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Calculating a Dependable Solar Generation Curve for SCE's Preferred Resources Pilot

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Calculating a Dependable Solar Generation Curve

ABSTRACT

As California moves toward a low-carbon future, the state and Southern California Edison (SCE) are increasingly looking to clean sources of energy to meet energy and reliability needs. Several performance assumptions have been made about clean distributed energy resources (DERs). In particular, state agencies have asked utilities to place increased reliance on DERs to meet the needs resulting from the closures of ocean cooled power plants. SCE was faced with the unique opportunity, which is pursued through its Preferred Resources Pilot (PRP), to investigate in advance of full dependence on DERs if these DERs can perform reliably, in an integrated controlled manner, to offset projected electrical demand growth in an area served by the Johanna and Santiago (J-S Region) substations.

The purpose of this document is to present the conclusions of a solar dependability study that will change how solar generation is credited in distribution planning and DER acquisition. Within SCE's territory, many customers have installed photovoltaic (PV) systems. These PV systems do not have meters visible to SCE. Therefore accounting for the dependable contribution of these PV systems to serving customer load is accomplished through an estimating process. Currently, SCE uses a single assumed peak solar dependable delivery amount across its territory in distribution planning. The current assumption is that PV systems produce 17% of their nameplate capacity at the hour of peak solar irradiation (Figure 1).[1] While a single PV system may have a 17% dependability level, this amount is likely underestimating the aggregate contribution from multiple systems. To solve this potential underestimation, SCE measured actual solar performance in the PRP region for existing metered systems, quantified the amount of generation from solar, established a confidence level across the metered systems, and then extrapolated the solar production level to the non-metered systems. Measurement was constrained by the small fraction of solar installations where SCE had access to meter data for solar generation. Notwithstanding this constraint, this study found that historically at the hour of peak solar irradiance, 95 percent of the solar systems in the PRP region (in June-Sept) are expected to produce at least 40 percent of their nameplate capacity. These results are highly location specific and therefore, it would be expected that PV system dependability would be higher inland from the PRP regions.

The implications of this dependability study resulted in changes in how PV is factored into distribution planning and acquisition for the PRP region. It is recommended that regional PV system dependability levels be further developed for the various SCE regions.

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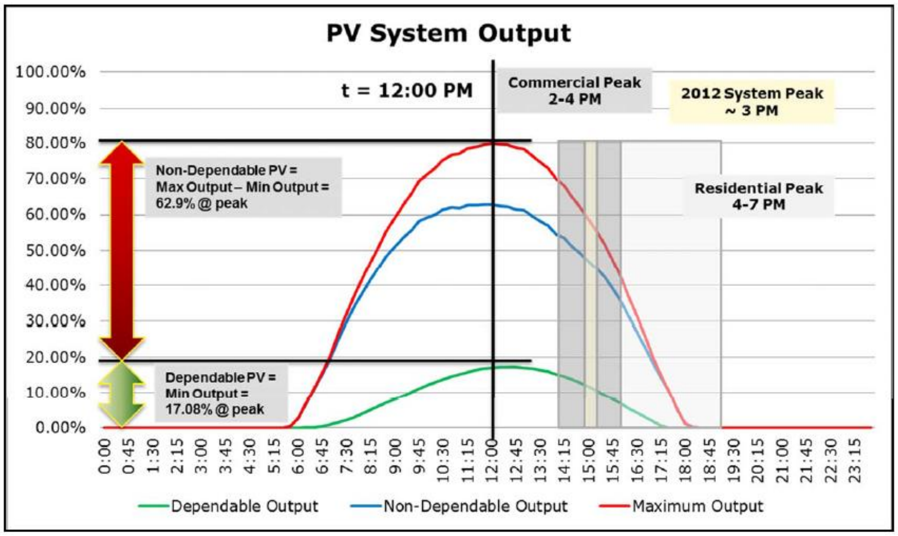
[1] The "non-dependable" and "dependable" solar PV generation values were calculated by the Distribution Engineering team for solar PV generators sized 1 MW or smaller. On average, Distribution Engineering has found that approximately 17% of solar PV nameplate generation capacity can be considered "dependable" in SCE's service territory. The "non-dependable" generation is the difference between the maximum output as a function of nameplate capacity and the "dependable" portion (minimum).

Figure 1: SCE Transmission System Study Shows Average Peak Dependability of 17%

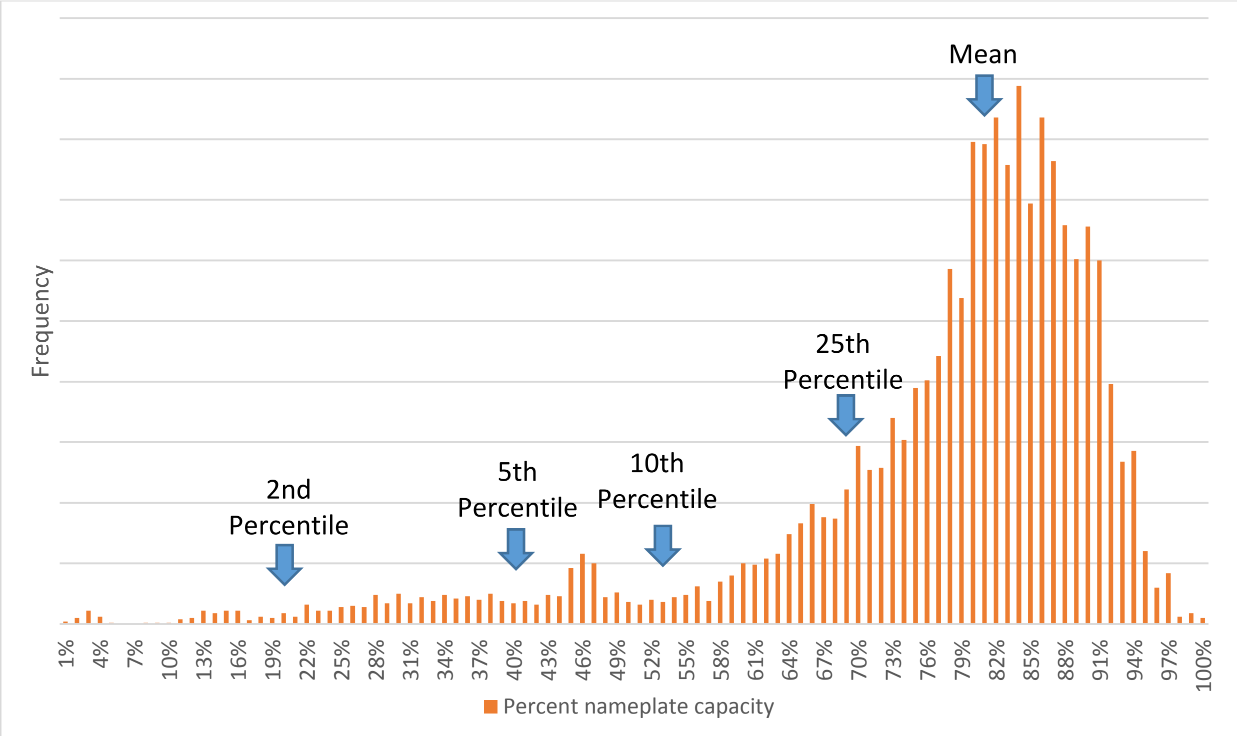


Development of Method

This paper illustrates a process for calculating dependable solar production for a region. Since solar generation is driven by the intensity of the sunlight on the solar panels (the rate of radiant flux on an area is referred to as irradiance), statistics may be applied to produce locational seasonal hourly production curves and informed by establishment of a confidence levels. This process produces an estimate of how much energy will be generated from the non-metered photovoltaic (PV) system. Many PV systems within SCE's territory do not have meters visible to SCE. These PV systems are "behind-the-meter" (BTM) solar resources located at a customer's facility. The PV systems are called BTM resources because the solar generation is behind the SCE customer meter and serves part of the customer's on-site load.

The statistical approach used was percentile as opposed to a confidence interval around a mean based on standard deviation since a standard deviation assumes a normal distribution of the data. The percentile was based on the solar resource output on any given day and time below the 5 percent line and above the line 95 percent line at any time. The generation output of solar at a particular time is not a normal curve, however, and a histogram of the data shows a long left tail (Figure 2). Because the data is not normally distributed, a standard deviation approach is not appropriate. Instead, the analysis uses the actual pool of data to determine the points of different "percentiles", below which a certain number of data points fall, and therefore below which a certain percent of the data can be expected to fall in the future. For example, the 5th percentile of a data set is the point where 5 percent of the quantity of data points fall below and 95 percent of the data points fall above. The 50th percentile is the same as the median (the point at which fifty percent of the data fall below and fifty percent fall above).

Figure 2: Hourly percent nameplate capacity histogram at HE 13:00 (data from June-Sept 2014 & 2015, PDT)



If SCE is to rely on solar generation to meet the needs of the region, it is important to have high confidence that the generation will perform as expected on a peak day. Furthermore, the data in this pool comes from BTM solar customers which are generally small but numerous. SCE does not have operational control of these resources and the broad variation in their maintenance, operation, and outages make their generation more difficult to predict.

This analysis can be produced for any percentile level (ex. the fifth percentile curve for which 95% of the systems will generate at a level higher than the curve or the 25th percentile curve for which 75% of the systems will generate at a level higher than the curve). In renewable energy project finance, 1st, 10th, and 50th percentiles are often used to model the amount of revenue a system could generate under different production assumptions.[2]

SCE used the fifth percentile curve to determine the dependable solar generation (in terms of percent of nameplate capacity) over time. SCE used this curve to calculate the impact of solar generation on future electricity demand the PRP region in the Portfolio Design Report.

[2] National Energy Laboratory, "P50? P90? Exceedance Probabilities Demystified," https://financere.nrel.gov/finance/content/p50-p90-exceedance-probabilities-demystified, October 3, 2011, Accessed June 21, 2017.

Methodology

Data Sources

Most customers with BTM PV systems do not provide SCE data on their solar generation. SCE has access only to the customers' on-site energy use through the SCE meter, which is net energy use of the customer's load and generation combined. A small subset of customers that participate in the California Solar Initiative (CSI) program that selected the Performance Based Incentive (PBI) do provide separate solar generation data to SCE. The data analyzed in this paper is from CSI PBI customers in the Johanna and Santiago substation areas.

Because the PRP is a summer-peaking region, the data set for the analysis was from June through September of 2014 and 2015. The data set includes between 30 and 45 systems reporting data each month which ranged in size from 18 kW to 998 kW. Further details on data quality and clean-up can be found in Appendix A.

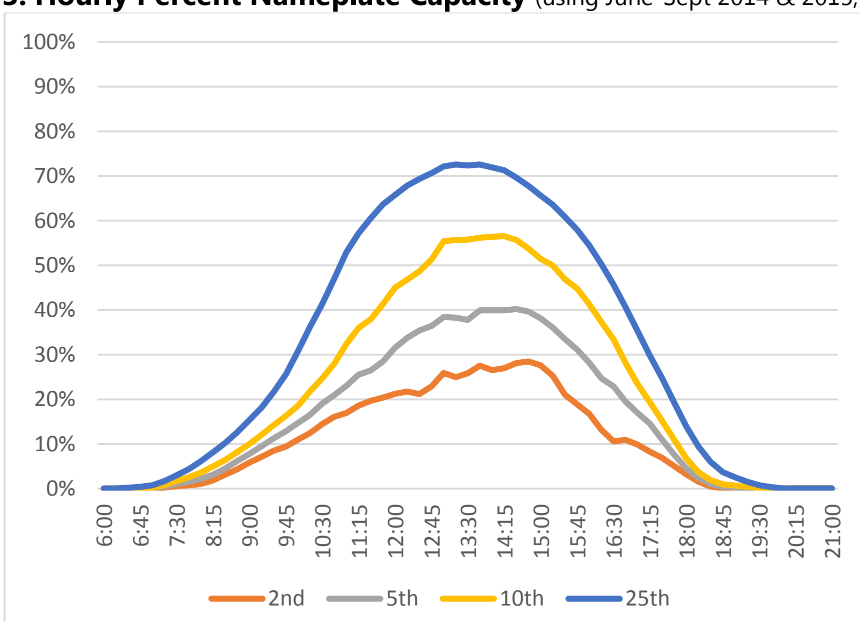
Calculations

The data for each solar resource is recorded in kilowatt hours (kWh) of energy generated at 15 minute intervals. In order to translate those numbers to a percent of nameplate capacity, each interval was multiplied by four to convert to kilowatts (kW). Then the kW were divided by that individual resource's nameplate capacity (the CEC-AC rating). Next, the fifth percentile of the distribution was calculated at each time interval to produce an hourly production curve for the day. The percentile curve analysis was repeated using the second, tenth and twenty-fifth percentiles.

Results

Figure 3 represents the second, fifth, tenth, and twenty-fifth percentile curves for the solar generation in terms of nameplate capacity in the PRP region.

Figure 3: Hourly Percent Nameplate Capacity (using June-Sept 2014 & 2015, H.E., PDT)



The fifth percentile curve peaks at Hour Ending (HE) 14:00 (Pacific Daylight Time) and drops to zero by HE 19:00. Note that 'hour ending' means the hour ending at that time. HE 14:00 is the hour between 1pm and 2pm. This graph indicates that an individual BTM solar resource on any given day and time is expected to be below the line 5 percent of the time and above the line 95 percent of the time. In HE 14:00, 95 percent of the solar systems in the PRP region (in June-Sept) are expected to produce at least 40 percent of their nameplate capacity.

The California Public Utilities Commission (CPUC) creates monthly Qualifying Capacities for each in-front-of-the-meter resource (see Appendix B for details). To reflect seasonal changes in the position of the sun and PV generation, production curves should be produced for specific time windows (for example, monthly curves). Figures 4 and 5 illustrates the month to month capacity output differences in the fifth percentile and average curves in the PRP region.

Figure 4: 5th percentile hourly percent nameplate capacity (using 2014 & 2015, H.E., PDT)

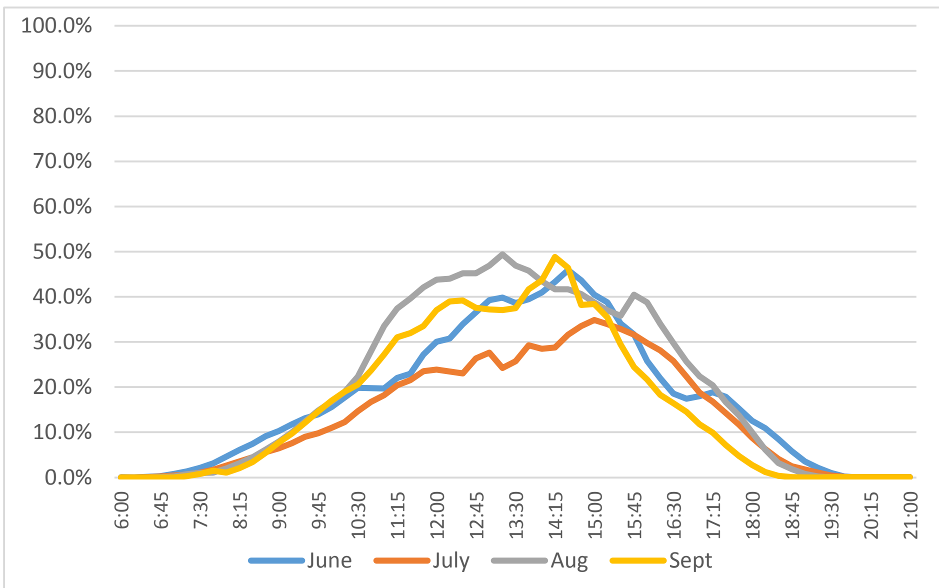
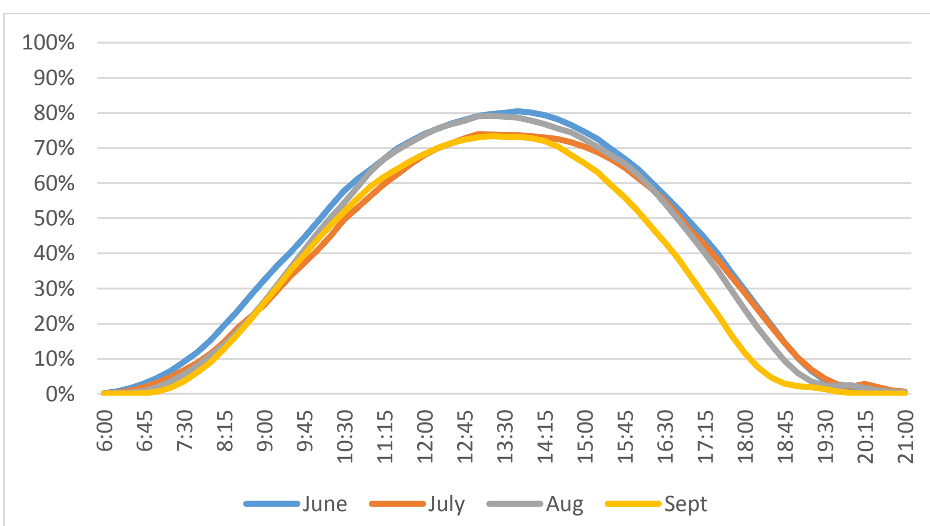


Figure 5: Average Hourly percent nameplate capacity (using 2014 & 2015, H.E., PDT)



Recommendations and Next Steps

SCE calculated the fifth percentile solar dependability curve on an hourly basis for the PRP Portfolio Design Report in early 2016. Since testing this methodology, SCE's Expansion Plan Coordination (EPC) group, which creates SCE's distribution forecast, used the approach in the 2017 Distribution Forecast. However, as more experience and data is gathered, the EPC group will be further refining their approach.

In the future, greater locational and temporal granularity could be incorporated, but today the practical limitations of the small number of behind-the-meter solar resources with generation data available (approximately 1,000 across SCE's territory) and their geographic distribution would offer very small data pools if the areas were smaller than the planning regions. The analyses could also be performed using data from the specific peak month (or other time frame) in order to better determine the solar power contribution to the peak load.

Applying this methodology allowed SCE to better account for the solar contribution in PRP planning and preferred resources acquisition. Updating solar dependability assumptions improves the distribution load forecast, helping SCE appropriately size and distribution infrastructure upgrades. Additionally, the solar dependability is useful when making portfolio selection decisions during procurement activities. Given the access limitations to BTM solar generation data, this methodology provided a sound approach to calculating the PV systems contribution to serving SCE customers' load.

APPENDIX A – DATA QUALITY

Like any data set, the data from metered CSI PBI customers contained some errors. There were systems that reported zeroes all of the time, systems that occasionally report zeroes seemingly at random, and systems that report a string of zeroes and have a very high number right before or right after the string of zeroes (indicating the meter might have summed all of the output during the intervals that reported zero and reported the sum in one time interval). There were also some meters that did not record many (or any) decimal places of kWh and therefore the output was "binary" and only ever presented two values: zero or the maximum kWh that system can produce in 15 min.

There is currently no process to comprehensively cure these errors, but some actions were taken to improve the overall quality of the data. For this analysis, all zeroes and all values greater than 101 (percent of nameplate capacity) were removed. If 43 systems were reporting non-zero values less than 101 percent at 12:15 PM, 1 system was reporting zero, and 1 system was reporting 189 percent of nameplate capacity, the average generation (in terms of percent of nameplate capacity) at 12:15 PM would be of the 43 systems and not include the other two. If all 45 systems were reporting greater than zero and less than 101 percent at 12:30 PM, then all systems would be included in the average at the 12:30 PM time stamp. Because there was no information available regarding whether a zero reported during daylight hours was due to a faulty meter or a true resource outage, this analysis assumes they are due to faulty meters and therefore presents a solar dependability curve of the percent of nameplate capacity *when a resource is generating*. Another consideration for future studies could be incorporating the likelihood of an outage to the dependability curve.

APPENDIX B – BENCHMARKING

To benchmark the approach, SCE searched for other utilities' public information accounted for solar dependability. In particular, the analysis in this report is focused on developing an estimating process for unmetered "behind-the-meter" (or customer-sited) generation that is intended to serve customer load and not export like "in-front-of-the-meter" (or grid-connected) resources whose main purpose is to export power to the grid for sale.

One such analysis was a paper from Tennessee Valley Authority titled "Distributed Generation – Integrated Value (DG-IV): A Methodology to Value DG on the Grid" from October, 2015[3] in which they explained a "net dependable capacity" calculation for solar. This paper used modeled solar data from Clean Power Research on the top twenty load days of summer, determined the generation for the 20 peak hours in terms of percent of nameplate capacity, and then took the 25th percentile value (above which 75 percent of the data fell) and averaged the values across all years of the analysis. This approach narrows the data set for analysis. The study recognized that solar PV generation is a function of solar irradiance, a variable fuel source, and to meet the needs of continuous energy loads on the utility grid, traditional sources such as natural gas must be dispatched to fill in any "gaps" in solar energy generation profiles. During clear sky conditions, PV generation profiles are manageable, however during irregular cloud pattern conditions, dynamic solar capacity ramping events can occur repeatedly. They also conclude that generation volatility and reliability risk is greater for large utility-scale solar PV projects but still exists for distributed solar generation. It should be pointed out that TVA's study was based on model outputs of solar generation using irradiance data as opposed to actual solar meter data.

Similarly, the California Public Utilities Commission (CPUC) has historically determined the Qualifying Capacity (QC) of in-front-of-the-meter solar resources by using a percentiles methodology. (The CPUC typically uses the term "exceedance" and refers to the percent of data that exceeds the curve rather than the percent of data included under the curve, so 25th percentile is the same thing as a 75th percent exceedance.) The QC of a solar resource is the 70 percent exceedance point and the data used is hourly average MW from that specific resource's historic power generation. If the resource is new and does not have historic power generation data, then QC is based off of power generation data from the other resource of that technology type (solar, in this instance) in California with a calculated QC. The CPUC calculates QC by month and determines one 70 percent exceedance value for the whole time interval that defines Resource Adequacy (RA) in that particular month (in April through October, the RA hours are Hour Ending 14:00 to Hour Ending 18:00). The calculations are updated annually and based on the prior 3 years of data (for example, the solar QC used in 2016 is based on solar generation data from 2012, 2013, and 2014 because the calculation was performed in 2015 before all of the 2015 data was complete).

[3] https://www.tva.gov/file_source/TVA/Site percent20Content/Energy/Renewables/dgiv_document_october_2015-2.pdf