Analyzing and Simulating the Reduction in PV Powerplant Variability Due to Geographic Smoothing in Ota City, Japan and Alamosa, CO

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***Abstract* — Ota City, Japan and Alamosa, Colorado present contrasting cases of a small rooftop distributed PV plant versus a large central PV plant. We examine the effect of geographic smoothing on the power output of each plant. 1-second relative maximum ramp rates are found to be reduced 6-10 times for the total plant output versus a single point sensor, though smaller reductions are seen at longer timescales. The relative variability is found to decay exponentially at all timescales as additional houses or inverters are aggregated. The rate of decay depends on both the geographic diversity within the plant and the meteorological conditions (such as cloud speed) on a given day. The Wavelet Variability Model (WVM) takes into account these geographic smoothing effects to produce simulated PV powerplant output by using a point sensor as input. The WVM is tested against Ota City and Alamosa, and the WVM simulation closely matches the distribution of ramp rates of actual power output.**

***Index Terms* —solar power generation, wavelet transforms, solar energy, power grids, photovoltaic systems.**

I. Introduction

The variable nature of solar photovoltaic (PV) power can be a concern to operation of the electric grid. Solar PV power is variable due to solar cycles (rising and setting sun), clouds, changes in atmospheric composition, and module-specific variables such as temperature and soiling. Cloud-caused fluctuations affect power production at short timescales and can cause challenges to the electric grid such as voltage fluctuations resulting in increased use of tap changers. The other causes of variability typically occur over longer timescales and are predictable to an extent. Fortunately, since cloud cover is typically not homogenous, geographic smoothing over PV powerplants will reduce the relative variability (variability relative to capacity) of the plant power output. The amount of geographic smoothing is dependent on the plant footprint and the correlation within the cloud field.

Many previous studies have focused on the relative aggregate irradiance variability of a combination of sites as a proxy for PV power variability. These have shown that sites a few to hundreds of kilometers apart lead to a smoothed aggregate output, and that the amount of smoothing varies based on the distances between sites and local climates [1, 2]. Other studies [3, 4] have modeled the correlation of irradiance fluctuations between sites as a function of distance and found decorrelation distances – the distances over which sites become almost totally independent of one another – to vary based on fluctuation timescale, geographic layout, and local climate.

A few studies have directly examined the variability of PV power [5, 6]. The variability of 50 to 100 small (residential scale, typically ~2.5 to 3.2kW) PV systems spread across Japan or Germany, tens to hundreds of kilometers apart at medium timescales (minutes to hours), showed a large amount of smoothing in the aggregate output of all systems. At certain timescales, a limit was found whereby adding additional systems did not significantly affect the geographic diversity and hence did not lead to any additional smoothing [5].

In this paper, we address two deficiencies in previous works. (1) In section III, we compare the reduction in variability due to geographic diversity at a small distributed plant to a large central PV plant. The effect of geographic smoothing is shown at much shorter distances (<1.5km) and timescales (1-second) than previous PV power studies. (2) In section IV, we demonstrate a method for simulating the variability of a PV powerplant that accounts for different geographic, climatological, and timescale effects, and test this model against the actual powerplants' outputs.

II. Data

We used irradiance and power output data collected at a $2.1MW_p$ residential rooftop distributed PV plant located in Ota City, Japan, and a $19MW_p$ central power plant in Alamosa, Colorado. The shapes and relative sizes of each plant are shown in Fig 1. Even though the Alamosa plant has nearly 10 times the rated capacity of Ota City, its footprint is only about twice as large, meaning the density of PV at Alamosa (30.5 W m^{-2}) is much larger than the density of PV at Ota City (7.55 W m^{-2}).

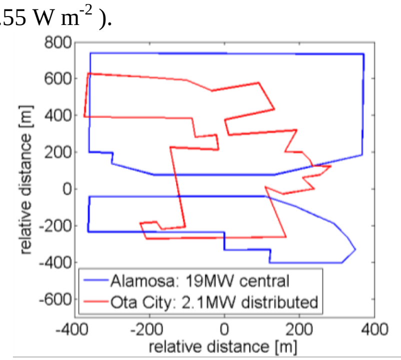

Fig 1. Footprints of the Ota City and Alamosa PV plants showing their areas relative to one another. The Ota City plant covers 0.278 km^2 and the Alamosa plant covers 0.623 km^2, giving PV densities of 7.55 W m^{-2} (Ota City) and 30.5 W m^{-2} (Alamosa).

The Ota City plant consists of 553 houses with PV systems ranging from 3-5kW at varying tilts and azimuths. PV power output data was collected from the inverters at each house, and global horizontal irradiance (GHI) was measured by a pyranometer in the northeast of the footprint. All measurements had 1-second resolution. For a further description of the Ota City data, see [7].

The Alamosa plant is utility-scale and has PV modules mounted on 20-degree tilted, single-axis tracking systems. Power output was collected from each of 38 500kW inverter blocks, and tracker plane of array (POA) irradiance was measured by a pyranometer mounted on the tracking system in the northwest corner of the plant. Just as for Ota City, all measurements had 1-second resolution.

We used a highly-variable test day at each Ota City and Alamosa as the focus of our analysis. Results from additional days are presented when appropriate. July 16th, 2007 was chosen as the test day at Ota City, and February 11th, 2012 was chosen for Alamosa. The irradiance profiles on these test days are shown in Fig 2. While the irradiance profiles have different shapes due to the different types of irradiance measured (GHI versus tracker POA), it is clear that both days were highly variable.

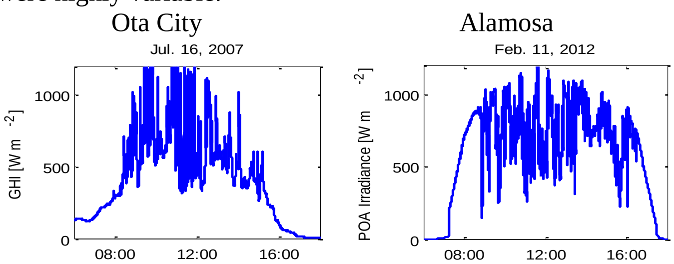

Fig 2. Irradiance profiles for Ota City GHI (left) and Alamosa tracker plane of array (right) showing the high variability on the test days.

III. Variability Reduction due to Aggregation

To examine the variability reduction due to aggregation at these two plants, we chose to use the maximum absolute (positive or negative) daily ramp rate (RR) as our variability metric. Maximum RRs are of interest to grid and powerplant operators because they describe the worst-case scenarios – the strongest effects that PV can cause to the grid.

A. Maximum Ramp Rate Calculations and Aggregation Method

1-second RRs were calculated as the difference of subsequent measured points. RRs at timescales longer than 1-second were calculated by applying a moving average with a window equal to the timescale of interest, then differencing values separated by that timescale. For example, for the 60-second timescale, a 60-second moving average was applied to the data, and then differences between values 60-seconds apart were found. The maximum RR was then the largest such difference.

Due to data quality issues at Ota City, the maximum RRs were not representative of PV-induced fluctuations, but rather caused by instantaneous errors in the data collection. Therefore, we used the 99th percentile RR as an indicator of the true maximum RRs. This may cause a slight under-estimation of the maximum RRs, but comparison between RRs on the same day should still be accurate (i.e., the ratio of the 99th percentile RR at a point sensor to the 99th percentile RR over the whole plant should be representative of the same ratio between point sensor maximum RR and plant maximum RR). For simplicity, we refer to the 99th percentile RRs at Ota City as the maximum RRs. The maximum RRs presented for Alamosa are truly the maximum ramp rates, as no correction due to errors was necessary.

To test the reduction in variability due to aggregation, the plots in this section show maximum RRs as a function of total aggregated capacity. These plots were created by aggregating a certain number of houses (Ota City) or inverter blocks (Alamosa) to achieve the desired capacity. Since the locations corresponding to the house power output timeseries were not known for Ota City, we randomly selected the correct number of houses to equal the desired power capacity. For example, to compute the 8kW (2 house) maximum RR, we randomly selected a pair of houses, aggregated their power outputs, then found the maximum RR of the aggregate. Since the amount of smoothing is greatly dependent on the pair chosen, this method was repeated 30 times to obtain results that are representative of all possible combinations. The same method was applied to Alamosa using the inverter blocks instead of houses. In this way, we find the maximum RRs for various amounts of PV capacities spread over the plant footprint.

Under this method, the footprint of the aggregated sites is not directly proportional to the plant capacity. For example, when aggregating 19 randomly chosen inverters at Alamosa to achieve half the plant capacity, the 19 inverters are not necessarily next to one another geographically, and the footprint is not necessarily half the area of the Alamosa footprint. If we were to have aggregated sites based on geographic location, we would have seen a greater reduction in maximum RRs at large capacities, as capacity would have been more directly related to footprint size. Such a method, though, was not possible at Ota City where house locations were not known, and was not employed at Alamosa for consistency with the Ota City results.

All RRs presented in this section are relative RRs, meaning they are normalized by capacity. This allows for easy comparison between different amounts of aggregated capacity. Actual RRs can be obtained by multiplying the relative RRs by the capacity. It is important to note that while relative RRs will decrease as capacity increases, actual RRs will always increase due to the increased capacity.

B. Maximum Ramp Rates based on Aggregate PV Capacity

Fig 3 shows the maximum relative RRs at Ota City as a function of total aggregated capacity on the test day over various timescales. At all timescales, the variability of a single house is much higher than the variability of the aggregate of multiple houses. The curves follow an exponential decay pattern, such that maximum RRs are strongly reduced when capacity is added to a small exiting capacity (such as in going from 4kW to 8kW), but hardly changed when adding capacity to large existing capacity (such as going from 1000kW to 1500kW). Each timescale decays at a different rate; the shorter timescales benefit more from geographic smoothing (e.g., at 1-second, even sites close to one another are nearly independent) and so continue to have significant decay even at large capacities.

The magnitudes of the maximum RRs and the rates of decay as a function of capacity will change day-by-day. Clear days will have very small maximum RRs and have nearly no decay, since there is no variability to be reduced. Variable days will have larger magnitudes of RRs, but the decay rate will depend on the meteorological conditions (cloud speed, cloud type, etc.).

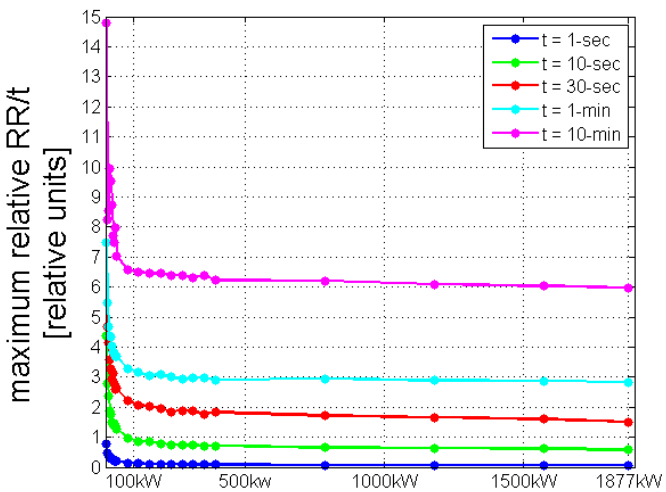

Fig 3. Maximum RRs at various timescales on July 16th, 2007 at Ota City. The points represent various combinations of houses: from 1 (~4W) to 477 houses (1877kW). Values on the y-axis were multiplied by an arbitrary scaling factor for consistency with results from Alamosa (Fig 4).

The maximum relative RRs at Alamosa are shown in Fig 4. Since a single inverter block is 500kW and will already have a significant amount of geographic smoothing built in, we included the maximum RRs of a point sensor in Fig 4 to better illustrate the reduction in variability. Just as at Ota City, there is an exponential decay of maximum RRs as capacity is increased, though the amount of decay is smaller. Also of interest is that the 1-minute maximum RRs always exceed the 10-minute maximum RRs. This indicates that the dominant cloud-caused shadow duration is approximately 1-minute such that the 9-minutes surrounding the most extreme 1-minute RR are all "restoring" – either all clear around a cloudy 1-minute ramp, or all cloudy around a clear 1-minute ramp – resulting in smaller 10-minute maximum RRs.

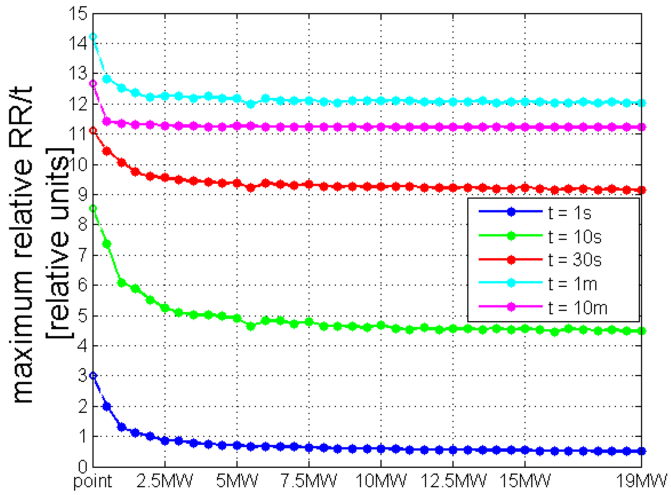

Fig 4. Maximum RRs at various timescales on February 11th, 2012 at Alamosa. The far left hollow point is the point sensor, while the solid points are 1 (0.5MW) to 38 inverters (19MW). Values on the y-axis were multiplied by an arbitrary scaling factor to protect the confidentiality of the power data.

C. Reduction in Maximum Ramp Rates

To better study the reduction in variability, we define the reduction in maximum RR (RMRR) as the ratio of the point sensor maximum RR to the maximum RR at a given capacity. Defined this way, $RMRR = 1$ indicates no benefit to geographic smoothing, and large RMRR values indicate more significant decreases in the aggregate variability. Fig 5 shows the RMRRs for both Ota City and Alamosa.

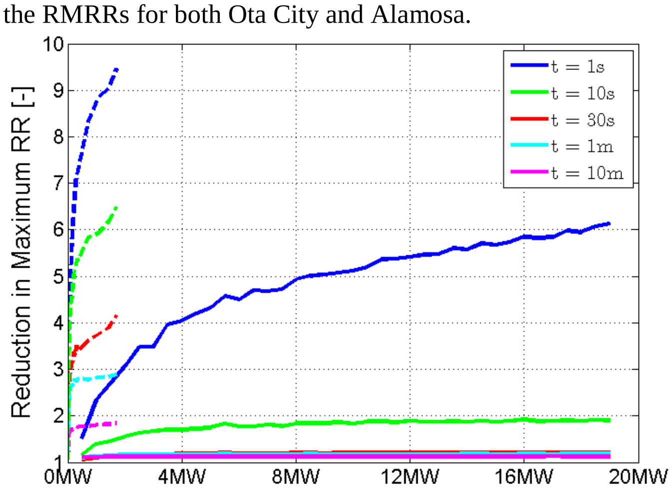

Fig 5. Comparison of the reductions in maximum RRs compared to a point sensor at Ota City (dashed lines) and Alamosa (solid lines) for varying capacities of PV (x-axis) on the test days. Larger values on the y-axis indicate greater geographic smoothing.

The RMRRs at Ota City are larger than the RMRRs at Alamosa. This is surprising since Alamosa has nearly 10 times the PV capacity as Ota City, but can be explained by two main factors. (1) Geographic smoothing depends on the geographic diversity of sites. Since the footprint of Ota City covers about half the area of Alamosa, we expect the geographic smoothing to still be significant at Ota City. (2) Smoothing depends on the meteorological conditions on any given day. Fig 6 shows how the RMRR changed from day to day at Alamosa in early 2012. On the test day at Ota City, the meteorological conditions were more favorable for smoothing than on the test day at Alamosa.

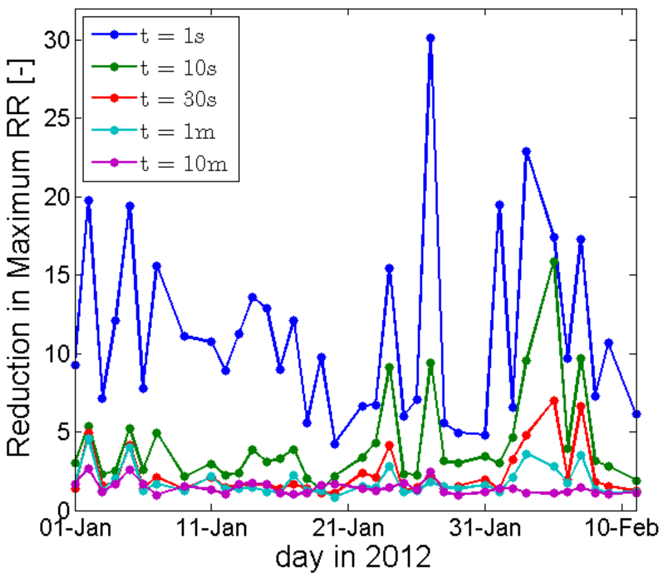

Fig 6. Reductions in maximum RRs at Alamosa for January 1 through February 12, 2012. Higher values indicate a stronger reduction in maximum RRs.

IV. Wavelet Variability Model

A. WVM Description and A Values

Based on the two main factors that affect geographic diversity mentioned in section IIIC (plant footprint and daily meteorological conditions), we have developed a wavelet-based variability model (WVM) for simulating the variability of a solar PV plant. The WVM is described in full in [8]. In short, the WVM takes as inputs a local irradiance point sensor, the PV plant footprint, PV plant capacity, and a meteorologically-related *A* value, and outputs a simulated plant power output timeseries.

While the other inputs to the WVM are fixed for a given PV plant, the *A* value changes from day-to-day. The *A* value describes the correlation between sites, and hence how much smoothing will be achieved when sites are aggregated. It is based on the assumption that correlations are a function of the distance between sites and timescale of interest.

The *A* value is similar to the RMRRs presented in section IIIC, although a small *A* value indicates more geographic smoothing and would lead to a large RMRR Small *A* values (1-3) are typically found in coastal areas, while larger *A* values (>5) are often found at inland sites. For a more detailed description of A values, see [9].

A values can be determined from an irradiance sensor network by plotting correlations versus the exponential of the negative ratio of distance to timescale. *A* value plots are shown in Fig 7 for Ota City and Alamosa on the test days.

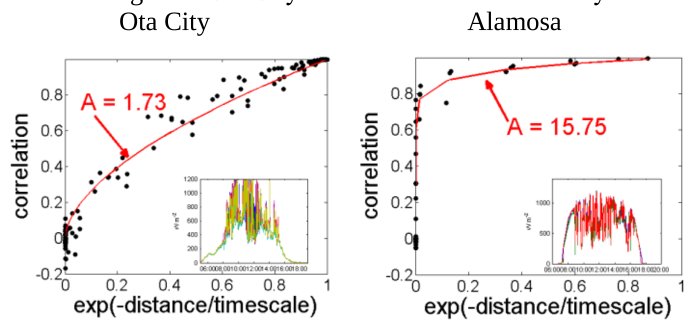

Fig 7. Correlation scaling coefficient (*A*) value for Ota City (left) and Alamosa (right) on the test days.

Since the *A* value is a meteorologically-driven value, it varies from day-to-day. Fig 8 shows the A values for Ota City in July 2007. The high variation of *A* values over the month shows that the smoothing was not consistent, and that the WVM will need to be run with separate *A* values for each day.

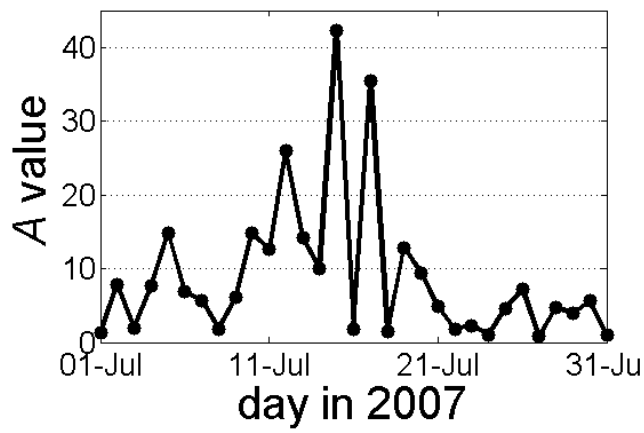

Fig 8. *A* values for Ota City in July 2007.

B. Testing the WVM at Ota City and Alamosa

The data available in this study provide a rare opportunity to test the WVM against actual PV powerplant output. Based on the plant footprints and PV densities of Ota City and Alamosa, measured irradiance at each site, and *A* values calculated in Fig 7, the WVM was run on the test days at Ota City and Alamosa.

The goal of the WVM is to accurately simulate the variability of the actual plant power output. The exact timing of fluctuations will not be perfectly matched, because the point sensors will "see" clouds at different onset times than the total plant aggregate, but the statistics of variability should match well between WVM simulated and actual power output.

To test this, we use the distribution of RRs as a metric for how well the WVM matches the actual power output.

Fig 9 shows the extreme (>75th percentile) RRs of actual power output and WVM simulated power output for Ota City on the test day. Also included is the RR distribution of the point sensor to show how the WVM has improved over the point sensor. Good matches are found between simulated and actual RR distributions at all timescales. The slight overestimation of extreme RRs in the WVM simulation may be due to the varied orientations (tilts and azimuths) of rooftop PV in Ota City. In running the WVM, it was assumed that the total plant had a due south azimuth and 25˚ degree tilt. The aggregate output of Ota City will not perfectly match this assumption, though, and this difference will lead to small errors in the WVM.

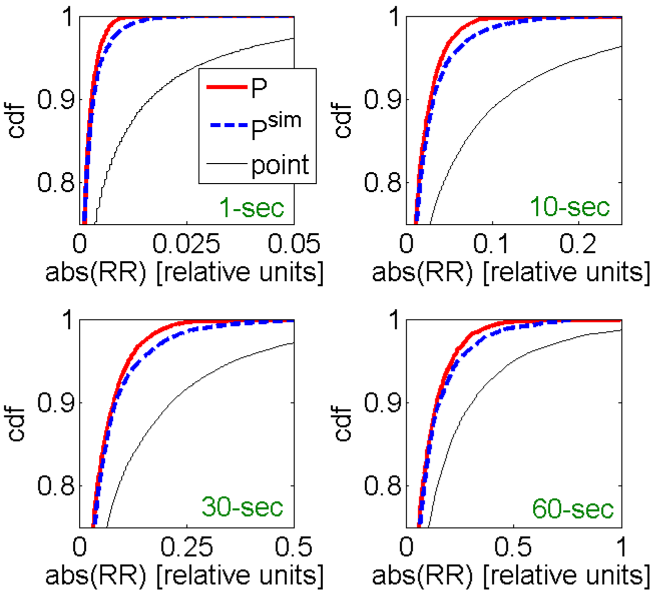

Fig 9. Comparison of extreme (>75th percentile) RR distributions at Ota City on July 16th, 2007 for the actual power output (red solid line), WVM simulated power output (blue dashed line), and a point sensor (black thin line) at 1-sec (top left), 10-sec (top right), 30-sec (bottom left), and 60-sec (bottom right) timescales. Units on the x-axis were multiplied by an arbitrary scaling factor to be consistent with Fig 10.

The RR distributions of actual power output, WVM simulated power output, and a point sensor at Alamosa on the test day are shown in Fig 10. Compared to Ota City, the WVM simulation matches the actual output better, partially because the module orientations are known for Alamosa. Additionally, the difference between the point sensor and the actual power output is much smaller than on the test day at Ota City. This is directly related to the *A* value: the *A* value at Ota City on the test day (1.73) was much smaller than the *A* value at Alamosa (15.75). The higher *A* value at Alamosa means higher correlations between sites and less benefit from geographic smoothing, so the power RRs are less reduced compared to the point sensor. This is consistent with the smaller RMRRs found for Alamosa than for Ota City in section IIIC.

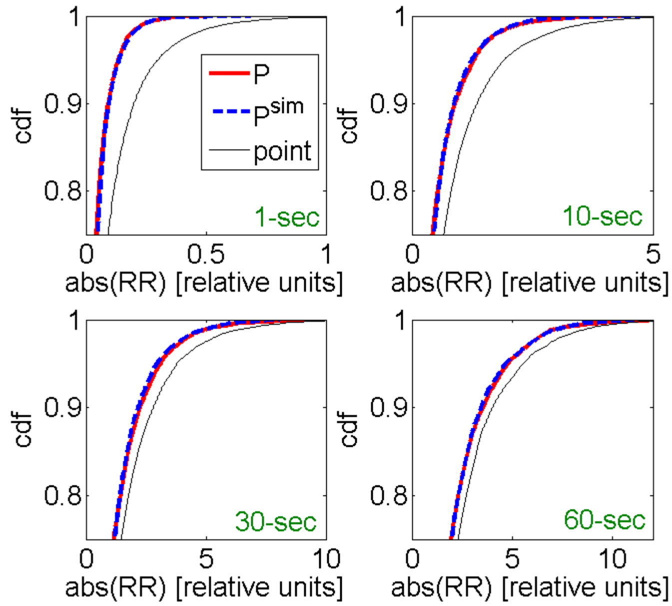

Fig 10. Comparison of extreme (>75th percentile) RR distributions at Alamosa on February 11th, 2012 for the actual power output (red solid line), WVM simulated power output (blue dashed line), and point sensor (black thin line) at 1-sec (top left), 10-sec (top right), 30-sec (bottom left), and 60-sec (bottom right) timescales. Units on the x-axis were multiplied by an arbitrary scaling factor to protect the confidentiality of the power data.

V. Conclusion

While the variability of PV powerplants can be a concern, geographic diversity within the plant will lead to a reduction in variability versus a single point. By examining a 2.1MW residential rooftop PV plant in Ota City, Japan and a 19MW central PV plant in Alamosa, Colorado, the relative variability as a function of capacity was found to decay exponentially for both plants. However, the rate of decay was not the same, and a greater reduction in variability was found on the test day at Ota City, even though the Alamosa plant has nearly 10 times the PV capacity. This is explained by both the lower density of PV at Ota City than Alamosa, and by meteorological differences (i.e., cloud differences) in the test days at each location. The reduction in variability at Alamosa was found to vary significantly over a month, showing the daily meteorological variation.

To address the dependence of geographic smoothing on plant footprint and meteorological conditions, the Wavelet Variability Model (WVM) was presented. The WVM accounts for the diversity within a plant and uses the *A* value to scale the smoothing over the plant. The WVM was run for the test days at both Ota City and Alamosa and good agreement was found between RR distributions of WVM simulated and actual power output. The smoothing effect at Ota City was much stronger than at Alamosa due to the lower *A* value indicating less correlation between PV modules separated by the same distance. The success of the WVM at simulating PV powerplant output means that it can be used to generate realistic simulated power output timeseries of hypothetical PV plants to be used as an input for grid impact studies (as done in [10].).

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