

Improving Bifacial Photovoltaic Models by Quantifying the Impact of Racking, Artificial Reflectors, and Varying Solar Spectrum

by

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Abstract

The deployment of photovoltaic (PV) energy is expected to rise exponentially in the next few decades, driven by decarbonization, electrification, and record-low system costs. Furthermore, bifacial PV modules, which generate electricity from both front and rear surfaces, are projected to make up 70% of the PV market share within the next ten years due to their increased generation capacity, more efficient land use, and reduced levelized costs. However, irradiance incident on the module rear is more variable than front-incident irradiance, resulting in higher uncertainty in bifacial energy yield models than in monofacial models.

PV energy yield models inform a wide range of stakeholders, including policy makers, lenders, grid operators, system owners, and system designers. Energy yield predictions are subject to uncertainty caused by weather fluctuations, input uncertainty, and necessary approximations. Reductions in these uncertainties and approximations promote PV adoption, reduce financing costs, increase design efficiency, facilitate maintenance, and improve grid integration.

This thesis aims to improve bifacial PV models by quantifying the impact of system design and environmental conditions on energy yield. The work is focused on three factors: (1) structural shading and reflection, (2) artificial ground reflectors, and (3) solar spectral irradiance. I combine field measurements with model results to identify the conditions where these effects are most impactful and when they are negligible.

Firstly, I present a method for quantifying the effect of racking shading and reflection on the rear irradiance, energy yield, mismatch losses, and bifacial gain of a bifacial PV system. I demonstrate that: (1) racking reflection is a significant structural effect on PV performance, and (2) structural effects vary seasonally, by time of day, and with albedo. In an example case with two-in-portrait single-axis-tracked modules in Livermore, California, incorporating racking reflection reduces the average structural rear shading by up to 9.1% per year compared with absorptive racking structures.

Secondly, I quantify the impact of artificial reflectors with 70% reflectivity on a bifacial one-in-portrait single-axis-tracked PV system in Golden, Colorado. Relative to natural albedo, I found a reflector power gain of up to 6.2% before inverter clipping from field experiments and up to 4.5% after inverter clipping in energy yield models. I demonstrate that: (1) the ideal placement of the artificial reflector is directly under the torque tube, (2) clipping effects must be considered when optimizing artificial reflector systems, and (3) artificial reflectors are most viable in locations with low energy yield and high system costs.

Finally, I demonstrate the importance of spectrally-varying solar irradiance in bifacial PV energy yield. The solar spectrum is constantly changing, causing errors in PV models due to deviations from the reference spectrum. I quantify the spectral error in bifacial PV model predictions for a range of North American locations (39.7-69.1°N). I demonstrate: (1) annual spectral irradiance impacts on energy yield from +0.7% to +2.7% and (2) spectral effects are most important for diffuse irradiance and ground-reflected irradiance. I then compare five parameterized spectral correction methods and two measured spectral irradiance correction methods in Roskilde, Denmark. These demonstrate that long-wavelength irradiance cannot be neglected in PV spectral correction.

This work supports bifacial PV model improvement by quantifying the effects of various environmental and system factors with the goal of reducing bifacial PV model uncertainty and increasing PV adoption worldwide.

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Declaration of Originality

The work presented in this thesis was performed by the author under the supervision of Dr. Karin Hinzer during the period of her Ph.D. studies. A preface describing the contributions of co-authors is provided for each manuscript presented in this thesis. Unless otherwise noted, all writing and figures in this thesis were created by the author.

Contributions

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List of Acronyms

2D	two-dimensional
3D	three-dimensional
Al-BSF	aluminium back-surface field
AM	air mass
AOI	angle of incidence
ASTM	American Society for Testing and Materials
CAMS	Copernicus Atmospheric Monitoring Service
CF	capacity factor
CRF	capital recovery factor
c-Si	crystalline silicon
CO ₂	carbon dioxide
DHI	diffuse horizontal irradiance
DNI	direct normal irradiance
DTU	Technical University of Denmark
EQE	external quantum efficiency
ETR	extraterrestrial irradiance
FARMS-NIT	Fast All-sky Radiation Model for Solar Applications with Narrowband Irradiances on Tilted Surfaces
GCR	ground cover ratio
GHI	global horizontal irradiance
GRI	global reflected irradiance
GTI	global tilted irradiance
IAM	incidence angle modifier
IEC	International Electrotechnical Commission
IQE	internal quantum efficiency
IR	infrared
IV	current-voltage

JRC	Joint Research Center
LCOE	levelized cost of energy
MERRA-2	Modern-Era Retrospective analysis for Research and Applications, Version 2
MODTRAN	MODerate resolution TRANsmission
NREL	National Renewable Energy Laborator
NSRDB	National Solar Radiation Database
PERC	passivated emitter rear contact
POA	plane-of-array
PV	photovoltaic
SAPM	Sandia Array Performance Model
SHJ	silicon heterojunction
SMARTS	Simple Model of the Atmospheric Radiative Transfer of Sunshine
SMM	spectral mismatch factor
SR	spectral responsivity
STC	standard test conditions
TMY	Typical Meteorological Year
TOPCon	tunnel oxide passivated contact
UV	ultraviolet

List of Symbols

α	absorption coefficient
β	module tilt angle
c	speed of light
C	solar concentration
d	discount rate
Δ	mean absolute difference
E	photon energy
E_y	electricity generated in year y
E_g	bandgap energy
η	efficiency
FF	fill factor
G	solar irradiance
G_{avg}	average irradiance
G_{eff}	effective irradiance
G_{meas}	measured solar spectrum
G_{ref}	reference solar spectrum
G_{stc}	reference solar irradiance
γ	temperature coefficient
h	Plank constant
I_0	diode reverse saturation current
I_L	light-generated current
$I_{\text{sc,meas}}$	short-circuit current under measured spectrum
$I_{\text{sc,ref}}$	short-circuit current under reference spectrum
I_W	total investment cost per watt
I_y	investment cost in year y
I_L	photogenerated current
I_{mp}	current at maximum power point

I_{sc}	short-circuit current
$I_{sc,front}$	front short-circuit current under reference illumination
$I_{sc,rear}$	rear short-circuit current under reference illumination
k	Boltzmann constant
k_c	clear sky index
k_t	clearness index
κ	extinction coefficient
L	solar path length through the atmosphere
L_0	thickness of the atmosphere
λ	wavelength
λ_g	bandgap wavelength
M	cell-to-module irradiance mismatch loss
M_W	annual maintenance cost per watt
M_y	maintenance cost in year y
n	ideality factor
N	system lifetime
n_e	number of electrons
n_{ph}	number of photons
$n_{ph,abs}$	number of photons absorbed
n_{pts}	number of points
$P_{air,0}$	reference air pressure
P_{air}	air pressure
$P_{belowBG}$	below-bandgap power loss
P_{cell}	cell power output at maximum power point
P_{clip}	clipping power loss
P_{in}	incident light power
P_{inv}	maximum module power output of inverter
P_{module}	module power output at maximum power point
P_{out}	power output of module after clipping
P_{therm}	thermalization power loss
P_{total}	total power
ϕ	azimuth angle
Φ	photon flux density
P_{mp}	maximum power
$P_{mp,front}$	front maximum power under reference illumination
$P_{mp,rear}$	rear maximum power under reference illumination
q	electron charge
r	reflection

ρ	albedo
R_s	series resistance
R_{sh}	shunt resistance
σ	scattering coefficient
SR_{module}	spectral responsivity of module
SR_{ref}	spectral responsivity of broadband measurement device
t	transmission
T	temperature
T_{ambient}	ambient temperature
T_{cell}	cell temperature
T_{module}	module temperature
T_{NOCT}	nominal operating cell temperature
T_{stc}	cell temperature under standard test conditions
τ	aerosol optical depth
θ	zenith angle
θ_{apparent}	apparent solar zenith angle
θ_{true}	true solar zenith angle
V	voltage
$\varphi_{I_{\text{sc}}}$	current bifaciality factor
$\varphi_{P_{\text{mp}}}$	power bifaciality factor
V_d	diode voltage
V_{mp}	voltage at maximum power point
V_{oc}	open-circuit voltage
WS	wind speed
y	years since system construction

Chapter 1

Introduction

1.1 Motivation

Today, electricity and heat generation are the largest sources of greenhouse gases, accounting for approximately 44% of global carbon dioxide (CO_2) emissions in 2021 [1]. As we decarbonize electricity grids while simultaneously electrifying sectors which have historically relied on fossil fuels, the deployment of photovoltaic (PV) energy is expected to rise exponentially [2, 3, 4]. Furthermore, thanks to recent cost reductions in PV modules and systems [3], PV has become the cheapest electricity source in the world in some contexts, and costs are expected to continue to decline [4].

PV energy yield prediction models take design specifications and meteorological data as inputs to calculate expected PV energy yield. These models are applied in many contexts: by policy makers to inform clean energy investments and energy roadmaps, by grid operators for PV integration and grid planning, by PV maintainers to troubleshoot underperforming systems, and by PV system designers to maximize power output and to facilitate cost-benefit analyses. Furthermore, these models are used to assess the viability of new systems before they are installed, which is necessary to secure funding. However, PV models are subject to uncertainty due to weather fluctuations, model input uncertainty, and necessary model approximations. Reducing the uncertainty in PV energy yield models promotes PV adoption by improving the bankability of the system: a reduction in financial risk translates to a reduction in financing costs [5].

Bifacial PV modules absorb light on both sides, resulting in increased energy yield from the module's rear-incident irradiance. This increase in energy yield reduces system

levelized costs [6], improves land use efficiency, and opens up new design possibilities such as vertical PV. Bifacial PV modules are becoming the most commonly-installed module type, and are projected to make up 70% of the PV market share within the next ten years [7]. However, rear-incident irradiance is more variable than front-incident irradiance due to the effects of structural shading, albedo, and other factors. This causes higher uncertainty in energy yield predictions for bifacial systems.

This thesis focuses on improving bifacial PV energy yield models by quantifying the impact of environmental and system design factors, including structural shading, high-albedo ground cover, and spectral variation in the solar resource, on bifacial PV energy yield. I evaluate the impact of these factors through field measurements and bifacial PV models. This work will enable PV model designers to evaluate and improve bifacial PV models.

1.2 Supporting Literature

The first solar cell was processed in Bell Labs in 1954 [8], and the first bifacial solar cell was patented in Japan in 1961 [9]. Researchers in Spain later demonstrated the first experimental bifacial solar cell with approximately 7% efficiency in 1977 [10]. In 1982, early bifacial PV experiments by Cuevas *et. al.* with high-albedo material found potential bifacial gains of over 50% [11].

Despite its long history, mass adoption of bifacial PV has only begun in the last decade, after high-efficiency passivated emitter rear contact (PERC) technology began displacing aluminium back-surface field (Al-BSF) in the silicon solar cell market (see section 2.2.3.3) [12]. Adapting PERC production lines to manufacture bifacial cells requires only a modification of the screen printing process step [12], so the barrier to bifacial PV adoption was reduced. The subsequent transition to bifacial technology has been fast: bifacial cells have grown from approximately 5% of market share in 2018 [13] to 90% in 2024 [14]. Today, even in monofacial modules, bifacial cells are often installed with an opaque backsheet [14].

Early bifacial PV models based on a view factor concept (see section 2.3.2.2) were reported in Spain in the 1980s [15]. View factor models continue to be a common bifacial PV optical modelling method today [16, 17, 18], although the popularity of ray-tracing methods [19, 20] (see section 2.3.2.1) has grown due to increased computational power. Many bifacial PV energy yield models are currently available, including MoBiDiG [21], PlantPredict [22], PVSyst [16], the System Advisor Model (SAM)[23], SolarFarmer [24], bifacialvf [17], bifacial_radiance [19], pvfactors [25], SunSolve [20], and DUET [26]. These

models offer a range of modelling detail and require different levels of computation. Assumptions that limit the computational expense of energy yield models, such as hourly resolution and the use of “typical” weather-years (known as Typical Meteorological Year (TMY) files), continue to be broadly employed today.

Recent studies have quantified the impact of various environmental and system effects on PV performance, including non-Lambertian ground reflection [27], soiling [28], snow [28], module degradation [29], cell-to-module irradiance mismatch [30], and sub-hourly clipping loss [31]. This thesis builds upon and complements this existing literature through its focus on the impact of structural supports and racking, artificial ground reflectors, and spectral irradiance on bifacial PV system performance.

The impact of structural supports on PV performance is typically represented by a constant rear structure shading factor [32, 16, 22], which does not account for changing racking shading over time or racking reflection. Previous studies have quantified the impact of racking on bifacial PV system performance, finding a decrease in rear irradiance [33], increase in irradiance mismatch losses [34], and a decrease in predicted bifacial gain [27, 35]. Furthermore, Ayala Pelaez *et. al.* found that torque tube reflections can reduce structural shading from 12% to 1% [36]. The work in Chapter 3 of this thesis builds upon this precedent by modelling a bifacial PV system with reflective racking in a detailed ray-trace model to quantify the impact of racking reflection over an entire year.

A broad range of artificial reflector materials have been proposed, including polymers and tarps [37, 38, 39], fabrics [40, 41], aggregate [42, 43], and paint [44]. Despite many studies of artificial reflectors in research-scale bifacial PV systems [45, 46, 37, 47], commercial adoption has been slow. The profitability of artificial reflectors in bifacial systems is still uncertain: while Lim *et. al.* found that pairing bifacial systems with mirrors can reduce the levelized cost of energy (LCOE) [48], Riedel-Lyngskær *et. al.* found a negligible LCOE improvement for white tarps [37]. In Chapter 4, I present a detailed analysis of optimal artificial reflector designs and the economic viability of artificial reflectors for a full year in three locations.

Although variation in the solar spectrum is typically neglected in PV models, its effects can be significant: spectral irradiance can cause weekly efficiency variations of -6% to +13% [49]. The effect of spectral irradiance on PV has been quantified through parameterized models [50, 51, 52, 53, 54], satellite models [55, 56], and spectral irradiance measurements [57, 58, 59, 60]. Bifacial systems are particularly impacted by spectral irradiance effects due to spectral albedo, which can cause instantaneous rear spectral effects from -11% to +20% [61, 62, 63, 64, 65]. However, the accuracy of these spectral correction methods, and the environmental conditions that most require spectral irradiance correction, remain

unclear. In Chapter 5, I demonstrate the conditions where spectral irradiance correction is necessary, identify shortcomings in existing spectral irradiance methods, and compare five parameterized spectral correction methods.

1.3 Thesis Outline

This thesis is comprised of six chapters, and includes four manuscripts. Before each manuscript, its scope and research impact, related background information and methodology, and co-author contributions are provided, followed by the manuscript and the published supplemental information.

The methodologies applied in this research are described in detail in each manuscript, with supporting details provided in the prefaces. An overview of bifacial PV modelling methodologies is provided in section 2.3 and an overview of spectral irradiance acquisition methods is provided in section 2.1.4.

Chapter 2 describes the background knowledge necessary to understand this work, including the properties of sunlight and the atmosphere, photovoltaic theory and operation, and bifacial photovoltaic modelling methods.

Chapter 3 contains a journal article, “Quantifying Structural Shading & Reflection Effects on Single Axis Tracked Bifacial Photovoltaic System Performance”, published in *Advanced Energy and Sustainability Research* in 2024. This work analyzes the impact of structural racking shading and reflection on bifacial photovoltaic system performance.

Chapter 4 presents another article, “Artificial Ground Reflector Size & Position Effects on Energy Yield & Economics of Single Axis Tracked Bifacial Photovoltaics”, published in *Progress in Photovoltaics* in 2024. This work studies the impact of highly-reflective artificial reflector material on a bifacial single-axis-tracked photovoltaic system.

Chapter 5 presents two manuscripts related to spectral irradiance effects on photovoltaic performance. The first, “Spectral Irradiance Correction of Photovoltaic Energy Yield Predictions”, was published in *Solar Energy* in 2025. This work analyzes the impact of changing spectral irradiance on the performance of bifacial silicon modules in North America. The second, “Comparison of Spectral Correction Methods: Spectral Irradiance Measurements and Parameterized Spectral Models”, is presented here in draft form. This work compares long-term spectral irradiance measurements in Denmark to various parameterized spectral correction models.

Chapter 6 summarizes the thesis and presents avenues for future research in the field of bifacial photovoltaic modelling.

Chapter 2

Background

To provide context for the research topics in this thesis, described in section 1.3, this chapter provides an overview of the theory of solar irradiance, the atmosphere, PV devices, bifacial PV systems, and bifacial PV modelling. This background information will support a detailed understanding of the methodology, results, and analysis presented in chapters 3, 4, and 5 concerning bifacial PV performance.

2.1 Properties of Sunlight and the Atmosphere

The sun emits radiation with a spectral distribution similar to that of a 5780 K blackbody (Figure 2.1) [66]. The solar irradiance incident on the upper limit of the atmosphere is the extraterrestrial irradiance (ETR). Although the ETR varies slightly with respect to the sun’s sunspot cycle and the earth-sun distance, it can be approximated by the American Society for Testing and Materials (ASTM) E-490 AM0 standard spectrum [67] shown in Figure 2.1. The AM0 solar spectrum has a peak at 500 nm, with about half of total irradiance in the visible range, and a total integrated irradiance of 1366.1 W/m² [68], although recent advancements show that the total solar irradiance is approximately 1361 W/m² [69, 70].

The atmosphere acts as a spectrally-selective filter on the incoming sunlight, such that the irradiance at ground level is highly variable. As sunlight passes through the atmosphere, it is scattered and absorbed by atmospheric constituents, as will be described in more detail in sections 2.1.2 and 2.1.3. This causes a reduction in total solar irradiance at the Earth’s surface, with some wavelengths of sunlight being more strongly attenuated than others. In

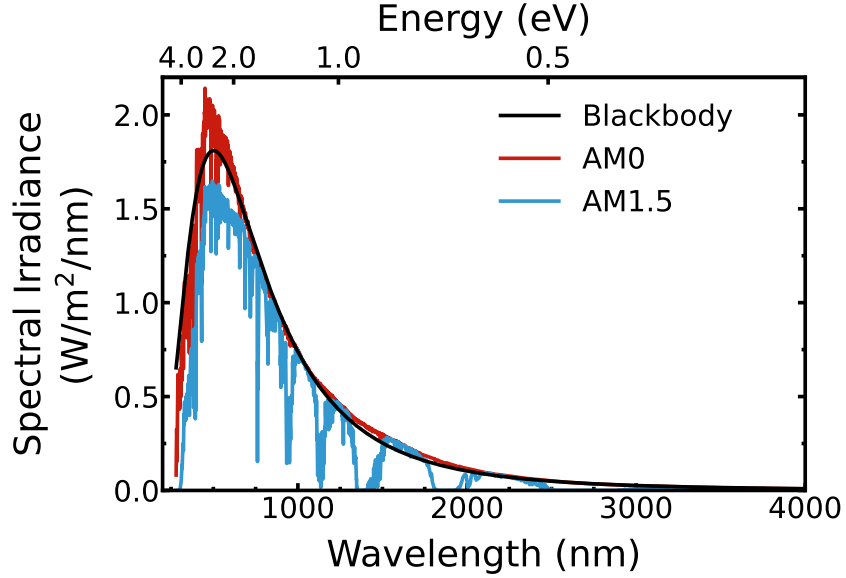


Figure 2.1: Spectral irradiance with respect to wavelength of a 5780 K blackbody (black), the AM0 spectrum (red), and the AM1.5G spectrum (blue).

the absence of clouds, up to 70-80% of all extraterrestrial irradiance passes through the atmosphere to the ground [71].

PV cell and module efficiency measurements and standard PV energy yield models assume that ground-level solar irradiance follows the ASTM G-173-03 standard spectrum [67], with a total irradiance of 1000 W/m^2 , an air mass (AM) of 1.5, and a 37° tilted receiving plane. These conditions were selected because they are most representative of locations in the southwestern United States where there is high solar irradiance, which is ideal for PV generation [72]. Chapter 5 explores the impact of solar irradiance deviating from the reference solar spectrum for bifacial PV systems.

2.1.1 Solar Irradiance

For a fixed observer on Earth, the sun moves in a predictable pattern over the course of the day and seasons. The sun's position in the sky can be defined by two angles: the *zenith angle*, θ , and the *azimuth angle*, ϕ . These are illustrated in Figure 2.2. The zenith angle is taken between a line perpendicular to the ground and the sun. The complement of this angle, between the ground and the sun, is called the *elevation angle*. The azimuth angle is

the angle between due North (or in some conventions due South) and the sun. The solar position can be calculated from the observer's location (latitude and longitude), the date, and the time of day. Calculating solar position is an essential step in PV performance modelling.

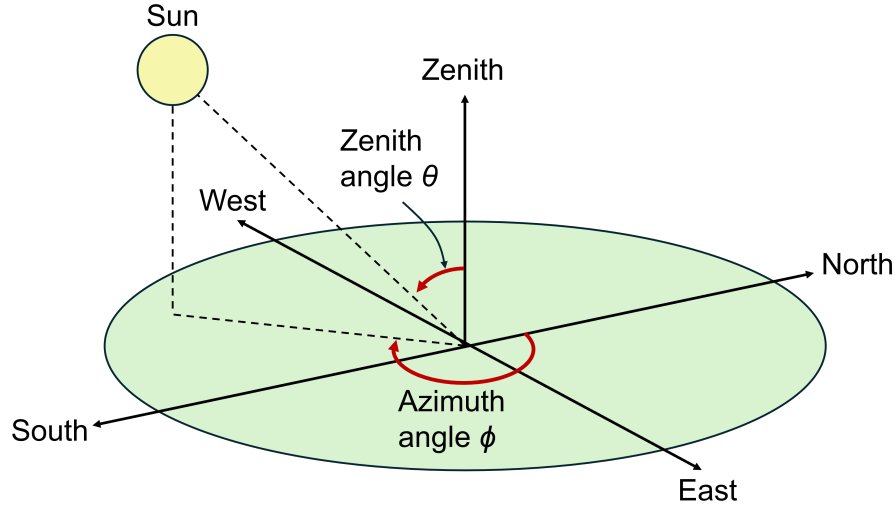


Figure 2.2: Diagram of solar position angles.

2.1.1.1 Air Mass

Air mass, AM, is the ratio of sunlight's path length through the atmosphere, L , to the thickness of the atmosphere, L_0 :

$$\text{AM} = \frac{L}{L_0} \quad (2.1)$$

If we approximate the atmosphere and the surface of the Earth as flat planes (Figure 2.3a), AM is defined by the cosine relationship:

$$\text{AM} = \frac{1}{\cos(\theta)} \quad (2.2)$$

where θ is the solar zenith angle as defined in the previous section.

This approximation is appropriate for most air masses. However, when the sun is low in the sky, the gradual change in the refractive index of the atmosphere with respect to altitude becomes significant. Sunlight's path bends through the atmosphere, resulting in two possible solar zenith angles: the true solar zenith angle, θ_{true} , which is defined by the sun's real position, and the apparent solar zenith angle, θ_{apparent} , which is defined by the apparent sun position (see Figure 2.3b) [73]. The bend in the sunlight's path causes the sun to appear higher in the sky than it is in reality.

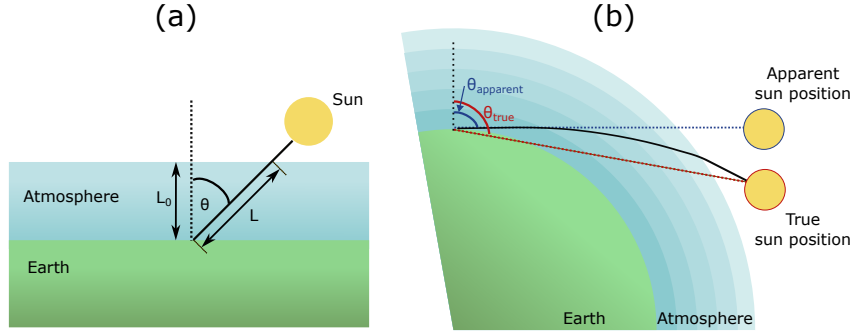


Figure 2.3: Air mass illustration for (a) flat Earth and atmosphere, and (b) gradual refractive index of the atmosphere.

There are many formulas to calculate the AM accounting for sunlight's refraction in the atmosphere. Many of these are implemented in the open-source Python library, *pvl* [74]. One common example is the Gueymard equation for relative AM from [75]:

$$AM \approx \left[\cos(\theta) + \frac{0.48353 \cdot \theta^{0.095846}}{(96.741 - \theta)^{1.754}} \right]^{-1} \quad (2.3)$$

where θ in this case refers to the apparent solar zenith angle, θ_{apparent} .

In Chapter 5, I apply the AM function from [76] to assess spectral irradiance impact with respect to air mass.

Equations 2.1 and 2.3 assume that the observer is at sea level. If the observer is above sea level, for example in a high-altitude mountain location, the AM must be corrected to account for the reduced path length the sunlight has taken. This can be done by applying a pressure correction to the AM:

$$AM_{\text{absolute}} = \frac{P_{\text{air}}}{P_{\text{air},0}} AM \quad (2.4)$$

where P_{air} is the air pressure and $P_{\text{air},0}$ is the reference air pressure of 101.325 kPa [75].

2.1.1.2 Solar Irradiance Components

Solar irradiance is typically defined by three measurements (Figure 2.4): global horizontal irradiance (GHI), diffuse horizontal irradiance (DHI), and direct normal irradiance (DNI). GHI is the irradiance incident on a horizontal plane, both directly from the sun and scattered in the atmosphere. DHI is the diffuse irradiance incident on a horizontal plane, not including direct irradiance from the sun. DNI is the direct irradiance from the sun incident on a plane normal to the sun's position. These three components of solar irradiance are taken as inputs to the PV performance models described in this thesis. For PV systems, we may also consider the global reflected irradiance (GRI), the upwelling solar radiation on a horizontal plane, and the global tilted irradiance (GTI), the irradiance incident on the module's tilted plane.

GHI, DHI, and DNI are related by the following equation [77]:

$$GHI = DHI + DNI \cos(\theta) \quad (2.5)$$

where θ is the zenith angle of the sun. Therefore, if two irradiance components are available, the third can be calculated from the solar zenith angle. For a PV module, the GTI is most important, since it determines the power output of the PV system. GTI is a combination of direct, diffuse, and ground-reflected irradiance. GTI can be measured by a plane-of-array pyranometer or can be calculated through optical models as will be discussed in section 2.3.2. GTI is also called the plane-of-array (POA) irradiance.

For bifacial systems, the GRI can be used to calculate albedo as described in section 2.3.1.2, which is essential for bifacial energy yield calculations.

2.1.1.3 Solar Irradiance Measurements

Broadband solar irradiance is measured by a *pyranometer* or *pyrheliometer*. Pyranometers measure the total radiation incident on a plane from any direction in a 2π hemisphere. When mounted horizontally, pyranometers measure GHI. When mounted horizontally with a shadow ball or band tracking the sun to block direct irradiance, pyranometers measure

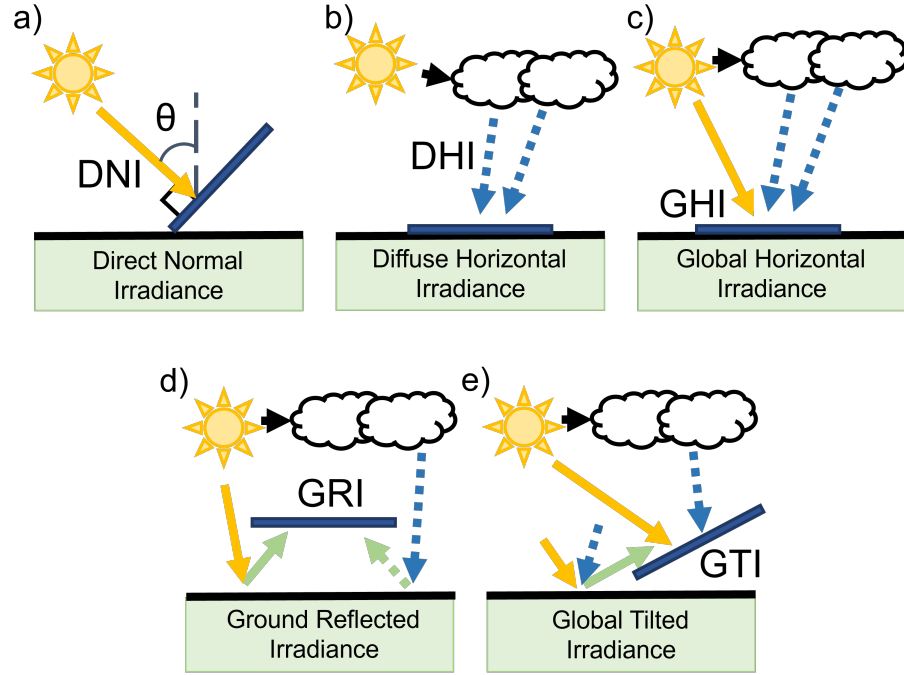


Figure 2.4: Diagram of irradiance components, including: (a) Direct Normal Irradiance (DNI), (b) Diffuse Horizontal Irradiance (DHI), (c) Global Horizontal Irradiance (GHI), (d) Ground Reflected Irradiance (GRI), and (e) Global Tilted Irradiance (GTI).

DHI. Pyrheliometers measure DNI by tracking the sun on a dual-axis tracker with a collimating tube that blocks diffuse irradiance [77]. The collimating tubes accept light from a narrow region of the sky normal to the receiving plane, typically in a 5° field of view. While these methods measure broadband irradiance, spectrally-resolved solar irradiance measurement approaches are described in section 2.1.4.

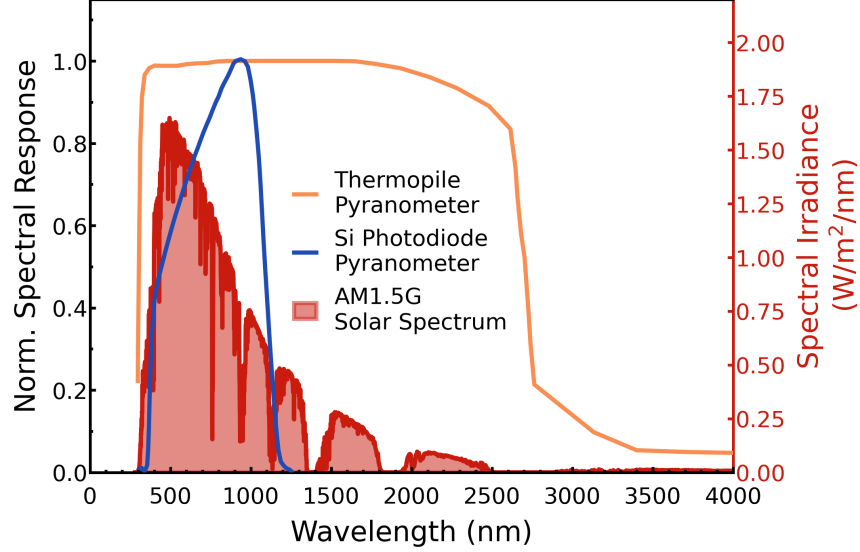


Figure 2.5: Spectral responsivity of example pyranometer types, including thermopile pyranometer and silicon pyranometer, with reference solar spectrum. Spectral response curves taken from [78] and [79].

Most high-quality pyranometers and nearly all pyrheliometers are thermopile radiometers [80], which are nearly spectrally flat from 300-3000 nm (Figure 2.5) [79, 81]. These use the thermoelectric effect, where voltage is generated at the junction of two metals at different temperatures. They contain a “hot” junction exposed to the sun, and a “cold” junction connected to a heat sink [77]. The temperature difference between these junctions is proportional to the received irradiance. Alternatively, silicon photodiode radiometers measure solar irradiance via the photovoltaic effect, similarly to a PV module; however, they are sensitive to the incident spectrum, ambient temperature, and the angle of incident irradiance. In general, thermopile pyranometers are more accurate than silicon pyranometers.

2.1.1.4 Cloudiness Metrics

There are many measures of the cloudiness level and haze in the atmosphere, including diffuse fraction, clearness index, and clear-sky index. The diffuse fraction is the fraction of GHI that comes from the diffuse component:

$$\text{Diffuse fraction} = \frac{\text{DHI}}{\text{GHI}} \quad (2.6)$$

The diffuse fraction is always between 0 and 1 (or 0% and 100%). I apply this metric in section 5.2 to separate meteorological conditions into cloudiness bins.

Another common metric is the clearness index, k_t , the ratio of the ground-level irradiance to the extraterrestrial irradiance [82]:

$$k_t = \frac{\text{GHI}}{\text{ETR} \cos(\theta)} \quad (2.7)$$

where ETR is the extraterrestrial irradiance, θ is the solar zenith angle, and GHI is the global horizontal irradiance. The cosine translates the ETR to a horizontal plane. The clearness index is a dimensionless number between 0 and 1. When the clearness index is high, it is sunny, and when the clearness index is low, it is cloudy.

Lastly, the clear sky index, k_c , is similar to k_t , but relies on clear-sky GHI rather than extraterrestrial irradiance [83]:

$$k_c = \frac{\text{GHI}}{\text{GHI}_{\text{clearsky}}} \quad (2.8)$$

where $\text{GHI}_{\text{clearsky}}$ is the clear-sky GHI, or the GHI that would pass through the atmosphere to the observer if the sky were completely clear [84]. Like the clearness index, the clear-sky index is a dimensionless number, typically between 0 and 1, where 1 is completely clear and 0 is completely overcast. Clear sky indices above 1 indicate “cloud lensing”, where clouds enhance the solar irradiance at ground level above the clear-sky limit [85].

The DHI fraction is the simplest of these metrics to calculate, since only the GHI and DHI are required; however, due to DNI geometric cosine losses at low solar elevation angles, the DHI fraction will have a solar position dependence. Clearness index and clear-sky index remove this solar position dependence. The clearness index requires extraterrestrial irradiance, which is simple to calculate, but neglects the AM, which is significant for atmospheric attenuation of irradiance [83]. The clear sky index is most difficult to obtain because it requires atmospheric parameters such as water vapour, aerosol optical depth, and ozone to calculate the clear-sky GHI [83].

2.1.2 Atmosphere-Sunlight Interactions

To understand the effect that the atmosphere has on solar irradiance, it is important to review the interactions between sunlight and the atmosphere. Atmospheric conditions strongly impact the spectrally-resolved solar irradiance as explored in chapter 5. It is also

important for the quantity of solar irradiance and degree of cloudiness, which impacts the results in chapters 3 and 4.

Absorption As light passes through a medium, such as the atmosphere, it is attenuated by absorption. Absorption is the reduction of propagating photons, usually through their conversion to heat or chemical energy. Absorption of light as it passes through a medium can be assumed to follow the Beer-Lambert law:

$$I(x, \lambda) = I(0, \lambda)e^{-\alpha(\lambda)x} \quad (2.9)$$

where x is the direction of propagation, $I(0, \lambda)$ is the intensity at $x = 0$, and α is the absorption coefficient [86]. This equation can also apply to scattering losses, in which case α is replaced by the scattering coefficient, σ [87]. This equation can represent both absorption and scattering effects by taking their sum to find the extinction coefficient, κ [87].

When modelling light passing through the atmosphere to ground level, x can be replaced by the optical AM. In this case, κ is an effective value across the total path through the atmosphere, and is dependent on atmospheric conditions [72].

Scattering Scattering is the redirection of an incident photon by a particle [88]. The degree and direction of scattering is dependent on: 1. the size of the particle compared to the wavelength of the radiation, 2. the refractive index of the particle material, and 3. the shape of the particle [89, 88]. Particle shape is typically ignored in scattering models [88, 90].

There are three primary models of scattering: Rayleigh scattering, Mie scattering, and nonselective scattering [91]. Rayleigh scattering is caused by small particles less than $1/10$ the radiation wavelength [86] such as gas molecules. It is strongly wavelength-dependent, with the highest scattering for the shortest wavelength light. This is why the sky is blue: blue (short-wavelength) light is more strongly scattered than green to red (long-wavelength) light. Mie scattering is caused by particles between $1/10$ and $10\times$ the radiation wavelength [86] such as water vapour. It scatters forwards more strongly than other directions and is less wavelength dependent than Rayleigh scattering [91]. Lastly, nonselective scattering is caused by particles over $10\times$ the radiation wavelength [86] such as water droplets in clouds. Nonselective scattering is equal across the visible wavelengths; this is why clouds appear white to the naked eye.

2.1.3 Atmospheric Parameters

The atmosphere contains various scattering and absorbing constituents, including water vapour and other gases, aerosols, and clouds. These constituents scatter and absorb light in a wavelength-dependent way, modifying the solar spectral irradiance that reaches the ground. Some examples are illustrated in Figure 2.6a, with the total atmospheric absorption shown in Figure 2.6b.

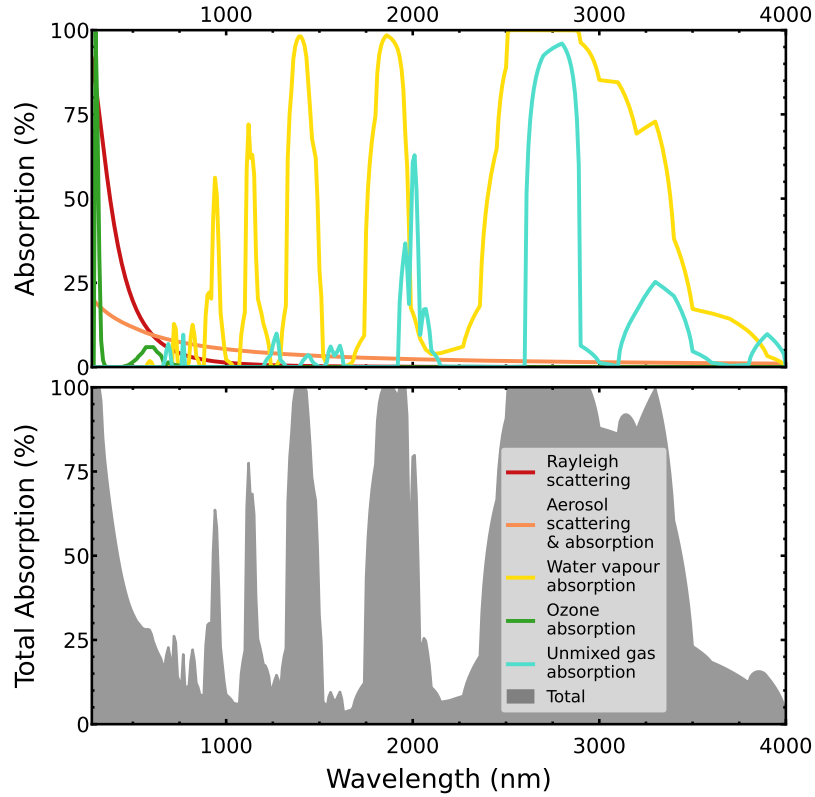


Figure 2.6: Atmospheric scattering and absorption with respect to wavelength for example AM1.5 conditions, calculated in PVLighthouse [92]. Generated for 2027-02-27, 12:00PM, 39.74° latitude, -105.6° longitude, 37° tilted plane, 1013.25 mb, 0.084 turbidity, 1.42 cm precipitable water vapour, 0.34 atm-cm ozone, 0.1 ground albedo.

2.1.3.1 Gases

Gases, such as water vapour, ozone, carbon dioxide, and oxygen, absorb sunlight as it passes through the atmosphere. The most important absorbing gases in the atmosphere are water vapour and ozone [93]. This absorption is wavelength-selective: for example, ozone absorbs strongly in short wavelengths below 350 nm [93] and is responsible for low ultraviolet (UV) irradiance at ground level, while carbon dioxide absorption is focused in the long wavelengths [94] (Figure 2.6).

Water Vapour

Water vapour is the atmospheric gas that causes the most attenuation of incoming solar radiation [95], with many absorption bands as illustrated in Figure 2.6a.

The amount of water vapour in the atmosphere can be quantified by the *precipitable water vapour*. The precipitable water vapour is the depth of water that would appear on the ground if all the water vapour in a vertical column of the atmosphere precipitated as rain [96]. This is an important input to solar spectral irradiance models, because higher precipitable water results in higher attenuation of sunlight in the water absorption bands (see Figure 2.7).

The precipitable water vapour is taken as an input to the parameterized PV spectral correction models explored in section 5.3. Precipitable water vapour can be calculated from temperature and relative humidity [97], satellite measurements [98], or from solar spectral irradiance measurements [99].

2.1.3.2 Aerosols

Atmospheric aerosols are solid or liquid particles suspended in the atmosphere [100]. Aerosols both scatter and absorb radiation. They scatter light in a wavelength-dependent way, with stronger scattering at short wavelengths. They are generated from both natural sources, such as volcanic eruptions, and anthropogenic sources, such as fossil fuel combustion.

The *aerosol optical depth* is a way to quantify the impact of aerosols on the solar spectrum. It represents the length after which incident light has been reduced to approximately one third ($1/e$) of its original intensity due to aerosol absorption and scattering. Aerosol optical depth is defined by the Beer-Lambert attenuation of sunlight in the atmosphere due to aerosols [95]:

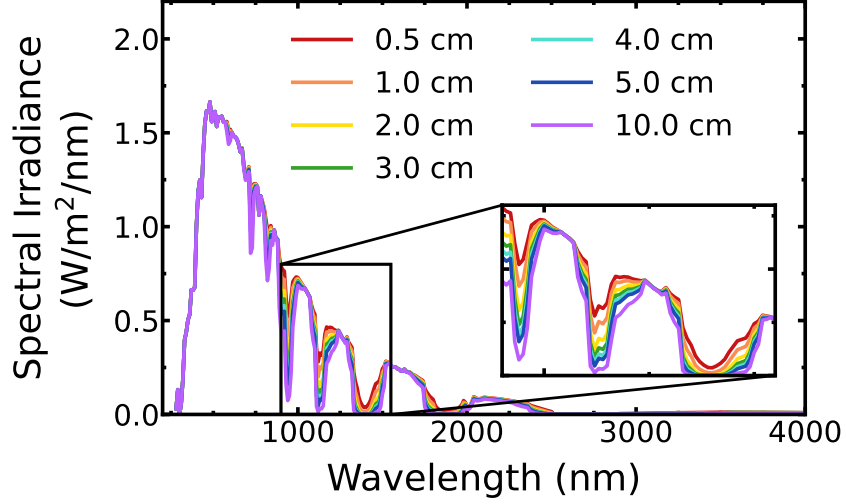


Figure 2.7: Global solar spectral irradiance for a range of precipitable water values from 0.5 to 10 cm, calculated in PVLighthouse [92]. Generated for 2027-02-27, 12:00PM, 39.74° latitude, -105.6° longitude, 37° tilted plane, 1013.25 mb, 0.084 turbidity, 0.34 atm-cm ozone, 0.1 albedo.

$$G(\lambda) = \text{ETR} \cdot e^{-\tau(\lambda) \cdot \text{AM}} \quad (2.10)$$

where G is the irradiance at ground level, ETR is the extraterrestrial irradiance, τ is the aerosol optical depth, AM is the air mass and λ is the wavelength.

While the aerosol optical depth varies with respect to wavelength, it is often quantified by a single value measured at 500 or 550 nm. For example, the MODIS Aerosol Product provides aerosol optical depth at 550 nm [101] and NASA's AERONET database provides aerosol optical depth at eight wavelengths, including 500 nm [102].

2.1.3.3 Clouds

Clouds have a significant effect on PV energy yield, primarily because they reduce total incident irradiance by reflecting, scattering, and absorbing incoming sunlight. Clouds are challenging to model because their composition, size, speed, and altitude can all vary on short timescales.

Clouds also have a spectrally-selective effect on incoming solar radiation, although this is complex to capture and is typically neglected in PV spectral irradiance models [103]. Below 900 nm, clouds scatter light evenly with respect to wavelength in the visible range, which is why they appear grey or white. However, long-wavelength irradiance is strongly scattered and absorbed by clouds, leaving more short-wavelength irradiance in the solar spectrum [104, 105], as shown in Figure 2.8. Although clouds decrease broadband irradiance, this spectral effect is well-known to increase PV efficiency for many single-junction technologies [106], as discussed in detail in chapter 5.

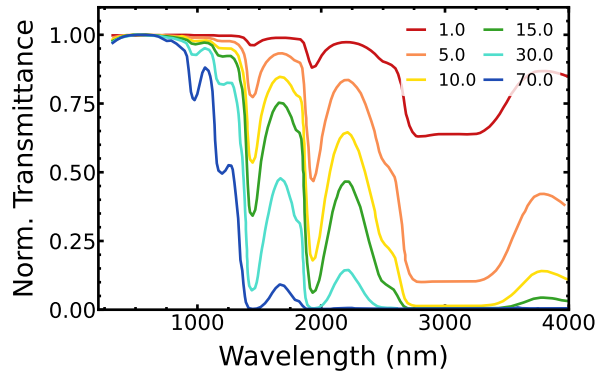


Figure 2.8: Cloud transmittance for a range of cloud optical depths normalized at 500 nm modelled in libRadtran. Adapted from [105], figure 2.6.

2.1.4 Spectral Irradiance Acquisition

Solar spectral irradiance can be acquired through spectral irradiance models or ground measurements. Spectral irradiance models are limited by the quality of the model inputs and the necessary assumptions required for modelling. Direct measurements are more expensive and challenging to acquire, but provide an accurate picture of the highly variable nature of local atmospheric conditions.

2.1.4.1 Spectral Irradiance Models

Most spectral solar irradiance models are radiative transfer models, which solve the radiative transfer equation of the Earth’s atmosphere [88]. These models take the extraterrestrial

solar irradiance and atmospheric parameters to calculate ground-level solar irradiance. Although detailed solar spectral irradiance models are not directly applied in this work, they provide important context for understanding the atmosphere and its effect on the solar spectrum.

The radiative transfer equation includes four processes for an incident beam passing through the atmosphere: 1. absorption loss, 2. scattering loss, 3. scattering source, or radiation scattered into the beam path, and 4. emission source, or radiation emitted by the atmosphere in the beam path [90]. For photovoltaic applications, radiation emitted by the atmosphere (point 4) is negligible because the atmosphere is much cooler than the sun [88]. Some models may also neglect light that is scattered into the beam path (point 3) but this results in an underestimation of ground-level radiance [89]. Some models assume a plane-parallel atmosphere, which is a good assumption for low zenith angles [88], but causes errors at high zenith angles above 70 degrees [72].

One important example of an atmospheric radiative transfer model is MODerate resolution TRANsmission (MODTRAN), which solves the radiative transfer equation for 0.2 to 100 μm [107]. This model treats the atmosphere as spherical layers that are horizontally homogeneous [89]. It applies vertical profiles of atmospheric constituents to find absorption, emission, and scattering of photons in the atmosphere. It can model water and ice clouds, rain attenuation, and light refraction in the atmosphere, and includes six built-in atmospheres for example conditions [89].

Other solar spectral irradiance models include LibRadtran [108], SBDART [109], and SPCTRAL2 [110].

Simple Model of the Atmospheric Radiative Transfer of Sunshine (SMARTS)

Simple Model of the Atmospheric Radiative Transfer of Sunshine (SMARTS) is the most commonly-used spectral irradiance model for photovoltaics, and is used to define the ASTM standard spectral irradiance spectra [67]. SMARTS can calculate solar irradiance from 280 - 4000 nm.

SMARTS is a spectral radiative transfer model that is intended to act as a fast, simple substitute of the more complex atmospheric models such as MODTRAN or Libradtran [72]. The model computes clear-sky spectral irradiances, including DNI, DHI, and GHI [103]. One unique ability of SMARTS is the calculation of spectral GTI, taken as a combination of in-plane direct, diffuse, and ground-reflected irradiance, which are calculated individually.

This model includes 22 scattering and absorption processes, including Rayleigh and Mie scattering, and absorption of water vapour, ozone, carbon dioxide, and other gases

[72]. It calculates the transmission function with respect to wavelength for each of these processes and applies it to the extraterrestrial irradiance to find the irradiance at ground level. As inputs, the model requires solar position, precipitable water, aerosol optical depth, atmospheric ozone content, pollution levels, and spectral albedo [72].

2.1.4.2 Fast All-sky Radiation Model for Solar applications with Narrowband Irradiances on Tilted surfaces (FARMS-NIT)

The Fast All-sky Radiation Model for Solar Applications with Narrowband Irradiances on Tilted Surfaces (FARMS-NIT) model [111, 112] is currently implemented in the National Solar Radiation Database (NSRDB) [113] Spectral On-Demand service. Under clear-sky conditions, FARMS-NIT applies the SMARTS model [111] with inputs derived from Modern-Era Retrospective analysis for Research and Applications, Version 2 (MERRA-2), a global meteorological dataset from satellite measurements [114]. For cloudy conditions, it applies a lookup table based on libRadtran results to apply cloud reflection, absorption, and scattering [112].

2.1.4.3 Spectral Irradiance Measurements

A *spectroradiometer* measures spectrally-resolved radiation, and can measure GHI, DNI, or DHI, depending on the mounting and shading elements installed. They typically separate light by wavelength through a diffraction grating or prism, then measure the irradiance with a detector [95]. In some devices, the grating is rotated to measure irradiance sequentially by wavelength [95], while in others, an array of spatially-separated detectors measure irradiance at many wavelengths simultaneously [115]. These detectors have limited wavelength ranges, and one significant challenge when using spectral irradiance measurements is stitching between instruments. For example, section 5.3.2.1 describes the process of stitching together measurements from an EKO MS-700 and EKO MS-701. Section 5.2 explores the impact of reduced solar spectral irradiance range in more detail.

SolarSIM Devices The SolarSIM devices are a series of solar spectral irradiance meters from Spectrafy [116, 117]. They apply filtered photodiodes to measure the solar spectrum in narrow wavelength bands. The wavelength bands target specific atmospheric parameters such as the aerosol optical depth, water vapour, ozone, and cloud cover. From these atmospheric parameters, a model calculates the solar spectral irradiance.

Chapter 5 contains an analysis of spectral irradiance data from seven sites across North America, including six Canadian locations in the CanSIM network [118]. At each station, two SolarSIM devices, the SolarSIM-G and SolarSIM-D2 (Figure 2.9), measure minutely data. The SolarSIM-D2 is mounted on a dual axis tracker to reconstruct the DNI spectrum and the SolarSIM-G is mounted horizontally to reconstruct the GHI spectrum. Both devices provide solar spectral irradiance from 280 - 4000 nm with 1 nm resolution.

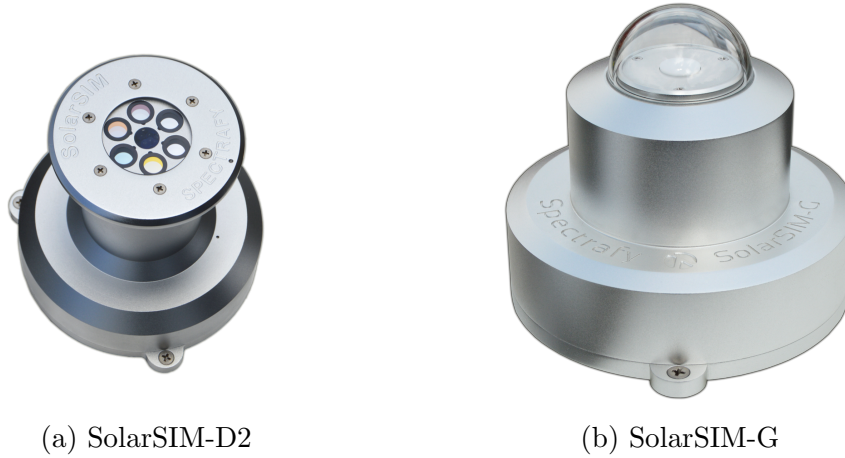


Figure 2.9: Photos of SolarSIM devices from [119]

2.2 Photovoltaic Theory and Operation

This section provides an overview of the fundamentals of photovoltaic solar cell operation. Understanding the theory of light absorption and power generation in solar cells is essential for accurate bifacial PV modelling.

2.2.1 Basic Operation of Semiconductors

Electrons in an isolated atom occupy discrete energy levels, with a maximum of two electrons per energy level. When many atoms are connected in a crystal lattice, the energy levels become bands due to the interaction between valence electrons of atoms in close proximity, resulting in a large number of energy states [120, 121].

The low energy states are filled by electrons first, with higher energy states left empty. The uppermost nearly-filled band is called the valence band, while the lowest nearly-empty band is called the conduction band [121]. Electrons in the conduction band are free to move between atoms, allowing current conduction. Gaps in the valence band, where there are missing electrons, are called *holes*; electrons from adjoining atoms are free to fill this hole. In this way, the hole can move through the material like an electron does, carrying current in the reverse direction.

In semiconductors, there is a region with no available energy states between the valence and conduction band called the *band gap*. Materials with a bandgap below 3 eV are considered semiconductors [121]. In a semiconductor at room temperature, thermal energy excites a small number of electrons from the valence band to the conduction band. Materials with band gaps above 3 eV are insulators, which prevent current flow, while materials with no band gap are metals, allowing current to flow freely [121].

2.2.1.1 Light Absorption in Semiconductors

Sunlight is absorbed in a semiconductor when photons excite electrons from the valence band to the conduction band, generating an electron and hole that are free to travel within the semiconductor [121]. Electrons in the conduction band and holes in the valence band are called *carriers*. To excite an electron-hole pair, photons must have an energy higher than the bandgap.

Photons with energy below the bandgap do not excite an electron-hole pair, and either generate heat or pass through the semiconductor (Figure 2.10). Photons with energy above the bandgap may be absorbed, but excess energy is lost to thermalization as the carriers relax to the band edge (Figure 2.10). These two loss mechanisms are fundamental to the efficiency limit of solar cells: increasing the semiconductor bandgap increases below-bandgap loss and decreases thermalization loss, while decreasing the semiconductor bandgap increases thermalization losses and decreases below-bandgap losses. Thermalization and below-bandgap losses are explored in more depth for realistic solar spectra in section 5.2.

Solar cells can include either direct or indirect bandgap materials as their absorber. Direct bandgap semiconductors have the top of the valence band and the bottom of the conduction band at the same value of crystal momentum. Indirect bandgap semiconductors have the top of the valence band and the bottom of the conduction band at different values of momentum. In indirect bandgap semiconductors, a phonon, a unit of lattice vibration, is required in addition to the photon to produce an electron-hole pair. Absorption near

the bandgap is lower in indirect bandgap materials because the requirement of a second particle decreases the likelihood of the absorption process. This thesis is focused on silicon, an indirect bandgap material, for motivations described in section 2.2.3.2.

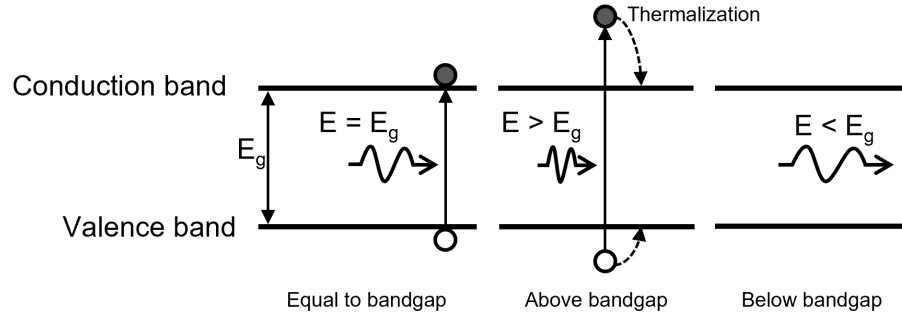


Figure 2.10: Electron-hole pair generation for photons with different energy levels.

2.2.1.2 Recombination

After an electron-hole pair is created, it quickly separates into an electron and a hole. These carriers can then be lost through *recombination*, where an electron returns to the valence band, filling a hole. There are three important recombination mechanisms in solar cells: radiative recombination, Auger recombination, and trap-assisted (or Shockley-Reed-Hall) recombination (Figure 2.11).

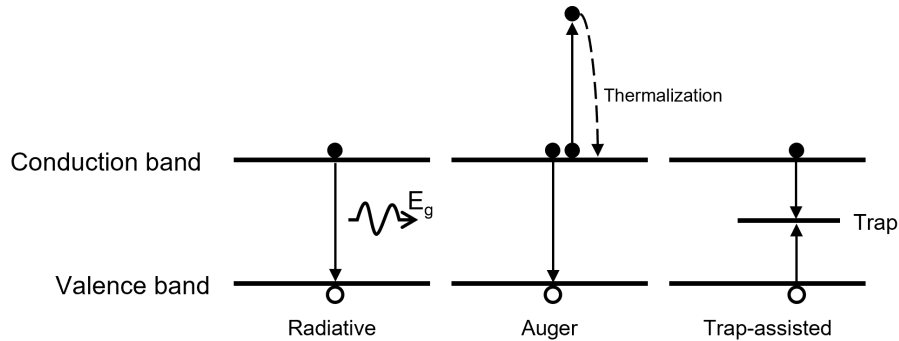


Figure 2.11: Types of recombination in semiconductors.

Radiative recombination is the reverse process to photon absorption, where an electron falls from the conduction band to the valence band, destroying a hole and generating a

photon with the energy of the bandgap of the material. Radiative recombination is higher in direct-bandgap semiconductors because no phonons are required for the process; it is low in silicon, an indirect bandgap material that requires a phonon for radiative recombination. Radiative recombination increases with illumination level because it is proportional to the number of carriers [122].

Auger recombination is the process of an electron falling from the conduction band to the valence band, passing its energy to another carrier (either an electron or hole). The excited carrier then thermalizes to the band-edge and its additional energy is lost. Auger recombination is most significant in highly-doped materials due to the high number of carriers, since it is a three-particle process.

Trap-assisted recombination is a multi-step process where a carrier passes into an energy level within the bandgap, then recombines. Intermediate energy levels are introduced by defects in the material. Trap-assisted recombination is high in low-quality materials, and is why material quality is so important to PV solar cell efficiency. Surface recombination is a sub-type of defect-assisted recombination. At the surface of a semiconductor, the crystal lattice ends, leaving many states within the bandgap and therefore many paths for trap-assisted recombination [122]. Surface recombination can be mitigated with surface passivation techniques, as will be discussed in section 2.2.3.2.

The recombination rate in a semiconductor can be quantified by the carrier lifetime, the average time between generation and recombination for a carrier in the material. It can also be quantified by the carrier diffusion length, the average length a carrier can travel before recombination. In general, higher quality semiconductor material will have longer carrier lifetimes and carrier diffusion lengths.

2.2.1.3 Silicon Lattice and Doping

Most photovoltaic modules deployed worldwide are based on silicon [7]. Silicon is a group IV material with four valence electrons. In a crystal lattice, silicon atoms form covalent bonds with four neighbouring silicon atoms (see Figure 2.12a).

Silicon can be doped by introducing atoms with one more or one less valence electron. If a dopant with 5 valence electrons is introduced, the material becomes n-type, with additional conduction band electrons. If a dopant with 3 valence electrons is introduced, the material becomes p-type. In silicon, gallium and boron are common p-type dopants while phosphorous is a common n-type dopant [7].

In p-type material, there are more holes in the valence band than electrons in the conduction band, so holes are the *majority carrier* and electrons are the *minority carrier*.

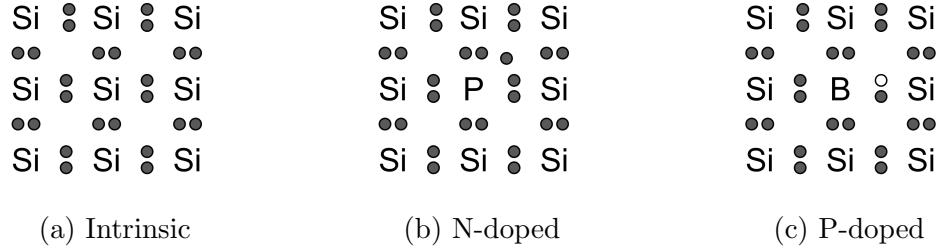


Figure 2.12: Diagram of silicon lattice for intrinsic, n-doped, and p-doped material.

In n-type material, the reverse is true, where electrons are the majority carrier and holes are the minority carrier.

2.2.1.4 The PN Junction

When a piece of p-type and n-type material are sandwiched together, this forms a PN junction (Figure 2.13). Due to the difference in carrier concentration, carriers diffuse across the junction: electrons diffuse from the n-type material into the p-type material while holes diffuse from the p-type material into the n-type material. Current caused by carrier diffusion is called the diffusion current. Carriers recombine at the junction, leaving ionized doping atoms behind in a *depletion region* mostly devoid of carriers. The remaining net charge creates an electric field at the junction that opposes carrier diffusion. The current caused by the electric field is the drift current. When the drift and diffusion currents balance each other, the PN junction is in equilibrium [123].

Under forward bias (Figure 2.13b), a voltage is applied across the PN junction with the positive lead connected to the p-type side and the negative lead connected to the n-type side. The barrier and therefore the electric field in the PN junction is reduced and current flows freely due to increased diffusion current [124]. Under forward bias, the width of the depletion region is reduced.

Under reverse bias (Figure 2.13c), where positive voltage is applied to the n-type side and negative voltage is applied to the p-type side, the bias voltage increases the barrier and electric field in the junction by adding to the built-in voltage and the width of the depletion region is increased [124]. Reverse bias allows electrons to flow from the p side to the n side and the holes to flow from the n side to the p side, but there are a small number of minority carriers in either side of the junction, limiting current flow [124]. This small current is the reverse saturation current, I_0 . If the applied reverse bias is large enough,

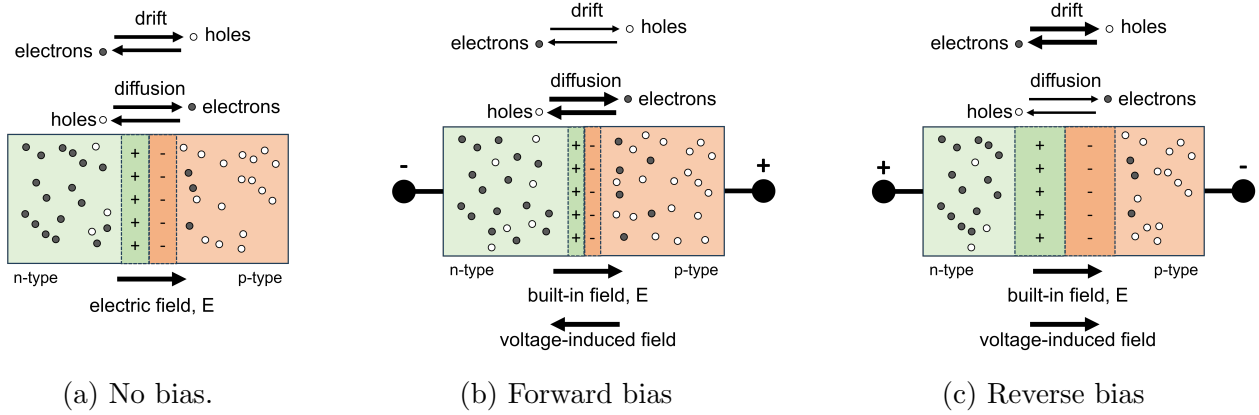


Figure 2.13: Diagram of the PN junction under no bias, forward bias, and reverse bias. Green = n-type material, orange = p-type material, white circles = holes, dark circles = electrons.

the PN junction breaks down and reverse current flows freely due to tunnelling and impact ionization at large electric field strengths.

The current-voltage (IV) characteristics of a PN junction in the dark can be described by the diode equation as follows [124]:

$$I = I_0 \left(\exp \left(\frac{qV}{kT} \right) - 1 \right) \quad (2.11)$$

where I_0 is the reverse diode saturation current, q is the charge of an electron, V is the applied voltage, k is Boltzmann's constant, and T is the temperature of the diode [124].

2.2.2 Solar Cell Operation

Fundamentally, a solar cell is a PN junction that generates power via the *photovoltaic effect* when under illumination and connected to an external circuit. When light is applied to the PN junction, carriers are generated as described in section 2.2.1.1. Minority carriers generated within the depletion region and within a diffusion length of the depletion region are swept across the depletion region by the electric field, thereby creating photo-generated current, I_L .

2.2.2.1 IV Curve

The superposition principle states that the diode current and the photo-generated current in a solar cell are independent and can be added in parallel [121]:

$$I = I_L - I_0 \left[\exp \left(\frac{qV}{nkT} \right) - 1 \right] \quad (2.12)$$

where I_L is the photo-generated current and n is the diode ideality factor, which describes how closely the diode follows ideal diode behaviour. As the incident irradiance increases, I_L increases linearly.

Therefore, an ideal solar cell can be represented as a current source in parallel with a diode (Figure 2.14). This model is focused on the one-diode model, but a second parallel diode may also be used to represent junction recombination in the cell.

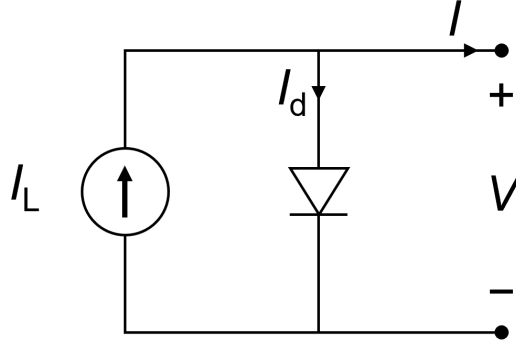


Figure 2.14: Equivalent circuit of photovoltaic device. I_{ph} : photogenerated current, I_d : diode current, V : voltage.

This gives the typical photovoltaic IV curve (Figure 2.15). Two significant points on the IV curve include the *short-circuit current* and the *open-circuit voltage*. The device current when the voltage across the PV device is 0 is the short-circuit current, I_{sc} . Typically we can assume $I_{sc} = I_L$, so the short-circuit current is proportional to incident irradiance. The device voltage when the current of PV device is 0 is the open-circuit voltage, V_{oc} . This is the maximum device voltage.

Furthermore, we can define another point on the IV curve where $V = V_{mp}$ and $I = I_{mp}$. These are the voltage and current at the operating point that generates maximum power, P_{mp} . In standard operation, we assume that solar cells are at their maximum power

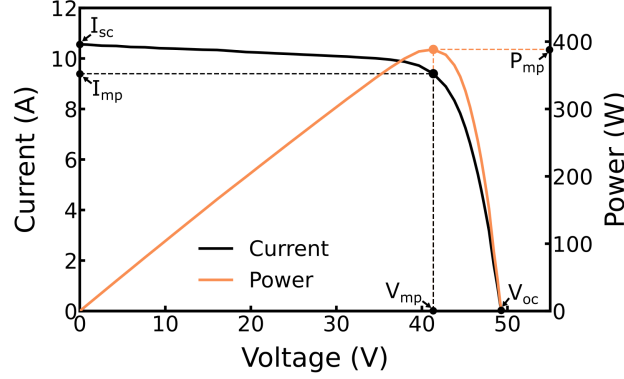


Figure 2.15: Current (black) and power (orange) with respect to voltage for a typical module. Data adapted from [125], figure 7.6.

point thanks to maximum power point trackers. The maximum power point, short-circuit current, and open-circuit voltage define the device's *fill factor*, FF [68]:

$$FF = \frac{V_{mp} I_{mp}}{V_{oc} I_{sc}} \quad (2.13)$$

The FF can also be defined as the ratio of two rectangles, one formed by V_{oc} and I_{sc} and one formed by V_{mp} and I_{mp} . The fill factor is a measure of PN junction quality and device resistances. The maximum power output of the device, P_{mp} , can be calculated from either V_{mp} and I_{mp} or V_{oc} , I_{sc} , and FF [68]:

$$P_{mp} = V_{mp} I_{mp} = V_{oc} I_{sc} FF \quad (2.14)$$

The efficiency, η , of the cell or module can then be calculated from the maximum power point and the power of the incident irradiance, P_{in} :

$$\eta = \frac{P_{mp}}{P_{in}} = \frac{V_{oc} I_{sc} FF}{P_{in}} \quad (2.15)$$

2.2.2.2 Resistances

While an ideal PV device has no resistance, in reality there are PV losses characterized by its *series resistance* and *shunt resistance*. The series resistance acts as a voltage loss,

and is caused by, for example, the bulk resistance of the semiconductor material and contact resistance. Shunt resistance acts as a current loss, and is caused by, for example, defect-assisted recombination [126]. Ideally, shunt resistance would be infinite; finite shunt resistance provides an alternate current pathway. Parasitic resistances are added to the one-diode model as shown in Figure 2.16.

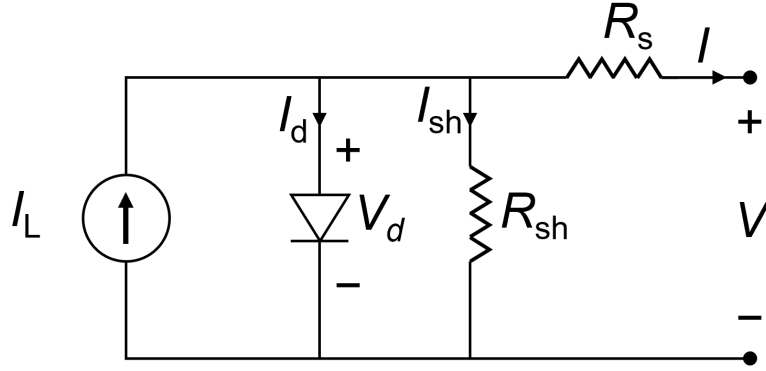


Figure 2.16: Equivalent circuit of photovoltaic device with parasitic resistances. I_{ph} : photo-generated current, I_d : diode current, I_{sh} : shunt current, V : voltage, R_{sh} : shunt resistance, R_s : series resistance.

With series resistance included, the voltage that falls across R_{sh} and the diode, V_d , is the output voltage plus the voltage drop across the resistor: $V_d = V + IR_s$. Therefore, the IV curve of a solar cell with resistances included becomes [121]:

$$I = I_L - I_{sh} - I_d = I_L - \frac{V + IR_s}{R_{sh}} - I_0 \left[\exp \left(\frac{q(V + IR_s)}{nkT} \right) - 1 \right] \quad (2.16)$$

With increasing R_s or decreasing R_{sh} , FF decreases, and efficiency suffers (Figure 2.17). Series resistance losses, equal to $I \cdot R_s$, are higher at high device current (Figure 2.17a). Shunt resistance losses, equal to $I_{sh} = \frac{V_d}{R_{sh}} = \frac{V + IR_s}{R_{sh}}$, are higher at low device current because the current through the shunt resistance represents a larger fraction of total device current.

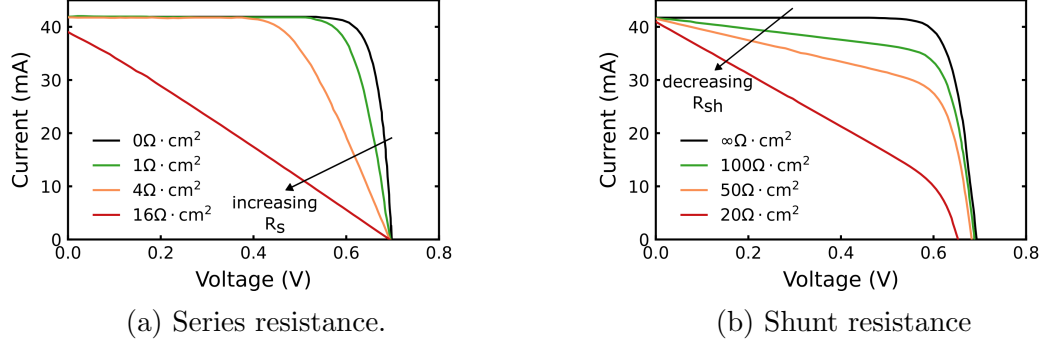


Figure 2.17: Effect of parasitic resistances on module IV characteristics. Adapted from [127], figures 4.8 and 4.10.

2.2.2.3 Quantum Efficiency and Spectral Response

Solar cells and modules can be characterized by their external quantum efficiency (EQE), internal quantum efficiency (IQE) and spectral responsivity (SR) (Figure 2.18).

The EQE is a measure of the efficiency of the conversion of photons to electrons, or from light to current:

$$\text{EQE}(\lambda) = \frac{n_e(\lambda)}{n_{\text{ph}}(\lambda)} \quad (2.17)$$

where λ is the wavelength of the incident irradiance, n_e is the number of electrons generated in the device that generate external current, and n_{ph} is the number of photons incident on the cell. An EQE of 1 means that all incident photons are converted into electrons that are then conducted into an external circuit.

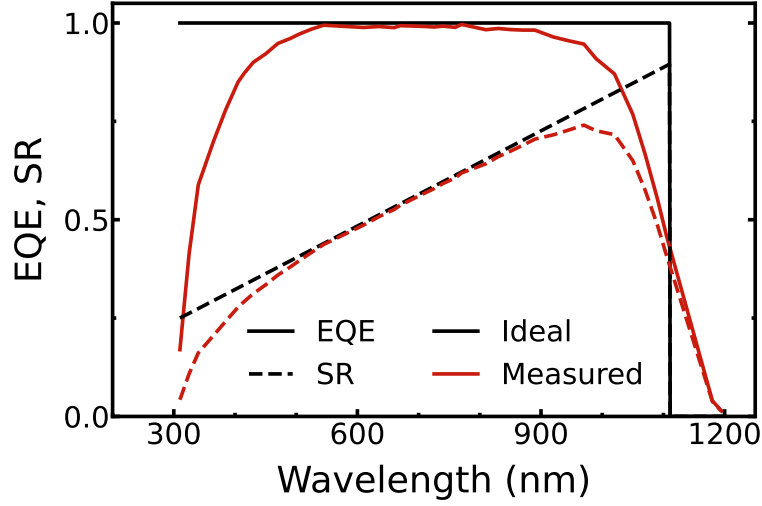


Figure 2.18: External quantum efficiency (EQE) and spectral responsivity (SR) of an ideal module (black) and a typical silicon module (red).

The IQE is the number of absorbed photons that are converted to current:

$$\text{IQE}(\lambda) = \frac{n_e(\lambda)}{n_{\text{ph,abs}}(\lambda)} = \frac{\text{EQE}(\lambda)}{1 - r(\lambda) - t(\lambda)} \quad (2.18)$$

where $n_{\text{ph,abs}}$ is the number of electrons absorbed in the solar cell, r is the reflection from the device and t is the transmission through the device.

The SR is a measure of generated current per unit of power of incident light:

$$\text{SR}(\lambda) = \frac{I(\lambda)}{P_{\text{in}}(\lambda)} = \frac{q \times n_e(\lambda)}{\frac{hc}{\lambda} \times n_{\text{ph}}(\lambda)} = \frac{q\lambda}{hc} \text{EQE}(\lambda) \quad (2.19)$$

where I_{sc} is the short-circuit current and P_{in} is the incident light power.

In Chapter 5, measured and ideal module SRs help to quantify the importance of solar spectral irradiance on bifacial PV performance.

2.2.3 Bifacial Silicon Cells and Modules

50% of the world market is currently comprised of bifacial modules, and this is expected to grow above 70% by 2034 [128]. In the past few years, once-standard aluminum back-surface field silicon cells have been phased out and are being replaced by the high-efficiency next-generation technologies described in section 2.2.3.3 [7]. These new cell types are simpler to convert to bifacial cells, which has reduced the costs of bifacial PV module manufacturing adoption. Therefore, in recent years, bifacial PV systems have shown lower electricity costs than monofacial PV systems thanks to increased energy yield with marginal cost increases [129]. An overview of silicon solar cell and module design choices is provided below.

2.2.3.1 Bifaciality Factor

Bifacial cells and modules are partly defined by their bifaciality rating, the fraction of module short-circuit current (or maximum power) from front-side illumination that rear-side illumination produces under reference conditions [130]. The bifaciality of a cell or module is affected by many factors, including its surface texture, antireflection coatings, metallization, surface passivation, and carrier lifetime [130]. The short-circuit current bifaciality factor is:

$$\varphi_{I_{sc}} = \frac{I_{sc, rear}}{I_{sc, front}} \quad (2.20)$$

where $\varphi_{I_{sc}}$ is the short-circuit current bifaciality factor, $I_{sc, rear}$ is the short-circuit current produced under reference illumination on the rear face, and $I_{sc, front}$ is the short-circuit current produced under reference illumination on the front face. The maximum power point bifaciality factor is:

$$\varphi_{P_{mp}} = \frac{P_{mp, rear}}{P_{mp, front}} \quad (2.21)$$

where $\varphi_{P_{mp}}$ is the maximum power point bifaciality factor, $P_{mp, rear}$ is the maximum power point under reference illumination on the rear face, and $P_{mp, front}$ is the maximum power point under reference illumination on the front face. In the model results described in this work, the bifaciality factor is applied to rear-side irradiance before adding to the front irradiance, effectively acting as a current bifaciality factor.

2.2.3.2 Silicon Solar Cells

Silicon is the second most abundant material on Earth [131], and is the most common semiconductor material in PV systems worldwide, with 97% of global PV module market share [132]. Silicon PV is a mature semiconductor technology that balances high efficiency, low cost, and long module lifetime.

Advanced silicon PV cell designs aim to reduce fabrication costs and increase power conversion efficiency. Design elements that are important for cell efficiency include high material quality, surface passivation, anti-reflection coatings, and surface texturing. High material quality reduces trap-assisted recombination in the device as described in section 2.2.1.2.

Passivation reduces surface recombination, thereby increasing carrier lifetime, by preventing minority carriers from recombining at the cell surface where there are many dangling bonds that act as recombination centers. The two main passivation methods are field-effect and chemical passivation. Field-effect passivation creates a layer of fixed charges at the surface, repelling minority carriers [133]. Chemical passivation reduces defects by saturating the surface dangling bonds, usually with hydrogen atoms, to remove trap states [133]. Most passivation methods, such as $\text{SiN}_x\text{:H}$ deposition, employ a combination of field-effect and chemical passivation to increase carrier lifetimes [133].

Anti-reflection coatings reduce reflection at the surface of the PV device through thin-film destructive interference. Solar cell anti-reflection coatings should be one quarter-wavelength thick at the wavelength where reflection should be minimized and have a refractive index between that of silicon and air [68, 134]. Often, a single material will act as both an anti-reflection coating and passivation layer for a silicon cell. For many technologies, amorphous hydrogenated silicon nitride (SiN_x) is standard because it can meet both requirements [135].

Most crystalline silicon (c-Si) solar cells include random surface pyramidal texturing, which reduces surface reflection by increasing the likelihood of reflected light hitting another portion of the device surface, increasing the chance that light penetrates inside the cell [134]. In a bifacial cell, the rear side may be planar or textured: a planar rear side favours front-side efficiency while a textured rear side improves rear efficiency and bifaciality [136].

2.2.3.3 Crystalline Silicon Solar Cell Types

This section provides an overview of the three most common high-efficiency silicon solar cell designs: PERC, tunnel oxide passivated contact (TOPCon), and silicon heterojunction

(SHJ). In the supplemental material presented in section 5.2, solar spectral irradiance effects are quantified for an ideal module, then compared to these solar cell types.

Passivated Emitter Rear Contact (PERC) PERC solar cells currently dominate the world's PV market, with 64% market share in 2023 [7]. They have an average bifaciality factor of 70% [7].

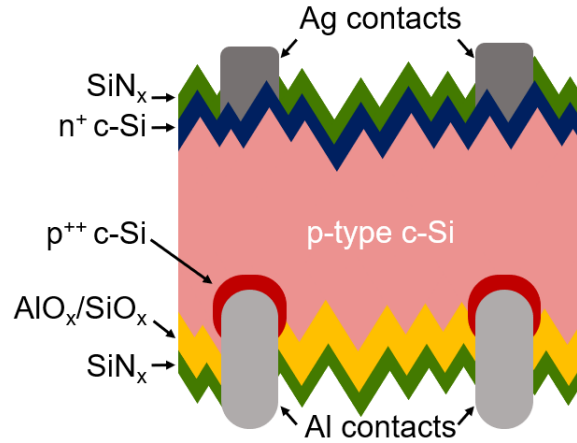


Figure 2.19: Diagram of cross-section of passivated emitter rear contact (PERC) solar cell. SiN_x - silicon nitride, AlO_x - aluminum oxide, SiO_x - silicon oxide, c-Si - crystalline silicon, Ag - silver, Al - aluminum.

PERC cells are nearly always based on a p-type substrate, with an n-type c-Si emitter at the front of the cell. At the rear of the cell, an AlO_x or SiO_x layer provides surface passivation. For both faces, silicon nitride (SiN_x) layers act as both surface passivation and anti-reflection coating. During manufacturing, laser contact openings are formed in the rear layers, then rear contacts are screen-printed on top. The Al contacts alloy with the c-Si wafer to form a local p++ back-surface field during furnace firing, which repels holes from the rear contacts, preventing them from recombining [130].

Tunnel Oxide Passivated Contact (TOPCon) TOPCon cells are a newer design that is growing in market share: they currently comprise 29% of the market and are projected to grow to 53% within 10 years [7]. This growth is attributed to TOPCon's higher efficiency limit [137], higher bifaciality (80% on average [7]), and lower temperature coefficient [138] compared to PERC, resulting in increased energy yields. TOPCon cells do have higher

silver consumption than PERC cells due to their rear silver contacts, which raise concerns about critical material limitations [139].

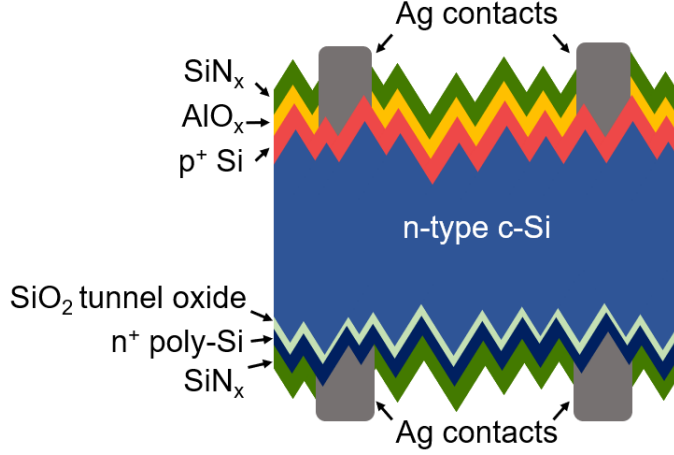


Figure 2.20: Diagram of cross-section of tunnel oxide passivated contact (TOPCon) solar cell.

SiN_x - silicon nitride, AlO_x - aluminum oxide, SiO_2 - silicon dioxide, poly-Si - polycrystalline silicon, c-Si - crystalline silicon, Ag - silver.

TOPCon cells are based on an n-type silicon substrate with a p+ emitter and aluminum oxide (AlO_x) passivation layer at the front, and an SiN_x passivation and antireflection layer on both faces [135]. The unique characteristic of TOPCon cells is the tunneling oxide SiO_x layer at the rear face, stacked with a poly-Si carrier, which together passivate the rear face of the cell very effectively. The poly-Si layer has high parasitic absorption in the short wavelengths, limiting the bifaciality of TOPCon cells. TOPCon cells can also be based on a p-type c-Si wafer [140], but these are much less common [7].

Silicon Heterojunction (SHJ) SHJ solar cells currently comprise 5% of market, but are projected to grow to 19% within 10 years [7]. These cells are highly bifacial due to their symmetrical design, with an average bifaciality factor of 85% [7]. They also have a low temperature coefficient below $-0.3\%/^{\circ}\text{C}$ [130].

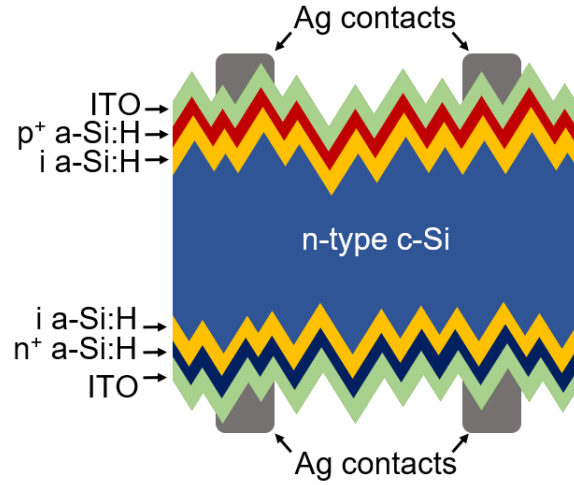


Figure 2.21: Diagram of cross-section of silicon heterojunction solar cell (SHJ). ITO - Indium tin oxide, a-Si:H - hydrogenated amorphous silicon, c-Si - crystalline silicon, Ag - silver.

SHJ cells are based on an n-type absorber with layers of hydrogenated amorphous silicon (a-Si:H), intrinsic stacked with p+ or n+ a-Si:H, and transparent conductive oxide (TCO) on top and bottom. The a-Si:H passivates the c-Si by occupying dangling Si bonds with H atoms and generating an electric field to repel minority carriers [141]. However, the a-Si:H layers do cause high parasitic absorption, resulting in optical losses [141]. The TCO layers conduct carriers laterally to the contacts while doubling as an anti-reflection coating [141].

2.2.3.4 Modules

Solar cells are assembled in modules to provide protection from the environment, electrical insulation, and structural strength [125]. To form modules, the cells are electrically connected in strings, then sandwiched between encapsulant and glass or backsheet layers (Figure 2.22). Bifacial modules may be glass-glass or glass-backsheet with a transparent backsheet. Glass-glass is more suitable to harsh environments and less affected by high temperature, high UV, high humidity, and high altitude [142]; however, they are typically heavier, increasing costs due to increased structural support requirements.

Wiring cells in series adds their voltages while wiring them in parallel adds their current. Since standard silicon solar cells may have open-circuit voltages of 0.5 to 0.7 V, which is

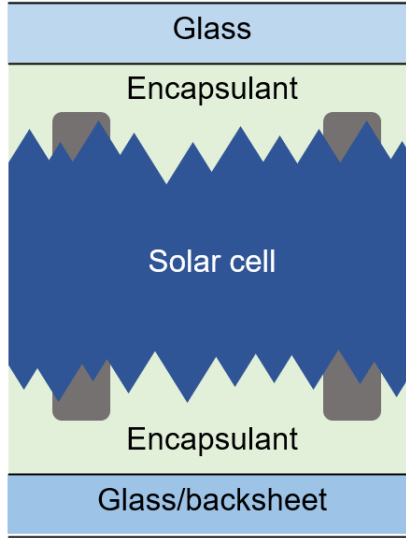


Figure 2.22: Diagram of cross-section of encapsulated silicon module.

low for most applications, they are connected in series to provide 30-40 V [125]. Typical modules will contain 60 (6×10) or 72 (6×12) full-size cells or 144 (6×24) or 156 (6×26) half-cut cells. The use of half-cut cells is a modern innovation which reduces cell current, thereby reducing current losses in module ribbons and wires [142].

2.2.3.5 Mismatch Loss

Solar cells that are connected in series are limited by the lowest-current cell in the string. If there is a difference in short-circuit current between cells, this will cause cell-to-module mismatch losses, M . These losses can be quantified as [143]:

$$M = 1 - \frac{P_{\text{module}}}{\sum P_{\text{cell}}} \quad (2.22)$$

where P_{module} is the power output of the module at its maximum power point and $\sum P_{\text{cell}}$ is the sum of the maximum power points of all of the cells in the module.

Mismatch losses are caused by efficiency differences between cells or by non-uniform irradiance. Solar cells within a module will have some variation and are not perfectly matched, causing some mismatch losses even under perfect operating conditions. Partial shading of the module, and the resulting irradiance non-uniformity, cause higher mismatch

losses as will be discussed in Chapter 3. Typically, a module’s rear-incident irradiance is more non-uniform than its front irradiance, and therefore bifacial panels may have higher mismatch losses than monofacial ones do. Deline *et. al.* reported up to 1.5% mismatch losses for close-mounted rooftop systems, but as low as 0.5% for high ground clearance systems [144]; Tao *et. al.* reported mismatch losses below 1% for a 20% albedo system and up to 2.5% for a 60% albedo system, with even higher losses for low solar elevation angles [145].

2.2.3.6 Bypass Diodes

Bypass diodes serve two functions: preventing hotspot damage to solar modules and reducing system shading losses by allowing current to circumvent shaded strings [125]. These diodes are connected in parallel with module cells in reverse polarity [125] such that in normal operation, they are reverse-biased and have no effect on the module.

In the absence of a bypass diode, when a cell is shaded, power generated by other series-connected cells is dissipated in the shaded cell, causing local heating (a hotspot) and potentially damaging the module. Furthermore, the current output of the module is reduced because the current of a string is limited by its lowest current cell.

To prevent this, when a cell is shaded, its bypass diode becomes forward-biased and conducts current around the shaded portion of the module. Ideally, modules would have a bypass diode on each individual cell, but for cost and logistical reasons, the diodes are connected over groups of cells in series (cell strings). The power dissipated in the shaded cell is limited to the power generated by the other cells in its string [125].

Full-cell modules will usually contain three substrings with bypass diodes while half-cut modules typically contain six substrings with three bypass diodes (Figure 2.23).

2.2.3.7 Angle of Incidence

In the field, sunlight is not perfectly normal to the plane of the module array, but has an angle of incidence (AOI), defined as the angle between the light beam and a line normal to the module face. This results in two effects: cosine losses and AOI losses.

Cosine losses are caused by a reduction in the power density of solar irradiance in a PV module plane due to its non-normal angle with the solar beam. When the module is turned away from the sun, the area it presents to the solar beam (its intercept area) is reduced. This reduces the irradiance on the module, thereby reducing module power.

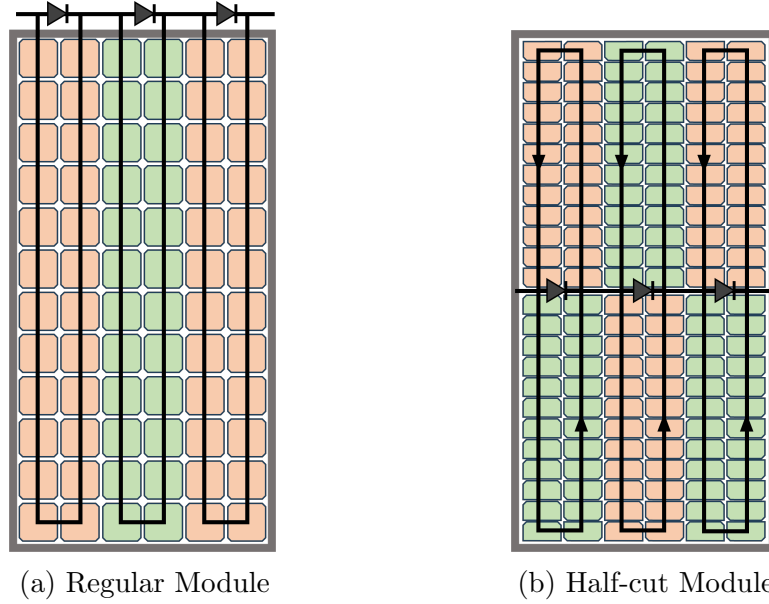


Figure 2.23: Diagram of typical photovoltaic cell and bypass diode configuration for a module based on regular cells or half-cut cells.

Furthermore, when a PV module is not perfectly normal to the incident sunlight, its efficiency is reduced due to AOI losses. Most AOI losses are caused by increased reflections at the glass-air interface, but other factors such as cell efficiency reductions with increasing AOI also contribute [146]. Efficiency is highest for normal incident irradiance and decreases with increasing AOI, dropping off sharply above 55° . To account for this, models apply an incidence angle modifier (IAM), a multiplier between 0 and 1 that represents the module's reduced efficiency at high AOI.

Incidence angle effects are typically more challenging to model on the rear of the module due to the contributions from diffuse and ground-reflected irradiance, which come from many different directions.

2.2.3.8 Module Degradation

PV module degradation is the reduction of module efficiency over time in the field. Modern silicon solar cells are degraded by high irradiance, high temperature, moisture, and mechanical stress [147]. Silicon modules may see nearly 4% of power output degradation in the first 5 hours of operation due to sun exposure [148]. Silicon modules see a large

efficiency reduction in the first year of operation, typically 1 to 3% [149], followed by an annual degradation rate of approximately 0.5% per year [125]. There is some evidence that bifacial modules are subject to higher degradation rates than monofacial modules due to their second face [150]. The detection, attribution, and prevention of silicon module degradation is an ongoing, active area of research [151, 152].

2.2.4 Photovoltaic Systems

This thesis is focused on large, ground-mount systems, often referred to as “utility-scale” PV systems. In a utility-scale PV site, modules are connected in series, adding their voltages together to form *strings*. These strings are then connected in parallel, adding their currents together and forming *arrays*.

In utility-scale systems, PV modules are mounted in rows with a standard spacing, called the row-to-row *pitch*. The ground cover ratio (GCR) is the ratio of the PV row collector width to the row pitch:

$$\text{GCR} = \frac{\text{row width}}{\text{row pitch}} \quad (2.23)$$

In other words, it is the fraction of the ground area that would be covered in the inter-row dimension if the modules were laid flat. If the GCR is high, the modules are tightly packed, and if the GCR is low, the modules are more spaced apart.

Modules can be arranged in portrait, with the short edge parallel to the ground, or in landscape, with the long edge parallel to the ground. They may also be mounted as a single module or multiple modules high. These configurations are typically shortened as “P” for portrait, “L” for landscape, preceded by the number of modules high. For example, a two-module-high system with its modules aligned in portrait is a two-in-portrait, or “2P”, system. Some examples are shown in Figure 2.24.

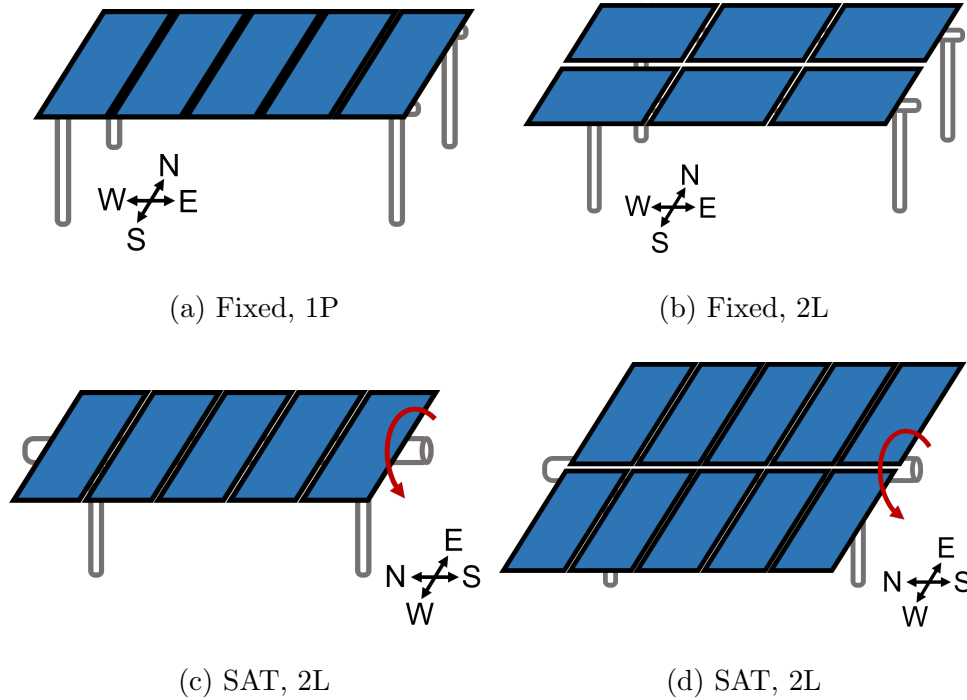


Figure 2.24: Diagram of example photovoltaic systems, including fixed-tilt (fixed) and single-axis-tracked (SAT).

For silicon bifacial systems, two configurations are common: fixed-tilt or single-axis-tracked. Chapters 3 and 4 focus on single-axis-tracked systems while chapter 5 focuses on fixed-tilt systems. The levelized cost of energy (see section 2.2.4.7) and expected energy yield, which are site- and location-dependent, are two key factors in selecting which system configuration to install.

2.2.4.1 Fixed-tilt

In *fixed-tilt* systems, the modules sit fixed at a single position throughout the day and year without moving. Fixed-tilt systems are defined by two angles: the array tilt angle and its azimuth angle (Figure 2.25). The tilt angle, β , is the angle between the module and a horizontal plane, with 0 degree tilt being totally horizontal (Figure 2.25a). The azimuth angle, ϕ , is the angle between due North and the projection of a normal vector from the module surface onto a horizontal plane (Figure 2.25b). South-facing modules have an azimuth angle of 180° . Some models define module azimuth with respect to the

equator, with equator-facing at 0° , East at -90° and West at $+90^\circ$, so it is important to always understand the frame of reference applied in the model. Fixed-tilt systems are typically installed tilted towards the equator, with increasing tilt angle at higher latitudes [153, 154].

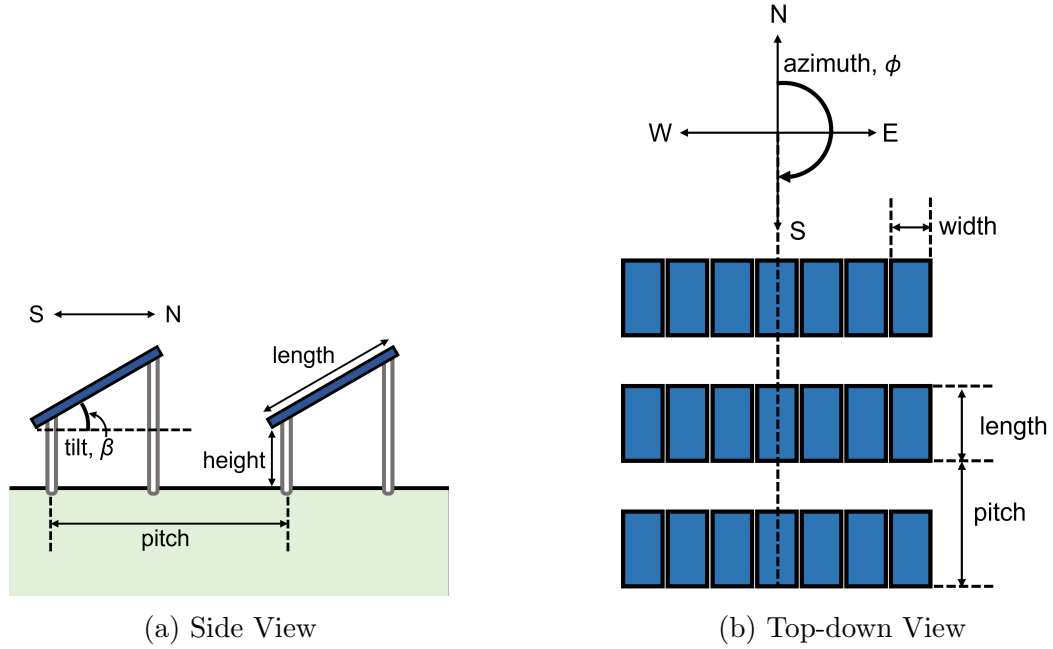


Figure 2.25: Diagram of fixed-tilt photovoltaic system from side view and top-down view, with (a) tilt angle, β , and (b) azimuth angle, ϕ , indicated.

2.2.4.2 Single-axis-tracking

Single-axis-tracked systems are mounted on a *torque tube*, a tube that runs the length of every row. Single-axis trackers are usually aligned North-South. The torque tube rotates the modules to track the sun from East to West throughout the day, reducing the AOI between the sun and the modules.

Tracking reduces cosine losses by presenting a larger surface area directly to the incident sun and also reduces angle-of-incidence losses due to reduced reflection from the front of the module face. Although it increases energy yield, particularly in the morning and evening, tracking systems are more expensive to build and maintain due to increased mounting

requirements and moving parts. The increase in energy yield for a tracked system compared to a fixed-tilt system is called the *tracking gain*.

Backtracking In the early morning and late afternoon, tracking to face the sun would create inter-row shading since the sun is low in the sky (Figure 2.26b). This creates shading and mismatch losses as discussed in section 2.2.3.5. To prevent inter-row shading, single-axis-tracking systems will backtrack during these hours of the day. The modules will reduce their tilt angle such that the direct beam irradiance is not shaded from one row to the next (Figure 2.26c).

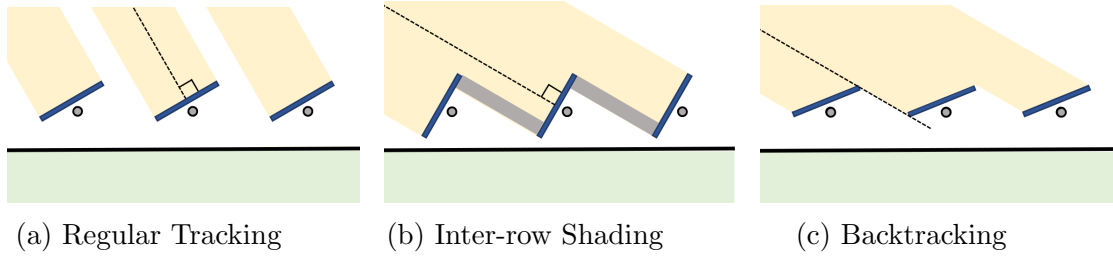


Figure 2.26: Diagram of backtracking in single-axis-tracked PV system.

2.2.4.3 Dual-axis-tracking

PV systems can also be dual-axis-tracking, where the modules are aligned normal to the sun by tracking on two axes, increasing module irradiance even further. Technologies that rely on concentrators, such as most ground-mounted III-V triple-junction modules, must be mounted on dual-axis trackers because only collimated light that is normal to the concentrator is effectively absorbed. Silicon modules on dual-axis trackers are uncommon, however: in the United States in 2023, 75% of all silicon systems surveyed by the U.S. Energy Information Administration were single-axis-tracked, 23% were fixed-tilt, and only 2% were dual-axis-tracked [155].

2.2.4.4 Structural Shading

One important source of loss for bifacial PV systems is structural shading. This is an irradiance loss due to mounting and racking elements such as posts, torque tubes, module supports, and module frames that block some light from hitting the rear of the module. In some models such as PVSyst, rear irradiance is de-rated by a “shading factor” to represent

structural shading. In Chapter 3, we model structural elements as three-dimensional (3D) elements in `bifacial_radiance` to quantify structural shading losses.

2.2.4.5 Soiling

Soiling losses occur when dust or snow accumulate on the surface of a PV module, blocking incident light and reducing module power output. Soiling rates are affected by local humidity, wind speed and direction, precipitation, and soil type, and are regionally-dependent [156].

Sand in arid environments is of particular concern [157], since precipitation that may partially remove accumulated soiling is infrequent. For example, in Spain, production losses due to dust accumulation were approximately 4.4%, but after long, dry periods losses exceeded 20% [158]. Many PV soiling loss models have been proposed in the literature [159, 160, 161, 162, 156], but they typically study a single location at a time, and their broader applicability remains unclear.

In some regions, snow accumulation on modules is a concern: annual energy losses of up to 34% have been reported, although the estimated global average is less than 10% [28]. There is some evidence that bifacial modules see lower snow soiling losses due to module heating by rear-irradiance power generation [163], an additional potential benefit for bifacial installations in snowy climates. As deployments grow in snowy regions, snow soiling is of growing concern; snow-loss models have been proposed [164, 165], but snow models are not yet commonly incorporated in energy models.

2.2.4.6 Inverters

Photovoltaic modules generate DC power, but the electrical grid is an AC system. Unless the module is being connected directly into a DC load, PV systems require an *inverter* to convert the DC power into AC. Inverter effects are modelled for a system with artificial reflectors in Chapter 4.

With decreasing module prices, the cost of the inverter has become a larger fraction of the system costs [166]. Furthermore, due to system configuration and weather effects, a PV system is rarely generating its full rated capacity. Therefore, if an inverter is sized to convert the full capacity of the PV system, it will be underutilized the majority of the time. PV system designers will reduce the size of the inverter, accepting that some power will not be converted when the PV system is generating its full capacity in exchange for a reduction in up-front system costs [166]. The ratio of PV module DC capacity to its

inverter capacity is the DC-to-AC ratio. For example, a PV system rated at 12 kW DC with a 10-kW inverter would have a DC-to-AC ratio of 1.2. The amount of power that cannot be converted by the inverter due to its reduced size is the *clipping loss*. Low-irradiance locations and monofacial systems generally benefit from higher DC-to-AC ratios, while high-irradiance locations and bifacial systems benefit from lower DC-to-AC ratios. Hourly PV modelling will underestimate clipping losses and can therefore recommend higher DC-to-AC ratios than is actually optimal [167, 31].

2.2.4.7 PV System Costs

As an emerging technology, the costs of PV systems are changing rapidly: from 2010 to 2020, the cost of PV electricity dropped 80% [168]. Emerging technologies often follow a *learning curve*, a consistent decrease in system costs as global manufacturing capacity increases [168]. Over the past 40 years, PV module costs decreased by 24.4% each time global module production doubled [132]. Over this time, PV modules have advanced quickly with higher efficiency and lower material consumption, facilitating lower costs [168]. Therefore, modules have become a smaller fraction of total PV system costs: in 2010, module costs alone were 44% of energy cost, while in 2023 they were 31% [169]. By comparison, labour costs were 11% in 2010 compared to 20% in 2023 [169]. Increasing efficiency can decrease module costs per watt while further reducing soft project costs such as labour due to higher energy density. The estimated up-front costs of a utility-scale single-axis-tracked PV system in the United States from 2010 to 2023 are shown in Figure 2.27.

Due to efficiencies of scale and installation costs, utility-scale PV systems have lower costs per installed capacity than residential systems. In 2023, the average US residential system cost \$2.68US/Wdc, while utility-scale systems cost \$1.17US/Wdc [170]. Maintenance is also less expensive for utility-scale systems, at \$16.58US/kWdc/yr compared to \$30.36US/kWdc/yr for residential [170]. In Canada, the average cost in 2022 was \$2.91CAD/W for residential PV and \$1.31CAD/W for utility-scale PV [171]. Future avenues for PV system cost reduction or revenue increase include: efficiency improvements, including a move to tandem perovskite-on-silicon PV [172]; thinner silicon PV wafers [173]; and replacing silver contacts with copper [174].

PV Levelized Cost of Energy (LCOE) The LCOE is the price per unit electricity of a production source that would cover its costs, including loan interest, operations and maintenance, and fuel costs. It can also be defined as the minimum sale price of electricity

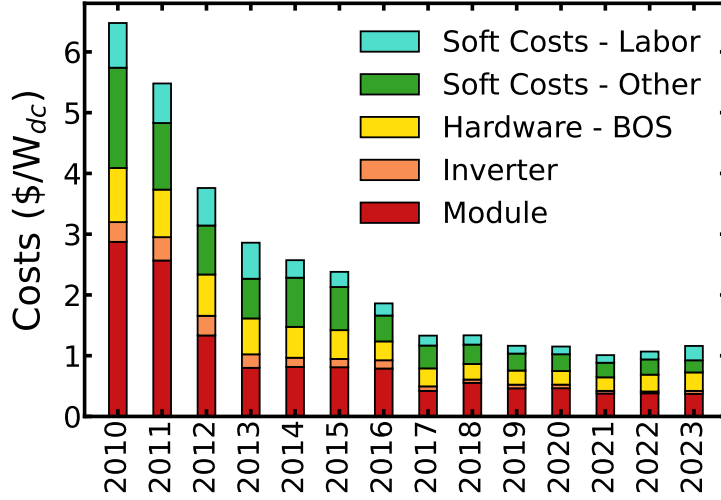


Figure 2.27: Solar installed system costs, in US dollars per watt DC installed capacity, of utility ground-mount single-axis-tracked PV systems. Adapted from [169].

(in \$/kWh) for the power plant to break even. The lower the LCOE, the less expensive the power is to produce. The LCOE is a common method to compare the costs of different energy sources which may have differing lifespan, costs, and efficiency. Although it is a useful comparison tool, the LCOE is very sensitive to financial assumptions and location.

LCOE can be represented as the total lifetime costs divided by the total lifetime energy produced, when converted to their present-day value [168]:

$$\text{LCOE} = \frac{\text{Present Value of Lifetime Costs}}{\text{Present Value of Lifetime Energy Generation}} \quad (2.24)$$

The discount rate, d , is a way to represent the time value of money, that is, that some fixed amount of money today is worth more than that same amount in the future. This encompasses inflation, opportunity cost, investment risk, and expected profits [168]. This rate can change based on the economic conditions in the country where the system is installed. For example, in chapter 4, we assume a discount rate of 3% for the United States as described in National Renewable Energy Laborator (NREL)’s 2021 U.S. Solar Photovoltaic System and Energy Storage Cost Benchmarks [175].

The discount rate can be applied to determine the present value, $\text{value}_{\text{today}}$, of future

money in year y , value_y [168]. :

$$\text{value}_{\text{today}} = \frac{\text{value}_y}{(1+d)^y} \quad (2.25)$$

In this way, the money in a future year is discounted to represent its value in the present. Accounting for the present value of expenditures as defined in equation 2.25, and incorporating capital investment and maintenance costs, the LCOE calculation becomes [168]:

$$\text{LCOE} = \frac{\sum_{y=1}^N \frac{I_y + M_y}{(1+d)^y}}{\sum_{y=1}^N \frac{E_y}{(1+d)^y}} \quad (2.26)$$

where y is the year, I_y is the investment cost in year y , M_y is the maintenance cost in year y , E_y is the electricity generated in year y , d is the discount rate, and N is the lifetime of the PV system in years.

Bifacial PV has been shown to reduce LCOE below monofacial system LCOE by increasing energy yield with marginal cost increases [129]. The LCOE has commonly been applied to analyze the costs of bifacial PV-generated power in the literature and to compare bifacial technologies [176, 177]. The detailed LCOE calculation methodology applied in Chapter 4 is provided in section 4.2.4.

2.3 Bifacial Photovoltaic Performance Modelling Methods

Several bifacial PV models are applied in this thesis, including `bifacial_radiance` (chapters 3 and 4) and `bifacial_vf` (chapter 5). Bifacial PV energy yield modelling typically requires: (1) site information (meteorological and system data), (2) an optical model, and (3) an electrical model. From system parameters and meteorological data, the optical model calculates the irradiance incident on the front and rear surface of the PV module(s). The electrical model then calculates module DC power output from the irradiance. An overview of the energy yield methodology applied in this thesis is shown in Figure 2.28.

Some models include further electrical calculations, such as line losses, transformer losses, and inverter behaviour, but these are often ignored. Another often-neglected effect

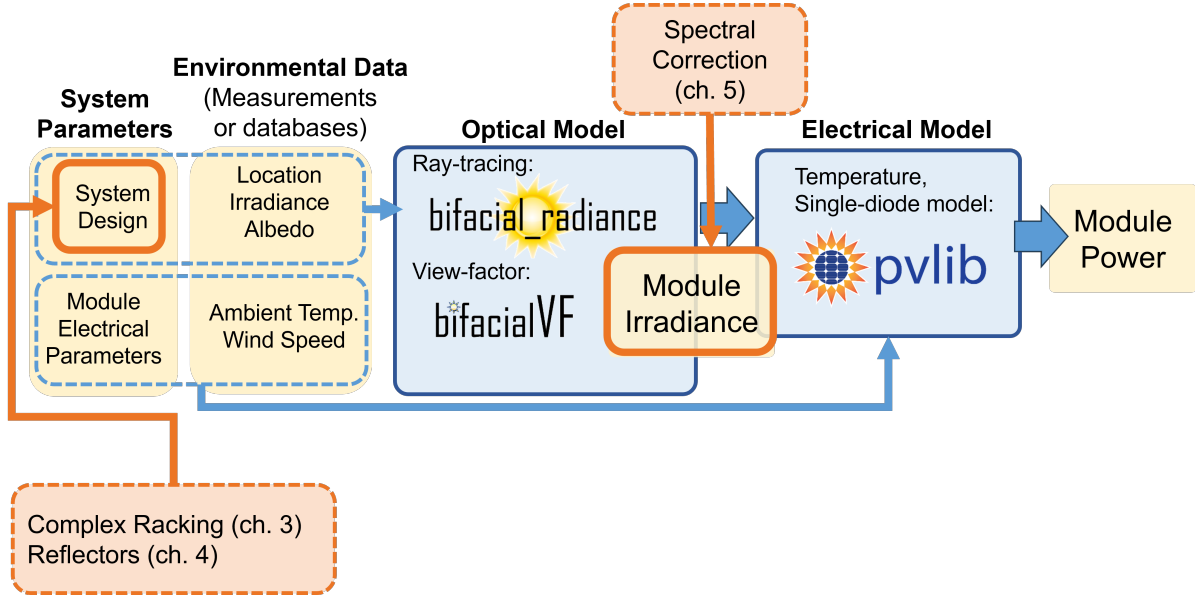


Figure 2.28: Bifacial energy yield methodology applied in this thesis, with contributions highlighted in orange.

is module degradation, where the modules become less efficient over time, typically at a rate of approximately -0.5% per year [125] (see section 2.2.3.8).

The important parameters for modelling a bifacial PV system were discussed in the previous section. An overview of meteorological data, optical modelling methods, and electrical modelling methods are provided in the following sections.

2.3.1 Meteorological Data

Meteorological data is an essential input to bifacial PV performance models. Most models require solar irradiance (GHI, DHI, and DNI), ambient temperature, albedo, and wind speed, at minimum. As discussed in section 2.1.1.2, if two irradiance components are known, the third can be calculated from the solar zenith angle.

Historical weather data can be obtained in a few ways: direct measurements, satellite-derived data, or interpolated data. Measured data is the direct acquisition of meteorological data from a weather station. These measurements may include irradiance, wind speed and direction, temperature, humidity, precipitation, and air pressure. Some examples of public

meteorological datasets from ground measurements include the BSRN [178] and CWEEDS for Canada [179].

Satellite-derived data applies models to satellite imagery to estimate irradiance. They may apply radiative transfer or an empirical approach [180]. Sources of satellite data include the NSRDB [113], the Photovoltaic Geographical Information System (PVGIS) [181], and NASA’s Prediction Of Worldwide Energy Resources (POWER) [182].

Interpolated data involves the interpolation of measured data from several sources to estimate the historical weather data of a site where meteorological measurements are unavailable. Many techniques will combine various data sources, such as ground and satellite measurements, to improve accuracy of interpolated datasets [183].

2.3.1.1 Typical Meteorological Year Data

TMY files are often applied in photovoltaic energy yield modelling to calculate expected average system performance [184]. TMY files are hourly datasets that include air temperature, irradiance (GHI, DHI, DNI), wind speed, wind direction, air pressure, and other meteorological parameters for a given location.

Taking an inter-annual average of meteorological data would reduce its variability, so TMY datasets are composed of individual months of historical data from different years that are selected as “typical” representative months for that location based on their weighted average irradiance, temperature, and wind speed [180]. Some TMY datasets include smoothing between months to prevent discontinuous values.

Applying TMY data for energy yield predictions is more computationally efficient than modelling a long time span. However, this method neglects the effects of changing weather over time, such as long-term warming.

2.3.1.2 Albedo

Albedo is an important input for bifacial PV performance models: it has a significant impact on bifacial PV energy yield and bifacial gain [185, 186], with bifacial gain increasing proportionally to ground albedo [187, 35]. The *albedo*, ρ , is the ratio of GRI to GHI (see figure 2.4) [188]:

$$\rho = \frac{\text{GRI}}{\text{GHI}} \quad (2.27)$$

Albedo can range between 0 and 1, and is typically measured by a pair of identical horizontally-mounted pyranometers, one facing the sky measuring GHI and one facing the ground measuring GRI. Ideally these pyranometers should be the same make/model and should have good performance at high AOI [188].

Albedo varies with respect to ground cover, solar position, and sky conditions. The ground cover has the most significant effect, with highly-reflective snow having average albedos above 0.9 and deep ocean having a low albedo of 0.04. Predicting albedo is challenging because it depends on many environmental factors. For example, snow albedo varies by snow type, with freshly-fallen snow showing the highest reflectivity and melting snow the lowest, and soil albedo varies with respect to its composition and water content [188].

Spectral Albedo Broadband albedo is often applied in bifacial modelling. In reality, most surface albedos have a strong wavelength dependence (Figure 2.29). For example, vegetation absorbs irradiance necessary for photosynthesis while reflecting long-wavelength irradiance that would cause heating. Dead vegetation demonstrates a much smoother spectral albedo than live vegetation. Snow is highly reflective at short wavelengths, dropping off significantly in the near-infrared (IR). Chapter 5 contains an analysis of the impact of spectral albedo on bifacial energy yield.

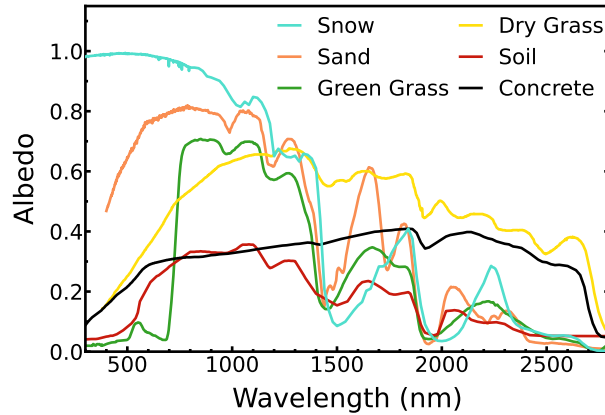
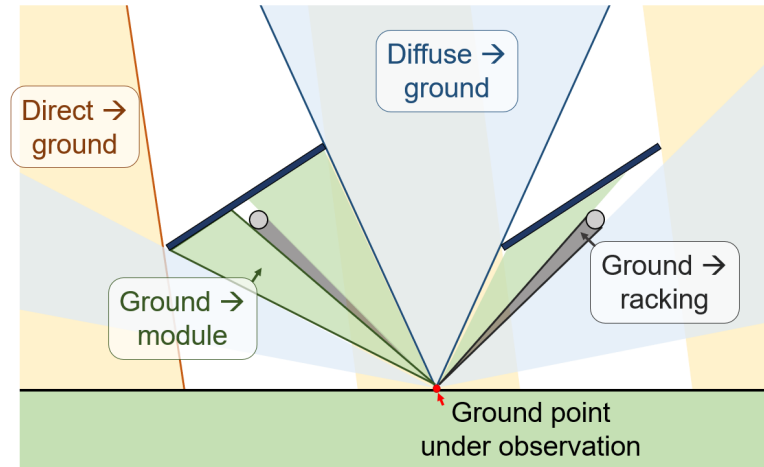


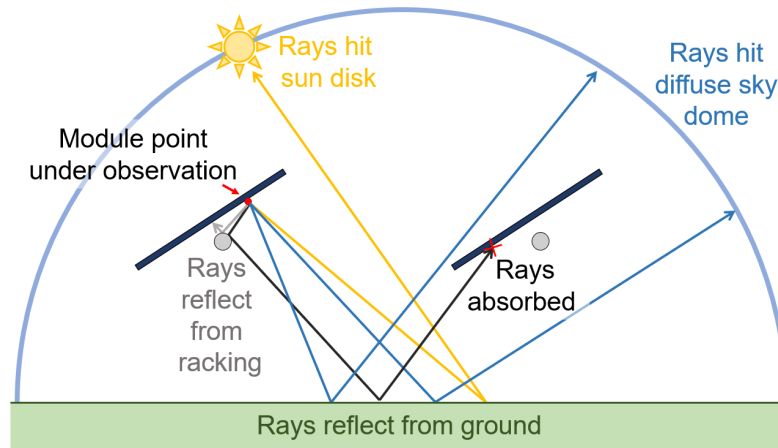
Figure 2.29: Spectral albedo of select ground cover materials. Data from [103].

2.3.2 Optical Modelling Methods

There are two primary approaches to irradiance modelling for a PV system: ray-trace modelling and view-factor modelling (Figure 2.30).



(a) View-Factor Modelling



(b) Ray-trace Modelling

Figure 2.30: Diagram of common bifacial PV irradiance model types.

2.3.2.1 Ray-trace Modelling

Ray trace modelling is a technique for modelling radiation’s propagation in an environment. A ray-tracing model uses hundreds or thousands of individual rays to trace the path that light takes through a complex 3D scene. Narrow beams, or rays, of radiation travel in a straight line before interacting with objects in the environment. The ray will be reflected, absorbed, or transmitted through these objects. Models can be forward ray-tracing (originating from the light source) or reverse ray-tracing (originating from a surface where we are evaluating the irradiance). Bifacial_radiance is a reverse ray-tracing model, with rays originating from the module surface.

Ray tracing models allow for a higher level of detail in the physical environment, such as racking elements or other complex shading objects, but require higher computational resources than view-factor models. Examples of ray-trace models for photovoltaics include bifacial_radiance [189, 19], SunSolve [190], Tracer [191], and MoBiDiG (which only applies ray trace modelling for the rear of a bifacial module) [21, 192].

2.3.2.2 View-Factor Modelling

View factor models are radiative transfer models that rely on geometric *view factors*, or the fraction of radiation emitted from one surface that hits another surface [193]. In practice, these models often divide relevant surfaces, such as the module faces, the ground, and the sky, into smaller units of area, then calculate the view factors between these units. From there, the irradiance on each surface, including the module faces, can be obtained.

Although view factor models are fast and computationally inexpensive, they are limited to basic geometry. For example, they may overestimate rear irradiance compared to ray-tracing methods because they cannot include all rear structural shading losses [194]. These models also assume that all radiation is isotropically emitted and scattered from reflecting surfaces.

PV view-factor models can be two-dimensional (2D), which simplifies system geometry to be invariable in the third dimension, assuming infinite rows of modules with no edge effects. PVSyst [16] and bifacialvf [195] are two examples of 2D view-factor models. These models are most appropriate for inner modules in large arrays where irradiance varies little along the row.

Some view-factor models are 3D, which is more computationally expensive than 2D view-factor models but incorporates details such as edge effects. DUET [26] is one example of a 3D view-factor model with additional ray-intersect shading functions.

2.3.2.3 Diffuse Sky Models

To calculate the diffuse irradiance incident on a module plane, a *diffuse sky model* must be applied. The simplest diffuse sky model is isotropic, assuming that irradiance comes from all portions of the sky dome equally.

However, in reality, there is significant non-uniformity in the distribution of diffuse irradiance in the sky dome. The anisotropic sky dome is often broken down into three components: isotropic, circumsolar brightening, and horizon brightening (Figure 2.31). Circumsolar brightening is an area of increased irradiance around the sun disk that is brighter due to the scattering of direct irradiance in the atmosphere. It is most intense near the sun disk and drops off in intensity away from the sun. Horizon brightening is a brighter area near the horizon due to light scattering in the atmosphere that is most intense nearest the horizon and drops away with increased elevation angle.

An important component of many bifacial PV models is the 1993 Perez model [196]. This model calculates the relative luminance of any given point in the sky dome from its zenith angle and its angle to the sun. The model applies empirical coefficients for the size of the horizon and circumsolar brightening regions and the relative intensity of these regions from the sky clearness index and the solar irradiance (GHI, DNI, DHI).

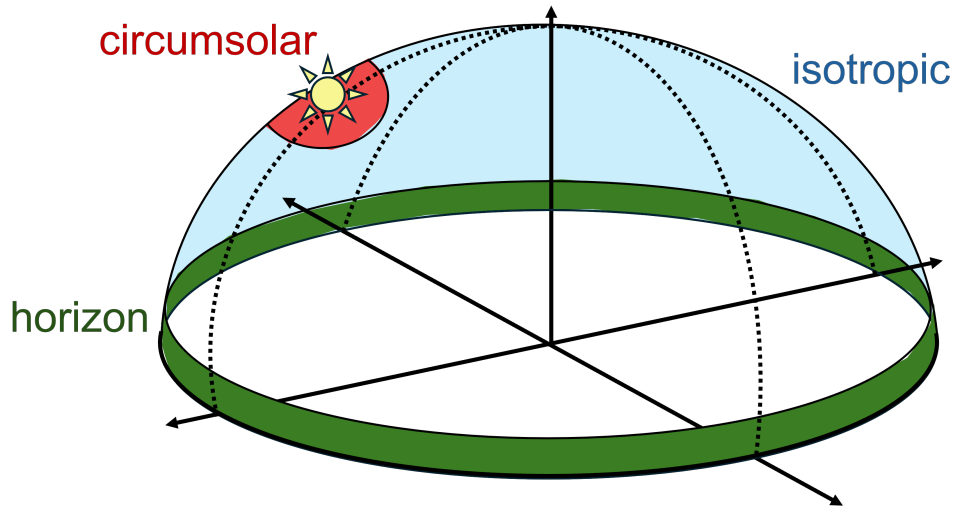


Figure 2.31: Diagram of components of anisotropic sky dome models, including the isotropic sky dome (blue), horizon brightening (green), and circumsolar brightening (red).

Standard diffuse sky models calculate plane-of-array diffuse irradiance, rather than

relative luminance. The most widely used anisotropic sky model for irradiance on a tilted plane is the 1990 Perez model [197]. The model applies empirical coefficients for distinct sky clearness bins, based on measured data across 13 sites, to calculate circumsolar and horizon brightening factors. These factors determine the fraction of diffuse irradiance received from each portion of the sky dome: isotropic, circumsolar, or horizon. This model was recently updated to reduce discontinuities in the model output [198]. Other anisotropic models include the Hay and Davies model [199], which includes a circumsolar component but no horizon brightening, and the Reindl model [200], which extends the Hay and Davies model to include horizon brightening.

2.3.3 Electrical Modelling Methods

PV electrical models calculate PV module electrical output from the incident irradiance, cell temperature, and module parameters. Electrical models can be described as either IV curve models, point value models, or efficiency models [201]. IV curve models calculate the entire IV curve of the module. Point value models find a few points on the IV curve, typically at the short-circuit current, maximum power point, and open-circuit voltage. Efficiency models predict module power at the maximum power point only [201].

Most bifacial PV models include a full IV curve model, such as the De Soto [202] or the California Energy Commission (CEC) model [203]. These IV curve models apply the one-diode equivalent circuit of a PV module (see Figure 2.16). A two-diode model also exists but is much less commonly applied. These models calculate the IV curve of the module from irradiance, temperature, and module characteristics such as temperature coefficients, material bandgap, and parasitic resistances. The necessary parameters for a specific module type may not always be available, but NREL’s System Advisor Model (SAM) provides the CEC parameters for a variety of PV modules in its database [23].

2.3.3.1 Effect of Irradiance Level

Module photo-generated current scales linearly with respect to incident irradiance (Figure 2.32), but the effect of irradiance on module power output is not strictly linear. Most silicon cells and modules are optimized for a standard irradiance level of 1000 W/m^2 ; at lower irradiance, module efficiency is reduced [204]. For low values of photogenerated current, shunt resistance losses become more significant [205]. Furthermore, for a module with no parasitic resistances, as module-incident irradiance decreases, its photogenerated current, I_L , decreases linearly while its open-circuit voltage, V_{oc} , decreases logarithmically (Figure

2.32). Therefore, at lower irradiance, the module fill factor (FF) and efficiency decrease logarithmically because the “elbow” in the IV curve becomes a more significant portion of the IV curve [127]. Conversely, at high incident irradiance, module efficiency is limited by increased series resistance losses [127].

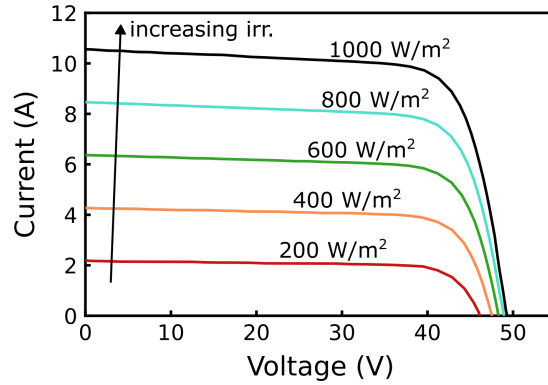


Figure 2.32: Effect of irradiance level on module IV curve. Adapted from [125], figure 7.6.

2.3.3.2 Effect of Temperature

In sunlight, a PV module will generate heat due to losses in the PV device, so PV cells operate at a higher temperature than ambient air. The temperature of a PV cell is dependent on module type, ambient air temperature, incident irradiance, wind velocity, and other factors. PV efficiency is highly dependent on temperature: as temperature increases, module short-circuit current increases, open-circuit voltage decreases, and efficiency decreases (Figure 2.33).

The short-circuit current, I_{sc} , increases with temperature because the semiconductor bandgap decreases at higher temperatures, thereby allowing lower-energy photons to be absorbed. This is a comparatively small effect. The open-circuit voltage, V_{oc} , decreases at higher temperatures due to an increase in the intrinsic carrier concentration (the number of thermally-excited carriers in the material), which increases the dark saturation current, I_0 [126]. At high temperatures, the voltage losses outweigh the current gains, and so efficiency decreases.

The IV curve of a module can be corrected for temperature by applying the temperature coefficients provided by the manufacturer. Temperature coefficients are generally provided

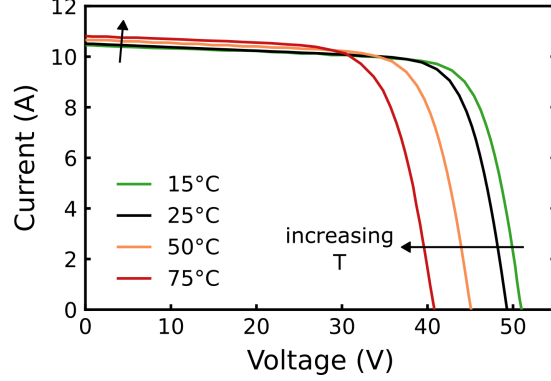


Figure 2.33: Effect of temperature on module IV curve. Adapted from [125], figure 7.6.

for I_{sc} , V_{oc} , and P_{mp} . For example, to find the output power of a module at a given cell temperature T_{cell} :

$$P_{mp}(T) = P_{mp,ref} \times [1 - \gamma(T_{stc} - T_{cell})] \quad (2.28)$$

where T_{stc} is the cell temperature at standard test conditions (25°C) and γ is the temperature coefficient. Typical temperature coefficients are approximately +0.04%/°C for I_{sc} and -0.3%/°C for V_{oc} [125], and -0.3%/°C to -0.5%/°C for efficiency [121].

Temperature Models To correct the IV curve for cell temperature effects, first T_{cell} must be estimated. Cell temperature is difficult to model accurately. It can also be challenging to measure because cell temperature is higher than external module temperature. Typical temperature models for solar PV modules include the NOCT model [206], the Sandia SAPM model [51], the Faiman model [207], and the PVSyst model [16].

The nominal operating cell temperature (NOCT) model assumes that cell temperature is linearly dependent on incident irradiance, G , and ambient temperature, $T_{ambient}$. The NOCT temperature, T_{NOCT} , is the expected cell temperature with an incident irradiance of 800 W/m², an ambient temperature of 20°C, and a wind speed of 1 m/s:

$$T_{cell} = T_{ambient} + G \left(\frac{T_{NOCT} - 20}{800} \right) \quad (2.29)$$

This model does not account for variable wind speed.

The Sandia Array Performance Model (SAPM) uses three empirical parameters, a , b , and ΔT , which vary based on the module type and mounting type of the system. First the module temperature, T_{module} , is determined from two of the empirical coefficients, the irradiance, and the wind speed, WS :

$$T_{\text{module}} = T_{\text{ambient}} + G(e^{a+b \cdot WS}) \quad (2.30)$$

Then the cell temperature is determined from the module temperature and the ratio of incident irradiance to the reference solar irradiance, G_{stc} (1000 W/m²):

$$T_{\text{cell}} = T_{\text{module}} + \Delta T \left(\frac{G}{G_{\text{stc}}} \right) \quad (2.31)$$

2.3.4 Uncertainty in Bifacial Energy Yield Models

Bifacial PV model improvement is an ongoing research endeavour, and model assumptions are continuously being questioned. PV model uncertainty is attributable to many factors that can be broadly categorized as input uncertainty, model uncertainty, or weather variability.

Input uncertainty incorporates the uncertainty attributable to all model inputs, including irradiance, PV electrical performance, albedo, and temperature. Pyranometer measurement uncertainty includes uncertainty related to calibration, zenith response, spectral response, nonlinearity, temperature response, and degradation [208], among other sources. These effects vary with respect to solar position, temperature, and other factors. Satellite-derived irradiance data is generally less precise than ground-based measurements due to the modelling steps required: a 2011 comparison of satellite-derived irradiance found an average standard deviation of 16% for GHI and 35% for DNI [209]. Irradiance decomposition, where DNI and DHI are determined from GHI also introduces uncertainty; when combined with irradiance transposition, where GTI is calculated from irradiance components, it introduces approximately 5% root mean square error [208, 210, 211, 212].

PV module performance is typically measured indoors under a solar simulator. However, module efficiency is not constant over time. Uncertainty in a module's light-IV characteristics originate from (1) measurement uncertainty and (2) module instability. Measurement uncertainty of 1.5% to 5% have been reported by module test laboratories for standard test conditions [212]. Those same laboratories reported higher uncertainties

under non-standard test conditions, such as low irradiance or elevated temperature. Long-term module degradation depends on module type and operating conditions (see section 2.2.3.8).

Model uncertainty can be introduced at every model step, including irradiance transposition, horizon and inter-row shading, and module efficiency translation from standard test conditions (STC) power to operating conditions [212]. There are also uncertainties related to various loss mechanisms, including non-Lambertian ground reflection [27], soiling [28], snow [28], module degradation [29], cell-to-module irradiance mismatch [30], and sub-hourly clipping loss [31]. Angle-of-incidence effects introduce approximately 1% error [212]. Spectral irradiance effects are shown in Chapter 5 to cause models to underestimate silicon PV performance by 0.7% to 2.7% annually. Work is ongoing to characterize and quantify all sources of uncertainty in energy yield models.

Lastly, when predicting long-term PV system performance, inter-annual weather variation is an inherent source of error [208]. This includes long-term changes in the solar resource and weather.

2.3.5 Open-source PV modelling Libraries

This work applies a variety of open-source Python PV modelling libraries.

pvlb [213, 74, 214] is an open-source library of functions and classes for PV performance simulation. It includes a wide range of PV simulation functions for: solar position, clear sky irradiance, AM, atmospheric parameters, transposition and decomposition, performance losses, tracking angle, input/output tools, and bifacial modelling. This work applies pvlb functions for AM, solar position, and others throughout. pvlb’s iotools function is applied in Chapter 5 to obtain atmospheric parameter inputs to the parameterized PV spectral impact models.

bifacialvf [195] is an open-source view factor irradiance model that models a 5-row, “infinite shed” 2D bifacial PV system. It can model fixed-tilt or single-axis-tracked systems. In this thesis, bifacialvf results are presented in Chapter 5 to quantify the effects of spectral irradiance on bifacial PV energy yield.

bifacial_radiance [19] is an open-source Python wrapper of the RADIANCE ray-tracing software [215] for bifacial PV irradiance modelling. It can incorporate complex 3-dimensional scene elements, any number of rows and modules, and multiple scene reflections. Chapter 3 includes bifacial_radiance modelling results that quantify the effects of shading and reflection of structural PV elements on PV system performance. Chapter 4

includes `bifacial_radiance` modelling results that quantify the bifacial energy yield gain due to artificial reflectors.

pvanalytics [216] is an open-source python library for quality control and filtering of measured PV field data. Chapter 5 includes field data from Technical University of Denmark that was filtered using `pvanalytics`.

Chapter 3

Quantifying Structural Shading & Reflection Effects on Single Axis Tracked Bifacial Photovoltaic System Performance

This chapter focuses on the importance of mounting structures in bifacial photovoltaic energy yield modelling. I model a two-in-portrait single-axis-tracked bifacial PV system in an open-source ray-trace energy yield modelling software, `bifacial_radiance` [19]. I combine model results with no racking, with absorptive racking, and with reflective racking to quantify the effect of racking on rear irradiance, module energy yield, cell-to-cell current mismatch losses, and bifacial gain. I demonstrate an increase of +9.1% in average rear irradiance on an annual basis, increasing the shading factor from -17.6% with absorptive racking to -8.5% with reflective racking.

3.1 Scope and Impact

The effect of structural shading and reflection on system performance is not well-quantified due to the lack of clear computational techniques. At present, in bifacial energy yield modelling, racking reflection is neglected and racking shading is represented as a flat derate factor on the rear irradiance, which does not account for the time- and albedo-dependence of these losses. To date, there is not a well-established method for quantifying the impact of both racking shading and reflection on bifacial photovoltaic performance.

This work includes:

1. An exact, easy-to-apply method to quantify the effect of racking on bifacial photovoltaic system irradiance, energy yield, mismatch losses, and bifacial gain.
2. An example case and analysis for a single-axis-tracked bifacial photovoltaic system, demonstrating the significance of racking effects for bifacial systems over time of day, month, and year.
3. The quantified effect of racking reflection on the annual shading factor.

This manuscript provides research groups with a clear, programmable set of equations to quantify racking effects. This will influence new optimal racking designs for electricity generation and dual-use systems, such as in agrivoltaics. It will also act as a guide to present photovoltaic system designers, advising them in their energy yield modelling and allowing them to obtain the most accurate prediction of system performance.

Furthermore, this work informed the development of the `bifacial_radiance` model. Throughout the research project, we shared our findings with the developers of `bifacial_radiance`. Today, the code base has been updated to allow for 2D irradiance sampling on the front and rear of the module and to add multiple module types within one scene.

3.2 Background Information

3.2.1 Cell Irradiances

To calculate the mismatch loss and energy yield of the systems modelled in this work, the average irradiance per cell is taken by grouping the sample points into groups of eight points as shown in Figure 3.1.

3.2.2 Irradiance Mismatch Losses

This work applies the mean absolute difference method, as defined in [143], to find cell-to-module irradiance mismatch losses. The mean absolute difference, Δ , is the sum of the

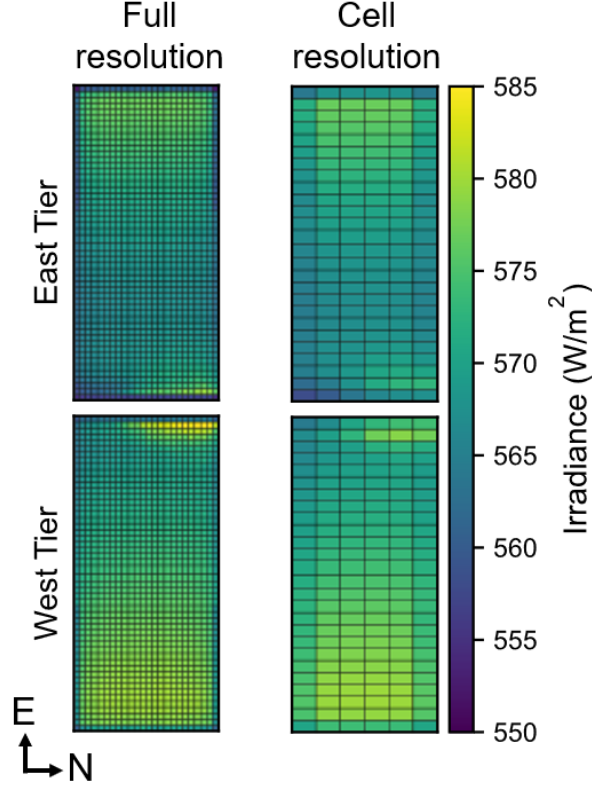


Figure 3.1: Total irradiance maps of individual sample points and cell-level average values. Example timestamp is for noon on a winter day,

irradiance difference between each pair of cells in the module, divided by the number of cells squared and the average irradiance:

$$\Delta[\%] = \frac{1}{n_{\text{pts}}^2 \bar{G}_{\text{avg}}} \sum_{i=1}^{n_{\text{pts}}} \sum_{j=1}^{n_{\text{pts}}} |G_i - G_j| \times 100\% \quad (3.1)$$

where n_{pts} is the number of points in the array, $\bar{G}_{\text{avg}}$ is the average total irradiance on the module, and G_i and G_j are the average irradiance on the i th and j th cells, respectively. This work applies the following mismatch loss fit from [143], equation 12 to find the mismatch loss, M :

$$M[\%] = 0.054\Delta + 0.068\Delta^2 \quad (3.2)$$

where the mean absolute difference, Δ , is in percentage.

3.2.3 Seasonal Torque Tube Shading

In this work, we found a seasonal effect of torque tube shading that occurred in winter but not in summer. In the winter, the Northern edge of the module would see higher torque tube reflection than the Southern edge of the module. In the winter, the module supports shade the torque tube from direct irradiance passing through the gap between modules, as illustrated in Figure 3.2. In the summer, the sun is higher in the sky and this effect is reduced. At higher latitudes with low solar elevation angles in the winter, this effect is more significant.

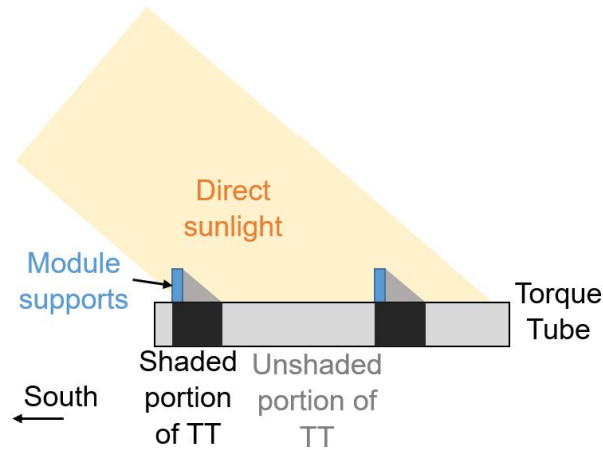


Figure 3.2: Diagram of direct irradiance shading on torque tube due to module supports in the winter.

This results in higher irradiance non-uniformity in winter than in summer, as shown in Figure 3.3. This effect is discussed in the manuscript below.

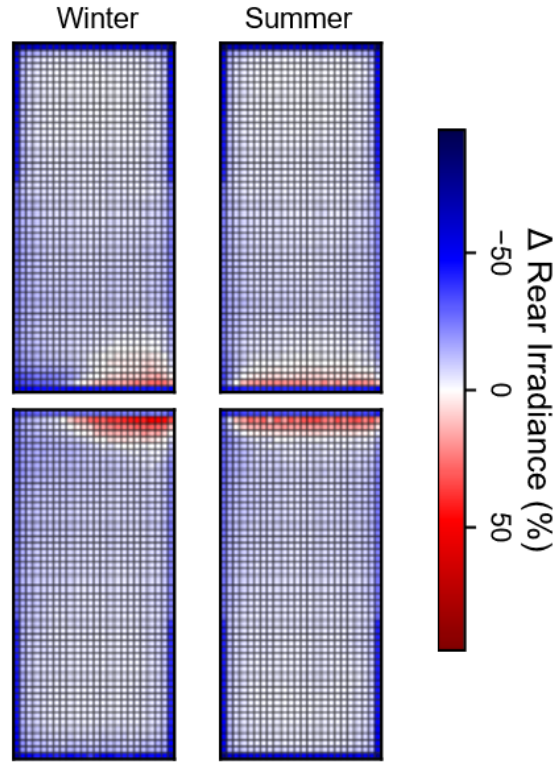


Figure 3.3: Rear irradiance difference maps, where the difference in irradiance is the change in incident irradiance due to racking, for a winter and a summer day at noon.

3.3 Author Contributions

M. R. Lewis revised the bifacial_radiance code, performed the modelling, performed the analysis, visualized the data, and wrote the manuscript.

T. J. Coathup assisted in revisions to the bifacial_radiance code base, data analysis, data visualization, and manuscript revision.

A. C. J. Russell assisted in data analysis and manuscript revision.

J. Guerrero-Perez guided methodology and assisted in manuscript revision.

C. E. Valdivia guided methodology and analysis and assisted in manuscript revision.

K. Hinzer oversaw the research and the manuscript.

All authors contributed to the manuscript.

3.4 Manuscript

The manuscript is included on the next page. This manuscript was published in Advanced Energy and Sustainability Research in 2024. This work is published open-access and is covered under an open CC BY 4.0 license.

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Quantifying Structural Shading and Reflection Effects on Single Axis Tracked Bifacial Photovoltaic System Performance

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Structural elements of bifacial photovoltaic (PV) systems, such as module frames, module supports, and torque tubes, affect module rear irradiance profiles through both shading and reflection. Standard bifacial energy yield models represent racking effects as a flat rear irradiance de-rate factor; however, this neglects 1) the impact of racking reflection, and 2) the variation of racking effects over time. In this work, a differential irradiance approach is presented to quantify the effect of racking shading and reflection on bifacial rear irradiance. Using this method, racking effects on system energy yield, irradiance mismatch losses, and bifacial gain are calculated. This is applied to a single-axis-tracked 2-in-portrait bifacial PV system in Livermore, California with 74.5% reflective racking using bifacial_radiance ray tracing software. Racking reflection counteracts the irradiance reduction and mismatch losses caused by racking shading. Racking reflection reduces average rear irradiance shading by up to 19.2% per timestamp and 9.1% per year compared to absorptive racking. Racking effects vary diurnally, seasonally, and with respect to albedo. In a single day, the impact of racking on rear irradiance varies up to 14.6%. Applying this method will improve energy yield modeling accuracy of bifacial PV systems.

1. Introduction

Bifacial photovoltaics (PV) generate additional energy yield by absorbing light incident on the module's rear face in addition to the front. Bifacial PV is predicted to make up 90% of the silicon PV market share within the next 10 years,^[1] having demonstrated increased energy yield^[2,3] and potential for reduced levelized cost of energy (LCOE)^[4,5] compared to monofacial modules. Single-axis-tracking can further boost PV energy yield above that of fixed-tilt systems, with bifacial single-axis-tracked systems demonstrating the lowest LCOE in 93.1% of the world's land area compared to fixed-tilt or monofacial modules.^[6]

A recent study across 500 PV systems with a total of 11 GW of capacity showed that fielded PV systems were underperforming by 7–13%,^[7] which may be partly due to modeling uncertainty.

While front PV irradiance modeling is well-understood,^[8–12] rear PV irradiance modeling is more complex due to the wide range of factors that affect rear-incident irradiance, including diffuse irradiance fraction, ground albedo, and system geometry.^[13,14]

Bifacial energy yield models are typically categorized as either view-factor^[15–18] or ray-tracing^[19–21] models, although hybrid approaches have also been demonstrated.^[22] While view-factor models are less computationally expensive, they include simplified system geometry and do not capture all effects that result in high rear irradiance variability. By contrast, ray-trace models can model detailed 3D geometries at higher computational cost to capture more environmental parameters that affect rear irradiance.

One of the challenges of standard view-factor-based bifacial PV single-axis-tracked performance modeling is accurately accounting for the effects of structural elements, such as the frame, module supports, and torque tube, on the rear irradiance.^[19,23,24] Racking can reduce module irradiance and induce non-uniform illumination profiles, leading to reduced energy yield and increased electrical mismatch.^[25] Bifacial PV performance models typically represent racking by a constant rear structure shading factor.^[26–29] However, this method does not account for time-dependent lighting conditions nor reflections, and rear structural shading losses that vary diurnally and seasonally.^[30]

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Racking shading has been shown to reduce rear-incident irradiance and increase cell-to-cell irradiance mismatch. Zhu et al. described a method to estimate the energy losses in bifacial systems due to shading objects and found optical losses of up to 49% for a 40 mm square beam located flush with the module.^[31] For fixed-tilt systems, Tsuchida et al. found that bifacial gain is reduced by mounting structures, particularly at high albedos, but that increasing the distance between a shading beam and the module reduces these effects,^[32] while Wang et al. demonstrated that crossbeam shading increased irradiance mismatch losses by 0.5–3.3%.^[33] Zhao et al. developed a ray-trace model to quantify the shading factor and irradiance mismatch losses of bifacial PV systems, with 2-in-portrait annual shading losses of 4.9–7.6%.^[34] Ernst et al. applied ray-tracing simulations to rooftop fixed-tilt bifacial PV systems over high-reflectivity material and demonstrated a decrease in bifacial gain of 1–2% due to mounting components.^[35]

While the effect of racking shading has been studied in more detail, racking reflection has not. Racking-reflected light can increase rear irradiance, and consequently energy yield, by partially offsetting racking shading.^[23] Ayala Pelaez et al. have demonstrated that torque-tube-reflected irradiance reduces the structural shading factor at one timestamp from 12% to 0.01%.^[23] McIntosh et al. included the effect of a reflective torque tube to analyze mismatch losses due to non-uniform illumination in single-axis-tracking systems, and demonstrated the difference in racking losses between the east and west module pair in a 2-in-portrait system.^[30]

This work expands upon these precedents by 1) incorporating both reflective frames and module supports in addition to the torque tube, capturing the effects of these racking elements, 2) calculating both front and rear 2D irradiance maps, capturing non-uniform illumination in both dimensions, and by 3) including two full model-years with two albedo values, quantifying the seasonal and annual impact of racking elements. Furthermore, we explicitly define a methodology to isolate the impact of racking shading and reflection on bifacial module rear irradiance, energy yield, mismatch losses, and bifacial gain.

Previous work in our group has isolated the effect of torque tube reflection on 1-in-portrait and 2-in-portrait single-axis-tracked bifacial systems.^[36] Here we expand on our previous work, providing a method that can be adapted to various modeling approaches to quantify the effects of structural shading and reflection. Although here we focus purely on the impact of the racking, this approach may be used for system design elements more generally, for example, adjacent structures in building-integrated PV.

In this work, we present a method to quantify the effects of structural shading and reflection on bifacial PV module irradiance and energy yield. We present a detailed example of this analysis for the two central modules of a 2-in-portrait single-axis-tracked bifacial system. In this study, we quantify the impact of racking shading and reflection of several racking elements, including the frame, module supports, and torque tube. By comparing results with no racking, absorptive racking, and reflective racking, we quantify the impact of racking reflection and shading on the irradiance profile, energy yield, irradiance non-uniformity losses, and bifacial gain on a range of timescales.

2. Model Description

We modeled the PV system in `bifacial_radiance`, an open-source Python-based tool developed by the NREL^[37] that leverages `RADIANCE`^[38] for stochastic reverse ray tracing. The model generates front and rear module irradiance in complex 3D scenes, then applies a single-diode energy calculation based on the open-source `pvl`^[39] library.

Unlike more standard view-factor performance models, `bifacial_radiance` can model arbitrary 3D shapes and several reflections from various surfaces in the surrounding environment. This facilitated the modeling of complex racking structures to analyze the effects of racking across the 2D module surface in this work.

We modified the `bifacial_radiance` software to reduce uncertainty, add racking elements, and facilitate 2D irradiance sampling. First, we reduced inherent stochastic irradiance uncertainty, particularly at module edges, by reducing the ambient accuracy (`aa`) `rtrace` setting from 0.1 to 0.05 and modifying the irradiance scan to progress from the module edges (where irradiance variability is highest) to the module centers (where irradiance variability is lowest). Second, we added frames and supports to the modules under test by defining them as a combination of primitive box shapes in the `makeModule()` function and adding them to the module object. We then replaced all other modules by primitive box shapes that rotate with the module under test, thereby including the racking on the central modules only. Lastly, we facilitated arbitrary 2D irradiance sampling across both faces of the modules under test by importing an array of arbitrary coordinates representing the (x, y) sample positions across the surface of the module, translating these to (x, y, z) sample positions in 3D space for each timestamp, and passing these modified values to the `rtrace` command for front and rear irradiance sampling. In this study, we calculated the front and rear irradiances in 2D arrays of 52×24 points per module (2496 total, 8 points per cell), each representing an equal active area of the module. We took the average of 10 ray trace calculations for each irradiance value to reduce uncertainty.

The model calculated front and rear irradiances for the center modules of a horizontal single-axis-tracked system from hourly typical meteorological year (TMY) data for the Bifacial Test Evaluation Center (BiTEC) site in Livermore, California (37.70° N, 121.82° W).^[40] The albedo was set to 20% and 60% for one model-year each. The modeled system consists of three rows of 23 sets of 2-in-portrait modules, with the torque tube oriented north-south, parallel to the ground.

Model parameters emulate a Soltec 2-in-portrait tracker, but with a round 10 cm diameter torque tube cross-section to simplify tracker modeling. **Figure 1a** shows detailed frame and module support dimensions; supports are 2.8 m long. We modeled the torque tube exclusively on the center row, and the frame and supports exclusively on the modules under test, rather than on all modules and all rows (**Figure 1b**); these simplifications reduced computation time with a negligible impact on rear irradiance. Modules emulate Jinko Solar Tiger Bifacial modules, including 1.032 m wide and 2.205 m long dimensions.^[41] The module gaps are 0.03 m (N–S) and 0.15 m (E–W). The row pitch is 10 m, and the maximum tracking angle is $\pm 60^\circ$ with simple backtracking emulated. The reflectivity of the frames, supports,

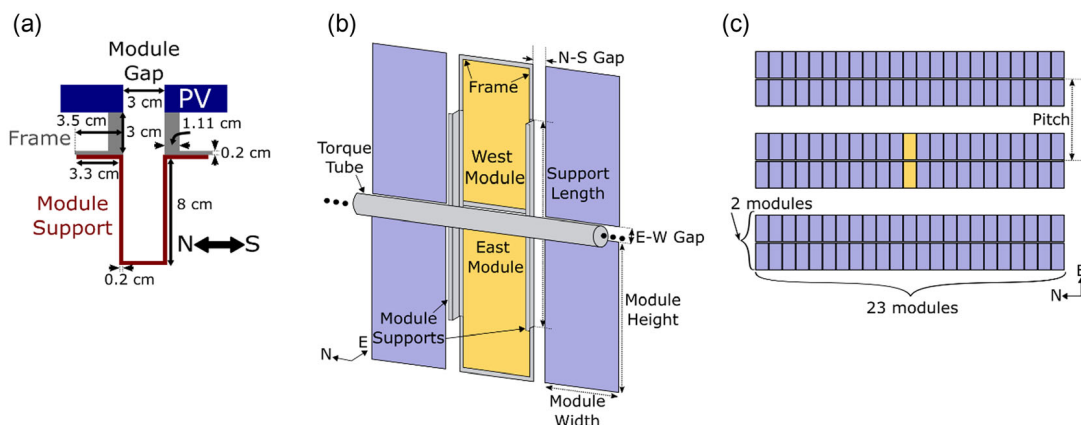


Figure 1. Model components in *bifacial_radiance*: a) cross-sectional schematic of frame and module support dimensions, facing East along module support, b) rear view of modules, including racking, facing North-East. Frame dimensions are identical along all four module edges, and c) top-down view of the modeled system, with modules under test highlighted in yellow.

Table 1. Modeled bifacial photovoltaic system parameters.

Parameter	Value
Number of Rows	3
Modules per Row	23
Row-to-Row Pitch	10 m
Hub Height	2.35 m
Tracking Limit	60°
East-West Module Gap	0.15 m
North-South Module Gap	0.03 m
Module Length	2.205 m
Module Width	1.032 m
Module Support Length	2.8 m
Module Support Height	8 cm
Torque Tube Diameter	10 cm
Racking Reflectivity	74.5%/0%
Racking Specularity	90%
Racking Roughness	20%
Module Reflectivity	0%
Ground Albedo	20%/60%

and torque tube is 74.5% (reflective) or 0% (absorptive). The reflective material has 90% specularity (90% of reflected irradiance reflected specularly) and 20% roughness (the root-mean-square slope of surface facets). Material specularity should be carefully evaluated in future racking reflection effect studies, as it can have a significant effect on model results.^[42] System parameters are summarized in **Table 1**.

3. Results and Discussion

To quantify the effect of racking on irradiance, we modeled the 2D front and rear irradiance profiles of the two central modules, one east and one west of the torque tube, for a typical

meteorological year in three cases: 1) with no racking, 2) with absorptive racking, and 3) with reflective racking. By taking the difference of rear irradiance map pairs, we calculated three racking effects: 1) shading, 2) reflection, and 3) combined shading and reflection:

$$\Delta G_s = G_{\text{absorptive}} - G_{\text{noracking}} \quad (1)$$

$$\Delta G_r = G_{\text{reflective}} - G_{\text{absorptive}} \quad (2)$$

$$\Delta G_{s+r} = G_{\text{reflective}} - G_{\text{noracking}} \quad (3)$$

where ΔG_s is the racking-shaded rear irradiance, ΔG_r is the racking-reflected rear irradiance (i.e., the irradiance due only to reflection from the racking), and ΔG_{s+r} is the net effect of racking on the rear irradiance; $G_{\text{noracking}}$ is the rear irradiance with no racking, $G_{\text{absorptive}}$ is the rear irradiance with absorptive racking, and $G_{\text{reflective}}$ is the rear irradiance with reflective racking, maintaining the symbology as is customary in the field.^[26,32,43,44] This approach will slightly overestimate direct shading losses, since the case with no racking will allow additional irradiance that would have been blocked by the torque tube to pass between the modules onto the ground, increasing $G_{\text{noracking}}$ and, consequently, ΔG_s . However, if rear irradiance is modeled without any racking elements, this error is expected, and this approach will correctly reduce rear irradiance to match expected rear irradiance.

In this work, we study a single sunny winter timestamp to observe the spatially-resolved effects of racking on the rear irradiance of the module, then a long summer day to observe time-dependent effects of racking over the course of the day. Lastly, we study the net monthly and annual effects of racking.

3.1. Effects of Racking on Localized Rear Irradiance

Single-timestamp 2D rear irradiance map examples for each metric on December 22 at noon with 20% albedo are presented in **Figure 2**. This shows a sunny winter day, where the sun at solar noon has a low elevation angle of 29°. For this timestamp,

rear irradiance without racking is 7.5% of the total irradiance, and the tilt angle is $+16.9^\circ$ (before solar noon).

The 2D irradiance maps in Figure 2 demonstrate that racking shading and reflections on the rear module faces are localized near the racking objects. Frame shading is on all four edges of the modules; module support shading and reflection extend partway up the module on the northern and southern edges of the modules; and torque tube shading and reflection is concentrated near the east-west tier gap between the modules.

Figure 2f shows a “bright spot” where racking reflection increases the rear irradiance. This localized irradiance increase is focused near the torque tube at the northern module edge. This high-irradiance spot is caused by sunlight passing through the torque tube gap, reflecting from the torque tube, and striking the module rear. This effect has been reported in previous 3D ray-tracing model results: NREL have shown similar edge-brightening effects for a single timestamp with a 1D irradiance scan through the center of a pair of 2 P modules, although other racking elements were neglected, such that the impact of the module frame blocking torque-tube-reflected irradiance was not captured in the rear irradiance profile.^[23]

This reflected irradiance is focused on the northern edge of the module due to module support shading of the torque tube at the module’s southern edge. Since this effect is caused by the sun’s position in the southern half of the sky, it is most pronounced in the winter when there are lower solar elevation angles around solar noon. Light also reflects from the northern module support onto both the northern portion of the module and the torque tube beneath it, further increasing racking reflection at the northern edge. In the summer, this effect is no longer present due to higher solar elevation angles.

The averages of these irradiance maps along the modules’ width and length for the same timestamp, December 22 at noon with 20% albedo, are presented in Figure 3. With no racking, the irradiance is highest at the outer eastern and western edges of the modules, with a similar gradient to either side of the torque tube (green solid lines). For this timestamp, the eastern module has a higher irradiance peak than the western module; throughout both days, the module nearer to the ground has higher rear irradiance and irradiance non-uniformity than the one nearer to the sky. Cells that are nearer to the ground receive more ground-reflected light, while those nearer to the sky receive more diffuse light;^[45] therefore, this effect varies due to site conditions, array configuration, albedo, direct beam irradiance, and other factors. For example, Ayala Pelaez et al. demonstrated that this rear irradiance non-uniformity is more significant for low module clearance heights through modeling and field measurements.^[14]

When racking shading is introduced (black solid lines), rear irradiance decreases by up to 37.8 W m^{-2} in some locations, particularly near the torque tube. Introducing reflective racking (gold solid lines) increases rear irradiance by up to 36.5 W m^{-2} in some locations, with these effects focused near the racking elements.

Racking shading (blue dashed lines) is localized near the racking elements, including the module edges near the frames, the northern and southern module edges along the span of the module supports, and the module edges near the torque tube. In this timestamp, there is more torque tube shading on the eastern module, with an irradiance reduction of 20.4% at the edge of the eastern module and a reduction of 14.9% at the edge of

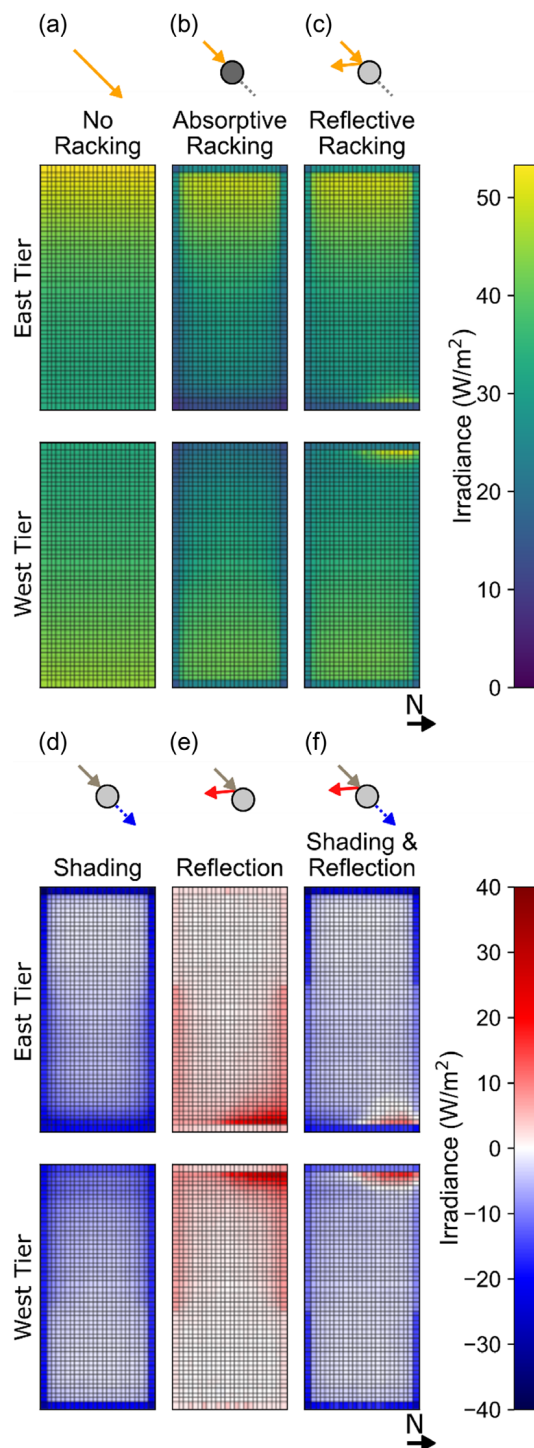


Figure 2. 2D rear irradiance maps of the 2-in-portrait modules for December 22 at noon, with a) no racking, b) absorptive racking, and c) reflective racking. The effect of racking on the rear irradiance of the modules is shown in 2D maps, including d) shading, e) reflection, and f) both shading and reflection. Racking includes the module frame, module supports, and the torque tube.

the western module. As will be discussed in Section 3.2.1, the module with higher torque tube shading varies with the time of day, time of year, cloudiness, and albedo.

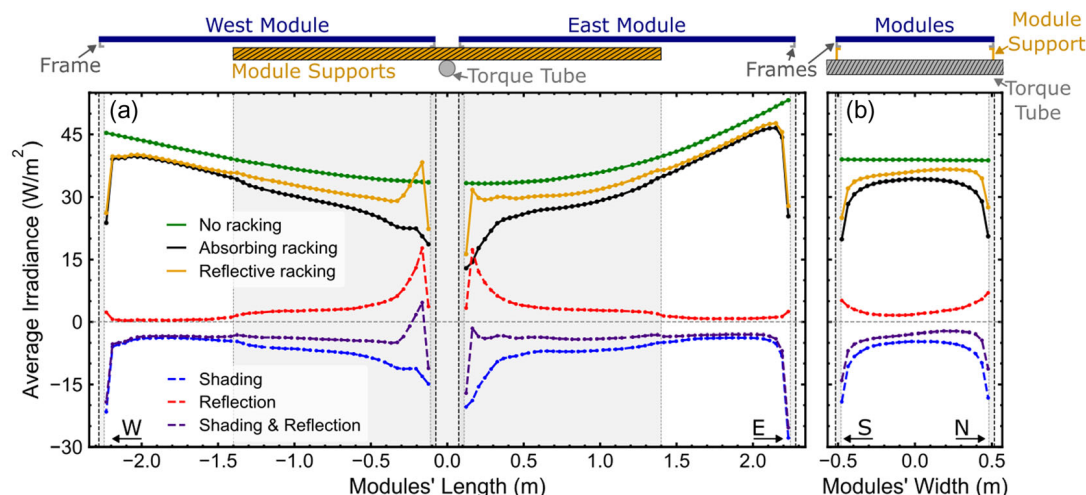


Figure 3. Cross-sectional average rear irradiance on the center modules in a 2-in-portrait configuration on December 22 at 12PM with 20% albedo, including no racking (green), absorptive racking (black), and reflective racking (gold). Cross-sectional average of effects of racking on module irradiance, including reflection (dash red), shading (dash blue), and both reflection and shading (dash purple). Averages taken along a) the modules' width and b) the modules' length. Racking element locations indicated by grey fill. Cross-sectional diagram (not to scale) of modules and racking elements above, with modules in blue, frames and torque tube in grey, and module supports in yellow.

Racking reflection (red dashed lines) is also localized near the racking elements. In Figure 3a, the end of the module supports can be identified at ± 1.4 m by the increase in racking-reflected irradiance, and in Figure 3b, module support reflection increases the irradiance at the southern and northern module edges. Torque tube reflection is focused near the adjacent module edges, except a small strip where this reflection is blocked by the frame. As seen in Figure 2e and 3b, torque tube reflection is higher at the northern module edge than at the southern edge due to the sun's position in the southern half of the sky. As previously discussed, this is due to the module supports – in the case with no racking, the rear irradiance is uniform in the North-South dimension.

Considering both racking reflection and shading combined (purple dashed line), racking reflection partially offsets racking shading, resulting in more uniform irradiance. However, rear irradiance is still typically reduced by the presence of racking, as shown by the reflective racking case in Figure 3 (gold solid line) compared to the case without racking (green solid line).

For this timestamp, the torque tube causes a positive net irradiance effect at the eastern edge of the western module. This bright spot, where racking results in a positive net change in rear irradiance, moves from the western module to the eastern module based on the tilt angle, with the brighter spot located on the module higher in the sky, in both the 20% and 60% albedo case. This is due to higher shading near the torque tube on the module closer to the ground (east before solar noon and west after), resulting in less irradiance on that module. The torque tube reflection, by contrast, is nearly equally distributed between the east and west modules when not backtracking. During backtracking, there is much higher torque tube reflection on the western module in the morning and the eastern module in the evening. This is likely caused by the module nearer to the ground shading a portion of the torque tube from direct incident light that would pass through the torque tube gap and reflect onto the module that is nearer to the ground.

3.2. Effects of Racking with Respect to Time of Day

3.2.1. Shading and Reflection Factor

The impact of racking on average rear irradiance can be quantified by a shading or reflection factor, taken as the racking effect (shading, reflection, or both) averaged over the modules and divided by the average rear irradiance with no racking. The shading factor (SF) is a unitless value, defined as the percentage of rear irradiance that is lost due to the presence of absorptive racking:

$$SF = \frac{\Delta \bar{G}_s}{\bar{G}_{\text{noracking}}} = \frac{\frac{1}{n} \times \frac{1}{A_T} \times \sum_{i=1}^n A_i (G_{\text{absorptive},i} - G_{\text{noracking},i})}{\frac{1}{n} \times \frac{1}{A_T} \times \sum_{i=1}^n A_i (G_{\text{noracking},i})} \quad (4)$$

The reflection factor (RF) is the percentage of rear irradiance that is gained by racking reflection:

$$RF = \frac{\Delta \bar{G}_r}{\bar{G}_{\text{noracking}}} = \frac{\frac{1}{n} \times \frac{1}{A_T} \times \sum_{i=1}^n A_i (G_{\text{reflective},i} - G_{\text{absorptive},i})}{\frac{1}{n} \times \frac{1}{A_T} \times \sum_{i=1}^n A_i (G_{\text{noracking},i})} \quad (5)$$

The shading and reflection factor (SRF) is the percentage change in rear irradiance caused by racking shading and reflection combined:

$$SRF = \frac{\Delta \bar{G}_{s+r}}{\bar{G}_{\text{noracking}}} = \frac{\frac{1}{n} \times \frac{1}{A_T} \times \sum_{i=1}^n A_i (G_{\text{reflective},i} - G_{\text{noracking},i})}{\frac{1}{n} \times \frac{1}{A_T} \times \sum_{i=1}^n A_i (G_{\text{noracking},i})} \quad (6)$$

where $G_{\text{noracking},i}$, $G_{\text{absorptive},i}$, and $G_{\text{reflective},i}$ are the rear irradiance with no racking, absorptive racking, and reflective racking, respectively, at the i th position on the module, A_i is the module active area represented by the i th sample point, n is the number of sample points across the surface of the module, A_T is the total

active area of the module, $\bar{G}_{\text{noracking}}$ is the spatially-averaged rear irradiance without racking, and $\Delta\bar{G}_s$, $\Delta\bar{G}_r$, and $\Delta\bar{G}_{s+r}$ are the net rear irradiance impact due to racking shading, reflection, and shading and reflection combined, respectively. A negative factor indicates reduced irradiance, while a positive factor indicates increased irradiance. Although our point density is sufficiently high for model convergence, we have chosen to represent these factors with summations rather than integrations to reflect our implementation.

These values vary over time. For the 20% ground albedo case, SF varied from -20.8% to -10.5% , RF varied from $+4.5\%$ to $+19.2\%$, and SRF varied from -12.7% to $+2.4\%$ on a per-timestamp basis. For the 60% albedo case, these ranges were -18.6% to -10.4% , $+4.5\%$ to $+13.1\%$, and -12.0% to -5.4% for the SF, RF, and SRF, respectively.

The rear insolation change due to racking shading (SF), reflection (RF), and racking and reflection combined (SRF) over the course of a sunny summer day are illustrated in **Figure 4a,b** for 20% albedo (left column) and 60% albedo (right column). This provides a more typical ground reflectivity case for California (lower albedo) and a potential look at racking effects in a high-albedo case, such as in locations with snow cover or high-albedo ground treatments. In this figure, the solid lines represent the east module and the dashed lines represent the west module.

As shown in **Figure 4a**, for the 20% albedo case, the shading factor is similar between the east and west modules, with little variation throughout the day. By comparison, for the 60% albedo case, as shown in **Figure 4b**, racking shading is highest on the western module in the morning and the eastern module in the afternoon. That is to say, the module that is further from the ground has the higher shading factor. On cloudy days (**Figure S3**, Supporting Information), the opposite is true, with a larger shading factor on the module closer to the ground. This is due to torque tube shading: the torque tube shades more ground-reflected irradiance for the module that sits further from the ground, and shades more diffuse irradiance for the module that is closer to the ground. Therefore, when there is a high fraction of ground-reflected rear-incident irradiance, as in the sunny summer day with 60% albedo, the module that is further from the ground receives more racking shading. On cloudy days, when there is a high proportion of diffuse irradiance, the module that is closer to the ground receives more racking shading. Furthermore, on sunny days, there is more rear irradiance on the module closer to the ground due to ground-reflected irradiance, and on cloudy days, there is more rear irradiance on the module further from the ground due to diffuse irradiance. This further exaggerates the trend.

RF (red lines) is smaller at mid-day for sunny days and is typically constant on cloudy days. A large fraction of racking-reflected rear irradiance is due to direct sunlight that passes through the torque tube gap, strikes the torque tube, and reflects onto the rear of the module. This irradiance increases with front-incident irradiance, which is high from mid-morning to mid-afternoon. Total rear irradiance peaks more sharply at midday, resulting in a smaller proportion of total rear irradiance that is torque-tube-reflected and a smaller RF at midday. On sunny days, racking reflection is higher on the eastern module in the morning and the western module in the afternoon, with a larger difference

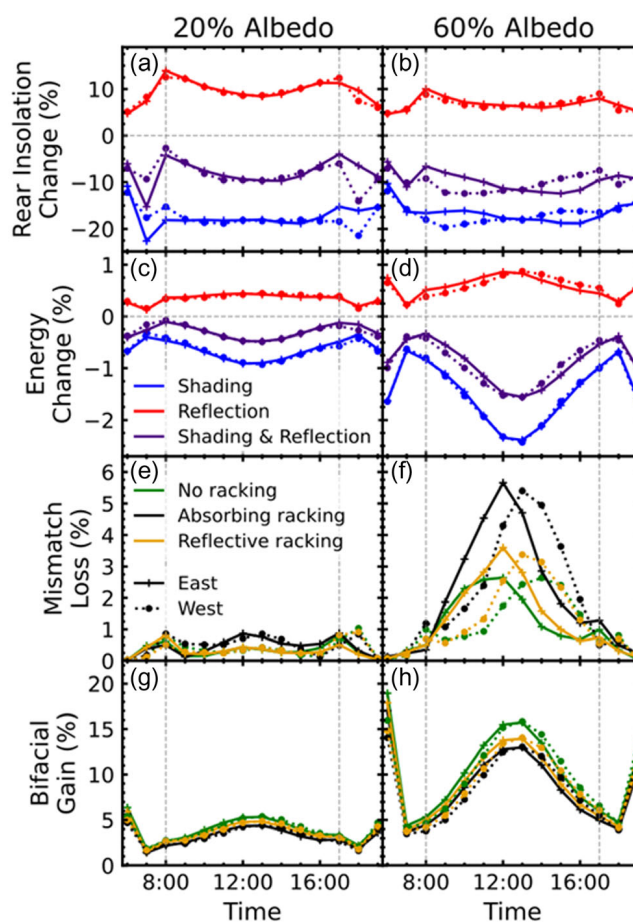


Figure 4. Daily effect of racking reflectivity on 2-in-portrait module for June 18, a sunny summer day, with 20% albedo (left column), and 60% albedo (right column): a,b) rear insolation change, c,d) energy change, e,f) mismatch energy loss, and g,h) bifacial gain. Vertical grey dashed lines indicate the end and start of backtracking hours. Horizontal grey dashed lines indicate zero.

away from solar noon. On cloudy days, the opposite is true, with more racking reflection on the western module in the morning and on the eastern module in the afternoon. Again, this is due to more ground-reflected irradiance striking the torque tube and reflecting onto the module that is nearer to the ground in sunny conditions, and more diffuse-sky irradiance striking the torque tube and reflecting onto the module nearer to the sky in cloudy conditions.

SRF (purple lines) is typically negative, with only a few exceptions near sunset in summertime when the total irradiance is low. Therefore, racking reduces average rear irradiance even when its reflection is considered. However, SRF is always larger than SF, demonstrating that racking reflection offsets racking shading. For example, on December 22 at noon, the shading factor is -18.4% , the reflection factor is $+7.6\%$, and the combined shading + reflection factor is -10.8% . SRF varies over the course of the day due to the changes in SF and RF. For the 20% albedo case, while shading is relatively constant, reflection varies. Therefore, racking reflection can introduce more variability in racking losses over time.

3.2.2. Energy Shading and Reflection Factor

Racking effects can be considered in the context of the module energy yield, as shown in Figure 4c,d. The impact of racking shading and reflection on module energy yield can be quantified by taking the percentage change in module energy yield due to racking effects. For example, the effect of shading on module energy yield, as a fraction of energy yield without racking, can be defined by the energy shading factor, ESF:

$$ESF = \frac{EY_{\text{absorptive}} - EY_{\text{noracking}}}{EY_{\text{noracking}}} \quad (7)$$

We can also define the energy reflection factor (ERF), which defines the change in energy yield due to racking reflection as a fraction of energy yield without racking:

$$ERF = \frac{EY_{\text{reflective}} - EY_{\text{absorptive}}}{EY_{\text{noracking}}} \quad (8)$$

Lastly, we define the energy shading and reflection factor (ESRF), which quantifies the combined impact of racking shading and reflection, as a fraction of energy yield without racking:

$$ESRF = \frac{EY_{\text{reflective}} - EY_{\text{noracking}}}{EY_{\text{noracking}}} \quad (9)$$

where $EY_{\text{noracking}}$, $EY_{\text{absorptive}}$, and $EY_{\text{reflective}}$ are the module energy yield in the case with no racking, with absorptive racking, and with reflective racking, respectively.

Since the front irradiance is nearly always larger than the rear irradiance, the total impact of racking as a fraction of total energy yield is less than the shading factor. As Figure 4 shows, the daily peak for all three quantities is at midday, when bifacial gain (Figure 4g,h) is high, and therefore the rear-irradiance racking effects contribute more to the total irradiance and module energy yield. In this work, bifacial gain (BG) is defined as the additional energy yield generated by the module due to the rear irradiance contribution, as a fraction of monofacial energy yield:

$$BG = \frac{EY_{\text{bifacial}} - EY_{\text{monofacial}}}{EY_{\text{monofacial}}} \quad (10)$$

where EY_{bifacial} and $EY_{\text{monofacial}}$ are the bifacial monofacial energy yields of the module, respectively.

In the 60% albedo case, the difference in ESF between the east and west modules (blue lines, Figure 4d) is less pronounced than the difference in SF between these modules (blue lines, Figure 4b). This is due to the difference in total irradiance, both front and rear, between the east and west modules. The module further from the ground has higher front-incident irradiance due to row-to-row diffuse shading, a phenomenon that is well-understood.^[46] Under sunny conditions, the module nearer to the ground has higher rear irradiance due to more ground-reflected light, and under cloudy conditions, the module nearer to the sky has higher rear irradiance due to more diffuse light. Therefore, in the 60% albedo case on the sunny summer day, despite the higher SF on the module nearer to the sky, that module has higher front irradiance and lower rear irradiance than the module nearer to the ground. This means that the shading losses

are less significant to the module nearer to the sky's total irradiance and energy yield compared to the module nearer to the ground. This results in a reduction in the difference in ESF between the modules. For the same reasons, the difference in ERF is larger compared to the difference in RF between the east and west modules. As a result, for this 60% albedo sunny summer day, while the ESRF losses are still greater on the module nearer to the sky, the difference is smaller than the difference in SRF.

3.2.3. Mismatch Losses

Racking also affects the rear irradiance non-uniformity and cell-to-module electrical mismatch losses. Mismatch power losses (M) are caused by the difference in generated current between cells in the same module string, and can be defined as:

$$M = 1 - \frac{P_{\text{module}}}{\sum P_{\text{cell}}} \quad (11)$$

where P_{module} is the total power output of the module, and P_{cell} is the individual power output of each of the module's cells.^[25]

We quantified mismatch losses for each timestamp's 2D irradiance maps for both modules in all three racking cases using the mean absolute difference method as defined in ref. [25] and further validated in ref. [47]. Mismatch losses are calculated by taking the cell-level average irradiance for each cell in the module, then determining the mean absolute difference across the module, before applying the fit equation defined in ref. [25]. We calculated the mismatch losses at each timestamp, with the losses for three racking cases and two albedos on a summer sunny day shown in Figure 4e,f.

Irradiance mismatch losses are higher for the high-albedo case, as expected: Riedel-Lyngskær et al. previously demonstrated an increase in maximum electrical mismatch losses from 0.25% to 3% for a single sunny day when ground albedo was increased from 22% to 60%.^[47] Irradiance mismatch losses are lowest for the case with no racking (0–2.6% loss) and highest for the case with absorptive racking (0.1–5.7% loss). Racking reflection partially counteracts non-uniform illumination profiles induced by racking shading, resulting in lower irradiance mismatch losses for the case with reflective racking (0.1–3.6%). This is primarily due to racking reflection near the torque tube, which offsets torque tube shading, resulting in a more uniform illumination profile on the rear of the module. The addition of absorptive racking increases mismatch losses by 0–3.0%, while the addition of racking reflection decreases mismatch losses by 0.1–2.0%.

In the 60% albedo case on sunny days, for all three racking cases (no racking, absorptive racking, and reflective racking), there is a peak in irradiance mismatch losses in the morning on the eastern module and in the afternoon on the western module (Figure 4f). Higher irradiance non-uniformity losses in the module closer to the ground were also reported in both^[30,47] for a 2-in-portrait single-axis-tracked system on a sunny day. McIntosh et al. reported up to 0.25% irradiance mismatch losses, with a peak at 11AM for the eastern module and at 1PM for the western module, with 5–45% spectral-dependent albedo.^[30] These values are consistent with our 20% albedo case with reflective racking. Riedel-Lyngskær et al. reported measured irradiance

mismatch losses of up to 2% over a 60%-reflective artificial albedo cover, also with a peak on the eastern module before solar noon and the western module after solar noon. However, their ray-trace modeled results did not agree with this trend, with a single peak of up to 3% irradiance mismatch losses at solar noon for both modules.^[47]

This trend in rear irradiance mismatch loss over the course of the day is due to the combination of front and rear irradiance profiles. Front irradiance non-uniformity is highest at high tilt angles because the module edge nearer to the sky receives more incident irradiance than the module edge nearer to the ground, with a near-linear irradiance gradient across the module's front length due to inter-row shading of diffuse light – this effect is most pronounced at high tilt angles. Rear irradiance non-uniformity is also highest at high tilt angles, in the morning for the eastern module and in the afternoon for the western module; the edge closest to the ground receives more ground-reflected irradiance, causing a bright edge near the ground and increased non-uniformity. These front and rear incident irradiance gradients counteract each other, resulting in a more uniform total irradiance at high tilt angles. Therefore, irradiance mismatch losses peak at mid-morning for the eastern module and mid-afternoon for the western module under sunny, high-albedo conditions.

For some high-tilt-angle timestamps, mismatch losses are smaller for the reflective racking case compared to the no racking case. With reflective racking, light reflects from the torque tube and generates a bright spot along the nearby inner module edges; this bright spot decreases the irradiance difference between the inner module edges and the outer module edges at high tilt angles. The outer module edges have high irradiance at high tilt angles due to ground-reflected irradiance for the module nearer the ground and diffuse irradiance for the module nearer the sky. In addition, module support and frame shading reduce the irradiance at these bright outer edges, further reducing the irradiance non-uniformity. On cloudy days with 20% albedo, mismatch losses are always lower with reflective racking than without racking. This is in part due to torque tube reflection, as just described, and due to torque tube shading of the module nearer to the ground that offsets its high front irradiance near the torque tube gap.

3.2.4. Seasonal Effect of Racking

To find the shading factor, reflection factor, and combined shading and reflection factor for a time period, we take the sum of the rear-incident irradiance change, divided by the sum of the rear irradiance with no racking:

$$SF_T = \frac{\sum_{ts} \bar{G}_s}{\sum_{ts} \bar{G}_{noracking}} \quad (12)$$

where T is the total number of timestamps, and ts is the timestamp index. The RF and SRF are summed in the same way to find their value over a day, month, or year:

$$RF_T = \frac{\sum_{ts} \bar{G}_r}{\sum_{ts} \bar{G}_{noracking}} \quad (13)$$

$$SRF_T = \frac{\sum_{ts} \bar{G}_{s+r}}{\sum_{ts} \bar{G}_{noracking}} \quad (14)$$

Similarly, the ESF, ERF, and ESRF over a period of time can be defined as:

$$ESF_T = \frac{\sum_{ts} EY_{absorptive} - \sum_{ts} EY_{noracking}}{\sum_{ts} EY_{noracking}} \quad (15)$$

$$ERF_T = \frac{\sum_{ts} EY_{reflective} - \sum_{ts} EY_{absorptive}}{\sum_{ts} EY_{noracking}} \quad (16)$$

$$ESRF_T = \frac{\sum_{ts} EY_{reflective} - \sum_{ts} EY_{noracking}}{\sum_{ts} EY_{noracking}} \quad (17)$$

It is important to note that this is not the mean over time of these metrics, which would provide equal weight to each timestamp. In this definition, high-irradiance and high-energy timestamps provide a greater contribution to the final value.

Figure 5 shows the seasonal effects of racking over the course of the year, with the monthly rear insolation change, energy

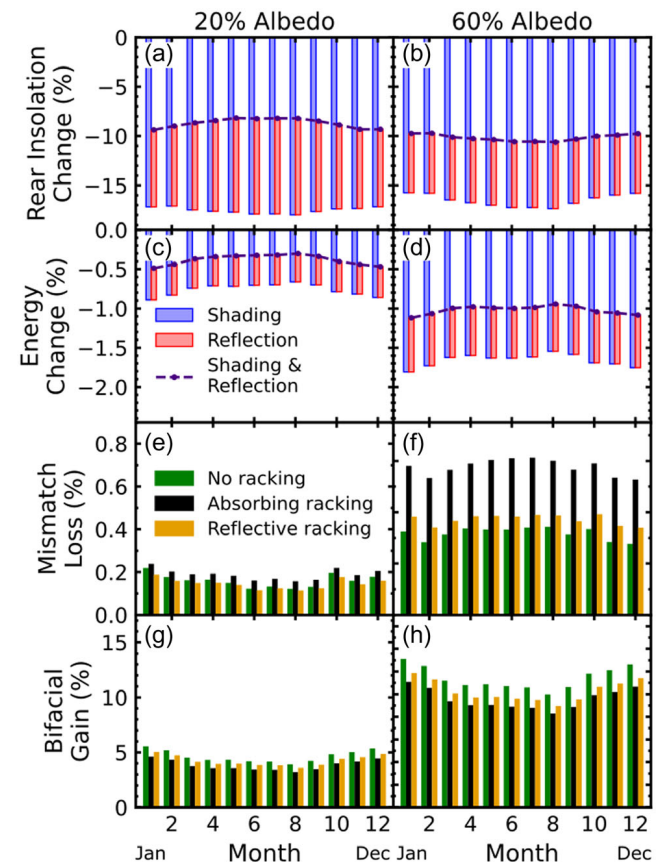


Figure 5. Monthly a,b) rear insolation change and c,d) energy change for the effect of racking shading (blue bars), racking reflection (red bars), and combined racking shading & reflection (purple lines). Monthly f,g) energy mismatch loss, and g,h) energy gain for a pair of modules without racking (green bars), with absorbing racking (black bars), and with reflective racking (gold bars). Calculated for a 20% albedo case (left column) and a 60% albedo case (right column).

change, mismatch losses, and bifacial gain shown for both a 20% albedo case and a 60% albedo case.

For the 20% albedo case, SF and RF are largest in the summer and lowest in the winter, varying from -18.0% to -17.1% and $+7.8\%$ to $+9.8\%$, respectively. The combined SRF is larger in the winter due to the smaller RF, varying from -9.4% to -8.2% . The 60% albedo case also has larger SF and RF in the summer, with a -17.4% to -15.7% and $+6.0\%$ to $+6.7\%$ range, respectively. In the 60% albedo case, the SRF is larger in the summer due to the larger SF, with a -10.6% to -9.7% range. While SF and RF have greater magnitudes in the 20% albedo case, showing that racking shading and reflection have a larger irradiance impact individually when the albedo is lower, the SRF has a greater magnitude in the 60% albedo case, and so the net racking effect is larger with a larger albedo.

For both albedos, the ESF follows the opposite trend, with larger values in the winter due to higher winter bifacial gain, while the ERF is nearly constant, within a 0.1% range year-round. ERF is less dependent on bifacial gain due to the large fraction of racking-reflected irradiance introduced by direct irradiance that is reflected from the torque tube, as previously discussed. The ESRF therefore has the largest magnitude in the winter for both albedos. The magnitude of the ESRF is greater for the 60% albedo case, again due to higher bifacial gain: the greater the rear irradiance contribution to total energy yield, the greater the impact of structural shading and reflections on the rear of the module.

As seen in the previous section, absorptive racking results in the highest mismatch losses, from $0.5\text{--}0.6\%$ and $0.1\text{--}0.2\%$ for the 60% and 20% albedo cases, respectively. In the 60% albedo case, racking reflection reduces mismatch losses to $0.3\text{--}0.4\%$, but does not reduce mismatch losses below the case with no racking. Comparatively, in the 20% albedo case racking reflection reduces mismatch losses below those with no racking for all months. This is due to the bright spot introduced by torque tube reflection counteracting the bright outer edges of the modules caused by diffuse inter-row shading and ground reflection, as previously discussed. Seasonally, mismatch losses are lower in the summer for the 20% albedo case due to the lower summer bifacial gains. In the 60% albedo case, mismatch losses are typically higher in the summer, despite lower summer bifacial gains.

Bifacial gain is higher in the winter due to increased diffuse irradiance. The diffuse irradiance fraction, taken as the diffuse horizontal irradiance divided by the global horizontal irradiance, peaks at 47% in February and is at its lowest at 24% in August. Cloudy days have been demonstrated to cause higher bifacial gains than sunny days in the literature.^[48–52]

3.2.5. Annual Effect of Racking

A summary of the annual effects of structural shading and reflection is presented in **Figure 6**. In the 20% albedo case, racking shading changes rear irradiance by -17.6% and racking reflection increases rear irradiance by $+9.1\%$ annually, resulting in a total annual racking effect of -8.5% . In the 60% albedo case, these effects are -16.8% , $+6.5\%$, and -10.3% annually for racking shading, racking reflection, and racking shading and reflection combined. Therefore, if racking shading is considered

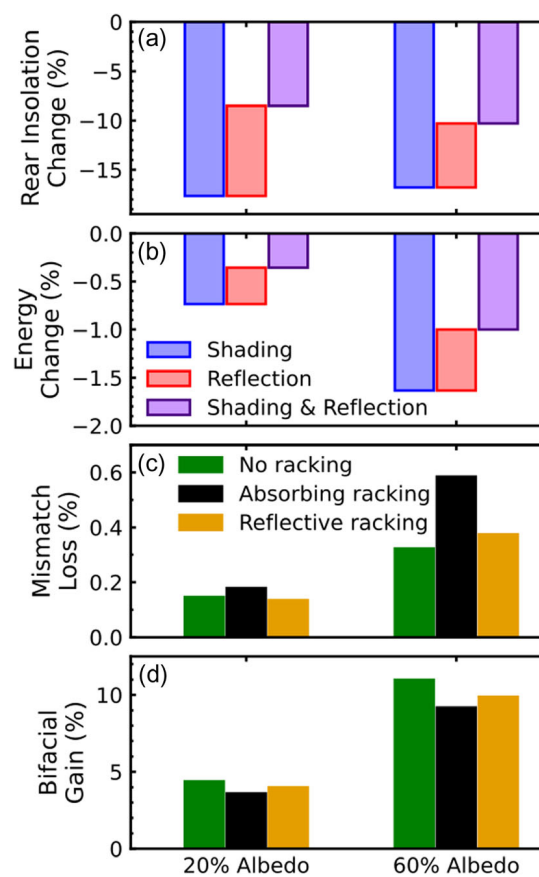


Figure 6. Annual impact of racking effects on module performance with 20% and 60% albedo: a) rear insolation change, b) energy change, c) mismatch loss, and d) bifacial gain.

without racking reflection, rear shading would be overestimated by $6.5\text{--}9.1\%$, and this overestimation is larger for lower albedos.

The annual energy impact of racking is larger for the higher albedo case, with -0.7% shading, 0.4% reflection, and -0.4% total racking impact in the 20% albedo case and -1.6% shading, $+0.6\%$ reflection, and -1.0% total racking impact in the 60% albedo case. These values are higher in the high-albedo case due to larger bifacial gain at higher albedo. This result implies that racking structural shading and reflection factors should be more carefully considered in cases with high bifacial gain, such as locations with high albedo or a high proportion of diffuse light.

Annual mismatch losses are also affected by racking shading and reflection: for the 60% albedo case, the addition of racking shading increases annual mismatch losses from 0.3% to 0.6% , but considering racking reflection reduces mismatch losses back to 0.4% . For the 20% albedo case, mismatch losses are 0.1% , 0.2% , and 0.1% for the case with no racking, with absorptive racking, and with reflective racking, respectively. In this case, racking reflection reduces total irradiance mismatch by offsetting the bright outer edges of the module, as discussed in the previous section, but it is a small difference on an annual scale. These results are consistent with the annual mismatch losses reported by McIntosh et al. for a 2 P bifacial system of 0.09% over loamy sand ($5\text{--}45\%$ spectral-dependent albedo) and 0.51% over frost (over 80% albedo).^[30]

Bifacial gain is highest in the high-albedo case with no racking, at 11.0% bifacial gain annually. With absorptive racking, annual bifacial gain falls to 9.2% due to reduced rear irradiance caused by racking shading. Considering racking reflection increases bifacial gain to 9.9%. In the 20% albedo case, bifacial gain is 4.4% without racking, 3.6% with absorptive racking, and 4.0% with reflective racking. As mentioned previously, it is expected that bifacial gain would be higher in the case with higher albedo. It is also expected that racking shading would reduce bifacial gain, since it reduces rear irradiance, and racking reflection increases bifacial gain, since it increases rear irradiance.

3.2.6. Influence of Albedo on Racking Effects

Figure 7 shows racking effects, combined as described in Equation (12)–(17), calculated over a single sunny summer day and a single sunny winter day for six albedos: 0%, 5%, 10%, 20%, 60%, and 90%.

As **Figure 7a** shows, low albedo results in a high RF, exceeding SF in the 0% albedo case and resulting in a positive SRF for that albedo. As albedo increases, RF decreases, from +36.7% at 0% albedo to +6.2% at 90% albedo. This is because a large proportion of RF is caused by light that passes through the torque tube

gap and is directly incident on the torque tube, which does not scale with albedo, but the total rear irradiance does increase with increasing albedo.

As expected, bifacial gain increases linearly with albedo,^[32,51] resulting in greater magnitude ERF, ESF, and ESRF at high albedos, despite lower SF and RF values, due to increased rear irradiance contribution to total irradiance.

Irradiance mismatch losses also increase with increasing albedo. For high-albedo cases, this is partly caused by an increase in the magnitude of the “bright edge” on the module edge nearest the ground.

3.2.7. Influence of Racking Reflectivity on Racking Effects

In this experiment, results were shown for a racking reflectivity of 74.5%, but racking reflectivity will vary in fielded systems. **Figure 8** shows the effect of racking shading and reflection on module performance for two sunny days, one in winter and one in summer, for a 20% ground albedo, combined as described in Equation (12)–(17).

As racking reflectivity increases, SF remains constant but RF increases – this is to be expected, as a higher racking reflectivity

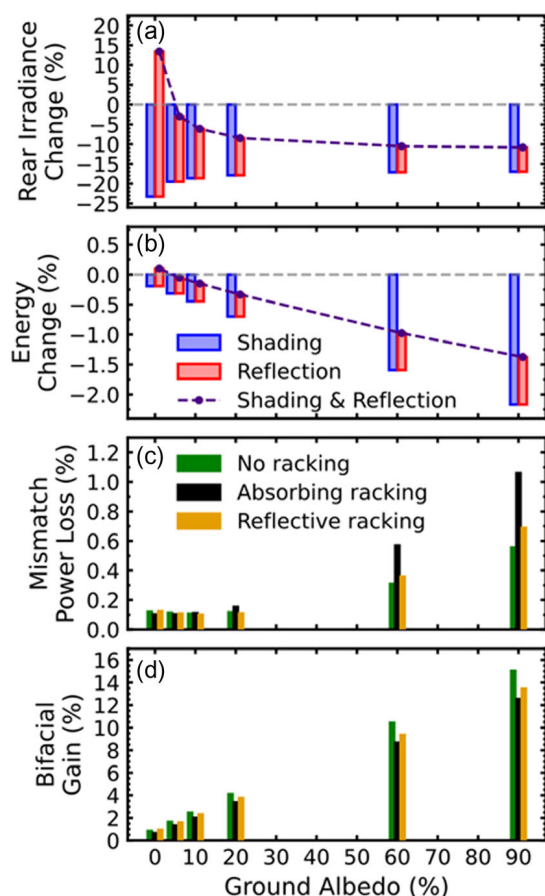


Figure 7. Effect of ground albedo on module performance for a sunny summer day and a sunny winter day combined for a) rear irradiance, b) energy, c) mismatch power loss, and d) bifacial gain.

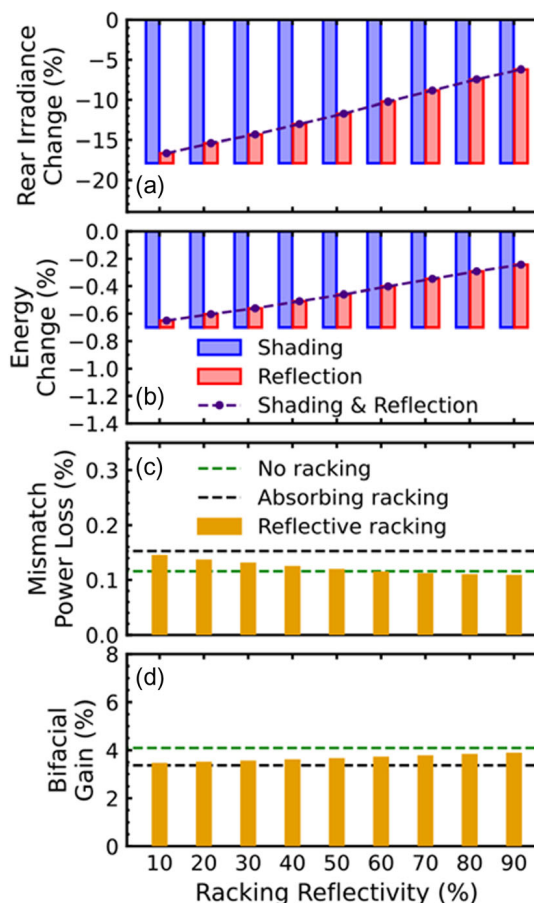


Figure 8. Effect of racking reflectivity on module performance for a sunny summer day and a sunny winter day combined: a) rear insolation change (%), b) energy change (%), c) mismatch power loss (%), and d) bifacial gain (%) for a range of racking reflectivity values.

naturally results in higher racking-reflected irradiance. In this case, RF and ERF increase linearly with racking reflectivity, increasing approximately 13% and 0.5% respectively per 10% increase in reflectivity. This implies that the results of this study can be approximately scaled to the reflectivity of a given material to estimate racking reflection effects on sunny days.

Mismatch losses decrease with increasing racking reflectivity, showing that higher racking reflection can decrease module non-uniformity and decrease mismatch losses below the case without racking, as seen in previous sections. Bifacial gains increase with increasing racking reflectivity, but do not exceed bifacial gain without racking; even with very high racking reflectivity, SRF remains negative, so racking still reduces rear irradiance.

4. Conclusion

While racking losses are typically modeled as a single de-rate factor, applied equally to all timestamps, racking losses in a bifacial photovoltaic system are not constant: they depend on time of day, time of year, cloudiness, albedo, and other factors. In addition, racking reflection is typically neglected when estimating racking losses for bifacial systems. In general, racking effects are most significant when bifacial gain is high, such as in cloudy or high-albedo conditions.

For the 2-in-portrait single-axis-tracked bifacial PV system modeled in this work, racking reflection is focused in the same areas of the module as racking shading, thereby counteracting the effects of shading. If racking reflection is neglected, the racking losses will be overestimated: for a two-in-portrait system in Livermore California over a 20% albedo ground cover, racking reflection reduces the annual shading factor from -17.6% to -8.5% , annual energy shading losses from -0.7% to -0.4% , and the annual irradiance mismatch losses from 0.2% to 0.1% . Racking reflections should therefore be considered whenever possible for accurate energy yield modeling.

Simplifying racking losses to a single shading de-rate factor results in further error in racking loss estimations: this neglects spatial variation in rear irradiance, which causes electrical mismatch between cells and reduces power output. In this case study, mismatch losses for a system with reflective racking varied from 0 to 6.7% on a per-timestamp basis, with an annual mismatch loss of 0.4% in the high-albedo case.

Lastly, the effects of racking, including both shading and reflection, vary significantly by time of day and year: with 20% albedo, the rear irradiance shading and reflection factor varied from -12.7% to $+2.4\%$ on a per-timestamp basis, and from -9.4% to -8.2% monthly, while the energy shading and reflection factor varied from -1.9% to 0.0% on a per-timestamp basis and from -0.5% to -0.3% monthly.

This work consisted of a case study for a single system design in one location. Future work can broaden the parameter space of this study, including a wider range of locations and system geometries, to determine general trends in racking effects. Furthermore, these studies may optimize racking designs to maximize annual system energy yield by capturing racking-reflected irradiance and minimizing rear shading and irradiance mismatch losses.

Accounting for these variations will improve energy yield prediction accuracy for bifacial photovoltaic systems.

Supporting Information

Supporting Information is available from the Wiley Online Library or from the author.

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Conflict of Interest

The authors declare no conflict of interest.

Data Availability Statement

The data that support the findings of this study are available from the corresponding author upon reasonable request.

Keywords

bifacial photovoltaics, racking shading and reflection, reflection factor, shading factor, single axis tracking

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Supporting Information

The following figures show the daily effects of racking on rear irradiance, module energy yield, mismatch losses, and bifacial gain for three more days: a cloudy summer day, a sunny winter day, and a cloudy winter day. Note that the cloudy summer day was only partly cloudy, with a sunny period around midday.

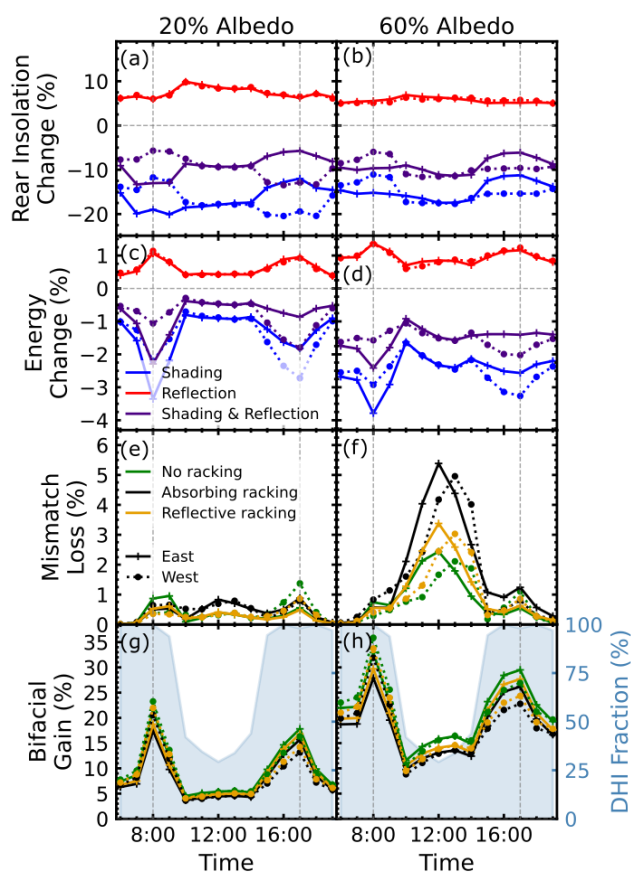


Figure S1. Daily effect of racking reflectivity on 2-in-portrait module for a **cloudy** summer day, with 20% albedo (left column), and 60% albedo (right column): (a)-(b) rear insolation change, (c)-(d) energy change, (e)-(f) mismatch energy loss, and (g)-(h) bifacial gain. Vertical grey dashed lines indicate the end and start of backtracking hours. Horizontal grey dashed lines indicate zero.

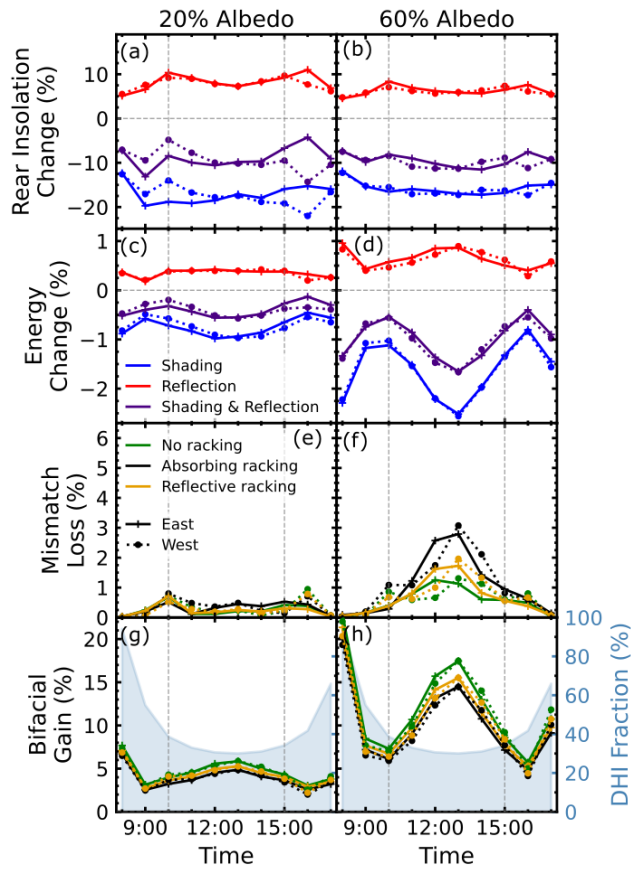


Figure S2. Daily effect of racking reflectivity on 2-in-portrait module for a sunny **winter** day, with 20% albedo (left column), and 60% albedo (right column): (a)-(b) rear insolation change, (c)-(d) energy change, (e)-(f) mismatch energy loss, and (g)-(h) bifacial gain. Vertical grey dashed lines indicate the end and start of backtracking hours. Horizontal grey dashed lines indicate zero.

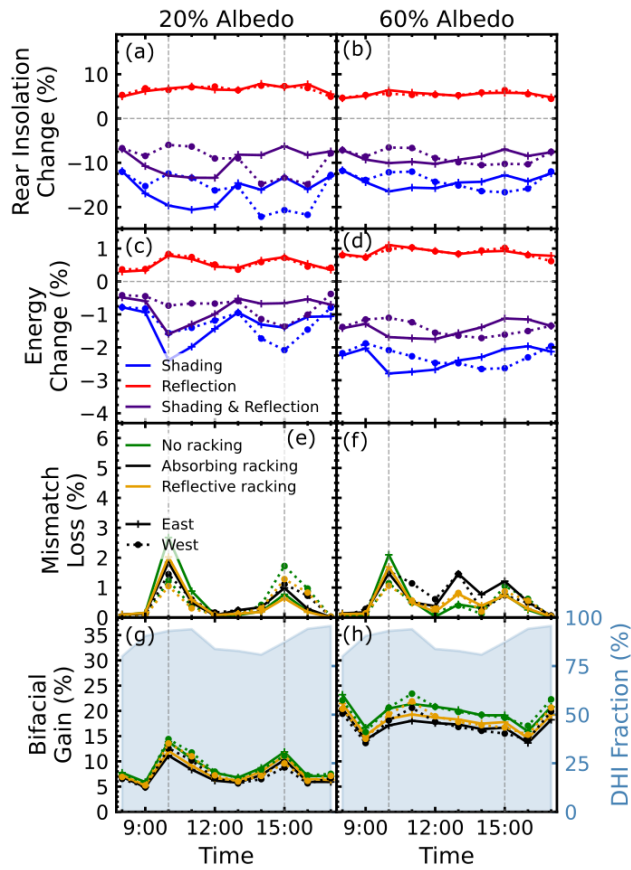


Figure S3. Daily effect of racking reflectivity on 2-in-portrait module for a **cloudy winter** day, with 20% albedo (left column), and 60% albedo (right column): (a)-(b) rear insolation change, (c)-(d) energy change, (e)-(f) mismatch energy loss, and (g)-(h) bifacial gain. Vertical grey dashed lines indicate the end and start of backtracking hours. Horizontal grey dashed lines indicate zero.

Chapter 4

Artificial Ground Reflector Size & Position Effects on Energy Yield & Economics of Single Axis Tracked Bifacial Photovoltaics

This chapter studies the impact of highly-reflective ground cover on the energy yield and economics of a bifacial PV system. I combine field measurements from the National Renewable Energy Laboratory (NREL) Bifacial Experimental Single-Axis-Tracking (BEST) site [217] and ray-trace modelling results to demonstrate that the ideal reflector placement is directly under the torque tube. I perform an economic analysis and find a break-even cost of \$3.50/m² for 70% reflective material.

4.1 Scope and Impact

Bifacial PV modules are rapidly becoming the technology of choice for new photovoltaic systems, and artificial reflectors are generating significant interest as an enhancement to further increase bifacial energy yield. Before this work, there had not been a comprehensive study of reflector parameters and their influence on bifacial photovoltaic performance.

This work describes the impact of artificial ground reflectors on single-axis-tracked bifacial photovoltaic system irradiance and energy yield for various reflector dimensions,

placement, and reflectivity. It also quantifies the economic viability of artificial reflectors. My major findings include:

1. Artificial reflectors should be placed under the torque tube to maximize annual energy yield.
2. Accounting for clipping losses is essential when designing systems with artificial reflectors.

This manuscript will act as a guide to future photovoltaic system designers and installers, advising them in their decision to incorporate albedo-enhancing materials and allowing them to obtain the greatest benefit from these materials.

4.2 Background and Methodology

4.2.1 National Renewable Energy Laboratory (NREL) Bifacial Experimental Test (BEST) Site

The National Renewable Energy Laboratory’s Bifacial Experimental Test (BEST) Site is a 75 kW, 10-row, 20-module-per-row outdoor single-axis-tracked bifacial PV test site in Golden, Colorado (39.74°N, 105.17°W) [218]. It includes a mix of monofacial and bifacial PV strings and various silicon module types. The site is highly instrumented, with front and rear plane-of-array irradiance sensors, module-level electrical monitoring, albedometers, temperature, wind speed, and other sensors. It is located 100 m from NREL’s Solar Radiation Research Laboratory Baseline Measurement System (SRRL BMS) site [219], which includes a large array of freely available meteorological and solar irradiance data.

Data from the BEST site has been applied to validate bifacial energy yield models [220], compare PV technologies [220], and quantify irradiance edge effects, racking losses, and bifacial gain [217]. In this thesis, results from this site supported an analysis of artificial reflectors and reflector gain.

4.2.1.1 Artificial Reflector Experiment

The artificial reflector experiment performed at NREL’s BEST site included five stages, illustrated in Figure 4.1. This experiment included various reflector sizes and placements to quantify the impact of reflectors on bifacial PV energy yield.

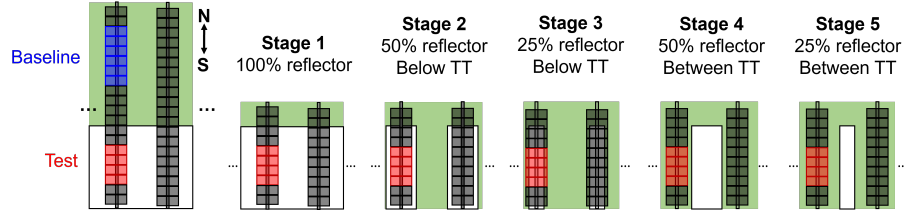


Figure 4.1: Diagram of stages in artificial reflector experiment performed at NREL’s BEST campus, with baseline (blue) and test (red) modules indicated and reflector configurations (white) illustrated.



(a) Stage 1



(b) Stage 2

Figure 4.2: Photos of artificial reflector experiment at National Renewable Energy Laboratory (NREL) Bifacial Experimental Single-axis-tracking (BEST) site. Photo (b) courtesy of Silvana Ovaitt.

4.2.2 Bifacial radiance Artificial Reflector Model

The model presented in this work is implemented in `bifacial_radiance` for a 10-row, 20-module-per-row single-axis-tracked system in Golden, Colorado. The dimensions of the model are shown in Figure 4.3. The system has a 5.7 m pitch, 1.3 m height, and 1 m × 2 m modules with a round, reflective torque tube. Modelling was run on NREL’s Eagle HPC.

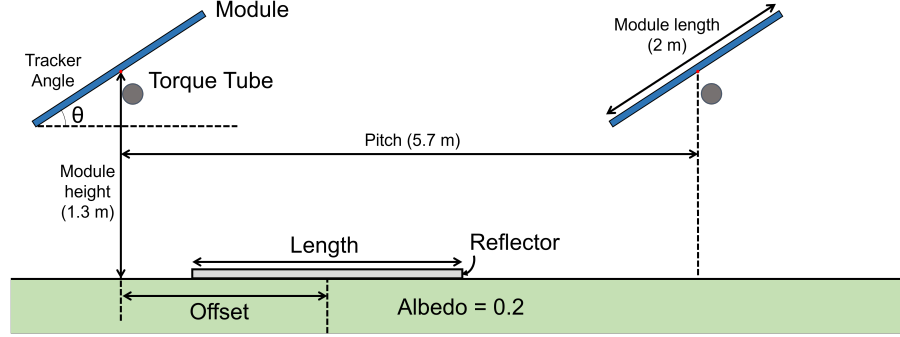


Figure 4.3: Diagram of artificial reflector model parameters for bifacial radiance experiment.

4.2.3 Clipping Loss

In this work, we assume that the maximum power output of the system is the rated power divided by the DC:AC ratio:

$$P_{\text{inv}} = \frac{P_{\text{rated}}}{\text{DC:AC ratio}} \quad (4.1)$$

We assume that the power output of the system, P_{out} , is clipped to this P_{inv} value:

$$P_{\text{out}} = \begin{cases} P_{\text{module}} & \text{if } P_{\text{module}} < P_{\text{inv}} \\ P_{\text{inv}} & \text{if } P_{\text{module}} > P_{\text{inv}} \end{cases} \quad (4.2)$$

where P_{module} is the maximum power output of the module. We can then calculate the clipping loss, P_{clip} , as the percent difference in system output due to clipping:

$$P_{\text{clip}} = 1 - \frac{\Sigma P_{\text{out}}}{\Sigma P_{\text{mp}}} \quad (4.3)$$

These results are reported in the manuscript below in the section concerning clipping losses.

4.2.4 LCOE Calculation

An overview of PV system costs and LCOE calculations is provided in section 2.2.4.7. In this work, the capital recovery factor (CRF) is applied. The CRF is the ratio of a constant

annuity to the present value of receiving that annuity for N years:

$$\text{CRF} = \frac{\text{Annuity}}{\text{Present Value of Annuity}} = \frac{d(1+d)^N}{[(1+d)^N] - 1} \quad (4.4)$$

where d is the discount rate and N is the number of years.

We also apply the capacity factor (CF). The *capacity factor* of a system is the ratio of the energy produced by the system to its theoretical energy output if it was generating its rated power at all times. This can also be taken as the ratio of the system's average power output to the rated power of the system. To calculate a PV system's CF over a year:

$$\text{CF} = \frac{\Sigma P_{\text{out}}}{8760 \times P_{\text{rated}}} \quad (4.5)$$

where ΣP_{out} is sampled hourly or is converted to kWh after the summation.

The LCOE becomes:

$$\text{LCOE} = \frac{I_W \cdot \text{CRF} + M_W}{8760 \times \text{CF}} \quad (4.6)$$

where I_W is the capital expenditure cost per watt and M_W is the maintenance cost per watt.

4.3 Co-Author Contributions

M. R. Lewis assisted with field experiments, assisted with material reflectivity measurements, performed the modelling, performed the analysis, visualized the data, and wrote the manuscript.

S. Ovaite assisted in field experiments, guided methodology, and assisted in manuscript revision.

B. McDanold assisted in field experiments.

C. Deline assisted in field experiments, guided methodology, and assisted in manuscript revision.

K. Hinzer oversaw the research and the manuscript.

All authors contributed to the manuscript.

4.4 Manuscript

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Artificial ground reflector size and position effects on energy yield and economics of single-axis-tracked bifacial photovoltaics

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Abstract

Artificial ground reflectors improve bifacial energy yield by increasing both front and rear-incident irradiance. Studies have demonstrated an increase in energy yield due to the addition of artificial reflectors; however, they have not addressed the effect of varying reflector dimensions and placement on system performance and the impact of these parameters on the reflectors' financial viability. We studied the effect of high albedo (70% reflective) artificial reflectors on single-axis-tracked bifacial photovoltaic systems through ray-trace modeling and field measurements. In the field, we tested a range of reflector configurations by varying reflector size and placement and demonstrated that reflectors increased daily energy yield up to 6.2% relative to natural albedo for PERC modules. To confirm the accuracy of our model, we compared modeled and measured power and found a root mean square error (RMSE) of 5.4% on an hourly basis. We modeled a typical meteorological year in Golden, Colorado, to demonstrate the effects of artificial reflectors under a wide range of operating conditions. Seventy percent reflective material can increase total incident irradiance by 1.9%–8.6% and total energy yield by 0.9%–4.5% annually after clipping is considered with a DC–AC ratio of 1.2. Clipping has a significant effect on reflector impact and must be included when assessing reflector viability because it reduces reflector energy gain. We calculated a maximum viable cost for these improvements of up to \$2.50–4.60/m², including both material and installation, in Golden. We expanded our analysis to cover a latitude range of 32–48°N and demonstrated that higher-latitude installations with lower energy yield and higher diffuse irradiance content can support higher reflector costs. In both modeling and field tests, and for all locations, the ideal placement of the reflectors was found to be directly underneath the module due to the optimized rear irradiance increase.

KEYWORDS

artificial reflectors, bifacial modules, high albedo, single axis tracking

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1 | INTRODUCTION

Bifacial photovoltaic (PV) solar panels, which absorb light on the rear face in addition to the front, are predicted to make up 70% of the PV market share within the next 10 years [1], primarily due to recent cost reductions in bifacial systems. Bifacial systems are becoming cost-competitive with monofacial systems [2] and have demonstrated a lower levelized cost of energy (LCOE) than monofacial systems [3–6]. In addition, bifacial systems allow increased energy density per area, thereby reducing land acquisition costs [7–9].

Bifacial gain, the increase in PV system energy yield over monofacial, highly depends on the site's albedo or ground reflectance. Higher albedo increases energy yield, particularly for bifacial systems [9–14]. Our groups have previously demonstrated the relationship between high-albedo ground cover, such as snow, and silicon bifacial system performance [7, 15–20] and have extended our analysis to bifacial system optimization in naturally high-albedo environments [21]. High-albedo locations demonstrate a boost in performance, with bifacial gains reported of over 19% in snowy months [22]. The bifacial PV industry has demonstrated an interest in extending this energy gain to non-snowy locations year-round using artificial reflectors [23, 24].

Albedo can be enhanced by incorporating artificial ground reflectors with high reflectivity, such as mirrors, white tarps, pebbles, or paint [25–30]. The cost-effectiveness of these approaches is still under consideration: Lim et al. demonstrated that bifacial solar cells paired with planar mirrors have an improved LCOE over monofacial solar cells [31], but Riedel-Lyngskær et al. showed a negligible LCOE improvement due to artificial ground reflectors using a combination of modeling and field test site data [32], while Rhazi et al. found that reflectors' effect on LCOE was either positive or negative, depending on material costs and system design [33]. However, these were site-specific results for single-reflector configurations. The present work investigates (1) the trade-off between costs and additional energy yield and (2) whether optimizing reflector ground coverage and placement can maximize their economic benefits.

In this study, we demonstrate the effects of artificial ground reflector size and position on energy yield and economics for horizontal single-axis-tracked (HSAT) systems. We validate the irradiance and energy yield model with field test measurements from the National Renewable Energy Laboratory's (NREL) bifacial experimental single-axis tracking (BEST) field [19]. We report artificial reflectors' ideal dimensions and placement and their LCOE impact. We define a new metric for quantifying the economic viability of artificial reflectors, the *breakeven installed cost*, which gives the maximum viable price of installed reflectors in $\$/\text{m}^2$. We analyze the effects of inverter clipping by calculating energy gain and breakeven installed cost for a range of DC-AC ratios. Finally, we widen our analysis to include a range of latitudes and weather conditions to demonstrate this study's applicability to a variety of locations.

2 | BIFACIAL PV TEST SITE WITH ARTIFICIAL REFLECTORS

2.1 | Artificial reflector field experiment

Field tests were performed at NREL's 75 kW bifacial single-axis-tracked test site in Golden, Colorado (39.8°N). Module-level power data and sensors were as described in Ovaith and Deline [34], with the addition of two rear-plane-of-array irradiance sensors over the artificial reflectors. We studied a single row of PERC+ modules with a bifaciality factor of 70%.

Module-level power and weather data were measured at 1-min intervals and right-averaged to obtain 15-min power values. As part of the data quality assessment, measurements where the front or global horizontal irradiance varied more than 75 W/m^2 and where albedo varied more than 10% between sensors were removed. In addition, measurements where the measured GHI was less than 25 W/m^2 were removed. Days with snow cover were also ignored because front-facing irradiance sensors would be obscured.

The artificial reflector material consisted of high-density polyethylene (HDPE) geomembrane material with a solar-weighted reflectivity of approximately 70% (Figure 1), provided by Solmax Geosynthetics; HDPE geomembranes have demonstrated lifetimes well in excess of 30 years [35, 36]. We used a Lambda 1050

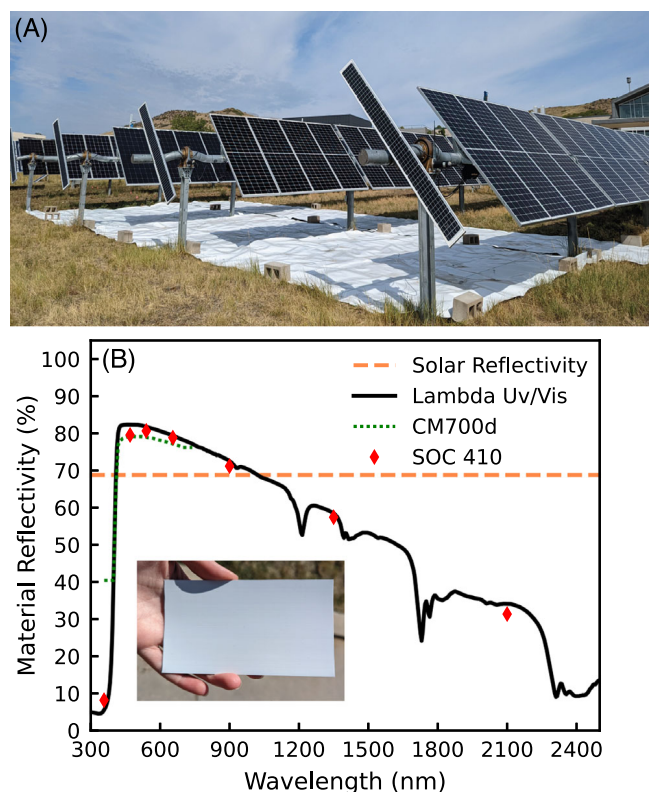


FIGURE 1 (A) Photo of NREL's bifacial experimental single-axis tracking (BEST) field with reflecting material installed (100% coverage case) and (B) measured spectral reflectivity of high-albedo material with photo of sample (inset).

UV-Vis-NIR spectrophotometer to measure the initial material spectral reflectivity and a handheld CM700d spectrophotometer to measure the reflectivity throughout the outdoor experiment. The average reflectivity loss due to soiling was $-0.1\%/day$, although this fluctuated due to varying environmental conditions, such as rain and snow. We measured an average material specular reflectivity of 2% using a 410-Solar handheld reflectometer. This material has a service life of over 30 years and is UV-resistant; to assess the longevity of the material, we performed 2000 h of A3 aging according to the IEC TS 62788-7-2 standard, which resulted in no change in the reflectivity of the material within the error of the measurement.

We installed reflectors in the southern half of the field, between four rows of the 10-row system, with the natural ground cover (grass and soil, 19% average albedo) left in the northern half to act as a reference. Two modules at the north and south edges of the row and six modules in the center at the material edge were ignored to mitigate edge effects, leaving six reference and four test modules to evaluate. We can then define $P_{\text{reflector}}$, the average of four southern modules, and P_{baseline} , the average of six northern modules, to compare performance. Recent work performed on this test site has demonstrated that neglecting two modules is sufficient to limit edge effects to less than 1% [19].

Irradiance sensors were placed to best approximate the average rear-incident irradiance of the modules: Over the reflectors, two sensors were positioned at approximately 20% of the module length from the module edge, as described in literature [37, 38], and averaged to obtain $\bar{G}_{\text{reflector, rear}}$, the average rear irradiance over the reflector. Over the baseline material, four sensors were positioned across the rear of the module as described in Ovaatt and Deline [34], and averaged to obtain $\bar{G}_{\text{baseline, rear}}$, the average rear irradiance over the natural ground cover.

We investigated five reflector configurations: (1) 100% ground coverage, (2) 50% and (3) 25% ground coverage, both centered on the torque tube, and (4) 50% and (5) 25% ground coverage, both centered in the middle of the open ground between rows. The experiment took place from September 7 to December 20, 2022, with each stage lasting between 13 and 24 days.

2.2 | Measured impact of artificial reflectors

Table 1 summarizes the field measurements of reflector impact, obtained as described in the previous section, for a few sunny days from each test stage.

TABLE 1 Measured impact of artificial reflectors on field test site for select sunny days.

Test stage #	Ground cover (%)	Reflector position	Rear irradiance gain (%)	Energy gain (%)
1	100	N/A	209.9	7.2
2	50	TT-center	112.0	4.3
3	25	TT-center	62.3	2.5
4	50	Between rows	97.0	3.3
5	25	Between rows	57.3	1.5

By comparing rear irradiance measurements between the baseline area of the test site and the reflector area of the test site, we can determine the reflector's *measured rear irradiance gain*, or the increase in rear-incident irradiance due to the reflector:

$$\text{Meas.rear irr.gain (\%)} = 100 \times \frac{\sum_{t=0}^T \bar{G}_{\text{refl, rear}} - \sum_{t=0}^T \bar{G}_{\text{base, rear}}}{\sum_{t=0}^T \bar{G}_{\text{base, rear}}} \quad (1)$$

where $\bar{G}_{\text{base, rear}}$ is the spatially averaged rear irradiance without the reflector, also called baseline irradiance, and $\bar{G}_{\text{refl, rear}}$ is the spatially averaged rear irradiance with the reflector included, t is the timestamp, and T is the number of timestamps observed.

We also calculate the *energy gain*, or the increase in module energy output due to the presence of the reflector, by comparing $P_{\text{reflector}}$ to P_{baseline} . We define the reflector *energy gain* as

$$\text{Energy gain (\%)} = 100 \times \left(\frac{\sum_{t=0}^T P_{\text{reflector}}}{\sum_{t=0}^T P_{\text{baseline}}} - 1 \right) \quad (2)$$

where $P_{\text{reflector}}$ is the average module power with reflectors, P_{baseline} is the average module power without reflectors, t is the timestamp, and T is the number of timestamps observed. Therefore, we can calculate instantaneous energy gain ($T = 1$) or energy gain over a longer period. For our field results, this metric includes the effects of cell-to-cell mismatch in the module but does not capture clipping effects, which will be discussed in Section 4.5.

Table 1 shows the measured rear irradiance gain and energy gain for a select sunny days in each test stage. As expected, rear irradiance and energy gain are highest for the 100% ground coverage case, with 209.9% higher rear irradiance and 7.2% higher energy output for the modules over the reflectors. Rear irradiance gain is much larger than energy gain because, while rear irradiance is nearly doubled in this case due to the reflector, it only represents a fraction of the total incident irradiance; front-incident irradiance is generally much higher than rear-incident irradiance, and the rear irradiance is further reduced by the module bifaciality factor (70%).

In cases with reduced reflector coverage, we see a greater irradiance and energy gain for reflectors that are centered under the torque tube, compared to those that are centered between rows.

Note that these results are only for a few sunny days for each reflector configuration and were obtained during the fall and winter—we expect higher reflector gains in the summer and lower reflector gains in the winter. To demonstrate the full potential of artificial reflectors, we must extend our analysis to cover an entire year, which we do in Section 4 via modeling.

3 | BIFACIAL PV MODEL WITH ARTIFICIAL REFLECTORS

3.1 | Bifacial energy yield model with reflectors

We use *bifacial_radiance*, an NREL open-source irradiance and performance software that uses the RADIANCE ray-tracing engine [39], to model NREL's outdoor 10-row, 20-module-per-row BEST HSAT field in Golden, Colorado (Figure 1a) [19]. Test site parameters are a 5.7 m row pitch, 1 m by 2 m modules in 1-up portrait configuration, and a 2 cm gap between modules. Backtracking is considered with a tracking angle limit of 50°. Round 44% reflective torque tubes, with 50% specularity and roughness, are modeled, but purlins, frames, and posts are not; torque tubes have been demonstrated to be the most significant racking element for rear irradiance [40, 41]. Artificial reflector material is assumed to be Lambertian with 70% reflectivity; for a 2% specular material, modeled rear irradiance is reduced by less than 1 W/m² on average.

At each timestamp, the Perez diffuse sky [42] is calculated, and the model performs a 20-point ray-tracing scan on the cross section of the innermost module in the system (the central module in the center row), sampling both the front and rear faces (Figure 2). The model de-rates the rear irradiance by the module's bifaciality factor of 0.7 to determine total incident irradiance and then applies the Sandia Array Performance Model [43] in *pvl*ib [44] to calculate cell temperature from incident irradiance, wind speed, and ambient temperature. To find module power output, the model determines the module CEC

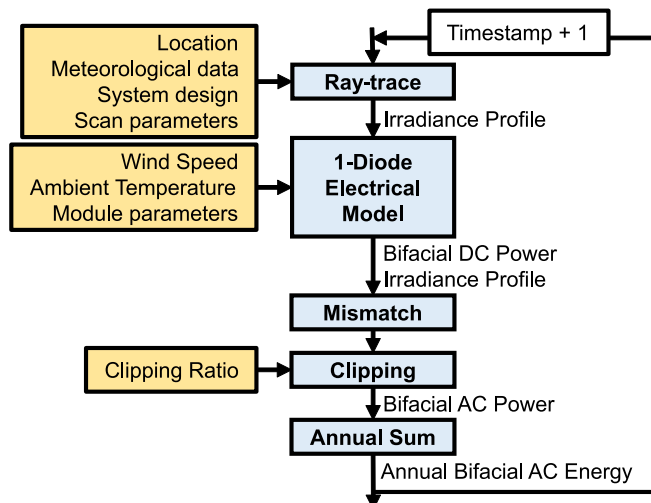


FIGURE 2 Bifacial energy yield model algorithm.

parameters [45] for that timestamp's irradiance and cell temperature and then calculates the module's maximum power with the one-diode model in *pvl*ib [44].

3.2 | Validation of bifacial energy yield model with reflectors

We applied measurements from the outdoor artificial reflector experiment described in Section 2.1 to validate the *bifacial_radiance* model described in Section 3.1. Both measured and modeled power were normalized to the nameplate module power to anonymize the module data.

Figure 3a shows the normalized modeled and measured power, and the reflector energy gain, for a single sunny day with 100% reflector coverage. This figure demonstrates that the model predictions are qualitatively similar to the measured results: peak reflector gain occurs at the same time at mid-day for both the measured and the modeled

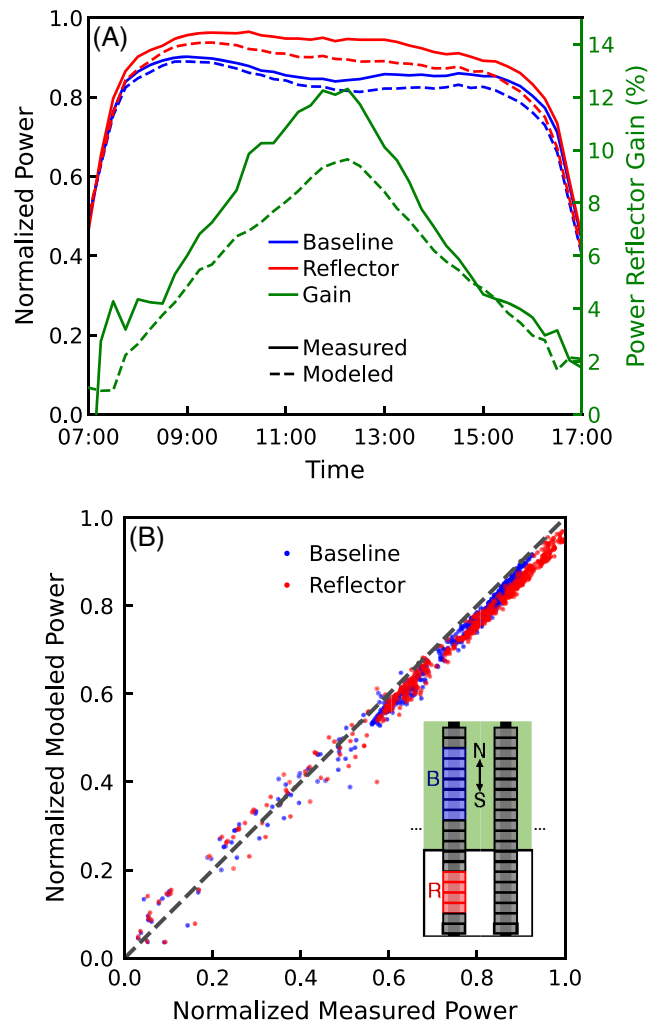


FIGURE 3 Bifacial energy yield model (A) comparison to field data: measured (solid) and modeled (dashed) normalized power and reflector gain and (B) normalized modeled power versus normalized measured power, with diagram of experimental setup (inset).

results. However, there is a model underestimation for the baseline and reflector power, as well as reflector gain, on the order of a few percent.

Figure 3b shows the normalized modeled power as a function of normalized measured power for each 15-min timestamp in two to three select sunny days from each stage. For this subset of sunny dates, the RMSE and MBE of the average baseline power are 4.8% and −3.6%, while the RMSE and MBE of the average reflector power are 5.7% and −4.5%. Note that most predicted module power values fall below the $x = y$ line, showing an underestimation of module power output.

Some of the discrepancy may be due to an overestimation of module temperature, and therefore an underestimation of module power, by the Sandia Array Performance Model [43], particularly on sunny afternoons—the RMSE is largest for high-irradiance, low-cloudiness timestamps in the afternoon. This may also be caused by uncertainty in model input parameters or by the assumption of a Lambertian reflector (0% specularity), since the specularity of the material is 2%.

Another source of the underestimation is the conservative estimate of rear irradiance provided by many software tools [46]. This underestimation may be partly due to the exclusion of table gaps in the model, which increase ground-incident irradiance and, therefore, rear-incident irradiance.

3.3 | Annual optimization modeling approach

To explore the reflector optimization under a wider range of parameters and for a full year, we used the bifacial_radiance model described in Section 3.1 to model a 10-row, 20-module-per-row HSAT system in Golden, Colorado [19]. While, due to space and system limitations, the outdoor reflector experiment was performed on the southern edge of the system, we extended the model for utility-scale PV projects by studying the innermost module of the innermost row. We used a typical meteorological year (TMY) to calculate hourly irradiance (front, rear, and total) and energy yield. Annual energy yield could then be used to calculate the LCOE of each system, as described in Section 4.4. We calculate mismatch losses with the fit equation described in Deline et al. [47], apply clipping losses with an assumed DC–AC ratio of 1.2, and calculate the energy yield by multiplying the power by the timestamp duration.

We performed this analysis for various reflector configurations with lengths from 150 cm (26% ground cover) to 550 cm (96% ground cover) and torque tube offsets from −285 cm (West of torque tube) to +285 cm (East of torque tube). Note, due to the repeating row/reflector configuration, an offset of +285 cm (halfway between rows) could also be expressed as −285 cm.

Computation was performed on NREL's High-Performance Computer (HPC). The hourly TMY for Golden, Colorado, consisted of 4380 non-zero-irradiance timestamps, requiring approximately 5.4 min per timestamp, or 11 h on a 36-core node. We modeled nine reflector lengths (150–550 cm) and 12 positions for each reflector, plus one

baseline year with no reflector, for a total of 109 simulations, or a total of 1183 h on 36 cores for the results discussed in Sections 4.1–4.5.

4 | MODEL RESULTS AND DISCUSSION

4.1 | Irradiance gain versus time of day

To quantify reflector impact on module-incident irradiance, we revise the definition of *irradiance gain*:

$$\text{Irradiance gain (\%)} = 100 \times \frac{\sum_{t=0}^T \bar{G}_{\text{reflector}} - \sum_{t=0}^T \bar{G}_{\text{baseline}}}{\sum_{t=0}^T \bar{G}_{\text{baseline, total}}} \quad (3)$$

where $\bar{G}_{\text{baseline}}$ is the spatially averaged irradiance without the reflector, also called baseline irradiance, and $\bar{G}_{\text{reflector}}$ is the spatially averaged irradiance with the reflector included, for either the rear irradiance, the front irradiance, or the total irradiance, and $\bar{G}_{\text{baseline, total}}$ is the total irradiance in the baseline case with no reflector, t is the timestamp, and T is the number of timestamps observed. Total irradiance is calculated by adding the front irradiance and rear irradiance, de-rated by the bifaciality factor.

Measurements and modeling both show the importance of time of day when evaluating reflector impact on a bifacial single-axis-tracking system. To demonstrate this, we took the annual average irradiance gain for each hour of the day for select reflector offsets and reflector lengths for the full TMY (Figure 4). Also shown is the hourly irradiance, averaged over the year, incident on the rear face (Figure 4a) and front face (Figure 4b).

As expected, the largest reflector (550 cm) results in the highest irradiance gain, while the smallest reflector (150 cm) results in the smallest irradiance gain, regardless of time of day.

The rear irradiance reflector gain (Figure 4a) is highest at mid-day (12 PM–1 PM) for reflectors that are larger than the module area (>200 cm) due to the large view factor between the rear of the module and the reflector at mid-day when the module is flat. For mid-size reflectors, the peak reflector irradiance gain is just before solar noon for reflectors to the east of the torque tube (positive offset) and just after solar noon for reflectors to the west of the torque tube (negative offset). For reflectors smaller than the module area, if the reflector is centered under the torque tube, this results in two peaks in rear reflector irradiance gain: one at mid-morning and one at mid-afternoon. For all reflector lengths, irradiance gain is high in the early morning and late evening when the modules are backtracking, resulting in low module tilt angles.

The front irradiance reflector gain (Figure 4b) has two peaks over the course of the day, one in mid-morning (10 a.m.) and one in mid-afternoon (4 p.m.), when the tilt angle of the module is high, resulting in more ground-reflected irradiance incident on the front face. The front irradiance gain is highest in the morning for reflectors to the east

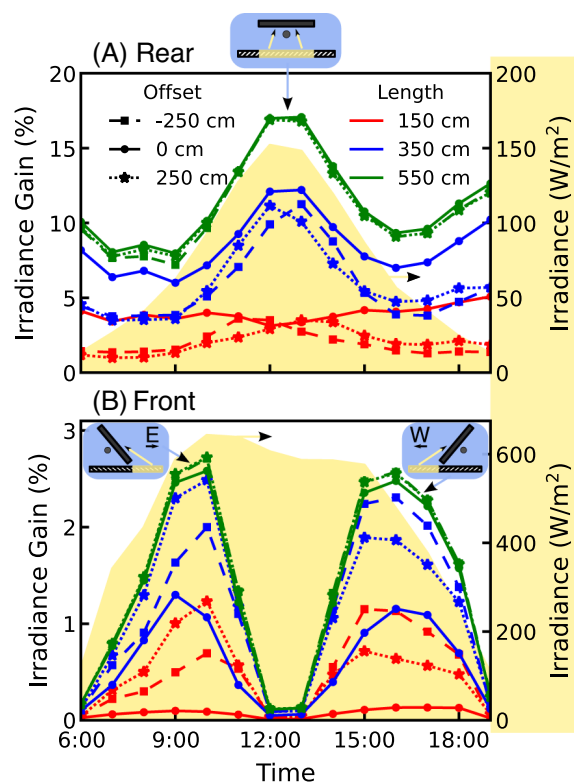


FIGURE 4 Reflector impact on (A) rear and (B) front irradiance for varying time of day, averaged on an annual basis, for various reflector offsets and reflector lengths. Positive offset = east of torque tube, negative offset = west of torque tube.

of the torque tube and is highest in the afternoon for reflectors to the west of the torque tube, because the modules face east in the morning and west in the afternoon.

4.2 | Annual irradiance

Total annual irradiance gain was calculated as described in Equation (2) for a TMY year in Golden for reflector lengths from 150 to 550 cm and for torque tube offsets from -285 cm to $+285$ cm. All three values ($\bar{G}_{\text{baseline}}$, $\bar{G}_{\text{reflector}}$, and $\bar{G}_{\text{baseline, total}}$) were summed over the model-year to find annual irradiance gain for the front (Figure 5a), rear (Figure 5a), and total irradiance (Figure 5b). As expected, more reflector material results in more irradiance gain on both the front and rear faces.

The largest total irradiance gain of 8.6% is obtained with the 550 cm reflector with an offset of $+275$ cm. This reflector is not very sensitive to placement: Its minimum irradiance gain is 8.4%. Compare to the smallest reflector's total irradiance gain, with a maximum of 2.7% ($+125$ cm) and a minimum of 1.9% ($+275$ cm).

For reflectors that are larger than the total module area, the rear irradiance gain is highest for reflectors centered under the module (Figure 5a) due to the higher view factor between the reflector and the module rear. For reflectors smaller than the module area (<200 cm), there are two symmetrical ideal positions to either side of

the torque tube under the module. This maximizes rear-incident irradiance while minimizing shading of the reflector by the module. The larger reflectors show a second ideal reflector placement centered between the torque tubes (± 285 cm); there are two strips to the right and left of the torque tube that contribute significantly to rear irradiance, balancing a view factor of the module rear with self-shading by the module itself. If the reflector is centered between the rows, it will cover these two strips on either side of the torque tube, leaving a gap between reflectors directly under the torque tube.

The placement that maximizes annual front irradiance gain (Figure 5a) is with the reflector edge placed exactly 1 m from the torque tube—in other words, beginning just under the edge of the module when the module is flat. This position creates a high view factor between the reflector and the module's front face, as described in Section 4.1.

If the weather in a location is perfectly symmetrical throughout the day, with equal morning and afternoon irradiances, reflector placement impact would also be symmetrical to the east and west of the module. However, these results for Golden show some asymmetry from east to west because of the cloudier conditions (more diffuse irradiance and less direct irradiance) in the afternoons. This can be seen from the average front-incident irradiance in Figure 4b (yellow fill); for example, for the 150 cm reflector, peak total irradiance gain is 2.7% for reflectors to the east of the torque tube and 2.4% for reflectors to the west of the torque tube. Therefore, there is a slight improvement in annual reflector performance for this particular location when reflectors are placed to the east of the torque tube, thereby maximizing the reflector irradiance contribution in the morning.

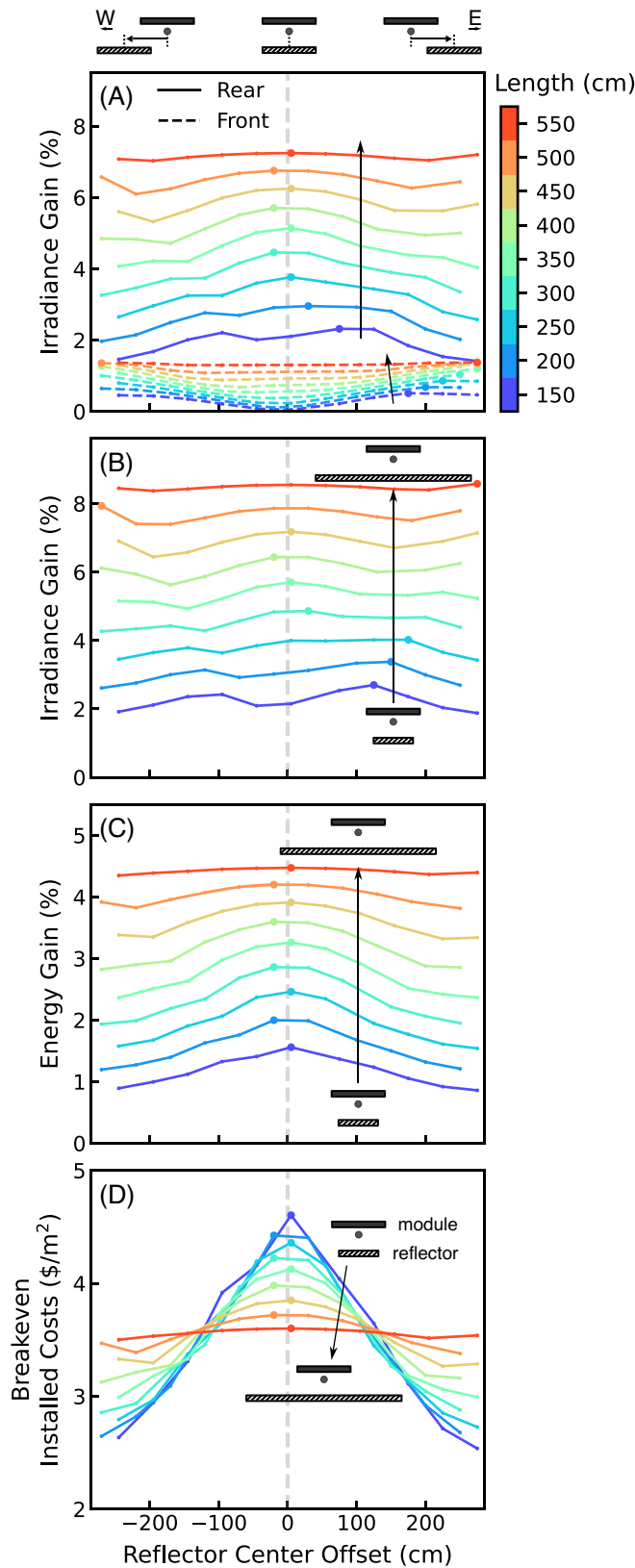
The total irradiance gain (Figure 5b) demonstrates the combined front and rear irradiance contributions. To maximize total irradiance gain, the largest reflectors (500 cm, 550 cm) should be centered between the torque tubes, the mid-size reflectors (350–450 cm) should be centered under the torque tube, and the smallest reflectors (150–250 cm) have an optimum location in between.

4.3 | Annual energy yield

Figure 5c displays the reflector energy yield gain for various reflector configurations after accounting for mismatch and clipping losses. Mismatch losses were calculated using equation (12) in Deline et al. [47] and were 0.3%–1.1% annually. Mismatch losses were most impactful for the smallest reflectors, contributing to the shift in optimal reflector placement to directly under the torque tube.

We define clipping losses as the percent reduction in energy yield between the system with no clipping and the system with a given DC–AC ratio. For a DC–AC ratio of 1.2, clipping losses were higher than the mismatch losses, up to 25.1% on a per-timestamp basis and 3.1%–5.2% annually. Clipping losses reduce annual reflector energy gain by 0.5%–2.8% and will be discussed in Section 4.5.

Reflector gain due to front-incident irradiance is more heavily clipped than rear-incident irradiance. This is due to the time of day when reflector gain on each face is at its maximum—front-incident



irradiance gain is highest in mid-morning and mid-afternoon when the module tilt angle is high. This is also the time of day when clipping losses are highest in the spring and fall. Rear-incident reflector-

FIGURE 5 Modeled impact of artificial reflectors on system performance: (A) annual irradiance gain (Equation 3) for rear and front module-incident irradiance, (B) total irradiance gain (front + rear, including bifaciality factor de-rating rear irradiance), (C) annual energy gain (Equation 2), and (D) breakeven installed material costs in \$/m² (Equation 6). Large markers represent the maximum value for each line. Diagrams show modules (black rectangle), torque tube (gray circle), and reflectors (white hashed rectangle); above the figure, these show changing reflector position on reflector center offset axis. Arrows show smallest to largest reflectors.

reflected irradiance is less heavily clipped, since peak rear-incident irradiance gain is at mid-day when there is a dip in module power production in the spring and fall.

When clipping and mismatch losses are considered, the ideal placement for the artificial reflectors is centered under the torque tube. This placement maximizes the reflector energy gain due to higher rear irradiance gain, lower clipping losses, and lower mismatch losses.

As expected, the highest energy yields are obtained with the largest reflectors, with a maximum annual energy yield gain of 4.5% for the 550 cm reflector at +5 cm. Just as for the total irradiance gain, the largest reflector is not very sensitive to placement, with a minimum energy gain of 4.3% at −245 cm. Again, compare with the smallest reflector, which has a maximum energy gain of 1.6% at +5 cm and a minimum of 0.9% at +275 cm.

4.4 | System economics

In this work, we define a breakeven installed cost (in \$/m²) as the cost of the artificial reflectors, including both materials and installation, resulting in the same LCOE with and without reflectors. In other words, this is the maximum cost of artificial reflectors where they are still viable. LCOE assumptions concerning system costs and operations and maintenance costs were taken from Ramasamy et al. [48]. We calculated the LCOE using the simplified LCOE method described in literature [49].

To find the breakeven material costs, we begin by calculating the breakeven annual costs (BAC) for each reflector configuration. The breakeven annual costs are the system costs per year, in \$/W, that would result in the same LCOE as in the system without the reflectors. These annual costs will include both operations and maintenance costs and up-front costs that have been annualized over the lifetime of the plant.

$$BAC = LCOE_{ref} \times CF_{test} \times 8760 \text{ h/yr} \quad (4)$$

where BAC is the breakeven annual costs, in \$/W, $LCOE_{ref}$ is the levelized cost of energy in the reference case in \$/Wh, CF_{test} is the capacity factor of the system with the reflectors present, and 8760 represents the number of hours in a year. We can take this breakeven annual cost to calculate the breakeven installed cost, in \$/W, as follows:

$$\text{BIC}_{\text{power}} (\$/W) = \frac{\text{BAC} - \text{O\&M}}{\text{CRF}} - \text{CAPEX} \quad (5)$$

where $\text{BIC}_{\text{power}}$ is the breakeven installed cost per unit power in $\$/W$, O&M is the annual operations and maintenance cost of the system, assumed here to be $16.06\$/kW_{DC}/yr$ [48], CAPEX is the total up-front cost of the system, assumed here to be $0.905\$/W_{DC}$ ($0.89\$/W_{DC}$ [48] with a $0.015\$/W_{DC}$ bifaciality premium), and CRF is the capital recovery factor, defined in literature [49]. These cost assumptions apply for 5–100 MW utility-scale projects [48]. The CRF was calculated with an interest rate of 1.5% and a system lifetime of 30 years.

The area of the reflector, in m^2/W , can then be used to calculate the breakeven material cost in $\$/m^2$:

$$\text{BIC}_{\text{area}} (\$/m^2) = \frac{\text{BIC}_{\text{power}} (\$/W)}{A (m^2/W)} \quad (6)$$

where BIC_{area} is the breakeven installed cost per unit area in $\$/m^2$ and A is the area of the reflector per watt, which varies based on the reflector length. As these equations show, while BIC_{area} is proportional to reflector area, it is not directly proportional to energy yield.

This analysis assumes that the reflector ends flush with the north and south edges of the row, and there is no additional material to consider in the cost analysis. Potential reduced maintenance costs due to reflectors, such as reducing or eliminating mowing requirements, are not considered here. These eliminated costs could further improve reflector economic viability. This may be offset by potentially increased maintenance costs due to reflector cleaning, which are also neglected here. Reflector cleaning expenses may exceed saved mowing costs as cleaning flexible reflector surfaces could be challenging on a wide scale. Module surface cleaning would have to be performed sequentially with reflector cleaning. Note that installation costs, in $\$/m^2$, are likely to be lower for larger reflectors due to some fixed installation costs.

The breakeven installed costs for various reflector lengths are shown in Figure 5d. The higher the breakeven cost, the greater the possible financial benefit to the system: If actual costs are less than the breakeven costs, there is a net economic benefit.

We found a maximum breakeven installed cost of $4.60\$/m^2$, with 150-cm reflectors offset +5 cm from the module center. These reflectors also show the smallest breakeven installed cost of $\$2.50/m^2$ at +275 cm. Note that the smaller the reflector, the more sensitive its resulting breakeven cost is to material placement. The largest reflectors, by comparison, have a maximum breakeven installed cost of $\$3.60/m^2$ at +5 cm and a minimum of $\$3.50/m^2$ at –245 cm.

This implies that the smallest reflectors may be the most economically beneficial to a bifacial SAT system on an annual basis, depending on fixed costs; however, care must be taken when installing these reflectors as their impact on the system is highly dependent on their location. Conversely, large-area reflectors allow for more flexibility in

placement while obtaining consistent reflector gain. We performed a sensitivity analysis on the breakeven material costs of the system by varying the interest rate, the system lifetime, the up-front system costs, and the operations and maintenance costs; the reflector breakeven installed costs are highly dependent on all of these inputs. See Figure S3.

4.5 | Clipping losses

Typically, PV systems will be designed with a larger PV array capacity than inverter capacity, resulting in clipping losses when the array generates power that exceeds the inverter's rating. Figure 6a shows the annual clipping losses of systems with varying reflector configurations. In the baseline case with no reflector present, the annual clipping loss is 2.7% for a DC–AC ratio of 1.2.

On an annual basis, clipping losses are highest for reflectors with their edge placed +50 cm from the torque tube, except for the largest reflector, which has the highest clipping losses with its edge at 0 cm from the torque tube. The largest reflectors incur the highest clipping losses, while the smallest reflectors incur the lowest clipping losses, regardless of reflector placement.

Clipping is dependent on the time of day and time of year. Clipping reduces module energy yield at the highest power times of day when front-incident irradiance is highest. Clipping does not affect ideal reflector placement, which is centered under the torque tube for all reflectors.

The breakeven installed costs of the reflectors decrease with increasing DC–AC ratio (Figure 6c). This is expected because an increase in the DC–AC ratio results in decreased annual reflector energy gain, thereby decreasing the viability of the reflectors. Clipping does result in a sharper peak in breakeven costs for the smallest reflectors, reducing the viability of reflectors that are not centered under the torque tube more heavily. Note that only the financial drawbacks of reduced energy yield are accounted for in this study, but not the changes in inverter costs due to changing DC–AC ratio.

4.6 | Material reflectivity

The effect of the reflector is heavily dependent on the reflectivity of the material, with higher-reflectivity material resulting in a higher irradiance gain, energy gain, and breakeven material cost (Figure 7). We have analyzed the effect of reducing material reflectivity from 70% to 60%. We kept all other parameters identical to those described in previous sections, including a DC–AC ratio of 1.2.

A reduction of 10% in the material reflectivity results in a 20% relative reduction in the annual energy gain: For the 550 cm reflector at +5 cm position, annual energy gain is 4.5% and 3.6% with the 70% and 60% reflective material, respectively (Figure 7a). For the 150 cm reflector at the same position, the annual energy gain is reduced from 1.6% to 1.3% when the material reflectivity is reduced from 70% to 60%. The ideal reflector placement and the relative difference in

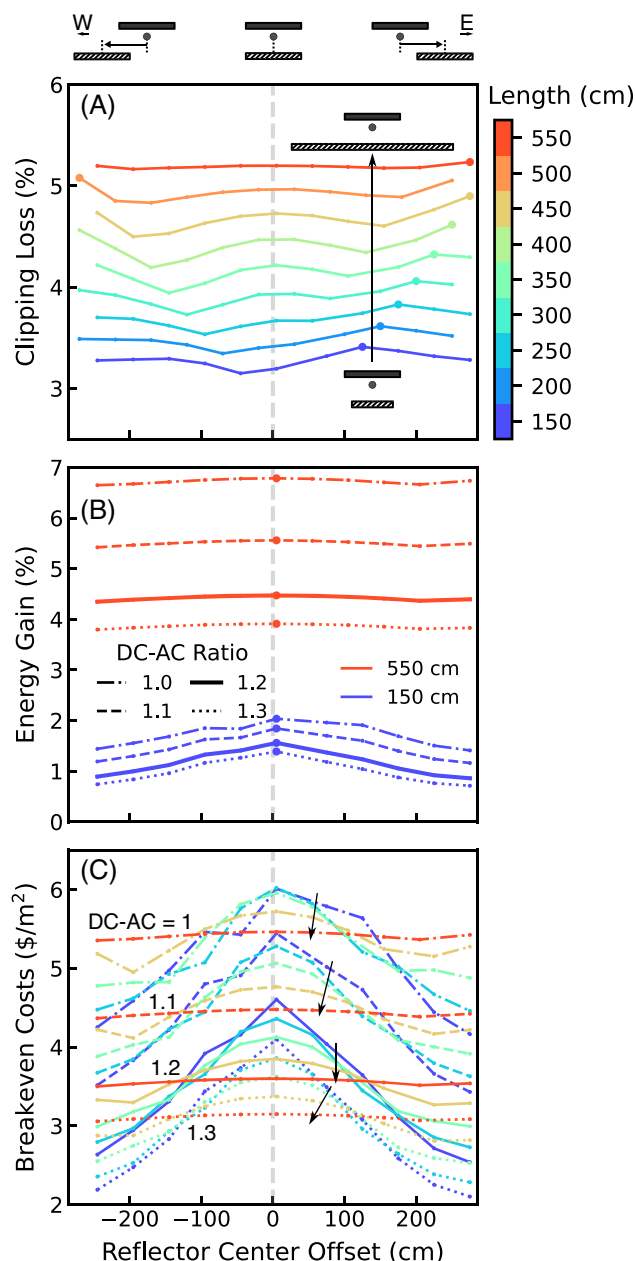


FIGURE 6 Effect of clipping ratio on system with artificial reflectors for a range of reflector offsets and dimensions. (A) Annual clipping losses for a DC-AC ratio of 1.2, (B) breakeven installed costs with DC-AC ratios from 1.0 to 1.3, and (C) effect of DC-AC ratio on breakeven installed reflector costs. Arrows indicate direction from smallest to largest reflector.

energy gain between different reflector lengths did not change with reflectivity.

The change in material reflectivity also results in a decrease in the breakeven installed costs (Figure 7b). For the 550 cm reflector, the maximum breakeven cost decreases from \$3.60/m² for the 70% reflective material to \$2.90/m² for the 60% reflective material. Therefore, the reflectivity of the specific material being deployed in a bifacial PV system is important to accurately quantify its effect on system performance and economics.

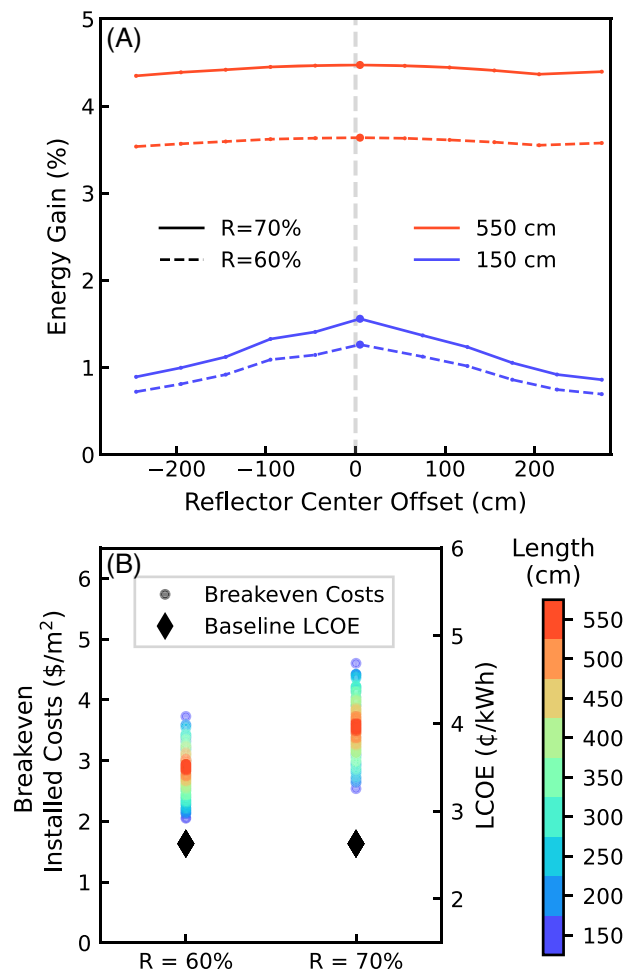


FIGURE 7 Effect of reflector albedo on system with artificial reflectors for a range of reflector offsets and dimensions. (A) Annual energy gain and (B) breakeven installed cost, with reference LCOE represented as a diamond. Each datapoint in (B) represents a reflector length/offset combination, with reflector length represented by datapoint color.

4.7 | System location

We repeated the modeling described in Section 3 for two other US-based locations: Seattle, Washington, and Tucson, Arizona (Figure 8). This allowed us to observe the effects of reflectors under a wider range of latitudes and weather conditions. For both locations, we modeled a typical meteorological year for a range of reflector configurations with a reduced resolution of lengths and offsets. In these calculations, the reflector albedo was set to 60%.

Figure 8a shows the annual irradiance gain as defined in Equation (2) for a 150-cm and 550-cm reflector for a range of torque tube offsets from -285 cm to +285 cm for all three locations. For the 150-cm reflector, the two peaks in irradiance gain to either side of the torque tube are present for all three locations. Irradiance gain is highest in Seattle (1.9–8.7%) and lowest in Tucson (1.4–6.3%) for all reflector configurations studied. This is due to the higher diffuse irradiance in Seattle as a fraction of total irradiance, resulting in a higher bifacial gain and, therefore, a higher reflector contribution to total

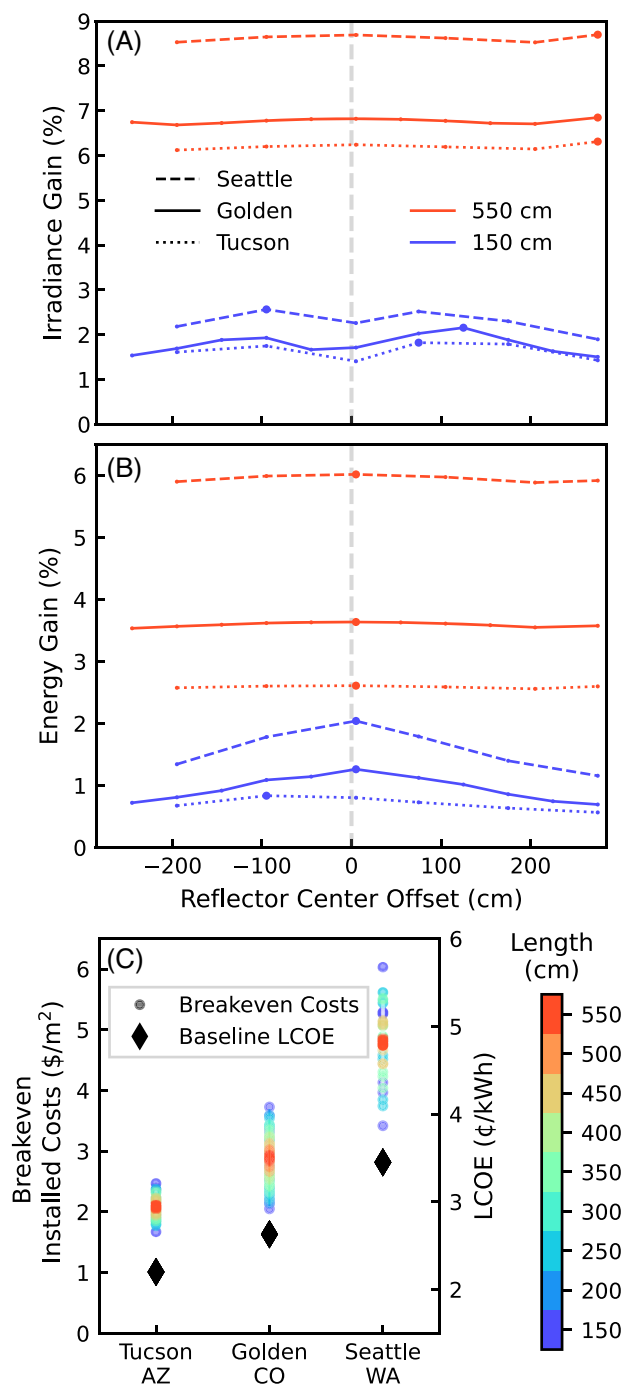


FIGURE 8 Effect of location on (A) reflector energy gain for varying reflector lengths and positions and (B) breakeven installed costs of a 60% reflective material, with reference LCOE represented as a diamond. Each datapoint in (B) represents a reflector length/offset combination, with reflector length represented by datapoint color.

irradiance. The relationship between diffuse irradiance and bifacial gain is well established [7–9]. This demonstrates that artificial reflectors are most beneficial in locations with lower annual energy yield and higher diffuse irradiance.

Figure 8b shows the annual energy gain as defined in Equation (1) for the same reflector configurations. As with the irradiance gain,

energy gain was highest in Seattle (1.2%–6.0%) and lowest in Tucson (0.6%–2.6%) for all reflector configurations studied.

To maximize energy gain, the ideal reflector placement was under the torque tube for all three locations, except for the smallest reflector (150 cm) in Tucson, which had an optimum placement to the west of the torque tube. This difference is due to the difference in clipping losses between the three locations; for the 150-cm reflector, Tucson demonstrated high clipping losses for reflector positions east of the torque tube.

Figure 8b shows the breakeven installed costs of the reflectors in all three locations, with the reference LCOE of each location. The breakeven installed costs are highest in Seattle, \$3.40–6.00/m², and lowest in Tucson, \$1.70–2.50/m².

The breakeven cost depends on reflector energy gain, which is higher in cloudy locations, and on the baseline system LCOE. A higher baseline LCOE allows for higher material costs (Equations 3–5). Since system costs are assumed to be identical between all three locations, LCOE only varies due to the change in annual energy yield between locations. Lower energy yield results in a higher reference LCOE, so the baseline LCOE is highest in Seattle (3.50 ¢/kWh) and lowest in Tucson (2.20 ¢/kWh).

These results demonstrate that artificial reflectors would be most economically beneficial in locations with high cloudiness levels and high energy costs, as well as regions with low natural ground albedo.

5 | CONCLUSION

We have demonstrated that artificial reflectors increase irradiance and energy yield through modeling and field tests. Based on 4 months of outdoor test data incorporating five reflector configurations, we describe and validate a bifacial energy yield model incorporating artificial reflectors and found an RMSE of 5.4%.

Modeling results show an increase in total annual irradiance of 8.6% and in annual energy yield of up to 4.5% when 70% reflective material is added to a single-axis-tracked system. The optimal reflector placement was centered directly under the torque tube for all reflector sizes.

In Golden, CO, we calculated artificial reflector breakeven installed costs of \$2.50–4.60 per m². Higher breakeven material costs are possible in systems with higher initial LCOE. For example, we found breakeven installed costs of \$3.40–6.00/m² for Seattle, Washington, with 60% reflective material. The impact of artificial reflectors depends strongly on location, with locations with higher LCOE and lower energy yield benefiting more from the addition of reflectors than locations with low LCOE and high energy yield.

Inverter clipping significantly impacts systems incorporating artificial reflectors, reducing the annual energy gain and shifting the ideal placement for the smallest reflectors in some locations. Therefore, clipping must be considered when optimizing a system with artificial reflectors.

These findings demonstrate how artificial reflectors can be optimized for different configurations and various locations and will serve

as a guide for researchers and solar developers who are interested in applying this technology.

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DATA AVAILABILITY STATEMENT

Examples of the analysis process performed in this journal are available from the bifacial_radiance GitHub repository: https://github.com/NREL/bifacial_radiance. Field data from NREL's BEST site, including module performance and weather data, can be downloaded from <https://datahub.duramat.org/dataset/best-field-data>.

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SUPPORTING INFORMATION

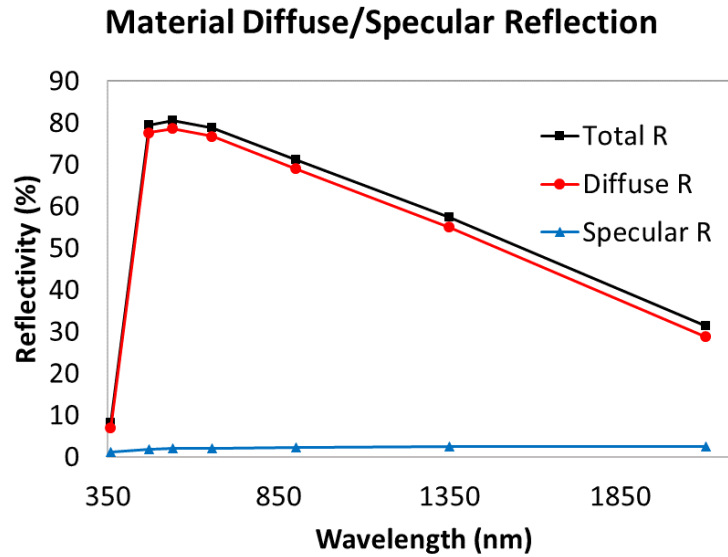
Additional supporting information can be found online in the Supporting Information section at the end of this article.

How to cite this article: Lewis MR, Ovatt S, McDanold B, Deline C, Hinzer K. Artificial ground reflector size and position effects on energy yield and economics of single-axis-tracked bifacial photovoltaics. *Prog Photovolt Res Appl*. 2024;32(10): 675-686. doi:[10.1002/pip.3811](https://doi.org/10.1002/pip.3811)

Supplemental Information

Specularity Measurement of Reflector Material

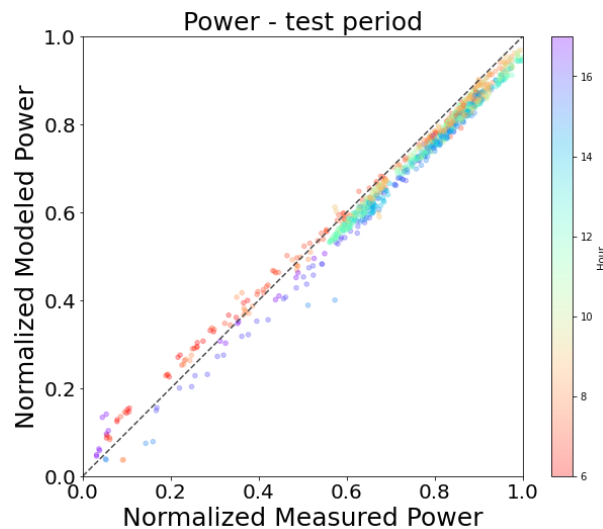
The following figure shows that the material specularity is approximately 2%, while the solar-weighted diffuse reflectivity of the material is approximately 68%.



Supplemental Figure 1 Measured total (black squares), diffuse (red circles) and specular (blue triangles) reflectivity of high-albedo material measured by 410-Solar handheld reflectometer.

Model Validation vs. Hour of Day

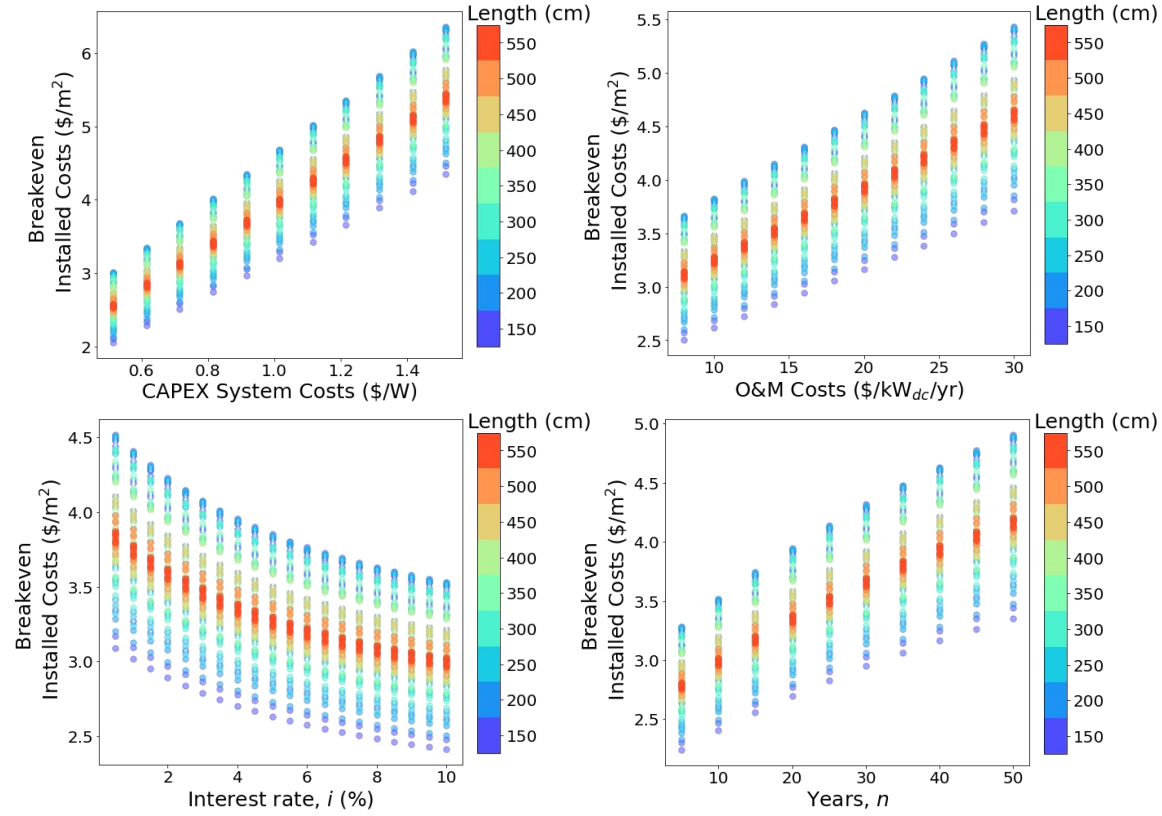
The following supplemental figure shows that the underestimation of module power is more significant in the afternoon than in the morning.



Supplemental Figure 2 Normalized modeled power vs. normalized measured power for select sunny days, with time of day indicated by color (red = morning, blue = afternoon).

Sensitivity of Breakeven Installed Costs to Cost Assumptions

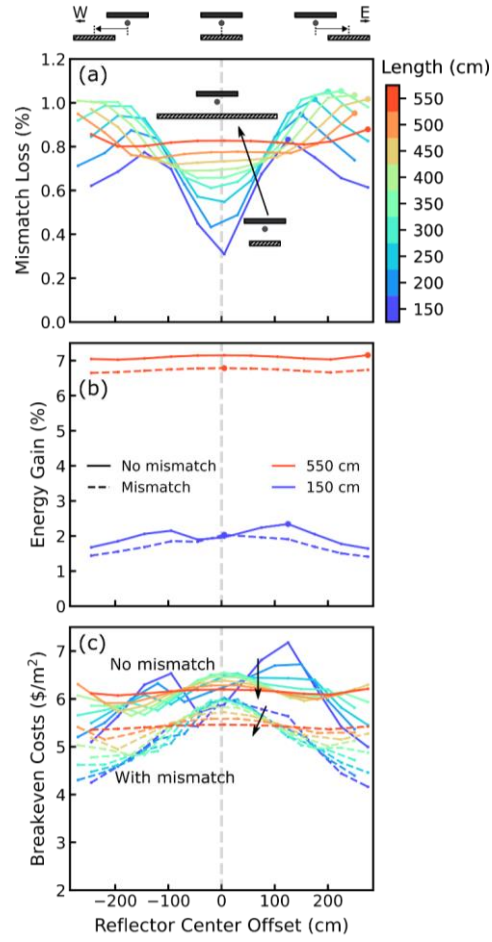
The following supplemental figure shows the sensitivity of the reflector breakeven installed costs to the levelized cost of energy input assumptions. Note that higher costs, either higher up-front costs or ongoing operations and maintenance costs, result in a higher installed breakeven cost for the reflectors. A longer system lifetime also results in a higher installed breakeven cost.



Supplemental Figure 3 Sensitivity of artificial reflectors' breakeven installed costs to levelized cost of energy (LCOE) parameters, including (a) CAPEX System Costs, in \$/W, (b) Operations & Management Costs, in \$/kW_{dc}/yr, (c) interest rate, in %, and (d) number of years.

Effect of Irradiance Mismatch Losses on Reflector Performance

The following figure shows that mismatch losses are important to consider when analyzing the impact of artificial reflectors. They are highest for reflectors that are centered between the rows. Ideal reflector placement is not affected by these losses for the largest reflectors, but the smallest reflectors see a shift in ideal reflector placement when mismatch losses are considered.



Supplemental Figure 4 Impact of mismatch losses on reflector (a) irradiance gain, (b) energy gain, and (c) breakeven installed costs for a range of reflector configurations.

Chapter 5

Spectral Irradiance Effects in Photovoltaic Systems

This chapter explores the effect of varying solar spectral irradiance on PV systems by analyzing spectrally-resolved solar irradiance measurements with PV spectral response curves. Section 5.2 includes an analysis of spectral irradiance measurements from seven sites across North America. The results quantify the impact of spectral irradiance on bifacial silicon PV module energy yield and identify the conditions where spectral effects are most impactful. Section 5.3 includes a comparison of five parameterized spectral correction methods with two methods that apply spectral irradiance measurements. This work identifies the conditions where these models diverge and why.

5.1 Background and Methodology

5.1.0.1 Spectral Mismatch Factor (SMM) Calculation

Both manuscripts include the concept of a spectral mismatch factor (SMM) as a PV model correction method. The SMM is a method for correcting module I_{sc} with varying incident spectrum and is simple to apply to existing models.

The I_{sc} produced by a PV module under a given solar spectrum is given by:

$$I_{sc} = \int SR(\lambda)G(\lambda)d\lambda \quad (5.1)$$

where SR is the spectral response of the module, G is the solar irradiance, and λ is the wavelength.

From the SMM, we can define an effective irradiance, G_{eff} , for a given level of solar irradiance, G :

$$G_{\text{eff}} = \text{SMM} \times G \quad (5.2)$$

where the effective irradiance is the irradiance that would produce the same short-circuit current if it had the spectral distribution of the reference spectrum [50].

To calculate the SMM, we take the short-circuit current under the real incident spectrum divided by the short-circuit current under the reference spectrum. This current ratio is then multiplied by the ratio of the irradiance measured by the broadband detectors:

$$\text{SMM} = \frac{I_{\text{sc, meas}}}{I_{\text{sc, ref}}} \times \frac{G_{\text{ref}}}{G_{\text{meas}}} \quad (5.3)$$

where $I_{\text{sc, meas}}$ is the module current under the measured spectrum $I_{\text{sc, ref}}$ is the module current under the reference spectrum, G_{ref} is the total reference irradiance and G_{meas} is the total measured irradiance.

From the spectral response of the module and equation , we can find the SMM as follows:

$$\text{SMM} = \frac{\int_{\lambda_1}^{\lambda_2} SR_{\text{module}}(\lambda) G_{\text{meas}}(\lambda) d\lambda}{\int_{\lambda_1}^{\lambda_2} SR_{\text{module}}(\lambda) G_{\text{ref}}(\lambda) d\lambda} \times \frac{\int_{\lambda_3}^{\lambda_4} SR_{\text{ref}}(\lambda) G_{\text{ref}}(\lambda) d\lambda}{\int_{\lambda_3}^{\lambda_4} SR_{\text{ref}}(\lambda) G_{\text{meas}}(\lambda) d\lambda} \quad (5.4)$$

λ_1 to λ_2 is the wavelength range where the spectral response of the module is non-zero, SR_{module} is the spectral response of the module, λ_3 to λ_4 is the wavelength range where the spectral response of the broadband irradiance measurement device is non-zero, SR_{ref} is the spectral response of the broadband irradiance measurement device, G_{meas} is the measured solar spectrum and G_{ref} is the reference solar spectrum.

If we assume the broadband irradiance measurement has a flat spectral response across the entire spectrum (in other words, that $SR_{\text{ref}} = 1$, this simplifies to:

$$\text{SMM} = \frac{\int_{\lambda_1}^{\lambda_2} SR_{\text{module}}(\lambda) \cdot G_{\text{meas}}(\lambda) d\lambda}{\int_{\lambda_1}^{\lambda_2} SR_{\text{module}}(\lambda) \cdot G_{\text{ref}}(\lambda) d\lambda} \times \frac{\int G_{\text{ref}}(\lambda) d\lambda}{\int G_{\text{meas}}(\lambda) d\lambda} \quad (5.5)$$

This is a reasonable assumption for many thermopile-based pyranometers but is a poor assumption for silicon-based pyranometers, so care should be taken when applying these

correction factors. This is how the SMM is calculated in the manuscript below from $SR_{\text{module}}(\lambda)$, $G_{\text{meas}}(\lambda)$, and $G_{\text{ref}}(\lambda)$.

The SMM varies with changing solar spectrum. Since the solar spectrum is continuously varying over time, so is the SMM. Therefore, the term SMM_t is applied below, where t represents time, in equation 3 in the first manuscript.

5.2 Spectral Irradiance Correction of Photovoltaic Energy Yield Predictions

In this section, the impact of changing spectral irradiance on photovoltaic performance is evaluated. The SMM, as defined in the International Electrotechnical Commission (IEC) 60904-7 standard [221], quantifies the impact of the deviation of the solar spectrum from the AM1.5G standard [67] on bifacial silicon PV module short-circuit current.

The manuscript includes an analysis of the SMM for seven locations, including one low-latitude location in the United States (Golden CO), five mid-latitude Canadian locations (Egbert ON, Ottawa ON, Varennes QC, Charlottetown PEI, and Devon AB), and one high-latitude Canadian location (Cambridge Bay NU). I find that spectral irradiance correction of cloudy and ground-reflected irradiance is most important for accurate bifacial PV energy yield prediction.

The manuscript includes a sensitivity analysis of the SMM with respect to diffuse fraction (or cloudiness), air mass, and irradiance source (direct, diffuse, or ground-reflected).

The supplemental material contains a comparison of the three most common silicon module types (SHJ, PERC, and TOPCon).

5.2.1 Scope and Impact

PV models and standards, developed for sunny areas such as the southwestern United States, are becoming less accurate as global deployment expands and technology progresses. As PV efficiency increases, system costs decrease, and power electronics & controls become agile, PV systems now operate in a broad range of weather conditions and locations.

Spectral effects are often ignored in PV system design and assessment but are significant in cloudy locations. Additionally, bifacial modules, which are rapidly becoming the technology of choice for new PV systems, have higher spectral irradiance impacts due to diffuse and ground-reflected light contributions.

While spectral correction methods are well-studied in literature, there has not been a comprehensive analysis of the conditions and locations where spectral effects are most significant for PV yield. This work examines the impact of spectral solar irradiance on fixed bifacial photovoltaic system performance across seven North American locations (39.7-69.1°N). This manuscript demonstrates that:

1. Spectral errors can lead to energy yield underestimation of 0.7-2.7% annually, with larger errors on shorter timescales.
2. Ground-reflected and diffuse light contribute the most to spectral energy yield estimation errors in bifacial systems.
3. Spectral error is most significant in cloudy and high air mass conditions.
4. Spectral correction is recommended for bifacial systems or for locations with a high diffuse irradiance fraction above 35%.

This manuscript aims to guide future PV policy and planning, system design, installation, and operation in incorporating spectral irradiance correction into their system evaluation and design processes.

5.2.2 Background and Methodology

5.2.2.1 Thermalization and Below-Bandgap Loss Calculations

To quantify the thermalization and below-bandgap losses for the spectra in the work presented below, some derivations were required, as presented here. These losses are represented as power losses, but if they are multiplied by the time step of the data, they can be converted to energy loss.

First we calculate the photon flux density, Φ :

$$\Phi(\lambda) [\text{photons}/\text{m}^2] = \frac{G(\lambda)}{E(\lambda)} = \frac{G(\lambda) [\text{W}/\text{m}^2] \lambda [\text{m}]}{h [\text{J} \cdot \text{s}] c [\text{m}/\text{s}]} \quad (5.6)$$

where G is the solar spectrum, E is the photon energy, λ is the wavelength, h is Planck's constant and c is the speed of light.

Then, for below-bandgap loss, P_{belowBG} , we take following approach from [222]:

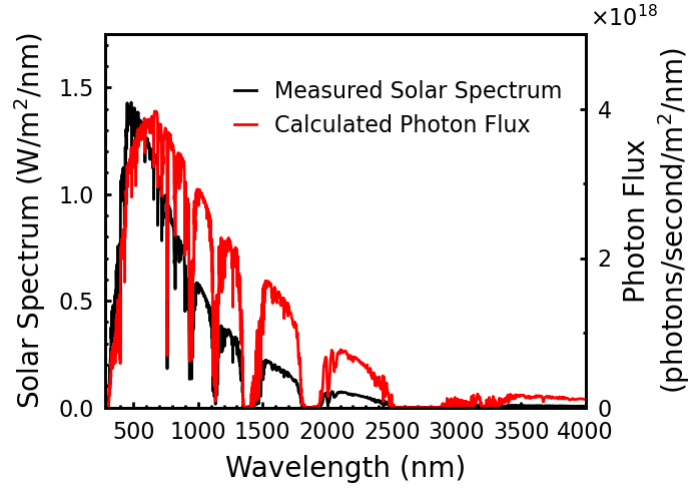


Figure 5.1: Photon flux and solar spectral irradiance with respect to wavelength.

$$P_{\text{BelowBG}} = C \int_0^{E_g} (1 - r - t) \Phi(E) \times E dE \quad (5.7)$$

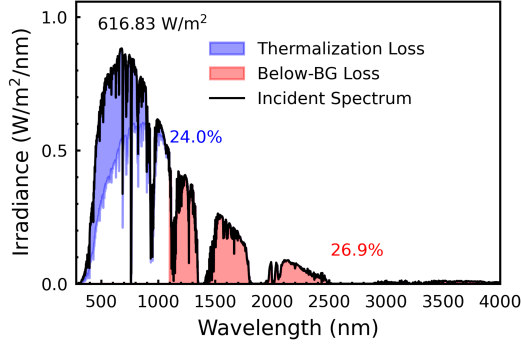
assuming the concentration, $C = 1$, and the reflection, r , and transmission, t , are 0 :

$$P_{\text{BelowBG}} = \int_0^{E_g} \Phi(E) \times E dE \quad (5.8)$$

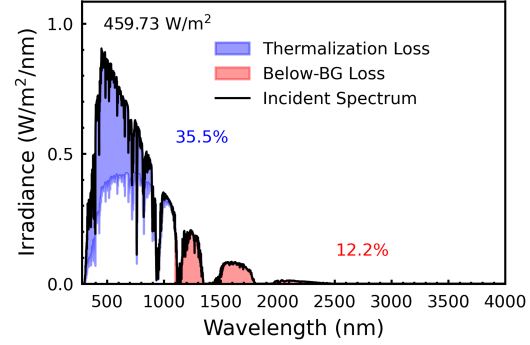
where E_g is the material bandgap. For convenience, we convert this to a calculation with respect to wavelength. As expected:

$$P_{\text{belowBG}} = \int_{\lambda_g}^{\infty} G(\lambda) d\lambda \quad (5.9)$$

where λ_g is the bandgap wavelength. In this work, the upper integration limit is 4000 nm since that is the limit of the input spectrum.



(a) High Air Mass



(b) High Diffuse Fraction

Figure 5.2: Effect of changing environmental conditions on thermalization and below-bandgap losses in silicon PV module.

For thermalization loss, P_{therm} , we take the following approach from [222], again assuming $C = 1$, $r=0$, and $t = 0$:

$$P_{\text{therm}} = C \int_{E_g}^{\infty} (1 - r - t) \Phi(E) \times (E - E_g) dE = \int_{E_g}^{\infty} \Phi(E) \times (E - E_g) dE \quad (5.10)$$

Again, converting to wavelength:

$$P_{\text{therm}} = \int_0^{\lambda_g} \Phi(\lambda) \times (E(\lambda) - E_g) d\lambda \quad (5.11)$$

This gives:

$$P_{\text{therm}} = \int_0^{\lambda_g} \Phi(\lambda) E(\lambda) d\lambda - \int_0^{\lambda_g} \Phi(\lambda) E_g d\lambda = \int_0^{\lambda_g} G(\lambda) d\lambda - \int_0^{\lambda_g} \Phi(\lambda) E_g d\lambda \quad (5.12)$$

Each of these can be divided by the total power of the spectrum, P_{total} to get the loss as a fraction of incident irradiance:

$$P_{\text{total}} = \int_0^{\infty} \Phi(\lambda) E(\lambda) d\lambda = \int_0^{\infty} G(\lambda) d\lambda \quad (5.13)$$

As always, care must be taken to ensure the correct units are applied when calculating these values.

5.2.3 Co-Author Contributions

M. R. Lewis designed the methodology, performed the modelling, wrote software, performed the analysis, visualized the data, and wrote the manuscript.

V. Jancowski assisted with writing software and data analysis.

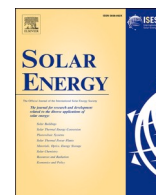
C. Valdivia guided methodology and assisted in manuscript revision.

K. Hinzer oversaw the research and the manuscript.

5.2.4 Manuscript

The submitted manuscript is included on the next page. This work is published open-access and is covered under a CC-BY-NC-ND license.

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Spectral irradiance correction of photovoltaic energy yield predictions in six high-latitude locations with measured spectra

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ABSTRACT

As solar power is expected to supply over 16% of the world's electricity mix by 2030, accurate energy yield prediction and forecasting is essential. The incident solar spectrum varies continuously, causing energy prediction error as sunlight deviates from the reference spectrum. This work quantifies spectral error in bifacial photovoltaic energy yield predictions, demonstrating instantaneous spectral impacts of −45% to +32% and annual impacts from +0.7% to +2.7% on energy yield. This work presents solar spectral impact analysis for seven North American locations (39.7–69.1°N). We apply measured spectra to bifacial fixed-tilt silicon modules using a 2D view-factor model. Ground-reflected and diffuse irradiance cause the largest spectral errors while direct irradiance is best-matched to reference conditions. This study indicates that spectral correction methods should be applied for bifacial systems or in locations with high diffuse fractions above 35%, representing over 75% of Earth's landmass. These effects indicate current PV system designs underestimate diffuse and ground-reflected irradiance contributions.

1. Introduction

Photovoltaic (PV) power is a growing part of the world's energy mix, contributing over 5.5% of global electricity demand in 2023 [1]; this is expected to grow to 16% by 2030 [2]. In sunny locations such as California, PV already contributes 28% of annual electricity needs [3], and PV systems are gaining traction globally due to record-low costs and increasing interest in decarbonization [4]. Bifacial PV, which converts irradiance incident upon both front and rear module faces into electricity, is rapidly becoming the dominant silicon PV technology, with a 30% market share in 2023 and a projected share of 70% in 2033 [5]. Bifacial technology facilitates PV adoption in mid- and high-latitudes due to high winter albedos [6]. However, these locations deviate more from standard test conditions of 25 °C, 1000 W/m², ASTM G-173 AM1.5G spectrum, and normal incidence [7]. PV efficiency is affected by temperature, irradiance, incident spectrum, and incidence angle, which all vary considerably in field conditions.

The ASTM AM1.5G solar spectrum [8] is typically assumed when predicting PV module efficiency and power output, despite constant variability of incident spectra with sun position, changing atmospheric parameters, and ground albedo. While broadband solar irradiance,

ambient temperature, and wind speed are typically measured on PV sites, spectral solar irradiance is rarely measured due to the high cost and complexity of spectral irradiance measurements. Neglecting spectral irradiance adds to prediction uncertainty, with weekly efficiency variations of −6% to +13% reported for silicon modules in a global analysis of solar spectral data [9], and even higher performance variations on shorter timescales. This uncertainty is of increasing concern as solar capacity grows to provide a larger fraction of our energy mix, particularly for instantaneous performance analysis and yield forecasting, which are both essential to reliable electrical grid operation.

Spectral irradiance effects are only one component of PV model uncertainty. Other sources of uncertainty include weather variation (4–10% standard deviation in GHI [10]), irradiance measurement (±2% uncertainty for secondary standard pyranometers [10]), and irradiance decomposition and transposition (5–6% error [10–13]). Error may also be introduced by losses such as structural shading (0.4–1% loss [14]), non-Lambertian ground reflection (2.5% bifacial gain reduction [15]), soiling (3–5% loss [16]), snow (up to 34% loss [16]), module degradation (0–0.5% additional loss per year [17]), and cell-to-module irradiance mismatch (0.1–0.6% loss [14]). Work is ongoing to reduce uncertainty in all aspects of bifacial PV models.

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Three methods for determining spectral effects in PV performance modelling include: parameterized models; atmospheric radiative transfer models; and direct measurement. These methods are summarized below.

Parameterized spectral correction methods estimate the spectral mismatch factor (SMM) directly from parameters such as air mass [18–24], precipitable water vapor [22–24], diffuse cloud fraction [21,22,25,26], aerosol optical depth [23], and average photon energy [27]. These proxy parameters are simpler to measure or calculate than the incident spectrum, allowing some spectral correction with reduced cost and complexity. However, neglecting the effects of other atmospheric parameters may mean the applicability of some models will be seasonally- and regionally-limited [18,28]. A recent comparison of parameterized spectral correction methods showed that the PVSPEC method [21], which depends on air mass and clear-sky index, models spectral effects in silicon modules most effectively [29]. A recent review of spectral irradiance correction methods proposed a decision-making matrix for method selection [30].

When solar spectral irradiance data is available, it can be combined with the module's spectral responsivity (SR) to calculate SMM. Two ways to obtain solar spectral irradiance include atmospheric models and outdoor measurements.

Atmospheric radiative transfer models such as SMARTS [31] or SEDES2 [32] calculate the spectrum from atmospheric parameters, often taking inputs from meteorological databases such as AERONET [33,34]. Previous studies have applied this method to find PV performance under clear-sky conditions [35,36]; however, these studies did not account for cloudy conditions, which have large spectral effects for silicon modules [37]. Previous studies have applied modeled spectra to bifacial c-Si systems and found spectral errors of ~3%, with higher spectral errors in cloudy conditions of ~8% when approximating cloud absorption and scattering as a neutral density filter [38]. The FARMS-NIT model was adapted to compute solar spectra under cloudy skies in recent years [39], but has not yet been widely applied to PV yield estimates.

Lastly, solar spectral irradiance can be measured directly through a spectroradiometer or similar tool. This has been studied in detail for crystalline silicon, with predicted total effects from –2.3% to +1.1% [40–43]. This is the most accurate and expensive approach. These studies are often limited to a single location, and site measurements are not broadly applicable to other locations. Furthermore, spectral irradiance measurements are often limited to a subset of the total solar spectrum, with a limited wavelength range.

Bifacial modules present additional complexity for spectral correction due to the importance of spectrally varying albedo, resulting in reported instantaneous rear spectral effects from –11% to +20% [44–49]. Due to the wide variety of possible ground covers, parameterized spectral correction approaches are not common. If available, the spectral global horizontal irradiance (GHI) can be multiplied by wavelength-dependent albedo to find spectral ground-reflected irradiance. Mouhib *et al.* presented an approach that combines front and rear spectral irradiance effects in a single “bifacial spectral factor” that can be easily incorporated in bifacial performance models [49], while Tonita *et al.* applied spectrally-weighted albedo to find combined module SMM [46]. This work applies separate correction factors for each irradiance component, thereby accounting for the difference in spectral mismatch between them.

An additional challenge in PV spectral irradiance correction is the necessity for spectral irradiance in a *tilted* plane, since most PV modules are tilted to maximize yield. Spectral irradiance transposition presents a unique challenge: spectral irradiance obtained in a single plane-of-array, such as normal to the sun, horizontal, or at a fixed tilt, cannot be easily extended to other planes. This detail is often neglected in existing spectral correction approaches, which may apply GHI [21], or fixed-tilt [24] spectral irradiance correction to any PV system regardless of tilt. This work applies separate direct, diffuse, and global irradiance spectra. To account for receiver tilt angle, a view-factor model to determine the

direct, diffuse, and ground-reflected contributions to front and rear plane-of-array irradiance and apply spectral correction to each element individually. This novel method could be extended to correct spectral effects for any receiver plane, including tracked PV systems.

This work analyzes reconstructed solar spectra in seven sites across North America in a wide range of latitudes (39.7–69.1°N). This study builds on previous work demonstrating the effects of clouds and air mass on PV efficiency by confirming these effects in a large spectral irradiance dataset and explaining them through changes in thermalization and below-bandgap losses. Furthermore, this work expands on a previous study comparing SMMs from different spectral irradiance wavelength ranges (350–1050 and 335–1700 nm) [50] by comparing SMMs calculated from three spectral irradiance wavelength ranges (280–1100 nm, 280–1700 nm, and 280–4000 nm).

In this work we apply reconstructed solar spectra to model module SMM and bifacial energy yield impact. We apply direct, diffuse, and ground-reflected spectral irradiance and show their effect on PV performance. We incorporate spectral correction in a view-factor model to quantify spectral impact on bifacial PV power output. We study the cause of changing PV efficiency in different climates. Lastly, we demonstrate the importance of wavelength range for spectral irradiance correction.

2. Methodology

2.1. Spectral irradiance measurements

We analyze measured spectral irradiance datasets in seven locations as listed in Table I, including six CanSIM sites by CanmetENERGY [51] and the Solar Radiation Research Laboratory at the National Renewable Energy Laboratory [52].

Each site employs two Spectrafy instruments which use narrowband detection channels to reconstruct the spectral irradiance from 280–4000 nm using their proprietary radiative transfer software [53,54]. The SolarSIM-D2 reconstructs the direct normal irradiance (DNI) spectrum and the SolarSIM-G reconstructs the GHI spectrum. The diffuse horizontal irradiance (DHI) spectrum is calculated from the GHI and DNI spectra and sun position using the closure equation.

SolarSIM instruments include hard-coated bandpass filters and photodiodes designed for photometric applications, resulting in a calibration drift of less than 0.2% per year [55,56]. The calibration uncertainty of each measurement channel is <2%. A Monte Carlo “random walk” analysis of spectral irradiance impact on silicon modules showed an uncertainty of 0.9% with EKO MS-710/712 spectroradiometers and CMP11 pyranometers [50]. Previous measurement campaigns have shown that the uncertainty of SolarSIM spectral irradiance measurements is within the uncertainty of EKO spectroradiometers [53,54]. In this work, a single instrument measures both spectral irradiance and total irradiance, rather than combining spectroradiometer and a pyranometer. For these reasons, we expect a higher precision for the spectral irradiance impact and SMMs found in this work.

We analyzed a year of data in each location except Cambridge Bay, where a 4-month period was available. All data was logged in 1-minute intervals. Data points where the GHI was below 25 W/m² or the air mass was above 20 were removed.

2.2. Spectral effect calculation

The change in module efficiency due to changing incident spectrum is represented by the SMM as defined in the IEC 60904–7 standard [57] (Fig. 1a). To find the SMM, the module short-circuit current density, J_{sc} , is calculated as:

$$J_{sc} = \int \frac{q\lambda}{hc} EQE(\lambda) G(\lambda) d\lambda = \int SR(\lambda) G(\lambda) d\lambda \quad (1)$$

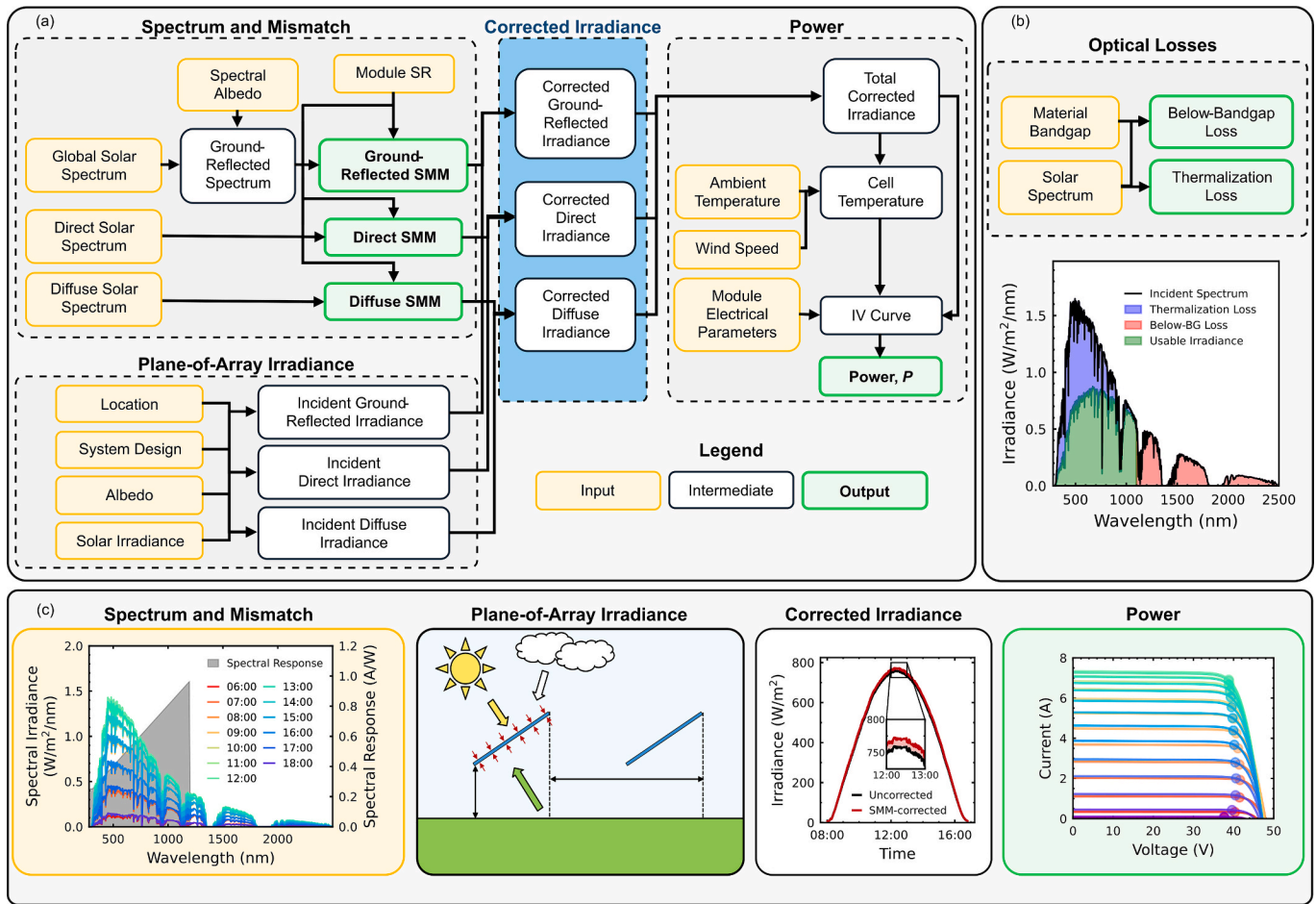


Fig. 1. Methodology for spectral impact calculation. Algorithm to calculate spectral mismatch factors (SMMs), module power output, and optical losses of the module with spectral correction applied. Diagram of: (a) SMM calculation from reconstructed solar spectra and module spectral response (SR); incident irradiance calculation in bifacial_{vf}; module incident irradiance correction via SMMs; and power calculation from total corrected incident irradiance, (b) optical loss calculation and standard ASTM AM1.5G solar spectrum (black line) with thermalization losses (blue fill), below-bandgap losses (red fill), and usable irradiance (green fill) indicated, and (c) illustrations of data and methodology for each algorithm step shown in (a), including: hourly reconstructed solar spectra over the course of a typical sunny day (lines) and ideal module spectral response (grey fill); modeled bifacial PV system including irradiance sampling points (red arrows), pitch (horizontal black arrow), and clearance height (vertical black arrow); incident irradiance (front + rear) on a fixed, latitude-tilt module over the course of a typical sunny day before spectral correction (black) and after spectral correction (red); and hourly module IV curves over the course of a typical sunny day with maximum power points indicated as round markers. Yellow boxes indicate inputs, green boxes indicate outputs, and white boxes indicate intermediate values. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

where $EQE(\lambda)$ is the module external quantum efficiency, q is the elementary charge, λ is the wavelength, h is Planck's constant, c is the speed of light, SR is the module spectral responsivity, and $G(\lambda)$ is the incident spectral irradiance. This work assumes an ideal silicon absorber SR for the PV module (Fig. 1c), except for the energy yield calculation, which applies the SR of a passivated emitter rear contact (PERC) bifacial PV module. If the on-site pyranometer has a flat spectral response for the entire wavelength range, the SMM is then calculated as:

$$SMM = \frac{J_{sc,meas}}{J_{sc,ref}} \times \frac{\int_{\lambda_1}^{\lambda_2} G_{ref}(\lambda) d\lambda}{\int_{\lambda_1}^{\lambda_2} G_{meas}(\lambda) d\lambda} \quad (2)$$

where $J_{sc,meas}$ and $J_{sc,ref}$ are the short-circuit current density under the measured spectrum and reference spectrum, respectively, G_{meas} and G_{ref} are the total integrated irradiance of the measured and reference spectrum, respectively, λ is the wavelength, and λ_1 and λ_2 are the lower and upper integral limits of wavelength. An SMM above 1 indicates increased J_{sc} and an SMM below 1 indicates decreased J_{sc} compared to the reference spectrum. We multiply incident irradiance by the SMM to find the effective irradiance. In this work, the reference spectrum is the ASTM G-173 AM1.5G spectrum [8] and measured spectra are those

described in the previous section. We analyse the following measured spectra: GHI, DNI, and DHI. Ground-reflected spectra are obtained by multiplying the grass or snow spectral albedo taken from SMARTS [31] by the GHI spectrum for each timestamp (see Appendix A).

For most calculations in this work, the integrals in Equation (2) include the full spectral range of the measurement, where $\lambda_1 = 280$ nm and $\lambda_2 = 4000$ nm. In one section, we repeat the calculation under scenarios of $\lambda_2 = 1700$ nm and $\lambda_2 = 1100$ nm to demonstrate the impact of long-wavelength irradiance.

The change in effective irradiance due to spectral correction is calculated separately for each irradiance component: front direct, front diffuse, front ground-reflected, rear direct, rear diffuse, and rear ground-reflected.

$$\Delta G_i = \frac{\sum_t SMM_t G_{i,t} - \sum_t G_{i,t}}{\sum_t \sum_i G_{i,t}} \quad (3)$$

where ΔG_i is the total change in irradiance for irradiance component i (DHI_{front}, DNI_{front}, GHI_{front}, DHI_{rear}, DNI_{rear}, GHI_{rear}) in percentage, t is the minutely timestamp, SMM_t is the SMM at timestamp t , and $G_{i,t}$ is the incident irradiance of component i at timestamp t . At each timestamp t ,

the irradiance change per component is divided by the total irradiance, or the sum of all six irradiance components. Before this calculation, rear irradiance values are de-rated by a bifaciality factor of 0.7. For each timestamp, the product of the SMM and the incident irradiance component ($SMM_i G_{i,t}$) is the corrected irradiance, also called effective irradiance, for that component at that timestamp.

2.3. Energy yield model

This work applies the open-source 2D view-factor bifacial irradiance calculation software, *bifacial_vf* [58] (version 0.1.8.1 [59]) to calculate bifacial energy yield on a minutely basis. A modification of the source code of *bifacial_vf* separates irradiance by source: direct, diffuse, and ground-reflected (Fig. 1a, *Spectrum and Mismatch*). This allows the SMMs for each irradiance component to be applied separately before calculating total effective irradiance and module power. The model calculates the energy yield for a bifacial photovoltaic system with and without spectral correction, leaving all other parameters identical.

The model assumes PERC modules, with SMMs calculated from bifacial PERC front and rear EQE curve (Fig. B1a) in a fixed, latitude-tilt, south-facing system with a ground cover ratio of 0.5 [60]. *bifacial_vf* models a dimensionally unitless system in terms of panel-lengths, defined as the length of the panel in the North-South dimension. The modeled glass-glass central module has a transmission factor of 0.013, a bifaciality of 70%, and a height of one panel-length. The model calculates incident irradiance at 6 points along the front and rear of the module, then takes the average (Fig. 1a, *Plane-of-Array Irradiance*). The model multiplies the plane-of-array irradiance components by the SMMs for that timestamp and irradiance source (direct, diffuse, or ground-reflected) before summing the three components to find total effective incident irradiance (Fig. 1a, *Corrected Irradiance*). The ground-reflected SMM is assumed to be either the grass-reflected SMM or the snow-reflected SMM for that timestamp based on snow coverage data in each location (see Appendix A). In *bifacial_vf*, the broadband albedo is assumed to be 0.2 for grass and 0.85 for snow. *pvlb's* SAPM method calculates module temperature, then *pvlb's* CEC parameter method and single diode IV curve function calculate module power from effective irradiance and module temperature. The model calculates module irradiance and power twice, once with SMMs applied and once without, to determine the effect of spectral correction. Irradiance mismatch losses between modules and cells, the effects of clipping, and structural near-shading losses are not included. Inter-row module shading is included. This model neglects structural shading effects, which can reduce rear irradiance by up to 8.5–20% [14,61]. Furthermore, non-Lambertian ground reflections have been shown to reduce bifacial gain by up to 2.5% [15]. Therefore, after accounting for structural shading and ground specularly, the ground-reflected portion of the irradiance may have a reduced impact on the total energy yield.

The change in energy yield due to spectral correction is calculated from the power output at each timestamp:

$$\Delta EY = \frac{\sum_t P_{SMM,t} - \sum_t P_t}{\sum_t P_t} \quad (4)$$

where ΔEY is the change in energy yield in percentage, $P_{SMM,t}$ is the power at timestamp t with SMMs applied, and P_t is the power at timestamp t without SMMs applied.

2.4. Optical loss

This work considers two sources of optical loss: below-bandgap loss, where photons have insufficient energy to excite an electron-hole pair, and thermalization loss, where photon energy above the bandgap energy is lost. These optical losses are illustrated in Fig. 1b for the reference spectrum. Losses in a single-bandgap semiconductor PV device are calculated as in [62] assuming no solar concentration, 1100 nm

bandgap, and neglecting reflection and transparency losses. This assumption overestimates thermalization and below-bandgap loss because reflected light should be removed from the calculation. Therefore, actual thermalization and below-bandgap losses will be smaller than those presented here.

First, calculate the spectral photon flux for a given spectrum, $G(\lambda)$:

$$\Phi(\lambda) = \frac{G(\lambda)}{\text{photon energy}} = \frac{G(\lambda)\lambda}{hc} \quad (5)$$

where $\Phi(\lambda)$ is the spectral photon flux. Then calculate thermalization losses, $Loss_{therm}$:

$$Loss_{therm} = \int_0^{\lambda_g} G(\lambda)d\lambda - \int_0^{\lambda_g} \Phi(\lambda)E_g d\lambda \quad (6)$$

where λ_g is the bandgap wavelength and E_g is the bandgap energy. Lastly, calculate below-bandgap losses, $Loss_{belowBG}$:

$$Loss_{belowBG} = \int_{\lambda_g}^{\infty} G(\lambda)d\lambda \quad (7)$$

These losses are divided by the total integrated spectral irradiance to find the relative loss as a fraction of that spectrum.

3. Results and discussion

3.1. Effect of spectra by location

We calculate the SMM of the GHI spectrum for every timestamp in every location listed in Table 1 and shown in Fig. 2a. For an ideal module (grey fill Fig. 1c, *Spectrum and Mismatch*), spectral impact varies from −45% to +32% on a per-timestamp basis, with 90% of global irradiance falling in the −3% to +10% range. Spectral impact is larger, and more positive, in the Canadian locations. GHI-weighted mean SMM, defined as the average of all minutely timestamps weighted by the GHI at each timestamp, varies from 0.99 in Golden to 1.04 in Cambridge Bay, and is

Table 1
Locations with measured spectral data.

	Location	Latitude	Longitude	Average Air Mass*	Diffuse Fraction [†]	Dates
1	Golden	39.7° N	105.2° W	1.52	32.3%	Jan 1 – Dec 31, 2022
2	Egbert	44.2° N	79.7° W	2.10	48.8%	Jan 1 – Dec 31, 2019
3	Ottawa	45.4° N	75.7° W	2.34	44.7%	Jan 1 – Dec 31, 2019
4	Varenes	45.6° N	73.4° W	2.19	45.6%	Jan 1 – Dec 31, 2019
5	Charlottetown	46.2° N	63.1° W	2.05	52.2%	Jan 1 – Dec 31, 2019
6	Devon	53.4° N	113.7° W	2.60	51.7%	Jan 1 – Dec 31, 2019
7	Cambridge Bay	69.1° N	105.1° W	5.84	98.5%	Aug 1 – Nov 13, 2019

*GHI-weighted for entire period

[†]total DHI divided by total GHI for entire period

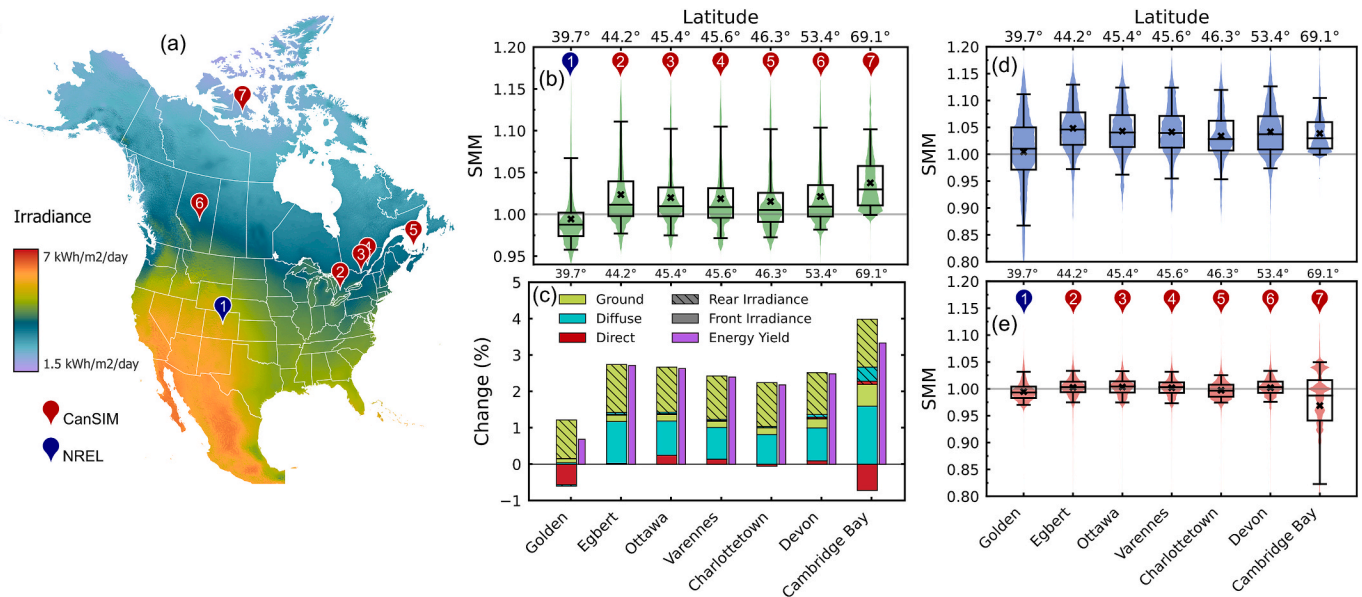


Fig. 2. Spectral Impact on PV Performance by Location. Spectral impact on silicon module performance for a range of locations in North America. (a) map of spectral irradiance measurement locations, including Canadian Solar Spectral Irradiance Meter Network (red) and National Renewable Energy Laboratory (blue), (b) spectral mismatch factors (SMMs) for each location, calculated from global horizontal irradiance (GHI) for an ideal module, (c) modeled irradiance impact of spectral effects by irradiance source (green: ground-reflected, blue: diffuse, red: direct) and module face (black hash: front, solid: rear) for a PERC module, (d) SMMs for each location, calculated from diffuse horizontal irradiance (DHI) for an ideal module, and (e) SMMs for each location, calculated from direct normal irradiance (DNI) for an ideal module. Map color in (a) represents average irradiance data per day, calculated from CHELSA+ mean RSDS dataset [63,64]. Subplots (b), (d), and (e) show irradiance-weighted 5th, 25th, 50th, 75th, and 95th percentiles (whiskers, box plot), irradiance-weighted mean (cross), and irradiance-weighted SMM violin plots (fill) for each location. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

1.02 for all other locations (Fig. 2b). Furthermore, the spectral impact on PV energy yield is more variable in the Canadian locations: the SMM inter-quartile range increases from 0.03 in Golden to 0.05 in Cambridge Bay.

These locations have higher average air mass and cloudiness, which cause their increased SMM and SMM variability. Air mass is the path length of sunlight through the atmosphere divided by the atmospheric thickness. As air mass increases, the spectrum redshifts due to short-wavelength losses (Fig. 3d). Average air mass increases with latitude, with a GHI-weighted minutely-averaged air mass of 5.84 in Cambridge Bay and 1.52 in Golden.

Diffuse fraction, defined as DHI divided by GHI, describes the fraction of irradiance on a horizontal plane that is scattered by the atmosphere and clouds, rather than following a direct path from the sun. A high diffuse fraction indicates cloudy conditions while a low diffuse fraction indicates sunny conditions. The Cambridge Bay dataset was very cloudy, with a diffuse fraction of 98.5%, compared to 32.3% in Golden. Cloudiness does not necessarily increase with respect to latitude worldwide [65], but does in this North American subset of locations. Subsequent sections demonstrate the impact of air mass and diffuse fraction on the solar spectrum and silicon module SMM.

3.2. Energy yield impact of solar spectrum

Spectral correction increases predicted bifacial PV energy yield in all locations, with a +3.3% change for the 4-month period in Cambridge Bay and a +0.7% change for a year in Golden, Colorado (purple bars, Fig. 2c). Therefore, spectral effects cannot always be neglected in energy yield modelling; the importance of spectral effects increase as conditions deviate from those modeled in the reference ASTM solar spectrum. On a per-timestamp (per-minute) basis, spectral impact varies from −45% to +32%, demonstrating the importance of spectral irradiance in short-timescale energy yield predictions.

The two largest contributors to the change in effective irradiance are diffuse (blue bars, Fig. 2c) and ground-reflected (green bars, Fig. 2c)

irradiance; effective irradiance increases by 1.1–1.3% and 0–1.6% due to ground-reflected rear irradiance and front diffuse irradiance, respectively. Therefore, spectral correction is more necessary in locations with high albedo and high cloudiness, and especially for bifacial systems.

Diffuse spectral irradiance has a net-zero impact on energy yield in Golden due to an overall low diffuse fraction. Diffuse irradiance SMMs are below 1 in sunny conditions and very high in cloudy conditions. In Golden, the large number of sunny timestamps counteract the cloudy timestamps, resulting in no net spectral impact. Direct spectral irradiance is a minor effect in most locations but is negative in Golden and Cambridge Bay due low and high air mass conditions, respectively, as further explored below.

The energy yield of a bifacial PV system depends on many factors, including irradiance, system design, temperature, module type, racking, and spectral effects. For example, when the height of this system is decreased to half a panel-length, the impact of ground-reflected rear irradiance is reduced by 0.03–0.09%. System design assumptions will affect the predicted importance of spectral irradiance, because the ratio of direct, diffuse, and ground-reflected irradiance will change. Single-axis-tracking systems will receive more direct irradiance than fixed-tilt systems on average, resulting in lower spectral impact since direct irradiance is well-matched to the reference solar spectrum. We expect the effect of increased direct irradiance contribution to outweigh the increased SMM DNI effect of high air mass hours. High-bifacial gain systems, including vertical bifacial systems, will see increased spectral impact due to ground-reflected and diffuse light. Furthermore, SMMs vary daily and seasonally, and system design affects irradiance distribution over time. Spectral correction should be applied in a time-varying manner to capture the full range of field conditions.

3.3. Spectral impact of diffuse fraction

As diffuse fraction increases, the solar spectrum blueshifts [37,66] (Fig. 3a) due to stronger long-wavelength absorption and reflection in

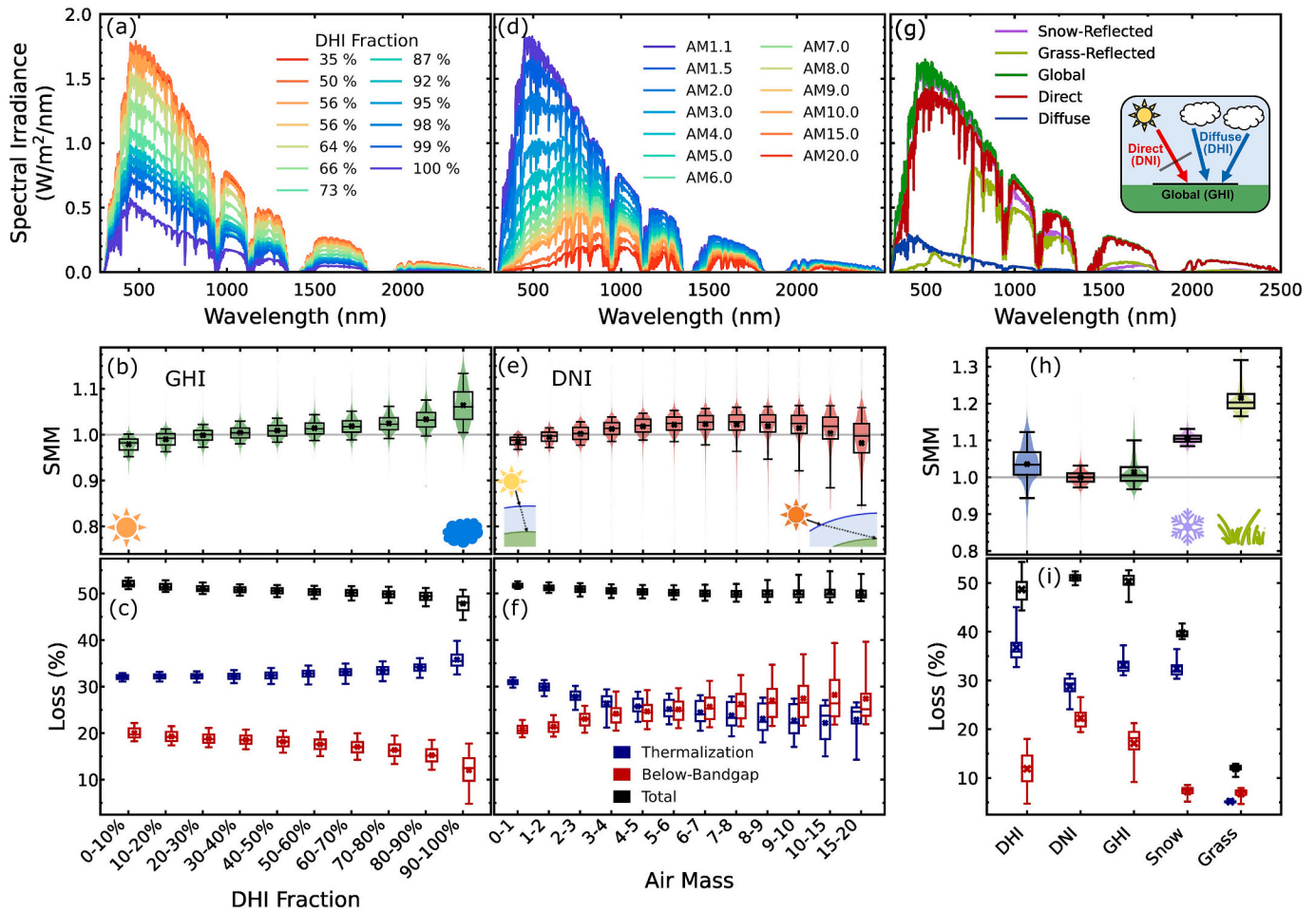


Fig. 3. Cloudiness, air mass, and irradiance type effects on solar spectra and module performance. Impact of cloudiness, air mass, and irradiance source on the incident spectrum, spectral PV impact, and optical losses: (a) example measured spectra for a range of diffuse fractions (sunniest in red, cloudiest in purple), (b) spectral mismatch factors (SMMs), binned by diffuse fraction, of measured global horizontal spectra, (c) thermalization (blue) and below-bandgap loss (red), binned by diffuse fraction, for a 1100 nm bandgap, (d) example global tilted clear-sky spectra for a range of air masses generated in SMARTS (low air mass in purple, high air mass in red), (e) SMMs, binned by air mass, of measured direct spectra, (f) thermalization (blue) and below-bandgap loss (red), binned by air mass, of measured direct spectra from all seven locations, (g) example spectra for five spectral irradiance sources: direct (red), diffuse (blue), global (green), snow-reflected (purple), and grass-reflected (light green), (h) SMMs for each irradiance source, and (i) thermalization (blue) and below-bandgap loss (red) for each irradiance source. Subplots show irradiance-weighted 5th, 25th, 50th, 75th, and 95th percentiles (whiskers, box plot), irradiance-weighted mean (cross), and irradiance-weighted violin plots for each bin. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

clouds [67]. This blueshift increases the SMM (Fig. 3b) by reducing below-bandgap losses (Fig. 3c, Equation (5)), thereby increasing module efficiency. As diffuse fraction increases from full sun to fully overcast, the GHI-weighted mean SMM increases from 0.98 to 1.06, the thermalization loss (Equation (4)) increases from 32% to 36%, and below-bandgap losses decrease from 20% to 12%. This effect has been reported elsewhere in silicon modules for cloudy spectra [37,68]. Many cloudy, low-GHI timestamps have high SMM values, while fewer sunny, high-GHI timestamps have low SMM values, causing the long “tail” of SMM values above 1 (Fig. 2b, green fill). This is most significant for instantaneous PV performance predictions.

A reduction in long-wavelength irradiance due to clouds should also cause a reduction in PV module heating; however, this effect was not captured in this study.

3.4. Spectral impact of air mass

High-latitude locations have high average air mass, resulting in large air-mass-related spectral effects: we have previously predicted an energy yield increase of 2.1% in Cambridge Bay for silicon heterojunction modules due to air mass under sunny conditions, compared to 0.3% in

Phoenix, Arizona [69]. That work also defined an air mass function based on modeled sunny spectra with peak module efficiency at AM7 [69]. This predicted air mass function is now supported by our results from measured direct spectra (Fig. 3e). GHI-weighted mean SMM increases from 0.99 for AM0-1 to 1.02 for AM6-7, then decreases to 0.98 for AM15-20. Similar air mass functions have also been reported elsewhere [18,19].

The change in module efficiency with air mass is caused by spectral redshift, which decreases thermalization loss and increases below-bandgap loss (Fig. 3f). DNI-weighted average below-bandgap losses increase from 21% for AM0-1 to 28% for AM10-15, while DNI-weighted average thermalization losses decrease from 31% to 22%. As air mass increases past AM7, the peak of the solar spectrum moves past silicon’s bandgap, causing below-bandgap losses that counteract reduced thermalization losses. Overall, while the effect of air mass is smaller than the effect of cloudiness and ground-reflected irradiance (Fig. 2c), it should be considered for high or low air mass locations where the SMM deviates most from 1.

3.5. Spectral irradiance components

PV plane-of-array irradiance is received from three main sources: direct irradiance from the sun, diffuse irradiance that is scattered in the atmosphere, and ground-reflected irradiance. In this work spectral ground-reflected irradiance is calculated by multiplying the GHI spectrum by the assumed spectral ground albedo. Direct irradiance has an average peak wavelength near 550 nm (red, Fig. 3g), compared to 450 nm for diffuse irradiance (blue, Fig. 3g). Ground-reflected spectral irradiance is dependent on the incident irradiance and the ground cover's spectral albedo, which is highly dependent on ground coverage. For example, the spectral albedo of green grass is low in the short wavelength range [70] (green, Fig. A1), resulting in little irradiance in that range (light green, Fig. 3g). Snow-reflected irradiance (purple, Fig. 3g) matches the global irradiance closely below 1000 nm, and drops off sharply at high wavelengths (blue, Fig. A1).

We calculate the SMM at all timestamps and locations for each irradiance source: global horizontal, diffuse horizontal, direct normal, grass-reflected, and snow-reflected (Fig. 3h). Spectral error is smallest for direct irradiance, with a DNI-weighted mean SMM of 1.00 and inter-quartile range of 0.02. Diffuse irradiance has a DHI-weighted mean SMM of 1.04 and inter-quartile range of 0.06. As discussed in the previous section, diffuse irradiance has high SMM due to decreased below-bandgap losses.

Ground-reflected spectra have high SMMs, with an irradiance-weighted average SMM of 1.11 for snow-reflected irradiance and 1.22 for grass-reflected irradiance (Fig. 3h). Other studies have shown a spectral impact of +13% for green grass and +11% for snow for silicon modules compared to pyranometers [47]. Low long-wavelength albedo reduces below-bandgap losses for snow-reflected irradiance: the irradiance-weighted average loss is 7% (Fig. 3i). Grass has high albedo in the 700–1400 nm range, a good match for silicon's 1100 nm bandgap, with low albedo in both the short and long wavelengths. Therefore,

irradiance-weighted average losses were only 5% thermalization and 7% below-bandgap for grass-reflected irradiance (Fig. 3i).

Due to the significant differences in spectral effects by irradiance source, spectral corrections should be separated by direct, diffuse, and ground-reflected components in energy yield predictions, and spectral albedo should be incorporated in models. However, this data is not often available at PV test sites, so decomposition algorithms or supplemental measurements would be necessary.

3.6. Spectral irradiance wavelength range

For all prior results, we have analyzed spectral irradiance impact for the 280–4000 nm wavelength range. However, many traditional outdoor spectral irradiance measurements are limited to a reduced wavelength range, often with an upper wavelength limit of 1700 nm or 1100 nm [40–43,71–73]. This affects the predicted spectral impact on PV performance: for direct irradiance, the irradiance-weighted average SMM for all locations is 1.00, 1.01, 1.04 for upper wavelength limits of 4000 nm, 1700 nm, and 1100 nm, respectively (Fig. 4f). For diffuse irradiance, these values are 1.04, 1.00, and 0.94. Therefore, for spectral correction from measurements in the 280–1100 nm range, direct irradiance would be overestimated by 4% while diffuse irradiance would be underestimated by 10%.

Cloud effects contribute to SMM underestimation for reduced-wavelength spectra. For the 280–1100 nm spectra, the increase in SMM with respect to cloudiness is not captured, and irradiance-weighted SMM decreases from 0.99 to 0.97 from the sunniest to the cloudiest conditions (Fig. 4d). For the 280–1700 nm spectra, cloud effects are present but are underestimated: the irradiance-weighted SMM increases from 0.98 to 1.02 as cloudiness increases, compared to 0.98 to 1.06 for the full spectrum. In the example sunny spectrum (Fig. 4a), 4.6% of irradiance is above 1700 nm and 13.2% of irradiance is in the 1100–1700 nm range. In the example cloudy spectrum, this is 2.3% and

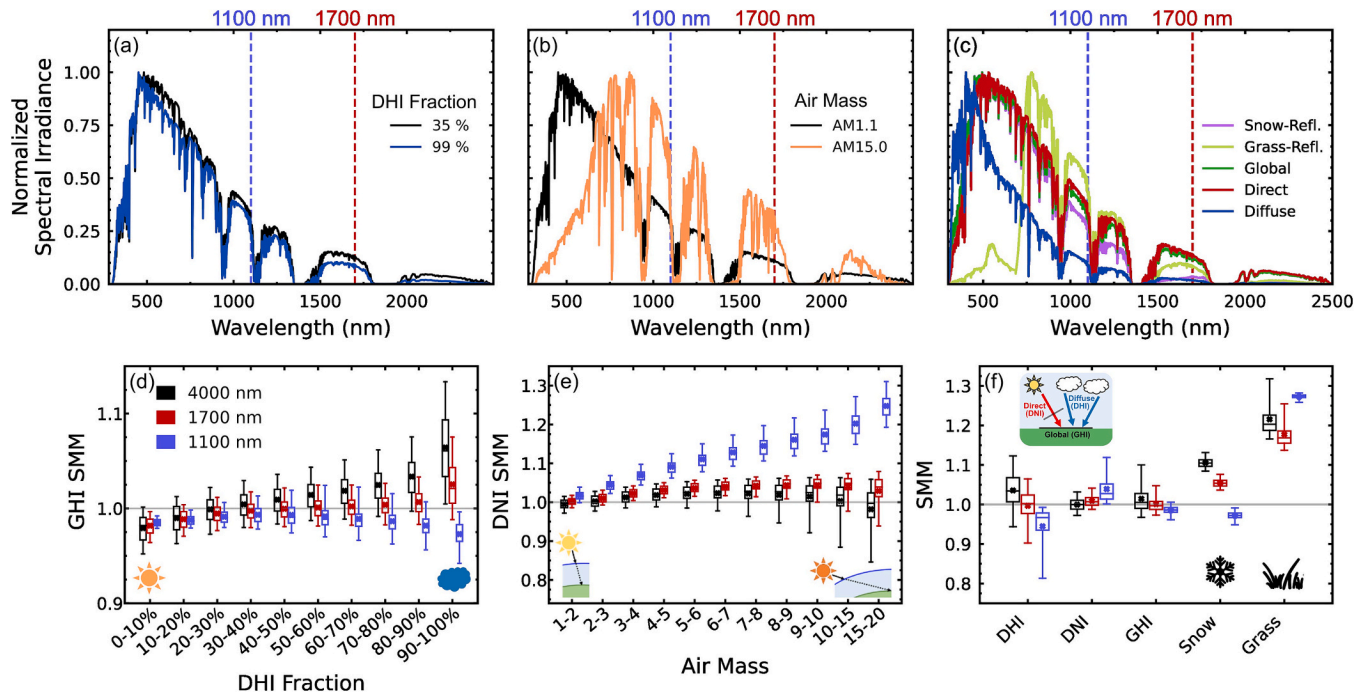


Fig. 4. Importance of spectral irradiance wavelength range for spectral impact calculation. Impact of spectral irradiance wavelength range on spectral correction calculation results. Example spectra normalized to the same maximum irradiance (a) for a sunny timestamp and a cloudy timestamp, (b) for a high air mass and low air mass timestamp, and (c) for the five spectral irradiance sources binned by diffuse fraction. Spectral mismatch factors (SMMs) for three integration ranges as defined in Eq. (2) from all locations for (d) measured global horizontal spectra binned by diffuse fraction, (e) measured direct spectra binned by air mass, and (f) each irradiance type. Plots d-f show irradiance-weighted 5th, 25th, 50th, 75th, and 95th percentiles (whiskers, box plot) and irradiance-weighted mean (cross) for each bin. The 4000 nm integration range SMMs (black boxplots) are also shown in Fig. 3b,e,h.

11.1% of irradiance, respectively. This reduction in long-wavelength irradiance under cloudy conditions decreases below-bandgap losses, resulting in high cloudy SMMs as described in the previous section. When spectral irradiance does not extend to the 1700–4000 nm irradiance range, the reduction in below-bandgap losses under cloudy spectra is not captured, resulting in an incomplete spectral correction.

Under high air mass conditions, SMMs calculated from the 280–1100 nm spectral irradiance range are larger than SMMs calculated from the broadband 280–4000 nm range: for AM15-20, the irradiance-weighted average SMM is 1.25 for the 280–1100 nm range compared to 0.98 for the 280–4000 nm range. As air mass increases, the decrease in thermalization loss is well-captured in the spectrum below 1100 nm (Fig. 4b), but the increase in below-bandgap losses is not. Therefore, this calculation predicts erroneously large SMM values under high air mass conditions. For the same reason, average SMM values for grass-reflected irradiance are overpredicted when the solar spectrum is limited to the 280–1100 nm wavelength range (Fig. 4f).

Therefore, when a reduced spectral irradiance range is applied for spectral irradiance corrections, the impact of thermalization will be overestimated while the impact of below-bandgap losses will be underestimated. In this work, this causes an underestimation of the GHI SMM by 2%, but this will vary based on local conditions. This result is in line with a previous study of tilted SMMs that found limiting the calculation to 350–1050 nm changed the calculated SMM from a spectral gain to a spectral loss, underestimating the spectral impact by 1–3% compared to the 350–1700 nm range [50]. Broadband spectral irradiance measurements, satellite spectral irradiance data, or extended spectra should be applied for accurate spectral correction.

4. Conclusions

In this work, we study the importance of solar spectral irradiance for silicon bifacial PV performance prediction in seven North American locations. Bifacial energy yield is underestimated when spectral effects are neglected, primarily due to ground-reflected and diffuse light. Neglecting spectral effects can cause up to 0.6–2.7% underestimation of annual energy yield, with higher error at shorter timescales. Bifacial modules are more susceptible to spectral errors due to an increased contribution from ground-reflected and diffuse light.

This work supports more accurate energy yield predictions by identifying conditions where spectral correction is necessary. While spectral effects may be neglected for monofacial systems in sunny locations with conditions that match the ASTM AM1.5G reference closely, high air mass and cloudy locations deviate from reference conditions, resulting in high spectral prediction error. Spectral correction is recommended for bifacial systems or for locations with a high diffuse irradiance fraction above 35%. Furthermore, we can infer that conditions that deviate from the ASTM standard in other ways, such as locations with air mass below 1 or locations with precipitable water content above 5 cm, must also consider spectral correction methods. In future studies, confirmation of these findings through cloudy-sky radiative transfer models and outdoor bifacial PV site experiments would be valuable. These results could corroborate the effect of clouds on spectral solar irradiance and cloudy-sky SMM values.

This work shows that spectral irradiance wavelength range has a significant impact on the resulting predicted spectral irradiance effects. Applying 280–1100 nm spectra overestimates effective direct irradiance by 4% and underestimates effective diffuse irradiance by 10% compared to 280–4000 nm spectra. In future applications, broadband spectral irradiance measurements, satellite spectral irradiance data, or extended spectra should be applied for accurate spectral correction.

Ideally, all PV sites would have co-located spectral measurements, but this is not standard practice. More spectral irradiance measurements worldwide are necessary to provide a better understanding of the impact of solar spectral irradiance variability globally. In the future, as tandem and multi-junction PV gain viability, spectral effects will increase

beyond those found in this work.

CRedit authorship contribution statement

Mandy R. Lewis: Writing – review & editing, Writing – original draft, Visualization, Validation, Software, Methodology, Investigation, Formal analysis, Conceptualization. **Victoria Jancowski:** Software, Investigation. **Christopher E. Valdivia:** Writing – review & editing, Supervision, Conceptualization. **Karin Hinzer:** Writing – review & editing, Supervision, Resources, Funding acquisition, Conceptualization.

Declaration of competing interest

The authors declare the following financial interests/personal relationships which may be considered as potential competing interests: Karin Hinzer is President and Chris E. Valdivia is Chief Technology Officer of Enurgen Inc.

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Appendix A. Supplementary data

Supplementary data to this article can be found online at <https://doi.org/10.1016/j.solener.2025.113816>.

Data availability

The data and code supporting this study are available upon request from the Lead Contact. Spectral irradiance data for station 1 is freely available from NREL's Solar Radiation Research Laboratory online at: <https://midcdmz.nrel.gov/apps/sitehome.pl?site=BMS>. SolarSIM-G data is available from April 30, 2021 and SolarSIM-D2 data is available from September 1, 2016. CanSIM spectral irradiance data for stations 2-7 is available upon request by contacting Natural Resources Canada at: <https://contact-contactez.nrcan-rncan.gc.ca/index.cfm?st=2&cat=2902&scat=-1&lang=eng>.

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APPENDIX A: Spectral Albedo

Spectral albedo of snow and grass applied to irradiance and energy yield modelling in this work. Ground albedo taken from SMARTS2 database [1].

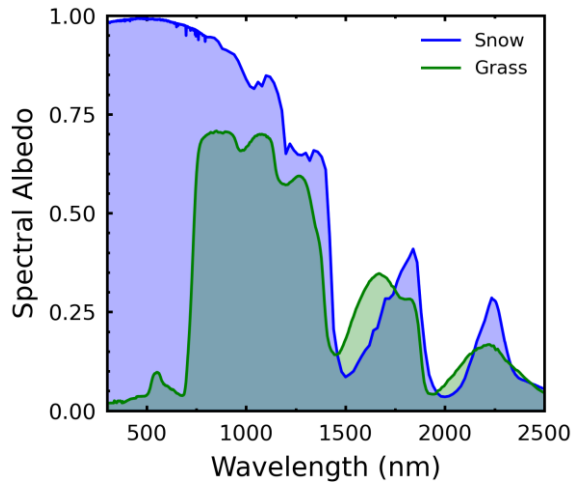


Figure A1. Spectral Albedo of Grass and Snow

Spectral albedo of grass (green) and snow (blue) applied to ground-reflected SMM calculations and energy yield impact calculations taken from SMARTS2 database.

To determine dates with snow cover in each location, we took snow coverage data from the Canadian Centre for Climate Services [2] and the NREL Solar Radiation Research Laboratory [3]. For the Canadian locations, we took the daily average between years from 2010 to present, then applied a threshold of 0.75 cm to the resulting average snow cover. For Golden, we take the same average range but apply a threshold of 1.5 cm due to the difference in the instrument's average minimum reading.

This resulted in a snowy date range as follows in each location:

Golden: October 26 to April 24

Egbert: November 09 to April 08

Ottawa: November 11 to April 11

Varenes: November 11 to April 11

Charlottetown: November 12 to May 01

Devon: November 01 to April 27

Cambridge Bay: September 15 to June 22

APPENDIX B: Importance of Module Type

Module Type Comparison

To improve the accuracy of spectral impact predictions for real-world silicon bifacial PV systems, we expanded the analysis to apply measured module spectral responsivity (SR) from three high-efficiency bifacial silicon technologies: passivated emitter and rear contact (PERC), tunnel oxide passivated contact (TOPCon), and silicon heterojunction (SHJ). EQE measurements, provided by NREL and TotalEnergies, were converted to SR (Figure B1).

The trends with respect to location, irradiance source, diffuse fraction, and air mass are similar between the three technologies. The most significant difference between module types are caused by short-wavelength parasitic losses in the SHJ and rear TOPCon module. These result in an increased sensitivity to high air mass (figure B1d,f), particularly for the front SHJ and the rear of all three modules. The TOPCon rear module shows the largest increase in SMM with respect to air mass due to poor efficiency in short wavelengths: as air mass increases, the fraction of the incident solar spectrum in these short wavelengths is reduced, and so SMM and module efficiency increases.

Furthermore, while all silicon technologies see an increase in SMM with respect to diffuse fraction, it is least pronounced for technologies with poor short-wavelength performance. As

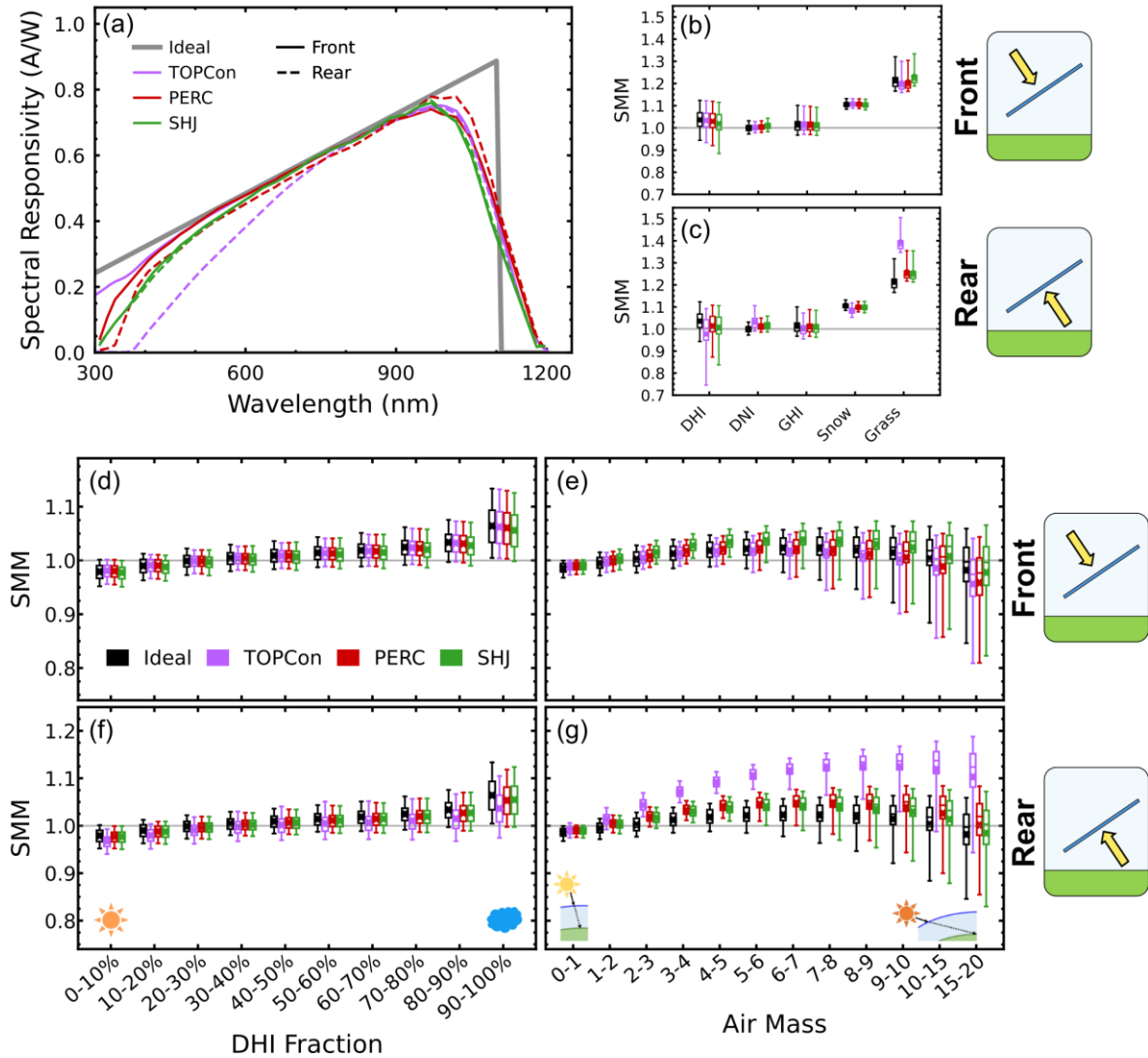


Figure B1. Impact of Module Spectral Response on Spectral Effects

Spectral mismatch factors (SMMs) for various silicon technologies with respect to diffuse fraction and air mass. (a) spectral response (SR) of ideal module (black), tunnel oxide passivated contact (TOPCon, purple), passivated emitter and rear contact (PERC, red), and silicon heterojunction (SHJ, green) for front (solid) and rear (dashed) faces, (b) front and (c) rear irradiance-weighted SMM values for diffuse, direct, global, snow-reflected, and grass-reflected irradiance, (d) front GHI-weighted SMM for GHI spectra, binned by diffuse fraction, (e) front DNI-weighted SMM for DNI spectra, binned by air mass, (f) rear GHI-weighted SMM for GHI spectra, binned by diffuse fraction, and (g) rear DNI-weighted SMM for DNI spectra, binned by air mass. Subplots (b-g) show irradiance-weighted 5th, 25th, 50th, 75th, and 95th percentiles (whiskers, box plot) and irradiance-weighted mean (cross) for each bin.

diffuse fraction increases, the fraction of the incident spectrum in the short wavelength range increases (as shown in Figure 3a), resulting in poorer efficiency for modules with high parasitic absorption at these wavelengths. These losses are still counteracted by the reduction in below-bandgap losses, and therefore the performance trend with respect to diffuse fraction is still positive.

Overall, front module performance is similar between technologies if electrical parameters and module bifaciality are neglected.

Furthermore, for real modules, there is not an abrupt step in the spectral response, as assumed with the ideal module. Real modules have a gradual reduction in SR at long wavelengths due to rear recombination and reduced absorption of long-wavelength light. The impact of this assumption was evaluated by creating a new spectral response curve with an ideal SR (EQE of 1) below 800 nm and with TOPCon SR values from 800-1200 nm. The results of this comparison are shown in Figure S3. The gradual band-edge of a real silicon module results in less variability in the SMM and a reduction in the importance of air mass for the typical air mass range (0-10). This accounts for most of the deviation between the SR with good short-wavelength performance and the ideal SR, such as the front of the TOPCon module, particularly at high air masses.

Therefore, module types with strong parasitic absorption in the UV are more susceptible to spectral irradiance effects at high air masses, while other modules are more susceptible to spectral irradiance effects under cloudy conditions. While silicon modules show similar trends, for most accurate predictions, the specific EQE of a given technology should be applied for spectral correction analysis, particularly for modules with poor UV performance.

Silicon modules with high short-wavelength losses are more susceptible to spectral irradiance effects at high air masses, while others are more affected by cloudy conditions.

Impact of Abrupt Band-Edge on Spectral Effects

Compared the spectral effects for an ideal module spectral response with a spectral response curve following a gradual bandgap, with TOPCon SR values for wavelengths above 800 nm. The results are shown below, for all locations, binned with respect to DHI fraction and air mass.

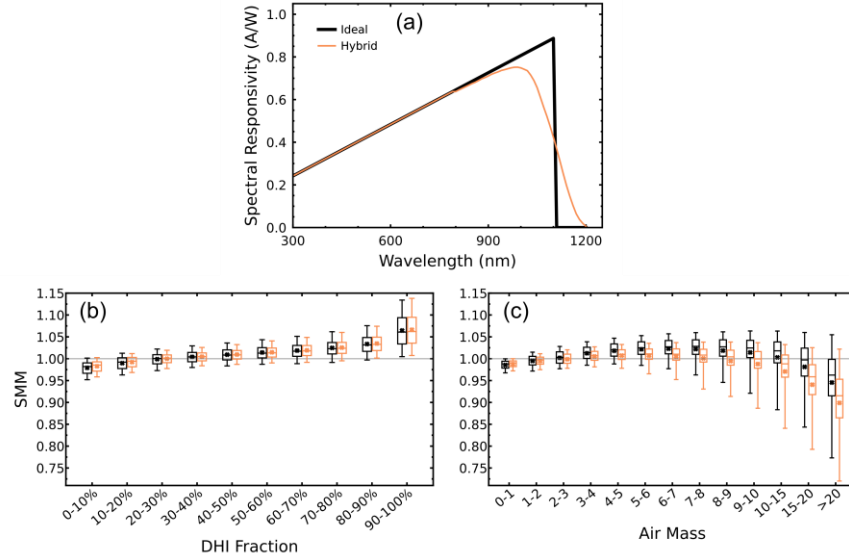


Figure B2. Impact of Band-Edge Performance on Spectral Effects

(a) spectral response of ideal module (black) with perfect absorption above the bandgap and no absorption below the bandgap, and hybrid module (orange) which combines ideal spectral response below 800 nm and the TOPCon spectral response above 800 nm, (b) GHI-weighted GHI spectral mismatch factor (SMM) boxplots binned by diffuse fraction, and (c) DNI-weighted DNI SMM boxplots binned by air mass.

APPENDIX C: Air Mass Calculation

In this work, we calculate the relative air mass by taking the solar zenith angle at a given timestamp and applying pvlib's [4] Gueymard 1993 function [5]. The absolute air mass is then pressure-corrected in pvlib by applying the measured air pressure at the given timestamp.

SUPPLEMENTAL REFERENCES

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5.3 Comparison of Spectral Correction Methods: Spectral Irradiance Measurements and Parameterized Spectral Models

This section studies parameterized spectral correction algorithms in a high-latitude site in Roskilde, Denmark. I compare predicted PV spectral effects from measured spectrally-resolved solar irradiance data with five parameterized spectral correction methods. These parameterized methods include the Sandia Array Performance Model (SAPM) [51], First Solar [52], Caballero [53], the European Commission’s Joint Research Center (JRC) [54], and PVSPEC [50].

5.3.1 Scope and Impact

The accuracy of PV models is essential for the optimization of PV system design and monitoring of PV performance. The deviation of solar irradiance from the standard solar spectrum causes modelling error, because PV efficiency varies with respect to the incident spectrum. Typically, PV models do not include spectral correction methods due to a lack of spectral irradiance data.

Parameterized spectral irradiance models that approximate spectral effects on PV energy yield are available, but their applicability is still an object of ongoing study; these models may not be accurate for all conditions and locations. This work seeks to validate and compare parameterized spectral irradiance models for a high-latitude, cloudy site in Roskilde, Denmark by analyzing a year of solar spectral irradiance measurements.

This work will inform system designers, system owners, researchers, and policy-makers on spectral irradiance correction methods for PV sites.

5.3.2 Background Information

5.3.2.1 Technical University of Denmark (DTU) Building 130 Test Site

The results presented in this manuscript were acquired on the roof of Building 130, Risø Campus at the Technical University of Denmark (DTU) (55.69°N, 12.10°E). This site includes an EKO MS-711 measuring GHI, DHI, and DNI from 290-1100 nm and an EKO MS-712 measuring GHI from 900-1700 nm. This site also includes an EKO-MS-802F pyranometer measuring DHI, an EKO MS-56 pyrliometer measuring DNI, a Lufft UMB600

measuring air pressure, and other instruments measuring GHI, UV, and other environmental conditions.



(a) DNI and DHI measurement



(b) GHI measurement



(c) Lufft UMB600

Figure 5.3: Photos of measurement station on roof of Building 130 at DTU Risø Campus.

Site Shading Analysis A plot of the 90th percentile of DNI measurements compared to solar position (Figure 5.4) can identify times when direct beam solar radiation is blocked at the measurement site. In this way, DNI is applied to find the solar positions where an obstruction, such as a tree, sits between the test site and the sun. We set a minimum solar elevation angle of 5 degrees because (1) there was a large number of trees surrounding the site that would shade the measurement devices for low elevation angles, and (2) pyranometer and spectroradiometer measurement error is high for high angle of incidence irradiance [223].

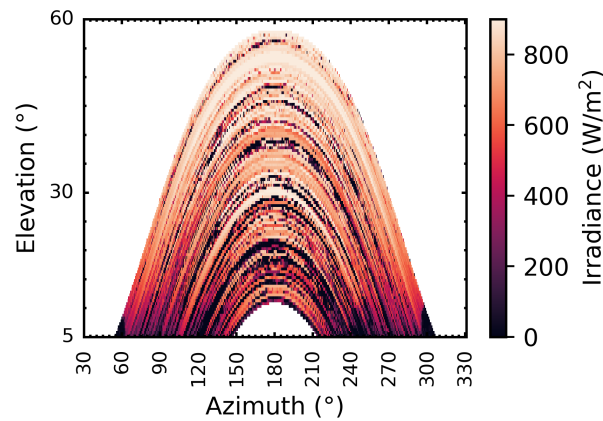


Figure 5.4: 90th percentile of DNI versus solar position for DTU test site.

The dark regions in the bottom left (below 62° azimuth) and bottom right (above 294° azimuth) show DNI shading, so timestamps where the solar azimuth angle was outside of that range are removed.

Spectral Irradiance Measurement Stitching To stitch the measurements from the MS-711 and MS-712 together, the spectrum is divided into three parts:

1. below 925 nm: MS-711
2. 925 nm to 975 nm: average MS-711 and MS-712
3. above 975 nm: MS-712

I discarded the MS-711 measurements from 975 - 1100 nm because the noise level of the measurements in this wavelength range was high.

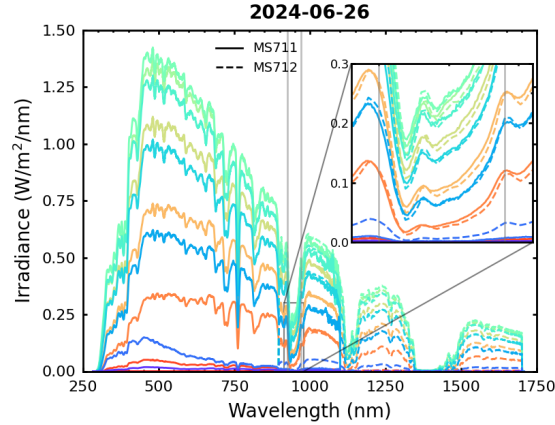


Figure 5.5: Example GHI solar spectral irradiance measurements for MS711 (solid, 290-1100 nm) and MS712 (dashed, 900-1700 nm). Overlap averaged range indicated by grey lines.

5.3.2.2 Pvanalytics Filtering

In this work, three pvanalytics [224] functions filtered the measured irradiance data to ensure that it was realistic. The *check_irradiance_limits_qcrad* function applies physically

plausible lower and upper bounds to the GHI, DHI, and DNI. The *check_irradiance_consistency_qgrad* function checks the consistency of the GHI, DHI, and DNI according to equation 2.5. The *clearsky_limits* function verified the clear-sky index from the GHI and clear-sky GHI. All three functions applied the default limits for the irradiances, consistency tolerance, and maximum clearsky index.

5.3.2.3 Parameterized Spectral Correction Algorithms

Parameterized spectral correction algorithms rely on intermediate parameters, such as air mass, clearness index, precipitable water, and aerosol optical depth, to approximate the effect of the solar spectrum on PV module performance (Figure 5.6). These parameters are explained in detail in section 2.1.3.

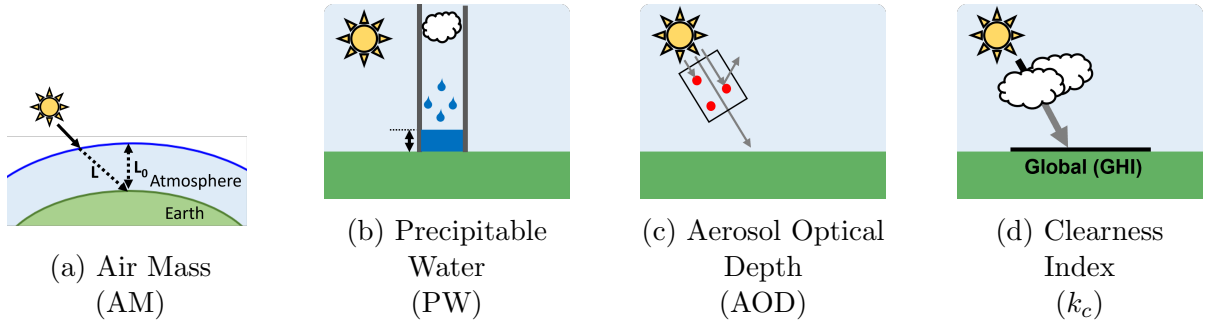


Figure 5.6: Diagram of atmospheric parameters applied in simplified spectral correction methods.

In this work, we compare five parameterized spectral correction models: SAPM [51], First Solar [52], Caballero [53], the European Commission’s Joint Research Center (JRC) [54], and PVSPEC [50]. They are summarized below.

Table 5.1: Parameterized spectral correction method summary.

Method	Parameters	Model Fit Data	Calculation
SAPM	Absolute AM	Module I_{sc} <i>2-axis-tracked</i>	$a_0 + a_1 AM + a_2 AM^2 + a_4 AM^4$
First Solar	Abs. AM PW	Modeled spectra <i>SMARTS</i>	$b_0 + b_1 AM + b_2 PW + b_3 \sqrt{AM} + b_4 \sqrt{PW} + b_5 \frac{AM}{\sqrt{PW}}$ $f(AM) + f(AOD) + f(PW)$, where: $f(AM) = c_0 + c_1 AM + c_2 AM^2 + c_3 AM^3 + c_4 AM^4$ $f(AOD) = (AOD_{meas} - AOD_{ref}) \times (c_5 + c_1 0 \cdot c_6 \cdot AM + c_1 1 \cdot c_6 \cdot \ln(AM) + c_7 AM^2)$ $f(PW) = (PW_{meas} - PW_{ref}) \times (c_8 + c_9 \cdot \ln(AM))$
Caballero	Abs. AM PW AOD	Modeled spectra <i>SMARTS</i>	
JRC	Rel. AM k_c	Module I_{sc} <i>fixed-tilt</i>	$1 + d_1(e^{-k_c} - e^{-1}) + d_2(k_c - 1) + d_3(AM - 1.5)$
PVSPEC	Abs. AM k_c	Measured spectra <i>Solar-SIM-G</i>	$e_1 k_c^{e_2} AM^{e_3}$

The SMM was calculated for each model with the relevant pvlib function.

5.3.2.4 Copernicus Atmospheric Monitoring Service (CAMS)

This work takes the clear-sky GHI, precipitable water vapour, and aerosol optical depth from the Copernicus Atmospheric Monitoring Service (CAMS) through pvlib’s iotools [214]. pvlib’s *get_cams* function takes the site latitude, site longitude, and timestamps as inputs and gives detailed irradiance and atmospheric data as outputs. This function queries the CAMS Radiation Service [225] Automatic Access via SoDa [226].

The CAMS Radiation Service provides historical solar radiation data under both clear and cloudy conditions. It combines satellite-based cloud data with models of water vapour, aerosols, and ozone to derive surface-level solar radiation values. This service uses the Heliosat-4 method [227], which combines the McClear model [228, 229] for clear-sky conditions and the McCloud model for cloudy conditions [230]. These models apply lookup tables from libRadtran reference values based on atmospheric parameters as described in

[230] and [227]. Due to the availability of ground measurements of GHI, DHI, and DNI, only the clear-sky model is applied in this work.

The McClear model in the CAMS Radiation Service takes aerosol parameter data from the CAMS global forecast and reanalysis service [230]. The CAMS global forecast and reanalysis services provide aerosol properties, precipitable water vapour, and ozone content every 3 hours [227]. This data is based on detailed individual models for the atmospheric parameters, including models of specific aerosol types. Satellite observations from many satellites are used to constrain the output of the global forecast and reanalysis model [231].

In this work, the *verbose* mode in pvlib’s *get_cams* function retrieves the aerosol optical depths and the total precipitable water vapour taken from the CAMS global forecast and reanalysis service. These parameters act as inputs to the parameterized PV spectral irradiance correction models. Individual aerosol optical depths for aerosols are summed to get the total aerosol optical depth.

5.3.2.5 SMM Calculation Method Comparison

In this work, we compare results from two SMM calculation approaches. These approaches provide different SMM values when the full spectrum (280 - 4000 nm) is unavailable. The first method is currently implemented in the pvlib Python library:

$$\text{SMM} = \frac{I_{\text{sc, meas}}}{I_{\text{sc, ref}}} \times \frac{\int_{\lambda_3}^{\lambda_4} G_{\text{ref}}(\lambda) d\lambda}{\int_{\lambda_3}^{\lambda_4} G_{\text{meas}}(\lambda) d\lambda} \quad (5.14)$$

This involves taking a truncated range of the reference solar spectrum that matches the range of the spectral irradiance measurement. This method neglects the effect of irradiance outside of the wavelength range, which is important for cloudy conditions as discussed in the manuscript in section 5.1.

Another option is to take the GHI as the “broadband measured irradiance” in the correction calculation:

$$\text{SMM} = \frac{I_{\text{sc, meas}}}{I_{\text{sc, ref}}} \times \frac{\int G_{\text{ref}}(\lambda) d\lambda}{\text{GHI}} \quad (5.15)$$

This method includes a wider range of spectral irradiance wavelengths, assuming the GHI measurement is taken with a thermopile pyranometer. However, if there are differences in response time, integration time, or placement between the spectroradiometer and the

pyranometer, this method will introduce significant errors. For the site discussed in this section, this method was inaccurate.

5.3.3 Co-Author Contributions

M. R. Lewis designed the methodology, performed the modelling, wrote the software, performed the analysis, visualized the data, and wrote the manuscript.

N. Riedel-Lyngskær guided methodology, assisted in data analysis, and assisted in manuscript revision.

J. K. Thorning maintains the measurement station, provided spectral irradiance data, and guided methodology.

A. R. Jensen contributed to software, assisted in data analysis, guided methodology, and assisted in manuscript revision.

K. Hinzer oversaw the research and the manuscript.

5.3.4 Manuscript

The draft manuscript is included on the following page.

Comparison of Spectral Correction Methods: Spectral Irradiance Measurements and Parameterized Spectral Models

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Abstract — A standard solar spectrum is assumed for photovoltaic (PV) module performance calculations, but spectral solar irradiance is continuously changing, impacting PV efficiency and energy yield. We calculate the spectral mismatch modifier (SMM) with two methods for 6 months of measured spectral irradiance data in Roskilde, Denmark. Method 1 relies on spectral irradiance data alone while method 2 combines broadband and spectral irradiance data. In method 1, effects outside of the device measurement range are not captured, but method 2 introduces significant errors due to instrument differences. Neither approach can fully account for changes to module efficiency under varying atmospheric conditions. We also compare five parameterized spectral correction methods. Methods relying on clearness index predict large positive spectral effects due to clouds, but this is not shown in the measured spectral impact. Further work is required to ascertain the most effective spectral correction approaches.

spectrum on PV efficiency. Module short-circuit current density (J_{sc}) is spectrally corrected by taking its product with the SMM. To calculate SMM, we begin with J_{sc} :

$$J_{sc} = \int \frac{q\lambda}{hc} \cdot EQE(\lambda) \cdot G(\lambda) d\lambda = \int SR(\lambda) \cdot G(\lambda) d\lambda \quad (1)$$

where EQE is external quantum efficiency, λ is wavelength, q is the elementary charge, h is Planck's constant, c is the speed of light, SR is spectral responsivity, and G is the solar spectrum. In this work, we use front silicon module EQE from [3].

From J_{sc} , there are two SMM calculation methods: normalization by either (1) integrated spectral irradiance or (2) global horizontal irradiance (GHI).

To normalize by integrated spectral irradiance (method 1):

$$SMM = \frac{J_{sc,meas}}{J_{sc,ref}} \times \frac{\int_{\lambda_1}^{\lambda_2} E_{ref}}{\int_{\lambda_1}^{\lambda_2} E_{meas}} \quad (2)$$

where $J_{sc,meas}$ and $J_{sc,ref}$ are the short-circuit current density under the test spectrum and the reference spectrum, respectively, E_{meas} is the measured spectrum, E_{ref} is the reference spectrum, λ_1 is the lower wavelength limit, and λ_2 is the upper wavelength limit. The reference spectrum in this case is the ASTM G173-03 AM1.5G spectrum. For our measurements, $\lambda_1 = 290$ nm and $\lambda_2 = 1700$ nm.

In method 2, we normalize by broadband GHI:

$$SMM = \frac{J_{sc,meas}}{J_{sc,ref}} \times \frac{\int E_{ref}}{GHI} \quad (3)$$

In this work, we compare these approaches. Method 1 (Eq. 2) neglects irradiance outside of the spectral measurement range but method 2 (Eq. 3) is affected by differences between measurement devices, for example in calibration, placement, exposure time, thermal offsets, or angular response.

B. Site Measurements

All measurement devices applied in this work are installed at Building 130, Technical University of Denmark, Risø Campus (55.69°N, 12.10°E). We analyze 5-minute resolution data from May 18 to October 31, 2024. We measure spectral global horizontal irradiance (spectral GHI) with an EKO MS-711

I. INTRODUCTION

A standard solar spectrum is typically applied to predict photovoltaic (PV) module efficiency and yield, but the solar spectrum constantly varies as solar position and atmospheric conditions change. A global comparison of measured spectral irradiance data demonstrated weekly spectral performance effects of +1 to +14% for silicon modules [1]. Thus, for accurate PV performance assessment, the impact of the solar spectrum should be quantified.

Spectral irradiance measurements are rarely available at PV sites due to the associated high cost and complexity. Parameterized spectral correction methods allow some spectral correction without requiring spectral irradiance measurements. These methods rely on commonly available parameters such as air mass, precipitable water, aerosol optical depth, and sky clearness as proxies for spectral irradiance.

In this work, we calculate spectral effects on a silicon module for 6 months in Roskilde, Denmark. We apply two spectral irradiance correction methods to measured solar spectra and compare with five parameterized spectral correction methods.

II. METHODOLOGY

A. Spectral Mismatch Modifier Calculation

The spectral mismatch modifier (SMM), defined in IEC 60904-7 [2], represents the effect of the incident irradiance's

TABLE I
PARAMETERIZED SPECTRAL CORRECTION METHODS

Method	Parameters	Model Fit Data	Technologies
SAPM [9]	AM (abs)	Module J_{sc} (2-axis-tracked)	CdTe, c-Si, mc-Si, CIS, a-Si, GaAs (database)
First Solar [10]	AM (abs), PW	Modeled spectra (SMARTS2)	CdTe, c-Si, mc-Si, CIGS, a-Si
Caballero [11]	AM (abs), PW, AOD	Modeled spectra (SMARTS2)	CdTe, c-Si, mc-Si, CIGS, a-Si, perovskite
JRC [12]	AM (rel), k_t	Module J_{sc} (fixed-tilt)	CdTe, mc-Si
PVSPEC [8]	AM (abs), k_t	Measured spectra (Solar-SIM-G)	CdTe, c-Si, mc-Si, CIGS, a-Si

(290-1100 nm) and an EKO MS-712 (900-1700 nm). We combine measurements from these two instruments by taking: MS-711 below 925 nm, average of MS-711 and MS-712 for 925-970 nm, and MS-712 above 970 nm. We calculate broadband GHI from broadband diffuse horizontal irradiance (DHI), broadband direct normal irradiance (DNI), and solar position. DHI is measured with an EKO MS-802F pyranometer shaded by a 5° field-of-view shadow ball. DNI is measured with an EKO MS-56 pyrliometer with 5° field-of-view. A Lufft UMB600 weather sensor measures air pressure.

We apply the pvanalytics python package (v0.2.2) [4] with default settings to filter implausible irradiance data. Timestamps with solar elevation angles below 5° and solar azimuth angles outside of 62°-294° are removed due to shading.

C. Parameterized Spectral Correction Methods

In this work, we compare five parameterized spectral correction methods, summarized in Table I. We obtain clear-sky GHI, precipitable water (PW), and aerosol optical depth (AOD) from the CAMS Radiation Service [5] using pvlib [6]

(v0.11.1). We calculate clear-sky index (k_t) by dividing measured GHI by CAMS clear-sky GHI. We sum the AOD of black carbon, dust, sea salt, organic matter, sulphate, and nitrate to obtain total AOD. We calculate absolute air mass (AM) using pvlib from relative air mass and measured air pressure.

We calculate the SMM for each parameterized method at each timestamp. We use c-Si coefficients for all methods except JRC, where only mc-Si coefficients are available.

D. Total Spectral Impact on Effective Irradiance

We calculate total spectral impact for each method over the entire period as follows:

$$\text{Spectral Impact (\%)} = \frac{\sum_t \text{SMM}(t) \times \text{GHI}(t)}{\sum_t \text{GHI}(t)} \quad (4)$$

where t is the timestamp. This gives the effective change in irradiance after spectral effects as a fraction of total irradiance.

III. RESULTS AND DISCUSSION

All parameterized models predict a change in SMM over the course of a sunny day with respect to air mass (solid lines, Fig. 1a), with the maximum at sunrise and sunset and minimum at noon. The self-normalized SMM (method 1, black dash) is similar, while the GHI-normalized SMM (method 2, orange dash) predicts smaller SMM values below 1, particularly in the afternoon. GHI-normalized SMM is smaller on average than self-normalized SMM, which was not expected.

During the cloudy day (Fig. 1b), SMMs from spectral measurements (black and orange dash) are above 1 because cloudy spectra are well-matched to the silicon bandgap. Clouds absorb long-wavelength irradiance above 900 nm, with strong absorption above 2000 nm for thick clouds [7]. Therefore, transparency losses are reduced, resulting in high SMMs.

Cloud-dependent spectral effects are not fully captured in the 290-1700 nm range, so method 1 underestimates this effect.

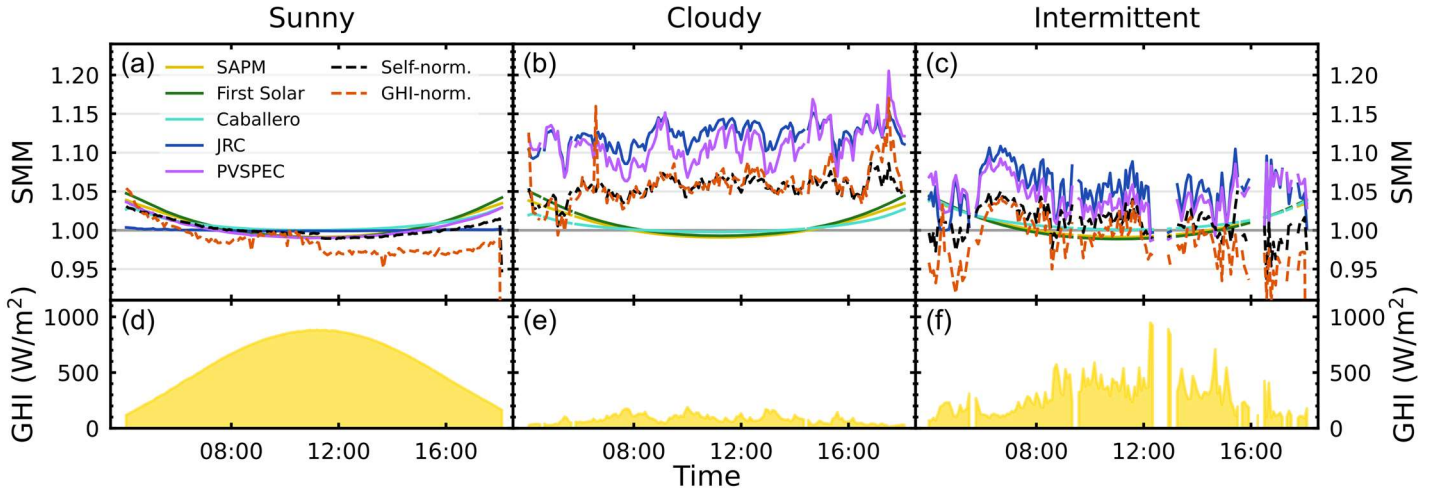


Fig. 1. Spectral Mismatch Modifiers (SMMs) for (a) a sunny day (2024-06-26), (b) a cloudy day (2024-06-22), and (c) an intermittently cloudy day (2024-06-19). (d)-(f) global horizontal irradiance (GHI) for the same dates.

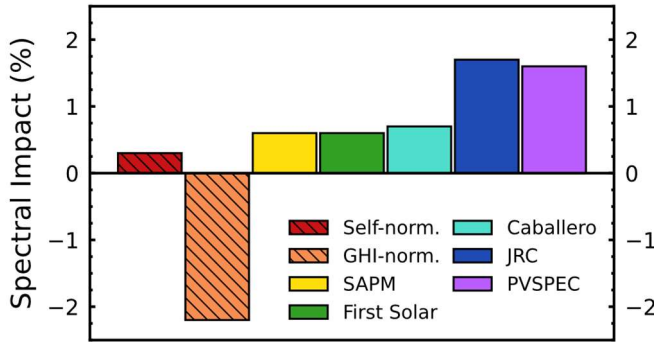


Fig. 2. Effective spectral impact for measured spectral irradiance calculations (black hash) and parameterized spectral correction methods (solid), defined in Eq. 4. Red: method 1, orange: method 2.

Ideally, GHI normalization (method 2) would capture long-wavelength cloud effects, since thermopile pyranometers detect long-wavelength irradiance, but we found erroneously small SMM values. This may be due to calibration error: GHI modifies the SMM in method 2 (Eq. 3), so an overestimation of GHI would cause an underestimation of SMM. Furthermore, any spectral irradiance measurement bias will modify J_{scmeas} and therefore SMM. Method 1 is unaffected by spectral irradiance bias, assuming it is equal at all wavelengths, because the SMM is normalized by the total irradiance of the measured spectrum. In addition, for method 2, differences between the measurement devices introduce noise. Therefore, we found method 2 is insufficient for spectral correction calculations without harmonized instrument calibration methods.

On the cloudy day, parameterized model SMMs relying on k_t input (JRC, blue and PVSPEC, purple) are approximately 5% higher than measured SMMs. These models may be predicting larger cloud effects because their training inputs (290-4000 nm irradiance and module J_{sc}) include long wavelength effects.

These trends are further illustrated by the total spectral impact (Eq. 4), shown in Fig. 2: there is a small positive impact for the self-normalized method (+0.3%) and a large negative impact for the GHI-normalized method (-2.2%). The spectral impact from Method 1 is smaller than reported elsewhere [8], possibly due to cloud effects as previously discussed. This work is also missing winter months when SMMs are typically high. Further investigation is required, including a full-year spectral effect calculation, which we intend to report in Montreal.

IV. CONCLUSION

In this work, we studied spectral irradiance effects for silicon modules through both spectral irradiance measurements and parameterized spectral correction methods. We found that GHI-normalized spectral effect calculations can give erroneous results due to measurement error and device differences. While all parameterized spectral correction methods predicted a positive spectral impact, methods relying on clear-sky index predicted larger impacts due to cloud effects. This effect may not be captured by spectral irradiance measurements that cut off

long wavelengths. Ideally, spectral irradiance data would include the entire solar spectrum (290-4000 nm).

While we investigate horizontal irradiance in this work, for accurate results, global *tilted* irradiance spectra should be obtained. A tilted plane will have a different ratio of direct, diffuse, and ground-reflected irradiance, resulting in changes to the spectrum. This remains a direction of future research.

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Chapter 6

Conclusion and Future Work

Bifacial photovoltaics are a growing portion of the global PV market, but bifacial energy yield models are subject to higher uncertainty due to the additional complexity of rear-incident irradiance modelling. This thesis aims to improve bifacial photovoltaic energy yield models by analyzing the impact of various factors, including structural effects, artificial reflectors, and spectral irradiance.

Chapter 3 quantifies the effect of structural shading and reflection on a single-axis-tracking system through modelling in `bifacial_radiance`, a reverse ray-tracing bifacial PV model. Structural shading and reflection effects are not constant and depend on time of day, time of year, cloudiness, albedo, and other factors. For a two-in-portrait system in Livermore California over a 20% albedo ground cover, the rear irradiance shading and reflection factor varied from -12.7% to +2.4% on a per-timestamp basis. Furthermore, neglecting racking reflection will overestimate structural losses, because reflections from racking elements counteract their shading effect. Racking reflection reduces the annual shading factor from -17.6% to -8.5% and annual energy shading losses from -0.7% to -0.4%.

Field validation of modelled structural losses would increase the impact of these results. Future work could apply this methodology to a broader set of system designs to assess their effect on structural shading and reflection. For example, the effect of structural shading and reflection with fixed-tilt racking, one-in-portrait systems, or systems in different locations can be studied. This could lead to the development of simplified modelling methods that account for time-varying structural effects, including reflection, with lower computational costs. The impact of environmental parameters, such as cloudiness or latitude, could also be assessed. Furthermore, this approach can be applied to design PV mounting structures that minimize shading, minimize mismatch losses, and increase total energy yield.

Chapter 4 demonstrates that artificial reflectors increase bifacial PV irradiance and energy yield through field experiments and modelling. A 70% reflective material causes annual irradiance reflector gains of up to 8.6% and annual energy yield reflector gains of up to 4.5%. According to a levelized cost of energy analysis, artificial reflector breakeven installed costs are between \$2.50-4.60 per m^2 in Golden, Colorado, with higher potential breakeven costs in cloudier locations. The optimal reflector placement is centered directly under the torque tube for any reflector size. Inverter clipping must always be considered when designing and evaluating artificial reflector systems, because clipping losses affect some designs more heavily than others.

In the future, this approach could be applied to assess the ideal reflector design for more system types, such as fixed-tilt systems or vertical bifacial systems. The study could also be broadened to include global locations, with a global cost analysis accounting for local financial conditions. Although the manuscript briefly touches on these topics, some questions remain concerning the importance of reflector soiling losses and reflector material degradation over time.

Chapter 5 evaluates the impact of spectral solar irradiance on bifacial PV systems. Chapter 5.1 includes an analysis of spectral irradiance in seven North American locations. Bifacial PV system energy yield is underestimated when spectral effects are neglected, because ground-reflected and diffuse light are more efficiently absorbed than reference sunlight. Bifacial modules have higher spectral error due to high diffuse and ground-reflected irradiance. Annual energy yield may be underestimated by up to 0.6-2.7% when spectral effects are neglected, with higher errors when analyzing short timescales. Spectral correction should be applied in locations with high diffuse irradiance and for bifacial systems. Chapter 5.2 studies measured spectral irradiance data and parameterized spectral correction methods in one such location: Roskilde, Denmark. Spectral correction predictions are strongly affected by whether cloud cover is incorporated in the model or neglected. Both manuscripts demonstrate the importance of spectral irradiance measurement wavelength range for accurate spectral correction.

Although it would be ideal if all PV sites had co-located spectral irradiance measurements spanning the entire spectrum, these measurements are rare. More spectral irradiance measurements worldwide could facilitate further analysis of spectral irradiance effects in bifacial PV. Spectral extension approaches could improve spectral correction with available reduced-wavelength spectral irradiance datasets. Other methods of spectral irradiance acquisition, such as satellite models like FARMS-NIT, should also be investigated. The effect of temperature on spectral irradiance sensitivity, particularly cell temperature's effect on bandgap, was not explored in this work. Lastly, because *tilted* spectral irradiance is the incident spectrum in the field, spectral transposition models should be evaluated and applied

to spectral irradiance. Future studies could also assess the impact of spectral irradiance on emerging PV technologies, such as tandem solar cells.

As PV continues to grow to a position of greater importance in our energy sector, PV energy yield models will need to continue to improve. The importance of other effects that are often neglected, such as edge effects and rough terrain, should be quantified and studied. Furthermore, as PV technology advances, PV models must evolve to accurately model improvements. New technologies and new applications such as tandem modules, diffuse smart-tracking algorithms, building-integrated PV, and floating PV will require accurate energy yield models to facilitate adoption and integration into existing energy networks.

As a whole, this work highlights the time-varying nature of bifacial PV energy yield. In systems that are exposed to the electricity spot market, the *time* of power generation is nearly as significant as the *magnitude* of power generated. Neglecting these effects can lead to price cannibalization and slows PV adoption. This work will inform future, detailed, time-dependent energy yield models, including digital twin models, allowing for a more rigorous accounting of energy flows and PV system profits.

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