as follows: 20% of moderate, 20% of medium and 60% of high degradation.
Table 4. The degradation factors of the tested PV modules of the sub-array1 of PVG2.

| Sub-array1 (PVG2) | Sub-array2 (PVG2) |
|------------------|------------------|
|                  | M1               | M1 | M2 | Mean DR |
| S1               | 5.65             | 5.96 | 10.67 | 8.32 |
| S2               | 8.32             | 5.11 | 4.72 | 4.92 |
| S3               | 16.25            | 7.91 | 7.31 | 7.61 |
| S4               | 7.03             | 5.01 | 1.93 | 3.47 |
| S5               | 6.74             | 21.88 | 6.5 | 14.19 |
| S6               | 7.39             | 12.95 | 12.67 | 12.81 |
| S7               | 7.37             | 5.86 | 2.04 | 3.95 |
| S8               | 5.79             | 5.28 | 5.73 | 5.51 |
| S9               | 5.62             | 1.08 | 8.79 | 4.94 |
| S10              | 5.07             | 6.86 | 5.58 | 6.22 |
| Mean DR          | 7.52             | 7.19 |     |     |

5.3. Visual inspection
Visual inspection is a part of the test described in IEC61215. It is the first step to evaluate the degradation mode in PV module. In order to present the long-term degradation of PV modules under test, the inspection allows detection some failures after 11 years of exposure in the first site and seven years in the second site that can be observed visually, such discoloration over partial and whole cells, corrosion of string interconnection, loose and brittle of junction boxes.

6. Conclusion
The degradation of the PV modules of the different PV systems installed in two different regions was presented in this work. Outdoor testing was performed on 120 modules, 90 of them were installed at Bouzareah (CDER) site on June 2004, and 30 other modules were installed at the site of Ghardaia on July 2008. The outdoor measurement was carried out in two different climates. The results were translated and compared with the characteristics given by the manufacturers of the tested modules. The modules have an average peak of power degradation between 0.53% and 21.88% lower than the average value measured before exposure.
We can notice that the modules are not only exposed but still working since their installation. However, we observed that the degradation is not homogeneous; the modules located in the middle of the 90 modules of the grid-connected system were the most affected by degradation is probably due to the lack of natural ventilation despite the fact that the modules are exposed to the sea. The higher degradation was observed on the system installed in a semi-arid climate, which is characterized by a hostile climate.

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