System Advisor Model: Flat Plate Photovoltaic Performance Modeling Validation Report

Janine Freeman, Jonathan Whitmore, Leah Kaffine, Nate Blair, and Aron P. Dobos

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NREL/TP-6A20-60204
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Prepared under Task No. SS13.5010

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List of Acronyms

AC	alternating current
BWA	B-Wing Array
CEC	California Energy Commission
CSP	concentrating solar power
CWA	C-Wing Array
DC	direct current
DHI	diffuse horizontal irradiance (W/m^2)
DNI	direct normal irradiance (W/m^2)
DOE	U.S. Department of Energy
EPI	energy production at each inverter
FPL	Florida Power and Light
GB	gigabyte(s)
GHI	global horizontal irradiance (W/m^2)
GWh	gigawatt-hour(s)
HDKR	Hay-Davies-Klucher-Reindl
km	kilometer
kW	kilowatt
kWh	kilowatt-hour(s)
LCOE	levelized cost of energy ($/kWh)
LEED	Leadership in Energy and Environmental Design
m	meter
MBE	mean bias error
MW	megawatt(s)
MWh	megawatt-hour(s)
NOAA	National Oceanic and Atmospheric Administration
NREL	National Renewable Energy Laboratory
POA	plane of array irradiance (W/m^2)
PV	photovoltaic
R^2	coefficient of determination
RMSE	root mean square error
ROI	return on investment
RSF	Research Support Facility (at NREL)
SAM	System Advisor Model
SDK	software development kit
SEP	solar energy production
SPSA	solar power services agreement
SRRL	Solar Radiation Research Laboratory (at NREL)
Std	standard deviation
S&TF	Science & Technology Facility
TMY	typical meteorological year
WAPA	Western Area Power Association

Executive Summary

To secure competitive financing for a photovoltaic (PV) system, the economic risks associated with resource variability, technology maturity, and system design must be quantified and minimized. Because a PV system's financial performance depends directly on its energy yield, the performance of a proposed system must be accurately characterized to gain the confidence of financial institutions in its design. Current performance modeling tools are not publicly validated across a broad range of systems, markets, and geographical locations to provide the financial and independent engineering community with sufficient acceptance of these models and the ability to make intelligent investment decisions. This report is a first step in addressing that issue by focusing on validation of the System Advisor Model (SAM) with measured system performance data. Based on the findings of this report, future work will increase the value of SAM to the community by improving algorithms and methods to increase the fidelity and accuracy of modeled results and translating this to the broader community via accessible tools and data. This will enable the industry to better characterize risk and have greater confidence in the bankability of PV projects, and will allow other industry tools to be compared to SAM to improve their bankability as well.

For this validation effort, 9 PV systems for which NREL could obtain measured performance data were analyzed in detail to quantify SAM's ability to predict performance for these systems. The systems analyzed include three utility-scale systems (greater than 10 MW) and six commercial-scale systems (75–700 kW). All systems were modeled in SAM with as much site-specific metadata as were available for the system, using onsite measured irradiance and meteorological data as inputs where possible. The SAM-predicted alternating current (AC) power production was then compared to the measured AC power production for each system. Once each system was analyzed separately, the results of this comparison were aggregated by system type (commercial or utility) and totaled over all systems. The systems studied are listed in Table ES-1.

Table ES-1. Systems Analyzed in the Validation Study

System	Category	Location	System Type	Years	Snow
Forrestal	Commercial	Washington, D.C.	Fixed tilt	2009–2010 (1 yr)	yes
S&TF	Commercial	Golden, CO	Fixed tilt	2011, 2012	yes
RSF 1	Commercial	Golden, CO	Fixed tilt	2011, 2012	yes
RSF 2	Commercial	Golden, CO	Fixed tilt	2012	yes
Visitor Parking	Commercial	Golden, CO	Fixed tilt	2012	yes
Mesa Top	Commercial	Golden, CO	One-axis tracking	2011, 2012	yes
FirstSolar2	Utility	SW USA	Fixed tilt	2011	no
DeSoto	Utility	Arcadia, FL	One-axis tracking	2012–2013 (1 yr)	no
FirstSolar1	Utility	SW USA	Fixed tilt	2011	no

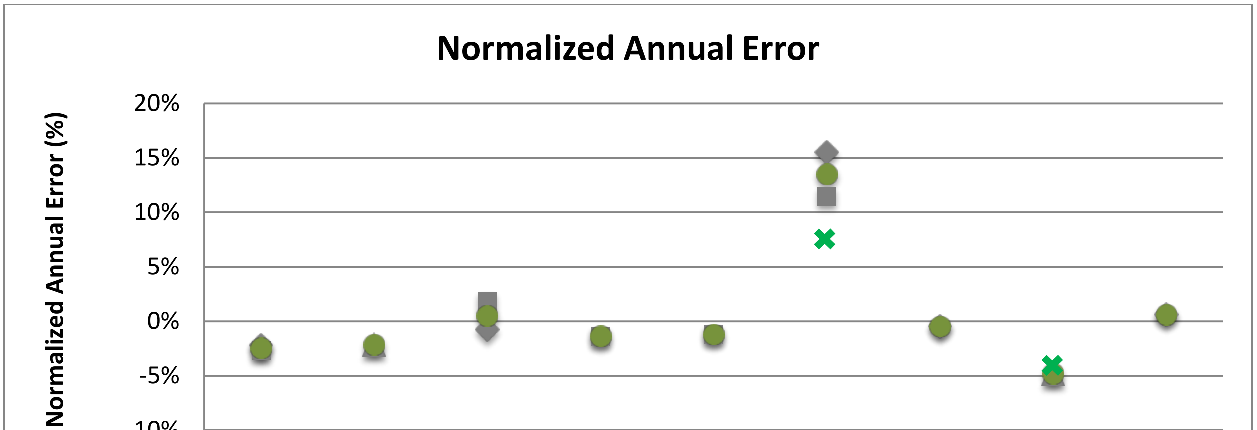
Known Causes of Error

During the course of these 9 system studies, we were able to isolate and identify two separate causes of modeling error (separate from data issues) that had large effects on SAM's ability to predict power production. These two sources of error do not account for all modeling error, but they do account for a significant portion of the error encountered in many of the systems. These two known causes of error are (1) snow cover and (2) an incorrect backtracking algorithm in the 2013.1.15 release of SAM. The errors related to backtracking systems were resolved in the 2013.9.20 release of SAM, but since the purpose of this report is validation of the 2013.1.15 release, the improved results are not included in overall statistics (see Section 4 for a full description of the error and resolution). Snow cover related issues are discussed in depth in the body of this report. Note that while most systems were affected by at least one of these known issues, we were able to remove data affected by snow cover using measured snow depth data near the affected sites. Therefore, only the two one-axis tracking systems, Mesa Top and DeSoto, still contain a known source of error (the backtracking issue) because this issue was an error in the code of the 2013.1.15 SAM release. Data for the DeSoto system are not as affected by the backtracking issue as Mesa Top due to the larger row spacing in the DeSoto system; however, the results of both systems are excluded from total results because we were unable to remove the known source of error while still using the 2013.1.15 release. Annual error results obtained with the 2013.9.20 release, which utilizes a fixed backtracking algorithm, are also presented for these two systems, but those results are not aggregated with the results from the other systems. It is important to note that we also suspect that the specifications for the Mesa Top system are incorrect, which may partially explain why the error for that system remains larger than the error for other systems even after the backtracking issue was resolved with the 2013.9.20 release. See Section 4 for more detail about this hypothesis.

Annual Results

Annual error was computed as the difference between measured and SAM-predicted annual power production values, with a positive error meaning that SAM overpredicted the system's power production (Figure ES-1). Excluding the Mesa Top and DeSoto systems, which still contain a known cause of error, the annual error for all systems is ±3% or less.[1] It is interesting to note that SAM tended to underpredict measured production. Default derates were used for this analysis, which include a default 5% annual soiling derate. There is no noticeable relationship between the magnitude of annual error and the size of the system, despite the fact that SAM does not explicitly model some utility-scale phenomena.

[1] The results of the 2013.9.20 release are also shown in Figure ES-1 for the Mesa Top and DeSoto systems, although we suspect that there is an error in the Mesa Top system specifications (see Section 4).



	S&TF	Forrest-al	RSF 1	RSF 2	Visitor Parking	Mesa Top	First Solar2	DeSoto	First Solar1
◆ 2011	-2.2%		-0.8%			15.5%	-0.5%		0.6%
■ 2012	-2.7%		1.8%	-1.4%	-1.2%	11.5%			
▲ Other Year		-2.1%						-4.8%	
● Average	-2.5%	-2.1%	0.5%	-1.4%	-1.2%	13.5%	-0.5%	-4.8%	0.6%

✖ Mesa Top system error decreases to 7.6% average with 2013.9.20 release, using suspected incorrect specifications (see Section 4). DeSoto system error decreases to -4.3% with 2013.9.20 release.

Figure ES-1. Normalized annual error, in order of system size

Monthly Results

On a monthly basis, a more interesting result becomes apparent. SAM exhibits a seasonal variation in error magnitude, appearing to be biased higher in the winter than in the summer (see Figure ES-2). In many systems, this seasonal variation results in SAM overpredicting performance in the winter months and underpredicting performance in the summer months, even after known sources of error have been removed.

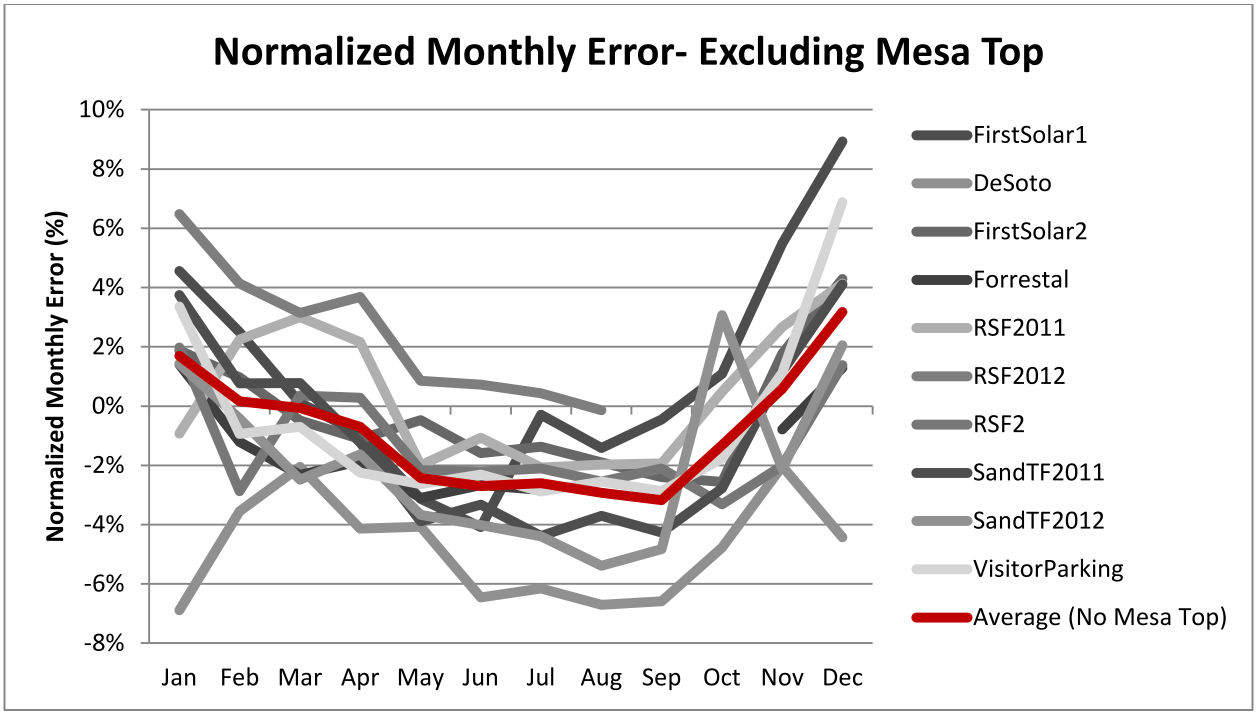


Figure ES-2. Normalized monthly error displaying a seasonal variation in SAM error[2]

This same seasonal variation in error was also seen in a 2008 paper written by Sandia National Laboratories, "Comparison of PV System Performance-Model Predictions with Measured System Performance" [1]. In this paper, the authors show that all of the radiation transposition models used within SAM, with the exception of the Isotropic Sky model, "calculate relatively more POA [plane of array] irradiance in the winter than in the summer," showing the same type of seasonal variation in error as encountered in this validation study, as shown in Figure ES-3 (Figure 3 in the aforementioned report). These radiation transposition models were developed by various non-NREL authors for the purposes of PV performance modeling in general, and are utilized in most, if not all, current PV performance modeling software packages.

[2] Mesa Top exhibited the same trend but with a significant offset so in order to make the trend more clear, Mesa Top is excluded.

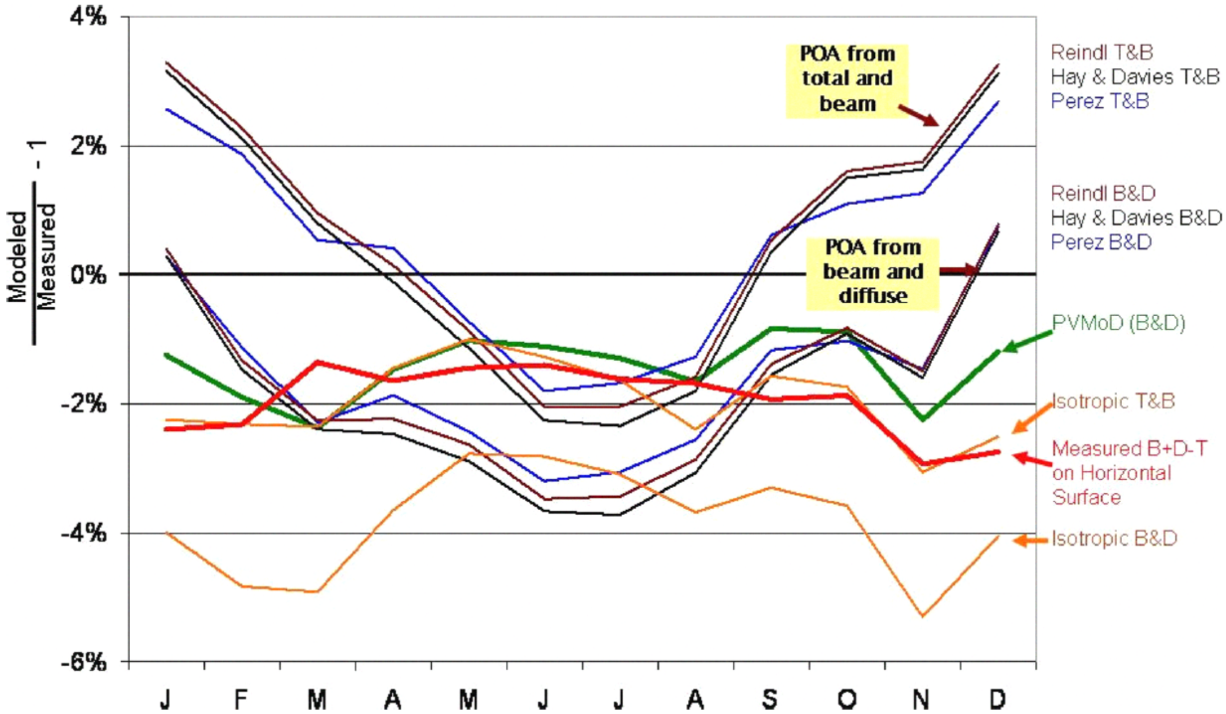


Figure ES-3. Seasonal variation in transposition model error (Sandia National Laboratories [1])

This trend in the transposition models may account for all or part of the seasonal difference in SAM error. Other contributors could include inaccurate module or inverter temperature coefficients, seasonal soiling differences, seasonal irradiance differences, or a combination of factors. We have conducted preliminary analysis on one system to determine whether the seasonal difference in SAM error correlates more highly with temperature or with rainfall (affecting the soiling of the panels) and have observed a much higher correlation with rainfall than temperature (Figure ES-4; see Section 10 for the full analysis). This and other possible causes will be investigated further with additional systems in subsequent validation efforts.

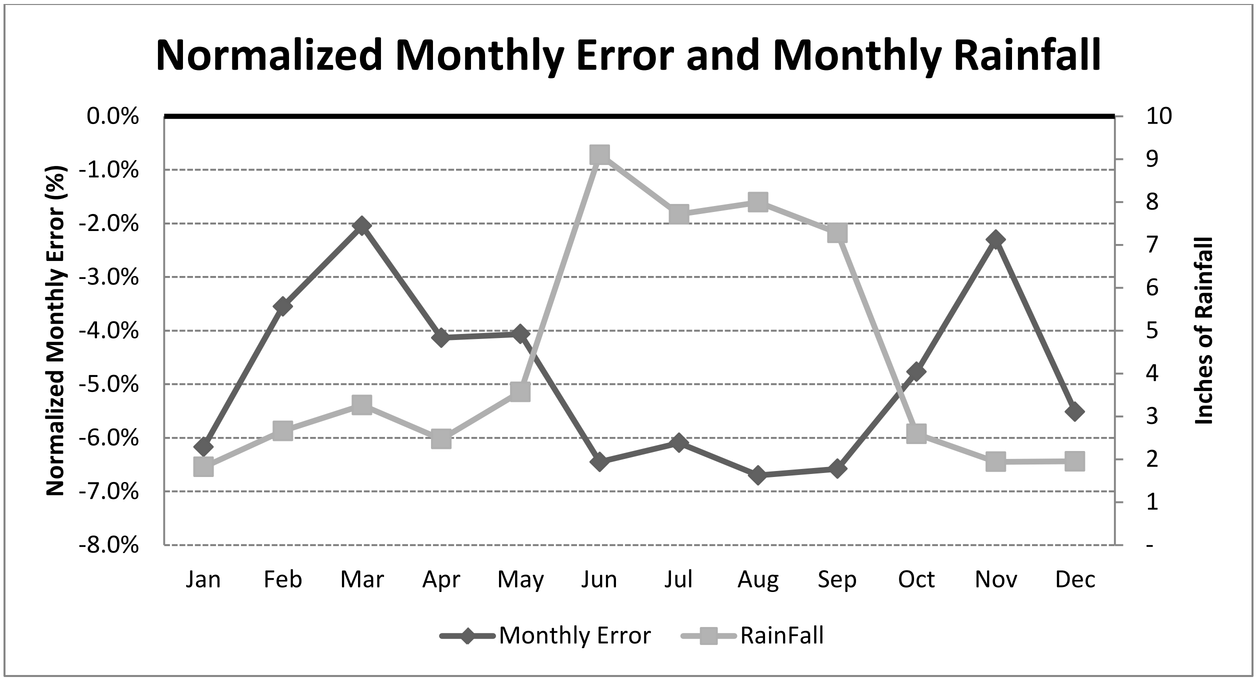


Figure ES-4. Rainfall correlating with seasonal error variability, DeSoto system

Hourly Results

The normalized root mean squared error (RMSE) is a good indication of overall agreement between SAM-predicted power production and measured power production for a given system on an hourly basis. Excluding the Mesa Top and DeSoto systems (still containing a known cause of error), the hourly normalized RMSE's for all systems were 5.1% or less. The best hourly normalized RMSE was observed in SAM's model of the Forrestal system—less than 2%. As with annual error, hourly performance prediction error does not appear to correlate with system size, meaning that SAM can predict commercial and utility-scale systems equally well for this sample of systems.

The normalized hourly mean bias error (MBE) and hourly 90% confidence intervals were also calculated for each system on an hourly basis (Figure ES-5; see Section 1.3 for how these metrics were calculated). Excluding the Mesa Top and DeSoto systems, which still contain the since-resolved backtracking error, all systems had normalized hourly MBE's of less than ±1.0%. The majority of the systems show slight underprediction. The system with the smallest normalized hourly MBE, the RSF 1 system, had an error of 0.3%. There is no observable relationship between system size and normalized hourly mean error. Excluding the Mesa Top and DeSoto systems, which still contain a known source of error, all systems have 90% confidence intervals within ±8% of measured values on an hourly basis. For example, the best confidence interval was that of the Forrestal system, for which 90% of the SAM-predicted values were within ±2% of their corresponding hourly measured values.

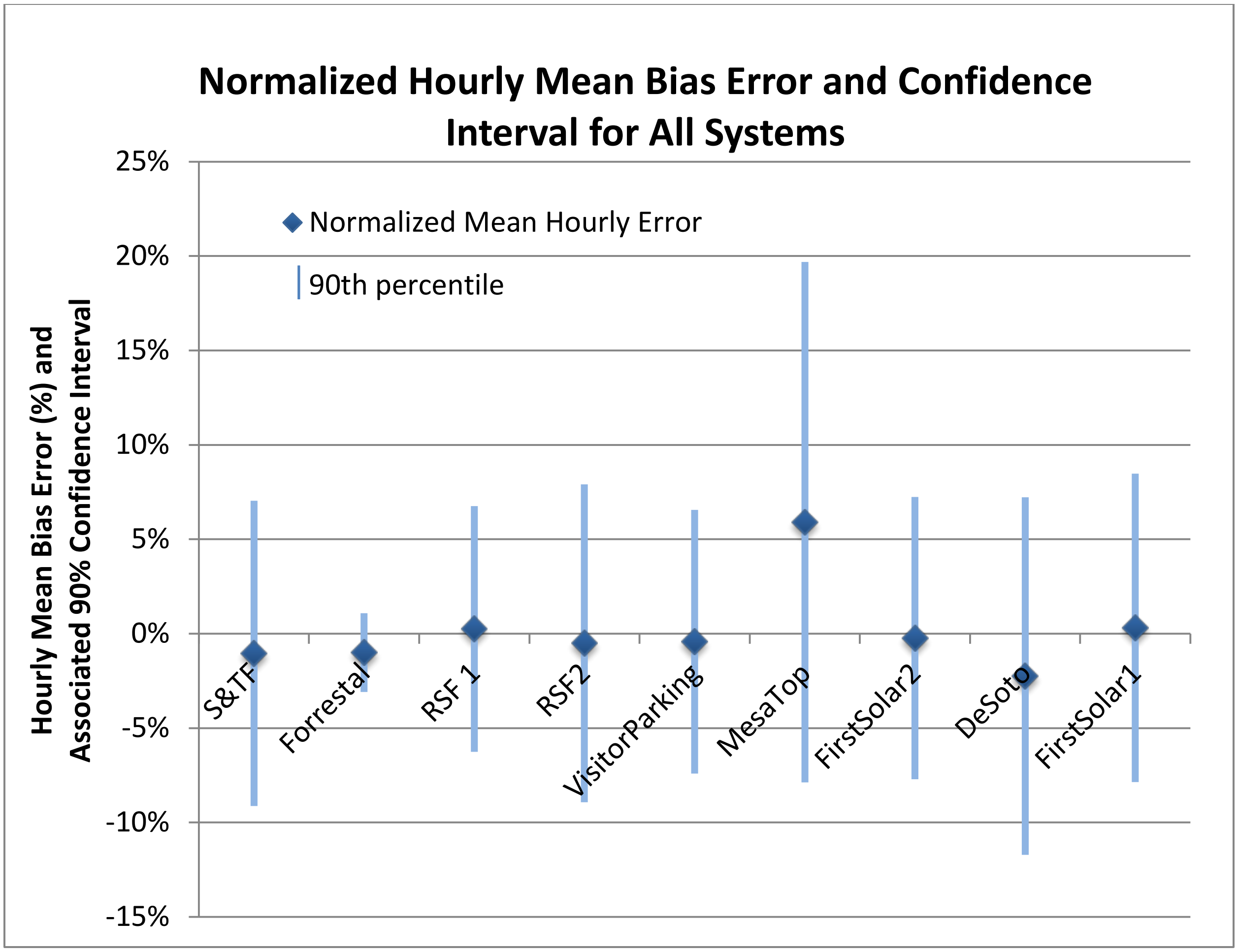


Figure ES-5. Normalized hourly MBE and 90% confidence interval, in order of system size[3]

Model Option Comparisons

The Forrestal system was selected to compare the differences between several of the model options available in SAM, because of the high data quality of the hourly measurements of the Forrestal system, and because high-quality measurements of all three components of irradiance data were available at that site. The following comparisons among model options were made for the Forrestal system only, in order to validate these SAM options:

- Sandia module model versus California Energy Commission (CEC) 5-parameter module model
- Perez versus Hay-Davies-Klucher-Reindl (HDKR) diffuse sky models
- "Total and Beam" irradiance inputs versus "Beam and Diffuse" irradiance inputs.

The most important conclusion that we drew from this model options comparison is that all of these module models, transposition models, and irradiance inputs perform well with respect to

[3] The Mesa Top and DeSoto systems still contain the since-resolved backtracking error.

measured data, within about ±3% total (annual) error, RMSE of 3.5%, and coefficient of determination (R^2) greater than 0.98 in all cases. This confirms the validation of SAM across all of its model and data options; if the module used in a project is available in the CEC module database but not the Sandia database, or if only beam and diffuse data are available at a site, SAM is still able to effectively estimate the production of that system.

In the Forrestal dataset, the Perez transposition model tends to have a slightly higher correlation and slightly lower RMSE than the HDKR transposition model, but similar total errors for the dataset. When using Total and Beam Irradiance, the CEC model has lower RMSE and total error than the Sandia model, but when using Beam and Diffuse Irradiance the reverse is true, making the comparison between the CEC and Sandia model inconclusive. It is interesting to note that the CEC module model shifts the annual SAM error down by about 3% compared to the Sandia module model under the same circumstances in both irradiance input cases. Using SAM's "Beam and Diffuse" irradiance as inputs causes larger underprediction (2.5% larger) in all cases and consistently produces a higher RMSE. However, this might not hold true for a dataset in which higher confidence is placed in the diffuse irradiation data than the global irradiation. It should be emphasized that all of these results are from only one system; these particular differences between models may not hold true for all systems. However, we consider this single-system test sufficient to confirm that all models available in SAM perform with similar levels of accuracy.

Conclusions

This validation study performed an in-depth examination of SAM's ability to predict the performance of 9 PV systems. The following list contains the main conclusions of this effort.

- The annual agreement between SAM-predicted and measured power production is within ±3% for all systems, excluding Mesa Top and DeSoto which still contain a known source of error.
- Hourly data matches well between SAM and measured production data, with a normalized RMSE of 5.1% or less and a normalized MBE of ±1.0%, excluding Mesa Top and DeSoto which still contain a known source of error.
- All of the model options explored with the Forrestal system in this effort (CEC versus Sandia module model, Perez versus HDKR diffuse sky model, "Beam and Diffuse" versus "Total and Beam" irradiance inputs) resulted in similar agreement with measured data.
- There exists a seasonal variation in monthly error that will be investigated in future work. This can likely be attributed to seasonal transposition model error variation as shown by Sandia [1]. We have begun testing several additional hypotheses for this seasonal variation.
- There is no increase in either annual or hourly error with an increase in system size, despite the fact that SAM does not explicitly model several issues inherent in utility-scale systems.

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1 SAM Validation Summary

1.1 Introduction

To secure competitive financing for a photovoltaic (PV) system, the economic risks associated with variability, technology maturity, and system design must be quantified and minimized. Because a PV system's economic viability depends directly on its energy yield, the performance of a proposed system must be accurately characterized to ensure that financial institutions are confident in the technology and system design. To be accessible by the financial community, the impact of variations in energy yield must also flow through to financial metrics, such as the levelized cost of energy (LCOE) and return on investment (ROI).

There are several shortcomings in the current solar modeling arena with respect to risk, uncertainty, and the ability of the financial community to ascertain the risk of a solar investment. Current tools, including the System Advisor Model (SAM), PVWatts, and others, are not sufficiently validated across a broad range of systems, markets, and geographical locations to provide the financial and independent engineering community with sufficient acceptance of these models. Additionally, there continue to be underlying modeling gaps with regard to derates, emerging technologies, and the unique characteristics of very large systems. These modeling gaps mean that financiers are not adequately equipped with tuned performance predictions to make informed investment decisions.

This seeks to improve the acceptance of SAM by focusing on validation of the model with extensive real data. Based on the findings of this report, we intend to increase the value of SAM to the community by creating new algorithms and methods to improve the fidelity and accuracy of modeled results and translating this to the broader community via accessible tools. The success of this project will therefore provide the PV and financial community with a rigorous scientific underpinning for best-in-class modeling algorithms to accurately predict PV system performance, thereby improving the industry characterization of risk and improving bankability across all markets (residential, commercial, and utility).

1.2 SAM Background

The National Renewable Energy Laboratory's (NREL's) SAM is a free software tool that implements a broad and robust set of models and frameworks for performing detailed analysis of both system performance and system financing. It does this across a range of technologies, including solar technologies such as PV and concentrating solar power (CSP). SAM also provides sophisticated and tightly integrated analysis tools for solar energy, including stochastic analysis and long-term interannual variability tools to calculate

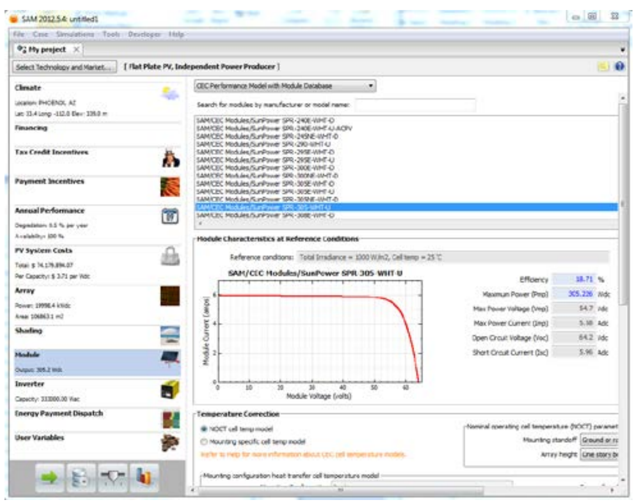


Figure 1-1. System Advisor Model interface

P50 and P90[4] exceedance probabilities. Such risk assessment tools are essential for assessing revenue streams and securing competitive financing for a proposed project.

The tool has been in development since 2004 and has been downloaded by 40,000+ unique users since its inception. Additionally, there are over 200 publications that used SAM to conduct their research. The original impetus for SAM acknowledged that, while a great deal of model development was being done inside and outside the U.S. Department of Energy (DOE) research community, these improvements were not effectively communicated to the solar industry. SAM is a means to make the latest research in renewable energy production modeling accessible to a wide variety of audiences and combine energy modeling with a consistent set of financial models across all technologies.

Today, SAM is used by utilities, developers, installers, manufacturers, policy analysts, and researchers. To facilitate ease of use of the tool, the SAM team has developed a software development kit (SDK) to deliver the underlying SAM calculation engine to the renewable energy industry, a capability of which multiple large PV manufacturers are taking advantage. These large companies are relying on SAM to provide performance estimates for their proprietary system siting and design tools.

1.3 Methodology

In order to validate the performance of SAM, 9 systems for which NREL could obtain measured performance data were analyzed in detail to quantify SAM's ability to predict performance for these systems. The systems analyzed include three utility-scale (greater than 10 MW) systems and six commercial-scale systems (75–700 kW). All systems were modeled in SAM with as much site metadata as were available for the system. Each system study will state if any assumptions were made in modeling that system. Onsite measured irradiance and meteorological data were used as inputs to SAM where possible. Finally, the SAM-predicted alternating current (AC) power production was compared to the measured AC power production for each system.

Once each system was analyzed separately, results were aggregated by system type (commercial or utility) and also at a total level. For the purposes of this report, we are defining systems that are less than 1 MW in size as commercial-scale systems and systems that are greater than 1 MW in size as utility-scale systems. It is important to analyze these two categories not only in conjunction but also separately in order to identify any modeling issues that might affect these two categories differently due to their extreme size differences. This section presents the aggregate results of all 9 systems analyzed. The results can be found in subsequent sections of this report, with a separate section for each system study, and the results aggregated by system type in two summary sections (Section 2 for the commercial-scale summary; Section 9 for the utility-scale summary).

1.3.1 Data and Specifications Collection

In all of the systems studied, all available production and resource data collected at the site were collected from the site owner, operator, or performance monitoring company. Site metadata was

[4] For more information on P50 and P90 exceedance probabilities, see "P50/P90 Analysis for Solar Energy Systems Using the System Advisor Model: Preprint" (A.P. Dobos et al. 2012)

collected from the site owner/operator if possible. When additional metadata was needed, an internet search was performed for the missing data. Some site metadata was also obtained through examination of the systems via Google Earth. If necessary meteorological data were not measured at the site, the required data were taken from the concurrent Solar-Anywhere-modeled dataset at that location.

1.3.2 Data Quality Control

Data quality control is necessary for this validation effort because the purpose of this validation is to compare SAM-modeled data to accurately measured data from an operating system. Once the data were received from the appropriate source, we performed extensive data quality control because often the raw data received had entries that were interpolated, estimated, repeated, or missing. Several distinct issues were corrected through quality control, as described in the list below. Further details of the quality control methods that were applied to each system can be found in the individual system studies. Figure 1-2 shows an example of a 12-day period containing multiple data quality issues with Global Horizontal Irradiance (GHI) that had to be corrected prior to the data being usable.

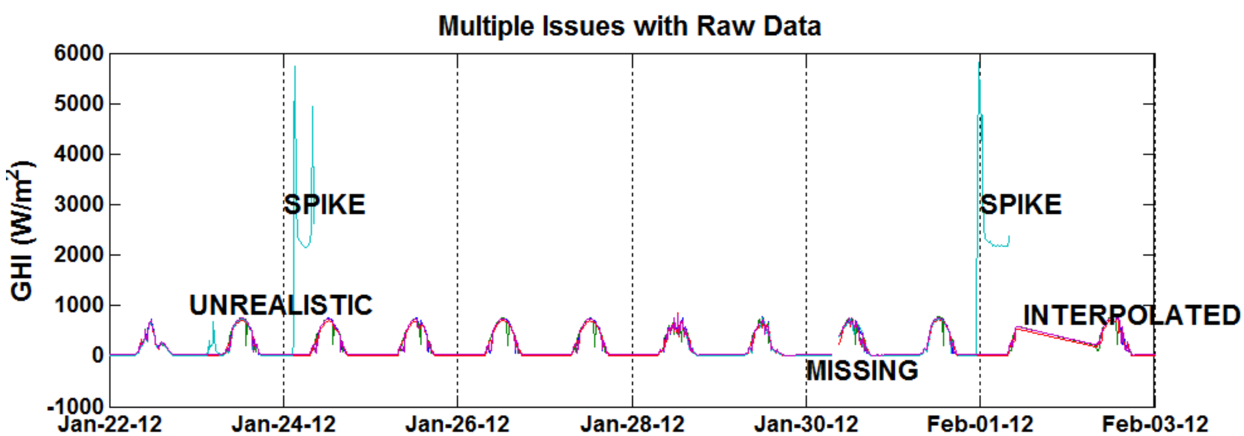


Figure 1-2 Examples of multiple data quality issues present in redundant GHI data streams

Issues addressed in quality control included the following items.

Missing Data: In the event that data were missing, either that the data timestamp skipped over several hours or that the timestamp was recorded but the data field was empty for that hour, the missing hour(s) was/were removed from the dataset. The corresponding hours predicted by the SAM simulation were also removed from the analysis.

Erroneous Data: Data that were reported as error codes (frequently -999 or similar) were removed from the analysis, and the corresponding hour(s) was/were also removed from the SAM simulation.

Data Interpolation: Data that was interpolated from two correctly recorded entries is often unrepresentative of the measurement that would have been taken at that timestamp. Thus, interpolated hours were removed from all datasets, as well as their corresponding hours from the SAM simulation.

Estimated Data: Any hour of data that was received that was marked as “estimated” by the data collection system was removed from the analysis, as was the corresponding hour from the SAM simulation because the purpose of this validation is not to compare SAM-modeled data to otherwise modeled or estimated data.

System Shutdowns: PV systems might experience enforced shutdowns for several reasons, at the request of the utility (e.g., for system maintenance or to add other systems to the interconnect). These system shutdowns were not always reported to NREL with the data collected from the system. In some cases, it was possible to verify system shutdowns from the system operator. The rest of the time, system shutdowns were identified by looking for prolonged periods of time where the system power output did not correlate appropriately with measured irradiance data, usually reporting zero for days at a time despite high irradiance values. If snow depth data were reported during this time, it was not identified as a system shutdown but was instead investigated as a snow cover problem. If no snow depth was reported during the time in question, it was identified as a system shutdown. System shutdowns would ordinarily be modeled in SAM as an availability “Performance Adjustment,” but validating availability assumptions is outside of the scope of this validation effort. Depending on the amount of downtime and the distinct methodology used in each system study, hours, days, or even months with system shutdowns were removed. System shutdowns were removed because the purpose of this validation is to compare SAM-predicted data with data from a correctly operating system.

Inverter Outages: Several systems experienced inverter outages. Like system shutdowns, these were not reported in the data that NREL received. Inverter outages are distinguished from system shutdowns by the fact that during inverter outages, one or more inverters are not operational, but the system as a whole still generates power. For this reason, inverter outages cannot be identified simply by zero power output during times with irradiance and zero snow cover. Inverter outages were identified by comparing the output of each inverter on an hourly basis when there were multiple inverters present in the system. The power output from each inverter should correlate very highly if all inverters are functioning properly. When large differences occurred, such as one inverter reporting zero when another inverter reported a normal output, an inverter outage was identified. An example of large inverter discrepancies can be seen in Figure 1-3.

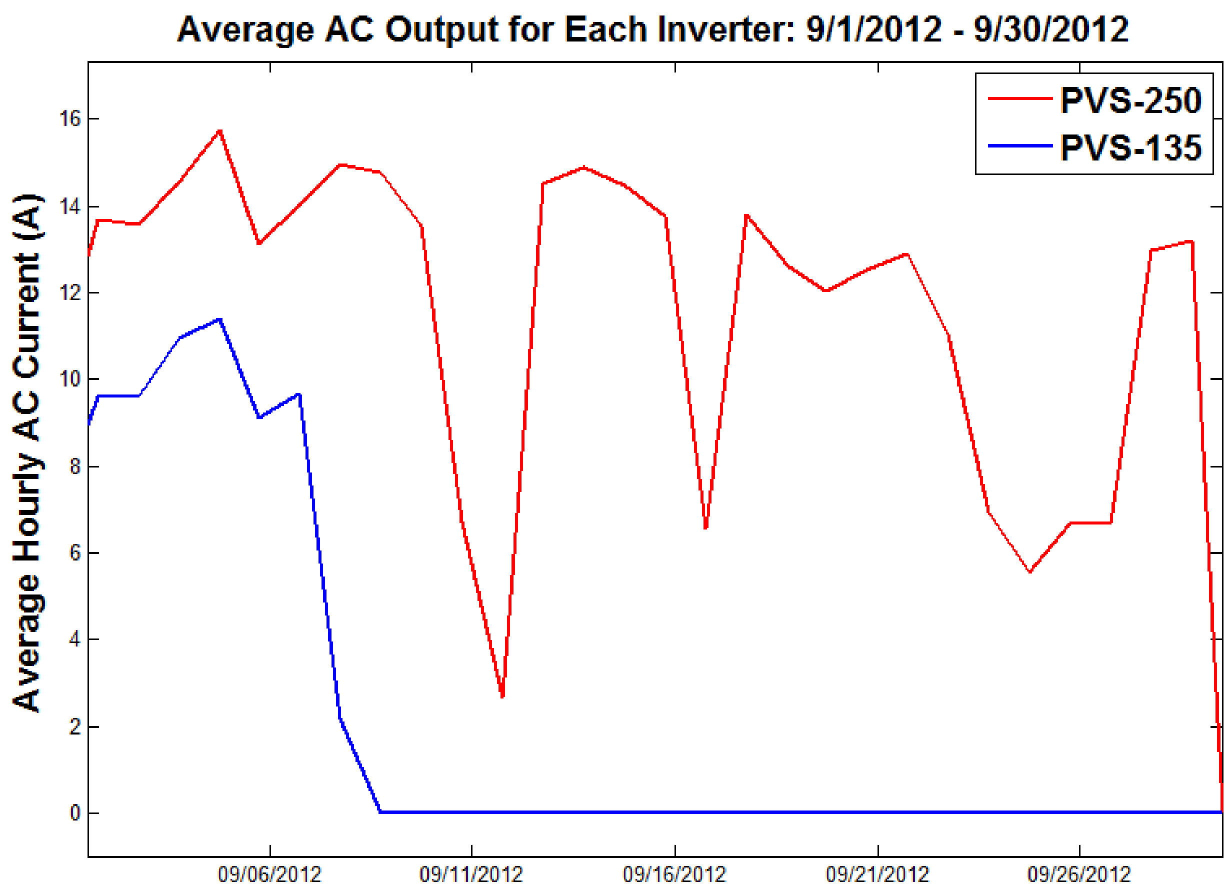


Figure 1-3. Inverter outages, where PVS-250 and PVS-135 are two different inverters

Like system shutdowns, inverter outages would normally be modeled in SAM using the availability Performance Adjustment, but the full hour or day of data for any data point experiencing an inverter outage was removed because predicting component availability is outside of the scope of this validation effort.

The presence of a prolonged inverter outage can also be indicated graphically by looking at a scatter plot of measured power production versus SAM-predicted power production on an hourly basis, as shown in Figure 1-4 (ignoring the zenith angle sorting). A prolonged inverter outage will create a very linear secondary trendline separate from the expected 1:1 trendline shown in black, similar to the one seen in the red circle in this figure. This is an indication that the data should be examined closely for a possible inverter outage.

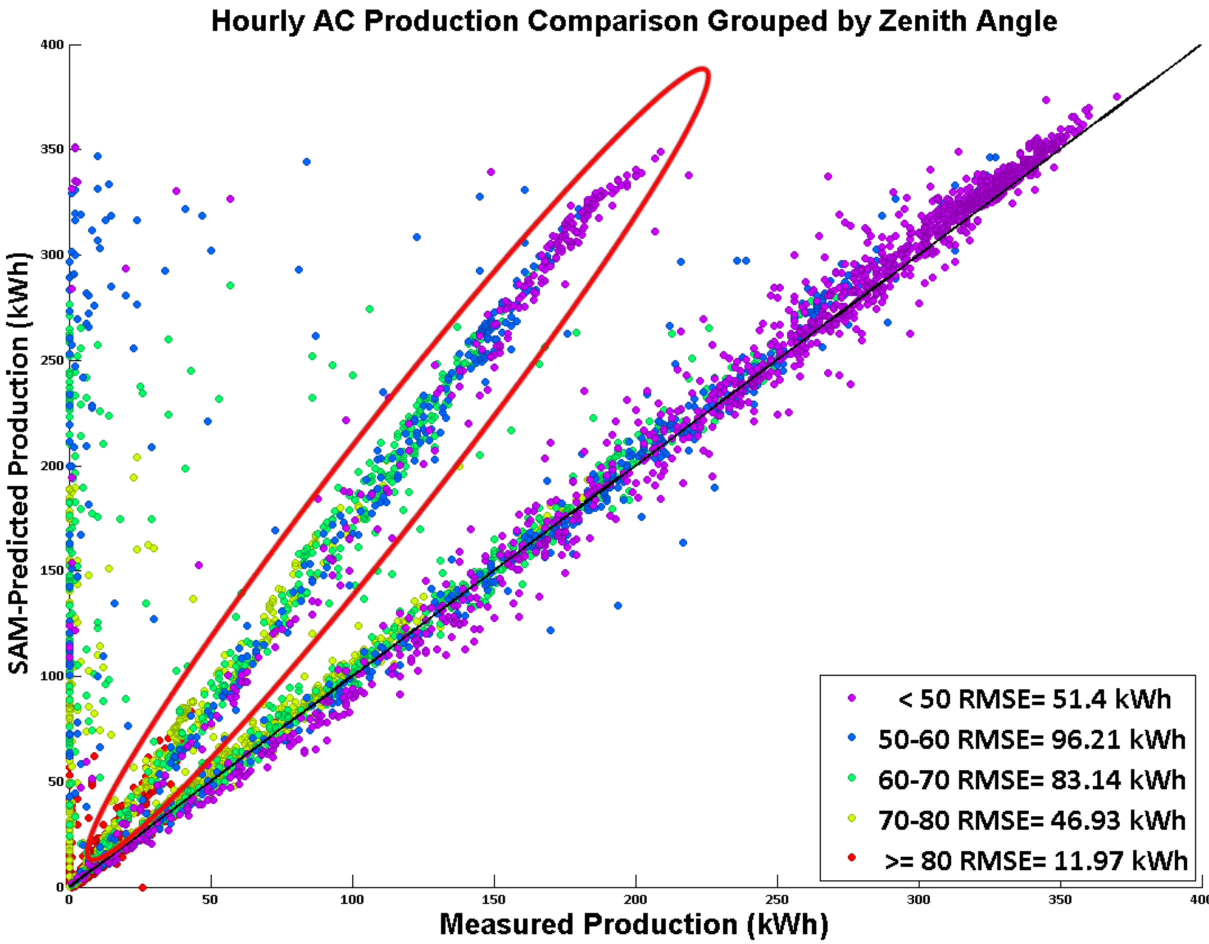


Figure 1-4. Second trendline formed by inverter outages

Sensor Offset Adjustments: If irradiance sensors have not been calibrated properly or on schedule, they will report a non-zero value at night. In order to eliminate uncertainty in the weather data input into SAM and isolate the model error, irradiance sensors with a non-zero nighttime value were offset by their nighttime value on a daily basis in the utility-scale systems. See Section 10 for more detail.

1.3.3 Simulation

All systems were run using a Typical Meteorological Year version 3 (TMY3)-formatted year of all available measured irradiance and meteorological data for the period concurrent with the available measured performance data. For any simulation run in 2012, February 29 was removed from the analysis because SAM only outputs an 8760-hour-per-year dataset, which does not account for leap years. Every system had at least total (global horizontal) irradiance measured onsite. If needed components, such as temperature or a second irradiance component (beam or diffuse), were not available, the concurrent data from Clean Power Research's Solar Anywhere dataset (CPR data) was used. Clean Power Research (CPR) provides data with a two-year time lag via their Solar Anywhere website which anyone can access. The CPR data used in this report that was recorded within the last two years (e.g., 2011 data) was accessed via a special license granting NREL access to the data for research purposes. The Perez model was used for plane-of-array calculations.

If the module at the site was known, it was taken from one of the module databases available in SAM [California Energy Commission (CEC) or Sandia]. For a few utility-scale sites, the module series was known, but the exact model was not; therefore, a representative model of that series was selected to model the system. Likewise, the inverter model, if known, was selected from the Sandia inverter model database; otherwise, the "Single-Point Efficiency" inverter model was used. See Section 10, Section 11, and Section 12 for more information about how this was performed. Lack of exact specifications has the potential to skew the error in systems where exact specifications were not known, but represents the best ability of the modelers to model the system with the information given.

If exact numbers were known for the number of modules per string and strings per inverter, these numbers were used in SAM's simulation. If these numbers were unavailable, the system was modeled using the SAM-suggested layout based on the nameplate system size. In one case, the system featured two different inverters; because SAM does not accept sub-arrays using different modules or inverters, this system was modeled as two separate cases and their outputs summed. See Section 6 for more detail.

The SAM output metric compared against measured performance data was "Gross AC Output" (kWh) because all measured performance data were measured at the inverter output.

1.3.4 Derate Adjustments

All results presented in the Executive Summary and Section 1 are presented for simulations run using the default derates. These include a 5% annual soiling loss, 2% mismatch loss, 2% DC wiring loss, and 1% AC wiring loss, among others. See SAM for a complete list of default derates.

In commercial-scale systems, if the system had been operating for more than one year, a 0.5% annually compounding performance degradation was applied to the system for subsequent years. The exact values of degradation rates applied are specified in each system study.

All other available derates were left at their default values for both commercial- and utility-scale systems.

1.3.5 Known Causes of Error

During the course of these 9 system studies, we were able to isolate and identify two separate causes of error that had large effects on SAM's ability to predict power production. While not accounting for all model error, these two problems do account for a significant portion of the error encountered in many of the systems and therefore merit mention. These two problems are snow cover and an incorrect backtracking algorithm in the 2013.1.15 version of SAM (a resolved issue as of the 2013.9.20 release). Amongst the various potential causes of error in SAM (e.g., derates and soiling), snow cover and the now-resolved backtracking issue are specifically addressed in this report due to the large discrepancies they create.

1.3.5.1 Snow Cover

Snow cover is a particularly problematic cause of error in forecasting energy production because it is very difficult to predict when snowstorms will occur, how much snow will stick to the panels when it does, and how quickly the snow will melt or fall off of the panels after the storm. The latter is particularly tricky due to the fact that the angle of repose of snow varies greatly depending on local conditions; surfaces that accumulate snowfall during one storm might not accumulate snowfall during the next storm. The melting and sloughing patterns are particularly complicated for a tracking system or a fixed system abutting a wall. This is a known source or error that is currently being researched at NREL, and when an algorithm is developed it will be implemented in SAM. However, this validation effort revealed the extent to which snow cover can affect a system.

Some of the difficulty in modeling this phenomenon correctly is that snow melts off of pyranometers much more quickly than it melts off of solar panels, in part because of the domed shape of most pyranometers and in part because many pyranometers are heated. Therefore, in some cases the pyranometer will measure normal irradiance values even though the panels cannot produce normal power because they are wholly or partially covered in snow. This in turn causes SAM to substantially overpredict energy production during those days. The phenomenon of snow accumulation reducing actual power production can be identified by graphing SAM-predicted power production, measured production, and snow depth as a function of time (see Figure 1-5).

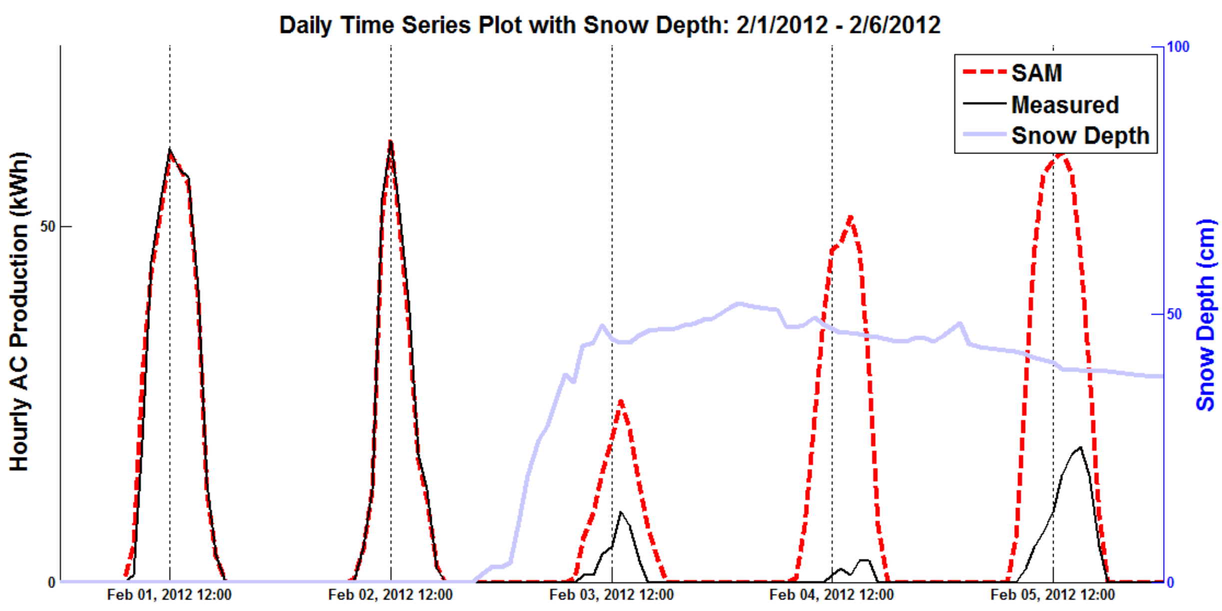


Figure 1-5. Snow-related power discrepancies

For all systems experiencing snow cover, the data were examined both before and after removing any data experiencing this known cause of error, in order to quantify the portion of the error due to snow cover and also to unveil any other potential problems that might be masked by the presence of such large snow cover error. Snow cover data removal was accomplished in one of three ways: (1) whole days were removed based on visual examination of a plot, such as the one shown in Figure 1-5; (2) whole days were removed based on recorded dates during which a region was experiencing a large storm combined with unusually low power output on those days; or (3) hours were removed based on an algorithm that removed every hour with a measured snow depth of 1 cm or more. These different methods were used due to different snow depth data availability and also different observed melting rates in the systems.

1.3.5.2 Backtracking (Resolved)

Another important issue revealed in this validation effort is that the SAM 2013.1.15 backtracking algorithm was incorrect for one-axis tracking systems. This was revealed when high zenith angles resulted in larger errors for the Mesa Top one-axis tracking system, indicating that there was an error with the backtracking or row-to-row shading algorithms in the 2013.1.15 release. Experimentation with SAM inputs yielded that in the 2013.1.15 release, SAM-predicted AC power production was independent of changes in the distance between rows. Further investigation showed that this error was produced because during many hours where SAM should have been utilizing backtracking it was instead setting the tracker rotation angle to its maximum. This effectively should act to reduce the power production of the system; however, when a system is designated as a backtracking system SAM correctly disables the row-to-row shading algorithm. These two effects coupled together resulted in unusually large errors for higher zenith angles, as shown in Figure 1-6.

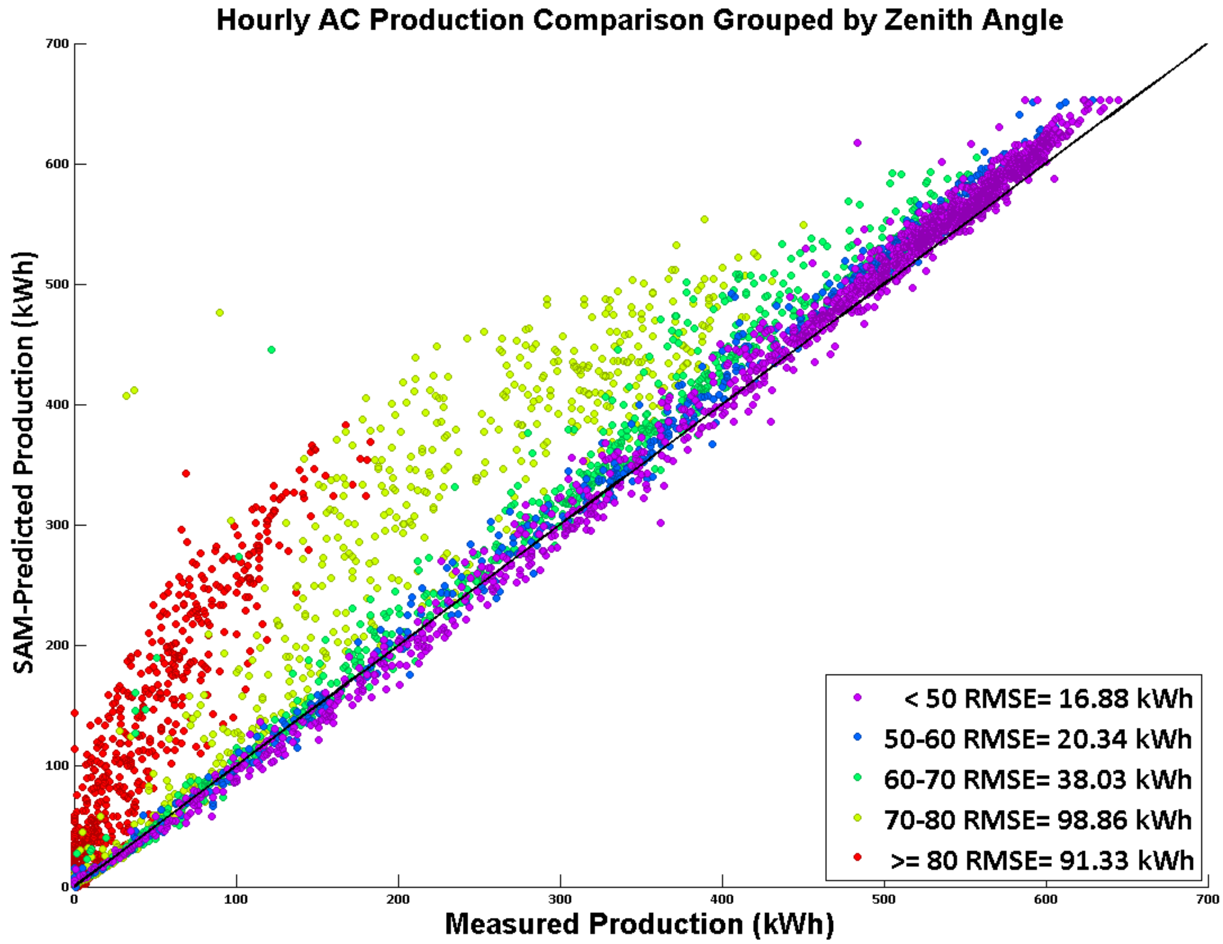


Figure 1-6. Problems with one-axis tracking systems at high zenith angles - 2013.1.15 release

This issue was addressed in the 2013.9.20 release of SAM, resulting in much better agreement with one-axis tracking systems whose rows are spaced closely enough to cause significant backtracking (see Figure 1-7).

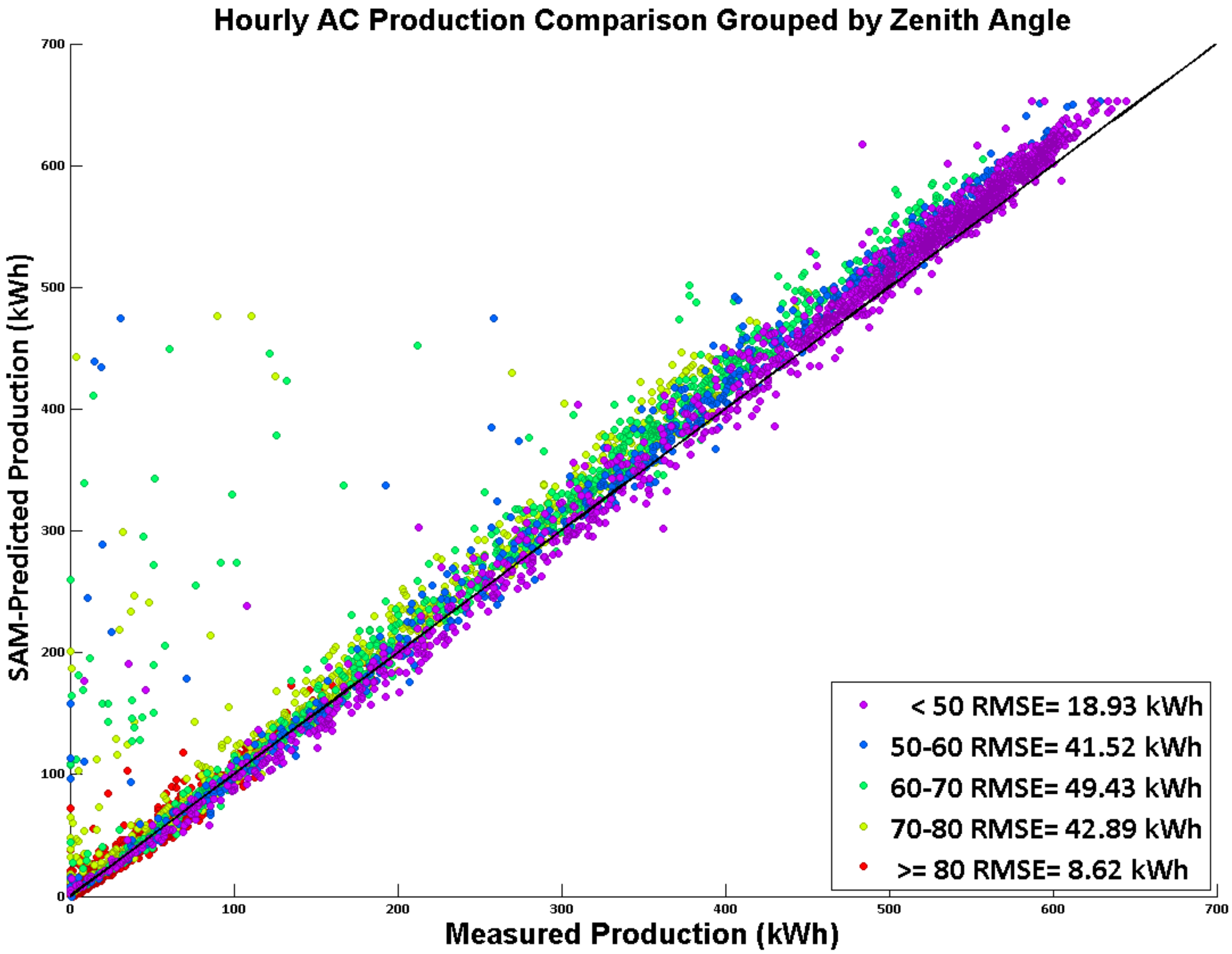


Figure 1-7. Corrected problems with one-axis tracking systems at high zenith angles - 2013.9.20 release

More details about the diagnosis and resolution of this issue can be found in Section 4, the Mesa Top system study. This issue also affected the DeSoto system study, although its effects were not as noticeable because the row spacing is larger for the DeSoto system.

1.3.6 Analysis Methods and Metrics

Many different statistics were examined as a part of this analysis. SAM users may care about accuracy on a range of timescales, from an annual basis down to an hourly basis, so an attempt was made to characterize SAM's performance accordingly. This section describes the various metrics used in this report to quantify SAM's performance. All metrics were computed after all data quality control measures had been taken because a comparison of SAM's prediction to low-quality data would not provide an accurate assessment of SAM. However, when it comes to the known causes of error listed above, many of these statistics were computed both before and after removing those causes of error in order to quantify the effect of the known causes of error.

Additionally, nighttime hours were removed from all of the datasets prior to statistical analysis in order to avoid presenting misleading statistics. The algorithm that SAM uses to determine whether the sun is up or down is very accurate and automatically assigns no direct current (DC) power production at nighttime, making the AC power production a small negative value equal to the inverter operating losses. Therefore, the error during all night hours is very low. Leaving these points in the analysis would skew hourly statistics by indicating that the mean hourly error and RMSE are much lower than the daytime hourly error. Thus, nighttime hours were removed from the datasets prior to performing any analysis. The algorithm used to remove nighttime hours analyzed both the measured performance data and the SAM-predicted data; if either SAM or measured production data showed power production for a given hour, that hour was not removed from the analysis. Table 1-1 is an example of the large artificial reduction in root mean square error (RMSE; defined on the next page) that is present if nighttime hours are included in the analysis.

Table 1-1. The Effect of Removing Nighttime Hours on RMSE

Season	RMSE - Including Nighttime Hours (kWh)	RMSE - Nighttime Hours Removed (kWh)	Percent Difference
Winter	13.56	19.86	-46.46%
Summer	10.53	13.77	-30.76%

The following statistics and plots were calculated for all systems after all appropriate data quality control measures had been implemented and nighttime hours had been removed.

Scatter Plots: All scatter plots shown in this report (see Figure 1-8) feature measured inverter-output AC power production plotted on the x-axis and SAM-predicted power production plotted on the y-axis for each hour in the dataset. If SAM were to perfectly model measured production, the points in this plot would be coincident with the 1:1 line shown in black. However, because all models are imperfect, there is some scatter around the ideal line. The further away a point is from the black line, the worse agreement between SAM and measured power production for that hour. Points above or below the line represent values where SAM predicted higher or lower power production, respectively, than was measured.

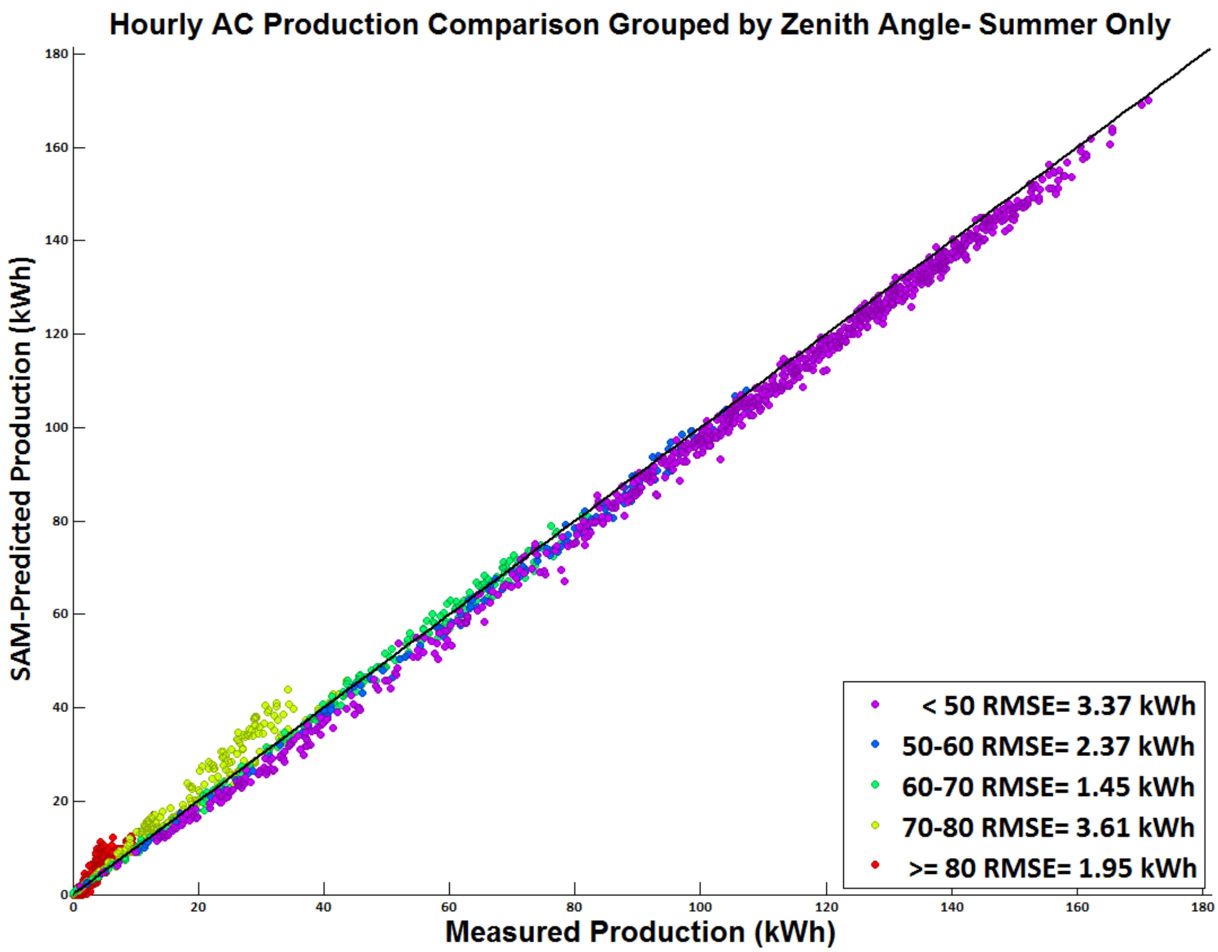


Figure 1-8. Example scatter plot with ideal 1:1 trendline in black (Forrestal system)

Hourly Root Mean Square Error (RMSE): The hourly RMSE is defined as:

$$RMSE = \sqrt{\frac{\sum_i^N (SAM_i - Measured_i)^2}{N}} \tag{1}$$

where N is the number of observations.

The RMSE is a common metric to examine model error. Squaring the error ensures that hours where SAM overpredicts power production do not cancel out errors where SAM underpredicts power production, which could create the false impression that SAM's error is lower than it actually is. RMSE exponentially weights data points with larger errors prior to summing them, meaning that the farther a data point is from the 1:1 trendline the more of an effect it has on the calculated RMSE.

Normalized RMSE: The normalized hourly RMSE is used to compare the RMSE between different systems. The RMSE for each system is calculated as described above; then this value is normalized by the maximum observed output for that system. This was chosen in lieu of normalizing by either nameplate AC or DC capacity because in several of the systems studied, the inverter was either greatly oversized or undersized relative to the DC capacity of the system. Normalizing by the maximum observed AC output from the inverter avoids the skew that would be introduced to the normalization by choosing either the AC or DC nameplate capacity. This normalization results in a metric that is given as a percentage of the maximum observed system output.

Normalized Mean Bias Error (MBE): The MBE is used with confidence intervals (defined below) to understand the center point of the confidence interval. The MBE is computed on an hourly basis by averaging all of the hourly residuals (SAM – Measured) for a given system. The MBE is then normalized by the maximum observed output of the system; this normalization method is chosen for the same reasons as mentioned in the definition of the normalized RMSE. This normalization results in a metric that is given as a percentage of the maximum observed system output. A positive normalized MBE corresponds to SAM overpredicting measured production.

90% Confidence Interval: The 90% confidence interval was calculated on the hourly values for each system, for sake of comparison of systems. The interval assumes a normal distribution and is defined as:

$$1.645[Std(\ SAM_i - Measured_i)] = Confidence\ Interval_{90\%} \qquad (2)$$

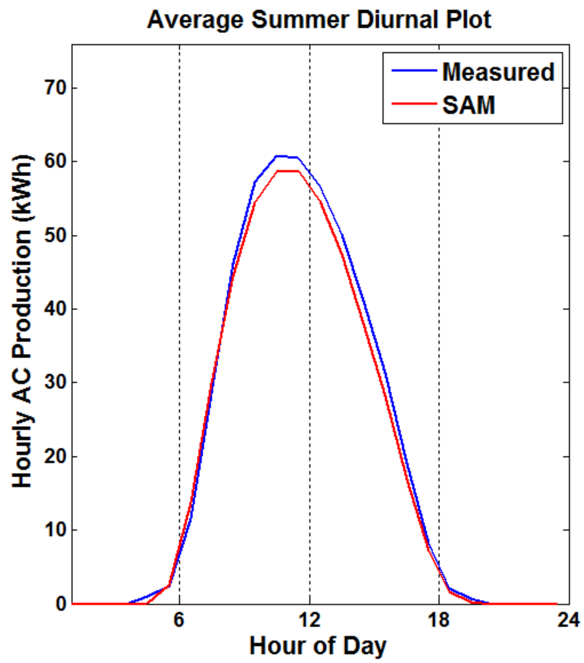
where *Std* is the standard deviation of the quantity indicated in the parentheses.

Coefficient of Determination (R^2): The correlation strength, or R-squared (R^2), is defined as:

$$R^2 = \frac{\sum_i^N (SAM_i - Measured_{avg})^2}{\sum_i^N (SAM_i - SAM_{avg})^2} \qquad (3)$$

where N is the number of observations. This value indicates how well a dataset fits a linear correlation. For example, in a scatter plot like the one in Figure 1-8, the wider the scatter around the ideal line, the lower the correlation strength, and therefore the lower the value of R^2. Due to the way that this statistic is calculated, a high correlation ($R^2 = 1$) does not necessarily ensure a good fit to the 1:1 trendline shown in the figure; it could instead indicate that the data fits a line with a different slope or intercept. Thus, this metric was not used extensively in this report.

Average Diurnal Plots: The average diurnal plots (see Figure 1-9) were computed by averaging the power production for each hour of the day in a given season (winter or summer). For example, to create the blue line in Figure 1-9, all measured production values with the timestamp 9:00 a.m. during the winter were averaged, and this was repeated for 10:00 a.m., 11:00 a.m., and so on for the full 24-hour day. This was done separately for measured production data and SAM-predicted production data for comparison purposes and was separated by season in order to illuminate any seasonal differences in diurnal patterns. Winter is defined as October through March, and summer is April through September. This graph served primarily diagnostic purposes.



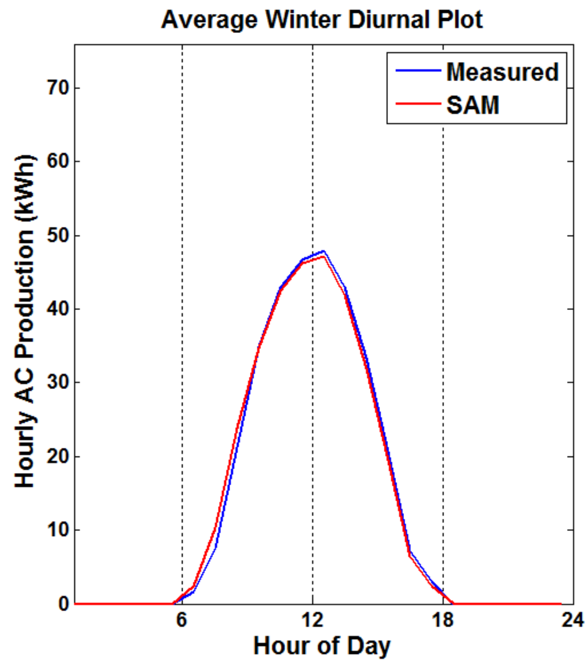


Figure 1-9. Average summer and winter diurnal plots

Monthly Error: Within each one-month period, all available hours of SAM-predicted power production and measured power production are summed separately, and then the percentage error is calculated according to (4).

$$Error\ (\%) = \frac{\sum SAM\ (kWh) - \sum Measured\ (kWh)}{\sum Measured\ (kWh)} * 100\% \qquad (4)$$

A positive monthly error corresponds to SAM overpredicting measured production.

Total/Annual Error: The total (annual in most cases) error is calculated in a similar fashion to monthly error. Within a given year, all available hours of SAM-predicted power production and measured power production are summed separately, and then the percentage error is calculated according to (4). A positive error corresponds to SAM overpredicting measured production.

1.4 Aggregate Validation Results

Nine individual systems were studied in this analysis, including six commercial systems and three utility systems. The systems studied are summarized in Table 1-2.

Table 1-2. Summary of Systems Studied

System	Category	Location	System Type	Years	Snow
Forrestal	Commercial	Washington, D.C.	Fixed tilt	2009–2010 (1 yr)	yes
S&TF	Commercial	Golden, CO	Fixed tilt	2011, 2012	yes
RSF1	Commercial	Golden, CO	Fixed tilt	2011, 2012	yes
RSF 2	Commercial	Golden, CO	Fixed tilt	2012	yes
Visitor Parking	Commercial	Golden, CO	Fixed tilt	2012	yes
Mesa Top	Commercial	Golden, CO	One-axis tracking	2011, 2012	yes
FirstSolar2	Utility	SW USA	Fixed tilt	2011	no
DeSoto	Utility	Arcadia, FL	One-axis tracking	2012–2013 (1 yr)	no
FirstSolar1	Utility	SW USA	Fixed tilt	2011	no

As mentioned previously in this section, the two largest-known sources of error were snow cover and a backtracking algorithm error (corrected in the 2013.9.20 release). Snow cover was present in all of the commercial systems, but snow depth data available at these sites allowed us to remove the hours affected by snow cover. Therefore, all of the statistics for commercial systems in this section are presented excluding hours with snow cover. More information on how snow cover affects the commercial systems can be found in Section 2. Snow cover was not present in any utility systems.

The backtracking problem (resolved in the 2013.9.20 SAM release) only pertains to the two one-axis tracking systems: Mesa Top (commercial-scale) and DeSoto (utility-scale). The effect of this known cause of error can be seen in the Mesa Top system (see Section 4 for more detail) but is not nearly as noticeable in the DeSoto system. This is due to the fact that the DeSoto system has a larger row-to-row spacing than the Mesa Top system, and therefore spends much less time in backtracking mode, making the effect of this error less noticeable for DeSoto. However, because we were unable to remove the known source of error from these two systems using the 2013.1.15 release, all statistics included in this summary are presented both including and excluding the Mesa Top and DeSoto systems.

1.4.1 Hourly Results

The normalized RMSE, which is normalized by each system's maximum measured power, is a good indication of overall agreement between SAM-predicted power production and measured power production for a given system on an hourly basis. Excluding the Mesa Top and DeSoto systems (which still contain a since-resolved cause of error), the hourly normalized RMSE's for all systems were 5.1% or less (see Figure 1-10). The best hourly normalized RMSE was observed in SAM's model of the Forrestal system—less than 2%. This is because, for the Forrestal system, all of the necessary weather data was measured on-site with high quality instruments, and the measured performance data was also high-quality. There is no noticeable relationship between system size and normalized RMSE.

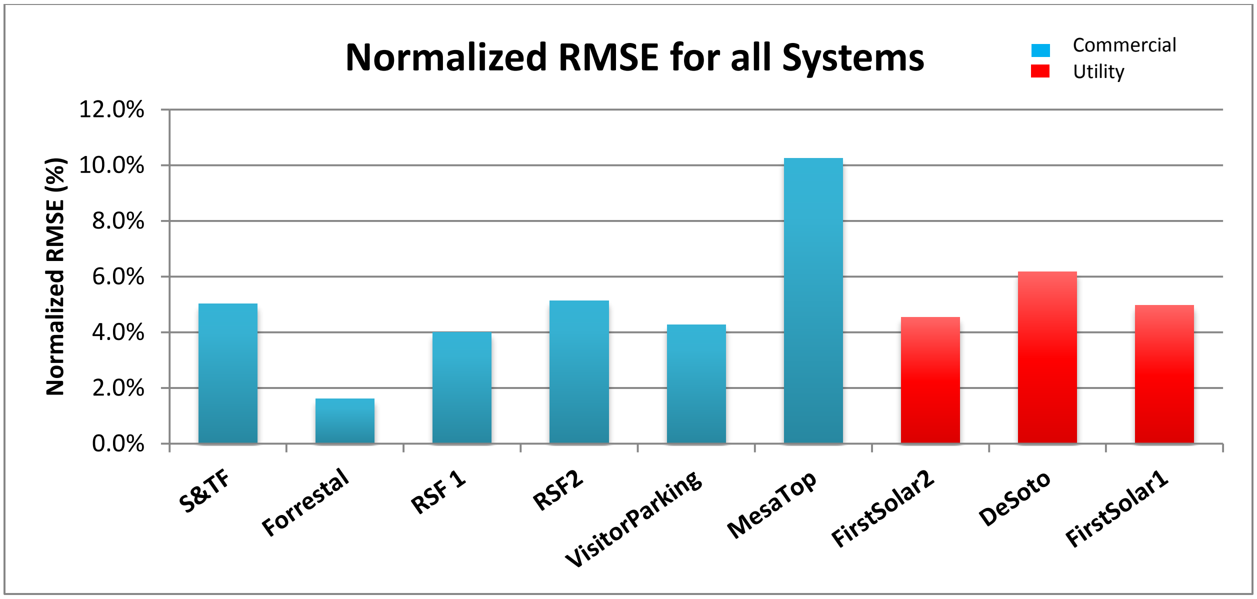


Figure 1-10. Normalized RMSE for all systems, in order of size[5]

The normalized hourly MBE is a measure of SAM's average hourly bias in predicting power production of a system as compared with measured data. Figure 1-11 shows the normalized hourly mean error and 90% confidence interval for each system in order from smallest to largest system size. Almost all of the examined systems had a normalized hourly MBE of less than ±1.0%, the only exceptions being the DeSoto and Mesa Top systems, which still contain known sources of error and had normalized hourly mean errors of -2.2% and 5.9%, respectively. The majority of the systems show slight underpredictions. The Mesa Top system had the largest normalized hourly mean error of any of the modeled systems, largely due to the since-resolved cause of error in SAM with the backtracking algorithm (resolved in the 2013.9.20 SAM release). The system with the smallest normalized hourly mean error, the RSF 1 system, had an error of 0.3%. There is no observable relationship between system size and normalized hourly mean error or confidence interval.

[5] The Mesa Top and DeSoto systems still contain the since-resolved backtracking error.

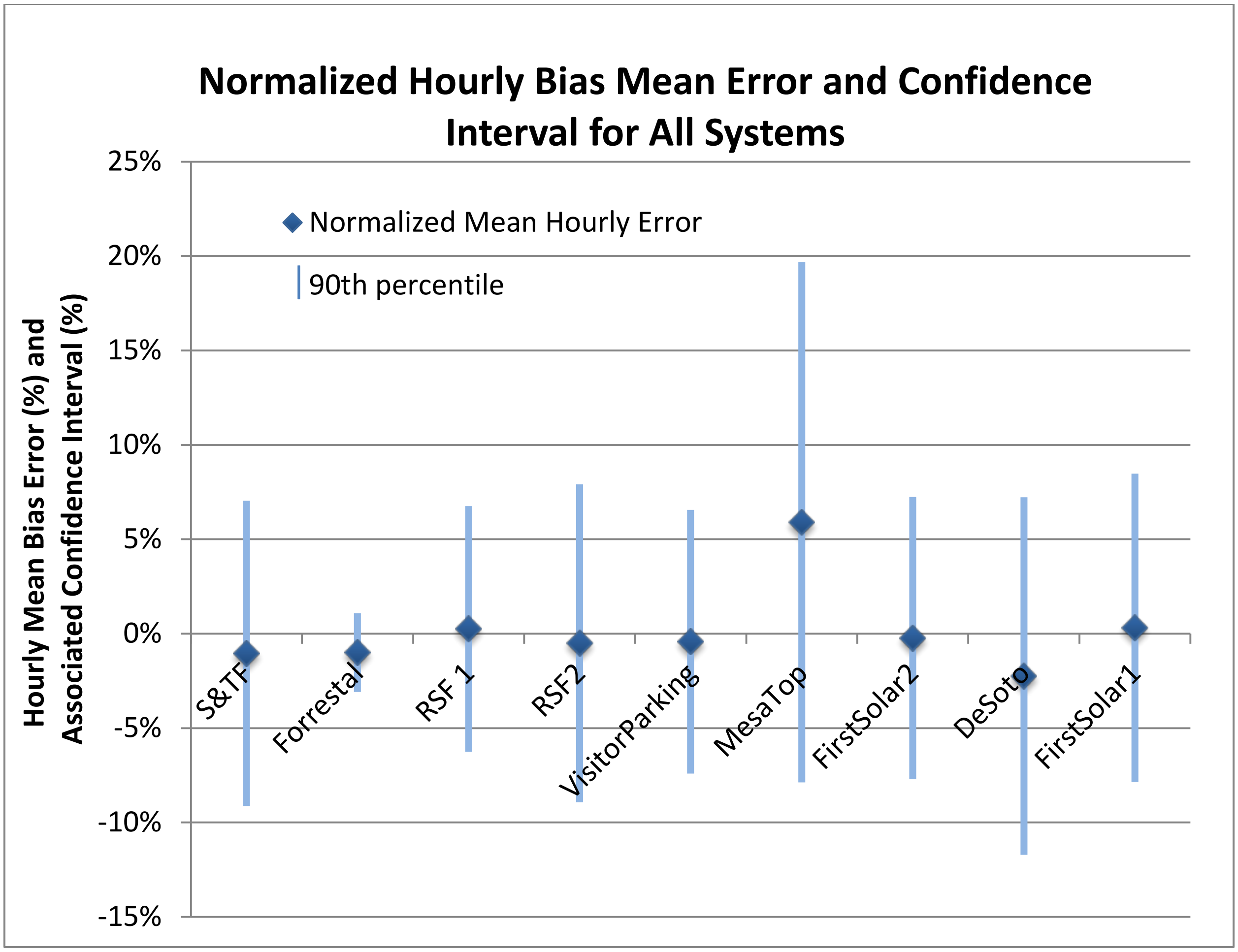


Figure 1-11. Normalized hourly mean error and confidence interval for all systems[6]

The confidence interval is a good measure of SAM's ability to accurately predict a system's power production because a small confidence interval indicates agreement for the majority of hours (and a tight grouping around the 1:1 trendline of an hourly scatter plot). Excluding the Mesa Top and DeSoto systems, which still contain a known source of error, all systems have 90% confidence intervals within ±8% of measured values on an hourly basis, which means that 90% of all hourly predictions are within ±8% of measured values. The Mesa Top and DeSoto systems still contain an aforementioned cause of error, which contributes to their larger-than-normal confidence intervals. The smallest confidence interval observed was the Forrestal system's confidence interval of 2%. This confidence interval is representative of the very tight grouping of points shown in Figure 1-8. As mentioned above, this is because of the high quality of the measured weather data used as inputs, as well as the high quality of the power measurements at this system.

[6] The Mesa Top and DeSoto systems still contain the since-resolved backtracking error.

1.4.2 Monthly Results

Figure 1-12 shows the results for all systems in all years on a monthly timescale. Most lines have a strong grouping around the x-axis (or zero-error line). The two distinct lines above the majority of the systems represent the Mesa Top system (both years) and its associated problems with backtracking (resolved in the 2013.9.20 release). These problems are not as obvious in the DeSoto system due to its larger row spacing compared to Mesa Top. The red trendline represents the monthly unweighted average of all the system-years. From Figure 1-12, we can see that every system's monthly error has a similar convex shape. This convex shape is emphasized by the red trendline that represents the unweighted average of all of the system's seasonal errors.

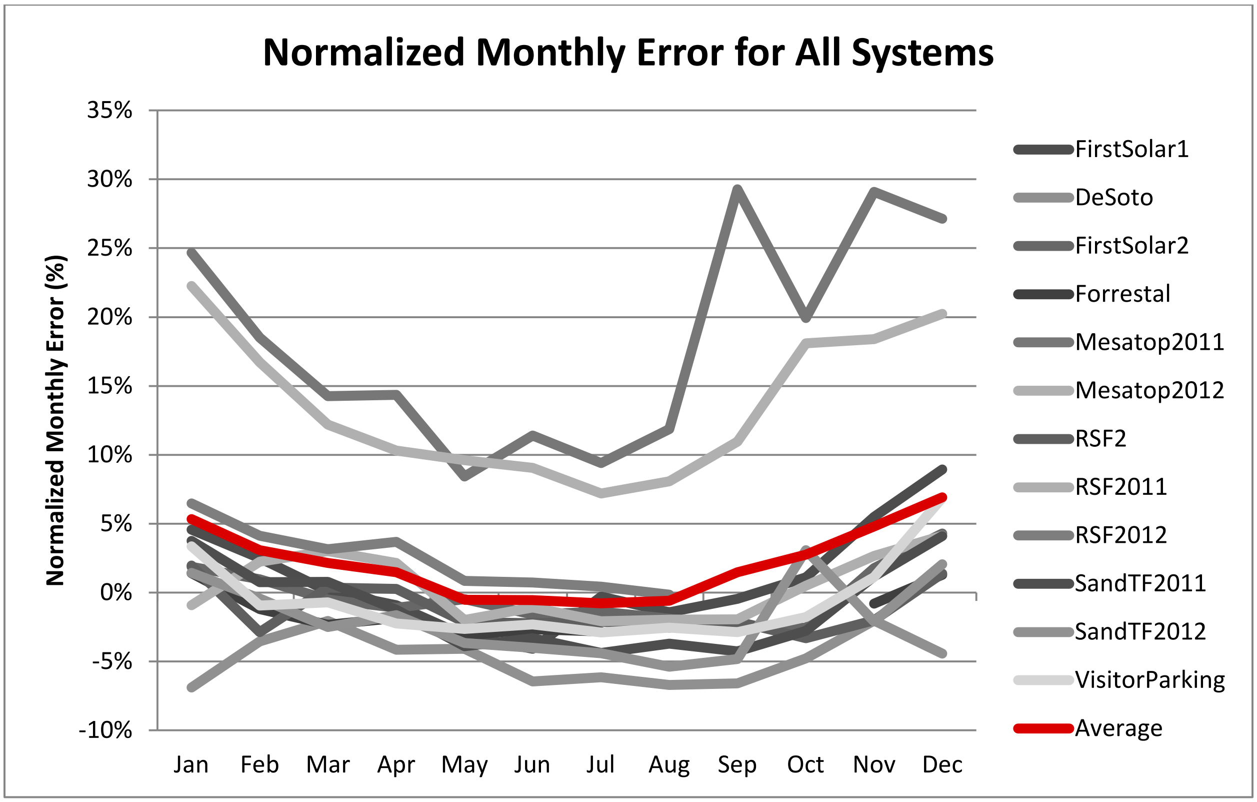


Figure 1-12. Normalized monthly error for all systems

If we remove the Mesa Top system from the above graph in order to show the phenomenon at higher resolution, the convex trend becomes even more apparent, indicating a seasonal trend of SAM overpredicting power production during the winter months and underpredicting power production during the summer months (see Figure 1-13).

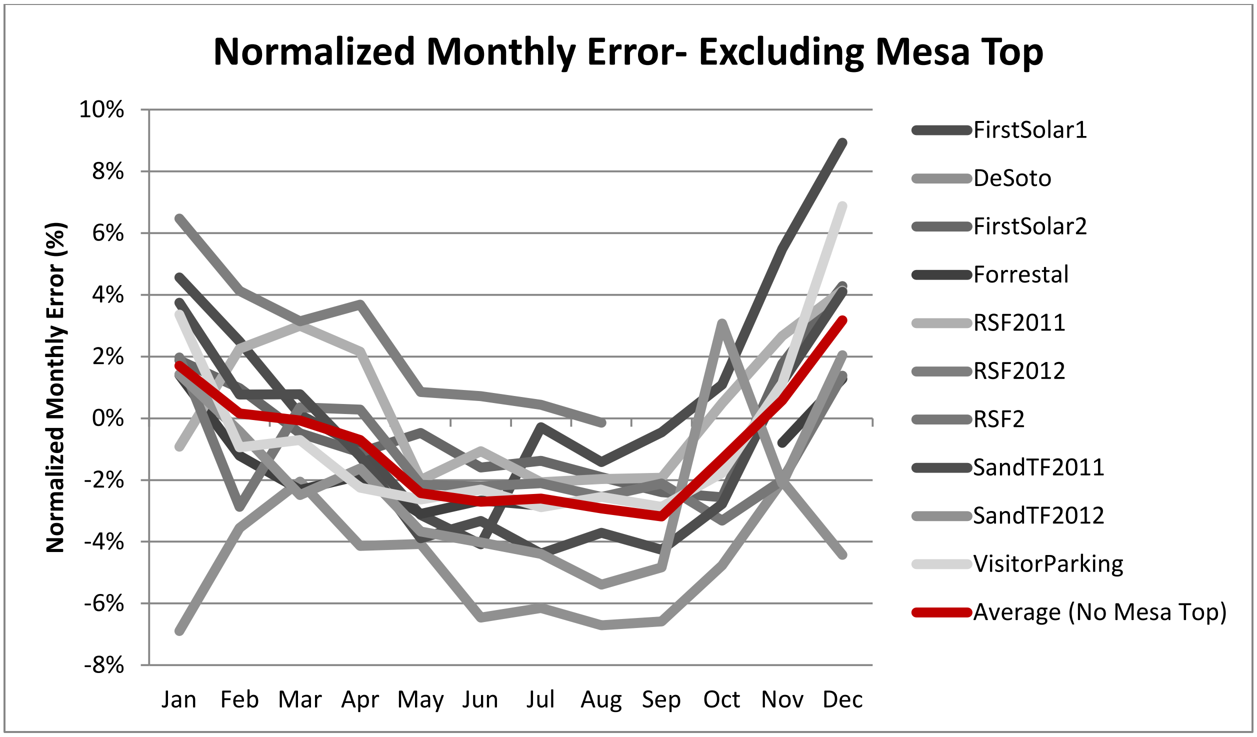


Figure 1-13. Normalized monthly error excluding Mesa Top

This is consistent with findings by Sandia National Laboratory that the radiation transposition models used in SAM "calculate relatively more POA irradiance in the winter than in the summer" [1]. Figure 1-14 shows this trend from Sandia's findings in their report.

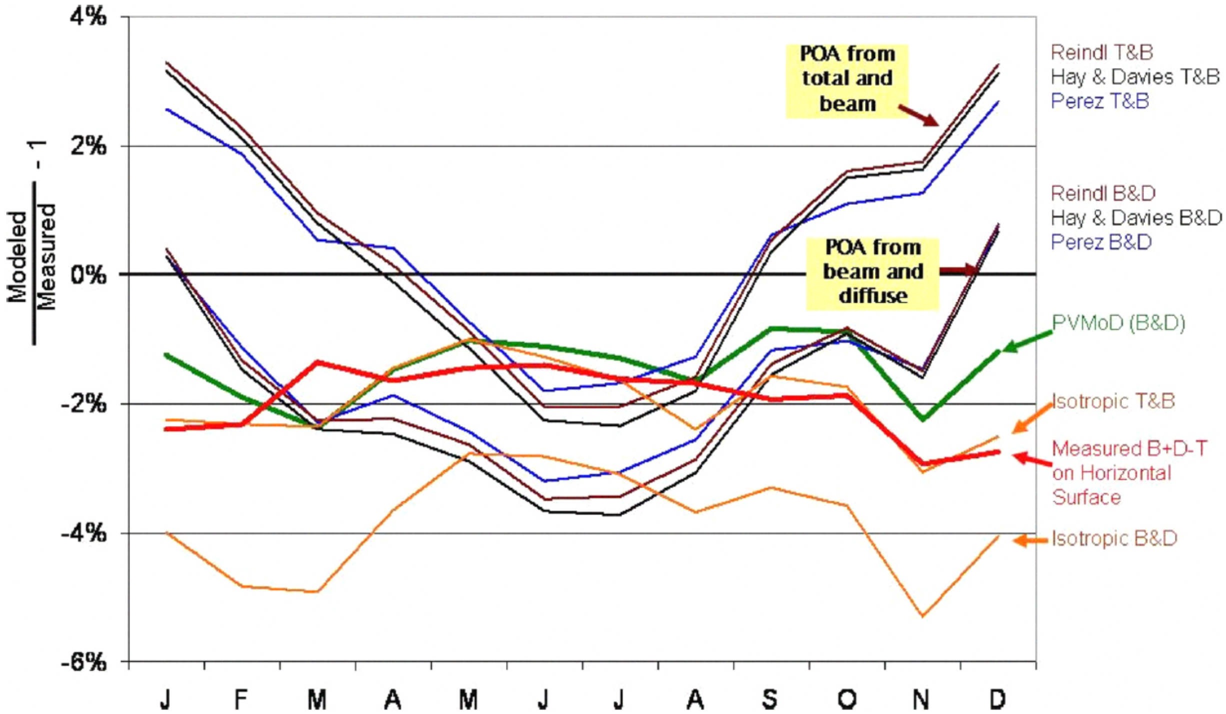


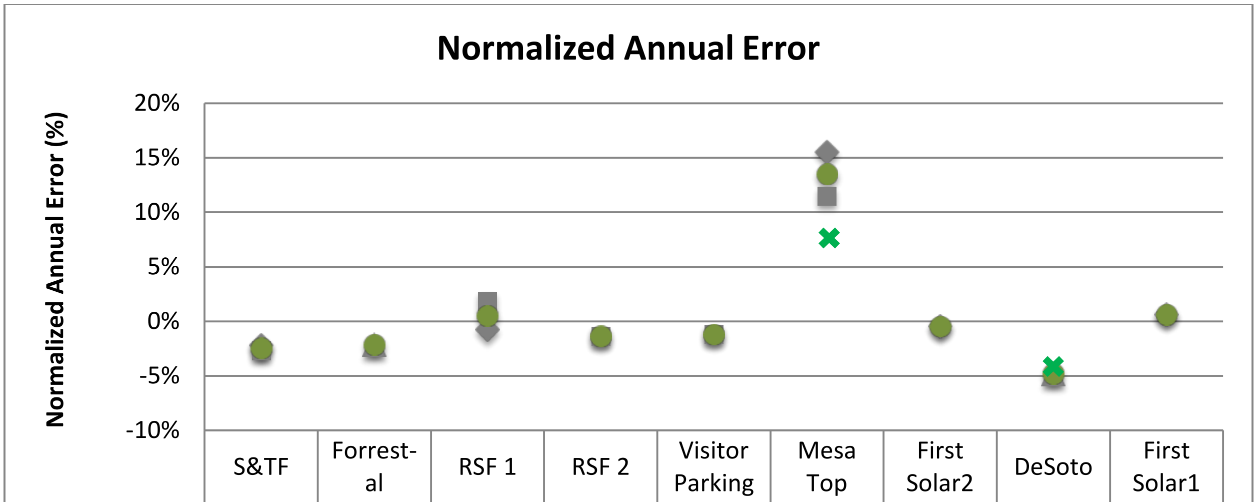
Figure 1-14. Seasonal variation in transposition model error (Sandia National Laboratories [1])

This data suggests that the seasonal difference in SAM error may be attributed in whole or in part to the seasonal error in the irradiance transposition models used. Note that the Isotropic Sky model does not exhibit this behavior; however, the Perez and HDKR transposition models are generally regarded to be more accurate models. These radiation transposition models are not SAM specific, but were developed by various non-NREL authors for the purposes of PV performance modeling in general and are utilized in most if not all current PV performance modeling software packages. Other potential contributors to this seasonal difference in SAM's performance include insufficient temperature correction or seasonal soiling differences. Preliminary analysis (Section 10) indicates that this seasonal bias is more correlated with rainfall than with temperature, but further investigation with multiple systems is needed to confirm this hypothesis. Future work will also investigate any correlation with strength of radiation.

1.5 Annual Results

Excluding the Mesa Top and DeSoto systems because they still contain the backtracking error, overall error for all systems is ±3% or less.[7] It is interesting to note that SAM tends to underpredict production. There is no observed relationship between system size and annual error. As stated in Section 1.3.6, a positive error corresponds to SAM overpredicting measured production.

[7] The results of the 2013.9.20 release are also shown in Figure ES-1 for the Mesa Top and DeSoto systems, although we suspect that there is an error in the Mesa Top system specifications (see Section 4).



	S&TF	Forrest-al	RSF 1	RSF 2	Visitor Parking	Mesa Top	First Solar2	DeSoto	First Solar1
◆ 2011	-2.2%		-0.8%			15.5%	-0.5%		0.6%
■ 2012	-2.7%		1.8%	-1.4%	-1.2%	11.5%			
▲ Other Year		-2.1%						-4.8%	
● Average	-2.5%	-2.1%	0.5%	-1.4%	-1.2%	13.5%	-0.5%	-4.8%	0.6%

✖ Mesa Top system error decreases to 7.6% average with 2013.9.20 release, using suspected incorrect specifications (see Section 4). DeSoto system error decreases to -4.3% with 2013.9.20 release.

Figure 1-15. Annual error for all systems

1.5.1 Model Option Comparison Results

Due to the availability of all three components of measured irradiance data and the availability of the solar module used in the Forrestal system in multiple module databases, as well as the high quality of measured data at the site, the Forrestal system was also used to compare the performance of several different model options available in SAM. The comparison was made after known issues (snow cover and shading) were removed from the data. The following comparisons were made:

- Sandia module model versus CEC 5-parameter module model
- Perez diffuse sky model versus Hay-Davies-Klucher-Reindl (HDKR) diffuse sky model
- "Total and Beam" irradiance inputs versus "Beam and Diffuse" irradiance inputs.

Table 1-3 shows the total error, hourly correlation strength, and hourly normalized RMSE for each of the model option combinations examined, along with their correlation strengths on an hourly basis.

Table 1-3. Statistical Comparisons Between SAM and Measured Data Using Different Model Options—Forrestal System

Model	Total Error	R^2	Normalized RMSE
Sandia- HDKR- Total & Beam	2.41%	0.994	2.3%
Sandia- HDKR- Beam & Diffuse	-0.11%	0.985	3.1%
Sandia- Perez- Total & Beam	2.41%	0.998	1.7%
Sandia- Perez- Beam & Diffuse	-0.22%	0.988	2.8%
CEC- Perez- Total & Beam	-0.67%	0.996	1.6%
CEC- Perez- Beam & Diffuse	-3.06%	0.986	3.3%

The most important conclusion that we drew from this model comparison is that all of these combinations of module models, transposition models, and irradiance inputs perform well with respect to measured data, within about ±3% total error, RMSE of 3.5%, and R^2 greater than 0.98 in all cases. This confirms the validation of SAM across all model options; if the module used in a project is available in the CEC module database but not the Sandia database or if only beam and diffuse data are available at a site, SAM is still able to effectively capture the production of that system.

In this dataset, the Perez transposition model tends to have a slightly higher correlation and slightly lower RMSE than the HDKR transposition model but similar total errors for the dataset. When using Total and Beam Irradiance, the CEC model has lower RMSE and total error than the Sandia model, but when using Beam and Diffuse Irradiance the reverse is true, making the comparison between the CEC and Sandia model inconclusive. It is interesting to note that the CEC module model shifts the SAM error down by about 3% compared to the Sandia module model under the same circumstances in both irradiance input cases. Using Beam and Diffuse irradiance as inputs causes larger underprediction (2.5% larger) in all cases and consistently produces a higher RMSE. However, this might not hold true for a dataset in which higher confidence is placed in the diffuse irradiation data than the global irradiation.

See Section 3 for more detail on this model option comparison.

1.6 Conclusions

This validation study revealed two very important known causes of error that are already being addressed by the SAM development team. These two causes of error are backtracking issues (resolved in the 2013.9.20 release) and snow cover. Future work will include developing an algorithm to predict a production loss due to snow cover. For this validation study, these known causes of error were removed from the data in order to estimate their effects, search for additional causes of error, and estimate model accuracy.

After known issues have been removed from all systems, and excluding the Mesa Top and DeSoto systems (due to the aforementioned backtracking problem), all systems had RMSEs of 5.1% or less, normalized hourly MBEs within ±1.0%, and 90% confidence intervals within ±8%. The system with the best agreement between SAM and measured values—Forrestal—had a RMSE of less than 2%, a normalized hourly mean error of -1%, and a confidence interval of

±2%. These statistics are reflective of the tight grouping around the 1:1 trendline seen in Figure 1-8.

On a monthly basis, SAM shows seasonal variability, with a tendency toward a higher monthly bias in the winter than the summer. This seasonal variation in bias frequently results in SAM overpredicting in the winter months and underpredicting in the summer months, even after known sources of error have been removed. Preliminary research indicates that this seasonal variation may be due to seasonal variations in the underlying transposition models themselves. However, despite this seasonal variability, all systems except the Mesa Top system have trendlines that closely follow the 0% error line (see Figure 1-13).

On an annual basis, after known sources of error were removed and excluding the Mesa Top and DeSoto systems, overall errors were found to be ±3% or less.

By examining various model options using the Forrestal system, we determined that all of the model options explored in this effort (CEC versus Sandia module model, Perez versus HDKR diffuse sky model, and Beam and Diffuse versus Total and Beam irradiance inputs) resulted in similar agreement with measured data, which confirms the consistency of SAM across its many available model options.

One of the most interesting conclusions from these statistics is the validation of the assumption that SAM performs similarly independent of system size. We expected to see the SAM error increase or decrease as a function of the size of the system, but there was no indication that this was the case on any of the timescales (hourly, monthly, or annually).

The next step for this validation effort is to implement the improvements indicated by the results of this report, specifically with respect snow cover. Once these improvements are made, this validation will be performed again in order to compare results and confirm that the changes made to SAM have corrected these known causes of error.

2 Commercial-Scale Summary

2.1 Introduction

Six commercial systems (<1 MW) were examined as part of this validation effort. Five of these systems are located on the NREL campus in Golden, Colorado, shown in blue in Figure 2-1, and the sixth is on a DOE building in Washington, D.C, shown in green. It was not possible to obtain operational data for commercial-scale non-NREL/DOE systems (although attempts were made).

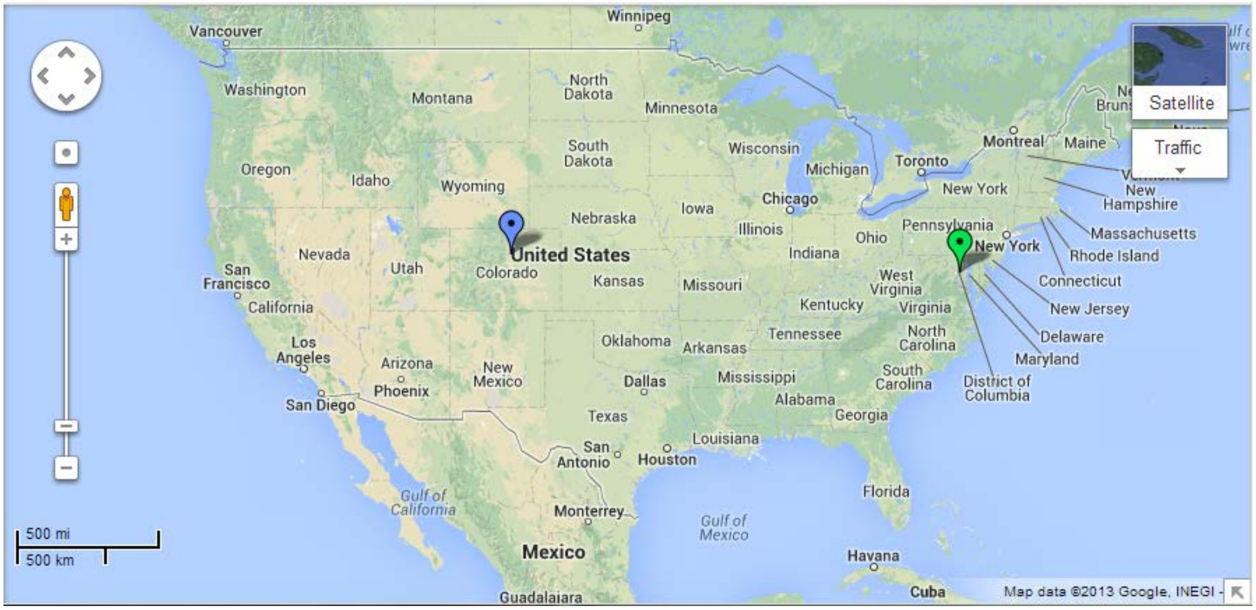


Figure 2-1. Locations of the commercial-scale systems [2]

2.2 Methodology

The methodology used for data quality control, SAM simulation, and identifying and removing problems is consistent with the methodology described in Section 1. As a reminder, the annual derates were not tuned for commercial-scale systems due to the importance of the annual error, the higher confidence in the performance data, and the lower likelihood of commercial system operators to adjust models based on previously measured data. The data sources used in the commercial system analysis are described below.

2.2.1 Weather Data

Weather data for all of the NREL sites was acquired from the Solar Radiation Research Laboratory (SRRL). One of SRRL's objectives is to develop a solar resource climate database that can be used for solar modeling, such as that done by SAM. Historical weather data is available from SRRL in multiple formats, which makes it ideal to use for validation. Weather files concurrent with the production data for each system were downloaded from the SRRL website in TMY3 formats. The measured values in these files that were used in the SAM simulation included the following values, measured by the instruments indicated inTable 2-1.

Table 2-1. SRRL Weather Data Instruments

Value	Measurement Instrument
Global Horizontal Irradiance	Kipp & Zonen CMP-22 ventilated pyranometer
Diffuse Horizontal Irradiance	Eppley 8-48 ventilated pyranometer with shading ball
Direct Normal Irradiance	Kipp & Zonen CH1 pyrheliometer
Wind Speed	NRG Systems #40H rotating cup anemometer
Ambient Temperature	Campbell Scientific HMP45C-L
Relative Humidity	Campbell Scientific HMP45C-L
Barometric Pressure	Vaisala PTB101-B pressure transmitter
Precipitation	Texas Electronics TE525 tipping bucket rain gauge

The TMY3 format removes leap days from leap years; however, the 2012 data had not yet been fully formatted as a TMY3 at the time of its download. The dataset that was downloaded contained a leap day, which had to be removed because SAM was designed to utilize an 8760 weather file, which does not include leap days. Because of the high quality of the SRRL measurements, no further processing was required.

Snow depth data were also required for all of the systems located at NREL and was likewise downloaded from the SRRL database for every year concurrent with measured production data. Snow data were measured using a Senix Ultra-Sonic distance sensor that measures the distance between its mounting height and the ground in order to determine snow depth. Unlike the SRRL data used in the SAM simulations, the snow depth data did require some quality control. It comes in two hourly data streams, the first stream showing snow depth and the second showing the quality of the snow depth measurement. Low-quality measurement points throughout the snow data were eliminated and therefore were not used to disqualify energy production values for comparison with SAM.

The meteorological and snow depth data used for the Forrestal system study is described in Section 3 because it was only used for that system.

2.2.2 Performance Data

For the commercial systems, performance data were obtained from three unique sources: SunEdison, SunPower, and DOE. The source data format and any source-specific data processing techniques are outlined below. After performing the necessary data format processing for each data source, additional data processing techniques were performed as needed for each individual system. These data processing techniques are described in Section 1. The specific data processing required for each system will be mentioned in each system study.

2.2.2.1 SunEdison Data

The Mesa Top, RSF 1, and S&TF systems are all maintained by SunEdison. SunEdison monitors power production for its systems and keeps records of many different measurements. This data is recorded in 15-minute intervals, and the most useful metric recorded for the purposes of comparison with SAM is "Solar Energy Production" (SEP), which is a record of the amount of energy that was produced during the relevant time interval. For the 15-minute data mentioned above, this metric is the amount of energy the system generated during the 15-minute time period immediately preceding the record (measured at the energy meter). These data were acquired through a user interface created by SunEdison for each system. It was downloaded in one-month increments and then aggregated into a single dataset that spanned all relevant years for each system [3]. “Energy Production at each Inverter” (EPI) data were also downloaded from SunEdison in the same 15-minute time intervals. EPI has applications for determining inverter outages and was aggregated in a similar fashion to the SEP data.

The most appropriate SAM output to compare with the SEP dataset is Gross AC Output, which is the measure of the energy that SAM predicts will be produced by the system after it is converted to AC at the inverter. SAM applies the “Percent of Annual Output” after it applies AC losses (losses in transmitting the power from the inverter to the grid interconnection). However, we want to include Percent of Annual Output to model year-to-year decline in output and account for each system’s age since installation, and we do not want to include AC losses. Because SEP is measured at the inverter output, Gross AC Output was multiplied by the respective Percent of Annual Output for each year depending on each system’s age in that year for any system that had been operating for at least one year.

In the event of a communications outage (resulting in power production data being available at a given time), SunEdison estimates a power production measurement. These estimated values are approximated by some undisclosed model, have an unknown accuracy, and were removed from the analysis. Negative power production values in the SEP dataset were set to zero.

2.2.2.2 SunPower Data

SunPower designed, installed, and monitors two of the commercial systems analyzed in this effort: the RSF 2 system and the Visitor Parking system. SunPower measures AC power production at hourly resolution for their systems at the output of each inverter in the system; therefore, for all SunPower systems, the inverter data streams were subsequently summed to obtain total system output. The data obtained from SunPower was marked with an hour-beginning timestamp, meaning that the energy collected from 8:00–9:00 a.m. was marked with the timestamp 8:00 a.m. However, SAM outputs an hour-ending timestamp, so the SunPower data timestamps were shifted to match SAM’s.

2.2.2.3 DOE Data

The data processing required for the data obtained from DOE is described in Section 3 because DOE provided data only for the Forrestal system study.

2.3 Commercial System Results

The issue that by far had the biggest effect on SAM’s agreement with measured data, present in all of the commercial systems studied, is that of snow cover. As mentioned in Section 1, snow cover may be a problem for any system in a snowy climate where the input irradiance data into SAM may not reflect the lingering presence of snow partially or wholly covering a PV system. Even with snow depth data entered into the TMY3 format, SAM will continue to predict full power production, frequently resulting in a drastic overprediction of measured production. This is a known cause of error in SAM, and NREL is currently researching an algorithm to accurately predict power production based on snow depth data. Until this algorithm is implemented, it should be understood that this issue can greatly affect the agreement of SAM with measured data. On a monthly basis, the total error was increased by up to 350% in one of the systems studied as part of this validation effort. Snow cover interference can be identified visually or programmatically when snow depth data are available for a site location. Because this issue was identified, all of the subsequent results presented in this section will be presented with snow cover issues excluded from the data.

The last issue revealed in the commercial system study was that SAM's backtracking algorithm in the 2013.1.15 version had an error (an issue that was corrected in the 2013.9.20 release of SAM). See Section 1 for the full description of this known cause of error. Because this issue was present in only the Mesa Top system, commercial-scale results will be presented both with and without this system included.

The normalized RMSE, which is normalized by the systems maximum measured power, is the best indication of overall agreement between SAM-predicted power production and measured power production for a given system. Excluding Mesa Top because it still contains a known source of error (see Section 1), the normalized RMSE for all systems was roughly 5% or less (see Figure 1-11). The best normalized RMSE was observed in SAM's model of the Forrestal system—less than 2%—while the worst normalized RMSE was observed in SAM's model of the Mesa Top system—over 10%.

Figure 1-12 shows the normalized mean hourly error for all six commercial systems as well as a 90% confidence interval (assuming a normal distribution) surrounding those points. As described in Section 1, the hourly mean error was normalized by the maximum observed power output of the system, which is a close approximation of AC nameplate capacity for most systems but also accounts for DC nameplate capacity in the event that the inverter is oversized. Taking the RSF 2 system as an example, the calculated normalized mean hourly error is -0.5%. The confidence interval around this point indicates that 90% of all hourly recorded values will lie between -9% and +8% of the normalized mean hourly error.

Overall, results show that the normalized hourly mean error is 1% or less for most systems on an hourly timescale (excluding the Mesa Top system). The Mesa Top system shows the worst overall agreement with SAM, and hence has the largest normalized hourly mean error and confidence interval, 5.9% and ±13.5%, respectively. This large error and confidence interval is in part due to the backtracking problems identified in the 2013.1.15 release and then resolved in the 2013.9.20 release (see Section 1 and Section 4 for more detail). Additionally, the mean or magnitude of the error does not seem dependent on system size. The RSF 1 system has the smallest normalized hourly mean error—0.3%. However, confidence interval is arguably a better overall measure of SAM's ability to accurately predict power production on an hourly timescale, and the system with the smallest confidence interval is the Forrestal system—2.1%. The size of the confidence interval reflects the very tight grouping of data points observed in Section 3.

On a monthly basis, an interesting and noteworthy trend can be observed. On the whole, SAM appears to have a seasonal bias that is higher in winter months and lower in summer months. As seen in Figure 1-13, this results in overpredicting power production during the winter months and underpredicting power production during the summer months for most systems. This manifests as an overall convex shape for every system and their average non-weighted trendline (shown in red). The two lines that are separated above the majority of the pack represent Mesa Top and its associated backtracking algorithm problems (a problem which was corrected in the 2013.9.20 release). Excluding the Mesa Top system from this plot results in Figure 1-14; this more clearly shows the convex trend of seasonal variation in SAM's error.

This seasonal difference in SAM is consistent with the seasonal change in radiation transposition model error found by Sandia National Laboratories (Figure 1-15, [1]). This variation in underlying model error is likely the partial or entire cause of this seasonal variation in SAM error. Other potential contributors to this error include inaccurate module or inverter temperature coefficients or seasonal soiling differences. We have conducted preliminary analysis on one system to determine whether the seasonal difference in SAM error correlates more highly with temperature or with rainfall (affecting the soiling of the panels) and have noticed a much higher correlation with rainfall than temperature (see Section 10). An initial look to see if the correlation with rainfall holds true for commercial systems is shown in Figure 2-2, where the commercial systems' monthly performance are plotted with rainfall in Golden, Colorado (the location of the majority of the commercial systems). The seasonal bias does seem to correlate for the majority of the commercial systems as well. The contributions of these various potential sources of error to the seasonal phenomenon seen in SAM will be investigated further with additional systems in subsequent efforts.

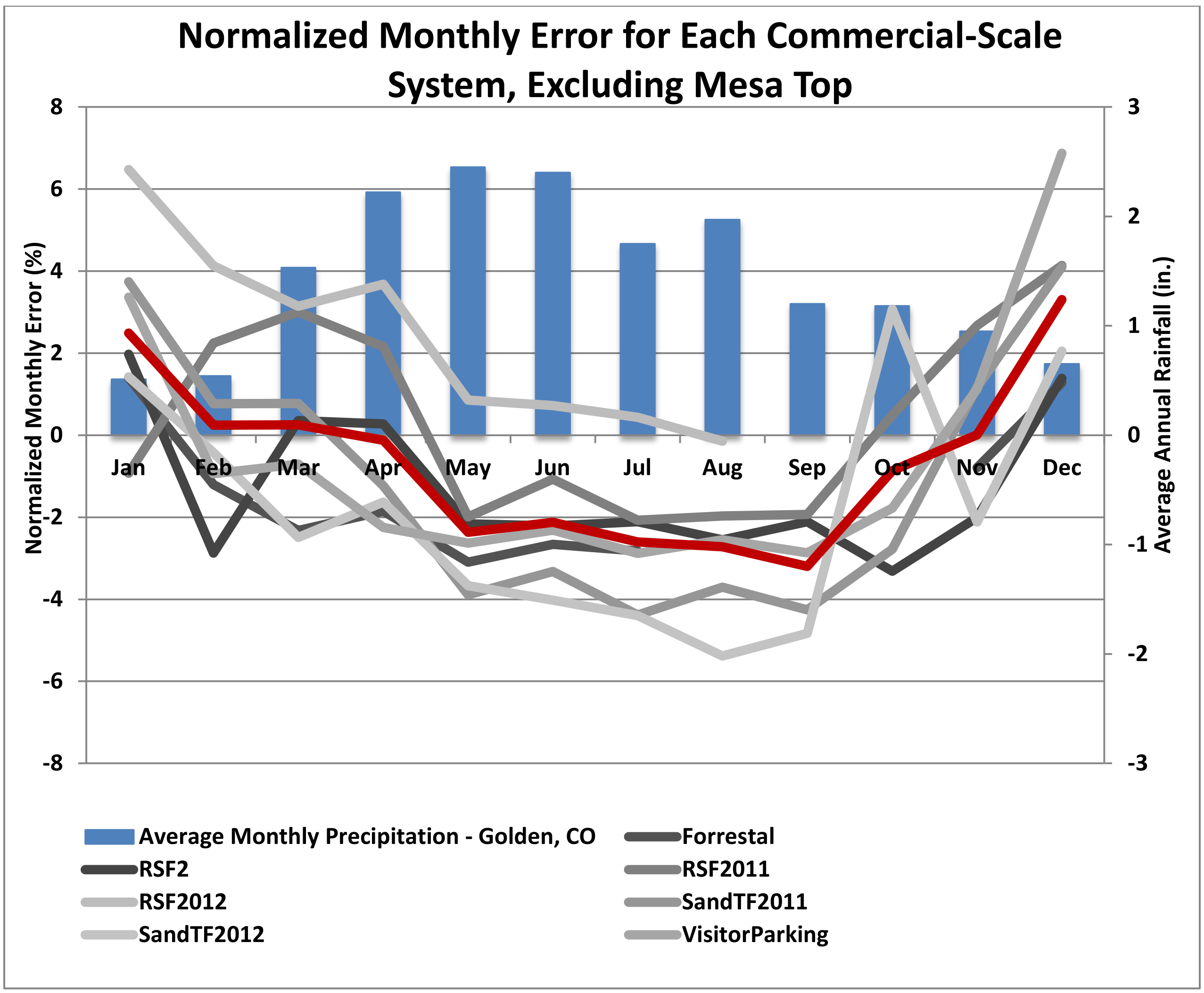


Figure 2-2. Commercial system correlation with Golden rainfall

On an overall basis, SAM is relatively accurate for most systems. Many systems did not have full years of data with which an analysis could be performed, so the results for this section are annual for some systems or simply an aggregate of all of the data available at the largest timescale (at least 8 months). Figure ES-1 shows the results for each system's annual/total results. Systems with multiple years (Mesa Top, RSF 1, and the S&TF) are aggregated into an average. The systems are organized in terms of maximum power production. All systems but the Mesa Top system show errors of less than 3% for every year and show average errors of less than 3%.

On an annual/total basis, the largest absolute error was the Mesa Top system, with an overprediction averaging 13.5%. However, as was previously noted, the Mesa Top system is the only commercial system that utilizes one-axis tracking—one of the known causes of error identified in this report and corrected in the 2013.9.20 SAM release (see Section 4).

As mentioned in Section 1, the Forrestal system was also used to compare various model options. See the summary of this comparison in Section 1 or the full comparison in Section 3 for more detail.

2.4 Conclusions

In summary, for all fixed-tilt commercial systems, the RMSE was around 5% or less, the normalized hourly mean error was 1% or less, and neither changed with respect to system size. A problem was identified with backtracking systems in the 2013.1.15 release that increased the normalized hourly mean error for the Mesa Top system to 5.9%, an issue that was corrected in the 2013.9.20 release. Another important metric at the hourly timescale, the confidence interval, was 9% or less for all fixed-tilt commercial systems. This indicates that for a fixed-tilt commercial system given all the proper information and accounting for known causes of error (such as snow accumulation and system downtime), SAM's AC power production predictions are within 9% of their corresponding measured values 90% of the time.

It was further discovered, by looking at error on a monthly basis, that SAM appears to have a seasonal bias; it overpredicts during the winter and underpredicts during the summer. The reason for this seasonal bias will be further investigated by the SAM team in future work, although preliminary research indicates that it may be due to a seasonal error in the transposition models themselves [1]. Again excluding the one-axis tracking Mesa Top system, SAM predicted measured data within 3% on an overall basis for every system and year examined as part of the commercial-scale study.

3 Forrestal System Study

3.1 Introduction

The James Forrestal Building is DOE's headquarters in Washington, D.C. The 205-kW rooftop PV array was installed in 2008 with the goal of producing up to 8% of the building's peak energy needs in order to fulfill the Transformational Energy Action Management Initiative. SunPower designed and installed the system, while it is metered and owned by DOE. The system-grid interconnect is inside the Forrestal building, where it is tied into the Potomac Electric and Power Company's grid.

3.2 Data Collection

3.2.1 Data Sources

DOE provided measured climate and system performance data from the Forrestal site from November 13, 2009, through July 25, 2010. All data were measured with one-minute resolution and post-processed into hour-averaged or hour-cumulative data for comparison with SAM's AC Gross Output.

The climate data measured at the site used in the SAM simulation is shown in Table 3-1.

Table 3-1. Various Values and Their Associated Measurement Instrument

Value	Measurement Instrument
Global Horizontal Irradiance	Hukseflux SR11 pyranometer
Diffuse Horizontal Irradiance	Hukseflux SR11 pyranometer with vertical shade band
Direct Normal Irradiance	Hukseflux DR01 pyrheliometer
Wind Speed	NRG Systems #40H rotating cup anemometer
Ambient Temperature	NRG Systems #110S temperature sensor with radiation shield
Relative Humidity	NRG Systems RH5 relative humidity sensor
Barometric Pressure	NRG Systems BP-20 barometer
Precipitation	Novalynx tipping bucket rain gauge

The measured performance data metric compared with the SAM Gross AC Output was the system AC power production, measured at the Xantrex GT250 inverter with a Class 320 meter.

Snow depth data were retrieved from the National Oceanic and Atmospheric Association (NOAA) meteorological measurement station at Camp Springs, Maryland, for the month of February 2009. The snow depth measurement was taken once per day at midnight.

3.2.2 Data Quality Control

The first and last complete hours of data were used as boundaries for the comparison time period. Within that time period, 34 consecutive hours of measured data were missing on July 22–23, 2010; therefore, these hours have been removed from the analysis. Outside of those missing hours, there was no missing data in the data received from DOE. All data were range-checked to fall within reasonable ranges of values for each climate variable (i.e., irradiance values must be greater than zero, relative humidity must be between 0% and 100%, etc.).

3.2.3 Simulation Specifications

All three components of measured irradiance data, plus measured wind speed, ambient temperature, relative humidity, barometric pressure, and precipitation at the site during the analysis time period were pasted into a custom weather data file created using the "Create TMY3" function in SAM. In order to use this function in SAM, one of the default TMY3-formatted files must be selected and then modified; we chose the Baltimore TMY3 due to its proximity to Washington, D.C. The site specified in the simulation was: latitude: 38° 53' 13.66" N; longitude: 77° 1' 33.69" W; elevation: 40 m. All other system specifications are shown in the Table 3-2 (taken from the SAM output report). All losses and derates were left at their default values unless otherwise specified. The Perez sky diffuse model and the Sandia PV array performance model were used.

Table 3-2. SAM Specifications—Forrestal System

Performance Model

Modules	
SunPower SPR-230-WHT	
Cell material	c-Si
Module area	1.2 m^2
Module capacity	230.2 DC Watts
Quantity	891
Total capacity	205.1 DC kW
Total area	1,108 m^2

Inverters	
Xantrex Technologies, Inc.: GT250-480 480V	
Unit capacity	250 AC kW
Input voltage	300 - 480 VDC
Quantity	1
Total capacity	250 AC kW
AC derate factor	0.99

Array	
Strings	81
Modules per string	11
String DC voltage	451.0
Tilt (deg from horizontal)	0
Azimuth (deg E of N)	180
Tracking	fixed
Backtracking	-
Rotation limit (deg)	-
Shading	no
Soiling	yes
DC derate factor	0.96

3.3 Results

3.3.1 Hourly Comparison

Agreement between SAM-predicted AC production and measured AC production is shown in the scatter plot in Figure 3-1. Noticing the odd scatter pattern in this data, we grouped the hourly scatter plot by season. The fact that all of the hourly scatter occurs in the winter indicates that there is a snow cover issue at this site, which is reasonable because it is located in Washington, D.C., which experienced an unusually snowy winter during the winter of 2009–2010.

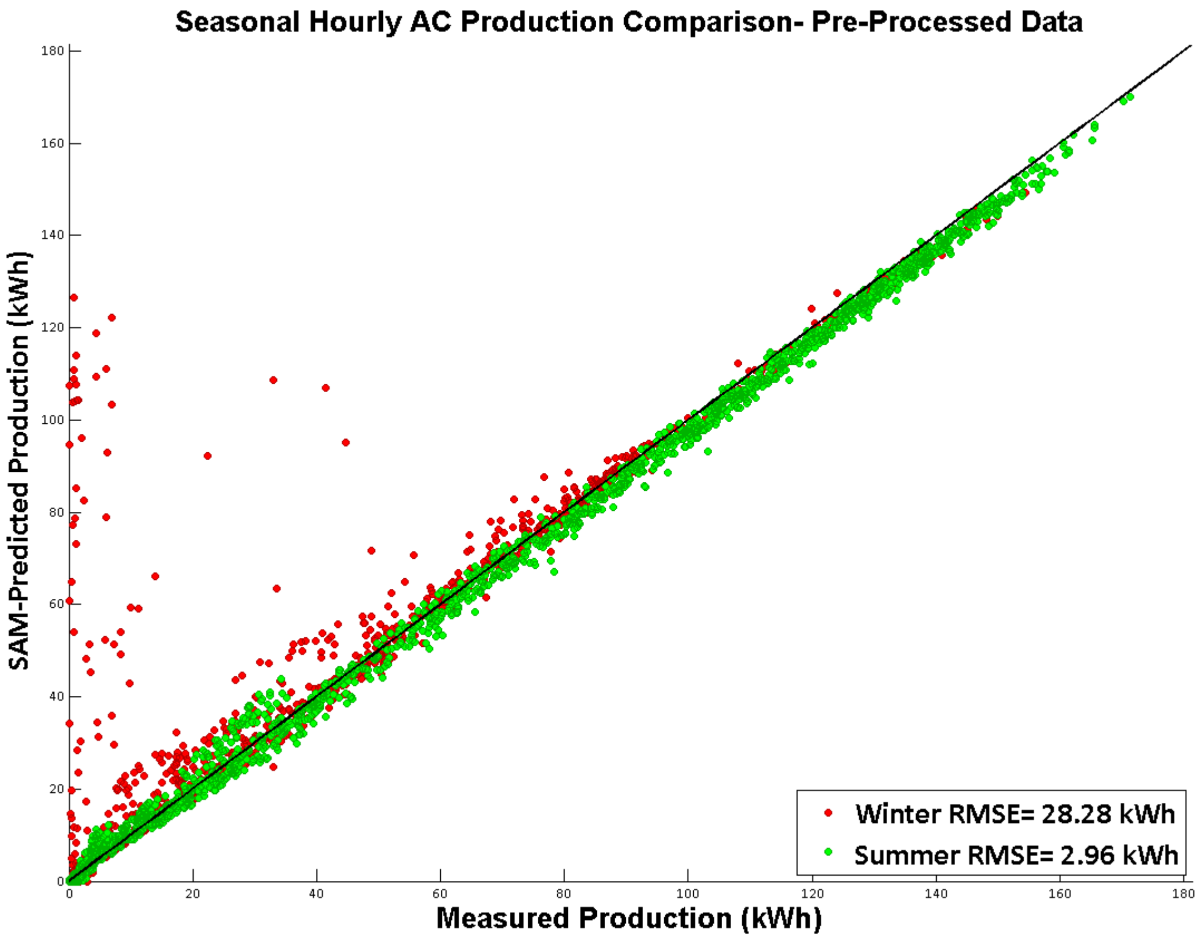


Figure 3-1. Seasonal hourly AC production comparison—Forrestal system (pre-processed)

To verify the hypothesis of snow-cover-related power production problems for this system, snow-depth data were collected near this site from the NOAA Camp Springs weather station for the month of February 2010. SAM-predicted performance and measured performance were then plotted as a function of time, together with the measured snow-depth data (Figure 3-2). Snow depth data appears as a step function on this graph because the data were only collected once per day.

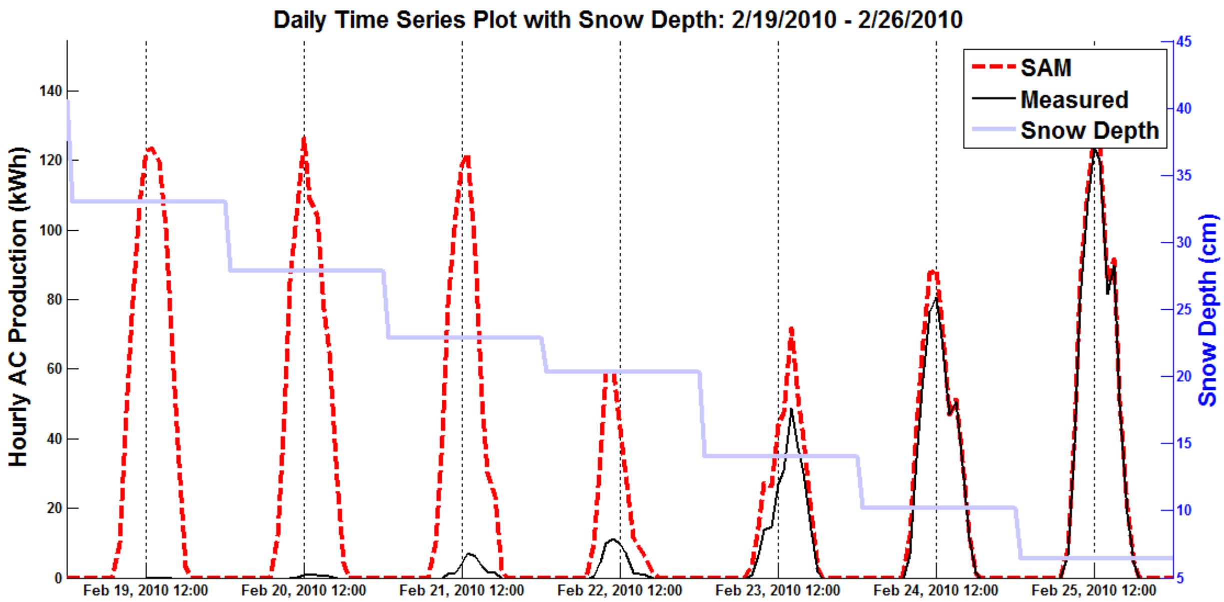


Figure 3-2. Snow-related power production discrepancies—Forrestal system

This plot clearly shows the relationship between snow depth and reduced measured performance with respect to SAM-predicted performance. As the snow depth decreases, the measured production continues to increase until it eventually matches SAM-predicted data again. Therefore, in order to appropriately quantify the error of the algorithms in SAM and not the lack of appropriate snow correction, days experiencing snow cover were classified as known causes of error and removed from the remainder of the analysis. The days removed due to snow cover were: December 19–31, 2009, and January 20–February 25, 2010.

Looking at summer data only, we noticed a section of points that seemed to deviate from the overall good agreement between the model and measured data in the subset of summer hours. The cause of this was investigated further, and we determined that these points all occur at high zenith angles above 70^0 (dawn and dusk hours), as shown in yellow and red in Figure 3-3.

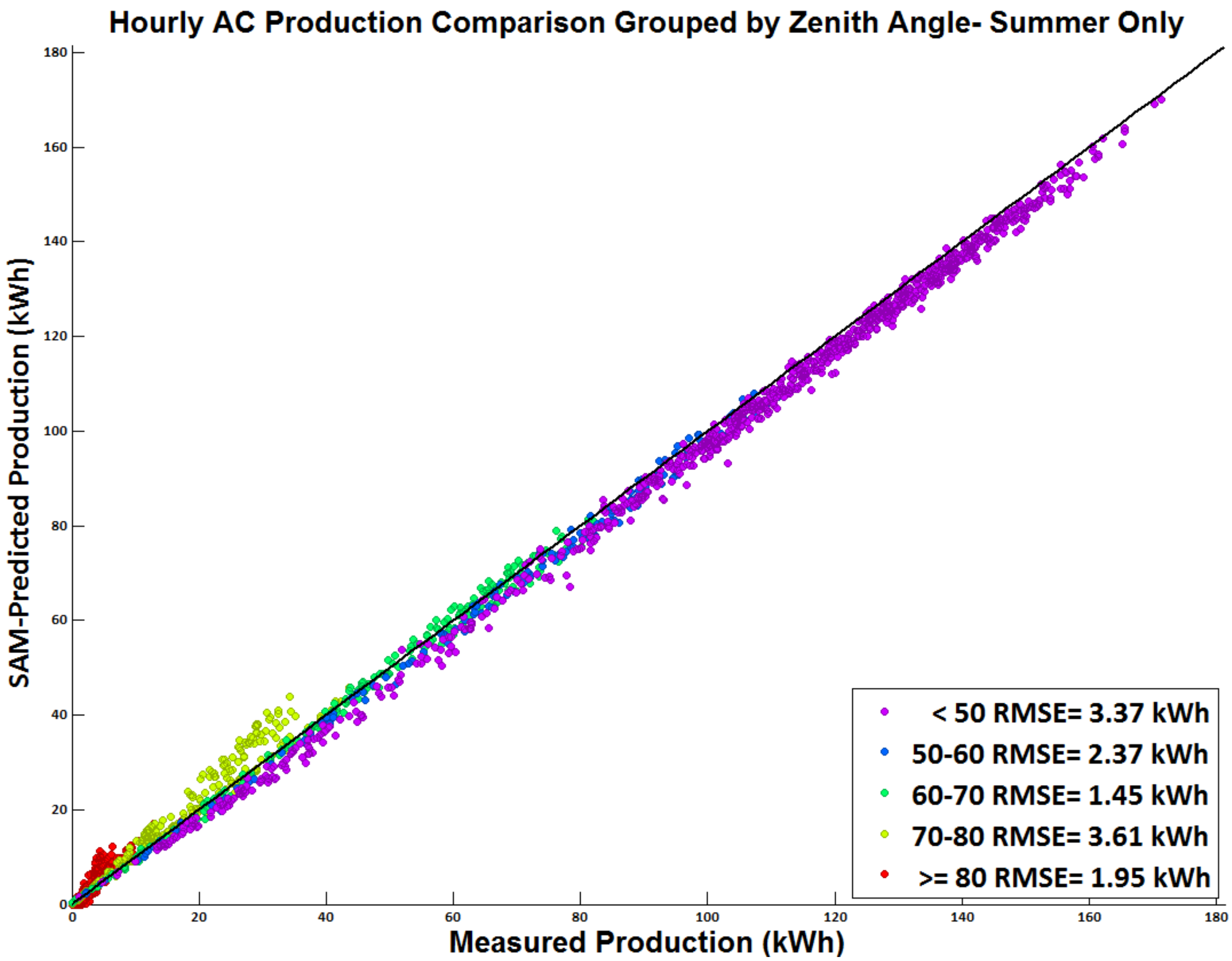


Figure 3-3. Hourly AC production grouped by zenith angle—Forrestal system (summer only)

We concluded that there is shading on this system during these hours, which is causing SAM to overpredict system output for high zenith angles. Sandia National Laboratories staff with onsite experience and available images of the rooftop confirmed that there is a parapet on top of this building, which shades the system during the morning and evening hours. However, sufficient information was not known about this parapet in order to appropriately model the shading in SAM. Therefore, all hours with zenith angles above 70^0 were treated as an identified problem and removed from the remainder of the analysis. Future SAM developments include a three-dimensional shading interface that will allow for accurate modeling of this parapet.

After removing both known causes of error from the hourly data, the hourly agreement for the Forrestal system is very good, achieving RMSEs of only 2–3 kWh, as shown in Figure 3-4.

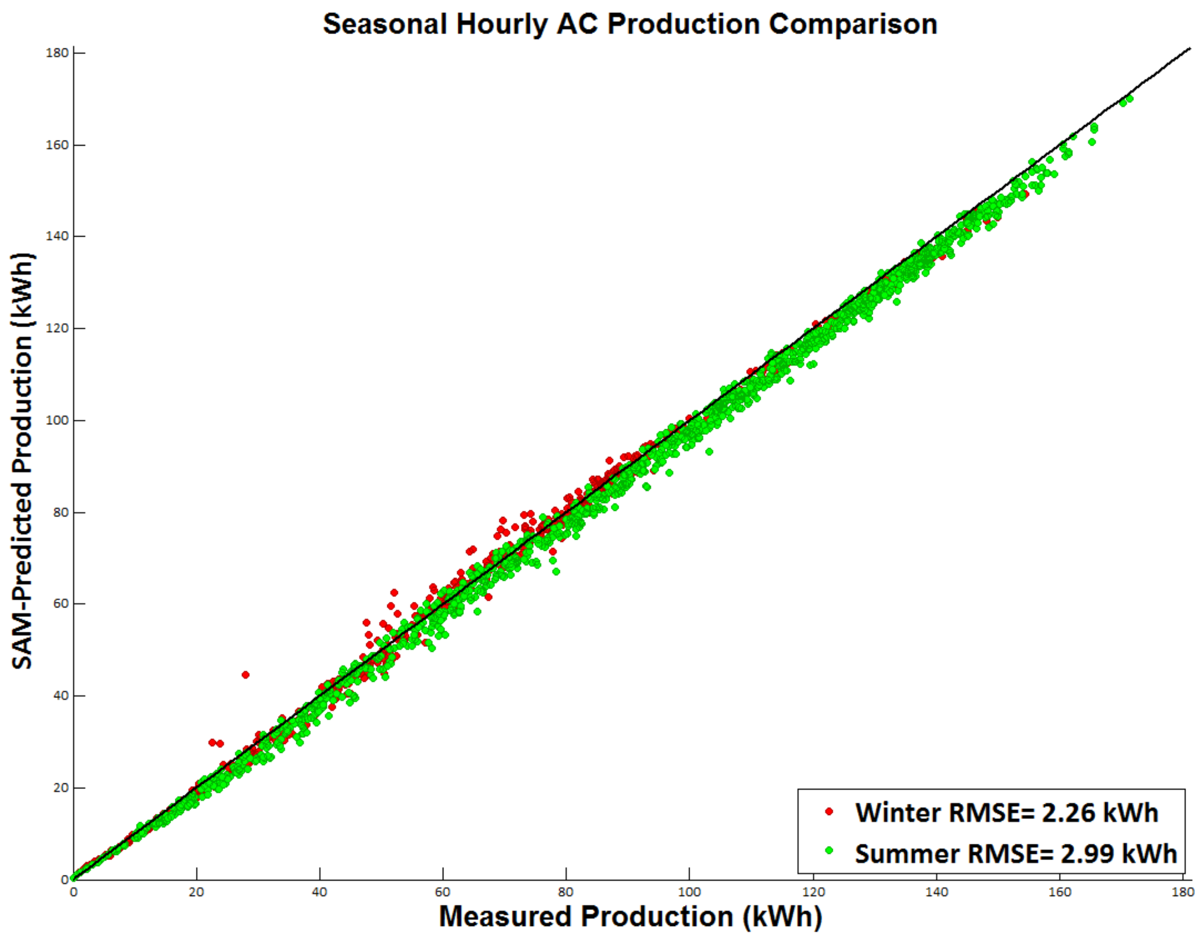


Figure 3-4. Seasonal hourly AC production comparison—Forrestal system (post-processed)

3.3.2 Monthly Comparison

On a monthly basis, the sums of both the SAM-predicted AC production and the measured AC production are shown in Figure 3-5. Table 3-3 and Figure 3-5 quantify the error by month. It can be clearly seen that SAM error increases dramatically in winter months when known issues (snow and high zenith angle shading) are included, with the monthly error in February 2010 being a staggering 329%. However, after removing the known causes of error, SAM predicts the total monthly AC production within 3% of the measured AC production in kilowatt-hours. It is interesting to note that even after correcting for known causes of error, SAM still overpredicts energy production in the winter and underpredicts energy production in the summer. This seasonal variation is likely due to seasonal variations in the underlying transposition models; see Section 1.4 for more detail.

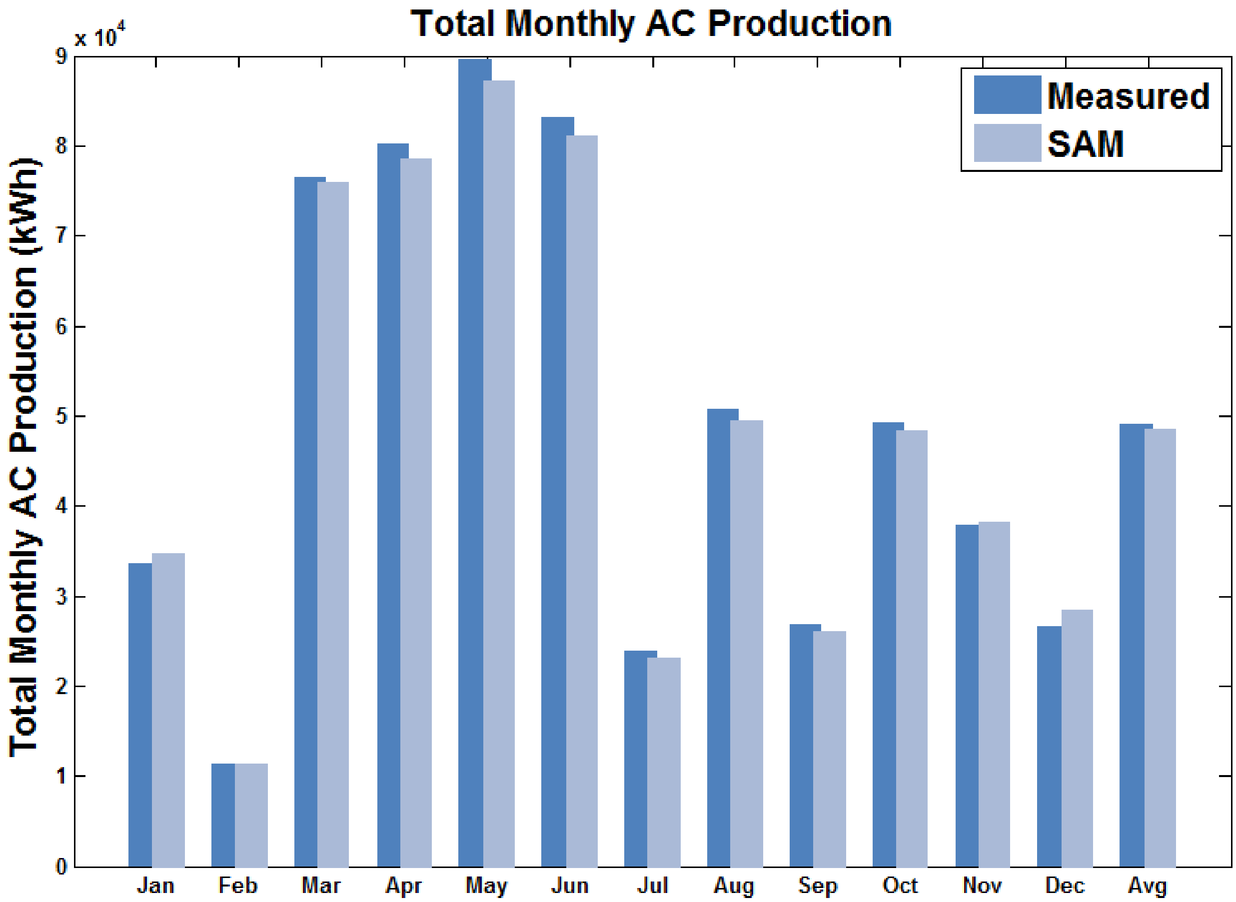


Figure 3-5. Total monthly AC production comparison—Forrestal system

Table 3-3. Monthly Comparison of Percent Error Before and After Removal of Known Causes of Error—Forrestal System

Month Date	Percent Error, Prior to Removing Issues	Percent Error, Known Issues Removed
November 2009	2%	-1%
December 2009	40%	1%
January 2010	12%	1%
February 2010	329%	-1%
March 2010	-2%	-2%
April 2010	-2%	-2%
May 2010	-2%	-3%
June 2010	-2%	-3%
July 2010	-2%	-3%
October 2012	-3%	-3%
November 2012	-2%	-2%
December 2012	13%	2%

3.3.3 Annual Comparison

As shown in Table 3-4, for the total period of record examined prior to removing hours with known causes of error, the total measured AC output of the Forrestal system was 157.3 MWh. For the same period of time, SAM predicted a total measured AC production of 170.4 MWh, representing an overprediction of 8%. However, removing the hours experiencing known causes of error for the Forrestal system (snow cover and high zenith angle shading, described previously) resulted in a measured total of 143.3 MWh and a SAM-predicted total of 140.2 MWh, representing a total error of -2%, or that SAM underpredicted performance by 2% on a total basis.

Table 3-4. Overall Comparison Before and After Removal of Known Causes of Error—Forrestal System

Total	All Data	Removed Data
SAM (kWh)	170,431	140,242
Measured (kWh)	157,308	143,308
Error (kWh)	**13,124**	**-3,066**
Percent Error	**8%**	**-2%**

3.3.4 Model Option Comparisons

Due to the availability of a variety of measured irradiance data and the availability of the solar module used in the Forrestal system in multiple module databases, the Forrestal system was also used to compare the performance of several different model options available in SAM. The following comparisons were made:

- Sandia module model versus CEC 5-parameter module model
- Perez diffuse sky model versus HDKR diffuse sky model
- “Total and Beam” irradiance inputs versus “Beam and Diffuse” irradiance inputs.

In order to isolate model error from implementation error and therefore make the most accurate comparisons between the different model options and measured data, a subset of data from which known causes of error (snow cover and shading) had been removed was used for this part of the analysis.

Table 3-5 shows the total error, correlation strength, and RMSE for each of the model combinations examined, along with their correlation strengths on an hourly basis (see Section 1 for definitions of these terms as used in this paper). Scatter plots comparing modeled data to measured data for each model combination are shown in Figure 3-6.

Table 3-5. Various Statistical Comparisons between SAM and Measured Data Using Different Models—Forrestal System

Model	Total Error	R^2	RMSE
Sandia- HDKR- Total & Beam	2.41%	0.994	3.96
Sandia- HDKR- Beam & Diffuse	-0.11%	0.985	5.36
Sandia- Perez- Total & Beam	2.41%	0.998	2.92
Sandia- Perez- Beam & Diffuse	-0.22%	0.988	4.73
CEC- Perez- Total & Beam	-0.67%	0.996	2.78
CEC- Perez- Beam & Diffuse	-3.06%	0.986	5.59

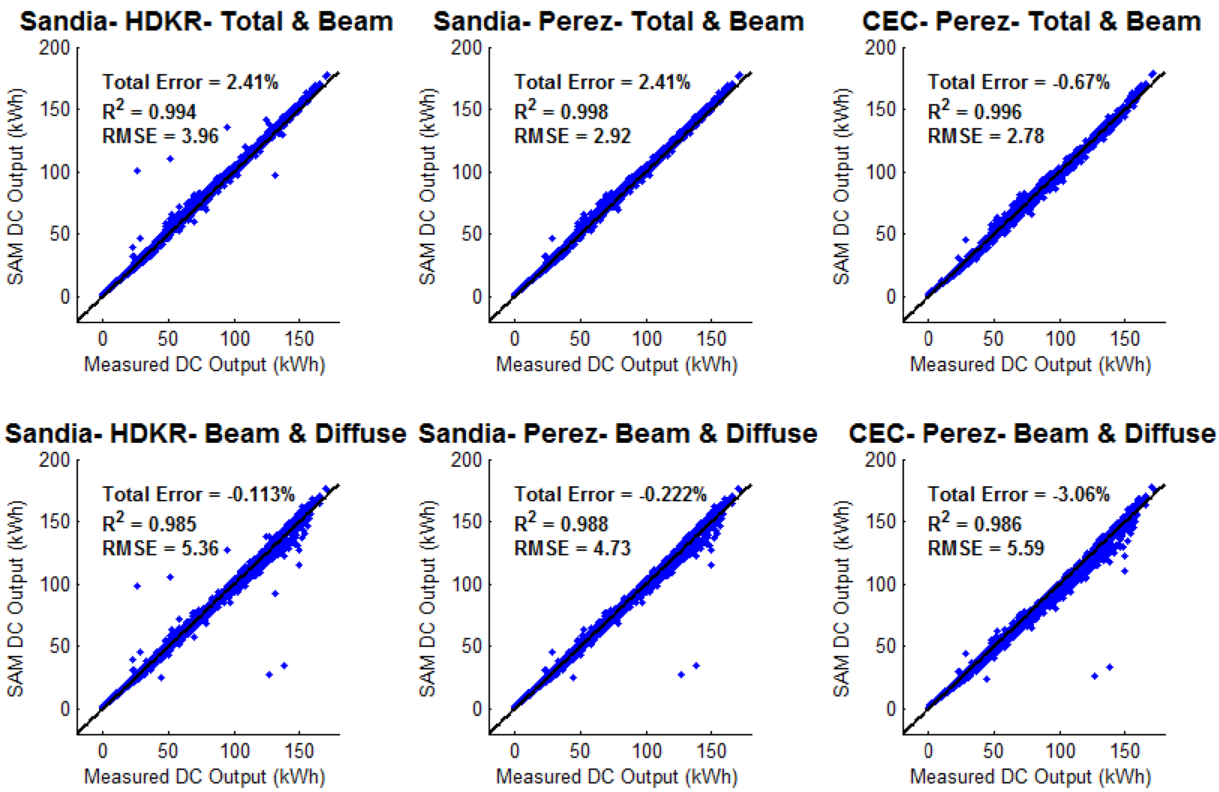


Figure 3-6. Hourly AC production comparison plots for different models—Forrestal system

The most important conclusion that we drew from this model comparison is that all of these combinations of module models, transposition models, and irradiance inputs perform well with respect to measured data, within about 3% total error, 6 kWh of RMSE, and $R^2 > 0.98$ in all cases. This confirms the consistency of SAM across its many model options; if the module used in a project is available in the CEC module database but not the Sandia database, or if only beam and diffuse data are available at a site, SAM will still able to effectively capture the production of that system.

That said, it is interesting to examine some of the differences between these model choices. We evaluate all three error measures in conjunction (total error, RMSE, and correlation strength) because together they paint a more complete picture of the differences between these models than any one measure individually.

In this dataset, the Perez transposition model tends to have a slightly higher correlation and slightly lower RMSE than the HDKR transposition model but similar total errors for the dataset. In one irradiance case, the CEC model has lower RMSE and total error than the Sandia model, but in the other irradiance case the reverse is true, making it an inconclusive comparison. The CEC module model shifts the SAM error down by about 3% compared to the Sandia module model under the same circumstances in both irradiance input cases. Using “Beam and Diffuse” irradiance as inputs causes larger underprediction (2.5% larger) in all cases and consistently produces a higher RMSE. However, this might not hold true for a dataset where higher confidence is placed in the diffuse irradiation data than the global irradiation. It is also interesting to note that using Beam and Diffuse as inputs creates three very low outliers that do not exist in the results using the Total and Beam data. Looking at these points in the original data, they are for three consecutive hours, which suggests an error in one of the sensors that was not revealed in the original quality checks of the climate data.

3.4 Conclusions

For the Forrestal system in Washington, D.C., we demonstrated the extreme effect that the known issue of snow cover can have on a system, both on an hourly basis and on a monthly basis, introducing as much as 25 kWh to the hourly RMSE and anywhere from 1%–330% error on a monthly basis. NREL is in the process of developing an algorithm that will better predict snow cover issues, which will be implemented in SAM as part of future work. Additionally, we discovered that shading had not been adequately modeled in this simulation due to a lack of information about the layout of the Forrestal building roof. After removing both of these known causes of error, SAM predicted the measured AC power production quite accurately. The RMSE on an hourly basis was only 2–3 kWh, and summed production prediction in kilowatt-hours was within 3% of measured values on a monthly basis. However, we also noticed that even after correcting for snow cover, SAM still tends to overpredict power production in the winter and underpredict it in the summer. This seasonal variation is likely due to seasonal variations in the underlying transposition models and will be investigated further; see Section 1.4 for more detail. For the entire period of record, SAM underpredicted power production by 2%.

Finally, the Forrestal system data were used to compare several model options: the Perez versus HDKR transposition model, the Sandia versus CEC module database, and using Total and Beam irradiance inputs versus Beam and Diffuse inputs. For all permutations of these model options, SAM was in good agreement with measured data, within about 3% total error. Additionally, all permutations had extremely high correlation with measured data, with R^2 values all greater than 0.98. The fact that all of these model combinations had such good agreement with measured data validates the presence of multiple model options in SAM. If a user chooses different irradiance inputs based on available data, chooses the module from the CEC or Sandia database based on its availability in these databases, or chooses between the two transposition models, SAM produces similar energy production results from an hourly to an annual basis.

A few differences between models were noted. For this dataset, the CEC model tends to have an error consistently shifted down by 3% from the Sandia model under the same input conditions. Also, for this dataset, using Beam and Diffuse as inputs consistently produces a higher RMSE than using Total and Beam and consistently shifts the error down by 2.5% compared to Beam and Diffuse. This observation might be specific to this dataset, where the accuracy of the Total measurement appears to be higher than the accuracy of the Diffuse measurement.

4 NREL Mesa Top System Study

4.1 Introduction

The Mesa Top PV system is a 658-kW AC one-axis tracking system with backtracking that sits on top of South Table Mountain, which is immediately to the northwest of NREL's main campus. This system began operation in December 2008 and is expected to continue producing power for at least 20 years. It was designed to provide roughly 7.2% of NREL's electricity needs, with an annual energy production of around 1.2 GWh. The system is managed by SunEdison and the Western Area Power Administration (WAPA) via a 20-year solar power services agreement (SPSA) to provide solar energy services to DOE for use at NREL [4] [5].

Figure 4-1. Aerial view of the Mesa Top system [4]

4.2 Data Quality Control

The Mesa Top system is a SunEdison system, and as such, the datasets and data quality control techniques were applied as described in Section 1. Any hours with known system outages (such as inverter outages) or estimated data were removed from the analysis. Overall, this resulted in the removal of 16 hours in 2011 and 79 hours in 2012.

4.3 SAM Modeling

The system is located at a latitude of 39°44'41"N, a longitude of 105°10'37"W, and an elevation of 1,829 m. This PV system consists of two main arrays, a "north array" and a "south array." Each array consists of 1,848 solar panels that are wired in strings of 7. These strings are then wired in parallel with one another with 264 strings constituting each array. Each array has its own identical inverter [6]. The entire array has a tilt angle of 0º along the north-south tracking axis and an azimuth angle of 180º (due south).

Figure 4-2. Aerial view of the Mesa Top system's north and south arrays [7]

The appropriate SRRL weather data file was selected for each year (a formal description of the SRRL weather data files can be found in Section 2). Percent of annual output was adjusted based on a 0.5% year-to-year decline in output (compounded annually) and an installation date of December 2008. This results in a percent of annual output of 98.5% and 98.0 for 2011 and 2012, respectively.

Table 4-1. SAM Specification—Mesa Top

Performance Model

Modules		
Sanyo Electric HIP-195DA3		
Cell material	c-Si	
Module area	1.2 m^2	
Module capacity	195.3 DC Watts	
Quantity	3,696	
Total capacity	721.8 DC kW	
Total area	4,483 m^2	
Inverters		
Advanced Energy: Solaron 333-3159000-105 480V		
Unit capacity	333 AC kW	
Input voltage	330 - 600 VDC	
Quantity	2	
Total capacity	666 AC kW	
AC derate factor	0.99	
Two subarrays:	**1**	**2**
Strings	264	264
Modules per string	7	7
String DC voltage	390.6	390.6
Tilt (deg from horizontal)	0	0
Azimuth (deg E of N)	180	180
Tracking	1 axis	1 axis
Backtracking	yes	yes
Rotation limit (deg)	45	45
Shading	no	no
Soiling	yes	yes
DC derate factor	0.96	0.96
Performance Adjustment		
Annual	98.015%	
Year-to-year decline	0.5%/yr	
Hourly factors	no	

Although the north array and south array are constructed identically, they were modeled in SAM as two separate subarrays as they are set up. The results are the same as if they were modeled as one larger array.

4.4 Results

On an hourly basis, SAM shows large hourly errors based on zenith angle. As discussed in Section 2, significant error at the hourly timescale was observed and a direct correlation can be drawn between this error and increasing zenith angles. Further investigation of this error yielded that SAM-predicted Gross AC Production results were independent of the row-to-row spacing value entered into SAM. This is indicative of an issue with the SAM backtracking/shading algorithm for one-axis trackers in the 2013.1.15 release being validated in this report. The error in SAM's backtracking/shading algorithm caused results to be identical to those for a system that did not have any row-to-row shading (due to the rows being sufficiently spaced to reduce this shading to zero). Since in reality the Mesatop system's rows are close enough that shading causes significant backtracking, this resulted in major overpredictions by SAM at high zenith angles. Figure 4-3 and Figure 4-4 show this error and its direct dependence on zenith angle.

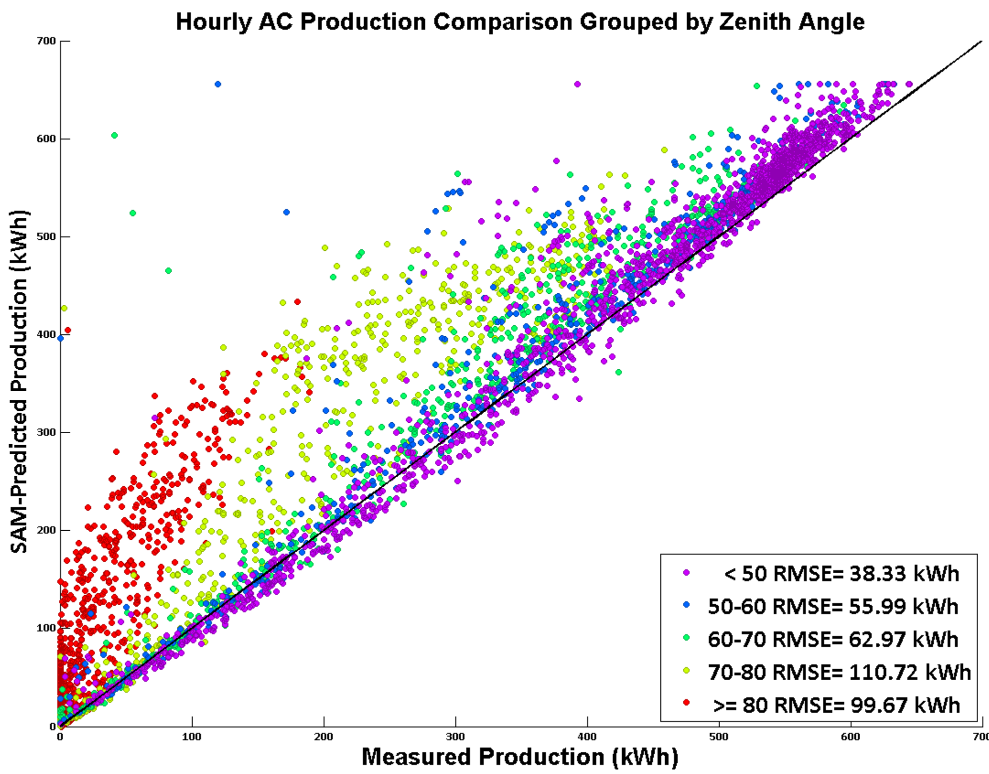


Figure 4-3. Hourly AC production grouped by zenith angle—Mesa Top system 2011 (post-processed)

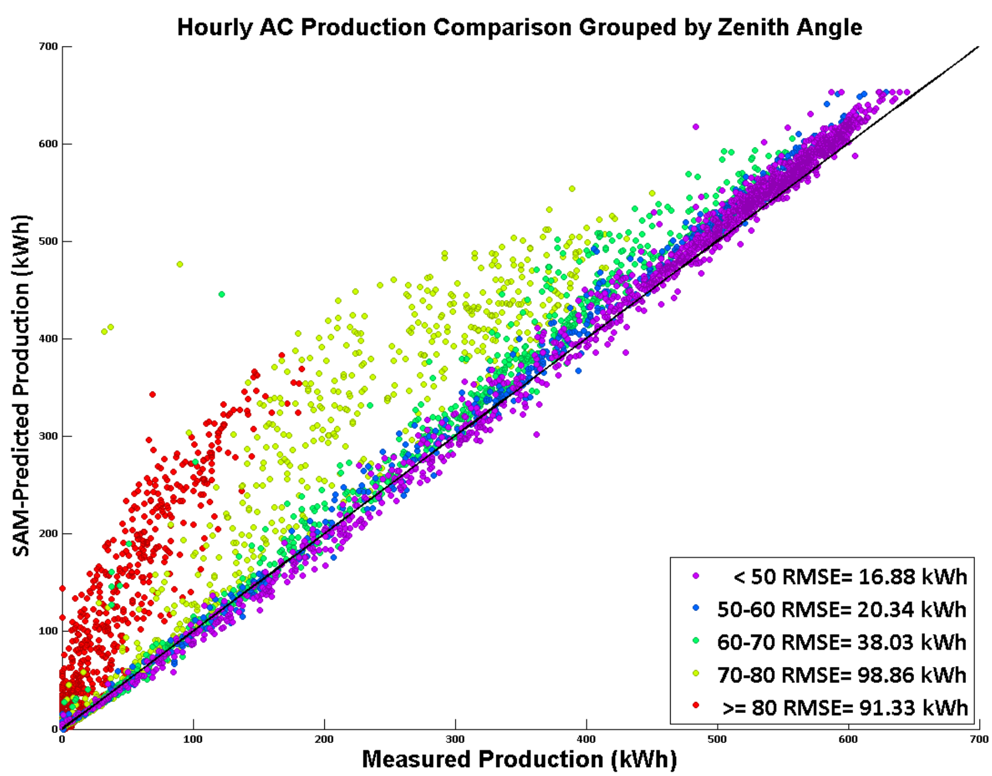


Figure 4-4. Hourly AC production grouped by zenith angle—Mesa Top system 2012 (post-processed)

Further investigation showed that this error was produced because during many hours where SAM should have been utilizing backtracking it was instead setting the tracker rotation angle to its maximum. This effectively should act to reduce the estimated power production of the system, however, when a system is designated as a backtracking system SAM correctly disables the row-to-row shading algorithm. These two effects coupled together resulted in unusually large errors for higher zenith angles, as shown in Figure 4-3 and Figure 4-4 for 2011 and 2012, respectively.

A new version of SAM was released on 2013.9.20 with this issue corrected. Since the purpose of this validation report is to validate SAM 2013.1.15, the improved results are not included in the aggregate results of this report. However, it is still noteworthy to consider the consequences of improvement on SAM's model of this system. Figures 4-5 and 4-6 below allow visualization of the improved match between measured and modeled for the Mesa Top system for 2011 and 2012, respectively, when compared with Figures 4-3 and 4-4.

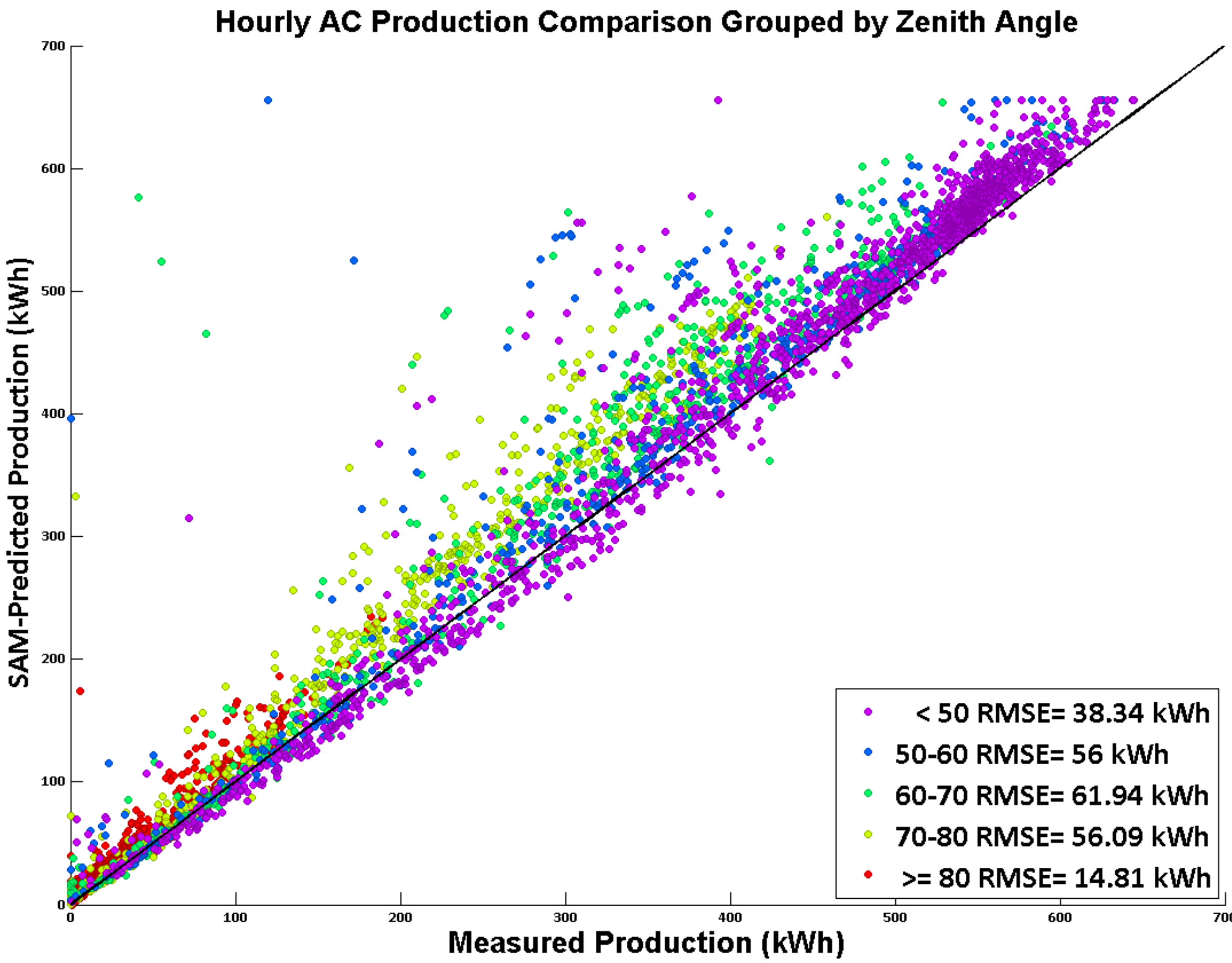


Figure 4-5. Hourly AC production grouped by zenith angle - Mesa Top system 2011 (post-processed) 2013.9.20 release

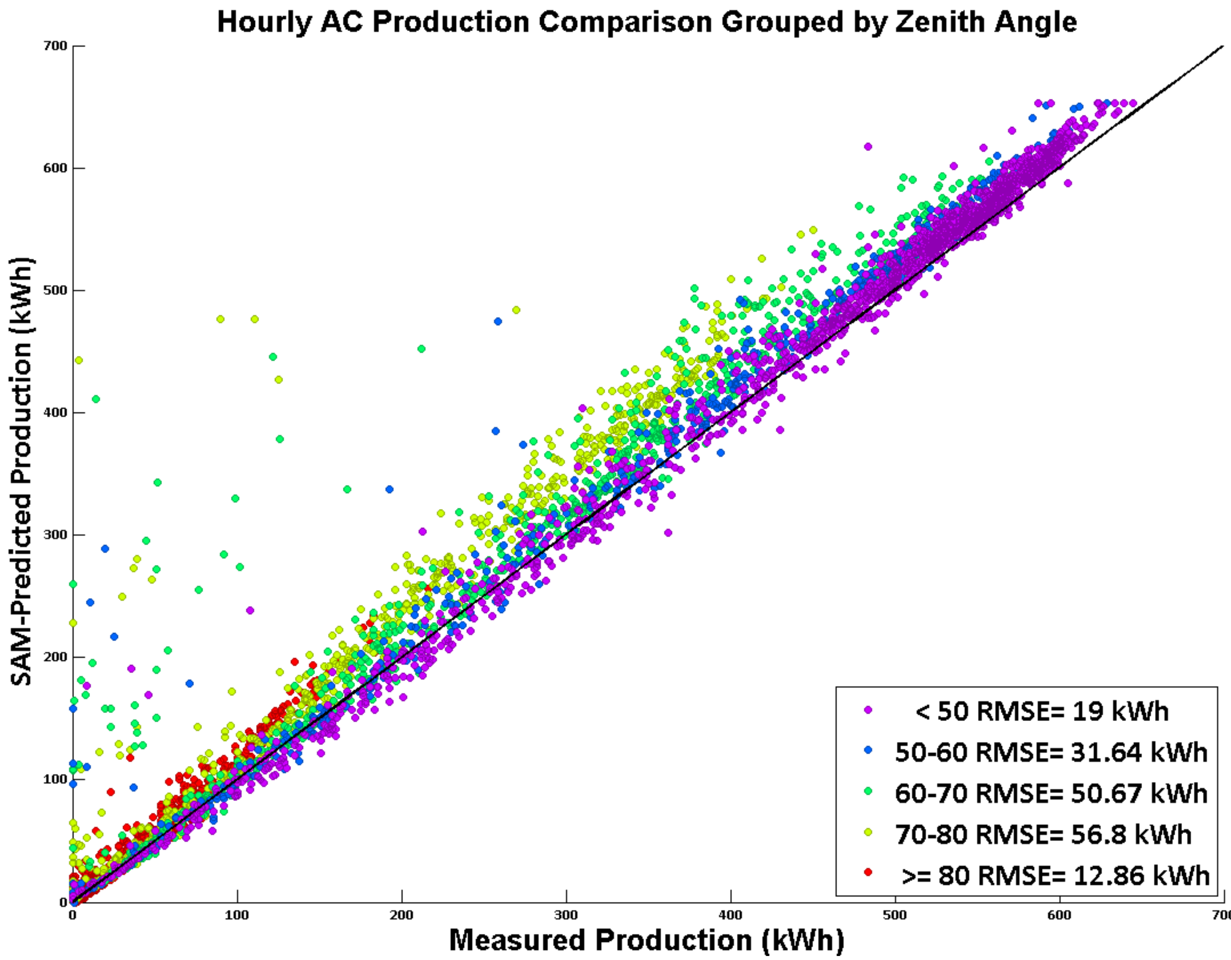


Figure 4-6. Hourly AC production grouped by zenith angle - Mesa Top system 2012 (post-processed) 2013.9.20 release

This improvement at the hourly timescale obviously manifests as improvement at the annual timescale as well. Normalized annual error for this system in the 2013.1.15 release was 15.5% in 2011 and 11.5% in 2012, resulting in an average of 13.5% for both years. In the 2013.9.20 release, these errors were reducing to 8.7% in 2011 and 6.5% in 2012, resulting in an average of 7.6%. This is a significant reduction in modeling error which was entirely the result of fixing an error in SAM's backtracking algorithm.

Table 4-2. Annual Percent Error for the 2013.1.15 Release and the 2013.9.20 Release

Year	Percent error post snow removal - 2013.1.15 release	Percent error post snow removal - 2013.9.20 release
2011	15.5%	8.7%
2012	11.5%	6.5%
Average	**13.5%**	**7.6%**

The errors observed in Table 4-2 for the 2013.9.20 release are still larger than all other systems modeled in this report, indicating that there is still something that is not being correctly captured by SAM for this system. Looking again at Figure 4-5 and Figure 4-6, this error appears to still be related to zenith angle. Other PV models were run using the same data to check if this error might be a SAM-specific issue, but they show very similar results to Figure 4-5 and Figure 4-6.

One hypothesized reason for this persistent zenith-angle-related error is that the information used for the system is actually an inaccurate portrayal of system specifications. In support of this hypothesis, Figure 4-7 shows the improvement in Mesa Top’s 2012 scatter plot grouped by zenith angle when the Ground Coverage Ratio (GCR) was increased from the 0.40 specified in the system drawings to an experimental 0.45.

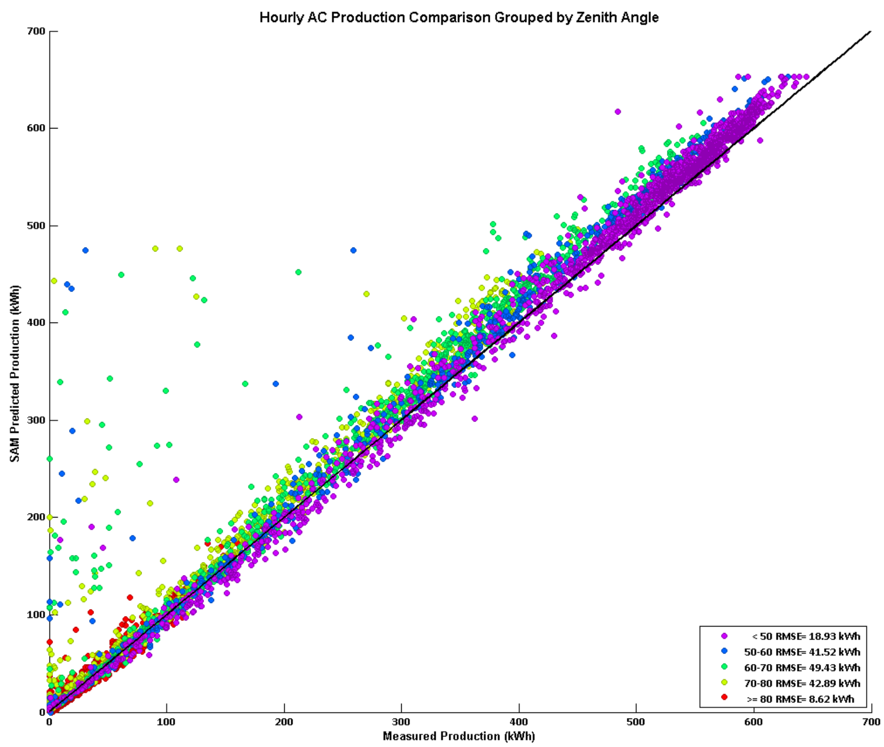


Figure 4-7. Hourly AC production grouped by zenith angle - Mesa Top system 2012 (post-processed) 2013.9.20 release, 0.45 GCR

The improvement from the 0.40 GCR is quite apparent when comparing Figure 4-5 to Figure 4-6, and shows a significant improvement with many more points lying closer to the 1:1 trendline. Additionally, RMSE at high zenith angles decreased appreciably. At zenith angles greater than 80º, RMSE decreased by 5 kWh and at zenith angles between 70º and 80º, RMSE decreased by 16.07 kWh.

4.5 Conclusions

If we examine Figure 4-3 and Figure 4-4, it becomes apparent that SAM version 2013.1.15 was not correctly representing one-axis tracking systems. As the sun approaches the horizon, this known cause of error had a larger and larger effect on power production, and SAM got farther and farther from correct power estimation. It was determined that this issue was a result of an incorrect backtracking algorithm in SAM. This error has been addressed in the subsequent SAM release, resulting in significantly better results in the 2013.9.20 version of SAM.

Despite the improvements to SAM's backtracking model via the 2013.9.20 release, there are still errors that are directly related to increasing zenith angles. This may or may not be the result of incorrect information regarding the system's GCR, as modifying this was shown to improve the results. Future work will determine if this persisting disagreement is (1) a result of incorrect metadata, (2) a problem with the one-axis tracking algorithm itself (either in the backtracking algorithm, the row-to-row shading algorithm, the fact that SAM can only model at hourly resolution, or elsewhere), or (3) if the behavior of this tracker is not performing to its specification. However, fixing the bug in the backtracking algorithm in the 2013.9.20 release of SAM resulted in reducing the average annual error for this system from 13.5% to 7.6%, which is a significant improvement.

5 NREL Research Support Facility 1 System Study

5.1 Introduction

The Research Support Facility (RSF) 1 PV system is a 385-kW AC fixed system that sits on top of one of NREL's newest buildings, the RSF. The RSF 1 system occupies the roof space of both the B and C wings, which were the first of three wings to be constructed. This system began operation in November 2010. The system is managed by SunEdison to provide solar energy services to DOE for use at NREL [8].

Figure 5-1. Aerial view of the RSF 1 system (picture 17767) [9]

5.2 Site Specification

The system is located at a latitude of 39°44'26"N, a longitude 105°10'15"W, and an elevation of 1,829 m. The full system consists of 1,872 Solon Black 230/07 240WP modules and two different inverters that are split between two different arrays: the "C-Wing Array" (CWA), which is the southernmost rooftop array, and a "B-Wing Array" (BWA), which is the northernmost rooftop array. The CWA has 780 modules mounted at an azimuth of 180º that are wired to a Satcon PVS-135 inverter. Each string is made up of 13 modules mounted in series, and there are 60 total strings mounted in parallel to form the full CWA. The BWA has 1,092 modules mounted at an azimuth of 165º that are wired to a Satcon PVS-250. Each string is composed of 13 modules mounted in series, and there are total of 84 string mounted in parallel to form the full BWA [8].

Figure 5-2. Aerial view of the RSF 1 system's BWA and CWA [10]

5.3 Data Quality Control

The RSF 1 system is a SunEdison system, and as such, the datasets and data quality control techniques were applied as described in Section 1. Any hours with known system outages (such as inverter outages) or estimated data were removed from the analysis. Overall, this resulted in the removal of 1,157 hours in 2011 and 3,221 hours in 2012 as a result of outages in the months of September, October, November, and December 2012. This large number of hours was removed due to significant problems with the PVS-135 inverter being down.

5.4 SAM Modeling

The appropriate SRRL weather data file was selected for each year. Percent of annual output was adjusted based on a 0.5% year-to-year decline in output and an installation date of November 2010 with interest compounded annually. This results in annual output percentages of 100% and 99.5% for 2011 and 2012, respectively.

In its current form, SAM cannot model systems with more than one type of inverter inside the same case, so one case was created for each array (CWA and BWA), each with its own set of modules, azimuth, and inverter. The hourly outputs of the two systems were summed to get total system power production for a given hour.

Table 5-1. RSF 1 System Study CWA SAM Specifications

Performance Model

Modules	
SOLON SOLON Black 230-15 240	
Cell material	c-Si
Module area	1.5 m^2
Module capacity	240.2 DC Watts
Quantity	780
Total capacity	187.4 DC kW
Total area	1,170 m^2
Inverters	
Satcon Technology Corporation: PVS-135 (208V) 208V	
Unit capacity	135 AC kW
Input voltage	310 - 600 VDC
Quantity	1
Total capacity	135 AC kW
AC derate factor	0.99
Array	
Strings	60
Modules per string	13
String DC voltage	385.1
Tilt (deg from horizontal)	10
Azimuth (deg E of N)	180
Tracking	fixed
Backtracking	-
Rotation limit (deg)	-
Shading	no
Soiling	yes
DC derate factor	0.96
Performance Adjustment	
Annual	none
Year-to-year decline	0.5%/yr
Hourly factors	no

Table 5-2. RSF 1 System Study BWA SAM Specifications

Performance Model

Modules	
SOLON SOLON Black 230-15 240	
Cell material	c-Si
Module area	1.5 m^2
Module capacity	240.2 DC Watts
Quantity	1,092
Total capacity	262.3 DC kW
Total area	1,639 m^2
Inverters	
Satcon Technology Corporation: PVS-250 (208V) 208V	
Unit capacity	250 AC kW
Input voltage	320 - 600 VDC
Quantity	1
Total capacity	250 AC kW
AC derate factor	0.99
Array	
Strings	84
Modules per string	13
String DC voltage	385.1
Tilt (deg from horizontal)	10
Azimuth (deg E of N)	165
Tracking	fixed
Backtracking	-
Rotation limit (deg)	-
Shading	no
Soiling	yes
DC derate factor	0.96
Performance Adjustment	
Annual	none
Year-to-year decline	0.5%/yr
Hourly factors	no

5.5 Results

Using the simulation designated above (all values not indicated in the above tables were left as their respective defaults in SAM), a SAM simulation was performed. From this simulation, SAM outputs were taken for comparison with measured data.

5.5.1 Annual and Monthly Comparison

5.5.1.1 Data Pre-Processing

Table 5-3 shows the monthly and annual pre-processing results for the RSF 1 System. All absolute monthly errors are between 0% and 145%, with positive values representing overpredictions in energy production by SAM. The months with the largest errors are all winter months, and in particular, February and December show the largest errors. This indicates that snow accumulation on the panels is likely a major contributor to the differences seen between SAM-predicted output and measured data.

Overall, SAM is overpredicting power production by 7% in both 2011 and 2012 prior to snow removal. Additionally, it is generally overpredicting power production during the winter months and underpredicting power production during the summer months.

Table 5-3. Monthly and Annual Comparison for 2011 and 2012—RSF 1 System (Pre-Processed)

Percent Error Prior to Removal of Known Causes of Error		
Timescale	2011	2012
January	4%	13%
February	145%	109%
March	3%	3%
April	7%	6%
May	-2%	1%
June	-1%	1%
July	-2%	0%
August	-2%	0%
September	-2%	N/A
October	6%	N/A
November	11%	N/A
December	86%	N/A
Total Year	**7%**	**7%**

5.5.1.2 Removal of Known Causes of Error

Examining 2011 and 2012 in conjunction allows for a few trends to be observed. SAM is very close to accurately predicting this system's output in the summer months, but many winter months have errors of 10% or more. Further examination of a plot of hourly data for 2012 that is grouped by season (Figure 5-3) confirms that a much more significant overestimation is occurring during the winter months, with many more points lying closer to the y-axis than the ideal 1:1 trend line shown in black.

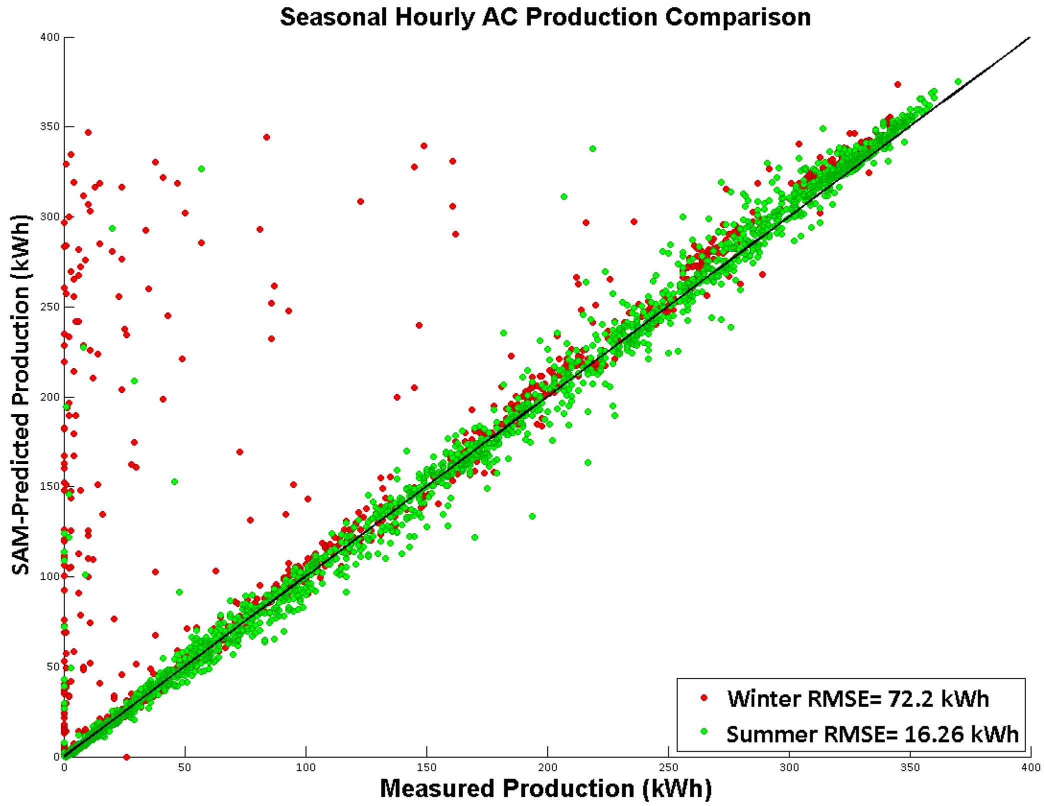


Figure 5-3. Seasonal hourly AC production comparison—RSF 1 system 2012 (pre-processed)

A closer look at some days with snow reveals that the problem is likely due to snow accumulation. Figure 5-4 indicates that there is a large error between SAM's energy production estimate and measured values when a large snowfall accumulation is present.

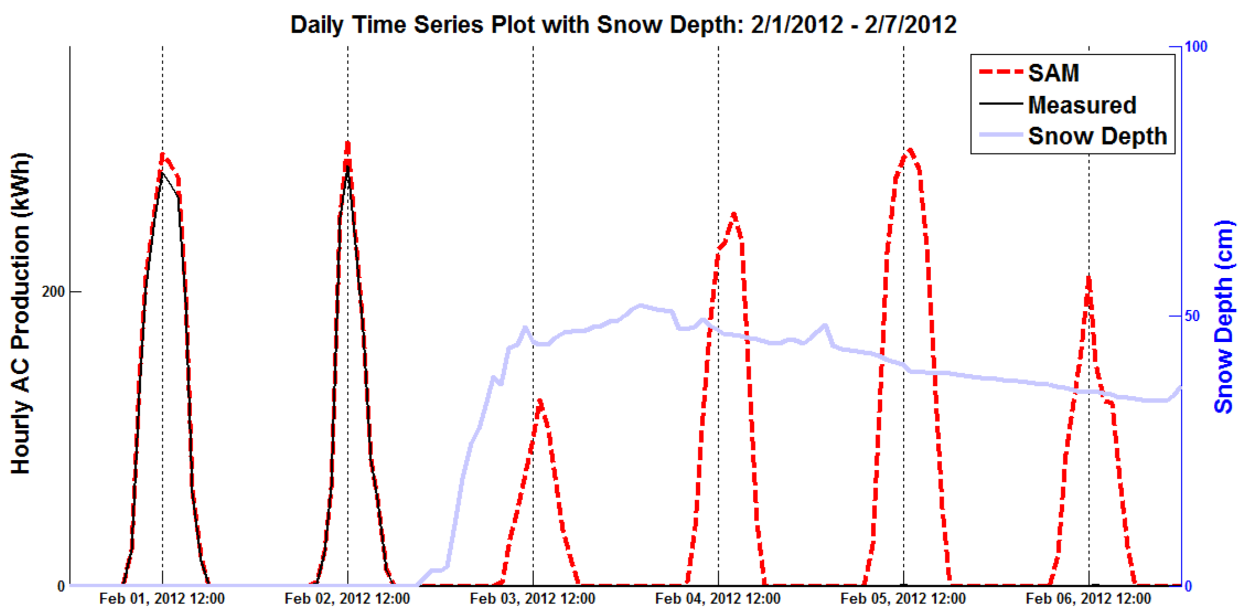


Figure 5-4. Snow-related power production discrepancies—RSF 1 system

After removing any hours with snowfall accumulations of more than 1 cm, another hourly plot was produced with a much cleaner overall dataset (Figure 5-5), showing that removing snow hours eliminated the majority of the points lying near the y-axis.

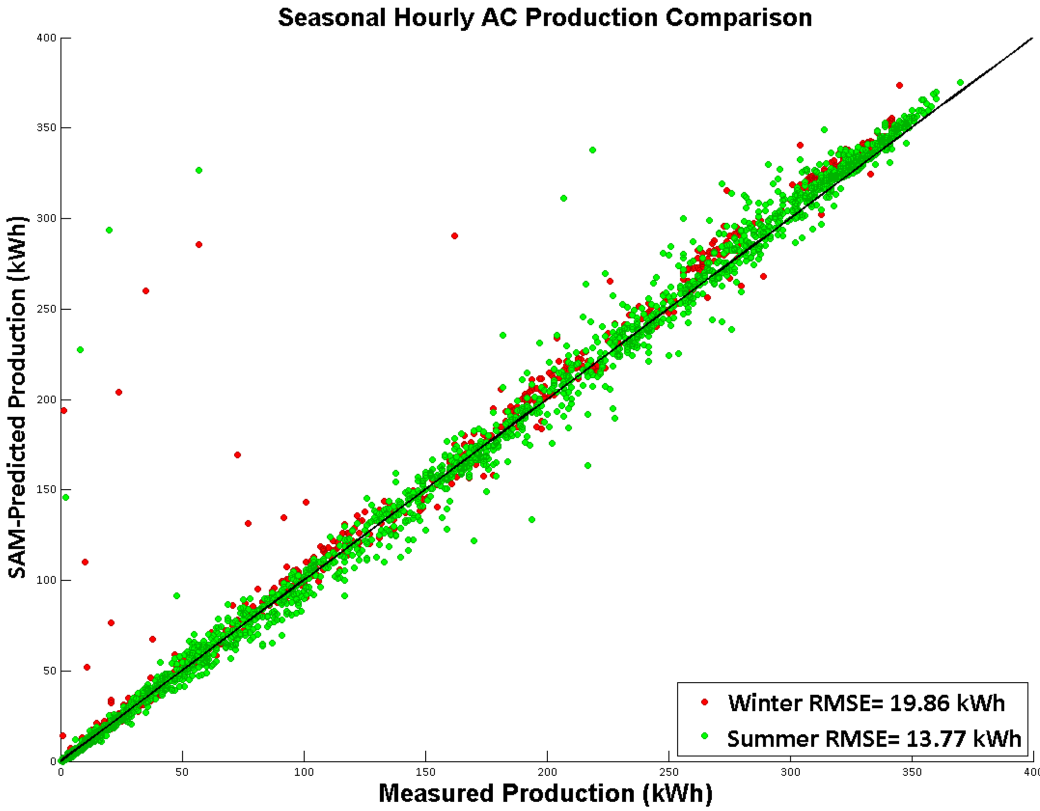


Figure 5-5. Seasonal hourly AC production comparison—RSF 1 system 2012 (post-processed)

For both 2011 and 2012, hours with greater than 1 cm of snow accumulation were removed from the analysis, and the remaining hours were used for the rest of the RSF 1 system analysis.

5.5.1.3 Data Post-Processing

5.5.1.3.1 Year 2011

After removing any hours affected by snowfall accumulation, a monthly comparison shows significantly better agreement between SAM's estimation and measured AC production. All months show less than 4% errors. The worst month prior to removal of hours with snow effects (February) saw an absolute error reduction from 143% to 2%.

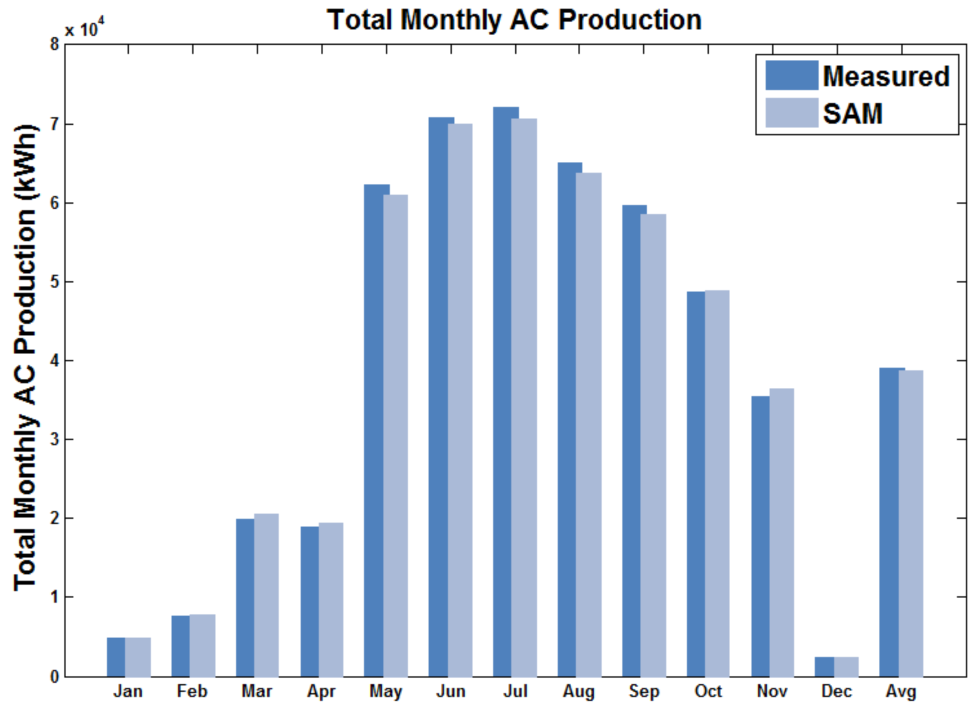


Figure 5-6. Total monthly AC production comparison—RSF 1 system 2011 (post-processed)

Table 5-4. Monthly Comparison of Percent Error Before and After Removal of Known Causes of Error—RSF 1 System 2011

Month	Percent Error Prior to Removal of Known Causes of Error	Percent Error After Removal of Known Causes of Error
January 2011	4%	-1%
February 2011	145%	2%
March 2011	3%	3%
April 2011	7%	2%
May 2011	-2%	-2%
June 2011	-1%	-1%
July 2011	-2%	-2%
August 2011	-2%	-2%
September 2011	-2%	-2%
October 2011	6%	0%
November 2011	11%	3%
December 2011	86%	4%

Removal of hours with snowfall accumulation also reduced the total error between the predicted and measured values to -1% or -3,507 kWh. This is a significant reduction in total error but did result in SAM now underpredicting system power generation instead of overpredicting; it is thus only an absolute error reduction of 6%.

Table 5-5. Overall Comparison Before and After Removal of Known Causes of Error—RSF 1 System 2011

System	Total AC Power Production (kWh) Prior to Removal of Known Causes of Error	Total AC Power Production (kWh) After Removal of Known Causes of Error
SAM	523,899	463,924
Measured	489,307	467,431
Error	**34,592**	**(3,507)**
Percent Error	**7%**	**-1%**

5.5.1.3.2 Year 2012

After removing any hours affected by snowfall accumulation, a monthly comparison for the year of 2012 also shows significantly better agreement between SAM's estimation and measured AC production. All months show less than 6% errors. The worst month prior to removal of hours with snow effects (February) saw an absolute error reduction from 109% to 4%.

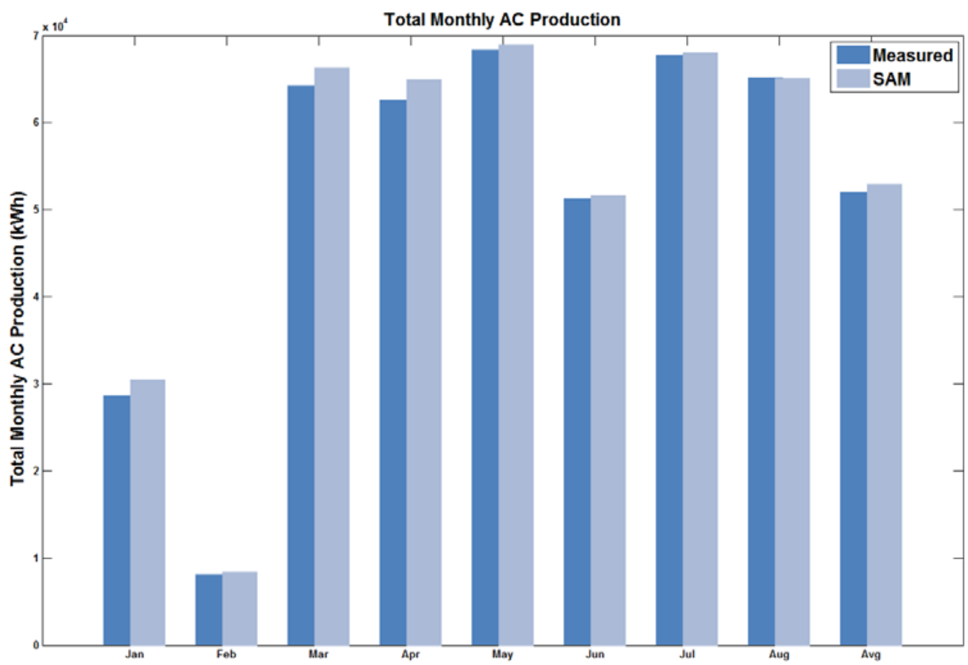


Figure 5-7. Total monthly AC production comparison—RSF1 system 2012 (post-processed)

Table 5-6. Monthly Comparison of Percent Error Before and After Removal of Known Causes of Error—RSF 1 System 2012

Month	Percent Error Prior to Removal of Known Causes of Error	Percent Error After Removal of Known Causes of Error
January 2012	13%	6%
February 2012	109%	4%
March 2012	3%	3%
April 2012	6%	4%
May 2012	1%	1%
June 2012	1%	1%
July 2012	0%	0%
August 2012	0%	0%

Removal of hours with snowfall accumulation reduced the total error between the predicted and measured values to 2%, or 8,890 kWh—an absolute error reduction of 5%.

Table 5-7. Overall Comparison Before and After Removal of Known Causes of Error—RSF 1 System 2012

System	Total AC Power Production (kWh) Prior to Removal of Known Causes of Error	Total AC Power Production (kWh) After Removal of Known Causes of Error
SAM	484,813	442,813
Measured	451,858	433,923
Error	**32,955**	**8,890**
Percent Error	**7%**	**2%**

5.5.2 Daily and Hourly Comparison

A daily time series plot for part of June 2012 was created (Figure 5-8). It shows agreement between SAM-predicted production and measured production and shows that SAM tracks measured data well even on days with intermittent solar resource when provided a weather file that reflects that intermittency.

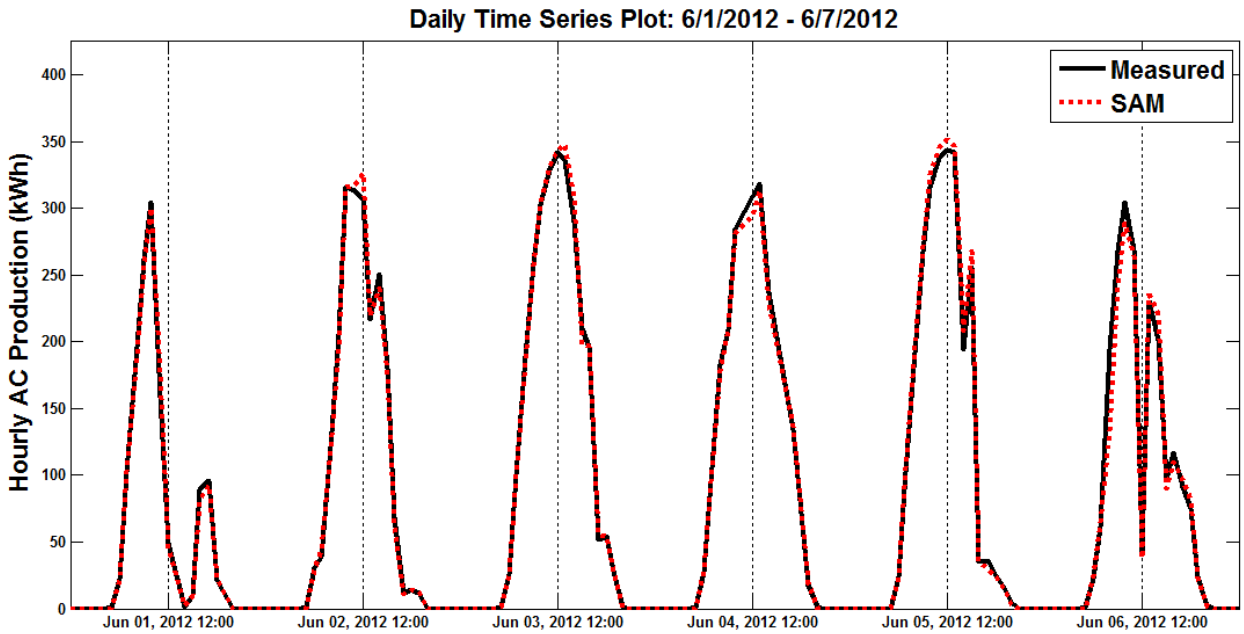


Figure 5-8. Daily time series plot—RSF 1 system (post-processed)

For 2011 and 2012, the average summer and winter diurnal plotlines show agreement. The winter plot in particular has almost indistinguishably identical lines for measured and SAM values. There is slight underprediction by SAM during the summer months, particularly around noon. This is consistent with the seasonal variation findings reported in Section 1.4 that may result from seasonal variations in the underlying radiation transposition model [1].

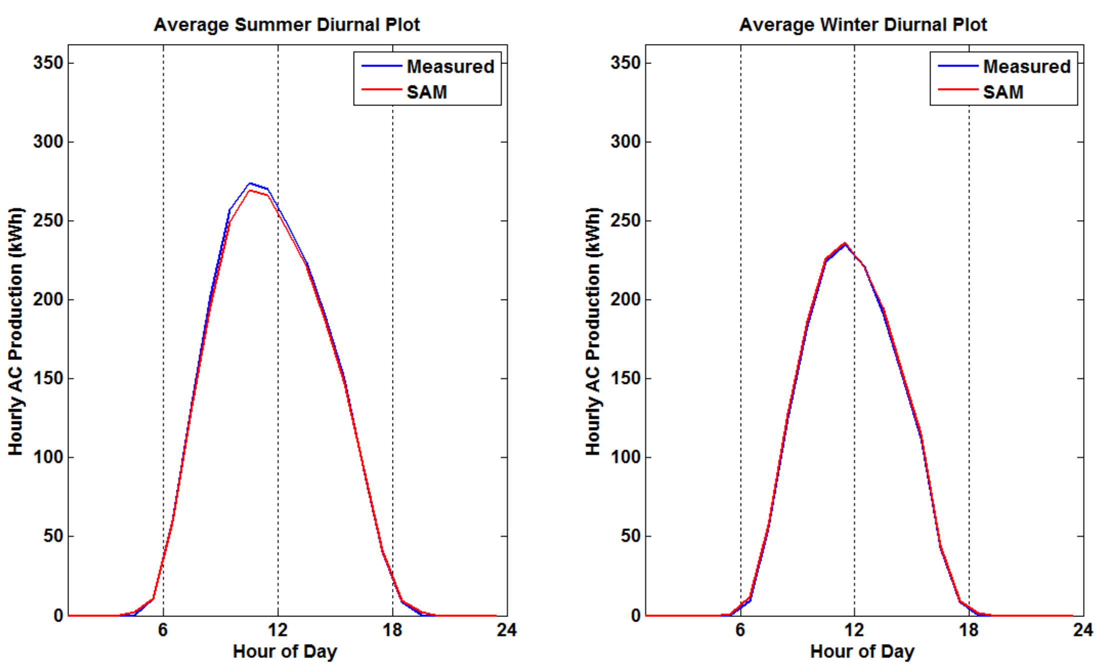


Figure 5-9. Average summer and winter diurnal plots—RSF 1 system 2011 (post-processed)

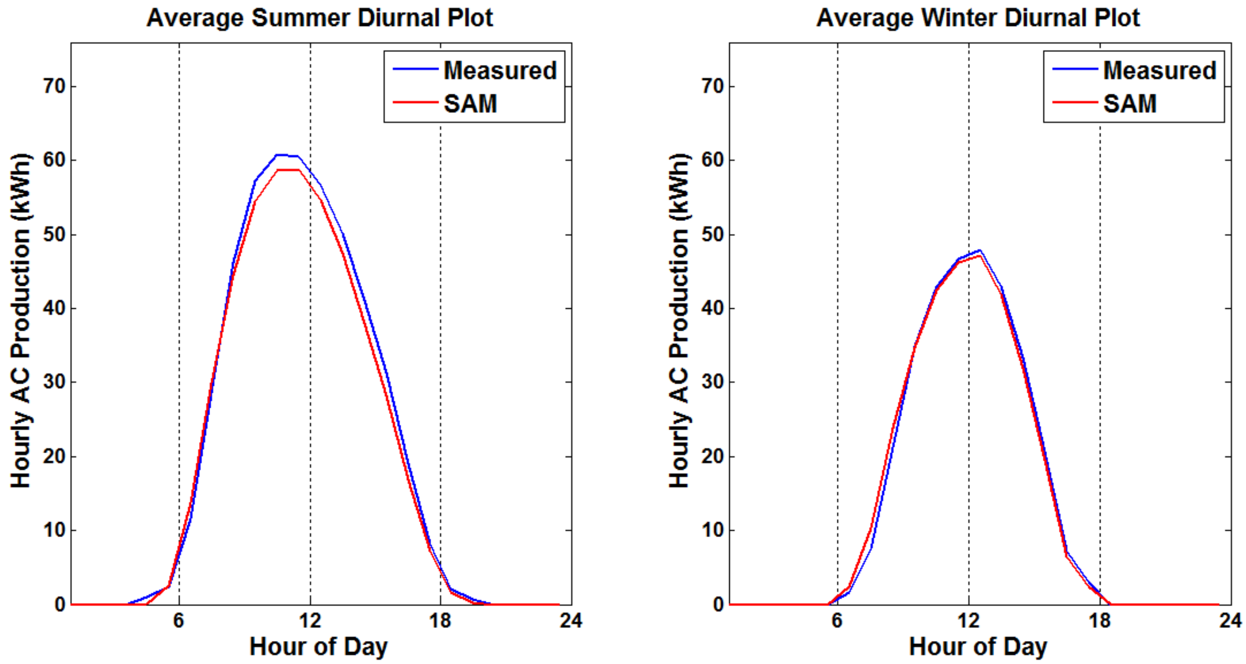


Figure 5-10. Average summer and winter diurnal plots—RSF 1 system 2012 (post-processed)

For 2011 and 2012, on an hourly basis SAM is very close for the majority of hours. There are still a few outlier hours that indicate a potential issue with either SAM or the measured data, but on the whole the correlation is grouped fairly tightly around the ideal 1:1 trend line.

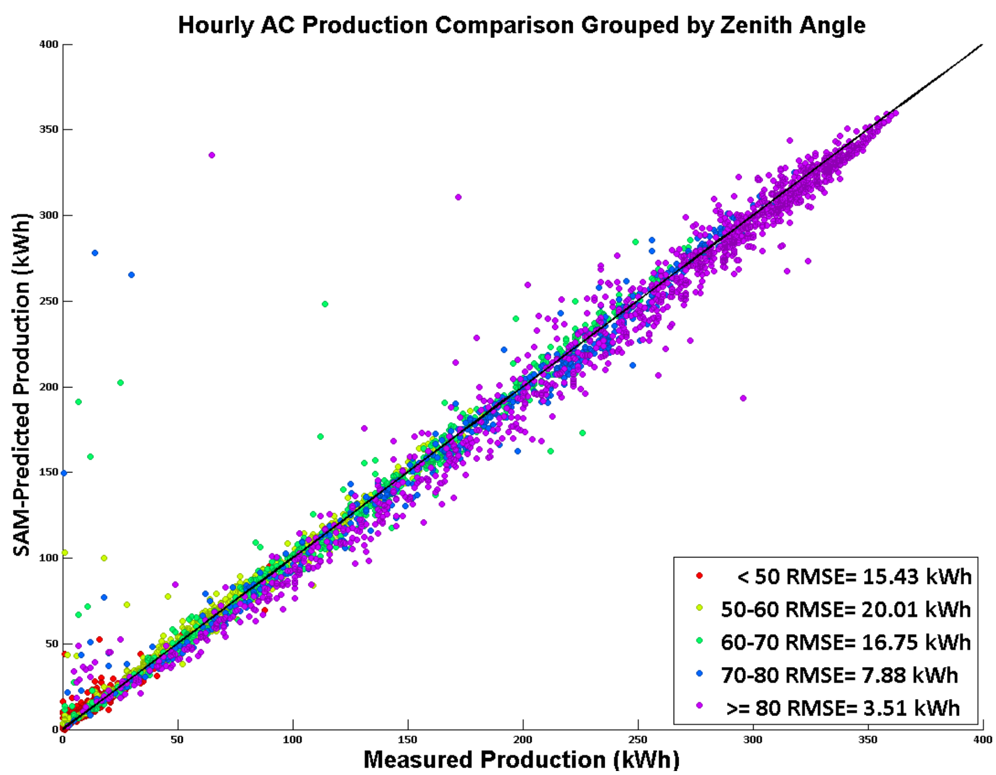


Figure 5-11. Hourly AC production comparison grouped by zenith angle—RSF 1 system 2011 (post-processed)

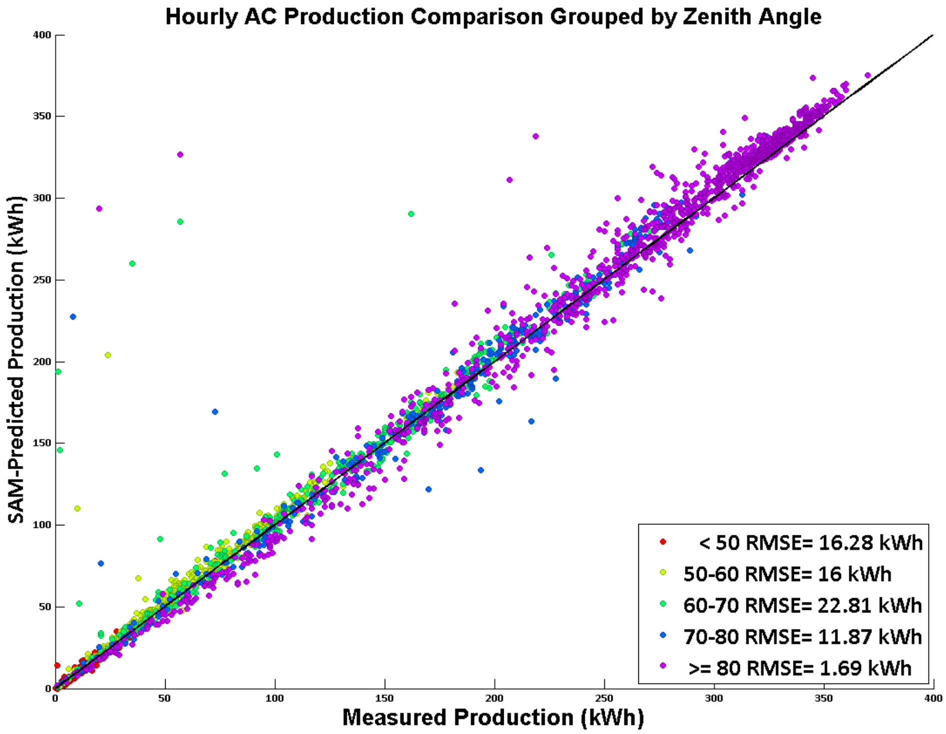


Figure 5-12. Hourly AC production comparison grouped by zenith angle—RSF 1 system 2012 (post-processed)

5.6 Conclusions

Removal of all hours with snow depth greater than 1 cm resulted in a significant reduction in the error between measured values and SAM's energy prediction on a monthly basis. On an annual basis, removal of hours with snow accumulation resulted in an absolute error reduction of 6% for 2011 and 5% for 2012.

If we examine Figure 5-9 and Figure 5-10, we can see a trend being established that SAM-predicted power matched the measured power production of the RSF 1 system on a diurnal basis. Figure 5-11 and Figure 5-12 also show that while SAM-predicted power production on an hourly basis is not perfect, it has a RMSE within 25 kWh for both years.

A comparison of SAM's AC Gross Output (corrected by a given percent of annual output for each year due to system degradation) and the measurements provided by SunEdison, after known causes of error have been accounted for, yield annual errors for 2011 and 2012 of -1% and 2%, respectively. Absolute monthly errors for both years ranged from 0% to 6% with the majority of months having errors less than 4%. Both years showed appropriate diurnal agreement.

6 NREL Research Support Facility 2 System Study

6.1 Introduction

In 2011, NREL installed a 408-kW solar array on the roof of the new A-wing expansion of the RSF, referred to henceforth as the RSF 2 solar system, as part of the building's Leadership in Energy and Environmental Design (LEED) platinum certification. This PV system was designed, constructed, and is serviced by SunPower.

6.2 Data Collection

6.2.1 Data Sources

NREL obtained the measured system performance data from SunPower for the RSF 2 system for the entire year of 2012. AC power was measured at each of the two inverters and reported hourly in kilowatt-hours. The output at each inverter was summed in order to obtain total system output.

As with all of the NREL systems, the weather data used was from the SRRL (in this case 2012 data), described previously.

6.2.2 Data Quality Control

SAM can only accept 8,760 hours of data in a single simulation. However, because 2012 was a leap year, the datasets obtained for the RSF 2 system contained 8,784 values, necessitating the removal of February 29, 2012 from both the SunPower dataset and the SRRL dataset for modeling accuracy in SAM.

From the 8,760 hour dataset, nine hours of system performance data were missing on March 3, 2012, three hours were missing on April 6, 2012, and one hour was missing on December 2, 2012. These 13 hours were removed from the analysis.

Additionally, inverter outages and system shutdowns were identified and removed from the analysis. Table 6-1 summarizes the 38 days removed for these reasons.

Table 6-1. Reasoning for Date Removal—RSF 2 System

Dates Removed	Reason
January 17	System shutdown
February 28–March 7	Inverter outage
April 3–4	System shutdown
June 29–July 23	System shutdown
October 5	System shutdown
November 10	System shutdown

6.3 SAM Modeling

6.3.1 Simulation Specifications

The SRRL data for 2012, in TMY3 format, was used as the weather data for the SAM simulation. The site specified in the simulation was at: latitude: 39.74^0 N; longitude: 105.18^0 W; and elevation: 1,829 m. All other system specifications are shown in Table 6-2 (taken from the SAM output report). All losses and derates were left at their default values unless otherwise specified. The Perez sky diffuse model and the Sandia PV array performance model were used.

Table 6-2. RSF 2 System Study SAM Specifications

Performance Model

Modules	
SunPower SPR-315E-WHT	
Cell material	c-Si
Module area	1.6 m^2
Module capacity	315.1 DC Watts
Quantity	1,296
Total capacity	408.3 DC kW
Total area	2,113 m^2
Inverters	
SMA America: SC250U 480V	
Unit capacity	250 AC kW
Input voltage	300 - 600 VDC
Quantity	2
Total capacity	500 AC kW
AC derate factor	0.99
Array	
Strings	162
Modules per string	8
String DC voltage	437.6
Tilt (deg from horizontal)	10
Azimuth (deg E of N)	165
Tracking	fixed
Backtracking	-
Rotation limit (deg)	-
Shading	no
Soiling	yes
DC derate factor	0.96

6.4 Results

6.4.1 Hourly Comparison

As with all other systems located in snowy climates, the first step in our analysis of the RSF 2 system was to remove days affected by snow cover (an example of which can be seen in Figure 6-1). Forty-one days of snow cover were removed by visually inspecting the data for snow depth that cancelled out system performance.

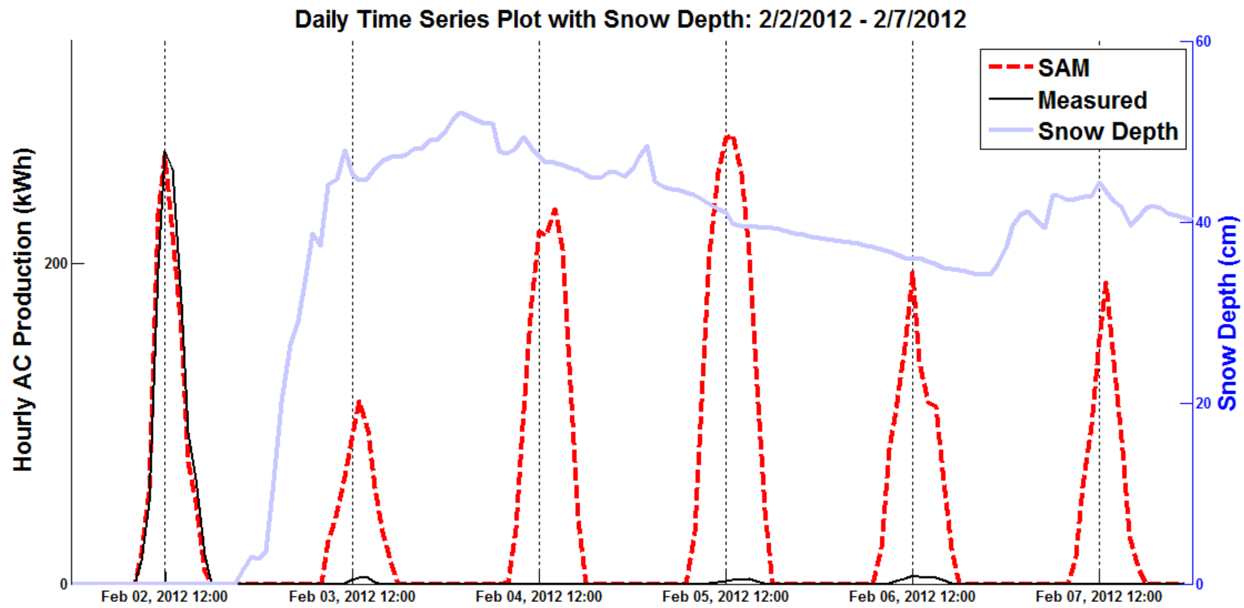


Figure 6-1. Snow-related power production discrepancies—RSF 2 system

After removing snow cover issues, the scatter on an hourly basis was relatively consistent between winter and summer, as shown in Figure 6-2. Summer had an hourly RMSE of 20.5 kWh, and winter had an hourly RMSE of 18.3 kWh.

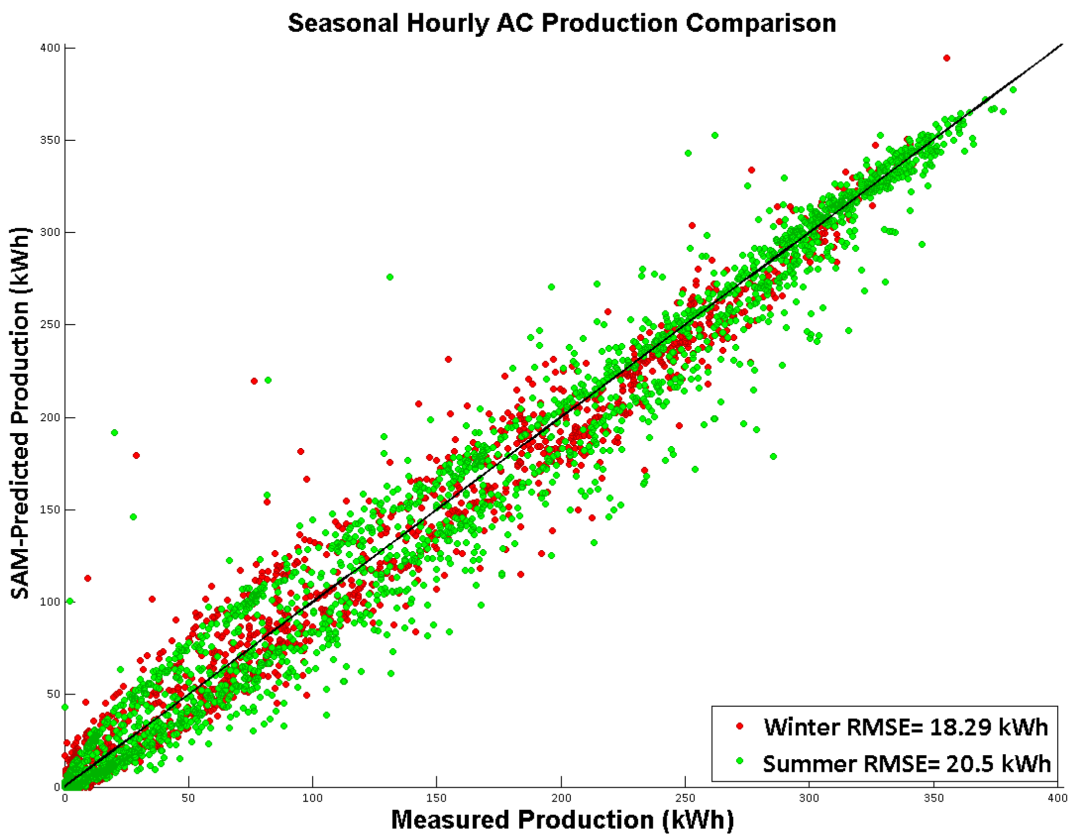


Figure 6-2. Seasonal hourly AC production comparison—RSF 2 system (post-processed)

The data were additionally examined grouped by zenith angle to see if there were any clear shading issues or other zenith angle-dependent issues that could be discovered. Sorted by zenith angle, the scatter also looks fairly uniform (Figure 6-3). It is important to note that higher zenith angles have a lower RMSE because the magnitude of measurements at high zenith angles is lower.

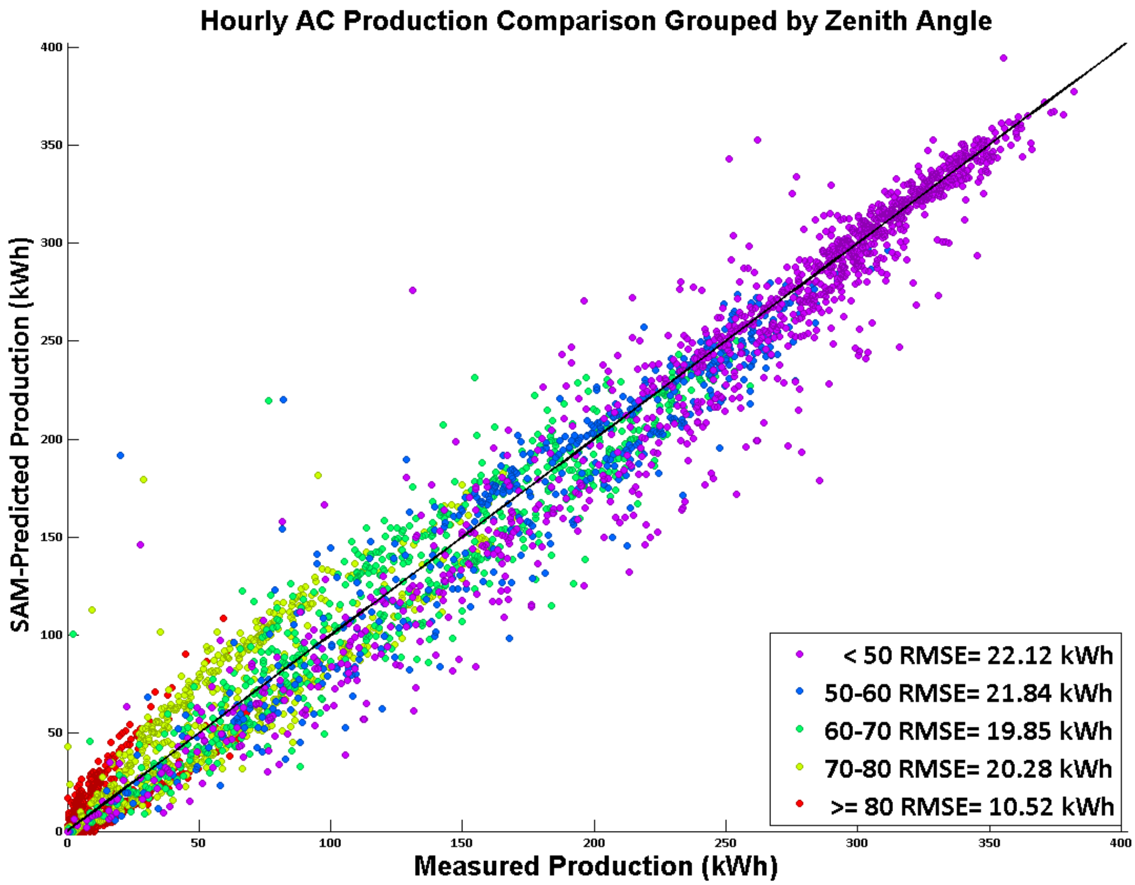


Figure 6-3. Hourly AC production grouped by zenith angle—RSF 2 system (post-processed)

Finally, a heat map of the hourly data was produced in order to examine the overall trend of agreement between SAM-predicted AC power production and measured AC power production. As can be seen in Figure 6-4, SAM's agreement with measured data gets better at higher production values, which generally occur during times of high irradiance (the middle of the day).

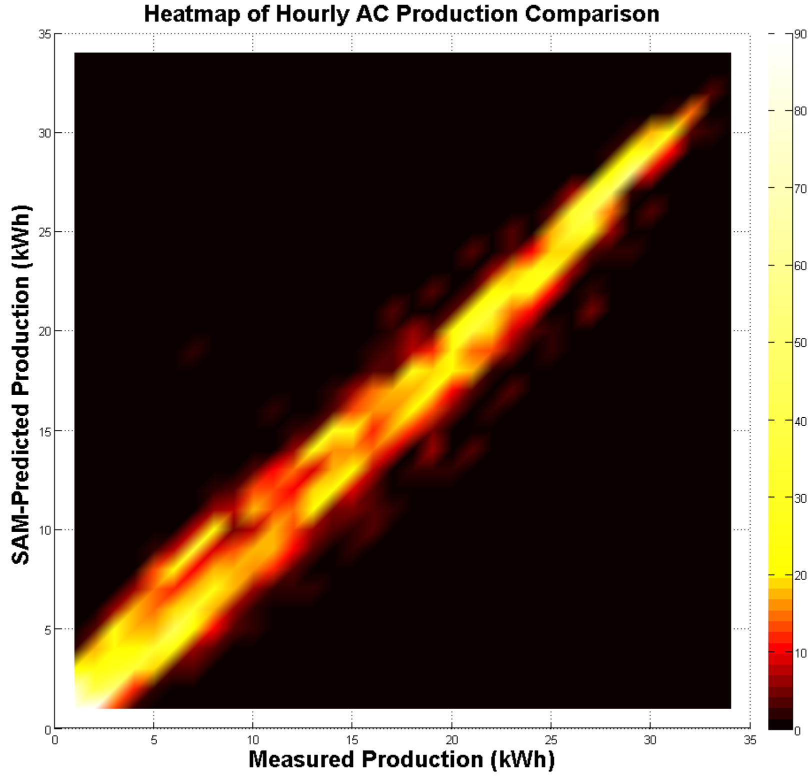


Figure 6-4. Heat map of hourly AC production comparison—RSF 2 system (post-processed)

6.4.2 Diurnal Comparison

On an average diurnal basis, the shape of SAM-predicted power production matches very closely with the shape of measured power production, both during the summer and the winter (Figure 6-5).

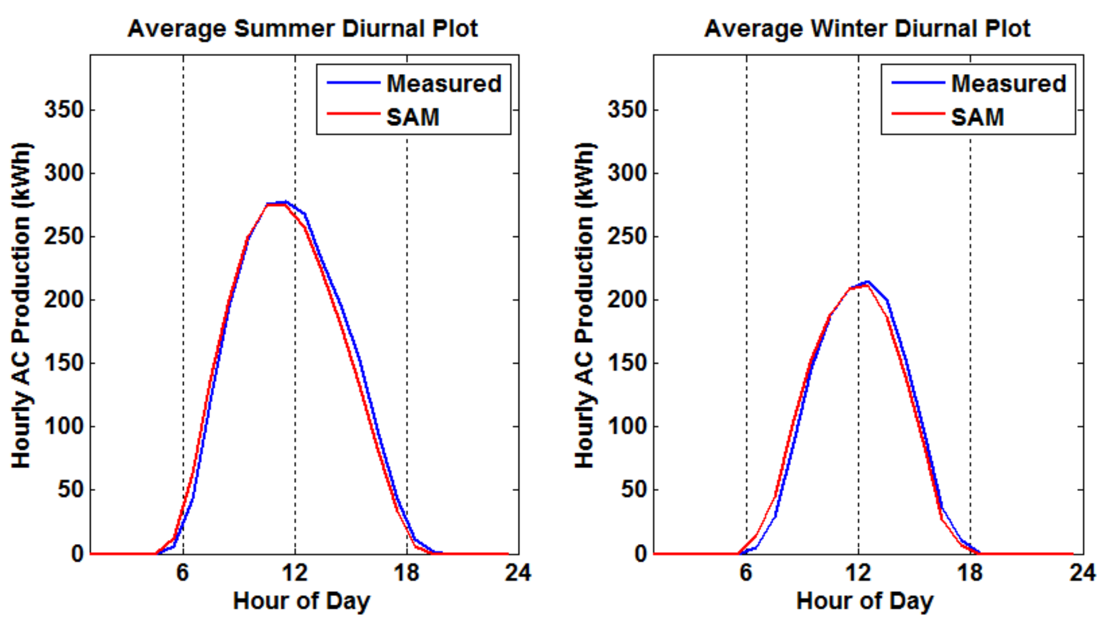


Figure 6-5. Average summer and winter diurnal plots—RSF 2 system 2011 (post-processed)

6.4.3 Monthly Comparison

Examining the monthly comparison plot in Figure 6-6, it is apparent that SAM tends to overpredict AC power production in the winter and underpredict production in the summer. This is quantified in Table 6-3. This seasonal variation is likely due to seasonal variations in the underlying transposition models; see Section 1.4 for more detail.

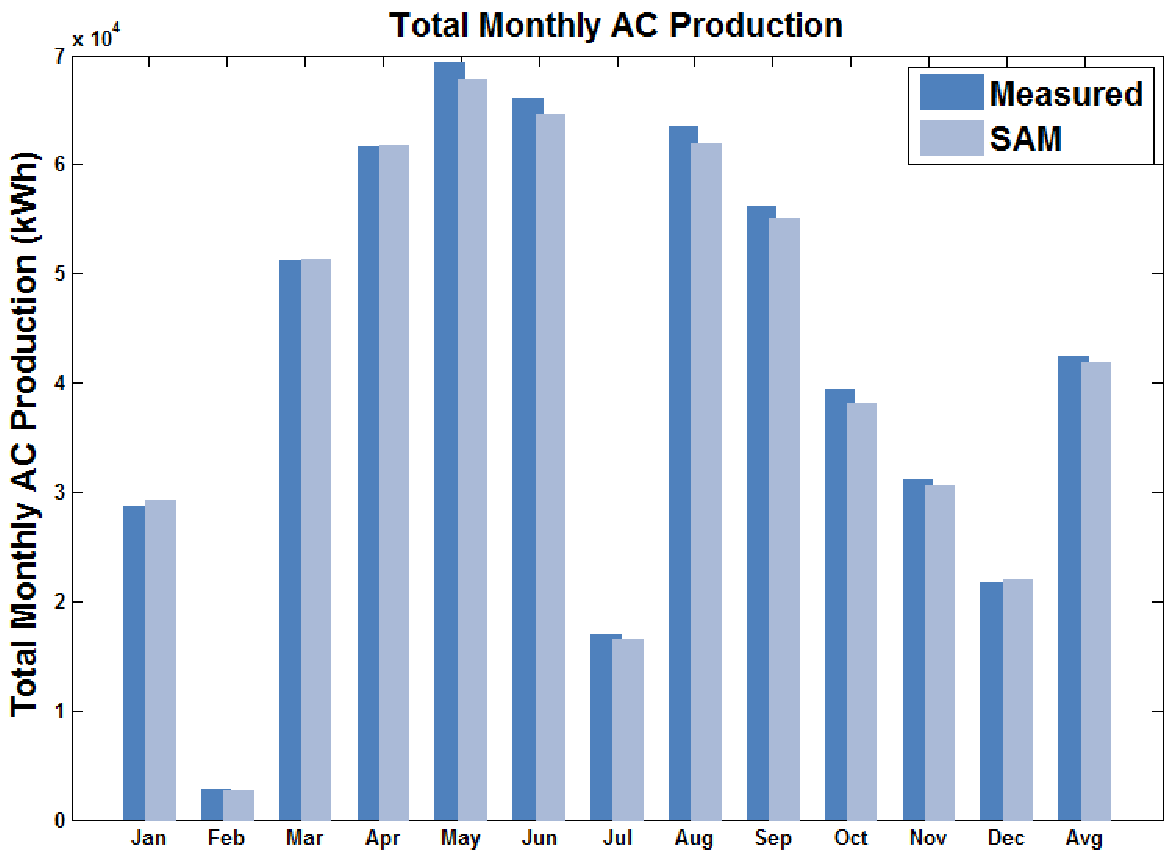


Figure 6-6. Total monthly AC production comparison—RSF 2 system (post-processed)

Table 6-3. Monthly Comparison of Percent Error Before and After Removal of Known Causes of Error—RSF 2 System

Month Year	Percent Error, Known Causes of Error Included	Percent Error, Known Causes of Error Removed
January 2012	13%	2%
February 2012	355%	-3%
March 2012	0%	0%
April 2012	0%	0%
May 2012	-2%	-2%
June 2012	-2%	-2%
July 2012	-2%	-2%
August 2012	-3%	-3%
September 2012	-2%	-2%
October 2012	7%	-3%
November 2012	4%	-2%
December 2012	16%	1%

Table 6-3 demonstrates once more that snow cover issues can cause a huge error in predicted performance. For this system, in February, the error due to snow cover was 355%. Other snowy months, such as January and December, also show snow-cover-related issues, introducing roughly 15% error on a monthly basis. After removing hours impacted by snow cover, SAM predicted measured production within 3% on a monthly basis.

6.4.4 Annual Comparison

For the period of time examined, before removing hours impacted by snow cover, SAM predicted an annual energy production sum of 553.5 MWh, representing an overprediction of 6% compared to the measured 520.1 MWh. After removing known causes of error, which for the RSF 2 system referred explicitly to snow cover, SAM predicted a sum of 501.6 MWh compared to the measured 508.5 MWh, which was an underprediction of 1%.

Table 6-4. Overall Comparison Before and After Removal of Known Causes of Error—RSF 2 System

Total	Known Causes of Error Included	Known Causes of Error Removed
SAM	553,593	501,598
Measured	520,066	508,505
Error	**33,527**	**-6,908**
Percent Error	**6%**	**-1%**

6.5 Conclusions

In general, SAM-predicted power production matched the measured power production for this system, especially on an average diurnal basis. The RSF 2 system is a great example of how big an effect snow cover can have on the power production of a system. In the extreme example of the month of February, snow cover introduced about an additional 350% modeling error on the monthly power production sum. Removing snow cover issues allowed SAM to predict within 3%

on a monthly basis, with a standard deviation on the monthly error of 2%. SAM has the tendency to overpredict power production during winter months and underpredict it during summer months, the potential causes of which are discussed in Section 1.4. On an annual basis, SAM overpredicted by 6% compared to measured values with snow cover issues included and underpredicted by 1% with snow cover issues removed.

7 NREL Science & Technology Facility System Study

7.1 Introduction

The S&TF PV system is a 75-kW AC fixed system that sits on top of one of NREL's research buildings, the Science and Technology Facility. This system began operation in September 2009. The system is managed by SunEdison to provide solar energy services to DOE for use at NREL. This is the smallest system that was studied in this analysis [11].

Figure 7-1. View of the S&TF [12]

7.2 Site Specification

The system is located at a latitude of 39°44'31"N, a longitude 105°10'18"W, and an elevation of 1,829 m. The full system consists of 495 Evergreen ES190-RL modules and a PVS-75 480-V inverter. Each string is made up of 15 modules mounted in series, and there are 33 total strings mounted in parallel to form the full S&TF array [11]. The entire array has a tilt angle of 10º and an azimuth angle of 164º.

Figure 7-2. Aerial view of the S&TF system [13]

7.3 Data Quality Control

The S&TF system is a SunEdison system, and as such, the datasets and data quality control techniques were applied as described in Section 1. Any hours with known system outages (such as inverter outages) or estimated data were removed from the analysis. Overall, this resulted in the removal of 17 hours in 2011 and 48 hours in 2012.

7.4 SAM Modeling

The appropriate SRRL weather data file was selected for each year. Percent of annual output was adjusted based on a 0.5% year-to-year (compounded annually) decline in output and an installation date of September 2009. This results in a percent of annual output of 99.5% and 99.0025% for 2011 and 2012, respectively.

Table 7-1. SAM Specification—S&TF System

Performance Model

Modules	
Evergreen Solar ES-190-RL	
Cell material	c-Si
Module area	1.5 m^2
Module capacity	190.1 DC Watts
Quantity	495
Total capacity	94.1 DC kW
Total area	738 m^2
Inverters	
Satcon Technology Corporation: PVS-75 (480V) 480V	
Unit capacity	75 AC kW
Input voltage	315 - 600 VDC
Quantity	1
Total capacity	75 AC kW
AC derate factor	0.99
Array	
Strings	33
Modules per string	15
String DC voltage	400.5
Tilt (deg from horizontal)	10
Azimuth (deg E of N)	164
Tracking	fixed
Backtracking	-
Rotation limit (deg)	-
Shading	no
Soiling	yes
DC derate factor	0.96
Performance Adjustment	
Annual	99.5%
Year-to-year decline	0.5%/yr
Hourly factors	no

7.5 Results

Using the system parameters designated above (all values not indicated in Table 7-1 were left as their respective defaults in SAM), a SAM simulation was performed. From this simulation, SAM outputs were compared with measured data. For a full description of which outputs from SAM were utilized see Section 1.

7.5.1 Annual and Monthly Comparison

7.5.1.1 Data Pre-Processing

Table 7-2 shows the monthly and annual pre-processing results for the S&TF system. All absolute monthly errors are between 0% and 43%, with positive values representing overpredictions in energy production by SAM. The months with the largest errors are all winter months; in particular January, February, and December show the largest errors. This indicates that snow accumulation on the panels is likely a major contributor to the differences between predicted output and measured data.

Overall, SAM overpredicts power production by 4% and 1% in 2011 and 2012, respectively, prior to snow removal. Additionally, it generally overpredicts power production during the winter months and underpredicts power production during the summer months.

Table 7-2. Monthly and Annual Comparison for Both Years—S&TF System (Pre-Processed)

Timescale	Percent Error Prior to Removal of Known Causes of Error - 2011	Percent Error Prior to Removal of Known Causes of Error - 2012
January	27%	12%
February	43%	29%
March	1%	-2%
April	0%	0%
May	-4%	-4%
June	-3%	-4%
July	-4%	-4%
August	-4%	-5%
September	-4%	-5%
October	5%	4%
November	6%	3%
December	33%	16%
Total Year	**4%**	**1%**

7.5.1.2 Removal of Known Causes of Error

There are some similarities between 2011 and 2012, namely that SAM underpredicts power production during the summer months, but during the snowy winter months it tends to significantly overpredict power production.

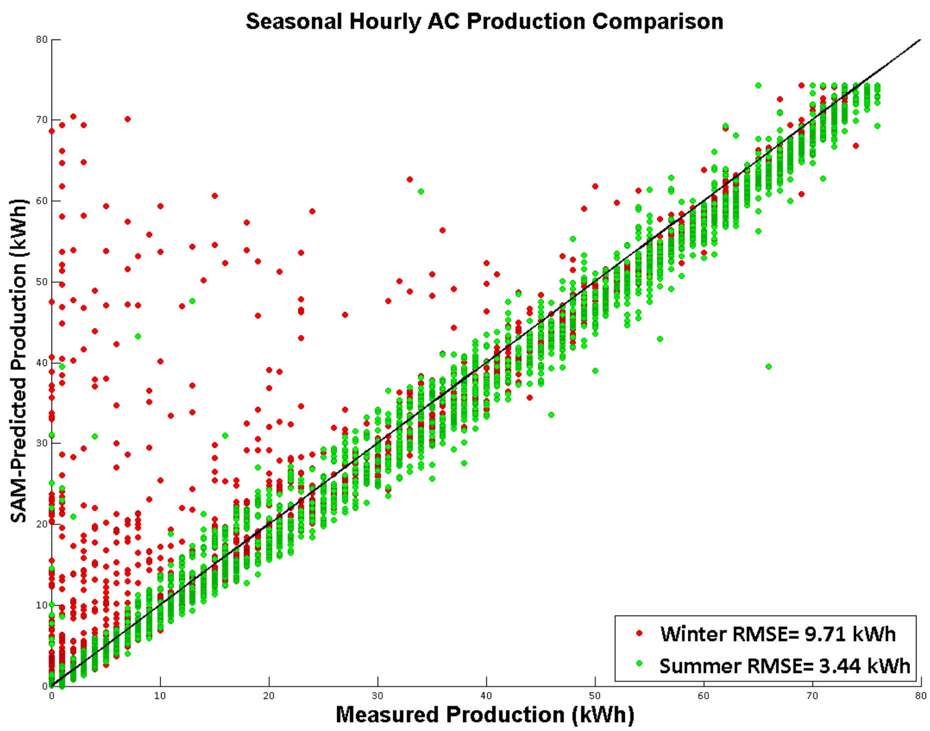


Figure 7-3. Seasonal hourly AC production comparison—S&TF system 2012 (pre-processed)

Figure 7-3 shows a large number of points on or near the y-axis (particularly hours during the winter), which is indicative of snow problems. The discretized look of this data is due to rounding in SunEdison's record keeping system and the relatively low maximum power production of the S&TF system. A closer look at some days with snow reveals that the problem during winter months is likely due to snow accumulation, as seen in Figure 7-4.

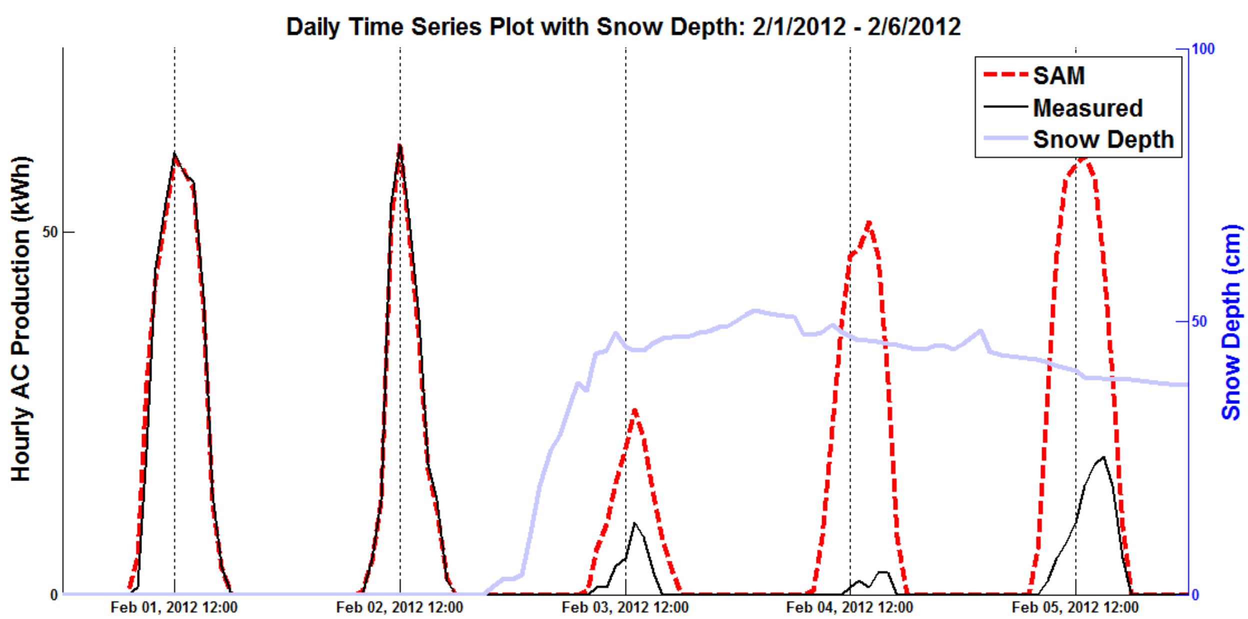


Figure 7-4. Snow-related power production discrepancies—S&TF system

Figure 7-4 indicates that there is a large error between SAM's energy production estimate and measured values when large snowfall accumulation is present. After removing any hours with snowfall accumulations of more than 1 cm, another hourly plot was produced showing a much cleaner overall dataset (Figure 7-5) and much better agreement between predicted energy production and measured energy production.

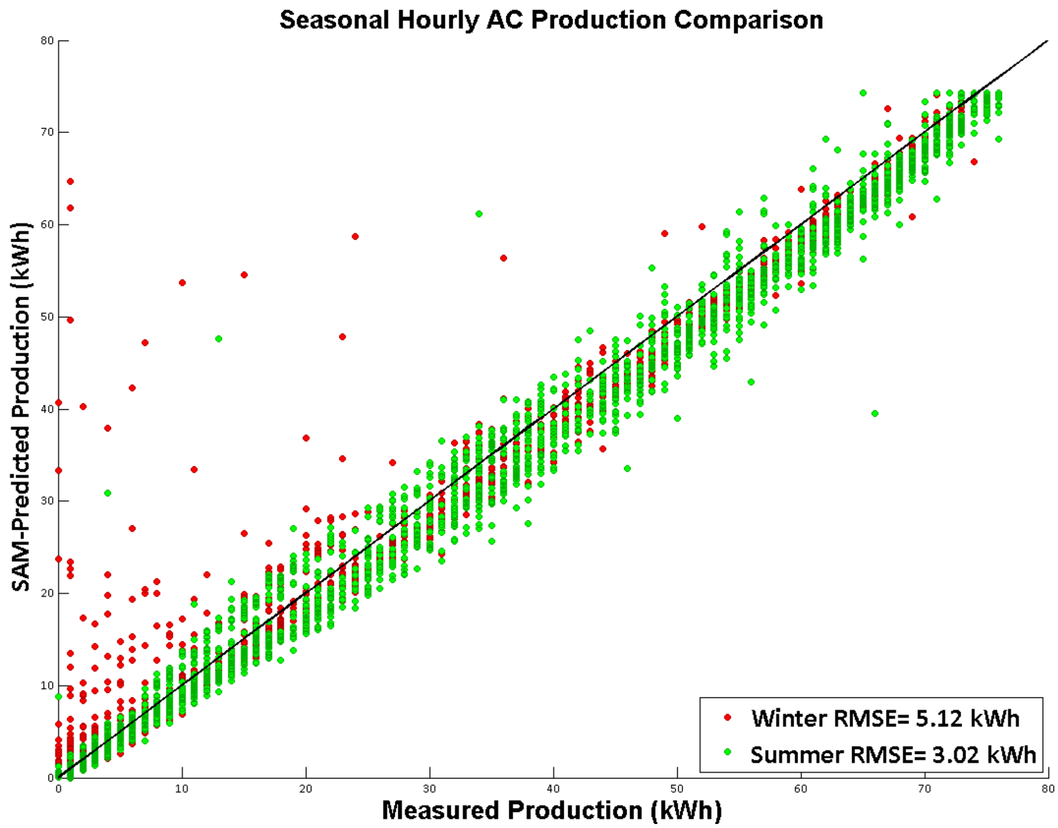


Figure 7-5. Seasonal hourly AC production comparison—S&TF system 2012 (post-processed)

For both 2011 and 2012, hours with significant snow accumulation were removed and the remaining hours were used for the rest of the S&TF system analysis. Again, the discretized look of data is due to rounding in SunEdison's record keeping system and the relatively low maximum power production of the S&TF system.

7.5.1.3 Data Post-Processing

7.5.1.3.1 Year 2011

After removing any hours where snowfall accumulation affected the data, the monthly comparison plot shows the winter months having significantly closer predicted and measured values. SAM-predicted and measured values show a significantly better correlation after known causes of error were removed, with February (the month with the most identified error) showing an absolute error reduction of 42% to only 1% error.

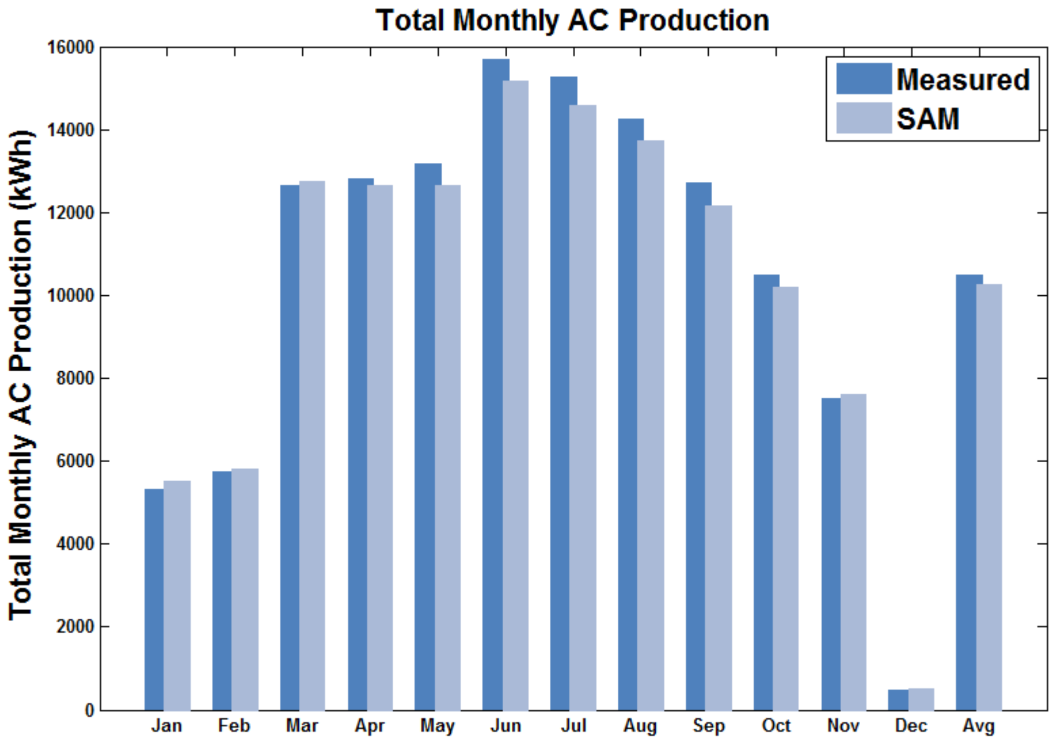


Figure 7-6. Total monthly AC production comparison—S&TF system 2011 (post-processed)

Table 7-3. Monthly Comparison of Percent Error Before and After Removal of Known Causes of Error—S&TF System 2011

Month	Percent Error Prior to Removal of Known Causes of Error	Percent Error After Removal of Known Causes of Error
January 2011	27%	4%
February 2011	43%	1%
March 2011	1%	1%
April 2011	0%	-1%
May 2011	-4%	-4%
June 2011	-3%	-3%
July 2011	-4%	-4%
August 2011	-4%	-4%
September 2011	-4%	-4%
October 2011	5%	-3%
November 2011	6%	1%
December 2011	33%	4%

After the removal of hours with an accumulated snowfall of more than 1 cm, SAM underestimates power production by -2%, or 2,772 kWh, for 2011.

Table 7-4. Overall Comparison Before and After Removal of Known Causes of Error—S&TF System

System	Total AC Power Production (kWh) Prior to Removal of Known Causes of Error	Total AC Power Production (kWh) After Removal of Known Causes of Error
SAM	139,118	123,263
Measured	134,286	126,035
Error	**4,832**	**(2,772)**
Percent Error	**4%**	**-2%**

7.5.1.3.2 Year 2012

After removing any hours where snowfall accumulation affected the data, the monthly comparison plot shows the winter months having significantly closer predicted and measured values. SAM-predicted and measured values show a significantly better correlation after known causes of error were removed, with February (the month with the most identified error) showing an absolute error reduction of 29% to 0% error.

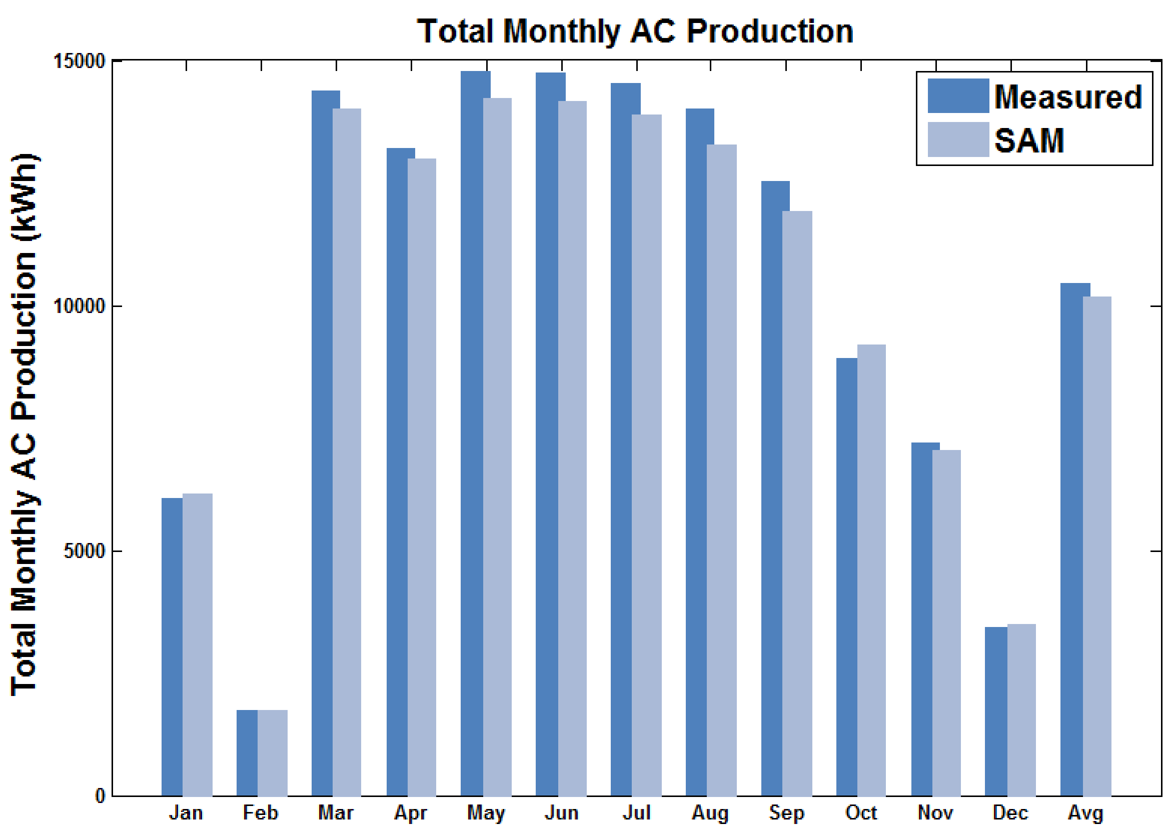


Figure 7-7. Total monthly AC production comparison—S&TF system (post-processed)

Table 7-5. Monthly Comparison of Percent Error Before and After Removal of Known Causes of Error—S&TF System

Month	Percent Error Prior to Removal of Known Causes of Error	Percent Error After Removal of Known Causes of Error
January 2012	12%	1%
February 2012	29%	0%
March 2012	-2%	-2%
April 2012	0%	-2%
May 2012	-4%	-4%
June 2012	-4%	-4%
July 2012	-4%	-4%
August 2012	-5%	-5%
September 2012	-5%	-5%
October 2012	4%	3%
November 2012	3%	-2%
December 2012	16%	2%

Removal of hours with snowfall accumulation increased the total error between the predicted and measured values to -3%, or 3,435 kWh. This increase is primarily due to removal of hours in which SAM is overpredicting power production (due to removal of hours with snow accumulation). By removing these hours without removing any hours with underprediction, the effective error was increased. For a more detailed on the seasonal variability of model error, see Section 1.

Table 7-6. Overall Comparison Before and After Removal of Known Causes of Error—S&TF System

System	Total AC Power Production (kWh) Prior to Removal of Known Causes of Error	Total AC Power Production (kWh) After Removal of Known Causes of Error
SAM	136,050	122,059
Measured	135,013	125,494
Error	**1,037**	**(3,435)**
Percent Error	**1%**	**-3%**

7.5.2 Daily and Hourly Comparison

A daily time series plot for part of June 2012 was created (Figure 7-8). It shows good agreement between SAM-predicted production and measured production and also shows that SAM tracks measured data well even on days with intermittent solar resource when provided a weather file that reflects that intermittency.

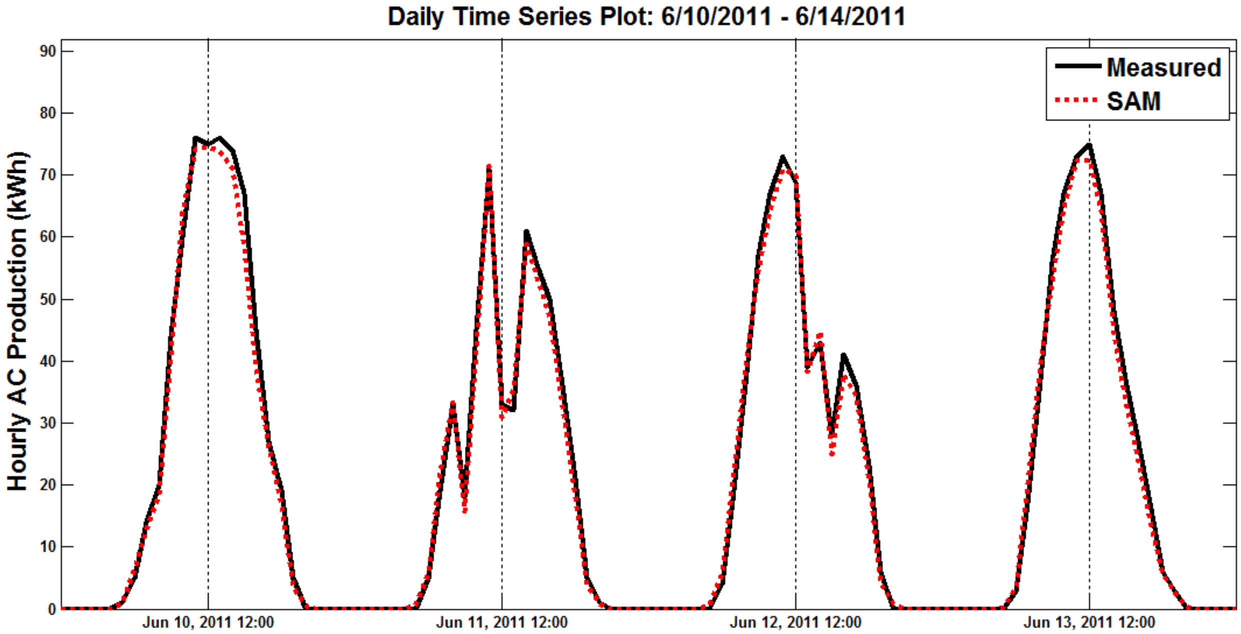


Figure 7-8. Daily time series plot—S&TF system (post-processed)

For 2011 and 2012, the average summer and winter diurnal plotlines show agreement. The winter plot in particular has almost indistinguishably identical lines for measured and SAM-predicted values. There is a slight underprediction by SAM during the summer months, particularly around noon.

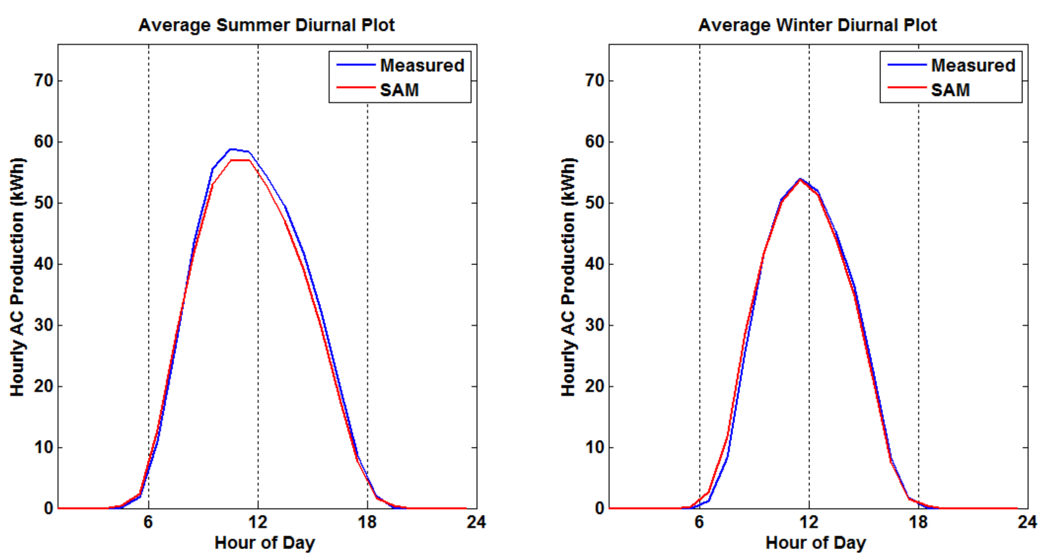


Figure 7-9. Average summer and winter diurnal plots—S&TF system 2011 (post-processed)

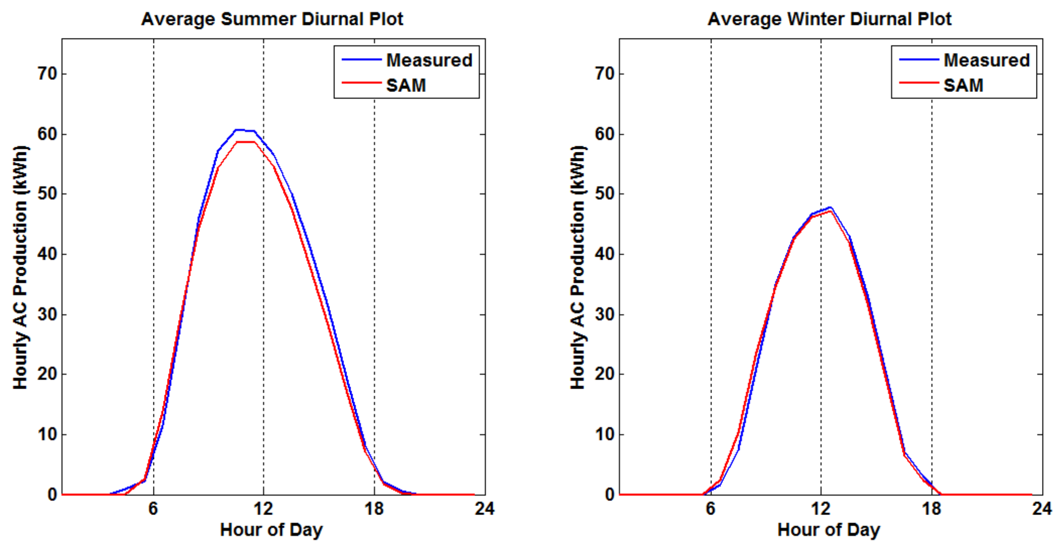


Figure 7-10. Average summer and winter diurnal plots—S&TF system 2012 (post-processed)

For 2011 and 2012, on an hourly basis, SAM is very close for the vast majority of hours. There are still a few outlier hours that indicate SAM is not perfect, but on the whole the correlation is strong.

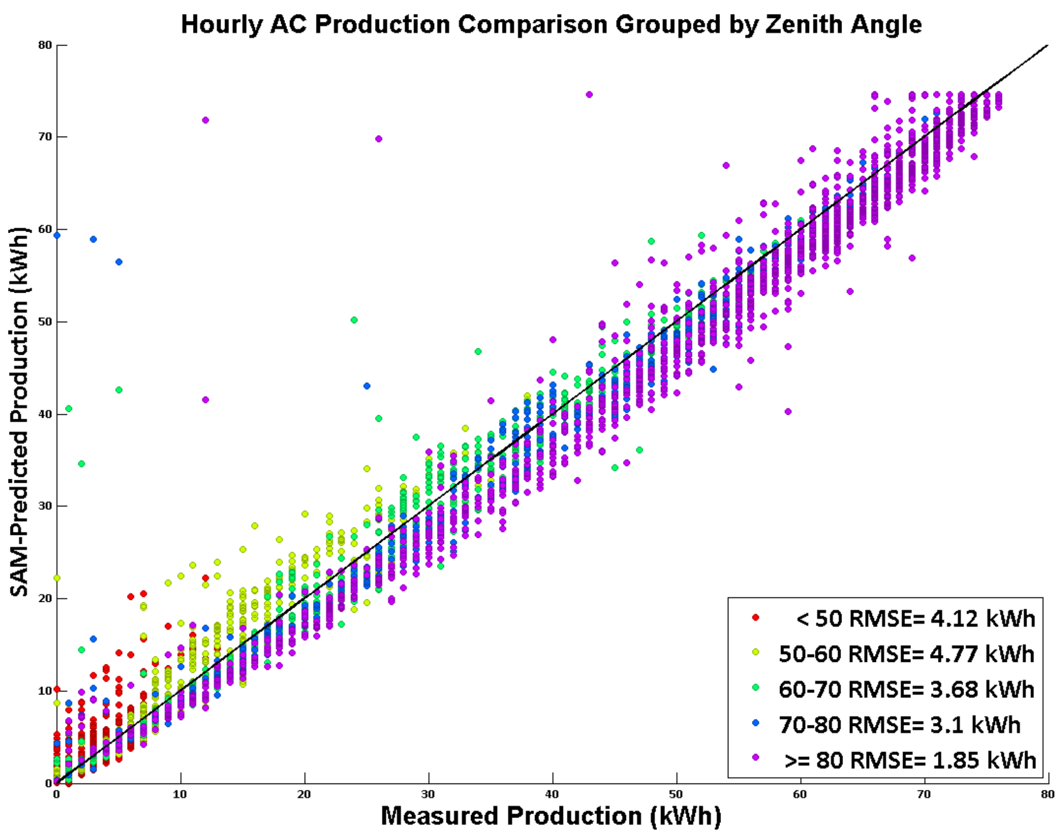


Figure 7-11. Hourly AC production grouped by zenith angle—S&TF system 2011 (post-processed)

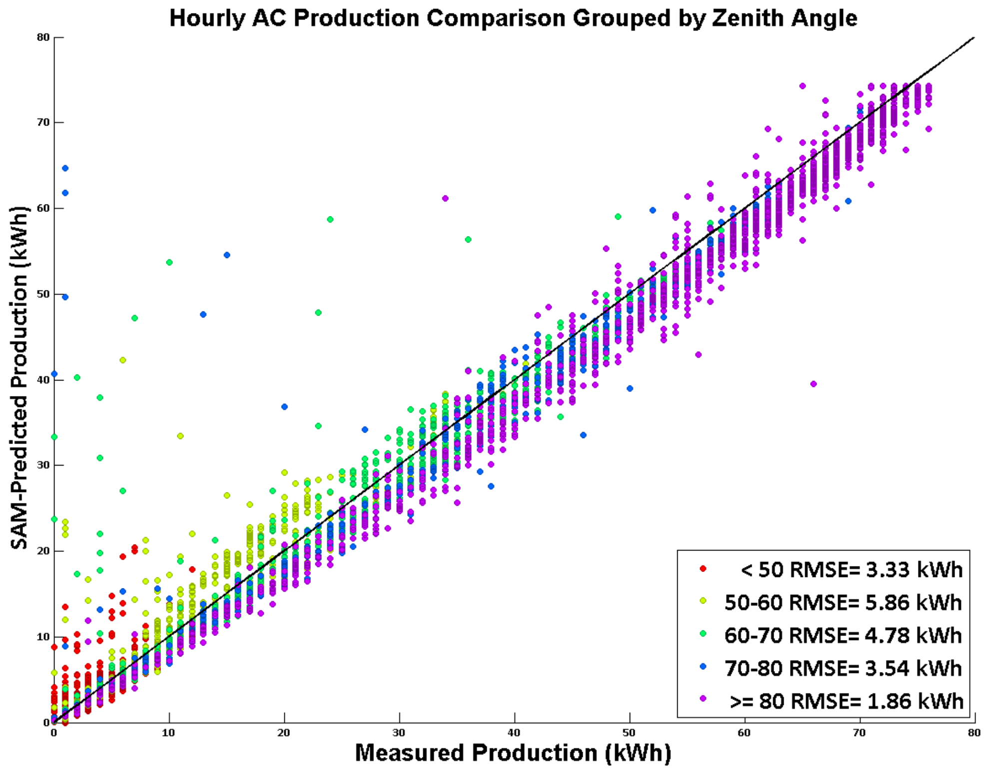


Figure 7-12. Hourly AC production grouped by zenith angle—S&TF system 2012 (post-processed)

7.6 Conclusions

Removal of all hours with snowfall accumulations greater than 1 cm resulted in a significant improvement on a monthly basis, with large error reductions in any months experiencing snowfall. On an annual timescale, error decreased from 4% to 2% in 2011 and increased from 1% to 3% in 2012. As mentioned previously, the noted increase in error in 2012 is the result of removing only hours of overprediction, making it more difficult to sum to a value close to 0%.

If we examine Figure 7-9 and Figure 7-10, we begin to see a trend being established that SAM is very accurately predicting the power production of the S&TF system on a diurnal basis. Figure 7-11 and Figure 7-12 show that SAM's power production on an hourly basis is not perfect, but both figures show a very clear and distinguished trend that SAM is very close to measured values for this system.

A comparison of SAM's AC Gross Output (corrected by a given percent of annual output for each year) and the measurements provided by SunEdison indicate that the power production for the S&TF system is very closely estimated by SAM once known causes of error have been accounted for. Annual errors for 2011 and 2012 were found to be -2% and -3%, respectively. Absolute monthly error for both years ranged from 0% to 5%, with the vast majority of errors being less than 4%. Both years showed seasonal variability with SAM overpredicting power production in the winter and underpredicting power production in the summer. This seasonal variation is likely due to seasonal variations in the underlying transposition models; see Section 1.4 for more detail. Both years show diurnal agreement. On an hourly basis, both years show a very close approximation to the expected 1:1 trendline.

8 NREL Visitor Parking Garage System Study

8.1 Introduction

In 2011, NREL installed a 524-kW solar array covering their visitor parking lot. This arrangement has the double benefit of providing a covered parking lot, and producing energy. SunPower designed, installed, and monitors the system.

8.2 Data Collection

8.2.1 Data Sources

NREL obtained the measured system performance data from SunPower for the Visitor Parking system for the entire year of 2012. AC power was measured at each of the two inverters and reported hourly in kilowatt-hours. The output at each inverter was summed in order to obtain total system output.

As with all of the NREL systems, weather data from the SRRL was utilized (described previously). In this case, the 2012 weather files were used to simulate performance in SAM.

8.2.2 Data Quality Control

SAM can only accept 8,760 hours of data in a single simulation. However, because 2012 was a leap year, February 29, 2012 was removed from both the SunPower dataset and the SRRL dataset for modeling accuracy in SAM, which does not account for leap years.

Additionally, inverter outages and system shutdowns were identified and removed from the analysis. In total, June 27–July 23 were removed because both inverters were shut down, and August 19–September 18 were removed because one inverter experienced an outage.

8.3 SAM Modeling

8.3.1 Simulation Specifications

The SRRL data for 2012, in TMY3 format, was used as the weather data for the SAM simulation. The site specified in the simulation was at: latitude: 39.74^0 N; longitude: 105.18^0 W; elevation: 1,829 m. All other system specifications are shown in Table 8-1 (taken from the SAM output report). All losses and derates were left at their default values unless otherwise specified. The Perez sky diffuse model and the Sandia PV array performance model were used.

Table 8-1. Sam Model Specification – Visitor Parking System

Performance Model

Modules	
SunPower SPR-315E-WHT	
Cell material	c-Si
Module area	1.6 m^2
Module capacity	315.1 DC Watts
Quantity	1,664
Total capacity	524.3 DC kW
Total area	2,713 m^2
Inverters	
SMA America: SC250U 480V	
Unit capacity	250 AC kW
Input voltage	300 - 600 VDC
Quantity	2
Total capacity	500 AC kW
AC derate factor	0.99
Array	
Strings	208
Modules per string	8
String DC voltage	437.6
Tilt (deg from horizontal)	8
Azimuth (deg E of N)	165
Tracking	fixed
Backtracking	-
Rotation limit (deg)	-
Shading	no
Soiling	yes
DC derate factor	0.96

8.4 Results

8.4.1 Hourly Comparison

The hourly data were first examined for days experiencing snow cover. Figure 8-1 shows a selection of days in February, with the SAM-predicted AC production, the measured AC production, and snow depth plotted as functions of time. This figure shows a clear correlation between snow depth and decreased performance. It also exemplifies the fact that if an irradiance sensor is not covered by snow and the solar array is, SAM will predict normal performance for the day when in fact the system output is greatly diminished. However, for days not affected by snow cover, SAM tracks not only the magnitude but also the shape of the AC power production plot fairly well. Based on this analysis, 32 days were excluded from the analysis due to snow cover issues.

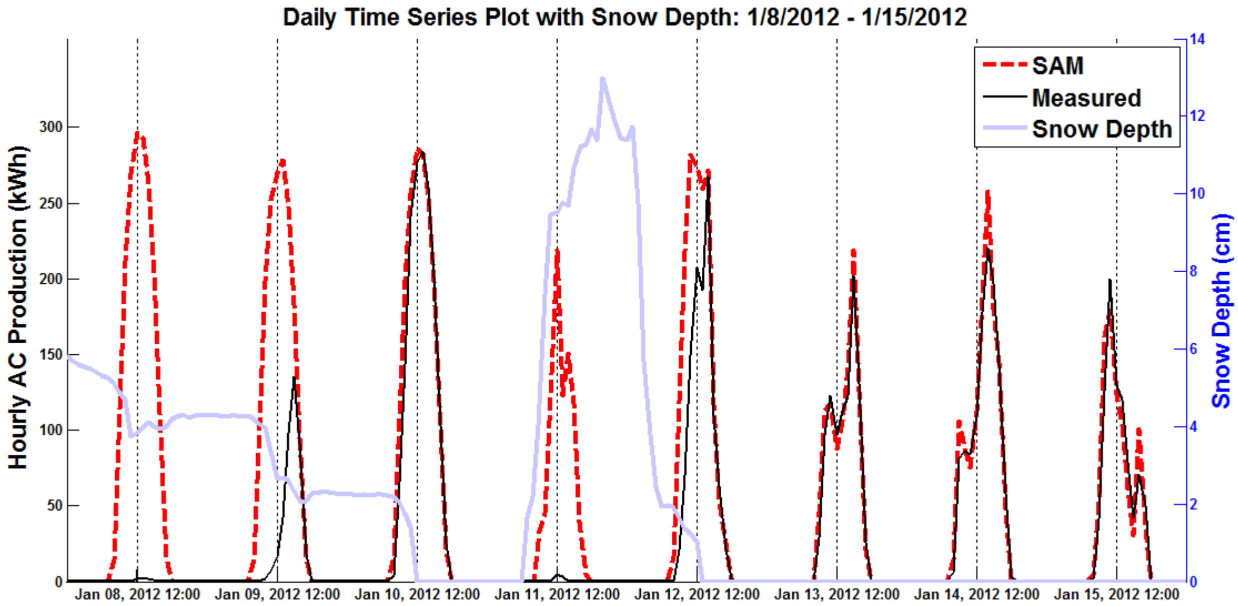


Figure 8-1. Snow-related power production discrepancies—Visitor Parking system

The performance of SAM on an hourly basis is quantified through its root-mean-squared error, as explained in Section 1. Figure 8-2 shows SAM-predicted performance plotted against measured performance on an hourly basis with the RMSE of each subset of data. Ideally, a one-to-one prediction would be expected (shown by the black line). The data shows some scatter around the ideal line. After removing data affected by snow cover, the winter hourly RMSE is 18.4 kWh, with a summer hourly RMSE of 20.3 kWh.

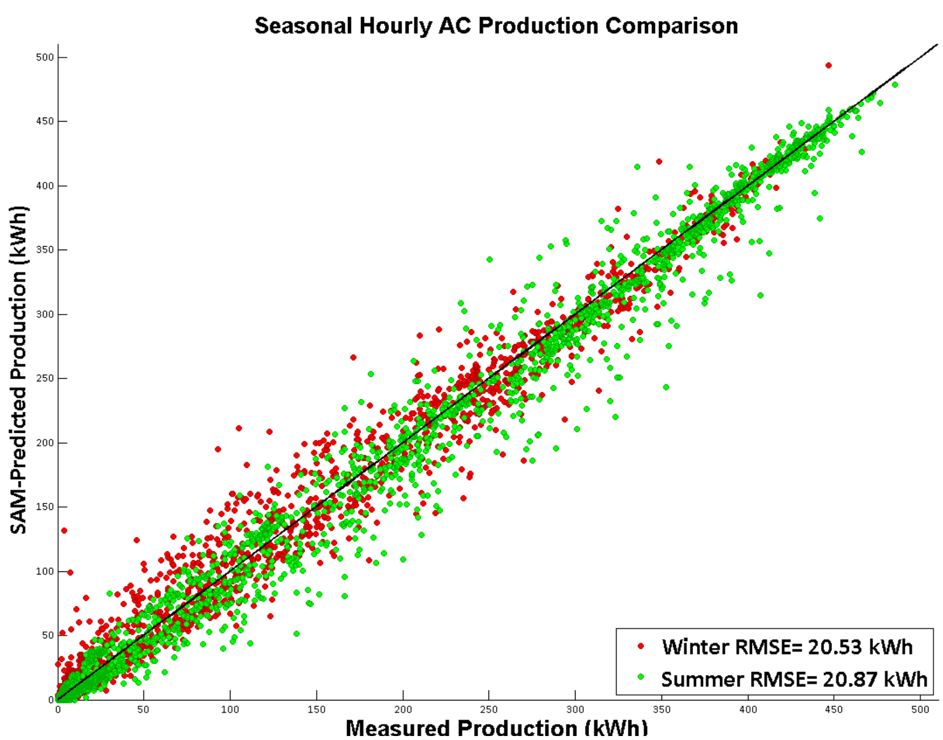


Figure 8-2. Seasonal hourly AC production comparison—Visitor Parking system (post-processed)

8.4.2 Diurnal Comparison

On an average diurnal basis, after removing data affected by snow cover, SAM-predicted power output matches very well with what was measured at the site, as shown in Figure 8-3.

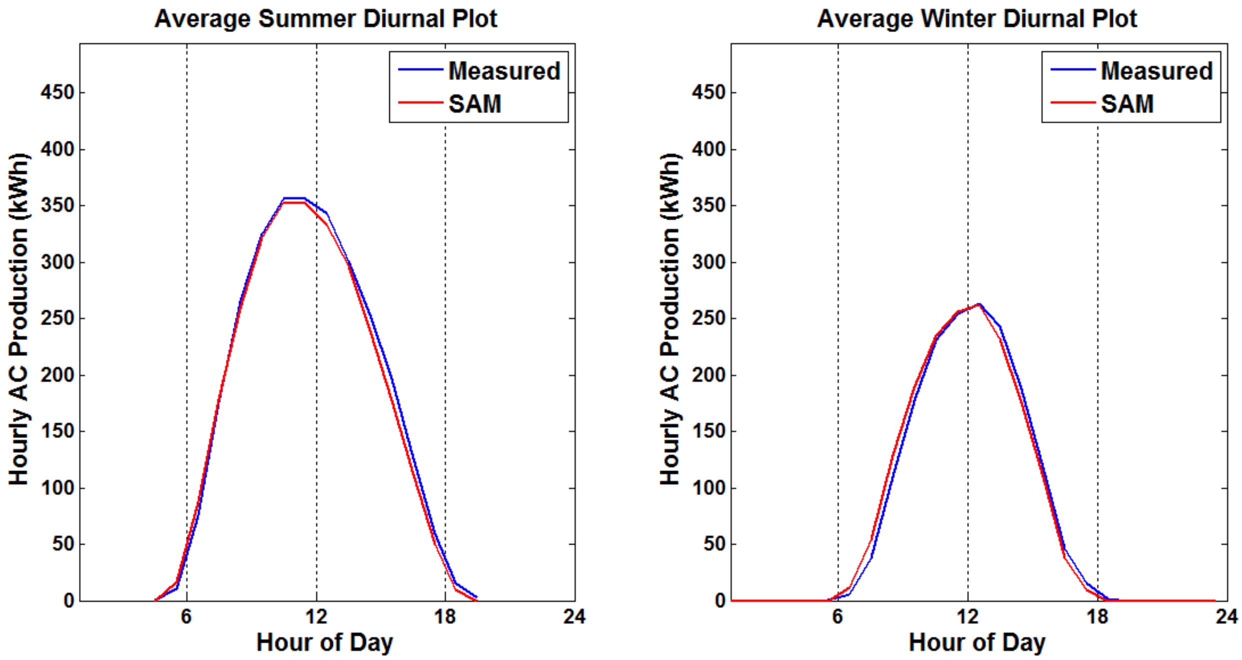


Figure 8-3. Average summer and winter diurnal plots—Visitor Parking system (post-processed)

8.4.3 Monthly Comparison

The monthly sums of the SAM-predicted AC power and the measured AC power, after removing data affected by snow cover, are shown in Figure 8-4 without adjusting the model derates for annual agreement. As explained in Section 1, the annual derate for this system was adjusted in order to achieve annual agreement, then the monthly results were re-examined. 8-2 quantifies the monthly error for all combinations of (1) snow cover included or excluded and (2) default annual derates, or annual derates adjusted for annual agreement.

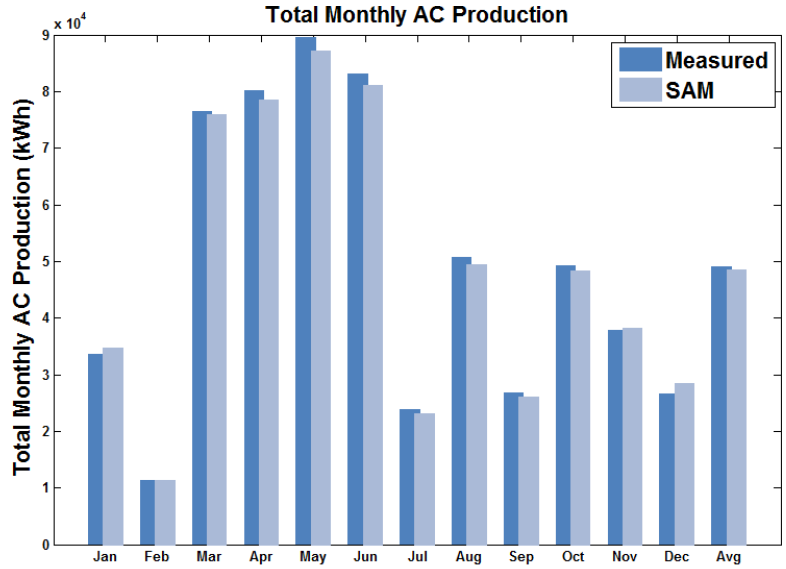


Figure 8-4. Total monthly AC production comparison—Visitor Parking system (post-processed)

Table 8-2. Monthly Errors with Derates Excluded/Included and Snow Cover Hours Included/Excluded—Visitor Parking System

	Snow Cover Included		Snow Cover Excluded	
Month Year	Monthly Error, Default Derates	Monthly Error, Adjusted Derates	Monthly Error, Default Derates	Monthly Error, Adjusted Derates
January 2012	16%	17%	3%	4%
February 2012	215%	217%	-1%	0%
March 2012	-1%	0%	-1%	0%
April 2012	-2%	-1%	-2%	-1%
May 2012	-3%	-2%	-3%	-2%
June 2012	-2%	-1%	-2%	-1%
July 2012	-3%	-2%	-3%	-2%
August 2012	-3%	-2%	-3%	-2%
September 2012	-3%	-2%	-3%	-2%
October 2012	-2%	-1%	-2%	-1%
November 2012	1%	2%	1%	2%
December 2012	27%	28%	7%	8%

It can be seen in the figure and the table that SAM generally overpredicts power production in the winter months and underpredicts production in the summer months, which indicates that SAM does not have a clear annual bias. Because of this, simply adjusting the annual derate for agreement on the total annual number gives some months better agreement with measured data and some months worse agreement. This seasonal variation is likely due to seasonal variations in the underlying transposition models; see Section 1.4 for more detail.

Additionally, from Table 8-2 it can be seen that snow cover that is present on the system, but doesn't act to reduce measured irradiance by covering the irradiance sensor, can cause large monthly errors—up to 225%—for this system in February. If snow depth data is measured near the site, it is possible to get better agreement with measured data looking backwards. Snow depth is of course very difficult to predict on a forward-looking simulation, making this a huge factor to consider for systems that are located in snowy regions. In order to accurately predict energy production, algorithms will need to be developed to estimate at least a monthly percentage loss for systems due to snow cover.

In general, after data experiencing snow cover has been removed, SAM predicts within 3% of measured energy production on a monthly basis.

8.4.4 Annual Comparison

The sum of the measured AC power for the Visitor Parking system during 2012, without adjusted derates and after removing both missing hours of data and inverter outages/shutdowns, is 597.3 MWh (Table 8-3). The sum of the SAM-predicted AC power for this same time period is 636.5 MWh, representing a total overprediction of 7%. However, after further analysis removing hours experiencing snow cover, the measured total AC power for this time period is 589.1 MWh, whereas the SAM-predicted AC power production is 582.1 MWh, representing an underprediction of 1%.

Table 8-3. Overall Comparison Before and After Removal of Known Causes of Error—Visitor Parking System

Total	All Data	Removed Data
SAM	636,468	582,103
Measured	597,305	589,066
Error	**39,163**	**(6,963)**
Percent Error	**7%**	**-1%**

8.5 Conclusions

The Visitor Parking system had a fair amount of scatter around the ideal line on an hourly basis, with RMSEs of about 18–20 kWh. Additionally, this system is a good example of how snow cover can diminish the performance of a system because if the irradiance sensor is not also covered, SAM will continue to predict normal power production for those days, highlighting the importance of developing a method to predict production losses due to snow cover. On a diurnal basis, the shape of power production predicted by SAM matches well with what was measured from the system. On a monthly basis, SAM predicts total energy production within 3% of measured energy production after known issues are removed. However, even after removing snow issues, SAM continues to overpredict production in the winter but underpredict production in the summer. This seasonal variation is likely due to seasonal variations in the underlying transposition models; see Section 1.4 for more detail. On an annual basis, SAM underpredicted energy production by 1% after known issues were removed. Before known issues were removed, it overpredicted energy production by 2%. Additionally, tuning the annual derate for this system to match on an annual basis made some monthly agreements better, but some worse. This is due to the fact that SAM does not consistently overpredict or underpredict energy on a monthly basis. See Section 1 for a more complete discussion of the seasonal variation in SAM error.

9 Utility-Scale Summary

Previous SAM system studies have featured both residential and commercial sites but lacked analysis of utility-scale systems. The generation capacity of utility-scale plants is an order of magnitude larger than commercial and residential scale, and there are some utility-scale phenomena that SAM does not explicitly model, making it important to verify SAM's modeling capabilities at this scale. The utility plants in this report are larger than 10 MW, while a typical commercial site is on the scale of a few hundred kilowatts. Utility plants are closely monitored for reliability and power dispatch, providing a valuable dataset for analysis.

For all of the utility-scale systems discussed, SAM hourly prediction of Gross AC Output (kWh) was compared to AC power measurements taken at the inverter banks of each site.

The utility-scale systems in Table 9-1 were selected from available data for analysis.

Table 9-1. List of Utility-Scale Systems

Site Name	Location	Data Provider
DeSoto	Florida	NextEra Energy
FirstSolar1	SW USA	First Solar
FirstSolar2	SW USA	First Solar

The locations across the southwestern United States to Florida provide diversity to the validation, with climates varying from dry deserts to Florida's humid subtropical climate.

Table 9-2 summarizes some of the key results of the analysis across all sites. Capacity factors ranged from 21%–24%, which is typical of most utility-scale plants.

Table 9-2. Summary of Utility-Scale Results

Site	Annual Error	Normalized RMSE (RMSE/Maximum Measured)
FirstSolar2	-0.5%	4.6%
DeSoto	-4.8%	6.2%
FirstSolar1	-0.6%	5.0%

The percent error of the systems did not clearly vary by system size. FirstSolar2, the smallest facility, had about 4.6% normalized RMSE. The largest facility, FirstSolar1, had the same percent error.

As can be seen in Figure 9-1, SAM overpredicted power production during winter months and underpredicted power production during summer months. This is a recurring theme not only in the utility-scale systems but in all systems studied in this report. This seasonal variation is likely due to seasonal variations in the underlying transposition models; see Section 1.4 for more detail. Future work will include further investigation into this phenomenon.

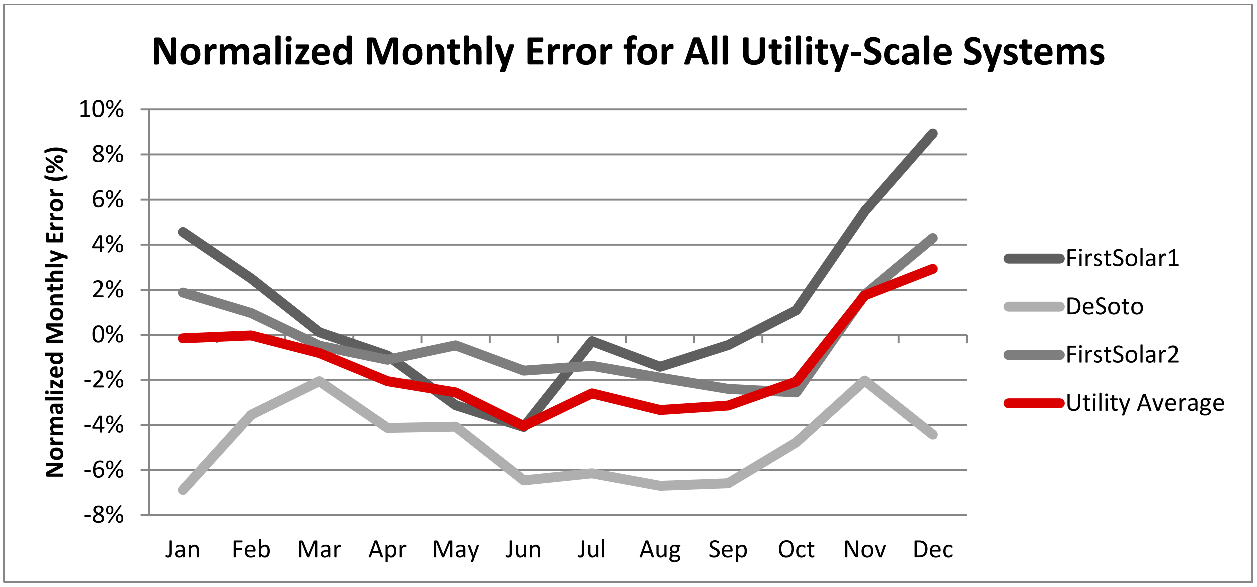


Figure 9-1. Normalized monthly error for all utility-scale systems

Most utility sites did not have measured direct normal irradiance (DNI) or diffuse horizontal irradiance (DHI) data available to aid in this analysis. Only DeSoto had measured irradiance data from pyranometers less than 5 km away (other utility-scale systems used concurrent CPR data). Despite this close proximity of irradiance measurements, predicted production was not closer to measured values for the DeSoto system. It was also very difficult to acquire reliable and detailed site specifications for utility-scale sites. One would expect that with this lack of data and the assumed variability of such a large system, modeling performance would be much worse for utility-scale systems than commercial-scale systems; however, utility-scale system results were found to be comparable with commercial-scale system results in most measureable quantities used to analyze SAM performance (see Section 1).

10 DeSoto Next Generation Solar Energy Center System Study

DeSoto Next Generation Solar Energy Center is a PV site owned by Florida Power and Light (FPL). The 25-MW facility is located on 180 acres of land in DeSoto County, Florida. The plant was developed by SunPower and has been producing electricity since October 2009. When the plant opened, it was the largest solar PV plant in the country. FPL has initiated permitting for additional PV facilities because up to 275 MW of PV generation could be constructed on the remaining undeveloped land in DeSoto County [14].

10.1 Data Collection

10.1.1 Data Sources

NextEra Energy, the development company associated with FPL, provided 15-minute intervals of site-measured data from March 2012 through February 2013. Plane of array (POA) irradiance is measured at three reference cell locations. Global horizontal irradiance (GHI) is measured by five pyranometers throughout the facility. DNI and DHI are measured at two locations just outside the facility. Data is available at 3-second intervals and was aggregated into hourly data for our analysis. Measured air temperature and relative humidity data were also available from these locations.

10.1.2 Site Specifications

The DeSoto system is located in DeSoto county, Florida, as shown in Figure 10-1.

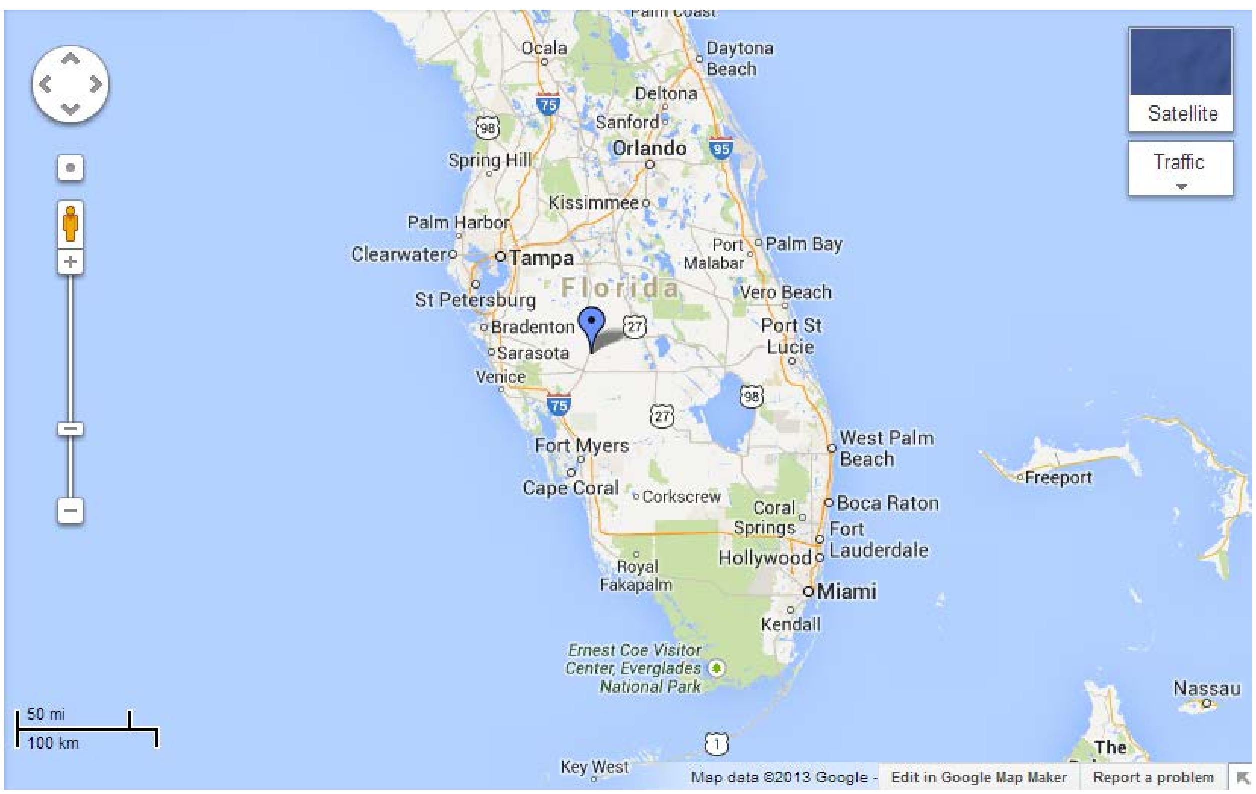


Figure 10-1. Location of DeSoto system [15]

The area has been mostly cleared of vegetation. However, the site has a band of trees cutting through the middle of the facility, as shown in Figure 10-2, which could cause some shading at high zenith angles.

Figure 10-2. Aerial view of DeSoto [16]

Five pyranometers are located throughout the facility. Figure 10-3 shows the approximate location of each of the sensors.

Figure 10-3. Five pyranometer locations near DeSoto [17]

Figure 10-4 shows the two measurement locations located outside the facility. DHI, DNI, temperature, and relative humidity were available at both of these locations specified in the figure. RSR Station 1 and RSR station 2 are about 1.5 km and 5 km away from the PV array, respectively.

Figure 10-4. Locations with DHI and DNI measurements [18]

10.1.3 Data Quality Control

All data used for site modeling was investigated for possible data quality issues. Data quality is critical to this analysis because including unreliable measured data could falsely indicate or disguise an issue with SAM. All data quality algorithms were applied to 15-minute interval data before being averaged into hourly data for use in SAM. The following days were excluded from the analysis for the indicated reasons.

- April 2, 2012: Power output missing after hour 9
- April 3, 2012: Power output missing before hour 16
- October 31, 2012: No power data hour 11 to 13
- January 30, 2013: Missing hour 8 power output
- February 1, 2013: Interpolated power output after hour 10
- February 2, 2013: Interpolated power output before hour 8.

Data quality problems observed in the raw data include: spikes that could contain measurements over five times larger than normally observed values, no data available for a given time period, interpolated data, and unrealistic data (e.g., irradiance measurements at night). Figure 10-5 shows a three-week section of raw data that contains all of these issues.

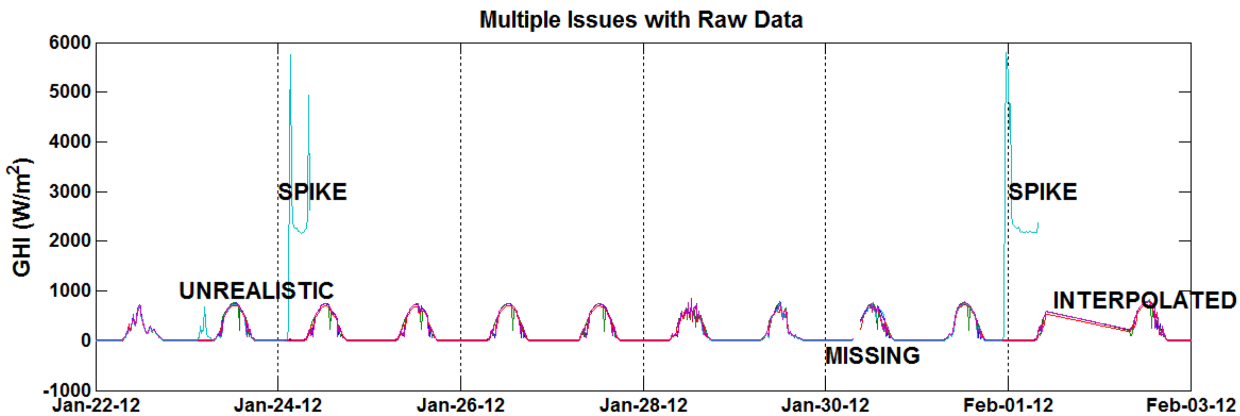


Figure 10-5. Multiple raw data quality issues

10.1.3.1 Non-Zero Baseline

Perhaps due to lack of calibration, irradiance sensors at DeSoto do not read zero at night as they should. Each sensor has a different baseline at night, and that nighttime reading is not constant throughout the year. An algorithm was used to apply a daily adjustment equal to the minimum value observed that day to each data stream, effectively bringing the nighttime hours close to the zero measurement expected.

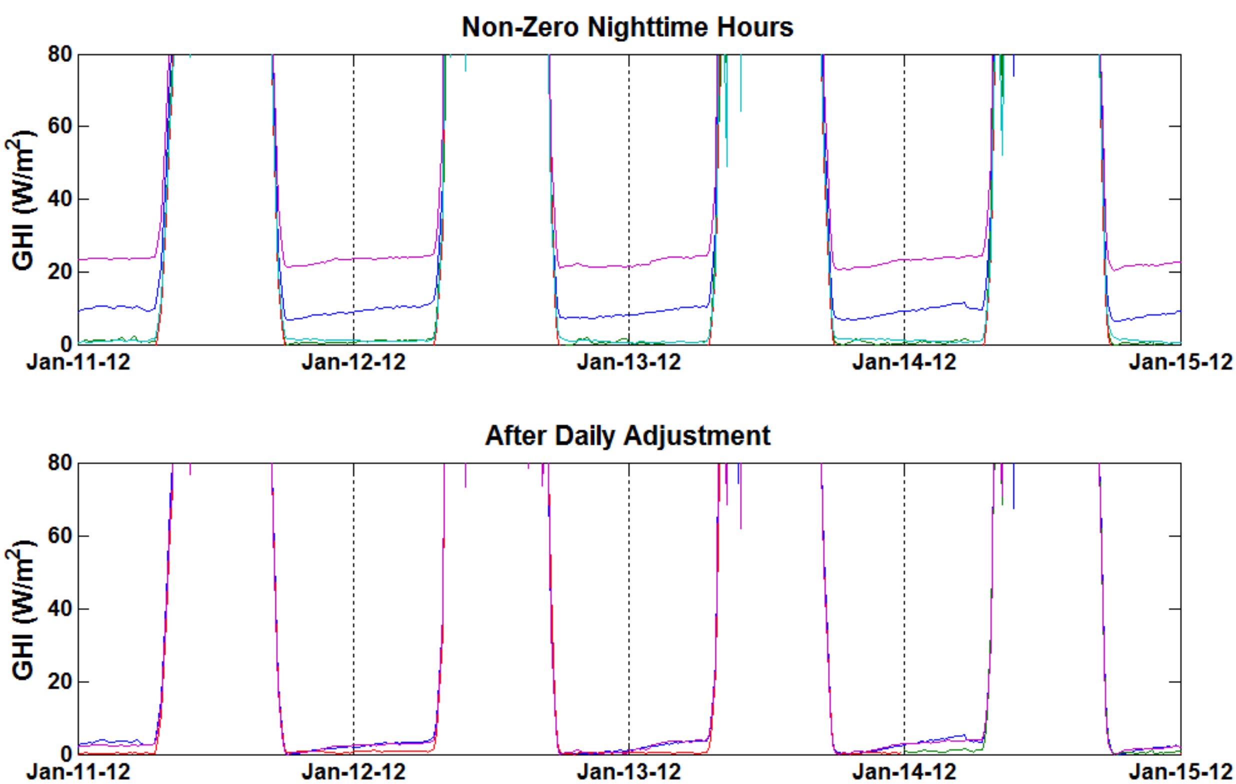


Figure 10-6. Irradiance measurements during nighttime hours before and after correction

10.1.3.2 Spikes

Because five GHI sensors were available at the DeSoto site, it was possible to look for outliers in the data. Outliers were detected by comparing the maximum hourly value at each sensor for each day with values from the other sensors. If the maximum of a given sensor was 50% greater than the average of the other four maximums, then the data was removed. This method was selected in lieu of other methods because other methods removed a significant amount of usable data from the available measured data, and this method takes advantage of having multiple sensors measuring the same value. If a single outlier was detected in a day, the entire day of data given by that sensor was removed.

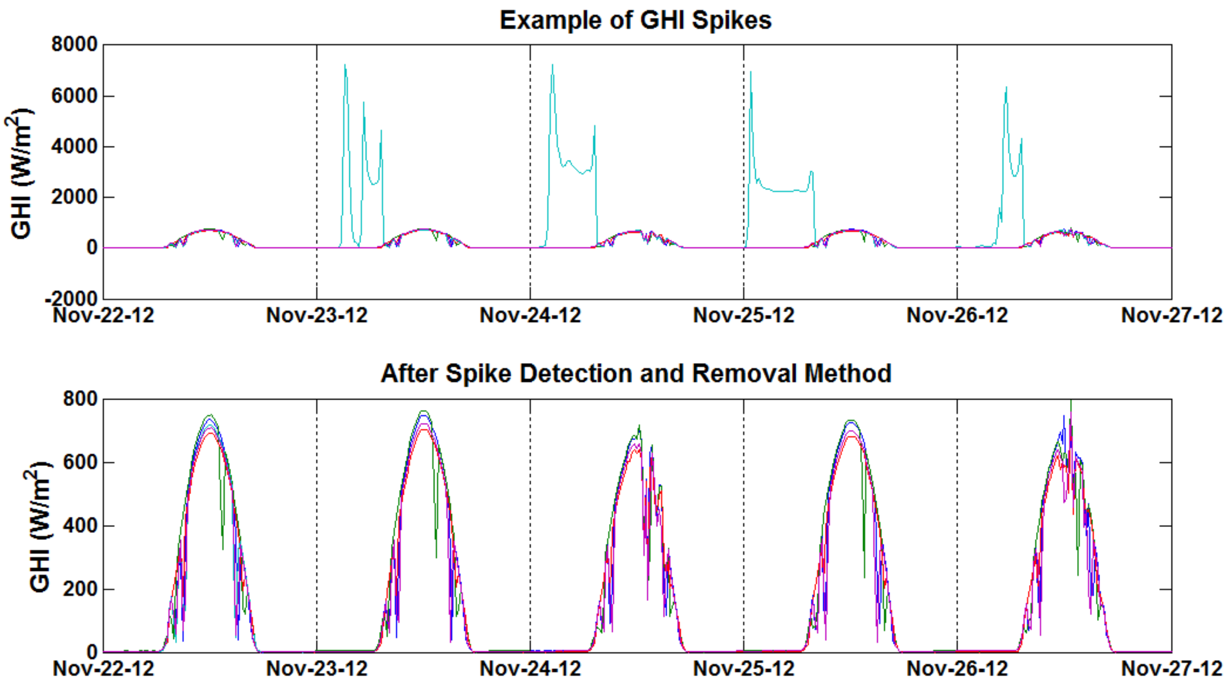


Figure 10-7. Before and after removal of unrealistic data spikes

10.1.3.3 Interpolated Data

There were only two days with interpolated data, which were both removed from the analysis. This occurred on February 1 and 2, 2013. Interpolation was visually identified (see Figure 10-8).

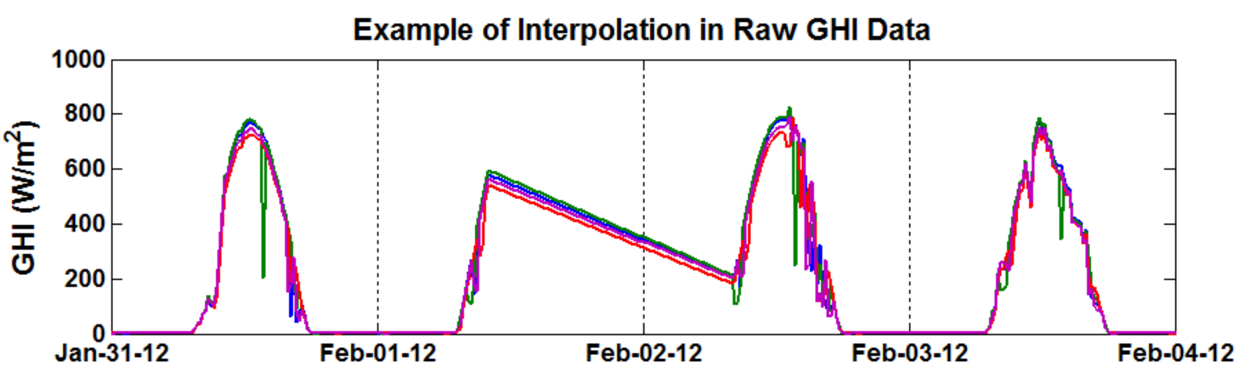


Figure 10-8. Example of interpolated data

10.1.3.4 Missing Data

Days containing any missing data during daytime hours were removed from the analysis. This was also done through visual inspection (see Figure 10-9).

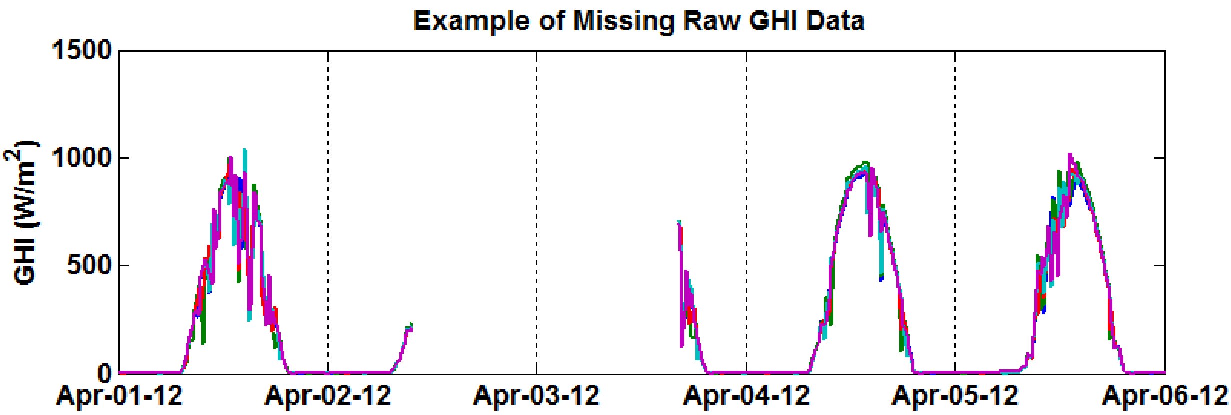


Figure 10-9. Example of missing raw GHI data

10.1.3.5 Unrealistic Data

Unrealistic data, such as non-zero nighttime values, can be difficult to detect via algorithm. In this location we had the unique benefit of having five sensor locations that were all attempting to measure GHI. Because SAM only requires one input stream of GHI, we could exclude multiple sensors at any one time. Using the sum of absolute differences, we selected the three series that were closest to each other each day. This process assumed there will be at least three operational sensors per day. Figure 10-10 shows the data before and after removal of unrealistic GHI data.

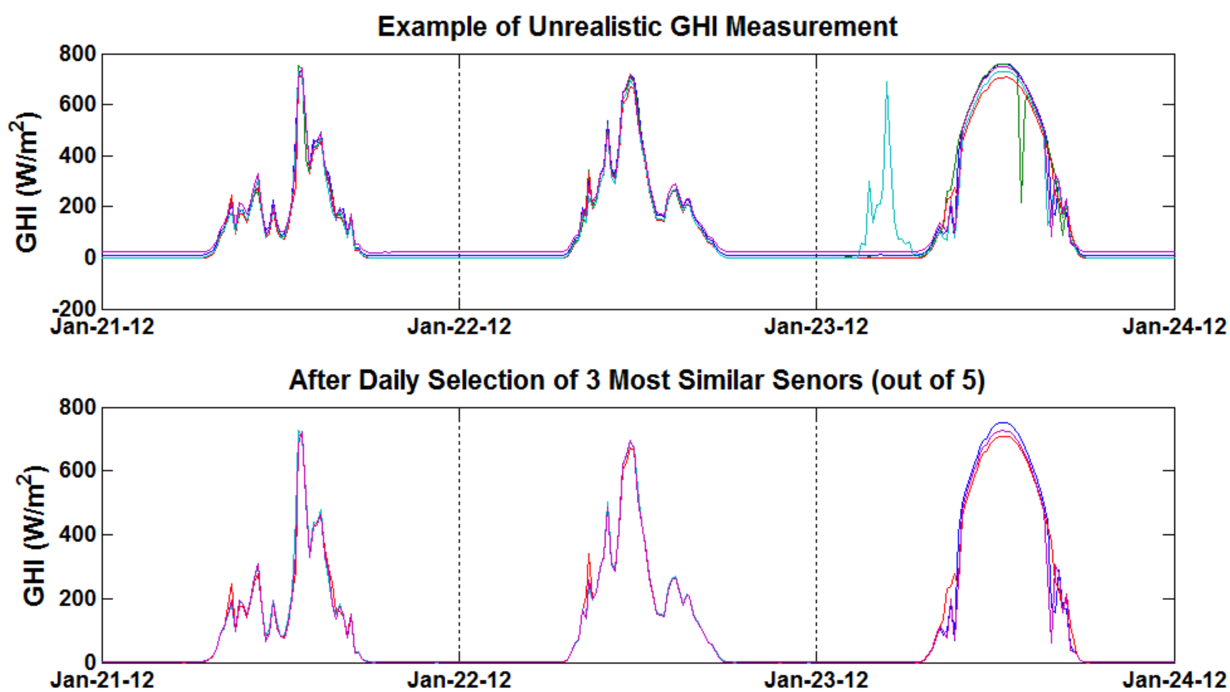


Figure 10-10. Before and after removal of unrealistic data

10.2 SAM Modeling

10.2.1 Simulation Specifications

Measured irradiance data that had undergone data quality control were entered into a custom TMY3-formatted file, along with concurrent temperature and wind speed data that were obtained from the CPR dataset. The SAM simulation indicated in Table 10-1 was then run, and its results utilized for comparison with measured data.

Table 10-1. SAM Specifications—DeSoto System

Performance Model

Modules	
SunPower T5-SPR-305	
Cell material	c-Si
Module area	1.6 m^2
Module capacity	305.2 DC Watts
Quantity	90,504
Total capacity	27.6 DC MW
Total area	147,612 m^2
Inverters	
Generic Inverter	
Unit capacity	420 AC kW
Input voltage	n/a
Quantity	64
Total capacity	26.9 AC MW
AC derate factor	0.99
Array	
Strings	7,542
Modules per string	12
String DC voltage	656.4
Tilt (deg from horizontal)	0
Azimuth (deg E of N)	180
Tracking	1 axis
Backtracking	no
Rotation limit (deg)	45
Shading	no
Soiling	yes
DC derate factor	0.96
Performance Adjustment	
Annual	none

The site was located at latitude 27.32°, longitude -81.80°, and an elevation of 21 meters.

The default Perez transposition model was used, and the module was found in the CEC database. Because inverter specifications were unavailable, the Single Point Inverter model was used. All system derates were left at default values for the initial SAM simulation and were modified for an adjusted run after obtaining preliminary results as described above and in the utility-scale summary (Section 9). Because DeSoto is a one-axis tracking system, SAM's one-axis tracking option was utilized. This could potentially result in additional error due to the backtracking issue described in Section 1 and Section 4.

10.3 Results

10.3.1 Annual Comparison

Assuming SAM's default derates, modeled results are 4.8% lower than measured. SAM estimated that the plant generated on 49.7 GWh of electricity for the 12 months from March 2012 to the end of February 2013, compared to the measured AC output of 52.2 GWh.

Table 10-2. Annual Results: DeSoto System

Measure	Value (MWh)
SAM	49,683
Measured	52,192
Error	(2,509)
Percent Error	-5%

10.3.2 Monthly Comparison

SAM predicted within 7% of measured energy output on a monthly basis. SAM consistently estimated lower than measured data throughout the year, particularly June–August.

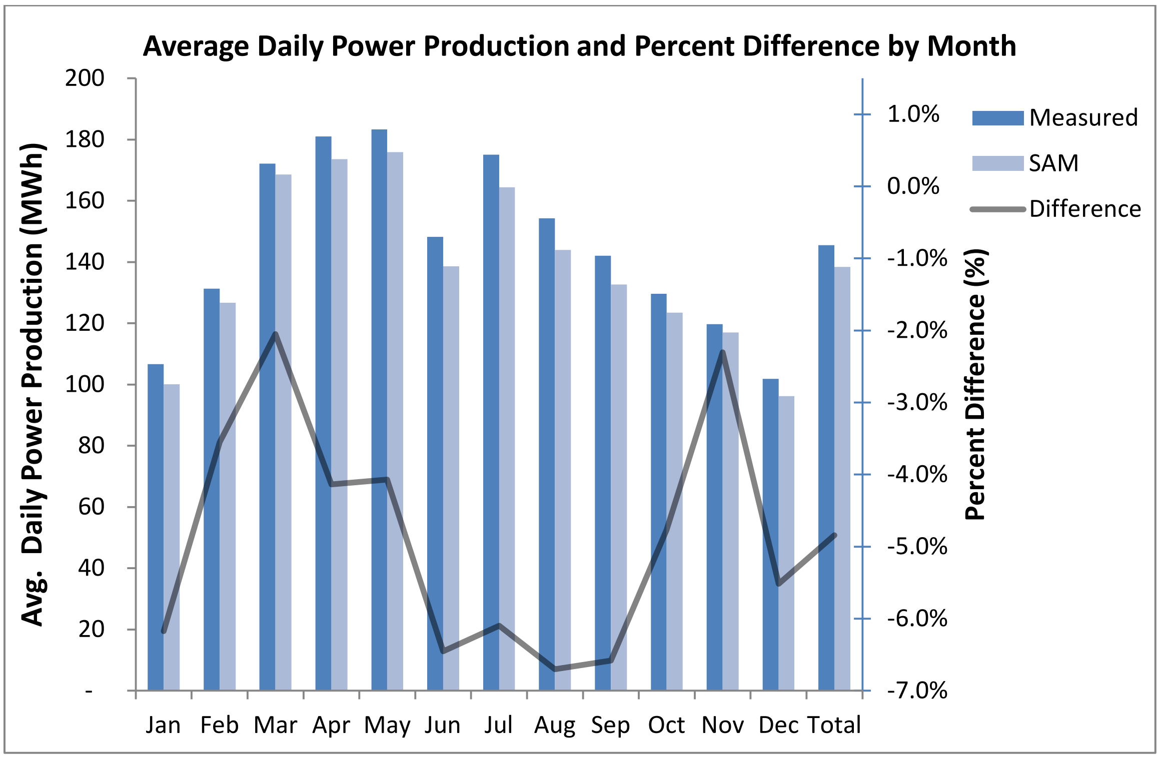


Figure 10-11. Average daily power production and percent difference by month (post-processing)

This seasonal variation is consistent with the seasonal variation in the underlying transposition models discussed in Section 1.4. However, other potential contributors were also explored for this system. An initial guess at the cause of the seasonal variation seen in Figure 10-11 is that that it is related to the increased temperature experienced by the system during the summer. However, upon further analysis we observed that seasonal changes in average temperature do not correspond with the observed seasonal variation in model error.

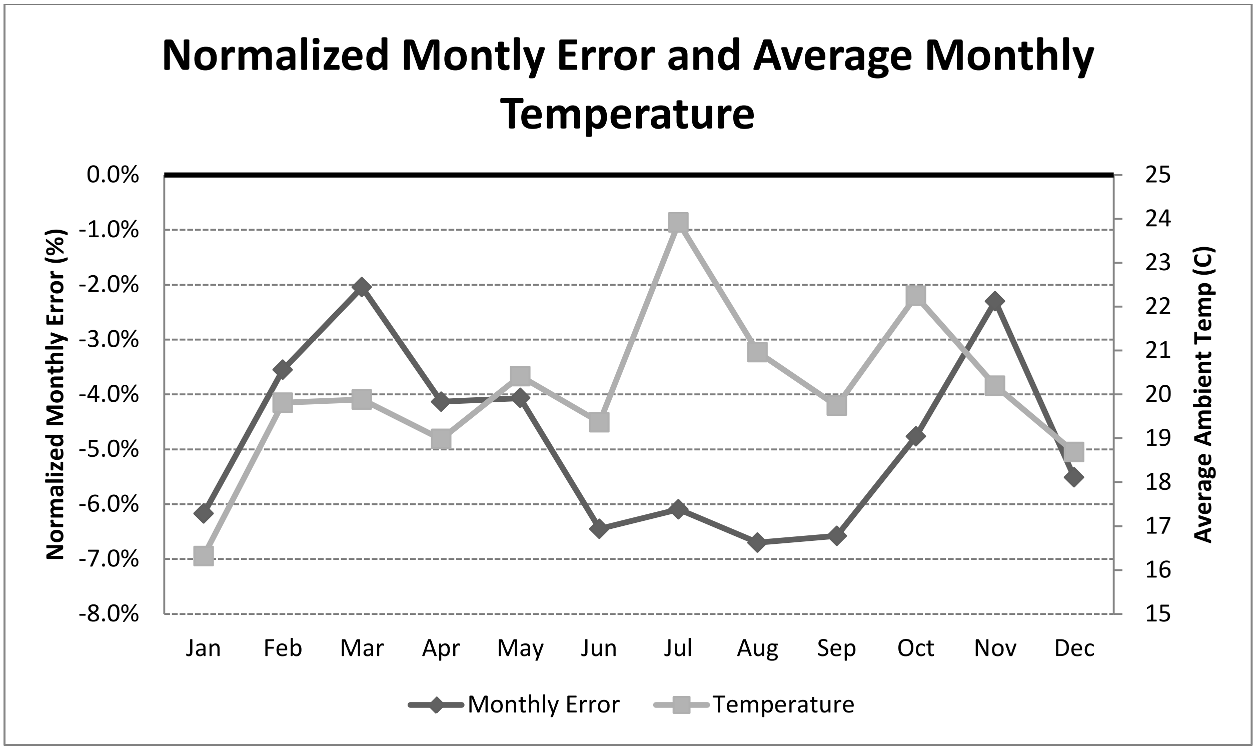


Figure 10-12. Percent error and average temperatures on a monthly basis—DeSoto system (post-processing)

The next examined possibility for the source of the observed variation in seasonal error was soiling. The subtropical climate of DeSoto county Florida has a distinct rainy season from early June through September. Conditions are very dry outside the rainy season, with brush fire danger peaking during the late spring. This climate cycle would imply more loss during the dry months (due to dust and dirt accumulation on the panels) and less during the rainy season (due to "washing" of the panels from rainfall). Examination of rainfall measurements and model error indicate that rainfall might also contribute to the seasonal variability in error seen in Figure 10-11 and Figure 10-12. Future work will investigate this relationship further.

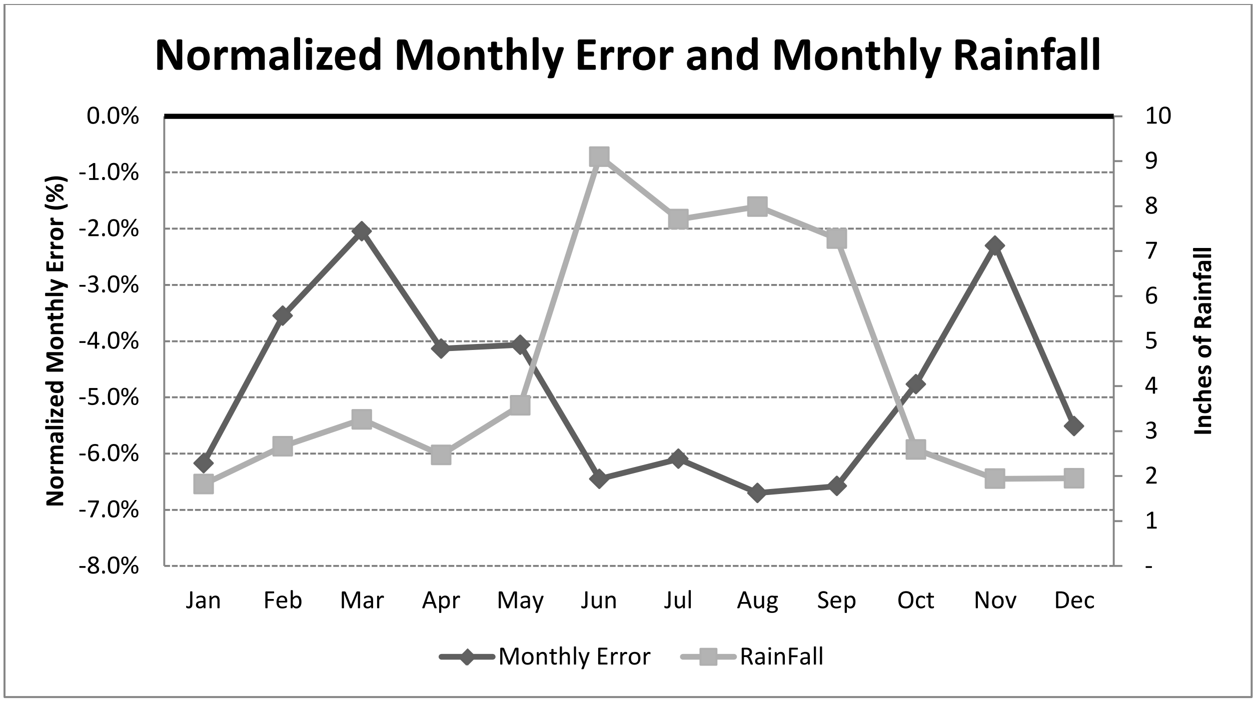


Figure 10-13. Percent error and average rainfall on a monthly basis—DeSoto system

10.3.2.1Daily and Hourly Comparison

Looking at the error on a daily and hourly basis reveals detailed information about the model performance. In the summer, SAM has an hourly RMSE of 1.67 MWh falling to 1.38 MWh in the winter. By this measure, the performance of the model in winter is around 20% better than summer.

Figure 10-14 shows the hourly error grouped by zenith angle. Here we can see SAM is consistently overestimating at higher zenith angles, which is consistent with the known backtracking issue seen in the Mesa Top system (section 4). This source or error was identified in the 2013.1.15 SAM release and then corrected in the 2013.9.20 release (see Section 1). However, it does not affect this system as strongly as the Mesa Top system due to the larger row-to-row spacing found in the DeSoto system.

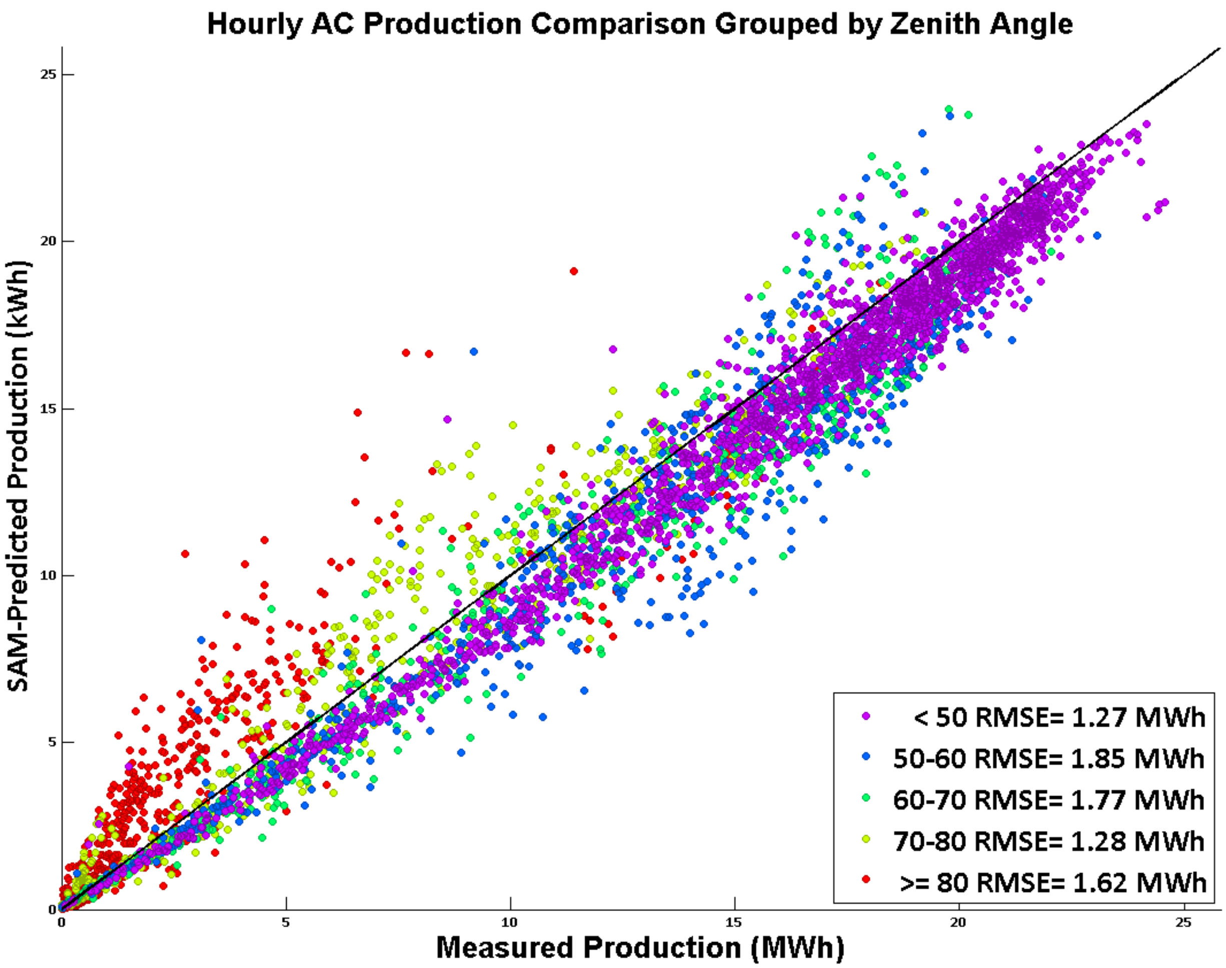


Figure 10-14. Hourly AC production grouped by zenith angle—DeSoto system 2011 (post-processing)

Average diurnal plots show that SAM is consistently underestimating for this system.

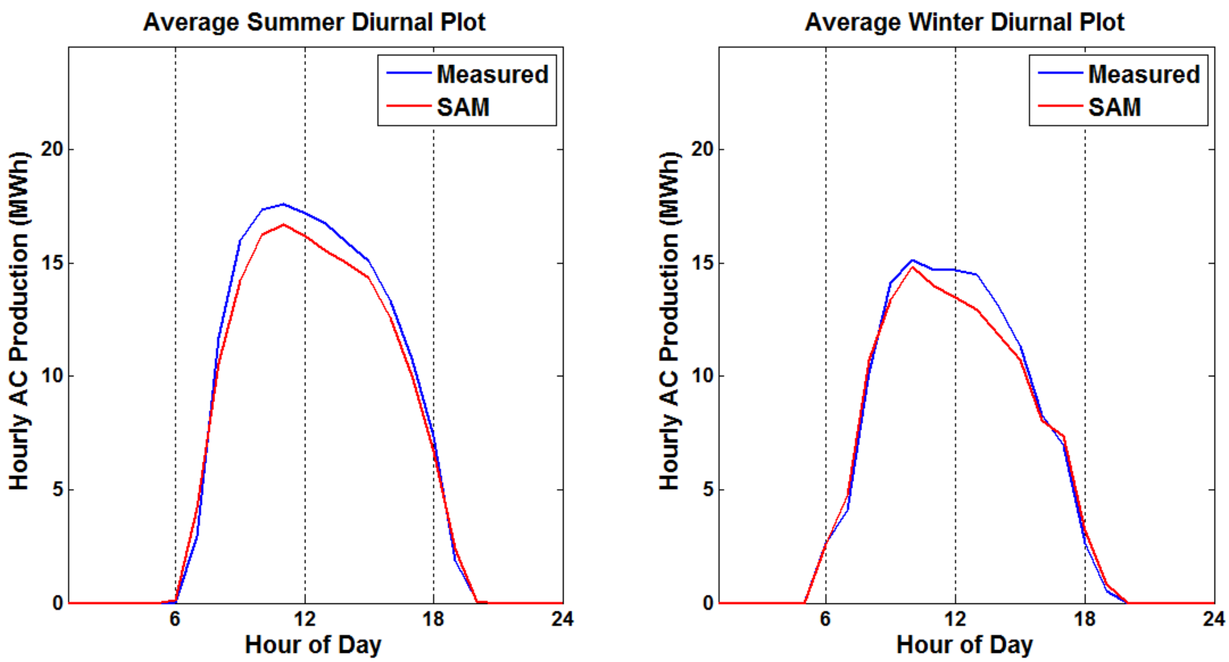


Figure 10-15. Average summer and winter diurnal plots—DeSoto system (post-processing)

10.4 Conclusions

Overall, SAM-predicted performance on a monthly basis is within 7% of measured data. Analysis of hourly residuals revealed several additional issues leading to larger errors between SAM's power production prediction and measured power production.

First, the most significant improvement to the analysis of this system would be to have site DNI data. At this point it is impossible to know what fraction of error is coming from the satellite DNI estimate. However, improved agreement with measured data could also potentially be achieved if SAM accepted POA irradiance as an input (it does, but only for the PVWatts model). Second, running this system in the 2013.9.20 release of SAM featuring the corrected backtracking algorithm would improve the agreement in this system study significantly. Third, the inverter for this site was not included in the database. Expanding the inverter database or having another more detailed representation besides the single-point efficiency would also contribute to a more accurate model.

11 FirstSolar1 Solar Facility System Study

FirstSolar1 is sited on a flat desert floor bordered on the west and north by mountains. The landscape is rocky and dusty covered with low-lying desert vegetation.

Measured site data for 2011 and 2012 were available; however, data for DHI, DNI, temperature, and wind speed was not available for 2012. Therefore, for this report, only 2011 was analyzed. All metrics were normalized by maximum measured power, not nameplate capacity.

11.1 SAM Modeling

11.1.1 Simulation Specifications

The weather file used for the SAM simulation was a TMY3-formatted file of data using measured irradiance data from site-measured GHI and DHI, DNI, wind speed, and ambient temperature from the CPR dataset. The specifications used for the SAM simulation can be found in Table 11-1. Two sub-arrays were used to model the system, because documentation specified that the system is a mix of 25° tilt and 30° tilt angles. Based on this information, two sub-arrays were used to model this system; one with a tilt of 25º and one with a tilt of 30º.

Table 11-1. SAM Specifications—FirstSolar1 System

Tilt (deg from horizontal)	25	30
Azimuth (deg E of N)	180	180
Tracking	fixed	fixed
Backtracking	-	-
Rotation limit (deg)	-	-
Shading	no	no
Soiling	yes	yes
DC derate factor	0.96	0.96

The default Perez transposition model was used. The module was found in the CEC database and the inverter was found in the Sandia inverter database. All system derates were left at the default values.

11.2 Results

11.2.1 Annual Comparison

With default derates, SAM overpredicted annual energy production by 0.6%.

11.2.2 Monthly Comparison

On a monthly basis, SAM deviated from measured data by at most ±9%. SAM's agreement with measured data varied on a clearly seasonal basis, overpredicting energy production during the winter and underpredicting during the summer (see Figure 11-1). This seasonal variation is likely due to seasonal variations in the underlying transposition models; see Section 1.4 for more detail. The only month that does not satisfy this seasonal variation is July, which we considered to be an outlier.

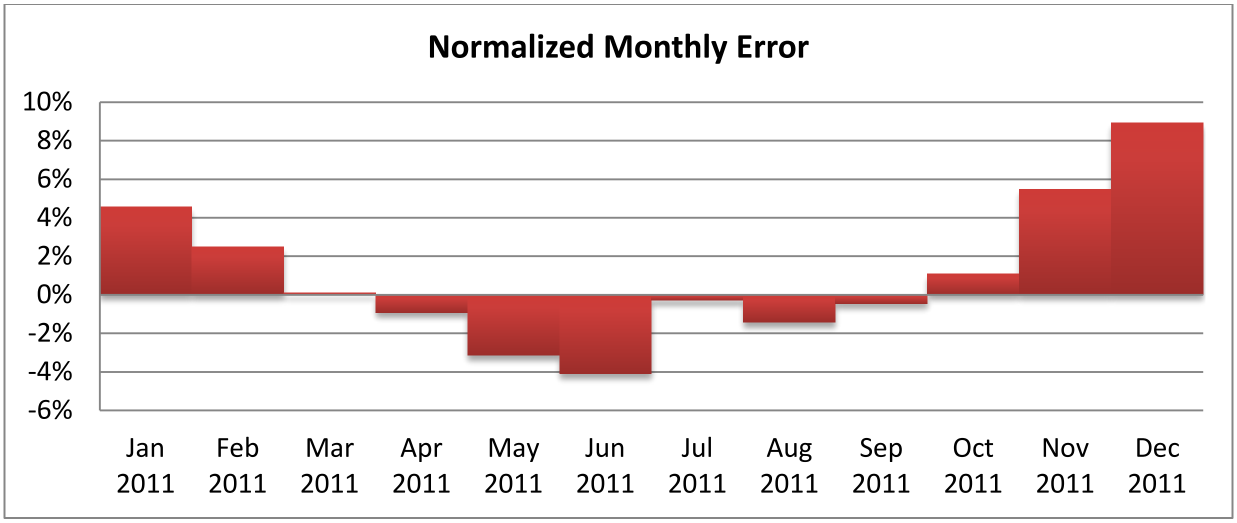


Figure 11-1. Normalized monthly error—FirstSolar1 (post-processing)

11.2.3 Hourly Comparison

Hourly AC production grouped by zenith angle for the FirstSolar1 system was normalized by the maximum measured hourly value. The grouping of red and yellow points above the 1:1 trendline in Figure 11-2 show only slight overprediction at high zenith angles, which could be due to far shading from the nearby mountains that was not accounted for in the SAM simulation.

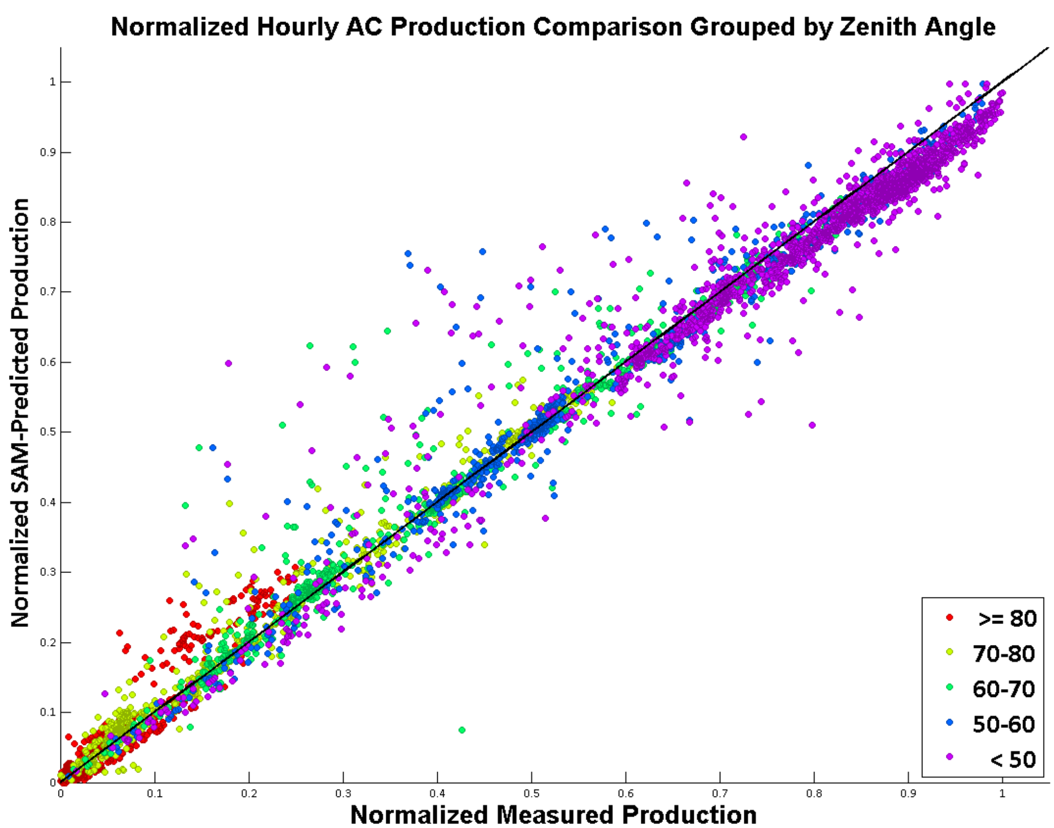


Figure 11-2. Hourly AC production grouped by zenith angle—FirstSolar1 system (post-processing)

The average diurnal plots utilized the normalized hourly SAM and measured values and therefore are also normalized. The average seasonal diurnal plots in Figure 11-3 show SAM overpredicting in the summer sunset hours. Again, this is likely due to the shading by the nearby mountains to the west and north side of the facility. Not properly accounting for the shading effects of these mountains in SAM's simulation is likely the reason that overpredictions occur during the summer months at the end of the day (when the sun is setting behind the mountains). This shading is also seen in the graph above, which shows that at high zenith angles SAM is overpredicting AC production.

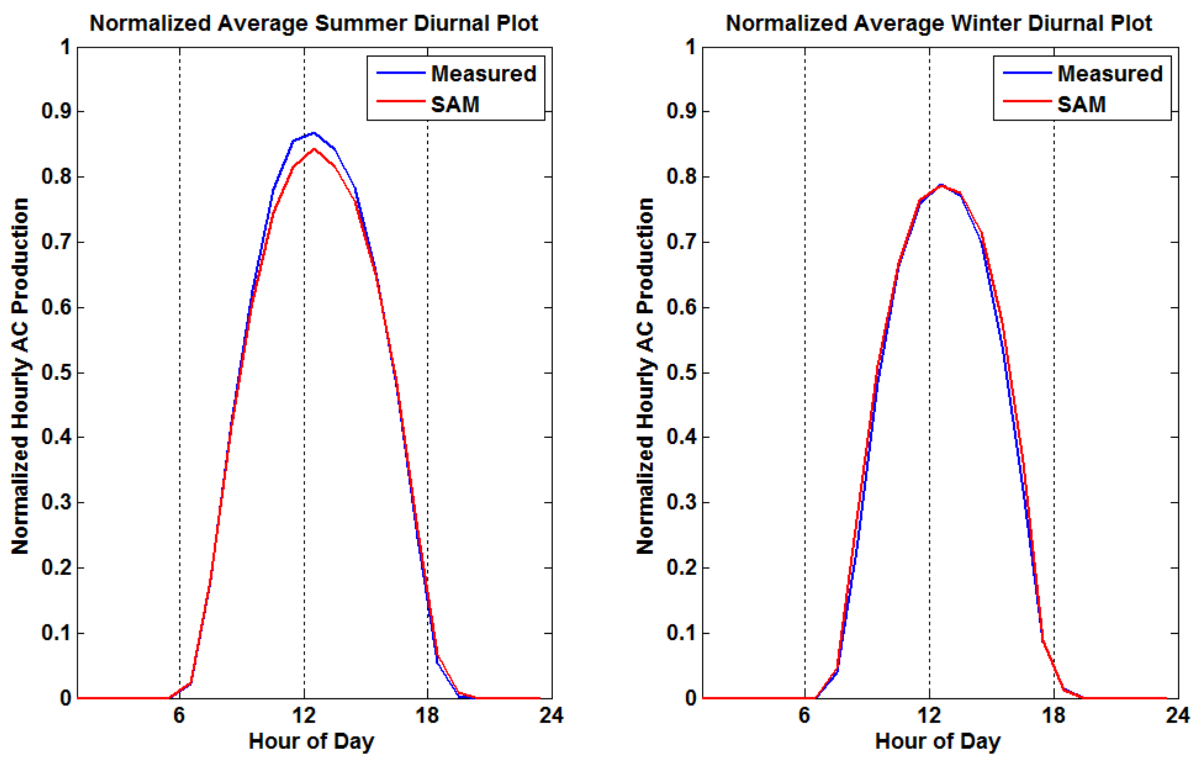


Figure 11-3. Average summer and winter diurnal plots—FirstSolar1 system (post-processing)

11.3 Conclusions

The annual error for this system with the default derates was an overprediction of 0.6%. Monthly errors were at most 9%. Site topography is an important factor at FirstSolar1. Hours with high zenith angles (particularly zenith angles over 80º) showed higher hourly error than hours with lower zenith angles (as evidenced by Figure 11-2). This is likely because shading from the nearby mountains was not accounted for in SAM but did affect measured production. The ability to import surrounding mountain elevations and account for shading impacts would improve the simulation of this site, as well as obtaining more detailed system specifications.

12 FirstSolar2 Solar Facility System Study

The FirstSolar2 solar facility is located close to FirstSolar1. FirstSolar2 construction was finished in 2008, 2 years prior to FirstSolar1.

12.1 SAM Modeling

12.1.1 Simulation Specifications

As mentioned above, the same weather file was used for input into SAM as FirstSolar1. As with FirstSolar1, specifications for FirstSolar2 indicated that the system is a mixture of 25° tilt and 30° tilt angles, so half of the system was modeled at each tilt angle as two different sub-arrays in SAM.

Table 12-1. SAM Specification—FirstSolar1 System

Tilt (deg from horizontal)	30	25
Azimuth (deg E of N)	180	180
Tracking	fixed	fixed
Backtracking	-	-
Rotation limit (deg)	-	-
Shading	no	no
Soiling	yes	yes
DC derate factor	0.96	0.96

The default Perez transposition model was used, and the module was found in the CEC database. The inverter was found in the Sandia inverter database. All system derates were left at default values.

12.2 Results

12.2.1 Annual Comparison

With default derates, SAM-predicted annual production had an error of -0.5%, which corresponds to SAM underpredicting measured performance.

12.2.2 Monthly Comparison

Monthly error patterns are very similar to FirstSolar1, although smaller in magnitude with a maximum of only ±4%, as shown in Figure 12-1. As discussed in Section 11, this seasonal variation is likely due to seasonal variations in the underlying transposition models; see Section 1.4 for more detail.

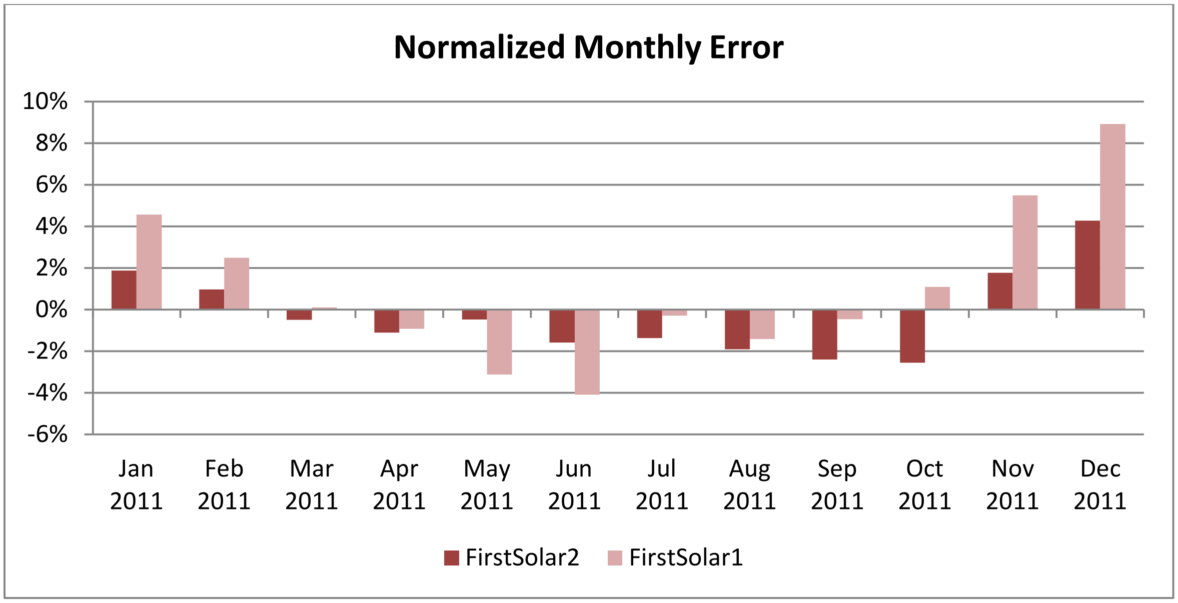


Figure 12-1. Normalized monthly error—FirstSolar2 and FirstSolar1 systems (post-processing)

12.2.3 Daily and Hourly Comparison

Just as in FirstSolar1, hourly AC production grouped by zenith angle for the FirstSolar2 system was normalized by the maximum measured hourly value. It can be seen on the hourly scatter plot in Figure 12-2 that SAM is underpredicting at higher power outputs. The non-linearity in the error as the system approaches maximum power output is also seen in FirstSolar1 but to a lesser degree. Shading was a likely cause of error for FirstSolar1, which showed a grouping of red and yellow (high zenith angle) points above the 1:1 trendline. However, shading seems to be less of an issue at FirstSolar2 than FirstSolar1 because there are less high-error points at high zenith angle (see Figure 11-2 for comparison).

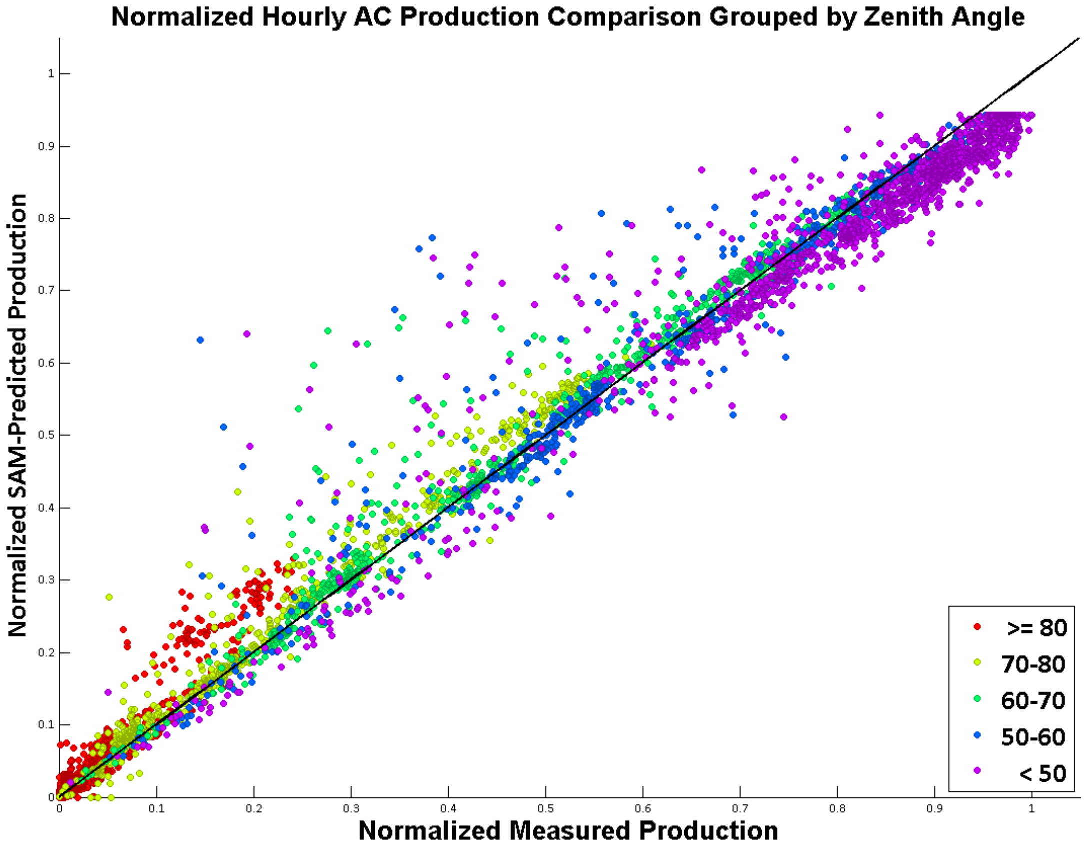


Figure 12-2. Hourly AC production grouped by zenith angle—FirstSolar2 system (post-processing)

Identically to FirstSolar1, the average diurnal plots utilized the normalized hourly SAM and measured values and therefore are also normalized. The diurnal plots are consistent with the summer sunset shading seen at FirstSolar1 (see Section 11), although this effect is not as pronounced on the zenith scatter plot as it was for FirstSolar1.

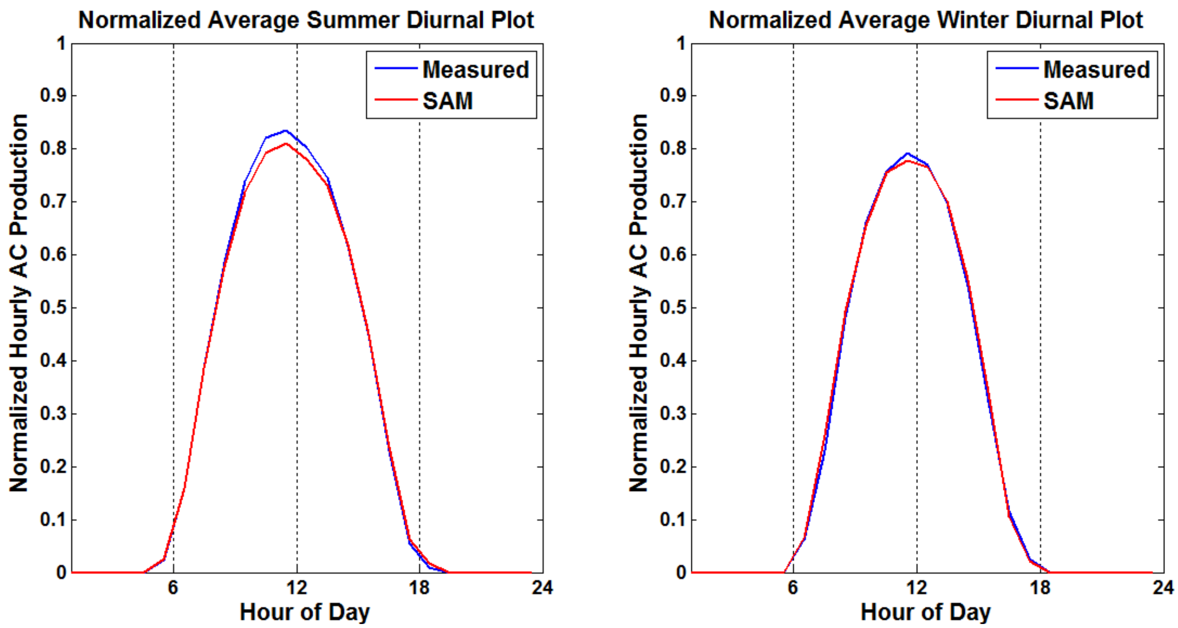


Figure 12-3. Average summer and winter diurnal plots—FirstSolar2 system (post-processing)

12.3 Conclusions

The annual error for this system with the default derates was an underprediction of -0.5%. Monthly errors were at most ±4%. FirstSolar2 showed some error patterns consistent with those at FirstSolar1, such as overprediction in the winter months and potential sunset shading. However, there was a larger underprediction at higher power outputs that was not seen at FirstSolar1. Having site DNI data would likely improve the modeling effort, as well as more detailed system specifications.

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