Final Technical Report

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Signature of Certifying Official   11/17/2023
Date

By signing this report, I certify to the best of my knowledge and belief that the report is true, complete, and accurate. I am aware that any false, fictitious, or fraudulent information, misrepresentations, half-truths, or the omission of any material fact, may subject me to criminal, civil or administrative penalties for fraud, false statements, false claims or otherwise. (U.S. Code Title 18, Section 1001, Section 287 and Title 31, Sections 3729-3730). I further understand and agree that the information contained in this report are material to Federal agency's funding decisions and I have any ongoing responsibility to promptly update the report within the time frames stated in the terms and conditions of the above referenced Award, to ensure that my responses remain accurate and complete.

1 Acknowledgment

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2 Disclaimer

3 Executive Summary

The cost delta between monofacial and bifacial photovoltaic (PV) modules was decreasing in 2018 when this study was initially proposed, making bifacial modules an attractive offering. However, there were limited field studies available that could be considered utility-scale representative, and PV module manufacturers were stating large ranges for the expected energy yield improvements of bifacial technology. This generated uncertainties regarding bifacial performance gains and the actual LCOE (levelized cost of energy). There was also relatively low confidence in the industry's energy modeling tools' ability to accurately predict bifacial energy yield, meaning that early adopters of bifacial modules were not able to fully account for the increased energy yield in their energy and financial models.

The intent of this project was to provide the solar industry with greater certainty on the energy yield gains of bifacial modules and provide higher confidence in the ability for different energy modeling software to model bifacial PV site performance. Achieving this would allow for bifacial technology to become bankable (i.e. accepted by Independent Engineers, site financiers and other PV site stakeholders), offering a step change in PV site performance that had not been seen since the widespread adoption of the single-axis tracker.

Over the course of this study other economic factors including a significant tariff exemption for bifacial modules resulted in accelerated adoption of bifacial technology throughout the US utility scale solar segment. The number of early adopters increased rapidly, and with many investors accepting this module choice the question of bifacial bankability was seemingly answered faster than expected.

However, PVEL's study has still achieved significant accomplishments in demonstrating the accuracy of bifacial modeling across three different software platforms. The results of this study have shown that the mean biased error (MBE) between the field data and the predicted values from all three software platforms were aligned with a maximum MBE of 1.3% and a minimum MBE of -1.8%.

	Mean Bias Error	
Parameter	**1A (White)**	**1A (Grass)**
Total Error – PVsyst	-1.8%	-1.1%
Total Error – Solar Farmer	1.2%	1.0%
Total Error – Plant Predict	1.3%	0.9%

Table 3-1: Modeled vs. measured energy error summary

The study has also demonstrated utility-scale representative monthly bifacial performance gains in the range of 2-18% over monofacial counterparts from the same module manufacturers. This analysis is based on three-module systems installed on the same trackers.

		Manufacturer					
Start Date	End Date	1	2	3	4	5	8
11-01-2020	11/30/2020	11%	11%	12%	10%	11%	12%
12-01-2020	12/31/2020	12%	11%	13%	10%	12%	11%
01-01-2021	1/31/2021	12%	12%	13%	13%	13%	13%
02-01-2021	2/28/2021	16%	13%	14%	14%	14%	14%
03-01-2021	3/31/2021	13%	13%	13%	11%	12%	11%
04-01-2021	4/30/2021	11%	10%	9%	9%	13%	6%
05-01-2021	5/31/2021	11%	10%	9%	7%	15%	
06-01-2021	6/30/2021	10%	11%	8%	8%	18%	
07-01-2021	7/31/2021	11%	11%	7%	7%		8%
08-01-2021	8/31/2021	12%	11%	9%	8%		9%
09-01-2021	9/30/2021	10%	10%	8%	7%	17%	9%
10-01-2021	10/31/2021	10%	10%	8%	8%	12%	10%

Table 3-2 Monthly average bifacial gain on white groundcover

		Manufacturer					
Start Date	End Date	1	2	3	4	5	8
11-01-2020	11/30/2020	4%	6%	4%	5%	6%	6%
12-01-2020	12/31/2020	3%	5%	5%	5%	7%	6%
01-01-2021	1/31/2021	4%	4%	4%	6%	7%	7%
02-01-2021	2/28/2021	3%	3%	5%	3%	5%	6%
03-01-2021	3/31/2021	4%	6%	5%	4%	5%	5%
04-01-2021	4/30/2021	5%	5%	4%	4%	5%	4%
05-01-2021	5/31/2021	3%	5%	3%	3%	7%	
06-01-2021	6/30/2021	3%	5%	4%	4%	11%	
07-01-2021	7/31/2021	4%	6%	4%	5%		5%
08-01-2021	8/31/2021	5%	6%	5%	5%		6%
09-01-2021	9/30/2021	4%	6%	4%	3%	7%	5%
10-01-2021	10/31/2021	4%	6%	5%	4%	5%	5%

Table 3-3 Monthly average bifacial gain on natural groundcover

Based on the results of this study and the proliferation of bifacial systems being financed throughout the USA and abroad, it is clear to PVEL that the current bifacial system energy modeling solutions have reached the point of bankability and industry acceptance.

PVEL has been quite prolific with sharing the results of this study in a variety of industry events and documents, including in-person and virtual conferences, workshops, whitepapers and webinars.

4 Table of contents

5 Background

5.1 Similar studies

Although bifacial solar cells were first patented in 1960 by Hiroshi Mori for what is now the Sharp Corporation, it was not until PERC (passivated emitter and rear contact) cells began mass production in 2016 and drove down bifacial production costs, as the production process is similar to PERC[i], that adoption of bifacial solar technology began steadily trending upward. However, the cost-effectiveness of p-type PERC cells, which has caused them to dominate in the market, has overshadowed n-type technologies, such as PERT (passivated emitter rear totally diffused) and HJT (heterojunction), that have the potential for higher energy yield. Contributors to the bifiPV2020 Bifacial Workshop showcased these and other new bifacial technology trends including larger wafer sizes and thinner glass, as well as different project applications still being researched, such as vertically mounted PV, rooftop, carports, and horizontal single-axis tracking (HSAT).

Also included were results from the field, and an overview of simulations that include the use of advanced ray-tracing optical tools such as Mobidig, ATAMOSATEC/CEA-INES, bifacial_radiance and PV Lighthouse to accurately represent real bifacial PV plants, in order to measure expected energy gains and gauge the bankability of bifacial modules.

PVLighthouse's research was conducted on how PVsyst inputs for bifacial systems depend on conditions. It used a simulation of a central module in a large array with no edge effect to determine bifacial inputs from ray tracing and SPICE modeling and calculated the discrepancy in yield between the two. The study looked at changes in location with albedo kept as baseline (white rocks), changes of albedo, and module height. Although it addressed separate albedos, as PVEL's project did, there was no field component.

Like PVEL's project, Array Technologies conducted research on field testing and modeling. However, their study focused on validating the 2D view factor model using loss factors calculated from a PVLighthouse systematic ray tracing study. ATAMOSTEC's study looked at LCOE calculations for their own technology using lab and a bifacial PV testing platform in their outdoor test facilities, specifically for desert and high radiation zones, rather than third-party independent testing as with PVEL's project. Nextracker also utilized PVEL's bifacial testing center at PVUSA to conduct their research on measured bifacial gains using PVsyst bifacial parameters to compare their products to other tracker solutions. While their study looks at comparative energy yield, it is focused on model validation rather than model to field validation.

Currently, NREL[ii] is conducting a study on performance models and standards for bifacial PV module technologies that includes designing and building a bifacial test bed capable of controlling performance parameters, developing and validating ray-tracing models of back side irradiance, and finally implementing performance models to draft a standard for bifacial performance ratings. Their study is similar to PVEL's, but is ongoing and can pull from PVEL's research to accelerate the bankability of bifacial PV technology.

5.2 The Section 201 Bifacial Exemption

In 2018, "safeguard" tariffs (under "Section 201") were added to almost all c-Si cells and modules imported from outside the US to make US-based manufacturers more competitive in the market. The Commerce Department's decision was prompted by the low-cost Chinese solar products that flooded the market and drove many American solar manufacturers out of business, although critics argue that inexpensive products also pushed adoption of solar energy by providing incentives for developers and installers. When bifacial modules were exempted from the tariffs in 2019, the potential for lower costs for PV systems drove significant bifacial demand, which was met by the relative ease of pivoting monofacial manufacturing facilities to bifacial manufacturing.

By the end of 2019, despite some instability in the policy outlook, Wood Mackenzie noted that global installed capacity of bifacial modules doubled from 2018 to 2019, and was predicting that bifacial module installations in the U.S. would expand from just over 500 megawatts in 2019 to more than 7,000 megawatts by 2024, largely driven by the bifacial exemption. As seen in Figure 5-1 below, the average selling price of bifacial mono PERC in the U.S. remained roughly in line with and occasionally lower than monofacial crystalline modules until the exemption was removed in Q4 2020.

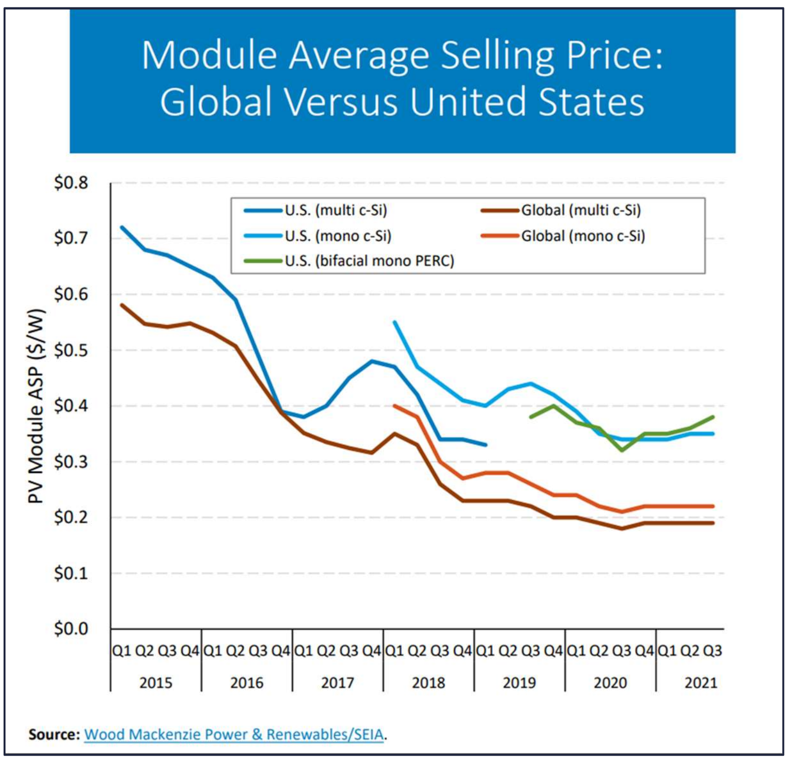

Figure 5-1 Module Selling Price by Technology

Figure 5-2, below, shows the percent of modules under test in the Product Qualification Program at PVEL that are monofacial versus bifacial. During the first year in which bifacial modules were submitted for testing, only one module type was bifacial. By the end of 2021, 62% of modules submitted, or 40 out of 65, were bifacial. It is clear that the bifacial exemption has been a strong driver of bifacial adoption.

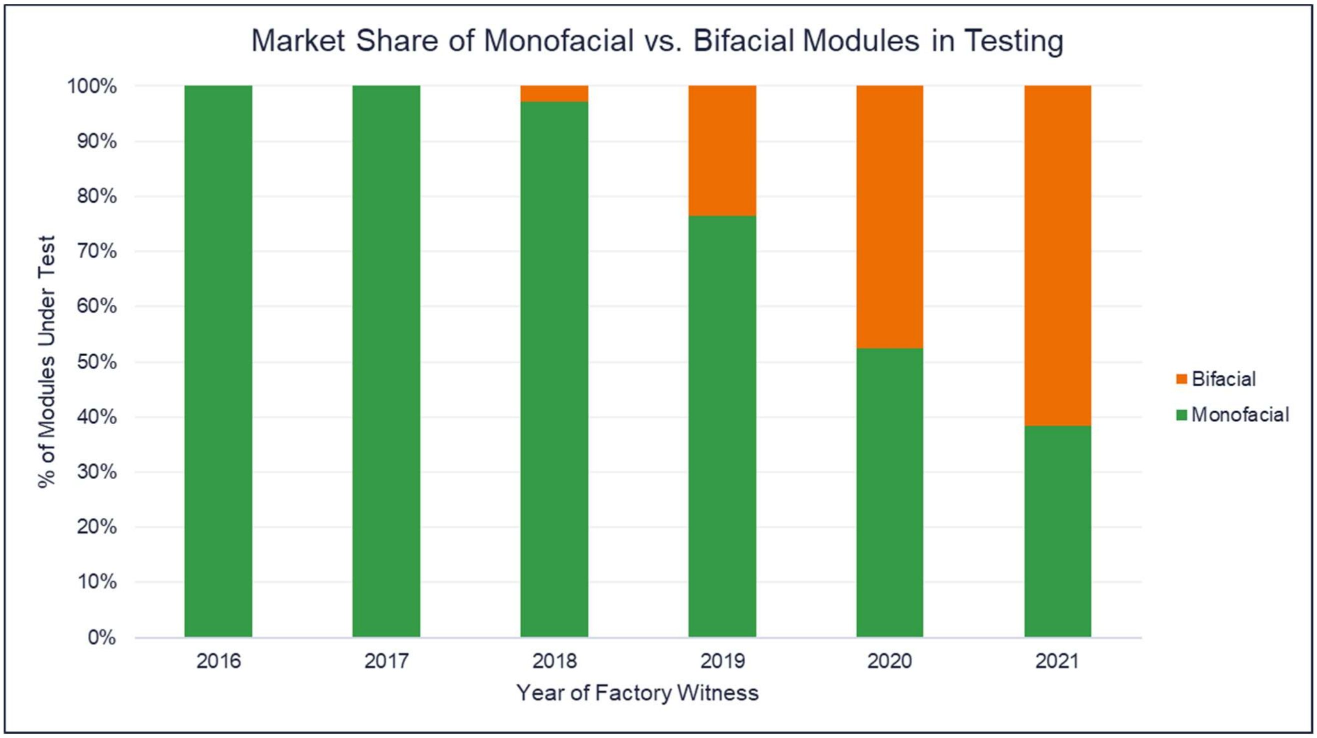

Figure 5-2 PVEL's Product Qualification Program Module Technology - Monofacial versus Bifacial

6 Project Objectives

Bifacial photovoltaic (PV) modules have the potential to increase energy output by 5-10% annually in many locations. To achieve commercial viability, however, the products need to be considered bankable. Common testing models, including National Renewable Energy Laboratory System Advisor Model (NREL SAM) and PVsyst, have begun to incorporate bifacial models, but little validation data exists, and often lacks third-party review. This study intended to validate various contemporary energy models relating to bifacial solar PV modules in order to provide assurances to PV system engineers, owners, and financiers that PV systems using bifacial PV technology will yield expected energy gains. In turn, the study aimed to accelerate the bankability of bifacial PV technology and eventually lead to a lower levelized cost of electricity (LCOE).

6.1 Technical Scope Summary

Four module manufacturers each provided approximately 50 kilowatts' capacity at direct current (kWDC) of monofacial and bifacial PV modules, split evenly between the two technologies. The modules all used a p-type PERC bifacial cell architecture with either full- or half-cut cells.

Once received at PVEL's laboratory in Berkeley, CA, the PV modules underwent initial flash testing at Standard Test Conditions (STC) using two Class A+A+A+ Pasan SunSim 3b pulsed solar simulators, as well as electroluminescence (EL) imaging at short-circuit current, wet leakage at system voltage, and visual inspection. They then were subjected to at least 40 kWh/m^2 of light-soaking outdoors, followed by flash testing at STC and EL imaging at short-circuit current on a subset of 17 modules per module type. In order to obtain the bifaciality factor both the front and rear sides of the bifacial modules will be flashed, in accordance with IEC TS 60904-1-2. IEC 61215:2016 was also referenced for flash testing, wet leakage and visual inspection.

Following these measurements, three sample modules per module type were randomly selected and submitted to additional flash testing following IEC 61853-1, which entails taking 22 measurements at several ambient temperatures and irradiances in order to produce relevant efficiency coefficients. Three additional samples per module type were also subjected to incidence angle modifier (IAM) coefficient measurements following the guidance of IEC 61853-2. These measurements were then used in creating PVEL-optimized .pan files (one for each model type in scope), which was used to represent the modules' performance in subsequent energy simulation models.

Upon completion of initial laboratory testing, all modules in scope were transported to PVEL's outdoor testing facility in Davis, CA, and installed across eight rows of Nextracker's one-in-portrait single-axis tracker racking. Each tracker row included two 1500V strings, each containing 28 modules of one model type installed over two different ground coverings representing two albedos. One ground cover was low-lying vegetation (a combination of grass and dirt) and the other was a higher albedo modified ground cover comprised of a white landscaping fabric. Each tracker row had four 'buffer' modules installed on the northern and southern ends as well as four 'buffer' modules on either side of the albedo transition in the middle of the array, and entire rows of ‘buffer’ modules on the east and west sides of the array. These ‘buffer’ modules and rows meant that the 1500V strings under test were in the interior of the array and therefore the results would be representative of utility-scale PV sites.

The test site employed a wide array of monitoring equipment, including an ambient weather station, four albedometers (for global horizontal irradiance and plane of array irradiance and albedo measurements for both ground coverings), and thermocouples on the rear of each module type being tested. Measured data points included wind speed, wind direction, ambient temperature, precipitation, relative humidity, barometric pressure, module operating temperature, irradiance and albedo. Additionally, power, current, and voltage data was measured at one-minute intervals for each string.

The test study was intended to run for 12 months, following which the PV system was decommissioned and the subset of 17 modules were transported back to the laboratory in Berkeley, CA, for flash testing and EL imaging, as per the aforementioned standards. With the field data collected, PVEL could now complete a comparison between the measured data from the study to energy models from different industry leading software. PVEL worked with internal energy modeling experts using PVsyst, as well experts at DNV using SolarFarmer and TeraBase using Plant Predict to conduct these measured versus modelled comparisons, using one of the manufacturer’s monofacial and bifacial results.

7 Project Results and Discussion

7.1 Test Design

7.1.1 Test Overview

The outdoor test portion of this study evaluated the energy yield and performance of a PV products over different ground coverage types when installed on a single-axis tracker. Four manufacturers provided enough PV modules for 1500V strings of monofacial and bifacial modules to be installed over a grass (or natural) groundcover and identical modules to be installed over a modified white groundcover. These strings were connected to a 1500V string inverter. In addition to the 1500V strings, three modules per module type and groundcover were installed while connected to microinverters on the same trackers. Those modules came from the same four manufacturers, plus four other manufacturers also had bifacial and/or monofacial modules installed in these three module set-ups.

7.1.2 Test Array Layout

This project was conducted at PVUSA, in Davis, CA on the array shown in the highlighted box of Figure 7-1.

Figure 7-1: Site location of test system

Buffer modules were deployed throughout the array to ensure that the data captured on the modules under test was considered field relevant. These buffer modules included the entirety of the first and tenth tracker rows (those that were furthest to the east and west, respectively); the four modules at both the north and south extremities on each of the middle tracker rows (the second to ninth tracker rows); and the four modules to both the north and south of the albedo transition in the middle of the array.

Representative images of the array are shown in Figure 7-2 and Figure 7-3.

Figure 7-2: Test array overview with natural groundcover

Figure 7-3: Test array overview with white groundcover

The high-level details for the site and array are listed in Table 7-1.

Table 7-1: Site & Array Details

Site & Array Specifications	
Deployed Site	PVEL PVUSA
Latitude	38° 34' 53.0076" N
Longitude	121° 43' 58.1556" W
Racking Type	1-in-portrait Single Axis Tracker
Tilt	±45°
Azimuth	180°
Distance Between Rows	5.2 m (17 feet)
Tracker Height (from ground to top of torque tube)	1.3 m (46 inches)
Surrounding Ground Coverage	High reflective white ground covering and grass

7.1.3 DC Configuration

For this study, 125 kW string inverters were used for the 1500 V strings. For the three-module smaller systems, a selection of an AE INV350-60, AEINV500-90, Enphase IQ 7+ microinverters and Sunny Boy 3.0-US string inverter were employed. To confirm there would be no mis-operation of the strings with the operating DC envelope of the inverter, a comparison was performed using the module and inverter electrical parameters.

7.1.4 AC Configuration

For this study, the output of the 1500 V string inverters was 480 VAC, for the smaller systems the associated inverters were interconnected to the grid via a 208 VAC connection.

7.1.5 Data Acquisition

The layout of data acquisition for each test string is detailed in Figure 7-4.

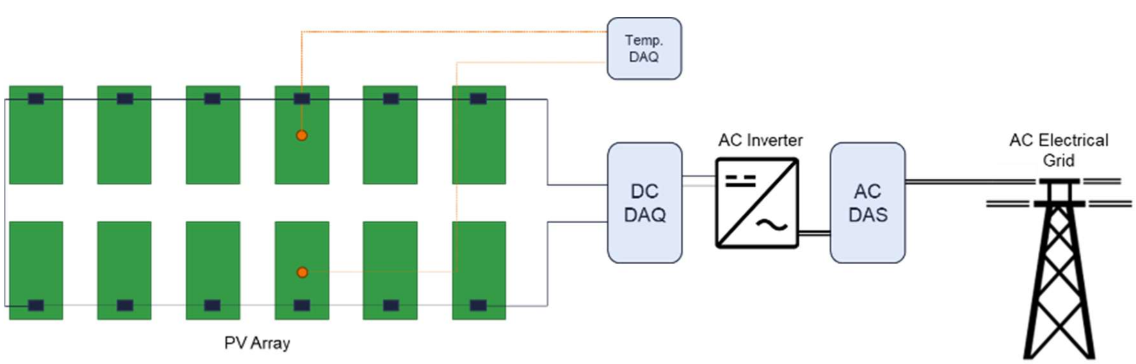

Figure 7-4: Conceptual data acquisition layout per system

DC electrical parameters were monitored through remote sensors reporting to a network-connected data logger. The voltage measurement was captured using a 1500VDC-rated galvanically isolated sensor. Current was measured using active current transducers. Standard parameters monitored were DC voltage and current, with power calculated in the monitoring portal. Reporting to the data monitor portal was 5-minute.

Backsheet/rear-glass temperature of the modules was captured using T-type thermocouples. Attachment was achieved via a sequential application of thermally conductive epoxy, aluminum tape, and then polyamide top covering. All sensor measurements were captured using a network connected datalogger. Reporting to the data monitor portal was 5-minute.

7.1.6 Meteorological Overview

To obtain high fidelity meteorological data, PVEL utilized sensors deployed extensively throughout the site. These are detailed in this section.

7.1.6.1 Irradiance

In support of robust and nuanced irradiance data capture, PVEL has a heterogenous sensor fleet deployed at PVUSA. The fleet contains the following types of sensors:

<u>Thermopile Pyranometer</u>

This device is a double-domed thermoelectric sensor and relies on a blackbody detector that provides a millivolt signal scaled to the irradiance measured.

<u>Reference Cell</u>

PVEL’s in-house calibrated and accredited reference cells are an ESTI split cell, with a half cell in short circuit and the other in open circuit. Monitoring both, in conjunction with the measured calibration coefficient, provides a spectrally matched temperature corrected irradiance value.

<u>Pyrheliometer</u>

Similar in functional design as a thermopile pyranometer, a pyrheliometer has a windowed aperture. When coupled with a 2-axis tracker, it tracks the sun path to measure the direct beam component of irradiance.

<u>Albedometer</u>

An albedometer is a combination of two thermopile pyranometers aligned 180° from each other. Beyond global horizontal or plane-of-array irradiance, albedometers were employed to measure the reflected irradiance off of the ground coverage to provide albedo readings.

7.1.6.2 Ambient Temperature & Humidity

PVEL has multiple multi-function weather stations deployed at the PVUSA test site. The ambient and humidity sensors are integrated into these units.

7.1.6.3 Other Sensors

Wind direction and speed were captured at multiple locations on the site. Mechanical/cup and ultrasonic anemometers are employed at PVUSA.

Ancillary meteorological sensors are employed to monitor barometric pressure, rainfall rate, and cumulative rainfall.

7.1.7 Module Characterizations

Preliminary characterizations of the PV modules were performed at PVEL's indoor testing lab, with the following characterizations performed:

- STC Power Determination
- EL Imaging at I_{sc}

These characterizations were performed on all modules participating in the study, with a subset of 17 modules per module type also receiving these characterizations following ≥ 40 kWh/m^2 of light exposure in an effort to quantify any light-induced degradation (LID) effects.

7.2 Operational Notes

Modules were cleaned at intervals depending on soiling levels, with a minimum of monthly cleanings. Higher soiling months stipulated more frequent cleaning.

During the study period, there were several issues with the data acquisition equipment that caused incorrect data to be collected. This monitoring downtime and erroneous data resulted in comparisons between the sixteen 1500V strings being quite limited and potentially misleading. Rather than using those results, PVEL decided to compare the results of the three-module smaller systems from November 1, 2020 to October 31, 2021 as that comparison data was more complete. However, some erroneous data was still present on the smaller systems which needed to be filtered out of the final analysis. The following smaller systems have missing data due to this: System 5 for July-August 2021, System 7 June-August 2021, System 8 May-June 2021.

7.2.1 Data Filtration Criteria

All performance analysis was filtered for downtime events, clipping events and G_{POA} values less than 200 W/m^2. For the comparative evaluation of the smaller systems, uniform operational status was confirmed using a 16% difference filter for current and a 5% difference filter for voltage. All systems were then compared using the same timestamp, so that periods where all systems are properly operational were used, except the months where various systems were down as detailed above.

7.3 Results & Performance Analysis: Measured Weather & Temperature Data

This section details the weather data collected over the study period.

7.3.1 Weather Data Summary

Summary weather data for the reporting interval is detailed in Table 7-2.

Table 7-2: Summary weather data

Period Start	Period End	Plane of Array Insolation	Global Horizontal Insolation	Rainfall	Relative Humidity	Barometric Pressure	Ambient Temperature
		kWh/m²	kWh/m²	mm	%	mb	°C
11/1/2020	11/30/2020	126.18	93.10	0.00	18-98%	921.8-1026	-0.5 to 23.8
12/1/2020	12/31/2020	92.87	69.75	0.03	15.9-97.7%	1005.4-1030.4	-0.7 to 18.3
1/1/2021	1/31/2021	84.22	65.90	0.06	16.1-97.9%	925.2-1028.8	-0.2 to 18.9
2/1/2021	2/28/2021	142.98	104.09	0.02	12.9-100%	916.8-1030.6	2.2 to 23.4
3/1/2021	3/31/2021	206.29	155.05	0.03	14.5-97.3%	917.2-1025.5	4.2 to 23.8
4/1/2021	4/30/2021	260.47	198.63	0.00	9.3-92.6%	1005.1-1021.7	1.8 to 32.7
5/1/2021	5/31/2021	278.36	204.40	0.00	8.8-87.9%	912.3-1018.7	9.6 to 34.9
6/1/2021	6/30/2021	274.87	243.09	0.00	9.7-88.9%	1001-1022.9	10.3 to 40.6
7/1/2021	7/31/2021	313.48	245.88	0.00	12-91.5%	1004.5-1015	11.2 to 37.9
8/1/2021	8/31/2021	194.77	197.45	0.00	10.8-90.8%	908.9-1017.2	9.2 to 35.9
9/1/2021	9/30/2021	212.56	153.47	0.00	8.7-89%	905.5-1018.4	5.6 to 32.8
10/1/2021	10/31/2021	163.10	121.16	0.12	10.7-97.2%	999.8-1026.7	4.2 to 23.2

7.3.2 Detailed Irradiance Analysis

Table 7-3 provides monthly summations of plane-of-array irradiances, global horizontal irradiance, and their respective inversions. Table 7-4 provides monthly averages of the albedo values recorded over the study period.

Table 7-3: Summary irradiance data by reporting condition

Start Date	End Date	Plane of Array Insolation: Grass	Inverse Plane of Array Insolation: Grass	Plane of Array Insolation: White	Inverse Plane of Array Insolation: White	Global Horizontal Insolation: White	Inverse Global Horizontal Insolation: White	Global Horizontal Insolation: Grass	Inverse Global Horizontal Insolation: Grass
		kWh/m²	kWh/m²	kWh/m²	kWh/m²	kWh/m²	kWh/m²	kWh/m²	kWh/m²
11/1/2020	11/30/2020	125.53	10.57	126.18	16.86	89.84	42.88	93.10	17.81
12/1/2020	12/31/2020	93.26	6.74	92.87	13.90	68.38	34.54	69.75	12.62
1/1/2021	1/31/2021	84.47	5.59	84.22	13.94	65.16	31.84	65.90	8.86
2/1/2021	2/28/2021	143.99	8.37	142.98	20.06	103.60	49.28	104.09	15.64
3/1/2021	3/31/2021	206.11	14.48	206.29	31.10	153.48	72.03	155.05	26.07
4/1/2021	4/30/2021	260.02	19.57	260.47	38.91	194.86	85.39	198.63	36.01
5/1/2021	5/31/2021	276.98	24.37	278.36	37.62	206.79	88.82	204.40	40.15
6/1/2021	6/30/2021	275.87	29.53	274.87	39.16	203.98	85.99	243.09	51.56
7/1/2021	7/31/2021	314.31	33.33	313.48	43.64	232.40	97.27	245.88	53.43
8/1/2021	8/31/2021	194.72	22.99	194.77	29.96	150.57	63.05	197.45	44.98
9/1/2021	9/30/2021	208.47	19.21	212.56	28.15	154.18	67.71	153.47	33.13
10/1/2021	10/31/2021	157.40	14.19	163.10	23.18	121.44	55.94	121.16	25.78
	Total	**2341.13**	**208.94**	**2350.16**	**336.47**	**1744.68**	**774.74**	**1851.97**	**366.04**

Table 7-4: Monthly average albedo & G_{POA}^{-1}/G_{POA}

Start Date	End Date	Grass Albedo GHI	White Albedo GHI	Grass G_{POA} Ratio	White G_{POA} Ratio
		%	%	%	%
11/1/2020	11/30/2020	8.4%	13.4%	19.1%	47.7%
12/1/2020	12/31/2020	7.2%	15.0%	18.1%	50.5%
1/1/2021	1/31/2021	6.6%	16.5%	13.4%	48.9%
2/1/2021	2/28/2021	5.8%	14.0%	15.0%	47.6%
3/1/2021	3/31/2021	7.0%	15.1%	16.8%	46.9%
4/1/2021	4/30/2021	7.5%	14.9%	18.1%	43.8%
5/1/2021	5/31/2021	8.8%	13.5%	19.6%	43.0%
6/1/2021	6/30/2021	10.7%	14.2%	21.2%	42.2%
7/1/2021	7/31/2021	10.6%	13.9%	21.7%	41.9%
8/1/2021	8/31/2021	11.8%	15.4%	22.8%	41.9%
9/1/2021	9/30/2021	9.2%	13.2%	21.6%	43.9%
10/1/2021	10/31/2021	9.0%	14.2%	21.3%	46.1%
	Total	**8.7%**	**15.8%**	**19.7%**	**42.6%**

7.4 Results & Performance Analysis: Energy Production

The smaller three-module system study evaluated the energy yield of 108 modules including monofacial and bifacial over two ground coverage types. The energy yield and specific energy yield of these systems is presented in this Section. Table 7-5 summarizes the anonymized system configurations that are discussed in this section.

Table 7-5: Test configuration details

System	Model Technology	Albedo	Average Measured Pmp
1A	Monofacial	White	369.50
1B	Monofacial	Grass	369.80
1C	Bifacial	White	362.70
1D	Bifacial	Grass	365.10
2A	Monofacial	White	377.10
2B	Monofacial	Grass	378.10
2C	Bifacial	White	375.30
2D	Bifacial	Grass	376.40
3A	Monofacial	White	378.10
3B	Monofacial	Grass	378.30
3C	Bifacial	White	372.80
3D	Bifacial	Grass	371.30
4A	Monofacial	White	382.10
4B	Monofacial	Grass	382.90

[redacted]

System	Model Technology	Albedo	Average Measured Pmp
4C	Bifacial	White	375.90
4D	Bifacial	Grass	375.90
4E	Bifacial	White	373.40
4F	Bifacial	Grass	374.40
4G	Bifacial	White	376.90
4H	Bifacial	Grass	377.00
5A	Bifacial	White	381.60
5B	Bifacial	Grass	381.10
5C	Monofacial	White	397.90
5D	Monofacial	Grass	398.50
5E	Bifacial	White	384.20
5F	Bifacial	Grass	384.10
6A	Bifacial	White	383.30
6B	Bifacial	Grass	378.50
6C	Bifacial	White	368.30
6D	Bifacial	Grass	370.70
7A	Monofacial	White	426.06
7B	Monofacial	Grass	423.40
8A	Monofacial	White	387.60
8B	Monofacial	Grass	387.10
8C	Bifacial	White	381.40
8D	Bifacial	Grass	384.00

7.4.1 DC Energy Production

The summation of the average daily energy produced for each module is shown tabularly in Table 7-6 through Table 7-9, and graphically in Figure 7-5 through Figure 7-8. As per Section 7.2.1, only the time periods where all systems were operational were used in these comparisons, except when specific systems were down for extended periods in which case those systems are marked with a “-“ and the data for the others systems is presented.

Table 7-6: Bifacial white average daily energy production per month- Wh/day

Start Date	End Date	1C	2C	3C	4C	4E	4G	5A	5E	6A	6C	8C
11/1/2020	11/30/2020	670.06	705.30	667.30	666.60	690.11	-	682.68	712.04	701.29	666.73	676.64
12/1/2020	12/31/2020	525.14	548.36	521.73	519.45	537.23	-	532.48	553.63	545.79	517.46	526.90
1/1/2021	1/31/2021	198.97	207.66	197.91	198.62	205.52	-	203.24	210.54	203.77	195.20	200.25
2/1/2021	2/28/2021	157.47	164.77	156.90	157.04	162.47	170.38	160.96	166.90	163.39	157.68	158.33
3/1/2021	3/31/2021	342.16	359.56	343.87	342.03	353.90	369.66	348.81	361.28	357.37	346.70	343.78
4/1/2021	4/30/2021	568.89	601.74	567.85	575.15	590.63	614.73	587.20	584.77	604.66	592.93	568.48
5/1/2021	5/31/2021	359.89	381.76	363.74	366.59	375.52	381.98	370.23	355.97	389.52	382.50	-
6/1/2021	6/30/2021	907.07	971.19	915.44	931.22	949.97	954.28	914.48	872.19	986.37	973.23	-
7/1/2021	7/31/2021	1140.18	1218.14	1129.67	1163.43	1188.88	1191.84	-	-	1235.22	1217.35	1126.13
8/1/2021	8/31/2021	418.47	443.56	414.37	427.55	433.18	438.80	-	-	450.19	443.89	413.08
9/1/2021	9/30/2021	959.42	1016.36	941.65	965.37	991.45	1022.31	987.27	973.11	1022.18	993.65	953.58
10/1/2021	10/31/2021	535.95	569.31	530.47	542.14	556.32	588.16	556.50	570.11	559.22	544.77	542.50

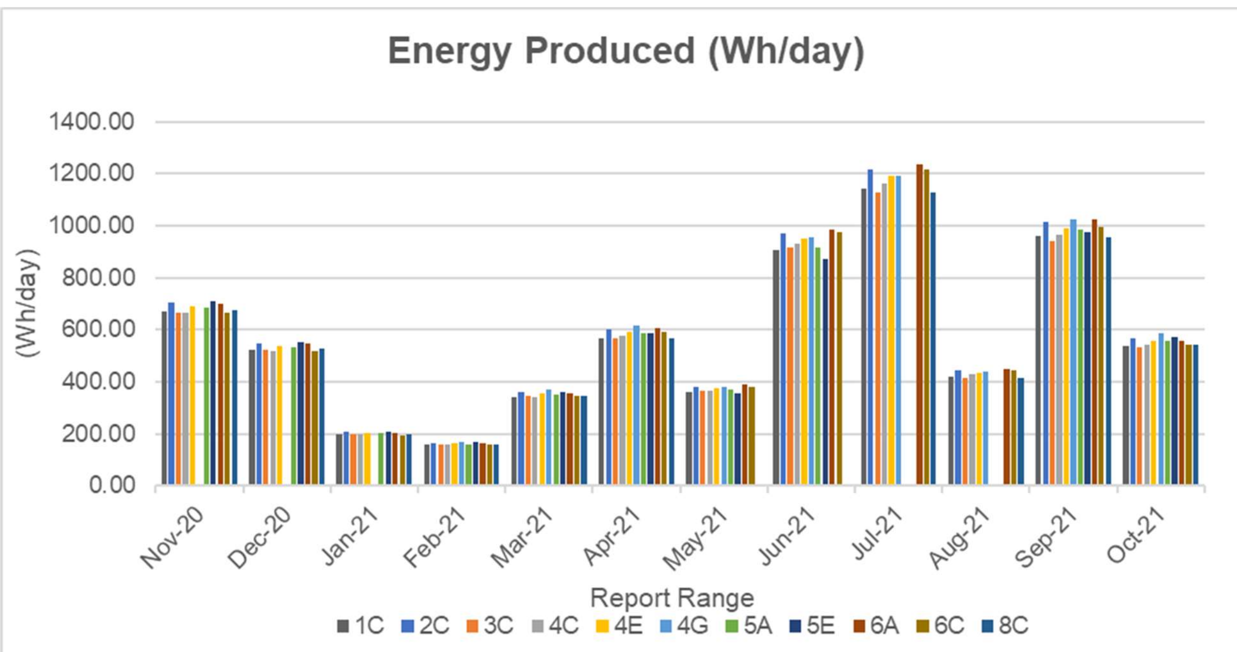

Figure 7-5: Average monthly energy produced – bifacial white

Table 7-7: Bifacial grass average daily energy production per month – Wh/day

Start Date	End Date	1D	2D	3D	4D	4F	4H	5B	5F	6B	6D	8D
11/1/2020	11/30/2020	632.62	669.65	633.81	647.83	649.72	-	648.79	686.95	650.26	639.87	645.85
12/1/2020	12/31/2020	491.50	515.86	490.41	501.13	501.61	-	502.42	531.51	499.57	492.39	499.09
1/1/2021	1/31/2021	182.05	191.29	183.21	186.65	188.56	-	187.98	196.64	182.06	179.60	186.90
2/1/2021	2/28/2021	143.46	151.44	144.52	147.40	148.96	157.25	148.18	154.46	145.68	143.76	146.90
3/1/2021	3/31/2021	317.61	335.17	319.14	324.15	328.57	344.22	325.90	336.45	326.01	319.53	322.18
4/1/2021	4/30/2021	543.47	575.94	542.71	553.01	563.21	583.92	552.04	553.28	571.12	556.48	550.85
5/1/2021	5/31/2021	343.31	366.35	345.07	353.38	358.49	356.92	351.23	338.19	368.70	359.38	-
6/1/2021	6/30/2021	872.78	935.18	875.09	899.72	913.13	893.18	886.42	823.84	950.29	925.14	-
7/1/2021	7/31/2021	1096.11	1174.51	1090.06	1126.44	1147.66	1106.39	-	-	1188.66	1160.36	1100.08
8/1/2021	8/31/2021	403.32	429.38	400.71	414.75	419.80	416.08	-	-	434.24	424.01	403.11
9/1/2021	9/30/2021	922.33	979.61	909.83	936.34	958.02	981.78	934.31	935.46	977.55	955.87	922.11
10/1/2021	10/31/2021	514.72	549.85	512.89	525.93	537.77	565.61	528.50	549.06	533.88	524.04	522.59

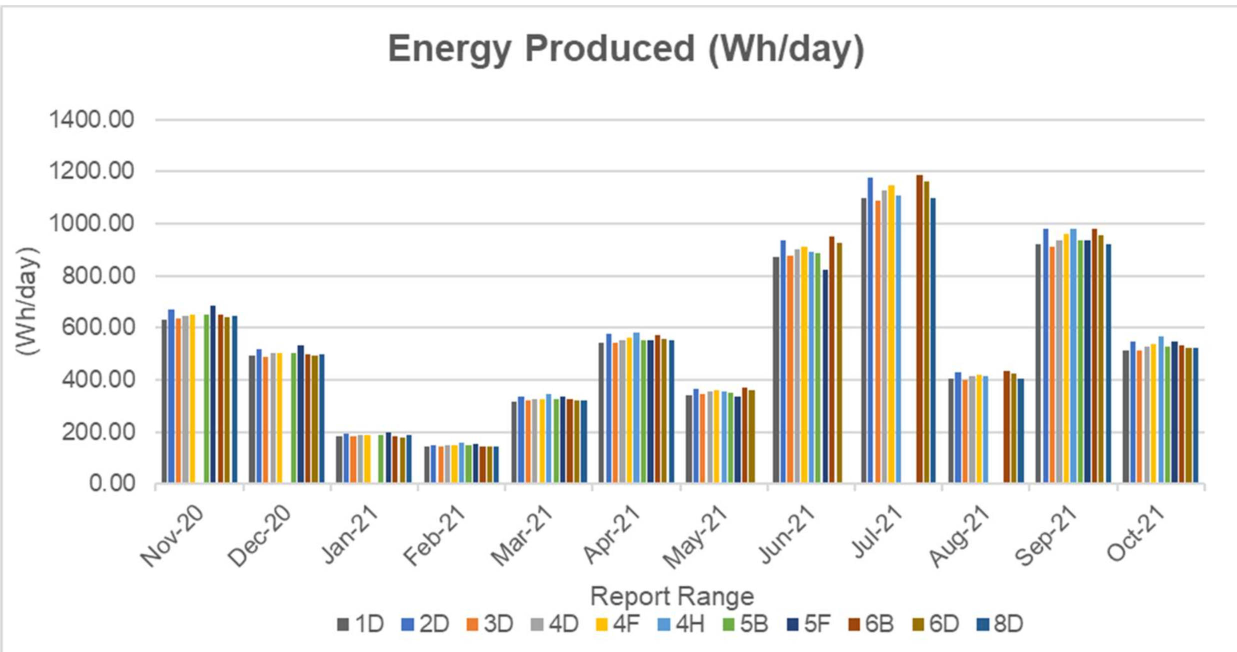

Figure 7-6: Average monthly energy produced – bifacial grass

Table 7-8: Monofacial white average daily energy production per month – Wh/day

Start Date	End Date	1A	2A	3A	4A	5C	7A	8A
11/1/2020	11/30/2020	614.31	636.23	610.39	618.74	637.84	634.14	617.47
12/1/2020	12/31/2020	479.19	493.36	473.12	480.40	494.64	484.33	479.42
1/1/2021	1/31/2021	178.99	184.58	178.05	181.14	186.41	193.78	181.18
2/1/2021	2/28/2021	140.83	145.67	140.77	143.59	147.45	156.02	142.19
3/1/2021	3/31/2021	308.91	319.53	310.15	315.57	323.23	344.21	311.90
4/1/2021	4/30/2021	519.58	547.59	531.23	542.27	539.31	607.31	541.58
5/1/2021	5/31/2021	332.65	349.11	341.38	348.46	334.22	403.69	-
6/1/2021	6/30/2021	839.26	881.14	863.97	882.75	805.75	-	-
7/1/2021	7/31/2021	1050.08	1105.77	1071.52	1103.92	-	-	1059.16
8/1/2021	8/31/2021	385.40	401.73	389.97	405.54	-	-	384.45
9/1/2021	9/30/2021	889.25	927.27	889.70	923.96	876.66	980.32	887.31
10/1/2021	10/31/2021	497.13	519.64	499.41	511.47	514.63	567.63	501.28

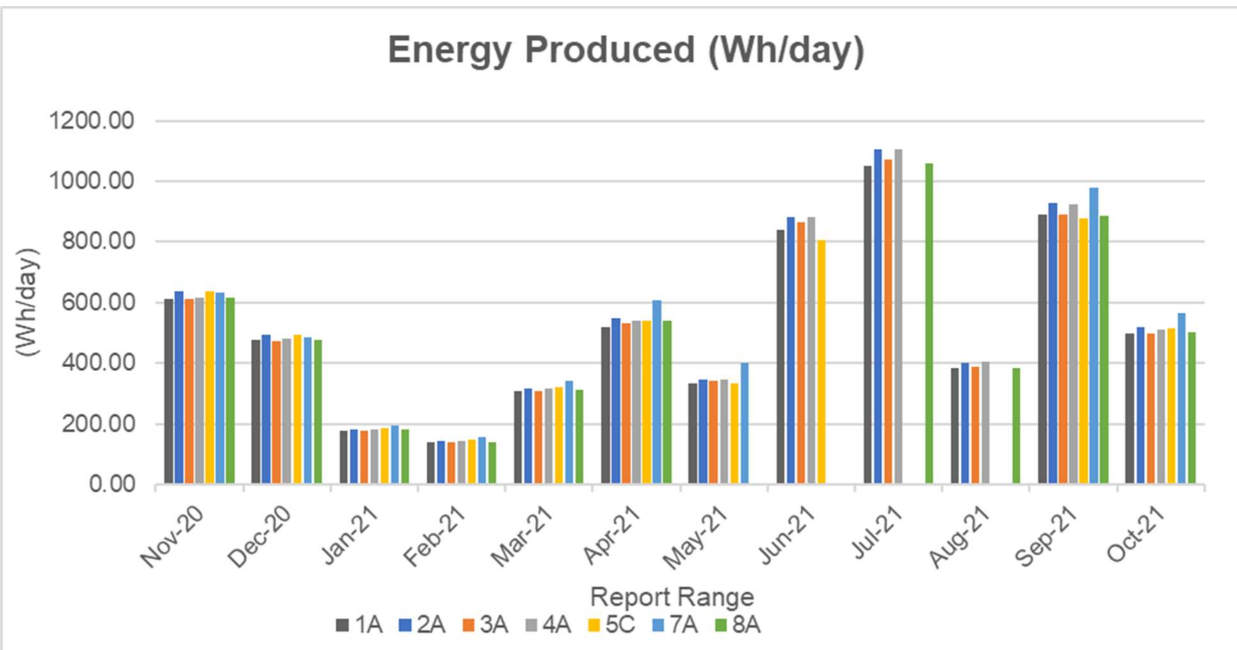

Figure 7-7: Average monthly energy produced – monofacial white

Table 7-9: Monofacial grass average daily energy production per month – Wh/day

Start Date	End Date	1B	2B	3B	4B	5D	7B	8B
11/1/2020	11/30/2020	622.25	636.08	613.16	629.33	632.82	655.01	614.71
12/1/2020	12/31/2020	484.13	492.36	474.71	487.13	491.22	502.71	477.20
1/1/2021	1/31/2021	179.48	183.01	177.28	181.60	184.09	199.77	179.33
2/1/2021	2/28/2021	141.68	145.17	139.68	144.04	146.06	168.04	140.91
3/1/2021	3/31/2021	311.84	319.83	308.90	316.87	321.53	349.65	309.98
4/1/2021	4/30/2021	529.59	553.41	529.07	539.92	546.34	608.72	538.09
5/1/2021	5/31/2021	339.30	352.17	338.41	346.66	341.44	403.90	-
6/1/2021	6/30/2021	859.91	893.08	856.36	881.74	833.45	-	-
7/1/2021	7/31/2021	1077.41	1117.93	1062.56	1099.80	-	-	1061.65
8/1/2021	8/31/2021	393.55	405.63	387.83	402.53	-	-	383.77
9/1/2021	9/30/2021	904.63	936.04	883.85	921.18	908.42	989.28	886.06
10/1/2021	10/31/2021	503.01	523.56	493.98	513.39	523.45	576.16	499.62

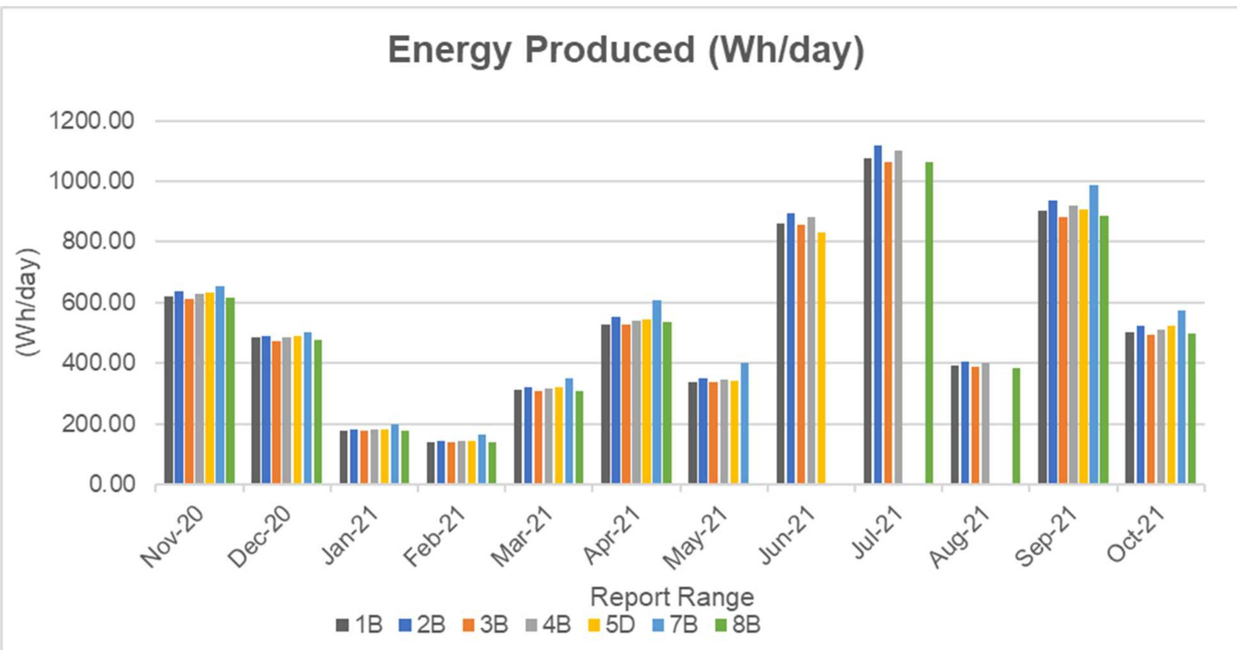

Figure 7-8: Average monthly energy produced – monofacial grass

7.4.2 Comparison of Bifacial gain

Bifacial gain is defined as the ratio of monthly energy yield from a bifacial module placed on a white/natural groundcover to the energy yield from a monofacial module on similar white/natural groundcover subtracted from unity. The monthly average bifacial gain for PV modules placed on white groundcover is shown in Table 7-10. Results show that bifacial gain for white groundcover bifacial modules is in the range of 8-18%.

Start Date	End Date	1	2	3	4	5	8
11-01-2020	11/30/2020	11%	11%	12%	10%	11%	12%
12-01-2020	12/31/2020	12%	11%	13%	10%	12%	11%
01-01-2021	1/31/2021	12%	12%	13%	13%	13%	13%
02-01-2021	2/28/2021	16%	13%	14%	14%	14%	14%
03-01-2021	3/31/2021	13%	13%	13%	11%	12%	11%
04-01-2021	4/30/2021	11%	10%	9%	9%	13%	6%
05-01-2021	5/31/2021	11%	10%	9%	7%	15%	
06-01-2021	6/30/2021	10%	11%	8%	8%	18%	
07-01-2021	7/31/2021	11%	11%	7%	7%		8%
08-01-2021	8/31/2021	12%	11%	9%	8%		9%
09-01-2021	9/30/2021	10%	10%	8%	7%	17%	9%
10-01-2021	10/31/2021	10%	10%	8%	8%	12%	10%

Table 7-10 Monthly average bifacial gain on white groundcover

Average bifacial gain for the PV modules mounted on natural groundcover is shown in Table 7-11. Results show that bifacial gain in the natural groundcover is in the range of 2-11%.

Start Date	End Date	1	2	3	4	5	8
11-01-2020	11/30/2020	4%	6%	4%	5%	6%	6%
12-01-2020	12/31/2020	3%	5%	5%	5%	7%	6%
01-01-2021	1/31/2021	4%	4%	4%	6%	7%	7%
02-01-2021	2/28/2021	3%	3%	5%	3%	5%	6%
03-01-2021	3/31/2021	4%	6%	5%	4%	5%	5%
04-01-2021	4/30/2021	5%	5%	4%	4%	5%	4%
05-01-2021	5/31/2021	3%	5%	3%	3%	7%	
06-01-2021	6/30/2021	3%	5%	4%	4%	11%	
07-01-2021	7/31/2021	4%	6%	4%	5%		5%
08-01-2021	8/31/2021	5%	6%	5%	5%		6%
09-01-2021	9/30/2021	4%	6%	4%	3%	7%	5%
10-01-2021	10/31/2021	4%	6%	5%	4%	5%	5%

Table 7-11 Monthly average bifacial gain on natural groundcover

7.4.3 Specific Energy Yield Comparison

To provide a normalized benchmark, energy yield normalized to PVEL's initial flash data is shown tabularly in Table 7-12 through Table 7-15, and graphically in Figure 7-10 through Figure 7-18. These specific energy yield values have been calculated as per Equation 1:

$$Y = \sum_{i=0}^{n} \frac{P_{mpp,i}}{P_{mpp,f0}} \Delta t$$

$$P_{mpp,i} = Instantaneous\ power$$
$$P_{mpp,f0} = Peak\ power\ of\ system$$

Equation 1: Yield Calculation

Comparing the results from the bifacial and monofacial datasets shows that higher specific energy yields were achieved for bifacial modules, and that the bifacial white had the highest values amongst all four datasets.

Table 7-12: Bifacial white average daily energy yield per month - Wh/Wp/day

Start Date	End Date	1C	2C	3C	4C	4E	4G	5A	5E	6A	6C	8C
11/1/2020	11/30/2020	1.85	1.88	1.80	1.77	1.84	-	1.79	1.85	1.90	1.81	1.78
12/1/2020	12/31/2020	1.45	1.46	1.41	1.38	1.43	-	1.40	1.44	1.48	1.40	1.38
1/1/2021	1/31/2021	0.55	0.55	0.53	0.53	0.55	-	0.53	0.55	0.55	0.53	0.53
2/1/2021	2/28/2021	0.44	0.44	0.42	0.42	0.43	0.45	0.42	0.43	0.44	0.43	0.42
3/1/2021	3/31/2021	0.95	0.96	0.93	0.91	0.95	0.98	0.91	0.94	0.97	0.94	0.90
4/1/2021	4/30/2021	1.57	1.60	1.53	1.53	1.58	1.63	1.54	1.52	1.64	1.61	1.49
5/1/2021	5/31/2021	1.00	1.02	0.98	0.97	1.00	1.01	0.97	0.93	1.06	1.04	-
6/1/2021	6/30/2021	2.51	2.59	2.47	2.48	2.54	2.53	2.40	2.27	2.67	2.64	-
7/1/2021	7/31/2021	3.15	3.24	3.04	3.09	3.17	3.16	-	-	3.35	3.30	2.96
8/1/2021	8/31/2021	1.16	1.18	1.12	1.14	1.16	1.16	-	-	1.22	1.20	1.08
9/1/2021	9/30/2021	2.65	2.71	2.54	2.57	2.65	2.71	2.59	2.53	2.77	2.69	2.50
10/1/2021	10/31/2021	1.48	1.52	1.43	1.44	1.49	1.56	1.46	1.48	1.51	1.48	1.42

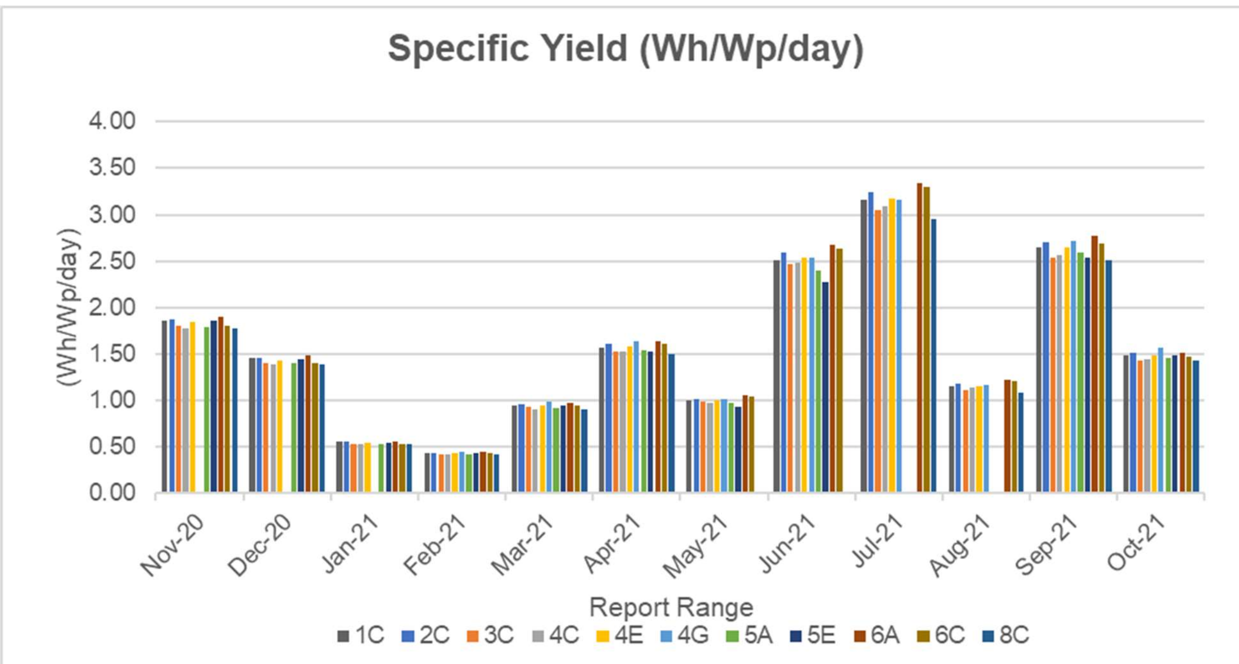

Figure 7-9: Average monthly specific energy yield – bifacial white

Table 7-13: Bifacial grass average daily energy yield per month - Wh/Wp/day

Start Date	End Date	1D	2D	3D	4D	4F	4H	5B	5F	6B	6D	8D
11/1/2020	11/30/2020	1.74	1.79	1.70	1.72	1.74	-	1.69	1.79	1.69	1.68	1.69
12/1/2020	12/31/2020	1.35	1.38	1.32	1.33	1.34	-	1.31	1.38	1.30	1.29	1.30
1/1/2021	1/31/2021	0.50	0.51	0.49	0.50	0.50	-	0.49	0.51	0.47	0.47	0.49
2/1/2021	2/28/2021	0.39	0.40	0.39	0.39	0.40	0.42	0.39	0.40	0.38	0.38	0.38
3/1/2021	3/31/2021	0.87	0.90	0.86	0.86	0.88	0.91	0.85	0.88	0.85	0.84	0.84
4/1/2021	4/30/2021	1.50	1.54	1.46	1.47	1.51	1.55	1.44	1.44	1.49	1.46	1.44
5/1/2021	5/31/2021	0.95	0.98	0.93	0.94	0.96	0.95	0.92	0.88	0.96	0.94	-
6/1/2021	6/30/2021	2.40	2.50	2.35	2.39	2.44	2.37	2.31	2.15	2.48	2.43	-
7/1/2021	7/31/2021	3.02	3.14	2.93	3.00	3.07	2.93	-	-	3.10	3.05	2.87
8/1/2021	8/31/2021	1.11	1.15	1.08	1.10	1.12	1.10	-	-	1.13	1.11	1.05
9/1/2021	9/30/2021	2.54	2.62	2.44	2.49	2.56	2.60	2.44	2.44	2.55	2.51	2.41
10/1/2021	10/31/2021	1.42	1.47	1.38	1.40	1.44	1.50	1.38	1.43	1.39	1.38	1.36

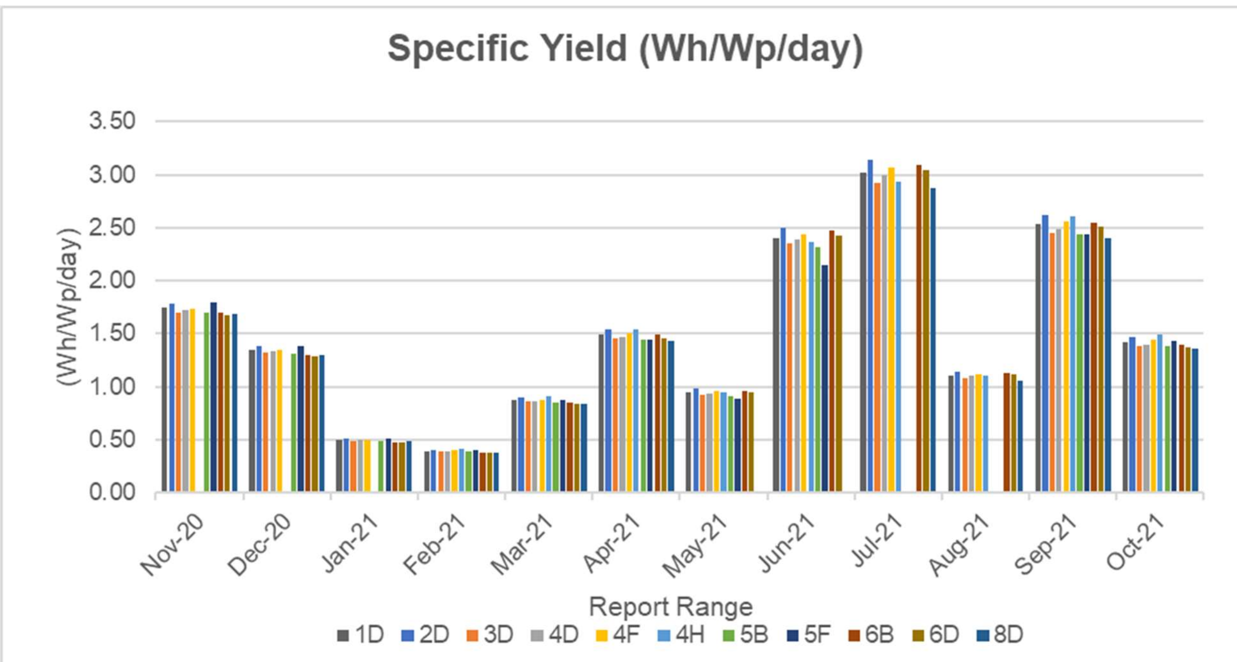

Figure 7-10: Average monthly specific energy yield – bifacial grass

Table 7-14: Monofacial white average daily energy yield per month - Wh/Wp/day

Start Date	End Date	1A	2A	3A	4A	5C	7A	8A
11/1/2020	11/30/2020	1.67	1.69	1.61	1.61	1.61	1.49	1.59
12/1/2020	12/31/2020	1.30	1.31	1.25	1.25	1.25	1.14	1.24
1/1/2021	1/31/2021	0.49	0.49	0.47	0.47	0.47	0.46	0.47
2/1/2021	2/28/2021	0.38	0.39	0.37	0.37	0.37	0.37	0.37
3/1/2021	3/31/2021	0.84	0.85	0.82	0.82	0.81	0.81	0.81
4/1/2021	4/30/2021	1.41	1.45	1.41	1.41	1.36	1.43	1.40
5/1/2021	5/31/2021	0.90	0.93	0.90	0.91	0.84	0.95	-
6/1/2021	6/30/2021	2.28	2.34	2.29	2.30	2.03	-	-
7/1/2021	7/31/2021	2.85	2.93	2.83	2.88	-	-	2.73
8/1/2021	8/31/2021	1.04	1.06	1.03	1.06	-	-	0.99
9/1/2021	9/30/2021	2.41	2.46	2.35	2.41	2.21	2.31	2.29
10/1/2021	10/31/2021	1.35	1.38	1.32	1.33	1.30	1.34	1.29

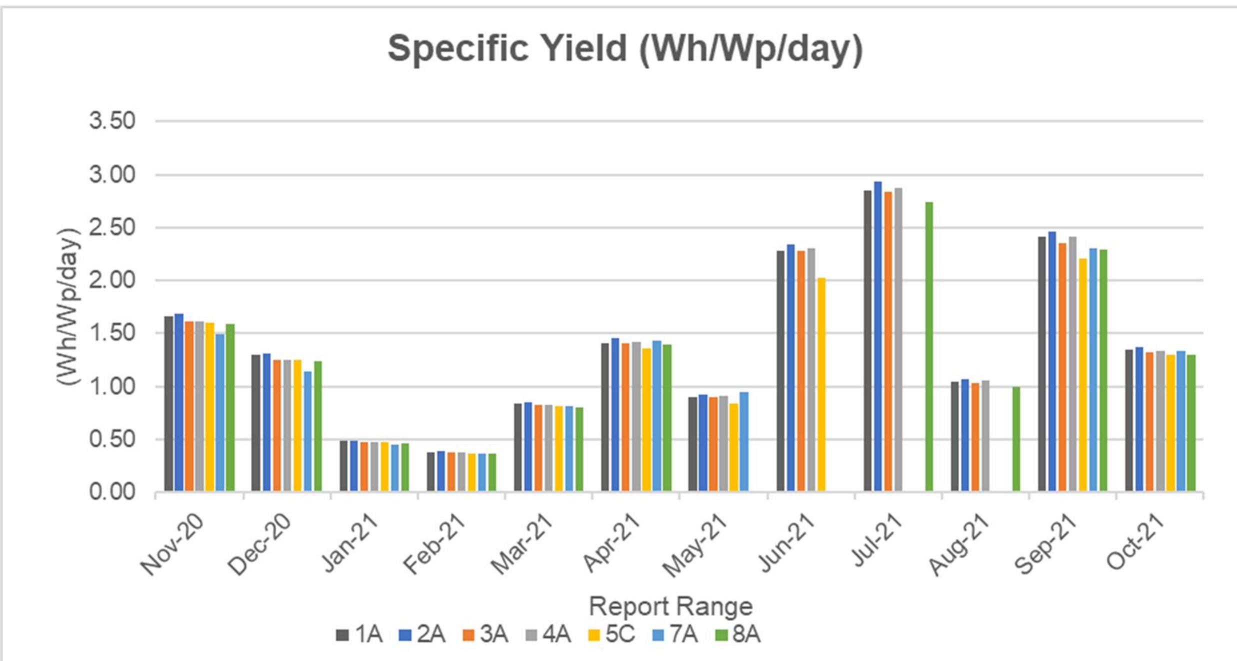

Figure 7-11: Average monthly specific energy yield – monofacial white

Table 7-15: Monofacial grass average daily energy yield per month - Wh/Wp/day

Start Date	End Date	1B	2B	3B	4B	5D	7B	8B
11/1/2020	11/30/2020	1.68	1.69	1.63	1.64	1.59	1.54	1.59
12/1/2020	12/31/2020	1.31	1.31	1.26	1.27	1.23	1.18	1.23
1/1/2021	1/31/2021	0.48	0.49	0.47	0.47	0.46	0.47	0.46
2/1/2021	2/28/2021	0.38	0.39	0.37	0.38	0.37	0.40	0.36
3/1/2021	3/31/2021	0.84	0.85	0.82	0.83	0.81	0.82	0.80
4/1/2021	4/30/2021	1.43	1.47	1.40	1.41	1.37	1.43	1.39
5/1/2021	5/31/2021	0.92	0.93	0.90	0.91	0.86	0.95	-
6/1/2021	6/30/2021	2.32	2.37	2.27	2.30	2.09	-	-
7/1/2021	7/31/2021	2.91	2.97	2.82	2.87	-	-	2.74
8/1/2021	8/31/2021	1.06	1.08	1.03	1.05	-	-	0.99
9/1/2021	9/30/2021	2.44	2.48	2.34	2.41	2.28	2.33	2.29
10/1/2021	10/31/2021	1.36	1.39	1.31	1.34	1.31	1.36	1.29

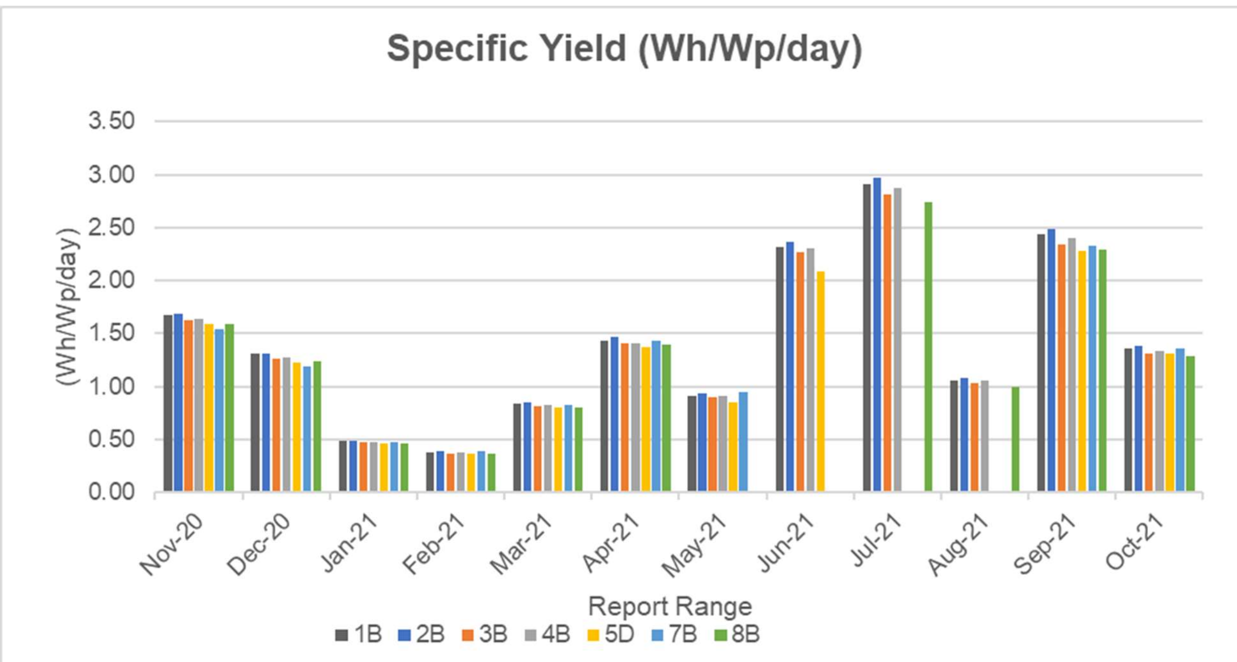

Figure 7-12: Average monthly specific energy yield – monofacial grass

7.5 Simulation Results

Energy models were conducted for manufacturer 1A's monofacial and bifacial 1500V strings. This manufacturer was selected as having the most days of useable measured data after filtering. PVEL completed the PVsyst simulations directly, and provided modeling inputs to DNV's Solar Farmer and Terabase's Plant Predict so that those organizations could perform simulations and provide results to PVEL for incorporation into this report. The results of these three energy models are included in this section, including a comparison of the expected (modelled) results versus actual (measured) results and recommendations on how these models can be improved.

7.5.1 Measured Data Filtration

To achieve an accurate comparison between modelled and measured results, the measured data needed to be filtered. The following filters were applied to the measured dataset to remove erroneous measured data:

- Exclude periods of missing environmental data (GHI, ambient temperature, or wind speed).
- Exclude hours where GHI < 50 W/m^2.
- Exclude hours where visual inspection suggests a monitoring or performance issue.

A visual inspection of measured data was then performed to remove additional cases of erroneous data. Examples of such erroneous data are included below:

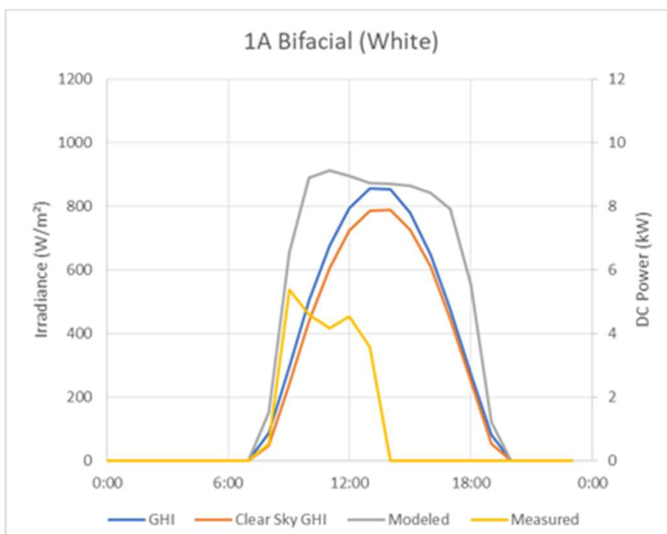

Figure 7-13: Erroneous measured data from 9/17/19

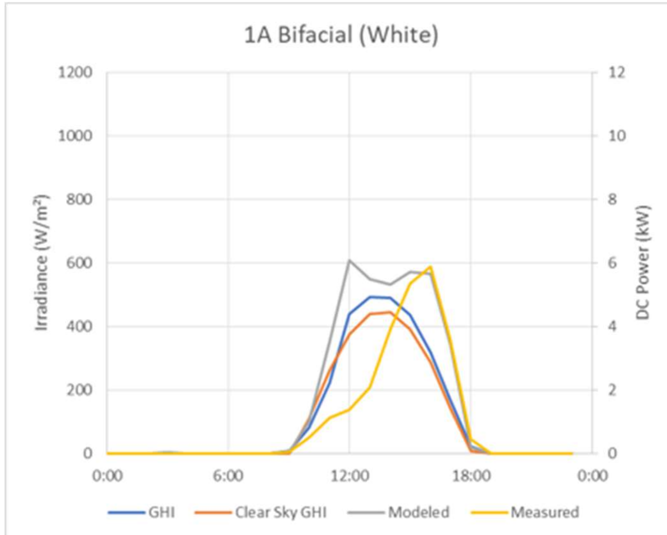

Figure 7-14: Erroneous measured data from 12/23/19 due to a stalled tracker

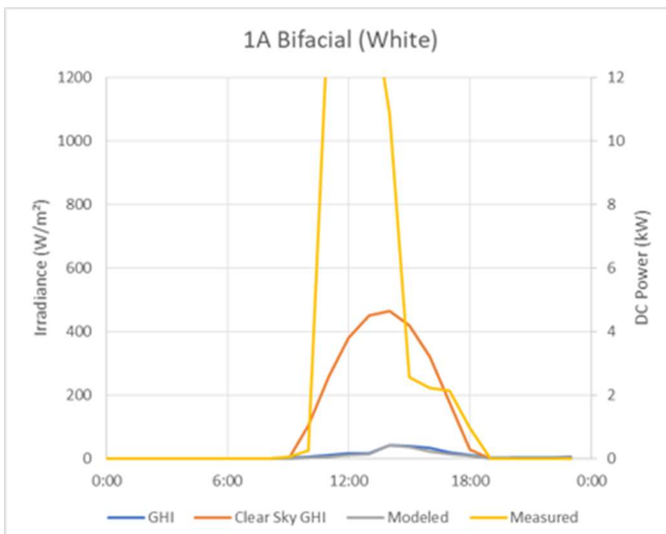

Figure 7-15: Erroneous measured data from 1/9/20 due to a power measurement issue

Following this filtration, there were determined to be 438 days / 4382 hours of valid data. Of these, there were 3885 hours of clear sky conditions (≥0.6 clearness ratio) and 497 hrs of cloudy conditions (<0.6 clearness ratio). The monthly breakdown of valid data is shown below:

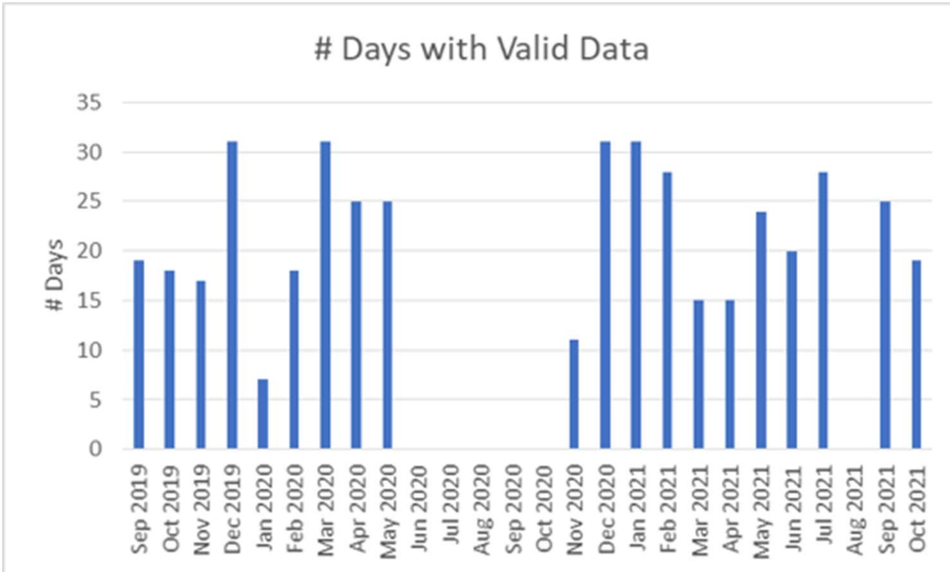

Figure 7-16: Number of days of valid data per month over the extended study period

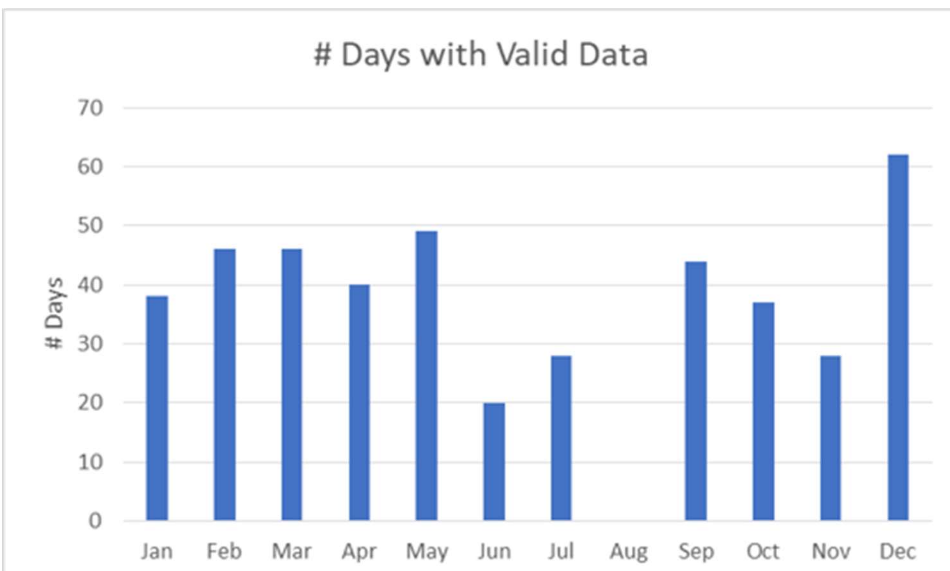

Figure 7-17: Number of days of valid data aggregated per month

7.5.1.1 Modeling Inputs

The following table of input assumptions were used for the energy simulations along with the average measured monthly albedo values, and the hourly measured GHI, ambient temperature and windspeed.

Model Parameter	Unit	1 A Mono White	1 A Bifi White	1 A Mono Grass	1 A Bifi Grass
Latitude	°N	38.5814	38.5814	38.5814	38.5814
Longitude	°W	-121.7332	-121.7332	-121.7332	-121.7332
Altitude	M	16	16	16	16
UTC Offset	--	-8	-8	-8	-8
Site Albedo	%	TBD	TBD	TBD	TBD
Modules in Series	--	28	28	28	28
Module in Parallel	--	1	1	1	1
Tilt	°	N/A	N/A	N/A	N/A
Azimuth	°	N/A	N/A	N/A	N/A
Number of Sheds	--	100	100	100	100
Collector Pitch	m	5.18	5.18	5.18	5.18
Collector Width	m	2.01	2.01	2.01	2.01
Ground Fraction Beam (Calc.)	%	N/A (Mono-facial)	46.90%	N/A (Mono-facial)	46.90%
Ground Factor Diffuse (Calc.)	%	N/A (Mono-facial)	61.10%	N/A (Mono-facial)	61.10%
Ground Factor Global (Calc.)	%	N/A (Mono-facial)	50.30%	N/A (Mono-facial)	50.30%
Shed Transparent Fraction	%	N/A (Mono-facial)	0%	N/A (Mono-facial)	0%
Reemission Form Factor (Calc.)	%	N/A (Mono-facial)	37.40%	N/A (Mono-facial)	37.40%
Structure Shading Factor	%	N/A (Mono-facial)	5.00%	N/A (Mono-facial)	5.00%
Bifacial Mismatch Loss Factor	%	N/A (Mono-facial)	10.00%	N/A (Mono-facial)	10.00%
Height Above Ground	m	N/A (Mono-facial)	1.22	N/A (Mono-facial)	1.22
Module Model	--	1 A Mono 365 W	1 A Bifi 365 W	1 A Mono 365 W	1 A Bifi 365 W
Module Bifaciality Factor	%	N/A (Mono-facial)	77.00%	N/A (Mono-facial)	77.00%
Inverter Model	--	125 kW PV Inverter	125 kW PV Inverter	125 kW PV Inverter	125 kW PV Inverter
Soiling	%	3	3	3	3
Module Mismatch MPP	%	1	1	1	1
Module Mismatch Fixed Voltage	%	2.5	2.5	2.5	2.5
String Mismatch	%	0.1	0.1	0.1	0.1
Module Quality Factor	%	1.4%(gain)	0.8%(loss)	1.4%(gain)	0.8%(loss)
Light-induced Degradation	%	0.2%(gain)	0.7%(gain)	0.2%(gain)	0.7%(gain)

Model Parameter	Unit	1 A Mono White	1 A Bifi White	1 A Mono Grass	1 A Bifi Grass
DC Wire Loss	%	1.5	1.5	1.5	1.5
Min. Tracker Rotation Angle	°	-60	-60	-60	-60
Max. Tracker Rotation Angle	°	60	60	60	60
Module Width	m	0.99	0.998	0.99	0.998
Module Length	m	1.954	1.98	1.954	1.98
Number of Cells in Module	--	72 series x 1 parallel=72 Cells	72 series x 1 parallel=72 Cells	72 series x 1 parallel=72 Cells	72 series x 1 parallel=72 Cells
Short-circuit Current	A	9.75	9.62	9.75	9.62
Open-circuit Voltage	V	47.82	48.54	47.82	48.54
Current at MPP	A	9.27	9.12	9.27	9.12
Voltage at MPP	V	39.38	40.04	39.38	40.04
Temperature Coefficient of Isc	A/°C	0.00419	0.00419	0.00419	0.0041925
Temperature Coefficient of Gamma	1/°C	-0.042%	-0.052%	-0.042%	-0.052%
Lower Power Tolerance	%	3	3	3	3
Upper Power Tolerance	%	3	3	3	3
Series Resistance	Ohm	0.294	0.315	0.294	0.315
Shunt Resistance at 0 W/m^2	Ohm	500	400	500	400
Shunt Resistance at 1000 W/m^2	Ohm	2000	1600	2000	1600
Shunt Resistance Exponential Term	--	5.5	5.5	5.5	5.5
Incidence Angle Modifier	--	Fresnel (Air=1.526, ARC=1.29)	Fresnel (Air=1.526, ARC=1.29)	Fresnel (Air=1.526, ARC=1.29)	Fresnel (Air=1.526, ARC=1.29)
Temperature Delta, Backsheet to Cell	°C	N/A; Tcell=f (Uc,Uv,G,Ta,Ws)	N/A; Tcell=f (Uc,Uv,G,Ta,Ws)	N/A; Tcell=f (Uc,Uv,G,Ta,Ws)	N/A; Tcell=f (Uc,Uv,G,Ta,Ws)
Reference POA Irradiance at STC	W/m^2	1000	1000	1000	1000
Reference Cell Temperature at STC	°C	25	25	25	25
Thermal Conduction Coeff. (U_c)	$W/m^2 \cdot K$	23 (empirical avg.: Davis, CA)	23 (empirical avg.: Davis, CA)	23 (empirical avg.: Davis, CA)	23 (empirical avg.: Davis, CA)
Thermal Convection Coeff. (U_v)	$W/m^2 \cdot K/m/s$	6.3 (empirical avg.; Davis, CA)	6.3 (empirical avg.; Davis, CA)	6.3 (empirical avg.; Davis, CA)	6.3 (empirical avg.; Davis, CA)
PVsyst Equivalent NOCT	°C	45	45	45	45

Table 7-16: PVsyst modeling inputs

Multiple modeling runs were completed representing three different portions of the study period (Sep 2019 – Sep 2020, Jan 2020 – Dec 2020, and Oct 2020 – Oct 2021), and four subsystems (bifacial/monofacial, white/grass) . Leap day (2/29/20) was not included. Each system was modelled as having multiple identical strings with the results divided by the number of modelled strings to get the single string output.

7.5.1.2 Discussion on Modeling Inputs

The various modeling inputs are discussed below. Some of these are specific to the PVsyst simulation, as noted.

Meteorological Data

Solar insolation and meteorological conditions strongly influence PV system production. Energy simulation estimates by extension are largely dependent on accurate weather file selection. Quality assessment of weather input files consider such factors as site proximity, data quality, period of record, method of data generation/creation, and their associated uncertainties.

For the energy simulations, the meteorological data file was created from measured on-site data.

PV Module and Inverter Selection

The temperature and irradiance dependence of a PV module’s electrical parameters are captured for PVsyst simulations within an input file called a .PAN file. The .PAN file for the selected module type was generated by PVEL using IEC 61853-1 flash test measurements and PVEL’s .PAN optimization process.

PVsyst also requires an input file for PV inverters, referred to as an .OND file. The .OND file for the selected inverter was generated by PVEL, developed based on datasheet values.

Tracker Inputs and Loss Considerations

The tracker systems had single modules in portrait attached at their frames to mounting brackets. These brackets were connected to a supporting torque tube that was driven by a motor situated at the mid-point of the tracker row. Additionally, more subtle variations in the placement of ancillary equipment, as well as the way in which the tracker rows rotate, result in different rear-side shading profiles when bifacial PV modules are installed. The main variables impacting this gain are the tracker structure rear shading loss, transparency of the tracker shed, and bifacial rear-side mismatch. Rear-side mismatch, transparency, and rear-side shading are driven by structural obstructions of the tracker underneath the array, such as the piers, bearings, and mounting rails and brackets of the modules. The gap between bearings, spacing of piers, drive motor placement, and wire management design all can affect rear-side mismatch, transparency, and the rear-side shading factor. This in turn affects the amount of solar isolation that the rear side of the PV module may be exposed to.

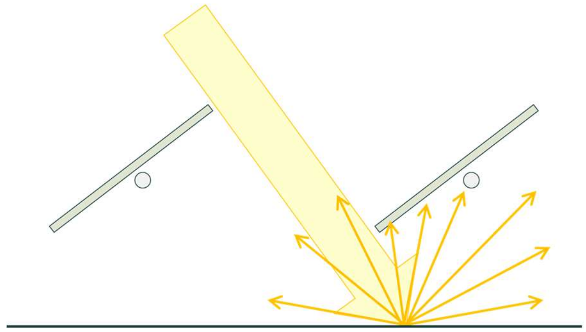

Figure 7-18: Module rear-side illumination diagram. Source: PV Lighthouse.

Figure 7-18 above shows a simplified diagram of light rays reaching the back side of a PV module that is mounted on a tracker. Light passes between modules, reflects off the ground, and hits the back of the modules at a wide range of incident angles, with the reflection being almost entirely isotropic. The total irradiance that hits the back of the module varies as a function of time of day, time of year, site conditions, and tracker design, and is attenuated by other obstructions between the back of the module and the ground. There are several factors in PVsyst that capture these considerations.

Other System Loss Factors

In addition to weather and equipment selection, structural and electrical system design parameters contribute significantly to estimated production. They must be carefully considered in the estimation of PV system losses. Information sources included the preliminary site layout drawing, equipment specifications, client-provided documentation, as well as PVEL's experience to accurately account for expected losses.

Irradiance Transposition Model

PVsyst allows users to convert global horizontal irradiance into front-side plane-of-array (POA) irradiance by using either the Perez or Hay transposition model. The Perez model was selected, which typically yields a higher result and is the more commonly used of the two models in the industry today. The Hay model might reduce the POA irradiance by approximately 2%, but Perez is typically used when diffuse irradiance data is available, as was the case in this project.

Soiling Consideration

Soiling is a complex environmental input that is typically estimated outside of PVsyst before inclusion as a set of monthly averages.

Incident Angle Modifier

The Incident Angle Modifier (IAM) factor represents a reduction in irradiance reaching the solar cell due to the irradiance partially reflecting off the front glass, particularly at low angles of light. The IAM factors applied were based on the profile included in the .PAN file.

Light-induced Degradation

Light-induced degradation (LID) is a specific type of initial performance degradation that is known to occur in PV modules constructed of solar cells that are based on positively doped (p-type) crystalline silicon wafers. The loss mechanism is understood to be the result of boron reacting with interstitial oxygen within the solar cells under lighted conditions.

PV Module Temperature Loss

PV system performance is highly dependent on irradiance and temperature conditions. PV module power output is linearly correlated with plane-of-array irradiance, except for during low irradiance conditions (less than 200 W/m^2), in which performance is significantly reduced. Performance is also largely dependent on operating temperature and degrades at a consistent rate while temperature increases, as typically specified in the form of PV module temperature coefficients.

Mismatch/Wire Loss

Individual PV modules within a string have slight variations in their maximum operating voltage and current due to normal variations in the manufacturing process. Because PV modules are electrically connected in series and are controlled by an inverter using a maximum power point tracking (MPPT) algorithm, each PV module typically operates slightly off its ideal power. Resulting effects are known as “mismatch” losses.

DC and AC ohmic losses are primarily dependent on PV system wiring design and configuration.

Module Quality Loss Factor

The Module Quality Loss factor is typically used to include other losses that are not otherwise captured and often registers as a gain based on the effects of positive nameplate binning, when applicable.

Annual Degradation

Annual degradation rate is typically defined as the annual change in PV system performance (e.g., power at STC) or energy. Annual degradation is typically a negative value on average, meaning the PV modules and system degrade over time. However, some technologies or systems may show positive rates or no change for some period. The simulation results do not incorporate annual degradation.

7.5.2 Expected Vs. Actual Comparison (PVsyst)

This section presents the results of PVsyst modeling compared to the actual site performance.

7.5.2.1 Results Overview

On average, PVsyst under-predicted bifacial energy gain. For the white surface, measured bifacial gain was 1.8% higher than modeled. For the grass surface, measured bifacial gain was 1.1% higher than modeled. While cloudy conditions accounted for only <10% of hours and <5% of energy production, the bifacial energy gain errors differed for clear vs. cloudy conditions as shown in Figure 7-19. For the white surface, model error was greater under cloudy conditions. For the grass surface, model error was greater under clear conditions.

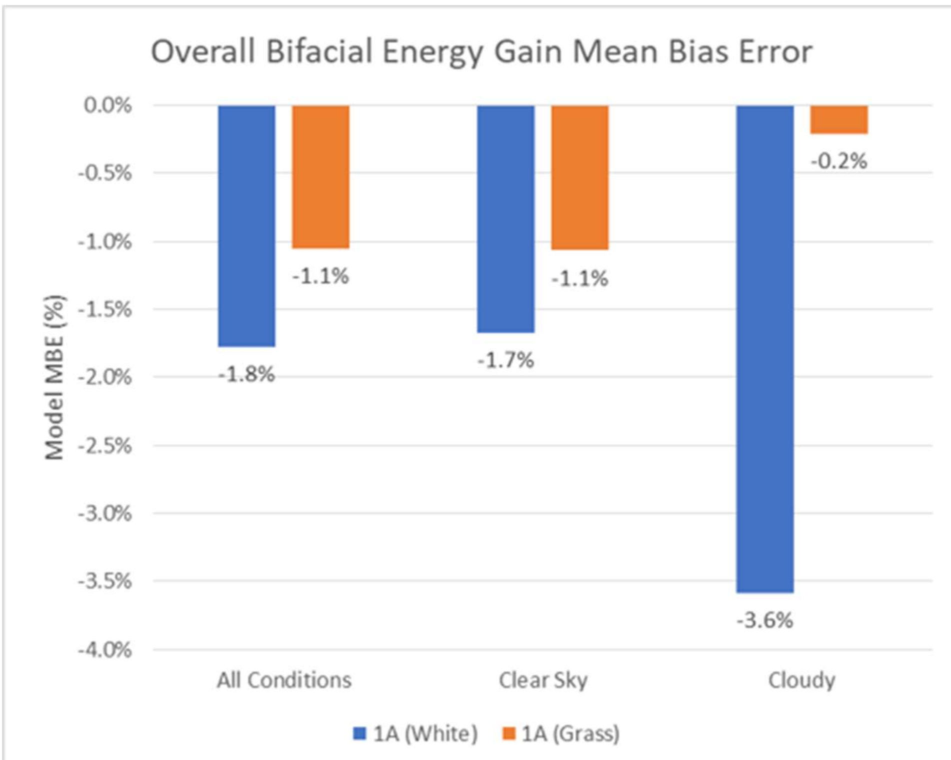

Figure 7-19: Overall bifacial energy gain mean bias error per weather condition

PVsyst energy production modeling errors (mean bias error & root mean square error) were comparable in magnitude for the bifacial and monofacial systems on a daily, monthly, and overall basis.

Daily and monthly fluctuations in model accuracy for predicting bifacial energy gain were likely driven by varying levels of on-site soiling, seasonal biases in the PVsyst model and/or differing sources of model bias under clear versus cloudy conditions.

The final dataset of measured versus modelled per DC power output for the two bifacial strings for grass and white are shown in Figure 7-20 and Figure 7-21, respectively.

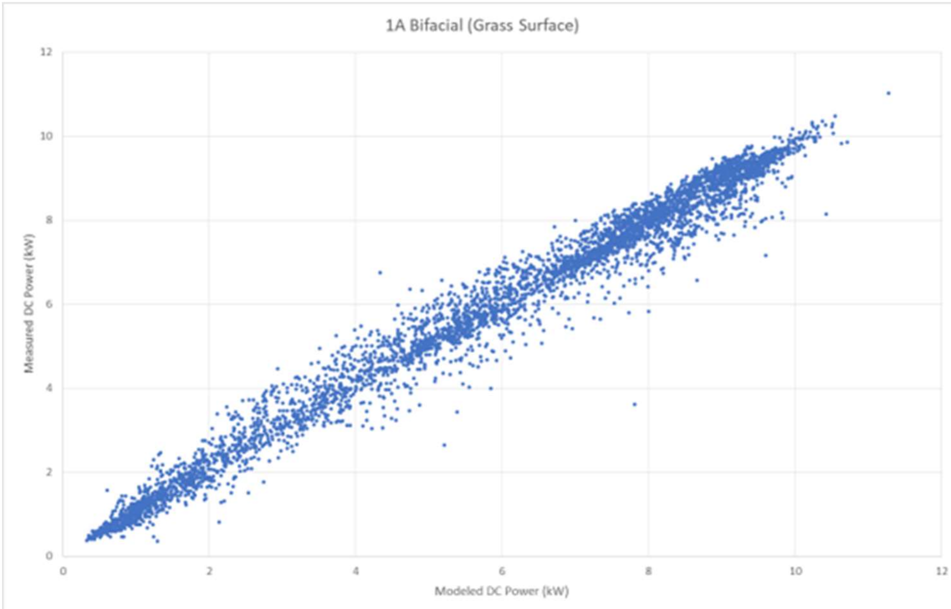

Figure 7-20: Bifacial measured versus modeled per dc power output - grass

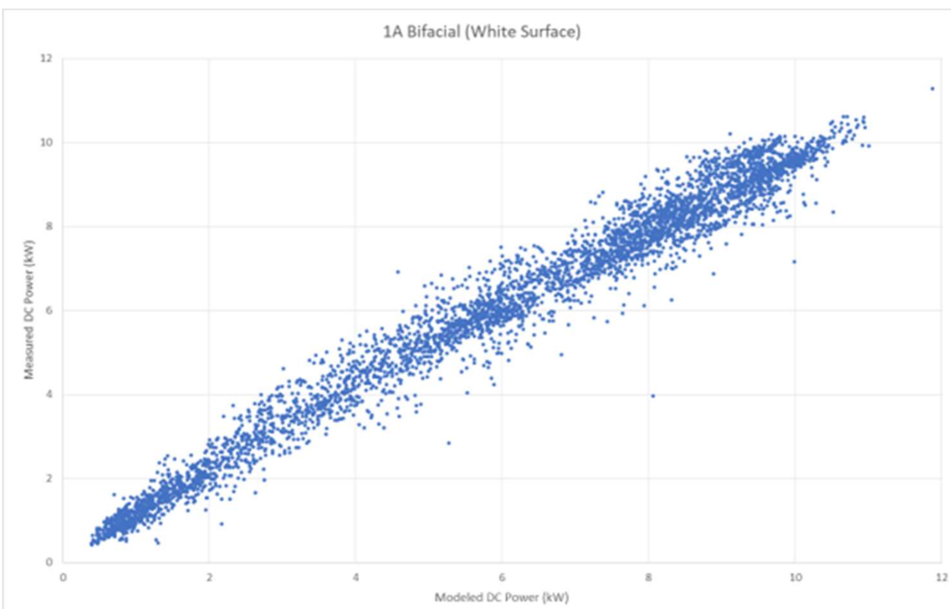

Figure 7-21: Bifacial measured versus modeled per dc power output - white

7.5.2.2 Results Discussion – Cloudy Versus Clear Sky

A stated above, for the white surface, model error was greater under cloudy conditions. For the grass surface, model error was greater under clear conditions.

With all months and weather conditions combined, Figure 7-22 shows that the highest model error (i.e. the largest gap between modeled and measured), occurs during the winter months for the white groundcover dataset. This not the case for the grass groundcover, where there is no seasonal trend for model error, as shown in Figure 7-23.

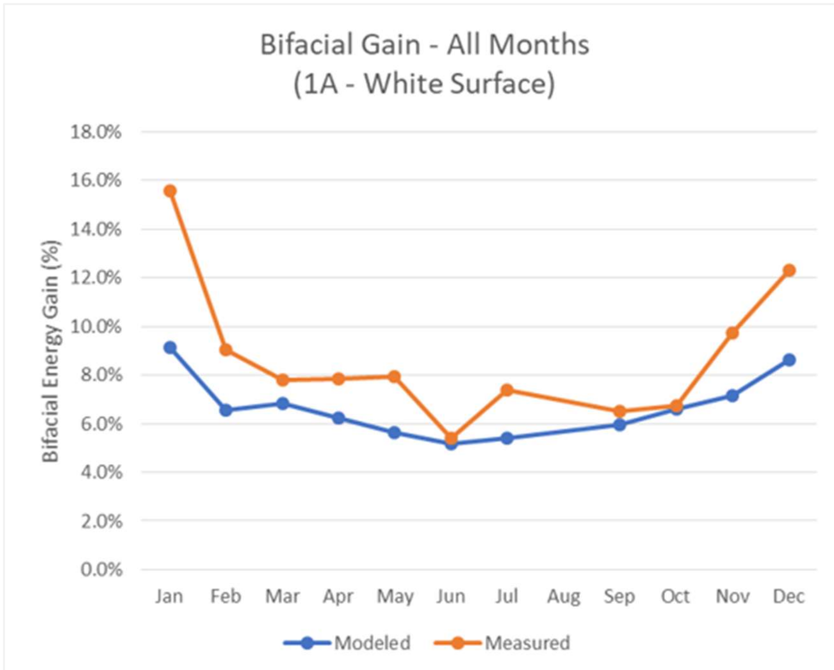

Figure 7-22: Modeled and measured, all months and conditions combined - white

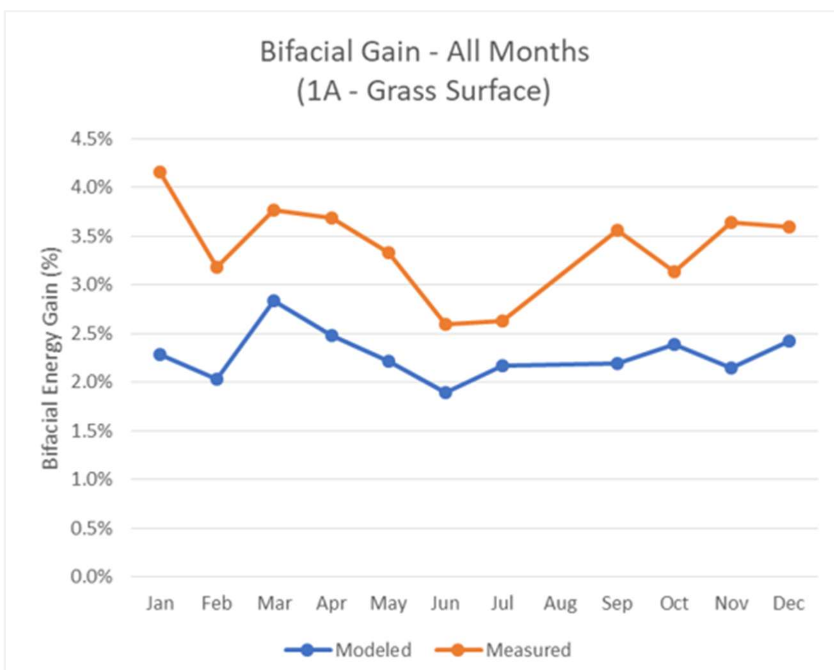

Figure 7-23: Modeled and measured, all months and conditions combined - grass

Filtering these datasets into clear sky and cloudy conditions did not reveal any additional seasonal trends as similar results can be observed when filtering the above dataset for only clear sky conditions, as shown for white in Figure 7-24 and grass in Figure 7-25.

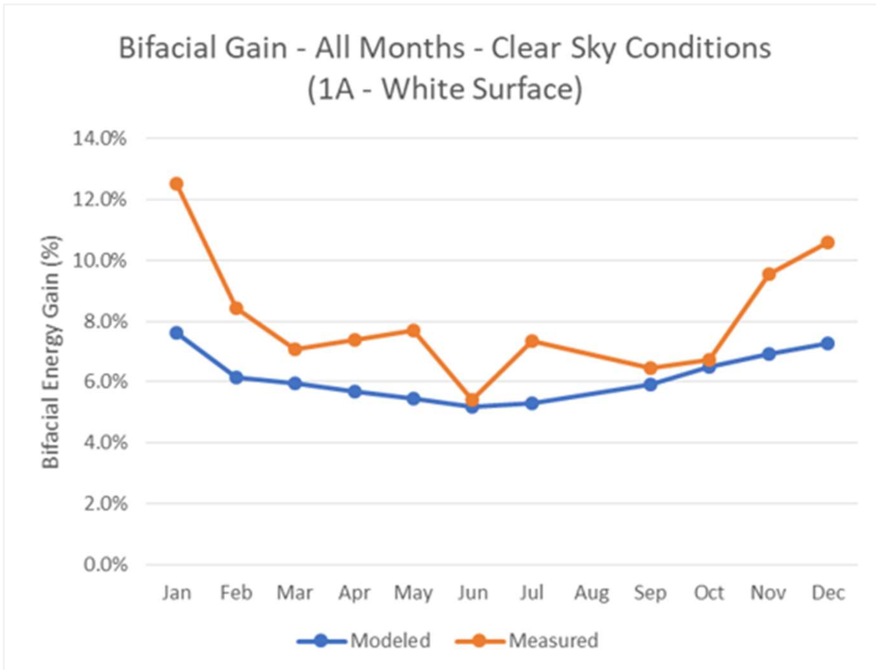

Figure 7-24: Modeled and measured, all months combined, clear sky only - white

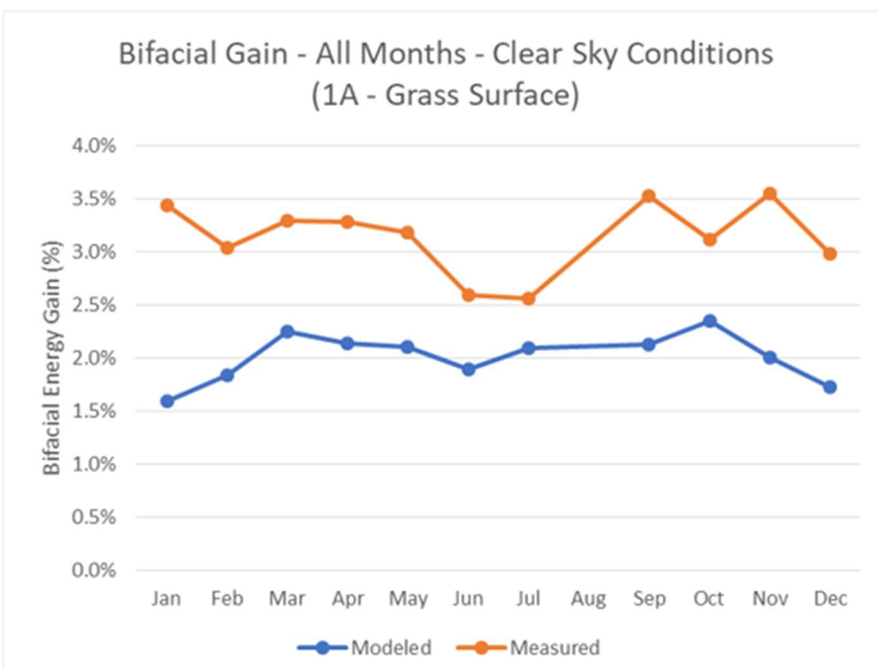

Figure 7-25: Modeled and measured, all months combined, clear sky only - grass

There are no seasonal trends observed for bifacial gain model error during cloud conditions, as shown in Figure 7-26 and Figure 7-27.

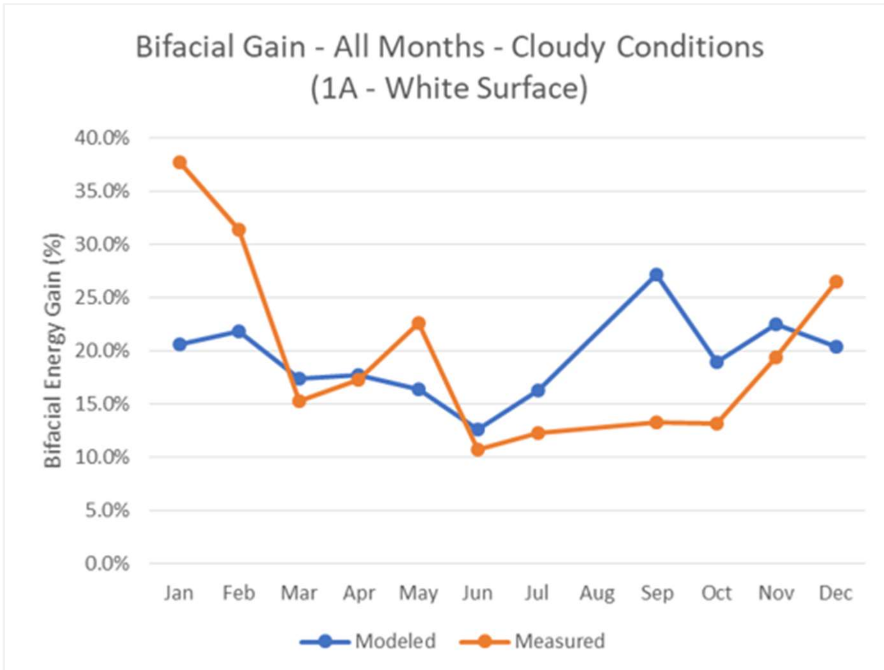

Figure 7-26: Modeled and measured, all months combined, cloudy conditions – white

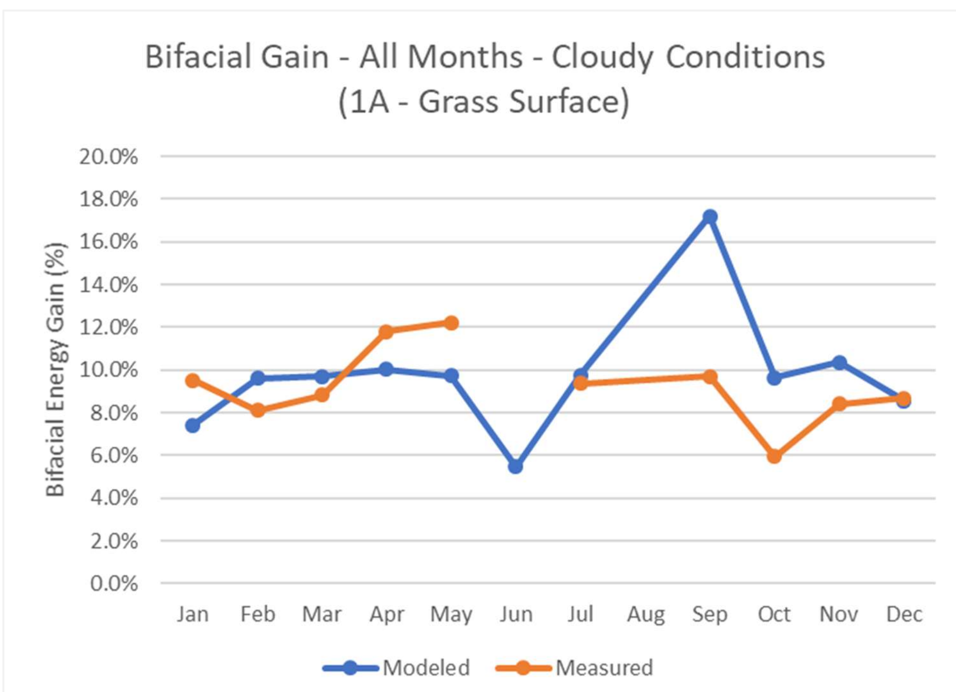

Figure 7-27: Modeled and measured, all months combined, cloudy conditions - grass

7.5.2.3 Results Discussion – Soiling

Analyzing the daily measured versus modeled values for the monofacial and bifacial strings provides insight into how module soiling may have impacted the results. Starting with the monofacial strings in Figure 7-28, the measured divided by modeled energy for both the grass and white strings is typically >1, but typically decreases in the lead up to cleaning event (either precipitation or module cleaning).

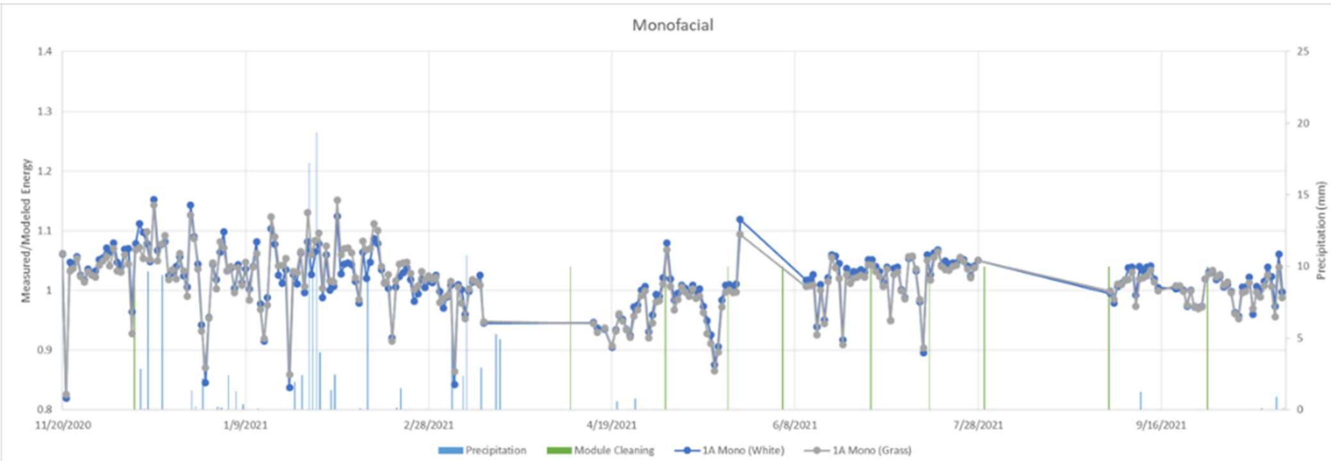

Figure 7-28: Daily measured/modeled with cleaning events - monofacial strings (11/20/20-10/19/21)

This can also be seen with the bifacial strings shown in Figure 7-29. Additionally, during the winter months (on the left side of the graph) the measured energy significantly exceeds modeled energy on cloudy days, especially for the white surface the increased albedo resulted in a greater bifacial gain than predicted by PVsyst.

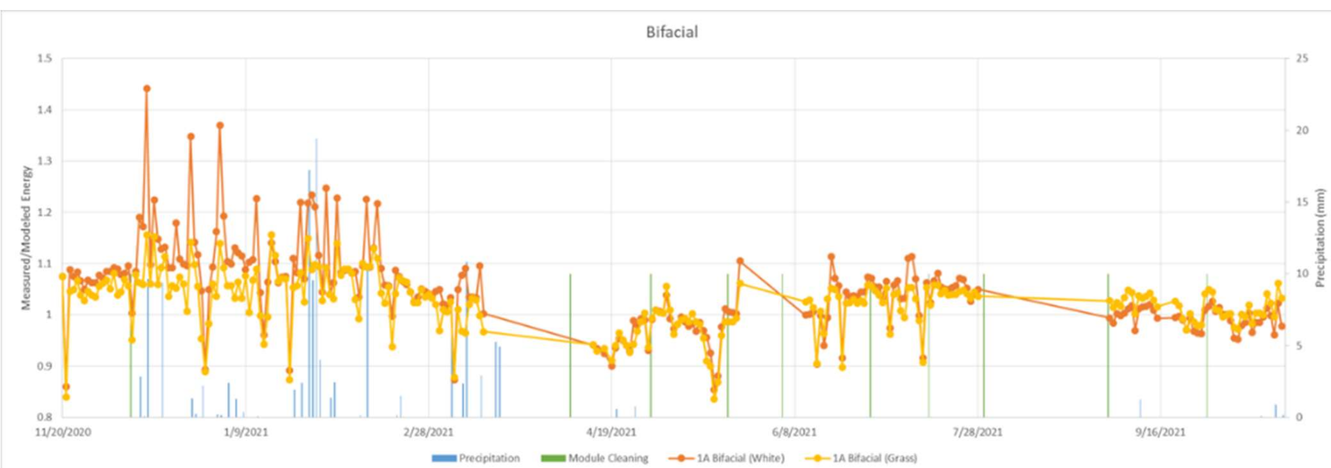

Figure 7-29: Daily measured/modeled with cleaning events - bifacial strings (11/20/20-10/19/21)

7.5.2.4 Results Discussion – Error Summary

As stated, over the entire period, PVsyst under predicted bifacial gain by 1.8% for the white surface and 1.1% for the grass surface. On average, in any given month, PVsyst predicted bifacial gains were 2.0% lower than measured for the white surface and 1.1% lower than measured for the grass surface. This is shown in Table 7-17.

	Mean Bias Error		Root Mean Square Error	
Parameter	**1A (White)**	**1A (Grass)**	**1A (White)**	**1A (Grass)**
Total Error	-1.8%	-1.1%	---	---
Average Monthly Error	-2.0%	-1.1%	4.0%	1.6%
Average Daily Error	-2.5%	-1.1%	11.7%	4.0%

Table 7-17: Modeled vs. measured bifacial gain error summary

Drilling down into the energy production modeling errors (rather than the above which is bifacial gain), this is comparable for both bifacial and monofacial systems where there is a similar magnitude MBE and RMSE on a daily, monthly, or overall basis. This is shown in Table 7-18.

	Mean Bias Error				Root Mean Square Error			
Parameter	**1A Mono (White)**	**1A Bifacial (White)**	**1A Mono (Grass)**	**1A Bifacial (Grass)**	**1A Mono (White)**	**1A Bifacial (White)**	**1A Mono (Grass)**	**1A Bifacial (Grass)**
Total Error	1.3%	-0.4%	0.9%	-0.1%	---	---	---	---
Average Monthly Error	1.1%	-0.7%	0.8%	-0.2%	4.4%	4.9%	3.6%	3.6%
Average Daily Error	0.4%	-1.7%	0.3%	-0.8%	13.0%	14.4%	11.6%	11.4%

Table 7-18: Modeled vs. measured energy error summary

Looking at the combined monthly MBE for all four strings makes evident seasonal trends for modeled energy production, indicating a seasonality effect has not effectively been captured in the PVsyst model for both monofacial and bifacial systems. This is seen in Figure 7-30.

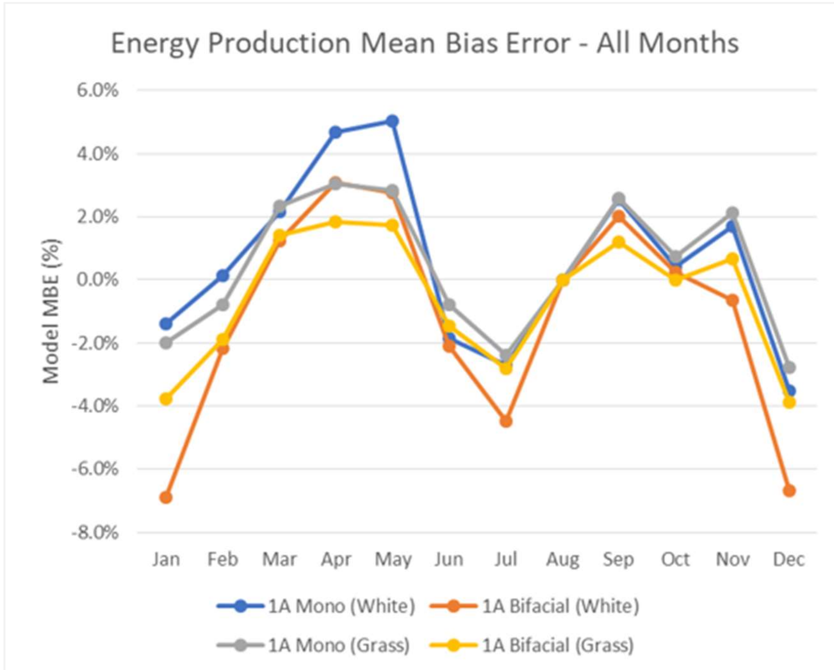

Figure 7-30: Monthly combined MBE – all strings

7.5.2.5 Recommendations for Model Improvement

A number of suggestions for modeling improvement arose during this analysis. They include the following:

- Incorporating on-site soiling measurements (or washing arrays weekly) would reduce model error. The arrays were cleaned on an irregular schedule every 2-4 weeks and the PVsyst model assumed constant (and seemingly inaccurate) 3% soiling loss. Measured data shows a handful of instances (e.g. Apr 2021 and May 2021) where module washing coincides with ~10% performance improvement.
- Nextracker has published recommended bifacial loss factors of 12.3% for rear shading and 3.5% for rear mismatch based on ray tracing analysis; adopting these in PVsyst could improve model accuracy.
- The mismatch loss could be determined by I-V curve modeling; 1.1% combined series/parallel mismatch is likely high for this system.

7.5.3 Expected Vs. Actual Comparison (SolarFarmer)

This section presents the results of SolarFramer's modeling compared to the actual site performance.

7.5.3.1 Results Overview

DNV used PVEL's measured dataset and input parameter assumptions with their modeling tool, SolarFarmer 2D API. This assumed standard tracking in flat terrain including backtracking, and the missing DHI values were derived using Erbs decomposition model (which was automatically included in SolarFarmer calculation). As SolarFarmer results are not available for specific tracker rows, single tracker proportion of a larger array consisting of 96 tracker rows was used to derive a typical “mid-row” output. The output of this was simulation results aggregated to hourly to be comparable with measured hourly power data. The results used for validation are DC power from the string, including DC collection effects.

The MBE of measured versus modelled for the study period ranged from 0.39% for monofacial grass, up to 1.33 for monofacial white, with similar values for the bifacial strings (1.19% for grass and 0.95% for white).

DNV observed a trend of power overprediction in the middle of the day. A seasonal trend was also observed with power underprediction in the winter and summer and an overprediction in the spring and autumn.

The final dataset of measured versus modelled per DC power output for all four strings are shown in Figure 7-31, Figure 7-32, Figure 7-33 and Figure 7-34.

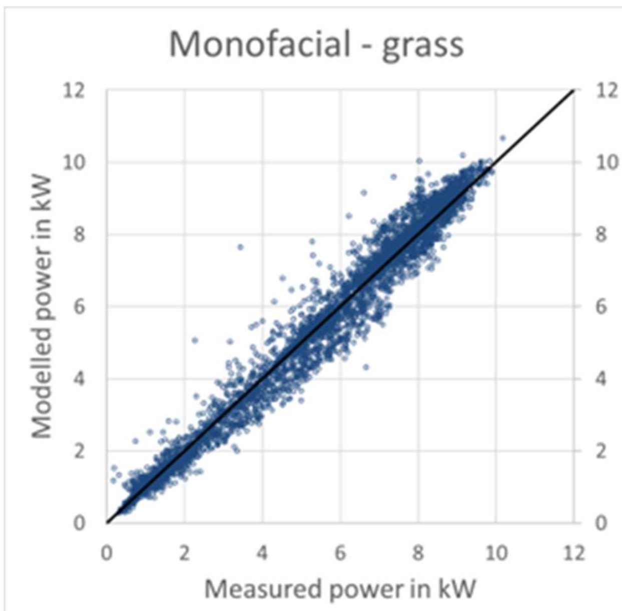

Figure 7-31: Monofacial measured versus modeled per dc power output – grass

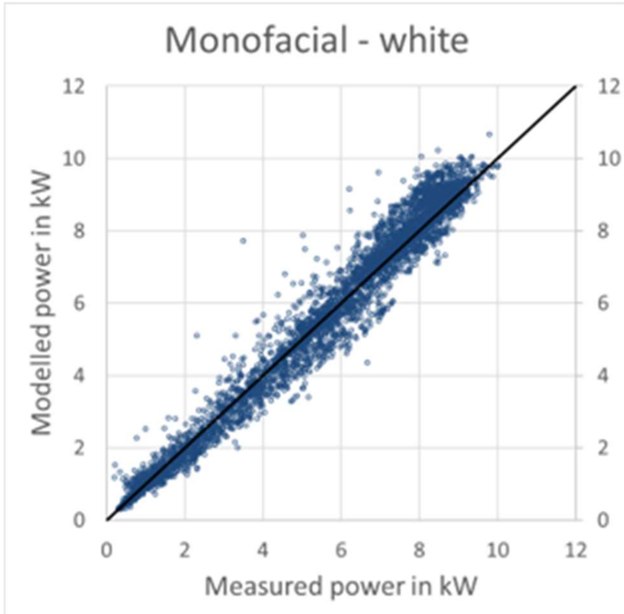

Figure 7-32: Monofacial measured versus modeled per dc power output – white

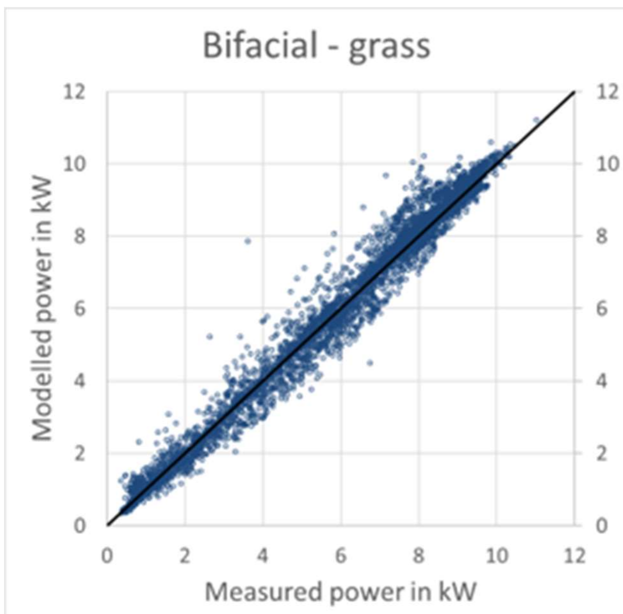

Figure 7-33: Bifacial measured versus modeled per dc power output - grass

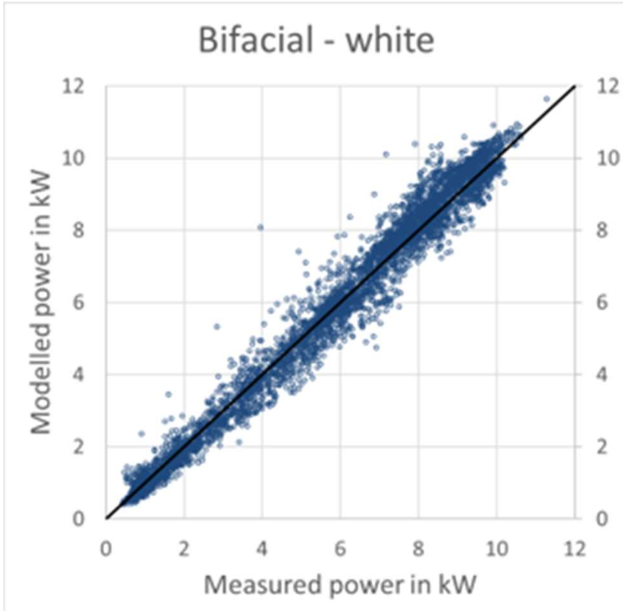

Figure 7-34: Bifacial measured versus modeled per dc power output - white

7.5.3.2 Results Discussion – Seasonality and Time of Day

Following their modeling work, DNV highlighted that there was a modelled power underprediction in winter and summer, and overprediction in spring and autumn. This was apparent across all four stings and can be seen in Figure 7-35, Figure 7-36, Figure 7-37 and Figure 7-38 where the measured and modelled power is graphed, along with the MBE in kw for each month. DNV also highlighted that there was a power overprediction in the middle of the day and an underprediction during the mornings and evenings. Again, this was apparent across all four strings and can be seen in Figure 7-39, Figure 7-40, Figure 7-41 and Figure 7-42.

DNV noted that further investigation is required to identify the source of these trends, but that doing this would be somewhat limited due to lack of data like GHI diffuse portion.

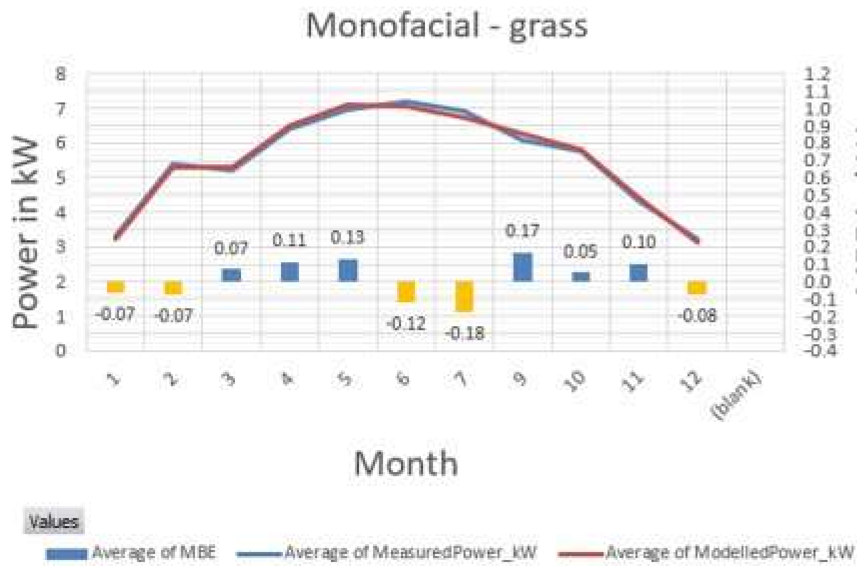

Figure 7-35: Monofacial measured vs. modelled power, all months combined - grass

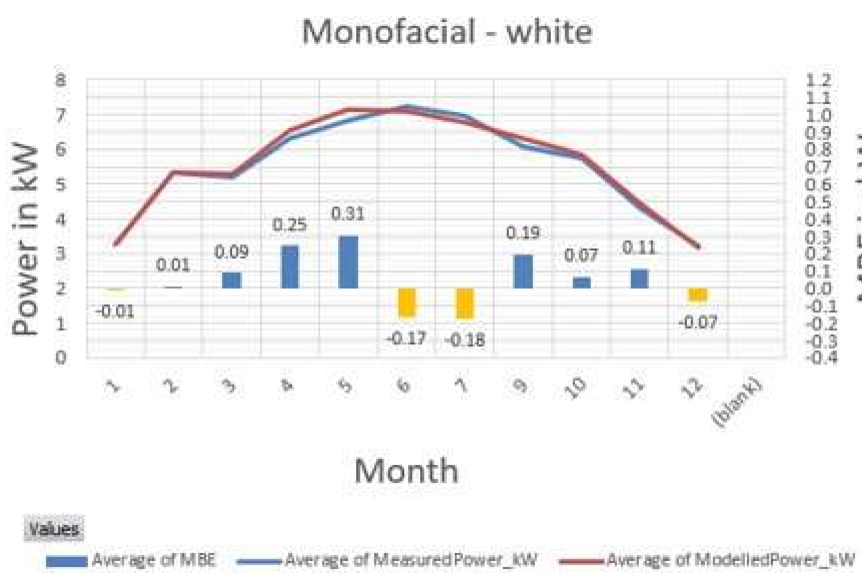

Figure 7-36: Monofacial measured vs. modelled power, all months combined – white

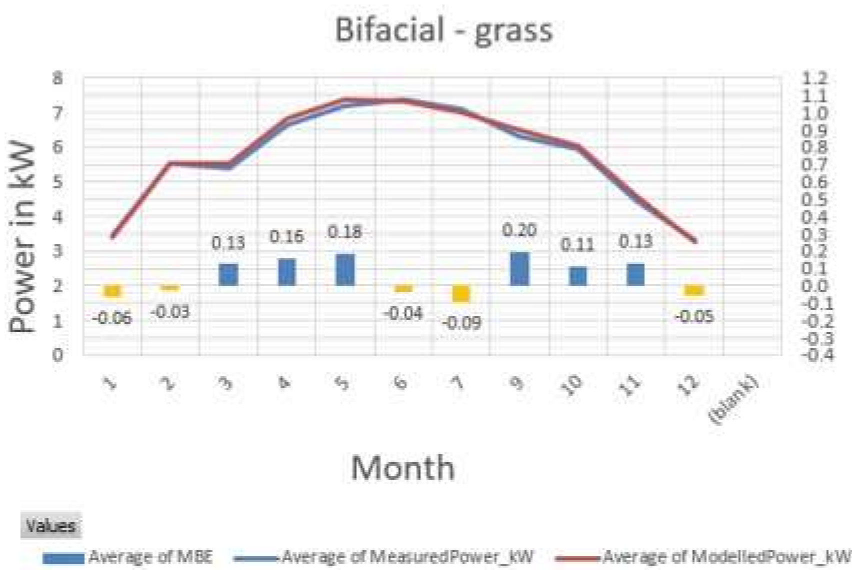

Figure 7-37: Bifacial measured vs. modelled power, all months combined - grass

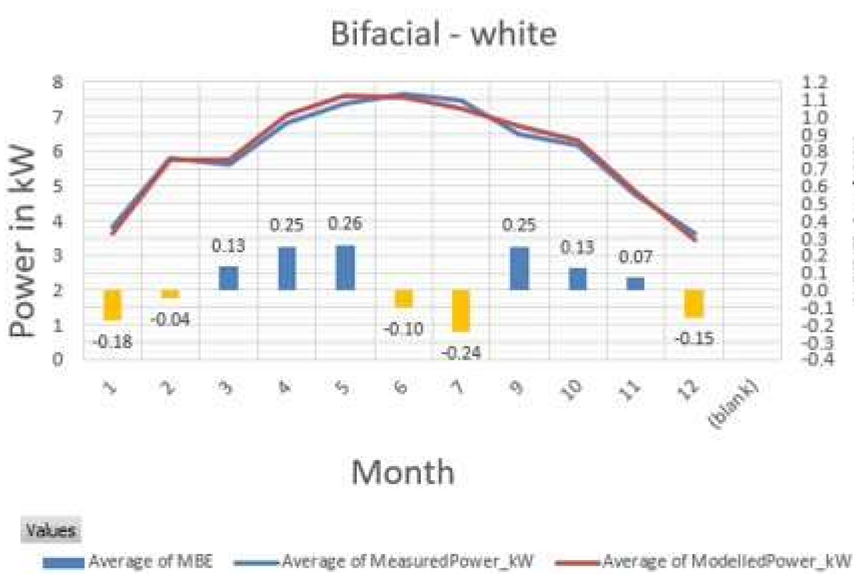

Figure 7-38: Bifacial measured vs. modelled power, all months combined - white

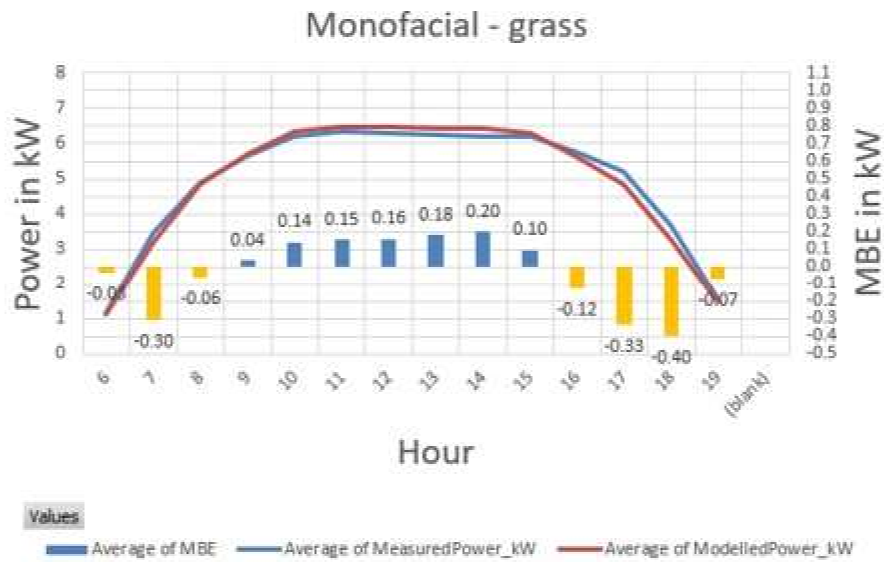

Figure 7-39: Monofacial measured vs. modelled power, all hours combined - grass

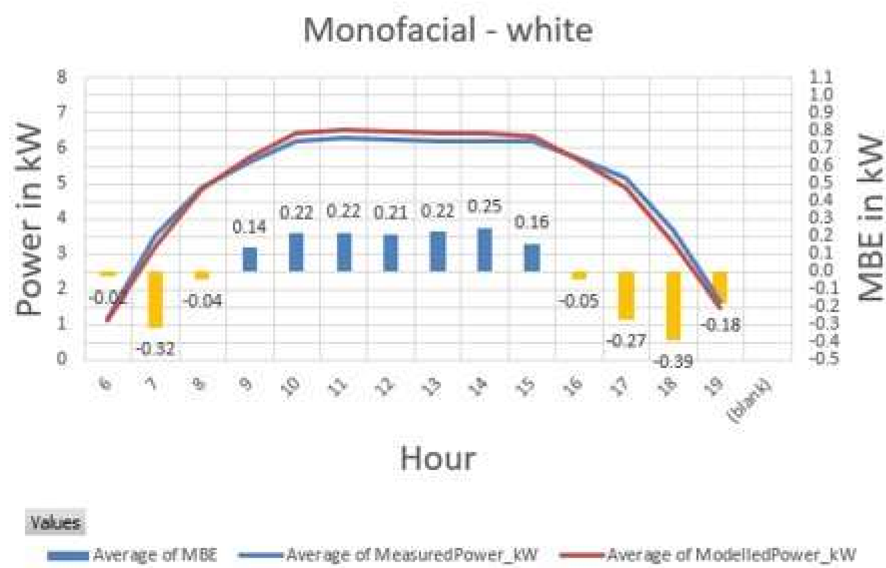

Figure 7-40: Monofacial measured vs. modelled power, all hours combined – white

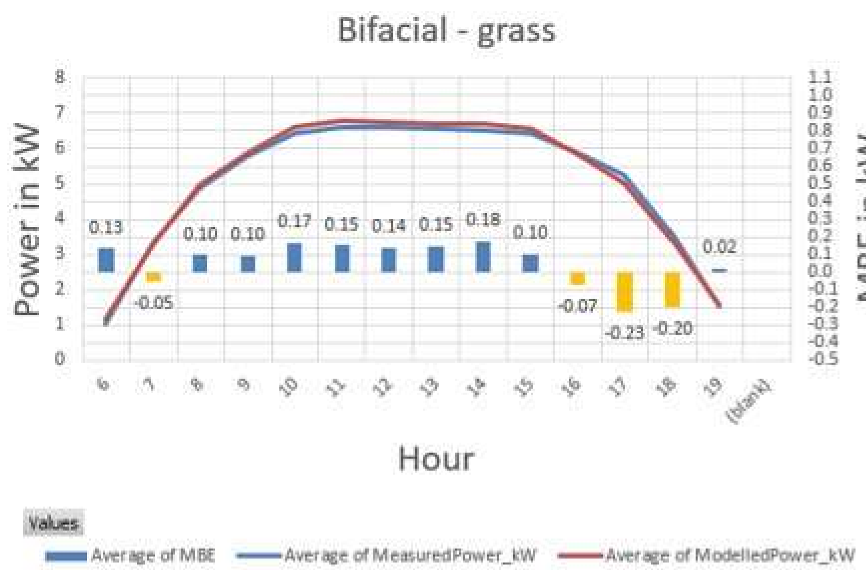

Figure 7-41: Bifacial measured vs. modelled power, all hours combined - grass

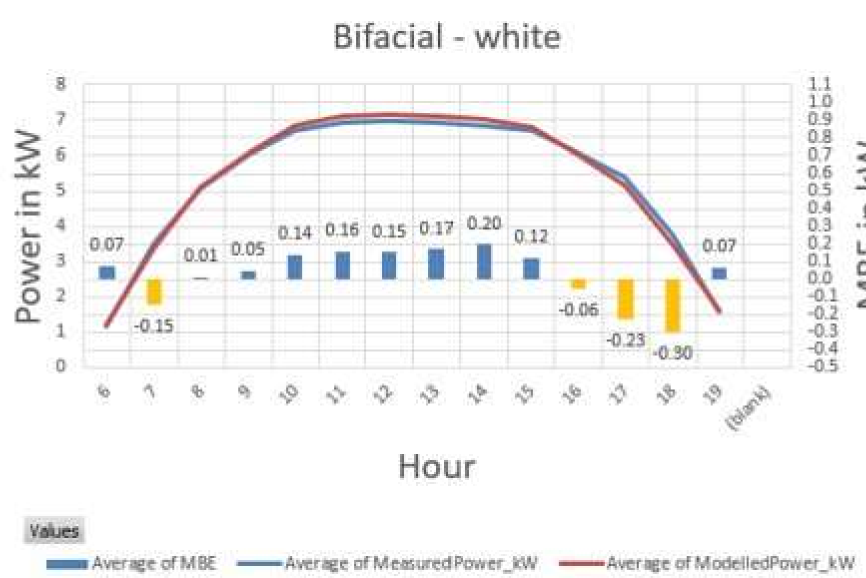

Figure 7-42: Bifacial measured vs. modelled power, all hours combined - white

7.5.3.3 Recommendations for Future Validation Studies

While DNV did not provide any recommendations for modeling improvements, they did provide the following recommendations for future validation studies:

- Measure tracker angles so that calculated ones can be compared.
- Measure diffuse horizontal irradiance.

- Measure backside irradiance to enable validation of irradiance modeling for bifacial sites.

7.5.4 Expected Vs. Actual Comparison (Plant Predict)

This section presents the results of Plant Predict modeling compared to the actual site performance.

7.5.4.1 Results Overview

On average, Plant Predict under-predicted bifacial energy gain in a similar result to PVsyst. For the white surface, measured bifacial gain was 1.7% higher than modeled. For the grass surface, measured bifacial gain was 1.0% higher than modeled. While cloudy conditions accounted for only <10% of hours and <5% of energy production, the bifacial energy gain errors differed for clear vs. cloudy conditions as shown in Figure 7-43. For the white surface, model error was greater under cloudy conditions, quite similar to PVsyst's model error for the same conditions. For the grass surface, model error was greater under clear conditions and, again, quite similar to PVsyst's results.

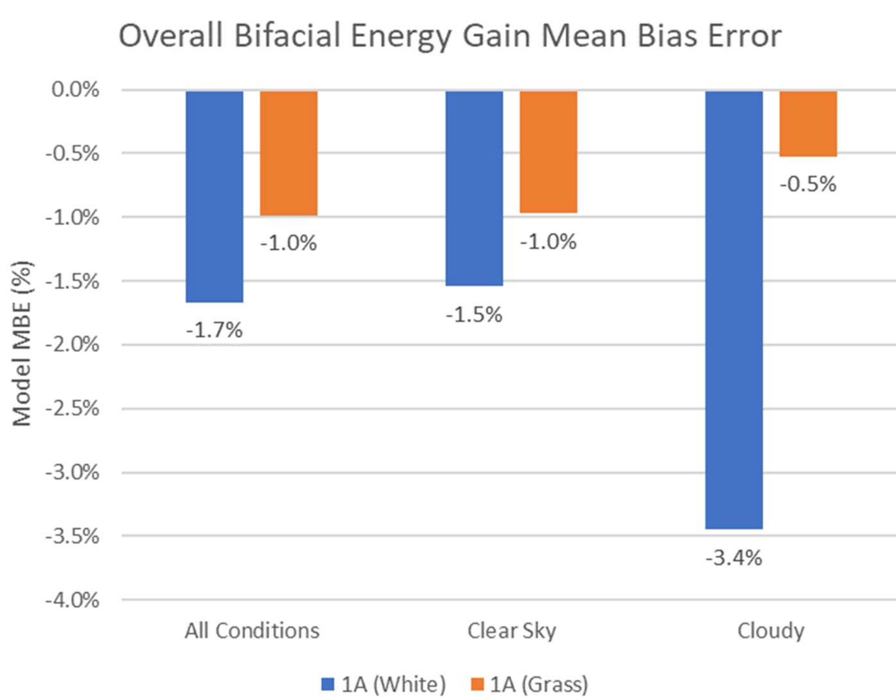

Figure 7-43: Overall bifacial energy gain mean bias error per weather condition

Similar to the PVsyst results, daily and monthly fluctuations in the Plant Predict model accuracy for predicting bifacial energy gain were likely driven by varying levels of on-site soiling, seasonal biases in the model and/or differing sources of model bias under clear versus cloudy conditions. Further fluctuations for the white surface results may have been caused from modeled inverter clipping as discussed below.

The final dataset of measured versus modelled per DC power output for the two bifacial strings for grass and white are shown in Figure 7-44 and Figure 7-45, respectively. Modelled inverter clipping can be seen in the white dataset. This is likely due to forcing Plant Predict to model a small (single string) system rather than the utility-scale systems that it is designed for. It is likely that re-running the Plant Predict modeling with different inverter parameters could have resolved this issue and lead to a decrease in mean bias error for the white surface.

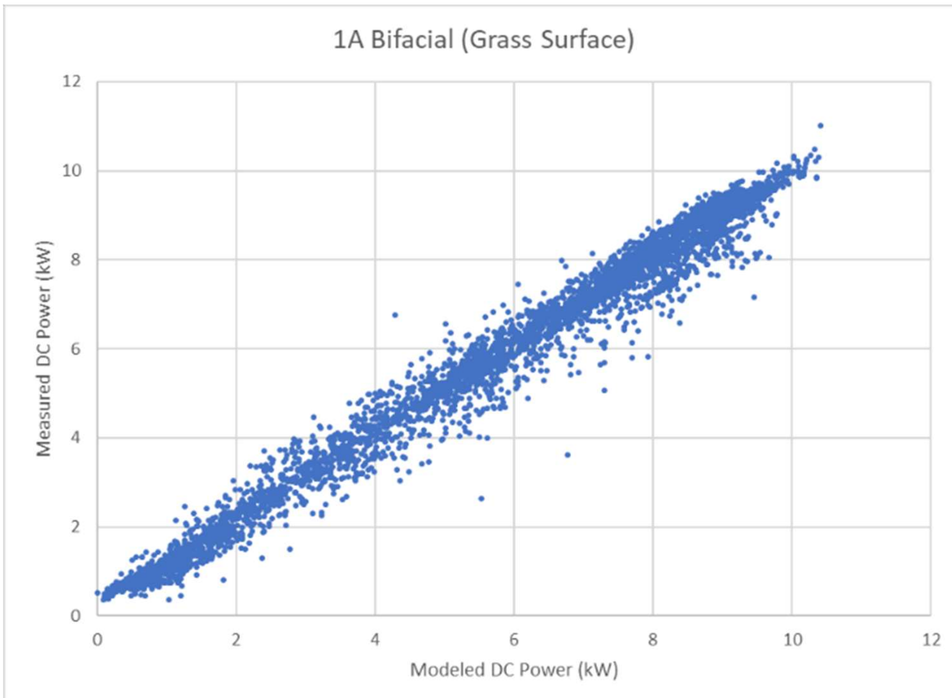

Figure 7-44: Bifacial measured versus modeled per DC power output - grass

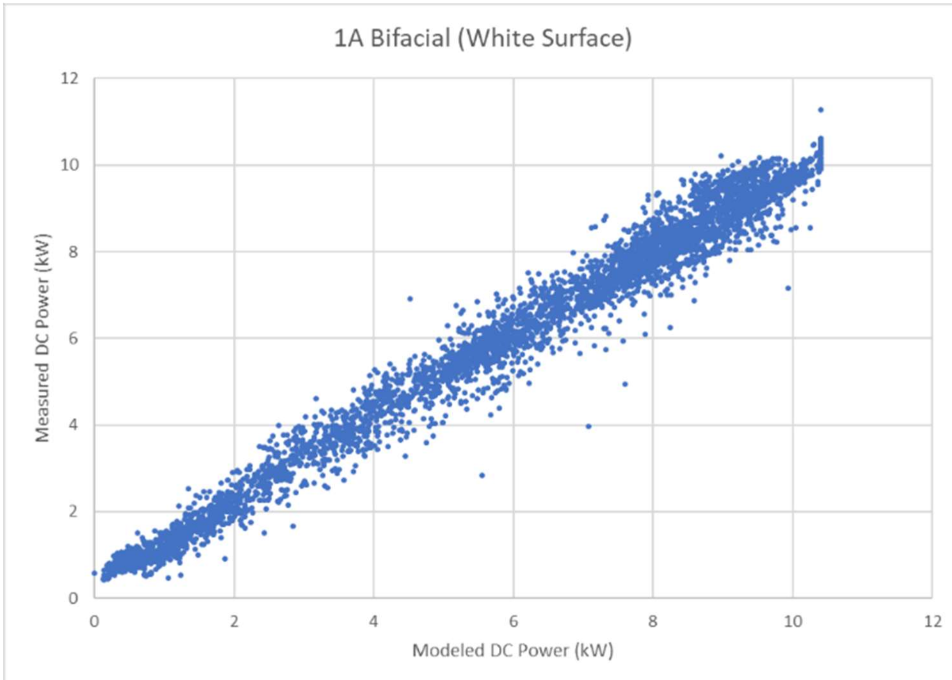

Figure 7-45: Bifacial measured versus modeled per DC power output - white

7.5.4.2 Results Discussion – Cloudy Versus Clear Sky

Similar for PVsyst and as stated above, for the white surface, Plant Predict model error was greater under cloudy conditions. For the grass surface, model error was greater under clear conditions.

With all months and weather conditions combined, Figure 7-46 shows that the highest model error (i.e. the largest gap between modeled and measured), occurs during the winter months for the white groundcover dataset. This not the case for the grass groundcover, where there is no seasonal trend for model error, as shown in Figure 7-47.

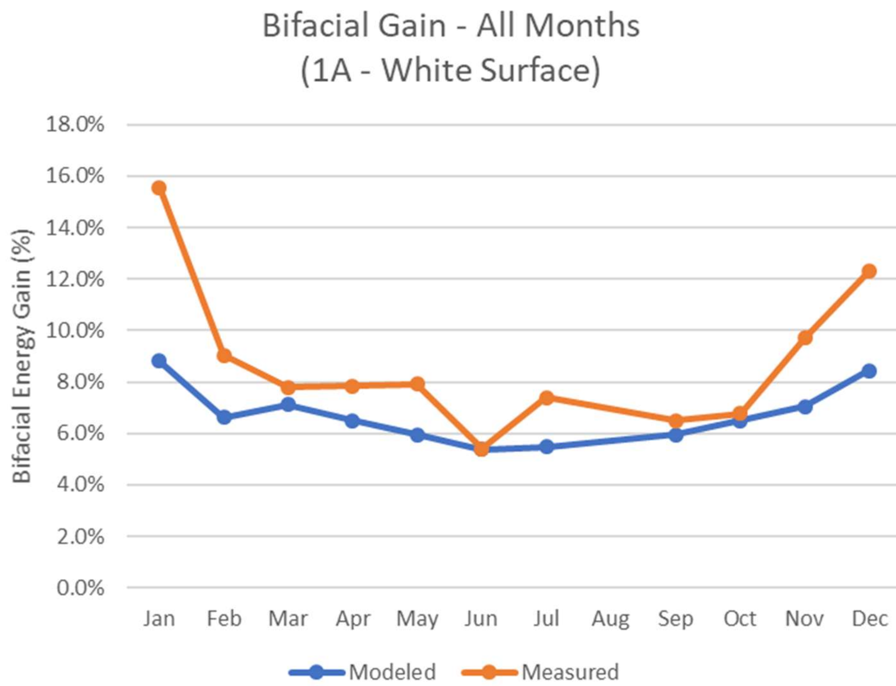

Figure 7-46: Modeled and measured, all months and conditions combined - white

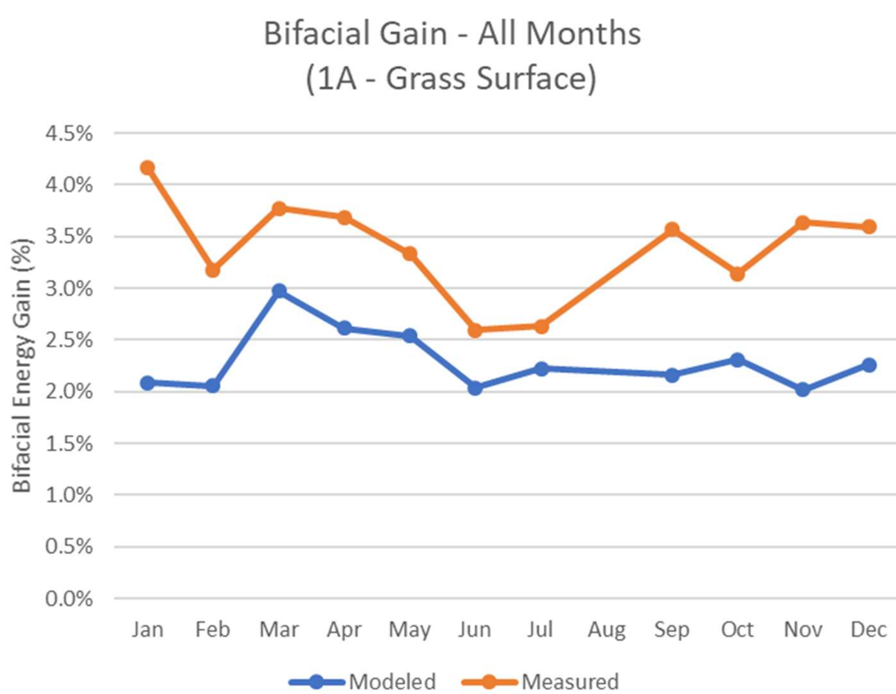

Figure 7-47: Modeled and measured, all months and conditions combined - grass

Filtering these datasets into clear sky and cloudy conditions for Plant Predict did not reveal any additional seasonal trends which is another similar finding to the PVsyst results.

7.5.4.3 Results Discussion – Soiling

Not unlike the PVsyst results, the impacts of soiling can be seen in the Plant Predict daily measured versus modeled values for the monofacial and bifacial strings. Starting with the monofacial strings in Figure 7-48, the measured divided by modeled energy for both the grass and white strings is typically >1, but typically decreases in the lead up to cleaning event (either precipitation or module cleaning).

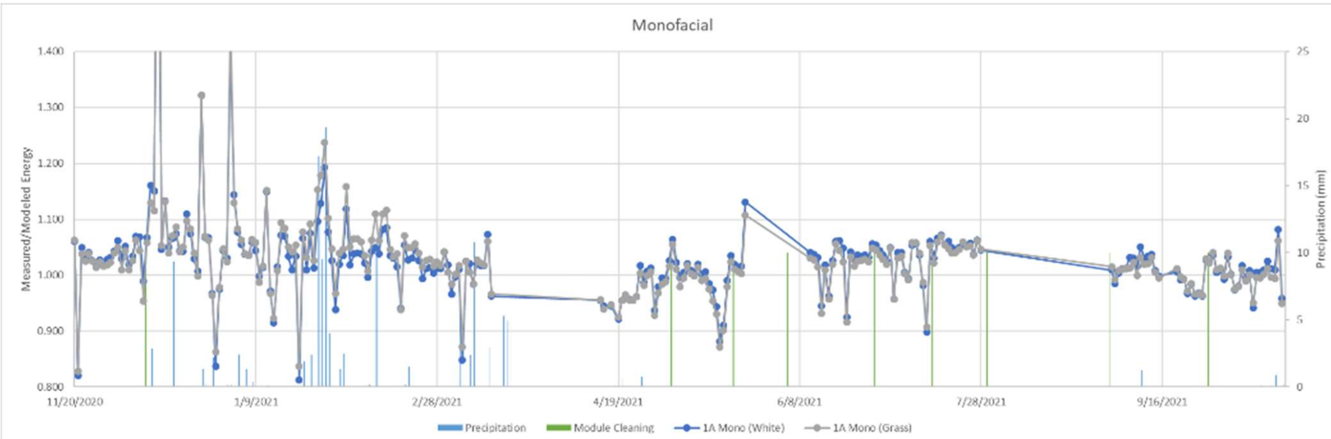

Figure 7-48: Daily measured/modeled with cleaning events - monofacial strings (11/20/20-10/19/21)

This can also be seen with the bifacial strings shown in Figure 7-49. Additionally, during the winter months (on the left side of the graph) the measured energy significantly exceeds modeled energy on cloudy days, especially for the white surface where, just like PVsyst, the increased albedo resulted in a greater bifacial gain than predicted by Plant Predict.

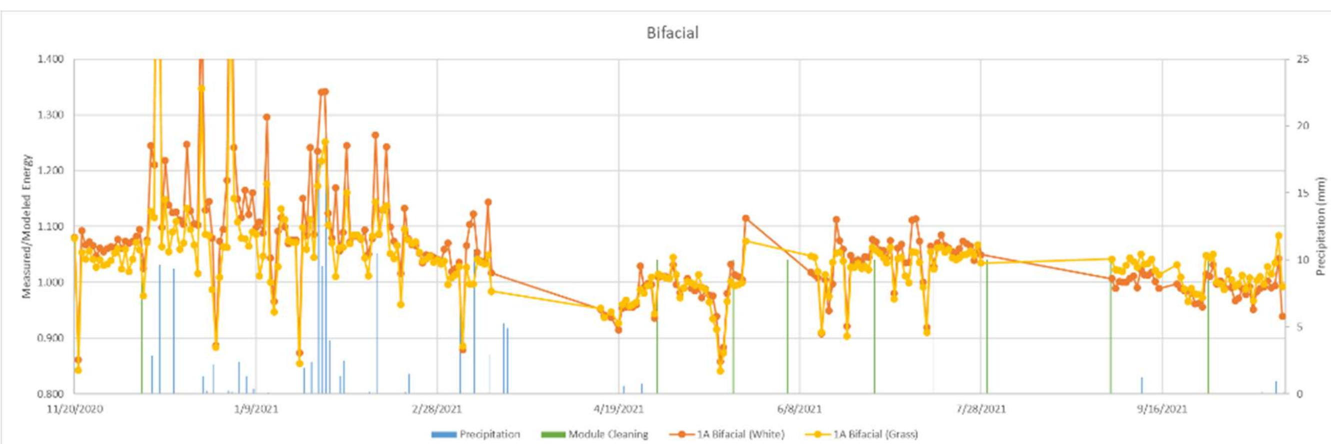

Figure 7-49: Daily measured/modeled with cleaning events - bifacial strings (11/20/20-10/19/21)

7.5.4.4 Results Discussion – Error Summary

As stated, over the entire period, Plant Predict under predicted bifacial gain by 1.7% for the white surface and 1.0% for the grass surface. This compares to 1.8% and 1.1% for PVsyst, respectively. On average, in any given month, Plant Predict predicted bifacial gains were 2.0% lower than measured for the white surface and 1.1% lower than measured for the grass surface, which were the exact values for PVsyst as well. These Plant Predict results are shown in Table 7-19.

	Mean Bias Error		Root Mean Square Error	
Parameter	**1A (White)**	**1A (Grass)**	**1A (White)**	**1A (Grass)**
Total Error	-1.7%	-1.0%	---	---
Average Monthly Error	-2.0%	-1.1%	4.0%	1.6%
Average Daily Error	-2.3%	-1.1%	11.5%	4.0%

Table 7-19: Modeled vs. measured bifacial gain error summary

Drilling down into the energy production modeling errors (rather than the above which is bifacial gain), a similar magnitude MBE is seen for overall and monthly, but it's higher for average daily error. This is shown in Table 7-18. It is likely that some of the low irradiance day outliers shown in Figure 7-48 and Figure 7-49 are driving up this daily average.

When comparing to the PVsyst results (shown in Table 7-18), the mean bias error for the monofacial strings is lower for Plant Predict than PVsyst for total error and average monthly error, but higher for average daily error. For bifacial strings, the mean bias error is higher for Plant Predict than PVsyst for all three time periods (total, average monthly and average daily). This hints to higher accuracy for monofacial modeling in Plant Predict and perhaps an opportunity for bifacial modeling improvements.

	Mean Bias Error			
Parameter	**1A Mono (White)**	**1A Bifacial (White)**	**1A Mono (Grass)**	**1A Bifacial (Grass)**
Total Error	0.4%	-1.1%	-0.1%	-1.1%
Average Monthly Error	0.3%	-1.4%	-0.1%	-1.1%
Average Daily Error	-1.1%	-3.0%	-1.5%	-2.6%

Table 7-20: Plant Predict modeled vs. measured energy error summary

Looking at the combined monthly MBE for all four strings yields another result similar to PVsyst, where seasonal trends for modeled energy production can be seen. There may be an opportunity to improve Plant Predict's modeling of the seasonality effect for both monofacial and bifacial systems. This is seen in Figure 7-50.

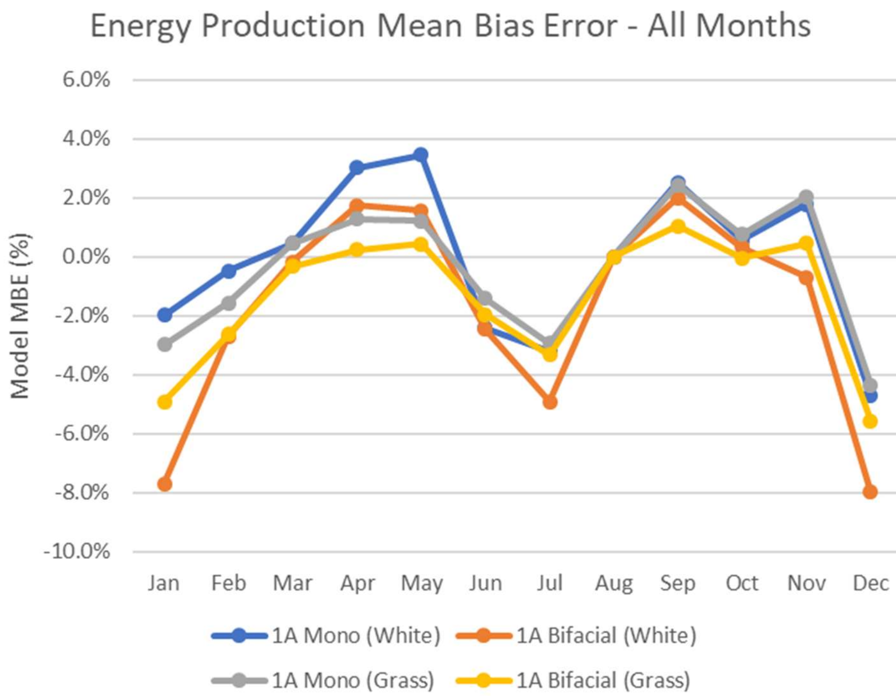

Figure 7-50: Monthly combined MBE – all strings

7.5.4.5 Recommendations for Model Improvement

Beyond some of the suggestions stated in 7.5.2.5 for improving PVsyst modeling (including on-site soiling measurements or increased washings), a few other improvements for Plant Predict have been noted within 7.5.4 and are summarized below.

- The improving the modeling the seasonality effects, especially for low irradiance months would increase accuracy.
- Reducing inverter clipping would improve the modelled results for the white surface.
- Plant Predict results showed better mean bias error for monofacial strings than for bifacial strings, leaving some room for improvement for bifacial modeling.
- According to Plant Predict, modeling at the sub-hourly level (15- or even 1-minute) is within their capabilities and would have improved the deviation between measured and modelled.

7.5.5 Error Summary Across Modeling Software

A comparison of MBE from PVsyst, Solar Farmer and Plant Predict is shown in . Results show that the error between the field data and the predicted values from all three software were relatively aligned, with a maximum MBE of 1.3% and a minimum MBE of -1.8%.

	Mean Bias Error	
Parameter	**1A (White)**	**1A (Grass)**
Total Error – PVsyst	-1.8%	-1.1%
Total Error – Solar Farmer	1.2%	1.0%
Total Error – Plant Predict	1.3%	0.9%

Table 7-21: Modeled vs. measured energy error summary

7.6 Achieving Project Objectives

Despite the difficulties encountered (detailed in Section 7.7), this project ultimately achieved the key original objective to a certain extent. The main goal of this project was to validate energy models relating to bifacial PV modules, and that was successfully completed for PVsyst, SolarFarmer and Plant Predict using Manufacturer 1's measured data over both albedos. Ideally the measured versus modelled analysis would have been conducted on all four manufacturers' results, but given the data quality issues experienced and need for data filtering, completing this for all four manufacturers would have been an onerous task for the modeling companies.

A summary of the status of each project task is shown in Table 7-22.

Task	Status
Sign contracts and receive units	Successfully completed
Initial Module Characterizations	Successfully completed
Transportation and system commissioning	Successfully completed
Interim data distribution	Successfully completed
Communicate interim findings	Successfully completed
Deinstallation, initial analysis, manufacturer model disclosure, model selection	Successfully completed
Energy yield simulation creation and collection	Successfully completed for Manufacturer 1
Data analysis, presentation of initial results, delivery of manufacturers' reports.	Successfully completed
Final report, further stakeholder outreach	Successfully completed
Project closing	Successfully completed

Table 7-22: Task list progress

7.7 Difficulties Encountered

There were a variety of difficulties experienced throughout the duration of this study, which caused delays and impacts. These included the following:

- Delays in project start due to one of the four manufacturers providing their modules months after the others.
- Delays in IAM testing due to needing to test bifacial modules outdoors during ideal weather conditions, rather than indoor IAM testing which is not susceptible to weather.
- Voltage data monitoring issues due to voltage sensors behaving erratically or outright failing. These sensors needed to be replaced, but troubleshooting the source of the poor data was time and resource consuming.
- Inverter reliability issues, with the 1500V string inverter not performing as expected and needing to be replaced.

- Inverter maximum power point tracking issues, with different strings all operating at one maximum power point, rather than having an inverter with separate maximum power point tracking per string.
- There were difficulties in keeping the modified white albedo surface clean and properly situated following wind and/or rain events.
- Periods of downtime and outages not being identified in a timely manner.
- Sensor accuracy/data integrity issues that extended the time required for post-test data analysis and reporting.
- Due to the data quality issues, only results from one of the four manufacturers' data was used in the measured versus modelled analysis.
- PVEL provided the data for Manufacturer 1 to four external modeling providers, but only two completed the analysis, along with the internal PVsyst analysis.

8 Significant Accomplishments and Conclusions

The most significant accomplishment of this project was to provide evidence that energy modeling for bifacial modules is within what PVEL would consider industry acceptable accuracy, similar to monofacial modules. Having accurate energy models for bifacial modules will make bifacial PV systems acceptable to financial institutions, Independent Engineering firms, and solar site project stakeholders, thus allowing for the industry to benefit from the additional energy generation available from bifacial technology.

Despite that accuracy being achieved, room for continual improvement in the modeling software was identified. Those improvements being implemented would allow for increased confidence in the energy models.

Another accomplishment of the study was that the analysis of energy yield and specific energy yields of the various systems provides conclusive evidence that the energy generation of bifacial modules is greater than monofacial modules. This is not a surprising finding as it is aligned with industry expectations of bifacial technology, but publicly-available energy yield data on a utility-scale representative PV site can be difficult to obtain. This dataset also shows that modified groundcover for higher albedo values will results in higher energy yields.

A number of challenges were experienced during the execution of this project, including shipment delays on some of the equipment, sensor and inverter issues, and equipment downtime. This ultimately led to the project timelines begin extended so that a sufficient amount of field data could be achieved. It also led to a reduction in scope for the energy modeling where the data for only one of the four manufacturers with 1500V strings was used in the actual versus modelled analysis. Additionally, rather than comparing the energy yield and specific energy yield of the 1500V strings, PVEL decided to use smaller systems on the same trackers for this analysis.

Through these challenges, PVEL established some lessons learned on how to better complete similar studies in the future. These include using higher precision voltage sensors, having the sites monitored delay with better automated alarms within the monitoring software, using white gravel rather landscaping cloth for a higher albedo groundcover, keeping inverters and/or voltage and current sensors within temperature-controlled enclosures to avoid temperature derates, perform weekly module cleanings rather than monthly.

9 Budget and Schedule

Withheld.

10 Path Forward

Over the duration of this project bifacial modules rose to prominence throughout the US solar industry and abroad. The Section 201 tariff policies were the main impetus for the market acceptance of bifacial modules, leading to them now being used on the majority of utility-scale projects, which have been financed by a range of investors. This, by extension, is evidence that bifacial modules and their associated energy and financial models are considered bankable.

Given these developments, PVEL will continue to focus on indoor and outdoor lab testing of different bifacial modules from module manufacturers throughout the globe. These activities will be in an effort to answer the ongoing question of which module model/bills of materials offer the best reliability and performance, which is now a more important question than the more general questions this project aimed to answer.

There were many lessons learned for designing a more robust study with regards to sensor placement and accuracy/precision, choice of groundcover material for modified albedos, and conducting ongoing (minimum weekly) monitoring to flag any downtime events. These have been incorporated into PVEL's outdoor studies.

Aside from PVEL, in an effort of continual improvement, PVsyst, DNV and TeraBase will continue revising their modeling tools to achieving higher accuracy.

11 Inventions, Patents, Publications, and Other Results:

No inventions or patents were to be realized as a result of this project, however PVEL was quite prolific with sharing the results of this study in a variety of industry events and documents. The list of those is below:

- October 2019 - PVEL presented initial results at the PV ModuleTech conference in Penang, Malaysia during a presentation titled “Top 12 assumptions about bifacial: addressing the unknowns with data”
- April 2020 - PVEL presented initial results from PVEL's indoor and outdoor bifacial testing on a PV Magazine webinar with Jinko Solar.

- May, June, July 2020 - PVEL participated in Nextracker's bifacial webinars series. These showcased PVEL site data and focused on validation of Nextracker's design of experiment and bifacial data analysis.
- July 2020 - PVEL teamed with NREL, Sandia, ISC Konstanz and other technical partners to present a two-day bifacial workshop. Jenya Meydbray, PVEL's CEO, presented a manufacturer "bake-off" comparing manufacturer data from this project.
- August, 2020 - PVEL released a whitepaper with Nextracker on bifacial performance, including case studies and comparative analysis featuring PVEL's bifacial site data.
- 2020 - PVEL teamed with NREL to release an article "bifiPV2020 Bifacial Workshop: A Technology Overview", NREL/TP-5K00-77817
- February 2021 - PVEL participated in NREL's PVRW Workshop and presented "Bifacial Update - Field Results".
- March 2021 - PVEL presented some results from this project during a "Trends in Bankability Testing" presentation for PV ModuleTech.
- May 2021 - PVEL participated in a webinar on "Bifacial Conversation with Industry Experts" hosted by PI Berlin and referenced the findings from this study.
- December 2021 – PVEL presented some results from this study during a "Hot topics, cool results: Insights from PVEL's recent module testing" presentation at PV ModuleTech.
- March 2022 - PVEL presented some results from this study during a "Outdoor Testing" presentation at the Bifacial Workshop.
- May 2022 – PVEL presented some results from this study during a "Understanding test results for heterojunction-based pv modules" presentation for a SolarBe webinar.

12 References

[i] https://www.nrel.gov/docs/fy21osti/77817.pdf
[ii] https://www.energy.gov/eere/solar/project-profile-performance-models-and-standards-bifacial-pv-module-technologies