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Review

High-frequency irradiance fluctuations and geographic smoothing

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Abstract

Using six San Diego solar resource stations, clear-sky indices at 1-s resolution were computed for one site and for the average of six sites separated by less than 3 km to estimate the smoothing of aggregated power output due to geographic dispersion in a distribution feeder. Ramp rate (RR) analysis was conducted on the 1-s timeseries, including moving averages to simulate a large PV plant with energy storage. Annual maximum RRs of up to 60% per second were observed, and the largest 1-s ramp rates were enhanced over 40% by cloud reflection. However, 5% per second ramps never occurred for a simulated 10 MW power plant. Applying a wavelet transform to both the clear-sky index at one site and the average of six sites showed a strong reduction in variability at timescales shorter than 5-min, with a lesser decrease at longer timescales. Comparing these variability reductions to the Hoff and Perez (2010) model, good agreement was observed at high dispersion factors (short timescales), but our analysis shows larger reductions in variability than the model at smaller dispersion factors (long timescales).

Keywords: Wavelet; High-frequency; Clear-sky index; Ramp rate; Variability

1. Introduction

The variable nature of solar radiation is a concern in realizing high penetrations of solar photovoltaics (PV) into an electric grid. High frequency fluctuations of irradiance caused by fast moving clouds can lead to unpredictable variations in power output on short timescales. Short-term irradiance fluctuations can cause voltage flicker and voltage fluctuations that can trigger automated line equipment (e.g. tap changers) on distribution feeders leading to larger maintenance costs for utilities. Given constant load, counteracting such fluctuations would require dynamic inverter VAR control or a secondary power source (e.g. energy storage) that could ramp up or down at high frequencies to provide load following services. Such ancillary services are costly to operate, so reducing short-term variation is essential. Longer scale variations caused by cloud groups or weather fronts are also problematic as they lead to a large reduction in power generation over a large area. These long-term fluctuations are easier to forecast and can be mitigated by slower ramping (but larger) supplementary power sources, but the ramping and scheduling of power plants also adds costs to the operation of the electric grid. Grid operators are often concerned with worst-case scenarios, and it is important to understand the behavior of PV power output fluctuations over various timescales.

Many previous studies have shown the benefit of high-frequency irradiance data. Suehrcke and McCormick (1989) and Gansler et al. (1995) found 1-min data to have different statistics from lower-frequency data, including a much more bi-modal distribution than 1-h or 1-day data. Gansler et al. (1995) mention that while using 1-h data may be acceptable for space and water heating systems, where the thermal capacitance effects dampen out short-term variations, the time response of PV systems is much faster and using 1-h data will likely lead to errors.

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Understanding that high-frequency fluctuations are important, further studies have looked to characterize these fluctuations, often by comparing fluctuations at one site to fluctuations at the average of multiple sites. Otani et al. (1997) use a fluctuation factor defined as the root mean squared (RMS) value of a high-pass filtered 1-min time series of solar irradiance to demonstrate a 2–5 times reduction in variability when considering nine sites located within a 4 km by 4 km grid. Curtright and Apt (2008) and Lave and Kleissl (2010) used 1-min timeseries to show reductions in the mean, maximum, and standard deviation of ramp rates (RRs) when considering the average of three or four sites versus only one site. Power spectral densities (PSDs) presented in Otani et al. (1997), Curtright and Apt (2008), and Lave and Kleissl (2010) all show strong reductions in power content of fluctuations of the average of multiple sites versus the power content of fluctuations at one site. Lave and Kleissl (2010) also present coherence spectra which show that sites which were 60 km or more apart were uncorrelated on timescales shorter than 12-h. Two sites that were only 19 km apart were uncorrelated on timescales shorter than 3-h.

Wiemken et al. (2001) used 5-min normalized output from 100 PV sites spread throughout Germany. They found the standard deviation of the average of 100 sites to be 0.61 that of one site for the month of June, and that 5-min fluctuations of ±5% of power output at nameplate capacity are virtually nonexistent in the average, yet single sites have fluctuations larger than ±50%. Also included in that paper is a figure from Beyer et al. (1991), which shows exponential decay of cross-correlation as a function of distance for hourly irradiance data from six sites in Germany which can be used to estimate the reduction in standard deviation when averaging sites. Murata et al. (2009) analyzed 1-min data from 52 PV systems spread across Japan to determine the "smoothing effect" of aggregating multiple systems. The authors introduce a fluctuation index, which is the maximum difference in aggregated power output over a given time interval. They found that over 1-min, sites more than about 50–100 km apart were uncorrelated. However, eventually adding more PV sites did not leader to further reductions in variability, since the variability introduced by the diurnal cycle eventually becomes larger than the cloud-induced variability. For times greater than 10-min, however, they reject the hypothesis that sites within 1000 km are independent, though some of the dependence may be due to diurnal solar cycles and could be eliminated by using a normalized solar radiation.

Hoff and Perez (2010, hereafter HP10) present a framework to estimate the decrease in standard deviation of irradiance achieved by aggregating PV sites. The reduction in standard deviation is a function of the number of PV sites and a dispersion factor, D, defined as the number of time intervals it takes for a cloud to pass over all PV sites across the region being considered. The dispersion factor is useful in determining when the transition from PV sites being uncorrelated to correlated occurs. They predict a factor of $\sqrt{N}$ reduction in standard deviation of the average of N sites compared to the standard deviation of one site for the "spacious region," where the number of sites is much less than the dispersion factor, $N \ll D$. This corresponds to the sites being fully independent of one another, and is a known result from statistics on independent random variables. At an "optimal point" where the number of sites equals the dispersion factor, $N = D$, they derive a factor of N reduction in standard deviation. At this point, sites would be perfectly correlated when shifted by an appropriate timestep (the dispersion factor divided by the number of sites), and the standard deviation of the average of all sites will be reduced more than would be expected if the sites were entirely independent. HP10 also define a "limited region," between the "spacious region" and the "optimal point," $N < D$. In the "crowded region" where the number of sites is larger than the dispersion factor, $N > D$, they propose that the standard deviation will be reduced by a factor of D, since the sites are at least partially dependent, and adding additional sites will not reduce the standard deviation of the average since the reduction is only a function of the dispersion factor, and not the number of sites. HP10 perform a limited model validation by simulating a fleet of PV systems based on measured irradiance at only one site. In the simulated system, the irradiance at the non-measured sites was found by shifting the timestamp but otherwise maintaining the measured data, thus simulating an equally spaced system in which frozen clouds move at a constant speed along a line containing all sites.

Woyte et al. (2007) present a unique study in that they use very high frequency data (1-s, 5-s, or 1-min depending on the site) collected for up to 2-years, instantaneous clearness index, and a wavelet transform to analyze fluctuations of all scales in time, from very short to very long. The Haar wavelet was applied to each clearness index dataset to detect fluctuations over various timescales. They introduce a fluctuation power index, which is the sum of the square of the wavelet mode at each timescale, and is used to quantify the amplitude and frequency of occurrence of fluctuations on a specific timescale. In other wavelet studies, Kawasaki et al. (2006) applied the Daubechies 4 wavelet to 1-min irradiance 2-year timeseries from nine sites in a 4 × 4 km grid, and Perpinan and Lorenzo (2011) applied the MODWT wavelet to 1-s solar irradiance timeseries from a few days in October, 2009.

This paper builds on these previous works by using 1-s clear-sky index (K_c) data from six sites on a microgrid similar to urban distribution feeders (Section 2) to quantify extreme ramp rates (RRs). Methods are described in Section 3. RRs were analyzed by computing statistics at different time steps and by using varying moving average intervals to represent large PV plants or storage (Section 4.1). Coherence spectra are employed in Section 4.2 to analyze the correlation between six sites at different time scales. We apply a wavelet to detect variability over various timescales relevant to the operation of a power grid