System Advisor Model (SAM) Case Study:

NREL's Science & Technology Facility (S&TF)

Golden, CO

Abstract

The S&TF Building is part of NREL's South Table Mountain campus located in Golden, CO. The S&TF's rooftop PV array has a nameplate capacity of 94.5 kW. The system is owned and operated by SunEdison, who sells the generated energy through a Power Purchase Agreement (PPA) with NREL and Xcel Energy. SunEdison provided access to performance data for the system from when the system began operation in September 2009 to the present date. The SAM model good agreement with the measured data for the system at the monthly level, though there does seem to be a trend of overestimation in the winter months and underestimation in the summer months. This is most likely due to small errors in determining the temperature coefficients used in the Sandia PV performance model, which is in the process of being improved upon.

Figure 1: Aerial view of the PV array on the S&TF roof [1]

System Description

The S&TF roof system is comprised of two rectangular sub-arrays (Figure 1) that are connected to a single grid-tied inverter. There are 495 Evergreen ES-190 modules that make up the array, with 15 modules per string and 33 strings in parallel. The array delivers power to a Satcon PVS-75 (480 V) inverter. Each row of modules is tilted at a 10° angle and each row is spaced sufficiently to avoid inner row shading. The rows are arranged on metal racks sitting about a foot off the ground (Figure 2). Both sub-arrays are oriented such that both of their azimuths are 16° east of due south.

Figure 2: Rows of Evergreen ES-190 modules on the roof of the S&TF [2]

Data Acquisition

This study used climate data collected at NREL's Solar Radiation Research Laboratory (SRRL) located at the South Table Mountain site. Monthly data sets from SRRL's Baseline Measurement System (BMS) were downloaded for each month in 2010 in TMY3 format and then compiled into a year-long data set using SAM's TMY3 creator [3]. The array layout and module specifications were obtained from NREL records. Because the system is maintained and owned by SunEdison, measured performance data was acquired from SunEdison's Client Connect portal (https://my.sunedison.com/). A password is required to gain access to the data, which we obtained because NREL is the site owner. Daily energy output data was downloaded for January 2010 - December 2010. Cost data was extracted from NREL's Open PV Project Database [4].

SAM Inputs

The SAM technology for this system is Component-based Photovoltaics. The market and associated financing is Commercial PPA. Even though there are two sub-arrays, we can model the system as a single case because they run through one inverter and have the same source circuits and layouts. We selected the Evergreen ES-190 from the Sandia module model drop-down list on the module page and then chose the Satcon PVS-75 (480 V) from the list of Sandia inverter models on the inverter page. We started with the default inputs and then made a few changes to fit the system specifications (Table 1).

Table 1: SAM performance inputs that differ from the default values for the S&TF roof system

Page	Variable	Default Value	S&TF Roof
Climate	Location	Phoenix, AZ (TMY2)	NREL - SRRL (TMY3)
Array	Modules per String	12	15
	Strings in Parallel	3145	33
	Number of Inverters	44	1
	Tracking	1 Axis	Fixed
	Tilt	0°	10°
	Azimuth	0°	-16°

The financial data for all the NREL systems is proprietary, so we used mostly the default values for Commercial PPA. However, in order to get a more accurate cost assessment for the system, we used NREL's Open PV Project Database to get an estimate of the total installed cost [4]. We searched for the total installed cost of similar sized (80-110 kW) systems throughout the U.S. that were installed around the same time (May-November 2009) that the S&TF system was and then took the average cost per watt for these systems. This gave us a total installed cost per capacity of $6.99/W. In SAM, we changed the module cost to $4.41/W from $2.05/W in order to set the total installed cost per capacity at $6.99/W. We also set the PPA price at the default 15¢/kWh and the PPA escalation rate at 2.5% as these values are representative of similar PPAs.

Results and Discussion

The SAM metrics table is shown in Table 2. Because mostly default values were used for the financial side of the model, these metrics do not necessarily represent the S&TF system.

Table 2: SAM metrics table

Metric	Base
Net Annual Energy	136,300 kWh
First year PPA price	36.71 ¢/kWh
LCOE Nominal	36.71 ¢/kWh
LCOE Real	28.16 ¢/kWh
After-tax IRR	15.00 %
Pre-tax min DSCR	0.57
After-tax NPV	$ -10,219.54
PPA price escalation	0.00 %
Debt Fraction	60.00 %
DC-to-AC Capacity Factor	16.5 %
First year kWhac/kWdc	1,449
System Performance Factor	0.76

The SAM financial graphs are very useful in analyzing the system. For example, we can examine the levelized cost of energy (LCOE) for the system and see how much incentives lower the LCOE, as shown in Figure 3. However, because we were able to obtain actual system output data, we focused mostly on the performance model. In order to analyze how accurately this SAM case represents the actual system, we compared the SAM output data to the available measured performance data. Figure 4 (below) shows the monthly energy output comparison between the SAM estimates and the SunEdison measured data for 2010.

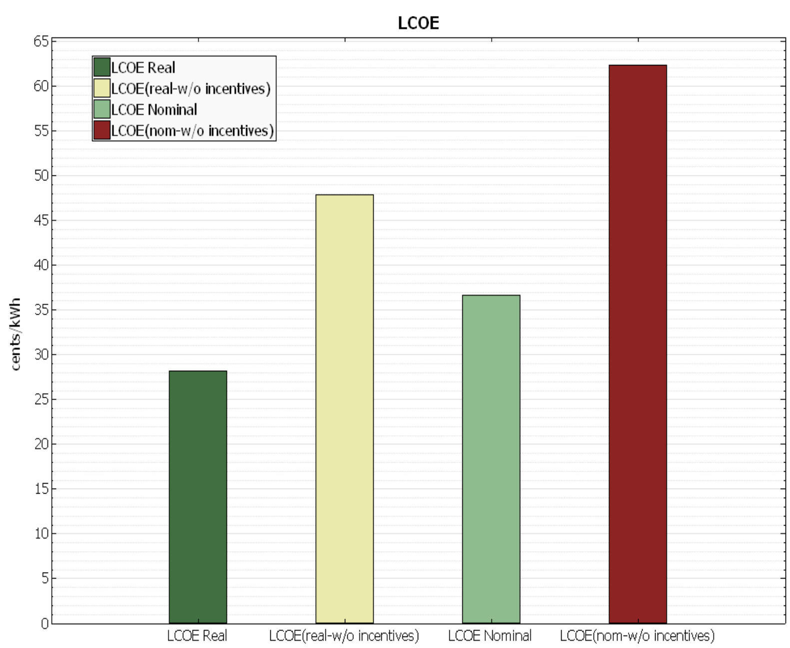

Figure 3: Levelized cost of energy (LCOE) with and without incentives

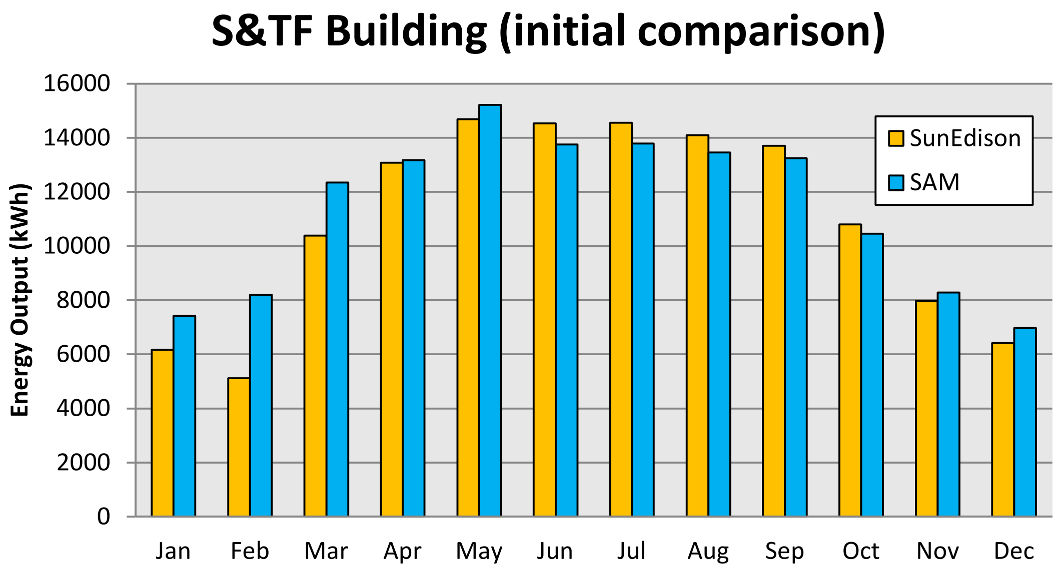

Figure 4: Initial comparison of SunEdison measured system output data (blue) to SAM estimates

It is clear that there is significant disagreement between the SAM output estimates and the SunEdison measured output data, especially in January, February and March. However, with a closer look at the SunEdison data, we found a number of discrepancies between the SunEdison insolation (plane-of-array irradiance) data and the SunEdison energy output data. For certain days there would be a large amount of irradiation but zero or very little energy output. This was especially noticeable in the winter months (e.g. January, February and March). Figure 5 depicts the measured daily solar energy output and insolation during February 2010.

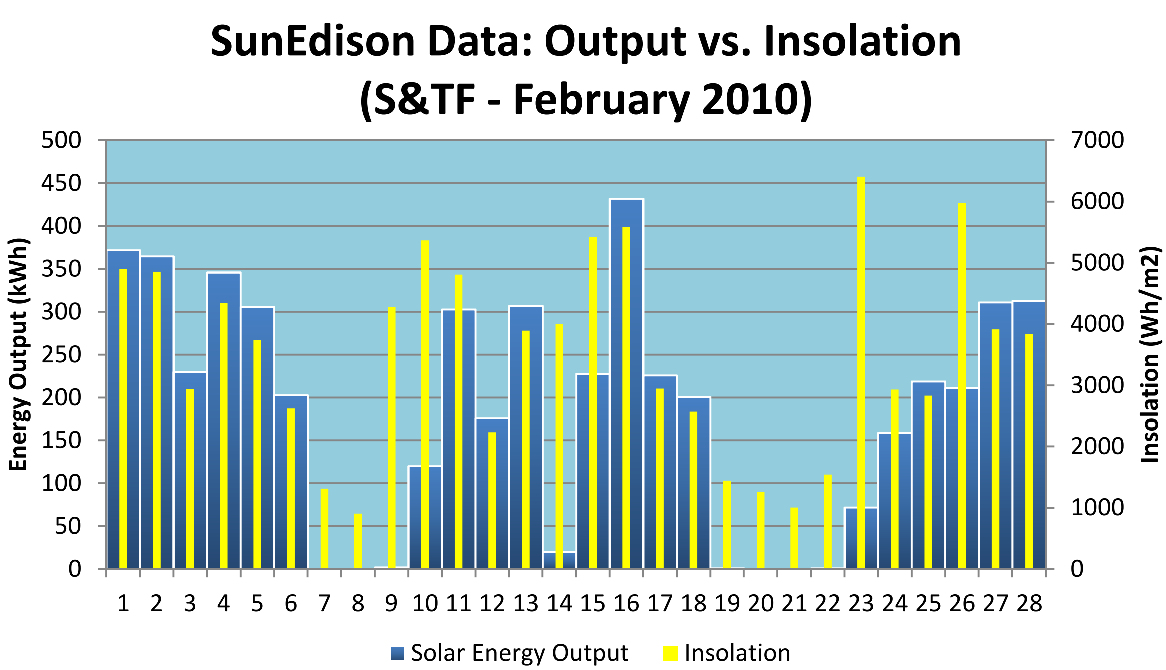

Figure 5: Shows the SunEdison measured energy output and insolation for each day in February 2010

In Figure 5 we focused on the general trend of the relationship between the energy output and insolation. One would expect similar height bars for each variable on a given day because insolation is directly proportional to energy output (i.e. more insolation leads to higher energy output). This is the case for the first six days of February, but clearly not for many other of the days throughout the month. This explains why SAM overestimated in February: SAM calculates an energy output proportional to the irradiance and there are several days where the measured output is much less than – zero in some cases – what would be expected given the irradiance for that day. On the other hand, for a month like September, where there is better agreement between the SAM estimates and the SunEdison measured data, the energy output is proportional to the irradiance for almost every day of the month. The SunEdison daily data comparison for September is located in Appendix A.

As we found with other NREL PV sites, snow cover was the obvious cause of the discrepancies in the winter months. We found snow depth data on the SRRL website and then plotted it with the solar energy output for each day in February [2]. This is depicted in Figure 6 (below).

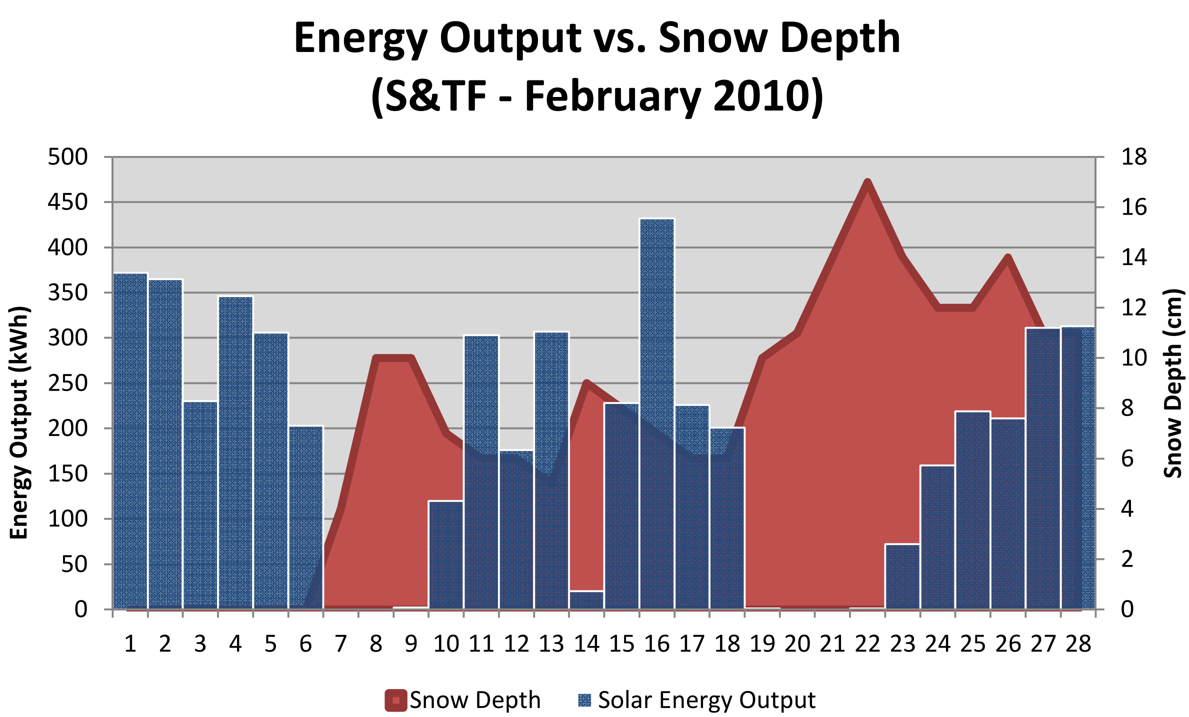

Figure 6: Snow depth (red) and energy output (blue) for each day in February 2010, explaining the discrepancies between the irradiance and generated energy throughout the month.

There are a few important points when analyzing Figures 5 and 6 together. For example, when it starts to snow on February 7th, we can see that the energy output is zero suggesting that the array is completely covered in snow. It remains covered until the snow starts to melt and slide off on the 10th and 11th, where we see some energy generation, though not the amount that would be expected based on the irradiance for those days, suggesting that the array was still partially covered in snow. By the 12th and 13th the array is completely clear and generating energy as expected. One thing to note on these days is that even though there is snow reported on the ground, it does not necessarily mean that snow is covering the array. This is especially true for arrays that are set up on racks above ground level and that have a tilt because the snow can slide off onto the ground below without accumulating in front of it. The S&TF array has both of these qualities, which explains why the array is generating energy even though snow is on the ground. In comparison, the PV array on the roof of NREL's Research Support Facility (RSF) is integrated into the slope of the roof and therefore is affected much more by snow cover because the snow has to melt completely (rather than slide off) before energy production can continue. Refer to the case study for the RSF PV array for more information. Eleven more centimeters of snow falls on the 19th to 22nd that completely covers the array again until partial generation resumes on the 23rd and 24th after some of the snow melts and slides off. We can also see how the energy production is diminished as the snow covers the array on days, like the 14th and 26th, where the snow falls during the day, explaining the poor correlation between the energy output and insolation for those days in Figure 5. Another issue to keep in mind when using the current version of SAM is that if a climate file contains snow data, the ground albedo for snowy days increases and actually enhances the simulated system performance, when in reality the output should be reduced most of the time due to snow cover.

Snow cover, therefore, explains the discrepancies between the SunEdison insolation and performance data in the winter months and consequently why SAM overestimated the energy production in those months. There are also a few minor issues in other months, where a few hours (or occasionally days) of performance data would be missing. The most notable example of this was in the month of May; the daily profile for May is shown below (Figure 7).

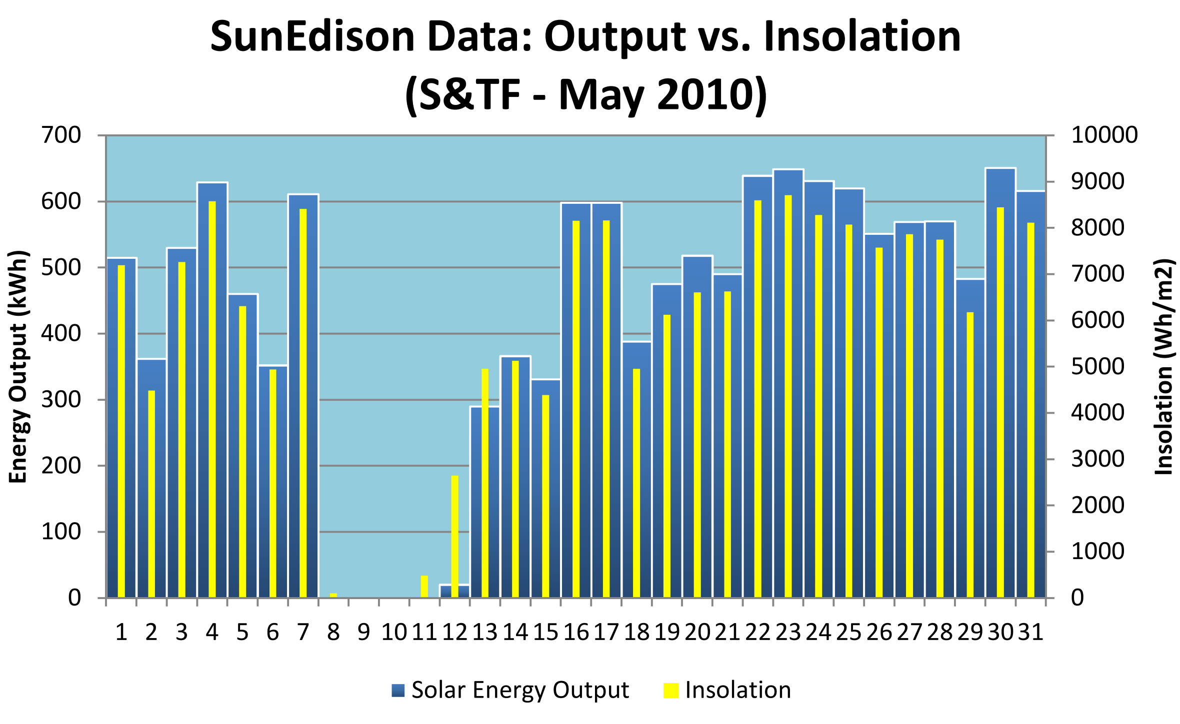

Figure 7: Shows the SunEdison measured energy output and insolation for each day in May 2010

Most days in May show a good correlation between the insolation and output except for the six-day chunk from the 8th to the 13th. Though it doesn't seem like a major issue because the insolation is zero (or nearly zero) so it would seem that SAM should not overestimate by much, the problem is that there is significant irradiance data in the SRRL weather file used for the simulation in SAM. The reason for the missing (or incomplete) data is most likely due to system maintenance or malfunction. There were 12 other days spread out throughout the year that had missing performance data (not due to snow cover).

In order to make a more reasonable comparison between SAM and the SunEdison measured data, we removed days with discrepancies (due to either snow cover or missing data) from the analysis; we took out both the SAM estimate and the SunEdison value for the day in question and then summed only the "good" days to come up with a monthly output for each month. For example, we discarded February 7-10, 14-15, 19-23 and 26 due to snow cover and May 8-13 because of system malfunctions. We went through this process for each month, and ended up with the comparison shown below in Figure 8. We did not remove days like February 11th and 24th that were mostly clear of snow and generated close to the expected output; however, this is probably the reason that SAM still slightly overestimates in the winter months. The total output is decreased for both SAM and SunEdison due to the removal of flawed days from each dataset; therefore, the values in Figure 8 are not representative of the expected or measured system output.

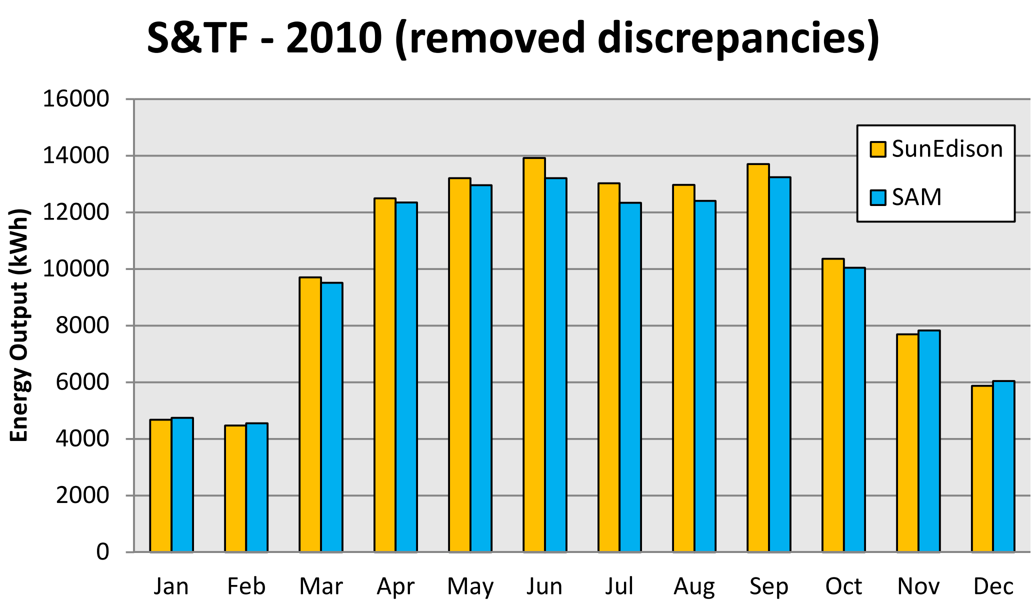

Figure 8: Comparison of SunEdison measured data to SAM estimates after the removal of days with flawed data

After removing the discrepancies, the SAM data shows much better agreement with the measured data. The SAM estimates are within 5.3% of the measured values for each month in 2010, while the annual output estimated by SAM is 2.3% less than the measured. However, to minimize the error we can calibrate the model for the S&TF system by adjusting the derate factor, which is not a precisely known value for any system and can vary quite a bit from system to system. To calibrate the total derate factor, we ran a parametric simulation in SAM, varying the nameplate derate from 90-100% at 1% intervals. The derate algorithm in SAM simply multiplies the derate factors for each component of the system and calculates a total derate factor for the entire system; so by changing the nameplate derate, we were effectively varying the total derate factor over the range 80.9-89.9%. By doing this, we were able to find the optimum derate factor that minimized the output error. Figure 8 (below) shows the derate factor calibration by plotting the annual output error against the total derate factor.

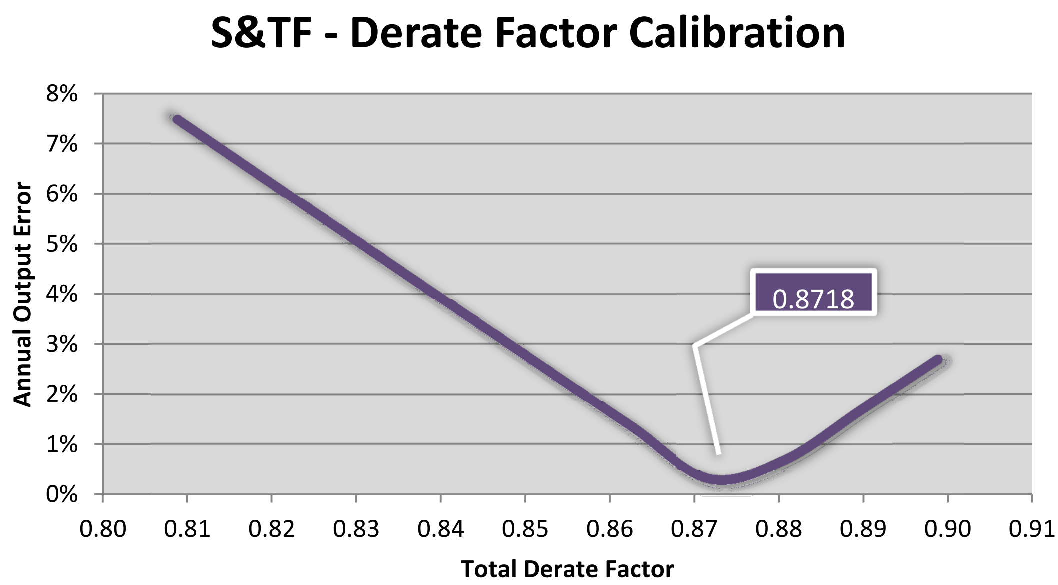

Figure 9: Shows the derate factor calibration by minimizing the total output error

From Figure 9, we determined that the total derate factor should be around 87.2%, which corresponds to a nameplate derate of 97%. After running SAM with this derate factor, we were left with the final comparison graph below (Figure 10). The annual output error was reduced to 0.3% while every month is within 3.7% of the measured value except for November (4.0%) and December (5.0%).

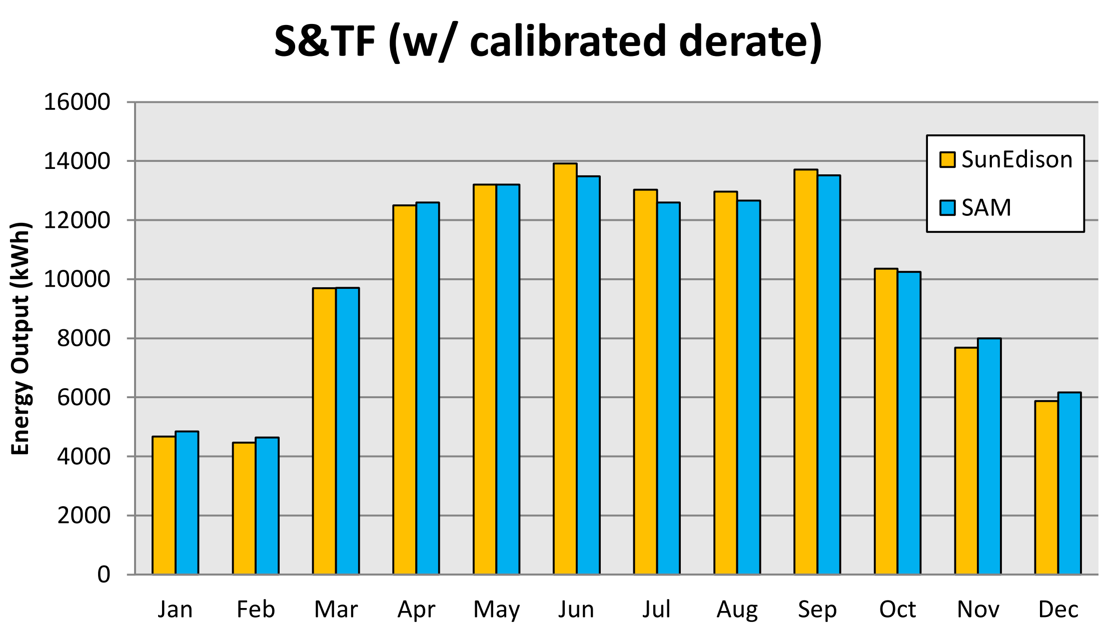

Figure 10: Final comparison graph of the SunEdison measured data vs. the SAM estimates after removing flawed data and calibrating the derate factor for the system.

The remaining error is not consistent and has a seasonal trend: SAM underestimates in the summer and overestimates in the winter. This suggests that there is an issue regarding temperature coefficients in the Sandia performance model. There is evidence of a temperature dependence of the difference between the modeled and measured outputs, even when there is a good match between the modeled and measured module back-surface temperature [5]. This implies that either the temperature coefficients (P_{mp} or I_{mp} and V_{mp}) may be wrong or that there is an irradiance-dependent term. There is an irradiance term (mβVmp) included in the model, but it has not been found to be useful. On top of this, the module manufacturers are not very forthcoming in explaining how they obtain the values on their datasheets. Therefore, Sandia is currently working on improving their process for determining the coefficients in order to enhance the model.

As a check we used the CEC model of the Evergreen ES-190 module for this system, we found similar results though there was slightly less error. This comparison is located in Appendix B.

Conclusions

We used SAM to model the PV system on NREL's S&TF roof based on the system specifications provided by SunEdison. We were able to model the system with very few changes to the default values in SAM. After accounting for days with snow cover or system malfunction, we calibrated the derate value and were able to get within 0.3% of the measured annual output and within 3.7% of the measured value for every month except November and December which had an output error of less than 5%. This case study was another example of the issues surrounding snow cover, which should be addressed in future model enhancements. There were other slight issues involving uncertainties in the temperature coefficients in the Sandia module model that caused model overestimation in the winter and underestimation in the summer. A more precise way of calculating these coefficients is currently being researched at Sandia National Laboratories. This study is still a good example of a simple commercial PV system. The SAM file associated with this case study is located in the SAM samples folder.

References

[1] Satellite photograph found on Google maps: http://maps.google.com/

[2] Arvizu, D. "Moving Toward a Clean Energy Future". NREL PowerPoint slides at National University of Singapore. 3 November 2010. < http://me.nus.edu.sg/NREL/singapore_20101103_2.pdf>

[3] Monthly climate files and weather data available at: http://www.nrel.gov/midc/srrl_bms/

[4] PV system cost data available at: http://openpv.nrel.gov/

[5] King D et al, 2004. "Photovoltaic Array Performance Model". Sandia National Laboratories. SAND2004-3535. <http://photovoltaics.sandia.gov/docs/PDF/King%20SAND.pdf>

Appendix A

Figure 10 shows the SunEdison daily data for both energy output and insolation for September 2010, illustrating what a month without discrepancies looks like.

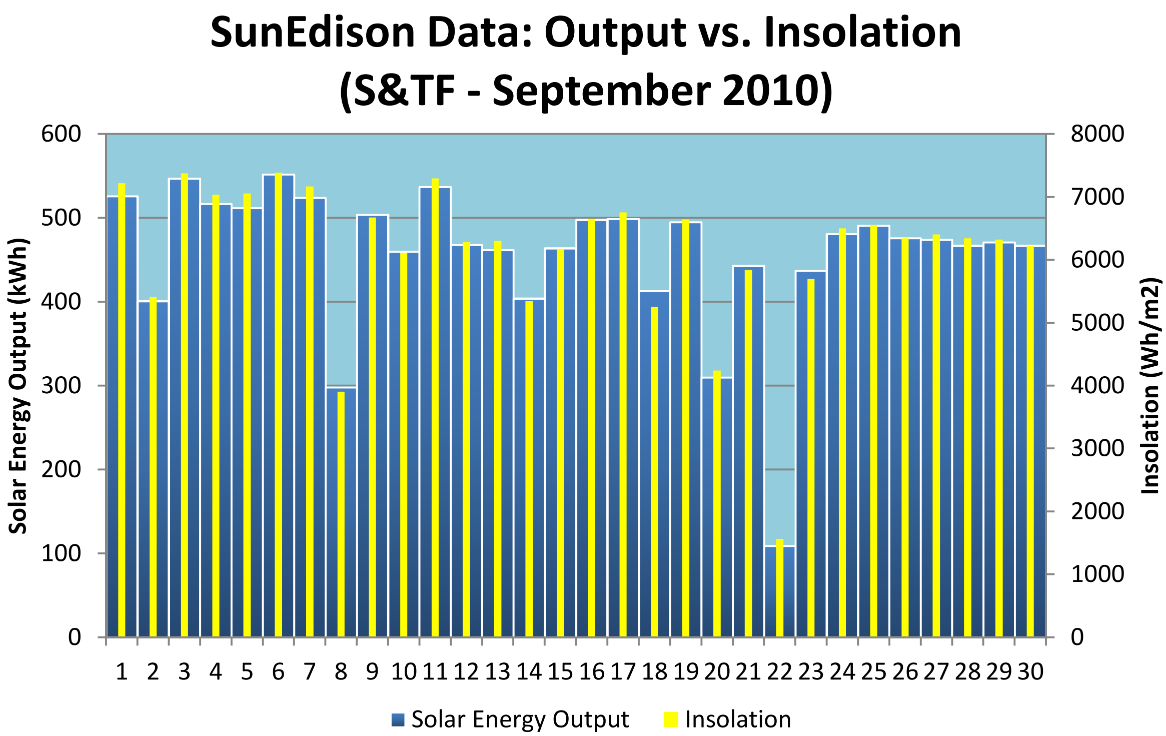

Figure 11: Shows the SunEdison measured energy output and insolation for each day in September 2010

Appendix B

Figure 11 shows the final comparison between SAM and the measured data, this time using the CEC module model, after going through the same process of flawed data removal and derate calibration. It is very similar to the results from the Sandia model. The SAM estimate is within 2.6% of the measured output for every month. It should also be noted that the CEC module model seems to be slightly more accurate than the Sandia model for most of months, especially in the winter. This is probably due to the fact that CEC model does not deal with the uncertainty of the temperature coefficients like the Sandia model.

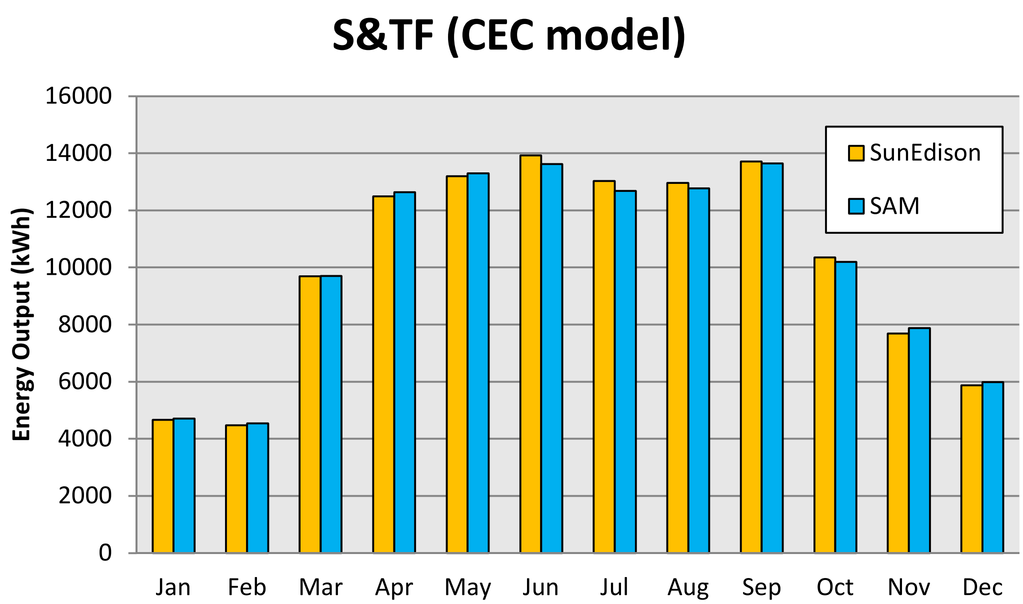

Figure 12: Final comparison between the SunEdison measured data and the SAM estimates using the CEC module model