System Advisor Model (SAM) Case Study:

NREL Research Support Facility (RSF)

Golden, CO

Abstract

The RSF building is part of NREL's South Table Mountain campus located in Golden, CO. The RSF's rooftop PV array has a nameplate capacity of 449 kW, contributing to the building's net-zero energy standard. The system is owned and operated by SunEdison, who supplies the generated energy through a Power Purchase Agreement (PPA) with NREL and Xcel Energy. SunEdison provided access to performance data for the system dating from its installation in November 2010 to the current date. The SAM model shows good agreement at the monthly level with the measured data for the system.

Figure 1: Looking west at the RSF roof PV array (computer generated image) [1]

System Description

The RSF roof system is comprised of two sub-arrays, one on each wing of the building's "lazy-H" configuration, covering a total of approximately 2,800 m². Figure 2 (below) shows an aerial view of the RSF. Fixed flat-plate Solon Black 230-07 (240Wp) modules were used for the entire system. The north roof array (which includes the connector roofs) is made up of 84 strings in parallel each with 13 modules in series.

These 1092 modules are connected to a Satcon PVS-250 grid-tied inverter. The north array is at a 10° tilt with an azimuth 15° east of due south. The south array also has 13 modules per string with 60 strings in parallel, for a total of 780 modules that run through a Satcon PVS-135 grid-tied inverter. The south roof is still at a 10° tilt, however due to the "lazy-H" design, the azimuth is due south.

Figure 2: Computer generated aerial view of the RSF's "lazy-H" configuration (bottom right building) [1]

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 (June 2010 - May 2011) were downloaded in TMY3 format and then compiled into a year-long data set using SAM's TMY3 creator [2]. 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 from December 2010 through May 2011. Cost data was extracted from NREL's Open PV Project Database [3].

SAM Inputs

The SAM technology for this system is Component-based Photovoltaics. The market and associated financing is Commercial PPA. In order to account for the two sub-arrays, we created two cases (one for each sub-array) and used the Multiple Subsystems feature in the Configure Simulations tab to aggregate the systems. Because there is not currently a CEC or Sandia model for the Solon Black 230-07 module, we had to create a custom module using a coefficient calculator for the CEC 6 parameter PV module model [4]. The coefficient generator converts general manufacturer datasheet specifications into normalized parameters that characterize a module's current-voltage (IV) curve. This tool is included in the most recent SAM release from November 2011. To create a custom module, we first created a new library named "custom modules" and added a similar module (SOLON Black 230-01 240) as a new entry. After inputting the necessary datasheet specs into the coefficient generator, we entered the calculated parameters for the custom module in the new library. We then selected the custom Solon Black 230-07 240Wp module from the drop-down list on the module page for both cases. Next we selected the Satcon PVS-250 inverter for the north array case and the

Satcon PVS-135 inverter for the south array case (both are Sandia models). We started with the default values for both cases and then made a few changes based on the system description (Table 1).

Page	Variable	Default	RSF North	RSF South
Climate	Location	Phoenix, AZ (TMY2)	Golden [NREL - SRRL], CO (TMY3)	
Array	Modules per String	12	13	13
	Strings in Parallel	3145	84	60
	Number of Inverters	44	1	1
	Tracking	1 Axis	Fixed	Fixed
	Tilt	0°	10°	10°
	Azimuth	0°	-15°	0°

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 [3]. We searched for the total installed cost of similar sized (420-480 kW) systems throughout the U.S. that were installed around the same time (June-December 2010) that the RSF system was installed and then took the average cost per watt for these systems. This gave us a total installed cost per capacity of $5.29/W. In SAM, we changed the module cost to $2.74/W from $2.05/W in order to set the total installed cost per capacity at $5.29/W. We also specified a first year PPA price (default 15¢/kWh) and PPA escalation rate (3%) rather than specify an Internal Rate of Return target. These are numbers that are associated with similar systems in the area. We left the rest of the financing and cost inputs as the default values and then ran the simulation.

Results and Discussion

The SAM metrics table is shown in Table 2. Since mostly default values were used for the financing and cost inputs, these metrics do not necessarily represent the RSF system.

Table 2: SAM metrics table

Metric	Base	Combined
Net Annual Energy	394,773 kWh	672,224 kWh
First year PPA price	15.00 ¢/kWh	15.00 ¢/kWh
LCOE Nominal	20.09 ¢/kWh	20.09 ¢/kWh
LCOE Real	15.41 ¢/kWh	15.41 ¢/kWh
After-tax IRR	0.00 %	0.00 %
Pre-tax min DSCR	0.27	0.19
After-tax NPV	$ -226,995.92	$ -483,445.81
PPA price escalation	3.00 %	3.00 %
Debt Fraction	60.00 %	60.00 %
DC-to-AC Capacity Factor	17.2 %	17.1 %
First year kWhac/kWdc	1,505	1,495
System Performance Factor	0.79	0.79
Total Land Area	1.01 acres	1.01 acres

The SAM graphs are very useful in analyzing the financial side of the system. Though we did not have accurate cost data, it is still interesting to see the cost breakdown of the $2.74/W value for the total installed cost per watt in Figure 3.
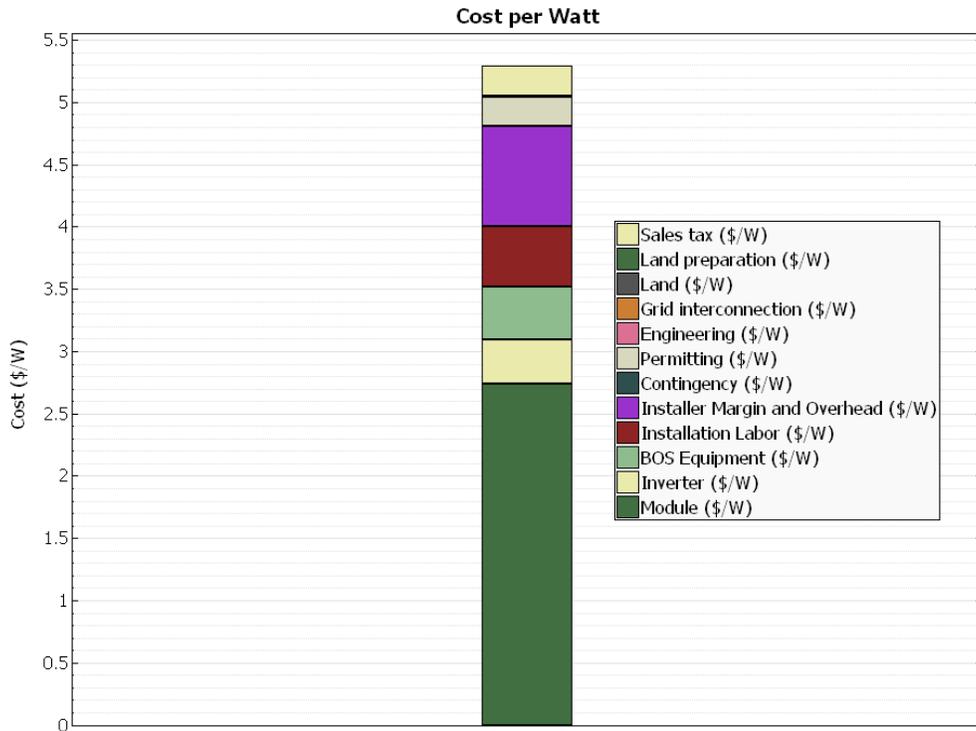

Figure 3: Breakdown of costs that make up the total installed cost per watt, including the $5.29/W module cost from OpenEI

Since we had in depth system specifications, we have a more complete performance model than financial model. Figure 4 shows the monthly output for the combined system for the time period June 2010 to May 2011. In accordance with the way we set up the weather file, Jan-May in Figure 4 is 2011 and Jun-Dec is 2010.
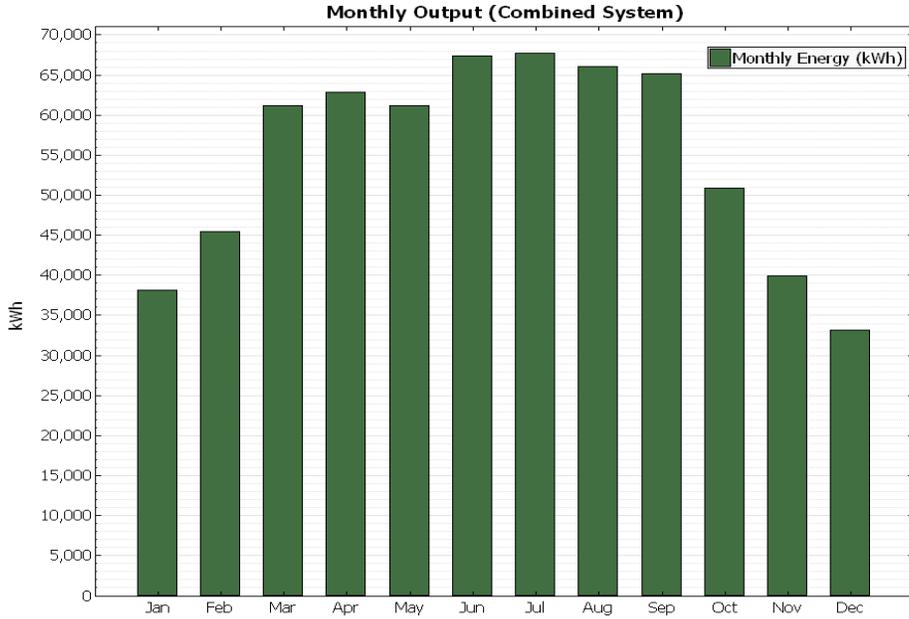
Figure 4: SAM graph of monthly energy output for Jan-May 2011 and June-Dec 2010

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 5 (below) shows the monthly energy output comparison between the SAM estimates and the SunEdison measured data for December 2010 - May 2011.
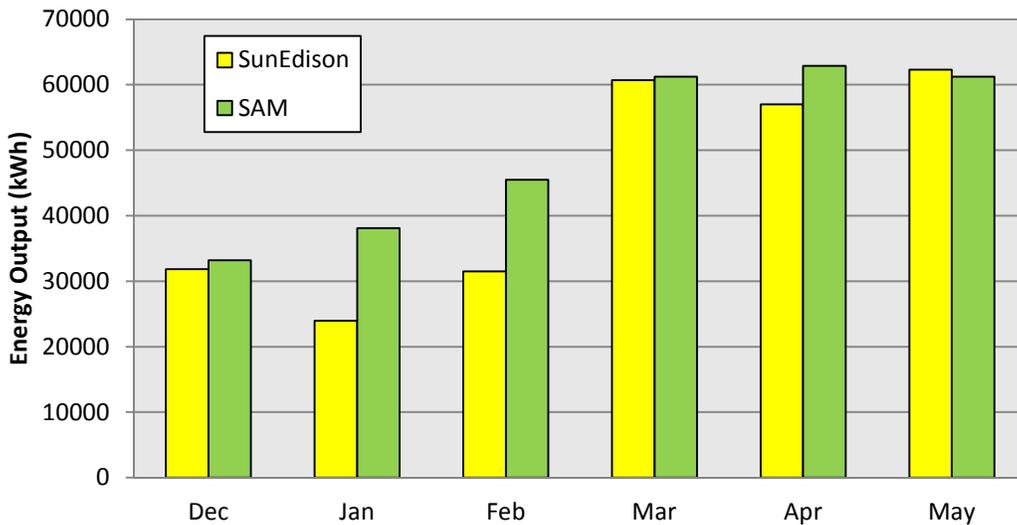

Figure 5: Comparison of SunEdison measured system output data (yellow) to SAM estimates (green)

It is clear that there is significant disagreement between the SAM output estimates and the SunEdison measured output data, especially in January, February and April. 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

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irradiation but zero or very little energy output. This was especially noticeable in the winter months (e.g. January and February). Figure 6 depicts the measured daily solar energy output and insolation during February 2011.

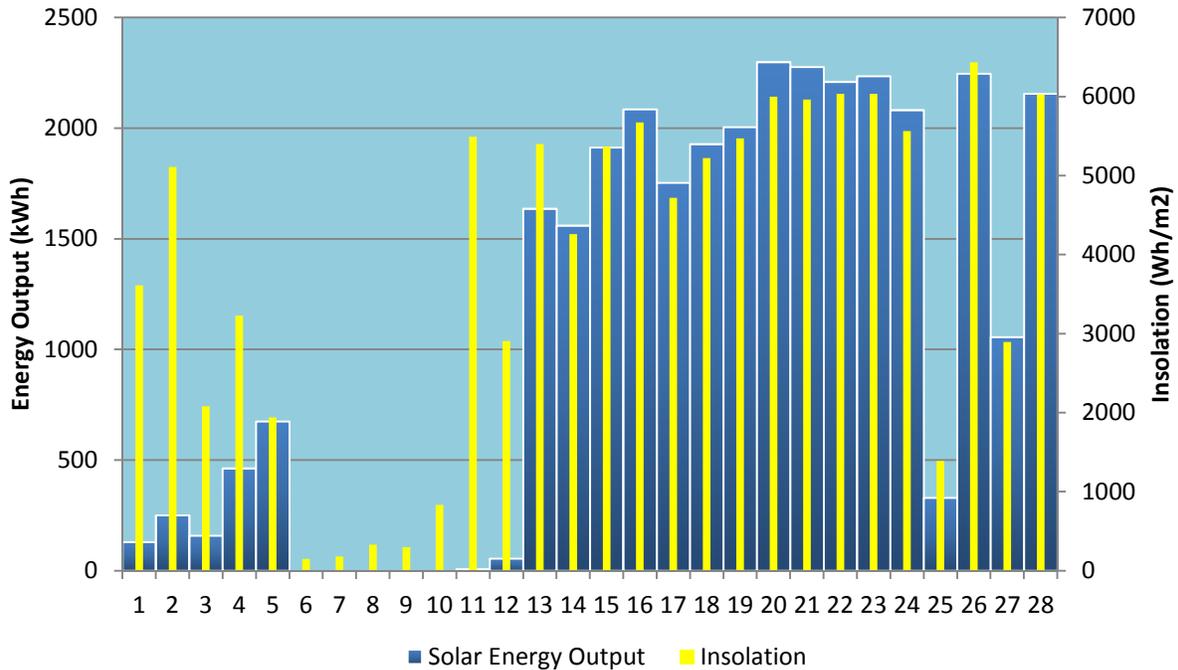## SunEdison Data: Output vs. Insolation (RSF - February 2011)

Figure 6: Shows the SunEdison measured energy output and insolation for each day in February 2011

In Figure 6 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 second half February, but clearly not for the first two weeks of 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 March, where there is good 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 March is located in the Appendix.

After searching through the climate data on the SRRL website, it was obvious that snow cover was the cause of the discrepancies in the winter months [2]. The snow depth was plotted with the solar energy output for each day in February in Figure 7 (below).

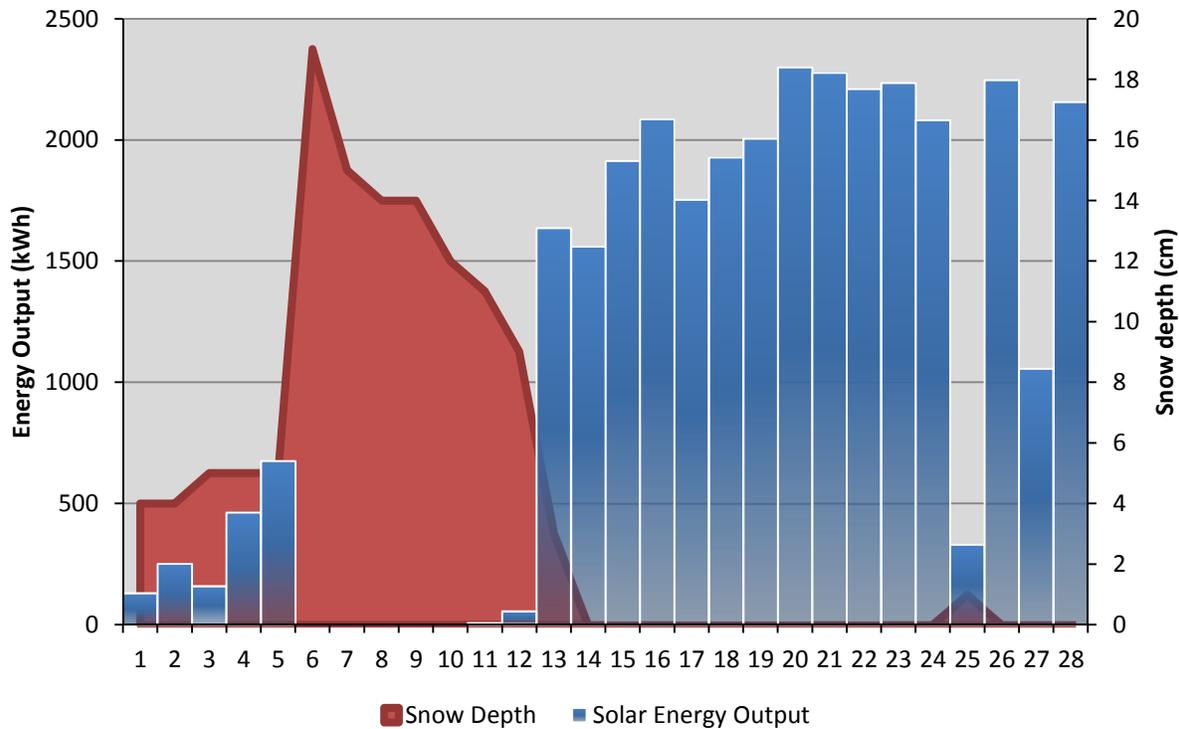# Energy Output vs. Snow Depth
(RSF - February 2011)

Figure 7: Snow depth (red) and energy output (blue) for each day in February 2011, explaining the discrepancies between the irradiance and generated energy for the first two weeks of the month.

When analyzing Figures 6 and 7 in tandem, there are a few notable points. First, for Feb. 1-4, it is probable that the rooftop array was partially snow covered, as there is limited (but non-zero) energy output and the snow depth is only 4-5 cm suggesting that some spots may have melted or been blown off, possibly forming drifts at the edges of the roof. February 5th is an interesting day as these graphs do not tell the whole story. The hourly snow depth data shows that early in the day the snow melted so for the peak irradiance hours the array was clear and able to generate energy proportional to the solar resource. However, during the night 19 cm of snow fell at the South Table Mountain site, skewing the average snow depth for that day (5 cm). This explains why Figure 6 shows a good correlation between insolation and output for the 5th: snow was not actually covering the array during the peak irradiance hours. Additionally, one can infer that the large irradiance values on the 11th and 13th helped melt the snow cover allowing partial energy generation after 5 days where the array was completely covered. On top of this, on the 25th we can assume that the snowfall meant it was a cloudy day, thus lowering the insolation value, while the 1 cm of snow restricted energy production slightly below the expected output based on the irradiance. A final contributing factor to the snow issue is that for climate files that include snow depth data, a typical SAM assumption is that snow slides off quickly from most arrays. Therefore, if a climate file contains snow data, it increases the ground albedo for those days and actually enhances system performance, when in reality the output should be reduced most of the time.

January had a similar daily profile, with snow cover limiting the energy output and causing SAM to overestimate based on the irradiance for those days. Therefore, snow cover explains why SAM grossly overestimated in January and February, but there is a different issue in April as no snowfall was recorded for the month. The daily profile for April is shown below (Figure 8).

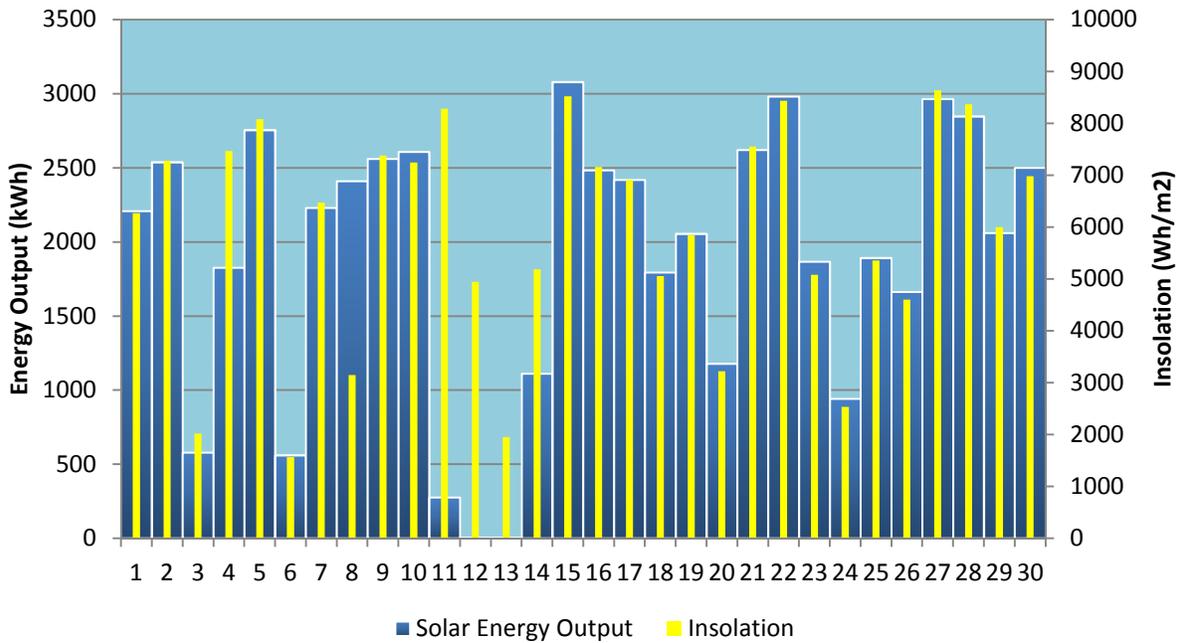## SunEdison Data: Output vs. Insolation (RSF - April 2011)

Figure 8: Shows the SunEdison measured energy output and insolation for each day in April 2011

Once again, we can see why SAM overestimated in April: there were days where the energy output was much less than what would be expected based on the irradiance for those days. Upon examining the hourly profiles of the days in question it became apparent that these discrepancies were most likely based on system maintenance or malfunction. A good example of this is the time period from April 11-14. Figure 9 (below) depicts the hourly profiles for the insolation and energy output for those days. We can presume that the PV system was either disconnected for maintenance or there was a system failure at about 9 A.M. on the 11th and then turned back on or repaired at around 12 P.M. on the 14th. In between, no energy was generated even though there was substantial insolation, which is the primary reason SAM overestimated in April. There are other days that have similar discrepancies, like the 4th and the 8th. The 8th is a little different in that there are 4 hours of missing irradiance data in the middle of the day, suggesting that the instrument used to measure the insolation was malfunctioning or being worked on.
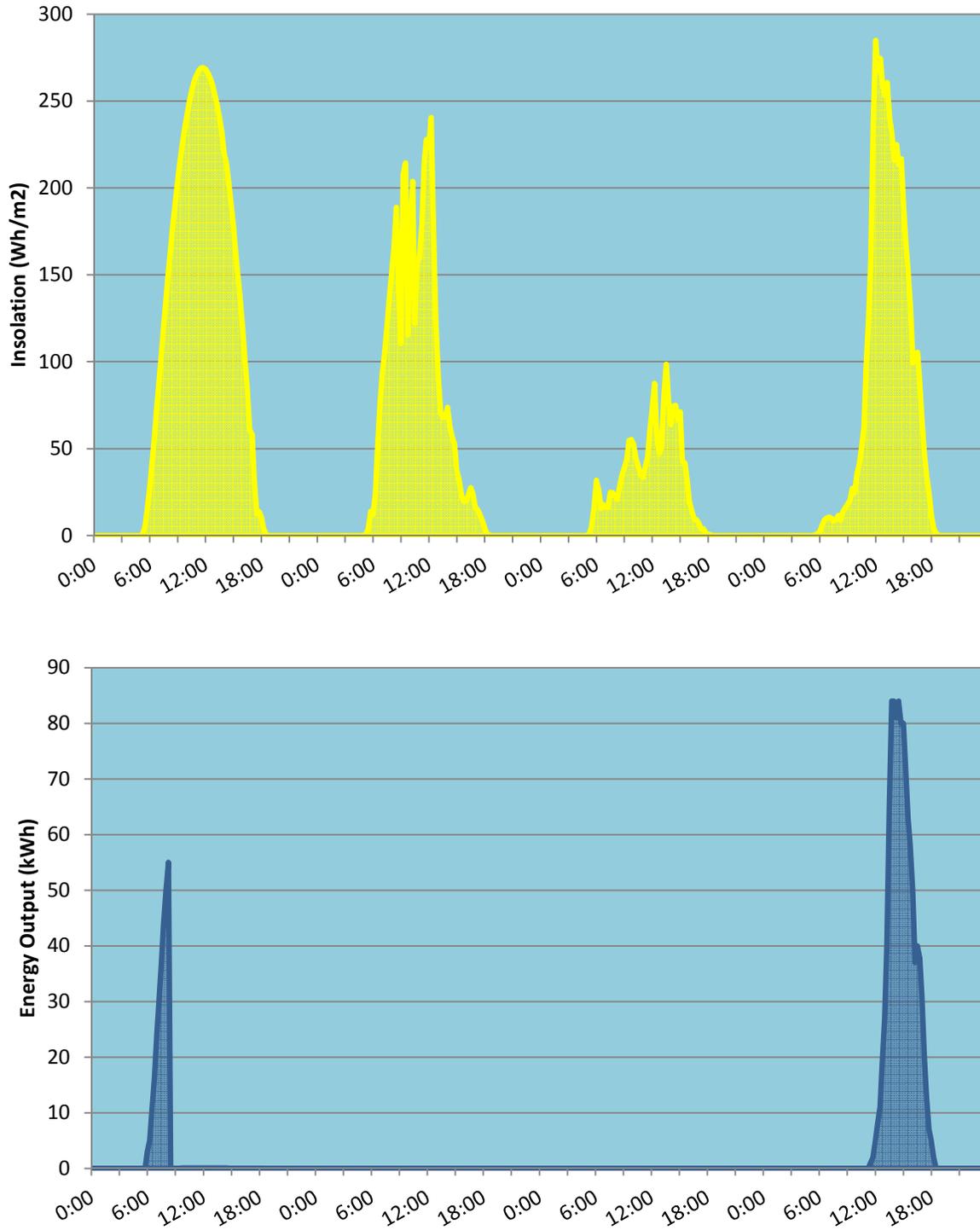
April 11-14, 2011

Figure 9: Hourly profiles for insolation (top) and energy output (bottom) for the time period April 11-14, showing the system maintenance/malfunction beginning around 9 A.M. on the 11th and ending around 12 P.M. on the 14th.

In order to make a more reasonable comparison between SAM and the SunEdison data, we decided to remove days with discrepancies 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. For example, we discarded February 1-4 and 6-13 due to snow cover and April 4, 8, and 11-14 because of system malfunctions. We went through this process for each month, and were left with the comparison shown in Figure 10. The total output is decreased for both SAM and SunEdison due to the removal of flawed days from each dataset; therefore, the graph below is not representative of the expected or measured system output.
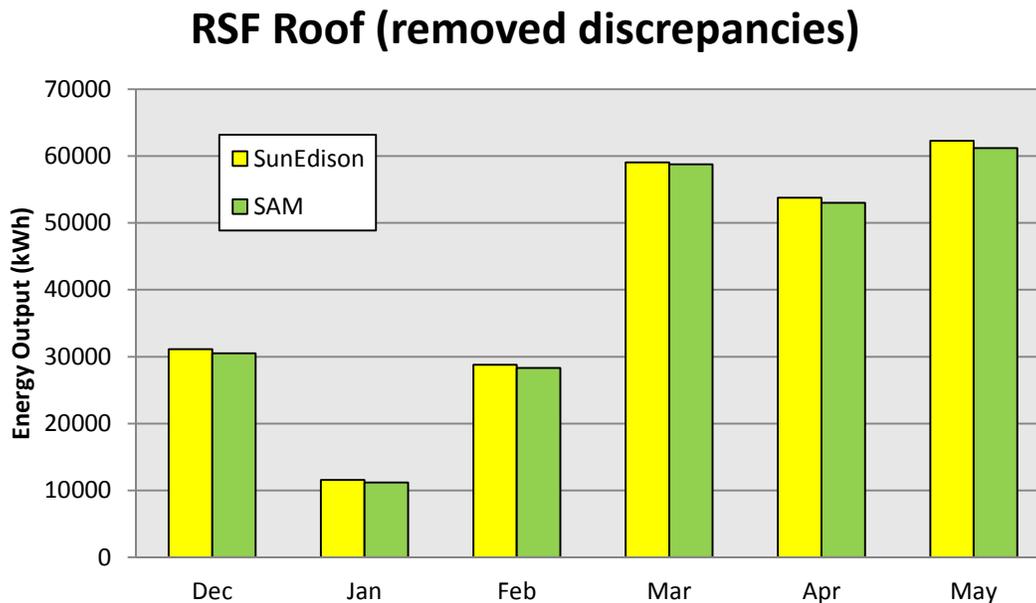
RSF Roof (removed discrepancies)

Figure 10: 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 3.1% of the SunEdison values for every month. However, it should be noted that SAM underestimated the output for each month. Because it is a consistent error, we can increase the accuracy of the model 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. In order to calibrate the total derate factor for the RSF system, we ran a parametric simulation in SAM, changing 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. First, we looked at just the "annual" output error – where annual corresponds to the sum of the outputs for the days without discrepancies during the 6 months that were studied. Figure 11 (below) shows the derate factor calibration by plotting the annual output error against the total derate factor.
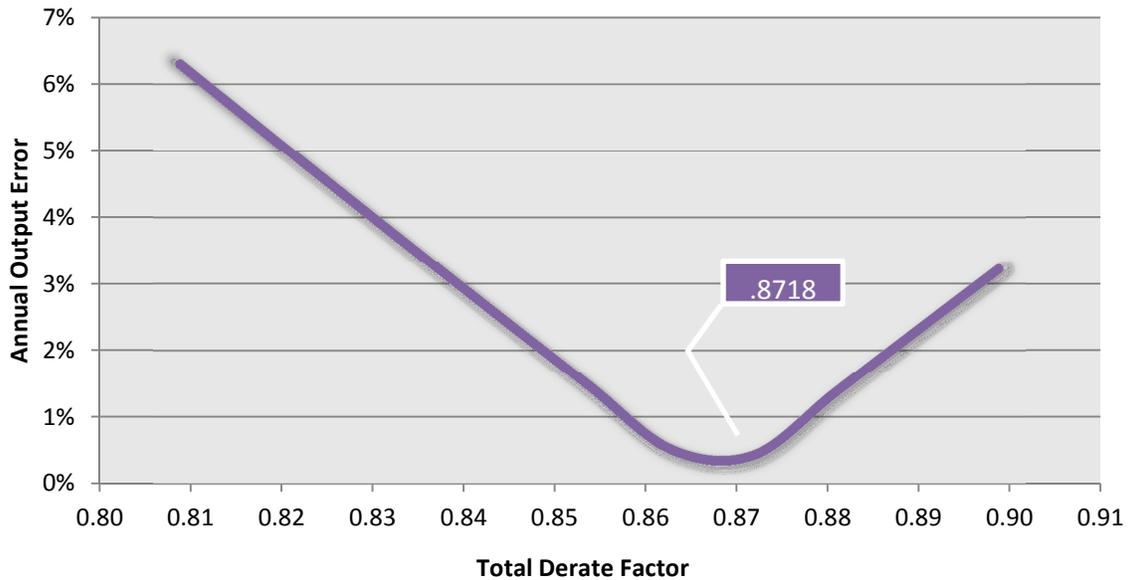
RSF - Derate Factor Calibration

Figure 11: Shows the derate factor calibration by minimizing the total output error

From Figure 11, we determined that the total derate factor should be around 87.2%, which corresponds to a nameplate derate of 97%. In order to check if this was the optimum derate at the monthly level, we followed up with a similar analysis, depicted in Figure 12.
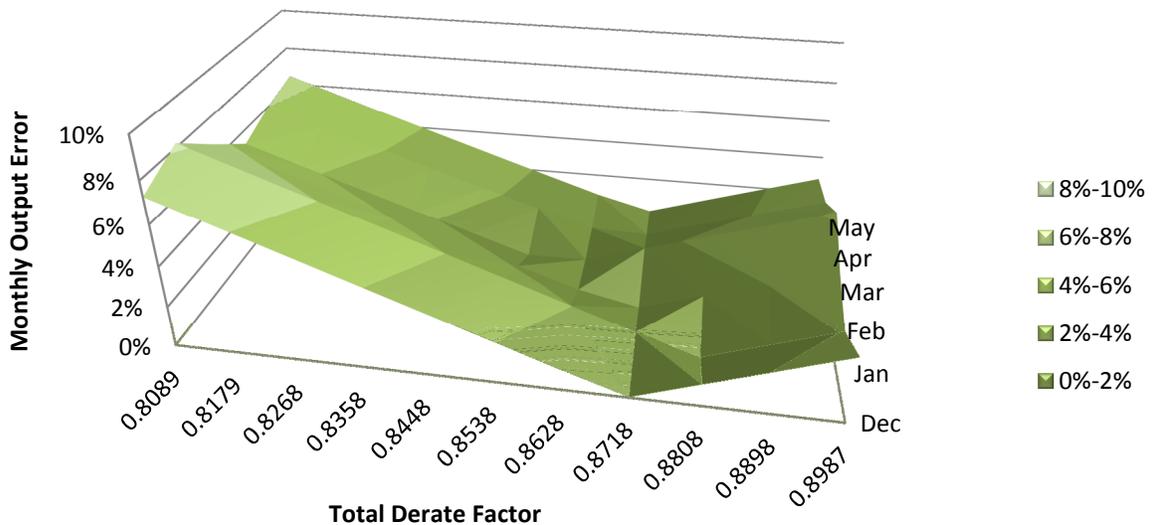
RSF - Monthly Optimum Derate

Figure 12: Shows the derate factor calibration at the monthly level, confirming that .8718 is the optimum total derate factor the RSF roof system

From the "valley" in the surface chart of Figure 12, we can see that the total derate factor that minimizes the monthly output error for just about every month is the same value that minimizes the "annual" output error: 87.2%. If the surface chart had a random or curved valley (minimization path), rather than a straight valley, we would not be able to maintain that the monthly error was due to the indefinite nature of the derate factor.

By calibrating the derate factor, we can make more accurate energy output predictions for the RSF roof system in the future. After the calibration, the final comparison graph for the system is shown below (Figure 13). The SAM estimates are within 1.5% of the SunEdison values for every month.
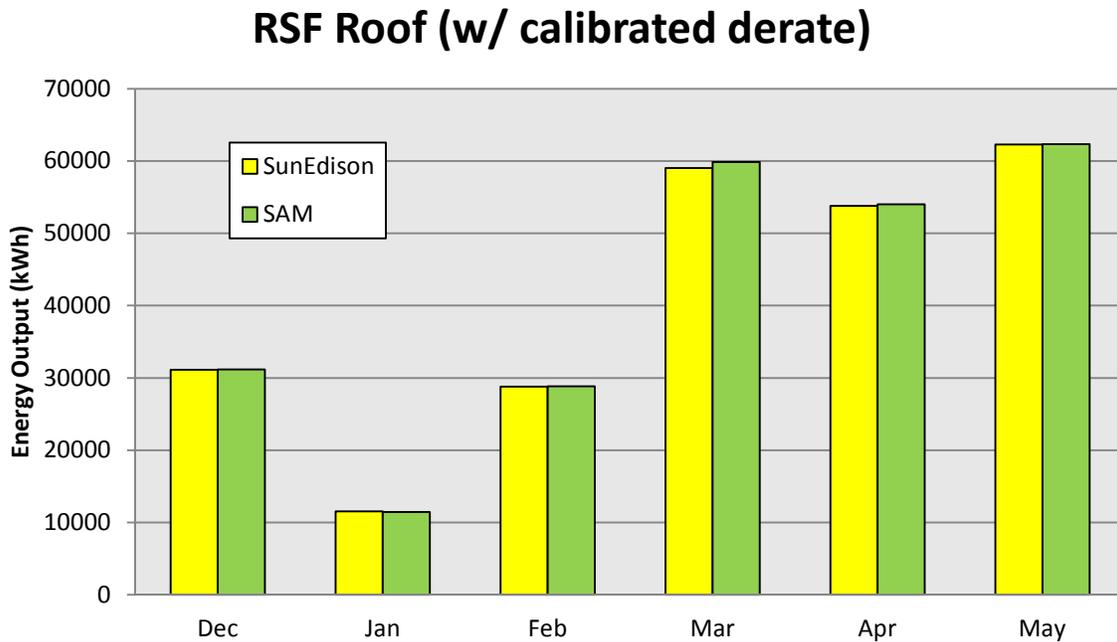

Figure 13: Final comparison graph of the SunEdison measured data vs. the SAM estimates after removing flawed data and calibrating the derate factor for the system.

Conclusions

Using SAM, we modeled the PV system on NREL's RSF roof. The Solon modules used for the array are not currently in the SAM database so we had to create a custom module using the CEC 6 parameter PV module coefficient generator. We were able to model the system with few changes to the default values based on the system specifications provided by SunEdison. After accounting for days that had snow cover or system maintenance, we calibrated the derate value, and were able to get within 1.5% of the measured energy output for each of the 6 months that were studied. This case study raised issues about how best to handle snow cover in future model enhancements – especially when snow cover is a measured value. It is still a good template for a commercial PV array with multiple subsystems. The SAM file associated with this case study is located in the SAM samples folder.

References

[1] VanGeet, O. "ZEB Definitions and Classification System." PowerPoint slides. August 2009. <http://www.govenergy.com/2009/pdfs/presentations/Sustainability-Session08/Sustainability-Session08-VanGeet_Otto.pdf>

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

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

[4] Dobos, A. "An Improved Coefficient Calculator for the CEC 6 Parameter Photovoltaic Module Model." Internal NREL documentation – tool available in SAM, November 2011.

Appendix

Figure 13 shows the SunEdison daily data for both energy output and insolation for March 2011, illustrating what a month without significant data discrepancies looks like.
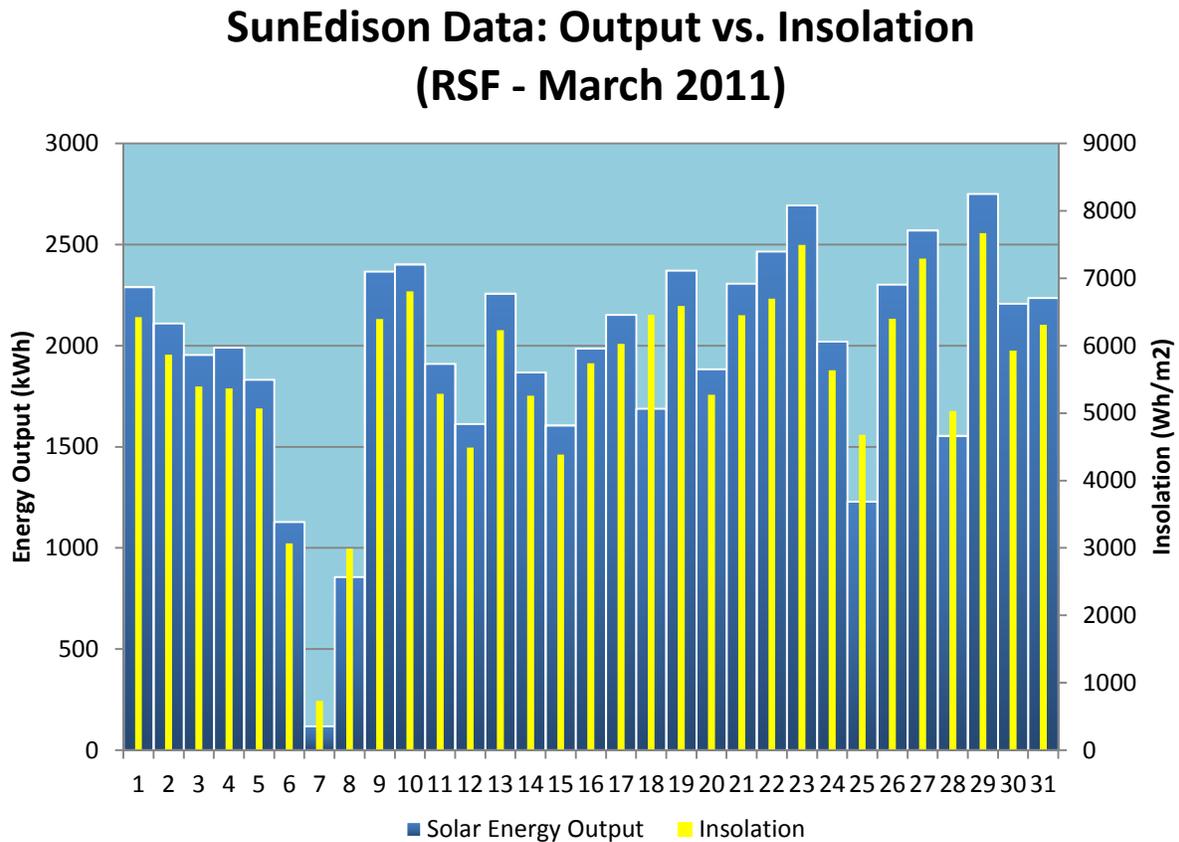

Figure 14: Shows the SunEdison measured energy output and insolation for each day in March 2011