Theoretical and experimental research to development of water-film cooling system for commercial photovoltaic modules

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Abstract
This work aims at developing and validating mathematical models and empirically evaluating a water-film cooling system for commercial photovoltaic modules. Methodologically, thermal, electrical and climatological data measured in a specific purpose on-grid outdoor test unit were used. In this work they are used to study the improvement in the performance of photovoltaic energy production due to temperature reduction. The first-order state-space linear parametric model presents the best performance to predict the temperature of the uncooled photovoltaic modules, with normalised mean square error (NRMSE) of 86.75%. In contrast, the non-linear model performance of cooled photovoltaic modules is lower, with NRMSE of 44.5%; however, the results show that the performance of the complete thermoelectric model is satisfactory, with NRMSE of 76.38%. On the other hand, empirical tests showed that the cooling system reduces temperature in 15–19%, on average, and to a maximum of 35%. In terms of power, there are average gains of 5–9%, and maximum gains of 12%. Regarding gross generation, there are average gains of 2.3–6%, and maximum gains of 12%. It was concluded that it is possible to mathematically model and predict this generation using non-linear models with a 0.2% error between modelled and measured generation.

1 INTRODUCTION

Solar energy can be converted into two main applications, electric and thermal energy, depending on the types of technology employed [1]. They are two main categories of technology that can convert solar energy into electricity, concentrating solar power and photovoltaic (PV) system [2]. This second system can provide power for small or large installed such as commercial buildings, residential homes, offices, housing developments and public buildings [3] in scale across the world [4].

However, there are technologies that convert solar energy into electricity and heat simultaneously [5,6], which perform better overall performance and space savings than the two separate systems [7]. This simultaneous generation of electric and thermal energy introduces the hybrid photovoltaic thermal systems (PV/T), which are suitable for an increase in energy collection and especially to improve the generation of electric energy [8].

Depending on the type of PV cell technology, the efficiency of the module may range from 5% to 24% [3,9,10]. However, exposure to solar radiation associated with high ambient temperatures causes an expressive increase in the operating temperature of the PV module [11]. It is shown that the temperature profile of the PV modules ranges from 27 to 52°C to an ambient temperature of 24.5°C [12], which can reach temperatures above 90°C [13]. This heating is one of the main obstacles for developers and users of PV modules [14]. To improve the performance of PV technologies, there is a wide range of technical solutions proposed and developed in the international literature that are systematically organised and classified [6,15–20].

In cooling systems for open-circuit PV modules, in which the fluid is directed at the PV module, running through its area in an unconfined manner, without the aid of pipes, ducts and chambers. The injection of fluid is mainly done by spraying or dripping onto the upper surface of the PV module [21–32], running on it and simultaneously cleaning and removing heat [33].
by forced convection [27]. This system has been showing itself to be quite rewarding from the energy outlet perspective [24]. Regarding the type of fluid used, water has been proved to be more cooling than air [28] due to its higher thermal capacity [34], and fluids with nanoparticles have also been successfully used in cooling and PV/T systems [24,35–39], such as: Addition of copper nanoparticles (0.3% vol%) into ethylene glycol increased the effective thermal conductivity by up to 40% [40]; addition of silver nanoparticles (10 vol%) in the water increases the electrical efficiency by 3.9% and thermal efficiency above 12% [41]; addition of SiC nanoparticles (1 wt%) in the water increases the electrical efficiency above 42% and thermal efficiency in almost 13% [42].

The gain is higher in cloudless days and especially when the solar irradiance angle is direct [22]. Moreover, it is a way to reduce the thermal degradation rate of the PV module, once the surface temperature reduction decreases the heat stored inside the cells [43]. According to Kim et al. [25], during tests, the amount of evaporated water was 0.8 kg m⁻²h, in the period with temperatures on the PV module between 30 and 35°C, which proves the need for a system with periodical replacement.

Results obtained by [21] show that due to convection heat loss between water and the top surface of the PV module, energy production increased in 15% in conditions of peak solar radiation. Additionally, results showed that a 5% increase in generation can be reached during dry and hot seasons. Dorobanțu et al. [33] have empirically demonstrated that the cooling of a PV module from the water-film flow over the top surface can increase power output by 9.5% compared to uncooling.

Odeh et al. [44] assembled an arrangement that consisted of tubes to allow water flow on the PV module surface—the tests were carried out in Australian cities with different latitudes. Results showed that the increase in the system output power varied between 4% and 10%, when the cooling system was running, whereas half of this increase (50%) is directly caused by the cooling of the module, and the other half is caused by the increase on the incident solar radiation on the PV modules due to refraction of the sunbeam on the layer of water.

Moharram et al. [26] carried out an experimental study that consisted of using six PV modules cooled by water pulverisation on their surface. Results showed that it is possible to cool and clean the PV module surface in a hot environment with a lot of suspended particles—once the system is installed in Cairo, Egypt, where there is a lot of airborne silica—and that the cooling speed of the PV cells for the site is 2°C min⁻¹. Therefore, the system can operate for 5 min and reduce temperature in 10°C, showing that the system can operate turning it on and off.

Tabaei et al. [29] empirically tested four systems: (1) Conventional system (only PV module); (2) PV module with superficial water film; (3) PV module with reflector and (4) PV module with superficial water film and reflector; and observed that, on a day with ambient temperature of 35°C, the temperatures of the modules were 59, 36, 71 and 39°C, with maximum temperatures of 65, 41, 84 and 42°C, respectively. Additionally, there was a 17.8% gain in energy production of the system (3) in comparison to system (1), and a 3.9% gain, in comparison to system (2), which is lower than the 50.4% gain in system (4).

Irwan et al. [30], using two PV modules—one with a water and forced ventilation cooling system, and another one as reference—observed that, when the water cooling system was running, there was a 3.52%, 36.27% and 38.98% increase in output current, voltage and power, and a 6.35°C reduction, in comparison to the uncooled PV module. The forced ventilation system increased in 3.47%, 29.55% and 32.23% the output current, voltage and power, and promoted a 6.10°C reduction, proving that the water-cooling system is better than the forced ventilation system.

Nizetic et al. [45] demonstrated, using the technique of cooling PV modules by spraying water onto surfaces, that it is possible to achieve a maximal total increase of 16.3% in electric power output and a total increase of 14.1% in the electrical efficiency of the PV module in conditions of peak solar irradiation.

Schiro et al. [31] have shown that the achievable energy gain of a PV module with cooling of the water-film is greater when the need for pumping is low and the climatic conditions are such that the uncooled PV module reaches high temperatures, which occurs under ambient conditions of low wind speed, high ambient temperature and high solar irradiation. In addition, they used the steady state thermal model to calculate the permanent regime temperature of the module relative to fixed and constant ambient conditions and cooling regime, while the dynamic model is used to predict the time response of the thermal mass during the variation of the external parameters. It was concluded that the steady state model allows to estimate the potential of a refrigeration system, while the transient model allows to optimise the working cycle of such a system.

Even though many studies have investigated the performance of different proposed hybrid PV technology energy solutions [45], there are relatively few works based on numerical research and experimental [12,31,39,46–52]. Therefore, the contribution of this paper is twofold. First, it develops accurate models for uncooled and cooled mono-Si PV modules with water film flow over the upper surface. Among the broad range of applications where these models can be used, in this work they are used to study the improvement in the performance of PV energy production due to temperature reduction.

Second, this work provides a detailed empirical analysis based on data collected in an outdoor test unit (ODTU), designed and built specifically to study the performance of uncooled and cooled PV systems using the equipment, methods and data acquisition of parameters recommended by IEC 61724.

It is noteworthy that cooled PV modules have a highly non-linear behaviour and their accurate modelling is non-trivial task. Thus, this work applies the following methodology. To gain insight into the thermal behaviour, uncooled PV modules are studied first. Since physical modelling is usually cumbersome task, in a first approach the system’s behaviour is studied through linear black-box models, discussed in Section 3.2. Important characteristics are derived from these linear models, mainly about the delays associated with the model inputs and the time constants involved. These characteristics are used for the development of a physical model in Section 3.3. Section 3.4
is devoted to the mathematical modelling of the cooled PV modules. Cooling turns the system into non-linear, and consequently, linear black-box models are no longer adequate. For this reason, only physical modelling is analysed. The model development in section 3.3 serves as a starting point for the design of a cooled PV model. Several adjustable parameters, unknown to the model, are identified from the data measured in ODTU. An optimisation tool that penalises error between the measured and simulated data is used for this task.

In Section 4 the empirical analysis of the performance of the cooled PV modules from data collected in ODTU is discussed. Finally, Section 5 includes a discussion where the results obtained are analysed and compared with other results reported in the literature.

2 | SPECIFIC PURPOSE OUTDOOR TEST UNIT

The on-grid, specific purpose ODTU has 1.65 kWp installed power and is composed of six 275 Wp m-Si PV modules independently connected to six solar microinverters that are connected to the power grid in 220 V/127 VAC three-phase system. There are two PV modules with water-film (PV1 and PV2), two with reflective film (PV5 and PV6) [53]—not used in this work—and two PV modules used as reference (PV3 and PV4), see Figure 1(a). There are also two electric panel destined for generation, control, monitoring and supervision: (i) One panel holds the generation and monitoring system; (ii) the other panel holds the control system of the PV modules water-film cooling system.

2.1 | Composition of the cooling system

Schematic arrangement of the ODTU cooling system (see Figure 1(b)).

(i) 01 peripheric 0.5 hp pump [54] with speed control by frequency variation
(ii) 01 flow sensor [55] installed on the supply line to measure flow
(iii) 01 “Y” filter to remove fragments and avoid clogging the distributor
(iv) 02 water tanks: one 0.1 m³ to feed the pump and store the water after the PV modules cooling; and one 1.0 m³ to store a water that allows the functioning of the system for long periods without having to replace the grid
(v) 02 fluid supply lines: One main line with heat exchanger; and one secondary or by-pass
(vi) 01 heat exchanger (coil) in the main line and immerse in the 1.0 m³ tank
(vii) 01 flushing/collection line that returns the water to the 0.1 m³ tank
(viii) 01 distributor to inject water on the top surface of the PV modules (water-film cooling system)
(ix) 01 gutter for water collection, after it runs on the top surface of the PV

2.2 | Photovoltaic modules measurement and monitoring system

(i) 03 PT100 resistance thermometer sensors (TS) with screwable head [56]: One connected to the 1.0 m³ tank; one connected to the beginning of the flushing line (right after the gutter); and one connected to the distributor line
(ii) 18 TS with exposed bulb type A [13], fixated on the bottom surface of the PV module. Three TS are fixated in each module, one for each arrangement of cells in series of the PV module [57]
(iii) 03 dataloggers [58] to obtain and register the measured temperatures
(iv) 06 DC voltage transducer [59] and 6 DC current transducer [60] to measure each PV module individually
(v) 02 active/reactive power transducer (three-phase) [61] to measure the power in unbalanced loads

2.3 | Meteorological monitoring system

(i) 01 pyranometer [62] installed on the tilted surface of the PV module
(ii) 01 anemometer [63] to measure the wind speed blowing on the location
### 3 | NUMERICAL MODELING

For the mathematical modelling of the PV modules, the white-box (or physical modelling) and black-box approach models were used. Two submodels compose the thermoelectric general model (see Figure 2). The first one is related to the thermal behaviour of the PV module and the second one models its electric response. The thermal submodel inputs are solar radiation ($R_{ad}$), ambient temperature ($T_{amb}$), wind speed ($v_w$) and electric power ($P_e$). The output of the thermal submodel is the temperature of the PV cell ($T_{cell}$), which together with the solar radiation, feeds the electric submodel. The output of the submodel (i.e. module power) re-evaluates the thermal submodel. In this work, only the thermal submodule is developed, since the modelling of the electrical behaviour of the PV modules has been studied extensively in the last decades, resulting in mature and high quality models [68,69].

#### 3.1 | Data treatment

The thermal models for the uncooled PV modules were calibrated/adjusted with the data monitored from the module PV4 (see Figure 1), on 09/19/2017 and 09/20/2017, between 9 AM and 3 PM. Data from the 19th were used to estimate the parameters, and the ones from the 20th were used to validate the model. The data are treated in accordance with the IEC Standard 61724/1998 [69]. Quality checking consists of: (i) Checking the maximum and minimum limits for each parameter monitored, based on the characteristics of the PV installation and the environment; (ii) checking the maximum variation rate between successive data and (iii) checking outliers. The data that did not pass the quality check were not included in the subsequent analyses. Additionally, for smooth data, a digital filter of moving average was used on the wind speed data, with a 5 s window. The PV module temperature corresponds to the average of three independent sensors installed on the back-surface of the PV module.

#### 3.2 | Black-box modelling

Linear parametric models, such as autoregressive exogenous model (ARX) and state-space models are used due to their commitment between flexibility and complexity. The ARX model structure is defined by Equation (1).

$$A(q) \times y(t) = B(q) \times u(t - n_k) + e(t).$$

$$q^{-1} \times u(t) = n(t - T).$$

where $y(t)$ and $u(t)$ are the outputs and inputs of the system, respectively; $e(t)$ represents the system disturbance (modeled as a zero-mean Gaussian white noise); $A$ and $B$ are polynomials, whose order and parameters must be estimated from the collected data; $n_k$ is the delay on the input signals; $q$ is the time-shift operator; and $T$ is the sample-time of the measured data.

The ARX is usually the simplest model to be estimated, though it has the disadvantage that the polynomial $A(q)$ represents both the system dynamics and the noise properties. Thus, the model tends to incorrectly estimate the dynamics of the system and, usually, higher orders of polynomials $A(q)$ and $B(q)$ are necessary to obtain a satisfactory result.

The State-Space models, Equation (2), are common representations of dynamic systems, representing the same type of linear relationship between the inputs and outputs of an ARX model; however, state variables are used.

$$x(t + 1) = A \times x(t) + B \times u(t) + K \times e(t),$$

$$y(t) = C \times x(t) + D \times u(t) + e(t).$$

where $A, B, C, D$ are matrices that describe the dynamics of the system; $x(t)$ is the vector of the state variables; and $K$ is the matrix that specifically models the dynamics of the noise $e(t)$. The state-space model is more flexible than the ARX model and its advantage is the property to model the noise separately from the signal.

#### 3.2.1 | Initial estimate of the models order and delay

A linear time-invariant system can be characterised entirely by the impulse-response. The output of the system is simply the convolution of the input to the system with the system’s impulse-response [70]. To gain a better insight into the dynamics, we first calculate the finite-impulse response (FIR) to estimate the model order and delay, using non-parametric models available in the Matlab System Identification Toolbox. Figure 3 shows the FIR for the four inputs of the model. The region marked in light blue represents the confidence interval calculated for 2.58 standard deviations (i.e. 99% confidence interval), where FIR is considered insignificant. It can be observed that, except for wind speed, all inputs caused an alteration in the system response higher than the uncertainty region, right on the first sample time of the simulation. This is a clear indication...
that there is no input delay for solar radiation, ambient temperature and electric power. FIR from the wind speed leaves the uncertainty region after three sample times, showing a delay of about 3 s, which can be caused by the inertia of the anemometer and/or the moving average filter used to smooth wind speed data. Anyhow, FIR provides a good starting point to estimate the system delay vector \( n_k \). From the above analysis, as a first approximation, we consider \( n_k = [0, 0, 3, 0] \).

The second step is to determine the order of the models. For this, the step response is estimated from the FIR model. The four step responses do not show any oscillation (see Figure 4). This behaviour is compatible with a first-order system, or with a high-order over damped system, that is, a system with only real poles.

### 3.2.2 Autoregressive exogenous model

Matlab’s toolbox is used to estimate ARX structures with different order combinations of polynomials \( A(q) \), \( B(q) \) and \( n_k \), Equation (1). Using the ARX model structure selection window, where the abscissa in Figure 5 shows the total number of parameters of polynomials \( A(q) \) and \( B(q) \), called \( n_a \) and \( n_b \), respectively, and the ordinate called unexplained output variance, is the portion of the output not explained by the model. The best fit to the measured data is obtained with a model composed of 10 parameters (red), where \( n_a = 2 \); \( n_b = [2, 1, 3, 2] \) and \( n_k = [0, 0, 4, 0] \). However, the difference between the models is minimal, so we chose the simplest model, composed only of 7 parameters, where \( n_a = 1 \); \( n_b = [1, 1, 3, 1] \) and \( n_k = [0, 0, 4, 0] \).

Thus, the ARX model structure will be a third-order model, Equation (3).

\[
A(q) = 1 - 0.9977q^{-1}.
\]

\[
B1(q) = 6.532q^{-5}
\]

\[
B2(q) = 3.29q^{-3}.
\]

\[
B3(q) = -6.556q^{-2} + 0.149q^{-5} - 0.1128q^{-6}.
\]

\[
B4(q) = 4.449q^{-5}.
\]

Validating a model consists in checking the predictive quality of the model. For such, two methods are used: The normalised root-mean-square error (NRMSE) and the residual analysis. The NRMSE is a parameter that quantifies the fit of the model response \( \hat{y} \) to the measured data \( y \) used for validation. This parameter is calculated by Equation (4). The NRMSE can range from −Inf, for an entirely inadequate model, up to 100%, for a perfectly fit model. If the value is equal to zero, then the model is no better at fitting the measured data than a straight line equal to the mean of the data.

\[
\text{NRMSE} = 100 \times \left( 1 - \frac{||y - \hat{y}||}{||y - \bar{y}||} \right). \tag{4}
\]
The residual analysis studies the behaviour of the differences between observed and predicted values of the data. Thus, residuals represent the portion of the validation data not explained by the model. Ideally, a perfect model residue should be independent from the input signal. Otherwise, it can be concluded that there are some dynamics that the model cannot describe.

Figure 6 shows the temperature of the PV module, measured on 20 September 2017, with its temperature estimated by the ARX model. The performance of the ARX model presents NRMSE of 85.15%. It is clear that some peaks and valleys are underestimated in some cases, or overestimated in other cases, especially between 12 PM and 1 PM. Figure 6(b) presents the difference between the measured and simulated value (residue).
Residue value (blue line) together with its uncertainty (light-blue line), calculated with a 95% confidence interval. The maximum error between the measured and estimated value of the module temperature oscillates, approximately, between ±3°C, with a 0.05 significance level. Moreover, the residue presents a rather random behaviour, without any apparent tendency, with an average of 0.19°C.

Figure 7 shows the cross-correlation between the inputs and the residuals for each input-output pair. The region marked in light blue represents the range of residual values that have a 95% probability of being statistically insignificant. The correlation plot shows all values within the confidence region and indicates that the model produces uncorrelated residuals. It can be concluded that the third-order linear ARX model is suitable to predict the dynamic behaviour of the PV module temperature with an 85.15% precision, except for periods when the PV cell does not operate on maximum power point trackers (MPPT) or for systems that do not have solar inverters equipped with MPPT.

### State-space model

The initial values for the delay and order serve as a starting point to estimate different state-space structures with several combinations of orders and delays on the inputs. In case of state-space models, a range of orders may be evaluated simultaneously in Matlab toolbox, and the best order picked from a Hankel singular value plot (Figure 8), which displays the relative measure of how much each state contributes to the input-output behaviour of the model. The abscissa in Figure 8 shows the order of the models; the ordinate shows a relative importance measurement of each state on the dynamic behaviour of the model. It can be observed that the first state (red) provides a significant contribution for the system dynamic behaviour. The other states (≥ 2) present little contribution.

Seeking balance between precision and simplicity, we chose a first-order model represented by Equation (2), with the parametrisation provided by Equation (5). Each element in vector “B” is related to a system input in the following order:

\[
A = [0, 9979] .
\]

\[
B = [2, 494e^{-7}, 1, 713e^{-5}, -1, 596e^{-4}, 8, 845e^{-7}] .
\]

\[
C = [160, 3] \quad D = [0] \quad K = [5, 477e^{-3}] .
\]

\[
\text{InputDelay} = [0 \ 0 \ 4 \ 0] .
\]

Figure 9(a) shows the PV module temperature, measured on 20 September 2017, with the module temperature estimated by state-space model. Model performance is better than ARX model, reaching NRMSE of 86.75%. This reflects in a better follow-up of the system dynamics, especially between 12 PM and 1 PM. The best performance is justified by the fact that the ARX model does not present flexibility to model the noise, requiring an increase in the order of the model to obtain a satisfactory result. Figure 9(b) shows the residue (red line) together with its uncertainty (light-red line), calculated with a 95% confidence interval. The maximum error between the measured and estimated value of the module temperature oscillates between −2.4°C and +3°C, with a 0.05 significance level. The residue presents a random behaviour, with no apparent tendency, and average of 0.20°C.

Figure 10 shows the cross-correlation between the inputs and residual with a 95% confidence interval (light-blue area). None of the values crosses the uncertainty threshold in the independence test of the residues. Thus, it can be concluded that the first-order state-space model, Equation (5), is suitable to predict the dynamic behaviour of the PV module, with a performance superior to the ARX model, presenting an 86.75% precision.

### Brief analysis of the estimated linear models

From the estimated model, we can calculate the time constant (τ) of the PV module. It can be observed that the τ of the PV
3.3 Physical modelling

3.3.1 Derivation of the model equations

One PV module is basically composed of 5 layers: (i) Frontal cover, made of high transparency tempered glass; (ii) the frontal encapsulation of the PV cell with EVA; (iii) the PV cell; (iv) the posterior EVA encapsulation and (v) one posterior Tedlar isolation film. There is an anodised aluminium structure to ensure its physical integrity. The thermal model can be equated considering the thermal and electrical energy exchange between the PV module and the environment. Heat exchange happens by the heat transfer mechanism by conduction, convection and radiation, whereas, the electric energy transfer happens between the module and the power grid. Thus, the energy balance between the PV module and the environment must consider the incident solar radiation, the thermal losses, the optical losses and the electric power generation, see Equation (6).

$$Q_{in} = Q_{loss} + C_{mod} \times \frac{dT_{mod}}{dt} + Q_e [W].$$

where $Q_{in}$ is the short-wave solar radiation that reaches the PV cell itself in [W]; $Q_e$ is the electric power produced by the PV cell in [W]; $Q_{loss}$ is the thermal losses of the PV module with the environment in [W]; $C_{mod}$ is the equivalent thermal capacitance of the PV module in (Joule/K) and $T_{mod}$ is the PV module temperature in (K).

Even though Equation (6) properly describes the dynamic behaviour of the PV module, it must be reformulated to be expressed in terms of known and/or measured variables. The term $Q_{in}$ is related to the optical losses of the PV module, which happen on the glass and the frontal EVA cover. To determine the short-wave solar radiation incidence, the optical loss by reflectance and absorbance on the glass and on the EVA must be considered. This loss can be quantified by a single parameter, known as transmittance-absorptance ($\tau_{\alpha}$). However, the $\tau_{\alpha}$ parameter is not constant, as it is a function of the solar radiation incidence angle on the PV module. With the purpose of simplifying the module, an annual average value is assumed for this parameter, without too much loss in precision [51]. Thus, $Q_{in}$ can be calculated from the incident global radiation measured on the tilted surface, see Equation (7).

$$Q_{in} = (\tau_{\alpha}) \times A_{f} \times G [W].$$

where $A_{f}$ is the effective area of the PV module in (m$^2$); $G$ is the incident global radiation on the tilted surface in (W/m$^2$); $\tau_{\alpha}$ is the effective transmittance-absorptance of the PV module. The term $Q_{loss}$ in Equation (6) is related to the thermal losses of the PV module with the environment. It is known that when two flat parallel plates are in contact, the heat transfer by convection and radiation is negligible compared to conduction, especially when the thermal conductivity of the plates is relatively high, and/or their thickness is too small [68]. Thus, it is reasonable to assume that inside the PV module, the only heat transfer

module is 482 s (~8 min), a value consistent to the one presented by [71]. The $\tau$ in thermal systems is related to the product of the thermal resistance ($R$) and the thermal capacitance ($C$) equivalent from the system ($\tau = R \times C$), where $C$ equals mass ($m$) times the specific heat ($C_p$) equivalent from the system. On the other hand, it presents a pole located in $\approx 1$, Equation (5), which is equivalent to having a pure integrator on the system. This integrator is related to the thermal inertia of the PV module. Another important characteristic of a linear system is the rise time, defined as the time required for the response to rise from 10% to 90%. The rise time of the PV module temperature was estimated in 17.6 min.
mechanism is conduction, Equation (8).

\[ Q_{loss\_conduction} = \frac{1}{R} \times A_p \times \Delta T \ [W]. \tag{8} \]

where \( A_p \) is the area of the module [m\(^2\)]; \( \Delta T \) is the temperature gradient between the layers of the PV module [K]; \( R \) is the thermal resistance of the material [m\(^2\)/W/K]. \( R \) is calculated by Equation (9).

\[ R = \frac{l}{k} \ [m^2/W/K] \tag{9} \]

where \( l \) is the layer thickness and \( k \) is the thermal conductivity [W/m/K]. It can be deduced from Equation (9) that the thermal resistance is a function only of the material and the dimensions of the conductor; consequently, the equivalent thermal resistance (\( R_{eq} \)) of the PV module will be a constant, formed by the series arrangement of the isolated thermal resistances of each one of its layers.

The PV module heat loss with the environment happens through heat transfer mechanisms by radiation and convection. Heat exchange especially happens between glass and the environment, and between Tedlar and the environment. The component of radiation heat loss can be calculated by considering the emissivity and temperature of the emitting and receiving surfaces, together with the view factor. For modelling purposes, the sky can be considered a black body with average temperature equivalent to the ambient temperature. It can be assumed that the radiant temperature of the sky is equal to the surrounding ground temperature and both are equal to the ambient temperature (\( T_{amb} \)). Thus, the radiation heat transfer (\( h_r \)) can be estimated by the following expressions:

\[ h_{r,\text{glass-sky}} = \sigma \times \varepsilon_{\text{glass}} \times F_{\text{glass-sky}} \times (T_{\text{glass}}^2 + T_{\text{amb}}^2) \times (T_{\text{glass}} + T_{\text{amb}}) \times (1 - \cos \beta) \].

\[ h_{r,\text{glass-ground}} = \sigma \times \varepsilon_{\text{glass}} \times F_{\text{glass-ground}} \times (T_{\text{glass}}^2 + T_{\text{amb}}^2) \times (T_{\text{glass}} + T_{\text{amb}}) \times (1 - \cos \beta) \].

\[ h_{r,\text{Tedlar-sky}} = \sigma \times \varepsilon_{\text{Tedlar}} \times F_{\text{Tedlar-sky}} \times (T_{\text{Tedlar}}^2 + T_{\text{amb}}^2) \times (T_{\text{Tedlar}} + T_{\text{amb}}) \times (1 - \cos \beta) \].

\[ h_{r,\text{Tedlar-ground}} = \sigma \times \varepsilon_{\text{Tedlar}} \times F_{\text{Tedlar-ground}} \times (T_{\text{Tedlar}}^2 + T_{\text{amb}}^2) \times (T_{\text{Tedlar}} + T_{\text{amb}}) \times (1 - \cos \beta) \].

where \( h_r \) is the radiation heat transfer coefficient [W/m\(^2\)/K]; \( \sigma \) is the Stefan–Boltzmann constant (56,697 \times 10\(^{-8}\) W/m\(^2\)/K\(^4\)); \( \varepsilon \) is the surface emissivity; \( T \) is the surface temperature [K]; \( F \) is the view factor. The \( F \) between the surfaces is dependent of the tilting angle (\( \beta \)) of the module, see Equation (11).

\[ F_{\text{glass-sky}} = \frac{1}{2} \times (1 + \cos \beta) \].

\[ F_{\text{glass-ground}} = \frac{1}{2} \times (1 - \cos \beta) \].

\[ F_{\text{Tedlar-sky}} = \frac{1}{2} \times [1 + \cos (\pi - \beta)] \].

\[ F_{\text{Tedlar-ground}} = \frac{1}{2} \times [1 - \cos (\pi - \beta)] \].

The heat loss by radiation of each surface of the module can be overall calculated by applying Equation (12).

\[ Q_{loss\_radiation} = b_r \times A_p \times \Delta T \ [W]. \tag{12} \]

Comparing Equation (8) with Equation (12), the thermal resistance (\( R \)) in the conduction phenomenon is equivalent to the inverse of the heat transfer coefficient (\( b_r \)) in the radiation phenomenon. However, differently from \( R \), \( b_r \) is not constant once it depends on the difference in temperature between the surfaces of the PV module and the environment. Consequently, the \( b_r \) value for each surface of the PV module must be calculated for each simulation time-step. Additionally, since they are coupled equations, it is not possible to obtain an explicit equation and the solution must be calculated in an iterative manner.

The convection heat loss component is related to the heat transfer between the PV module and the environment, mainly due to forced convection. As first approach, we consider a linear model between wind speed and the convection heat transfer coefficient (\( b_c \)), which models the losses by natural and air-forced convection in a single expression, using it with a reasonable precision for Reynolds numbers up to \( 10^6 \) [68] and see Equation (13).

\[ b_c = m \times v + b \ \text{em} \ [W/m^2/K]. \tag{13} \]

where \( v \) is the wind speed in [m s\(^{-1}\)]; and \( m \) and \( b \) constants of the linear model. [71] provides a table that shows the variation rates for \( m \) and \( b \), where \( 2 \leq m \leq 6 \) and \( 2 \leq b \leq 8 \). Consequently, an optimisation algorithm is required to determine the \( m \) and \( b \) values based on the measurements. Using \( b_c \) calculated by Equation (13), heat loss by convection, for each of the module surfaces, is calculated by Equation (14).

\[ Q_{loss\_convection} = b_c \times A_p \times \Delta T \ [W]. \tag{14} \]

The third term of Equation (6) is thermal capacitance, which establishes a relationship between the temperature and heat stored in a body. Without any change of phase, and as long as the temperature range is not high, the relationship can be considered linear. Consequently, the equivalent thermal capacitance of the PV module can be calculated as a parallel arrangement of the capacitances of its layers. For a body with mass \( m \), and specific heat \( C_p \), the thermal capacitance (\( C \)) is given by Equation (15).

\[ C = m \times C_p \ [J/K]. \tag{15} \]

Thus, it is possible to determine the thermal capacitance of each layer by knowing the mass and specific heat of the material that composes them. Finally, the equivalent thermal capacitance of the module (\( C_{mod} \)) can be estimated by Equation (16).

\[ C_{mod} = \sum_{i=1}^{N} C_i \ [J/K]. \tag{16} \]
where $N$ is the number of layers that compose the module; and $C_i$ is the thermal capacitance of the $i$-th layer. Figure 11(a) shows a thermal-electrical analogy of the physical model. Using the manipulation and simplification rules of electric circuits, it is possible to introduce the concept of a global loss coefficient ($h_g$) for the PV module, which covers thermal losses by conduction, radiation and convection, see Figure 11(b).

The time constant ($\tau$) of this circuit is equivalent to the product of the capacitance times the resistance, that is, regarding the global loss coefficient ($h_g$), the time constant of the PV module can be estimated by Equation (17). It is worth highlighting that, since $h_g$ is not a constant, the time constant of the PV module varies throughout the day.

$$\tau = \frac{C_{mod}}{h_g} \ [s]. \quad (17)$$

From Figure 11(b), a general expression to calculate the thermal losses of the PV module can be derived, see Equation (18).

$$Q_{loss} = h_g \times A \times (T_{celula \ solar} - T_{amb}) \ [W]. \quad (18)$$

Finally, the PV module temperature can be determined by solving the differential Equation (19).

$$\frac{dT_{mod}}{dt} = \frac{1}{C_{mod}} \times [Q_{in} - Q_{loss} - Q_e]. \quad (19)$$

### 3.3.2 Physical model parameters estimation

Since the PV modules manufacturers do not provide the transmittance-absorptance, thermal conductivity and thickness of the layers, we must use an optimisation tool that penalises error between the measured and simulated data (objective function) until the best fit of the model is obtained with the measured PV module temperature data. It is necessary to supply the optimisation algorithm with initial values of the parameters to be estimated. The initial values used are the average values presented by [31,48,51,71], are systematised in Table 1. The parameters that mostly influence the response of the physical model are the coefficient $m$ of Equation (13), which simulate convection heat loss. The transmittance-absorptance factor ($\tau \alpha$) and the thermal conductivities ($k$) of the layers are also relevant to the response sensibility of the model. The emissivity ($\epsilon$) of the glass and the Tedlar and the thickness of the layers (except for the Tedlar) have little influence on the sensibility of the objective function. Thus, we carried out and adjustment (tuning) on the model parameters that have the highest influence in the response, using the optimisation algorithm.

Figure 12(a) shows the temperature of the PV module, measured on 20 September 2017, and its temperature estimated by the physical model parametrised with the data of Table 1. It is observed that the fit of the model is good, however, the performance it slightly lower that the ARX and state-space models.

![FIGURE 11 Thermal-electrical analogy, a) full circuit and (b) simplified circuit](image)

### TABLE 1 Values (initial and adjusted) for the optimisation of the physical model parameters

| Condition values | Material | Thickness [mm] | Thermal conductivity [W/m/K] | Density [kg/m³] | Specific heat [J/kg/K] | Emissivity | Transmittance-absorptance | Parameters Equation (13) |
|------------------|----------|----------------|------------------------------|----------------|------------------------|------------|--------------------------|--------------------------|
| Initial          | Glass    | 4.10           | 0.95                         | 3000           | 500                    | 0.58       | 0.90                     | —                        |
| EVA              | 0.65     | 2530           | 879                          | 3.49           | 3.41                   | —          | —                        | —                        |
| PV               | 0.20     | 150            | 2300                         | 0.35           | 0.37                   | —          | —                        | —                        |
| Tedlar           | 0.25     | 1200           | 1250                         | 0.83           | —                      | —          | —                        | —                        |
| Adjusted         | Glass    | 3.20           | 0.92                         | 2530           | 879                    | 0.90       | 0.96                     | —                        |
| EVA              | 0.54     | 2400           | 2.39                         | —              | —                      | —          | —                        | —                        |
| PV               | 0.30     | 2329           | 2300                         | 0.53           | 0.53                   | —          | —                        | —                        |
| Tedlar           | 0.10     | 1200           | 1250                         | 0.83           | —                      | —          | —                        | —                        |
| m                | —        | —              | —                            | —              | —                      | —          | —                        | 3.49                     |
| b                | —        | —              | —                            | —              | —                      | —          | —                        | 3.41                     |
The NRMSE is only 83.75%. Figure 12(b) shows the residue. The maximum error between the measured and estimated value ranges from $-2.0^\circ C$ to $+1.9^\circ C$, however, a slight negative bias is observed. A sensitivity analysis shows that the coefficients $m$ and $c$ of Equation (13) are the parameters that most influence the response of the model. Therefore, it is reasonable to think that the problem lies in the linear model used to calculate the heat transfer coefficient by forced convection. To improve performance, more detailed models should be developed.

3.4 Mathematical modelling of the cooled photovoltaic modules

3.4.1 Derivation of the model equations

Cooling turns the system into non-linear, and consequently linear black-box models are no longer adequate. For this reason, only physical modelling is analysed. Four inputs are added to the physical model to represent the behaviour of the water-film: water flow rate; water temperature; atmospheric pressure and relative air humidity, see Figure 13.

The thermal model of the PV module can be equated considering the thermal energy exchange between the PV module and the water-film, and between the water-film and the environment, as well as the electric energy exchange between the PV module and the power grid. This energy balance is presented by Equation (6), with the difference that the term $Q_{loss}$ must incorporate the thermal losses of the PV module with the environment that are related to the water-film. The main heat transfer mechanism between the frontal surface of the module and the water-film is forced convection, Equation (20).

$$Q_{loss\_convection} = h_{fc} \times A_p \times \Delta T \ [W].$$  (20)

where $h_{fc}$ is the forced convection coefficient between the fluid and the PV module [$W/m^2/K$]; $A_p$ is the module area [$m^2$]; $\Delta T$ is the temperature difference between the module and the environment [$K$]. The $h_{fc}$ value can be calculated by Equation (21).

$$h_{fc} = \frac{Nu \times k}{l} \ [W/m^2/K].$$  (21)

where $Nu$ is the Nusselt number; $k$ is the water thermal conductivity [$W/m/K$]; $l$ is the characteristic thickness of the PV module ($l = 4 \times \text{Area/Perimeter}$). $Nu$ can be determined for $Pr \geq 0.6$ by Equation (22) [72].

$$Nu = 0.332 \times Re^{0.5} \times Pr^{0.333}. $$  (22)

where $Re$ is the Reynolds number; $Pr$ is the Prandtl number, which can be obtained in thermodynamic tables, having the fluid temperature as input parameter. $Re$ is also a dimensionless number and can be calculated by Equation (23).

$$Re = \frac{v_f \times l}{\nu}. $$  (23)

where $v_f$ is the fluid speed [$m/s$]; $\nu$ is the water kinematic viscosity [$m^2/s$]. Regarding the water-film flowing on the PV module—the blade flow and thickness on the perpendicular direction to the movement are known—but the blade speed and thickness are related and are unknown. An assumed thickness of the constant water-film is calculated by Equation (24).

$$\delta = \sqrt{\frac{3 \times \bar{v} \times \bar{\nu}}{\rho \times g \times \sin(\beta)}}. $$  (24)

where $\delta$ is the water-film thickness [$m$]; $\bar{v}$ is the average fluid speed [$m/s$]; $\rho$ is the fluid density [$kg/m^3$]; $g$ is the gravitational acceleration [$m/s^2$]; $\beta$ is the PV tilting angle. To determine a correspondence between the fluid flow ($Q$) and average speed, the average fluid speed ($\bar{v}$) was experimentally measured at the ODTU for four different flow values ($Q$), see Table 2.
TABLE 2  Fluid speed as a function of flow

| Flow [l/min] | Average speed [m/s] |
|--------------|---------------------|
| 3.0          | 0.54                |
| 3.4          | 0.56                |
| 4.1          | 0.58                |
| 5.5          | 0.70                |

Replacing the maximum speed values ($\bar{v}$) on Equation (24), it is possible to determine a relationship between flow ($Q$) and the water-film thickness ($\delta$). Thus, the Reynolds number, as a function of the fluid flow, can be determined by Equation (25).

$$Re = \frac{\bar{v}}{\nu} \times \frac{Q}{\delta \times H \times f}.$$  \hspace{1cm} (25)

where $H$ is the thickness of the PV panel on the direction perpendicular to the movement [m]; and $f$ is the fluid occupation factor, that is, the area of the PV module that is effectively filled by the water-film ($\approx 0.9$). The convection heat loss component, associated with heat transfer between the water-film and the environment, and caused by air flowing, can be estimated by a linear model between wind speed and the convection heat transfer coefficient, similar to the one used in the uncooled PV modules modelling, and expressed by Equation (13), making it necessary to use an optimisation algorithm to determine the $m$ and $b$ values. Additionally, heat loss by fluid evaporation must be considered. [68] proposes a dimensionless equation for the calculation of this loss.

$$q_{evap} = P_a \times \left[ 35 \times \nu_w + 43 \times (T_{H2O} - T_{amb})^{\frac{1}{3}} \right] \times (W''_{H2O} - W').$$  \hspace{1cm} (26)

where $P_a$ is the atmospheric pressure [kPa]; $v$ is the wind speed [m s$^{-1}$]; $T_{H2O}$ is the fluid temperature [°C]; $T_{amb}$ is the ambient temperature [°C]; $W''_{H2O}$ is the saturation humidity ratio calculated on the fluid surface; $W'$ is the ambient humidity ratio calculated in the ambient temperature. The $W''_{H2O}$ and $W'$ values can be estimated from the atmospheric pressure ($P_a$), relative air humidity ($\phi$), fluid temperature ($T_{H2O}$) and ambient temperature ($T_{amb}$) [73].

$$\ln \left( \rho_{ws-H2O} \right) = -\frac{5.8002206E^3}{T_{H2O}} + 1.3914993 - 4.8640239E$$

$$- 2 \times T_{amb} + 4.1764768E - 5 \times T^2_{H2O}$$

$$- 1.4452093E - 8 \times T^3_{H2O} + 6.5459673 \times \ln \left( T_{amb} \right).$$  \hspace{1cm} (29)

$$\rho_w = \phi \times \rho_{ws}$$  \hspace{1cm} (30)

$$W' = 0.62198 \times \frac{\rho_w}{P_a - \rho_w}.$$  \hspace{1cm} (31)

Dividing Equation (26) by the difference in temperature between the PV module glass and ambient temperature, the heat transfer coefficient associated to the fluid evaporation can be derived and is expressed by Equation (32).

$$h_{evap} = \frac{q_{evap}}{(T_{glass} - T_{amb})} \left[ \text{W/m}^2/\text{K} \right].$$  \hspace{1cm} (32)

Finally, the PV module temperature can be determined by iteratively solving the differential Equation (19), using the proper value for the term $Q_{loss}$ as a function of the operation, or not, of the water-film during the respective time-step of the simulation.

### 3.4.2 Implementation and validation of the physical model

Data measured on 7 February 2018 and 8 February 2018 were respectively used to adjust and validate the model. Figure 14(a) shows the PV module temperature measured on 8 February 2018 with the module temperature simulated by the physical model. The NRMSE value of the physical module is 44.5%. The maximum error between the measured and estimated value of the PV module temperature oscillates between $-3, 5$ °C and $+2, 5$ °C, clearly showing a tendency for negative values in the behavior of the physical module residue (Figure 14(b)). Nevertheless, an error of approximately $\pm 3$ °C in the temperature estimation does not represent a large deviation in the estimation of the electric power generated by the PV module, since the power loss coefficient as a function of temperature—typical of a m-Si PV module—is $-0.5\%$.

### 3.5 Performance analysis of the photovoltaic module thermoelectric model

The electric power output of the PV module can be compared to the simulated cooling with measurement on the ODTU on 8 February 2018. The thermoelectric model shows the same synchronised peaks and valleys on time, with 76.38% NRMSE. However, it can be observed in Figure 15(a) that there are
short-duration transient effects of electric power that the physical model cannot predict. This phenomenon occurs when the microinverter control system detects abnormal operation conditions in the grid and disconnects itself. This characteristic does not have a significant impact in energy production, and that is why it was not incorporated on the mathematical model. Figure 15(b) shows the residue, which has a random behaviour, without any apparent tendency, and evidence of a satisfactory mathematical model. In fact, in terms of energy, the results show that the difference between the measured and simulated value is less than 0.2%, where the measured energy was 0.7783 kWh day$^{-1}$ and the simulated energy was 0.7770 kWh day$^{-1}$.

4 | EMPIRICAL ANALYSIS

The empirical analysis considers the period between 31 December 2017 and 31 March 2018, between 9:30 AM and 3:30 PM. On the week of 21 January 2018 to 28 January 2018, solar radiation on the tilted surface of the PV modules and the ambient temperature presented the best values, with maximum reaching levels over 1200 W m$^{-2}$ and 33.0°C; the average solar radiation values varied between 407 and 803 W m$^{-2}$ and ambient temperature between 23 and 32°C. Analysing Figure 16, which presents the temperature of the cooled modules PV1 and PV2, and reference model PV4, the operation of the cooling system reduces the temperature of PV1 and PV2 to 40°C, while the reference model PV4 remains 25°C above, see Figure 16(a). For a day with low levels of solar radiation, there is little difference between the three PV modules (with and without cooling), Figure 16(b). The difference in the average daily temperature of the cooled modules PV1 and PV2, in comparison to the reference model PV4, reach 32.7% and 35.6%, respectively, on 23 January 2018. In absolute values, that is a −21°C difference, with an average
reduction of 18%, showing that the cooling system decreases the temperature of the modules. The difference in temperature between the cooled modules PV1 and PV2 is lower than 2.0°C in the daily average. This result was expected due to the fluid flow sequence on the PV1 and PV2 modules.

Analysing Figure 17, on the days when the cooling system is not running, energy generation of the cooled modules PV1 and PV2 are lower than the reference module PV4, presenting 2.6% and 2.1% deficit in generation, respectively. When the cooling system is running intensively, it can be observed that the cooled modules PV1 and PV2 generate, in average, 103.4% and 101.9% of the energy of module PV4, respectively. The generation gain obtained in the cooled module PV2 is lower than the one from the cooled module PV1, even with PV2 presenting lower operating temperatures. The maximum gain in energy generation was registered in 23 January 2018, when it was obtained 109% and 108% more energy generated by the cooled modules PV1 and PV2, respectively. It was concluded that the cooling reached significant peaks of improvement of 12% and 10% for the cooled modules PV1 and PV2, respectively, in comparison to the reference module PV4.

The power profile linked to the cooled modules PV1 and PV2 and reference module PV4 suffer variation with minimum on the beginning and end of the day, in levels lower than 100 Wp, and maximum between 11 AM and 2 PM, and in levels higher than 200 W, see Figure 18. There is little difference between the maximum powers obtained by the three modules, though the average power of the cooled modules is superior in more than 10 W. In the days when the cooling system is running, the output power of the cooled modules PV1 and PV2 is, in average, 4.0% and 2.6% superior to the reference module PV4, respectively. Even when the module PV2 is cooled before the module PV1, it shows a 1.9 W lower average power, reinsuring that the module PV2 performance is naturally lower than the module PV1.

5 | RESULTS CONSOLIDATION

Using the systematic review method [74], it was possible to select, systematise and compare the theoretical and experimental results of ODTU with the results obtained in the international bibliography. Where was considered the exclusive selection of works whose have theoretical and experimental evaluation of the cooling system using water as cooling fluid for PV modules.

A systematisation demonstrates that cooling systems are divided in two groups: (i) Open system, when the fluid comes in direct contact with the top surface of PV module [25,26,32,44,75], with bottom surface of PV module or both surfaces [45]; and (ii) closed system, when the fluid is confined and makes the thermal exchange through the equipment installed on the bottom surface of the PV module [49,76–79], see Tables 3 and 4. Hence, the ODTU system of this work can be characterised as Open system and top side surface. The theoretical and experimental results of the work demonstrate that:
TABLE 3  Consolidation of the characteristic of the theoretical and experimental research

| Ref. | Year | Cooling system | Theorical research | Experimental research | Thermal results | Electric results |
|------|------|----------------|--------------------|-----------------------|-----------------|------------------|
| [44] | 2009 | Open system Top side of PV | Thermolectric model for hourly solar radiation data for different locations in Australia: | Test of system performance under different radiation conditions Does not compare the cooled with uncooled PV module at the same time | PV temperature: Uncooled: ≈58°C, Cooled: Decrease about 26°C | The increase in cell temperature above the standard operating temperature (45°C) caused a drop of 5% in output power When introducing water cooling technique, a surplus in power of about 15% |
| [25] | 2011 | Open system Top side of PV | Thermal model of the surface cooling system | Compare and validate the measured with predicted model Compare the cooled with uncooled PV module | PV temperature: Deviation between measured and predicted is <4°C Maximum deviation between the cooled and uncooled was 20°C | The average voltage between the cooling system and the control were 1.2, 2.2 and 1.4 V higher for each test day, with a maximum of 3.2 V The maximum power enhancement in response to the cooling was 11.6% when compared with a control module |
| [26] | 2013 | Open system Top side of PV | Thermal model to determine how long it will take to cool the PV modules to the normal operating temperature minimizing the amount of water and energy needed for cooling | Determine the influence of cooling and overheating on the performance of the PV cells Does not compare the cooled with uncooled PV module at the same time. | PV temperature: Simulated 46°C and measured 42.5°C Temperature reduction of 10°C after the cooling system has operated for 5 min. | Theoretical: The output power of the PV modules is 790 W for 35°C and 640 W for 65°C Experimental: Determines that the efficiency of the PV module operating at 45°C is 10.5% and for 35°C is 12.5% |
| [76] | 2014 | Close system Bottom side of PV | Thermal model to determine: conversion of solar radiation into thermal energy by PV module absorbers; and transporting absorbed thermal energy towards polyethylene heat exchangers. | Examine the effectiveness of a cooling system in the improve of the PV cell efficiency Compare the measured with predicted model cumulative water produced | PV temperature: Experimental values indicate that water temperature difference could reach up to 16°C Simulated 62°C and measured 57°C | – |
| [77] | 2016 | Close system Bottom side of PV | Thermoelectric model to determine the PVT module transient temperature and the to increase the overall PV effectiveness | Analyse the performance of each series-connected PV cell in PVT modules Compare and validate the measured with predicted model | PV temperature: Difference between the measured and the modelled is 8–12% Measured difference between cooled and uncooled is 5–10°C | – |
| [45] | 2016 | Open system Top side and bottom side of PV | Thermal model to evaluate the energy efficiency | Analyse the cooling effect impact on the power output and electrical efficiency Analyse four applied cooling options: (i) Without cooling; (ii) back surface cooling; (iii) top surface cooling; (iv) simultaneous surfaces cooling | Average PV temperature: (i) 56°C (ii) 33.7°C (iii) 29.6°C (iv) 24.1°C | Maximal power output/Relative increase in power output: (i) 35 W/ -; (ii) 39.9 W/14%; (iii) 40.1 W/14.6% and (iv) 40.7 W/16.3% Electrical efficiency/Effective increase: (i) 13.9%/ -; (ii) 15.6%/3.6%; (iii) 15.4%/2.5% and (iv) 15.9/5.9% |

(Continues)
| Ref. | Year | Cooling system | Theoretical research | Experimental research |
|------|------|----------------|----------------------|-----------------------|
| [78] | 2017 | Close system | Bottom side of PV | Investigate the effects on the operating power and efficiency | Electrical efficiency decreases by 26.1% as the temperature increases by 0.02% |
| [79] | 2018 | Close system | Bottom side of PV | Thermal model to evaluate the energy efficiency | Electrical efficiency decreases by 10% as the temperature increases by 0.01% |

**Cooling system**

- Theoretical research
  - Investigate the effects on the operating power and efficiency
  - Does not compare the cooled with uncooled PV module at the same time

- Experimental research
  - Investigate the effects on the operating parameters on the output power and efficiency
  - Does not compare the cooled with uncooled PV module at the same time

**Electric results**

- For every 100 W m$^{-2}$ increase in solar irradiation intensity, the electrical efficiency increases by 0.006%, respectively.
- For every 10 L h$^{-1}$ increment of fluid flow rate, the electrical efficiency increases about 0.43%

**Thermal results**

- For every 100 W m$^{-2}$ increase in solar radiation, the electrical power and electrical efficiency increase about 19.65 W and 0.06%, respectively.
- For every 100 W m$^{-2}$ increase in solar radiation, the temperature increases by 0.9°C.
- Difference between the measured and modelled is 3.3–4.2%

**6 | CONCLUSIVE ELEMENTS**

The ARX and state-space linear parametric models present the good performance in predicting the temperature of the uncooled PV modules, though these models are only valid when the PV cell runs in MPPT. Being the best one corresponding to the first-order state-space model, with NRMSE of 86.75%. It is justified by the fact that the ARX model does not present flexibility to model the noise satisfactorily. The maximum error between the measured and estimated temperature oscillates between -2.4°C and +3°C, with a significance level of 5%. The residue presents a random behavior, with no apparent tendency, and average of 0.20°C.

Even though the physical model for the modules without cooling presents a NRMSE of 83.75%. The maximum error between the measured and estimated temperature ranges from -2.0°C to 1.9°C. However, a slight negative bias is observed in this case. The validation analyses show that the residues have a negative tendency, tending to overestimate the temperature of the PV module. The problem lies in the linear model used to calculate the heat transfer coefficient by forced convection. To improve performance, more detailed models should be developed.

The modelling of the cooled modules is only possible through non-linear models. The thermal model of the module presents a NRMSE of 44.5% in the estimation of the operating temperature. The maximum error between the measured and estimated value oscillates between -3.5°C and 2.5°C, showing a negative bias. Though this error does not represent a large deviation in the estimation of the electric power generated by the PV module, once the coefficient of power loss due to temperature, which is typical of a monocrystalline module, is
| Ref. | Year | Cooling system | Theoretical research | Experimental research | Thermal results | Electric results |
|------|------|----------------|----------------------|----------------------|----------------|------------------|
| [32] | 2018 | Open system Back side of PV | Mathematical model is built for predicting the system performance | Spraying water onto the back side of the PV module. The pump was switched on once the module temperature reached 45°C, and was switched off when it cooled to 35°C. Three cases: (i) Uncooled; (ii) cooled without U-shaped bore-hole heat exchanger (UBHE); and (iii) cooled with UBHE. Does not compare the cooled with uncooled PV module at the same time. | PV temperature: (i) The average between theoretical and experimental data was about 1.49%; Regardless of modelled and experimental, the highest temperature of both was over 65°C. | The cooling system improved the efficiency by 14.3%; Experimental: Average power output/Conversion efficiency: (i) 33 W/6.8%; (ii) 37.4 W/6.9%; (iii) 37.5 W/7.4%; Theoretical: Average power output/Conversion efficiency: (i) 38.8 W/8.72%; (ii) 43.5 W/9.13%; (iii) 44 W/9.52%; | |
| [49] | 2018 | Close system Back side of PV | Thermal model and simulation using specialised computer program | The results of the simulation were compared with the experimental data collected during a 1-week period. Experimental consisted in series-connection of the two PV modules. Does not compare the cooled with uncooled PV module at the same time. | PV temperature: Experimental: The maximum difference between two modules are 3.0–4.0°C; The average errors of theoretical and experimental was 6.53%. | Cooling system increased almost 1.5% in the electrical power generated. The average errors of theoretical and experimental was 5.29%; | |
| [75] | 2018 | Open system Top side of PV | Analytical model to evaluate the energy efficiency and helps in ascertaining the influence of temperature on their performance of building integrated photovoltaic-thermal | Five PV modules: Monocrystalline silicon (m-Si), polycrystalline silicon (p-Si), amorphous thin film silicon (a-Si), cadmium telluride (CdTe) and copper indium gallium selenide (CIGS). Does not compare the cooled with uncooled PV module at the same time. | Cooled—PV temperature: All obtained almost the same: 36°C. The maximum fluctuation was in CIGS. Uncooled—PV Temperature: (m-Si): 49.8°C; (p-Si): 50°C; (a-Si): 53°C; (CdTe): 54°C; and (CIGS): 58°C. | Cooled—electrical efficiency: (m-Si): 12.3%; (p-Si): 11.0%; (a-Si): 6.1%; (CdTe): 6.6% and (CIGS): 7.7%; Uncooled—electrical efficiency: (m-Si): 11.4%; (p-Si): 10.3%; (a-Si): 5.9%; (CdTe): 6.3% and (CIGS): 7.6%; |
−0.5%/°C. The performance of the complete model of the PV module (thermal+electric) is satisfactory, presenting NRMSE of 76.38%. This performance, in terms of predicting the energy generated by the PV module cooled with water-film, represents less than 0.2%.

Regarding empirical analysis, it was observed that the water-film cooling system produces a significant loss in temperature of the cooled modules, with average temperature reduction of 15−19%, and maximum reduction of 24−35%. In terms of power, the average gains are 5 to 9% on the time of day with higher solar radiation, and maximum gains of 12% on days with solar radiation above average. Regarding gross energy generation, average gains of 2.3-6%, and maximum gains of 6.3−12%, were obtained.

It was concluded that the water-film cooling system for PV modules is effective in reducing the module temperature and, thus, is also effective in increasing the performance in energy generation, especially on days with high ambient temperature and solar radiation incidence. Additionally, it was observed that the thermoelectric model is satisfactory in predicting the generation of this type of system, if there are consistent measures.

Finally, the systematisation, discussion and results of this work contributed to the numerical and experimental research literature linked to the water-film cooling system for PV modules.

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