Evaluation of Performance Models against Actual Performance of Grid Connected PV Systems

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Abstract: Evaluation of energy performance of grid connected photovoltaic systems is a critical task during project design. In this assessment the common practice is to use modeling software tools that provide an estimated performance of the system and calculate the expected energy yield considering the location and system design specifications.

The aim of this research was to understand and evaluate the modeling process in PVsyst v6.25. This study presents a comparison of the real performance of six grid connected PV systems located in Spain, Italy and Chile with their modeled performance using PVsyst. Five systems were fixed structure and one with tracking system. Only systems equipped with crystalline silicon PV modules were evaluated.

On an annual basis PVsyst was found to underestimate the energy yield in almost all the studied cases, except in the case of the tracking system. For the system in Chile, the measured data was at high resolution and included the irradiation in the plane-of-array and array temperature allowing a better comparison. In this case, the total relative error between the modeled and measured energy yield in the evaluated period was –0.74%, showing that for this particular system the modeled performance matched the measured output with high accuracy.

Keywords: photovoltaic systems, energy yield, modeling tools, simulation, PVsyst, system performance

1. INTRODUCTION

Grid connected photovoltaic (PV) systems represent the most common type of PV systems with installed nominal capacities from several hundred kilowatts (kW) to hundreds of megawatts (MW). There are about 20 utility-scale PV systems of over 100 MW capacity in the world, mostly in China and in the United States [1]. The 550 MW Topaz Solar Project located in San Luis Obispo County, California is currently the largest operational grid connected PV power plant in the world [2].

The economic viability of a grid connected PV system is directly connected to its expected energy output and determines the interest of developers and investors in pursuing a project.

It is common practice at the beginning of the project to estimate the performance of the system using modeling software tools. These tools use as basic input the meteorological conditions of the location, system design details and definitions of the main components. The tools then calculate the expected energy yield for a given period of time using modeling algorithms.

Currently, the commercial software package PVsyst is one of the most common modeling software tools used in the PV industry to simulate the performance of grid connected or stand-alone PV systems and calculate their energy yield.

This study is focused on the evaluation of PVsyst's energy yield estimations in modeling the performance of grid connected PV systems. First, a background research of the main characteristics of the software and the calculation methods for energy yield estimation was conducted.

For the evaluation of the modeling process of PVsyst v6.25, six grid connected PV systems located in Spain, Italy and Chile were simulated using measured meteorological data and as-built design parameters as inputs. The performance data measured on-site was compared with the modeled performance in PVsyst in order to evaluate the possible sources of deviation. Conclusions and recommendations were drawn according to the results.

2. ENERGY YIELD ESTIMATION

A variety of software for the modeling of PV systems are available in the market including PV*Sol, Homer, System Advisor Model (SAM), PVsyst, among others. Currently, PVsyst is one of the most common software used by developers, installers and consultants and has become the industry standard in the U.S. for the simulation of utility-scale PV systems [3]. PVsyst is the focus of this research.

The development of PVsyst started in 1992 at the University of Geneva and is now managed by PVsyst SA [4]. It is a highly complex tool which allows the study, sizing, simulation and data analysis of grid connected and stand-alone PV systems.

PVsyst allows the definition of meteorological databases from many different sources and formats, as well as on-site measured data. The system components can be selected from an extended database or created from technical specifications. The design allows the definition of up to eight sub-arrays each with different modules and inverter models, allowing the simulation of more complex systems. It is possible to complement the design with further details like far and near shading, and specify detailed loss factors such as soiling, module quality, mismatch, ohmic wiring, and external transformer losses [5].

Few studies are available in literature regarding the evaluation of the accuracy of the modeling process of PVsyst in the prediction of energy yield in grid connected systems. According to PVsyst documentation [5], the validation of the accuracy of old versions of the software using measured data from 7 grid-connected systems showed that global results of the simulation were in the order of 2 to 3% Mean Bias Error (MBE). All the systems in the validation had relatively small capacities (0.5 – 100 kW_p) and were located in Switzerland. In 2011, Lee, G. et al. [6] evaluated the performance of six PV systems of small capacity (< 7 kW) in Central Australia using PVsyst among other modeling software and showed that PVsyst tends to slightly underestimate the performance, confirming the investigation from SolarPro Magazine in 2010 [7] that found PVsyst to be the most conservative of the modeling tools evaluated.

2.1. Modeling process in PVsyst

In PVsyst the calculation of energy yield in grid connected PV systems is a multi-step process which includes the modeling of the incident irradiation in the plane-of-array (POA), the array direct current (DC) output and the inverter alternating current (AC) output. This proceeds as follows:

1. For the modeling of irradiation in the plane-of-array, PVsyst offers two transposition models; Hay [8] and Perez models [9].
   These models show a correspondence with the measurements at different locations, especially at south oriented planes with tilt angles $\leq 45°$ [10]. Some studies show that the Perez model usually predicts higher irradiance than the Hay model [11]–[15].
   In the case of input data that contains only POA irradiance, especially from measured data, the program first performs a retro-transposition using the Liu-Jordan model to evaluate the horizontal global and diffuse irradiances and then calculate the global irradiance in the plane-of-array [5].
   The shading effect over the module surface is calculated according to the system layout designed in a 3D CAD editor in PVsyst. The reflection losses at the surface of the modules are then calculated in order to finally obtain the effective incident irradiation reaching the modules' surface.
2. For the modeling of the DC array output, the electrical behavior of the modules in the array is modeled using the "one-diode" equivalent circuit model in the case of silicon crystalline and CIS technologies. A modified version is used for thin film modules [5]. The in-operation module temperature used in the model is calculated as an energetic balance between the energy absorbed and the thermal losses from the module to the surroundings.
   As a result, for a given effective POA irradiance and module operation temperature including the array loss factors, the DC power at MPP is calculated.
3. The AC output is calculated using the efficiency curve of the inverter. The self-consumption of the inverter (fans, control systems) is also taken into account.
   The final energy output is calculated after the corresponding losses due to AC cabling and losses in the medium voltage external transformer.

The main simulation results include monthly and yearly values for the total energy yield (MWh), performance ratio PR (%) and the specific energy (kWh/kW_p). The final report also includes a loss diagram that shows the energy balance and details of all losses in the system, providing a quick and graphical representation of the quality of the PV system design by identifying the main sources of losses [5]

3. METHODOLOGY

In order to evaluate the modeling process in PVsyst v6.25, six grid connected PV systems with nominal capacity between 1 and 12 MW_p [16], whose details are shown in Table 1, were simulated in PVsyst and their modeled performance compared to the actual measured performance of the systems.

The meteorological data measured on-site was used as input for the simulations. The system components and layouts were configured according to the as-built design and then the detailed loss factors were defined. After the simulation, the modeled energy yield was compared with the measured output and the deviations were analyzed. The methodology used for the evaluation was similar for every system. More details are given in the next section.

Table 1: Summary of PV systems included in this study

System	PV1	PV2	PV3	PV4	PV5	PV6
Location	Spain	Spain	Italy	Italy	Italy	Chile
Module Technology	Si-poly	Si-poly	Si-mono	Si-mono	Si-mono	Si-poly
Structure	fixed	fixed	fixed	fixed	one-axis tracker	fixed
Measurement period	2009	2009 2010	2012 2013	2012 2013	2012 2013	2013
Data resolution	monthly	monthly	daily	daily	daily	1 minutely
Irradiation data	global horizontal and plane-of array	global horizontal and plane-of array	global horizontal and plane-of array	global horizontal and plane-of array	global horizontal and plane-of array	plane-of array
Temperature data	ambient	ambient	ambient	ambient	ambient	ambient and array temperature
Wind speed data	not measured	not measured	yes	yes	yes	not measured
AC Energy meter	measured after inverter	measured after inverter	measured after inverter	measured after inverter	measured after inverter	measured at delivery point in substation
System availability details	not avaliable	not avaliable	yes (daily values)	yes (daily values)	yes (daily values)	yes (1 minutely)

3.1. System Design in PVsyst

The following steps explain the detailed design process for each system in PVsyst:

1. The geographical location and meteorological data of the system was specified. For Systems PV1 and PV2, the monthly measured global horizontal irradiance (GHI) and ambient temperature values

were imported. From this monthly dataset, PVsyst generated hourly synthetic data using Aguiar R., Collares-Pereira M. model [17], that first creates random sequence of daily values, using a library of Markov transition matrices and then applies a time-dependent, autoregressive, Gaussian model for generating the hourly sequences for each day. For the generation of synthetic temperature data, PVsyst constructs the daily sequences using random daily slopes with constraints on the monthly average temperature imported [5].

For Systems PV3, PV4 and PV5, the daily measured GHI and ambient temperature values were converted into a format file that could be imported into PVsyst. From this daily data set, PVsyst generated hourly values using a random distribution based on the Markov matrices [5].

In the case of System PV6, the 1-minute measured POA irradiance, ambient temperature and array temperature were compiled into a file and imported into PVsyst. However, the program is only able to perform simulations starting from the horizontal irradiance. Therefore, for this system, from the measured irradiance PVsyst calculated the horizontal global and diffuse components (inverse of transposition) and then calculated the specified POA irradiance that was used in the simulation [5]. In the conversion process, PVsyst averages the imported meteorological data to get one-hour intervals.

2. The as-built configuration of design parameters of the PV systems were defined in PVsyst. The nominal capacity of each plant was taken from the flash list given by the module manufacturer. For systems operating for more than one year, the linear annual degradation was applied according to the specifications from the module datasheet.
3. Modules and inverter models were selected from the component database in PVsyst. For each model, the technical specifications were validated against the manufacturer's datasheet. For cases where the specific model of any component was not available in this database, a new component was created using the corresponding tool in PVsyst.
4. The layout of the plants was created using PVsyst's 3D CAD editor, in order to evaluate near shadings. For the evaluation of far shadings the horizon profile was created using a panoramic image taken on-site, when available, otherwise a free horizon was considered.
5. The input parameters for detailed losses in PVsyst (i.e. thermal parameters, ohmic losses, module quality, soiling losses and IAM losses) were set at their default values or modified according to the experience of Lahmeyer International GmbH (LI) experts in similar projects.

3.2. Data quality control

The purpose of this study was the comparison between modeled and measured energy yield during periods of full operation of the systems, therefore, all the information gathered from each system was filtered in order to eliminate non-useful data.

The availability of the systems was also checked in the Operation & Maintenance (O&M) reports (except in PV1 and PV2 systems because of the lack of this information in the reports), and those days or hours during system shutdowns, or when one or more inverters reported operational problems were removed and not considered in the analysis.

In System PV6, the measured meteorological data was screened and checked in order to remove any period of time when data was missing or erroneous.

3.3. Metrics

In order to quantify the performance of the modeling process of PVsyst, the metrics used for the evaluation of the software System Advisor Model (SAM) reported by Freeman J. et al. [18] were considered and adapted for the evaluations in this study.

For the evaluation of the relative modeling error on a monthly and annual basis, all available hours or days during the month/year of the modeled and measured values were summed separately according to Equation (1). A positive error represented an overestimation from PVsyst.

$$Relative\ Error(\%) = \frac{\sum Modeled - \sum Measured}{\sum Measured} \qquad \text{Equation (1)}$$

In order to quantify the model performance in hourly basis two dimensionless metrics were used, Normalized Mean Bias Error (NMBE) and Normalized Root Mean Square Error (NRMSE).

NMBE is the average difference between modeled and measured values on an hourly basis and calculated according to Equation (2). Normalization was done with the maximum measured output of each system [18].

$$NMBE = \frac{\frac{\sum_i^N Modeled_i - Measured_i}{N} \times 100\%}{Maximum\ measured\ output} \qquad \text{Equation (2)}$$

NRMSE is a common metric that ensures that those hours that the model overestimates the output values do not cancel out errors when the output is underestimated and calculated according to Equation (3). The normalization was done as in NMBE [18].

$$NRMSE = \frac{\sqrt{\frac{\sum_i^N (Modeled_i - Measured_i)^2}{N}}}{Maximum\ measured\ output} \times 100\% \qquad \text{Equation (3)}$$

This normalization also applies for measured irradiance or energy yield values in each system in order to preserve the confidentiality of the projects.

4. RESULTS AND DISCUSSIONS

For the systems with fixed structures (i.e. System PV1, PV2, PV3, PV4), the measured irradiance used as input for the simulation corresponded to GHI values and they were converted into POA irradiance using the two transposition models available in PVsyst.

Using Perez model, the total relative error between the modeled and the measured energy yield were in the range of –4.2 to 2.2%. Using Hay model the total relative errors were in the range of –5.9 to 0.7%, showing that PVsyst tended to underestimate the energy yield on an annual basis in most of the evaluated systems. (Refer to Table 2, Table 3, Table 4 and Table 5 in Appendix A of this section for monthly detailed errors).

Regarding the one-axis tracking System PV5, the measured irradiance also corresponded to GHI values and both transposition models were used in the conversion into POA irradiance. The comparison between modeled and measured energy yield for this case showed annual relative errors of 4.0% and 7.0% using Perez model, and 2.0% and 6.1%, using Hay model showing that PVsyst overestimated the energy yield in each of the two years of the evaluation. (Refer to Table 6 in Appendix A of this section for monthly detailed errors).

Figure 1 and Figure 2 show the total energy yield relative errors for the five systems (i.e. PV1, PV2, PV3, PV4 and PV5). It can be seen that in the systems evaluated for two years, the corresponding total relative errors for each year are close to each other with slight differences. This could be related to the estimation of loss factors and the linear annual degradation of the systems that for this study was assumed to be equal for all the modules in the arrays.

Figure 3 shows the comparison of monthly energy yield relative error of the systems (PV1, PV2, PV3, PV4 and PV5) between modeled and measured energy yield using Perez model. It can be seen that for the fixed systems the variability of the relative errors on monthly basis, which were in the range of –10 to 5%. A similar tendency was found in the results using Hay model.

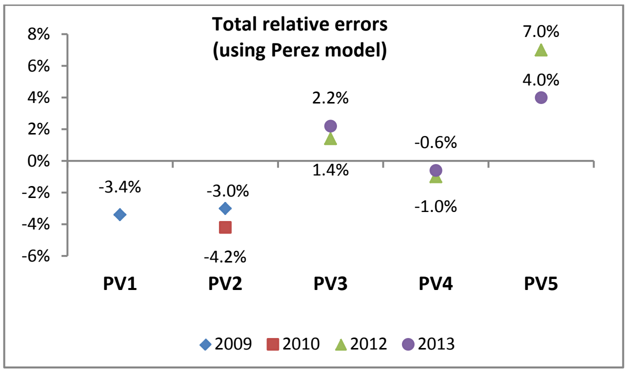

Figure 1: Total energy yield relative errors for Systems PV1 through PV5 using Perez model in the simulation (Notes: PV1 was evaluated only 11 months, PV5 is one-axis tracking system)

For all the previous systems (i.e. PV1, PV2, PV3, PV4) the measured dataset was on a monthly or daily basis, which did not allow comparison of the hourly results from PVsyst in order to better understand the sources of the deviations from the measured values. It was inferred that the main contributors for the differences were the transposition models.

For the one-axis tracking system PV5, it can be seen in Figure 3 that the errors are higher than for the fixed systems and they increased in winter time, with errors up to 20%.

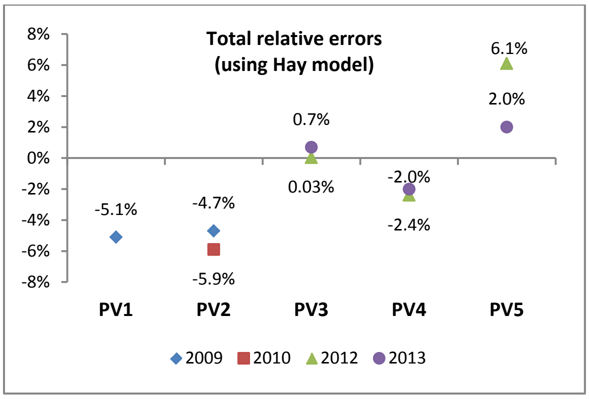

Figure 2: Total energy yield relative errors for Systems PV1 through PV5 using Hay model in the simulation (Notes: PV1 was evaluated only 11 months, PV5 is one-axis tracking system)

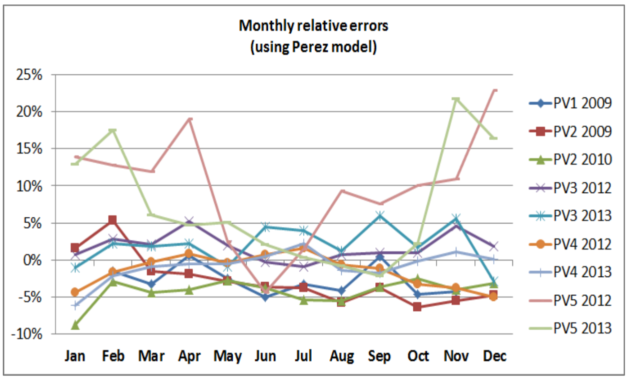

Figure 3: Monthly energy yield relative errors for Systems PV1 through PV5 using Perez model in the simulation (Note: PV5 is one-axis tracking system)

A recent study published by Westbrook O. and Collins F. [3] in 2013 regarding validation of PVsyst for a horizontal single-axis tracking system in the U.S. Southwest Desert, where Hay and Perez transposition models were evaluated using measured data, revealed that the overall annual and monthly transposition model mean bias errors were below 1.5%, but increased further on daily and hourly time scales (around 25% to 30% hourly RMSE). According to the authors, in locations with more sub-hourly weather variability than Las Vegas, higher transposition model errors maybe expected. This could be the case for the system PV5 located in Italy and provide an explanation for the behavior of the modeled results.

Further analysis was however not possible because of the low resolution of the measured data.

On the other hand, the measured dataset in System PV6, was recorded at higher resolution and included additional parameters i.e. POA irradiance, array temperature and electrical parameters from the inverter, allowing a better analysis. The modeling process was evaluated for three parameters: DC energy at the inverter input, AC energy at the inverter output and AC energy after the transformer. A total of 10 months were evaluated, night-time hours and hours when the plant was not 100% available were excluded from the comparisons.

The use of POA irradiance as input in the simulation in this system diminished the effect of the transposition models, but it was not completely avoided because the simulation process in PVsyst starts from the horizontal irradiance, that was calculated with a retro-transposition process. Through this process, PVsyst generated the measured values with a high correlation (R^2= 0.9998).

In this system, two variations of the simulation were performed. The first variant was designed using the thermal loss factors as default values proposed in PVsyst for free-standing arrays and in the second variant using the measured array temperature.

For the first variant, the total relative error between modeled and measured AC energy yield after the transformer was –2.8%, with –1.4% NMBE and 2.3% NRMSE in the evaluated period. (Refer to Table 7 in Appendix A of this section for monthly detailed errors).

In the second variant, the total relative error between modeled and measured AC energy yield after the transformer was –0.74% with –0.43% NMBE and 2.14% NRMSE. (Refer to Table 8 in Appendix A of this section for monthly detailed errors).

The hourly comparison of measured and modeled AC energy yield after the transformer can be seen in Figure 4 (where the values are normalized by the maximum measurement).

The overestimation of array temperature in the first variant resulted in an increase of the thermal losses by 1.6% compared with the second variation, according to the values reported for thermal losses in the loss diagram in PVsyst of both variations. Figure 5 shows this effect graphically

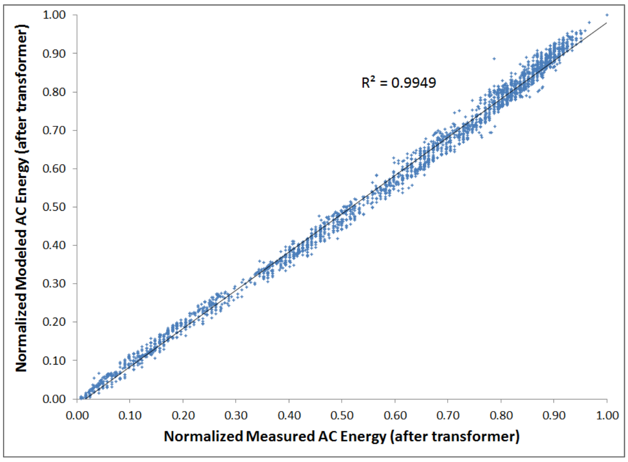

Figure 4: Hourly AC Energy (after transformer) comparison SystemPV6 (Second simulation variant)

The results in the DC side showed that the modeled DC energy followed the measured DC energy, with a total relative error of –0.23%, NMBE of –0.13% and NRMSE of 2%. These results included the effects of physical factors such as soiling, mismatch and DC cabling losses that were modeled according to the loss factor parameters set in the simulation.

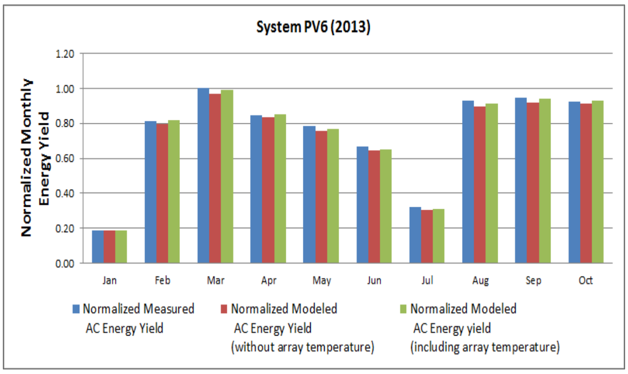

Figure 5: Monthly comparison of measured and modeled normalized AC energy yield after the transformer (without and including array temperature measurements) – System PV6

Comparing measured and modeled AC energy in the inverter output resulted in total relative error of –0.1%, NMBE of –0.05% and NRMSE of 2.54%. The results of this section included the effect of the modeled performance of the inverter calculated according to the efficiency curve. The modeled auxiliary consumption of the inverter (control system and fans) is also included. This was specified in the datasheet at nominal AC Power and 25°C. PVsyst used this value as fixed consumption for every hour along the simulation. In reality, the consumption could be higher with increase in temperature, leading to an underestimation of the modeled auxiliary consumption of the inverter.

Figure 6 shows the monthly variation of the relative errors between modeled and measured energy yield in the DC and AC side from the second variant. A tendency of higher errors in winter time can be seen.

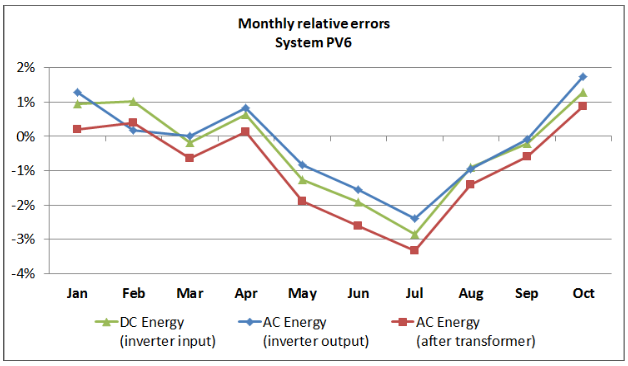

Figure 6: Monthly DC and AC energy yield relative errors for Systems PV6 – Second variant including array temperature

5. CONCLUSIONS

Six grid connected PV systems located in Spain, Italy and Chile, were assessed in order to compare the measured energy yield of each system with the modeled energy yield using PVsyst v6.25. Five systems were fixed structure and one system with one-axis tracker.

The results of the comparison for the fixed structure systems (PV1, PV2, PV3 and PV4) showed that PVsyst tended to underestimate the energy yield on an annual basis in almost all the studied cases. On a monthly basis the errors are more scattered and are correlated with the uncertainty of the transposition model.

For the system with tracking mechanism analyzed in this study (PV5), the results showed that PVsyst tended to overestimate the energy yield on an annual and monthly basis and it is correlated with the overestimation of the modeling of POA irradiance.

The evaluation of the System PV6, with measured dataset recorded at short intervals and including additional parameters (i.e. POA irradiance and array temperature) showed a total relative error of –0.74%, –0.43% NMBE and 2.14% NRMSE. Therefore, for the design conditions of this particular system, the modeled energy yield in the evaluated period (10 months) matched the measured output with high accuracy.

6. RECOMMENDATIONS

This study only considered systems with silicon crystalline module technologies and the evaluation of systems with different module technologies and locations, as well as more tracking systems will provide a broader understanding about the accuracy of the modeling process in PVsyst.

In order to improve the evaluation of the modeled energy yield using PVsyst for the case of fixed PV systems, the use of measured POA irradiance from pyranometers recorded at short intervals as input in the simulation is recommended. For tracking systems, at the moment it is not possible to import measured POA irradiance into PVsyst, which represents a shortcoming that limits the evaluation of the modeled performance in tracking systems.

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APPENDIX A

Table 2: Monthly and total energy yield relative errors – System PV1

		Monthly Relative Error											Total Error
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	
2009	Perez Model	-14.5%	-1.6%	-3.3%	0.6%	-2.5%	-5.0%	-3.3%	-4.1%	0.4%	-4.6%	-4.3%	**-3.4%**
	Hay Model	-16.5%	-3.1%	-5.4%	-1.2%	-4.3%	-6.8%	-5.2%	-5.7%	-1.4%	-5.8%	-5.3%	**-5.1%**

Table 3: Monthly and total energy yield relative errors – System PV2

		Monthly Relative Error												Annual Error
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
2009	Perez Model	1.6%	5.3%	-1.5%	-1.9%	-2.9%	-3.7%	-3.8%	-5.8%	-3.8%	-6.4%	-5.5%	-4.8%	**-3.0%**
	Hay Model	-0.3%	3.8%	-3.4%	-3.7%	-4.7%	-5.4%	-5.5%	-7.4%	-5.6%	-7.9%	-7.5%	-6.9%	**-4.7%**
2010	Perez Model	-8.8%	-2.9%	-4.3%	-4.1%	-2.8%	-3.8%	-5.4%	-5.5%	-3.6%	-2.5%	-4.1%	-3.2%	**-4.2%**
	Hay Model	-10.5%	-5.0%	-5.9%	-5.9%	-4.5%	-5.6%	-7.1%	-7.2%	-5.3%	-4.2%	-5.8%	-5.1%	**-5.9%**

Table 4: Monthly and annual energy yield relative errors – System PV3

		Monthly Relative Error												Annual Error
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
2012	Perez Model	0.7%	2.8%	2.1%	5.2%	2.0%	-0.3%	-1.0%	0.8%	0.9%	1.0%	4.6%	1.9%	**1.4%**
	Hay Model	-0.3%	1.5%	0.7%	3.7%	0.5%	-1.7%	-2.4%	-0.6%	-0.7%	-0.3%	3.2%	0.6%	**0.03%**
2013	Perez Model	-1.1%	2.2%	1.9%	2.2%	-1.0%	4.4%	4.0%	1.2%	6.0%	1.7%	5.6%	-2.9%	**2.2%**
	Hay Model	-2.4%	0.5%	0.5%	0.8%	-2.5%	2.9%	2.5%	-0.3%	4.3%	0.2%	4.2%	-4.1%	**0.7%**

Table 5: Monthly and annual energy yield relative errors – System PV4

		Monthly Relative Error												Annual Error
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
2012	Perez Model	-4.4%	-1.7%	-0.3%	0.8%	-0.5%	0.7%	1.6%	-0.6%	-1.2%	-3.3%	-3.7%	-5.1%	**-1.0%**
	Hay Model	-5.5%	-3.0%	-1.6%	-0.7%	-1.9%	-0.7%	0.1%	-2.1%	-2.7%	-4.9%	-5.1%	-6.0%	**-2.4%**
2013	Perez Model	-6.2%	-2.1%	-0.9%	-0.5%	-0.5%	0.5%	2.2%	-1.4%	-1.8%	-0.1%	1.1%	0.1%	**-0.6%**
	Hay Model	-7.5%	-3.5%	-2.5%	-1.8%	-1.9%	-0.9%	0.8%	-2.9%	-3.3%	-1.6%	-0.1%	-1.2%	**-2.0%**

Table 6: Monthly and annual energy yield relative errors – System PV5

		Monthly Error Relative												Annual Error
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
2012	Perez Model	13.9%	12.8%	11.9%	19.1%	2.5%	-4.5%	1.4%	9.2%	7.5%	10.1%	11.0%	22.9%	**7.7%**
	Hay Model	12.6%	11.3%	10.6%	17.1%	0.8%	-6.1%	-0.1%	7.9%	5.6%	8.6%	9.5%	21.2%	**6.13%**
2013	Perez Model	12.9%	17.5%	6.0%	4.7%	5.1%	2.1%	0.3%	-0.8%	-2.2%	2.3%	21.7%	16.4%	**4.4%**
	Hay Model	11.2%	14.4%	3.6%	1.6%	3.3%	0.9%	-1.2%	-3.1%	-4.3%	-0.2%	13.4%	11.2%	**2.0%**

Table 7: Monthly and total relative errors, NMBE and NRMSE – System PV6 (First simulation variant)

Parameter	Monthly Relative Error										Total		
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Relative Error	NMBE	NRMSE
DC Energy (inverter input)	-1.3%	-1.2%	-2.7%	-1.2%	-2.9%	-3.2%	-4.5%	-2.8%	-2.6%	-1.0%	**-2.3%**	**-1.1%**	**2.1%**
AC Energy (inverter output)	-1.0%	-2.0%	-2.5%	-1.0%	-2.5%	-2.8%	-4.0%	-2.9%	-2.4%	-0.6%	**-2.1%**	**-1.0%**	**2.5%**
AC Energy (after transformer)	-2.0%	-1.8%	-3.1%	-1.7%	-3.5%	-3.8%	-5.0%	-3.3%	-2.9%	-1.4%	**-2.8%**	**-1.4%**	**2.3%**

Table 8: Monthly and total relative errors, NMBE and NRMSE – System PV6 (Second simulation variant including array temperature)

Parameter	Monthly Relative Error										Total		
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Relative Error	NMBE	NRMSE
DC Energy (inverter input)	1.0%	1.0%	-0.2%	0.6%	-1.3%	-1.9%	-2.9%	-0.9%	-0.2%	1.3%	**-0.23%**	**-0.13%**	**2.00%**
AC Energy (inverter output)	1.3%	0.2%	0.0%	0.8%	-0.8%	-1.6%	-2.4%	-1.0%	-0.1%	1.7%	**-0.10%**	**-0.05%**	**2.54%**
AC Energy (after transformer)	0.2%	0.4%	-0.6%	0.1%	-1.9%	-2.6%	-3.3%	-1.4%	-0.6%	0.9%	**-0.74%**	**-0.43%**	**2.14%**

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Title: Evaluation of Performance Models against Actual Performance of Grid Connected PV Systems

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1. Abstract

Evaluation of energy performance of grid connected photovoltaic systems is a critical task during project design. In this assessment the common practice is to use modeling software tools that provide an estimated performance of the system and calculate the expected energy yield considering the location and system design specifications.

The aim of this research was to understand and evaluate the modeling process in PVsyst v6.25. This study presents a comparison of the real performance of six grid connected PV systems located in Spain, Italy and Chile with their modeled performance using PVsyst. Five systems were fixed structure and one with tracking system. Only systems equipped with crystalline silicon PV modules were evaluated.

On an annual basis PVsyst was found to underestimate the energy yield in almost all the studied cases, except in the case of the tracking system. For the system in Chile, the measured data was at high resolution and included the irradiation in the plane-of-array and array temperature allowing a better comparison. The total relative error between the modeled and measured energy yield in the evaluated period was –0.74%, showing that for this particular system the modeled performance matched the measured output with high accuracy.

2. Introduction and Scope

The economic viability of a grid connected photovoltaic (PV) system is directly connected to its expected energy output and determines the interest of developers and investors in pursuing a project.

It is common practice at the beginning of the project to estimate the performance of the system using modeling software tools. These tools use as basic input the meteorological conditions of the location, system design details and definitions of the main components. The tools then calculate the expected energy yield for a given period of time using modeling algorithms.

Currently, the commercial software package PVsyst is one of the most common modeling software tools used in the PV industry by developers, installers and consultants to simulate the performance of grid connected or stand-alone PV systems and calculate their energy yield.

This study is focused on the evaluation of PVsyst's energy yield estimations in modeling the performance of grid connected PV systems. First, a background research of the main characteristics of the software and the calculation methods for energy yield estimation was conducted. The main loss factors in grid connected PV systems and considerations concerning some of the parameters for energy yield calculation in PVsyst were also analyzed.

For the evaluation of the modeling process of PVsyst v6.25, six grid connected PV systems located in Spain, Italy and Chile were simulated using measured meteorological data and as-built design parameters as inputs. The performance data measured on-site was compared with the modeled performance in PVsyst in order to evaluate the possible sources of deviation. Conclusions and recommendations were drawn according to the results.

3. Grid connected PV systems

Grid connected PV systems represent the most common type of PV systems with installed nominal capacities from several hundred kilowatts (kW) to hundreds of megawatts (MW). There are about 20 utility-scale PV systems of over 100 MW capacity in the world, mostly in China and in the United States [1].The 550 MW Topaz Solar Project located in San Luis Obispo County, California is currently the largest operational grid connected PV power plant in the world [2].

Grid connected systems require inverters for the conversion of direct current (DC) power from the PV modules into alternating current (AC) power. The output is matched in voltage and frequency with the grid specifications. The balance of the system (BOS) includes support structures, electrical junction boxes, wiring, transformers and monitoring equipment.

In utility scale PV systems monitoring equipment allow a comparison of the performance of the plant with the expected energy yield or the performance guarantee calculated at the beginning of the project.

The monitoring system includes data from a meteorological station with equipment for measuring horizontal as well as plane-of-array irradiance, ambient temperature and wind speed. In some cases rain gauges are also installed. Inverters are also connected to the monitoring system, providing operational data from both the DC and AC sides.

The electricity produced by the system is measured using an energy meter installed at the connection point assigned by the utility and is also integrated to the monitoring system.

4. Losses in grid connected PV systems

During the process of converting solar energy into electricity, different energy losses occur in PV systems. These losses can be grouped into optical, array and system losses as can be seen in Figure 1. Optical losses are caused by the attenuation of the incoming irradiation due to shading and reflection. Array losses are the effects that diminish the available array output with respect to the nominal power stated by the manufacturer at Standard Test Conditions (STC) [3]. These effects include temperature dependence, electrical mismatching, and module quality. System losses include the conversion losses in the inverter and transformer and losses due to wiring. Section 4.1 briefly describes some of these losses.

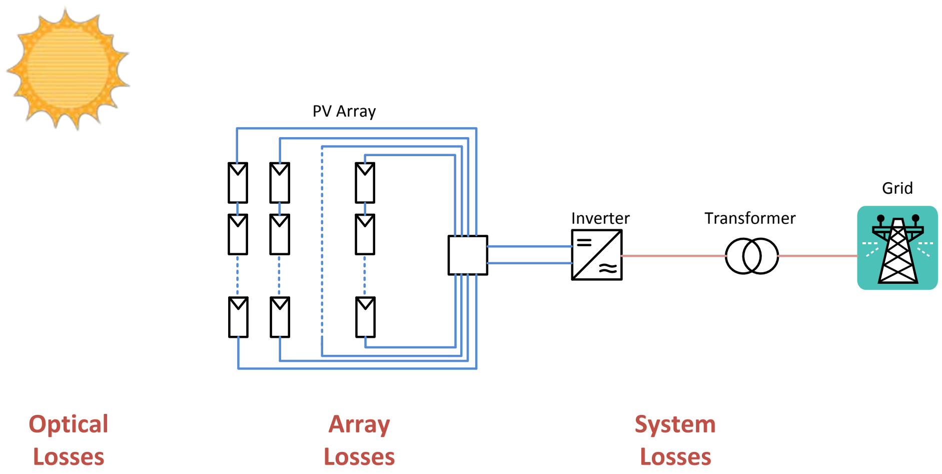

Figure 1 Losses in grid connected PV systems

4.1. Optical losses

4.1.1. Shading losses

In PV modules, the cells are connected in series for specific output voltages and shading on even a single cell results in degraded module output [4]. Module internal bypass diodes are usually placed in antiparallel (reverse biased) to small group of series connected cells(18 or 24 cells) in order to prevent the deleterious effect of shadowed cells on the current path in a string [5].

A shadow cast on a PV system can be characterized as far or near shading.

Far shading is caused by elevated horizons or distant objects such as mountains and hills that can produce an equal shade effect on all modules of the PV array. The losses due to this effect for a particular location can be assessed by use of a shading analyzer consisting of overlapping pictures taken from the surroundings with a digital camera, and a suitable software (such as HorizOn) that combines the pictures into a complete panoramic image and draws in the horizon line. This processed information can then be imported in an appropriate file format to evaluate the losses due to horizon shading in simulation programs [6].

On the other hand, near shading affects only a part of the PV array and they are produced by external objects close to the PV modules such as trees, buildings and poles. In rack-mounting systems, shading may be caused by the row of modules in front affecting the bottom edge of the modules behind them. In this case the actual yield loss will be determined by the number of modules that are mounted on top of each other. In racks with several rows, the lowest module row is most affected, while shading decreases in the upper module rows [6]. These losses are evaluated using a 3D representation of the plant layout in simulation software.

4.1.2. Reflection losses

This type of losses represents the effect of the angle of incidence (AOI) of the beam component of solar irradiance that reaches the PV modules surface. It depends on the transmission and reflection coefficient of the modules' glass cover, which increases significantly for AOI greater than 60°. The influence of this type of loss on annual energy yield is relatively small. However, depending on the modules orientation, it can be significantly high on a monthly basis [7].

4.2. Array losses

4.2.1. Losses due to low irradiance

These represent the losses in efficiency of the PV modules due to operation under low irradiance levels other than at STC, i.e. 1000 W/m^2 irradiance, 25°C cell temperature, and an air mass (AM) 1.5 spectrum. These conditions are hardly ever met in real operational conditions.

4.2.2. Temperature losses

The operating temperature conditions can have a strong influence on the electrical performance of the PV module. In Figure 2 it can be seen from the solar cell characteristic current-voltage (I-V) curve, that even though short circuit current slightly increases with increasing temperature, the open circuit voltage decreases affecting the maximum power point (MPP) and consequently the cell efficiency.

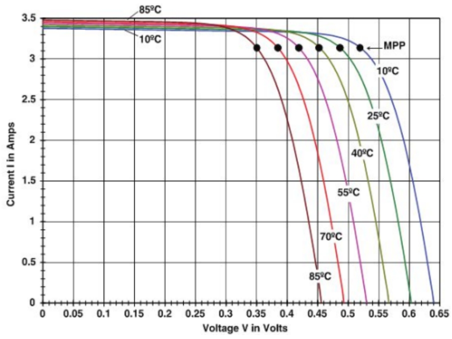

Figure 2 Characteristic I-V curves for a solar cell at different temperature levels with irradiance 1000W/m^2 and 1.5AM [8]

The amount of change depends on the cell type and the structure and it is normally defined by the temperature coefficient. Temperature impact on the PV modules' performance is more severe for crystalline silicon modules, than for thin film modules (Cadmium Telluride (CdTe) and Copper Indium Gallium Diselenide (CIGS)) and amorphous silicon (a-Si) solar cells [9]. A study conducted by Kumar and Rosen [10], showed that the decrease in the efficiency of polycrystalline silicon cells and thin film cells was found to be about 15% and 5% respectively when the module temperature rose from 27 - 57°C. The performance losses due to the temperature effect on the annual energy yield on different grid connected PV technologies installed in Cyprus was analyzed by Makridesa, et al. [11]. The results showed that the average annual yield thermal loss was 8% for Si-monocrystalline and 9% for Si-polycrystalline technologies, while for thin-film technologies, the average losses were 5%. For amorphous silicon technologies, a performance increase from spring until early autumn was observed and was attributed to thermal annealing.

4.2.3. Soiling losses

The accumulation of dust or dirt particles over the module's surface produces a dimming effect on the incident irradiation, which can significantly reduce the power output. The accumulation is highly dependent on weather conditions and geographic location.

To mitigate the effect of soiling accumulation in large-scale PV plants, one current technique is washing the surface with water or detergent solution, however this can increase operation and maintenance costs, and also can represent a shortcoming, especially in locations where water resources are scarce [12].

4.2.4. Module quality loss

The deviation between the real module capacity and the nominal capacity specified in the manufacturer's datasheet represents the module quality loss.

4.2.5. Array mismatch losses

In a PV array, modules are connected in series-parallel and the maximum power output of the total PV array is always less than the sum of the maximum output of the individual modules due to variations of their I-V characteristics [13]. This loss of power is referred to as electrical mismatch loss. A study performed by Koirala, B. et al. [5] stated that considering aging of modules the mismatch losses may rise up to 12% in series strings, however these losses may be reduced drastically to between 0.4 and 2.4% by means of appropriate series-parallel connections and a pre-selection of the modules according to their electrical characteristics. Investigations developed by Herrmann, W. et al. [14] showed that pre-sorting according to maximum power current proved to be the most efficient approach for performance optimization of a PV array.

4.3. System losses

4.3.1. Inverter losses

Part of the DC power generated by the PV array will be lost in the conversion to AC power. A typical inverter datasheet only identifies the maximum efficiency, but inverter efficiency is a function of input power level and input voltage [15].

4.3.2. Transformer losses

In multi-megawatt PV systems a step-up transformer is used after the inverters to match output with the grid voltage. Losses in the transformers include no-load losses (also called iron losses) and load losses (also called ohmic losses). No-load losses are constant, whether the transformer is on load or not, and occur due to eddy currents and magnetization of the core. The magnetic material and geometry of the core is the determining factor for these losses [16]. For transformers that are connected to the grid these energy losses are considered as a critical factor [17].

During operation, load losses are proportional to the current circulating through the windings that causes resistive heating of the conductors.

For the calculation of these losses, the transformer manufacturer provides in the technical datasheet specific values at nominal power.

4.4. Typical loss factors

The loss factors of PV systems that have to be deducted from the theoretically expected energy yield are exclusive for each individual system, the location and system components. During the design and installation of PV systems, it is important to make decisions in order to obtain the maximum energy yield possible from the PV array, which means taking into account and trying to reduce the losses associated with the system components [13].

Some literature proposes a typical range of values that can be considered for the evaluation of loss factors in a PV system. As a guideline for installers, architects and engineers, the book Planning and Installing Photovoltaic Systems [6] proposes the average percentage loss factors to be considered during system design as shown in Table 1

Table 1: Range of loss factors mentioned in the book Planning and Installing Photovoltaic Systems [6]

Losses	Range
Shading	0.0 - 5.0%
Module soiling	1.0 - 3.0%
Reflection	3.0 - 5.0%
Spectral variation of AM 1.5	1.0 - 2.0%
Mismatch and deviations from manufacturer's specifications	0.5 - 2.5%
Lower module efficiency due to deviation from STC	4.0 - 9.0%
DC cabling losses	0.5 - 1.5%
MPP adaptation errors exceeding or falling below the inverter work area	0.5 - 3.0%
Conversion losses of the inverter	3.0 - 7.5%
AC cabling losses	0.2 - 1.5%

5. Energy yield estimation

It is common practice at the beginning of the project to estimate the performance of a grid connected PV system using modeling software tools. These tools use as basic input: the meteorological conditions of the location, system design details and definitions of the main components. The tools then calculate the expected energy yield for a given period of time using modeling algorithms.

A variety of software for the modeling of PV systems are available in the market including PV*Sol [18], Homer [19], System Advisor Model (SAM) [20], PVsyst [21], among others. Currently, PVsyst is one of the most common software used by engineers, installers, and investors and has become the industry standard in the U.S. for the simulation of utility-scale PV systems [22]. PVsyst is the focus of this research.

The development of PVsyst started in 1992 at the University of Geneva and is now managed by PVsyst SA [23]. It is a highly complex tool which allows the study, sizing, simulation and data analysis of grid connected and stand-alone PV systems. There are two available user levels to perform the simulations of PV systems, a pre-dimensioning tool with visual elements and reduced numbers of parameters to achieve a quick initial estimation, and a more complex level with different options and parameters for a detailed design. A comprehensive set of documentation is available in order to guide the user in most of the selections and input fields along the modeling process [6].

PVsyst allows the definition of meteorological databases from many different sources and formats, as well as on-site measured data. The system components can be selected from an extended database or created from technical specifications. The design allows the definition of up to eight sub-arrays each with different modules and inverter models, allowing the simulation of more complex systems. It is possible to complement the design with further details like far and near shading, and specify detailed loss factors such as soiling, module quality, mismatch, ohmic wiring, and external transformer losses [3].

Few studies are available in literature regarding the evaluation of the accuracy of the modeling process of PVsyst in the prediction of energy yield in grid connected systems. According to PVsyst documentation [3], the validation of the accuracy of old versions of the software using measured data from 7 grid-connected systems showed that global results of the simulation were in the order of 2 to 3% Mean Bias Error (MBE). All the systems in the validation had relatively small capacities (0.5 – 100 kW_p) and were located in Switzerland. Another publication in 2009, available also in PVsyst documentation [24], presented the comparison of modeled and measured output in a 10kW installation of amorphous silicon modules, showing that PVsyst underestimated the annual energy yield by 1.7% (MBE).

In 2011, Lee, G. et al. [25] evaluated the performance of six PV systems of small capacity (< 7 kW) in Central Australia using PVsyst among other modeling software and showed that PVsyst tends to slightly underestimate the performance, confirming the investigation from SolarPro Magazine in 2010 [26] that found PVsyst to be the most conservative of the modeling tools evaluated. In 2013, Westbrock, O. and Collins, F. [22] performed a validation of PVsyst for a large-scale one-axis tracking PV system (602 kW_p Si-polycrystalline) and concluded that on an annual basis the range of MBE was –1.4% to 5.4%, which depended on the meteorological data type used as input, but performed with lower accuracy on shorter time scales. For that specific evaluated system, the transposition model was a large contributor to the AC energy error.

5.1. Modeling process in PVsyst

In PVsyst the calculation of energy yield in grid connected PV systems is a multi-step process which includes the modeling of the incident irradiation in the plane-of-array (POA), the array DC output and the inverter AC output. This proceeds as follows:

1. For the modeling of irradiation in the plane-of-array, PVsyst offers two transposition models; Hay [27] and Perez models [28].
   The Hay model is a robust model that gives good results even when the knowledge of the diffuse irradiation is not perfect while the Perez model is a more sophisticated model, which requires well measured horizontal data [3]. These models show a correspondence with the measurements at different locations, especially at south oriented planes with tilt angles ≤ 45° [29]. Some studies show that the Perez model usually predicts higher irradiance than the Hay model [30]–[34].
   In the case of input data that contains only irradiation in the plane-of-array, especially from measured data, the program first performs a retro-transposition using the Liu-Jordan model (which assumes that the diffuse radiation is isotropic) to evaluate the horizontal global and diffuse irradiances and then calculate the global irradiance in the plane-of-array [3].
   The shading effect over the module surface is calculated according to the system layout designed in a 3D CAD editor in PVsyst. This takes into account the surface area of shades in relation to predefined strings or the entire PV generator [6]. The reflection losses at the surface of the modules are then calculated in order to finally obtain the effective incident irradiation reaching the modules' surface.
2. For the modeling of the DC array output in PVsyst, the electrical behavior of the modules in the array is modeled using the "one-diode" equivalent circuit model in the case of silicon crystalline and CIS technologies. A modified version is used for thin film modules [3].The in-operation module temperature used in the model is calculated as an energetic balance between the energy absorbed and the thermal losses from the module to the surroundings.
   As a result, for a given effective irradiance and module operation temperature including the array loss factors, the DC power at MPP in the array is calculated.
3. The AC output is calculated using the efficiency curve of the inverter. The self-consumption of the inverter (fans, control systems) is also taken into account.
   The final energy output is calculated after the corresponding losses due to AC cabling and losses in the medium voltage external transformer.

The main simulation results includes monthly and yearly values for the total energy yield (MWh), performance ratio PR (%) and the specific energy (kWh/kW_p) [23]. The final report also includes a loss diagram that shows the energy balance and details of all losses in the system, providing a quick and graphical representation of the quality of the PV system design by identifying the main sources of losses [3].

6. Methodology

In order to evaluate the modeling process in PVsyst v6.25, six grid connected PV systems with nominal capacity between 1 and 12 MW_p [35], whose details are shown in Table 2, were simulated in PVsyst and their modeled performance compared to the actual measured performance of the systems.

The meteorological data measured on-site was used as input for the simulations. The system components and layouts were configured according to the as-built design and then the detailed loss factors were defined. After the simulation, the modeled energy yield was compared with the measured output and the deviations were analyzed. The methodology used for the evaluation was similar for every system. More details are given in the following section.

Table 2: Summary of PV systems included in this study

System	PV1	PV2	PV3	PV4	PV5	PV6
Location	Spain	Spain	Italy	Italy	Italy	Chile
Module Technology	Si-poly	Si-poly	Si-mono	Si-mono	Si-mono	Si-poly
Structure	fixed	fixed	fixed	fixed	one-axis tracker	fixed
Measurement period	2009	2009 2010	2012 2013	2012 2013	2012 2013	2013
Data resolution	monthly	monthly	daily	daily	daily	1 minutely
Irradiation data	global horizontal and plane-of-array	global horizontal and plane-of-array	global horizontal and plane-of-array	global horizontal and plane-of-array	global horizontal and plane-of-array	plane-of-array
Temperature data	ambient	ambient	ambient	ambient	ambient	ambient and array temperature
Wind speed data	not measured	not measured	yes	yes	yes	not measured
AC Energy meter	measured after inverter	measured after inverter	measured after inverter	measured after inverter	measured after inverter	measured at delivery point in substation
System availability details	not available	not available	yes (daily values)	yes (daily values)	yes (daily values)	yes (1 minutely)

6.1. Detailed system design in PVsyst

The following steps explain the detailed design process for each system in PVsyst:

1. The geographical location and meteorological data of the system was specified. For Systems PV1 and PV2, the monthly measured global horizontal irradiance (GHI) and ambient temperature values were imported. From this monthly dataset, PVsyst generated hourly synthetic data using Aguiar R., Collares-Pereira M. model [36], that first creates random sequence of daily values, using a library of Markov transition matrices and then applies a time-dependent, autoregressive, Gaussian model for generating the hourly sequences for each day. For the generation of

synthetic temperature data PVsyst constructs the daily sequences using random daily slopes with constraints on the monthly average temperature imported [3].

For Systems PV3, PV4 and PV5, the daily measured GHI and ambient temperature values were converted into a format file that could be imported into PVsyst. From this daily data set, PVsyst generated hourly values using a random distribution based on the Markov matrices [3].

In the case of System PV6, the 1-minute measured POA irradiance, ambient temperature and array temperature were compiled into a format file that could be imported into PVsyst. However, the program is only able to perform simulations starting from the horizontal irradiance. Therefore, for this system, from the measured irradiance PVsyst calculated the horizontal global and diffuse components (inverse of transposition) and then calculated the specified POA irradiance that was used in the simulation [3]. In the conversion process, PVsyst averages the imported meteorological data to get one-hour intervals.

2. The as-built configuration of design parameters of the PV systems were defined in PVsyst. The nominal capacity of each plant was taken from the flash list of the module manufacturer. For systems operating for more than one year, the linear annual degradation was applied according to the specifications from the module datasheet.
3. Modules and inverter models were selected from the component database in PVsyst. For each model, the technical specifications were validated against the manufacturer's datasheet. For cases where the specific model of any component was not available in this database, a new component was created using the corresponding tool in PVsyst.
4. The layout of the plants was created using PVsyst's 3D CAD editor, in order to evaluate near shadings. For the evaluation of far shadings the horizon profile was created using a panoramic image taken on-site, when available, otherwise a free horizon was considered.
5. The input parameters for detailed losses in PVsyst (i.e. thermal parameters, ohmic losses, module quality, soiling losses and IAM losses) were set at their default values or modified according to the experience of Lahmeyer International GmbH (LI) experts in similar projects.

6.2. Data quality control

The purpose of this study was the comparison between modeled and measured energy yield during periods of full operation of the systems, therefore, all the information gathered from each system was filtered in order to eliminate non-useful data.

The availability of the systems was also checked in the Operation & Maintenance (O&M) reports (except in PV1 and PV2 systems because of the lack of this information in the reports), and those days or hours during system shutdowns, or when one or more inverters reported operational problems were removed and not considered in the analysis.

In System PV6, the measured meteorological data was screened and checked in order to remove any period of time when data was missing or erroneous.

Detailed information about the number of days or hours that were removed is specified in the sections corresponding to the analysis of each system.

6.3. Metrics for the evaluation

In order to quantify the performance of the modeling process of PVsyst, the metrics used for the evaluation of the software System Advisor Model (SAM) reported by Freeman J. et al. [37] were considered and adapted for the evaluations in this study.

For the evaluation of the relative modeling error on a monthly and annual basis, all available hours or days during the month/year of the modeled and measured values were summed separately according to Equation 1. A positive error represented an overestimation from PVsyst.

$$Relative\ Error(\%) = \frac{\sum Modeled - \sum Measured}{\sum Measured} \qquad \text{Equation 1}$$

In order to quantify the model performance in hourly basis two dimensionless metrics were used, Normalized Mean Bias Error (NMBE) and Normalized Root Mean Square Error (NRMSE).

NMBE is the average difference between modeled and measured values on an hourly basis and calculated according to Equation 2. Normalization was done with the maximum measured output of each system [37].

$$NMBE = \frac{\frac{\sum_i^N Modeled_i - Measured_i}{N} \times 100\%}{Maximum\ \ measured\ output} \qquad \text{Equation 2}$$

NRMSE is a common metric that ensures that those hours that the model overestimates the output values do not cancel out errors when the output is underestimated and calculated according to Equation 3. The normalization was done as in NMBE [37].

$$NRMSE = \frac{\sqrt{\frac{\sum_i^N (Modeled_i - Measured_i)^2}{N}}}{Maximum\ measured\ output} \times 100\% \qquad \text{Equation 3}$$

This normalization also applies for measured irradiance or energy yield values in each system in order to preserve the confidentiality of the projects.

7. Results and Discussion

The following sections describe the results for each of the six PV system simulated in PVsyst V6.25 according to the methodology detailed in previous section:

7.1. System PV1

7.1.1. Modeling details

General details of System PV1 are shown in Table 3:

Table 3: System PV1 details

Location	Spain
Installation Type	Ground mounted
Module Technology	Si-Polycrystalline
Field type	Fixed tilted plane
Tilt/Azimuth	30° / 0°
Inverter configuration	Mini central inverters

Irradiation data: Monthly on-site measured GHI values from a pyranometer and monthly POA irradiance from reference cells.

Temperature data: Monthly mean diurnal temperature values.

Nominal capacity: This system was operating for more than one year, for this reason, the nominal capacity for the design in PVsyst was calculated first applying the module degradation due to light induced degradation (LID) (1.5%, typical for Si-polycrystalline modules) to the initial nominal capacity indicated in the flash test list and then applying the annual module degradation percentage (0.4% per year).

Array configuration: The number of modules per string and per inverter was specified in the as-built design parameters; however, it was noticed that strings of modules from the same manufacture, but different nominal power range were connected to the same inverter. In PVsyst it is not possible to design this type of configuration; therefore the system was designed selecting the nominal module capacity which represented the largest share in the installation.

Energy yield: From January until November 2009 the AC energy yield was reported from the meters installed after the inverters. The energy yield value reported in December was not measured at the same point as the previous months and it was estimated from the measurement of a second meter installed just before the feed in point at the delivery substation. The reported value is an approximation and it is not representative for the analysis.

Detailed loss factors in PVsyst: Albedo: 0.2, thermal loss factors: Uc: 29W/m²K, Uv: 0W/m²K/m/s, DC cabling loss: 1.5%, module quality: 0%, mismatch loss at MPP: 1%, IAM factor ASHRAE model (bo): 0.05, soiling losses: 1%, free horizon and linear near shading losses. AC cabling losses and transformer losses were not considered.

7.1.2. Results

Two simulations of the system were performed using the Perez and Hay transposition model to calculate the irradiance in the plane-of-array from the monthly measured GHI. The comparison between the measured and modeled energy yield using each model is shown in Figure 3. The monthly relative error is shown in Table 4.

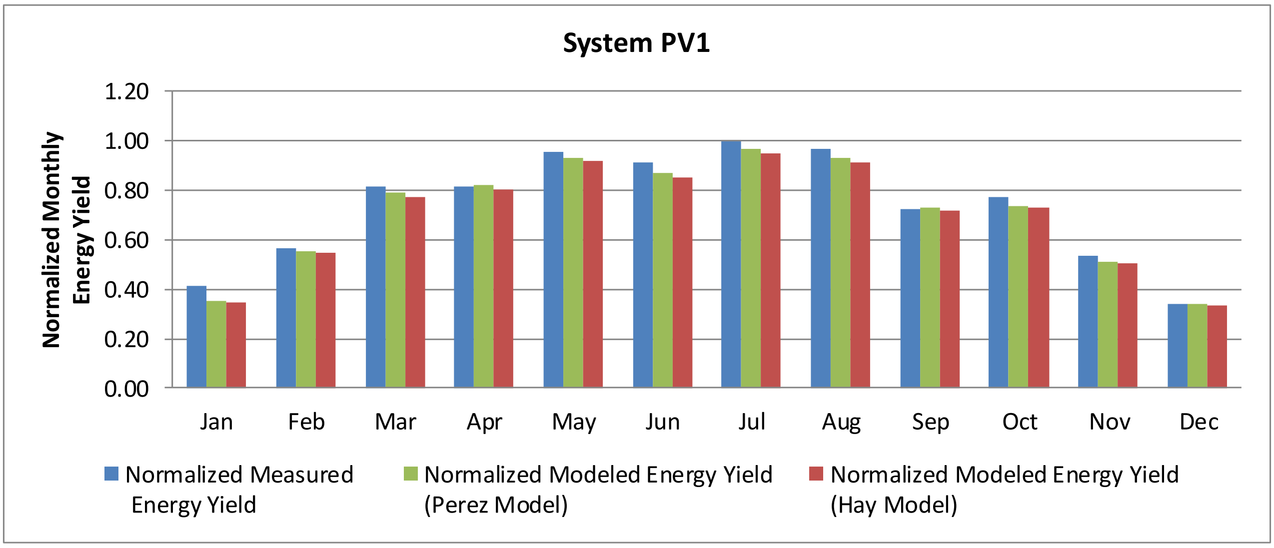

Figure 3 Monthly comparison of measured and modeled normalized energy yield - SystemPV1

Table 4: Monthly energy yield relative errors SystemPV1

		Monthly Relative Error											
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2009	Perez Model	-14.5%	-1.6%	-3.3%	0.6%	-2.5%	-5.0%	-3.3%	-4.1%	0.4%	-4.6%	-4.3%	0.8%
	Hay Model	-16.5%	-3.1%	-5.4%	-1.2%	-4.3%	-6.8%	-5.2%	-5.7%	-1.4%	-5.8%	-5.3%	-0.9%

As mentioned before, the energy measured in December is not consistent for the purpose of this comparison; therefore it is excluded in the analysis. The total error for the evaluated period is shown in Table 5.

Table 5: Monthly and total energy yield relative errors excluding December - SystemPV1

		Monthly Relative Error											Total Error
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	
2009	Perez Model	-14.5%	-1.6%	-3.3%	0.6%	-2.5%	-5.0%	-3.3%	-4.1%	0.4%	-4.6%	-4.3%	**-3.4%**
	Hay Model	-16.5%	-3.1%	-5.4%	-1.2%	-4.3%	-6.8%	-5.2%	-5.7%	-1.4%	-5.8%	-5.3%	**-5.1%**

7.1.3. Discussion

As shown in Figure 3 and Table 5, PVsyst underestimated the energy yield during the evaluated period by –3.4% and by –5.1% using Perez and Hay model respectively. It can be seen that there is a monthly variation and the tendency is to underestimate for almost all the months, with two exceptions using Perez model. The highest difference occurs in January for both models.

Figure 4 presents a comparison between the monthly measured POA irradiance from the reference cells and the effective POA irradiance calculated in PVsyst using the two transposition models. It can be seen that calculations using Hay model were lower compared to the results using Perez model during the year, as predicted by literature. It can also be seen that in January the modeled POA irradiance is significantly lower than the measured one and could infer that this was a contributor to the large error during this month.

In order to analyze this large error, the GHI from a Typical Meteorological Year (TMY) predicted by two meteorological databases (Meteonorm [38] and SolarGIS [39]) for the same location and the measured GHI were compared. This comparison showed that the relative error between the measured and predicted value was around -20%, which suggests that there was a possible failure in the measurement device or in the data acquisition system. This was confirmed from the maintenance reports where it was mentioned that during 1 day and some hours during this month, the system did not record any information from the meteorological station.

In Figure 4, it can also be seen that modeled POA tends to be higher than the measured and suggests that higher losses were modeled due to higher array temperatures. Further analysis was however not possible because of the low resolution of the measured data and unavailability of required information (i.e. array temperature and wind speed) in addition to the complexity of such analysis.

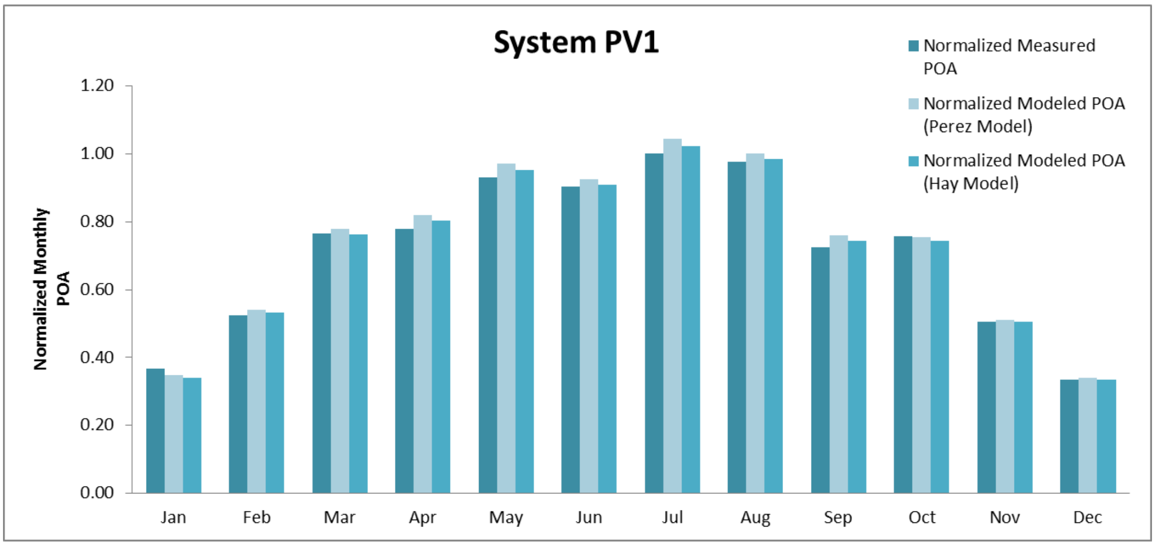

Figure 4: Monthly comparison of normalized measured and modeled irradiation in the plane-of-array (POA) - System PV1

7.2. System PV2

7.2.1. Modeling details

General details of System PV2 are shown in Table 6:

Table 6: SystemPV2 details

Location	Spain
Installation Type	Ground mounted
Module Technology	Si-Polycrystalline
Field type	Fixed tilted plane
Tilt / Azimuth	30° / 0°
Inverter configuration	Mini central inverters

Irradiation data: Monthly on-site measured GHI values from a pyranometer and monthly POA irradiance from reference cells.

Temperature data: Monthly mean diurnal temperature values.

Nominal capacity: This system was operating for more than one year, for this reason, the nominal capacity for the design in PVsyst was calculated first applying the module degradation due to LID (1.5%, typical for Si-polycrystalline modules) to the initial nominal capacity indicated in the flash test list and then applying the annual module degradation percentage (0.4% per year).

Array configuration: The number of modules per string and per inverter was specified using the as-built design parameters. In this system, modules with two different nominal capacities were installed, therefore in PVsyst the system was configured as two sub-arrays, each one with the corresponding module capacity.

Energy yield: AC energy yield was measured with energy meters after the inverters.

Detailed loss factors in PVsyst: Albedo: 0.2, thermal loss factors: Uc: 29W/m²K, Uv: 0W/m²K/m/s, DC cabling loss: 1%, module quality: 0%, mismatch loss at MPP: 0.4%, IAM factor ASHRAE model (bo): 0.05, soiling losses: 1%, free horizon and linear near shading losses. AC cabling losses and transformer losses were not considered.

7.2.2. Results

Two simulations of the system were performed using the Perez and Hay transposition model to calculate the irradiance in the plane-of-array from the monthly measured GHI. The comparison between the measured and modeled energy yield using each model is shown in Figure 5 for 2009 and Figure 6 for 2010. The monthly and annual relative error is shown in Table 7

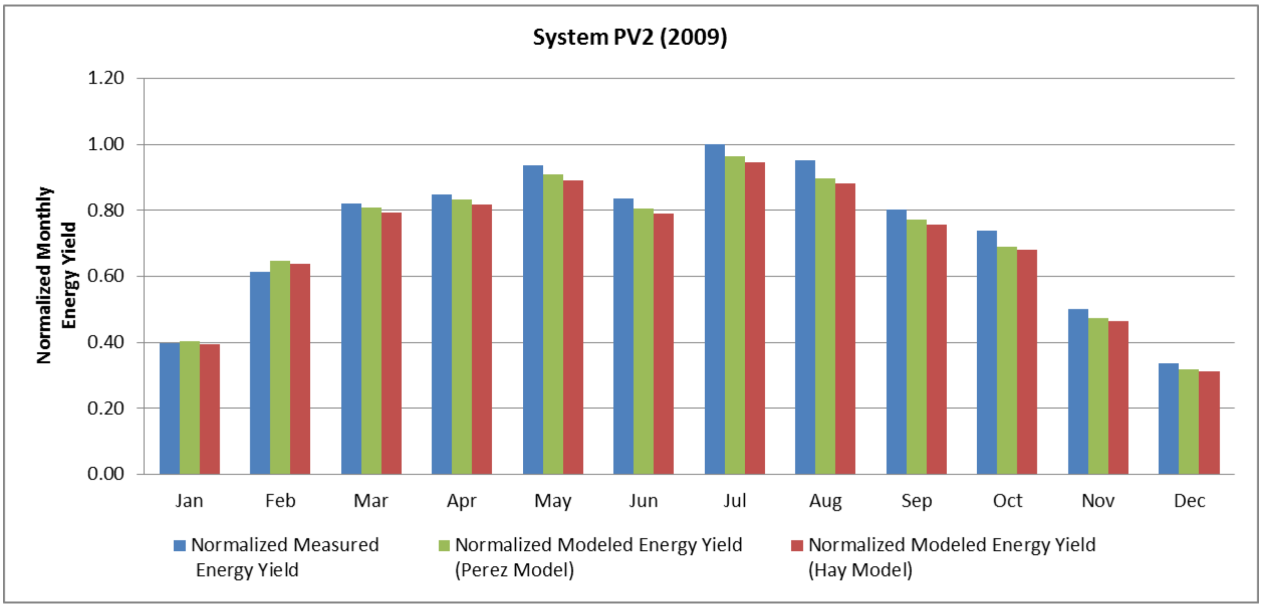

Figure 5: Monthly comparison of measured and modeled normalized energy yield – SystemPV2 in 2009

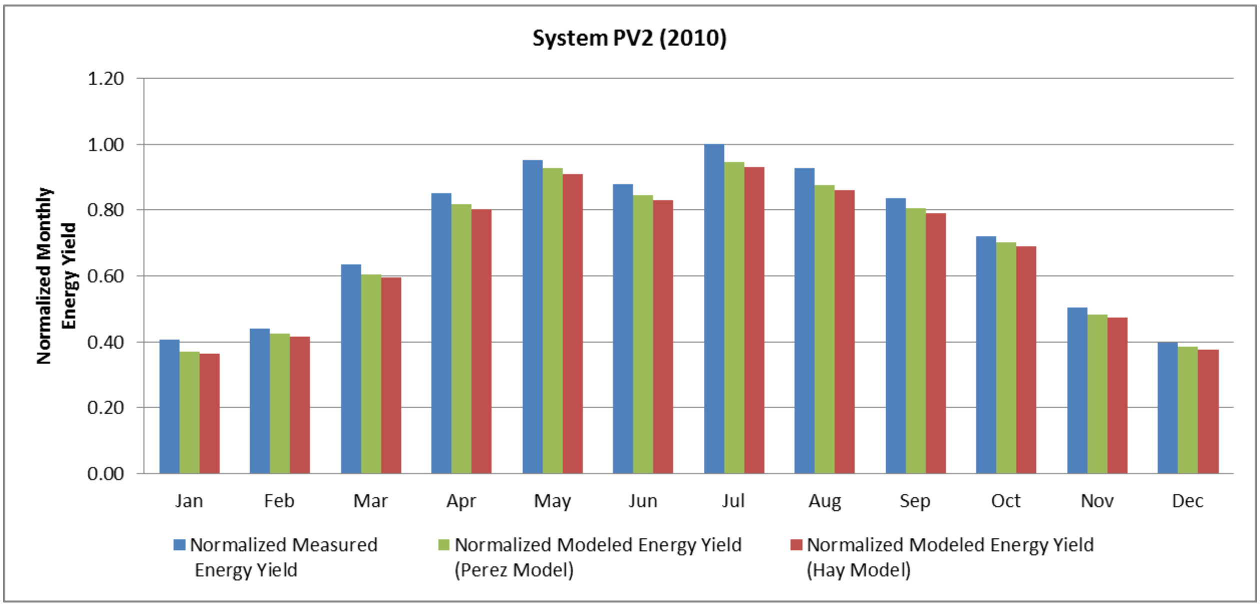

Figure 6: Monthly comparison of measured and modeled normalized energy yield – SystemPV2 in 2010

Table 7: Monthly and annual energy yield relative errors - System PV2

		Monthly Relative Error												Annual Error
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
2009	Perez Model	1.6%	5.3%	-1.5%	-1.9%	-2.9%	-3.7%	-3.8%	-5.8%	-3.8%	-6.4%	-5.5%	-4.8%	**-3.0%**
	Hay Model	-0.3%	3.8%	-3.4%	-3.7%	-4.7%	-5.4%	-5.5%	-7.4%	-5.6%	-7.9%	-7.5%	-6.9%	**-4.7%**
2010	Perez Model	-8.8%	-2.9%	-4.3%	-4.1%	-2.8%	-3.8%	-5.4%	-5.5%	-3.6%	-2.5%	-4.1%	-3.2%	**-4.2%**
	Hay Model	-10.5%	-5.0%	-5.9%	-5.9%	-4.5%	-5.6%	-7.1%	-7.2%	-5.3%	-4.2%	-5.8%	-5.1%	**-5.9%**

7.2.3. Discussion

As can be seen in Figure 5, Figure 6 and Table 7, PVsyst underestimated the energy yield by 3.0% and 4.2% using Perez model, and by 4.7% and 5.9% using Hay model, in 2009 and 2010 respectively.

Similar to System PV1, the input irradiation data for the simulation was monthly global horizontal measurements and the uncertainty of the transposition model contributed to the uncertainties of the modeled energy yield. Figure 7 and Figure 8 show the comparison between the monthly measured POA irradiance from the reference cells and the results from PVsyst using the two available transposition models. Again, as predicted by literature, POA irradiance calculated using Hay model was lower compared with the results using Perez model during the year.

From Figure 7 and Figure 8 it can also be seen that modeled POA tends to be higher than the measured value. As found in System PV1, it can be inferred that higher losses were modeled due to higher array temperatures. Further analysis was however not possible because of the low resolution of the measured data and unavailability of required information (i.e. array temperature and wind speed) in addition to the complexity of such analysis.

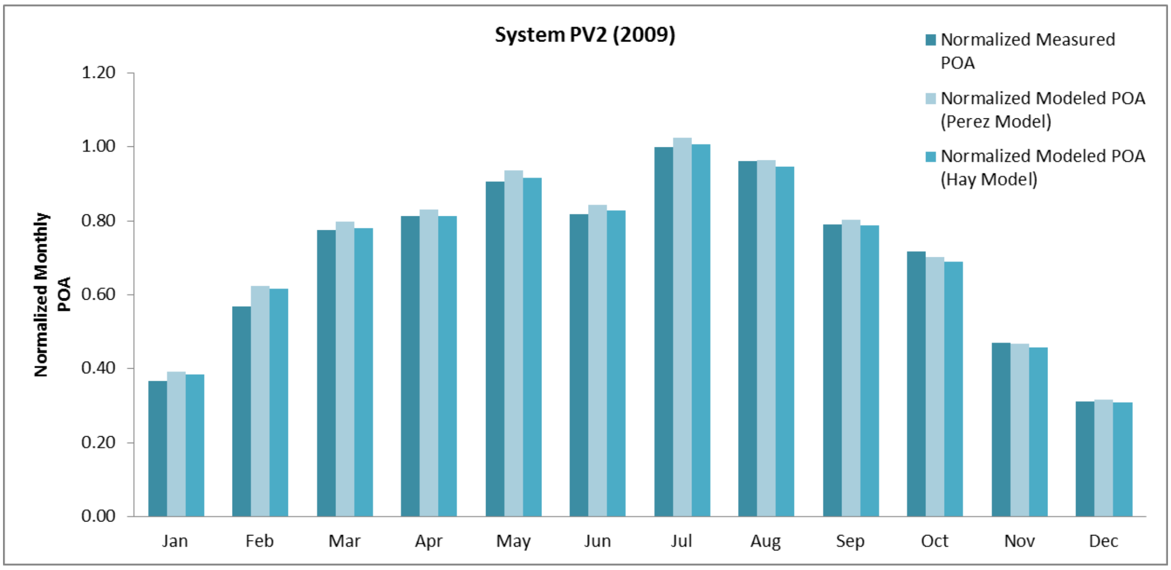

Figure 7: Monthly comparison of normalized measured and modeled irradiation in the plane-of-array (POA) – System PV2 in 2009

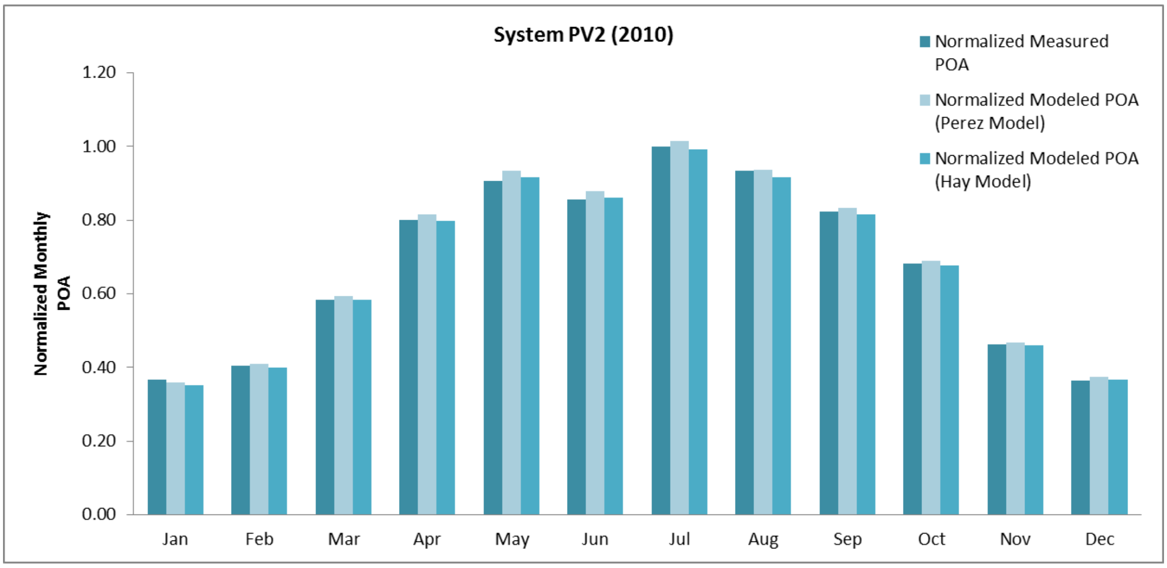

Figure 8: Monthly comparison of normalized measured and modeled irradiation in the plane-of-array (POA) – System PV2 in 2010

7.3. System PV3

7.3.1. Modeling details

General details of System PV3 are shown in Table 8:

Table 8: System PV3 details

Location	Italy
Installation Type	Ground mounted
Module Technology	Si-Monocrystalline
Field type	Fixed tilted plane
Tilt / Azimuth	20° / 0°
Inverter configuration	Central inverters

Irradiation data: Daily on-site measured GHI values from secondary standard pyranometers and daily POA irradiance measurements from reference cells.

Temperature data: Average daily temperature values.

Nominal capacity: This system was operating for more than one year, for this reason, the nominal capacity for the design in PVsyst was calculated applying an annual degradation percentage (0.5% per year) to the initial nominal capacity indicated in the flash test list. According to the manufacturer, the modules installed in this system are not affected by LID losses and thus these were not considered.

Array configuration: The number of modules per string and per inverter was specified using the as-built design parameters. In this system, inverters of two different nominal capacities were installed, therefore in PVsyst the system was configured as two sub-arrays, each one with the corresponding inverter capacity

Energy yield: AC energy yield was measured with energy meters after the inverters.

Detailed loss factors in PVsyst: Albedo: 0.2, thermal loss factors: Uc: 29W/m²K, Uv: 0W/m²K/m/s, DC cabling loss: 1.5%, module quality: 0%, mismatch loss at MPP: 0.5%, IAM factor ASHRAE model (bo): 0.05, soiling losses: 1.5%, on-site profile horizon and linear near shading losses. AC cabling losses and transformer losses were not considered.

Data quality control: 44 days in 2012 and 30 days in 2013 when the system was not operating at 100% availability (according to O&M reports) were excluded for the comparison.

7.3.2. Results

Two simulations of the system were performed using the Perez and Hay transposition models to calculate the irradiance in the plane-of-array from the monthly measured GHI values for the years 2012 and 2013. As the input values were in daily basis, PVsyst generated synthetic hourly data from irradiance and temperature measurements, as explained in section 6.1.

The comparison between the measured and modeled energy yield is shown in Figure 9 and Figure 10. The error calculation was evaluated in the monthly and annual basis and is shown in Table 9:

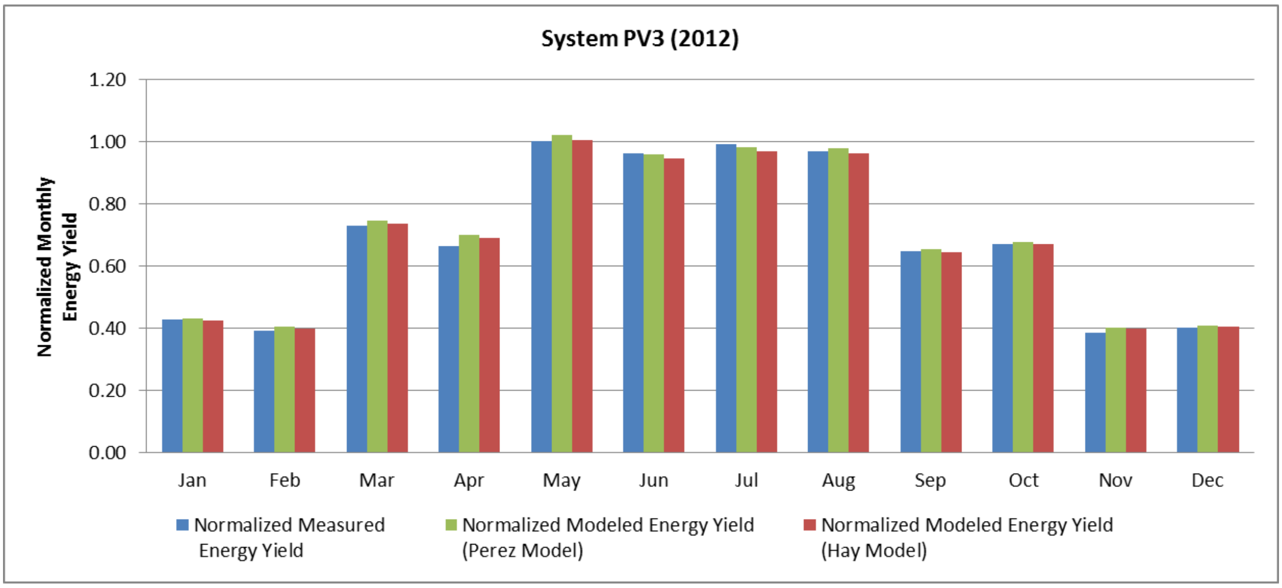

Figure 9: Monthly comparison of measured and modeled normalized energy yield – SystemPV3 in 2012

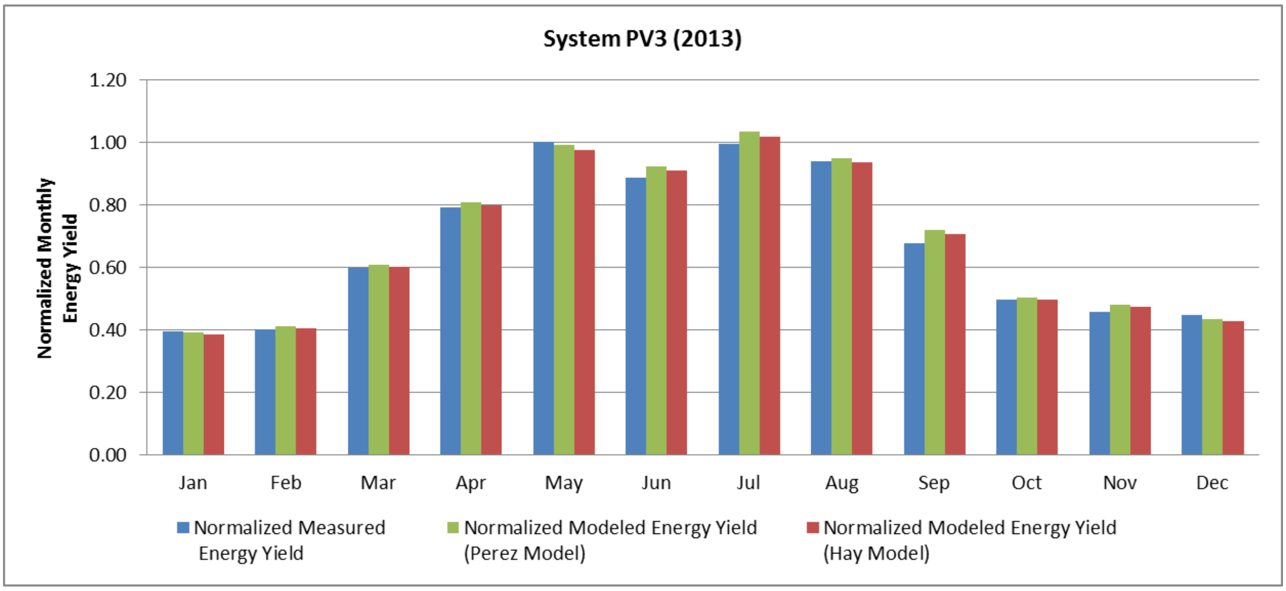

Figure 10: Monthly comparison of measured and modeled normalized energy yield – SystemPV3 in 2013

Table 9: Monthly and annual energy yield relative errors – System PV3

		Monthly Relative Error												Annual Error
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
2012	Perez Model	0.7%	2.8%	2.1%	5.2%	2.0%	-0.3%	-1.0%	0.8%	0.9%	1.0%	4.6%	1.9%	**1.4%**
	Hay Model	-0.3%	1.5%	0.7%	3.7%	0.5%	-1.7%	-2.4%	-0.6%	-0.7%	-0.3%	3.2%	0.6%	**0.03%**
2013	Perez Model	-1.1%	2.2%	1.9%	2.2%	-1.0%	4.4%	4.0%	1.2%	6.0%	1.7%	5.6%	-2.9%	**2.2%**
	Hay Model	-2.4%	0.5%	0.5%	0.8%	-2.5%	2.9%	2.5%	-0.3%	4.3%	0.2%	4.2%	-4.1%	**0.7%**

7.3.3. Discussion

As shown in Figure 9, Figure 10 and Table 9, for this system PVsyst overestimated the energy yield up to 2.2% using Perez model in 2013. On the other hand, using Hay model, the annual results from the simulation are close to the measured values with annual relative errors less than 1%. In both models, it can be seen that the monthly error for the two consecutive years ranges from –4.1% to 5.2%, and during almost all months the tendency was to overestimate.

The additional information about the availability of the system allowed a comparison of the performance only during those days when the system was 100% available, eliminating the uncertainties from these values. However, as the measured data was on a daily basis, there were still other uncertainties that were difficult to isolate, specifically the effect of the transposition models used in PVsyst for the calculation of the irradiance in the plane-of-array.

A comparison between the measured irradiance from the reference cells and the modeled effective POA irradiance showed that there was a tendency for PVsyst to overestimate this value. In order to quantify the difference, irradiance measurements from a pyranometer in the module plane would be required, due to PVsyst generates broadband POA irradiance and the measurements from the references are spectral sensitive. It was also found out in literature, that a correction model was used by Reich, N. Mueller, B. et al. [40], that allowed calculating the combined influence of angular losses and spectral effects based on irradiance data measured by only reference cells. Detailed information about the correction model was going to be presented after the publication of the mentioned study and would allow quantifying the difference of the modeled and measured POA irradiance. Nevertheless, further analysis about this topic was considered out of the scope of the present work.

Regarding the evaluation of modeled thermal losses, even though the wind speed in the location was measured, daily mean values do not provide enough information about the cooling effect over the modules during sunny hours, when the array is operating and PVsyst does not have any algorithm to generate hourly values of wind velocity from daily measurements. Another drawback was the lack of array temperature measurements, which are necessary to compare with the modeled array temperature and evaluate the thermal losses in the system.

Using the flash test list of the manufacturer of the modules installed in this system, it was possible to evaluate the mismatch loss factor due to the differences in the modules' nominal power. The as-built design revealed that the PV modules were sorted according to the short circuit current (Isc) detailed in the flash list in order to minimize the mismatch effect.

7.4. System PV4

7.4.1. Modeling details

General details of System PV4 are shown in Table 10:

Table 10: System PV4 details

Location	Italy
Installation Type	Ground mounted
Module Technology	Si-Monocrystalline
Field type	Fixed tilted plane
Tilt / Azimuth	20° / 0°
Inverter configuration	Central inverters

Irradiation data: Daily on-site measured GHI values from secondary standard pyranometers and daily POA irradiance measurements from reference cells.

Temperature data: Average daily temperature values.

Nominal capacity: This system was operating for more than one year, for this reason, the nominal capacity for the design in PVsyst was calculated applying an annual degradation percentage (0.5% per year) to the initial nominal capacity indicated in the flash test list. According to the manufacturer, the modules installed in this system are not affected by LID losses and thus these were not considered.

Array configuration: The system consists of the same type of modules and inverters, therefore in PVsyst the system was configured as one array.

Energy yield: AC energy yield was measured with energy meters after the inverters.

Detailed loss factors in PVsyst: Albedo: 0.2, thermal loss factors: Uc: 29W/m²K, Uv: 0W/m²K/m/s, DC cabling loss: 1.5%, module quality: 0%, mismatch loss at MPP: 0.5%, IAM factor ASHRAE model (bo): 0.05, soiling losses: 1.5%, free horizon and linear near shading losses. AC cabling losses and transformer losses were not considered.

Data quality control: 37 days in 2012 and 48 days in 2013 when the system was not operating at 100% availability (according to O&M reports) were excluded in the comparison.

7.4.2. Results

Two simulations were performed using Perez and Hay model to calculate the irradiance in the plane-of-array from the GHI measurements for the years 2012 and 2013. As the input values were daily averages, PVsyst generated synthetic hourly data from irradiance and temperature measurements, as explained in section 6.1.

The comparison between the measured and modeled energy yield is shown in Figure 11 and Figure 12. The error calculation was evaluated on a monthly and annual basis and is shown in Table 11:

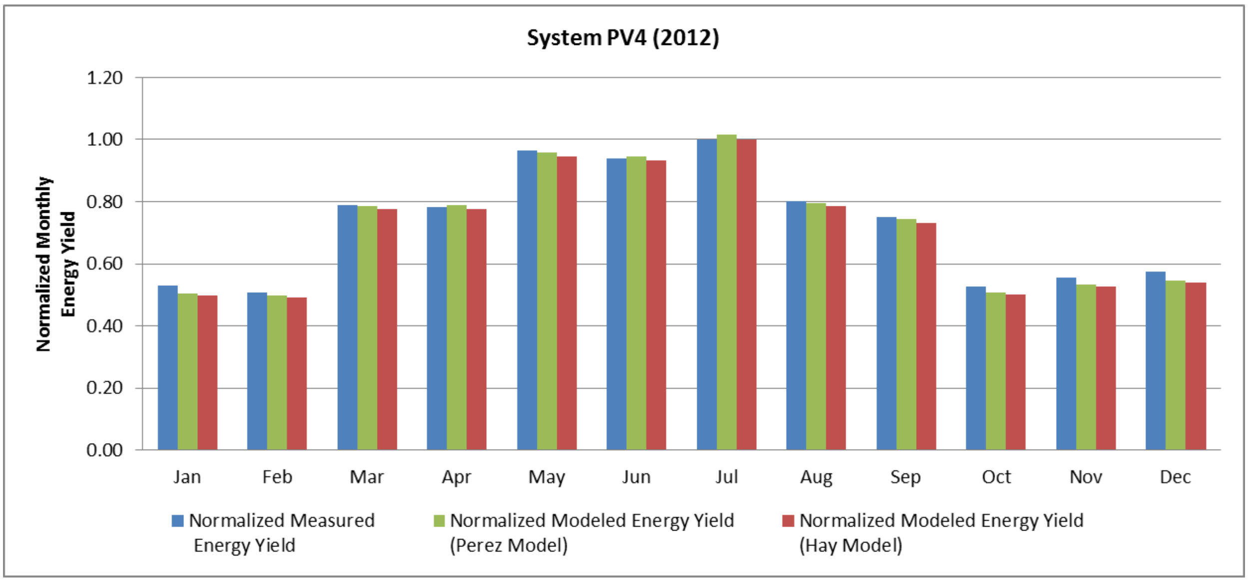

Figure 11: Monthly comparison of measured and modeled normalized energy yield – SystemPV4 in 2012

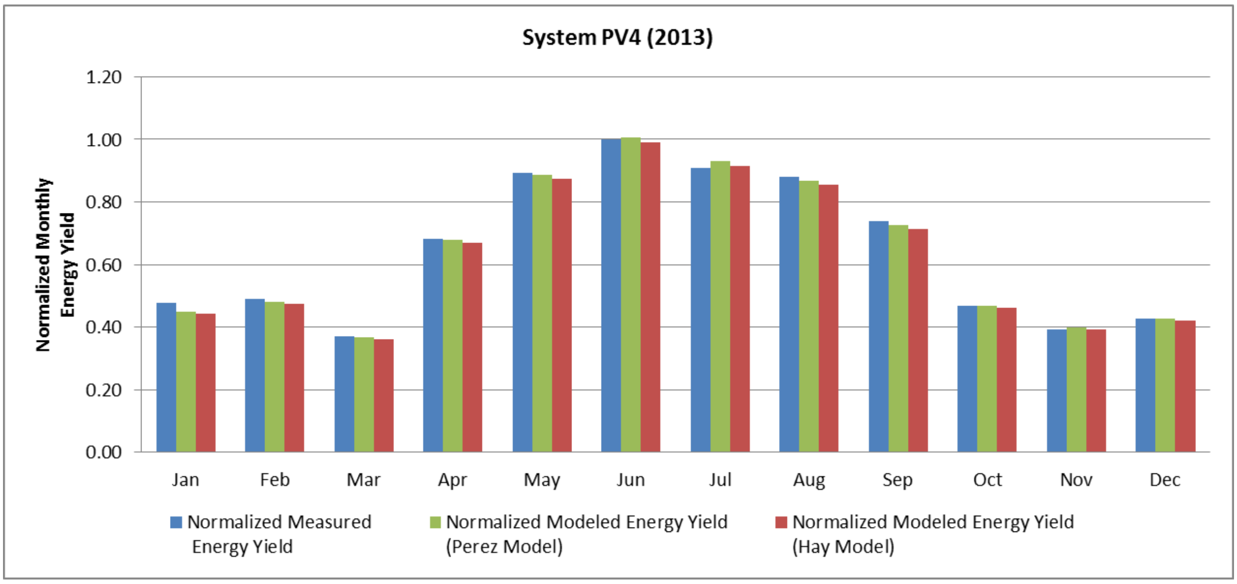

Figure 12: Monthly comparison of measured and modeled normalized energy yield – SystemPV4 in 2013

Table 11: Monthly and annual energy yield errors – System PV4

		Monthly Relative Error												Annual Error
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
2012	Perez Model	-4.4%	-1.7%	-0.3%	0.8%	-0.5%	0.7%	1.6%	-0.6%	-1.2%	-3.3%	-3.7%	-5.1%	**-1.0%**
	Hay Model	-5.5%	-3.0%	-1.6%	-0.7%	-1.9%	-0.7%	0.1%	-2.1%	-2.7%	-4.9%	-5.1%	-6.0%	**-2.4%**
2013	Perez Model	-6.2%	-2.1%	-0.9%	-0.5%	-0.5%	0.5%	2.2%	-1.4%	-1.8%	-0.1%	1.1%	0.1%	**-0.6%**
	Hay Model	-7.5%	-3.5%	-2.5%	-1.8%	-1.9%	-0.9%	0.8%	-2.9%	-3.3%	-1.6%	-0.1%	-1.2%	**-2.0%**

7.4.3. Discussion

As shown in Figure 11, Figure 12 and Table 11, for this system PVsyst underestimated the energy yield by up to 2.4% using Hay model in 2012. On the other hand, using Perez model, the annual results from the simulation were close to the measured values. In both models, it was seen that PVsyst tends to have a higher under-prediction in winter season.

The shortcomings for a deep analysis of the results are the same as mentioned in the discussion of System PV3. The uncertainty evaluation of transposition model and the calculation of array temperature is a complex process without the required information.

7.5. System PV5

7.5.1. Modeling details

General details of System PV5 are shown in Table 12:

Table 12: System PV5 details

Location	Italy
Installation Type	Ground mounted
Module Technology	Si-Monocrystalline
Field type	One-axis tracking
Inverter configuration	Central inverters

Irradiation data: Daily on-site measured GHI values from secondary standard pyranometers and daily POA irradiance measurements from reference cells.

Temperature data: Average daily temperature values.

Nominal capacity: This system was operating for more than one year, for this reason, the nominal capacity for the design in PVsyst was calculated applying an annual degradation percentage (0.5% per year) to the initial nominal capacity indicated in the flash test list. According to the manufacturer, the modules installed in this system are not affected by LID losses and thus these were not considered.

Energy yield: AC energy meters installed after the inverters.

Detailed loss factors in PVsyst: Albedo: 0.2, thermal loss factors: Uc: 29W/m²K, Uv: 0W/m²K/m/s, DC cabling loss: 1.5%, module quality: 0%, mismatch loss at MPP: 0.5%, IAM factor ASHRAE model (bo): 0.05, soiling losses: 1.5%, location horizon profile and linear shading losses. AC cabling losses and transformer losses were not considered.

Data quality control: 30 days in 2012 and 48 days in 2013, when the system was not operating at 100% availability (according to O&M reports) were excluded.

7.5.2. Results

Two simulations were performed using Perez and Hay models to calculate the irradiance in the plane-of-array from the GHI measurements for the years 2012 and 2013. As the input values were daily averages, PVsyst generated synthetic hourly data from irradiance and temperature measurements, as explained in section 6.1.

The comparison between measured and modeled energy yield is shown in Figure 13 and Figure 14. The deviations were evaluated on a monthly and annual basis and are shown in Table 13:

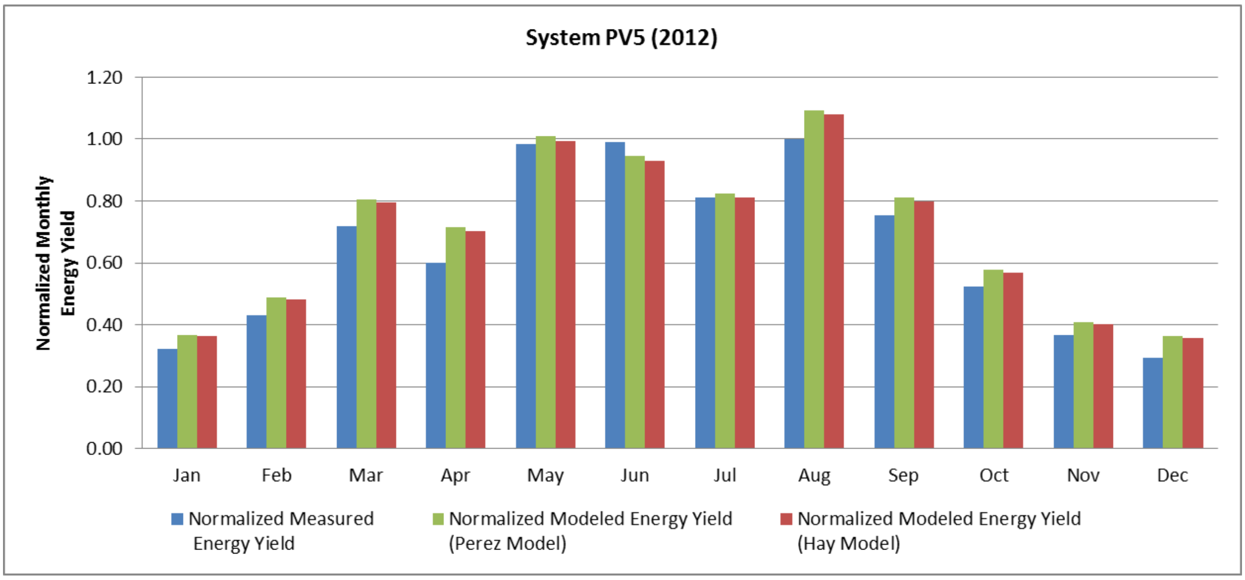

Figure 13: Monthly comparison of measured and modeled normalized energy yield – SystemPV5 in 2012

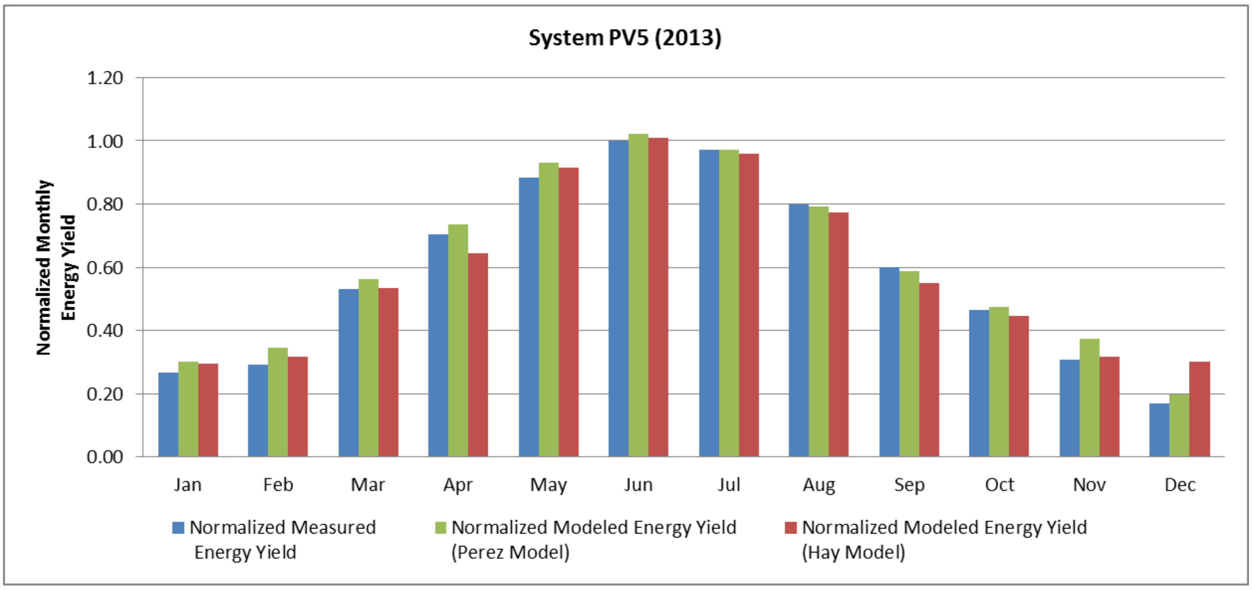

Figure 14: Monthly comparison of measured and modeled normalized energy yield – SystemPV5 in 2013

Table 13: Monthly and annual energy yield relative errors – System PV5

		Monthly Error Relative												Annual Error
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
2012	Perez Model	13.9%	12.8%	11.9%	19.1%	2.5%	-4.5%	1.4%	9.2%	7.5%	10.1%	11.0%	22.9%	**7.7%**
	Hay Model	12.6%	11.3%	10.6%	17.1%	0.8%	-6.1%	-0.1%	7.9%	5.6%	8.6%	9.5%	21.2%	**6.13%**
2013	Perez Model	12.9%	17.5%	6.0%	4.7%	5.1%	2.1%	0.3%	-0.8%	-2.2%	2.3%	21.7%	16.4%	**4.4%**
	Hay Model	11.2%	14.4%	3.6%	1.6%	3.3%	0.9%	-1.2%	-3.1%	-4.3%	-0.2%	13.4%	11.2%	**2.0%**

7.5.3. Discussion

From the results in Table 13, it can be seen that PVsyst significantly overestimated the energy yield in almost all the months in the two years. The highest overestimations occurred during winter time and the tendency was the same when using the two transposition models. In order to understand the effect of the uncertainty produced by the transposition model in the calculation of the irradiance in the plane-of-array for this tracking system, the monthly differences between the modeled and measured energy yield and the same difference for POA irradiance were plotted as in Figure 15. It can be seen that the deviation of the energy yield is highly correlated to the tendency of deviation in the calculation of POA irradiance. This means that PVsyst overestimated the effective irradiance in the module plane and consequently overestimated the energy production. A similar tendency was found in 2013.

It is important to mention that irradiation in plane-of-array was measured with crystalline silicon reference cells and Figure 15 is only used to provide a visual representation of the difference between modeled and measured POA irradiance. This was done in order to see the correlation to the energy yield, and not to quantify the differences, due to the spectral sensitivity of the reference cells and broadband irradiation values as generated by PVsyst in the plane-of-array, as explained in section 7.3.3.

A recent study published by Westbrook O. and Collins F. [22] in 2013 reported a validation of PVsyst for a horizontal single-axis tracking system in the U.S. Southwest Desert, where Hay and Perez transposition models were evaluated using measured data. The simulation's inputs were measured GHI data from a pyranometer, both with and without DHI data provided by the National Renewable Energy Laboratory (NREL). The overall annual and monthly transposition model mean bias errors were reported to be below 1.5%, but increased further on daily and hourly time scales (around 25% to 30% hourly RMSE). According to the authors, in locations with more sub-hourly weather variability than Las Vegas, higher transposition model errors maybe expected. This could be the case for this system located in Italy and provide an explanation for the behavior of the modeled results.

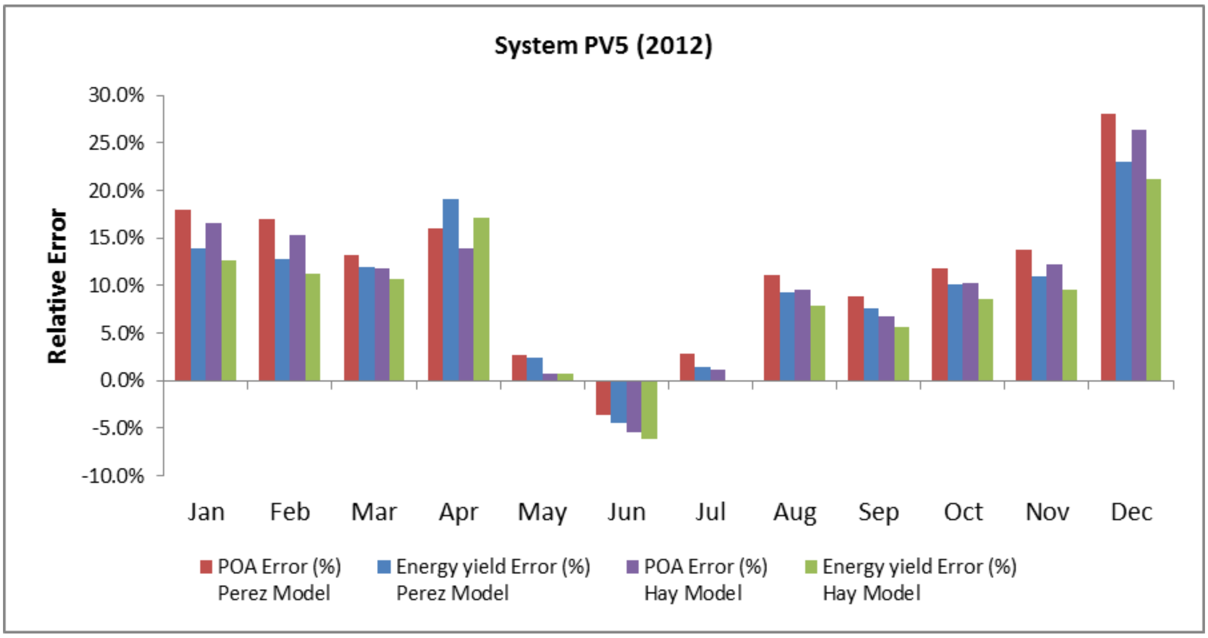

Figure 15: Comparison of monthly energy yield and POA irradiance relative errors – System PV5 in 2012

7.6. System PV6

7.6.1. Modeling details

General details of System PV6 are shown in Table 14:

Table 14: System PV6 details

Location	Chile
Installation Type	Ground mounted
Module Technology	Si-Polycrystalline
Field type	Fixed
Tilt / Azimuth	20° N / 0°
Inverter configuration	Central inverters

Irradiation data: 1 minute on-site measured POA irradiance measurements from a secondary standard pyranometer and reference cell.

Temperature data: 1 minute ambient and back-of-module temperature.

Nominal capacity: Nominal capacity from flash test list

Detailed loss factors in PVsyst: Albedo: 0.2, thermal loss factors: Uc: 29W/m²K, Uv: 0W/m²K/m/s, DC cabling loss: 1.5%, module quality: 0%, LID loss factor: 1.5%, mismatch loss at MPP: 1.0%, IAM factor ASHRAE model (bo): 0.05, soiling losses: 1.5%, free horizon profile and linear near shading losses. AC cabling losses were neglected. Iron losses and resistive/inductive losses for the transformer were calculated according to technical details from the transformer datasheet.

Energy yield: AC energy meter installed at delivery substation after the medium voltage transformer.

Data quality control: Nighttime hours and hours when the plant was not 100% available were excluded. A total of 2785 hours were considered for the comparison.

7.6.2. Results

In this system, two variations of the simulation were performed. The first variant was designed using the thermal loss factors described above and in the second variant using the measured array temperature.

As described previously in methodology section, the 1-minutely measured POA irradiance, ambient temperature and array temperature were imported into PVsyst, and then PVsyst averaged the data to get one-hour intervals used in the modeling process. The hourly results from the simulation were then compared with the measurements values.

Figure 16 shows the energy yield modeled results from the first variant compared with the measured output after the transformer. The deviations were evaluated on a monthly and annual basis and are as shown in Table 15.

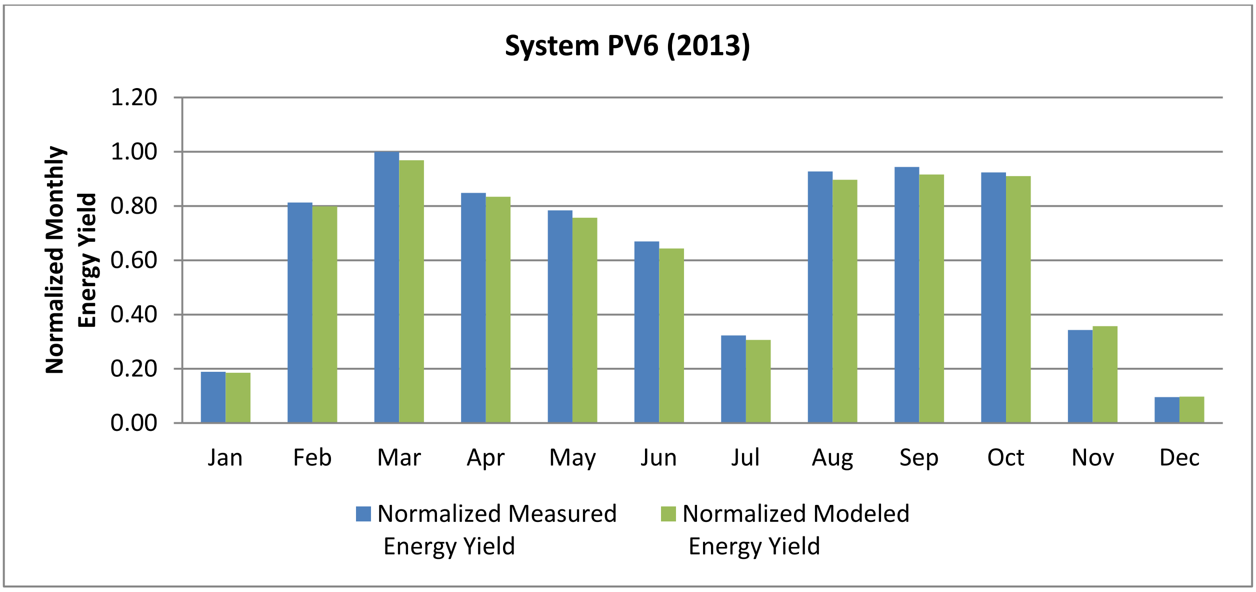

Figure 16: Monthly comparison of measured and modeled normalized energy yield – SystemPV6 (First simulation variation)

Table 15: Monthly energy yield relative errors – SystemPV6 (First simulation variation)

	Monthly Relative Error											
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2013	-2.0%	-1.8%	-3.1%	-1.7%	-3.5%	-3.8%	-5.0%	-3.3%	-2.9%	-1.4%	4.0%	2.1%

As can be seen in Table 15, PVsyst underestimated the energy yield during almost the whole year, except in November and December. Further investigations on the events that occurred in the location during these months concluded that in November some construction activities started near the PV plant, which caused rising of dust that then settled on the surface of PV modules. This fact was considered as a known source of reduction in the energy yield, therefore data from November and December was eliminated from the analysis.

For this system, due to the availability of more measured data, the modeling process was evaluated for three parameters: DC energy at the inverter input, AC energy at the inverter output and AC energy after the transformer. The results were compared and evaluated the difference. Table 16 shows the monthly and total relative error, NMBE and NRMSE.

Table 16: Monthly and total relative error, NMBE and NRMSE excluding November and December - SystemPV6 (First simulation variant)

Parameter	Monthly Relative Error										Total		
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Relative Error	NMBE	NRMSE
DC Energy (inverter input)	-1.3%	-1.2%	-2.7%	-1.2%	-2.9%	-3.2%	-4.5%	-2.8%	-2.6%	-1.0%	**-2.3%**	**-1.1%**	**2.1%**
AC Energy (inverter output)	-1.0%	-2.0%	-2.5%	-1.0%	-2.5%	-2.8%	-4.0%	-2.9%	-2.4%	-0.6%	**-2.1%**	**-1.0%**	**2.5%**
AC Energy (after transformer)	-2.0%	-1.8%	-3.1%	-1.7%	-3.5%	-3.8%	-5.0%	-3.3%	-2.9%	-1.4%	**-2.8%**	**-1.4%**	**2.3%**

The second variation was performed in order to evaluate the results excluding the uncertainties from modeling the array temperature and the related thermal losses. Figure 17 shows the modeled energy yield from this simulation variant compared with the measured energy after the transformer. (November and December were not included for the reasons explained above). Monthly and total relative error, NMBE and NRMSE are shown in Table 17.

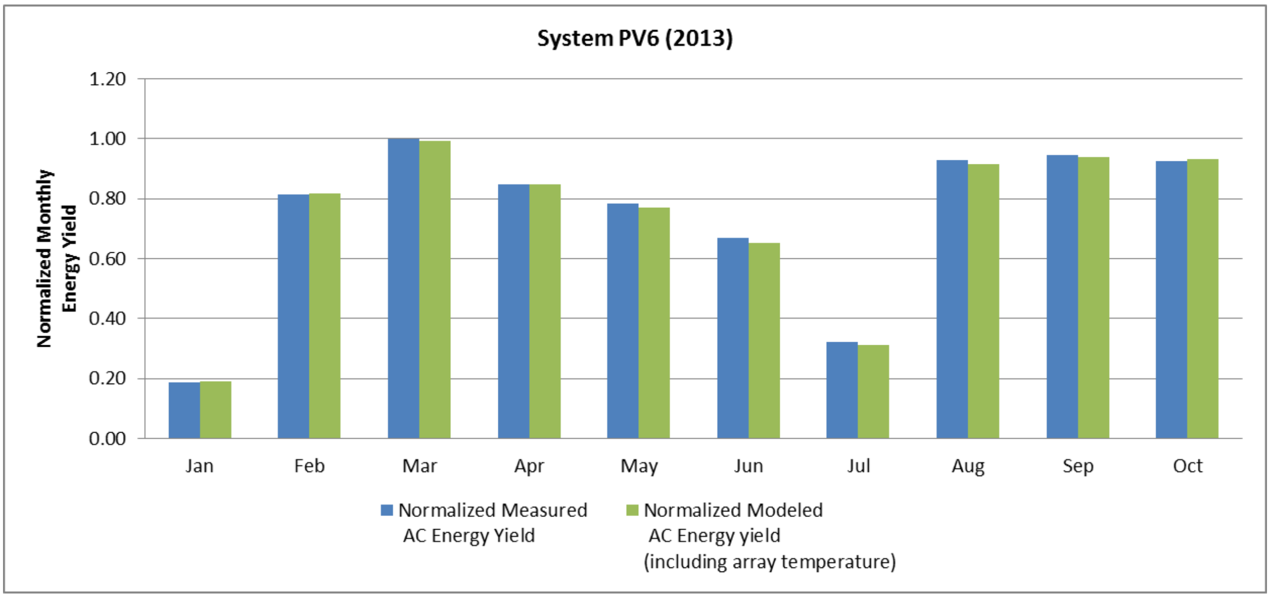

Figure 17: Monthly comparison of measured and modeled normalized AC energy yield (after the transformer) – SystemPV6 (Second simulation variant including array temperature)

Table 17: Monthly and total relative errors, NMBE and NRMSE – SystemPV6 (Second simulation variant including array temperature)

Parameter	Monthly Relative Error										Total		
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Relative Error	NMBE	NRMSE
DC Energy (inverter input)	1.0%	1.0%	-0.2%	0.6%	-1.3%	-1.9%	-2.9%	-0.9%	-0.2%	1.3%	**-0.23%**	**-0.13%**	**2.00%**
AC Energy (inverter output)	1.3%	0.2%	0.0%	0.8%	-0.8%	-1.6%	-2.4%	-1.0%	-0.1%	1.7%	**-0.10%**	**-0.05%**	**2.54%**
AC Energy (after transformer)	0.2%	0.4%	-0.6%	0.1%	-1.9%	-2.6%	-3.3%	-1.4%	-0.6%	0.9%	**-0.74%**	**-0.43%**	**2.14%**

7.6.3. Discussion

For this system, because measured POA irradiance was available, it was possible to reduce the effects on the modeled energy yield due to the use of transposition models. Additionally, it was possible to analyze the modeling performance of PVsyst and compare its results to the measurements taken in three different sections of the system, i.e. DC energy in the inverter input, AC energy in the inverter output and AC energy from the energy meter located after the transformer.

As mentioned, the measurements from the pyranometer located in the plane-of-array were used as input and imported into PVsyst. However, PVsyst does not use them directly, but converts them first into GHI values and then calculates the corresponding POA irradiance (see section 5.1). Through this process, PVsyst generated the measured values with a high correlation (R^2= 0.9998), but it could be seen that during periods in the early morning and late evening the difference between measured and generated values increased. This could not be avoided in spite of correcting the time shift of the dataset in the importing process (0 minutes shift at the end), as suggested in literature [41]. Nevertheless, this deviation did not represent a large impact on the final energy yield modeled, due to low irradiance values during these hours.

The first simulation variant was carried out according to the model parameters mentioned in the beginning of this section. The thermal loss factors were set as Uc: 29W/m²K, Uv: 0W/m²K/m/s, which are the default values proposed in PVsyst for free-standing arrays since version 4.0 [3]. With this configuration, the array temperature was overestimated with an hourly MBE of 3.4°C and RMSE of 4.5°C compared with the measured value. The overestimation of array temperature increased the thermal losses by 1.6% compared with the second variation, according to the values reported for thermal losses in the loss diagram in PVsyst of both variations. Figure 18 shows this effect graphically.

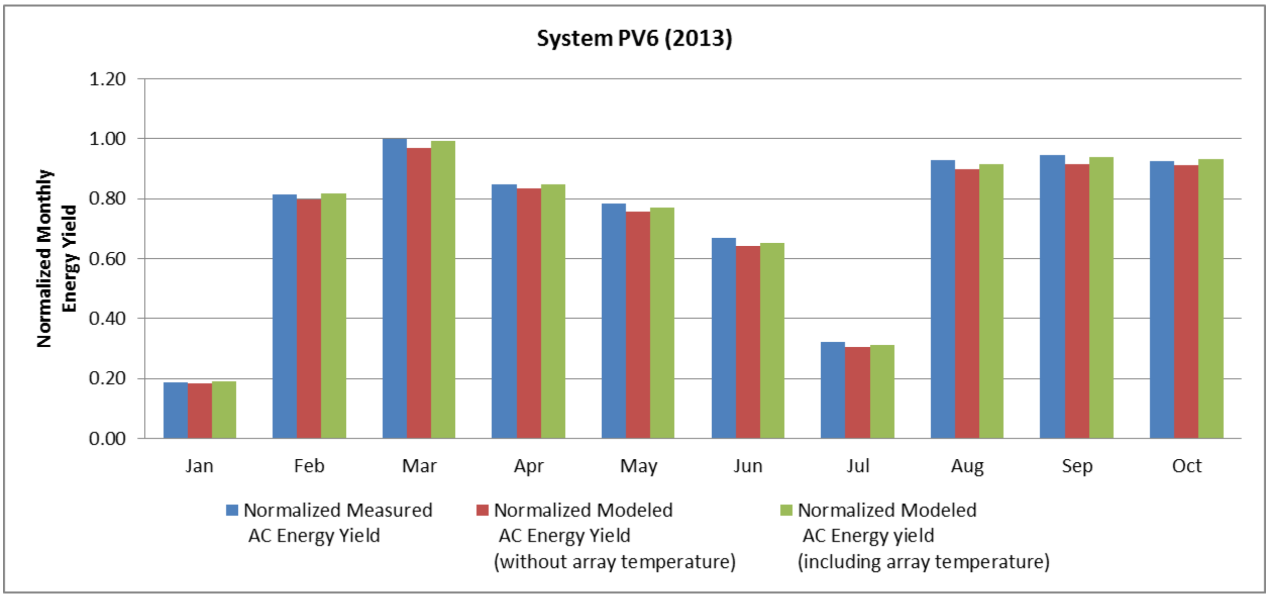

Figure 18: Monthly comparison of measured and modeled normalized AC energy yield after the transformer (without and including array temperature measurements) – SystemPV6

In a second approach, the measured array temperature was included in the simulation,(assuming that PVsyst does not make a difference between cell temperature and array temperature [42]), in order to evaluate the electrical modeled performance of the array comparing with the measurements at the inverter input. As can be seen in Table 17, the modeled DC energy followed the measured DC energy, with a total relative error of

–0.23%, NMBE of –0.13% and NRMSE of 2%. These results included the effects of physical factors such as soiling, mismatch and DC cabling losses that were modeled according to the loss factor parameters set in the simulation. Soiling loss factor was set according to experience and DC cabling losses was set to default values.

Analyzing the hourly comparison shown in Figure 19, (where the values are normalized by the maximum measurement), it can be seen that PVsyst slightly overestimated the yield at high irradiation levels when the output of the array was maximum. This can also be confirmed looking at Figure 20, where the average values in winter and summer are plotted. These showed that during summer, at around noon PVsyst overestimated the array energy. This behavior will be reflected in the error calculation of the subsequent sections of the system i.e. AC energy at inverter output and after the transformer.

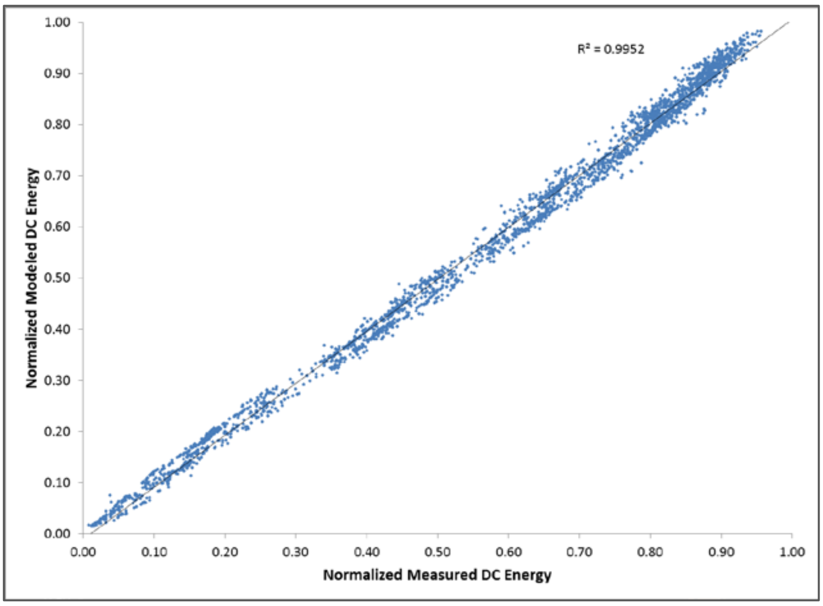

Figure 19: Hourly DC Energy (inverter input) comparison SystemPV6 (Second simulation variant)

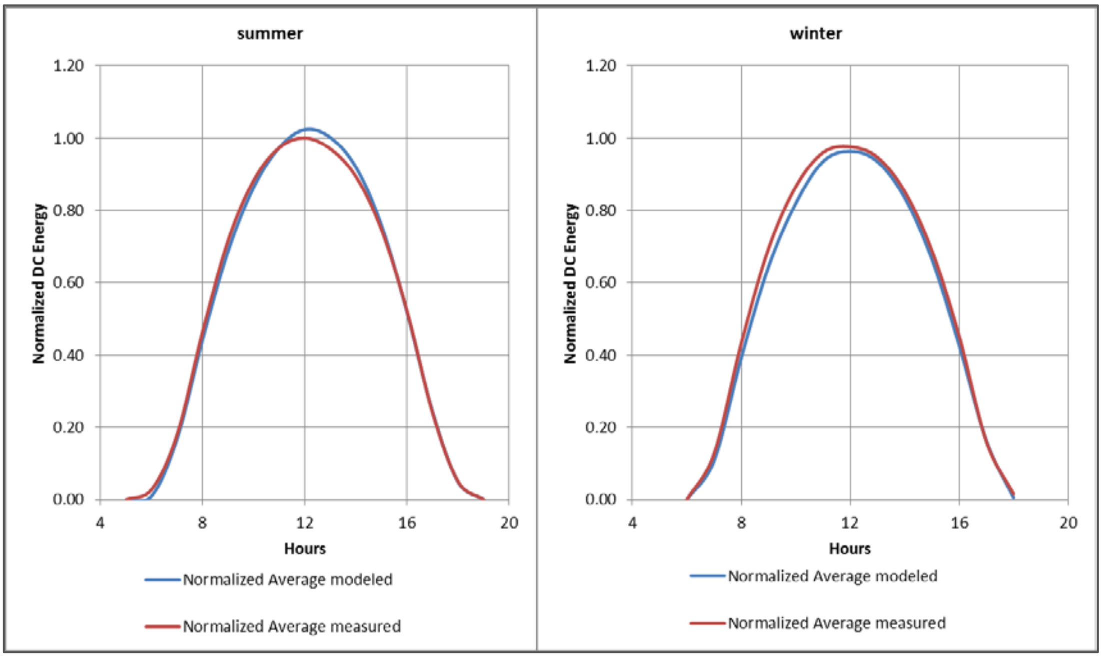

Figure 20: Comparison of modeled and measured average DC energy in summer and winter time SystemPV6 (Second simulation variant)

Comparing measured and modeled AC energy in the inverter output resulted in total relative error of –0.1%, NMBE of –0.05% and NRMSE of 2.54%. Besides the effect found in the array output, the results of this section also included the effect of the modeled performance of the inverter calculated according to the efficiency curve. The modeled auxiliary consumption of the inverter (control system and fans) is also included. This is specified in the datasheet at nominal AC Power and 25°C. PVsyst uses this value as fixed consumption for every hour along the simulation. In reality, the consumption can be higher with increase in temperature, leading to an underestimation of the modeled auxiliary consumption of the inverter.

Finally, the modeled AC energy after the transformer was compared with the energy meter measurements. This resulted in a total relative error of –0.74%, NMBE of –0.43% and NRMSE of 2.14%.These results included the effects found in the array output as can be seen in the hourly comparison shown in Figure 21, with the plot having the same tendency as in Figure 19. Additionally, the results include the modeling of transformer losses according to the input parameters considered in the simulation.

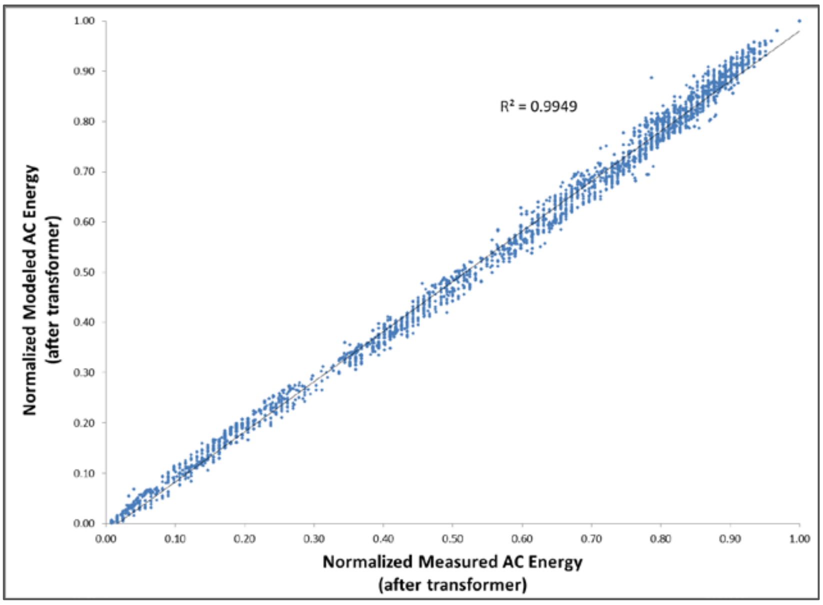

Figure 21: Hourly AC Energy (after transformer) comparison SystemPV6 (Second simulation variant)

8. Final discussion

For the systems with fixed structures (i.e. System PV1, PV2, PV3, PV4), the measured irradiance used as an input for the simulation corresponded to GHI values and they were converted into POA irradiance using the two transposition models available in PVsyst.

Using Perez model, the total relative error between the modeled and the measured energy yield were in the range of –4.2% to 2.2%. Using Hay model the total relative errors were in the range of –5.9% to 0.7%, showing that PVsyst tended to underestimate the energy yield on an annual basis in most of the evaluated systems.

Regarding the one-axis tracking System PV5, the measured irradiance also corresponded to GHI values and both transposition models were used in the conversion into POA irradiance. The comparison between modeled and measured energy yield for this case showed annual relative errors of 4.0% and 7.0% using Perez model, and 2.0% and 6.1%, using Hay model showing that PVsyst overestimated the energy yield in each of the two years of the evaluation.

Figure 22 and Figure 23 show the total energy yield relative errors for the five systems (i.e. PV1, PV2, PV3, PV4 and PV5). It can be seen that in the systems evaluated for two years, the corresponding total relative errors for each year are close to each other with slight differences. This could be related to the estimation of loss factors and the linear annual degradation of the systems that for this study was assumed to be equal for all the modules of the arrays.

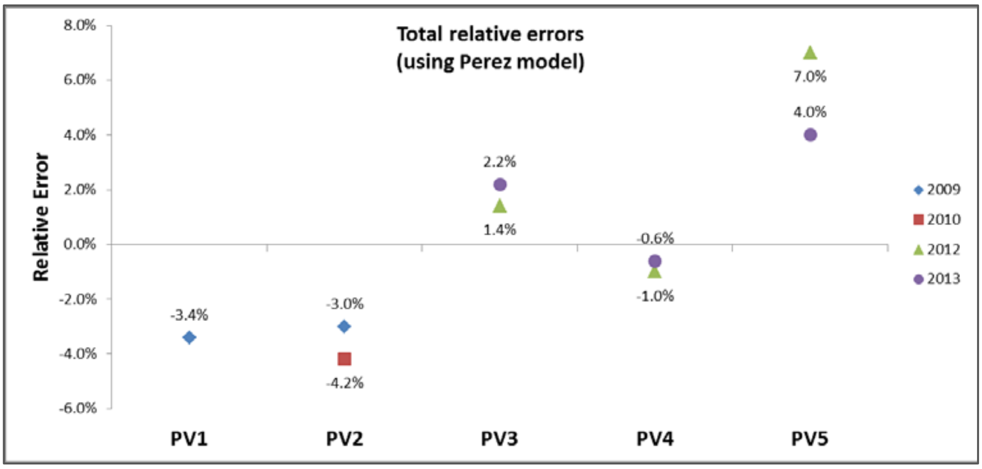

Figure 22: Total energy yield relative errors for Systems PV1 through PV5 using Perez model in the simulation (Notes: PV1 was evaluated only 11 months, PV5 is one-axis tracking system)

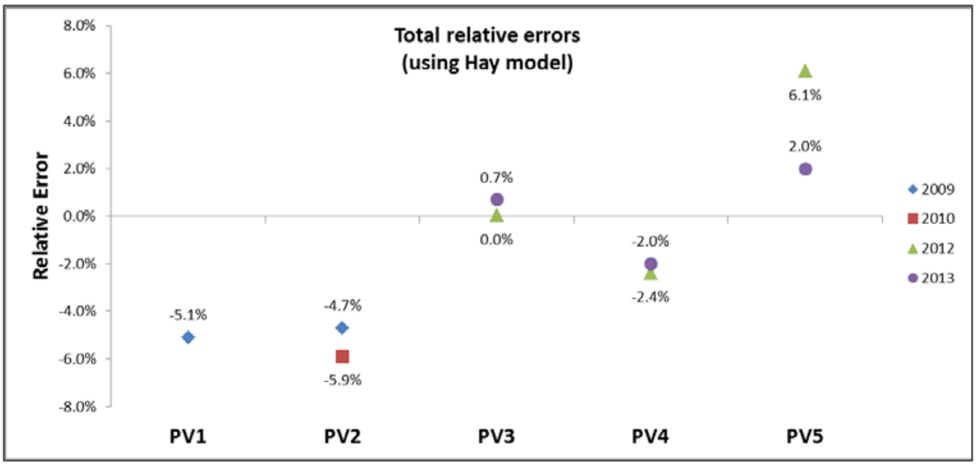

Figure 23: Total energy yield relative errors for Systems PV1 through PV5 using Hay model in the simulation (Notes: PV1 was evaluated only 11 months, PV5 is one-axis tracking system)

Figure 24 and Figure 25 show the comparison of monthly energy yield relative error of the systems (PV1, PV2, PV3, PV4 and PV5) and the variability on a monthly basis of the errors between modeled and measured energy yield using Perez and Hay model can be seen. For the one-axis tracking system PV5 it can be seen that the errors are higher than for the fixed systems and they increased in winter time.

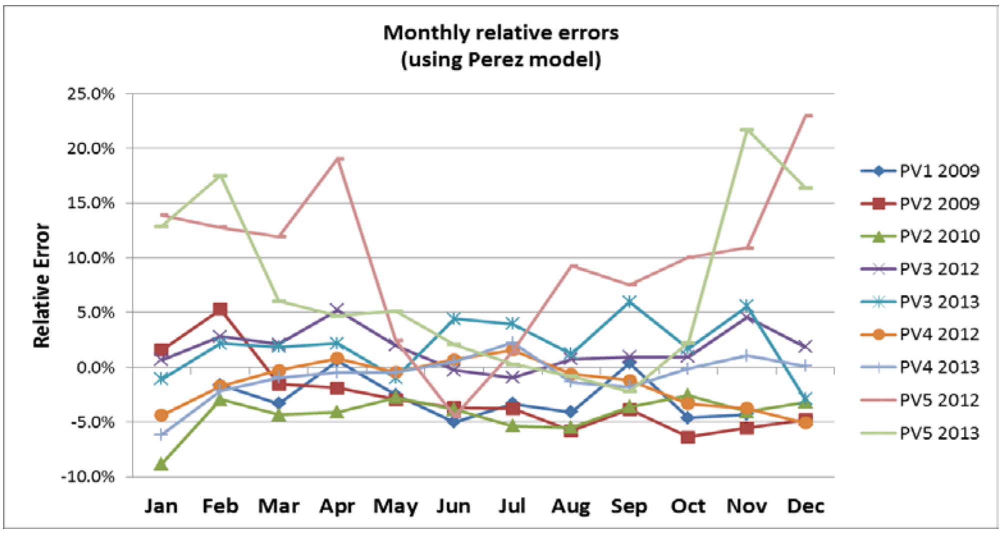

Figure 24: Monthly energy yield relative errors for Systems PV1 through PV5 using Perez model in the simulation (Note: PV5 is one-axis tracking system)

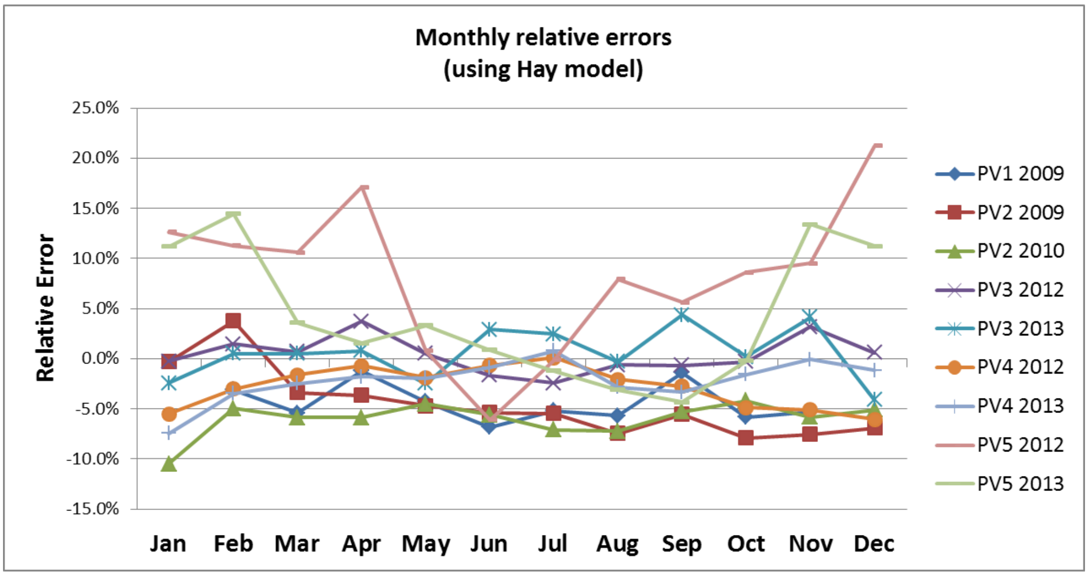

Figure 25: Monthly energy yield relative errors for Systems PV1 through PV5 using Hay model in the simulation (Note: PV5 is one-axis tracking system)

For all the previous systems (i.e. PV1, PV2, PV3, PV4, PV5) the measured dataset was on a monthly or daily basis, which did not allow comparison the hourly results from PVsyst in order to better understand the sources of the deviations from the measured values.

On the other hand, the measured dataset in System PV6, was recorded at higher resolution and included additional parameters i.e. POA irradiance, array temperature and electrical parameters from the inverter. This allowed for a better analysis and comparison of the performance of the modeled and measured yield. It was also possible to evaluate the modeling performance of the DC side and the AC side of the system.

The use of POA irradiance as input in the simulation of the System PV6 diminished the effect of the transposition models, but it was not completely avoided because the simulation process in PVsyst starts from the horizontal irradiance, that was calculated with a retro-transposition process.

The comparisons for the System PV6 showed that the simulation using the default values for the thermal loss factors the relative error was -2.8% with -1.4% NMBE and 2.3% NRMSE. In the second variant of the simulation, when the measured temperature was included the total relative error was -0.74% with -0.43% NMBE and 2.14% NRMSE. Figure 26 shows the monthly variation of the relative errors between modeled and measured energy yield in the DC and AC side from the second variant. A tendency of higher errors in winter time can be seen.

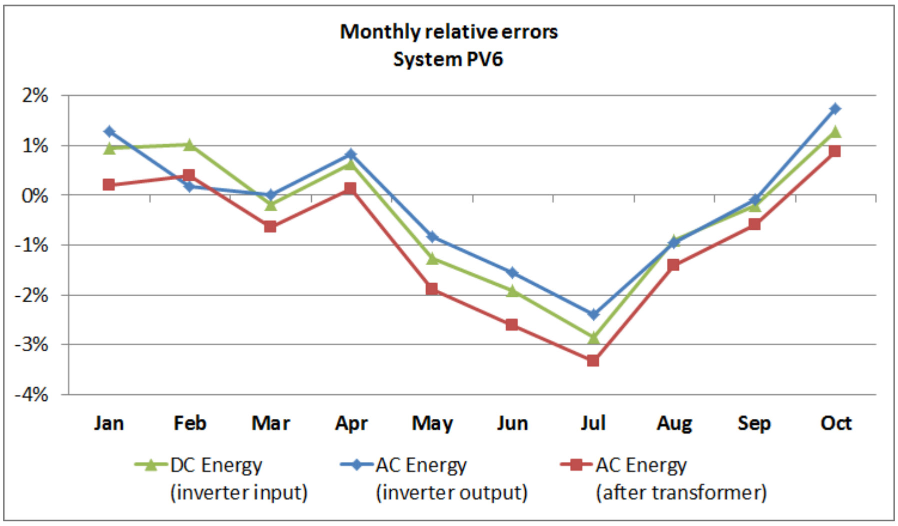

Figure 26: Monthly DC and AC energy yield relative errors for Systems PV6 – Second variant including array temperature

9. Conclusions and Recommendations

Six grid connected PV systems located in Spain, Italy and Chile, were assessed in order to compare the measured energy yield of each system with the modeled energy yield using PVsyst v6.25. Five of these systems were fixed structure (System PV1, PV2, PV3, PV4 and PV6) and one system was a one-axis tracker (System PV5).

Regarding the results of the comparison the conclusions are:

- The results of the comparison for the fixed structure systems (System PV1, PV2, PV3 and PV4) showed that PVsyst tended to underestimate the energy yield on an annual basis in almost all the studied cases. On a monthly basis the errors are more scattered and are correlated with the uncertainty of the transposition model.
- For the system with tracking mechanism analyzed in this study, the results showed that PVsyst tended to overestimate the energy yield on an annual and monthly basis and it is correlated with the overestimation of the modeling of POA irradiance.
- The evaluation of the System PV6, with measured dataset recorded in short intervals and including additional parameters (i.e. POA irradiance and array temperature) showed a total relative error of –0.74%, –0.43% NMBE and 2.14% NRMSE. Therefore, for the design conditions of this particular system, the modeled energy yield in the evaluated period (10 months) matched the measured output with high accuracy.

Regarding the simulation process and the loss parameters used as input, the conclusions and recommendations are:

- The results from the modeling process are directly related with the inputs in the simulation, the quality of solar data, the reliability of information about system components and the parameters for loss factors set by the designer. The latter has a considerable impact in the results.

- In this study, the systems were simulated using the nominal capacity of the plant according the flash test data, which reduced the uncertainties of the modules nominal power and thus the uncertainties of losses due to modules quality.
- During this study it was possible to analyze the loss parameter for the estimation of mismatch losses and it was concluded that if during the installation the modules are sorted according to their performance as stated in the flash data from the manufacturer, the losses due to this mechanism can be reduced less than 1%.
- Regarding thermal losses, the evaluation of the System PV6 in Chile showed that using the default value proposed by PVsyst for the thermal coefficient (29 W/m^2K) the losses increased by 1.6% compared to the performance incorporating the measured array temperature. As this system was located in hot climate zone this result could not match with other locations and mounting conditions.
- The tracking system evaluated in this study showed that PVsyst overestimated the annual energy yield. However, the results are specific to this system and could differ in others. In the case of the evaluation of the yield assessment of a PV system with tracking, it is recommended to ask the manufacturer of the tracking system the modeled energy yield using their proprietary simulation software (if available) to compare with the results from PVsyst.

Suggestions for future studies:

- This study only considered systems with silicon crystalline module technologies and the evaluation of systems with different module technologies and locations will provide a broader understanding about the modeling process in PVsyst.
- Because only one tracking system was analyzed it would be also valuable to include more systems in the evaluation.
- In order to improve the evaluation of the modeled energy yield using PVsyst for the case of fixed PV systems, the use of measured POA irradiance from pyranometers recorded at short intervals as input in the simulation is recommended. For tracking systems, at the moment it is not possible to import measured POA irradiance into PVsyst, which represents a shortcoming that limits the evaluation of the modeled performance in tracking systems.

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List of abbreviation and acronyms

LI	Lahmeyer International GmbH
PV	Photovoltaic
kW	Kilowatt
MW	Megawatt
DC	Direct Current
AC	Alternating Current
Isc	Short Circuit Current
BOS	Balance of the System
STC	Standard Test Conditions
AOI	Angle Of Incidence
AM	Air Mass
MPP	Maximum Power Point
PR	Performance Ratio
MBE	Mean Bias Error
GHI	Global Horizontal Irradiance
POA	Irradiance In The Plane-Of-Array
O&M	Operation & Maintenance
NMBE	Normalized Mean Bias Error
NRMSE	Normalized Root Mean Square Error
LID	Light Induced Degradation
ASHRAE	American Society Of Heating, Refrigerating, And Air-Conditioning Engineers
TMY	Typical Meteorological Year