Implications of Geographic Diversity for Short-Term Variability and Predictability of Solar Power

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***Abstract*—Worldwide interest in the deployment of photovoltaic generation (PV) is rapidly increasing. Operating experience with large PV plants, however, demonstrates that large, rapid changes in the output of PV plants are possible. Early studies of PV grid impacts suggested that short-term variability could be a potential limiting factor in deploying PV. Many of these early studies, however, lacked high-quality data from multiple sites to assess the costs and impacts of increasing PV penetration. As is well known for wind, accounting for the potential for geographic diversity can significantly reduce the magnitude of extreme changes in aggregated PV output, the resources required to accommodate that variability, and the potential costs of managing variability. We use measured 1-min solar insolation for 23 time-synchronized sites in the Southern Great Plains network of the Atmospheric Radiation Measurement program and wind speed data from 10 sites in the same network to characterize the variability of PV with different degrees of geographic diversity and to compare the variability of PV to the variability of similarly sited wind. We find in our analysis of PV and wind plants similarly sited in a 5 X 5 grid with 50 km spacing that the variability of PV is only slightly more than the variability of wind on time scales of 5-15 min. Over shorter and longer time scales the level of variability is nearly identical. Finally, we use a simple approximation method to estimate the cost of carrying additional reserves to manage sub-hourly variability. We conclude that the costs of managing the short-term variability of PV are dramatically reduced by geographic diversity and are not substantially different from the costs for managing the short-term variability of similarly sited wind in this region.**

I. Introduction

WORLDWIDE interest in the deployment of photovoltaic generation (PV), both distributed throughout the urban landscape and in large-scale plants, is rapidly increasing. PV plants as large as 60 MW are operating in Europe, while 500 MW PV plants are in various stages of development in the United States. Operating experience with large PV plants, however, demonstrates that large, rapid changes in the output of PV plants are possible. The output of multi-MW PV plants in the Southwest U.S., for example, are reported to change by more than 70% in five to ten minutes on partly-cloudy days [1]. The reliable integration of generating plants with variable and uncertain output requires that power system operators have adequate resources to ensure a balance between the load and generation. The variability of PV output may create some concern about the ability of system operators to maintain this balance.

Early studies of the power system impacts of PV highlighted the rapid ramping of PV plants due to clouds, and the commensurate increased need for balancing resources, as a potential limiting factor in the grid penetration of PV. Many of these early studies, however, lacked high-quality data from multiple sites to assess the costs and impacts of increasing PV penetration. Similar concerns were raised some years ago regarding the variability of wind energy in studies that were often based on scaling the output of single wind turbines or anemometers to hypothetical large scale deployment [2]. More recent state-of-the-art studies of wind energy integration into the electric power system, however, have demonstrated the significant smoothing effect of geographic diversity, particularly with regards to rapid changes in the output of several interconnected wind plants. The lack of correlation between rapid changes in the output of different wind turbines reduces the variability of the aggregated wind output relative to the variability projected from simple scaling of the output of a single turbine [3]–[10]. A large body of experience with and analysis of wind energy demonstrates that this geographic smoothing over short time scales results in only a modest increase in balancing reserves required to manage the short-term variability of wind energy [11]–[14].

The objective of this study is to assess the potential impact of the short-term variability of PV plants by exploring the short-term variability of PV output, the spatial and temporal scales of geographic diversity of PV, and the implications for the cost of managing the short time-scale, stochastic variability in the power system. To asses the potential impact of short-term variability of PV, the characteristics of short-term variability of PV are compared to the characteristics of wind in a specific region of the United States. The data used in this analysis are measured 1-min solar insolation and estimated 1-min clear sky insolation for 23 time-synchronized sites in the Southern Great Plains network of the Atmospheric Radiation Measurement program. Wind speed data from 10 of the sites in the same network are converted into estimated wind power output to compare the variability of PV and wind. Variability across different time scales is analyzed by calculating the step changes from one averaging interval to the next over different averaging intervals from 1-min to three hours. Diversity across these different time scales is measured by the degree of correlation of variability as a function of distance between sites. The results of this analysis demonstrate that, at individual sites, PV is more variable than wind for sub-hourly time scales, but that the distances between sites required to obtain diversity and therefore smooth the output for sub-hourly variability are slightly less for PV than for wind. Overall, for similarly sited PV and wind plants sited in a 5 $\times$ 5 grid with 50 km spacing, we find that the variability of PV is slightly more than

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wind, particularly for variability on time scales of 5-15 min. Finally, we use a simple approximation method to estimate the cost of carrying additional reserves to manage short-term variability. We conclude that the costs of managing the short-term variability of geographically distributed PV plants are not substantially different from the modest costs to manage the short-term variability of similarly sited and geographically distributed wind in this region.

II. Methodology

The short-term variability of PV generation will impact the power system in a variety of ways. Our analysis focuses only on the operational integration impacts of stochastic (i.e. cloud-induced rather than deterministic changes due to the movement of the sun) PV variability over short time scales. Namely, our analysis is focused on the need for power system operators to maintain a short-term balance between generation and loads.

The operational integration impacts of PV plants will depend on the characteristics of the variability over various time scales, $\bar{t}$. A common method for characterizing the variability of a resource over different time scales is to calculate the "deltas" or "step changes", which refers to the difference in the output of a plant from one averaging interval to another. The overall average variability of the resource at a single point over an averaging interval can then be characterized by the standard deviation of the step changes,$\sigma^{\bar{t}}_{\Delta P_1}$, over a long observation period or by some percentile of the step changes. A common metric is the 99.7th percentile [15], which corresponds to three standard deviations from the mean for a normally distributed random variable.

The 99.7th percentile may be more or less than three standard deviations from the mean depending on the shape of the distribution of the step changes. A distribution with relatively "fat tails" will have a 99.7th percentile that exceeds three standard deviations.

System operators need only to balance the load net of all generation rather than the output of individual plants. The role of geographic diversity is to reduce the variability of the aggregate of multiple plants relative to scaling the output of a single plant (even though the absolute level of variability of N plants in aggregate will be larger than the absolute level of variability at an individual site). For purposes of simplification, if it is assumed that all N plants are similar in that they have the same variability, then the ratio of the standard deviation of step changes for a time interval different time scales reduces to:

$$\frac{\left(\sigma^{\bar{t}}_{\Delta P}/N\right)}{\sigma^{\bar{t}}_{\Delta P_1}} = \frac{1}{N}\sqrt{\sum_{i=1}^{N}\sum_{j=1}^{N}\rho^{\bar{t}}\left(\Delta P_i^{\bar{t}}, \Delta P_j^{\bar{t}}\right)} \tag{1}$$

Where $\rho^{\bar{t}}\left(\Delta P_i^{\bar{t}}, \Delta P_j^{\bar{t}}\right)$ is the correlation coefficient of the $\bar{t}$-min step changes between sites i and j. The ratio of the variability of PV at the system level to the variability of PV at all sites individually therefore depends on the correlation of the step changes for each time scale, which is a function of both the spatial and temporal scales. For sites located very close to each other, such that they are perfectly correlated over a time scale of $\bar{t}$ (and therefore $\rho^{\bar{t}} = 1$), the ratio is equal to 1: the variability at the system level is equivalent to the sum of the variability of PV at all sites individually. When plants are sited such that they are perfectly uncorrelated over a time scale of $\bar{t}$ (and therefore $\rho^{\bar{t}} = 0$) the ratio is equal to $\frac{1}{\sqrt{N}}$: the variability at the system level is $\sqrt{N}$ times the variability at a single site (again assuming all sites have similar size and variability characteristics).

Based on relationships developed by [8] and [16], and results from [17], it is expected that the correlation of deltas between two sites will decrease exponentially with increasing distance, d_{ij}, and will similarly decrease with shorter averaging intervals, $\bar{t}$. A functional form that captures both this spatial and temporal behavior of correlation is:

$$\rho^{\bar{t}}\left(\Delta P_i^{\bar{t}}, \Delta P_j^{\bar{t}}\right) = \frac{1}{2}\left(e^{-\frac{C_1}{\bar{t}}d_{ij}^{b_1}} + e^{-\frac{C_2}{\bar{t}}d_{ij}^{b_2}}\right) \tag{2}$$

Where C_1, C_2, b_1 and b_2 are constant parameters that can be estimated from a fit to solar data in a particular region. At zero distance the correlation is one and as the distance between sites increases the correlation reduces to zero. Similarly, for very long time scales the correlation increases to one and over very short time scales falls to zero.

Assuming this particular functional form and that all plants are similar in their ramping characteristics and size allows the ratio to be specified in terms of the distance between PV plants and two model constants.

$$\frac{\left(\sigma^{\bar{t}}_{\Delta P}/N\right)}{\sigma^{\bar{t}}_{\Delta P_1}} = \frac{1}{N}\sqrt{\sum_{i=1}^{N}\sum_{j=1}^{N}\left(\frac{1}{2}\left(e^{-\frac{C_1}{\bar{t}}d_{ij}^{b_1}} + e^{-\frac{C_2}{\bar{t}}d_{ij}^{b_2}}\right)\right)} \tag{3}$$

For PV, rapid output changes are largely driven by fast moving clouds. PV output also changes based on diurnal cycles of the sun, but this variability can be perfectly forecast. The variability due to changes in the position of the sun can therefore be evaluated by system operators without consideration of geographic diversity. Because of the relative lack of understanding of the short-term variability due to fast moving clouds we focus on the stochastic component of the variability of PV output. This stochastic component due to cloud movement can be separated from the deterministic component due to changes in the position of the sun in the sky by focusing only on the clear sky index, $k(t)$, in place of the overall change in power output, $P(t)$. The clear sky index is the ratio of the actual global insolation measured at the site to the global insolation expected if the sky were clear (Figure 1). Since PV plant output is generally proportional to solar insolation, the variability of the clear sky index is similar to the variability of the ratio of actual PV plant output to PV plant output if the sky were clear. The stochastic variability in solar insolation is not exactly equivalent to the stochastic variability in actual PV plants due to "within-plant" smoothing that can occur relative to variability of insolation at a point [18], changes in PV plant efficiency with temperature, PV tracking systems, and diverse PV panel orientations other than

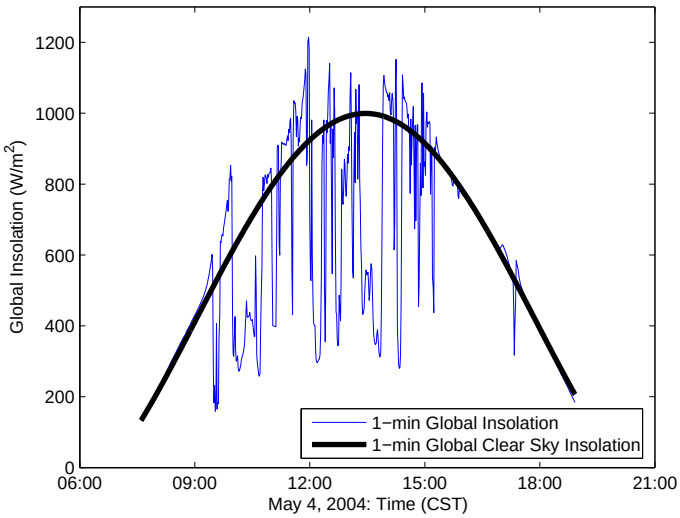

Fig. 1. Example of 1-min global insolation and global clear sky insolation on a partly cloudy day

horizontal for non-tracking PV systems.[1] We focus on the variability of the clear sky index from insolation measurements rather than the variability of the clear sky index from actual PV plants for the bulk of this study because of the relative higher quality of the insolation dataset available at the time of this study. The variability, particularly over shorter time scales, in our results will most likely provide an upper bound to the stochastic variability expected from actual PV plants.

A. Estimation of the Cost to Manage Short-Term Variability at the System Level

The additional variability and uncertainty introduced by PV plants will, to some degree, increase the use of system resources and methods to maintain balance, which will impose costs to the power system. Additional uncertainty and variability over time scales shorter than the time it takes to start and synchronize fast-start units, for instance, must be met by balancing reserves from spinning resources. An increase in spinning resources held in reserve leads to more units dispatched to "part load" levels, which leads to an efficiency penalty and higher costs than dispatching units to optimal set points [19].

Determining the cost of managing sub-hourly variability is a complex problem that is generally evaluated through detailed integration studies. Without performing a detailed integration study we still want to understand in general terms the relative difference in cost between managing variability at a single site and variability estimated for an aggregate of multiple sites. Similarly, we want to understand the cost of managing short-term variability of PV relative to the more-well-known cost of managing the stochastic short-term variability of wind. Based on these broad objectives, we provide a simple estimate of the costs to manage short-term variability that is largely based on methods and assumptions from [4], [20]–[23]. These simple estimates are only meant to illustrate relative changes in costs; the cost impact of short-term variability should in the future be evaluated with more detailed methods. Details of the assumptions and equations used to estimate the cost of providing reserves can be found in Ref. [24].

[1] [18] summarize comparisons between variability of point insolation measurements and PV plant output. Within-plant smoothing reduces variability on time scales shorter than about 10-min for a 13.2 MW PV plant.

III. Data

The primary data required for this analysis are high time resolution solar and wind data for multiple time-synchronized sites covering a broad geographic region. The only readily available U.S. dataset that fit this need was one that contains historic data from the Atmospheric Radiation Measurement (ARM) Program at the Southern Great Plains (SGP) network. The SGP dataset also includes 1-min averaged wind speed data at 10 m from 15 instrument sites in the SGP network. The wind speed data were extrapolated to the typical hub height of wind turbines, 80 m, using a simple $1/7^{th}$ power law extrapolation. The wind speed data were then converted into wind power output using a multi-turbine power curve [9]. Wind speed data from five of the 15 sites showed very low annual capacity factors (below 20%) and were therefore excluded from our assessment of wind variability.

IV. Results

The anecdotes of extreme deltas from PV plants and the conclusions from many of the previous solar integration studies are based, in large measure, on data from single sites. In this section we examine the deltas at individual sites within the SGP network.

Consistent with previous anecdotes and literature, severe deltas are apparent in the point insolation measurements from the SGP data. Deltas greater than +/- 0.6 in the global clear sky index were observed in one minute at individual sites. Similarly, deltas greater than +/- 0.6 were observed based on 10-min and 60-min averaging intervals (Figure IV). Figure IV is a cumulative probability distribution plot of the deltas from the individual sites where the magnitude of the deltas are smaller than the value on the x-axis for the percent of the deltas shown on the y-axis. For reference cumulative distribution functions of normal or "bell curve" distributions with the same standard deviations as the actual 1-min, 10-min, and 60-min deltas are included as thin lines in the figure. This chart shows that extreme deltas occur very infrequently, but the shape of the distribution, particularly for the 1-min deltas, shows a higher probability of extreme deltas than would be expected for a normal distribution with a similar standard deviation. In other words, the distribution of the deltas exhibits "fat tails" relative to a normal distribution.

The standard deviation of the deltas in the global clear sky index increase with longer time scales from 1-min to 180-min (Figure 3). The 180-min deltas have nearly double the standard deviation of the 1-min deltas. Figure 3 shows the standard deviation and 99.7^{th} percentile of the deltas averaged (but not aggregated) across the 23 sites in the SGP network. The error bars represent +/- one standard error, but are small enough to fit within the markers. The figure shows that 99.7% of the

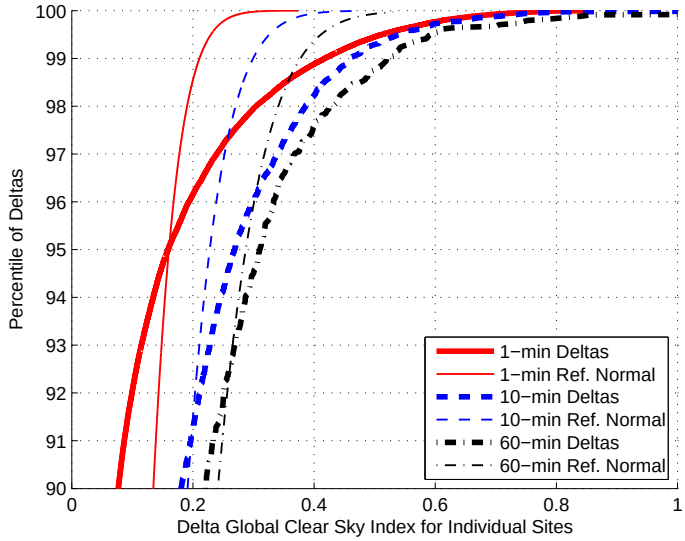

Fig. 2. Cumulative probability distribution of 1-min, 10-min, and 60-min deltas of the global clear sky index at individual sites in the SGP network. The thin lines show the shape of normal distributions with similar standard deviations as the actual data.

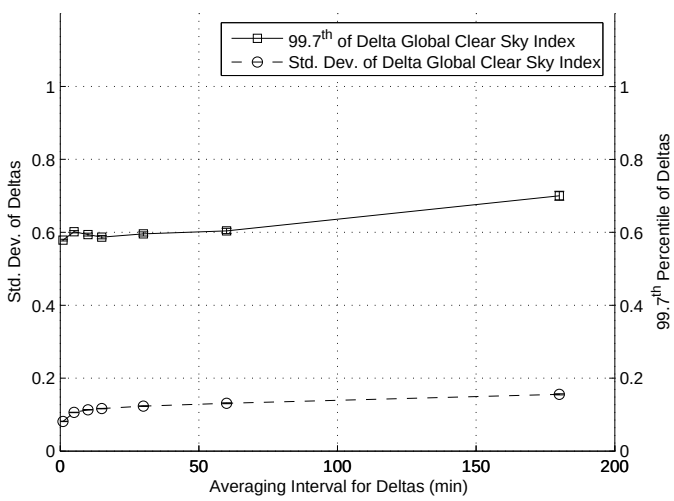

Fig. 3. Standard deviation and 99.7^{th} percentile of deltas in global clear sky index over different averaging intervals for the individual sites within the SGP network. Error bars represent +/- one standard error from the mean (N = 23).

deltas are consistently below about 0.6 for 60-min and shorter deltas. For these time scales, deltas larger than 0.6 are therefore likely to occur less than 0.3% of the year. Another way to interpret these results is that for a single site, the average clear sky index over a 60-min period only has a probability of 0.3% of being 0.6 larger or smaller than the average clear sky index in the next 60-min period.

The deltas at individual sites therefore demonstrate that severe changes are possible and that they occur more frequently than expected if the deltas were assumed to have the same standard deviation but be normally distributed. These deltas for individual sites reflect behavior similar to the assumptions used in many of the previous studies on PV integration. Such severe changes in PV output would be technically challenging and expensive to accommodate if they did in fact occur with large scale PV deployment.

A. Correlation of Deltas with Distance

We now turn to a consideration of the correlation of deltas in the clear sky index across a region in order to understand the impact of aggregating the output of several PV sites. Figure 4 shows the correlation of deltas across the time-scales of 1-min to 180-min for pairs of sites at different distances from one another. In addition, the figure includes the line of best fit to Eq. 2. As shown in the figure, we find nearly zero correlation of 1-min deltas between all 23 sites in the SGP network. Even the closest sites in the network, separated by 20.5 km, demonstrate zero correlation in 1-min deltas.

The near zero correlation for sites as close as 20 km was similarly found for 5-min deltas in the clear sky index. For 10-min deltas, however, a slight increase in the correlation between deltas at the closest sites becomes apparent. Hourly deltas exhibit clearer correlation between sites especially for sites that are closer than about 75 km apart. Three hour deltas are correlated for sites that are even farther apart.

The near zero correlation for 1-min and 5-min deltas implies that aggregating output from PV sites at least 20 km apart[2] will smooth, as measured by the standard deviation, the 1-min and 5-min deltas by a factor of $\frac{1}{\sqrt{N}}$. Aggregating the output from sites 20 km apart will smooth deltas over longer time scales to a lesser degree than the deltas for shorter time scales due to the greater correlation of deltas with larger averaging intervals.

B. Aggregate Deltas from Geographically Dispersed Sites

In this section we consider the impact of aggregating geographically dispersed sites. We first aggregate clear sky data from five close sites within the SGP network and then aggregate the data from all 23 sites within the SGP network. Figure 5 shows an example of smoothing from averaging of the global insolation across multiple sites on a partly cloudy day. As expected, the aggregation of the simultaneous output of sites within the SGP network leads to a reduction in the *relative* magnitude of the deltas for all time scales compared to scaling the output of a single site across the entire year, Figure **??**. This reduction in the relative magnitude of the deltas is more pronounced for all sites than for five close sites. The distribution of the 1-min deltas from the aggregation of sites also appears to be more normal in that the tails of the distribution are less pronounced than the tails of the distribution of 1-min deltas from a single site. Aggregating the output from 5 close sites in the SGP network, for example, reduces the magnitude of the most extreme 1-min deltas to below +/- 0.4 from the observed +/-0.8 deltas shown for a single site in the previous section. Aggregating all 23 sites further reduces the most extreme 1-min deltas to below +/-0.2. Assuming that such a severe delta occurred while PV plants were at their rated capacity would lead to a maximum 20%

[2]Or at least 2 km apart for 1-min deltas and 9 km apart for 5-min deltas, according to the data from [17].

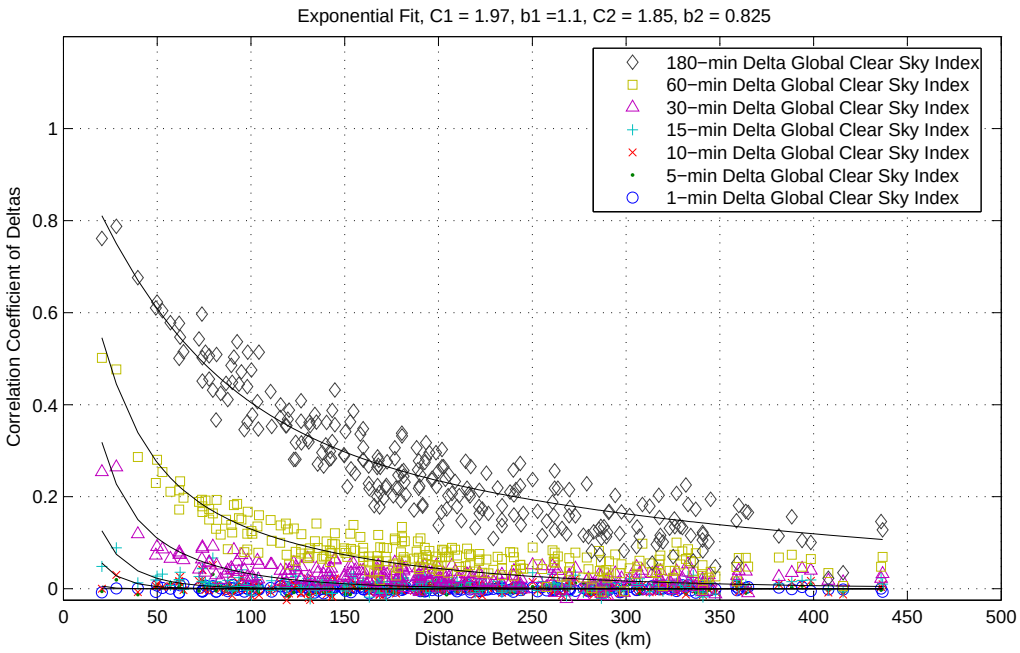

Fig. 4. Correlation of changes in global clear sky index between 23 geographically dispersed solar insolation measurement sites in the SGP network. (—) Fit to the correlation data to the relationship in Eq. 2.

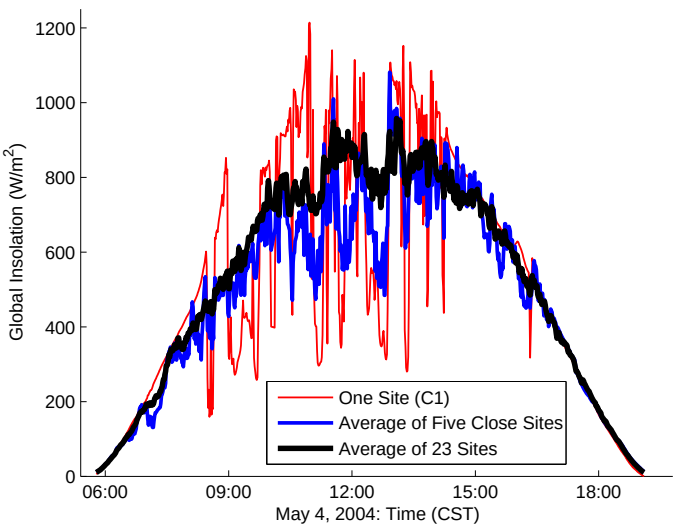

Fig. 5. Example of 1-min global insolation from one site, the average of five close sites, and the average of all 23 sites in the SGP network on a partly cloudy day.

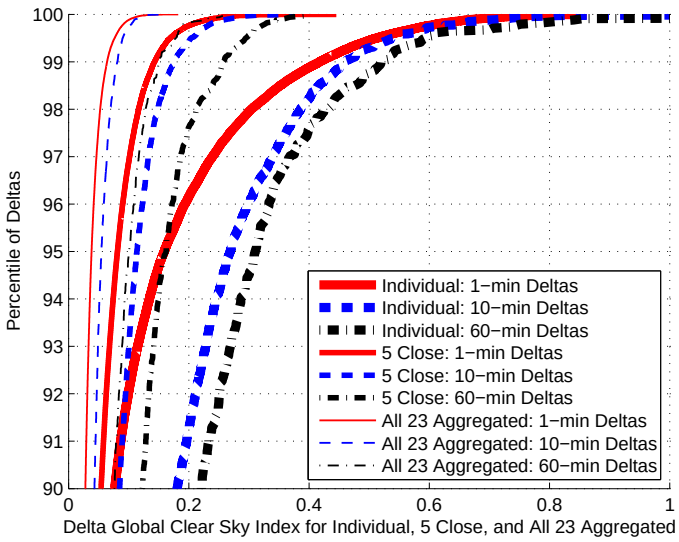

Fig. 6. Cumulative probability distribution of 1-min, 10-min, and 60-min deltas of the global clear sky index for individual sites, five close sites, and all 23 sites in the SGP network aggregated together.

change in the output of all PV plants in 1-min, far below the 80% change that could occur at a single site in 1-min under the same assumptions.

The 99.7^{th} percentile and the standard deviation of the deltas for different averaging intervals is also significantly lower for the five and 23 aggregated sites than for individual sites. For example, if all of the sites in the SGP network were to be aggregated, the balancing resources required to manage 99.7% of the 1-min deltas of the clear sky index would be only 16% of the resources required to manage 99.7% of the 1-min deltas if the same level of PV capacity were developed at an individual site. This compares to a 22% reduction of the standard deviation of the 1-min deltas when moving from an individual site to 23 aggregated sites.

Whereas the deltas are uncorrelated between all sites in the SGP network for time scales shorter than 5-min, Figure 4 shows that there is positive correlation for both 60-min and 180-min deltas between sites in the SGP network. Aggregating the sites that are positively correlated therefore leads to a slightly lesser benefit of geographic diversity than if all of the sites were uncorrelated. The balancing resources required to manage 99.7% of deltas from the 23 aggregated SGP sites

would be 31% and 54% of the resources required to manage 99.7% of the 60-min and 180-min deltas, respectively, from an individual site (this compares to 16% for 1-min deltas, as reported earlier).

C. Comparison of Solar and Wind Deltas from Similarly Sited Plants

One way to put these results into perspective is to compare the expected variability from an array of PV sites to a similarly spaced array of wind sites. We performed a similar analysis for 1-min normalized wind power data estimated from 10 wind speed measurement sites within the SGP network.

The standard deviation of 1-min deltas at individual wind sites was comparable to the 1-min deltas of the clear sky index at individual sites, but the standard deviation of deltas over longer time scales were somewhat less for the wind sites. The 99.7^{th} percentile was significantly less for wind than for solar, especially for 60-min and shorter averaging intervals. Overall, however, deltas for wind were slightly more correlated than deltas for solar (the non-deterministic component measured by the clear sky index) for any given distance, particularly for deltas longer than 30-min. This comparison of the correlation with distance and variability at individual sites suggests that wind is less variable than solar at individual sites, but wind in this region benefits slightly less from geographic diversity than does solar.

Next we use the fit to the correlations based on Eq. 2, the deltas observed at individual sites and Eq. 1 to predict the deltas that would be observed from aggregating an array of wind sites for comparison to a similarly arranged array of solar sites. The array we chose for this section was based on the constraint that we did not want to extrapolate from the data obtained from the SGP network. Since the closest wind measurement sites were 50 km apart, we simulate a 5 $\times$ 5 site square array of 25 sites spaced by 50 km on a grid for both solar and wind (see Figure **??**).

The results of this simulation demonstrate that the standard deviation of the deltas of similarly sited solar and wind plants in the 5 $\times$ 5 array are reasonably comparable, particularly for 30-min and longer deltas. The 99.7^{th} percentile of the 5 to 15-min deltas are notably smaller for wind, however. If balancing resources were procured based on the 99.7^{th} percentile, for example, the 10-min deltas for solar would require nearly double the balancing resources that wind requires.[3] The results also show for both the aggregated solar and wind, the longer time scale deltas are expected to be much larger in magnitude than the shorter time scale deltas. The 60-min deltas, for instance, are double or greater the magnitude of the 15-min and shorter deltas.

D. Potential Cost Impacts

Detailed studies of the changes in power system operations required to manage the short time-scale variability of PV are required to fully understand the cost implications of short-term PV variability. As a first approximation, however, we can use a simple method and set of assumptions to estimate the cost of managing the short time-scale variability of solar. With this simple method, we examine the relative difference in cost of managing solar all based at a single site, solar dispersed over multiple sites, and similarly sited solar and wind. Our comparison lacks any consideration of within-plant smoothing based on geographic diversity, which may be relatively more important for short time scales (1-10 min) for wind in comparison to solar due to the lower areal density of wind plants. Regardless, we rely on a simple method to estimate the additional cost of holding spinning or utilizing non-spinning reserves to accommodate the short-term variability of PV and wind assuming a 10% penetration of wind or solar (on a capacity basis). These costs only address the short-term variability and do not address other costs (e.g., unit commitment costs due to day-ahead forecast errors) or benefits (e.g., capacity value and energy value) of PV.

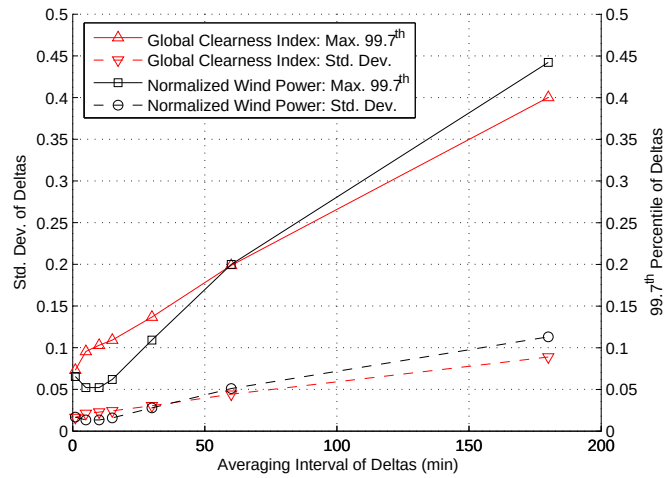

Fig. 7. Comparison of the simulated standard deviation and 99.7^{th} percentile of deltas in global clear sky index to normalized wind power from similarly arranged array of 5 $\times$ 5 grid with 50 km spacing between sites.

1) Estimated Cost of Reserves: The estimated increase in the cost of balancing reserves per unit of variable generation relative to the cost of balancing reserves without variable generation is summarized in Table II. The costs for a single site and five close sites of solar are based on the standard deviation of the deltas for the different time scales observed in Table I. The costs for a 25 site grid of solar and wind are based on the standard deviation of the deltas for the different time scales projected in Figure **??**. Again, the standard deviation is used because we do not use 1-min time synchronized load data from the same region to determine the shape of the distribution of the net load deltas. The results in the four leftmost columns of Table II shows the cost of balancing reserves assuming that to accommodate the increase in solar or wind system operators conservatively increase reserves at a constant level throughout the year ("Reserves Constant Throughout Year"). The column

[3]We tested a variety of different spacings for the array of sites to determine if these conclusions depended on our choice of array spacing. Although the overall shape of Figure **??** changes, the primary conclusions still hold with other array orientations.

TABLE I
SUMMARY OF STANDARD DEVIATION AND 99.7^{th} PERCENTILE OF GLOBAL CLEAR SKY INDEX FOR INDIVIDUAL, 5 CLOSE SITES, AND ALL 23 SITES IN THE SGP NETWORK.

	$\sigma^{\bar{t}}_{\Delta k}$			99.7^{th} percentile		
Deltas	1-min	10-min	60-min	1-min	10-min	60-min
Individual Sites	0.08	0.11	0.13	0.58	0.59	0.60
5 Close Sites	0.03	0.05	0.07	0.19	0.23	0.31
All 23 Sites	0.02	0.03	0.05	0.09	0.10	0.19

on the right shows the increase in the cost of balancing reserves for the 25 site grid of solar assuming, instead, that system operators set the additional reserves knowing that the variability of the solar output will change with clear sky insolation ("Reserves Change with Position of the Sun"). This captures the fact that system operators do not need to maintain reserves for solar at night and fewer reserves are required when clear sky insolation is low. The opportunity cost of capacity, however, is assumed to be based on only the peak net-load hours of the year and therefore does not change from hour-to-hour.

Placing all of the solar at a single point and holding reserves constant throughout the year leads to an increase in the cost of balancing reserves that is large enough to substantially erode any value of adding solar to the power system. Adding the same quantity of solar to the grid at the five locations that correspond to the five closest sites in the SGP network, however, increases the cost of balancing reserves relative to load alone by only about a quarter of the increase in costs from adding the solar at a single point. Further spreading the same quantity of solar to 25 sites in a 5×5 grid leads to an increase in the cost of balancing reserves that is only about 7% of the cost of adding the solar at a single site. Clearly, the number and orientation of the solar systems added to the grid will have a substantial impact on the overall increase in balancing reserves and the associated cost to manage the sub-hourly variability of PV. The earlier studies that scaled the output of single sites and found limits to the penetration of PV based on short-term variability may have come to dramatically different conclusions had they accounted for the potential smoothing effects of geographic diversity.

The cost of balancing reserves for geographically diverse solar sites is also not expected to be substantially different than the cost for similarly sited wind. The slightly greater variability of solar than similarly sited wind for time scales shorter than 60-min projected in Figure **??** leads to a slightly greater increase in the cost of balancing reserves for solar than for wind if the increase in balancing reserves is constant throughout the year. If the required increase in balancing reserves is in proportion to clear sky insolation, however, the cost of balancing reserves for solar can be nearly identical to the cost of balancing reserves for wind. The decrease in the cost of balancing reserves when reserves are held in proportion to clear sky insolation is due to the fact that no reserves are needed for solar at night. The increased costs of balancing reserves for similarly sited solar and wind in a 5×5 grid are modest, but these results should be verified with more detailed solar and wind integration studies.

V. CONCLUSIONS

Our analysis demonstrates that step-changes or deltas in solar insolation at individual points can be severe. Infrequent step changes from one averaging interval to the next with averaging times from 1-min to 180-min can exceed 60% of the clear sky insolation. The distributions of sub-hourly deltas at individual sites are fat-tailed relative to a normal distribution. The 99.7^{th} percentile of the deltas, therefore, is much larger than three standard deviations.

Previous studies of the integration of PV into the electric power system demonstrate that scaling the output from an individual solar site leads to limits of the penetration of PV on the grid. The limit is due to the additional balancing resources required to accommodate the variability of PV plants, and the variability over short time scales (sub-hourly) is found to be particularly challenging to accommodate. Increasing balancing reserves to accommodate the variability of solar located at a single point is estimated to lead to a significant increase in costs and, as suggested by earlier studies, could limit the amount of solar that can be added to the power system.

As is well known for wind, however, accounting for the potential for geographic diversity can significantly reduce the magnitude of extreme deltas, the resources required to accommodate variability, and the potential increase in balancing reserve costs. The aggregate of just five close sites in the SGP network show that 99.7% of the 15-min and shorter deltas are no larger than 25% of the expected clear sky output of the aggregated sites. We also find that the sub-hourly deltas from similarly sited solar and wind are expected to be within the same order of magnitude, though deltas in the 5-15 min range are expected to be somewhat more severe for solar than for wind.

The cost of accommodating the short-term variability of similarly sited solar and wind plants is expected to be comparable in this region, but further research is required to understand the costs of managing the variability and the within-plant smoothing for solar that can occur on shorter time scales.

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TABLE II
ESTIMATED UNIT COST OF RESERVES TO MANAGE SHORT-TERM VARIABILITY

Time Scale	Increased Reserve Costs ($/MWh)				
	Reserves Constant Throughout Year				Reserves Change with Position of Sun
	Solar			Wind	Solar
	1 Site	5 Sites	25 Site Grid		
1-min Deltas	$16.7	$4.8	$1.2	$0.9	$0.8
10-min Deltas	$17.3	$4.4	$1.0	$0.2	$0.7
60-min Deltas	$5.0	$1.6	$0.6	$0.5	$0.5
Total Cost	$39.0	$10.8	$2.7	$1.6	$1.9

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