OBSERVED FLUCTUATIONS IN OUTPUT FROM A REGIONAL FLEET OF PV POWER PLANTS USED TO COMPUTE HOURLY SCHEDULES OF SPINNING RESERVE REQUIREMENTS

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ABSTRACT: We examine fluctuations in power from an 80 MW fleet of utility scale power plants deployed around Tucson, Arizona, and a 500MW fleet deployed throughout Arizona and New Mexico. We observe that individual plants exhibit frequent rapid changes in power, greater than 50% of nameplate capacity in less than one minute. The aggregate fleet generally has slower ramps. Local utilities face the challenge of addressing this variability in a cost effective manner. We present a method to use historical data to estimate appropriate spinning reserves for variability mitigation for each hour of the day for different seasons. We contrast the results for recommended reserves when calculated on a fleet wide basis or when summed from a plant by plant basis.
Keywords: Utilities, Large Grid-connected PV systems, Grid Management, Grid Stability

1 INTRODUCTION

What measures should grid operators deploy in response to the variable power output from PV plants? PV power can fluctuate quite rapidly due to passing clouds. Changes in output over the course of one minute as large as 50% of a PV power plant's AC-capacity have been observed for utility scale (multi MW) PV power plants in several locations [1]-[3]. This variability can lead to mismatches between supply and demand, and potentially raise the cost of integrating solar power plants into the electric grid. From the point of view of a local utility, an individual power plant may generate enough variability to warrant special measures [4], however in large interconnected grids this is generally not the case.

Previous studies of PV plant variability have generally focused on classifying the variability of individual days, for example by computing the Daily Aggregate Ramp Rate (DARR) [1], Variability Index (VI) [5], or Cumulative Distribution Functions (CDF) for changes in irradiance [2]. Several studies have also considered the impact of geographic dispersion on aggregate ramp rates either by direct measurement of PV plant output or by measurement of irradiance [6]-[9]. In this paper we explore CDFs made using historical production data on an hour by hour basis and introduce a method to recommend schedules for spinning reserves. We also show how the geographic distribution of these PV plants affects the resulting recommended schedules for fast acting reserves.

In the United States the interconnected electrical grid is a cooperative effort between a large number of relatively independent local utilities. Government regulation is applied at several levels with various objectives including increased system reliability and reduced cost for consumers. The Western Interconnect is divided into a number of regions identified as Balancing Authorities (BA). Each BA is responsible for seeing that the net inflow and outflow of power through its perimeter is within scheduled amounts. In case of a disruption, power will naturally flow without respect for these boundaries to fill in for missing generation or excess load. This is referred to as inadvertent interchange. One challenge for a BA is managing PV variability without accumulating excess inadvertent interchange. Maintaining an appropriate amount of spinning reserves is a potential solution to this issue. This is why we are motivated to generate a recommended schedule of reserves to support PV fleets in various seasons.

The cloud patterns above various PV plants in a region may be somewhat uncorrelated [6], resulting in an aggregate fleet of power plants whose fluctuations occur at different times and therefore do not result in coordinated dropouts. The relative locations of these plants will impact the degree of coordination. Spreading plants out over a larger area should reduce the total observed fluctuation level. This is the well known Portfolio Effect which has been discussed in [1,6 - 11]. What is not well known is how the portfolio effect will change a recommended schedule of reserves.

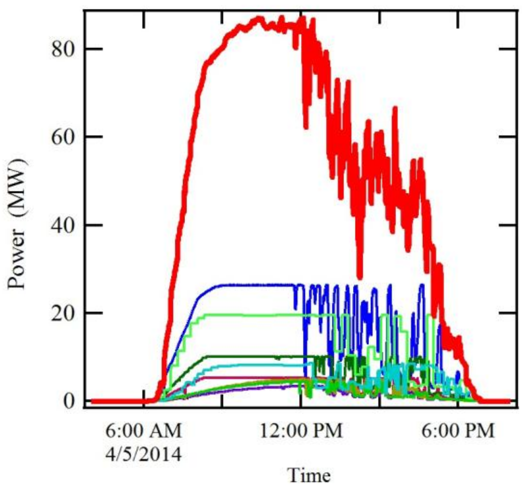

Figure 1: Output from a fleet of 8 PV power plants near Tucson, AZ. The thick red line indicates the sum of all 8 power plants; the smaller lines show output from the 8 individual systems.

This paper is concerned with determining reasonable amounts of spinning reserves which a local utility, Tucson Electric Power (TEP), should carry in anticipation of fluctuations in output from a fleet of PV power plants. We consider this by time of day and by season of year. One implication of the portfolio effect is that the total reserves required for the fleet is generally less than the sum of reserves needed to compensate for fluctuations from each individual plant. To test this prediction we calculate the values of recommended reserves using historical production from individual plants and also compare these to schedules calculated using historical data for aggregated production from the entire fleet.

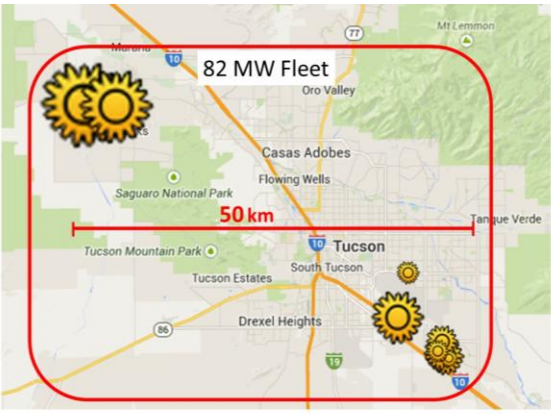

Figure 2: Locations of PV sites around the Tucson area. One additional 10 MW plant in the TEP service area is included in the study and is located approximately 500 km northwest of Tucson.

2 POWER FLUCUATION SCHEDULE

To determine required reserves we consider the fluctuations in power from a fleet of megawatt scale power plants located in the desert southwest of the United States. The combined output of these eight plants regularly peaks at 82 MW. These sites comprise roughly 50% of the total PV power in TEP's service territory. The balance of PV power in the region comes largely from Distributed Generation, in the form of several thousand commercial and residential systems.

We developed an analysis to characterize patterns in the PV power fluctuations and used these characterizations to generate profiles of typical fluctuations at each hour of the day. Our intention is to quantify the amount of dispatchable reserves that TEP should carry as spinning reserves in order to manage PV variability on a 1 to 15 minute time scale. So for this study we start with 2 second power data provided by TEP for each plant. For each time interval we identify the largest observed increase or decrease from current output over a 15 minute rolling window. A fluctuation time series is presented for a single day in figure 3. The 15 minute window size is used as it meets or exceeds the response times required for some traditional generation sources to efficiently respond to fluctuations. A typically observed trend is that there is nearly zero variability at night, some variability in the morning and increased variability in the afternoon, with maximum fluctuations between the hours of 3pm and 5pm. A useful estimate of required reserves will therefore have a daily schedule with different values for each hour of the day. Seasonal effects will be considered in Section 4.

We considered total fluctuations for the fleet in several ways. First we consider the simple aggregated output of the sites. This necessarily includes the impact of sunrise and sunset. To account for this we determined clear sky profiles for each site. These clear sky profiles are computed for each day of the year so that seasonal changes in sunrise and sunset times, peak power, clipping, etc. are considered on a daily basis. By subtracting the clear sky profile from the PV output we are able to remove this predictable source of fluctuation. Figure 4 is representative of fluctuations observed on a clear sky day. Figures 1,3,4 and 5 do not have the clear sky profile removed. All other figures are created after subtracting the clear sky profile.

Upon close examination we infer that the observed worst-case events are not directly weather related. Interconnect-wide events such as frequency out of range can trigger some number of inverters at the PV plants to automatically disconnect. More localized events such as transient low voltage can also induce local disconnections of PV inverters in the region. While we observe a small number of partial dropouts due to both of these types of disruptions in the dataset, we also note that utility scale power plants are exempt from the UL 1741 requirements. We have never observed a total loss of all PV power from these plants as a result of a frequency or voltage disruption.

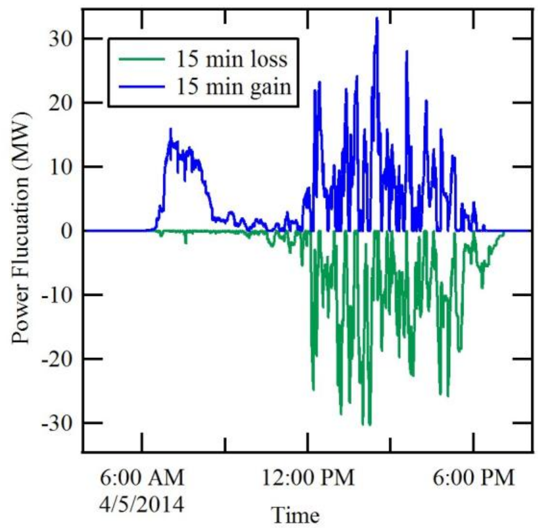

Figure 3: 15 min power fluctuations observed for the aggregate power in fig 1. The blue line represents the maximum amount of power increase over next 15 minutes. The green line is the maximum observed decrease in power over the next 15 minutes.

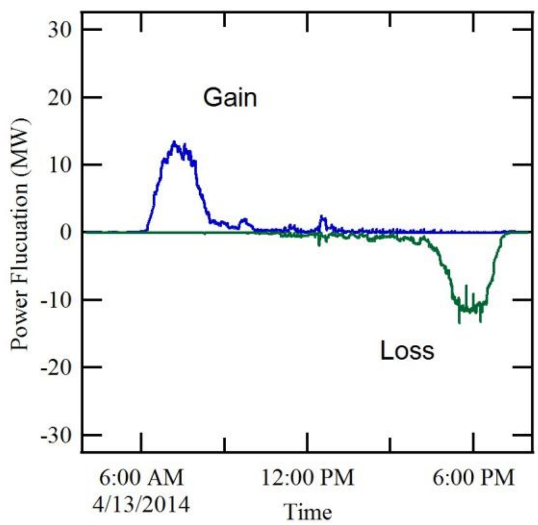

Figure 4: Observed fluctuations in power from the 82 MW fleet for a nearly cloudless day. The major source of power change is sunrise and sunset.

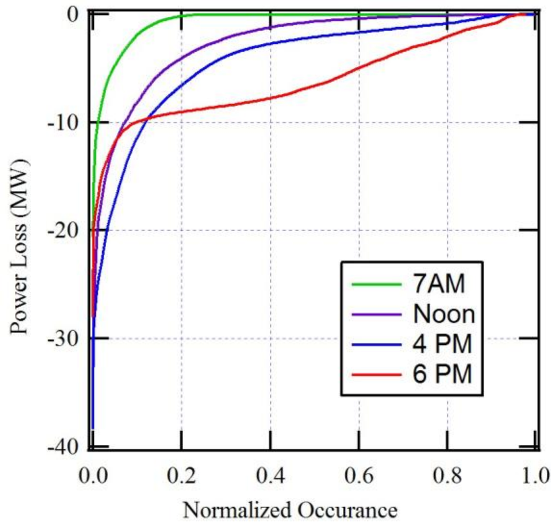

Figure 5: Normalized CDF plots of maximum power decrease in a 15 min window during selected hours of May through August 2014 from the 82 MW TEP utility scale fleet. The clear sky profile has not been removed, and this highlights the impact of sunset during the 6 pm hour. The time indicates the start of an hour bin.

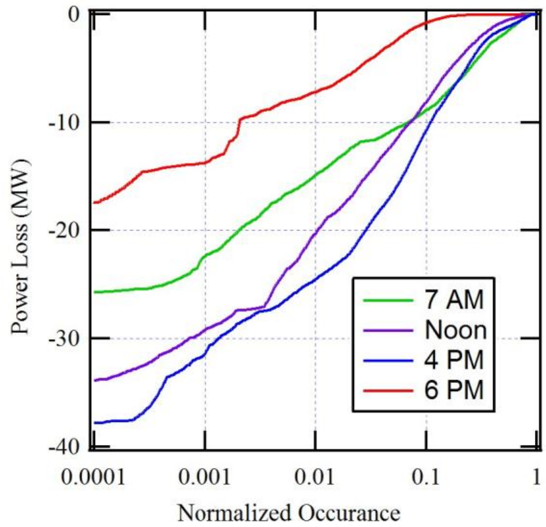

Figure 6: CDF plot showing the same values as figure 5 except that the clear sky profile has been subtracted and put on a logarithmic scale to highlight the rare occurrence events. The observed 15 minute dropout during the 4pm hour was less than 10 MW 90% of the time and less than 25 MW 99% of the time.

To understand typically observed fluctuations we divide the year into three seasons, based on regionally appropriate weather patterns. During the summer, defined here as May through August, Tucson experiences a monsoon season with frequent cloudy days and occasional heavy rainstorms. During the winter months, defined as December and January, Tucson also receives some rainfall. Throughout the rest of year there are occasional clouds and dramatically less rain. The fluctuation data is further binned by hour of the day during each season. The results are displayed in terms of cumulative distribution function (CDF) plots, shown in figures 5 and 6.

Examination of the CDF in figure 6, which has the impact of sunset removed, lends support to the initial assessment that afternoons in the summer are more variable than the mornings. Furthermore by selecting a percentile level it is possible to quantify typical patterns of fluctuations. For example we can interpret figure 6 in the following way: After measuring current production at any point during the noon hour, historically we have seen that the maximum decrease in power over the next fifteen minutes will exceed 8 MW just 10% of the time. Alternately 90% of all power measurements during the noon hour were followed by a maximum decrease over the next 15 minute period of less than 8 MW. The 4 pm result is slightly higher at 10 MW.

3 SPINNING RESERVE CONSIDERATIONS

A general planning method for spinning reserves in a utility is the n-1 consideration, in which the utility considers the unexpected loss of the largest single generation asset [12]. In a similar vein the operator may consider the unexpected loss of a portion of PV power and designate an amount of reserves to compensate for likely dropouts. PV fluctuations are distinct from the loss of a generation asset in at least two ways. Firstly they occur frequently but irregularly and secondly there are relatively common events where the magnitude of dropout in the aggregated power exceeds the size of the largest single PV plant. For these reasons an n-1 approach may not be appropriate. Instead this paper recommends that a utility such as TEP may schedule reserves for PV on a probabilistic basis. For TEP's reliability planning purposes at the current PV penetration level of less than 20% by power, the consideration of a once per year event is likely not necessary. For now the motivation for reserve scheduling may be primarily for economic benefits and not necessarily a requirement for grid reliability. In this case the level of recommended reserves can be based on only commonly observed fluctuations.

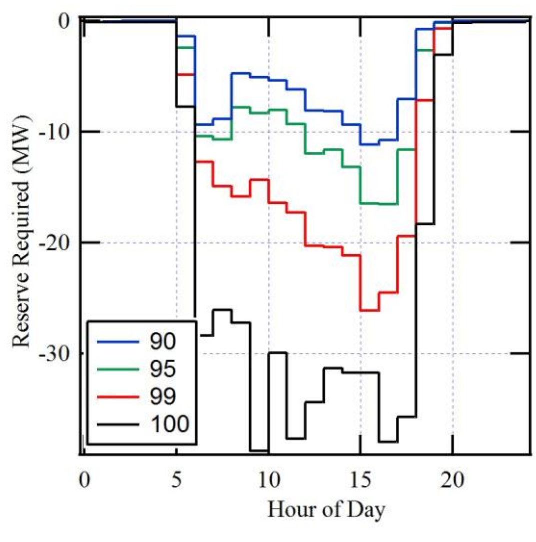

Figure 7: Frequency of observed dropouts binned by hour of day. The black line indicates maximum observed loss. The red line indicates a schedule for the 99th percentile of losses each hour of the day. Green and blue represent the 95th and 90th percentiles respectively.

We suggest the following approach for constructing this schedule: Using the CDFs demonstrated in figures 5 and 6 one may construct a schedule of recommended reserves for each hour based upon observed fluctuations for that hour of the day. For example we see that only 1% of the time do we observe a dropout in excess of 25 MW at 4pm. Based on this historical data we then posit that 27 MW of spinning reserves should be able to compensate for fluctuations 99% of the time during this hour. While the maximum observed dropout at nearly any hour between 9 AM and 6 PM is in excess of 30 MW, the cost for carrying this level reserve may be unjustified. Figure 7 shows probabilistic schedules for power loss. We can use the schedules to develop a schedule of recommended reserves required to meet dropouts during the summer months with various levels of frequency. As an example we suggest that the utility consider the 95th percentile.

A more complete picture will include both the anticipated dropouts and the sudden increases in power as well. This is intended to give the utility information concerning the total dynamism they can expect. Using the same methods to map out dropout occurrences we also map out increases. The result is a combined plot of both dropouts and increases as shown figure 8. Sunset and sunrise, and other seasonal predictable changes in power have accounted for in the analysis in figure 8.

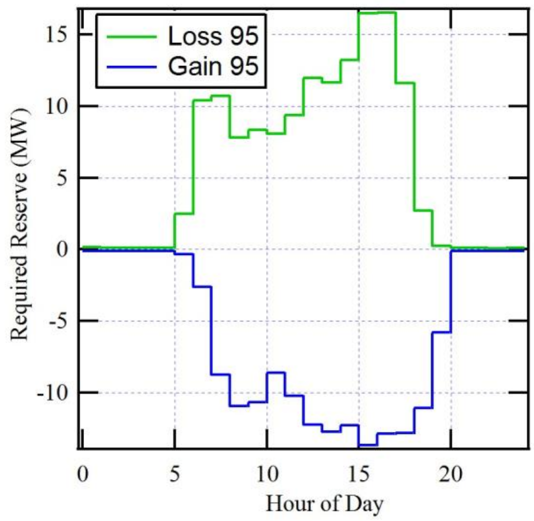

Figure 8: A schedule of reserves required to compensate for 95% of the observed fluctuations in power from fluctuations from an 82 MW fleet of 8 power plants during the summer months. Positive values indicate that the reserve must generate power to compensate for a dropout. Negative values indicate the reserve must act a sink to absorb power.

4 SEASONAL COMPARISONS

The difference in weather between the spring and summer in the southwest is well known. Spring days are more frequently clear than days in July. We find that the computed reserves for February through April are smaller than those required May through August. However we acknowledge that the reduction in reserves is not especially great. Figure 8 shows the required reserves to meet power dropouts at the 95th percentile. We propose three factors to understand this result.

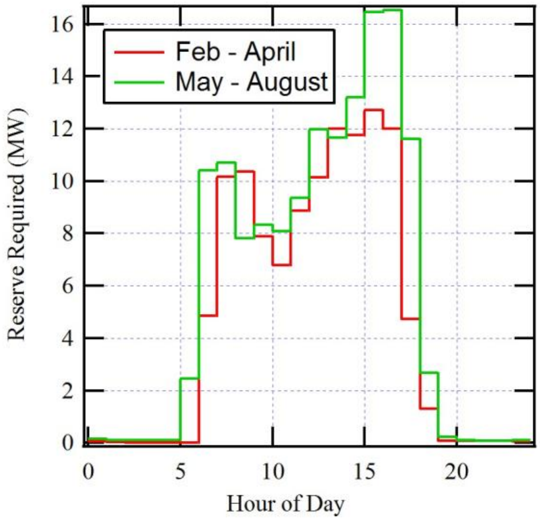

Figure 9: Computed reserves required by hour for two seasons in Tucson. These reserves are estimated to be sufficient to meet fluctuations in an 82 MW fleet 95 percent of the time.

Firstly the peak PV output is generally higher in these months, especially for the fixed tilt systems which comprise roughly 15 MW of the fleet. This is result of cooler temperatures and a more optimal sun position. The output has farther to fall when clouds do appear. Secondly the majority of the fleet is of the single axis tracker variety. Several of those installed in the TEP service territory have high DC/AC ratios and therefore clip much of the summer. This results in the SAT systems having some ability to reduce fluctuations due to optically thin clouds. During the spring however these systems do not clip as much and are more vulnerable to thin clouds. Finally fluctuations are driven by variability in cloud cover. There may be a qualitatively different nature to the clouds present during these seasons. Very patchy cloud cover can generate a great deal of fluctuation but with uniform cloud cover, fluctuations can actually decrease.

5 THE PORTFOLIO EFFECT

At present the existing fleet of PV power plants may not exhibit sufficient fluctuations to warrant allocation of additional quantities of spinning reserves. Present projections suggest that within 10 years the peak power required from all PV in the TEP service area should exceed 1 GW in order to comply with the renewable portfolio standard mandated by the Arizona Corporation Commission. A useful question then is, how valid are these results when the PV fleet is scaled up? We can address this two ways. Firstly we can consider the result if we had simply computed the required reserves for a single plant and up-scaled the resulting schedule by ratio of the current fleet to the size of the single PV plant. Alternately we can consider the result if we examined a larger fleet of PV power plants situated throughout the entire state of Arizona.

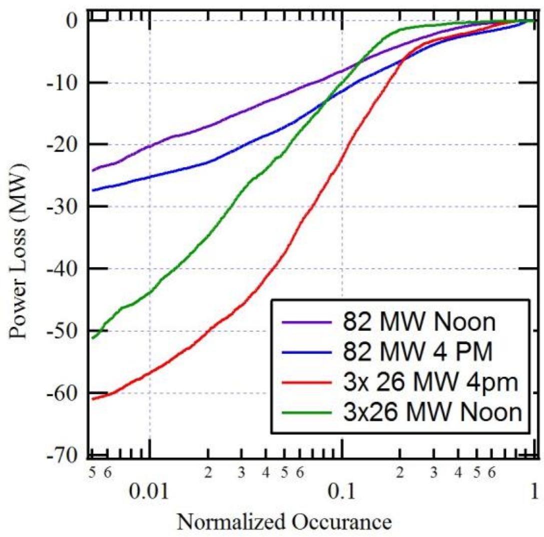

Figure 10: Comparison of fluctuation CDFs at noon and 4 pm for the aggregate 82 MW fleet and a single upscaled 26 MW PV plant.

The largest single power plant currently in the TEP fleet is the NRG Energy single axis tracker system in Avra Valley whose peak output is 26.5 MW [13]. Figure 10 illustrates the result of simply scaling the resulting fluctuations for noon and 4pm by a factor of 3 in order to imitate a 78 MW power plant at that same location. We note that the site demonstrates less than average fluctuations much of the time. This is likely due to the design of the site. TEP reports that the site has a relatively high 1.3 DC/AC ratio [13]. This results in inverter clipping and provides some resistance to fluctuations from optically thin clouds. However the site does experience relatively severe dropouts that occur much more frequently than is observed for the entire fleet. This example of the portfolio effect in the Tucson region reduces the required level of reserves. A reserve schedule based upon the same 95th percentile as earlier but generated only using historical data from the NRG site would require nearly double the reserves of what was found by examination of the fleet wide fluctuations.

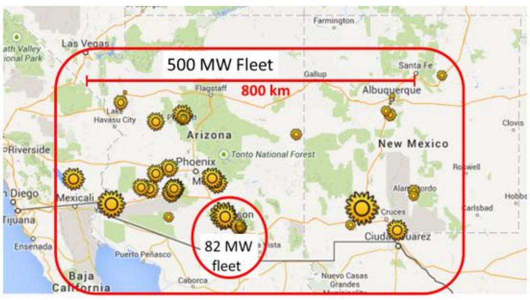

Figure 11: Map of the 82 MW fleet, and 500 MW fleet showing the PV power plant locations (and sizes) for the data analyzed in this paper. The relative size of the sun icons indicates the rated power of each PV generating station.

An alternate approach is to consider the nearly 500 MW of PV power jointly reported by the Southwest Variable Energy Resource Initiative, comprised of 7 utilities including TEP, APS, SRP, PNM, IID, WALC, and EPE [14]. Aggregated PV power from seven utilities across the American southwest are reported as a single time series. This total amount of PV approaches half the anticipated requirements of TEP in 2025 but is spread over a much larger geographic area. Figure 12 compares fluctuations from the entire fleet of SVERI PV power plants and the TEP PV fleet by down-scaling the fluctuations in the SVERI fleet by a factor of 6.

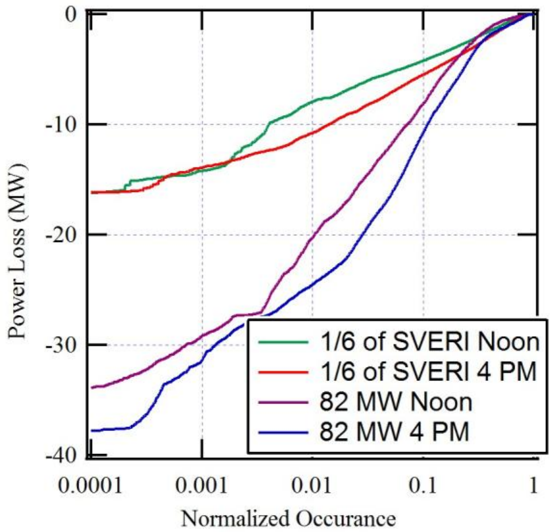

Figure 12: Comparison of down-scaled fluctuations from the 500 MW SVERI PV fleet to the 82 MW TEP fleet at noon and 4pm.

Figure 12 suggests that the fluctuations observed from an 80MW share of the 500 MW fleet warrant a smaller proportional reserve than the TEP only data does. For most hours of the day the TEP share of the SVERI fluctuations, calculated at the 95th percentile, would be slightly less than half of what the TEP only calculations would indicate. Scaling the SVERI wide fluctuations to the TEP service area is somewhat problematic as it introduces geographic diversity not possible strictly within the TEP service area.

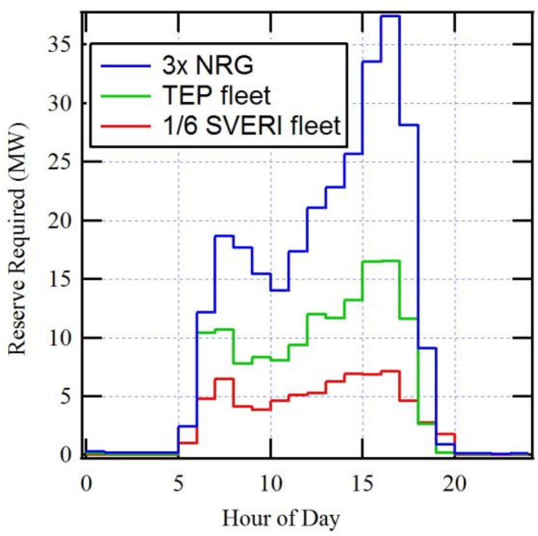

Figure 13: Recommended schedule of reserves for an 82 MW fleet computed in three ways; directly from the from the aggregated power of the 82 MW TEP fleet, up scaling the single 26 MW NRG site by a factor of 3, and finally dividing the SVERI 500 MW fleet by 6.

We also note that as the geographic area increases, the perimeter of the region and thus the bandwidth of connections to the larger interconnect will grow more slowly. The tolerance then for extreme events is reduced; as a result the whole the SVERI group should perhaps carry sufficient reserves to accommodate events at a higher level than the 95th percentile.

6 CONCLUSION

In summary we have presented schedules of reserves that would be required to manage historically observed fluctuation from PV power plants. Using a cumulative distribution function (CDF) for power fluctuations for each hour of the day and selecting, for example, the 95th percentile of power loss results in a schedule of recommended reserves sized 10 to 15 MW (greater in the afternoon) to backup an 82 MW fleet of PV power plants in TEP's service territory. The Portfolio Effect was explored in two ways. First, based upon fluctuation of a single 26 MW site. If a 78 MW plant were located all at this site, the recommended reserve nearly doubles to become 17–33 MW. Conversely if the 82 MW is taken as a share of a much larger 500 MW fleet distributed throughout Arizona and New Mexico the schedule of recommended reserves is reduced by roughly half to 5-7 MW throughout the day.

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