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DISTINTAS TECNOLOGÍAS DE PANELES SOLARES
OPERANDO EN LAS MISMAS CONDICIONES**

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*Los seres humanos no nacen para siempre el día en que sus madres los alumbran,
sino que la vida los obliga a parirse a sí mismos una y otra vez.*

*Human beings are not born once and for all on the day their mothers give birth to them,
but that life obliges them over and over again to give birth to themselves.*

人不是从娘胎里出来就一成不变的，
相反，生活会逼迫他一次又一次地脱胎换骨。

El amor en los tiempos del cólera

Love in the Time of Cholera

By: Gabriel García Márquez

给我的家人，我的父母还有潇潇

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Glossary

LATIN	DESCRIPTION	UNIT
<i>A</i>	PV array area	m ²
<i>a</i>	Slope of linear regression on PR time series or trend	%
<i>B</i>	Backshift operator	–
<i>b</i>	Y-axis intercept of linear regression	%
<i>b₀</i>	Constant normalized self-consumption loss coefficient	%
<i>b₁</i>	Linear efficiency coefficient	%
<i>b₂</i>	Coefficient for losses proportional to the square of output power	%
<i>C₀ and C₁</i>	Empirical parameters for modeling PV-generated current	–
<i>C_A</i>	Annual energy output per annualized investment cost	kWh/€
<i>C_C</i>	Annual energy output per system investment cost	kWh/€
<i>D</i>	Seasonal difference order	–
<i>d</i>	Non-seasonal difference order	–
<i>E_{AC}</i>	PV system energy output	kWh
<i>E_{DC}</i>	PV array energy output	kWh
<i>e_t</i>	Error term of ARIMA	–
<i>F_t</i>	Fuel cost at year t	€
<i>G_i</i>	In-plane irradiance	W/m ²
<i>G_{i,e}</i>	Effective in-plane irradiance	–
<i>G_{STC}</i>	In-plane irradiance at STC	W/m ²
<i>H</i>	Height of the PV module (low edge to the ground)	m
<i>H_i</i>	In-plane irradiation	kWh/m ²
<i>h</i>	Local altitude	m

I_c	Initial investment expenditures of PV system	€
I	Current	A
i	Real interest rate	%
I_{mp}	Maximum power point current	A
I_{mp0}	Maximum power point current at STC	A
I_{sc}	Short-circuit current	A
k	Coverage factor	–
k_t	Clearness index	–
L_c	Monthly average capture losses per day	kWh/kWp/day
L_{PV}	PV module lifetime	year
L_{inv}	PV inverter lifetime	year
L_s	Monthly average System losses per day	kWh/kWp/day
L_{sat}	Energy losses due to inverter saturation	%
M_t	Maintaining cost at year t	€
n	Number of samples	–
Np	Net profit	€/ha/year
O_t	Operating cost at year t	€
P	Seasonal autoregressive order	–
p	Non-seasonal autoregressive order	–
P_e	Domestic electricity price	€/kWh
P_l	Local air pressure	Pa
P_0	Sea level air pressure	Pa
P_{AC}	GCPV system output power	W
$P_{inv,N}$	Nominal capacity of PV inverter	W
P_{max}	Maximum power point power	W
$P_{max,L}$	Y-axis interception of linear fitting on DC power duration curve	W
$P_{PV,P}$	Peak power of PV array	Wp
P_{STC}	P_{max} corrected to STC	W
Q	Seasonal moving average order	–
q	Non-seasonal moving average order	–
R_c	Crop income reduction due to the added PV modules	€
R_d	GCPV system performance ratio degradation rate	%
$R_{S,E}^{opt}$	Energetic optimum sizing ratio	–

R_{inv}	PV inverter cost	€/Wp
R_{PV}	PV array overall initial cost (excluding the inverter)	€/Wp
R_s	Inverter sizing ratio	–
R_{series}	Series resistance	Ω
R_{shunt}	Shunt resistance	Ω
R_t	Remainder of PR time series decomposition at time t	%
r	Discount rate	%
S	Distance between PV array rows	m
s	Number of periods per season	–
S_e	Energy savings	€
S_t	Seasonal index of PR time series decomposition at time t	%
T	Tilt angle of PV modules	$^\circ$
t	Time index	–
$\bar{t}$	Mean of time index t	–
Δt	ETSIAAB GCPV plant sampling interval	h
T_a	Ambient temperature	$^\circ\text{C}$
T_m	Module temperature	$^\circ\text{C}$
T_c	Cell temperature	$^\circ\text{C}$
T_t	Trend of PR time series decomposition at time t	%
U	Statistical uncertainty	%
V	Voltage	V
V_{mp}	Maximum power point voltage	V
V_{oc}	Open-circuit voltage	V
Y_a	Monthly average daily array yield per day	kWh/kWp/day
$Y_{crop,AV}$	Crop yield of agrivoltaic farm	t
$Y_{electricity,AV}$	Produced electricity of agrivoltaic farm	kWh
$Y_{electricity,PV}$	Produced electricity of regular PV plant	kWh
Y_f	Monthly average daily final field	kWh/kWp/day
$Y_{solecrop}$	Crop yield of sole crop farm	t
Y_t	Original PR time series	%
y	Monthly PR or trend	%
$\hat{y}$	Estimation of y	%
W	Width of individual PV module	m

GREEK	DESCRIPTION	UNIT
α	Temperature coefficient of current	%/°C
β	Temperature coefficient of voltage	%/°C
γ	Temperature coefficient of power	%/°C
φ_p	p-order non-seasonal autoregressive model	–
Φ_p	P-order seasonal autoregressive model	–
ϑ_q	q-order moving average model	–
Θ_Q	Q-order moving average model	–
η_f	PV system efficiency	%
$\overline{\eta_f}$	Average PV system efficiency	%
η_{inv}	PV inverter efficiency	%
$\eta_{f,daily}$	PV system daily efficiency	%
η_{STC}	PV array (or module) peak efficiency rated at STC	%

ABBREVIATION	DESCRIPTION
AC	Alternating Current
AM	Air Mass
ANN	Artificial Neural Network
ANOVA	Analysis of Variance
AOI	Angle of Incidence
APE	Average Photon Energy
ARIMA	Auto-Regressive Integrated Moving Average
a-Si	Amorphous silicon
a-Si/ μ c-Si	Tandem structures of amorphous silicon and microcrystalline silicon
BOS	Balance-of-System
CdTe	Cadmium Telluride
CIEMAT	Centro de Investigaciones Energéticas, MedioAmbientales y Tecnológicas
CIGS	Copper Indium Gallium Selenide
CSD	Classical Seasonal Decomposition
c-Si	Crystalline silicon
DC	Direct Current
DNI	Direct Normal Irradiance

ETSIAAB	Escuela Técnica Superior de Ingeniería Agronómica, Alimentaria y de Biosistemas
EU-28	28 European Union members
EVA	Ethylene Vinyl Acetate
FF	Fill Factor
GCPV	Grid-Connected Photovoltaic
GDI	Global Diffuse Irradiance
GHGs	GreenHouse Gases
GHI	Global Horizontal Irradiance
HIT	Hetero-junction Intrinsic Thin layer silicon
IEA	International Energy Agency
IEA-PVPS	International Energy Agency: Photovoltaic Power Systems Programme
IEC	International Electrotechnical Commission
LCOE	Levelized Cost of Electricity
LOESS	LOcally wEighted Scatterplot Smoothing
LSE	Light Soaking Effect
MAE	Mean Array Efficiency
MAPAMA	Ministerio de Agricultura y Pesca, Alimentación y Medio Ambiente
mono-Si	Monocrystalline Silicon
MPP	Maximum Power Point
MPPT	Maximum Power Point Tracking
MTOE	Million Tonnes of Oil Equivalent
NREL	National Renewable Energy Laboratory
PECVD	Plasma-Enhanced Chemical Vapor Deposition
PV	Photovoltaic
PVGs	Photovoltaic Greenhouses
poly-Si	Polycrystalline or Multicrystalline silicon
PR	Performance Ratio
PTC	PVUSA Test Conditions
PVUSA	Photovoltaics for Utility Scale Applications
RIE	Radiation Interception Efficiency
SWE	Staebler–Wronski Effect
STC	Standard Test Conditions
STL	Seasonal and Trend decomposition based on LOESS

SPVWPS	Solar Photovoltaic Water Pumping System
STICS	Simulateur mulTidisciplinaire les Cultures Standard
SSA	Sub-Saharan Africa
SAM	System Advisor Model
μc-Si	Microcrystalline or nanocrystalline silicon
UPM	Universidad Politécnica de Madrid
VAT	Value-Added Tax
WUE	Water Use Efficiency

ABSTRACT

Promotion of renewable energies is a global strategy to tackle the deleterious effects of continuously consumed fossil fuels. Being one of the most promising renewable energy implementations, solar photovoltaic (PV) converts solar irradiation into electricity directly. A solar grid-connected PV (GCPV) plant is a facility that injects the PV generated electricity into the utility grid.

Based on the four years continuously monitoring of the GCPV plant located at Madrid, Spain, this thesis thoroughly compared the performance of three side-by-side GCPV systems, constructed in different PV materials, i.e., polycrystalline silicon (poly-Si), amorphous silicon (a-Si) and Cadmium Telluride (CdTe) but under the same operating conditions, i.e., total capacity, mounting and balance-of-system. Through evaluating the impacts of local meteorology and the GCPV system configuration on the GCPV systems performances, this thesis intends to offer some contributions to complete the portray for global GCPV system performance map and some investigation on PV generator performance degradation. Then, the optimum inverter sizing ratio with respect to the PV array capacity was determined in GCPV systems from two points of view: energetic and economic. The optimum ratio was determined by both empirical and analytical approaches, and based on two PV arrays connected to their inverters, plus three simulated inverters. Finally, a set of simulations was carried out to investigate the potential of agrivoltaic farm, i.e., installing PV arrays upon a conventional farm for co-producing electricity and durum wheat. Four prototypes based on poly-Si PV differing in structures were proposed at Madrid, Spain. The light availabilities at crop level, electricity and crop generation, and socioeconomic impacts have been assessed and discussed.

The most relevant results can be summarized into four sections: results on performance comparison, degradation rate, inverter sizing ratio and agrivoltaic farm.

Results on performance comparison:

The inverter saturation annual losses triggered by high in-plane irradiance were 1.79% (poly-Si), 4.48% (a-Si) and 1.59% (CdTe), respectively.

Notable solar air mass (AM) spectrum dependence ($-11.22\%/AM$) of the power but undetectable instantaneous temperature dependence was observed in the a-Si array. In contrast, the poly-Si array suffered the highest power decline ($-0.56\%/^{\circ}C$). The CdTe array exhibited a tempered interaction with the solar spectrum ($-4\%/AM$) and temperature ($-0.25\%/^{\circ}C$).

The significant maximum power gap between two months (April and September) due to the thermal annealing and light soaking effects in the a-Si array is confirmed, where the quantified variation of these two effects were 5.9% and -5.7% , respectively.

Results on PV degradation:

The undersized inverter decreased the performance degradation and seasonal amplitude of the three GCPV systems. The average degradation rate decreased from 1.37%/year (poly-Si), 2.12%/year (a-Si) and 2.10%/year (CdTe) to 1.14%/year (poly-Si), 1.48%/year (a-Si) and 1.60%/year (CdTe). Meanwhile, the time-phase of seasonality for a-Si system was changed by inverter saturation.

According to outdoor I-V curves comparison between two separated years (2016 and 2017) under unvaried weather conditions, the power decline of poly-Si array was ascribed to the loss in current, while the main contributor to degradation of CdTe array was the voltage.

Results on inverter sizing:

The broad range of the optimum-energy region due to the inverter characteristics was decreased when economic factors were taken into account. The GCPV system with lower specific DC power generation and inverter/module cost ratio presented a wider interval (1.12–1.25) than the interval (1.17–1.19) of the system with higher specific DC power generation and cost ratio.

The optimum sizing ratio was completed by considering a PV module degradation rate of 1%/year, which resulted in a 10% increase in the optimum sizing ratio for a 20-year lifetime.

Results on agrivoltaic:

The results showed that the land productivity was improved by at least 22% with the minimum PV-density prototype without remarkable reduction in crop yields; and the light availability remained above 90% intercepted by crop.

The calculations yielded an attractive annual net profit (5,106 €/ha) of the transformation a conventional durum wheat farm to an AV farm. In addition, the dual use of agricultural land could be of great help to fulfil Spanish official commitment on energy and environment.

RESUMEN

La promoción de las energías renovables es una estrategia global para abordar los efectos nocivos del continuo consumo de combustibles fósiles. Siendo una de las formas de energía renovable más prometedoras, la energía solar fotovoltaica (PV) convierte la irradiación solar en energía eléctrica directamente. Una planta solar fotovoltaica conectada a la red (GCPV) es una instalación que inyecta la electricidad generada en la red eléctrica.

Con base en los cuatro años de monitoreo continuo de la planta ubicada en Madrid, España, esta tesis comparó el rendimiento de tres sistemas GCPV, construidos con diferentes materiales fotovoltaicos, i.e., silicio policristalino (poli-Si), silicio amorfo (a-Si) y telurio de cadmio (CdTe) bajo las mismas condiciones de operación, i.e., potencia total, orientación y condiciones del sistema. Mediante la evaluación del impacto de la meteorología local y la configuración del sistema GCPV sobre los rendimientos de los sistemas GCPV, esta tesis pretende ofrecer algunas contribuciones para completar el mapa de rendimiento global del sistema GCPV y algunos avances sobre la degradación del rendimiento del generador fotovoltaico. Además, se determinó la relación óptima de dimensionamiento del inversor con respecto a la capacidad de la matriz PV en los sistemas GCPV desde dos puntos de vista: energético y económico. La relación óptima se determinó mediante enfoques empíricos y analíticos, y se basó en dos matrices PV conectadas a sus inversores, más tres inversores simulados. Finalmente, se llevó a cabo un conjunto de simulaciones para investigar el potencial del concepto de granja agrivoltáica, i.e., la instalación de sistemas fotovoltaicos en una granja convencional para la coproducción de electricidad y trigo duro. Se propusieron cuatro prototipos basados en poli-Si PV que difieren en las estructuras en Madrid, España. La

disponibilidad de luz a nivel de cultivos, la generación de electricidad y cultivos, y los impactos socioeconómicos han sido evaluados y discutidos.

Los resultados más relevantes se pueden dividir en cuatro secciones: resultados de comparación de rendimiento, índice de degradación, dimensionamiento del inversor y granja agrivoltáica.

Resultados en comparación de rendimiento:

Las pérdidas anuales por saturación del inversor desencadenadas por la alta irradiación en el plano fueron del 1,79% (poli-Si), 4,48% (a-Si) y 1,59% (CdTe), respectivamente.

Se observó una notable dependencia de la potencia respecto del espectro en función de la masa de aire solar (AM) ($-11,22\%/AM$), pero la dependencia instantánea de temperatura fue indetectable en el sistema de a-Si. Por el contrario, la matriz de poli-Si sufrió la mayor disminución de potencia ($-0,56\%/^{\circ}C$). El conjunto de CdTe exhibió una interacción moderada con el espectro solar ($-4\%/AM$) y la temperatura ($-0,25\%/^{\circ}C$).

Se confirma la diferencia de potencia máxima significativa entre dos meses (abril y septiembre) debido al recocido térmico y los efectos de absorción de luz en el conjunto de a-Si, donde la variación cuantificada de estos dos efectos fue del 5,9% y del $-5,7\%$, respectivamente.

Resultados en la degradación de PV:

El inversor de menor tamaño disminuyó la degradación del rendimiento y la amplitud estacional de los tres sistemas GCPV. La tasa de degradación promedio disminuyó de 1,37%/año (poli-Si), 2,12%/año (a-Si) y 2,10%/año (CdTe) a 1,14%/año (poli-Si), 1,48%/año (a-Si) y 1,60%/año (CdTe). Mientras tanto, la fase temporal de la estacionalidad para el sistema a-Si se modificó por la saturación del inversor.

Según la comparación de curvas I-V al aire libre entre dos años (2016 y 2017) en condiciones climáticas similares, la disminución de potencia de la matriz de poli-Si se atribuyó a la pérdida de corriente, mientras que el principal contribuyente a la degradación de la matriz CdTe fue el voltaje.

Resultados en el dimensionado del inversor:

El rango de la región donde se obtiene el óptimo de energía debido a las características del inversor se redujo cuando se tuvieron en cuenta los factores económicos. El sistema GCPV con menor generación específica de DC y relación entre el costo del inversor y el módulo

presentó un intervalo más amplio (1,12–1,25) que el intervalo (1,17–1,19) del sistema con una mayor generación específica de DC y una relación de costos.

La relación óptima de dimensionado se obtuvo al considerar una tasa de degradación del módulo fotovoltaico del 1%/año, que dio como resultado un aumento del 10% en la relación óptima de dimensionamiento para una vida útil de 20 años.

Resultados en agrivoltáica:

Los resultados mostraron que la productividad se mejoró en al menos un 22% con el prototipo de densidad PV mínima sin una reducción notable en el rendimiento del cultivo; y la disponibilidad de luz se mantuvo por encima del 90% interceptada por el cultivo.

Los cálculos arrojaron una ganancia neta anual atractiva (5.106 €/ha) de la transformación de una explotación convencional de trigo duro a una explotación agrivoltáica. Además, el uso dual de tierras agrícolas podría ser de gran ayuda para cumplir el compromiso oficial español sobre energía y medio ambiente.

CHAPTER 1 – INTRODUCTION

The electric energy consumption has been increasing parallel to the world's growing population. This ever-increasing energy demand stresses the challenges of climate change mitigation and sustainable development. For example, the global electricity consumption in 2016 had reached more than 20,000 TWh, compared to 10,000 TWh of 1990. Among the various renewable energies, solar photovoltaic (PV) converts solar irradiation into electricity directly, positioning itself as the green, abundant and secure energy source. The installation of solar PV has seen a substantial growth since the 2000s and keeps booming; even the conservative market prospect of year 2050 from International Energy Agency (IEA) will be 800 GWp (Teske et al., 2015). In 2016, the global new installed PV capacity was 75 GWp, contributing to a cumulative capacity to 303 GWp (IEA-PVPS, 2017). By 2015, Solar PV shared 1.2% global energy production. While in some PV pioneer countries, PV has met more than 5% of electricity demand, e.g., 7.8% in Italy, 6.5% in Greece and 6.4% in Germany (Adib et al., 2016).

Europe has been the frontrunner of PV development over last decade and shared more than 70% of the global PV market until 2012 (European Photovoltaic Industry Association, 2013). Nevertheless the harsh economic conditions and diverse reluctance to PV in some countries, the European cumulative PV installation was 98 GWp by 2015. It is still the most solarized continent with an impressive 4% electricity consumption from solar PV (Solarpower Europe, 2016). According to the PV cumulative capacity, the top five European countries in 2015 were Germany (39.7 GWp), Italy (18.9 GWp), France (6.6 GWp), Spain (5.4 GWp), and Belgium (3.3GWp) (IEA-PVPS, 2016).

Among European countries, Spain is a fertile soil for solar applications with the most substantial solar irradiation as shown in Fig. 1. During 2007 and 2008, Spain's Feed-In Tariff (FIT) program (e.g., Royal Decree-Law 661/2007) triggered a flourish in the domestic PV market and propelled Spain to the second place in the PV world in 2008. Then the constraint PV regulations parallel to difficult economic circumstances sank the Spanish PV market. The cumulative installed capacity was 5.4 GWp by 2015, with 60% improvement compared to 2008's record (3.4 GWp), whereas German PV market exploded 650% during 2008–2015 (IEA-PVPS, 2009, 2016).

Solar PV Energy also has a significant positive impact on sustainable agriculture and rural development (Van Campen et al., 2000). Renewable energy accounted for 9% of total energy consumed by agriculture in the EU-28 in 2015, while this share was only 5% in 2005 according to Eurostat database. Meanwhile, the PV-generated energy's contribution in agriculture-consumed energy experienced a booming development, which increased from 0.002% in 2004 to 0.331% in 2014. Solar PV is also an alternative activation for agriculture area and thus diversifies the land utilization. A 1 MW c-Si based PV plant with fixed structure requires 2–3 ha area (Mir-Artigues and Del Río, 2016). Thereby, a normal 100 GW PV plant requires 0.8–1.25% (0.2–0.3 million ha) of total agriculture area (24 million ha) and its energy output would meet 19.5% of total energy consumption in 2015 (80 MTOE) for Spain.

Photovoltaic Solar Electricity Potential in European Countries

Fig. 1. Photovoltaic solar electricity potential in European countries. From (Huld et al., 2012).

1.1 BACKGROUND AND MOTIVATION

In 2012, a small grid-connected solar PV plant has been installed in one roof of the *Escuela Técnica Superior de Ingeniería Agronómica, Alimentaria y de Biosistemas* (ETSIAAB) of *Universidad Politécnica de Madrid* (UPM). This solar PV plant serves not only electric energy generation, but also as a platform for research and educational objectives. It is resulted from the cooperation of two research groups, i.e., *Laboratorio de Propiedades Físicas y Técnicas Avanzadas en Agroalimentación* (LPF-TAGRALIA) and *Centro de Investigaciones Energéticas, Medioambientales y Tecnológicas* (CIEMAT). One important research area of the LPF-TAGRALIA group is ‘Investigation on generation, transportation, storage and use of energy in rural areas, with special attention to renewable energies’ (REGENERA). The Laboratory of Photovoltaic Solar Energy in CIEMAT focuses at reducing costs, increasing performance and reliability of PV modules, components and systems.

Solar PV is susceptible to environmental conditions such as irradiance, temperature, and sun spectra among others. Generally, low temperature and high irradiance with suitable spectral range increase the solar PV outdoor performance. Therefore, this thesis summarizes the monitored results of ETSIAAB grid-connected PV (GCPV) plant operation since its installation in Madrid, Spain. The main purpose is learning about the PV system-level (or array-level)¹ performance as a function of environmental conditions and differences in performance among relatively new technologies.

Different PV technologies perform diversely under the same conditions. Nowadays, Si-wafer based PV technology is still the mainstream. In 2016, it was accounted for about 94% of the total production. However, new emerging technologies encounter a steady increase in module production. Over the last decades, the annual module production of all thin film technologies increased from 0 to about 5 GW in 2016 (Burger et al., 2016). One important issue rises accompanied with this increase in thin film module production: with respect to better known technologies, such as polycrystalline silicon (poly-Si), could thin film modules perform better under some specific environmental conditions?

The renewable based electricity generation technologies such as wind, solar PV, solar thermal and small hydro have a similar lifetime span of 20–30 years (Varun et al., 2009). However, for solar PV module it is hard to define its lifetime because there seldom appears a

¹ Hereinafter, the term ‘PV system’ refers to the whole system with inverter, while ‘PV array’ refers to the PV modules part excluding inverter.

fixed catastrophic point but more of a gradual degradation (Skoczek et al., 2009). In general, therefore, PV manufacturer provides a guaranty (such as power reduction no more than 20% after 20-year operation) through indoor accelerated aging test. More frequently, the degradation rate of PV generator (module, array and system) is defined based on long-term outdoor monitoring. An accurate quantification of degradation rate and a better understanding of degradation mechanisms are essential for PV penetration.

Nowadays, in GCPV system, PV array of higher capacity with respect to inverter capacity have become more common. Three driving factors contribute to this phenomenon: 1. PV module prices have decreased in recent years, 2. Inverter technology is with improved efficiencies especially at partial loads, 3. it is hard for PV array to reach its capacity during realistic operation. The relevant researches are mainly focusing on the energetic consideration through simulation process. However, economic optimum is attractive for the stakeholders. Following this gap, this thesis proposes an optimum interval taking dual-consideration of energy and economy.

Solar PV is a well-established technology for rural electrification in general, and water pumping, and greenhouse among others. Essentially, both solar PV and plants convert sun light into available energy in physical (electricity) or biological (food) form. The increasing population of 1.18%/year in 2016 (World Bank, 2017) stresses the demand not only of energy but also of food. Vast land requirement for solar PV plant will increase the land competition between electricity generation and food production, especially in high population density regions and mountainous areas (Dinesh and Pearce, 2016). The idea of combining the solar PV plant and agricultural crops to maximize the efficiency of natural resources (irradiation, land and water) use can ameliorate these land challenges.

1.2 THESIS AIMS AND OBJECTIVES

The major objective is to understand the impact of the operating conditions (viz. constantly high irradiance, hot summer and cold winter, varying solar spectrum) on the diverse performance of different GCPV systems, working at the same conditions. To do that, the roof integrated GCPV plant operating at ETSIAAB (Madrid, Spain 40.4426°N, 3.7295°W) since January of 2013 has been analyzed. Its specific characteristics refer to two differentiated parts, where one focus on electricity production and the other one aims at the experimental purpose for the comparison of different technology modules. Concretely, this experimental subfield consists of conventional poly-Si modules, amorphous silicon (a-Si) modules and cadmium telluride (CdTe) modules, working at the same conditions and location to infer conclusions of main influencing factor.

Consequently, the objectives of this thesis were carried out from the following aspects with respect to the GCPV systems at Madrid:

- ❖ To compare the performance of the three GCPV systems operating in Madrid, Spain, which allows inferring conclusions of the different behaviors of each technology affected by the same operation conditions.
- ❖ To estimate the performance degradation rates of the three PV technologies installed side-by-side, using different statistical methods and testing techniques;
- ❖ To establish a proper relation between the inverters and PV arrays from energetic and economic points of view to facilitate the pre-design of GCPV system as well as to reduce the financial risk;
- ❖ To evaluate the potential of agrivoltaic farm for co-producing electricity and crops on the same area of land.

CHAPTER 2 – LITERATURE REVIEW

2.1 GRID-CONNECTED PHOTOVOLTAIC SYSTEM

A grid-connected photovoltaic (GCPV) system is a solar PV power system for electricity generating and feeding it to utility grid. Unlike stand-alone PV system, GCPV system operates synchronously with utility grid without storage system (Obi and Bass, 2016). Hence, GCPV has somewhat superior performance compared with the stand-alone (off-grid) PV (Jahn et al., 2000; Jahn and Nasse, 2004). IEA reported that GCPV system accounted for more than 99% of the total installed PV systems among its member countries in 2013 (IEA-PVPS, 2013). The cumulative capacity of GCPV system in 2015 doubled from 2013, with the value of 50 GWp, where the centralized GCPV system accounted for 67% (IEA-PVPS, 2016). The PV industry is expected to continue to grow as a result of several factors like the decreasing cost of silicon and PV modules, technological improvements in large scale manufacturing, favorable policy supports, maturation and reinforcement of favorable international connections, and continued improving inverter efficiency and availability (Obi and Bass, 2016).

The main drawback of GCPV system compared to fuel energy source is that they are unable to meet the electricity demand in the hours following sunset (when demand for electricity is greatest) (Obi and Bass, 2016). Additionally, GCPV system performance depends on the system design, such as PV module types (Makrides et al., 2010b), inverter size and characteristics (Peippo and Lund, 1994), array tilt angle (Yan et al., 2013), shading, and array azimuth (Ueda et al., 2009). Another crucial factors are environmental parameters such as insolation (Huld et al., 2010), ambient temperature (Ishii et al., 2011; Skoplaki and Palyvos, 2009a), and sun spectra (Alonso-Abella et al., 2014)). Consequently, a wise design with respect

to GCPV system's operating circumstances will enhance solar PV to join in the mainstream energy source.

GCPV system emphasizes on PV modules as the core, supported by PV inverter(s) to convert direct current (DC) power generated from PV modules to alternating current (AC) power, with some other essential balance-of-system (BOS) components (power conditioning unit and connect supplements) (Eltawil and Zhao, 2010).

2.1.1 Photovoltaic Modules

PV modules are formed by the interconnection and encapsulation of various types of PV cells. Regarding the type of cell, they can be typically categorized into crystalline silicon (c-Si) based, thin film, organic and dye sensitized cells as well as high-efficiency III-V multijunction. Currently, commercial PV module power has a typical rating or specification from 50W up to 300W with the common efficiency varying from 7% to 20% (IEA-PVPS, 2016).

2.1.1.1 Crystalline silicon

Crystalline silicon (c-Si) based PV technology has been prominent in PV applications for many years, as it promoted the emergence and the continuous development of PV industry. Major characteristic of c-Si is that each atom perfectly lying in a pre-determined position contributes to an order crystal structure (Makrides et al., 2010b). The most common c-Si based solar cells are monocrystalline silicon (mono-Si) and polycrystalline or multicrystalline silicon (poly-Si). The prevalent fabrication method for mono-Si is Czochralski process at high temperature for long process time (Endrös, 2002). For poly-Si, the high productivity process with high-quality and less productivity duration is ingot casting at high temperatures of about 1400 °C (Franke et al., 2002) or directional solidification for large size (Ferrazza, 2002). High quality mono-Si produced for semiconductor industry is also used for mono-Si solar cells, contributing to the higher efficiency but slower manufacturing process and higher price. Lower efficiency due to grain boundaries but cheaper price makes poly-Si a competent alternative of mono-Si. A 335 W world-record mono-Si module with $21.3\pm0.4\%$ efficiency was achieved by Trina (Zhang et al., 2016), which also keeps the efficiency record of poly-Si module with the efficiency of $19.5\pm0.4\%$ (Pierre Jacques Verlinden, 2016). The present average prices of commercial mono-Si module and poly-Si module are both around 0.6\$/W (PV insights, 2017). PV module of c-Si usually has a warranty more than 20 years and a low annual degradation rate less than 1% (Jordan and Kurtz, 2013), as a mature PV technology.

2.1.1.2 Amorphous silicon

Thin film silicon PV technologies such as amorphous silicon (a-Si), microcrystalline or nanocrystalline silicon ($\mu\text{c-Si}$) as well as multi-junction a-Si have been alternatives to traditional c-Si based PV technologies. The advantages include: abundant and non-toxic material (Yang et al., 2003), large area and rigid substrates can be used for building integration, low Si-cost and fast processes (Yang et al., 2011). Thus, after a dozen years booming development, global a-Si PV installation has been ramping up to 0.6 GWp by 2015 (Burger et al., 2016) from 0.034 GWp in 2001 (Yang et al., 2003). For the fabrication of a-Si, the most common method is plasma-enhanced chemical vapor deposition (PECVD) (Pearce et al., 2007) with a hydrogenate process and a lower depositing temperature (less than 300 °C) (Hamakawa, 1994; Minemoto et al., 2007b).

Although a-Si takes advantages both from a suitable band gap (1.7–1.8 eV) and non-crystalline structure improving its sunlight capture performance, the higher recombination makes its efficiency lower than c-Si PV technology (Muñoz-García et al., 2012). Typically, the conversion efficiency of a-Si module is 5–14% (absolute value) lower than c-Si module (Meillaud et al., 2015). The best conversion efficiency in thin film a-Si modules was achieved by tandem structures (a-Si/ $\mu\text{c-Si}$) module with over 12% stabilized efficiency (Cashmore et al., 2016).

Presently, the obstacle to the penetration of a-Si is the low efficiency and the initial performance degradation of Light Soaking effect (LSE) attributed to the Staebler–Wronski effect (SWE)² (Staebler and Wronski, 1977). This effect pulls down the efficiencies by 10–30 % in the initial hundreds sun-exposure hours (Gostein and Dunn, 2011). Although there is still no global consensus on the exact nature of this light-induced defects or the mechanisms explained to their creation (Markvart and Castañer, 2003), a general agreement has been established that recombination-induced breaking of weak Si-Si bonds increases dangling bonds; after prolonged illumination, dangling bonds reaches equilibrium so that further light induced degradation is limited (Stutzmann et al., 1985). This initial light induced power degradation is perfectly reversible by thermal annealing above 150 °C for a few hours (Markvart and Castañer, 2003). Additionally, after a prolonged process with lower annealing temperature such as operating in summer, a part of the decreased power can be recovered as well (Fanni et al.,

² Light Soaking effect exhibits in nearly all PV technologies, resulting in changes in device performance under extended duration illumination. However, due to the SWE, the magnitude of these changes is much greater in a-Si device (Gostein and Dunn, 2011).

2011). Consequently, the performance of a-Si PV modules is influenced by the historical module temperature more than the instantaneous temperature (Ishii et al., 2011). The combination of SWE and thermal annealing effect contributes to a seasonal performance variation in a-Si PV modules (Akhmad et al., 1997).

To investigate the seasonal variation of a-Si module due to LSE and thermal annealing, the tested modules are usually at controlled conditions, i.e., continuous light exposure at fixed temperature or dark storage condition at high temperature (usually 60 °C). The fill factor (FF) of a-Si module is affected by these two effects significantly, while typically the open-circuit voltage (V_{oc}) and short-circuit current (I_{sc}) changed slightly (see Fig. 2) (Nikolaeva-Dimitrova et al., 2010).

2.1.1.3 Cadmium telluride

Cadmium telluride (CdTe) PV technology is another approach to convert solar energy effectively with significant economic impact. CdTe has a direct band gap of 1.45 eV, which is therefore suitable for solar spectrum and leading to a strong light absorption with a very thin layer of about 2 μm thickness (Yang et al., 2016). Easy fabrication process (typical method is formation of a p-n heterojunction by p-type CdTe film and n-type CdS film), large-area monolithic structure, long-term stability, low-life energy requirement (Peng et al., 2013) and shorter energy payback time (Kim et al., 2014) contribute CdTe to a competitive PV technology against c-Si. The theoretical conversion efficiency of CdTe is 29% (Dobson et al., 2000), where present efficiency record is held by First Solar *Inc.* with the value of 18.6% (Green et al., 2016). The global cumulative CdTe installation has achieved 2.5 GWp by 2015 (Burger et al., 2016).

Fig. 2. I-V curves measured at standard test conditions (STC) daily during the light soaking (LS) and during the annealing experiments (presented on the inset). From Nikolaeva-Dimitrova et al. (2010).

Metastability is a common characteristic of CdTe modules affected by irradiance, electrical bias, temperature, cell materials, and processing (Dirnberger, 2014). It strongly depends on the back contact material containing Cu, which improves the performance of CdTe but segregates at grain boundaries under long run (Romeo et al., 2004). Unlike SWE of a-Si, the metastability effect of CdTe modules activates the performance after it has been exposed to sunlight for some hours (Muñoz-García et al., 2012). Some studies expressed it as *short-time LSE* due to the shorter period than SWE (Virtuani et al., 2011).

Safety and environment issues remain a concern about CdTe modules. The toxic element Cd requires a careful disposal and recycling systems to be set up for commercial CdTe modules (Polman et al., 2016).

2.1.2 Photovoltaic Inverter

Inverter is arguably the second essential element (apart from PV modules) among the other components that set up GCPV system. The power electronic inverters help optimize the output of PV modules through maximum power point tracking (MPPT) algorithm, realize the power conversion, grid interconnection and control optimization (Yang et al., 2010). Since the output of PV arrays highly depends on changeable solar irradiance and temperature, a MPPT inverter supports a GCPV system extract maximum power from PV arrays and enhance the performance by up to 25% when compared to systems without MPPT controllers (Enslin et al., 1997). A suitable inverter with a reasonable cost is the guaranty of high quality and profitability GCPV-generated electricity feeding into grid (Eltawil and Zhao, 2010; Kjaer et al., 2005). The essential functions of a PV inverter include: 1. current shaping into a sinusoidal waveform; 2. converting DC into AC; 3. low voltage boosting to grid voltage (Myrzik and Calais, 2003).

Commonly, the PV inverter topologies are: central inverter, string inverter, multi-string inverter and module integrated inverter according to the PV array capacity (Islam et al., 2015). Warranty life time of an inverter is usually 10 years, half shorter than that of a PV module. Accordingly, the replacement of inverter is extra cost of GCPV system. Advancement in semiconductor industry and filter components lead to inverter efficiency improvements; present typical weighted efficiency is ranging between 95% to 99% (IEA-PVPS, 2016). The little room for further efficiency improvement forces PV inverter companies focus more on product quality and cost reduction.

2.2 PERFORMANCE RATING METRICS

Comparison and evaluation for the performance of GCPV system relies on the chronological ratings of the performance of relative GCPV generators (module, array or system). The first order measurements recorded directly by the power meters according to IEC 61724 (International Electrotechnical Commission, 2009b):

- current-voltage (I-V) curve characteristics;
- DC current and voltage at the maximum power point (MPP) and subsequently their product, DC power and energy;
- AC power and energy injected to the grid.

However, these first order measurements are related to the nominal ratings and ambient parameters. A benchmark is usually set to provide a uniform comparison and evaluation platform. Common performance metrics used to rate the PV performance can be grouped into four categories (Phinikarides et al., 2014a):

- First order measurements recorded under outdoor or simulated indoor conditions and corrected to STC or other conditions;
- Regression models such as the PVUSA (Photovoltaics for Utility Scale Applications) model for PVUSA Test Condition (PTC) rating;
- Scaled ratings such as specific yields.
- Normalized ratings such as Performance Ratio (PR) and conversion efficiency;

2.2.1 I-V Curve Measurements

I-V curves contain several pivotal points relating to operating conditions (see Fig. 3): short-circuit current (I_{sc}), open-circuit voltage (V_{oc}), current and voltage at MPP (I_{mp} and V_{mp}) as well as their product, i.e., maximum power (P_{max}). The fill factor (FF) is the ratio of P_{max} and product of I_{sc} and V_{oc} (Durán et al., 2009). Furthermore, series resistance (R_{series}) dissipating the voltage with main influence in high voltage area, and shunt resistance (R_{shunt}) dissipating the current, with more influence in low voltage area, are detrimental to solar cell performance (van Dyk and Meyer, 2004).

Fig. 3. I-V curve of a practical PV device and the three remarkable operating conditions: short circuit $(0, I_{sc})$, maximum power point (V_{mpp}, I_{mp}) , and open circuit $(V_{oc}, 0)$. From Villalva et al. (2009).

Both the outdoor and indoor I-V curves are measured periodically, whereas the discrete interval of the latter is more unrestrained due to the more controllable indoor conditions (Virtuani and Fanni, 2014). The difficulties of outdoor I-V characterization test include: 1. Labor-intensive, where the test has to be conducted under high and stable irradiance condition, 2. Portable I-V tracer may not be available for large arrays (Jordan, 2011). Indoor I-V characterization test is less commonly used because: 1. it is a time consuming process; 2. it is inefficient for PV systems with many PV modules; 3. delivery to a testing facility raises the risk of module failure due to mishandling (Phinikarides et al., 2014a). Sometimes, a proper compromise of indoor test is extracting one or several field-exposed module(s) from a GCPV system (Phinikarides et al., 2012).

Fig. 4. Sketch of I-V curve measurement system at indoor simulated STC. From Nakamura et al. (2011).

The procedures for accurately correcting measured I-V characteristics to other temperature and irradiance conditions (such as STC) are applied to providing a uniform comparison platform. IEC published an international standard namely, IEC 60891 (International Electrotechnical Commission, 2009a), introducing three procedures for temperature and irradiance correction. The first two procedures are algebraic correction methods requiring correction parameters, where the second one yields better results for large irradiance differences ($> 20\%$). The third procedure is an interpolation method only needs three I-V curves measured meeting the irradiance and temperature requirements.

Although measuring I-V curves is a harsh process, the comparison of I-V curves measured under similar operating conditions provides a periodically visual representation of the performance degradation and the clues to degradation mechanism (Jordan, 2011; Ye et al., 2014). After more than 20 years outdoor exposure, the indoor I-V curves comparisons made by Skoczek et al. (2009) of two c-Si based modules demonstrated the remarkable losses in FF and I_{sc} contributing to the P_{max} degradation (see Fig. 5). Subsequently, the authors attributed the losses in FF and I_{sc} to the deterioration of R_{series} and optical properties, respectively.

Fig. 5. The I-V curves of two c-Si based modules measured before and after long-term outdoor exposure. From Skoczek et al. (2009).

Another usage of I-V curve is providing the prototype of prediction models such as one-diode (De Soto et al., 2006) or two-diode (Salam et al., 2010) equivalent circuit. Those models offer a deeper insight to the working mechanisms of PV cell and module, for example,

explanations of metastability (van Dyk and Meyer, 2004) and effects of low irradiance and temperature (Cuce et al., 2013; Ghani et al., 2015).

2.2.2 Photovoltaics for Utility Scale Applications Test Condition Rating

PV module performance rating at STC is the most common metric provided both by manufacturers and researchers. However, these reporting conditions rarely occur outdoors, leading to a controversy about the usefulness and applicability of the PV module indoor characterization at STC (Almonacid et al., 2009; Keller and Affolter, 1995). The most remarkable contradiction between STC and field conditions is that the operating temperatures are generally much higher than 25 °C when the irradiance is 1000 W/m² (Davis et al., 2012). The extrapolation to STC introduces errors and unfairly benefits the PV modules with high operating temperature or temperature coefficients (absolute value) (Kimber et al., 2009). Since 1980s, the PVUSA project developed a realizable rating method compared with STC, namely, PVUSA Rating Conditions (PTC) (Dows and Gough, 1995). The comparison between the conditions stated in STC and PTC is summarized in Table 1, where the divergence relates to the temperature conditions. PTC requires a 20 °C ambient temperature, which usually resulted to a 40 °C module temperature of free standing system (Nordmann and Clavadetscher, 2003). Thus, ratings under PTC with higher module temperature are generally 10% lower than ratings under STC (Dows and Gough, 1995).

Table 1. Comparison of Standard Test Condition (STC) and Photovoltaics for Utility Scale Applications Test Condition (PTC).

	STC	PTC
Temperature	25 °C module temperature	20 °C ambient temperature
Irradiance	1000 W/m ²	1000 W/m ² (for flat plates) 850 W/m ² (for concentrators)
Spectrum	AM 1.5G	NA
Wind speed	NA	1 m/s at 10 meters above ground

The method is based on the regression of the system power output against a combination of irradiance, wind speed, and ambient temperature for a period of time (Myers, 2009). The advantages of PVUSA rating model include:

- Representation of the actual outdoor conditions and discouraging the poor thermal design (Whitaker et al., 1997);
- Availability for the AC rating (Kimber et al., 2009);
- Comparison with other method such as Sandia array performance model can monitor the accuracy of the inverter's MPPT circuit (Whitaker et al., 1997);

- Applications on PV performance degradation and seasonality (Jordan and Kurtz, 2010), power prediction (Meyer and Van Dyk, 2000), performance comparison among different PV systems (Marion et al., 2005).

However, its disadvantages exhibit in:

- High error under low irradiance conditions (PVUSA Project Team, 1991);
- Possible long time to meet preliminary criterion of a minimum in-plane irradiance above 1 kW/m^2 for more than 10 hours (Kimber et al., 2009);
- Inaccurateness in thin film technologies, which require a modified model (Phinikarides et al., 2014a);
- Requiring spectral and angle of incidence (AOI) corrections (Whitaker et al., 1997).

2.2.3 Scaled Ratings

The scaled ratings usually refer to the specific yields of the PV array (DC) or system (AC), in addition the reference yield. The IEC 61724 (International Electrotechnical Commission, 2009b) describes the specific array (or system) yields as the PV array (or GCPV system) generated energy delivered to the grid per nameplated power of the GCPV system, respectively, with the unit of kWh/kWp. These specific yields denote the number of hours that a PV array or system would need to operate at its nominal power to provide the same DC and AC energy generation, respectively. Because of the simplified calculation, they are particularly useful for the performance comparison of side-by-side systems of identical design and detection of any operation problems (Marion et al., 2005).

The term of capture losses comes from the difference between reference yield and array yield of a particular GCPV system. It stands for the losses caused by the attenuation of the incoming light (soiling or snow, shading, reflection, etc.), thermal loss, electrical mismatching, parasitic resistances in PV modules and imperfect MPPT (Woyte et al., 2013), in addition the particular power limitation due to undersized inverter. Capture losses is a useful indicator for system problems in GCPV systems, where a remarkable rise of capture losses will reflect a malfunction or inverter MPPT failure. This effect can be seen in Fig. 6, where capture losses values are extremely high in June and July 1997 (Jahn et al., 2000).

Fig. 6. Monthly average daily final yields (Y_f), array capture losses (L_c) and system losses (L_s) for an Italian plant from January 1992 to December 1997. From Jahn et al. (2000).

Analogously, the indicator system losses is defined as the gap between array yield and system yield. It is competent for monitoring the inverter conversion performance. In general, system losses is affected by ambient temperature, irradiance, and inverter characteristics as well as the inverter sizing ratio (Woyte et al., 2014).

2.2.4 Normalized Ratings

2.2.4.1 Performance ratio

The performance ratio (PR) is defined in IEC 61724 (International Electrotechnical Commission, 2009b), as the ratio of specific array or system yield (kWh/kWp) to the reference yield (kWh/kW). It quantifies the discrepancy between DC (or AC) energy a PV system generated and an ideal lossless PV system would have produced, if this lossless PV system operates with the same irradiation and an operating temperature of 25 °C (Nordmann et al., 2014).

PR values are commonly calculated on a long time interval (monthly or yearly) to identify the PV system seasonal performance variation and permanent long-term performance loss (Sharma and Chandel, 2013). With the improvements both in PV modules (more realistic ratings) and components in GCPV system (e.g., higher efficiency inverter with increasing reliability), typical ranges of PR values rose from reported 50–75% in the late 1980s, and then 70–80% in the 1990s, to more than 80% nowadays (Ueda et al., 2009).

The PR is one of the widely used gauges to assess the relative merits of PV systems of different sizes, technologies, locations and even orientations. It is a straightforward indicator to compare diversely designed systems, equal system design but operated at different

locations or year-to-year performance of the same PV system. It packages the capture losses and/or system losses, interpreting the overall losses directly (Reich et al., 2012).

However, as PR includes the thermal losses, it is higher in winter and lower in summer for most c-Si PV systems (Aste et al., 2014). On the contrary, due to thermal and spectral characteristics of a-Si technologies, the PR values of a-Si PV systems is higher in summer and lower in winter (Makrides et al., 2014). Additionally, PR is susceptible to the PV system failures, i.e., problems due to inverter operation (faults/failures, peak-power tracking, software/control), solder-bond failures inside PV module junction boxes, inoperative sun trackers, circuit-breaker trips, diode failures, shading, snow, soiling among others (Marion et al., 2005). On the other hand, PR values are also affected by the corresponding in-plane irradiance sensor. Both pyranometer and c-Si reference cells are eligible for measuring the on-site irradiation in PV monitoring systems as described in IEC 61724 (International Electrotechnical Commission, 2009b). Differently, due to the angular and spectral mismatch between pyranometer and PV arrays, the monitored PR is systematically lower by 2–4 % when calculated with irradiation data obtained by pyranometer than the records from reference cell (Reich et al., 2012), as shown in Fig. 7.

Fig. 7. Comparison of annual irradiation deviations obtained by pyranometers (orange circle) and reference Si- sensors (blue circle) and resulting accuracies for a correction routine. From Reich et al. (2012).

Incorrect PV system power rating and high irradiation measuring uncertainty may contribute to abnormal PR profile (Makrides et al., 2014). Occasionally, PV system features high PR values approaching even exceeding the optimum (PR of 100%) during the winter seasons (see Fig. 8).

Fig. 8. Monthly DC performance ratio (PR) of installed mono-Si PV systems over the period June 2006–June 2011 in Nicosia, Cyprus. From Makrides et al. (2014).

Although the PR describes a global profile about PV system operating performance, it is still insufficient to identify the malfunctions of the individual components of the GCPV system and to point out the direction to repair and improve the system (Chouder and Silvestre, 2010). Briefly, PR can indicate the existence of a problem rather than the cause, which requires further investigation, including a particular site visit by maintenance personnel (Marion et al., 2005).

2.2.4.2 Conversion efficiency

As a frequently mentioned term in PV industry, conversion efficiency describes how effective the PV generator it is or how many energy generated by the PV generator under a certain irradiation. Conversion efficiency of a PV generator is defined as the ratio between its produced power and received in-plane solar irradiance with respect to its area.

PV conversion efficiency significantly depends on operating temperature, in addition less affected by irradiance (Evans, 1981; Skoplaki et al., 2008). Consequently, it is a useful indicator for assessment of different technologies or same technologies from different manufacturers with clear definition of the area and identical insolation and temperature (Green and Emery, 1993).

The efficiencies of PV modules provided by manufacturer and their outdoor values are usually different as shown in Fig. 9 (Başoğlu et al., 2015), where mean array efficiencies are generally lower than the values given under STC. Maximum deviation in efficiency is detected in winter of 4.5% and 4.21% for mc-Si (poly-Si) and c-Si arrays, respectively.

Fig. 9. Differences between mean array efficiencies (MAE) and STC efficiency. From Başıoğlu et al. (2015).

Table 2 shows the abovementioned performance rating metrics for PV systems varying in types, locations and installed time. Generally, overall PR of thin film PV systems is unremarkably higher than c-Si based PV systems. The PV systems at the sites with high solar source such as Spain and Arabic countries produce more final yields but less PR than the less insolation countries such as Ireland and Germany with less thermal losses. The PV system without inverter, i.e., the one at Malaga (Spain), has higher PR since it is free of system losses. Furthermore, the performance trend along with time is remarkable, where the common values are below 70% at 2000s while they increased to more than 80% after 2010.

Table 2. Performance metrics for different PV generators.

Location	PV type	Y_o (kWh/kWp)			η_{STC}	η_f %		η_{inv}	PR	Source
		Y_o	Y_f			η_f	%			
India	Poly-Si	-	1590		15.8	-	-	-	85*	(Sharma et al., 2013)
	HIT ²	-	1580		17.3	-	-	-	90*	
	a-Si	-	1474		7.6	-	-	-	92*	
Malaga, Spain ¹	CdTe	-	1971		9.7	8.8	-	-	94.2	
	a-Si	-	1971		6.6	5.7	-	-	94.8	(Cañete et al., 2014)
	a-Si/uc-Si	-	1971		8.5	7.2	-	-	93.9	
	poly-Si	-	1935		13.4	12.2	-	-	92.9	
Jaen, Spain	mono-Si	833–1223	846–1000		12.4	7.2–8.1	80.6–95.9	-	58–65	(Drif et al., 2007)
Castile & Leon, Spain	mono-Si	1180	511–1752		13.7	12.2	89.5	-	69.8	(De Miguel et al., 2002)
Dublin, Ireland	mono-Si	960	876		14.9	12.6	89.2	-	84.5	(Ayompe et al., 2011)
Ireland	mono-Si	675–737	588–642		7.5–10.0	6.0–9.0	87	-	60–62	(Mondol et al., 2006a)
Kuwait	CIGS ³	-	1643		14	-	98.1	-	70–85	(Al-Otaibi et al., 2015)
Turkey	mono-Si	-	-		14.7	12.7	96	-	83.8	(Başoğlu et al., 2015)
	poly-Si	-	-		15	12.0	96	-	82.1	
	CdTe	-	-		12.2	10.8	96	-	89.8	
China	-	-	-		-	-	-	-	80.88	(Zou et al., 2016)
Germany	-	-	793		-	-	-	-	76.5	(Jahn and Nasse, 2004)
Japan	-	-	-		-	-	-	-	71.0–79.0	(Oozeki et al., 2010)

* Visual estimation

¹ PV individual module

² Heterojunction with intrinsic thin-layer

³ Copper Indium Gallium Selenide

2.3 BASIC METEOROLOGICAL FACTORS

2.3.1 Irradiance

A PV generator converts the incident solar irradiance (or irradiation, when referring to accumulated irradiance) into electricity directly. Hence, the in-plane solar irradiance is the first-order factor determining the performance of a PV module and system (Huld et al., 2010). Furthermore, the generated current rather than the voltage is more sensitive to the incident irradiance as the light generated current is directly proportional to light intensity (Cuce et al., 2013). There is hence a proportional relation between the PV generated power and the incident irradiance.

Although the temperature is a dominant parameter for module efficiency, severe reductions of commercial module efficiency at low irradiance levels have been reported by Bücher (1997) and (Parretta et al., 1998). The effect of irradiance intensity on the cell parameters of a c-Si solar cell has been investigated based on one diode model (Khan et al., 2010). This indoor work revealed the positive relation between R_{shunt} and irradiance intensity in a fairly wide irradiance range (150–1800 W/m²). Thereby, more energy is shunted by the decreasing R_{shunt} leading to lower module efficiency. Analogously, Bunea et al. (2011) pointed out that a good mono-Si cell (high R_{shunt}) almost maintained its efficiency when the irradiance level decreases two orders of magnitude, while a same type cell with lower R_{shunt} had an efficiency that sank linearly with decreasing irradiance. The low-irradiance intensity losses are PV material-dependent. Among the typical PV modules in the market, a-Si and CdTe modules have a generally better low-light performance, while c-Si and copper indium gallium selenide (CIGS) modules perform worse under low irradiance intensity (Huld et al., 2010; Marion et al., 2014; Randall and Jacot, 2003; Reich et al., 2005).

The incident irradiance is a function of extra-terrestrial irradiance, sun position, cloudiness, tilted angle, environmental reflection (Paulescu et al., 2012). Its value can be obtained by on-site measurements or mathematical calculation with simple inputs from meteorological satellite or nearby meteorological station. For the field measurements of the irradiance, the top two popular tools utilized by the PV industry are thermopile pyranometer and PV reference sensor (Dunn et al., 2012). On the other hand, the approach of mathematical calculation usually employs an estimation model (Duffie and Beckman, 2013), i.e., the isotropic sky model of Liu and Jordan (1960), the anisotropic sky model modified by Reindl et al. (1990) and the model of Perez et al. (1990). Predictably, the mathematical approach is flawed with

high uncertainty and hysteresis at a fast-changing weather. In addition, the data availability is usually limited to an extended time interval, which is hourly, daily even monthly.

The influence of irradiance on some PV modules is not only instantaneous but also historical, especially on thin film technologies. Under long term illumination, almost all thin film technologies (i.e., a-Si, CdTe, CIS/CIGS) exhibit fluctuating performance posterior to the installation, although the diverse magnitudes of these performance changes are material-dependent (Gostein and Dunn, 2011). Thus, the particular criterion in IEC 61215 (International Electrotechnical Commission, 2016) claims that, for thin film performance stabilization, the module should be exposed to an irradiation totaling 60 kWh/m².

2.3.2 Temperature

Temperature accompanied with thermal characteristic of PV modules results in a significant impact on PV systems performance. Temperature relations are usually described as temperature coefficients for the power, voltage and the current, respectively. In common, the PV module has negative temperature coefficients for the power and voltage but slightly positive temperature coefficient for the current. The negative correlations between module temperature and its efficiency or other electrical parameters (P_{max} , V_{oc}) are abundant (Skoplaki and Palyvos, 2009a). Most of them use the familiar linear form, but different values of the relevant parameters to express the material and system dependences (Dubey et al., 2013). Normally, PV module manufacturer provides the temperature coefficients of electrical parameters with laboratory tests conducted at STC. However, research is necessary for validation of these laboratory-established values under realistic operating conditions instead of indoor controlled conditions (Silverman et al., 2014).

On the other hand, the instantaneous temperature impact on a-Si modules is less explicit due to the additional dependence on the operation history (Ishii et al., 2011). In some studies (Akhmad et al., 1997; Makrides et al., 2012), positive relation between the a-Si module output and its operating temperature has been reported. Akhmad et al. (1997) concluded this phenomenon as the thermal recovery effect, through the investigation of the relation between the daily module efficiency and daily average module temperature of one poly-Si module and one a-Si module, respectively. They even pointed out that, once the module temperature surpassed the turning point, the a-Si module's efficiency would be higher than the efficiency of the poly-Si module during summertime (Fig. 10).

Fig. 10. Relation between the daily watt-hour efficiency and daily average module temperature of the a-Si and poly-Si modules. Curve A and B are resulted from the fitting data of poly-Si and a-Si modules. For comparison, the daily watt-hour efficiency of the a-Si module at the unstabilized state are also shown but not included for the curve fitting (closed rectangular). Curve C shows the extrapolation of the a-Si module having higher efficiency more than the present module, where the turning temperature could be 60 °C. From Akhmad et al. (1997).

Based on semiconductor physics, the temperature dependence of c-Si cells or modules is fundamentally attributed to the band gap and the recombination of minority-carrier (Radziemska, 2003). Concretely, when the PV cell temperature increases, the reducing band gap enhances the penetration of photons to the material and the generation of charge carriers. This leads to a logarithmically increase in the I_{sc} (Dubey et al., 2013; Ghani et al., 2015). However, the temperature caused recombination of minority-carriers creates an increase in the reverse saturation current but a decrease in R_{shunt} , both leading to a reduction in the V_{oc} (Ghani et al., 2015; Singh et al., 2008). Through an equivalent circuit based on PV cell one diode model and proper numerical derivation, Ghani et al. (2015) claimed that reverse saturation current was the most strikingly affected parameter with over a 2700% increase from 25 °C to 70 °C (Fig. 11).

Fig. 11. Normalized reverse saturation current (I_0) as a function of temperature. From Ghani et al. (2015).

Operating temperature of PV generator is sensitive to the environmental variables (irradiance, ambient temperature, wind speed and direction). Implicit and explicit correlations were proposed for the simulation of the module temperature with these variables. A comprehensive overview is given in the study of Skoplaki and Palyvos (2009b). These abundant expressions were elaborated through the thermal processes in the PV module or numerical statistical methods such as regression applied on empirical data.

The module back-side temperature is generally measured and represents the operating temperature of PV generator (Bianchini et al., 2016; Carr and Pryor, 2004). In fact, the PV cell temperature is typical higher than the back-side temperature where the difference is a function of irradiance level, module type and mounting configuration (King et al., 2004).

2.3.3 Spectrum

Since different semiconductor materials have different band gaps, they vary in their responses to different wavelengths irradiance (Fig. 12). On the other hand, the solar spectrum undergoes a seasonal variation: it has a larger blue (shorter wavelength) content during summer and higher red (longer wavelength) content during winter (Virtuani and Fanni, 2014). For the same PV technology with small differences in spectral response (Fig. 13), it is not necessary to differentiate between them with regard to the small oscillation (from 1.1% to 1.4%) of annual spectral impact (Dirnberger et al., 2015).

Fig. 12. Relative spectral responses of four modules: a-Si, CdTe, CIS, m-Si (mono-Si). From Nofuentes et al. (2014)

Fig. 13. Normalized Spectral response of different c-Si PV modules, measured by Fraunhofer ISE. From Dirnberger et al. (2015).

Commonly, sun spectral influence on PV generator is characterized by three approaches: average photon energy (APE) (Jardine et al., 2002; Katsumata et al., 2011), useful fraction (Gottschalg et al., 2003), and air mass (AM) (King et al., 1997). In addition, the investigation time span affects the impact of the seasonal varying solar spectrum on the energy yield, i.e., the longer period of investigation, the lower the spectral effect on the energy yield, regardless of the considered PV material (Alonso-Abella et al., 2014).

APE represents the average energy per photons included in a spectrum (Minemoto et al., 2009). The calculation of APE is through dividing the integrated irradiance with the

integrated photon flux density (Norton et al., 2015). However, from this definition, the uniqueness of APE to the spectral irradiance distribution should be verified to assure that an APE value and its corresponding sun spectra are bijective, before adopting APE as the index of solar spectrum (Minemoto et al., 2009). This uniqueness was reported by Minemoto et al. (2009) and Norton et al. (2015) with quite small standard deviation in both cases. Recently, Dirnberger et al. (2015) asserted that an APE value could not uniquely describes the shape of a solar spectrum and concluded that APE was not a good quantitative indicator for instantaneous spectral impact.

Useful fraction is defined as the ratio of the irradiance within the absorption range of the PV generator to the total incident irradiance (Gottschalg et al., 2003). For example, a-Si has the spectral response from 300 to 780 nm, where around 60.4% of the energy of standard AM1.5 spectrum falls in this range; thus the useful fraction of a-Si is 0.604 at standard AM1.5 (Gottschalg et al., 2004). Gottschalg et al. (2003) pointed out that the useful fraction is a function of AM and weather conditions (see Fig. 14). The latter is described in a simplified manner, i.e., clearness index k_t . Higher k_t and AM values both lead towards a lower useful fraction, and this process is independent of location.

Fig. 14. Influence of the weather and the air mass (AM) on the useful fraction for a-Si. The influence of the weather can be expressed using the clearness index k_t ; The steep flank for low k_t is exclusively due to a lack of points in this region. From Gottschalg et al. (2003).

The term 'Air Mass (AM)' is calculated through geographical considerations and describes the relative length that the sun's rays travel through the atmosphere. The AM is a

specific indicator to express sun spectral influence; but it neither includes realistic solar spectrum measurements nor the influence of water vapor, turbidity and air pollution. Thus, prior to its utilization, a clarification of clear sky condition should be stated.

The IEC office claimed one of the STC requirements is a reference solar spectral distribution called AM 1.5G (Fig. 15), under the following conditions (International Electrotechnical Commission, 2008):

- U.S. Standard Atmosphere with CO₂ concentration increased to current level (370 ppm), a rural aerosol model, and no pollution;
- precipitable water: 1.4164 cm;
- ozone content: 0.3438 atm-cm (or 343.8 DU);
- turbidity (aerosol optical depth): 0.084 at 500 nm;
- pressure: 1013.25 hPa (i.e., sea level).

Fig. 15. Reference solar spectral irradiance distribution of AM 1.5G. From IEC office (International Electrotechnical Commission, 2008).

The experimental work presented by Aste et al. (2014) with the monthly PR, revealed a positive relation between monthly PR of a-Si system and AM (Fig. 16). Meanwhile, the PRs of the c-Si and HIT systems are rather stable and predictable with the AM variation. However, this work did not distinguish the individual effect of three ambient parameters (i.e., ambient

temperature, in-plane irradiance and AM) on PV systems seasonal performance variation. Neither has it provided the quantified criteria for clear sky conditions.

Fig. 16. Monthly average PR, ambient temperature and air mass over the monitoring year (January–December 2013). From Aste et al. (2014).

Nakada et al. (2010) compared the PR as functions of AM and k_t between a-Si and c-Si modules (Fig. 17). The PR of a-Si module decreased with increasing k_t and decreasing AM because the cloud consists of water vapor which absorbs long-wavelength light with low energy and more short-wavelength light scattered with higher AM. Meanwhile, the PR of c-Si had no apparent relationship with AM and k_t since the spectral response of the c-Si PV module widely covers the solar spectrum with the wavelength range of 350–1050 nm. Nevertheless the potential influence of non-excluded thermal effect, this work indicated that the a-Si module is more suitable in the low latitude and cloudy or humid sites.

Fig. 17. Contour maps of average of PR for (a) a-Si and (b) sc-Si (mono-Si) PV modules as a function of air mass (AM) and clearness index (k_t). From Katsumata et al. (2011).

More meticulously, to mitigate the potential thermal effect (i.e., thermal annealing) in a-Si technology, Virtuani and Fanni (2014) conducted a complex experiment. They investigated the I_{sc} dependence on AM for a-Si and c-Si modules, which were stored indoors in a controlled environment between the outdoor solar noon tests. The I_{sc} for the a-Si module is negatively linear with AM values. The decreasing rate is 5.8%/AM as shown in Fig. 18. However, this effect for the c-Si module is not so apparent compared with a-Si.

Fig. 18. Short-circuit current dependence on AM-units of a single-junction a-Si (red circles) module and of a c-Si (green squares) module. Both modules were stored indoors in a dark-controlled environment between the tests. Both solid lines correspond to the theoretical model. Measurements were performed on clear-sky days only and were all corrected to STC. From Virtuani and Fanni (2014).

2.4 PERFORMANCE COMPARISON

Previous studies have portrayed the PV performance map of how different PV technologies perform under site-specific climate conditions, emphasizing the importance of the performance evaluation under realistic field operation.

Akhmad et al. (1997), through the comparison of a-Si and poly-Si modules for a 2-year period, suggested that a-Si is more suitable than c-Si for tropical climates based on its thermal recovery effect (Fig. 19). The large output current improvement in summer for the a-Si technology is primarily due to thermal recovery effect and secondly due to spectral effect, assessed by an assumption about the solar spectrum from a geographical consideration.

Fig. 19. Characteristics of the daily integrated output power (P_{wh}) of both a-Si and poly-Si modules normalized to their calculated output power at STC ($P_{wh,STC}$). Only the P_{wh} with total irradiance more than 0.1 kW/m^2 and incident solar energy more than $3.0 \text{ kWh/m}^2/\text{day}$ are shown in this figure for the period of March 1994 to May 1995. Ins. and T_{dm} show the daily incident solar energy and average module temperature, respectively. From Akhmad et al. (1997).

Carr and Pryor (2004) compared the performance of five types PV modules (Fig. 20) and reported that after stabilization and proper ratings, the analyzed a-Si and CIGS modules outperformed the c-Si based technologies in Perth, Western Australia, especially in summer because of lower thermal losses. The energy generated by the triple junction (3j) a-Si modules (US64) was over 15% more than that produced by c-Si module (BP275) in summer, and around 8% more in winter. The CIGS module consistently produced between 9% and 13% more energy than c-Si module (BP275).

Fig. 20. Monthly module efficiency, based on total module area, where SX-75 and PW750/70 are poly-Si modules, BP275 and BP585 are c-Si modules, UN-2 and US64 are 3j,a-Si modules, ST 40 is CIGS module. From Carr and Pryor (2004).

However, with the expansion of the PV industry, new studies have emerged to assess the performance differences on GCPV systems and their overall energy output profile.

Sasitharanuwat et al. (2007) evaluated the first six months of operational performance of a 10 kWp PV system based on three PV technologies including a-Si, poly-Si and HIT. The average efficiencies of a-Si, poly-Si and HIT systems were 6.26%, 10.48% and 13.78%, respectively.

Minemoto et al. (2007a) characterized the effects of the solar spectrum distribution and module temperature on the performance of two GCPV systems based on a-Si and poly-Si through two contour graphs (Fig. 21). For poly-Si system (Fig. 21a), the PR decreased with increasing module temperature at fixed APE, whilst PR remained the same with the APE variations at fixed module temperature. In contrast, the PR of a-Si system increased with increasing APE at fixed module temperature as shown in Fig. 21b. The study revealed a stronger spectral dependence but weaker temperature dependence of the a-Si performance, while the poly-Si GCPV system had the opposite behavior.

Makrides et al. (2010b) highlighted the influences of the meteorological conditions and geographic locations on the energy performance of 13 GCPV systems located in two high irradiation cities (Nicosia, Cyprus and Stuttgart, Germany). These researchers outlined that thin

films with lower temperature coefficients generated more energy than c-Si technologies in high irradiation locations.

Ferrada et al. (2015) conducted a comparison concerning two GCPV systems consisting of mono-Si and a-Si/ μ c-Si technologies for 16 months under a coastal desert climate in Chile. The authors reported that the PR of thin films decreased 25% versus 18% for mono-Si in winter due to dust accumulation, and 21% versus 9% in summer, respectively. They concluded that the dust accumulation affected a-Si/ μ c-Si more severely than mono-Si.

Fig. 21. Contour graphs of PR for (a) mc-Si (poly-Si) and (b) a-Si PV modules as a function of average photon energy and module temperature (T_{mod}). In the figures, STC (25 °C and 1.88eV) and MFC (Most Frequent Condition) are indicated with circle and star symbols, respectively. From Minemoto et al. (2007a).

2.5 PERFORMANCE DEGRADATION

The availability, reliability, and durability of PV system, in addition to a continued decline in PV system cost, accelerate the penetration of PV into the main stream of energy source. The availability and lower cost attract more attention from consumers and investors. Meanwhile, the improvement of reliability and durability instils confidence in PV technology, implicitly enhancing the economic viability through delivering more energy over its lifetime (Phinikarides et al., 2014a). The typical statement of PV modules warranty by manufacturer is: the output power of the module will be at least 90% (80%) of its initial rated power at STC after 10–12 (20–25) years operation, associated with the manufacturing and the measurement tolerances for the module power (Vázquez and Rey-Stolle, 2008). In other words, this long-term warranty of 20 or 25 years life time can be interpreted by a typical linear degradation rate of 1 %/year (Shrestha and TamizhMani, 2015). A number of either extrinsic or inherent factors result in diverse degradation mechanisms, apparently at the cell, module or system level, contributing to a power or performance loss progression (Ndiaye et al., 2014). Thus, proper monitoring, accurate calculation and reasonable prediction of long-term performance degradation of PV under on-site operating conditions, have been gaining interests and reducing the risk on investment (Ndiaye et al., 2013; Phinikarides et al., 2014a). Due to the long-term evaluation period as well as the continuous appearance of improved PV technology, the accelerated qualification tests, i.e., IEC 61625 (International Electrotechnical Commission, 2016), are conducted by most PV module manufacturers on their modules to assess module reliability. However, these tests fail to provide an unambiguous value of lifetime, which can however be offered by long-term field aging evaluation (Sharma and Chandel, 2013; Skoczek et al., 2009).

2.5.1 Module-Level Degradation Mechanisms

Breakage and cracks are the most noticeable degradation factors of PV modules, occurring during installation, maintenance, and the transportation of modules towards their installation sites (Wohlgemuth and Kurtz, 2011). For economic benefit, decrease of thickness and increase in area make the cells more fragile and susceptible to fractures (Muñoz-García et al., 2011). Breakages and cracks are usually the catalysts of other degradation types such as corrosion, discoloration and delamination (Quintana et al., 2002).

Discoloration is a color change, i.e., from white to yellow and occasionally from yellow to brown, in the ethylene vinyl acetate (EVA) or the adhesive martial between the glass and the cells. It leads to the deterioration in the glass layer transmittance. Then this deterioration

reduces light absorbed by the solar cells and thus a decrease in the power output (Muñoz-García et al., 2011). The discoloration is mainly due to photo-oxidation deterioration, originally from irradiation especially the ultraviolet rays (Kojima and Yanagisawa, 2005; Wohlgemuth and Kurtz, 2011).

Delamination consists of the loss of adherence between glass/encapsulant and encapsulant/back sheet, more frequently in hot and humid climates. It is a severe problem because of the subsequent effects: module reflection increases and water penetration inside the module structure leading to corrosion (Muñoz-García et al., 2011), breakage uniform dissipation of heat resulting into higher operating cell temperatures (Sharma and Chandel, 2013).

A hot spot is an area of the PV module with a rather higher temperature than the rest that could damage a cell or other element of the module (Muñoz-García et al., 2011). Hot spot(s) can occur in a PV module by any combination of cell failure, interconnection failure, partial shading, and mismatch (Molenbroek et al., 1991). For example, a shaded PV cell operating in reverse model consumes rather than generates energy, resulting in a localized heat forming the hot spot. Bypass diodes are the common way to prevent cell overheating and hot spots, allowing current to pass around shaded cell and thereby reduce the reverse voltage to limit the temperature.

2.5.2 System-Level Degradation Mechanisms

The GCPV system includes PV modules and BOS. Therefore, the degradation mechanism consists of both module part and BOS part, which in general results in a higher degradation rate compared to modules (Jordan and Kurtz, 2013). The component of BOS with the most failures is the inverter (Collins et al., 2009). The high working temperature environment is the main reason for a PV inverter failures or degradation, where the high temperature incurs higher energy losses in semiconductor switches and capacitors. Inevitably, high energy losses increase the core temperature of switching devices, which degrades the inverter reliability and increases the risk of inverter aging failures (Zhang et al., 2012). The mismatch related power degradation in PV systems is ascribed to soiling, partial shading, temperature gradients, manufacturing tolerances and modules dispersion aging (Olalla et al., 2014). The cable aging is another source of PV system degradation. The mechanical influences of daily thermal cycling in the field inevitably result in a gradual increase in series resistance of cables as the system ages (King et al., 1999).

2.5.3 Degradation Rates

The term 'degradation rate' quantifies the power or performance decrease over a certain time (typically one year). Its accuracy is vital to all stakeholders — utility companies, integrators, investors, and researchers (Jordan and Kurtz, 2013). Remarkable diversity in the degradation rates can be caused by different PV technologies (Belluardo et al., 2015), performance metrics (Makrides et al., 2010a), age or investigating period (Osterwald et al., 2007), construction (encapsulation, front- and back-sheet) (Ye et al., 2014), electrical set-up (open-circuit, short-circuit, load resistor, grid-tied) (Skoczek et al., 2009), filtering criteria (Jordan and Kurtz, 2014) and analysis techniques (Makrides et al., 2010a).

Generally, the degradation rate of c-Si based PV modules or systems is lower than thin film modules, although this gap is decreasing with the maturity of thin film technology after 2000 (Jordan et al., 2010). Considering the average value of degradation rate estimated with linear regression (LR) on the PR time series data for three years, the study conducted by Belluardo et al. (2015) in Italy found typical rates of 0.2%/year for c-Si based technologies, around 0.9%/year for μ c-Si, 1.9%/year for CIGS, 1.4%/year for CdTe, 1.2%/year for single junction a-Si, and 1.5%/year for double junctions a-Si.

To understand the reasons leading to the diverse degradation rates of 10 PV modules, Ye et al. (2014) compared the outdoor I-V curves measurements under similar operating conditions on two days (1st of January) separated in two years in Singapore. The lower degradation rates of the c-Si based modules are mainly attributed by the slight declining I_{sc} . However, the thin film modules showed significant decreases in V_{oc} and FF. Meanwhile, they claimed that the performance degradation strongly affected by different module constructions deployed by different manufacturers.

Skoczek et al. (2009) conducted an investigation on 204 c-Si based modules installed more than 30 years ago in Italy. No statistical difference in degradation rates was found between mono-Si and multi-Si technologies, where the maximum power degraded by about 0.8%/year for all tested modules. However, the modules connected to the inverter encountered approximately twofold degradation rates compared to those modules in the open-circuit conditions (see Fig. 22). The difference is attributed to the thermomechanical fatigue of the cell interconnections, on which the current passing through module creates additional thermal stress. Furthermore, the encapsulate and substrate material affected the degradation rates: modules incorporating EVA (Ethylene Vinyl Acetate) and polyvinyl butyral

encapsulate showed higher degradation than those with silicone encapsulate; and glass-glass modules exhibited greater degradation rates than glass-polymer modules. They also concluded that high losses in FF (increases in R_{series}) led to high degradation rates, while optical losses in I_{sc} resulted in moderate module degradation.

Fig. 22. The average value of maximum power loss along with the standard deviation with regard to modules electrical conditions and the cell types. From Skoczek et al. (2009).

Meanwhile, Jordan and Kurtz (2010) found that investigating period was important to determine degradation rate uncertainty through the investigation of more than 44 modules of numerous technologies installed side-by-side. The degradation rate uncertainty decreased exponentially with increasing monitoring time and appeared to be independent of technology as shown in Fig. 23. A minimal monitoring period of three-year was suggested by Osterwald et al. (2006) to evaluate degradation rate. Short period of investigation likely results in inaccurate calculations because of seasonal variations and initial module performance stabilization.

Fig. 23. Degradation rate (R_D) uncertainty versus observation time, separated by technology. From Jordan and Kurtz (2010).

The common and straightforwardly statistical method in literature for degradation rate calculation is LR (Kyprianou et al., 2014). Statistical decomposition is known as a robust way to separate seasonality and trend with smaller uncertainties in shorter time series data compared to LR (Jordan and Kurtz, 2010; Ye et al., 2014). The statistical decomposition translates the slope of the PV performance time series trend to annual degradation rate, typically with unit of %/year (Phinikarides et al., 2014a). Model-based methods such as Classical Seasonal Decomposition (CSD) (Makrides et al., 2014), Holt–Winters exponential smoothing (Phinikarides et al., 2014b) and Auto-Regressive Integrated Moving Average (ARIMA) (Jordan and Kurtz, 2010) require the specification of a stochastic time series model. However, non-parametric statistical methods, such as Seasonal and Trend decomposition based on Locally weighted scatterplot smoothing (STL) do not require specification of a model and are popular because of their simplicity (Phinikarides et al., 2014a).

Apart from the analysis techniques, some studies have shown substantial differences in the degradation rates calculated by diverse performance metrics (i.e., PR, PVUSA power rating, I-V curve measurements, P_{max} and corrected P_{max}), which also lead to different statistical uncertainties (Belluardo et al., 2015; Jordan and Kurtz, 2014; Makrides et al., 2010a). Furthermore, this difference depends on PV technologies and even manufacturers (Jordan et al., 2016). Makrides et al. (2010a) applied LR on the monthly PR and PVUSA power rating of nine PV arrays in Cyprus during the first three years operation, while the first year was not considered due to the initial degradation. The noticeable difference between degradation rates evaluated by PR and PVUSA power rating has been found, where the degradation rate of

a-Si system was 0.23%/year based on PR compared to 2.10%/year obtained by PVUSA power rating (see Fig. 24).

Fig. 24. Long-term degradation using monthly PR and PVUSA power rating for Schott Solar a-Si system over the period June 2006–June 2009. From Makrides et al. (2010a).

Data filtering process aims to minimize the seasonality of PV performance data and to exclude the outliers due to the extreme weather or system outage (Davis et al., 2012; Jordan and Kurtz, 2014; Jordan et al., 2010; Makrides et al., 2010a). The filtering criteria is applied on irradiance (Jordan and Kurtz, 2014), or sets limited ranges of performance metrics (Belluardo et al., 2015). Generally, PVUSA performance metric requires the in-plane irradiance over 800 W/m² to minimize the spectrum and AOI effects (Whitaker et al., 1997). Jordan and Kurtz (2014) set an upper limitation of in-plane irradiance as 1200 W/m², to reduce the occasional effect of cloud brightening. The lower limitation of irradiance aims to exclude the low irradiance performance of PV module and to avoid any shading phenomenon that can occur close to dawn and dusk (Shrestha and TamizhMani, 2015). Limited interval of performance metric values is also known as outlier filter which is essential to reduce the effect of undocumented maintenance events: snow or shading (Jordan and Kurtz, 2014).

2.6 OPTIMUM INVERTER SIZING OF GCPV SYSTEM

The relation between inverter size and GCPV system nominal capacity is another key factor for GCPV penetration. With regard to the optimum energetic sizing ratio, Camps et al. (2015) claimed that simulation studies were more abundant than experimental ones. These extensive studies have been carried out from either the physical or technological aspects of the GCPV system. The physical aspects involve variables like location (Bakas et al., 2011; Burger and Ruther, 2005; Chen et al., 2010), mounting type (Velasco et al., 2007), and orientation and inclination (Mondol et al., 2009; Notton et al., 2010), as well as temperature and irradiance (Velasco et al., 2007). Technological aspects refer to the PV technology (Notton et al., 2010), inverter efficiency (Peippo and Lund, 1994), sun tracking system (Mondol et al., 2006b), and sampling interval (Burger and Ruther, 2005; Burger and Rther, 2006). These simulations are almost straightforward programming, while others are based on complex artificial intelligence algorithms (Bakhshi et al., 2014; Fernndez-Infantes et al., 2006; Mellit et al., 2009).

Due to the inverter characteristics, optimum sizing ratio can span a wide interval (Mondol et al., 2006b). Kil and Van der Weiden (1994), in a study conducted in Portugal and Netherlands, reported that there was only a 0.5% output energy variation when sizing ratio (R_s) ranged from 1.05 to 1.54. Macdo and Zilles (2007) verified that R_s between 0.98 and 1.82 did not significantly affect the GCPV system's final yields in Brazil. Both the simulation and emulation procedures conducted by Camps et al. (2015) in Barcelona (Spain) confirmed that the final yields experienced a reduction of less than 3% for an alternating current (AC) R_s ranging 1.00–1.24. Peippo and Lund (1994) claimed the flatness around optimum sizing ratio, and stated that deviations of $\pm 20\%$ from optimum sizing ratio point commonly resulted in only 2% energy loss. These studies suggested an optimum interval instead of a fixed optimum size value to facilitate pre-design of GCPV systems.

Furthermore, there are fewer studies based on the economic aspect than on energetic considerations to investigate the optimum sizing ratio. Ramli et al. (2015) considered unmet load, excess electricity, fraction of renewable electricity, net present cost, and carbon dioxide emissions to assess optimal sizing of the GCPV system in Saudi Arabia. Chen et al. (2013) computed the maximum savings for the optimum inverter size with considerations of PV incentives and electricity rates in nine locations in the USA. However, these economic criteria are country dependent due to different socioeconomic structures. Mondol et al. (2006b) and Peippo and Lund (1994) suggested two more general and simple economic criteria for GCPV system sizing optimization, namely, the annual energy output per system investment cost (C_c)

and the energy output per annualized investment cost (C_A). Analogously, R_S depending on these two economic criteria (C_C and C_A) should have an optimum interval, because C_C and C_A are related to the energy output as well.

2.7 PV FOR RURAL AND AGRICULTURAL DEVELOPMENT

2.7.1 Rural Electrification

By 2016, about 1.2 billion people (or nearly 17% of the global population) lived without access to electricity, with the vast majority in Asia-Pacific and sub-Saharan Africa (SSA) regions (Adib et al., 2016). Fig. 25 shows the world map of rural population percentage with access to electricity in 2014, where most SSA countries and some Southeast Asian regions were facing the low rate of rural electrification. Meanwhile, these regions are seeking for the solutions for electrification, especially in remote rural areas; and they have obtained the impressing penetration of renewable energy, where the percent renewable electricity output of total electricity output even exceed some developed countries (see Fig. 26).

Another common long-term solution for rural electrification is grid extension, while it is reported more expensive and less effective due to the remoteness, isolation, low electricity demand and low load factors of many rural communities (Mahapatra and Dasappa, 2012; Mandelli et al., 2016; Nguyen, 2007). Hence, the more distributable and flexible solar PV system is promoted by the World Bank, as a low-cost alternative to grid extension to deliver energy to rural households in about 30 countries in Africa, Asia, and Latin America (World Bank, 2007). Some projects supported by the World Bank are gathered in *Appendix B*. The PV solution for rural electrification has obtained impressive achievements in developing regions such as China, SSA, and South Asia.

Fig. 25. Access to electricity, rural (% of rural population). 2014 data from World Bank (2014a).

Fig. 26. Renewable electricity output (% of total electricity output). 2014 data from World Bank (2014b).

2.7.2 Agrivoltaic

The term –agrivoltaic– was first conceptualized by Goetzberger and Zastrow (1982) as *a photovoltaic-agricultural farm* to use the same piece of land for food and energy production. Then Dupraz et al. (2011) combined these two terms *agriculture* and *photovoltaic* into an abbreviation as *agrivoltaic* (AV).

Although Dupraz and his research group subsequently conducted a series of feasibility evaluations on this conceptual AV focusing on open cropping farm, the applicability of AV would be diversified by incorporating PV with greenhouses, livestock farms, fishing or aquaculture or other specific agricultural activities such as solar PV powered pumping system. One and the most advantage of AV is the dual-use of land, thus, increasing the land productivity and diversifying land production. This combination is not only a steady economic source for farmers but also a self-sustaining energy source for the vicinity area (Othman et al., 2015). There are numerous other opportunities for AV farms in the agricultural activities such as alleviation irradiation and temperature stress (Marrou, H. et al., 2013), lower evapotranspired water and hence lower water demand for crop growth (Ravi et al., 2014), less salinization due to less irrigation, soil quality improvement, higher crop yields (Hassanien et al., 2016).

2.7.2.1 Open cropping farm

The AV farm for open cropping was inspired by the successful intercropping system of *agroforestry*. By virtue of a well-designed AV open cropping farm a large amount of solar irradiation will be intercepted by the ground crop, which is growing beneath the PV modules (see Fig. 27).

Fig. 27. Model sketch of aerial PV array and crop field. From Goetzberger and Zastrow (1982).

In 2010, the first realization of AV farm was conducted by Dupraz et al. (2011) in Montpellier, France (43°65N, 3°87E). This first AV farm prototype (see Fig. 28) was designed taking considerations of reserved space for industrial size harvesters and standard farming equipment, manually adjustable tilt angle of PV modules, high efficiency mono-Si PV modules, and two PV module densities. Subsequently, the same research group conducted a series of evaluations on this AV farm, analytically and experimentally.

Fig. 28. General map of the experimental device during the wheat/lettuce season. In the bottom right frame, a zoom on the two central crop strips during wheat/lettuce season and cucumber season is represented. Closed circles represent irradiance sensors, located on North-to-South transects; closed square symbols represent thermocouples or microthermistances. FD represents the shaded plot with PV modules at full density whereas HD represents the shaded plot with PV modules at half density. W-C and E-C stand respectively for Western control and Eastern control plots. From Marrou, Hélène et al. (2013a).

In principal, the question is how the crop grows beneath the PV modules with reducing irradiation as there is a competition for irradiation between PV modules and crops. Dupraz et al. (2011) used an irradiation interception model to assess light transmission and distribution

at the ground level induced by solar PV arrays. The simulated average irradiation from November to June (durum wheat cropping season) reduced by 57% (full PV density) and 29% (half PV density) of the total incident irradiation, respectively. Then, these irradiation reductions resulted to the crop yield reduced by 19% (full PV density) and 8% (half PV density) through a crop model simulation. Finally, the authors concluded a predictable 35–73% increase of global land productivity for the two densities of PV modules.

Then, Marrou, Hélène et al. (2013b) continued the assessment of this AV farm through experiments on a more shade tolerant crop (lettuce) instead of durum wheat. The similar shade levels of 50% (full density) and 70% (half density) with respect to the total incident irradiation were assumed. Results showed that for summer cultivation, heavy shade (full density PV) significantly reduced the yield to 58% compared to the full sun condition (conventional farm without PV array), while yields were maintained at 81% in half density plot; for spring cultivation, yield reductions were lower: they were 21% in full density and only 1% in half density. The authors concluded the disproportion between crop yield reduction and crop intercepted irradiation was attributed to an improved Radiation Interception Efficiency (RIE) maintaining the lettuce yield in shade through an increase in the leaf area.

Subsequently, Marrou, Hélène et al. (2013a) analyzed the microclimate under the AV system and the growth rates of three crops (cucumber, lettuce and durum wheat). During three seasons (winter, spring and summer), mean daily air and crop temperature were stable from the full sun treatments to the PV shaded treatments, in spite of a decrease in soil temperature. The similar crop growth rates in all the treatments indicated that little adaptations in cropping practices should be required when an open cropping farm transforms to an AV farm. The authors suggested most attention should be paid to mitigate irradiation reduction and shade tolerant plants selection.

Ravi et al. (2014) envisaged an arrangement of biofuel (agave) and large solar PV infrastructure (see Fig. 29) in arid regions with limited water resources, to improve the Water Use Efficiency (WUE). Integrating the two systems was inspired by the similar water requirements for cleaning PV modules and irrigating agave. Thus, this dual-use of land and water produces both electricity and liquid fuel to mitigate the socioeconomic and environmental issues in harsh locations like desert. Life-cycle analysis of this AV farm indicated higher WUE than the sole system, where the WUE were 0.22 L/MJ and 0.42 L/MJ for PV–agave of baseline yield and high yield, respectively. The highest revenues per m³ of water were

achieved by this AV farm, of which the revenues were over 100 times higher than traditional crops. Moreover, an AV farm allowed saving 14–29% of evapotranspired water during crop growing, depending on the amount of shade created and the crop type (Marrou, H. et al., 2013).

Fig. 29. Prototype of agrivoltaic farm consisting of PV modules and agave plants. From Ravi et al. (2014).

An AV farm with high-value crops can also be offered as a solution to the fluctuating global market value of the traditional agricultural commodity for the agricultural countries (Othman et al., 2015).

Recently, Dinesh and Pearce (2016) reviewed the development of AV farm, then conducted simulations based on the prototype of Dupraz et al. (2011) through sensitive analysis to assess economic feasibility of this type AV farm in Kansas City, US. Notwithstanding the suspicious results due to ambiguous analytical process and intolerable errors, the economic evaluating method using net profit and Levelized Cost of Electricity (LCOE) is worthy of recognition.

2.7.2.2 Solar photovoltaic integrated greenhouse system

Apart from PV application with open cropping farms, integrated solar PV and agricultural greenhouses (PVGs) have seen a rapid prosperity in recent years. In these systems, PV modules mounted on greenhouse rooftops generate electricity for self-consumption and/or injecting to the grid. One difference between PVGs and AV farms is the microclimate under the PV modules, where the former is more controllable. Nonetheless, the experiences from PVGs could show some clues for AV farms development.

The PV modules projecting shade over the crops is the primary disadvantage of PVGs as well as AV farms. The PV-caused shade is related to PV module cover ratio, which equals the total PV module area divided by total roof area. The effect of cover ratio on the crop yield varies with PVGs location, crop type, PV array structures. The representative studies are summarized in Table 3. For tomato growing in PVGs, a low-level cover ratio (9.8%) does not induce significant reduction of crop yield (Ureña-Sánchez et al., 2012), while a high-level cover ratio (50%) reduces the crop yield by 11% (Cossu et al., 2014). For onion, 25% yield losses due to cover ratio of 12.9% have been found in straight-line PV array structure. However, there are no significant yield losses when the same PV array is transformed to a checkerboard structure (Kadowaki et al., 2012). For lettuce, cover ratio of 20% does not affect the final crop yield (Trypanagnostopoulos et al., 2017).

In addition, efforts are also paid on the most suitable PV material for PVGs. Although the a-Si module has the flexibility suitable for the plastic greenhouse roof, its low efficiency contributes to a financial deficit due to the shade caused crop losses (Kadowaki et al., 2012). Nowadays, the most popular PV material for PVGs is c-Si (Cossu et al., 2014; Trypanagnostopoulos et al., 2017), as well as some specially designed materials such as semi-transparent PV modules (Cossu et al., 2016; Marucci et al., 2012).

Table 3. Relevant studies about performance of PVGs.

Location	Cover ratio	PV type	Crop type	Shading effect on crop yields	Financial benefits or drawbacks	Source
Spain	9.8 %	a-Si	Tomato	No significant effect	Additional revenue of 6245 €/ha per crop cycle from PV-generated electricity	(Ureña-Sánchez et al., 2012)
Italy	50%	poly-Si	Tomato	Crop yield reduced by 11%	Revenue increased from 5.9 to 67 €/m ²	(Cossu et al., 2014)
Japan	12.9%	a-Si	Onion	Crop yield reduced by 25% (string-line structure)	A deficit of 1987 € per year in string-line structure	(Kadowaki et al., 2012), (Yano et al., 2010)
Greece	20%	poly-Si	Lettuce	No significant effect	Electricity generation of 0.47 kWh/day for 4.26m ² land area	(Trypanagnostopoulos et al., 2017)

2.7.2.3 Other agrivoltaic applications

Solar PV Water Pumping System (SPVWPS) catering domestic, livestock and irrigation water demands in remote regions is gaining enormously perspective due to the continuous depletion of conventional oil and fossil fuel reserves, uneven distribution and ever-increasing electricity price (Sontake and Kalamkar, 2016). The principle components of a SPVWPS are solar PV modules, a motor and a pump. A typical SPVWPS is shown in Fig. 30. The optional accessories include: battery, controller, DC/DC converter, DC/AC inverter, surface or deep well pumps, fixed or tracking structure (Gopal et al., 2013).

Fig. 30. Layout of a typical solar PV water pumping system. From Gopal et al. (2013).

These various mechanical, electrical and electronic components introduce the difficulties in integration and synchronization to form a SPVWPS. Furthermore, the performance of the PV module is influenced by load, solar irradiation and ambient temperature. Therefore, a thoughtless design and coordination of the diverse components will pose operation errors and overall poor performance.

These complex and interacting factors challenged and motivated the researchers worldwide from fields of engineering, in the past decades, to promote SPVWPS to be an efficient, technically simple and cost-effective water pumping system. These abundant researches were mainly focused on the investigation of the energy conversion efficiency, economic performance and technical maturity, regarding to the meteorological data, PV array features (configuration, size), water level and acceptance by the users.

Solar PV can be also applied to the offshore aquaculture installation such as powering the monitoring systems for remote automation. The daily energy consuming of this monitoring system for a typical Eastern Mediterranean off-shore aquaculture installation with 300 annual tonnage yields is of about 5 kWh/day. Menicou and Vassiliou (2010) reported that this energy demand could be satisfied in Cyprus. With annual irradiation varying between 1800 and 2000 KWh/m², a PV system of 1 kWp and 75% PR value would generate 1350 - 1650 kWh per year.

Meanwhile, the authors stated the challenges including: PV modules mounting, Operation and Maintenance, environmental salinity, power storage housing, power distribution and cabling losses, cabling interaction with the working environment, sun-tracking systems inapplicability.

CHAPTER 3 – MATERIALS AND METHODS

3.1 GENERAL DESCRIPTION OF EXPERIMENTAL SET-UP

3.1.1 System Components, Design and Features

This thesis was conducted by analyzing the data obtained from a grid-connected, roof-standing solar PV plant that has been in operation since January 2013, at ETSIAAB (Madrid, Spain, 40.4426°N, 3.7295°W). The operation flow chart of this ETSIAAB GCPV plant with monitoring system is illustrated in Fig. 31. The peak power of the entire plant is 21.77 kWp, divided into two main areas with several sub fields. The larger area consists of a poly-Si 16.83 kWp array connected to a 15.34 kWn inverter. The other area is an experimental plant, which is formed by three independent systems based on poly-Si (1.61 kWp), a-Si (1.68 kWp) and CdTe (1.65 kWp) with similar total voltages and currents, each connected to an independent 1.2 kWn inverter with MPPT. This thesis is mainly based on the experimental part. All of the modules are mounted in open-air aluminum support structures with a 30° tilt angle and oriented with an azimuth angle of 3°. The detailed information regarding these three systems is presented in *Appendix C*.

3.1.2 Monitoring Sensor Cluster

The ETSIAAB GCPV plant is monitored to evaluate its performance in the Madrid climate. The monitoring system was designed following the guidelines of IEC 61724 standard (International Electrotechnical Commission, 2009b).

The indoor data acquisition system (DAS) is connected to the inverter center installed on a neighboring wall with shelter and good ventilation. The in-plane irradiance sensors are

installed by the side of and coplanar with poly-Si array. The following parameters are recorded by the inverter and a cluster of sensors.

Electrical parameters:

- DC and AC power output;
- cumulated AC energy supplied to the grid;
- currents and voltages at both AC and DC sides;
- error and warning reports.

Meteorological parameters:

- in-plane irradiance;
- back-of-module temperature;
- ambient temperature;
- wind velocity.

Fig. 31. Operation flow chart of ETSIAAB GCPV plant equipped with data acquisition system (DAS).

Then, the signals from the inverters and sensors are delivered to the Sunny Webbox for system monitoring, remote diagnosis, data storage and visualization. Delivered data are

averaged and stored every 15 minutes. The main features of the inverter and the sensors are shown in *Appendix D*.

Additionally, an HD32 MT.1 data logger (*Delta OHM®*) with eight differential channels was installed to obtain measurements at a sampling rate of one-minute. One module of each technology was randomly selected to attach two thermocouples in the center of its rear side to record the operating temperature of randomly selected modules for each GCPV system. Additional irradiance data were monitored by an extra reference solar sensor based on a c-Si solar cell. The data logger was packed in a waterproof metal box and located beneath one PV array. Its storing data is extracted once a week. The main features of this equipment are listed in *Appendix E*

3.1.3 Regular I-V Characteristic Tests

The *Solar-4000®* I-V curve tracer carried out the on-site I-V characteristics of the pre-mentioned three PV arrays of the experimental part. Simultaneously, the in-plane irradiance and the operating temperature of the PV array under testing were recorded. The main feature of this device is presented in *Appendix F*.

The tests were periodically conducted on cloudless sunny days at solar noon to keep the sun spectra be almost identical because no solar spectrum data were available. The in-plane irradiance was measured by a reference sensor based on poly-Si and mono-Si, which is coplanar with the surface of the PV arrays. Measurements were recorded only when in-plane irradiance was not fluctuating by more than $\pm 1\%$ during each test and the minimal irradiance was 800 W/m^2 in order for reliable reference to STC. Modules center temperatures of its frond-side was measured by an infrared temperature sensor and then averaged for the PV array operating temperature. I-V curves for the three PV arrays were measured at least three times in a single day. The frequency of the tests was at least once a month depending on the local weather conditions.

3.1.4 International Electrotechnical Commission Standards

The International Electrotechnical Commission (IEC) is the leading global organization that prepares and publishes International Standards for all electrical, electronic and related technologies. IEC TC (Technical Committee) 82 –Solar photovoltaic energy systems– prepares International Standards for providing both benchmarks and proofs of quality in PV industry: from cell to module and system. The IEC standards applied in this thesis provide guidelines for

the installation and monitoring of GCPV plant, computation of performance metrics, requirements for particular tests, which are summarized in Table 4.

Table 4. International Electrotechnical Commission (IEC) standards applied in this thesis.

IEC standard	Application
IEC 61625	Thin film modules stabilization prior to indoor test
IEC 61724	GCPV system and PV array performance monitoring
IEC 60904-1	I-V curve measurements guidelines
IEC 60904-9	Solar simulator requirements
IEC 60891	I-V curve temperature and irradiance correction

3.2 METRICS FOR PV PERFORMANCE ASSESSMENT

3.2.1 Evaluation Metrics

To evaluate the short term (one-year) performance of the GCPV systems, the system efficiency and daily efficiency, daily performance ratio were calculated for 2013. For each data point, the system efficiency (η_f) was calculated as follows:

$$\eta_f(\%) = 100\% \cdot P_{AC} / (G_i \cdot A),$$

Equation 1. GCPV system efficiency

where G_i (W/m²) is the in-plane irradiance, P_{AC} (W) is the AC output power and A (m²) is the array area.

Analogously, the daily system efficiency ($\eta_{f, daily}$) was computed by this expression:

$$\eta_{f, daily}(\%) = 100\% \cdot \sum_{daily}(P_{AC}) / \sum_{daily}(G_i \cdot A).$$

Equation 2. GCPV system daily efficiency

The evaluation of energy losses due to the undersized inverters was based on the assumption of constant system efficiency during the inverter saturation period (Luoma et al., 2012):

$$L_{sat}(\%) = 100\% \cdot \sum_D(\overline{\eta_f} \cdot G_i \cdot A - P_{AC}) \cdot \Delta t / E_{AC},$$

Equation 3. Energy losses due to inverter saturation

where, L_{sat} is inverter saturation caused energy losses as a percent of the system energy output E_{AC} (kWh), D is the investigating period which is one month or one year in this line, Δt is the ETSIAAB GCPV plant sampling interval in hour. Herein, $\overline{\eta_f}$ was calculated as the average efficiency for the 1 hour before the first saturation and 1 hour after the last saturation on a given day. Note that this assumption of constant conversion efficiency would result in an overestimation of L_{sat} because the thermal effect was not excluded.

The indexes describing the long-term (three-year) operating process of GCPV system used in this thesis are those proposed in IEC 61724 (International Electrotechnical Commission, 2009b). They are described as follows:

The GCPVs converts the in-plane irradiation into DC energy. This process includes some capture losses and the specific energy flow (in kilowatt hours/kilowatt-peak [kWh/kWp/day]) can be expressed by:

$$Y_r = Y_a + L_c ,$$

Equation 4. CGPV system reference yield

where:

Y_r : reference yield, which is calculated by $Y_r = H_i / G_{STC}$, with H_i being the irradiation intensity during a particular period (one day herein) and G_{STC} is 1000 W/m²:

$$H_i = \sum_{daily}(G_i) .$$

Equation 5. Daily in-plane irradiation

Y_a : array yield, which is the specific produced energy at the DC output: $Y_a = E_{DC} / P_{STC}$, where E_{DC} is the produced DC energy and P_{STC} is the maximum power of GCPV at STC;

L_c : capture losses, which are caused by the reduction of the incoming light on module surface from such factors as soiling, shading, and reflection, as well as temperature effects, electrical mismatching, parasitic resistances in the PV modules, and imperfect MPPT (Woyte et al., 2013).

The inverter converts the DC energy to AC energy to be exported to the grid. The specific energy flow (kWh/kWp/day) is stated below:

$$Y_a = Y_f + L_s ,$$

Equation 6. CGPV system array yield

where Y_f is the final yield or system yield, i.e., the specified produced energy after DC to AC conversion: $Y_a = E_{AC} / P_{STC}$, where E_{AC} is the produced energy from the AC side; L_s is system losses, including the inverter conversion losses and the system outage.

3.2.2 Air Mass Calculation

An idealized formula (Equation 7) for calculating the pressure corrected AM (Equation 8) only needs the value of the sun's relative position in the sky and the site altitude (King et al., 1997). Complex mathematical expressions for the AM provided by Enslin et al. (1997) and Gueymard (1995) showed no difference between Equation 7 for sun zenith angles less than 80° (Paulescu et al., 2012).

$$AM = \cos(Z_s)^{-1} \cdot \frac{P_l}{P_0},$$

Equation 7. Idealized calculation for air mass

$$P_l/P_0 = \exp^{(-0.0001184 \cdot h)},$$

Equation 8. Air pressure correction for air mass

Where, Z_s : sun's zenith angle, calculated based on the work of Reda and Andreas (2004);

P_l : local air pressure;

P_0 : sea level air pressure;

h : altitude, 650 m of Madrid.

3.2.3 Clear Sky Condition

The AM is calculated by a geographical consideration and should be completed with the associated weather information, which also affects the spectral distribution. Thus, a pre-clarification about the weather condition or a uniform weather condition should be decided. Herein, a clear-sky condition, data filter and processing of the data used in *Section 4.1.3* and *4.1.4* are stated below:

- Clear-sky condition: the variation of the irradiance less than 10% from the maximum value to the minimum value recorded during the 15-min recording interval;
- In-plane irradiance range: 700 ± 20 W/m², to avoid inverter clipping, which occurs occasionally at irradiance above 800 W/m², which would subsequently affect the maximum power (P_{max});
- Correction: the P_{max} was linearly corrected to the maximum power at STC (P_{STC}) using the P_{max} temperature coefficient (γ) and module temperature (T_c) provided by the manufacturers by Equation 9:

$$P_{STC} = P_{max} \cdot G_{STC} / (G_i \cdot (1 - \gamma \cdot (T_c - 25))).$$

Equation 9. In-plane irradiance and temperature corrections for PV array maximum power

3.3 DATA COLLECTION AND STATISTICAL METHODS FOR PV PERFORMANCE DEGRADATION ASSESSMENT

3.3.1 Data Collection and Processing of Performance Ratio Based Method

The first step in this PR-based degradation rate investigation was to extract and filter outdoor measurements for each GCPV system of the experimental part over a given period. As this PR degradation rate investigation is on the system-level, the raw data collected were the monthly AC energy output and monthly in-plane irradiation excluding system faults and outages from January of 2014 to December of 2016. This duration of the PR time series has met the minimal investigating period of three-year as stated in Literature Review.

To compute the PR, the monthly reference yield (Y_r) and system final yield (Y_f) based on AC energy output (the detail of the calculations was described in *Section 3.2.1*) were used:

$$PR(\%) = 100 \cdot \frac{Y_f}{Y_r}.$$

Equation 10. GCPV system monthly performance ratio

Subsequently, the monthly PR was applied to construct a three-year time series, comprised of 36 data points for each GCPV system.

Note that the abovementioned data collective procedure included the power limitation data points. To investigate the influence of undersized inverter on the evaluation of GCPV system degradation rate, we recalculated the Y_r and Y_f excluding the power limitation data points.

The monthly PR of PV system is a time-series data (Y_t) could be decomposed into trend (T_t), seasonal fluctuation (S_t) as well as some remainders (R_t) (Equation 11). The trend is often downward indicating a long-term decrease of the PR time series. The seasonal fluctuation of PR is mainly attributed to the seasonal varying irradiance, spectrum and temperature. The statistical approaches for decomposing a PR seasonal time series are numerous, and all of them aim to separate each component of the series accurately. The basic process for such decomposition empirically consists of first extracting the trend component, then isolating the seasonal component and finally calculating the remainder by subtracting the seasonal component from de-trended time series data.

$$Y_t = f(T_t, S_t, R_t)$$

Equation 11. General mathematical representation of the decomposition approach

These most common approaches include Classical Seasonal Decomposition (CSD), Seasonal and Trend decomposition using Locally weighted scatterplot smoothing (STL), Autoregressive Integrated Moving Average (ARIMA) among others.

3.3.1.1 Statistical uncertainty of degradation rate

Once the trend component was extracted from the original PR time series, a linear regression (LR) was applied to the trend:

$$T_t = a \cdot t + b$$

Equation 12. Linear regression for trend component

Meanwhile, the degradation rate was also assessed through LR for the original PR time series without any decomposition approaches:

$$Y_t = a \cdot t + b$$

Equation 13. Linear regression for performance ratio time series

Therefore, the performance ratio degradation rate (R_d) was obtained by multiplying the slope (a) by 12:

$$R_d = 12 \cdot a.$$

Equation 14. Performance degradation rate

Consequently, the statistical uncertainty (type A uncertainty as defined in *Guide to the Expression of Uncertainty Measurement* (Lequin, 2004)) of estimated R_d was calculated by standard error of the slope estimator and coverage factor $k=1.96$, giving a confidence of 95% :

$$U = k \cdot \sqrt{\frac{1}{n-2} \cdot \frac{\sum_{i=1}^n (y_i - \hat{y}_i)^2}{\sum_{i=1}^n (t_i - \bar{t})^2}}$$

Equation 15. Statistical uncertainty

where n is the number of samples, y is the observed value and $\hat{y}$ is the estimation of y , t is the time indices and $\bar{t}$ is the mean value of t .

Notwithstanding the possible gap between the abovementioned statistical uncertainty and the error of the true degradation rate, U allows direct comparison among different statistical techniques (Jordan and Kurtz, 2010).

3.3.1.2 Classical Series Decomposition

The Classical Series Decomposition (CSD) method is the most commonly used decomposition procedure and forms the basis for most of the modern decomposition. It has two common expressions such as additive model (Equation 16) and multiplicative model. Additive model was chosen in this study instead of multiplicative model due to the stable amplitude of the seasonal component throughout the years. It follows the basic process of seasonal time series decomposition described previously (Makridakis et al., 2008).

$$Y_t = T_t + S_t + R_t.$$

Equation 16. Additive model of Classical Series Decomposition

Firstly, the trend was computed using a centered 12 moving average (12-MA):

$$T_t = \frac{1}{2} \left(\frac{1}{s} \sum_{i=t-s/2}^{t+s/2-1} Y_i + \frac{1}{s} \sum_{i=t-s/2+1}^{t+s/2} Y_i \right),$$

Equation 17. Centered 12 moving average for trend component

where, the s is the seasonal period equaling 12, which is the number of months in a year. Then the assumption about the constant seasonal component (S_t) of PR from year to year was proposed. Thereby, it only needs to calculate one value for each month by collecting all the de-trended values for a calendar month and taking the average. Finally, the remainder part was obtained by subtracting the estimated seasonal component from the de-trended series.

3.3.1.3 Seasonal and Trend decomposition using Locally weighted scatterplot smoothing (STL)

STL is the most popular implementation of local regression, developed by Bill Cleveland and co-workers at AT&T Bell Laboratories (Makridakis et al., 2008). The STL is a robust decomposition method with some protection against extreme observations or outliers through an iterative process (Kyprianou et al., 2014). An initial local regression is calculated to extract the trend from the original time series. Then, the difference (D_t) between each observation Y_t and the linear fitted curve T_t is obtained:

$$D_t = Y_t - T_t.$$

Equation 18. Difference between PR observation and linear fitted trend

Then the local regression is recalculated with the adjusted weights to ensure observations with large D_t be assigned smaller weights than they received at the initial calculation of T_t . Subsequently, a new D_t is found by subtracting the new estimate of T_t from Y_t . This procedure continues through further iterations, repeatedly smoothing the data until T_t converges. Once the final T_t is determined after iterations, the same process as used in CSD to find out the seasonality (S_t) and remainder part (R_t) is repeated. In this line, the *RStudio* software was used to implement the decomposition process by STL.

3.3.1.4 Autoregressive Integrated Moving Average

Autoregressive Integrated Moving Average (ARIMA) is one of the most sophisticated decomposition method currently available, which has advantages in dealing with seasonal variations, random errors, outliers and level shifts as well as removing the autocorrelations in the model remainders (Phinikarides et al., 2014a). The general model of ARIMA is usually abbreviated as ARIMA (p, d, q) (P, D, Q)_s, where the former bracket gathers the non-seasonal sub-model and the latter one includes seasonal sub-model. The subscript 'S' is the time span of repeating seasonal pattern, of which the typical values are 3 (quarterly), 6 (half-yearly) and 12 (yearly). The symbols p, d, q (or P, D, Q) are the non-seasonal (or seasonal) autoregressive (AR) order, differencing order and MA order, respectively.

The general ARIMA model is described as follows:

$$\phi_p(B)\Phi_P(B^S)(1-B^d)(1-B^{S*d})Y_t = \theta_q(B)\Theta_Q(B^S)e_t,$$

Equation 19. General ARIMA model

where B stands for a backshift operator: $B^k \cdot Y_t = Y_{t-k}$; and $\phi_p(B) = (1 - \phi_1 B - \dots - \phi_p B^p)$ is the p-order autoregressive model of B; analogously, $\Phi_P(B^S)$ is the P-order autoregressive model of B^S ; $\vartheta_q(B)$ is a q-order moving average model of B and $\Theta_Q(B^S)$ is a Q-order moving average model of B^S . The two terms $(1-B^d)$ and $(1-B^{S*d})$ respectively are non-seasonal and seasonal differencing processes aiming to remove non-stationarity in the series. The errors, e_t , are independent with a normal distribution (Makridakis et al., 2008; Phinikarides et al., 2015).

As ARIMA is complex and experience-requiring, entire implementation in software is an effective way to save manpower. Among the numerous statistical software involving ARIMA,

a most widely used software packages named *X-13ARIMA-SEATS* is a seasonal adjustment program developed by the *U.S. Census Bureau*. It is an enhanced version of the *X-11 Variant* of the *Census II* seasonal method with auto diagnostics checking for the model validation (U.S. Census Bureau, 2016). Due to the monthly PR time series as short as three years, some ARIMA models were unable to converge and therefore, the airline model $ARIMA(0, 1, 1)(0, 1, 1)_{12}$ was pre-selected with successful description about the majority of seasonal time series (Phinikarides et al., 2015). Another fundamentally important use of *X-13ARIMA-SEATS* is to extend the series with forecasts as long as 5 years.

3.3.2 Data Collection of I-V Curve Based Method

3.3.2.1 Outdoor test

I-V curve measurements as well as the corresponding meteorology (in-plane irradiance and module temperature) were recorded with the help of pre-mentioned *Solar-4000[®]* analyzer. Two cloudless sunny days in March of 2016 and 2017 were respectively chosen to maintain the identical outdoor conditions. Concretely, both tests were conducted at the same time around solar noon to ensure the same AM conditions, minimizing the difference in solar spectrum. When the tests were conducted on poly-Si array, the average irradiance with standard deviation was $1022 \pm 1 \text{ W/m}^2$ in 2016 and $1025 \pm 3 \text{ W/m}^2$ in 2017, respectively. Meanwhile, the difference in poly-Si array operating temperature between the two years was also negligible, i.e., $46.0 \pm 1.0 \text{ }^\circ\text{C}$ in 2016 and $45.5 \pm 1.0 \text{ }^\circ\text{C}$ in 2017. Accordingly, we can safely assume the PV array electrical performance affecting by meteorology is minimal in these two days. Analogously, the indistinguishable outdoor conditions were also achieved in the measurements of a-Si and CdTe PV arrays.

Hereinbefore, the approach provides a fairly straightforward comparison between two days in separate years under much the same operating conditions, through the I-V curves measurements. It could present the change of individual components, i.e., short circuit current (I_{sc}), open circuit voltage (V_{oc}), maximum power point current (I_{mp}), maximum power point voltage (V_{mp}), maximum power (P_{max}), and fill factor (FF).

However, once the remarkable differences exist in the operating conditions, a correction procedure for irradiance and temperature should be applied as expressed in IEC 61724 *Procedure 1* with some idealizations (International Electrotechnical Commission, 2009b):

$$I_2 = I_1 + I_{SC} \cdot \left(\frac{G_{i,2}}{G_{i,1}} - 1 \right) + \alpha \cdot (T_{m,2} - T_{m,1}),$$

Equation 20. Correction for current in IEC 61724

Procdeure 1

$$V_2 = V_1 - R_s \cdot (I_2 - I_1) + \beta \cdot (T_{m,2} - T_{m,1}),$$

Equation 21. Correction for voltage in IEC 61724

Procdeure 1

where:

I_1, V_1 are coordinates of points on the measured I-V curve;

I_2, V_2 are coordinates of the corresponding points on the corrected I-V curve;

$G_{i,1}, T_{m,1}$ are the measured in-plane irradiance and temperature of PV module;

$G_{i,2}, T_{m,2}$ are the standard or other desired irradiance and temperature of PV module;

I_{sc} is the measured short-circuit current of the test specimen at G_1 and T_1 ;

α, β are the current and voltage temperature coefficients of the test specimen;

R_s is the series resistance of the PV array which is obtained from the indoor tests at CIEMAT.

3.3.2.2 Indoor test

In June 2012, six months before the beginning of the operation of the plant, first indoor test was completed to provide original electrical information about each PV technology to be installed. Thereafter, the tested modules were operating under the same conditions as part of the entire ETSIAAB GCPV plant. A second test of the same modules was conducted in January (poly-Si and a-Si) and June (CdTe) 2015 after an approximate operating period of three years.

The indoor tests were conducted using a class AAA IEC 60904-9 (International Electrotechnical Commission, 2007) solar simulator (*Pasan*®), with a 10 ms single pulse flash. The I-V curve measurements were recorded to provide the maximum power at STC according to IEC 60904-1 (International Electrotechnical Commission, 2006). The technical specifications

of the simulator are described in *Appendix G*. All measurements were recorded at irradiance and temperature conditions very close to STC ($1000 \pm 5 \text{ W/m}^2$ and $25 \pm 2 \text{ }^\circ\text{C}$).

Note that a preconditioning state should be achieved before any indoor tests due to the light activation effect in the CdTe modules (Muñoz-García et al., 2012). A sunlight exposure of a minimum of 4 kWh should be accumulated by the CdTe modules to activate them prior to indoor testing. Since the activated state rapidly disappears (less than 15 minutes) and the module temperature increases with sunlight exposure, active cooling was performed immediately after the sunlight exposure and before the indoor test.

3.4 NUMERICAL TECHNIQUES FOR GCPV SYSTEM SIZING RATIO ASSESSMENT

3.4.1 GCPV Systems Description

In this topic, the focus was on the two systems based on poly-Si technology, hereinafter referred to as *System 1* from the experimental field and *System 2* from the commercial one. The details of these two systems are shown in Table 5.

Table 5. Main characteristics of the GCPV analyzed systems.

	System 1	System 2
PV array peak power (kW)	1.61	16.83
Inverter nominal input (kW)	1.32	15.34
Sizing ratio	1.22	1.10
Inverter max. efficiency (%) / Euro-eta (%)	92.1/90.9	98.1/97.7
Cell type	poly-Si	poly-Si
Recording interval (minute)	15	15
Annual performance degradation rate (%)	1	1

3.4.2 Estimation Actual Power at Power Limitation Points

The inverters of the two GCPV systems are undersized, which means that the peak power of the two PV arrays is higher than their respective inverters' nominal capacity. The sizing ratio (R_s) values are 1.22 and 1.10 for *System 1* and 2, respectively (see Table 5). One reason for installing an undersized inverter is that the STC (irradiance of 1000 W/m² for a solar spectrum of AM1.5G and module temperature 25 °C) are hard to reach in certain areas, resulting in lower actual generated power than its STC power (Keller and Affolter, 1995).

An undersized inverter clips the power output and blurs the actual power at high insolation conditions. When the power limitation is reached, the inverter forces the PV array to increase its operating voltage instead of working at the maximum power point voltage (V_{mp}), thus reducing the maximum power point current (I_{mp}) and maximum power (P_{max}).

For both GCPV systems, a DAS integrated in the inverter center measured and recorded the DC and AC power output data as well as the power limitation events. During the one-year period, *System 2* seldom met the power limitation, whilst approximately 13% of the records in *System 1* were affected by power limitation. The objective of this work is to define optimum inverter sizing of GCPV systems. Due to the more undersized inverter of *System 1*, a model has been applied to simulate the power in the inverter clipping areas in order to obtain

comparative results between the two systems. This model includes two sub-models to simulate I_{mp} and V_{mp} separately.

The current sub-model was extracted from the work by King et al. (2004):

$$I_{mp} = I_{mp0} \cdot (C_0 \cdot G_{i,e} + C_1 \cdot G_{i,e}^2) \cdot [1 + \alpha \cdot (T_c - 25^\circ\text{C})],$$

Equation 22. King's PV array current model

where $G_{i,e}$ is the effective irradiance, defined as the ratio of the irradiance measured by the PV cells to the total irradiance incident on the module; I_{mp0} is the I_{mp} at STC, which is provided by the manufacturer; T_c ($^\circ\text{C}$) is the PV cell temperature inside module and in this study it was assumed to equal the back-of-module temperature (T_m); α_{mp} ($^\circ\text{C}^{-1}$) is the temperature coefficient of current; C_0 and C_1 are empirical parameters obtained from Sandia National Laboratory module database.

The sub-model for V_{mp} was obtained through linear regression (Equation 23) on one year of V_{mp} and T_m filtered measurements. The filtering criteria include: 1. Power limitation points were excluded in cases where V_{mp} increased abnormally in the clipping area, 2. Data were excluded when the irradiance varied from the maximum to the minimum for more than 10% of the 15-min recording interval.

$$V_{mp} = 206.5 \cdot (1 - 0.0045 \cdot (T_m - 25^\circ\text{C})).$$

Equation 23. Linear regression for PV array voltage

The maximum power prediction model was built by combining the two sub-models, Equation 22 and Equation 23:

$$P_{max} = I_{mp} \cdot V_{mp}.$$

Equation 24. PV array power model

The power model (Equation 24) was validated by a series of tests at solar noon with high irradiance ($G_i > 900 \text{ W/m}^2$). These tests were conducted with a *Solar-4000*[®] I-V curve tracker during April–November 2016. A high degree of conformity was obtained as shown in Fig. 32, i.e., the measured and simulated results were very close, with a root mean squared error (RMSE) (see Equation 25) of 1.42%.

$$RMSE(\%) = \frac{100 \cdot \sqrt{\frac{1}{n} \sum (m_i - s_i)^2}}{\bar{m}_i},$$

Equation 25. Root mean squared error

where m_i is the i th measured value and s_i is the i th simulated value, N is the number of samples, which herein equals 117, and $\bar{m}_i$ is the average of the measured values.

To maintain most of the original DC power profile of *System 1*, only the abovementioned 13% of records encountering the power limitation were replaced by their corresponding values calculated using Equation 24. Hereinafter, the investigation on R_s of *System 1* is based on the mixing data profile, i.e., 13% simulated and 87% original.

Fig. 32. Comparison of measured and simulated maximum power values at high-irradiance solar noon for System 1.

3.4.3 Inverter Efficiency and AC Energy Output Model

Solar inverter conversion efficiency is a function (Equation 26) of the actual partial load ($P_{max}(t)/P_{inv,N}$), neglecting the dependency on inverter input voltage (Bakhshi et al., 2014; Demoulias, 2010).

$$\eta(P_{max}(t)) = b_0 \cdot \frac{P_{inv,N}}{P_{max}(t)} + b_1 + b_2 \cdot \frac{P_{max}(t)}{P_{inv,N}},$$

Equation 26. Inverter conversion efficiency model

where b_0 is the constant normalized self-consumption loss, b_1 is the linear efficiency coefficient and b_2 is the coefficient for losses proportional to the square of output power (Peippo and Lund, 1994); and the $P_{inv,N}$ is the inverter normal capacity.

The parameters were determined by Least-squares Fitting (LSF) of the efficiency curve points from the database of *PVsyst*® v.6.4.7 as shown in Fig. 33. In addition, based on the work by Peippo and Lund (1994), three sets of b_i coefficients (b_0 , b_1 , b_2) were selected to represent the generic high-, medium-, and low-efficiency inverters (Table 6). Hereinafter, inverters 1, 2, and 3 refer to the high-, medium-, and low-efficiency inverters, respectively.

Fig. 33. Least-Squares fittings (LSFs) of the inverter's efficiency as a function of partial load based on *PVsyst*® v.6.4.7 inverter database.

Table 6. Characteristics of three simulated inverters, from Peippo and Lund (1994), and the two actual inverters of the analyzed solar plant, obtained through LSF.

	b_0	b_1	b_2
High efficiency (inverter 1)	-0.35%	99.50%	-1.00%
Medium efficiency (inverter 2)	-2.00%	97.50%	-8.00%
Low efficiency (inverter 3)	-5.00%	91.50%	-15.00%
System 1 (SMA SB 1200)	-1.00%	94.30%	-4.00%
System 2 (SMA 15000TL)	-0.26%	98.70%	-1.10%

Subsequently, the AC power output of an inverter is expressed as Equation 27, which is derived from Equation 26 by three DC-power input regimes. When P_{max} is lower than the switch-on power (P_{min}) of the inverter, there is neither power output nor standby losses from the GCPV system. Once there is insolation, the inverter starts to operate based on Equation 26 until P_{max} is higher than $P_{inv,N}$. Then, the input of the inverter (or the DC power output of the PV array) is limited at $P_{inv,N}$. In other words, the input power above the inverter input capacity is rejected (Notton et al., 2010; Peippo and Lund, 1994).

$$P_{AC}(P_{max}(t), P_{inv,N}) = \eta(P_{max}(t)) \cdot P_{max}(t)$$

$$= \begin{cases} (b_0 + b_1 + b_2) \cdot P_{inv,N}, & P_{max}(t) > P_{inv,N} \\ \left(b_0 \cdot \frac{P_{inv,N}}{P_{max}(t)} + b_1 + b_2 \cdot \frac{P_{max}(t)}{P_{inv,N}} \right) \cdot P_{max}(t), & P_{min} \leq P_{max}(t) \leq P_{inv,N} \\ 0, & P_{max}(t) < P_{min} \end{cases}$$

Equation 27. PV system power model as a function of partial load

where P_{min} is assumed to be 0 in this study.

The AC annual energy output (E_{AC}) of the two GCPV systems as a function of various R_s or $P_{inv,N}$ was obtained using an empirical method (*Method 1*) and an analytical method (*Method 2*).

Method 1 uses one-year measurements of $P_{max}(t)$ to calculate E_{AC} :

$$E_{AC} = \sum P_{AC}(P_{max}(t), P_{inv,N}) \cdot \Delta t,$$

Equation 28. PV system energy output

where Δt is the recording interval.

Method 2 uses an analytical method proposed by Demoulias (2010), including the concept of the DC power duration curve (PDC) and its linear fitting. The PDC is defined as the curve that shows the aggregate time percentage in a period during which the DC power is larger than or equal to a certain value. The mathematical derivation of this analytical method is presented in the *Appendix H*.

Then, two economic criteria mentioned by Mondol et al. (2006b) and Peippo and Lund (1994) are used to investigate the related economic optimum sizing ratios. The first one, C_C (kWh/€), is defined as the ratio of annual energy output to the system's initial investment cost:

$$C_C = \left(\frac{E_{AC}}{R_{PV} \cdot P_{PV,N} + R_{inv} \cdot P_{inv,N}} \right),$$

Equation 29. Energy output per initial investment cost of the system

where R_{PV} is the overall initial cost of the array (excluding the inverter cost) per PV-array watt-peak (€/Wp) and R_{inv} is the inverter cost per watt-peak (€/Wp).

The second one, C_A (kWh/€), refers to the annual energy output per annualized investment cost with the considerations of PV module (L_{PV}) and inverter (L_{inv}) lifetime:

$$C_A = \left(\frac{E_{AC}}{CRF_{PV} \cdot R_{PV} \cdot P_{PV,N} + CRF_{inv} \cdot R_{inv} \cdot P_{inv,N}} \right),$$

Equation 30. Energy output per annual capital cost of the system

where CRF is the capital recovery factor:

$$CRF_{PV} = \frac{i}{1 - (1+i)^{-L_{PV}}},$$

Equation 31. Capital recovery factor for PV module

$$CRF_{inv} = \frac{i}{1 - (1+i)^{-L_{inv}}},$$

Equation 32. Capital recovery factor for PV inverter

where i is the real interest rate.

Through the mathematical derivation of E_{AC} detailed in *Appendix H*, the two corresponding optimum sizing ratios ($R_{s,c}^{opt}$, $R_{s,A}^{opt}$) can be obtained as the solutions of the first-order derivatives for these two economic criteria:

$$\left. \frac{dC_c}{dR_s} \right|_{R_c^{opt}} = 0.$$

Equation 33. First-order derivatives of C_c

$$\left. \frac{dC_A}{dR_s} \right|_{R_A^{opt}} = 0.$$

Equation 34. First-order derivatives of C_A

3.5 AGRIVOLTAIC FARM SIMULATION PROCESSES

3.5.1 PV Array Design and Installation

An envisaged south-facing agrivoltaic (AV) farm including aerial PV arrays and the crop area underneath the PV modules is sketched in the structure description Fig. 34, where S is the distance between PV array rows, H is the height of the PV module (low edge to the ground), T is the tilt angle in degrees of PV modules, and W is the width of individual PV module. In this thesis, several AV farm prototypes of different configurations were assessed, i.e., varying either in S or H . For example, a prototype named as SXHYTZ, means this prototype has a row space of X meters, Y meters above the ground level and $10 \times Z^\circ$ tilt angle. Then, a variable named Ground Coverage Ratio (GCR) is introduced as:

$$GCR = W/S.$$

Equation 35. Ground coverage ratio

Some technical requirements of PV array structure should be met such as the proper height and row space to allow an easy mechanical cultivation of the crops. The ground mounted PV system ($H=0$) is not recommended due to the following reasons:

1. Crops might induce shade to the low edge of PV modules during maturity;
2. The land beneath the modules is unproductive;
3. A wider row space is required for operating space of large farming equipment without affecting the PV system, compared to the aerial PV systems.

Furthermore, to avoid additional costs because of mechanical cultivation, the PV arrays should be designed to have vertical and horizontal dimension that are compatible with modern machinery. The optimum dimension of the PV array depends on the crop beneath the PV array. In this regard, the S6H4T3 prototype is the only solution among the prototypes stated in this thesis for durum wheat cultivation. However, other prototype such as S3H4T3 is suitable for other crops which do not need large farming equipment.

Fig. 34. Agrivoltaic farm structure.

The simulated AV farm prototypes are located at Madrid, and the total land area for each prototype is set to 240 m². The shading patterns and energy output are simulated by *System Advisor Model* (SAM) (SAM 2017.1.17, 2017), developed by *National Renewable Energy Laboratory* (NREL). The general location information is presented in Table 7. The default tilt angle is 30°, which is the optimum value at Madrid for maximum annual energy output given by the thumb rule, i.e., latitude minus 10° (Heywood, 1971). Rows of each PV array are designed to be 20 meters long. PV modules are poly-Si (Suntech STP 230, detail information is presented in *Appendix C array 1*), considered as opaque, 1.65 meters long and 1 meter wide. Each PV row consists of 1 string of 12 PV modules deployed in landscape orientation, leading to smaller self-shading losses than portrait orientation under the same condition (Barreiro et al., 2011). Every two PV rows connect to an inverter with DC-input capacity of 4566 W (Eltek THEIA 4.4HE-t UL (440 V)), contributing to an inverter sizing ratio of 1.21. Table 8 presents technical information of 3 simulated AV farms differing in row spaces, where S15 means 1.5 m row space.

Table 7. General local information, where the irradiation and temperature data are from SAM database.

Latitude	40.4426°N
Longitude	3.7295°W
Land area (m ²)	240
In-plane irradiation (30° tilt angle) (kWh/(m ² ·year))	1854.6
Annual average ambient temperature (°C)	14.3

Table 8. Agrivoltaic farm prototypes configurations.

Prototypes	Modules in row	Modules in parallel	PV array capacity	Number of inverter	PV array area (m ²)	Ground coverage ratio
S15H4T3	12	8	96 × 230 W	4	158.4	67%
S3H4T3	12	4	48 × 230 W	2	79.2	33%
S6H4T3	12	2	24 × 230 W	1	39.6	17%

3.5.2 Crop Farm Simulation

The *Simulateur mulTidisciplinaire les Cultures Standard* (STICS) crop model (STICS Version 8.41, 2017) was used to predict the crop yields under the PV arrays. STICS is a model developed by the French *National Institute of Agricultural Research* (INRA) to simulate crop growth as well as the interaction among soil, crop, and atmosphere on a daily time step driven by daily climatic data (irradiation, air maximum and minimum temperatures, rainfall) (Brisson et al., 2003). Numerous works have used and validated this crop model (Brisson et al., 2002; Schnebelen et al., 2004). Additionally, its application has been extended to intercropping systems such as agroforestry (Dufour et al., 2013) and agrivoltaic (Dinesh and Pearce, 2016; Dupraz et al., 2011). Apart from the climatic data, the inputs should include the soil parameters and crop management, defined by users for specific simulation or by default as the benchmarks. The outputs used in this study are the crop yield including aerial biomass at harvest, dry matter yield, and number of grains.

For this thesis, durum wheat was selected as the objective crop, with the sowing density of 221.1 plants/m². The inputs such as plant and soil parameters, crop management for the simulation were given by the default except the daily irradiation intercepted by crops. The other meteorological parameters (air and crop temperature, air vapor pressure deficit and wind speed) of the microclimate as well as growth rate under AV farm were not significantly modified with the reduction of light availability (Marrou, Hélène et al., 2013a). They were therefore remained the same in the climate files. Additionally, other resources such as water and nitrogen were not limiting.

CHAPTER 4 – RESULTS AND DISCUSSION

4.1 SEASONAL PERFORMANCE COMPARISON OF THE THREE GRID-CONNECTED PHOTOVOLTAIC SYSTEMS

The primary objective is conducting a comparative analysis about the diverse performance of the three GCPV systems located at ETSIAAB, Madrid (Spain). As it was mentioned in the Literature Review, the different performances of a GCPV system were generally ascribed to overlap of several concurrent meteorological effects as well as system design (inverter capacity). Thereby, this section mainly investigated the influences of the local irradiance, sun spectra and operating temperature on the performances of different PV technologies.

This section first presented local meteorological information about the ETSIAAB GCPV plant. Then, the PV system efficiency as a function of in-plane irradiance was depicted and analyzed. The high in-plane irradiance triggered the power limitation due to the undersized-inverter saturation. The energy losses due to inverter saturation for the three GCPV systems were calculated. To differentiate the mixed influences of irradiance, sun spectra and operating temperature, the clear-sky condition and irradiance range predefined in *Section 3.2.3* were applied on the evaluation of spectral and thermal effects on PV array maximum power. Concretely, a sun spectra indicator namely air mass (AM) was utilized to evaluate the influence of sun spectra on the PV array maximum power. Then, the relation between the PV array maximum power and its operating temperature was constructed. Complex influence of irradiation and temperature on the a-Si system was explained and quantified. At last, the energy conversion chains of the three GCPV systems during year 2013–2015 was illustrated and discussed.

4.1.1 General Description of the On-Site Meteorological Parameters

The site where the solar field is located has a transitional climate between the typical Mediterranean climate and the cold semiarid climate with high irradiation. The on-site measured annual meteorological profile in the daytime of 2013 shows the monthly average daily in-plane irradiation varied from 2.75 kWh/(m²·day) in January to 7.49 kWh/(m²·day) in July. The monthly average ambient temperature varied from 9.0 °C in January to 31.5 °C in July, the wind speeds at this site were weak with an annual average of 1.3 m/s; and the average relative humidity varied from 40.28% in August to 54.84% in January. The three determinant factors (irradiance, ambient temperature and AM) vary seasonally as illustrated in Fig. 35. Monthly average daily irradiation and ambient temperature peaked at summer and gradually sank to the beginning and end of the year, whereas the AM varied contrariwise. The overlap of these concurrent factors contributes to the difficulty to differentiate and analyses the diverse performance of PV generators individually.

Fig. 35. Monthly average of ambient temperature, in-plane irradiation and air mass (AM) over 2013, where monthly AM was calculated at solar noon of 15th day in each month.

4.1.2 In-Plane Irradiance Influence

In-plane irradiance is the dominant parameter of GCPV system energy output. Fig. 36 presents the percentage distributions of annual AC energy output from the three GCPV systems against different irradiance intervals, in 2013. The AC energy distributions were similar in all the three GCPV systems, of which the annual energy outputs were 2441 kWh (poly-Si), 2532 kWh (a-Si) and 2469 kWh (CdTe), in 2013. There was about 90% of the energy generated

when in-plane irradiance was over 400 W/m^2 . However, only 1% annual energy was generated when in-plane irradiance was below 100 W/m^2 . Thus, in addition to high uncertainty of the monitoring system under low irradiance conditions, the data with in-plane irradiance below 100 W/m^2 was excluded in this Section 4.1.2.

Fig. 36. Percentage distribution of annual AC energy generated by the three GCPV systems versus in-plane irradiance.

4.1.2.1 DC efficiency as a function of in-plane irradiance

The efficiencies of the three GCPV systems plotted versus in-plane irradiance (G_i) are shown in Fig. 37, where the red trending lines are depicted by LOcally wEighted Scatterplot Smoothing (LOESS) method. There are three striking stages in all the three figures, i.e., low irradiance stage ($100 \text{ W/m}^2 < G_i < 400 \text{ W/m}^2$), middle irradiance stage ($400 \text{ W/m}^2 \leq G_i \leq 800 \text{ W/m}^2$) and high irradiance stage ($G_i > 800 \text{ W/m}^2$). These three stages accounted for 10%, 42% and 48% of total energy output as shown in Fig. 36, respectively.

The three GCPV systems efficiencies scattered remarkably in the low irradiance stage. The absolute standard deviations of system efficiency were 2.70% (poly-Si), 1.17% (a-Si) and 2.00% (CdTe), respectively. The striking performance fluctuation was mainly attributed to the fast-changing irradiance conditions and high uncertainty of the recording devices at low irradiance level.

Then, when the in-plane irradiance varied from 400 W/m^2 to 800 W/m^2 , the absolute standard deviations of system efficiency were down to 1.58% (poly-Si), 0.60% (a-Si) and 0.94% (CdTe), respectively. The main features of this stage were the more concentrated system

efficiency and the immunity to the major inverter saturation effect. The three insets in each sub-figure of Fig. 37 depict the efficiency dependences on the in-plane irradiance at this stable stage. The efficiency of the a-Si system was practically less dependent on irradiance, of which the relative efficiency variation was -8.8% per kW of in-plane irradiance variation ($-8.8\%/kW$), with respect to the nominal efficiency. The system efficiencies of the other two GCPV systems encountered more negative relations with the increasing irradiance. The relative efficiency variations (compared to nominal efficiency) were $-22.8\%/kW$ of poly-Si and $-19.0\%/kW$ of CdTe, respectively.

In addition, the relation between system efficiency and in-plane irradiance seems to indicate the negative influence of module temperature on system efficiency. There is a positive correlation between the module temperature and in-plane irradiance as shown in Fig. 38. Accordingly, the efficiency of a-Si system had little dependence on the module temperature, compared to poly-Si and CdTe systems, which suffered greater extents of efficiency reduction when irradiance and module temperature increased.

Lastly, at the high irradiance stage, the undersized inverter cut off the proportion of PV array power output surpassing inverter input capacity, which results in a rapid decrease in the system efficiency. Based on the red trending line from LOESS, the efficiency decreases of the three GCPV systems are presented in Table 9. The a-Si system encountered the highest relative efficiency decrease of 28.0% , compared to the 23.0% of poly-Si system and 23.3% of CdTe system, with respect to their initial efficiencies at 800 W/m^2 . It is attributed by higher inverter saturation possibility because of the highest peak power of a-Si array (see Table 9). Furthermore, the higher inverter saturation possibility indicates an improving performance of a-Si array during summer when the high irradiance and temperature commonly co-occur.

Fig. 37. PV array efficiency versus in-plane irradiance, 2013. (a) poly-Si, (b) a-Si, (c) CdTe. The red line is the observed data smoothed by LOESS.

Table 9. Efficiency decrease in high irradiance stage of three PV arrays, where the initial efficiency is obtained at 800 W/m^2 and ultimate efficiency is at 1200 W/m^2 , based on the trend extracted by LOESS.

	Peak Power	Initial efficiency	Ultimate efficiency	Absolut decrease	Relative decrease
poly-Si	1610 Wp	12.65%	9.74%	2.91%	23.0%
a-Si	1680 Wp	6.72%	4.84%	1.88%	28.0%
CdTe	1650 Wp	10.27%	7.88%	2.39%	23.3%

Fig. 38. Daily average module temperature (poly-Si) vs. daily average in-plane irradiance over 2013, where the red line is the linear regression of observed data.

4.1.2.2 High-irradiance triggered inverter saturation

An undersized inverter clips the power output and blurs the actual power at high insolation conditions as shown in Fig. 39 and Fig. 40. When the power limitation is reached, the inverter forces the PV array increase its operating voltage instead of maximum power point voltage (V_{mp}), thus reducing maximum power point current (I_{mp}) towards open circuit conditions (V_{mp}' and I_{mp}'). Consequently, PV system power output is capped at inverter AC rating to protect the electrical components inside.

Fig. 39. Normalized array P_{max} , I_{mp} and V_{mp} as a function of in-plane irradiance (G_i), ambient temperature (T_a) at 25 August 2016 with power limitation occurrence.

Fig. 40. Shift of operating point when power limitation occurs in normalized array I-V and P-V Curves.

The annual energy losses from inverter saturation were 1.79% (poly-Si), 4.48% (a-Si) and 1.59% (CdTe) of each system final energy output, based on Equation 3 from 2016 data. The proportion of monthly inverter saturation losses to annual AC energy output was depicted in Fig. 41. There were rarely remarkable energy losses due to inverter saturation in January, November and December with generally low irradiance. Thereby, the PV power output did not meet the threshold of inverter saturation in this season. The fluctuations of the relative inverter saturation losses of poly-Si and CdTe systems were similar, i.e., higher in spring and

lower in summer and autumn. This phenomenon was attributed to the higher temperature in summer, by which the module efficiency as well as the PV array power output was attenuated more severely. Thus the inverter saturation losses were mitigated as the inverter input (or PV array output) prior to inverter saturation decreased, albeit the saturation possibility was high due to the frequent high irradiance conditions. However, for a-Si system, the converse fluctuation has been detected. The energy losses due to inverter saturation were remarkable during summer with extremely high irradiance and temperature, implying that the thermal losses of this system were less than the other two systems. On the other hand, considering the identical inverters to which the three PV arrays connected, the higher inverter saturation losses represented the higher array power generation inputting into the inverter if there would be no inverter saturation effect.

Fig. 41. Percent inverter saturation losses of annual energy output for the three GCPV systems.

4.1.3 Seasonal Spectral Effect

The PV module and system performances are affected by the solar spectrum, which is relevant to local weather conditions, day-of-year (see Fig. 42 left) and time-of-day (see Fig. 42 right). The data depicted in Fig. 42 was collected of four cloudless sunny days in 2015 at Madrid, with an *EKO MS-700* spectroradiometer³. The solar spectrum has a larger blue (APE = 1.9019 eV at solar noon of 25-08-2015) content during the summer and the noon when the sun is at higher elevation, which is represented by lower AM. Then, in winter or sunrise and sunset the solar spectrum turns to higher red (APE = 1.8492 eV at solar noon of 08-01-2015) content with a lower sun elevation (higher AM). This variation in the sun spectra rather than a simple change in the total incident irradiance affects the PV technology which has narrow

³ This data is kindly provided by Miguel Alonso Abella at CIEMAT.

spectral sensitivity range such as a-Si (in the range of 300–800 nm) more strongly (Virtuani and Fanni, 2014).

Fig. 42. Solar spectra of four days at solar noon in 2015 with different air mass (AM) values (left); Solar spectra at different time of 25 August (right). The values were scaled to 1000 W/m² total irradiance. Data from Miguel Alonso Abella at CIEMAT.

The P_{max} for poly-Si, CdTe and a-Si arrays increased successively with increasing AM from December 2014 to December 2015 as depicted in Fig. 43. The regression line parallel to the x-axis and a low R^2 value (16%) in Fig. 43a denotes no clear AM-dependence of the poly-Si array generating the P_{max} , as observed from the c-Si based reference irradiance sensor and the determined irradiance range. The AM-dependence of the P_{max} for a-Si and CdTe arrays is stronger, which is characterized by a decreasing trend for increasing AM values (redshift). The gradient of the applied linear least square fit can also provide information about the AM-dependence of the P_{max} for a-Si array varies at a higher rate $-11.22\%/AM$ compared to the $-4\%/AM$ variation of the P_{max} for the CdTe array, because of the narrower and more blue-sensitive spectrum response of the a-Si technology. Meanwhile, from the spectral point of view, the higher spectral response to shorter light wavelengths makes a-Si module or system perform better in summer (low AM), whereas the poly-Si works better in winter (high AM) due to its higher response to longer wavelength. Furthermore, the notable gap between the P_{max} gathered from two periods, i.e., Apr.2015–Jun.2015 and Jun.2015–Sep.2015, as shown in Fig. 43c, suggests there are some additional factors besides the varying AM that contributes to the seasonal variation of the a-Si performance, which is discussed in the following Section 4.1.4.

Fig. 43. Seasonal maximum power dependence in AM-units for the poly-Si, CdTe and a-Si arrays under clear-sky conditions.

4.1.4 Module Temperature Influence

Module temperature is another parameter influencing the energy performance of GCPV system. Fig. 44 demonstrates the percentage distribution of annual AC energy generated by the GCPV systems against different module temperature intervals. Under the same operating conditions, the module temperature of CdTe system was the highest among the three systems, even between 70 to 75 °C there was still energy generation. The annual average module temperatures during the time span (10 am–18 pm) were 37.8 °C (CdTe), 33.7 °C (a-Si) and 34.9 °C (poly-Si), respectively. For a-Si and poly-Si systems, the maximum energy was generated at module temperature interval of 50–55 °C, where the percentages of annual energy output were 16% and 15%, respectively. While for CdTe system, the maximum energy output was generated at module temperature interval of 55–60 °C accounting for 13% of total energy.

Fig. 44. Percentage distribution of annual AC energy generated by the three GCPV systems versus respective module temperature.

The maximum power temperature coefficient obtained at STC is variable and is affected by the meteorological conditions (YE Jiaying, 2014). Furthermore, the performance of the a-Si has a negligible relationship with the instantaneous operating temperature due to the Light Soaking Effect (LSE) and thermal annealing (Ishii et al., 2011).

The thermal effect on the P_{max} of the three arrays at two different irradiance levels ($600 \pm 20 \text{ W/m}^2$ and $700 \pm 20 \text{ W/m}^2$) restricted in a narrow AM range ($1.4 < \text{AM} < 1.6$) was analyzed (Fig. 45). The P_{max} data were collected under clear sky conditions and corrected by the irradiance and normalized to the rated maximum power at STC (see clear sky condition Section 3.2.3). The temperature dependence of the poly-Si and CdTe arrays are more significant, wherein the R^2 values are nearly 80% and 75%, respectively. The slope of the regression line gives the amplitude of thermal effects on P_{max} , which is higher in the poly-Si array with the value $-0.56 \text{ \%/}^\circ\text{C}$ and lower in the CdTe array as $-0.25 \text{ \%/}^\circ\text{C}$. These results are in agreement with the temperature coefficients provided by the manufacturer. The poly-Si array exhibits a stronger negative relationship with instantaneous the module temperature followed by the CdTe array with a lower temperature coefficient.

However, the linear temperature dependence for the a-Si array is not significant according to the rather low R^2 values (below 0.5%). In addition, the regression lines are parallel to the x-axis, where the slopes are $-0.04 \text{ \%/}^\circ\text{C}$ and $-0.03 \text{ \%/}^\circ\text{C}$ in both irradiance ranges, respectively. It is therefore considerably different from the temperature coefficient in the datasheet. This phenomenon could be explained by the LSE and thermal annealing, which

suggest that the output of the a-Si is affected by the gradually increasing/decreasing temperature and continuous insolation rather than by instantaneous operating temperature.

Fig. 45. The maximum power dependence on the module temperature for the poly-Si, a-Si and CdTe arrays under clear-sky conditions for two in-plane irradiance (G_i) ranges: (a) $580 \text{ W/m}^2 < G_i < 620 \text{ W/m}^2$, (b) $680 \text{ W/m}^2 < G_i < 720 \text{ W/m}^2$.

Consequently, there is a complex overlap of the solar spectral effect and the thermal annealing, in addition to the LSE. The relationship between the P_{max} and the AM, as arranged by season is shown in Fig. 43. The figure shows that the P_{max} values from July 2015 to September 2015 were higher than the P_{max} values from April 2015 to June 2015, even for the same AM range (AM1.2–AM1.6). A threshold temperature that triggers a more effective thermal recovery process was proposed as 38–40 °C by Skoczek et al. (2011). It is plausible that the ‘effective’ thermal annealing recovery could start from April and end in September according to Fig. 46.

Fig. 46. Monthly average module temperature.

The analysis of variance (ANOVA) for the month (April 2015 and September 2015) on P_{max} was constructed for the three arrays (Fig. 47). The reason for comparing April 2015 with September 2015 is that they can be considered the first and last month, respectively, of the effective thermal annealing recovery. All the data shown in Fig. 47 and Fig. 48 are collected under clear sky conditions and corrected with respect to the temperature. Significant differences ($F = 68.84$; $p\text{-value} = 8.87\text{e-}9$) were found between the two months for the a-Si array, which outperforms in September over April. In contrast, no significant differences were found in the P_{max} for the poly-Si and CdTe arrays between the two months.

Additionally, the mean P_{max} values for the poly-Si GCPVs in these two months are very close to the STC rating as a result of the fixed AM and a proper temperature and irradiance correction. However, the mean P_{max} values of the CdTe array are lower than the STC rating, indicating that the temperature and irradiance correction are not as effective as they were for the poly-Si array. Despite this ineffective correction, the uniform clear sky condition and the similar operating temperature provide a uniform comparison basis between April 2015 and September 2015. The mean P_{max} values for the a-Si increased from 1.63 kW in April to 1.7 kW in September 2015, indicating the improving performance due to the thermal annealing recovery. The higher values over the STC rating are due to the poor relationship between the a-Si array output and the instantaneous operating temperature.

Fig. 47. PV array maximum power (P_{max}) as a function of the month (April 2015 vs. September 2015) for each array. F-test and p-values of the corresponding analysis of variance are included in the plots.

Another ANOVA was done for the P_{max} of the a-Si array, spanning a longer period from September 2014 to April 2016. Significant differences were found between April and September ($p < 0.01$), whereas the difference is not statistically significant ($p > 0.01$) between the same months of two calendar years (i.e., Sep. 2014 & Sep. 2015 or Apr. 2015 & Apr. 2016). The maximum power variation between the four months is illustrated in Fig. 48. The superimposed interactions of the thermal annealing recovery and the spectral influence are isolated using a narrow AM range and clear sky conditions. We can infer that the variation from September to April is ascribed to the thermal annealing recovery and LSE. The generated power from the a-Si array decreased due to the LSE from September to April and then regenerated through the more effective thermal annealing recovery from April to the following September.

The mean value of the P_{max} in September 2014 was chosen as the baseline to obtain clearer quantities of the power variation among the four months. Then, through the *multiple comparisons method* whose results are listed in Table 10, the quantified LSE and thermal annealing recovery were obtained. From 2014 and 2016, the power decreased by 4.7% and 6.7%

from September to April, respectively, due to the LSE and then recovered 5.9% owing to the thermal annealing recovery from April to September. Additionally, the existence of the thermal annealing recovery and LSE also suggests that the instantaneous module temperature is unable to provide a proper temperature correction of the P_{max} for the a-Si. Consequently, a 6% annual performance variation due to the LSE is suggested in this study, which is in compliance with the investigation of Virtuani and Fanni (2014), as well as the report of Gottschalg et al. (2005) concerning the NREL case.

Fig. 48. PV array maximum power (P_{max}) of a-Si as a function of the month.

Table 10. Multiple comparisons of the power in four different months from Sep. 2014 to Apr. 2016 for a-Si array.

Month1	Month2	Means difference	p-value	Significant difference
Sep. 2014	Apr. 2015	−4.7%	2.31E−09	Yes
Sep. 2014	Sep. 2015	1.2%	0.05326242	No
Sep. 2014	Apr. 2016	−5.5%	2.20E−12	Yes
Apr. 2015	Sep. 2015	5.9%	8.90E−12	Yes
Apr. 2015	Apr. 2016	−0.8%	0.27343663	No
Sep. 2015	Apr. 2016	−6.7%	1.05E−14	Yes

4.1.5 Energy Conversion Chain

The general energy conversion chain is described by specific final yield (Y_f), capture losses (L_c) and system losses (L_s) according to Equation 4 and Equation 6. The variation of these parameters on a monthly basis for the three GCPVs under this study during three years is illustrated in Fig. 49, Fig. 50 and Fig. 51.

The three GCPV systems are operated under identical irradiation; thus their reference yields (Y_r) are also identical. This is demonstrated in Fig. 49 through Fig. 51 indicating that the

sums of Y_f , L_c and L_s for the three GCPV systems are the same. In addition, the Y_r values are higher in the summer and lower in the winter.

The ratios of L_s to the specific array yield (Y_o) remained stable throughout the year for the three GCPV systems. As the same inverter technology was used in these three GCPV systems, the L_s ratios (or the annual inverter efficiencies) were indistinguishable. The average annual L_s ratios over the three years are 10.08% (poly-Si), 10.36% (a-Si) and 10.27% (CdTe), slightly higher than the nominal value 9.1%, corresponding to the inverter's nominal efficiency of 90.9% (European efficiency). This suggests that most the system losses are attributed to the inverter's conversion losses. Additionally, a lower L_s ratio in the poly-Si GCPV system compared to the a-Si GCPV system indicates that the poly-Si system has a more proper sizing ratio with the relative inverter than the a-Si system.

The L_c of all the GCPVs experienced a sinusoidal-like trend along the years, i.e., they were lower in winter and higher in summer. This trend can be interpreted from the viewpoints of the system design and operating conditions as discussed above. For a-Si, the higher irradiation, proper sun spectra range and thermal annealing in the summer elevated its output; whereas the undersized inverters clipped more energy and it could more easily attain the power limitation condition, resulting in a higher L_c in the summer compared to the winter. For poly-Si and CdTe, higher ambient temperatures and hence higher operating temperature aggravate the L_c by increasing the thermal losses.

The amplitudes of this trend among three GCPV systems were different and varied with seasons. In cold seasons, the poly-Si and CdTe systems had a lower L_c than the a-Si, indicating better photon-electron conversion performance. The L_c ratios (L_c/Y_r) reached the values of -9.17% (poly-Si) and -4.00% (CdTe) in December 2014, mainly attributable to the lower ambient temperature and lower common power limitation conditions. The negative L_c values reflect performance ratio (PR) values greater than 100% for the DC portion. This over 100% PR was also reported in a similar study by Başoğlu et al. (2015), even though their investigation was at the AC portion. In contrast, from April to September, the L_c of all systems were relatively high, with the a-Si system performing better than the other two materials. For instance, in July 2015, the L_c ratios of three GCPV systems were 15.22% (poly-Si), 10.83% (a-Si) and 14.28% (CdTe).

From the viewpoint of the intrinsic characteristics of the PV materials, in winter, the higher spectral responses and the more negative temperature coefficients of the poly-Si and

CdTe over the a-Si resulted in their improved performances. On the other hand, the opposite trend in the summer led to the lower performance of the poly-Si and CdTe systems as compared with the a-Si.

Other factors, such as soiling, mismatch and shadowing, also aggravate the L_c . Ismail et al. (2013) reported a much higher L_c for two 200 kWp GCPV systems based on a-Si and poly-Si in Brunei, where the L_c were 18.2% and 26.7%. Meanwhile, the corresponding L_c of the two systems in ETSIAAB GCPV plant from 2014 to 2015, were 8.4% and 7.5%, respectively.

Fig. 49. Monthly average daily final yield (Y_f), capture losses (L_c) and system losses (L_s) of the poly-Si GCPV system month from January 2013 to December 2015.

Fig. 50. Monthly average daily final yield (Y_f), capture losses (L_c) and system losses (L_s) of the a-Si GCPV system from January 2013 to December 2015.

Fig. 51. Monthly average daily final yield (Y_f), capture losses (L_c) and system losses (L_s) of the CdTe GCPV system from January 2013 to December 2015.

The overall average annual Y_a were 1506 kWh/kWp, 1495 kWh/kWp and 1480 kWh/kWp of poly-Si, a-Si and CdTe GCPV systems, respectively. Compared with similar arrays studied by Sharma et al. (2013) in India, the Y_r for the poly-Si system was 2% less but the a-Si system was 5% more than our systems, even considering the undersized inverter in our case. The investigation of poly-Si and CdTe PV arrays with similar capacities connected to two proper inverters by Başıoğlu et al. (2015) showed mean PR values that were 83.80% and 89.76%, respectively, in 2015 in Turkey, whereas the corresponding PR values of the systems in this thesis were 83.24% and 81.94%, respectively.

The high ambient temperature in the summer is the predominant factor attenuating the output of the poly-Si GCPV system. In contrast, the seasonal behavior of the a-Si system is more complex, due to the overlap of the less negative temperature coefficient and the thermal annealing recovery as well as a much narrower spectral sensitivity (in the range of 300-800 nm). Therefore, the a-Si performs better in the summer (high temperature and low AM) and worse in the winter (low temperature and high AM) compared to the other two GCPV systems. It has been suggested by Notton et al. (2010) that the a-Si technology has more than a 20% improvement in the summer over the winter. However, the improvement is counteracted by the inverter clipping, which primarily occurs in the summer, attenuating the output. The CdTe GCPV system performs at a moderate seasonal variation due to a less negative temperature coefficient than the poly-Si and a wider spectral response than the a-Si, in addition the absence of the thermal annealing recovery and LSE.

4.2 DEGRADATION RATE BASED ON PERFORMANCE RATIO TIME SERIES AND CURRENT-VOLTAGE CURVE MEASUREMENTS

The durability associated with degradation rate is of vital importance to the flourish of the PV industry. The degradation rate should be investigated not only from the module-level but also from the entire system. Outdoor performance evaluation is crucial in quantifying the system long-term behavior and lifetime because PV systems typically work at this environment.

This section induced an investigation for the degradation rates of the three GCPV systems based on three performance metrics, i.e., three-year performance ratio (PR) time series, indoor and outdoor current-voltage (I-V) curve measurements. These approaches stand for the degradation rate assessment upon PV system-level (PR time series), array-level (outdoor I-V test), and module-level (indoor I-V test). Four statistical techniques were applied on three-year (2014–2016) PR time series to investigate the degradation rates and seasonalities for the three GCPV systems considering the influence of inverter saturation. Then, the outdoor I-V curve characteristic comparisons were conducted for two days in March of two years (2016 and 2017) under the almost identical weather conditions. The outdoor I-V characteristics comparisons aim at a better understanding about the performance deterioration mechanisms of the PV arrays. At last, the indoor tests provided the PV module performance variation from the initial peak power before operation, to the peak power after about 2.5-year outdoor operation.

Thereby, the influences of performance metrics, investigating period, analytical techniques and inverter saturation on the evaluation of GCPV systems degradation rates were studied in this section.

4.2.1 PR-Based Degradation Rate Calculation

4.2.1.1 Degradation rate by linear regression over the three-year period

The original PR time series of the three GCPV systems are illustrated in Fig. 52. The right figure demonstrates the evaluation excluding inverter saturation. For poly-Si system, the degradation rates were 1.11%/year (with inverter saturation) and 1.63%/year (without inverter saturation). For a-Si system, the degradation rates were 1.14%/year (with inverter saturation) and 1.73%/year (without inverter saturation). For CdTe system, the degradation rates were 1.47%/year (with inverter saturation) and 2.12%/year (without inverter saturation).

All the three GCPV systems exhibited significant seasonal performance fluctuations. Once the inverter saturation was excluded (Fig. 52 right), PR values improved by 2–4% during the summer and remained almost the same during the winter for poly-Si and CdTe systems. However, the undersized inverter changed remarkably the PR time series for a-Si system, not only from the amplitude of fluctuation but also time distribution referring to seasonality. This indicates the a-Si suffered more severe than the other two PV systems from the undersized inverter.

Fig. 52. Linear regression for three-year PR time series data for the three GCPV systems with (left) and without (right) inverter saturation.

4.2.1.2 Degradation rate using Classical Seasonal Decomposition (CSD) over the three-year period

Fig. 53–Fig. 55 show the trends, seasonalities and remainders of PR time series calculated by CSD for the three GCPV systems. The left figures are based on all data points, while these figures on the right exclude inverter saturation. As the inherent drawback of CSD method, the PR time series of beginning and ending 6 months (12 months in total) are lost.

The downward trends of PR time series were discovered among all the three systems, whether the inverter saturation was excluded or not. However, the extent of the downward trend, which is proportional to the degradation rate, varied among the three systems as well as the inverter saturation (included or excluded) cases. Comparing the two cases due to inverter saturation, all the three PR downward trends shown in left figures (inverter saturation included) started at lower locations and decreased slower than those in the right (inverter saturation excluded). If the inverter saturation was included, the a-Si and CdTe systems possessed the higher degradation rates, which were 1.61%/year and 1.71%/year, than the

poly-Si system of 1.08%/year. Analogously, if the inverter saturation was not considered, the a-Si and CdTe systems exhibited the degradation rates of 2.30%/year and 2.17%/year, respectively, compared to the poly-Si system of 1.17%/year. In addition, good agreements between the extracted trends and their linear fits with R^2 values in the range of 75.71–86.61% were presented.

In the case of inverter saturation included in the evaluation, the seasonalities of all the three GCPV systems peaked during winter and sank to the bottom during summer. The a-Si system showed the lowest seasonal peak-to-peak PR variation, which ranged from –3.49% to 5.83% with a standard deviation of 3.37%. The highest varying seasonality was found in poly-Si system. It varied from –7.94% to 12.80% with a standard deviation of 7.14%. The seasonality of CdTe system was from –5.27% to 10.26% with a standard deviation of 5.34%.

If the inverter saturation was excluded, the similar seasonal patterns were found in the poly-Si and CdTe systems with a minimum PR in summer (–8.48% of poly-Si and –4.53% of CdTe) and a maximum PR in winter (10.42% of poly-Si and 7.80% of CdTe), but lower amplitudes compared to the left figures. The standard deviations were 6.50% (poly-Si) and 3.94% (CdTe), respectively. However, in a-Si system, the inverter saturation not only narrowed down the seasonal fluctuation but also changed the time-phase. The downsizing fluctuation was from –2.48% to 2.68% with a standard deviation of 1.87%. It has shown the seasonality of a-Si system had a higher value in summer time but lower value in spring.

The average standard deviation of remainders for poly-Si, a-Si and CdTe were 0.87%, 0.58% and 0.65%, respectively.

The results of STL and ARIMA were presented in *Appendix I* and *Appendix J*, as the trends and seasonalities obtained through them were similar to the values given by CSD.

Fig. 53. Classical Seasonal Decomposition extracted trend, seasonality and remainder for three-year PR time series data of poly-Si GCPV system with (left) and without (right) inverter saturation.

Fig. 54. Classical Seasonal Decomposition extracted trend, seasonality and remainder for three-year PR time series data of a-Si GCPV system with (left) and without (right) inverter saturation.

Fig. 55. Classical Seasonal Decomposition extracted trend, seasonality and remainder for three-year PR time series data of CdTe GCPV system with (left) and without (right) inverter saturation.

4.2.1.3 Comparison of the different analysis techniques at two inverter cases

Fig. 56 summarizes the annual PR degradation rates evaluated by LR, CSD, STL and ARIMA over the three-year period, according to whether the inverter saturation was excluded from the evaluation or not. All systems at two inverter cases present the higher degradation rates than the nominal limits providing by manufacturers (1%/year as the dashed horizontal line in Fig. 56). The degradation rates with expanded uncertainty evaluated by the abovementioned statistical methods are specified in Table 11 (with inverter saturation) and Table 12 (without inverter saturation).

Comparing annual degradation rates among different GCPV systems, the poly-Si system experienced universally lower degradation rates assessed by all the four analysis techniques, in both cases of inverter saturation excluded and included, compared to the other two thin film GCPV systems. The average degradation rate for poly-Si was 1.14%/year (with inverter saturation) and 1.37%/year (without inverter saturation). On the other hand, the a-Si and CdTe systems showed average degradation rates of 1.48%/year, 1.60%/year in inverter saturation case and 2.12%/year, 2.10%/year (without inverter saturation).

When comparing the results computed by four statistical methods, the degradation rates obtained by LR were generally lower compared to the CSD, STL and ARIMA results. The LR is the least robust method since it was significantly affected by seasonality as well as outliers. The three decomposition methods are more statistical robust with much lower

uncertainties. This comparison claims that the degradation rate is affected by the selected methods which have the different strengths, while the advanced decomposition methods have similar results.

With respect to comparing annual degradation rates between the two inverter saturation conditions, the inverter saturation mitigates the degradation rates in all PV systems evidencing by the four statistical methods. The average increases are 0.23%/year (poly-Si), 0.54%/year (a-Si) and 0.50%/year (CdTe), but the uncertainties remain unvaried.

Fig. 56. Three-year performance degradation rates including the expanded statistical uncertainty of each GCPV system by applying LR on PR time series and on trends from CSD, LOESS and ARIMA, with (red) and without(blue) inverter saturation.

Table 11. Degradation rates from LR and three time series decomposition methods (CSD, STL and ARIMA) applied on three-year PR time series, including the expanded statistical uncertainty at 95% confidence level.

	poly-Si	a-Si	CdTe
LR (%)	1.11±2.72	1.14±1.35	1.47±2.09
CSD (%)	1.08±0.23	1.61±0.27	1.71±0.29
STL (%)	1.13±0.27	1.59±0.22	1.60±0.28
ARIMA (%)	1.24±0.30	1.57±0.29	1.63±0.32

Table 12. Degradation rates from LR and three time series decomposition methods (CSD, STL and ARIMA) applied on three-year PR time series without inverter saturation, including the expanded statistical uncertainty at 95% confidence level.

	poly-Si	a-Si	CdTe
LR (%)	1.63±2.55	1.73±0.84	2.12±1.65
CSD (%)	1.17±0.28	2.30±0.38	2.17±0.36
STL (%)	1.35±0.27	2.24±0.26	2.08±0.29
ARIMA (%)	1.31±0.35	2.21±0.36	2.04±0.29

4.2.1.4 Inverter efficiency time series analysis

The abovementioned decomposition analysis was conducted on the PR time series of AC side. Therefore the connecting inverters are the potential sources of the performance degradation and seasonality. Fig. 57 shows the monthly inverter efficiencies time series during the same three-year period as discussed previously. Concretely, the average inverter efficiencies of poly-Si, a-Si and CdTe systems during the three years were $89.86\pm0.20\%$, $89.65\pm0.17\%$ and $89.73\pm0.17\%$. The standard deviations are less than 0.20% indicating that the inverter efficiency fluctuations were rather small during the three years. The annual changing rates calculated by CSD of the three inverter monthly efficiencies are $-0.03\%/year$ (poly-Si), $0.01\%/year$ (a-Si) and $0.02\%/year$ (CdTe). Consequently, the deterioration in inverters conversion efficiency leading to GCPV systems degradation was excluded from the potential sources.

Fig. 57. Monthly average inverter efficiencies of the three GCPV systems.

4.2.2 Outdoor I-V Curve Approach

4.2.2.1 Validation of Solar-4000[®] analyzer

This thesis accomplished the investigation of PV arrays degradation through the I-V curve approach with the help of Solar-4000[®] analyzer. To obtain the confident data, the validation of this analyzer should be satisfied. The author compared the corrected outdoor I-V curves of a poly-Si reference module measured by Solar-4000[®] and by a solar simulator in an individual laboratory (CIEMAT). The poly-Si reference module is stored in a dark condition. Accordingly, it is safely assumed that its STC performance did not change between the two tests. The correction procedure is based on IEC 61724, as pre-expressed in Section 3.3.2.1. I-V curves measured by the abovementioned systems and then corrected to STC are illustrated in Fig. 58. The difference between the two curves is almost negligible, especially in the head and tail regions, indicating the same I_{sc} and V_{oc} measured by these two systems. Fig. 59 shows the numerical relative differences in the 5 parameters. The values given by the solar simulator were chosen as the benchmark and depicted as the dashed horizontal line. The mean values obtained by Solar-4000[®] as well as their standard deviations were also presented. All the 5 parameters measured by Solar-4000[®] analyzer were in conformity with the solar simulator measurements. The maximum gap exists in the term of P_{max} , where the Solar-4000[®] measured P_{max} were 1.2% lower than the measure of solar simulator. Thereby, the author can safely assume that there is no striking difference in the measurements from Solar-4000[®] and solar simulator.

Fig. 58. I-V curves measured by Solar-4000[®] analyzer (blue solid line) and solar simulator (orange dashed line).

Fig. 59. Comparisons of five parameters between Solar-4000[®] and solar simulator (dashed horizontal line).

4.2.2.2 Two years I-V characteristics comparison

Fig. 60–Fig. 62 present the measured I-V curves and 6 characteristics variations of the three PV arrays on two cloudless sunny days under almost identical condition as expressed in Section 3.3.2.1. Therefore, it is reasonable to assume that the differences in the I-V curves characteristics are ascribed to the degradation of the PV array rather than the differences in the testing conditions. In other words, there is no need to conduct the temperature and irradiance correction to reference conditions, such as STC. Accordingly, the accuracy of the evaluation is improved as the correction procedure would induce the uncertainty. In addition, the correction procedure is less effective in a-Si module due to the implicit relation with instantaneous irradiance and temperature, as discussed in the seasonal performance analysis Section 4.1.

In poly-Si array, the P_{max} changed by -2.3% mainly due to the degradation in currents, i.e., I_{sc} and I_{mp} , of which the reductions were 2.1% and 1.6% , respectively. The V_{mp} showed a moderate degradation by 0.8% . However, there was no obvious difference in cases of V_{oc} and FF. The possible reason of the decreasing currents is the deterioration of the optical properties, such as EVA discoloration and/or decreased transmission the light, even soiling. A stable FF value implies there were no significant changes in the R_{series} and R_{shunt} . The unchanged R_{series} and decreasing I_{sc} would result in a mitigation of power loss from the R_{series} . Thus, the power loss due to decreasing I_{sc} was slightly mitigated by the FF remaining the same.

On the other hand, for CdTe array (see Fig. 62), the main contributor to power loss was the voltage, i.e., V_{oc} and V_{mp} . The 3.3% degradation rate of P_{max} was related to 1.9%

degradation in V_{oc} and 2.8% in V_{mp} . A moderate degradation of 0.8% in FF was also found. The decrease in V_{oc} could be due to the deterioration of diode quality, i.e., an increase in the saturation current and/or in the ideality factor.

Interestingly, there was no significant difference between the two years I-V curve measurements of a-Si array, as shown in Fig. 61. Furthermore, the maximum power degradation rates of poly-Si and CdTe were higher than the rates obtained by statistical methods based on monthly PR time series stated previously. From one hand, this difference implies the diverse performance metrics could result in diverse degradation rates. On the other hand, a short investigating period (such as one year) would result in higher uncertainties. These significantly higher uncertainties relating to short-term investigating period were also reported in the work by Belluardo et al. (2015). Similarly, Makrides et al. (2014) claimed that more time was required for the stabilized performance degradation rate of thin film technologies. Nevertheless the existing shortcomings, this approach on I-V characteristics is able to offer detail information about which parameters contribute to the PV system power losses most. Further works should be continued in this line, when more available data pairs are provided at similar time of the separated years.

Fig. 60. I-V curves (a) and six parameters (b) of poly-Si PV system on two cloudless sunny days (11 March 2016 and 15 March 2017), at around 12:30 with the same irradiance over 1000 W/m^2 .

Fig. 61. I-V curves (a) and six parameters (b) of a-Si PV system on two cloudless sunny days (11 March 2016, 15 March 2017), at around 12:40 with the same irradiance over 1000 W/m^2 .

Fig. 62. I-V curves (a) and six parameters (b) of CdTe PV system on two cloudless sunny days (11 March 2016, 15 March 2017), at around 12:50 with the same irradiance over 1000 W/m^2 .

4.2.3 Indoor STC Power Variation

Table 13 presents the measured P_{max} at STC through the indoor tests as well as the measured variation, showing that the poly-Si modules reveal a more uniform distribution with the P_{max} variation from -1.3% to -1.6% . The annual maximum power variation rate of the poly-Si module is around $-0.57\%/year$, accounting for a 2.5-year interval. Regarding the CdTe modules, the performance variation rate is approximately $-0.3\%/year$. Compared to the poly-Si and CdTe array power degradations abovementioned, their indoor module maximum power annual variations were much lower. One potential reason is the cable aging in the PV arrays, causing higher performance degradation than the individual module. Another reason, especially for CdTe module, is the water-cooling process reduced the module surface soiling and hence the maximum power degradation.

Table 13. Peak power comparison between indoor tests of poly-Si, a-Si and CdTe modules.

Technology Module	poly-Si			CdTe	
	p1	p2	p3	c1	c2
$P_{\max}$ in 2012 (W)	233.10	234.00	233.04	82.77	80.43
$P_{\max}$ in 2015 (W)	229.40	230.80	230.01	82.37	79.33
$\Delta P_{\max}$ (%)	-1.6	-1.4	-1.3	-0.5	-1.4

4.3 OPTIMUM INVERTER SIZING OF GRID-CONNECTED PHOTOVOLTAIC SYSTEMS, FROM ENERGETIC AND ECONOMIC CONSIDERATIONS

A well designed GCPV system can reduce the high capital cost with the optimum size of PV array and corresponding inverter. Therefore numerous studies have been carried out to establish the optimum relationship between the capacity of GCPV system and the nominal power (either AC or DC) of the connecting inverter, as the most common express:

$$R_s = \frac{P_{PV,N}}{P_{inv,N}},$$

Equation 36. Inverter sizing ratio

where $P_{PV,N}$ is the rated PV capacity and $P_{inv,N}$ represents the rated inverter input power. When $0 < R_s < 1$, the inverter is oversized. For $R_s > 1$ the inverter is being undersized and will encounter to the power limitation condition.

Although an undersized inverter clips power output under high in-plane irradiance, it is more and more acceptable in current GCPV systems. Three factors promote this phenomenon, i.e., decreasing PV module cost ratio accounting for the entire GCPV system, infrequency of high irradiance, technological innovation in inverter efficiency.

The optimum sizing ratio of the PV array capacity to the nominal inverter input capacity, was determined in two GCPV systems from two points of view: energetic and economic. The optimum ratio was determined by both empirical and analytical approaches, and based on two PV arrays connected to their inverters, plus three simulated inverters.

Firstly, the inverter annual efficiency curve as a function of sizing ratio was discussed through high-, middle- and low- efficiency inverters. Then, the two approaches for monthly AC energy and energetic optimum sizing ratios were compared through a 12-month analysis. Subsequently, the energetic and economic optimum sizing intervals were defined as the sizing regions causing less than 1% variations from their corresponding optimum points. The energy-related optimum sizing interval was affected by the inverter characteristics. It narrowed taking economic factors into account. Thereby, a compound optimum sizing interval is proposed to maximize the energy injected to the grid and minimize the economic costs simultaneously. Finally, the optimum sizing ratio was completed by considering PV module degradation rate for lifetime analysis.

4.3.1 Annual Efficiency of High-, Medium-, and Low-Efficiency Inverters

Inverter annual efficiency is plotted against R_s in Fig. 63 for the high-, medium-, and low-efficiency inverters. These curves were generated from one-year measurements $P_{max}(t)$ (referred to as *Method 1* in Section 3.4.3) for *System 1* (dashed line) and *System 2* (solid line). In a rather wide range of R_s from 0.8 to 1.1, the annual efficiencies are approximately constant. The major advantage of a high-efficiency inverter is that it features a wider optimum sizing range without affecting the annual efficiency significantly.

On the other hand, the annual efficiency discrepancy between *System 1* and *System 2* does not emerge until R_s is higher than 1 in high- and medium-efficiency inverters, whilst the discrepancy in the low-efficiency inverter decreases until R_s equals 1, and subsequently increases.

Although Fig. 63 was obtained by the empirical *Method 1*, it can be mathematically interpreted in the light of the inverter characteristics and the different power duration curves (PDCs) in Fig. 64 of the two systems. From the mathematical derivation included in the *Appendix H (Method 2)*, the inverter annual efficiency can be expressed as:

$$\eta = \frac{E_{AC}}{E_{DC}}$$

$$= 2 \cdot \left(\frac{P_{PV,P}}{R_s \cdot P_{max,L}} \cdot b_0 + \frac{P_{max,L} \cdot R_s}{3P_{PV,P}} \cdot b_2 \right) + b_1, \left(R_s \leq \frac{P_{PV,P}}{P_{max,L}} \right)$$

Equation 37. Mathematical representation for inverter efficiency: case 1

$$= 2 \cdot \frac{P_{PV,P}}{P_{max,L} \cdot R_s} \cdot (b_0 + b_1 + b_2) - \frac{P_{PV,P}^2}{P_{max,L}^2 \cdot R_s^2} \cdot \left(b_1 + \frac{4b_2}{3} \right), \left(R_s > \frac{P_{PV,P}}{P_{max,L}} \right)$$

Equation 38. Mathematical representation for inverter efficiency: case 2

When R_s varies from 0.4 to $(P_{PV,P}/P_{max,L})$ (this ratio is typically around 1), inverter annual efficiency is expressed by Equation 37. Its first addend, $2 \cdot \left(b_0 \cdot \frac{P_{PV,P}}{R_s \cdot P_{max,L}} + \frac{b_2 \cdot P_{max,L} \cdot R_s}{3P_{PV,P}} \right)$, is rather smaller than the other constant addend b_1 , especially for the high- and medium-efficiency inverters, resulting in a flat efficiency curve in this R_s range. When sizing ratio changes from 0.8 to 1.1, for medium-efficiency inverters, the first addend is around -9% and b_1 is 97.5%. For high-efficiency inverters, the first addend is around -1% and b_1 is 99%. However,

for low-efficiency inverters, b_1 is only 91.5% and the first addend is about -20%. Thus, there is a slight difference between two systems because of the characteristics of PDCs in Fig. 64, i.e., $P_{PV,N}/P_{max,L}$.

When the R_s is higher than $(P_{PV,P}/P_{max,L})$, the annual efficiency is expressed by Equation 38. The increasing R_s in a steep drop in the annual efficiency curve; meanwhile, the characteristics of PDCs (Fig. 64), i.e., $P_{PV,P}/P_{max,L}$, leads to a higher discrepancy between the *System 1* and *System 2*.

Fig. 63. Annual inverter efficiency as a function of sizing ratio for high-, medium- and low-efficiency inverters. Dashed line: *System 1*; Solid line: *System 2*.

Fig. 64 Power duration curves and linear fittings of (a) *System 1* and (b) *System 2* from July 2015 to June.

4.3.2 Monthly AC Energy and Energetic Optimum Sizing Ratios

The monthly PDCs (solid blue lines) of *System 2* for one year are depicted in Fig. 65, together with the corresponding linear fittings (dashed orange lines). The linearities of the

monthly PDCs ranged from the worst case (Jan. 2016, with the lowest R^2 and highest $RMSE$) to a relatively better case (Mar. 2016, with the maximum R^2 and lowest $RMSE$), which are detailed in the last two columns of Table 14.

Fig. 65. Monthly DC power duration curves (solid blue lines) and linear fittings (dashed orange lines) during the period from Jul. 2015 to Jun. 2016, for System 2.

The two abovementioned methods are assessed by the comparisons between the monthly energy produced by System 2 (Table 14). E_{AC0} , E_{AC1} , and E_{AC2} are the AC energy generated by System 2, simulated by Method 1, and simulated by Method 2, respectively. ΔE_1 is the relative error between E_{AC0} and E_{AC1} $((E_{AC0} - E_{AC1})/E_{AC0})$, and ΔE_2 is the relative error between E_{AC0} and E_{AC2} $((E_{AC0} - E_{AC2})/E_{AC0})$. The rather low ΔE_1 (annual value of 0.6%) confirms the validation of Method 1, or the inverter power output model (Equation 27). However, E_{AC2} is slightly overestimated, as seen from Table 14. These errors in Method 2 occurred mostly in winter months, featuring worse linearities of PDCs and lower irradiance (e.g., from Dec. 2015 to Feb. 2016). This result suggests that the application of Method 2 to calculate E_{AC} in low-irradiance regions, like northern Europe, might be less efficient.

The next two columns of Table 14 are the monthly energetic optimum sizing ratio ($R_{S,E}^{opt}$) values obtained by Method 1 ($R_{S,E1}^{opt}$) and Method 2 ($R_{S,E2}^{opt}$), respectively. Both $R_{S,E}^{opt}$

values are characterized with a similar seasonal trend: higher values in cold and low-irradiance seasons; lower values in hot and high-irradiance seasons. This seasonal trend indicates that the GCPV systems at low-irradiance sites need a more undersized inverter than those exposed to high irradiance, to achieve better performance.

Table 14. The monthly generated and simulated system energy output (E_{AC}), together with energetic optimum sizing ratio ($R_{S,E}^{opt}$) by Method 1 and Method 2. R^2 and RMSE are the fitness parameters of the monthly power duration curves' linear fittings.

Month	E_{AC0} (kWh)	E_{AC1} (kWh)	E_{AC2} (kWh)	ΔE_1 (%)	ΔE_2 (%)	$R_{S,E1}^{opt}$	$R_{S,E2}^{opt}$	R^2	RMSE (x100%)
Jul.2015	2844	2831	2867	0.46	-0.81	0.97	0.93	0.98	0.12
Aug.2015	2990	2975	3004	0.50	-0.47	0.93	0.90	0.98	0.10
Sep.2015	2467	2456	2482	0.45	-0.61	0.94	0.91	0.99	0.09
Oct.2015	1624	1611	1641	0.80	-1.05	1.09	1.03	0.98	0.12
Nov.2015	1842	1829	1876	0.71	-1.85	1.03	0.98	0.96	0.15
Dec.2015	1401	1394	1449	0.50	-3.43	1.27	1.19	0.95	0.19
Jan.2016	834	829	881	0.60	-5.64	1.19	1.21	0.90	0.31
Feb.2016	1794	1784	1854	0.56	-3.34	1.04	0.99	0.95	0.19
Mar.2016	2380	2357	2398	0.97	-0.76	0.94	0.90	0.99	0.08
Apr.2016	2364	2348	2448	0.68	-3.55	1.02	0.96	0.95	0.18
May 2016	2555	2540	2624	0.59	-2.70	1.08	1.02	0.96	0.16
Jun.2016	3030	3014	3065	0.53	-1.16	0.97	0.93	0.98	0.11
Annual	26125	26099	26703	0.60	-2.21	1.01	0.96	0.98	0.12

4.3.3 Compound Optimum Sizing Intervals

E_{AC} , annual energy output per annualized investment cost (C_C) and annual energy output per system investment cost (C_A) as functions of R_S and the inverter types are shown in Fig. 66, where the results are generated by *Method 1* (orange dashed line) and *Method 2* (blue solid line). Fig. 66a represents the *System 1* and Fig. 66b denotes the *System 2*. The economic inputs for calculating C_C and C_A are described in Table 15, where the two financial terms R_{PV} and P_{inv} are the of the ETSIAAB PV plant. Table 16 summarizes the three sizing ratios obtained by *Method 1*.

Table 15. Economic factors of two GCPV systems.

	System 1	System 2
Module cost (R_{pv}) ¹ (€/Wp)	3	3
Inverter cost (R_{inv}) (€/Wp)	1	0.5
Real interest rate (i) (%)	5	5
Lifetime of PV module (L_{pv}) (years)	20	20
Lifetime of inverter (L_{inv}) (years)	10	10

¹ GCPV system overall cost, excluding inverter.

All the curves in Fig. 66 have similar shapes in both systems, although the results of *Method 2* are slightly overestimated with *RMSE* values smaller than 4%.

The low sensitivities (i.e., the flatness of the curves as a function of R_s) of E_{AC} around $R_{s,E}^{opt}$ are noticeable from Fig. 66 and Table 16. The values within brackets are the sizing ratio ranges corresponding to the 1% variation of E_{AC} from the maximum point calculated by *Method 1*. The low sensitivities were also reported in the works of Camps et al. (2015) as well as Peippo and Lund (1994): both groups of researchers suggested defining an optimum sizing interval for $R_{s,E}^{opt}$ instead of focusing on the precise value.

Regarding the terms C_c and C_a , the convexities of their curves around the respective optimum sizing ratios ($R_{s,C}^{opt}$ and $R_{s,A}^{opt}$) increase compared to E_{AC} , owing to the additional constraints and relevance to obtain the two terms. Their 1% variation ranges are narrower than the range of E_{AC} , as shown in Table 16. Subsequently, a combination from the energetic and economic considerations is proposed to define the optimum interval of R_s . That optimum interval is the overlap region of the three optimum sizing ranges at the last columns— $R_{s,I}^{opt}$ —of Table 16.

This compound optimum sizing ratio interval ($R_{s,I}^{opt}$) has benefits in terms of both energy and economic yield. It is able to mitigate the dispute between policy makers and investors. Concretely, a policy maker would desire as much energy being injected to grid as possible from the GCPV system, therefore he/she would prefer a higher-capacity inverter (compared to the inverter with the highest economic benefit). On the contrary, the first priority of an investor would presumably be cost reduction with its subsequent financial benefit; thus, he/she would adopt a lower-capacity inverter (compared to the energetic-benefit inverter).

The different PDCs affect the compound optimum interval more than the type of inverter. It is seen in Table 16, where *System 2* features a wider $R_{s,I}^{opt}$ (1.12–1.25) and *System 1* a narrower one (1.17–1.19).

Accounting for the comparison between *System 1* and *System 2* in Table 16, from the energetic aspect, $R_{S,E}^{opt}$ values of *System 2* are higher than those of *System 1* due to the lower specific DC power output, as shown in Fig. 64. Therefore *System 2* needs a more undersized inverter to achieve a better energetic performance. However, from the economic considerations, the higher R_{inv} of *System 1* requires an inverter with higher R_S (or more undersized) to improve C_C , resulting in higher $R_{S,C}^{opt}$ values than those of *System 2*. Analogously, the higher R_{inv} value leading to a higher replacement cost of the inverter of *System 1* intensifies the necessity of a further undersized inverter to maximize C_A .

Table 16. Optimum sizing ratios (energetic optimum sizing ratio ($R_{S,E}^{opt}$), economic optimum sizing ratio ($R_{S,C}^{opt}$) based on system investment cost, economic optimum sizing ratio ($R_{S,A}^{opt}$) based on annualized system investment cost) and the optimum intervals ($R_{S,I}^{opt}$) generated by Method 1. The values within brackets are the sizing ratio range corresponding to the 1% variation from the maximum.

	$R_{S,E}^{opt}$	$R_{S,C}^{opt}$	$R_{S,A}^{opt}$	$R_{S,I}^{opt}$
Syst. 1 Inverter 1	0.97 (0.40–1.20)	1.24 (1.12–1.36)	1.29 (1.18–1.44)	1.18–1.20
Syst. 1 Inverter 2	0.95 (0.62–1.18)	1.23 (1.10–1.36)	1.29 (1.17–1.44)	1.17–1.18
Syst. 1 Inverter 3	1.01 (0.79–1.19)	1.23 (1.11–1.36)	1.29 (1.17–1.44)	1.17–1.19
Syst. 1 SMA SB 1200	0.95 (0.56–1.19)	1.23 (1.12–1.36)	1.29 (1.17–1.44)	1.17–1.19
Syst. 2 Inverter 1	1.09 (0.41–1.25)	1.22 (1.08–1.34)	1.25 (1.13–1.38)	1.13–1.25
Syst. 2 Inverter 2	0.99 (0.64–1.23)	1.21 (1.07–1.33)	1.25 (1.12–1.37)	1.12–1.23
Syst. 2 Inverter 3	1.08 (0.82–1.24)	1.21 (1.07–1.33)	1.25 (1.12–1.37)	1.12–1.24
Syst. 2 SMA 15000TL	1.01 (0.40–1.25)	1.22 (1.08–1.34)	1.25 (1.13–1.38)	1.13–1.25

Fig. 66. Annual energy output (E_{AC}), the annual energy output per system investment cost (C_C), and the energy output per annualized investment cost (C_A) as a function of sizing ratio for different inverters in (a) System 1 and (b) System 2; the dashed orange line is generated by Method 1, whereas the solid blue line corresponds to Method.

4.3.4 Optimum Sizing Ratio as a Function of Degradation Rate

For investment decisions, the degradation rate (R_d) of the PV module is of great importance, as it affects the lifetime energy generation of the GCPV system (Belluardo et al., 2015; Makrides et al., 2014). The effects of R_d on the economic parameters C_C and C_A can be obtained by simply analyzing the effect on E_{AC} , as the denominators in Equation 29 and Equation 30 will not be altered with the addition of R_d .

With the consideration of R_d , Table 17 summarizes the three optimum sizing ratios, which is based on the following hypothesis:

- R_d is a constant of 1%/year and the investigating period is 20 years;
- Inverter conversion efficiency remains constant during its lifetime;
- The DC energy profile from July 2015 to June 2016 is taken as the first operating year.

The three parameters $R_{S,E}^{opt}$, $R_{S,C}^{opt}$ and $R_{S,A}^{opt}$, as well as their intervals, have a relative increase of 10%, compared with Table 16. As the DC annual energy decreases yearly by 1% in the investigating 20 years, the inverter should be smaller to maximize the lifetime AC output.

Table 17. Three optimum sizing ratios (energetic optimum sizing ratio ($R_{S,E}^{opt, Rd}$), economic optimum sizing ratio ($R_{S,C}^{opt, Rd}$) based on system investment cost, economic optimum sizing ratio ($R_{S,A}^{opt, Rd}$) based on annualized system investment cost) and the optimum intervals ($R_{S,I}^{opt, Rd}$) generated by Method 1 with degradation rate. The values inside brackets are the sizing ratio range corresponding to the 1% variation from the maximum point.

	$R_{S,E}^{opt, Rd}$	$R_{S,C}^{opt, Rd}$	$R_{S,A}^{opt, Rd}$	$R_{S,I}^{opt, Rd}$
Syst. 1 Inverter 1	1.05 (0.42–1.30)	1.36 (1.21–1.51)	1.42 (1.28–1.59)	1.28–1.30
Syst. 1 Inverter 2	1.04 (0.68–1.29)	1.35 (1.21–1.50)	1.42 (1.28–1.58)	1.28–1.29
Syst. 1 Inverter 3	1.11 (0.87–1.30)	1.35 (1.21–1.50)	1.42 (1.28–1.58)	1.28–1.30
Syst. 1 SMA 1200	1.03 (0.62–1.29)	1.35 (1.21–1.50)	1.42 (1.28–1.58)	1.28–1.29
Syst. 2 Inverter 1	1.13 (0.45–1.36)	1.32 (1.16–1.47)	1.37 (1.22–1.52)	1.22–1.36
Syst. 2 Inverter 2	1.09 (0.71–1.34)	1.31 (1.15–1.46)	1.36 (1.21–1.51)	1.21–1.34
Syst. 2 Inverter 3	1.16 (0.90–1.35)	1.32 (1.16–1.47)	1.36 (1.22–1.51)	1.22–1.35
Syst. 2 SMA 15000TL	1.11 (0.40–1.35)	1.32 (1.16–1.47)	1.37 (1.22–1.52)	1.22–1.36

4.4 POTENTIAL ASSESSMENT OF AGRIVOLTAIC FARM

One objective of the ETSIAAB GCPV plant is to investigate the potential agricultural activities incorporating solar PV energy. In this line, a concept of agrivoltaic (AV) farm for dual use of the land was investigated both from energetic and agricultural points of view by a set of simulations. Environmental and socioeconomic implications of this AV farm implementation were assessed in Spain. Some suggestions for a better penetration of AV farms into the agronomical were proposed.

The proposed AV prototypes are:

S15H4T3 aerial prototype has the same row space as the regular GCPV system has; it represents the AV farm with the highest electricity production.

S3H4T3 aerial prototype with a moderate row space is suitable for the crop which does not need large farming equipment.

S3H1T3 ground prototype is not recommended but an alternative in some extreme cases.

S6H4T3 aerial prototype with a broad row space is suitable for the crop which needs large farming equipment.

4.4.1 Spatio-Temporal Shading Patterns

The irradiation intercepted by crop area is modelled by *System Advisor Model* (SAM) (Version 2017.1.17). The height above ground level (H) and the row space (S) both affected the total quantity of irradiation intercepted at soil level (see Fig. 67). Hereinafter, crop level refers to soil level without the consideration of crop height. The average standard deviation of available irradiation for crop area of the four row spacing structures is 12.0%, higher than the average standard deviation of the six height structures of the value 5.1%. It indicates that for an AV farm design the row space is more important than the height above ground level. However the height effect is in contradiction with the statement of Dupraz et al. (2011), who might not consider the horizontal projection of the higher PV array would be out of the finite crop area more easily than the lower array. Meanwhile, the least PV-density AV prototype S6H4T3 remained about 90% irradiation for the crop level.

The irradiation intercepted by crop area varied according to the time and the AV farm structures (see Fig. 68). This temporal shading pattern reflects the relation between the sun

position and irradiation availability at crop level. The prototypes with the same height above ground level ($H=4\text{m}$) exhibit similar temporal shading pattern trend, where the higher sun's altitude (at the middle of the year and at the middle of the day) results in less available irradiation at crop level. The wider distance between the PV rows improved this irradiation availability compared to a narrower row space (Fig. 68 a, b, c). Near to the dawn and dusk of a certain day, the global diffuse irradiance (GDI) rather than direct normal irradiance (DNI) is the main component of global horizontal irradiance (GHI). The homogeneity of GDI and the outside shades due to the low sun's altitude increase the irradiation proportion intercepted by the ground. Then, at noon time, less outside shades and decreasing GDI proportion aggravate the irradiation availability at crop level. The systems with the same row space but different heights have a similar temporal shading pattern for a certain day (horizontally inspecting Fig. 68 b and d). However, the converse temporal shading patterns by vertically inspecting Fig. 68 b and d have been found for a certain time of the day (i.e. 13 pm) along the 12 months.

Fig. 67. Relative annual irradiation intercepted by crop area as a function of PV systems row space and height, simulated by SAM software.

Fig. 68. Heat maps of percent irradiation intercepted by crop area in four AV farms.

4.4.2 The Simulated Agricultural Performance of Agrivoltaic Farms by STICS

The crop production was evaluated by STICS model. The relative values with respect to the sole crop farm (without PV arrays) are presented in Table 18 for the four abovementioned prototypes. The simulated durum wheat production indexes (e.g., aerial biomass at harvest, dry matter and numbers of grains) reduced under all shade conditions. However, the relative crop reductions were lower than the relative irradiation reductions, indicating an increase in the irradiation use efficiency of the shaded durum wheat. This result is coherent with some works of agroforestry, i.e., Mu et al. (2010) and Dufour et al. (2013). They compared grain yield losses and Leaf Area Index (LAI) reduction of winter wheat with the shade-induced reduction of solar irradiation. Then they concluded the partial compensation by the increases in the leaf fraction (the top and bottom leaf area divided by the total leaf area) improved the interception of solar irradiation by the crop canopy.

Table 18. Simulated crop production by STICS under four conditions: sole crop farm (full-sun); ground-mounted agrivoltaic farm (S3H1T3); three aerial-mounted agrivoltaic farms (S15H4T3, S3H4T3 and S6H4T3).

	Annual irradiation at crop level (%)	Aerial biomass at harvest (%)	Dry matter (%)	Number of grains (%)
Sole crop farm	100	100	100	100
S15H4T3	64.1	65.6	74.8	77.8
S3H1T3	71.2	76.8	81.8	82.7
S3H4T3	80.2	86.9	88.7	88.7
S6H4T3	89.2	94.3	93.9	93.9

4.4.3 The Simulated Energetic Performance of Agrivoltaic Farms

The energetic performance of three AV farm prototypes was simulated by SAM with tilt angle of 30° (see Table 19). The annual grid-injected electricity (E_{AC}) is not always proportional to the total module area (or the number of modules). The decreasing PV-conversion efficiency parallels to the increasing PV-module density due to higher self-shading. The SAM-calculated annual self-shading losses of the S15H4T3 and S3H4T3 systems are 4.4% and 0.7%, respectively. A wider row space and landscape orientation mitigate the self-shading losses (Barreiro et al., 2011). The S3H4T3 and S6HET3 systems aim at allowing more available irradiation for the PV-beneath crop. They therefore produced less annual electricity as well as fewer self-shading losses compared to the regular PV array (i.e., S15H4T3).

Table 19. Annual produced PV electricity and efficiencies of three agrivoltaic farm prototypes, with the total land area of 240 m² for each prototype.

Prototype	E_{DC} (kWh)	E_{AC} (kWh)	PV array efficiency (%)	PV system efficiency (%)	AC PR (%)
S15H4T3	31718	30215	10.80	10.29	74.03
S3H4T3	17731	16879	12.07	11.49	82.66
S6H4T3	8910	8479	12.13	11.55	83.09

4.4.4 The Combined Performance of Agrivoltaic Farms

4.4.4.1 Land equivalent ratio assessment

Land Equivalent Ratio (LER) is a term original from agriculture. It is used to evaluate land utilization efficiency in mixed cropping systems with respect to sole crops (Bilalis et al., 2005; Mead and Willey, 1980; Riley, 1984). Then LER was extended to agroforestry area for investigating productivity of the land mixed with forest-type-trees and crops (Dupraz, 1998) as well as to the emerging AV farm (Dupraz et al., 2011) with the expression:

$$LER = \frac{Y_{crop,AV}}{Y_{solecrop}} + \frac{Y_{electricity,AV}}{Y_{electricity,PV}},$$

Equation 39. Land Equivalent Ratio

where $Y_{crop,AV}$ and $Y_{solecrop}$ refer to the crop yield of AV farm and sole crop farm; $Y_{electricity,AV}$ and $Y_{electricity,PV}$ are the produced electricity of AV farm and regular PV plant, respectively.

Taking into account that the S15H4T3 prototype has the same row space as a regular GCPV plant has, it therefore possesses the maximum PV capacity of an AV farm with 240 m² area. Then it was assumed that the 4 meters height above ground level does not affect the energy production compared with the ground mounted PV system. Thereby both systems' (S15H4T3 and S15H1T3) relative electricity productions equaled 1, as the baseline of produced electricity. Similarly, the sole crop farm (see Table 18) was chosen as the baseline with the relative crop production equaling 1.

Subsequently, the LERs of four AV farm prototypes are summarized in Table 20, based on the results of Table 18 and Table 19. The high LER values of AV farm prototypes ranged from 1.22 to 1.75 (or conservative case 1.66), compared to mixed cropping system of LERs ranging from 1.0 to 1.3 and agroforestry intercropping system of LERs from 1.1 to 1.5 (Dupraz et al., 2011). It implies AV farm has great advantage in saving land resource; even the least PV density system such as S6H4T3 prototype improved 22% land utilization efficiency. This improving efficiency is propelled by the more efficient irradiance utilization by AV farms, where the PV array unblocked irradiation is utilized by the crop and the irradiation in fallow period can be used for electricity production.

Table 20. Land Equivalent Ratios (LERs) of four agrivoltaic farm prototypes according to the simulation results.

	Electricity yield	Crop Aerial biomass	Crop dry matter	LER based on aerial biomass	LER based on dry matter
Sole crop farm	0	1	1	1	1
Sole PV plant	1	0	0	1	1
S15H4T3	1	0.66	0.75	1.66	1.75
S3H1T3	0.56	0.77	0.82	1.33	1.38
S3H4T3	0.56	0.80	0.87	1.36	1.43
S6H4T3	0.28	0.94	0.94	1.22	1.22

4.4.4.2 Economic assessment

The historical prices of durum wheat in Spain during the past five years (2012-2016) was 261.0 ± 28.5 €/t, where over the same period the electricity prices for domestic and industrial consumers were 226.5 ± 7.2 €/MWh and 141.1 ± 7.6 €/MWh, respectively. These statistical data were calculated according to Eurostat. The revenues in €/ha of four different AV farms with selling durum wheat and electricity are shown in Table 21 including sole crop farm and PV plant.

For a conventional wheat farm, the annual revenue for selling the grains is only 2,005 €/ha, while the annual revenue of a regular PV plant selling electricity to household is 285,154 €/ha. Even for the least PV density AV farm (S6H4T3), the revenue from selling electricity is more than 20 times with respect to that from selling durum wheat. Nevertheless, the principle objective of an AV farm should be born in mind is to grow crops and then to produce electricity. It requires the proper balance that the PV system and agriculture activities avoid inter-affecting each other dramatically. The negative influence on durum wheat quality such as grain size due to heavy shade has been justified in some agroforestry works (Artru et al., 2017; Dufour et al., 2013). Therefore, the recommended AV farm configuration for durum wheat is S6H4T3 with more available irradiation for crop growth and hence the fewer crop losses. In addition, the low economic revenue of durum wheat compared to other high revenue crop, such as tomato (in open air condition, the selling price of 543.2 €/t and yield of 82.8 t/ha in 2016 (MAPAMA, 2016) resulted in a revenue around 45,000€/ha), gives prominence to the economic advantage of PV productivity in the simulated AV farms.

Table 21. Annual revenues in €/ha for monoculture and four agrivoltaic farm prototypes.

	electricity value (domestic) (€/ha)	electricity value (industry) (€/ha)	Crop value (€/ha)
Sole crop farm	0	0	2,005
Sole PV plant	285,154	177,639	0
S15H4T3	285,154	177,639	1,550
S3H1T3	159,295	99,234	1,658
S3H4T3	159,295	99,234	1,809
S6H4T3	80,020	49,849	1,932

The high start-up cost of a PV installation is the major stumbling block and leads to the hesitating farmers to invest in this innovative intercropping system. In fact, this economic barrier is gradually eliminated due to the massive breakthrough in PV technology and the balance of system (BOS). Nowadays, a 75% drop in PV module costs and the lower installation costs approximately halved the cost of large-scale PV plant with respect to the year 2009

(Rojas and Tubío, 2015). The investment in adding PV systems upon crop area might be more attractive for farmers if the PV annual net profit (revenue minus cost) surpasses capital gap between sole crop and AV farms in selling crops.

The levelized cost of electricity (LCOE) is an economic assessment of the overall cost of the generated electricity over lifetime considering subsidies (i.e., feed-in tariff, net-metering) and incentives (i.e., free or low interest loan). It is often utilized as the break-even price for emerging technologies such as PV (Branker et al., 2011; Huld et al., 2014). A general mathematical expression of LCOE is:

$$LCOE = \frac{\sum_{t=0}^{L_{pv}} (I_c + O_t + M_t + F_t) / (1+r)^t}{\sum_{t=0}^T E_{AC} \cdot (1-R_d)^t / (1+r)^t},$$

Equation 40. levelized cost of electricity generated by PV system

where t is the t^{th} year since system starts, L_{pv} is the PV module lifetime, I_c is the investment expenditures, O_t and M_t are operating and maintaining costs, F_t is the fuel cost, E_{AC} is the estimated energy output of first year, r is the discount rate and R_d is the performance degradation rate.

One remarkable financial difference between AV farm and regular ground-mounted GCPV plant is the additional costs of mounting structures of AV farm. For a regular GCPV plant, the mounting structure costs are generally accounted for 10% of the total costs (Fu et al., 2017). Then, the costs of the 4 meters high aerial mounting structure of AV farm were assumed to be 4 times as the costs of the regular ground mounting structure. Accordingly, the initial investment encounters 40% improvements. A conservative assumption of these inputs is presented in Table 22, without the considerations of any incentives and loans.

Table 22. Inputs for levelized cost of electricity (LCOE) calculation.

Input	Value	Source
Initial investment (I_c) (€/kWp) (including 21% VAT)	1,634·140%=2288	(Jäger-waldau, 2016)
Operating and maintaining costs (% of I_c)	2	(Jäger-waldau, 2016)
Fuel cost (€/kWp/year)	0	(Huld et al., 2014)
Discount rate (%)	5	(Huld et al., 2014)
Annual energy output (kWh/year)	8,500 (S6H4T3)	SAM simulation
Performance degradation rate (%/year)	1.4	Self-calculation (see Section 4.2)
PV system lifetime (years)	20	(Huld et al., 2014)

The calculated LCOE by Equation 40 of the S6H4T3 prototypes had the value of 0.1695 €/kWh, without consideration of profile costs (including flexibility and utilization costs), balancing and grid costs. Those costs were integrated as integration costs which is difficult to be measured or estimated directly (Ueckerdt et al., 2013). The integration costs might raise the LCOE by 25% after system optimization (Jäger-waldau, 2016). Therefore, the final LCOE of the two prototypes is 0.2119 €/kWh, which is higher than the industrial electricity price (0.1416 €/kWh) but lower than the domestic electricity price (0.2265 €/kWh).

For a further determination about the economic viability of implementing AV farms in Spain, the annual energy savings (S_e) is calculated as follows:

$$S_e = E_{AC} \cdot (P_e - LCOE)$$

Equation 41. Energy saving

where P_e is the domestic electricity price (0.2265 €/kWh).

Marrou, Hélène et al. (2013a) suggested that there is little adaptation in agriculture practices required to converter a conventional cropping farm to an AV farm. Therefore, the capital cost of the cropping activities remains constant during this conversion. Then, the net profit (NP) of a conventional farm converting to an AV farm is obtained by:

$$NP = S_e - R_c,$$

Equation 42. Net profite

where R_c is the crop income reduction due to the added PV modules.

The economic estimations of S6H4T3 AV farms are shown in Table 23. As previously mentioned that the durum wheat is a low economic benefit crop and only 6% yield reduction is induced by the PV array, the Np (5,106 €/ha) per year approximately equals the S_e value (5,175

€/ha per year). Although the additional investment (adding a PV system) of an AV farm is huge and some sacrifice of crop production endures, the *NP* and the payback period of 6.4 years are still attractive for farmers. Foreseeably, PV-generating electricity for sale would diversify and stabilize farmer income and thereby improve the rural economy.

Table 23. Investments and net profits of S6H4T3 agrivoltaic farm.

Prototype	Capacity (kWp/ha)	Investment (€/ha)	Electricity savings (€/ha/year)	Crop income reduction (€/ha/year)	Net profit (€/ha/year)	Payback period ⁴ (year)
S6H4T3	230	526,240	5,175	69	5,106	6.58

4.4.5 Agrivoltaic Farms Environmental and Socioeconomic Implications in Spain

Notwithstanding the conservative calculation, it should note that the previous economic assessment about the AV farms based on durum wheat crop area in Spain is optimistic. In Spain, due to the current Royal Decree-Law 900/2015, self-consumption electric systems and the yield of renewable energy were regulated and charged with the colloquialism ‘The Sun Tax’ or ‘tolls’ for maintaining grid-connection. Fortunately, these tolls are estimated be gradually reduced in small-scale self-consumption systems until 2021 (Carreño-Ortega et al., 2017). The detail of this regulation is presented in *Appendix K*.

On the other hand, official commitment of Spanish government is far to fulfill. During 23–24 October 2014, European Council established 2030 Climate and Energy policy Framework named ‘*Policy Framework for Climate and Energy in the period from 2020 to 2030*’ (European Commission, 2014). By 2030, the entire EU should reach the goals including:

- At least 40% domestic reduction in greenhouse gases (GHGs) emissions compared to 1990.
- The share of renewable energy should be at least 27%.

By analyzing the relevant data of Eurostat, the share of renewable in gross final energy consumption of Spain was 16.2% in 2015, which was 2.8% (absolute value) higher than the share in 2009. The total domestic energy consumption was 935.8 TWh in 2015. In addition, the GHGs emissions were 335.7 MtCO₂eq in 2015, which is 16.6% higher than the value in 1990 of 287.8 MtCO₂eq. Meanwhile, by 2014, the GHGs emissions had reduced to 77.06% in EU 28

⁴ The calculation of payback period for an energy system is conducted through dividing the total investment cost by the first year’s revenues from energy saved, displaced, or produced (Eiffert, 2003).

compared to the value in 1990. The mandatory cap will be 172.7 MtCO₂eq by 2030 (60% of 287.8 MtCO₂eq) in Spain. Thus in 2015, the gap was 163.0 MtCO₂eq compared to the goal. Regarding these two facts, the possibility to fulfil the EU target seems pessimistic in Spain.

The implementation of AV farm mitigates this harsh condition. Thereby, this thesis proposed a hypothetical scenario: nationwide durum wheat area in Spain would transform to S6H4T3 AV farms. The total durum wheat cultivation area was almost 300,000 ha in Spain in 2014 (MAPAMA, 2016). If all area was converted to AV farms as S6H4T3 prototype, the total adding PV capacity could meet 69 GW with annual grid-injected electricity of 106 TWh/year.

The contribution of this transformation towards the renewable energy production and GHGs reduction is summarized in Table 24, where the coal and PV GHGs emissions factors were based on the study of Carreño-Ortega et al. (2017). Some additional renewable electricity of 106 TWh accounts for 11.3% of the total energy consumption in Spain in 2015. The new share of renewable thus increased to 27.5% (11.3% + 16.2%), which fulfils the 27% renewables share objective. The reduction of GHGs would reach 115.8 MtCO₂eq if this transformation is completed, considering PV plants substituting thermal power plants. This reduction approaches the 163.0 MtCO₂eq gap in 2015 to the official objective, whereas the rest reduction could be realized by wind and hydro. Consequently, the adoption of this AV farm on the conventional durum wheat farms would substantially improve the possibility to fulfil the commitments to the 2030 strategy.

Table 24. Estimating energy production and greenhouse gases reductions for Spanish durum wheat farms transforming to S6H4T3 agrivoltaic farms.

PV module area	1.65 m ²
PV module rating power	0.23 kWp
Density of PV modules	1000 units/ha
Total capacity	230 kWp/ha
Annual electricity production	354,167 kWh/ha
Annual electricity production (300,000 ha)	106 TWh
Coal greenhouse gases emissions factor	1.09 tCO ₂ eq/MWh
PV greenhouse gases emissions factor	0 tCO ₂ eq/MWh
Reduction of greenhouse gases emissions (300,000 ha)	115.8 MtCO ₂ -eq

4.4.6 Alternatives for Agrivoltaic Farm Improvements

4.4.6.1 Shade-tolerant crops

Similar to the conclusions stated by Barro et al. (2012) and Ehret et al. (2015) that the selection of shade-tolerant species is the key part to the success of agroforestry systems, the growth of AV farms could be also improved by cultivating the shade tolerant crops to minimize crop yield losses. The shade tolerant greens include: arugula, sorrel, Asian greens, chive, oregano, parsley, beans and peas, garlic, broccoli, cauliflower, mint, thyme, lettuce, spinach and cabbage (Frahan Ahsan, 2014). Some shade tolerant crops yields such as cacao, coffee and banana were even increased under shade (Heywood, 1971; Rodrigo et al., 2001). Other shade tolerant crops such as alfalfa and hog peanut (Lin et al., 1998), yam, taro, cassava and sweet potato (Johnston and Onwueme, 1998) are also targets for AV farm. Accordingly, the configuration of PV system (i.e., height) should be adjusted in consistent with the morphologies of the underneath crops. Furthermore, the different behaviors and irradiation requirements of these shade tolerant crops are worthy to investigate during their different phenological stages.

4.4.6.2 Adjustable tilt angle

The intercepted irradiation at crop level varies with the PV module tilt angle, which is also the key factor for capturing maximum solar irradiation falling on the PV modules. However, in an AV farm, the optimal tilt angle for PV modules is sacrificed to remain the prerequisite irradiation for the crop development. The crops during different phenological stages require different levels of the intercepted irradiation for photosynthesis.

The relative light transmission or intercepted irradiation at ground level under PV arrays versus tilt angles is shown in Fig. 69, based on an AV farm of S3H4 at Madrid. The steeper tilt angle allows more light transmission in summer, where the maximum

improvement against flatter PV arrays could reach 5%. However, the more frequent overcast conditions in winter containing massive DHI which is more homogenous. It attenuates the periodic advantage of flatter PV arrays in winter. For example, the portion of DHI to the GHI in December is 57.6% while the annual average value is 40.2%.

Regarding the periodic irradiation requirements of the crop, man power or automatic mechanism adjusting the PV module tilt angle could guarantee the crop growth. For example, for the spring or winter crop such as lettuce and wheat, the PV array should be flatter during these two seasons to maintain the irradiation at crop level above the required threshold. Then, the tilt angle should be raised to the optimum position for PV electricity generation during the fallow period, or when crops need less irradiation, to maximize the PV system output.

Fig. 69. Relative light transmission during one year at different PV module tilt angle of S3H4 AV farm prototype.

4.5 DISCUSSION

4.5.1 Seasonal Performance Comparison

The instantaneous or short-time conversion efficiency is usually used in lab-level under controlled temperature and irradiance to report the state-of-the-art results on a standardized basis (Green et al., 2017). For the outdoor investigation, the conversion efficiency is more common calculated in an extended time span such as daily, monthly, seasonally even yearly. Nevertheless, in this thesis the utilization of 15-min conversion efficiency relating with in-plane irradiance clarify the clipping effect of undersized inverters. Actually, the less time span of the conversion efficiency, the more clear clarification of the clipping effect of undersized inverters.

The methodology for assessing energy losses due to inverter saturation may induce the thermal losses into the results as the constant conversion efficiency during the inverter saturation was assumed. The practical efficiency would be lower than this constant value and results in an overestimation of energy losses due to undersized inverter especially in the more temperature-dependent system, i.e., poly-Si.

The three GCPV systems possessed diverse operating temperatures even at the same operating conditions. This difference is mainly related to the PV module heat transfer processes such as absorption, convection and radiation. These processes are dependent on conversion efficiency, cover and encapsulant materials. Additionally, a potential trigger could be the location of the measured module at corresponding PV array.

Portraying the performance map of GCPV systems globally to identify and quantify regional performance factors, according to the industry-recognized standards, promotes the growth of the PV industry. Compared to Cyprus, Germany, Italy, and U.S. among others, the reported PV performance remains scarce in Madrid, which is a natural fertile soil with abundant irradiance for PV electricity generation. Improved PV material diversity, accompanied with fundamental investigations into the different behaviors of different GCPV systems due to the changeful operating environment, is another determining factor for PV penetration. For commercial GCPV plant, the insufficient apparatus such as spectrometer, complete set of pyranometer as well as thermometers impede the performance monitoring and diagnosis of PV systems. For such GCPV systems, the operating temperature is usually modelled with the inputs of corresponding irradiance, ambient temperature and wind speed (Koehl et al., 2011; Skoplaki et al., 2008). The high model uncertainty and complex simulating process make it less favorable. In addition, the relation between PV performance and

operating temperature requires some complicated temperature-control treatments. Furthermore, the concurrent irradiance and spectral effects, as well as the metastability of a-Si modules hinder the process of separation and individualization.

For such purpose, this thesis proposed meticulous filter criteria through fixed irradiance range, air mass range, and clarification of the weather condition, to reconstruct the data. The utilization of spectral index, such as air mass, is a straightforward supplement for the absence of solar spectral data. This index is useful to build the relation between sun spectra with PV system performance at the expense of less available data. In addition, the metastability of a-Si, i.e., LSE and its reverse process thermal annealing recovery, mixed with the spectral effect, leads to a more complex performance variation. The investigation into this metastability of a-Si requires more meticulous evaluating methods and longer period, and it is usually on module-level. In this thesis, the investigation is on the system level and provided the numerical influence of LSE and thermal annealing recovery during their dominating period. The results are consistent with the works based on the module-level (Gottschalg et al., 2005; Virtuani and Fanni, 2014).

4.5.2 Degradation Rate and Seasonality

This section presented a comparative study on degradation rate from test condition (indoor or outdoor), statistical techniques (LR, CSD, STL and ARIMA), undersized inverter influence (excluded or included) and performance metrics (PR or I-V curve measurements). It was focusing on the PV system-level rather than module-level. The filed PR time series was constructed corresponding to the minimal requirements of time period as recommended by Osterwald et al. (2006). Another innovation of this thesis is the inverter saturation influence on the performance degradation rate. The results are consistent with the study by Jordan et al. (2016). In addition, the undersized inverter affects the seasonality of PV system performance not only from the amplitude but also the seasonal patterns (only in a-Si system). Meanwhile, the seasonal time series decomposition methods (CSD, STL and ARIMA) are superior in the degradation rate calculation with robustness and insensitivity to outliers, as recommended by other authors (Phinikarides et al., 2013; Phinikarides et al., 2015; Ye et al., 2014).

The PV array performance degradation based on I-V curve measurement is of uncertainties with insufficient data. It was also claimed by Jordan et al. (2016). Nevertheless, some studies were based on the one day I-V curve data using the similar instruments and methods (Ndiaye et al., 2014). Uncertainty would be induced by: 1. Insufficient data to

converge, 2. Different testing conditions, 3. Unknown correction procedure. Meanwhile, the infeasibility of correction procedure even exists in the IEC standards for thin film technologies due to the metastability and delaying reaction to the instantaneous environmental factors. Notwithstanding these difficulties, I-V curve based degradation rate assessment is useful at the clarifying the source of PV array performance degradation. Therefore, using a robust statistical method such as year-on-year method proposed by Jordan et al. (2016) and more data, well controlled outdoor test conditions, improves this method for the performance degradation evaluation.

4.5.3 Inverter Sizing Ratio

This section proposed an innovative methodology, i.e., inverter optimum sizing interval, to facilitate the pre-design of GCPV systems and to reduce the financial risk, from energetic and economic aspects. It was inspired by the previous works by Peippo and Lund (1994), Mondol et al. (2006b) and Demoulias (2010) among others focusing on the this topic. The main contribution of this study is a pre-design procedure for GCPV systems equipped with optimum-sized inverter(s), with the consideration of PV module degradation rate. The aim is to increase energy production and reduce capital cost.

The optimum size of an inverter with respect to the corresponding PV array is site-dependent. The relative study for Madrid was 35 years ago, where a simulation work was conducted by Macagnanlr and Lorenzo (1992) only from the final energy points of view. This thesis improved the evaluation from the energetic and economic points of view and completed the relevant study at the specific site, viz., Madrid.

Owing to technology innovation, current inverters feature improved efficiencies, especially at partial loads. The simulated low-efficiency inverter (inverter 3), and even medium-efficiency inverters (inverter 2 and SMA SB 1200 of *System 1*), are non-existent in large-scale commercial and utility GCPV systems. This is one reason to choose the high-efficiency inverter (inverter 1) and the SMA 15000TL inverter of *System 2*, of which the efficiency is more than 97%. They could stand for the common inverters used by large GCPV systems. One important result of comparing SMA SB1200 and SMA 15000TL is that the high-efficiency inverter has a wider energetic optimum sizing range than the lower-efficiency inverter.

For a large GCPV system, the optimum inverter sizing ratio or range would differ, as the sizing ratio is affected by the DC power output of the PV system, the characteristics of the connected inverter, and the GCPV system capital cost.

For the pre-design of a GCPV system with an optimum-sized inverter, the first step is to construct the DC power profile (power duration curve stated in the study) using a proper power model with inputs of local climate data. For a large-scale commercial or utility PV plant with a capacity of 1 MW or higher, the main difference with the smaller systems analyzed here is the power profile, due to the higher energy losses and possibility of mismatch among other factors. Subsequently, based on the DC power duration curve and adopting the simulated inverter type (low-, medium-, or high-efficiency inverter stated in this study) characteristics, *Method 2* offers a proper inverter sizing range; the realistic inverters are then selected based on this range. However, the realistic inverter's characteristics could be different from those of the simulated inverter type. Finally, the validation of the realistic inverter could be justified through recalculation by *Method 1* or *Method 2*.

Despite the substantial cost reductions for the technical components of GCPV systems ($P_{rva} + R_{inv}$) in recent years, the ratio (R_{PV} / R_{inv}) is in the range of 6 for commercial GCPV systems to 10 for utility GCPV systems in 2016 (Burger et al., 2016; Jäger-waldau, 2016). In this study, the ratio (R_{PV} / R_{inv}) of *System 2* is 6. Accordingly, these cost reductions only decrease the C_c and C_A values, while the stable cost ratio (R_{PV} / R_{inv}) resulted in a similar sizing ratio and interval. However, if this ratio moves towards a higher value, representing a lower inverter cost proportion, the optimum inverter sizing ratio could become smaller as the inverter cost becomes less important.

The assessment of optimum sizing ratio and interval was extended to the GCPV system lifetime performance considering the degradation rate. As expected, a more undersized inverter is necessary for a realistic GCPV system of which the performance is gradually deteriorating.

It is because determining the proper inverter is the work during the system design period. The inverter optimum sizing ratio was commonly assessed through simulation by using various models, i.e., PV array output model, inverter efficiency model. There are only few studies conducted on the field data (Keller and Affolter, 1995; Macêdo and Zilles, 2007). In this thesis, the optimum sizing ratio was calculated both from the field data and an analytical technique proposed by Demoulias (2010), respectively. Meanwhile, this analytical technique

was used for explaining the insignificant variation of inverter annual efficiency with sizing ratio changing in a broad range.

Furthermore, the investigation of inverter optimum sizing ratio on a monthly interval indicated the GCPV system at low irradiance site needs a more undersized inverter than those exposed to high irradiance, to achieve better performance.

4.5.4 Potential of Agrivoltaic Farm

Although this thesis adopted the AV farm configurations based on the prototypes proposed by Dupraz et al. (2011), a narrower PV row space representing the regular PV plants was added and assessed. Meanwhile, the design of the PV system was based on the conclusion of *Section 4.1* and 4.3, i.e., the poly-Si technology with highest efficiency compared to a-Si and CdTe; inverter size falling in the optimum sizing ratio interval. Furthermore, the diverse Spatio-temporal shading patterns of four AV farms with different configurations were assessed. It presented the clues to choose the proper PV array configuration for the irradiation requirements of crops during their development stages. Unlike the sunfleck region induced by tree canopy in an agroforestry system, the PV modules caused shade is more predictable and controllable. It thus simplifies the calculation of the crop annual reduction and the following optimization of the AV farm configuration with consideration of economic benefits from both electricity and crop products.

Based on the recent five years average prices of selling durum wheat and domestic electricity of Spain, the remarkable socioeconomic advantages of AV farm were presented. Although the LOCE was rigorously calculated, some specific factors are not taken into account, such as transmission line, or so-called generation-tie costs (Fu et al., 2015). These costs could be as high as 120€/m for the low tension subterranean connection to the grid (Muñoz-García et al., 2015). In addition, Fu et al. (2015) pointed out that these costs depend on the size of GCPV system. Based on their model, for system sizes less than 10 MW, 0 km is used. A typical 20MW PV system would need a 0.64 km transmission line and €0.6 million⁵ per km for the infrastructure cost. The average area of durum wheat farm was 41.3 ha in 2011 in Spain (European Commission-Agriculture and Rural Development, 2013). Thereby the average AV farm capacity could be 9.5 MW based on prototype S6H4T3 (see Table 23). Even if this average

⁵ The original value in the work of Fu et al. (2015) was \$1.13 million per mile; here the value was translated to million € per km based on the exchange rate of 2017-09-26.

capacity of a durum wheat AV arm increased to 20MW, the additional transmission line costs are only 4,597 €/ha, whilst the investment of a S6H4T3 AV farm is 526,240 €/ha (see Table 23).

Furthermore, the row space or density of PV modules on the crop area would bring about inconvenience of farming equipment. However, this inconvenience depends on the target crop of AV farm. For example, for some crops do not need large farming machine, a narrow row space (i.e., S3H4T3) is preferable as it results to more productivity; while for those crop like wheat, large farming equipment is important, thus a wider row space (i.e., S6H4T3) eliminates this inconvenience.

Meanwhile, the similar socioeconomic impacts on Spain was claimed by Carreño-Ortega et al. (2017), who conducted the study on the greenhouse partially covered by PV modules for producing tomato and electricity simultaneously. However, these authors did not consider the reduction of tomato production under the low covering percentage (below 10%).

CHAPTER 5 – CONCLUSIONS

The main conclusions of the present thesis can be pointed out as follows:

Seasonal performance comparison of the three grid-connected photovoltaic systems:

After comparing and analyzing the performance of the three grid-connected photovoltaic (GCPV) systems based on different technologies, the following conclusions can be drawn:

- Irradiance has great influence on PV performance. Low irradiance is of high uncertainty; PV system working at middle irradiance is immune to major inverter saturation with less varied conversion efficiency; high irradiance triggers inverter saturation.
- The PV system seasonal performance variation is a result of meteorological changes and material dependence. Performance of poly-Si system is affected most by module temperature at $-0.56\text{ \%/}^{\circ}\text{C}$. On the other hand, a-Si system is affected remarkably by sun spectra and historical temperature and irradiation. CdTe system is affected moderately by the module temperature and sun spectra.

Degradation rate assessment for the three GCPV systems:

The performance degradation of the three GCPV systems based on three levels has been investigated, the conclusions are as follows:

- On PV system level, the average performance ratio degradation rates of poly-Si, a-Si and CdTe systems were higher than 1%/year. In general, the degradation rate of poly-Si system is lower than the other two thin film systems. Meanwhile, the inverter saturation mitigates degradation rates.

- On PV array level, poly-Si power losses were mainly due to the currents deterioration, while the main contributor to CdTe power losses was the voltage degeneration. A prolonged investigating period is necessary to justify this I-V curve method.
- On PV module level, the maximum power at standard test conditions of poly-Si and CdTe modules varied at -0.57% and -0.30% per year, respectively.

Inverter sizing ratio:

Optimum inverter sizing intervals have been studied for two poly-Si GCPV systems (with inverter input capacities of 1.32 and 15.34 kW). The study utilizes measured DC power output profiles through a simplified inverter efficiency model and an analytical method. The following conclusions can be drawn:

- With respect to the first year, assuming a 20-year lifetime and degradation rate of $1\%/year$, both the optimum sizing ratio and the optimum interval experienced an increase of 10% .
- Annual inverter efficiency remaining at its maximum over a wide sizing ratio range was due to the inverter characteristics.
- The different DC power and investment profiles affected the compound optimum interval rather than the inverter type. The GCPV system with lower specific power generation and inverter cost exhibited a wider interval.
- The analytical method performed worse in winter months, suggesting it is less efficient in low-irradiance regions.

Agrivoltaic farm:

A simulation study on several agrivoltaic farm prototypes located at Madrid for durum wheat growing and electricity generation simultaneously has been carried out. The following conclusions can be drawn:

- For the pre-design of an agrivoltaic farm to allow sufficient light for the crop growth, the major factor is the PV array row space. The PV modules covering 17% area of an agrivoltaic farm resulted in a slightly decrease (6.1%) in crop yield due to 10.8% reduced irradiation intercepted by the crop.
- The implementation of PV modules on a conventional durum wheat farm could improve the land productivity, increase and diversify income of farmers, promote Spain to fulfil the official commitment on renewable energy and environment.

CHAPTER 6 – SUGGESTIONS FOR FURTHER WORK

The following proposals for further works are expounded:

1. Performance comparison and degradation rates:

- a. A spectrometer is suggested to investigate the solar spectral effects on the three GCPV systems performance based on the on-site solar spectrum instead of sole air mass index. Using diverse sensors for measuring in-plane irradiance such as reference cells and modules, pyranometer. These applications would expand the analysis of spectral effects to various areas such as spectral mismatch factor, useful fraction, and average photon energy. Meanwhile, it would eliminate the strict weather conditions used by air mass method.
- b. Continuous monitoring the GCPV systems for further assessment of the degradation rates based on PR time series. Meanwhile, the continuous measures of the I-V characteristics should be taken at least once per month at cloudless sunny solar noon. A more favorable frequency is once a week.
- c. Studying the responses of the three GCPV systems to the fast changing weather conditions (irradiance and sun spectra due to fast moving clouds, module temperature due to gust).
- d. Continuously periodic indoor tests in an independent laboratory not only for STC ratings but also for specific tests such as Electroluminescence imaging technique, by which the inner cracks locating at cells could be detected for investigating potential future problems.

2. Optimum sizing ratio:

The approaches investigated in this work could be extended to thin film systems by modelling the output power of the thin film (a-Si and CdTe) GCPV systems (or arrays) with inputs of instantaneous meteorology. As the a-Si module encounters the long-term effects of light soaking and thermal annealing, the directly foreseeable power output modelled by the instantaneous meteorology could be at high uncertainty. A suggesting method is adopting machine learning algorithms such as artificial neural networks (ANNs) to predict the generated power by a-Si system with the inputs of irradiance, module and ambient temperature, Julian Day Number and historical meteorology data among others.

3. Agrivoltaic farm:

Investigating the yield of crop under PV modules based on experimental data instead of using a simulation model, i.e., constructing a realistic AV farm instead of simulations. The influences of PV modules on the different crops should be investigated, mainly focusing on how the reduced irradiation availability affects the crop yield during different development stages.

CHAPTER 7 – APPENDICES

Appendix A: Publications arising from this work

Journal papers:

[1] **H.X. Wang**, Muñoz-García, M. A., Moreda, G. P., & Alonso-García, M. C. (2017). Seasonal performance comparison of three grid connected photovoltaic systems based on different technologies operating under the same conditions. *Solar Energy*, 144, 798-807.

[2] **H.X. Wang**, M.A. Muñoz-García, G.P. Moreda, M.C. Alonso-García (2017), Optimum inverter sizing of grid-connected photovoltaic systems based on energetic and economic considerations (accepted), *Renewable Energy*, doi: 10.1016/j.renene.2017.11.063.

Conference papers:

[1] **H.X. Wang**, M.A. Muñoz-García, G.P. Moreda, D. Alcala, I. Serrano, M.C. Alonso-García (2014), Comparison of c-Si, a-Si and CdTe technologies working at the same conditions, after the first year of electricity production, *29th European Photovoltaic Solar Energy Conference and Exhibition*. pp. 2646-2649 – 4516.

[2] M.A. Muñoz Garcia; **H.X. Wang**, G. P. Moreda Cantero, M.C. Alonso-García (2015), Análisis comparativo y determinación del sistema óptimo para la electrificación mediante energía fotovoltaica en el ámbito agrario, *VIII Congreso Ibérico de Agroingeniería. Retos de la nueva agricultura mediterránea*, pp. 23 – 24.

[3] **H.X. Wang**, M.A. Muñoz-García, G.P. Moreda, D. Alcala, I. Serrano, M.C. Alonso-García (2016), Analysis of air mass dependence of three photovoltaic arrays, *32th European Photovoltaic Solar Energy Conference*. pp 2221 – 2223.

[4] M.A. Muñoz-García, **H.X. Wang**, G.P. Moreda, D. Alcala, I. Serrano, M.C. Alonso-García (2016), Economic feasibility analysis of choices for not connected clients: photovoltaic off-grid systems, compared to grid based system, *32th European Photovoltaic Solar Energy Conference and Exhibition*. pp 3080 – 3082.

Appendix B: World Bank Group solar PV initiatives. From (World Bank, 2007)

Country	Project	Target number of systems	Capacity (kWp)	Total cost (US\$ million)
Argentina	Renewable Energy in the Rural Market	30,000	2,843	36.0
Bangladesh	Rural Electrification & Renewable Energy Development	198,000	9,900	91.4
Bolivia	Decentralized Energy, ICT for Rural Transformation	60,000	2,600	38.6
Burkina Faso	Energy Access Project	2,100	100	2.0
Cambodia	Rural Electrification and Transmission	10,000	400	4.0
Cape Verde	Energy and Water project	4,500	129	2.5
China	Renewable Energy Development	400,000	10,000	144.9
Ethiopia	Energy Access	6,300	407	5.4
India	Renewable Resources Development	45,000	2,500	24.0
Indonesia	Solar Home Systems	8,500	425	3.8
Lao PDR	Southern Provinces Rural Electrification, and Rural Electrification projects	13,000	460	4.3
Mali	Household Energy and Universal Access Project	10,000	350	3.5
Mexico	Renewable Energy for Agriculture, and Rural Electrification (FY08)	8,345	1,767	27.6
Mongolia	Renewable Energy and Rural Access	50,000	520	5.2
Mozambique	Energy Reform and Access, and PV for Schools and Health Clinics	9,800	1,096	13.5
Nicaragua	Off-grid Electrification for Rural Development	6,000	215	3.0
Pacific Islands	Regional Sustainable Energy Finance	21,000	630	16.5
Papua New Guinea	Teachers Solar Lighting	2,500	100	2.2
Philippines	Rural Power and IFC 1 MW grid-tied project	135,000	10,000	120.0
Sri Lanka	Energy Services Delivery, Renewable Energy for Rural Economic Development (RERED), and RERED Additional Financing	18,000	7,200	62.3
Tanzania	Energy Development and Access (FY08)	11,800	800	20.0
Uganda	Energy for Rural Transformation	8,300	600	18.8
Zambia	Increased Access to Energy (FY08)	8,300	415	11.0
Multiple countries	IFC-financed financing facilities	100,000+	8146	25.3
Totals		1.33 million	61.62 MW	US\$686 million

Appendix C: ETSIAAB GCPV plant performance data provided by the manufacturers.

	Experimental Part			Commercial part	
	Array1	Array 2	Array 3	Array 4	Array 5
Material	poly-Si	a-Si	CdTe	poly-Si	poly-Si
$P_{\max}$ (Wp)	230	105	82.5	235	280
V_{mp} (V)	29.8	30.5	48.3	29.8	35.2
I_{mp} (A)	7.72	3.44	1.71	7.89	7.95
V_{oc} (V)	36.8	41.1	60.8	36.9	44.8
I_{sc} (A)	8.25	4.05	1.94	8.47	8.33
NOCT (°C)	45±2	49	45	48	45±2
η (%)	13.9	7.2	11.5	14.4	14.4
γ ($P_{\max}$) (%/°C)	-0.47	-0.20	-0.25	-0.48	-0.44
β (V_{oc}) (%/°C)	-0.34	-0.33	-0.27	-0.33	-0.33
α (I_{sc}) (%/°C)	0.045	0.08	0.04	0.04	-0.055
Array Configuration	7s×1p	8s×2p	5s×4p	18s×1p	15s×3p
Array area (m ²)	11.55	23.2	14.4	29.5	87.3
Total array power (Wp)	1610	1680	1650	4230	12600

Appendix D: Main features of ‘SMA sunny boy 1200’ single-phase inverter.

Input (DC)	
Max. DC power (@cosφ=1)	1320W
Max. DC voltage	400V
MPP voltage range	100V–320V
Min. DC voltage/ short voltage	100V/120V
Max. input current/ per string	12.6A/12.6A
Output (AC)	
AC nominal power (@230V, 50Hz)	1200W
Max. output current	6.1A
Max. efficiency/Euro-eta	92.1%/90.9%
Accessory	
Sunny sensor box	Radiation reference sensor Air and PV module temperature based on PT100 Wind sensor based on anemometer
Sunny webbox	Integrated web server

Appendix E: Main features of HD32MT.1 data logger

Analog input	Measurement ranges: $\pm 25\text{mV}$, $\pm 100\text{mV}$, $\pm 1000\text{mV}$, $\pm 2500\text{mV}$ Resolution: 16bit Accuracy: 0.01% f.s.
Thermocouples	Type K 2 for each array Uncertainty: $\pm 2.2^\circ\text{C}$
Irradiance sensor	c-Si based cells
Storage	Scan period: 20s
mechanism	Stored period: 1min Algorithm: Average

Appendix F: Electrical specifications of “Solar- 4000” I-V curve tracer

Parameters	Range	Accuracy	Resolution
Voltage	1.0–1000 V	$\pm 1\%$	0.1V
Current	0.1–15.0 A	$\pm 1\%$	0.01A
Irradiance	100–1200 W/m ²	$\pm 5\%$	1 W/m ²
Temperature	0–100 °C	$\pm 3\%$	0.1 °C

Appendix G: Technical specifications of Pasan solar simulator

Applicable standard	IEC 60904-9
Overall class	Better than class A
Max. capacitors voltage	800 V
Pulse duration	10 ms–1 min.
Light pulse stability	$< \pm 1\%$
Min. light intensity	0.7 kW/m ² at 5.0 m and AM 1.5
Max. light intensity	1.2 kW/m ² at 5.0 m and AM 1.5
Light uniformity	$< \pm 1\%$ at 5.0 m and an area of 2 × 2 m
Load time	$< 30\text{ s}$

Appendix H: Mathematical derivation of analytical method for optimum sizing ratio

The DC power is described by the following equation, which is the linear fitting of PDC (Fig. 70):

$$P_{max}(t) = A \cdot t + P_{max,L}$$

Equation 43. Linear regression for power duration curve

where $P_{max,L}$ is the maximum value of PDC 's linear fitting. E_{AC} is calculated for two distinct cases due to the different inverter capacities ($P_{inv,N}$) by using Equation 43 and Equation 27. The first case is $P_{inv,N} > P_{max,L}$. The second case is $P_{inv,N} < P_{max,L}$.

Fig. 70. Power duration curve and its linear fitting for System 1, from Jul. 2015 to Jun. 2016.

When $P_{INV,N} \geq P_{max,L}$, the E_{AC} can be expressed as:

$$\begin{aligned} E_{AC} &= \int_0^T P_{max}(t) \cdot \eta(P_{max}(t)) \cdot dt \\ &= \left[-\frac{P_{max,L}}{A} \cdot \left(b_0 \cdot P_{inv,N} + \frac{b_1}{2} \cdot P_{max,L} + \frac{b_2 \cdot P_{max,L}^2}{3 \cdot P_{inv,N}} \right) \right] \cdot \end{aligned}$$

T_{total} .

Equation 44. Mathematical derivation for energy output: case 1

For maximum E_{AC} :

$$\left. \frac{dE_{AC}}{dP_{inv,N}} \right|_{P_{inv,N}^{opt}} = \left[-\frac{P_{max,L}}{A} \cdot \left(b_0 - \frac{b_2 \cdot P_{max,L}^2}{3 \cdot P_{inv,N}^2} \right) \right] \cdot T_{total} = 0.$$

$$P_{inv,N}^{opt} = P_{max,L} \cdot \sqrt{\frac{b_2}{3b_0}}.$$

Equation 45. Calculated optimum sizing ratio: case 1

Note that, in this case, the fact that $P_{inv,N} \geq P_{max,L}$ results in : $|b_2| \geq 3|b_0|$, otherwise $P_{inv,N}^{opt} = P_{max,L}$.

When $P_{inv,N} < P_{max,L}$, the inverter's annual energy output can be expressed as:

$$\begin{aligned} E_{AC} &= \int_0^T P_{max}(t) \cdot \eta(P_{max}(t)) \cdot dt \\ &= \int_{T_1}^{T_2} P_{max}(t) \cdot \eta(P_{max}(t)) \cdot dt + P_{inv,N} \cdot T_1. \end{aligned}$$

$\eta(P_{inv,N})$

$$= \left[P_{inv,N}^2 \cdot \frac{\frac{b_1 + 2b_2}{2} + \frac{2b_2}{3}}{A} - \frac{P_{max,L} \cdot P_{inv,N} \cdot (b_0 + b_1 + b_2)}{A} \right] \cdot T_{total}.$$

Equation 46. Mathematical derivation for energy output: case 2

And the optimum inverter capacity:

$$\left. \frac{dE_{AC}}{dP_{inv,N}} \right|_{P_{inv,N}^{opt}} = \left[2P_{inv,N} \cdot \frac{\frac{b_1 + 2b_2}{2} + \frac{2b_2}{3}}{A} - \frac{P_{max,L} \cdot (b_0 + b_1 + b_2)}{A} \right].$$

$T_{total} = 0$

$$P_{inv,N}^{opt} = \frac{P_{max,L} \cdot (b_0 + b_1 + b_2)}{b_1 + \frac{4b_2}{3}}.$$

Equation 47. Calculated optimum sizing ratio: case 2

In this case, $P_{inv,N}$ should be smaller than $P_{max,L}$, resulting in: $|b_2| < 3|b_0|$, otherwise $P_{inv,N}^{opt} = P_{max,L}$.

Appendix I: Degradation rate using STL over the three-year period

Fig. 71– Fig. 73 show the trends, seasonalities and remainders extracted using STL on the three-year PR time series for the three GCPV systems. The left figures gathered all the data points, while these figures on the right excluded the power limitation events.

The same effects of inverter saturation on the PR time series trends and seasonalities have been found as illustrated in the results of CSD. The extracted degradation rates in the case of including inverter saturation were 1.13%/year, 1.59%/year and 1.60%/year for poly-Si, a-Si and CdTe, respectively. When the inverter saturation was excluded, the degradation rates turned to 1.35%/year, 2.24%/year and 2.08%/year for poly-Si, a-Si and CdTe, respectively. The linear fits of the extracted trends for all the three systems were excellent with R^2 values between 66.82% and 89.33%.

In the case of seasonalities calculated by STL, the seasonal index distributed similarly to CSD. For poly-Si system with inverter saturation, seasonal indices varied from –8.60% to 12.51%; and they were from –9.34% to 10.32% for the case excluding inverter saturation. The standard deviations for these two conditions were 7.06% and 6.58%. The seasonal indices of a-Si system ranged from -3.70% to 5.95% with standard deviation of 3.40% and from –2.37% to 2.47% with standard deviation of 1.73%, for the evaluation including and excluding inverter saturation, respectively. For CdTe system, the seasonal indices changed from –5.86% to 10.36% with standard deviation of 5.38% and from –5.16% to 8.18% with standard deviation of 4.18%, for the cases including and excluding inverter saturation, respectively.

Fig. 71. STL extracted trend, seasonality and remainder for three-year PR time series data of poly-Si GCPV system with (left) and without (right) inverter saturation.

Fig. 72. STL extracted trend, seasonality and remainder for three-year PR time series data of a-Si GCPV system with (left) and without (right) inverter saturation.

Fig. 73. STL extracted trend, seasonality and remainder for three-year PR time series data of CdTe GCPV system with (left) and without (right) inverter saturation.

Appendix J: Degradation rate using ARIMA over the three-year period

The trends, seasonalities and remainders extracted by ARIMA on the three-year PR time series for the three GCPV systems are shown in Fig. 74–Fig. 76. The left figures present all data points, while the inverter saturation was excluded in right figures. All the results obtained by the airline model ARIMA (0, 1, 1)(0, 1, 1)₁₂ passed the diagnostics successfully.

The inverter saturation reduced the extent of PR degradation rate but increased PR seasonal fluctuation. The extracted degradation rates rose from 1.24%/year (with inverter saturation) to 1.31%/year (without inverter saturation) for poly-Si system, from 1.57%/year (with inverter saturation) to 2.21%/year (without inverter saturation) for a-Si system and from 1.63%/year (with inverter saturation) to 2.04%/year (without inverter saturation) for CdTe system, respectively.

Regarding seasonalities calculated by ARIMA, the seasonal index changed analogously to the results of CSD and STL. For poly-Si system with inverter saturation it ranged from –8.68% to 12.50% and from –9.80% to 10.49% without inverter saturation. The standard deviation of these two conditions was 7.03% and 6.62%, respectively. The seasonal indices of a-Si system ranged from –4.11% to 5.93% with standard deviation of 3.46% and from –2.5% to 2.88% with standard deviation of 1.82%, in the cases including and excluding inverter saturation, respectively. The seasonal indices of CdTe system were similar to poly-Si and ranged from

−5.86% to 10.37% with standard deviation of 5.40% and from −5.25% to 8.13% with standard deviation of 4.16%, for the evaluation with and without inverter saturation, respectively.

Fig. 74. ARIMA extracted trend, seasonality and remainder for three-year PR time series data of poly-Si GCPV system with (left) and without (right) inverter saturation.

Fig. 75. ARIMA extracted trend, seasonality and remainder for three-year PR time series data of a-Si GCPV system with (left) and without (right) inverter saturation.

Fig. 76. ARIMA extracted trend, seasonality and remainder for three-year PR time series data of CdTe GCPV system with (left) and without (right) inverter saturation.

Appendix K: Taxes for self-consumption of renewables (from January 2016).

Tolls	Temporary Charge for self-Consumption Energy (€/kWh)					
	2016	2017	2018	2019	2020	2021
2.0 A ($P_c \leq 10$ kW)	0.049033					
2.0 DHA ($P_c \leq 10$ kW)	0.063141	0.008907				
2.0 DHS ($P_c \leq 10$ kW)	0.063913	0.009405	0.008767			
2.1 A ($10 < P_c \leq 15$ kW)	0.060728					
2.1 DHA ($10 < P_c \leq 15$ kW)	0.074079	0.018282				
2.1 DHS ($10 < P_c \leq 15$ kW)	0.074851	0.021301	0.014025			
3.0 A ($P_c \geq 15$ kW)	0.029399	0.019334	0.011155			
3.1 A (1–36 kV)	0.022656	0.015100	0.014197			
6.1 A (1–kV)	0.018849	0.016196	0.011534	0.012518	0.013267	0.008879
6.1 B (30–kV)	0.018849	0.013890	0.010981	0.011905	0.012871	0.008627
6.2 (36–kV)	0.020138	0.016194	0.011691	0.011696	0.011996	0.008395
6.2 A (72.5–145 kV)	0.022498	0.017414	0.012319	0.011824	0.011953	0.008426
6.4 A (≥ 145 kV)	0.018849	0.013138	0.010981	0.011104	0.011537	0.008252

Source: Real Decreto 900/2015.

CHAPTER 8 – REFERENCES

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