THE AUGUST 21, 2017 TOTAL SOLAR ECLIPSE

SPP Impact

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DISCLAIMER

This report was prepared by SPP Staff and is intended for informational use only.

EXECUTIVE SUMMARY

On Monday, August 21, 2017, a total solar eclipse will pass over North America. Areas under the path of totality, including parts of Nebraska, Kansas, and Missouri will experience a complete blackout of the sun for up to two minutes and forty seconds. Other states in the SPP region will experience a partial eclipse of 80% solar obscuration or greater. The duration of the partial eclipse will affect the area for approximately 3 hours, with the first effects beginning at the western edge of the footprint around 11:30 AM and ending at the eastern edge at around 2:45 PM.

During the eclipse, demand changes and reduced generation from renewables will impact net system load as a result of the reduced solar radiation affects on temperatures and wind speeds. The reduction in solar radiation will reduce the output of solar photovoltaic (PV) generation across the region. A decrease in the output of PV resources connected to the distribution system will appear to be an increase in load from the transmission system perspective. As the sky darkens midday, the demand from lighting usage will increase. These factors will be counteracted by a potential drop in demand for electricity as millions of people nationwide make efforts to view the eclipse. If SPP anticipates significant volatility resulting from these impacts, additional generation resources will be required to be available to respond.

Currently, there are 215 MW of registered utility PV (UPV) resources in the SPP transmission system. Based on publicly available data, SPP has identified 111 MW of distributed PV (DPV), including residential rooftop solar and commercial solar farms, in the SPP region. Under clear sky conditions, the reduction of currently identified UPV and DPV generation will be approximately 200 MW at the time of maximum eclipse.

The August eclipse provides an opportunity to indirectly observe the amount of DPV capacity available and the combined effects of other loading factors. When the eclipse reduces DPV output, the load will experience an equivalent increase. Post-eclipse analysis may be able to better estimate magnitude and location of DPV installations based on the observed load during the event. The eclipse is worthy of study in light of the increasing numbers of distributed generators in the SPP footprint. The National Renewable Energy Laboratory (NREL) projects that in 2024, the SPP region may have up to 1.1 GW of DPV in the system. UPV is also likely to increase in SPP given that over 7 GW of solar generation is currently being studied in the SPP Generator Interconnection (GI) queue. In 2024, another eclipse will pass across North American, providing a stress test for a system with greater integration of renewable energy resources.

DEFINITIONS

Behind-the-meter (BTM) refers to power generating installations and facilities that are usually connected at the location of the end-use customer, serving the load without passing through the retail meter.

Net-metering is a program for electricity customers to connect their generation system to the grid with a two-way meter that allows their unused generated energy to flow back onto the grid, turning the meter backwards. Policies vary by state and utility company. The customer is usually only credited up to their own annual or monthly consumption and energy output in excess of that will not be reimbursed.

In **Power Purchase Agreements** (PPAs) customers do not own the resource installed on their premises, but agree to purchase all the energy produced at a contracted amount that may or may not increase over time.

PV penetration is the ratio of power output from installed PV to load.

Obscuration is the percent of the sun's area visible from the earth that is covered by the moon during a solar eclipse.

BACKGROUND

2017 SOLAR ECLIPSE IMPACT ON LOAD AND GENERATION

On Monday, August 21, 2017 a total solar eclipse will cross the SPP region when the moon's orbit passes between the earth and the sun, temporarily blocking all or some of the sun's light. Areas outside of the path of totality will experience partial eclipse to some degree (Figure 1). Along the center of the path of totality, the duration of the total eclipse will be up to 2 minutes, 40 seconds long [1]. For the SPP region as a whole the effects of the eclipse (from the beginning of partial obscuration to end of partial eclipse) will last approximately 3 hours. Table 1 records the start and end times of the eclipse across the SPP footprint. During this time solar photovoltaic (PV) generation will be either reduced or completely halted.

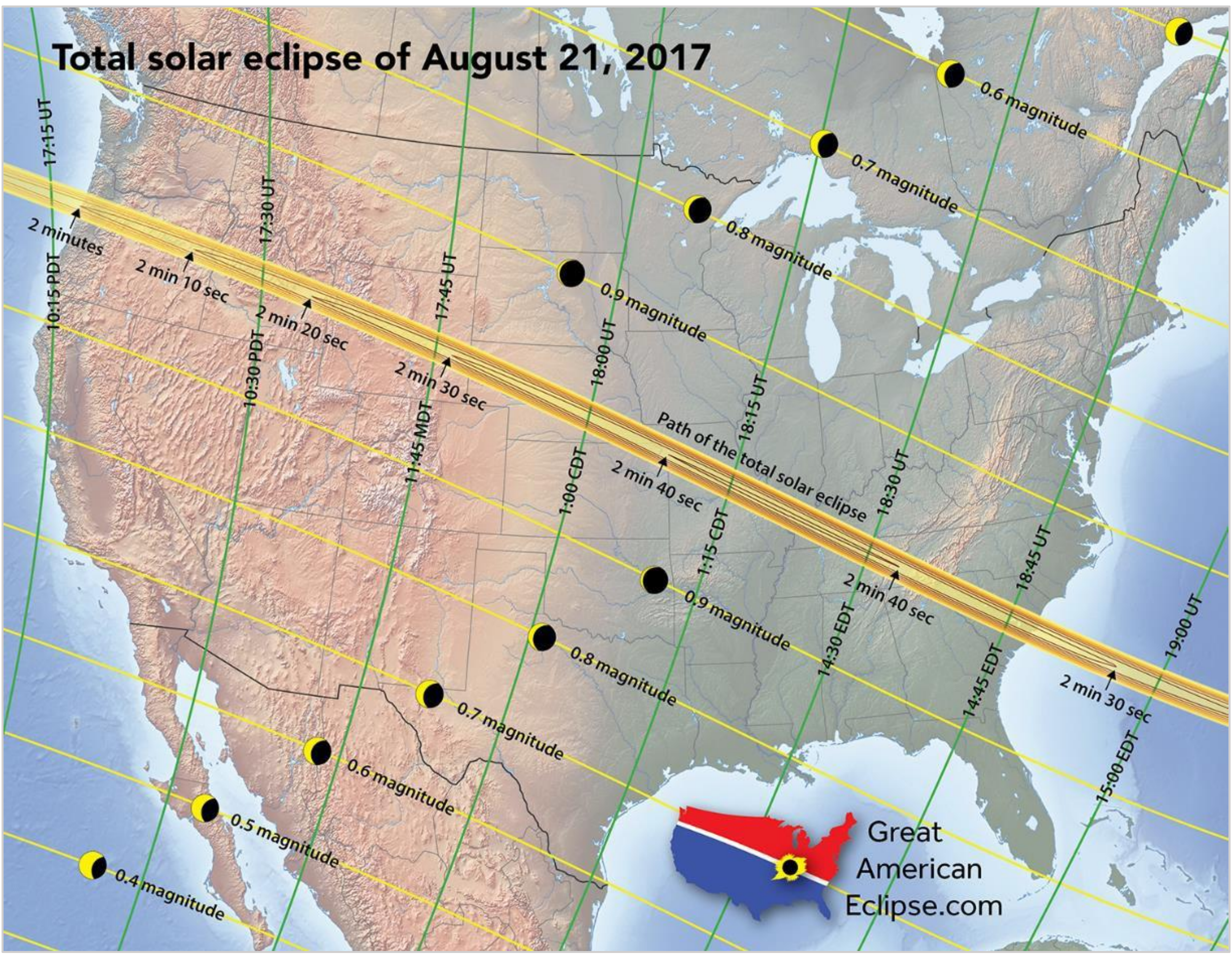

Figure 1. Trajectory of 2017 Eclipse [2]

Table 1. Eclipse timing across SPP region [1]

Location	Eclipse (Central Time Zone)			
	Start of partial	Maximum eclipse	End of partial	Maximum obscuration (%)
Fort Peck, MT	11:25 AM	12:43 PM	2:04 PM	83
Amarillo, TX	11:29 AM	12:56 PM	2:25 PM	78
Bismarck, ND	11:32 AM	12:52 PM	2:14 PM	84
Oklahoma City, OK	11:37 AM	1:05 PM	2:34 PM	84
Lincoln, NE	11:37 AM	1:03 PM	2:30 PM	100
Watertown, SD	11:37 AM	12:59 PM	2:23 PM	87
Omaha, NE	11:38 AM	1:04 PM	2:30 PM	98
Topeka, KS	11:39 AM	1:06 PM	2:34 PM	99
Tulsa, OK	11:39 AM	1:08 PM	2:37 PM	88
Kansas City, MO	11:40 AM	1:10 PM	2:35 PM	100
Shreveport, LA	11:46 AM	1:17 PM	2:46 PM	78
Little Rock, AR	11:47 AM	1:18 PM	2:46 PM	88

This event will provide an opportunity to indirectly observe the capacity of distributed PV (DPV) solar resources. Currently, the DPV generation is treated as negative load and the capacity of installed DPV resources is not visible in the transmission planning process. Output of each PV installation will be reduced by the percent obscuration during the eclipse as the moon blocks a percentage of the sun's light [3]. The maximum solar obscuration will take place around 1 PM, soon after solar noon in the region. This will result in a larger reduction of solar generation caused by the event than if the eclipse occurred earlier or later in the day. When the eclipse reduces PV generation, the net load will increase.

Based on lessons learned from the March 2015 European solar eclipse, other factors related to the eclipse will also have an impact on the net load. Lighting demand will increase as the sky darkens. In Great Britain, this effect lasted longer than the duration of the eclipse as people were slow to turn lights back off. Wind generation reduction is likely to occur during and after the eclipse due to the reduced wind speeds associated with eclipse-induced temperature drops [4].

Some European countries also experienced a suppression of demand due to human activity related to the 2015 solar eclipse. At the time of maximum eclipse many people will halt normal activities to go outside and observe the event. In Great Britain this resulted in a 300 MW demand decrease, even with cloudy weather and only a partial eclipse over the country, two factors that decrease the appeal of eclipse viewing [4]. Some predictions claim the 2017 North American eclipse will be the most watched eclipse in history with 12.2 million people living within the path of totality and millions more expected to travel to areas experiencing the full eclipse [5]. The suppression of demand caused by human observance of the eclipse will offset the net load increase caused by PV and wind generation reduction.

LESSONS LEARNED FROM 2015 EUROPEAN ECLIPSE

The 2015 European partial solar eclipse required extensive planning to ensure reliability with high penetration of photovoltaic (PV) solar generation resources in some European countries. The obscuration in the Continental Europe region ranged from 40% in Greece to 80% in the Netherlands. The British Isles were closest to the path of totality with obscuration in the most northern region of Scotland of approximately 95%. While there were no reliability problems during the event, the eclipse provided a variety of lessons learned [6][7][8]:

- Reliability and security were never endangered, resulting from preparation months before the eclipse. It was not necessary for the Transmission System Operators (TSOs) to assist each other during the event.
- Preparations included contracting additional sources of automatic and manual frequency restoration reserves and having interruptible load on notice. Approximately 25% of the extra reserves were called upon during the peak eclipse. System frequency never went out of bounds. However, additional reserves had high cost and therefore this solution is recommended only for exceptional situations
- Curtailment of 4.4 GWs of PV was successfully implemented by Italian TSO Terna to reduce the drop in solar output and limit ramps before and after the eclipse. The exact amount of PV feed in that will be switched off, the timing of switching off and on from the grid, and steps that are taken during switching PV back on the grid must be considered when using this practice on a larger scale in the future. Other European countries lacked the control capabilities to use curtailment for the eclipse.
- All TSOs agreed to have as few as possible planned outages during the eclipse to promote a strong and well meshed system to best cover power flow deviations caused by the eclipse.
- Due to weather conditions like fog, forecasting closer to real time and aggregating solar plant output over a large region produced the most valuable forecast. A clear description of the installed PV capacity and their capabilities is needed to produce accurate forecasts.
- A solar eclipse may be an event to analyze as a credible contingency in the future.
- The European electricity system was capable of handling high fluctuations in renewable generation for the eclipse but must prepare for such fluctuations regularly by 2030 as renewables penetration increases. The strategic use of pump storage power plants was significant in controlling the response to changing PV.

2024 NORTH AMERICAN TOTAL SOLAR ECLIPSE

On April 8, 2024, another total eclipse will cross North America. The trajectory of the 2024 eclipse is shown in Figure 2. The National Renewable Energy Laboratory (NREL) has projected values for installed DPV capacity in 2024, shown in Figure 3 [9]. Based on this research, SPP will have 1.1 GWs of DPV capacity within the current footprint, increasing from 2017 estimates by an order of magnitude. While SPP PV penetration is currently low, PV penetration projections indicate the 2024 eclipse will have a more significant impact on generation and load.

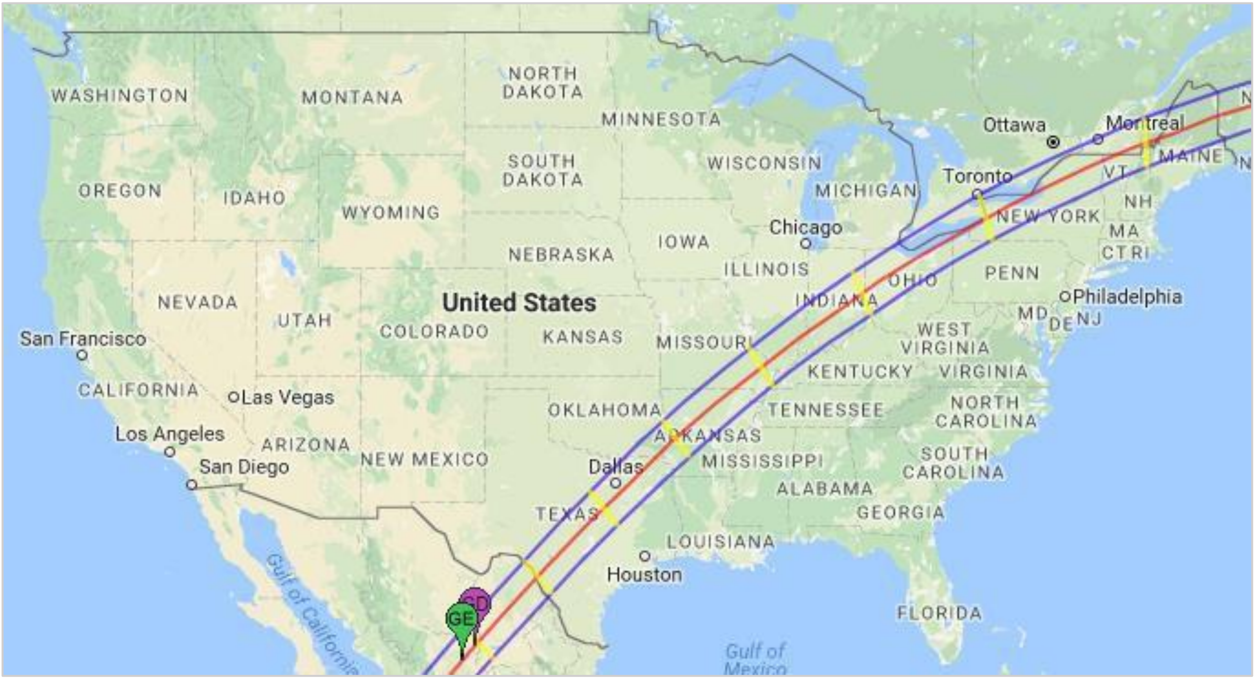

Figure 2. April 8, 2024 total solar eclipse trajectory [10]

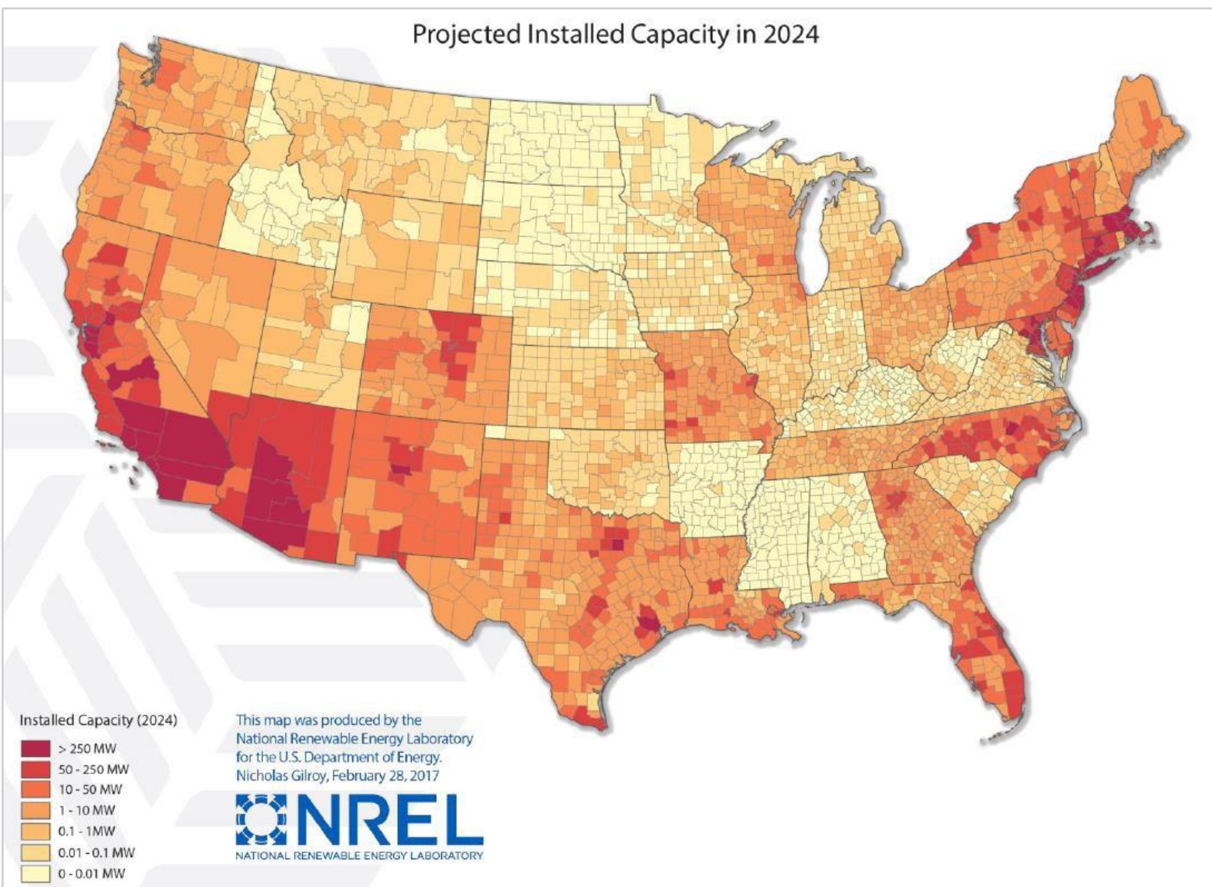

Figure 3. . NREL distributed PV capacity projections [9]

DISCUSSION

DISTRIBUTED PV DATA COLLECTION

Tracking distributed PV capacity is a challenge, with no census of the thousands of installations connected behind-the-meter in the United States [11]. Data for this analysis was compiled from databases, reports, and filings possessing a varying degree of completeness. From 2012 onward, the U.S. Energy Information Administration (EIA) Power Monthly includes estimates of small-scale and utility-scale PV solar installations by state [13]. EIA obtains these estimates through Form EIA-860 through which utility-scale (greater than 1 MW) power plants are reported and Form EIA-861 through which retail electricity providers report the net-metered generators they serve. As there are likely generators that are not reported on either form, the EIA estimates are treated as a lower bound for PV generation capacity.

More detailed and up-to-date information was obtained from the state public service commissions, corporation commissions, and power review boards of Arkansas, Kansas, Missouri, Oklahoma, Nebraska, New Mexico, North Dakota, and South Dakota. Reporting requirements are not consistent across the SPP footprint. When possible, the specific location of distributed generation resources was used in analysis.

Community solar farms allow members of communities who are unable to install their own PV array to reserve a designated amount of power from a nearby shared array. Community solar farms are occasionally referred to as utility scale when the arrays capacity is over 1 MW, but community farms are usually connected to the distribution lines. The capacity of currently operating community solar farms was gathered through regional solar installer websites, regional news organizations, and SPP member websites.

Table 2 summarizes the gathered data. Due to the data limitations described above, the estimated SPP aggregate DPV capacity is a lower bound.

Table 2. Capacity of Distributed PV in SPP Estimates

Region	Estimated Distributed PV Capacity (MW)
Kansas City – MO and KS [15][16]*	21.31
KCP&L- GMO [15]*	18.30
Cleco Power [14]	14.89
Empire District Electric – MO [15] *	13.03
Southwestern Public Service Company [14]	7.99
Lincoln, NE and surrounding region [17][18][19]	7.7
SWEPCO – LA [14] *	7.63
Westar and KEPCo [14] *	5.04
CUS Community Farm	4.95
Oklahoma (EIA statewide estimate) [13]	3.2
Omaha, NE and Northern Nebraska [17][18][20]	2.6
Texas Panhandle [14] *	1.5
NIPCO and Corn Belt Power Cooperative [14] *	1.1
SWEPCO – AR [21]	0.7
SWEPCO – TX [14] *	0.5
South Dakota (EIA statewide estimate) [13]	0.4
North Dakota (EIA statewide estimate) [13]	0.2
OG&E – AR [14][22]	0.11
Empire District Electric – AR [23]	0.016
Total	**111.17**

* Data through end of 2015

In addition to existing community solar farms, six farms totaling 32.38 MW of capacity are currently planned or under construction in the SPP region. These community solar projects will not be operational before the 2017 eclipse but demonstrate the rapid growth of larger scale PV farms in the SPP footprint. The April 2024 solar eclipse will greatly reduce the output of these farms due to their proximity to the path of totality.

Table 3. Community Solar Farms in Development

Location	Owner	Estimated on line date	Capacity (MW)	2024 Eclipse Obscuration
Covington, OK	SunPower Corp	Beginning 2018	10	91%
Nixa, MO [24]	Gardner Capital, Inc.	End of 2017	7.92	98%
Clarksville, AR [25]	Scenic Hill Solar	Mid-2018	6.5	100%
Kearney, NE [26]	SoCore Energy	January 2018	5.76	75%
Hutchinson, KS	SoCore / Westar	May 2018	1.2	85%
Fremont, NE [27]	City of Fremont	End of 2017	1	78%

UTILITY SCALE PV RESOURCES

SPP has 215 MW of registered utility PV connected to the transmission system. Additionally, the SPP GI queue currently contains active requests for over 7 GW of solar installations throughout New Mexico, Oklahoma, Texas, Kansas, Nebraska, and Arkansas.

SOLAR GENERATION ESTIMATION

As historical generation data does not exist for the thousands of DPV installations in the SPP region, forecasts for August 21 generation must be based on calculations and simulations.

PV generation varies by time of day and day of year due to changes in the amount of incident solar radiation called insolation. Factors such as temperature, the orientation of the array in relation to the sun, and periodic shading from other structures or adjacent panels during the day affect insolation. Unpredictable factors such as inverter efficiency, age of the panels, and dirt on the panels' surface further affect the complex process of converting solar radiation to electricity. Variability in weather leads to fluctuating output and difficulty in accurately forecasting the PV generation throughout the day.

NREL's PVWatts tool was used to estimate hourly generation near DPV installations' location for this analysis [29]. Historical output data has been used to validate the PVWatts simulations, and EIA used the tool to develop estimates of DPV monthly generation [28]. The PVWatts algorithm uses regional weather data and user inputs including location, estimated losses, inverter efficiency, array orientation, type of mount, cell material and whether the array utilizes axial sun tracking [30]. The default value for losses were used for this analysis. Due to decreased cooling by ambient air, rooftop panels operate less efficiently than rack-mounted panels. To model ideal operating conditions, the default open rack mount was chosen for simulations.

The hourly simulation data was examined and the output of the highest efficiency day in late August was selected. In Figure 4, August 20th represented clear sky conditions based on typical weather conditions. Figure 5 shows the normalized generation curve based on that day. The highest efficiency hourly data was chosen to create worst case conditions for the day of the eclipse. Some regions may experience cloudy or foggy weather, which will lessen the impact of the eclipse on the already reduced output. Distributed PV in SPP was grouped into fourteen regions and generation scaling was determined for each using PVWatts.

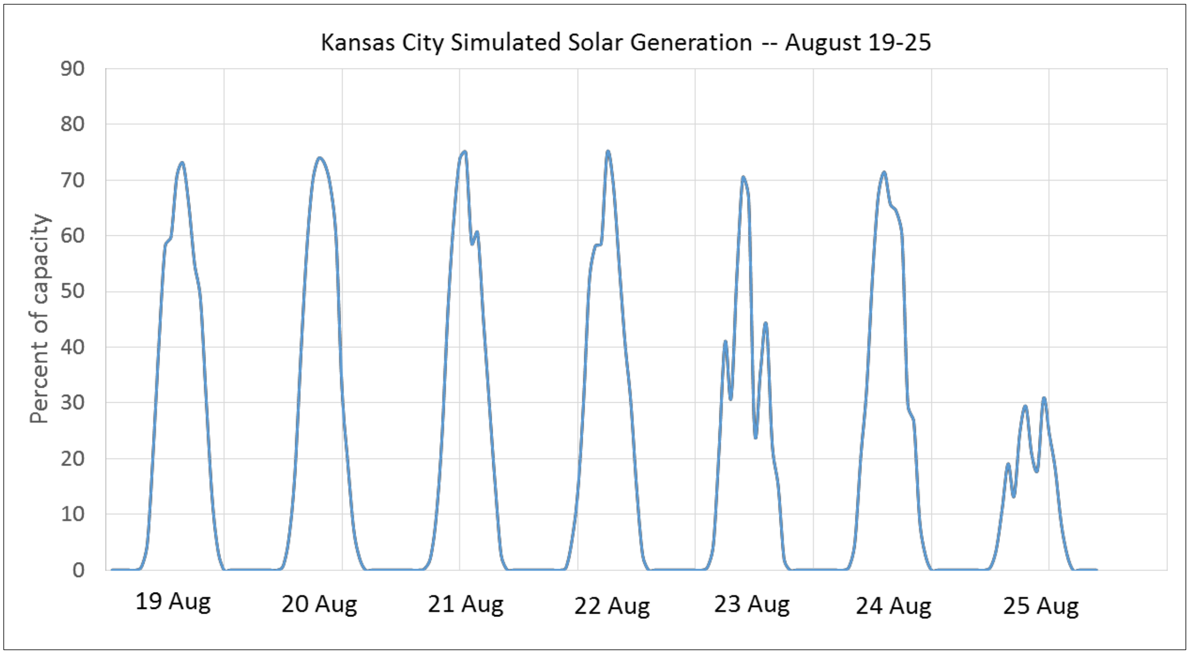

Figure 4. Simulation Result for Kansas City

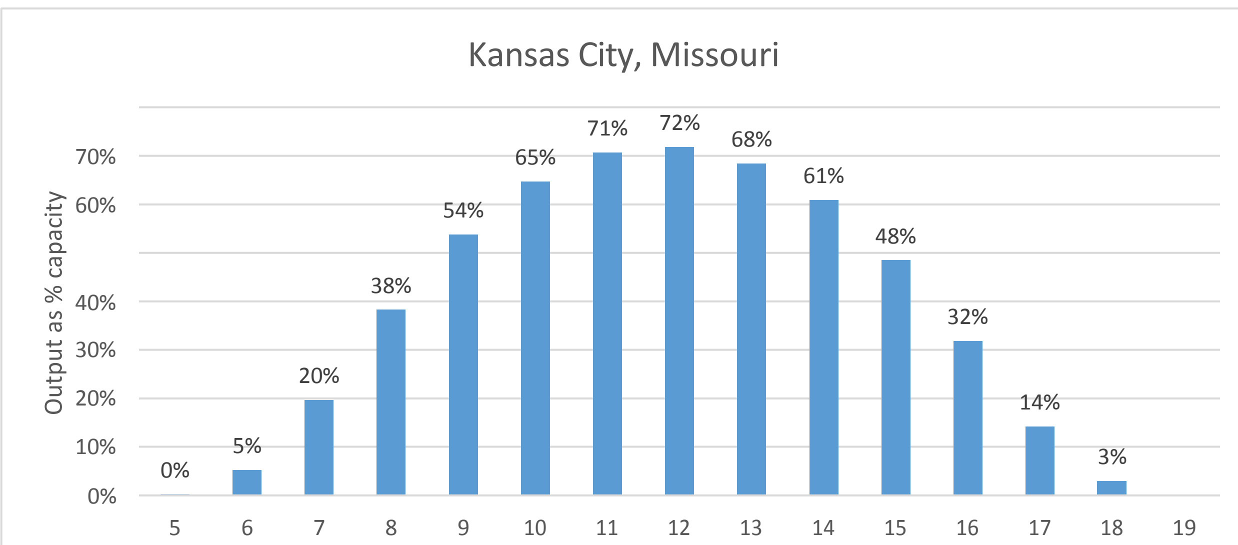

Figure 5. Hourly PV Output Scaling Result

SOLAR GENERATION REDUCTION DURING ECLIPSE

The solar output was scaled as directly proportional to the solar obscuration to produce the generation estimate during the eclipse. The maximum percent obscuration was assumed to occur at 1:00 PM for all PV to produce a worst case estimate, even though the time of maximum eclipse varies about 20 minutes across the SPP region.

When location was not known, the distributed resource was assumed to be in the maximum eclipse band for the state. This assumption was made in order to produce the "worst case" scenario, where the distributed PV resources would experience the greatest amount of solar radiance reduction during the eclipse.

The hourly PV generation on the day of the eclipse was calculated for 14 different regions of the SPP footprint, reducing the capacity by hourly generation scaling and eclipse obscuration as shown below.

*(MW Capacity) * (1 – Percent Obscuration) * (Regional Hourly Scaling) = Eclipse Output [MW]*

The total DPV generation reduction in the SPP region is shown in Figure 6. At the time of maximum eclipse the greatest difference between a clear day with no eclipse and a clear day during the eclipse is 72 MW at 13:00. This is a conservative estimate due to the assumptions that the eclipse totality will take place simultaneously across the SPP region and that weather conditions across the region will be ideal for PV generation.

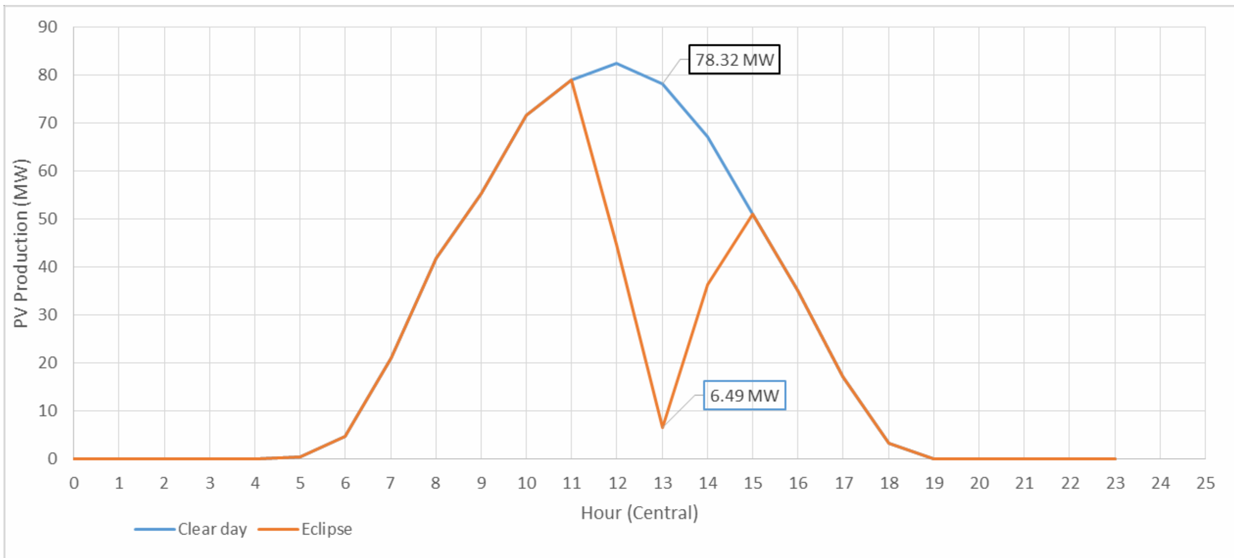

Figure 6. DPV Capacity Eclipse Reduction

The eclipse reduction of all PV in SPP, both estimated DPV and registered UPV, is shown in Figure 7. The 215 MW of UPV was assumed to be located in southeastern New Mexico and installed with axial sun tracking. With sunny weather, the maximum lost generation due to the eclipse is approximately 200 MW at 13:00. The reduction is a smaller percentage of clear sky generation compared to the DPV model (figure 6) due to the distance of UPV installations from the path of totality.

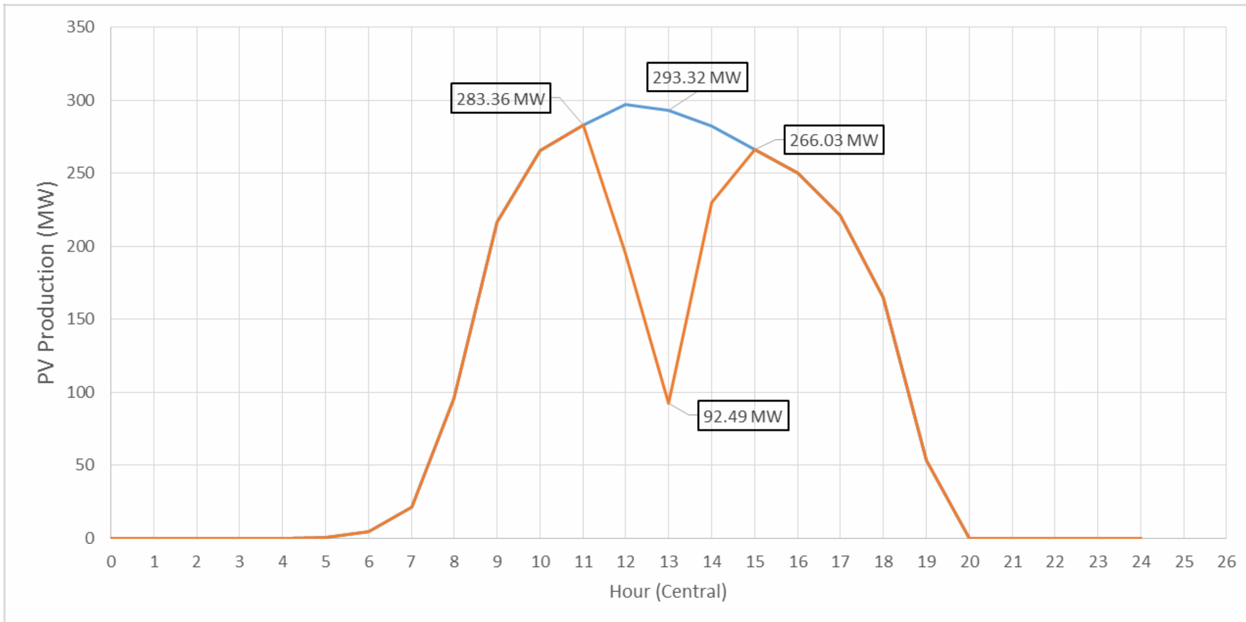

Figure 7. DPV and UPV Capacity Eclipse Reduction

The SPP GI Queue currently contains active requests for approximately 7.7 GW of solar generation. Using the location of the requests under study, the theoretical effect of the 2017 eclipse on the generation in the queue and currently existing PV resources was modeled (Figure 8).

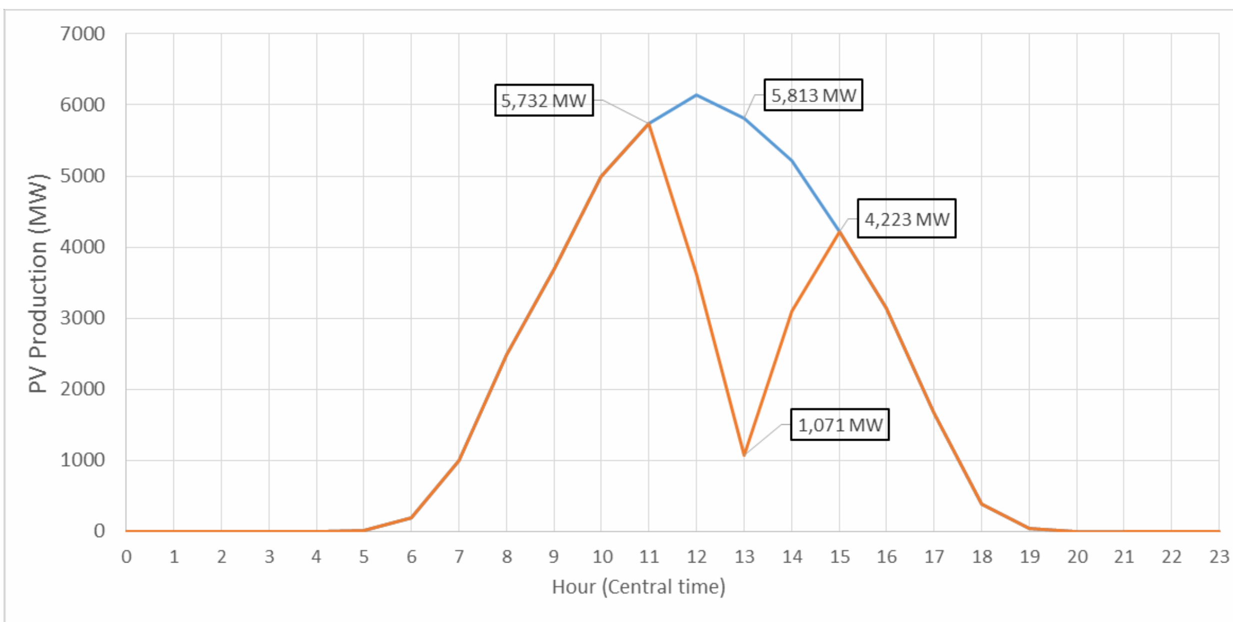

Figure 8. GI Queue Solar Capacity Eclipse Reduction

SOLAR REDUCTION'S EFFECT ON LOAD PROFILE

In 2015, the European electricity grid had 90 GW of solar power installed, covering 3.5% of the European Union's electricity demand. A large concern for the 2015 European eclipse was the ramping caused by reduced PV infeed at the time of the eclipse. Post-eclipse analysis showed that the maximum change in PV injection was a 21 GW increase within an hour after the eclipse. With mitigation measures including procuring reserves and having interruptible load on notice, this rapid change in generation was managed.

Due to the low penetration of PV resources in SPP, ramping will not be a concern for maintaining reliability during the event. Figure 9 is an illustrative curve demonstrating the effect of losing 200 MW of solar generation during the eclipse, created using August 21, 2016 load data. Figure 9 does not account for other changes to the load during the eclipse such as reduced wind speeds and increased lighting demand.

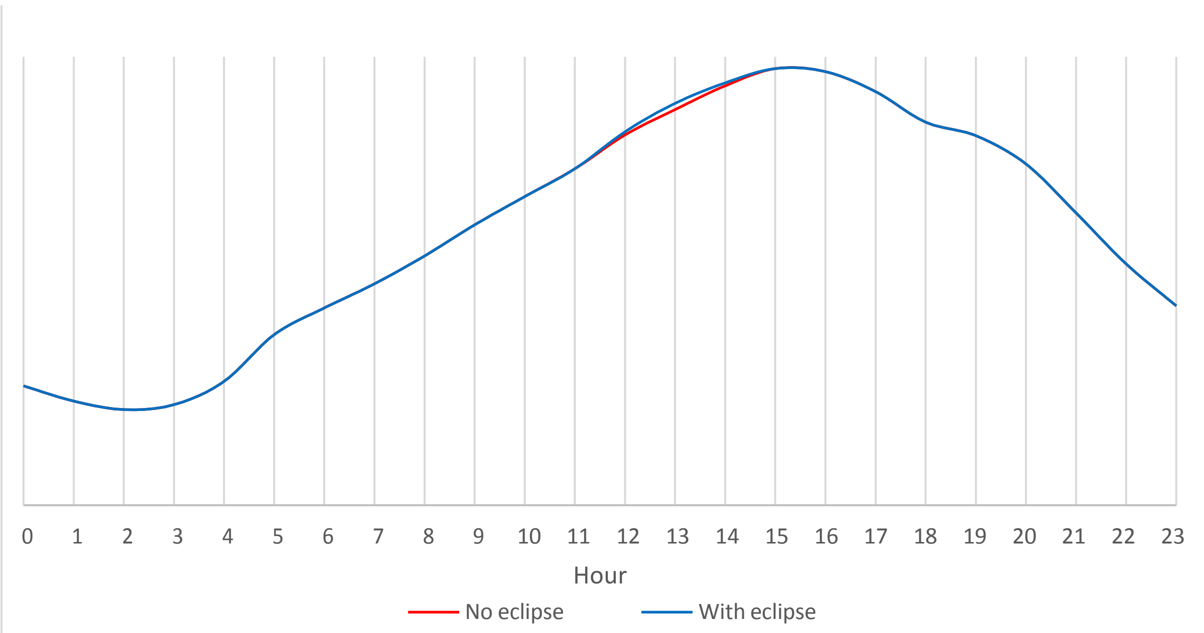

Figure 9. Example change in load shape from reduced PV output

OTHER FACTORS AFFECTING LOAD DURING ECLIPSE

Prior to the 1999 European solar eclipse, wind speed reduction associated with eclipses was documented only anecdotally. Researchers in Great Britain gathered meteorological data during the 2015 eclipse from a wide geographic area and compared the eclipse to a sunset in terms of effect on ground temperature and wind. The disappearance of the sun stops warm air from rising from the ground, consequently reducing wind speeds [31]. During the 2015 eclipse, grid operators in Great Britain noted a 10% (500 MW) decrease in wind generation [4]. Meteorological data showed that localized wind speed reduction was highly dependent on cloud cover. Wind speed in the few areas with clear skies was reduced by up to 2.3 mph. The majority of the country has cloudy skies and experienced a milder reduction in wind speed related to the eclipse [31]. The impact of the August 21, 2017 eclipse on SPP wind generation will be highly dependent on clouds in areas of higher wind penetration, as well as the pre-eclipse levels of wind generation on August 21.

Predictions of human demand reduction for the 2015 Europe eclipse were based off Great Britain's 3GW drop in demand during the August 1999 European eclipse. Forecasts for the 2015 eclipse predicted 40% of the 1999 effect but analysis after the event estimated that the load reduction in 2015 was only 10% of the 1999 effect (a 300 MW drop in demand). The weather was mostly cloudy over Great Britain during the eclipse, reducing public interest in viewing the event. Unlike the 2015 European eclipse, the 2017 North American eclipse has no comparable previous eclipse event on which to base estimates of the reduction in electricity demand caused by people observing the eclipse. The last total solar eclipse to cross the entire continent and be viewable across North America was in 1918 [32].

In Great Britain, the increase in lighting load was approximately the same as the increase in load caused by lost PV. The visible increase in load caused by lighting lingered after the eclipse as people were slow to turn the lights back off after the event (figure 7).

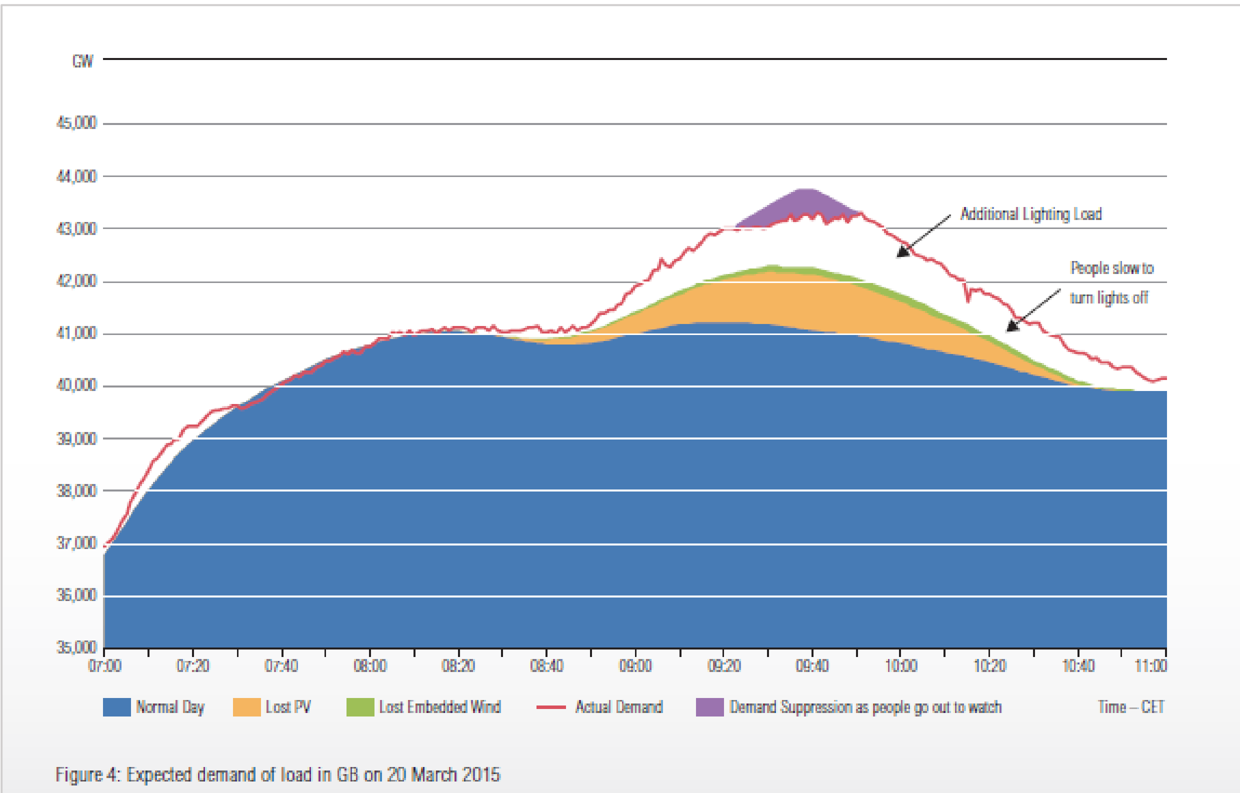

Figure 10. Great Britain 2015 Eclipse Load Profile [4]

The increase in lighting load for SPP during the eclipse will depend on the light intensity level required to trigger street lights off/on and the aggregate street light load in areas where solar obscuration will darken the sky past that threshold. Due to the short duration of the event, the increase in lighting demand should remain manageable. Cities that lay in a region of less than 90% solar obscuration will likely not get dark enough to trigger street lights to go on during the eclipse.

The information for a city within the band of totality is shown below. Other cities within the region of 90% or greater solar obscuration include Kansas City, Omaha, Lincoln, Topeka, Wichita, and Joplin. Omaha Public Power District (OPPD) has 101,211 street lights in the service territory as of March 2017, with 58,596 of those in Omaha [33]. It is possible that the additional lighting load may be larger than the increase resulting from lost PV in the path of totality.

Table 4. Lighting Load in St. Joseph, MO

St. Joseph, MO	
Electricity provider	KCP&L
Population	76,596
Number of street lights	6500
Aggregate lighting demand (kW)	979
Light intensity to turn on/off (fc)	1.5

CONCLUSION

The eclipse on August 21st, 2017 should not have a negative impact on operations or reliability in the SPP footprint. Under clear sky conditions, the eclipse will reduce the total PV generation beginning around 11:30 AM at the western edge of the SPP footprint and ending around 2:30 PM at the eastern edge. At the time of maximum eclipse around 1:00 PM, known DPV and UPV generation is expected to be reduced by approximately 200 MW in comparison to a clear day.

Wind speeds and wind power generation can also be expected to decrease during and after the eclipse. During the 2015 partial solar eclipse, wind speed in cloud-free regions of Great Britain fell by up to 2.3 mph with approximately 85% obscuration. The reduction of wind generation in the SPP region on August 21 will depend on wind generation prior to the eclipse. With lower pre-eclipse wind speeds, the percentage of wind generation lost during the eclipse will be higher than if wind speeds were relatively high prior to the eclipse.

If SPP anticipates significant volatility in demand and intermittent generation on August 21st, additional generation resources will be required to be available to respond to this volatility. This may be accomplished through additional "headroom" requirement, additional regulation reserve requirement, additional contingency reserve requirement, or a combination of these methods.

Eclipses demonstrate the challenges that will arise with higher penetration of DERs in the future, particularly from PV technology. In addition to the inherent uncertainty presented by variable renewable generation resources, low visibility of distributed generation sources limits accuracy of forecasting load and effectiveness in planning and operating the transmission system. Post-eclipse analysis may be useful to better understand the typically less visible contribution of DPV on the transmission system by using data of actual weather conditions. The eclipse of 2024 will provide another stress test for the grid with much greater capacity of PV installed and learning from the 2017 eclipse will improve our ability to prepare for future events.

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