SOLAR AND POWER MARKETS: PEAK POWER PRICES AND PV AVAILABILITY FOR THE SUMMER OF 2002

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ABSTRACT

The analysis presented in this paper builds off of early work to measure the capacity value of PV technology. In an era of electric power competition, it is equally important to demonstrate the relationship between PV capacity values and peak power prices in different, wholesale power markets. The authors conducted such an analysis for different regional power markets during the summer of 2000. They found that PV power is readily available during periods of peak power prices. This paper presents updated results for the summer of 2002. Results from two different regional power markets for the summer of 2002 are presented. Again, we show a strong relationship between peak power prices and the availability of PV power in the markets analyzed. Several important policy implications result from this analysis.

1. INTRODUCTION

The load matching capability of photovoltaic (PV) power generation with U.S. utility loads has been well established [1]. Letendre, Perez, and Herig [2] presented the first analysis of the relationship between peak power prices in several power markets and the availability of the solar resource. This study was in response to the changing electric utility landscape, whereby regulated power prices are being replaced with market-based pricing. In a deregulated market, the relevant analysis with regard to PV’s value deals with the relationship between peak power prices and the availability of PV output. In the authors’ previous study they found a strong relationship between PV availability and incidents of peak power prices during the summer of 2000 [2]. This paper updates this earlier analysis by looking at market-clearing electricity prices for the summer of 2002 in New York and the mid-Atlantic region.

2. POWER MARKETS AND PEAK PRICES ANALYSIS

Different regions of the country have different market structures in place for the purchase and sale of electricity. The process of electric utility restructuring has facilitated the operation of several competitive power markets across the country. This paper focuses on four different markets: California, New England, New York and PJM (the power market that serves major portions of the five mid-Atlantic states and the District of Columbia). Data from these power markets was obtained for the summer months of 2002 (May – September). The dates and times when, and locations where, power prices equaled or exceeded 20¢/kWh were identified for these different power markets.

The California energy market has been radically altered after the summer of 2000, when power prices skyrocketed and the state was plagued with rolling blackouts. As a result, increased state intervention and the disbanding of the California Power Exchange have virtually eliminated the bulk, wholesale power market in the state. The California Independent System Operator does however maintain a balancing energy spot (real-time) market. The market clearing price in
this market never exceeds the 20¢/kWh threshold described above. As part of the plan to stabilize energy prices in California, the Federal Energy Regulatory Commission imposed a price cap of $91.87/MWH for power sold in California’s balancing energy market.

PJM is the organization responsible for managing power markets and operating the power grid along the central, eastern seaboard. PJM operates both a day-ahead and hour-ahead market for bulk power. Like PJM, the New York Independent System Operator (NYISO) manages the NY power grid and operates day-ahead and hour-ahead markets for power. The market-clearing price in these markets is referred to as the Locational Based Marginal Price.

The New England ISO operates the New England electric grid and manages the wholesale power market in New England. It used to simply conduct a real-time market for power. They have recently undergone market restructuring. As part of the restructuring, the New England ISO now operates a day-ahead and hour-ahead market for power in New England, which is more in line with the PJM and NYISO market structures. These changes took effect during the late winter of 2003. The NE-ISO provides information on market clearing prices that used to be called the real time marginal price. Now the market-clearing price in New England is referred to as the locational marginal price.

Data on market clearing prices for all these markets were obtained and analyzed. Table 1 above indicates the number days in each market when the market clearing price was equal to or exceeded the 20¢/kWh threshold. Based on the data presented in Table 1, 65 percent of the 76 days with peak power prices occurred in July and August. In addition, the New York power market had the most days when power spiked above 20¢/kWh, 30 in the hour-ahead market and 9 in the day-ahead market. PJM was not too far behind with 24 days with peak power prices in the hour-ahead market and 11 days in the day-ahead market. There were very few days in New England when power prices spiked, only two. As a result, the remainder of this paper focuses on the NYISO and PJM wholesale power markets.

Although California does not currently have a functioning wholesale power market, the California ISO does issue electrical emergency notices when reserves are getting tight. The ISO issues either stage one, two or three electrical emergency notices. A stage one emergency is issued when reserves drop below seven percent and a stage two emergency is issued when reserves drop below five percent. Finally, a stage three emergency is issued when reserves drop below one and one half percent. At each of these stages, different measures are taken to conserve energy and reduce loads. The first 2002 stage one electrical emergency was issued on July 9. The second stage one emergency was issued on July 10, 2002. The July 10th electrical emergency was upgraded to a stage two. With a stage two emergency, voluntary interruptible customers are asked to curtail load.

3. SOLAR AND POWER MARKETS

Satellite-based solar resource assessment is a technique that has been developed and validated by several laboratories in the U.S. and abroad. This approach to resource assessment frees researchers from the limitations of traditional solar resource data given that solar resource data are not typically available for specific locations at specific times. Satellite derived resource data have been shown to be a reliable estimator of the actual ground-measured solar resource data [3]. As describe above, NREL has been utilizing satellite-based resource data to investigate the effective capacity of PV for U.S. electric utilities. In addition, solar satellite derived resource data have been utilized to assess market opportunities for PV technology on a state-by-state basis [4]. This paper utilizes this resource assessment technique to assess the relationship between peak power prices in different regions and PV availability.

| TABLE 1: NUMBER OF PEAK PRICE DAYS IN DIFFERENT POWER MARKETS SUMMER 2002 |
|------------------|------|------|------|------|------|
| PJM              | May  | June | July | Aug. | Sept.|
| Day-Ahead        | 3    | 1    | 2    | 5    | 0    |
| Hr.-Ahead        | 7    | 1    | 4    | 8    | 4    |
| NY-ISO           |      |      |      |      |      |
| Day-Ahead        | 0    | 0    | 2    | 6    | 1    |
| Hr.-Ahead        | 3    | 3    | 9    | 11   | 4    |
| ISO-NE           |      |      |      |      |      |
| Hr.-Ahead        | 0    | 0    | 1    | 1    | 0    |
Satellite derived solar resource data were obtained for all the dates, times, and locations when prices spiked in both the markets described above. The time- and site-specific solar resource data was used to calculate a measure we call PV availability. The PV availability (percent value) statistic represent the fraction of what a PV system would produce if the sky was ideally clear.

We calculate two different PV availability measures. The daily PV availability represents how a PV system would have performed throughout the entire day when the peak price event occurred. A daily PV availability rating of .70 indicates that a south facing appropriately angled PV array would be produce 70 percent of its ideal output, or rated output, during the day when power prices spiked upward. Our second measure, peak time PV availability, measures a PV system’s performance during the exact time of day that the peak power price event occurred. In this case, a .70 peak time PV availability measure would indicate that the PV system was performing at 70% of its ideal output during the hour(s) when power prices spiked. Both measures of PV availability were calculated based on peak price events in the NYISO and PJM wholesale power markets.

3.1 PV Availability and Peak Prices for New York, Summer 2002

In the NYISO’s control area, daily and peak time PV availabilities were calculated for four different regions corresponding to the different market zones: Hudson, Lower Hudson, Long Island, and NYC. If peak power prices occurred in more than one region on any particular day, an average across regions was calculated. These can be considered NYISO region-wide PV availability statistics.

Figures 1 and 2 below present summary data in chart form on daily and peak time PV availabilities respectively. The daily PV availabilities range from a low of .23 to a high of .97. In contrast, the peak time PV availabilities range from a low of 0 to a high of .99. Some peak price events occurred during the evening hours when the solar resource is not available; thus, these events receive a peak time PV availability rating of zero.

These evening peak price events could demonstrate a potential time lag in the market’s response to system-stressed days. Thus, distributed PV may not be producing power during the time when prices spike, but its existence on the grid may have alleviated stress during the daytime hours thus keeping power prices from spiking during the evening hours. We calculate an average adjusted peak-time PV substituting the daily PV availabilities for the peak time PV availabilities with zero values. This statistic is useful when compared to the separate average daily and peak time PV availabilities, as is done in Figure 3 below by region.

The average daily PV availability statistic for all 32 peak power price days in the summer of 2002 is .79. Thus, on average, in the NYISO control area, distributed PV systems would be operating at roughly 80 percent of their ideal output during the days when power prices spike in the wholesale market. The average peak time PV availability statistic is .55, thus we see a significant drop when we look at the solar resource during just those hour(s) when the peak power price occurred. The adjustment to account for time lags described above yields an average PV availability of .77. The average daily and peak time PV availabilities by the four regions in New York are presented in Figure 3, along with the adjusted PV availabilities to control for potential time lags.

Fig. 1: Peak Price Days and Daily PV Availability for NYISO, Summer 2002

Fig. 2: Peak Price Days and Peak Time PV Availability for NYISO, Summer 2002
3.2 PV Availability and Peak Prices for PJM, Summer 2002

In the PJM service territory PV availabilities were calculated for three sub regions: North (greater NYC), Central (greater Philadelphia), and South (greater Baltimore). Averages were again taken to represent PJM-wide PV availabilities for each day when power prices spiked to 20¢/kWh or above for both daily and peak time PV availabilities. Figures 4 and 5 below present the summary data for the PJM control area. Daily PV availability values range from a low of .36 to a high of .98 and peak time PV availability values range from a low of 0 to a high of .98.

The average daily PV availabilities for all peak power days in PJM’s control area is .81 and .72 for the average peak time PV availability. Replacing the zero peak time PV availability values with daily PV availabilities results in an average of .80. Average daily, peak, and adjusted PV availabilities for the three PJM regions analyzed are presented in Figure 6 below.

4. CONCLUSIONS

Wholesale power markets have now been functioning in different regions for several years. Data on market clearing prices is readily available from three of the nation’s largest power markets: New York, New England and the mid-Atlantic region (PJM). Economic theory suggests that when a commodity becomes scarce, prices should rise in response. Thus, as the demand for power approaches the maximum available capacity in a given control area, we would expect to see price spikes during these periods. During the months of May-September of 2002, we can observe this market behavior in the power markets analyzed.
Photovoltaic (PV) technology represents a growing, clean source of distributed power. Past research quantified the capacity value of PV for different regions across the United States. As described above, we would expect a strong relationship between peak system load requirements and peak power prices. Thus, we would also expect a strong relationship between PV output and peak power prices. An earlier analysis by the authors confirmed this relationship using market-clearing data for the summer of 2000.

This paper provides further evidence that PV output is readily available during peak power price events. During the summer of 2002, the average daily PV availabilities for the New York control area and the PJM control area was roughly .80. This indicates that distributed PV systems within these areas would be operating at roughly 80% of their ideal output during the days when power prices tend to spike to 20¢/kWh and above. The peak time PV availabilities are lower than the daily values (.55 NYISO and .72 PJM), due to the fact that some peak price events occur during the evening hours. Adjusted peak time PV availabilities were calculated in which the zero values were replaced with the daily values for that day. These adjusted PV availabilities are much closer to the daily PV availability averages (.77 NYISO and .80 PJM).

The empirical evidence presented here, and in other papers, demonstrates the value that PV can play in power markets across the nation. Given the strong relationship between peak power prices and PV availability, the widespread use of distributed PV could effectively serve as a hedge against price spikes in wholesale markets for power. Further research is needed to evaluate the level of PV penetration needed to put effective downward price pressure in different regions of the United States.

The findings presented here also support higher payments to net-metered customers with annual net excesses of energy from their PV systems. Currently, most states with net metering do not compensate PV system owners who produce more power than they consume in an annual cycle. Those few states that do compensate PV system owners with excess production, do so at their avoided costs. This seems to create a fundamentally unfair situation, where the utility company is obtaining peak power, which is highly valued in power markets, at a low cost. Furthermore, customers on time-of-use rates are providing valuable, peak power during the day, and then spin their meters backward during the evening when time-of-use rates tend to drop. In sum, customers are not currently able to capture the high value that their PV systems create as a source of energy readily available during days when power prices are there highest.

5. ACKNOWLEDGEMENT

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6. REFERENCES