High Penetration PV Initiative, California Solar Initiative Research, Development, Demonstration and Deployment Program

SMUD Contract No. HiP-PV-03

Deliverable VI:

Quantify forecast vs. measure error for PV Production

To validate our forecasts, we turned to a paper by Hoff et al. ("Reporting of Relative Irradiance Prediction Dispersion Error"). In their paper, they determined that the best metrics to use when analyzing the error of an irradiance forecast were Root Mean Square Error (RMSE) over Rated Capacity and Mean Absolute Error (MAE) over average. In the case of irradiance, "capacity" is given as 1000 W/m^2, while average would be the average irradiance over the time interval (typically an hour).

The formulas for calculating these metrics are:

$$\frac{RMSE}{Capacity} = \frac{\sqrt{\frac{\sum_1^N \left(I_t^{test} - I_t^{ref}\right)^2}{N}}}{1000}$$

where I_t^{test} is the forecast irradiance at time t, I_t^{ref} is the measured irradiance at time t, and N is the number of observations.

$$\frac{MAE}{Average} = \left(\frac{1}{\sum_{t=1}^N I_t^{ref}}\right) \sum_{t=1}^{N} \left|I_t^{test} - I_t^{ref}\right|$$

Here are the error metrics for the 66 secondary data acquisition stations (DAS):

MAE (W/m^2)	61.23
MAE/AVERAGE MEASURED IRRADIANCE (W/m^2)	12.9%
RMSE (W/m^2)	111.24
RMSE/1000 (W/m^2)	11.1%
MAE/1000 (W/m^2)	6.1%

Note that we calculated the above metrics using measured and forecast data from 6/1/2012 through 12/12/12. This was the time period for which we had “clean, interpolated” measured irradiance data. “Raw” measured data contained artifacts caused by short-term shadows cast by overhead lines and crosstrees. SMUD and Sandia developed a program to find these shadows, and replace the measured irradiance with an interpolated value.

These same metrics could also be applied to forecasting the power of a PV plant. In this case, capacity would be the rated capacity of the plant (MWdc) and average would be the average measured power (MWdc) over the time interval. Note that since we are using one hour as the interval, if the average power during that a particular hour for a plant was 10 MW, then one could also say that it produced 10 MWh of energy during that hour, since energy = power * time. For this reason, we use “power” and “production” interchangeably.

The following tables present the metrics for the 22 – 40 hour (day-ahead) power/production forecast for the eight FIT PV sites studied in this project. The model was run using “hindcasts” from 5/1/2012 through 5/1/2013 for all the sites except for McKenzie. This last site did not come on line until November 2012; hence our forecasts and related error analysis for McKenzie include only 11/1/2012 through 4/30/2013. Output from the models was then compared with measured production (power) from the sites, provided to NEO by SMUD.

Our metric algorithm eliminated instances when PV plant output and forecast output both equaled zero (i.e., night time hours), when measured output < 1% of rated capacity (thus eliminating early morning and late afternoon low irradiance hours), and when measured output was negative (usually occurred during nighttime but not always). Once all these conditions were filtered, we then lined up the remaining hours of output with the same hours of forecast, and performed our metric calculations.

Table 1

Bruceville (18MW)						
Monthly Hourly Averages	**RMSE (MW)**	**MAE (MW)**	**RMSE/Capacity**	**MAE/Capacity**	**MAE/Average**	**Ave Measured Pwr**
May-12	1.90	1.32	10.5%	7.4%	12.8%	10.33
Jun-12	1.80	0.91	10.0%	5.1%	9.2%	9.89
Jul-12	1.29	0.83	7.2%	4.6%	8.3%	9.93
Aug-12	1.33	0.81	7.4%	4.5%	7.9%	10.25
Sep-12	1.52	0.89	8.4%	5.0%	9.3%	9.61
Oct-12	2.32	1.33	12.9%	7.4%	16.1%	8.24
Nov-12	3.83	3.10	21.3%	17.2%	44.7%	6.95
Dec-12	4.19	3.27	23.3%	18.2%	65.9%	4.96
Jan-13	3.34	2.75	18.5%	15.3%	39.2%	7.01
Feb-13	3.35	2.38	18.6%	13.2%	27.4%	8.67
Mar-13	3.55	2.53	19.7%	14.1%	28.0%	9.03
Apr-13	1.80	1.07	10.0%	5.9%	10.8%	9.91
	RMSE (MW)	**MAE (MW)**	**RMSE/Capacity**	**MAE/Capacity**	**MAE/Average**	**Ave Measured Pwr**
Annual Average	2.52	1.77	14.0%	9.8%	23.3%	8.73

Table 2

Eschinger (15MW)						
Monthly Hourly Averages	**RMSE (MW)**	**MAE (MW)**	**RMSE/Capacity**	**MAE/Capacity**	**MAE/Average**	**Ave Measured Pwr**
May-12	2.72	1.79	18.1%	11.9%	16.3%	10.96
Jun-12	2.63	1.51	17.5%	10.1%	14.9%	10.16
Jul-12	2.24	1.34	14.9%	8.9%	12.1%	11.09
Aug-12	2.48	1.93	16.5%	12.9%	18.2%	10.63
Sep-12	2.89	2.18	19.2%	14.5%	23.0%	9.49
Oct-12	2.82	2.02	18.8%	13.5%	26.0%	7.75
Nov-12	3.65	2.74	24.3%	18.3%	43.1%	6.36
Dec-12	3.98	3.05	26.5%	20.3%	71.4%	4.27
Jan-13	2.76	1.98	18.4%	13.2%	29.5%	6.71
Feb-13	2.90	2.11	19.3%	14.1%	25.1%	8.43
Mar-13	3.63	2.64	24.2%	17.6%	30.0%	8.80
Apr-13	2.97	2.29	19.8%	15.3%	23.2%	9.91
	RMSE (MW)	**MAE (MW)**	**RMSE/Capacity**	**MAE/Capacity**	**MAE/Average**	**Ave Measured Pwr**
Annual Average	2.97	2.13	19.8%	14.2%	27.7%	8.71

Table 3

Boessow (3MW)						
Monthly Hourly Averages	**RMSE (MW)**	**MAE (MW)**	**RMSE/Capacity**	**MAE/Capacity**	**MAE/Average**	**Ave Measured Pwr**
May-12	0.33	0.23	10.9%	7.7%	13.9%	1.67
Jun-12	0.35	0.16	11.6%	5.4%	9.7%	1.66
Jul-12	0.22	0.12	7.4%	3.9%	7.2%	1.64
Aug-12	0.22	0.13	7.4%	4.4%	7.8%	1.71
Sep-12	0.27	0.18	9.0%	6.0%	10.7%	1.68
Oct-12	0.40	0.24	13.5%	8.1%	17.0%	1.44
Nov-12	0.68	0.53	22.6%	17.8%	45.0%	1.18
Dec-12	0.73	0.57	24.4%	19.0%	74.0%	0.77
Jan-13	0.57	0.47	19.2%	15.5%	42.8%	1.09
Feb-13	0.60	0.50	19.9%	16.7%	34.5%	1.45
Mar-13	0.60	0.43	20.0%	14.2%	28.2%	1.52
Apr-13	0.34	0.20	11.3%	6.6%	12.0%	1.64
	RMSE (MW)	**MAE (MW)**	**RMSE/Capacity**	**MAE/Capacity**	**MAE/Average**	**Ave Measured Pwr**
Annual Averages	0.44	0.31	14.8%	10.4%	25.2%	1.45

Table 4

Kammerer (15MW)						
Monthly Hourly Averages	**RMSE (MW)**	**MAE (MW)**	**RMSE/Capacity**	**MAE/Capacity**	**MAE/Average**	**Ave Measured Pwr**
May-12	2.93	1.98	19.5%	13.2%	18.5%	10.67
Jun-12	3.03	1.98	20.2%	13.2%	20.1%	9.88
Jul-12	2.33	1.41	15.5%	9.4%	12.8%	10.98
Aug-12	2.49	1.83	16.6%	12.2%	16.9%	10.84
Sep-12	2.92	2.17	19.5%	14.4%	22.8%	9.52
Oct-12	2.81	2.07	18.7%	13.8%	27.0%	7.65
Nov-12	3.77	2.82	25.1%	18.8%	44.3%	6.35
Dec-12	3.96	2.98	26.4%	19.9%	71.9%	4.15
Jan-13	3.49	2.54	23.3%	16.9%	36.9%	6.87
Feb-13	3.50	2.61	23.3%	17.4%	31.2%	8.38
Mar-13	3.56	2.62	23.7%	17.5%	29.6%	8.88
Apr-13	3.06	2.26	20.4%	15.0%	23.1%	9.78
	RMSE (MW)	**MAE (MW)**	**RMSE/Capacity**	**MAE/Capacity**	**MAE/Average**	**Ave Measured Pwr**
Annual Averages	3.15	2.27	21.0%	15.1%	29.6%	8.66

Table 5

Point Pleasant (1MW)						
Monthly Hourly Averages	**RMSE (MW)**	**MAE (MW)**	**RMSE/Capacity**	**MAE/Capacity**	**MAE/Average**	**Ave Measured Pwr**
May-12	0.11	0.08	11.0%	7.9%	15.5%	0.509
Jun-12	0.11	0.07	10.5%	7.5%	13.6%	0.551
Jul-12	0.12	0.08	11.7%	8.4%	16.6%	0.509
Aug-12	0.10	0.08	10.3%	7.5%	14.7%	0.511
Sep-12	0.11	0.09	11.0%	8.9%	16.4%	0.539
Oct-12	0.13	0.11	13.4%	11.1%	20.8%	0.535
Nov-12	0.25	0.20	24.6%	20.0%	48.5%	0.413
Dec-12	0.23	0.18	22.8%	18.1%	52.5%	0.344
Jan-13	0.19	0.16	18.5%	16.0%	36.6%	0.437
Feb-13	0.19	0.16	19.1%	15.8%	31.3%	0.505
Mar-13	0.20	0.15	20.0%	15.3%	29.6%	0.516
Apr-13	0.14	0.10	14.0%	9.6%	17.4%	0.553
	RMSE (MW)	**MAE (MW)**	**RMSE/Capacity**	**MAE/Capacity**	**MAE/Average**	**Ave Measured Pwr**
Annual Averages	0.16	0.12	16%	12%	26%	0.49

Table 6

Kost (3MW)						
Monthly Hourly Averages	**RMSE (MW)**	**MAE (MW)**	**RMSE/Capacity**	**MAE/Capacity**	**MAE/Average**	**Ave Measured Pwr**
May-12	0.34	0.21	11.3%	6.9%	13.6%	1.54
Jun-12	0.31	0.15	10.4%	5.0%	9.4%	1.59
Jul-12	0.23	0.13	7.8%	4.4%	8.3%	1.57
Aug-12	0.22	0.14	7.4%	4.6%	8.3%	1.66
Sep-12	0.28	0.16	9.3%	5.3%	10.5%	1.52
Oct-12	0.38	0.24	12.5%	7.9%	17.0%	1.40
Nov-12	0.68	0.53	22.6%	17.6%	43.4%	1.22
Dec-12	0.69	0.54	23.1%	18.1%	63.2%	0.86
Jan-13	0.59	0.49	19.6%	16.4%	41.5%	1.18
Feb-13	0.57	0.48	18.9%	15.9%	32.2%	1.48
Mar-13	0.59	0.42	19.8%	13.9%	28.0%	1.49
Apr-13	0.32	0.20	10.7%	6.7%	12.0%	1.66
	RMSE (MW)	**MAE (MW)**	**RMSE/Capacity**	**MAE/Capacity**	**MAE/Average**	**Ave Measured Pwr**
Annual Average	0.43	0.31	14%	10%	24%	1.43

Table 7

Dillard (9.4MW)						
Monthly Hourly Averages	**RSME (MW)**	**MAE (MW)**	**RSME/Capacity**	**MAE/Capacity**	**MAE/Average**	**Ave Measured Pwr**
May-12	2.01	1.38	21.4%	14.7%	21.6%	6.42
Jun-12	1.98	1.28	21.1%	13.6%	19.8%	6.46
Jul-12	1.95	1.25	20.8%	13.3%	19.9%	6.28
Aug-12	1.97	1.44	21.0%	15.4%	22.7%	6.37
Sep-12	2.24	1.68	23.8%	17.9%	29.2%	5.74
Oct-12	1.98	1.44	21.1%	15.3%	29.9%	4.80
Nov-12	2.48	1.85	26.3%	19.6%	47.6%	3.88
Dec-12	2.71	2.06	28.8%	21.9%	82.4%	2.50
Jan-13	2.12	1.56	22.5%	16.6%	37.5%	4.17
Feb-13	2.25	1.68	24.0%	17.9%	32.3%	5.20
Mar-13	2.39	1.74	25.4%	18.5%	31.3%	5.55
Apr-13	2.18	1.58	23.2%	16.9%	26.5%	5.97
	RSME (MW)	**MAE (MW)**	**RSME/Capacity**	**MAE/Capacity**	**MAE/Average**	**Ave Measured Pwr**
Annual Average	2.19	1.58	23.3%	16.8%	33.4%	5.28

Table 8

McKenzie (30MW)						
Monthly Hourly Averages	**RMSE (MW)**	**MAE (MW)**	**RMSE/Capacity**	**MAE/Capacity**	**MAE/Average**	**Ave Measured Pwr**
May-12	[redacted]					
Jun-12	[redacted]					
Jul-12	[redacted]					
Aug-12	[redacted]					
Sep-12	[redacted]					
Oct-12	[redacted]					
Nov-12	6.51	4.92	21.7%	16.4%	43.7%	11.28
Dec-12	8.02	6.24	26.7%	20.8%	73.3%	7.73
Jan-13	5.27	4.14	17.6%	13.8%	30.0%	13.79
Feb-13	5.26	4.37	17.5%	14.6%	24.8%	17.64
Mar-13	7.26	5.51	24.2%	18.4%	30.0%	18.40
Apr-13	8.87	7.42	29.6%	24.7%	44.3%	16.75
	RMSE (MW)	**MAE (MW)**	**RMSE/Capacity**	**MAE/Capacity**	**MAE/Average**	**Ave Measured Pwr**
Annual Average	6.87	5.43	22.9%	18.1%	41.0%	14.27

Table 9

Annual Metrics						
FIT Site	**RMSE**	**MAE**	**RMSE/Capacity**	**MAE/Capacity**	**MAE/Average Measured Power**	**Ave. Measured Power**
Bruceville (18MW)	2.52	1.77	14.0%	9.8%	23.3%	8.73
Eschinger (15MW)	2.97	2.13	19.8%	14.2%	27.7%	8.71
Boessow (3MW)	0.44	0.31	14.8%	10.4%	25.2%	1.45
Dillard (9.4MW)	2.19	1.58	23.3%	16.8%	33.4%	5.28
Kammerer (15MW)	3.15	2.27	21.0%	15.1%	29.6%	8.66
Point Pleasant (1MW	0.16	0.12	15.6%	12.2%	26.1%	0.49
Kost (3MW)	0.43	0.31	14.4%	10.2%	23.9%	1.43
McKenzie (30 MW)	6.87	5.43	22.9%	18.1%	41.0%	14.27
Aggregate*	**NA**	**NA**	**17.6%**	**12.7%**	**27.0%**	**NA**
***Does not include McKenzie.**						

A comparison of the metrics between irradiance and PV production indicates that the irradiance forecasts were more accurate:

Table 10

	Irradiance	**PV Production**
MAE/AVERAGE MEASURED	12.9%	27.0%
RMSE/CAPACITY	11.1%	17.6%
MAE/CAPACITY	6.1%	12.7%

There are a number of possible reasons. First, NEO could not know when a particular sub-array of a PV plant was offline (for maintenance, for example; much of this time was during the startup period for these systems). Our metric algorithm would not have eliminated these time periods of partial PV plant output, and hence they would have been compared to the model's full output forecast, thus introducing error. Second, NEO did not receive exact specifications for a number of the FIT sites (especially the four single-axis tracking sites), and hence we had to use best-fit specifications for modules, array layout, etc., when creating the PV plant models. For all of the single axis tracking systems we assumed that they employed a backtracking algorithm, however we had no confirmation of this and we had to assume the characteristics of the backtracking algorithm. If the actual components at a FIT site varied significantly from our best-fit components, errors would have been introduced. Finally, we suspect our models—especially for the tracking systems—could have used more adjusting to better fit the measured production. As just one example, here is a series of clear-sky days at Kammerer, one of the single-axis tracking sites:

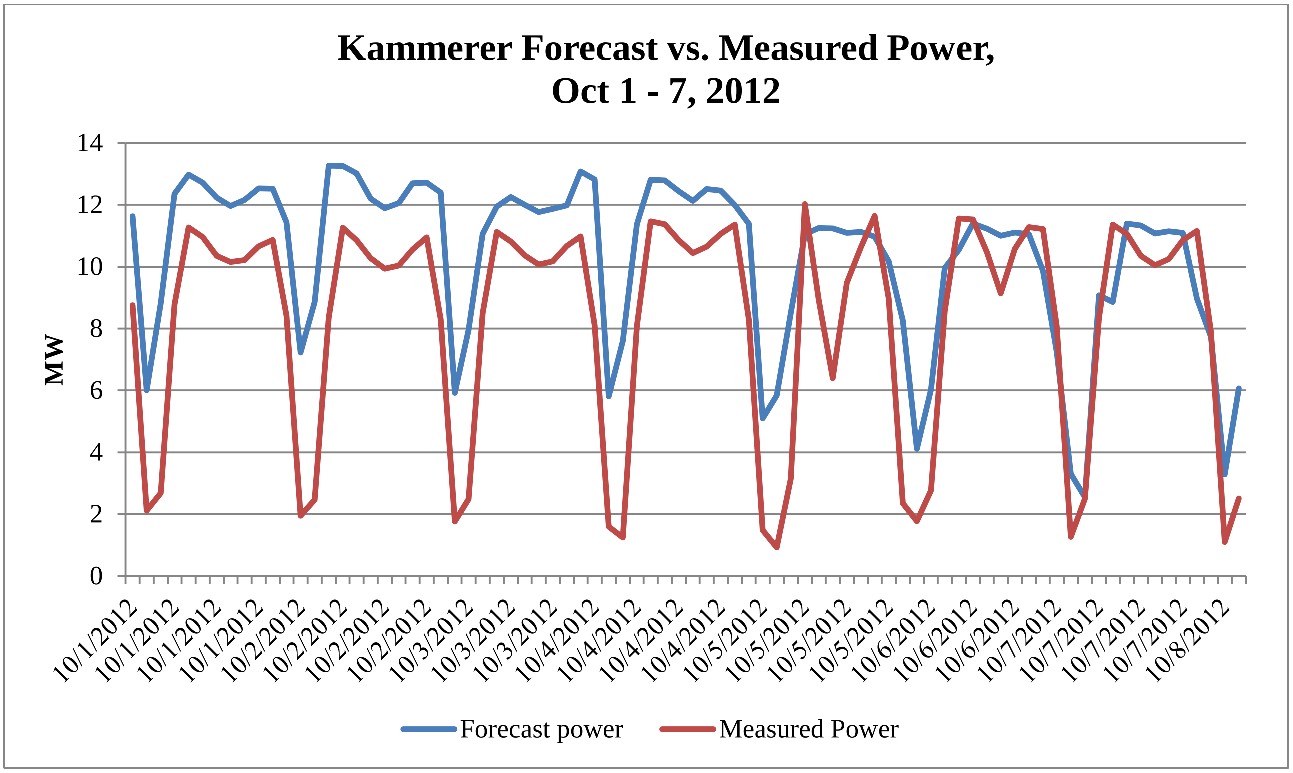

Figure 1

One can see that for the first four days, the model overestimates output, both during the peak hours and especially during the “troughs” that occur early and late in each day. However, for the final three days, the model is much closer to the measured power. The variation in forecast peak power can be attributed to forecast irradiance, as that was also lower later in the week, as can be seen in the following graph:

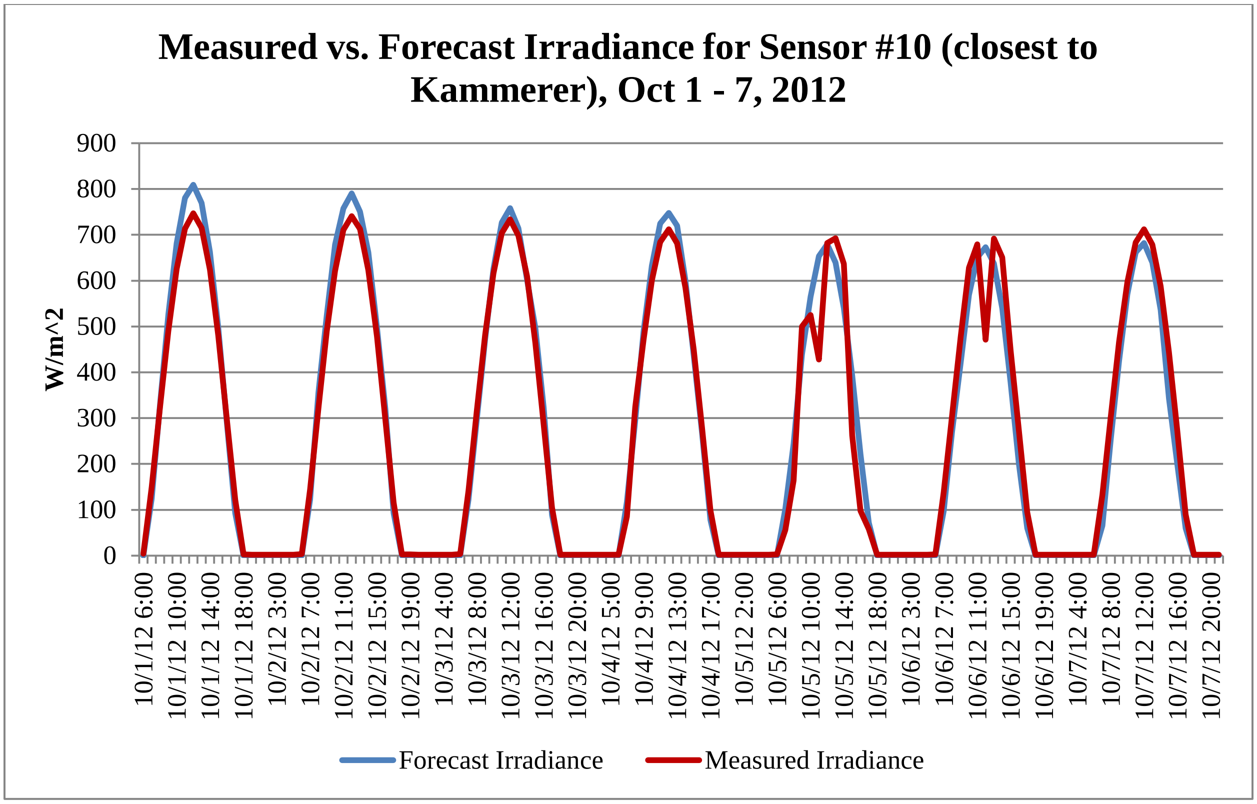

Figure 2

However, the decline in forecast peak irradiance does not explain the large deltas that occur early in the week. Also of note: the measured irradiance declines during the week, but the measured power remains essentially unchanged. Thus, we are left with a mystery as to why the forecast power follows the forecast irradiance (as one would expect, since the former is dependent upon the latter), but the measured power does not follow the measured irradiance.

Finally, this week is a good example of how a slight disagreement between forecast and measured irradiance manifests itself for only a couple of hours around local noon, whereas the same magnitude disagreement between forecast and measured power extends over the entire day. This extended period directly contributes to the relatively large error metrics for the power forecast.

Next, the following graph illustrates how the output of each FIT site varies over the year. The sharp decline in output during the winter months is attributable to both cloudier weather and to shorter daylight hours. This sharp decline (aproximately 50%) in average output is inversely proportional to the MAE/average power metric, as can be seen in the next graph. At this time, we have no way of knowing exactly how much error to attribue to shorter days and how much to cloudier weather. However, one can see that the two metrics related to capacity do not vary nearly as much, giving some indication that the shorter days (and hence lower average power output) contribute more to the MAE/average error than the increase in clouds. This gives some validity to the accuracy of our forecasts vis a vis cloud cover.

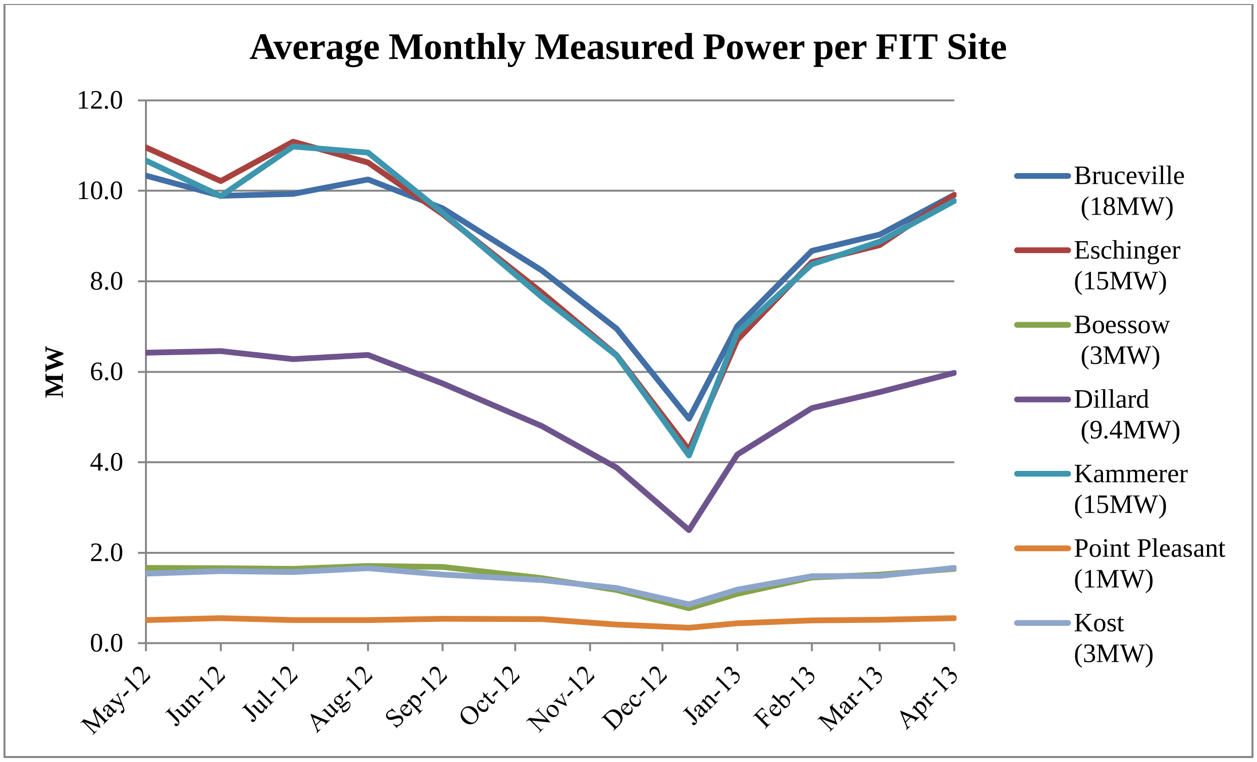

Figure 3

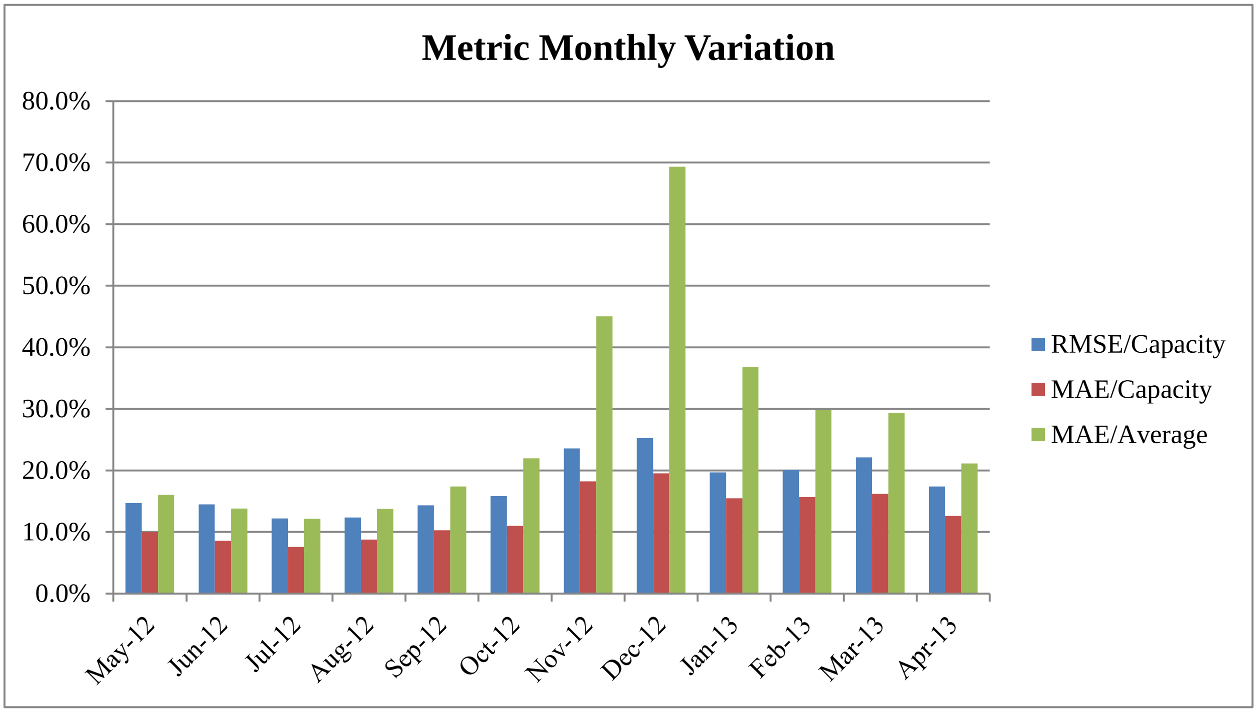

Figure 4

We could also see from our analysis that our fixed-axis model performed better than our single-axis tracking model (see the two scatter plots below). Again, part of this difference could be caused by inaccurate system specifications for the tracking arrays, and part could be the tracking model itself.

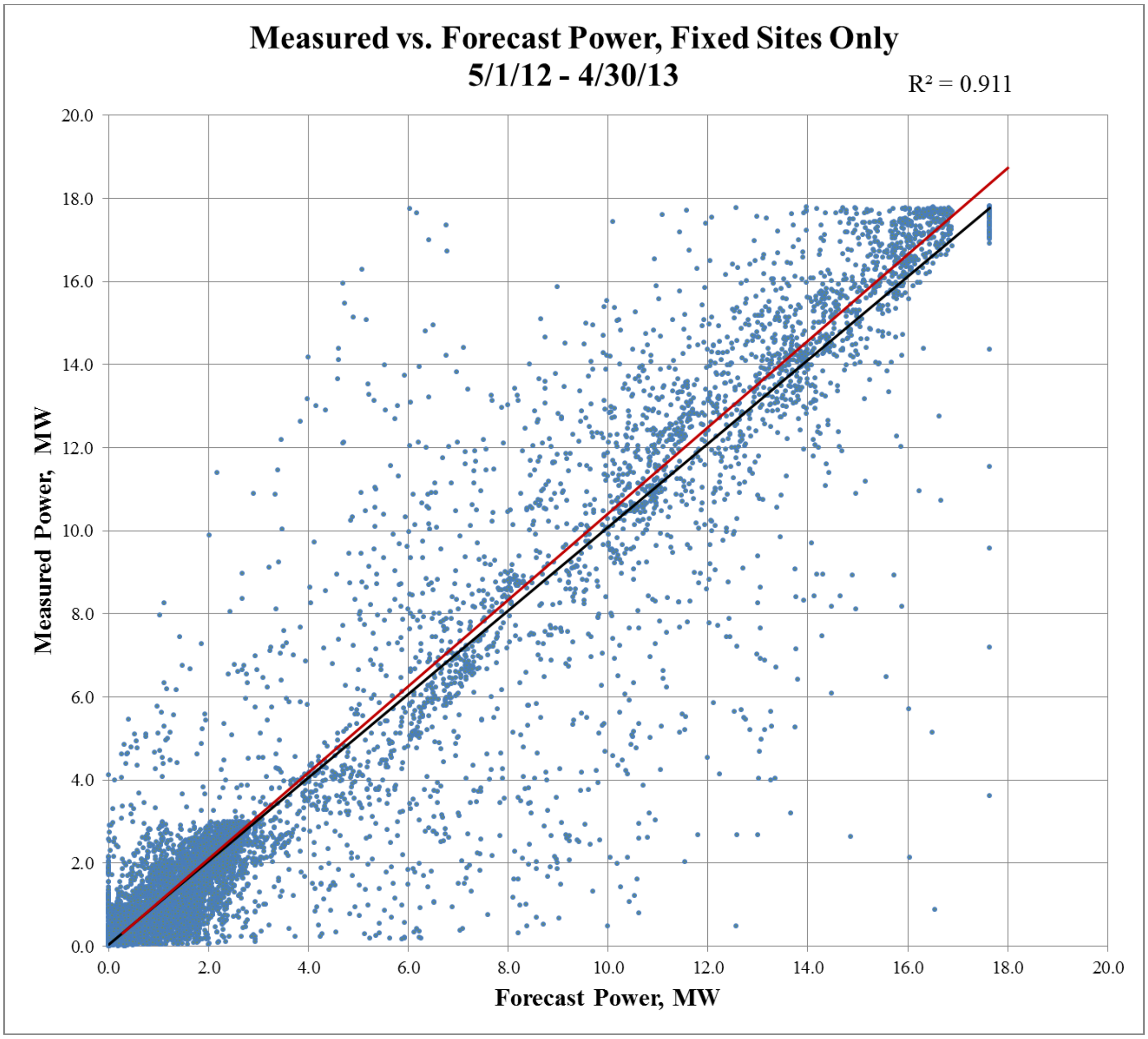

Figure 5

Note that the large cluster of points at low power levels are due to the fact that of the four fixed arrays (Bruceville, Boessow, Point Pleasant and Kost), three were relatively small (3 MW or less). Thus, the points from these relatively small systems all occur in the lower left quadrant of this plot.

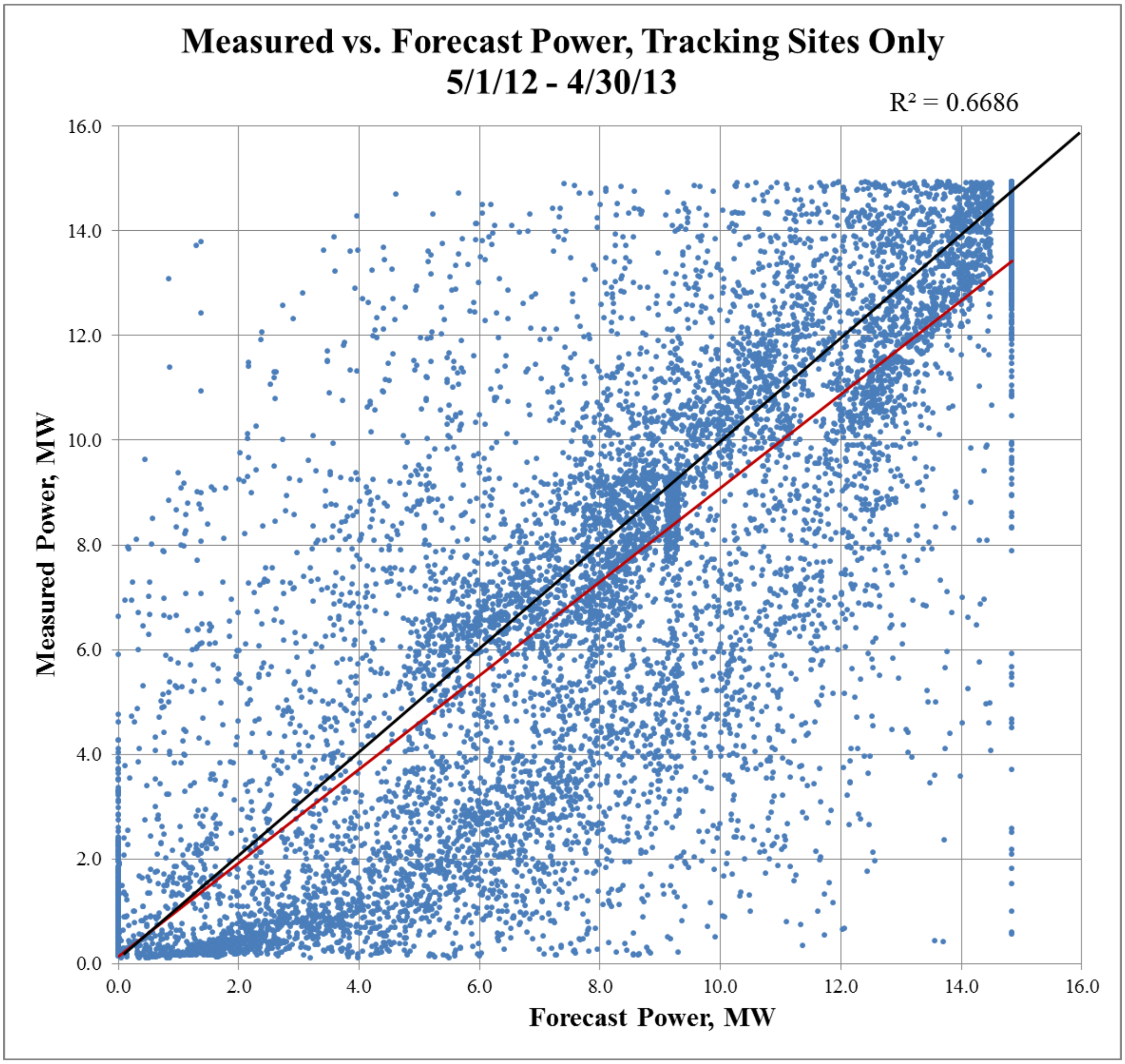

Figure 6

This plot of the tracking systems includes Kammerer, Eschinger and Dillard. Note the relatively low R^2 (coefficient of determination) value. This value indicates how closely data points fit a line, i.e., an R^2 value equal to one would indicate a perfect fit and hence perfect forecast (the black line in the plot).

Finally, the consistency of the irradiance models' and PV power models' metrics across the different sensors and FIT sites, respectively, is in itself an indication of the validity of the models. For example, the standard deviation of the MAE error for the 66 sensors was only 7.58 W/m^2, with an average MAE of 61.23 W/m^2. Likewise, the four MAE/averages for the fixed-array FIT sites all fell between 23.3% and 26.1%. The rest of the metrics exhibited similar consistency. Therefore, we conclude that our models do provide forecasts consistently, with our irradiance forecast performing the best, followed by our fixed array model, and then the single-axis tracking model.

Error analysis for our 0 – 3 hour PV production forecasts was performed in a similar manner to the day-ahead forecasts. Note that these forecasts produce power estimates in 15-minute increments, whereas measured power was only provided in hourly increments. To adjust for this, we assumed that the power for each hour remained the same for each 15-minute increment within that hour. This in itself may have increased the magnitude of the errors. The results of the error analyses are displayed in the table and graph below. The McKenzie FIT site is not included, since it did not come on-line until mid-November 2012.

Table 11

	0 - 3 Hour Forecast Metric Summary					
FIT Site	**RMSE**	**MAE**	**RMSE/Capacity**	**MAE/Capacity**	**MAE/Average Measured Power**	**Ave. Measured Power**
Bruceville (18MW)	3.57	2.91	19.8%	16.2%	33.3%	8.93
Eschinger (15MW)	3.09	2.12	20.6%	14.2%	22.9%	9.28
Boessow (3MW)	0.60	0.49	19.9%	16.2%	32.0%	1.51
Dillard (9.4MW)	2.53	2.07	26.9%	22.1%	38.3%	5.41
Kammerer (15MW)	3.13	2.18	20.9%	14.6%	24.9%	9.15
Point Pleasant (1MW)	0.23	0.18	22.9%	17.9%	36.4%	0.49
Kost (3MW)	0.50	0.38	16.7%	12.7%	27.7%	1.37
Aggregate	**NA**	**NA**	**21.1%**	**16.2%**	**30.8%**	**NA**

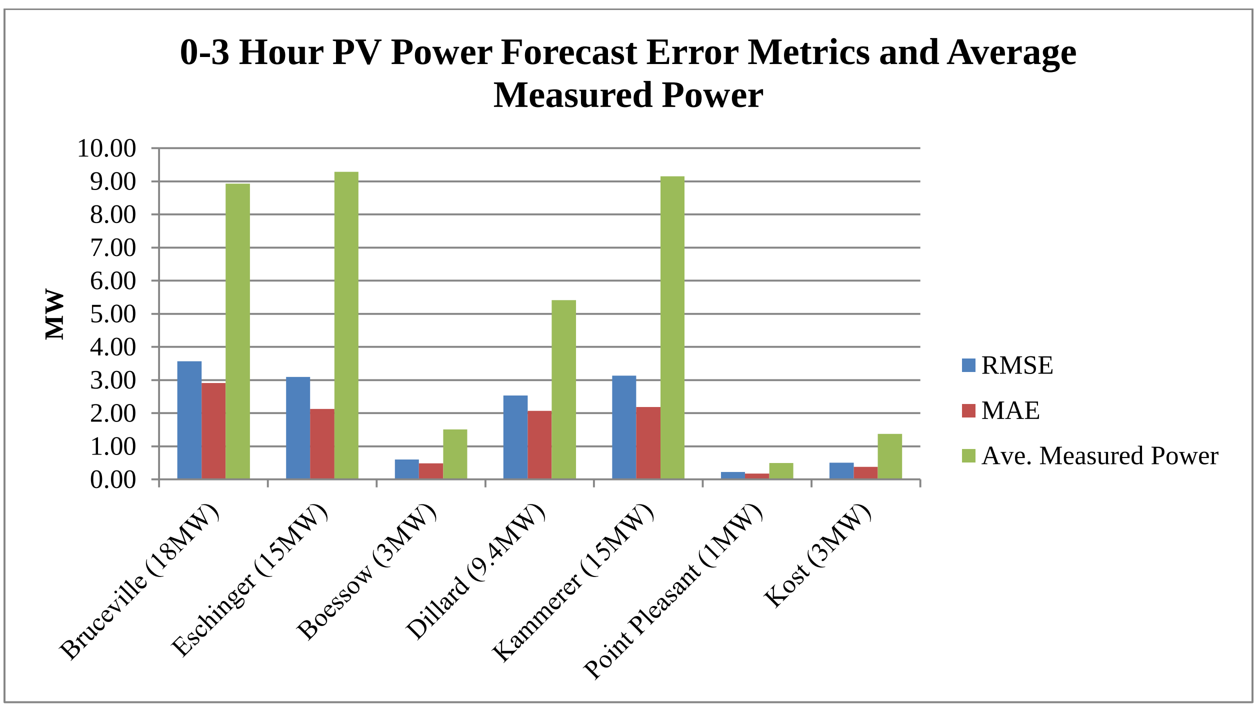

Figure 7

Finally, the table 12 below summarizes the error metrics for the three forecasts. It is clear that the irradiance day-ahead forecast yields the best aggregate results, followed by our day-ahead PV production forecasts, and then the 0 – 3 hour PV production forecasts.

Table 12

	Day Ahead Irradiance	Day Ahead PV Production Forecast	0 – 3 Hour PV Production Forecast
MAE/AVERAGE MEASURED	12.9%	27.0%	30.8%
RMSE/CAPACITY	11.1%	17.6%	21.1%
MAE/CAPACITY	6.1%	12.7%	16.2%

Our 0 – 3 hour forecasts are based on a neural network model that "learns" from measured irradiance data from sensors in the grid cells adjacent to each PV FIT site. This is a completely different methodology from our day-ahead forecasts, which begin with NDFD weather forecasts. Hence, we believe that the 5 km special resolution of our sensor network was the primary cause for the limited accuracy of our short-term predictions. We conclude that this is a function of our sensor spacing relative to typical cloud size.

It should be noted that the primary purpose of the sensor grid (or the SMUD-NEO Irradiance Network, "SNI") in Sacramento is to measure irradiance and temperature data over a large area at a high temporal rate and for multiple years. For future work that specifically focuses on short-term forecasting, we would recommend a denser network of sensors in close proximity to PV plants. Such a network would have a higher likelihood of capturing shading events caused by the motion of smaller clouds, and hence would provide more accurate input into our neural network model.