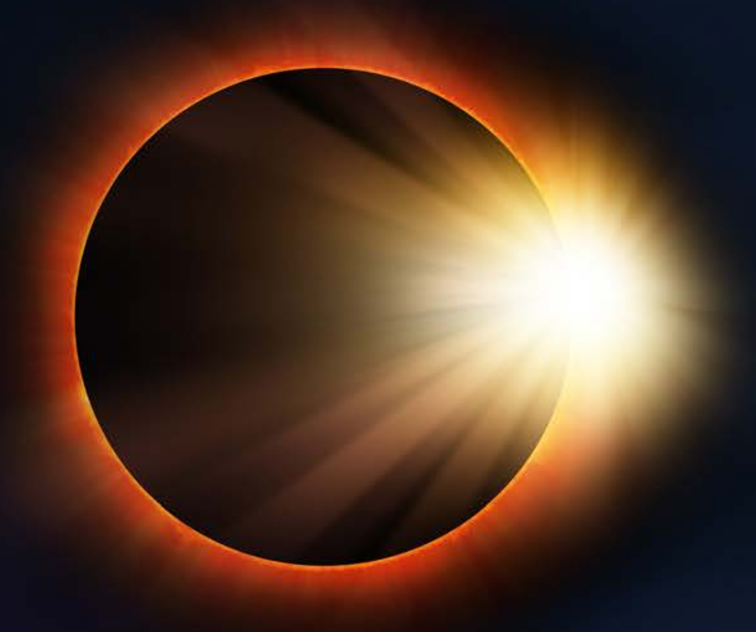

SOLAR ECLIPSE REPORT

Evaluating the Impact of the 2017 Solar Eclipse

on U.S. Western Interconnection Operations

SOLAR ENERGY TECHNOLOGIES OFFICE
U.S. Department Of Energy

NREL
NATIONAL RENEWABLE ENERGY LABORATORY

PEAKRELIABILITY
assuring the wide area view

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List of Acronyms

BA	Balancing Authority
CAISO	California Independent System Operator
CC	Combined cycle
CE	Continental Europe synchronous area
DPV	Distribution-level PV Systems
ENTSO-E	European Network of Transmission System Operators for Electricity
HVDC	High-voltage DC
ISO	Independent system operator
MODIS	Moderate Resolution Imaging Spectroradiometer
NASA	National Aeronautics and Space Administration
NSRDB	National Solar Radiation Database
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
NSS	Nordic synchronous system
PDCI	Pacific DC Intertie
PV	Photovoltaic
RC	Reliability Coordinator
SAMPA	Solar and Moon Position Algorithm
TOP	Transmission Operating Plan
TSO	Transmission system operator (European nomenclature)
WECC	Western Electric Coordinating Council
UPV	Utility-scale PV systems

Notice

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Executive Summary

With support from the U.S. Department of Energy Solar Energy Technologies Office, the National Renewable Energy Laboratory (NREL) partnered with Peak Reliability to evaluate the impact of the August 21, 2017, total solar eclipse on reliability and electric grid operations in the Western Electricity Coordinating Council (WECC) territory. As a North American Electric Reliability Corporation Reliability Coordinator, Peak Reliability manages the grid reliability across all or parts of the14 western United States, British Columbia, and the northern region of Baja California, Mexico. Peak Reliability used inputs from the study to augment its own analysis for preparing transmission operating plans for the day of the eclipse. Peak Reliability also provided NREL with data from across its footprint to uncover important insights into the impact of the eclipse from the penetration of photovoltaics (PV) along its path.

The 2017 total solar eclipse came and went without causing any issues to the operation of the North American electric power system. This report presents the results of NREL's studies performed before and after the August 21 event. In a pre-event analysis, NREL researchers focused on the spatial and temporal profile of the eclipse and how the output of PV sites across WECC would be affected. Although the size and location of utility-scale PV (UPV) sites are known and their outputs are monitored, distributed PV (DPV) (e.g., rooftop solar) poses a greater challenge for grid operations because of its lack of visibility.

The estimated installed capacity of UPV and DPV across the WECC region is 15,800 MW (without concentrating solar power plants) and 9,200 MW, respectively. NREL used databases developed through previous efforts funded by the U.S. Department of Energy to determine how much DPV was present at the substation level and then estimated the impact of the eclipse on its output. This geospatial analysis assumes a typical meteorological day from NREL's typical meteorological year database. NREL researchers estimated that during the peak of the event, the loss of PV would be around 5.2 GW, with UPV loss at 4 GW and the rest from DPV.

The second part of the analysis was a simulation of production costs. Using the results from the geospatial study, the economic dispatch and unit commitment strategies were evaluated to see how the other generators would be re-dispatched. The analysis showed that the loss of PV generation can be easily compensated by the existing generation fleet, with the natural gas fleet picking up the majority of the slack because of its flexibility. The change in system production costs were minimal. The third part of the analysis consisted of transient simulations to assess the stability and reliability of grid operations. No reliability concerns were identified, even for large system disturbance events. The system also exhibited high damping capabilities to mitigate inter-area oscillations.

In the post-event analysis, NREL researchers used the data collected by Peak Reliability to uncover additional insights into the impact of the eclipse on actual PV output, system loading, transmission flows, and generation by fuel types and by utility areas. The loss of UPV estimated during the pre-event analysis matches the observed values. Because there is insufficient data to measure the loss of DPV, the loss estimation was used to further study the impact of the eclipse on load as a result of non-PV factors. The production cost simulation estimated that natural gas and hydro resources would be most responsive, given their fast ramp rates, relative to their output at the start of the eclipse. A similar effect was observed with natural gas generators, which increased their output by 18%, and hydro power, which increased by 15%.

NREL researchers are working to extend this analytical approach to study the impacts of future large-scale disturbances caused by solar eclipses and weather storms.

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1. Background

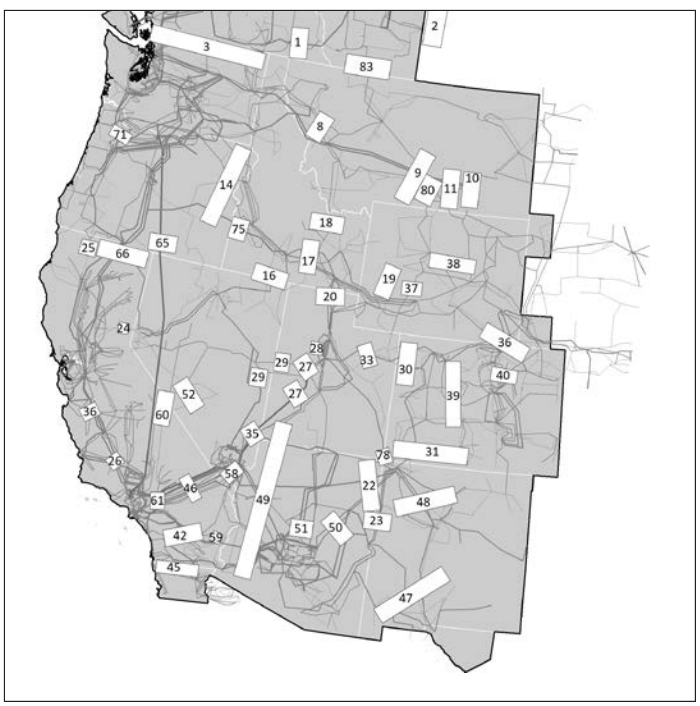
Funded by the U.S. Department of Energy Solar Energy Technologies Office, the National Renewable Energy Laboratory (NREL) partnered with Peak Reliability to estimate the impact of the August 21, 2017, transcontinental solar eclipse on the reliability and operations of the western U.S. electric power grid. The objectives of this project were to:

1. Learn from past grid operation experience to prepare for the solar eclipse event.
2. Develop tools to investigate the spatiotemporal evolution of the solar eclipse, its impact on renewable power generation, and the effect on grid operations and system reliability during these conditions.
3. Extend the framework and tools to perform extreme event analysis that can be translated to other significant weather events.

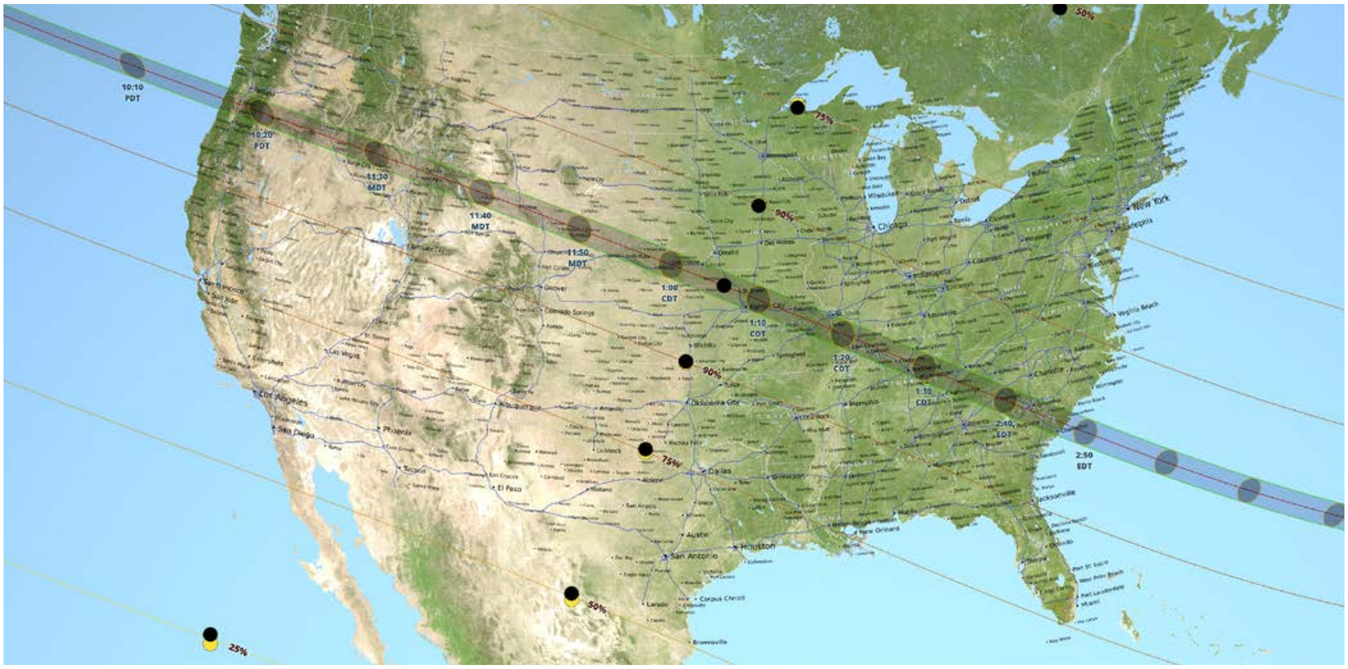
This report covers the pre-event and post-event analysis, which addresses objectives 1 and 2. The analysis was performed in partnership with Peak Reliability and covers the western United States, as shown in Figure 1. A follow-up report will focus on the framework.

On Monday, August 21, 2017, North America experienced a total solar eclipse from one coast to another. The total eclipse was first observable in Oregon at 10:15 a.m. PDT and was observed in South Carolina at 2:49 p.m. EDT. Though the path of totality was a relatively thin ribbon that extended about 70 miles wide, the rest of the continent experienced a partial eclipse. Although the peak of the eclipse lasted only a few minutes at locations along the path of totality, the darkness from the penumbra lasted a few hours before and after the peak. The U.S. Energy Information Administration estimated that more than 21 GW of installed photovoltaic (PV) systems would be affected [1].

Because total solar capacity on the grid has increased from 5 MW in 2000 to more than 42,619 MW in 2016 [2], such an extreme solar eclipse event called for further evaluation and analysis. With increasing penetrations of PV systems, it is important that grid operators understand the impact of an eclipse like the North American 2017 event on PV output and grid operations to undertake adequate preparatory measures.



Source: Western Electricity Coordinating Council (WECC)
Figure 1. Transmission lines in the WECC region.



Source: National Aeronautics and Space Administration/Goddard/SVS/Ernie Wright
Figure 2. Path of the August 21, 2017, solar eclipse.

Table 1. Eclipse Path and Times

	Eclipse Begins	Totality Begins	Totality Ends	Eclipse Ends	
Madras, OR	09:06 a.m.	10:19 a.m.	10:21 a.m.	11:41 a.m.	PDT
Idaho Falls, ID	10:15 a.m.	11:33 a.m.	11:34 a.m.	12:58 p.m.	MDT
Casper, WY	10:22 a.m.	11:42 a.m.	11:45 a.m.	01:09 p.m.	MDT
Lincoln, NE	11:37 a.m.	01:02 p.m.	01.04 p.m.	02:29 p.m.	CDT
Jefferson City, MO	11:46 a.m.	01:13 p.m.	01:15 p.m.	02:41 pm.	CDT
Carbondale, IL	11:52 a.m.	01:20 p.m.	01:22 p.m.	02:47 p.m.	CDT
Paducah, KY	11:54 a.m.	01:22 p.m.	01:24 p.m.	02:49 p.m.	CDT
Nashville, TN	11:58 a.m.	01:27 p.m.	01:29 p.m.	02:54 p.m.	CDT
Clayton, GA	01:05 p.m.	02:35 p.m.	02:28 p.m.	04:01 p.m.	EDT
Columbia, SC	01:13 p.m.	02:41 p.m.	02:44 p.m.	04:06 p.m.	EDT

2. Literature Review

This section presents a review of previous eclipse studies, most notably the transcontinental European eclipse in 2015 and lessons from the 1999 partial eclipse in Great Britain. Given the high penetration of PV in Germany and Italy, regions that witnessed the eclipse, European transmission operators had undertaken special measures to prepare for the 2015 eclipse. Studies performed by the California Independent System Operator (CAISO) and the North American Electric Reliability Corporation (NERC) are also presented in this section.

2.1 2015 European Total Eclipse

On March 20, 2015, a solar eclipse affected continental Europe. The eclipse started at 8:01 a.m. UTC in the western part of Portugal and ended at 11:58 a.m. UTC in the eastern part of Romania. For the first time, the eclipse had a significant impact on the operation of the European power system because of the fast growth in PV in the recent past.

2.1.1 Pre-Event Eclipse Simulation Analysis

Before the 2015 event, the European Network of Transmission System Operators for Electricity (ENTSO-E) community produced an analysis to assess the operational impacts from the 2015 total solar eclipse and developed a plan to mitigate these impacts [3]. Because of the widely distributed geographic locations—and therefore varying eclipse impacts on solar production—ENTSO-E conducted this study by dividing the grid into three areas: the continental Europe synchronous area (CE), Nordic synchronous system (NSS), and Great Britain synchronous area.

The main focus was on CE because the majority of the solar installation capacity and most significant effects of the eclipse were located in this area. As of 2014, the PV installation capacity in Europe had reached 90 GW, wherein Germany (38.3 GW), Italy (18.5 GW), France (5.6 GW), and Spain (4.8 GW) were the leading countries in terms of installation. Because of the large amount of PV installed, the transmission system operators (TSOs) in Italy and Germany were the most affected.

The assessment was based on input from different countries, such as an estimation of the total installed PV capacity by the date of the eclipse, an estimation of the energy from PV that would be produced during the hours of the eclipse, and an estimation for the energy demand. ENTSO-E also estimated the solar obscuration production during the eclipse by considering the radiation factor and obscuration factors. In the case of a clear sunny day, the eclipse was expected to cause a reduction in solar power by more than 34 GW, as shown in Figure 3.

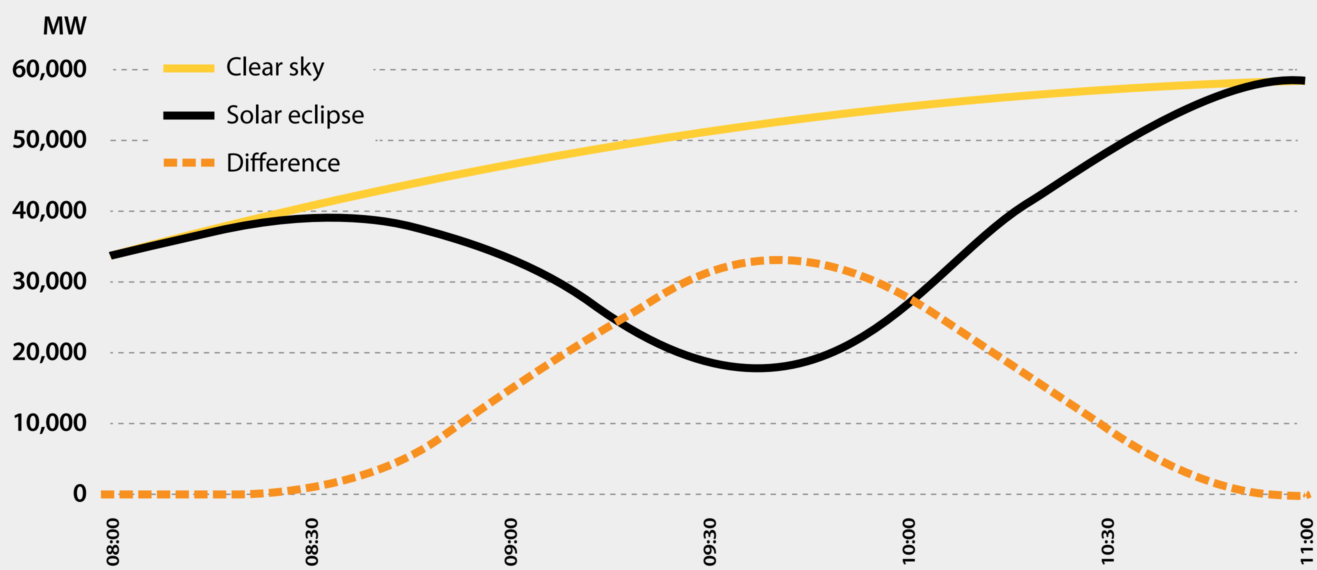


Figure 3. European PV output variation during solar eclipse

As shown in Figure 4, the maximum minute-to-minute ramping-down rate exceeded -400 MW/minute and the ramping-up rate after the solar eclipse was almost +700 MW/minute, which are two to four times higher than the normal daily PV ramping rates from sunrise and sunset, respectively [3]. Among these countries, 50% (16.9 GW) of the infeed reduction in the system was expected in Germany, and the maximum ramping-down rate and ramping-up rate were -273 MW/minute and +361 MW/minute, respectively. In Italy, the estimated reduction was 21% (7.2 GW), with a maximum ramping-down rate of -111MW/minute and ramping-up rate of +159 MW/minute.

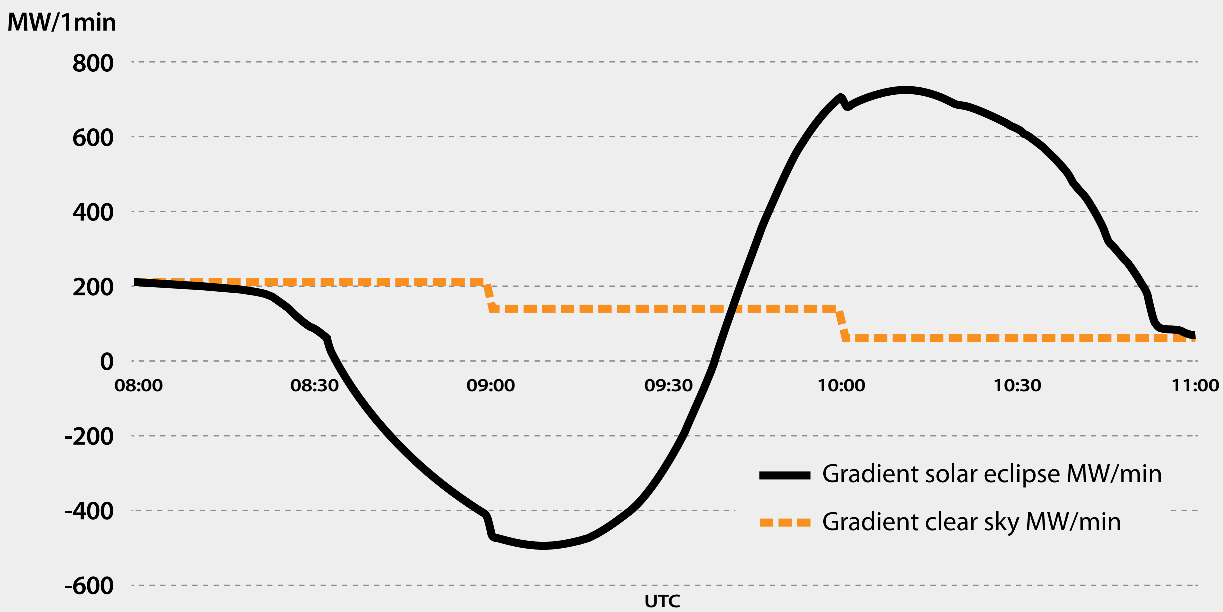


Figure 4. Estimated minute-to-minute ramping rate with and without the solar eclipse

Considering the simulation analysis, the main challenge for grid operation is the fast change in PV power generation. It was estimated that generation would decrease by 20 GW within 1 hour and increase by nearly 40 GW after the maximum impact of the eclipse. This situation could pose serious challenges to the regulating capability of the interconnected power system in terms of available regulation capacity, regulation speed, and geographical location of reserves.

2.1.2 Mitigation Countermeasures

The European grid is well-recognized as a strong grid capable of supporting power flow exchange based on flexible market operation among TSOs from different countries. To reduce the complication of control and prevent event propagation, TSOs were encouraged to limit the exchange and be prepared for emergency support. In addition, the day-ahead forecast of PV is particularly important for the management of power generation during an eclipse event. Careful preparation and coordination of solar forecasts were required among individual TSOs as well as careful preparation and coordination among TSOs and distribution system operators.

The recommended countermeasures for the March 20, 2015, event were made at two levels: CE coordination and individual TSOs. Primary recommendations included the preparation of extra reserve, strategic use of pumped storage power plants, the reduction in the interchange among TSOs, and the strengthening of management and coordination across CE.

The main countermeasures are summarized in Table 2.

Table 2. 2015 European Solar Eclipse Countermeasures

	All TSOs	TSOs in Germany	Terna (Italy)
Higher Reserves	Some TSOs increased amount of primary, secondary, and tertiary control reserves	Procured approximately double the amount of reserves Established a special operational concept for activation of reserves and emergency reserves	
Strategic Use of Pumped Storage Power Plants	Some TSOs used strategic pumped storage power plants in real-time operation		
Adjust Operation Rule	Reduced the interchange of HVDC for the NSS, Great Britain, and CE regions Increased synchronous area independence Minimized planned outages Minimized the area control error in nearly real time rather than at typical intervals of 15 minutes		Reduced the total net transfer capacity on the northern border of Italy to 1,000 MW
Market		Marketed the forecasted amount of PV at the quarterly hour market	Implemented a preventive decrease of planned PV production in the day-ahead market
Management and Coordination	Raised awareness and informed market players Held an operational teleconference Held a backup teleconference among system operation managers Provided extra training of control room operators and exercises on coordination procedures Hired additional operator staffing during the event Coordinated continuous communications among control rooms in CE and the NSS		

Because the TSOs in Italy and Germany had the highest relative impact on their available reserves, they took additional market response mitigation measures. TSOs in Germany broadcasted the forecasted amount of PV at the 15-minute market to ensure that they only needed to manage the difference between the quarterly hour market and the real feed-in with a high gradient in real time. Meanwhile, TSOs in Germany increased the additional upward/downward reserve, which is about twice the reserve for their normal operation. The TSO in Italy, Terna, had a preventive curtailment of planned PV production in the day-ahead market of approximately 4.4 GW through shutdowns between 7 a.m. and 2 p.m. CEST.

NSS operated independently during the eclipse event and was not significantly affected by the reduction in PV power production. The role it took was to provide regulation flexibility to support CE and maintain communications with neighboring CE TSOs. In operation, NSS was encouraged to limit the exchange with CE and NSS to a level that would allow energy security to CE in the unlikely event of a blackout.

Finally, increasing awareness during the event was also important from a management perspective. Therefore, the TSOs set up an extraordinary operational coordination the day before and during the eclipse, including day-ahead and real-time teleconferencing to coordinate PV forecasts, real-time frequency management, reserve exchanges, and power flow management.

2.1.3 Grid Operation on March 20, 2015

The weather conditions on March 20, 2015, the day of solar eclipse event, were cloudier than originally anticipated, which led to a less severe reduction in PV generation compared to a clear-sky condition. Thus, the observed ramp rates were lower than what was estimated during the pre-event analysis. In Germany, the actual solar output was 21 GW [4], and the change in Great Britain was about 850 MW, with no significant impact on grid operations. The quality of frequency regulation during the eclipse time frame was observed to be very good [5]. Note that increased reserve procurement during the eclipse event resulted in higher power prices. No significant changes were observed in the NSS. With Terna enforcing curtailment in Italy, the impact was muted.

2.1.4 Other Considerations

Residual Demand Effect

The eclipse effect on energy demand partially depends on human behavior, e.g., halting normal activities to observe the eclipse and the transient cooling effect. These two effects lower the actual energy demand. When distributed PV is present, an eclipse reduces the output from these sources, leading to an apparent increase in energy demand. Thus, these two counteract each other during an eclipse.

In the analysis of Great Britain, the change in residual demand dominated the PV effect. The greatest rates of change were caused by reduced demand rather than reduced solar insolation, with a maximum minutely rate of change of -300 MW/minute, but with typical values of -200 MW/minute before the maximum eclipse and +200 MW/minute after.

During the partial eclipse in August 1999, Great Britain experienced a 3-GW drop in demand that was attributed to people watching the event. Because there was such a high level of media interest in the 2015 solar eclipse, it was assumed that many people would again be watching the 2017 eclipse and there would be a similar drop in energy demand [6].

Impact on Wind Speed

Some discernible changes in meteorological signals during the eclipse were detected by comparing actual weather measurements with the predictions from a high-resolution spatiotemporal meteorological model ignorant of the eclipse [7]. These included changes to wind speeds, variability, and direction. For example, during the August 11, 1999, solar eclipse, the measurements show that the transient eclipse zone experienced temperature decreases of up to 3°C, a mean regional wind speed decrease of 0.7 m/s during the maximum eclipse hour with a mean anticlockwise wind direction change of 17°[8]. During the 2015 eclipse in Great Britain, wind generation dropped by around 10% (500 MW) because of the fall in wind speeds associated with the eclipse [6].

2.1.5 Summary

Pre- and post-event analysis of the 2015 European total eclipse indicated that there was "a great deviation in the amount of solar generation that [is] available before, during, and post eclipse which cause[s] the need for far more advanced coordination of primary, secondary, and tertiary reserves across Europe within a reduced time frame (faster than 10–15 minute intervals)" [2].

Through pre-risk evaluation, accurate forecasting, properly adjusted operational planning, improving reserve management, and using market rules to improve generation flexibility, the European grid operated safely during this event. Nevertheless, these mitigation strategies—acquiring additional reserves in particular—do have a significant cost, leaving such measures to be reserved for exceptional circumstances.

For Italy, the cost of the additional reserves during the solar eclipse has been estimated at €140,000, for Germany at €3.6 million, and for Czechia at €215,000. Note that because of the different mechanisms for reserve procurement, the prices for different countries are not comparable. The general conclusion is that the disconnection of PV resulted in higher power prices, and the additional reserve requirement resulted in higher service prices.

2.2 Impact Studies for the 2017 Eclipse

2.2.1 The California Independent System Operator Report

In August 2017, CAISO predicted that it would be affected by a partial eclipse between 9:02 a.m. and 11:54 p.m. PDT, obscuring 62% to 76% of the sun from Southern California to Northern California, respectively [9]. CAISO has nearly 10,000 MW of installed capacity of commercially operational utility-scale PV (UPV) within the balancing area. In addition, the California Energy Commission estimated that there would be more than 5,800 MW of rooftop solar installed in CAISO by August 2017. To maintain grid stability, CAISO identified the eclipse trajectory, estimated UPV and DPV installed capacities, and developed mitigation strategies to minimize risk.

Initial estimates showed that at the peak of the eclipse, UPV solar production within CAISO would be reduced from an estimated 8,754 MW to 3,143 MW before returning to 9,046 MW. The solar ramping-down rate was estimated at -70 MW/minute and ramping-up rate at 98 MW/minute (see Figure 5). By comparison, the estimated ramping-up rate during a similar period was 12.6 MW/minute on a normal clear day; however, DPV was expected to have a smaller effect. Assuming a clear sky during the eclipse, a total net load increase of around 1,365 MW was expected because of the loss of DPV generation. CAISO developed a net load forecast model that took rooftop solar generation into account.

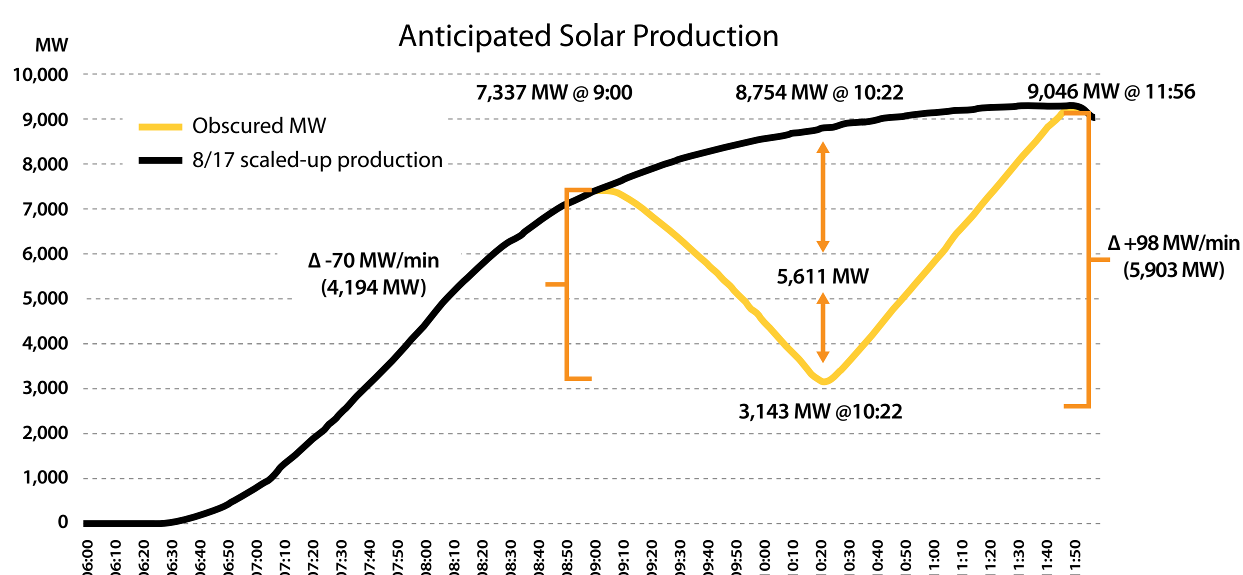


Figure 5. CAISO forecast of grid-connected solar production for the August 21, 2017, eclipse

Like the 2015 European total eclipse, the main challenges for CAISO were potential large ramping rates and energy imbalance. Faster-than-normal ramping during the eclipse would increase the burden on other generators, having a direct impact on CAISO's regulation capability in terms of available regulation capacity, speed, and location of reserves. The energy imbalance market would be impacted because of an additional 866 MW of UPV shortfall.

Informed by the 2015 European total eclipse and analysis, CAISO proposed a grid protection plan to maintain grid reliability and encouraged coordination across the Western Electricity Coordinating Council (WECC). Table 3 summarizes the proposed mitigation measures.

Table 3. CAISO Grid Protection Plan

Reserves procurement	Gas supply needs coordination.
Flex-ramp usage	Scheduling coordinator interaction
Special operating procedures	WECC/Peak Reliability coordination
Use of energy imbalance market transfer capability	Hydro generation
Internal market simulation	Potential use of Flex Alert
Day +2 conference bridge	Market participant coordination

2.2.2 The North American Electric Reliability Corporation Report

NERC combined region-specific hourly load estimates, generating unit capacity, and solar data from SEIA and GTM Research's U.S. *Solar Market Insight 2016* Q3 report to estimate the impact of the August 21, 2017, eclipse on grid-connected PV capacity across North America [2].

From 2013 – 2015, the reported load for each Monday in August was used as the set of possible hourly data points. For PV generation, an assumption was made to use the aggregated capacity of a facility and three representative hourly generation percentages to map the general shape of PV production.

The report found that the top four states that would require advanced system coordination for operations prior to the eclipse, during the eclipse, and after the eclipse were Utah, California, Nevada, and North Carolina. In some parts of each of these states, a 0.9 obscuration would be observed. (Utah had a maximum obscuration of 0.95, and Nevada and North Carolina would experience a total eclipse).

Where peak eclipse and peak demand coincided, the ramping-up and ramping-down rates required Balancing Authorities (BAs) with minimal standby energy storage to be challenged in maintaining grid stability. Following Germany's response to the 2015 eclipse, disconnecting UPV generators from the grid would mitigate instability caused by extreme ramping for the 2017 eclipse.

Peak eclipse obscuration occurred around 10 a.m. PDT for CAISO, many hours before peak demand and peak generation typically occurs in the late afternoon, therefore mitigating the ramping and balancing concerns. California and North Carolina, however, were identified as states that would require advanced planning and operating coordination for the August 21, 2017, eclipse because of their large PV installation capacity. NERC highlighted the need to coordinate the distributed energy resources for system protection and perform advanced planning and operating coordination.

2.2.3 Summary

Though CAISO and NERC relied on simple assumptions and simulations based on physical energy balance, both suggested significant changes to generation and load profiles in high PV areas during the eclipse event. To maintain grid stability, coordinated pre-event planning with tightly coupled cross-region communications during the event was required and proved beneficial by the response to the 2015 eclipse. This NREL report complements the CAISO and NERC reports by providing a detailed geospatial analysis followed by detailed production simulation and transient simulation studies.

3. Pre-Event Impact Estimation

The NREL team developed the detailed approach shown in Figure 6 for studying the impact of an eclipse on grid operations. This framework is flexible, developed with the intention to be extended to other wide-area phenomena that could similarly impact grid operations:

- Spatiotemporal analysis to estimate PV output
- Production cost simulation to estimate generation redispatch
- Transient simulation to assess grid stability.

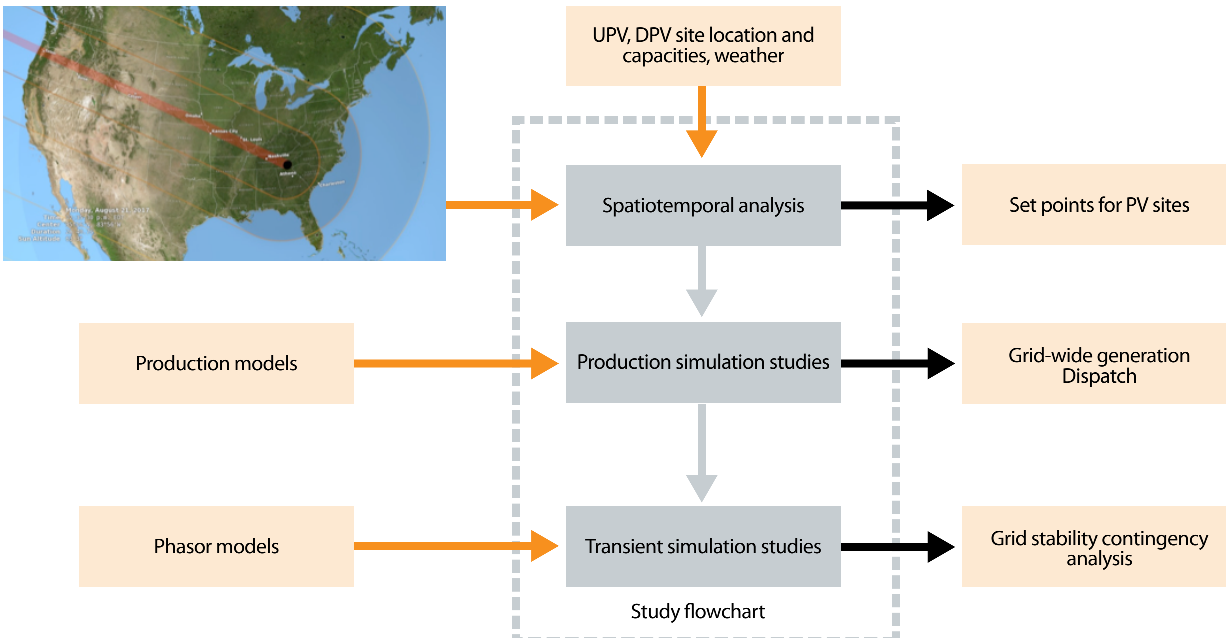


Figure 6. Flowchart of the eclipse study

3.1 Spatiotemporal Analysis of Photovoltaic Generation

NREL compared uPV and DPV minute-by-minute generation profiles for a typical meteorological day with and without the effects of the August 21, 2017, eclipse event on solar insolation.

3.1.1 Distributed Photovoltaic Capacity Extrapolation and Aggregation

The data for DPV installed capacity were derived from the Lawrence Berkeley National Laboratory *Tracking the Sun* report [10], which examined trends in the installed price of grid-connected PV systems in the United States by summarizing DPV systems through 2015. Of the 821,188 systems considered in *Tracking the Sun*, 338,386 were geocoded to precise latitude and longitude coordinates, 293,996 were geocoded to a zip code or utility service territory centroid, and 188,806 were outside the study area or removed because of incomplete information. The remaining 632,382 installations were then aggregated to the nearest substation location; general system characteristics such as array type, average tilt, and azimuth grouped by array type, generalized latitude, and longitude were retained.

To estimate the total DPV capacity in WECC, the 2015 *Tracking the Sun* data were extrapolated using several growth rates derived from state-level *Solar Market Insight 2017 Q2* data [11]. First, the total *Tracking the Sun* capacity from 2015 was linearly extrapolated to 2017 using the *Solar Market Insight* annual growth rate from 2015–2016 and 2016–2017. The resulting capacity was further extrapolated to 2017 Q2 using an average quarterly growth from Q1–Q2 for years 2014–2017. Finally, a daily growth rate for Q3 was determined from Q2–Q3 growth rates from 2014–2016. This allowed the extrapolation to consider both medium- and short-term growth rates. Rates were applied based on a per-state allocation across all of WECC. The extrapolation results in the total estimated DPV capacity in WECC grew from 6,000 MW at the end of 2015 to 9,200 MW on August 21, 2017.

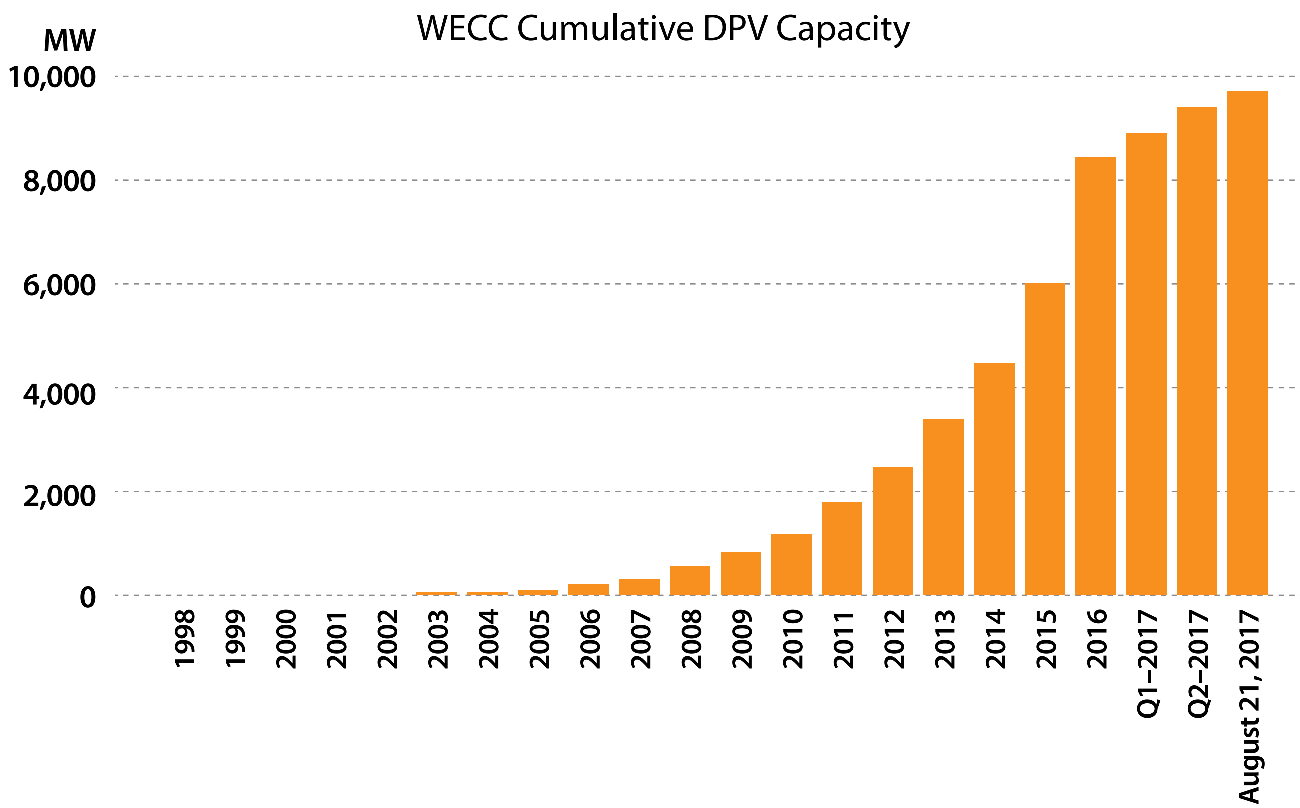


Figure 7. Cumulative DPV capacity in WECC

The DPV sites were then aggregated to the closest transmission substation. The objective was to disaggregate the loading at each substation into actual loading and DPV generation. This approach would allow the NREL team to study the impact on PV output more accurately. The utility areas with significant DPV penetration are shown in Table 4.

Table 4. Utility Areas in WECC with Significant DPV Capacities

Utility Area	Estimated DPV Capacity (MW)	Utility Area	Estimated DPV Capacity (MW)
Arizona Public Service	2,160	PacifiCorp East	57
Bonneville Power Administration	109	Pacific Gas and Electric	1,513
El Paso	261	Public Service Company of Colorado	101
Imperial Irrigation District	201	Southern California Edison	2,016
Idaho Power Company	453	San Diego Gas and Electric	522
Los Angeles Department of Water and Power	1,077	Sierra	97
Public Service Company of New Mexico	449	Western Area Power Administration	81
Nevada Power Company	169		

3.1.2 Utility-Scale Photovoltaic Capacity

The UPV capacity estimates were provided by the WECC Transmission Expansion Planning Policy Committee. The WECC Transmission Expansion Planning Policy Committee conducts an annual transmission system study program as a component of WECC's regional transmission planning process in accordance with WECC's broader mission to assess the reliability impacts of the Western Interconnection under varying economic, technological, and regulatory (policy) conditions. Installed UPV capacity is implemented in baseline PLEXOS models. The total UPV capacity (excluding concentrating solar power plants) was estimated at 15.8 GW.

3.1.3 Solar Insolation Calculation

Insolation profiles for a typical clear sky on August 21, 2017, were calculated at each generator location using the Solar and Moon Position Algorithm (SAMPA) [12]. A profile was created for a typical day without an eclipse event and with a total eclipse.

Weather data were obtained from NREL's National Solar Radiation Database (NSRDB) typical meteorological year approach and supplemented with atmospheric data from the National Aeronautics and Space Administration's (NASA's) Moderate Resolution Imaging Spectroradiometer (MODIS) database. The 2012–2016 MODIS data were averaged, and the NSRDB data were linearly interpolated from hourly values to minute values.

3.1.4 Photovoltaic Generation Calculation

NREL's System Advisory Model v2016.08.01 with PVWatts v5 was used to calculate minute generation profiles for each characteristic UPV and DPV system at each generator location. Again, profiles for both eclipse and non-eclipse days were generated using the SAMPA-derived insolation profiles. Generation was calculated assuming typical meteorological weather conditions in both scenarios.

3.1.5 Impact of Eclipse on Photovoltaic Production

3.1.5.1 Distributed Photovoltaics

DPV was estimated to reach a peak generation of less than 8 GW across WECC. Also, by 9 a.m. PDT, generation dropped until 10:30 a.m. PDT, when it began growing rapidly until 1 p.m. PDT (see Figure 6). The maximum loss of DPV production across WECC reached 1.9 GW.

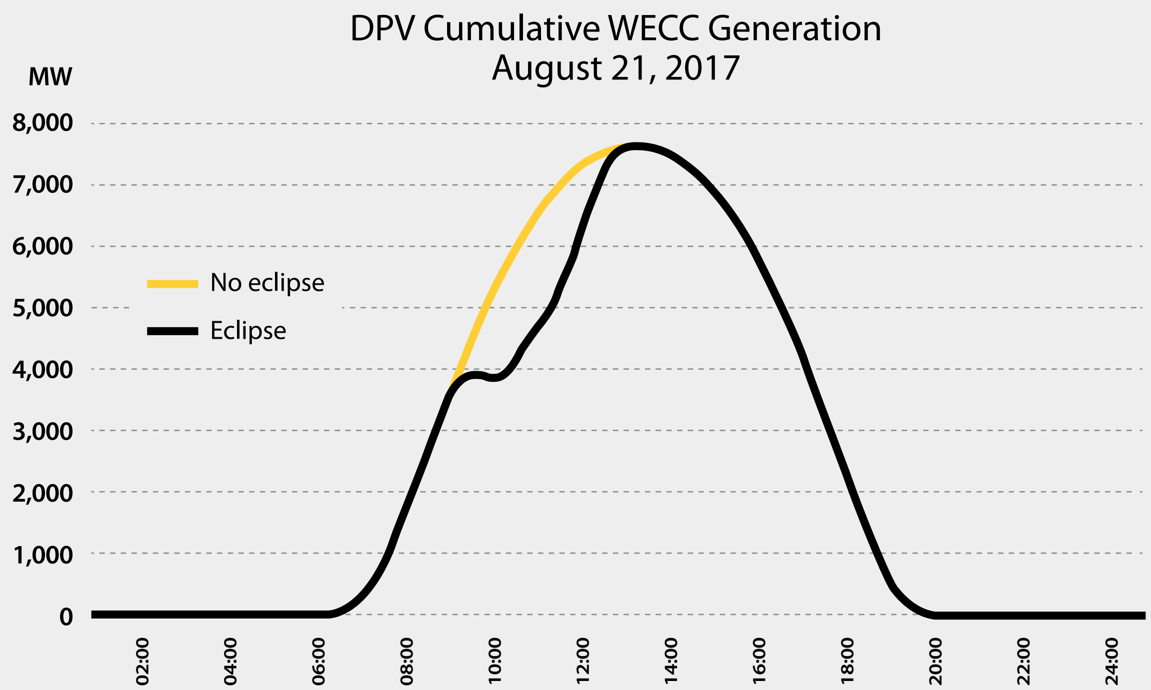


Figure 8. DPV cumulative WECC generation

3.1.5.2 Utility-Scale Photovoltaics

Across WECC, UPV saw a peak generation of more than 12 GW. The effects of the solar eclipse on generation became apparent around 9 a.m. PDT, when generation began to decrease to a nadir near 7 GW by 10:15 a.m. PDT. Generation then increased rapidly until 1 p.m. PDT, when the effects dissipated, and generation returned to non-eclipse scenario rates (Figure 7). The maximum loss of UPV production across WECC is estimated at 4 GW.

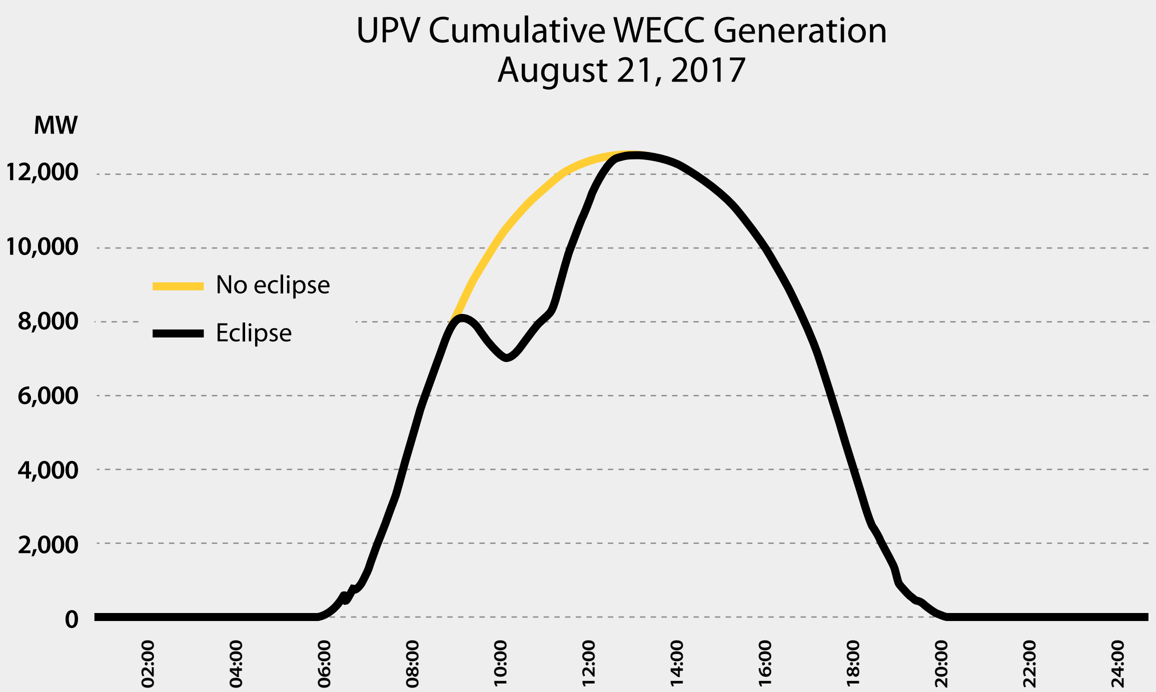


Figure 9. UPV cumulative WECC generation

3.1.5.3 Combined Utility-Scale Photovoltaics and Distributed Photovoltaics

The impact of the solar eclipse on the UPV and DPV sites combined is presented in Figure 10. The eclipse peak, from PV output reference data, occurred at 10:21am PDT. The total decrease in PV production across WECC reached 5.5 GW.

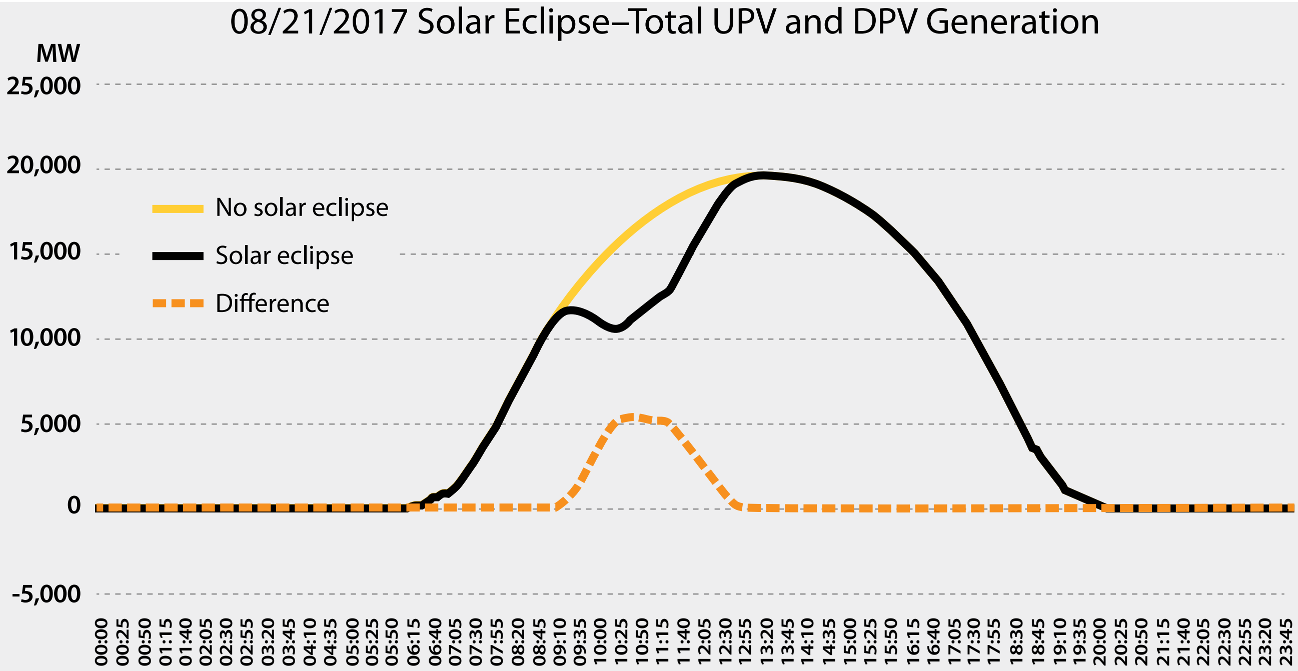


Figure 10. Impact of eclipse on combined UPV and DPV sites

3.2 Production Cost Simulation

The impact of the solar eclipse was examined using a standard differential study methodology. Two scenarios were simulated: the first was a standard operation model for WECC as it exists today, and the second was the same standard operation model but with the solar eclipse limiting the output of solar generators, both DPV and UPV.

The PLEXOS model simulates the real-time operations, consisting of a real-time security-constrained unit commitment and economic dispatch problem. This model was used to determine the operating schedules (commitments and dispatch) of all generation plants in the model at a 5-minute resolution.

3.2.1 Approach

The solar generation profiles, both with consideration of the eclipse and without, were calculated based on the methodology described in Section 2.2. The operation model was simulated in the commercially available software PLEXOS Integrated Energy Model. The simulations started from August 18 to allow the simulation model to settle an appropriate steady-state solution prior to the eclipse operating day. The simulations ran until August 22 to allow each time step a full 24 hours of foresight.

The baseline operations assumed a typical meteorological day in NREL's NSRDB database. Contingency reserves were assumed to be 3% of the load; different gas prices were assumed for different regions. Operation and management costs were included and assumed that the thermal power plants were running at a steady load without any on/off cycling. The transmission system was modeled without losses and was a fixed shift-factor AC optimal power flow. The chosen mixed integer program tolerance was 0.01% to ensure a near-perfect solution. The model ran with BA resolution, meaning that transmission was aggregated within BAs, and transmission details including constraints were maintained between BA areas.

Three stages comprised the model. First, a generator maintenance schedule was determined so that a minimum risk of capacity shortage would be based on load forecast. The 5-day operation ran in a single step under system constraints, such as hydro availability. Finally, these constraints were further decomposed to finer resolution, and the model ran at 5-minute steps.

3.2.2 Results

The solar eclipse results showed an approximate peak reduction of 5–6 GW in solar generation across WECC. One observation the research team made was that the geographical footprint of WECC is quite large, and this allowed for a staggered impact of the solar eclipse on the region during the approximate 4 hours that the eclipse occurred. This geographic smoothing naturally helps mitigate the impact of the eclipse.

During the eclipse, the burden of compensating for the lost energy from solar generators fell to the thermal fleet, mostly natural gas combined cycle (CC) generators. The CC generators have sufficient capacity with sufficient flexibility (i.e., ramping capacity, operational capacity) and therefore could shoulder most of the burden. The available headroom (remaining capacity) and footroom (current output) for the CC fleet is shown in Figure 11 and Figure 12, respectively. The figures also illustrate that there was sufficient capacity to compensate for the fall and rise in solar production during the eclipse.

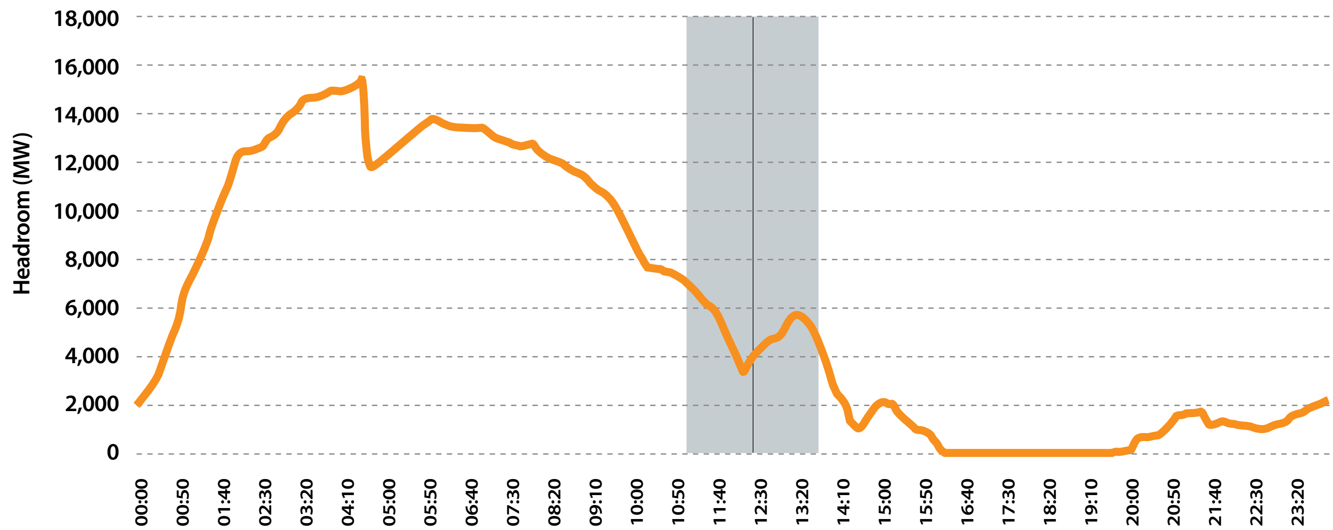


Figure 11. Aggregate headroom for the CC fleet for August 21, 2017, EDT

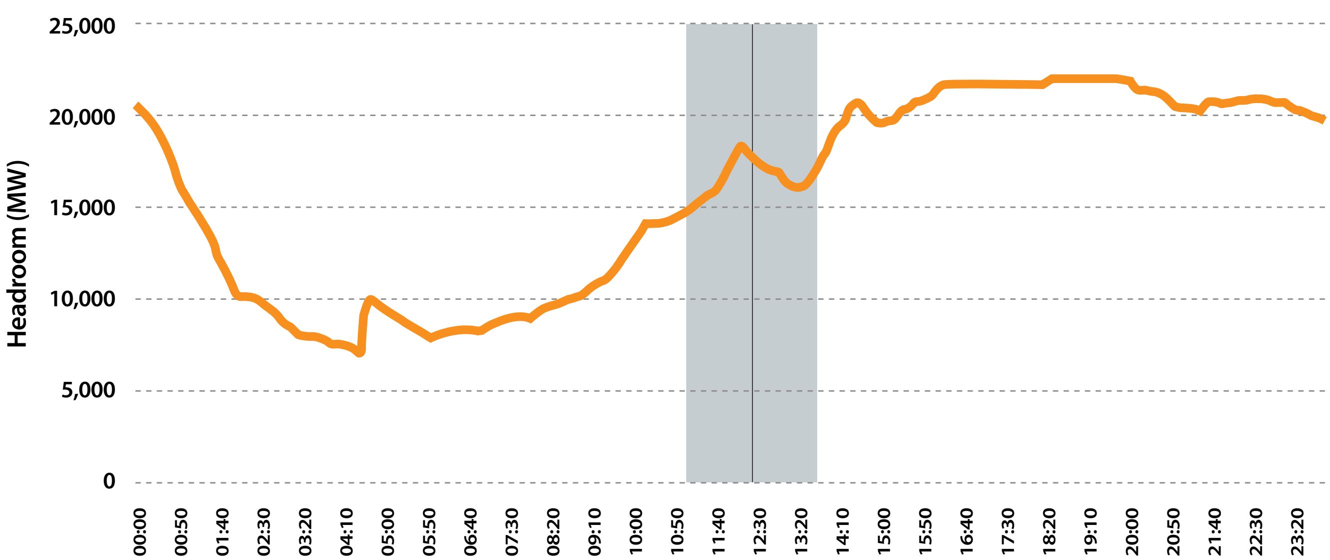


Figure 12. Aggregate footroom for the CC fleet for August 21, 2017, EDT

During the eclipse, from approximately 8 a.m. until noon PDT, the CC generators ramped up to compensate for the loss in solar generation, and the headroom decreased. Expectedly, the footroom increased as generators moved higher into their operating range. There was, however, substantial CC availability during this time, and these generators were able to provide the majority of the solar energy compensation. Figure 13 shows the change in aggregate energy production by generation technology type because of the solar eclipse.

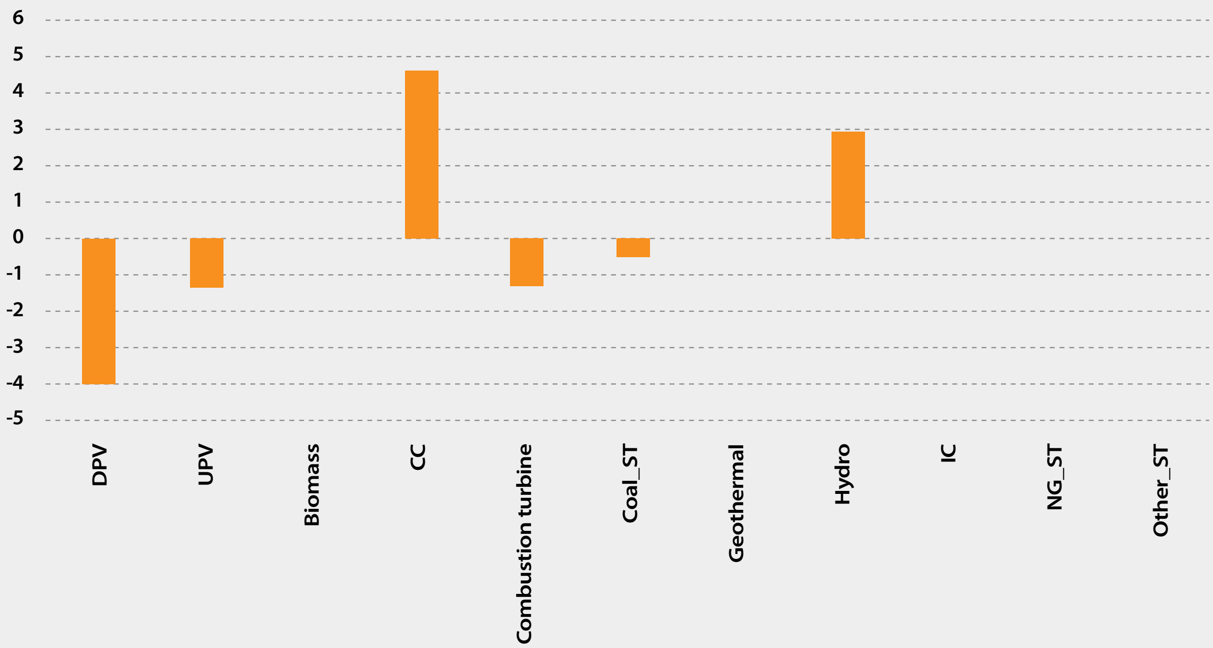


Figure 13. Change in energy production by generator type due to the eclipse

The next largest generation technology that helped make up the energy deficit was hydro generation. Hydro generators have desirable flexibility characteristics, but because of energy conservation constraints, they cannot compensate for the loss of solar generation alone. The total production cost for August 21, 2017, was 0.2% higher than a no-eclipse scenario, which was mostly attributable to the loss of solar generation being replaced with thermal generation for the duration of the eclipse.

3.3 Transient Simulation

Transient simulations were used for assessing the stability of the electric grid. During the eclipse, the stability of the grid was of utmost concern during the peak (at 10:21 a.m. PDT).

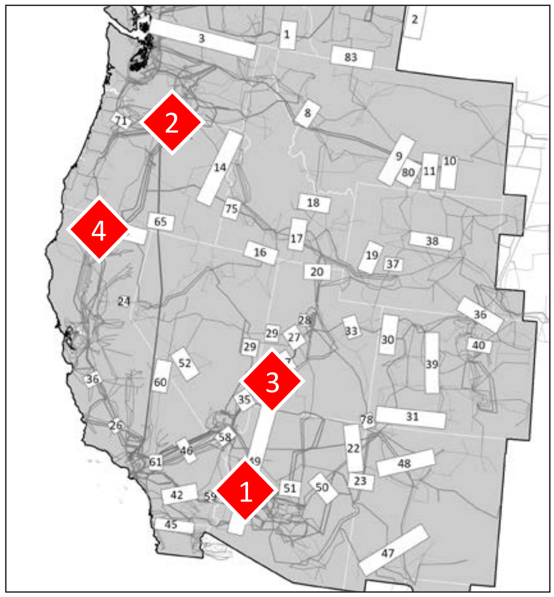
Transient simulation studies required a two-part differential-algebraic model to represent the entire WECC system: (1) a static model that represented the algebraic equations governing the flow of real and reactive power among all the buses and (2) a dynamic model that represented the differential equations describing the behavior of individual power system equipment and their controls. These models were updated to include the peak eclipse scenario by adjusting the current injections from different generators (generator set points), equipment status, and system loading at the load buses.

The WECC model described here was used for operational planning for the western U.S. grid. It consists of power plants, transmission lines, and substations from 500 kV to 69 kV, utility-scale renewable generation sites, and other special power systems equipment such as high-voltage DC (HVDC) systems and flexible AC transmission systems. The load and distribution systems are typically aggregated at the level of 69 kV. The current modeling paradigm does not distinguish between actual load and DPV because of lack of sufficient information from the distribution systems. The load is generally characterized as fractions of motor and static loads. The simulation does not consider further tripping of PV inverters because of high/low frequency, which might cause cascaded events; however, this is worth further studies.

3.3.1 Approach

Power system stability is typically assessed through the following characteristics: voltage, frequency, and phase angle. Angular stability is further divided into small-signal and large-angle stability. For stability analysis, the following credible contingencies were identified in collaboration with Peak Reliability. These contingencies are shown in Figure 14.

1. Loss of Palo Verde generators
2. Loss of Pacific DC Intertie (PDCI)
3. Loss of Intermountain HVDC line
4. Loss of one of the lines along the California-Oregon, Intertie



Source: WECC
Figure 14. Identified contingencies for stability studies

The four selected contingencies were not only severe but also represented unique challenges to the grid. These challenges were: loss of PV units represents a loss of massive generation, loss of PDCI represents a loss of a major DC intertie, loss of Intermountain HVDC represents a combined loss of generation and major DC intertie, and loss of California-Oregon Intertie represents a major contingency along a critical AC transmission corridor.

Transient simulations were performed by loading the power flow files that represent the static model of WECC. Then the dynamic models were loaded, and the simulation run was initialized. The dynamic simulation was run for a few seconds to ensure steady-state initial conditions. The dynamic solution was computed at a time step of 4.2 ms (4 time steps for each power system cycle at 60 Hz). Then a three-phase fault was placed at a bus near the selected contingency location, and the generator or line was removed from service. The simulation was allowed to run for the next 15 seconds to observe the system dynamics. Bus voltages, bus frequencies, and tie line power across the interconnection were monitored for discrepancies and stability concerns. The contingency studies showed that the system is stable in voltage, frequency, and angular terms during the peak eclipse.

During the transient simulations, triggering underfrequency load shedding was not observed. The prevalent underfrequency load shedding settings for WECC [13] are presented in Table 5.

Table 5. WECC-Coordinated Underfrequency Load-Shedding Plan

Load-Shedding Block	Customer Load Dropped (%)	Pickup Frequency (Hz)	Tripping Time*
1	5.3%	59.1	14 cycles
2	5.9%	58.9	14 cycles
3	6.5%	58.7	14 cycles
4	6.7%	58.5	14 cycles
5	6.7%	58.3	14 cycles
Additional automatic load shedding to correct underfrequency stalling			
	2.3%	59.3	15 seconds
	1.7%	59.5	30 seconds
	2.0%	59.5	60 seconds
Load automatically restored from 59.1-Hz block to correct frequency overshoot			
	1.1%	60.5	30 seconds
	1.7%	60.7	5 seconds
	2.3%	60.9	15 cycles
Tripping time includes relay and circuit breaker time.			

3.3.2 Results

The plots for frequency and tie line power for selected locations across WECC are shown for each of the selected contingencies described in this report.

3.3.2.1 Loss of Palo Verde units

The loss of three generating units at Palo Verde was considered the most severe contingency. The three generating units at Palo Verde produced about 3.3 GW. As shown in Figure 15, this caused a significant impact on the tie line flows and system frequencies.

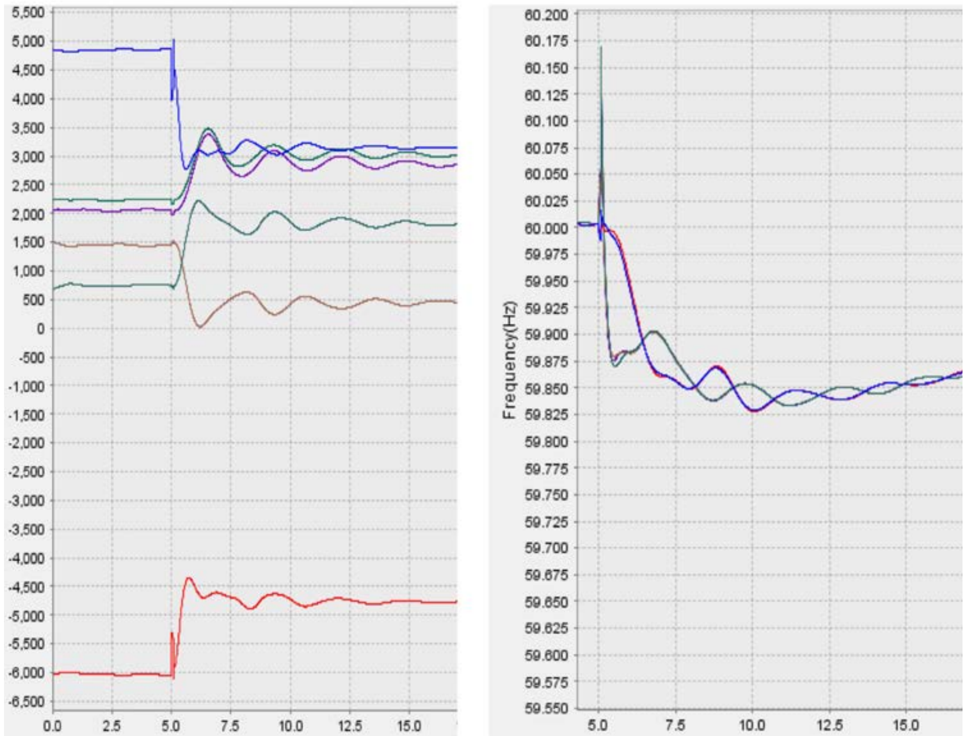


Figure 15. Transmission flows and bus frequencies at selected locations (Palo Verde)

Figure 15 shows how the change in power flow along selected corridors represented a change in system flows because of the loss of Palo Verde units. (Line flows were not identified because of confidentiality.) In the frequency plot, the frequency nadir was 59.8 Hz. The frequency and tie line flows showed small-signal oscillations with high damping. No other trips, load shedding, or voltage problems were observed. The flows along the tie lines were also within their rating limits.

3.3.2.2 Loss of PDCI

PDCI is a bipolar, multiterminal HVDC transmission system that brings power (chiefly, hydropower) from the Pacific Northwest region of the United States to Los Angeles, California. It is rated for 3,100 MW.

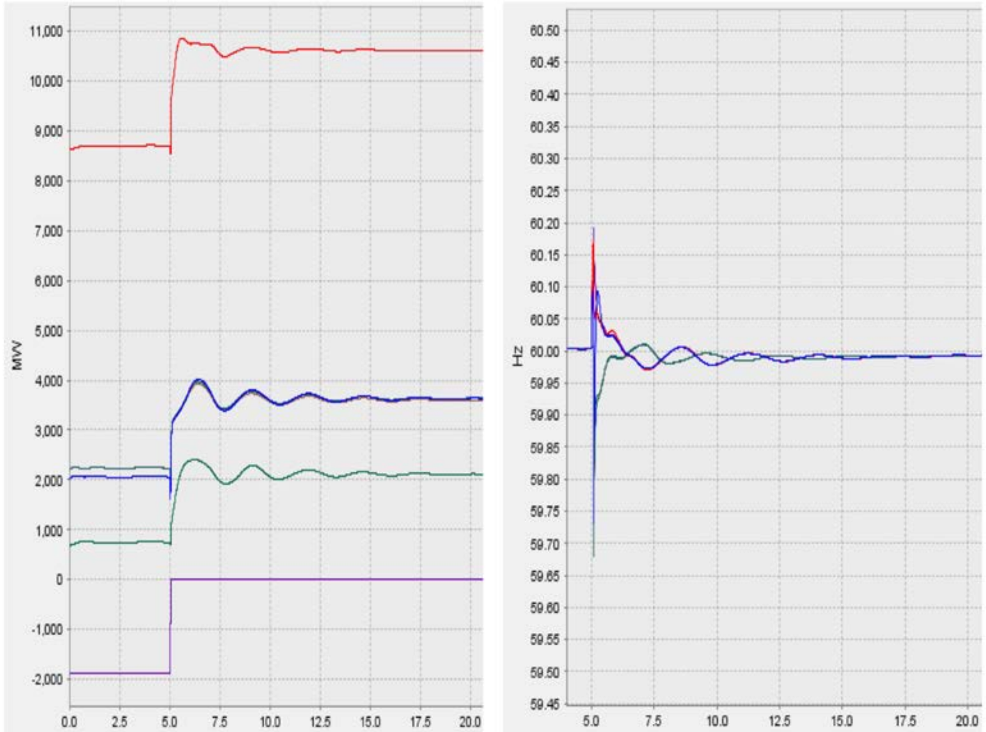


Figure 16. Transmission flows and bus frequencies at selected locations (PDCI)

In Figure 16, the tie line flows respond to the loss of PDCI. As the PDCI power transmission corridor was lost, the rest of the tie lines that cater to California picked up in response. (Line flows were not identified because of confidentiality.) Though the frequency nadir was 59.7 Hz, the frequency recovered to the nominal value before the end of the 20 seconds. Inter-area oscillations could also be observed; high system damping led to quick damping of these modes.

3.3.2.3 Loss of Intermountain Power Plant

The Intermountain Power Plant has an installed capacity of 1,900 MW and consists of two generating units. Most of the power from the Intermountain Power Plant is shipped through the Intermountain HVDC transmission line to Adelanto, California. This contingency combines aspects of the first two cases because of the loss of an HVDC line and the generation station. (Line flows were not identified because of confidentiality.)

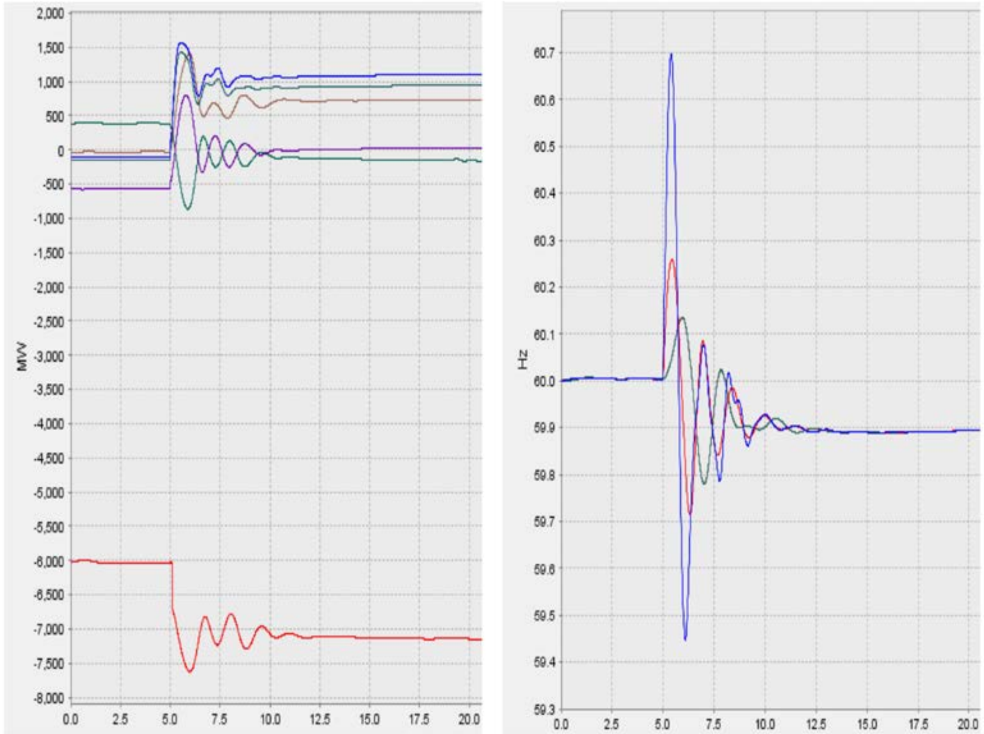


Figure 17. Transmission flows and bus frequencies at selected locations (Intermountain Power Plant)

Because the contingency represented a loss of generation and a major transmission corridor, the research team saw a pronounced impact on the tie line flows and on system frequencies. The frequency nadir was 59.5 Hz, and the oscillations were completely damped before 20 seconds. The frequency of oscillations was markedly different from the previous two cases.

3.3.2.4 Loss of California-Oregon Intertie

The California-Oregon Intertie is a collection of high-voltage AC transmission lines that are designated as Path 66 by WECC. The California-Oregon Intertie connects the electric grids of Oregon and California and is rated at 4,800 MW. For this case, one line along the California-Oregon Intertie path was removed from service after a three-phase fault.

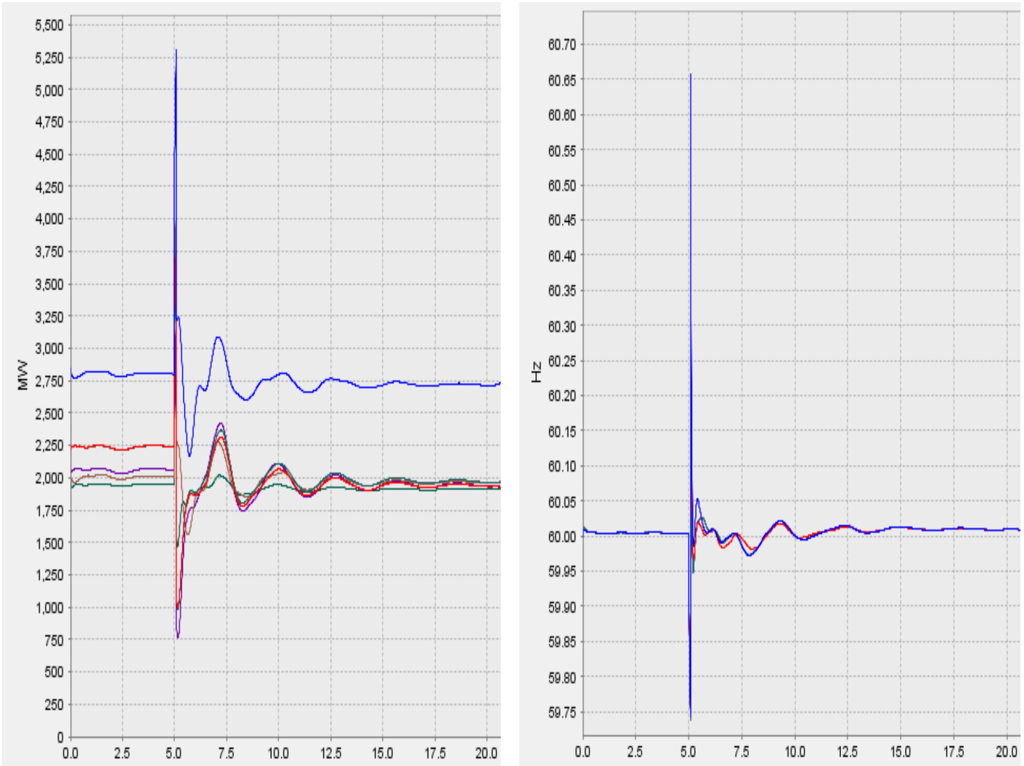


Figure 18. Transmission flows and bus frequencies at selected locations (California-Oregon Intertie)

As with the previous cases, frequency and tie line shifts were within acceptable limits. Underfrequency load shedding was not observed because of the short duration of frequency transients. The frequency recovered to the nominal because the load balance was not affected. The spike in tie line power during the three-phase fault was observable in this case because the fault was placed on a major AC corridor.

3.4 Peak Reliability Eclipse Preparation Efforts

As the Reliability Coordinator (RC), Peak Reliability has the highest level of authority for the WECC region and is therefore responsible for the reliable operation of the bulk electric system. In preparation for the solar eclipse, Peak Reliability surveyed its member BAs in the footprint of the eclipse as well as Alberta Electric System Operator (the other RC in the Western Interconnection) regarding the expected impact of the solar eclipse. The survey included a request for the estimated maximum amounts of both UPV and DPV that would potentially be reduced during the solar eclipse event. In addition, the survey requested any operating plans developed for the event and for information on reserves, asking Peak Reliability members how they expected to make up for the reduction in the UPV and DPV output. Peak Reliability summarized the results of the survey responses and created a footprint-wide operating memo to ensure awareness among its members.

Peak Reliability also performed a footprint-wide study to analyze the expected impact of the solar eclipse on its RC area. The study leveraged data from NREL, solar eclipse obscuration factors from NASA, recent state-estimator snapshots from its energy management system, and data obtained from its member survey to develop a case study that could be used to simulate two worst-case scenarios. The objective of the studies was to ensure readiness at the RC level for the solar eclipse event while also verifying the effectiveness of the member-supplied transmission operating plans (TOPs), including reserves sufficiency. After performing its assessments, Peak Reliability concluded that with the application of the member-supplied TOPs and their plans for reserves, its RC area was not expected to experience any reliability issues related to the solar eclipse.

4. Post-Event Analysis

The post-event analysis presented here studied the impact of the eclipse from actual field data collected by Peak Reliability and applies to the entire footprint. The U.S. Energy Information Administration performed a study to evaluate the impact on California, given its high PV penetration [1].

4.1 Data

Peak Reliability provided the data for the analysis. There are two types of data that are used in this study:

1. Real-time measurements. Peak Reliability used the OSIsoft PI system, a common utility supervisory control and data acquisition system, to collect real-time measurements from critical bulk grid elements such as generators, including utility wind and solar power plants; transmission lines; and interties among the different BA areas. In addition, Peak Reliability collected BA-level information, such as area control error, scheduled exchanges, spinning and total reserves, and total load and generation. The archived real-time measurements for 4 selected days were collected. The reporting rate for the data was at 10-second intervals on the day of the eclipse, and for the other three baseline days it was collected at 1-minute intervals. In addition, data archives spanning the first 6 months of 2017 were collected for renewable sites.
2. Energy management system-solved cases. The energy management system used the measurement data to estimate states for the entire WECC network through its state estimation application. The solved state estimation case was the most accurate representation of the system at that instant of time. Peak Reliability provided these cases at 1-minute intervals for the day of the eclipse and at lower rates for the other selected days.

4.2 Approach

4.2.1 Determining Baseline for Grid Operations on August 21, 2017

To estimate the impact of the eclipse on grid operations, it was important to establish a credible baseline for what the grid operations may have been without the eclipse event on August 21, 2017. To do this, the research team selected 3 days: August 22 (the day after the eclipse), August 14 (the Monday before the eclipse), and August 18 (the Friday before the eclipse). The total generation and load for WECC for the 4 days (including the eclipse day) between 8 a.m. and 2 p.m. PDT is shown in Figure 19. The gray-shaded areas represent the duration of the eclipse in the WECC footprint. The vertical black line represents the peak of the eclipse, defined as the point at which the impact on PV output was the highest.

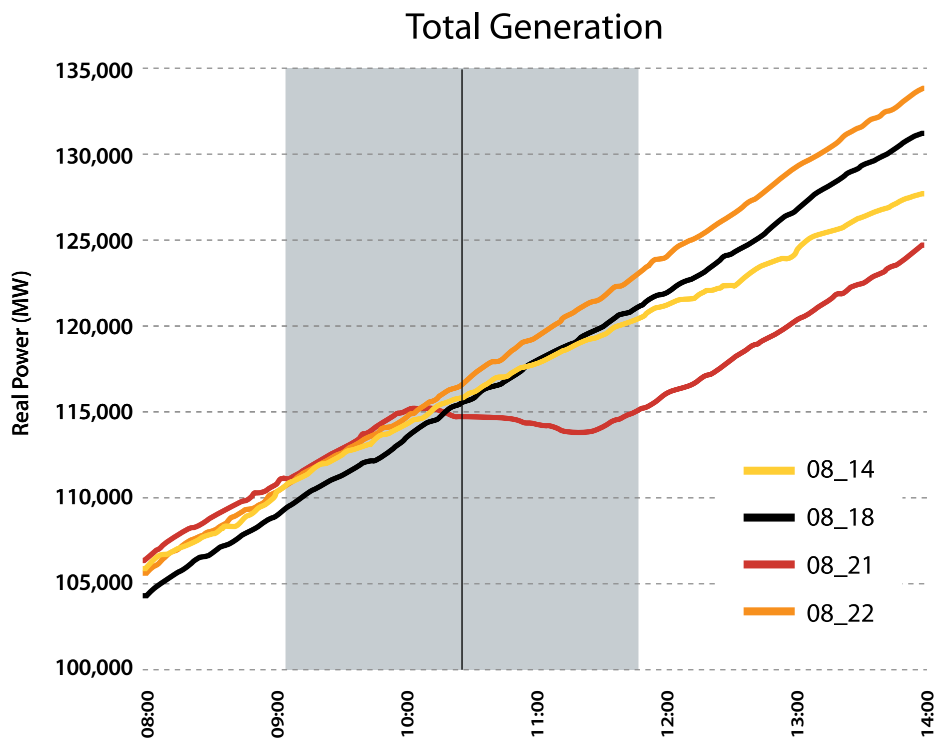


Figure 19. Total generation at WECC-level

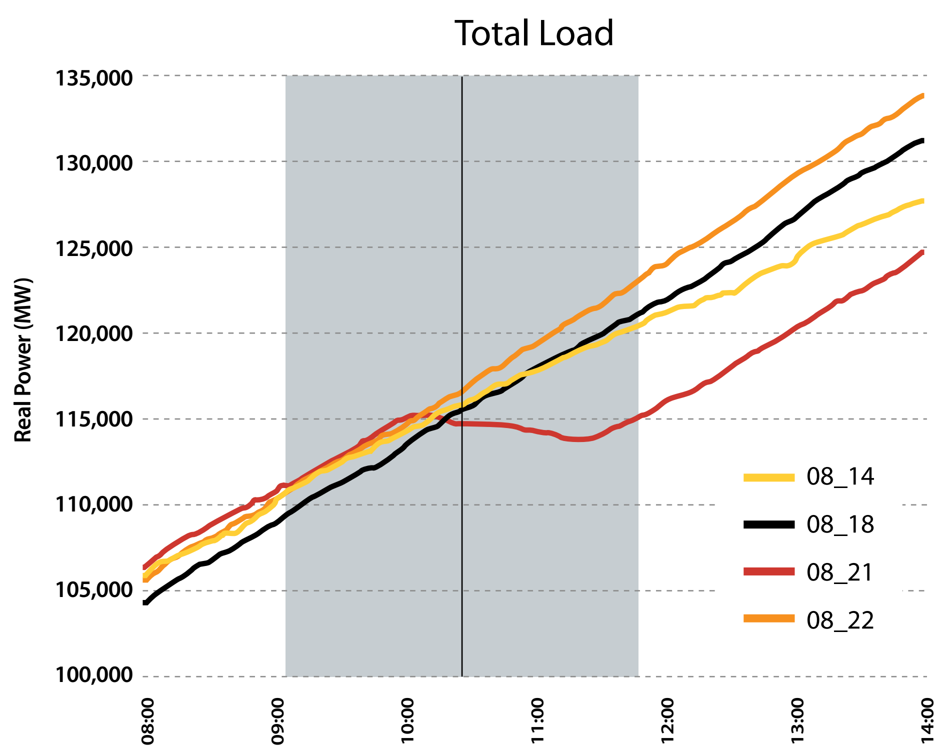


Figure 20. Total load at WECC-level

The system generation and loading charts may seem identical, but there is a certain offset. This offset represents the system losses at the transmission level. These charts illustrate that the load and generation profiles at the WECC level exhibit a linear characteristic as they ramp up during the day. The research team used this linearity assumption when determining the impact on load in a later section.

4.2.2 Determining Impact on Photovoltaic Output

The impact on the DPV output cannot be measured directly because of the lack of sufficient measurements from the distribution network. Hence, the impact on the DPV was interpreted as the same as the impact that was estimated earlier. This approach aligns with the approach adopted by Peak Reliability for their estimation of impact. The NREL team's previous studies showed a total DPV capacity of 9.2 GW across WECC. The maximum loss of DPV was expected to happen around 10:21 a.m. PDT with a loss of 1.9 GW.

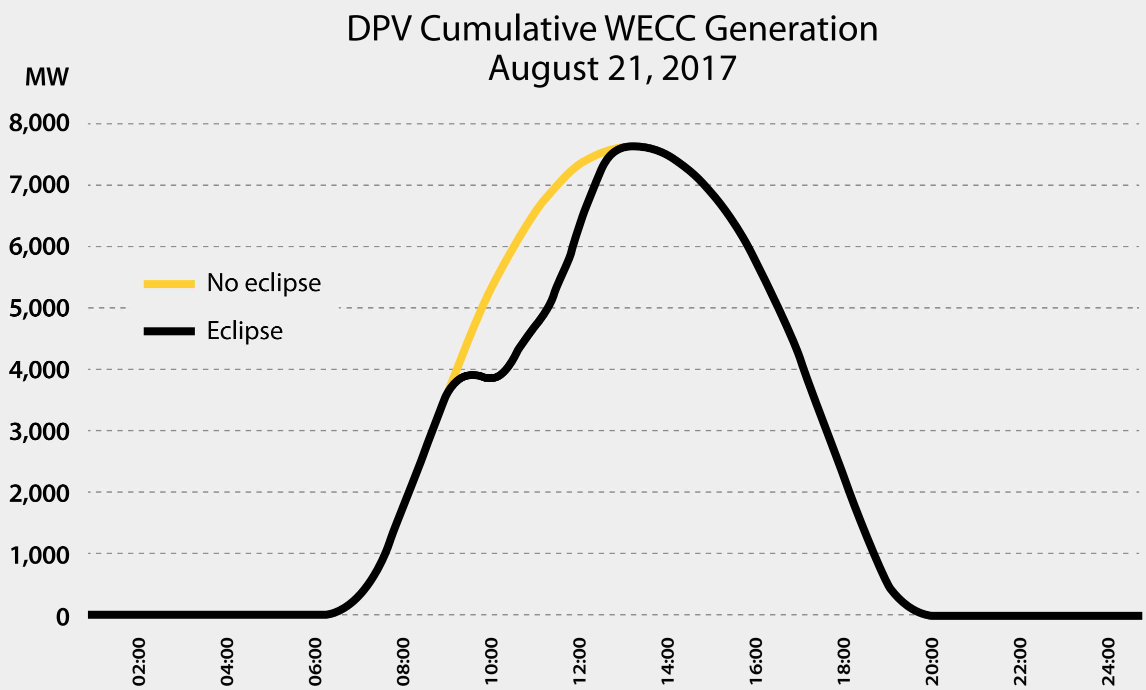


Figure 21. Loss of DPV during eclipse (estimated)

The impact on the PV output can be estimated by comparing the WECC-level PV output for the selected baseline days. The UPV output at the WECC level for the selected dates is shown in Figure 22.

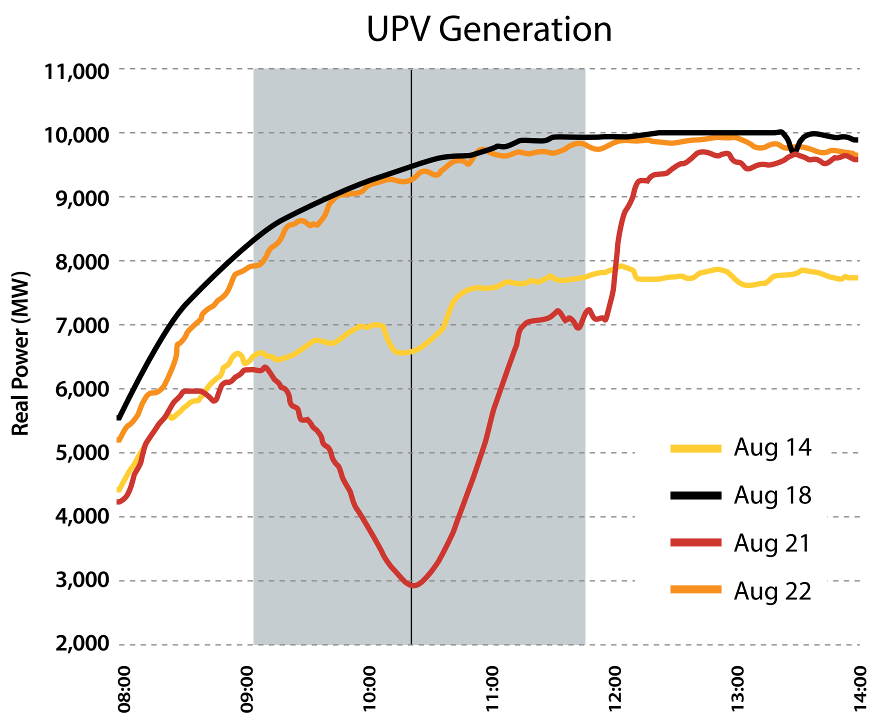


Figure 22. UPV generation at WECC-Level

As shown in Figure 22, the PV profile on August 21 at 8 a.m. PDT resembles a PV profile of August 14, a relatively cloudy day; however, at the end of the eclipse event (around 1 p.m. PDT), the output resembles the profile recorded on August 18, a relatively sunny day. It can be hypothesized that August 14 provided a lower estimation for the expected PV output on August 21, whereas August 18 provided a higher estimation for the expected PV output, hence the profiles for computing the impact on PV output.

The research team estimated that the observed loss of UPV was between 4 GW and 6.5 GW at the peak of the eclipse. The overall loss of energy from UPV resources was estimated to be between 5.5 GWh and 11 GWh.

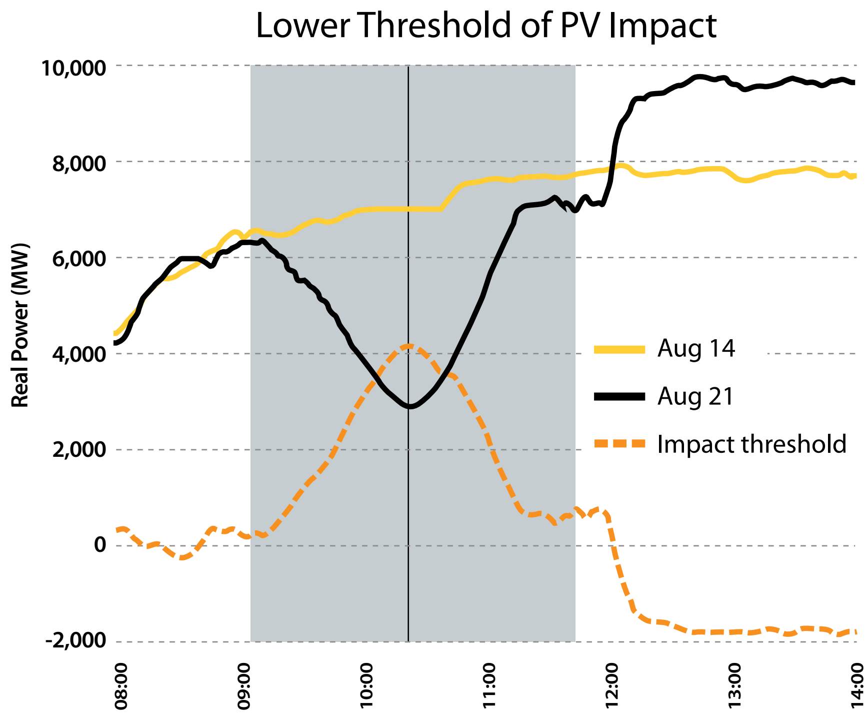


Figure 23. Minimum PV impact on eclipse day

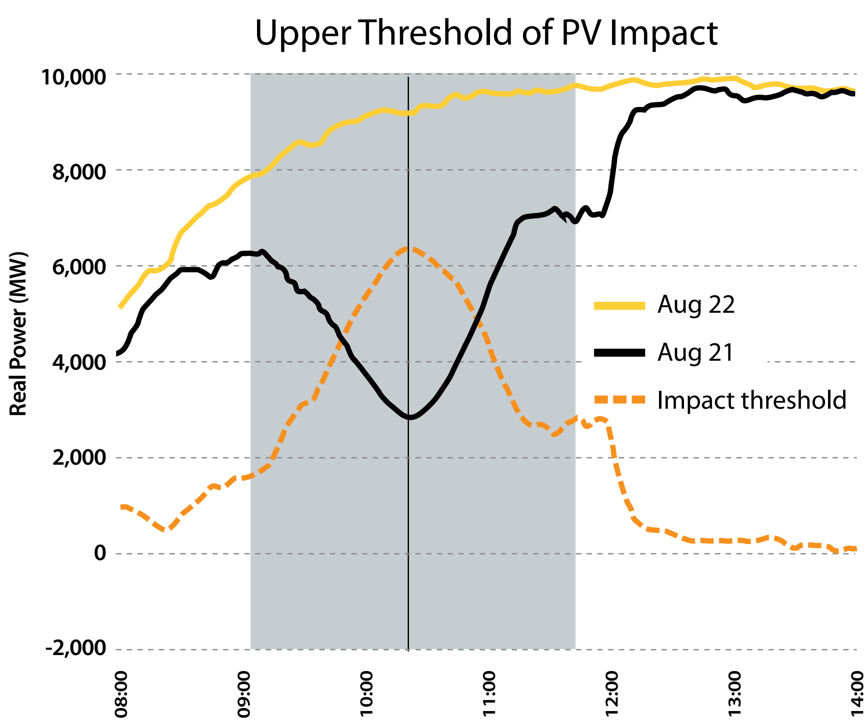


Figure 24. Maximum PV impact on eclipse day

When determining the impact on PV output, it is also pertinent to ask how an eclipse differs from another type of large weather event. To answer this question, the NREL research team collected PV output at the WECC system level for the first 6 months of the year and plotted the data in Figure 25, where each color represents a different month.

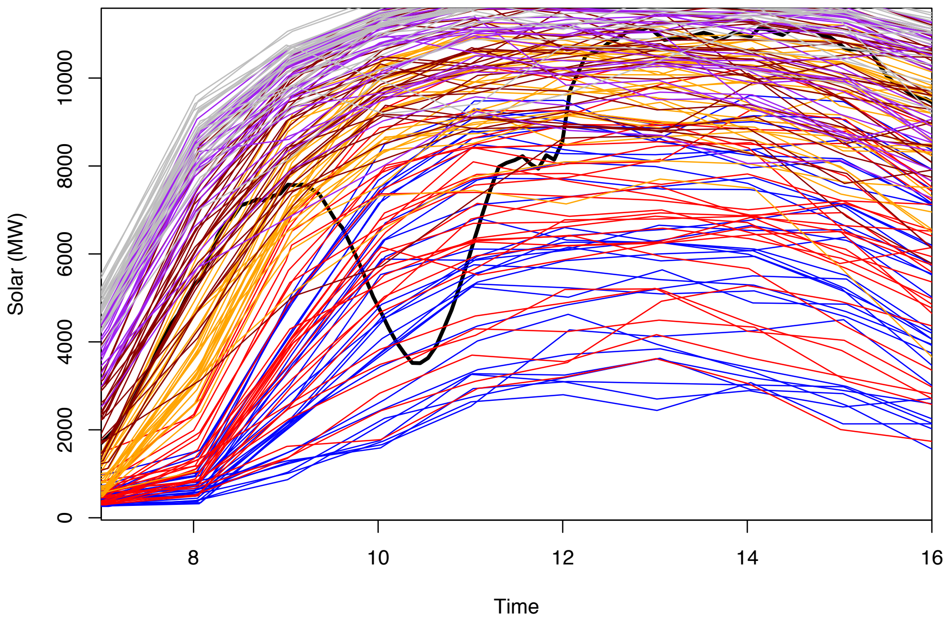


Figure 25. WECC-level aggregate PV output

Although overall PV output can vary from one day to another, the ramp rate associated with ramping up and down during the eclipse was markedly different. This can be seen clearly when the PV outputs are normalized to output power, as shown at 1 p.m. PDT in Figure 26.

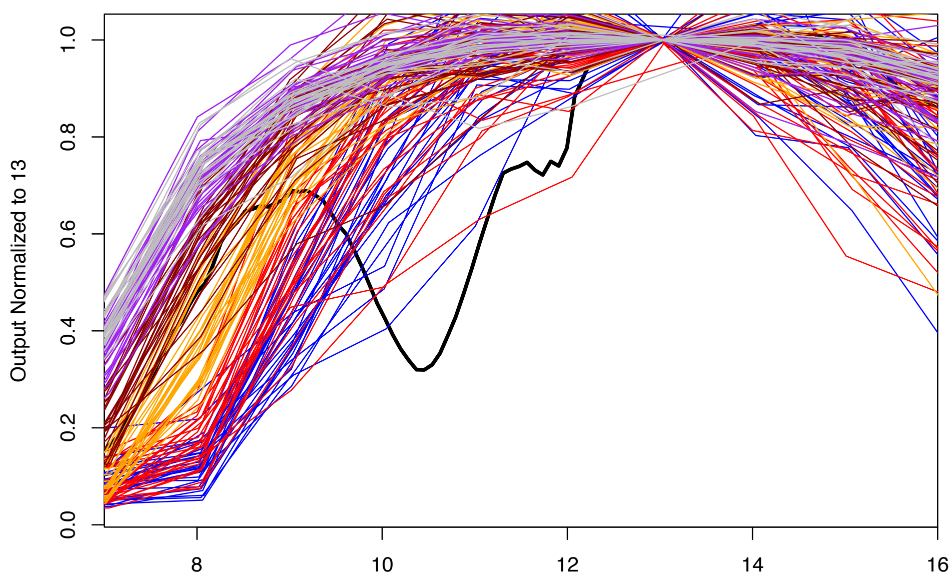


Figure 26. WECC-level aggregate PV output normalized

4.2.3 Determining Impact on System Loading

As the first few charts indicate, there was a drop in the total system load because of the eclipse. The change in system loading can be attributed to the following factors:

1. Loss of DPV (increases loading)
2. Non-PV factors: transient weather changes and behavioral factors (decreases loading).

As the eclipse gained totality across the footprint, it caused a loss of DPV as well. Assuming the profile for the DPV profile as was estimated earlier, it would result in a general increase in the actual load. This is shown in Figure 27, where the actual total load was computed after applying the DPV profile.

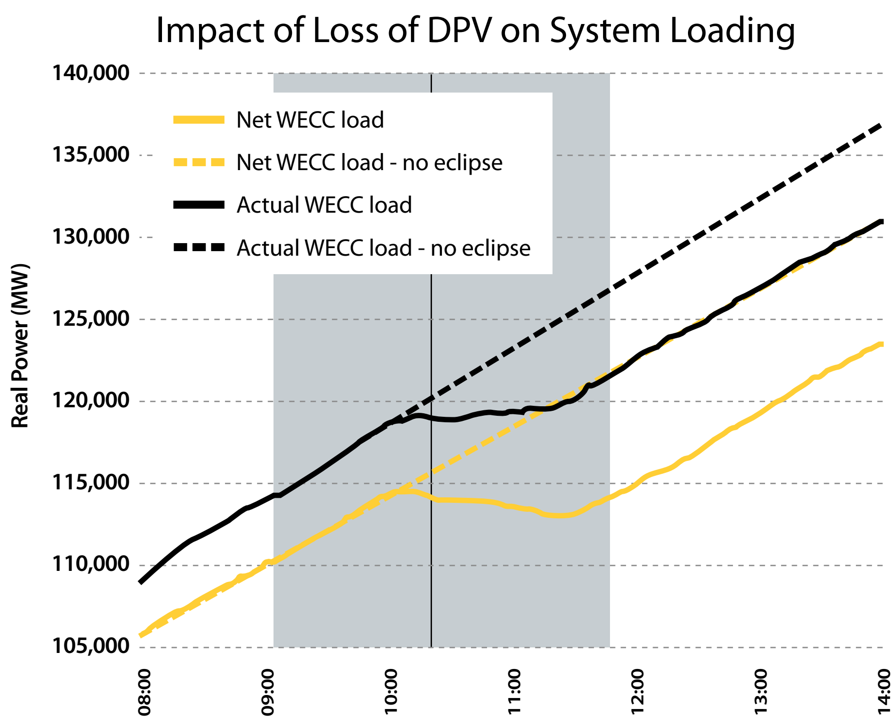


Figure 27. Actual and net load at WECC-level on eclipse day

The impact on actual and net load as a result of the eclipse can be estimated by calculating the difference between the eclipse and no-eclipse profiles, shown in Figure 28. The change in net loading as a result of the eclipse was 7.2 GW. Assuming a system loading of 120 GW, the change was 6%. This magnitude represents the change in load as a result of DPV and non-PV factors. The change in actual load (where DPV is removed) represents the change in load because of non-PV factors. Although there are currently limited means to estimate the impact caused by non-PV factors, the information from this study and from previous studies can provide a rule-of-thumb estimate for future studies. Figure 28 shows that a change in actual system loading (without DPV) as a result of the eclipse is 5.4 GW, or 4.5%. The maximum impact on load did not coincide with the maximum impact on PV output.

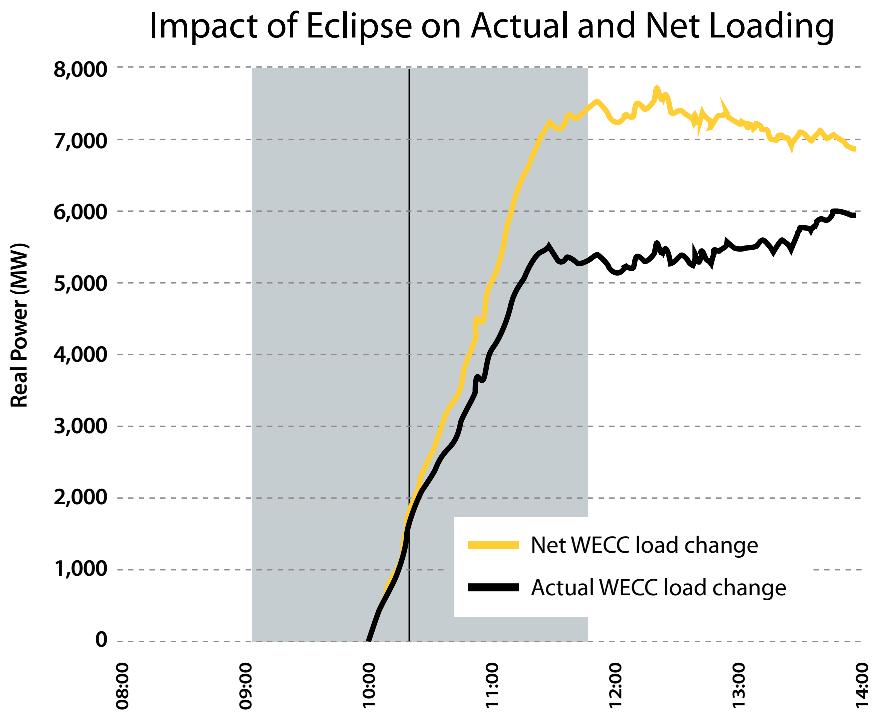


Figure 28. Actual and net load impact due to eclipse

4.2.4 Impact on System Reserves

The total system reserves for the 4 selected days are plotted below in Figure 29. The higher reserves were procured by the WECC entities, which was confirmed by Peak Reliability. Note that the available reserves continued to dip until the peak of the eclipse, after which they increased as the totality left the WECC footprint.

Another observation is that the peaking of the available total system reserves at 29.5 GW coincided with the start of the PV curtailment. After the eclipse event, reserves were taken off the market, which could lead to declining reserves until the valley point occurring at about 28 GW at 11:56 a.m. PDT. This valley point marks the end of PV curtailment, thus the curtailment must have been caused by the availability of additional reserves coupled with a decrease in system loading, leading to a potential overgeneration scenario.

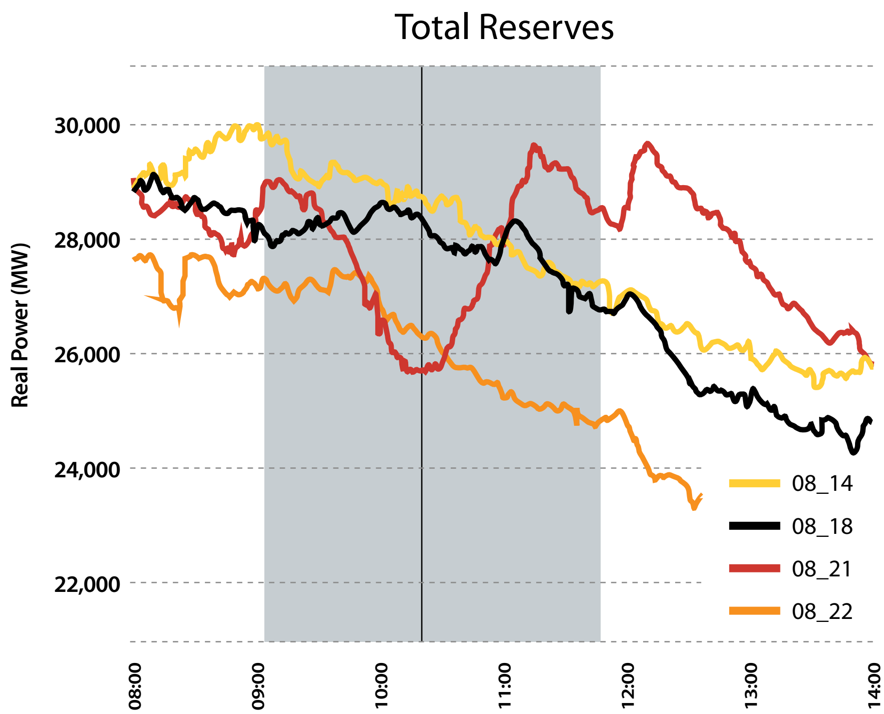


Figure 29. Total reserves at WECC-level

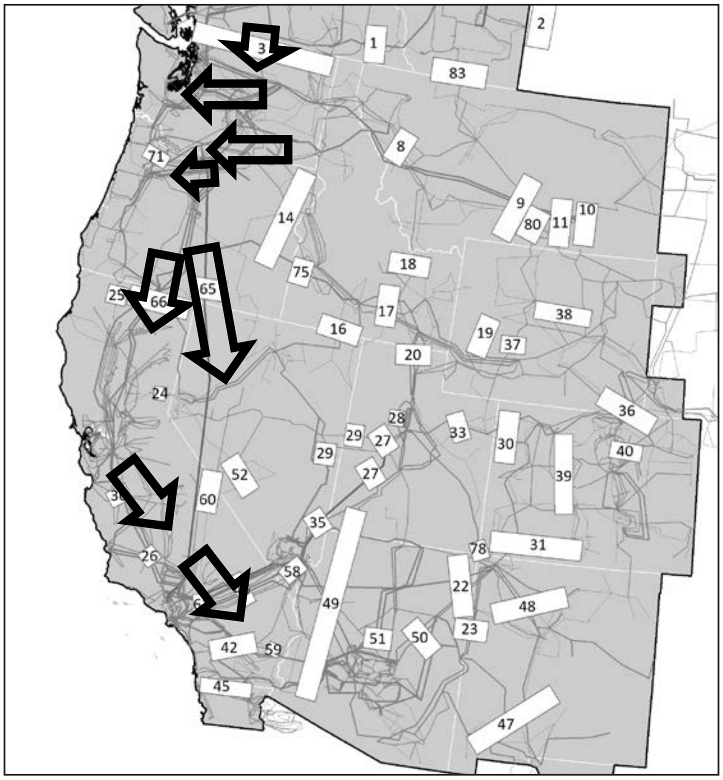
4.2.5 Impact on Western Electricity Coordinating Council Path Flows

As the eclipse event progressed, the flows along the critical WECC paths were altered because of the redispatch of resources to account for the loss of PV. WECC has 25 paths defined for power transfer among the different BA areas. Although a path typically represents multiple transmission lines, a path could also be a single, long, high-capacity transmission line. The definitions and ratings for all WECC paths are presented in Appendix A. The path flows that were impacted by the eclipse were identified by power flow trends during the eclipse event, after being normalized by the pre-eclipse flows. These ratings and definitions of the affected paths are shown in the Table 6.

Table 6. Definition and Ratings of Affected WECC Paths

Path #	Path Name	Path Rating Transfer Limit (MW)		Primary Direction (Positive Flow)
		E to W (N to S)	W to E (S to N)	
Path 03	NorthWest to British Columbia	3,150	2,000	S to N
Path 04	NorthWest to British Columbia	10,200		E to W
Path 05	Bonneville Power Administration to Bonneville Power Administration	7,000		E to W
Path 15	Pacific Gas and Electric to Pacific Gas and Electric	500	360	N to S
Path 61	Southern California Edison to Southern California Edison	2,400	900	N to S
Path 65	PDCI	3,100	3,100	N to S
Path 66	California-Oregon Intertie	4,800	3,675	N to S
Path 73	North of John Day			

The selected paths are shown in the Figure 30 [14].



Source: WECC
Figure 30. Affected WECC paths

During the eclipse, the paths that transfer power from the north of the footprint to the load centers in Southern California had increased to make up for the loss of PV in California. Conversely, the flows along the paths inside California were affected. The path flow trends for selected paths are presented in Figure 31. The plot shows how the path flows trended relative to the start of the eclipse.

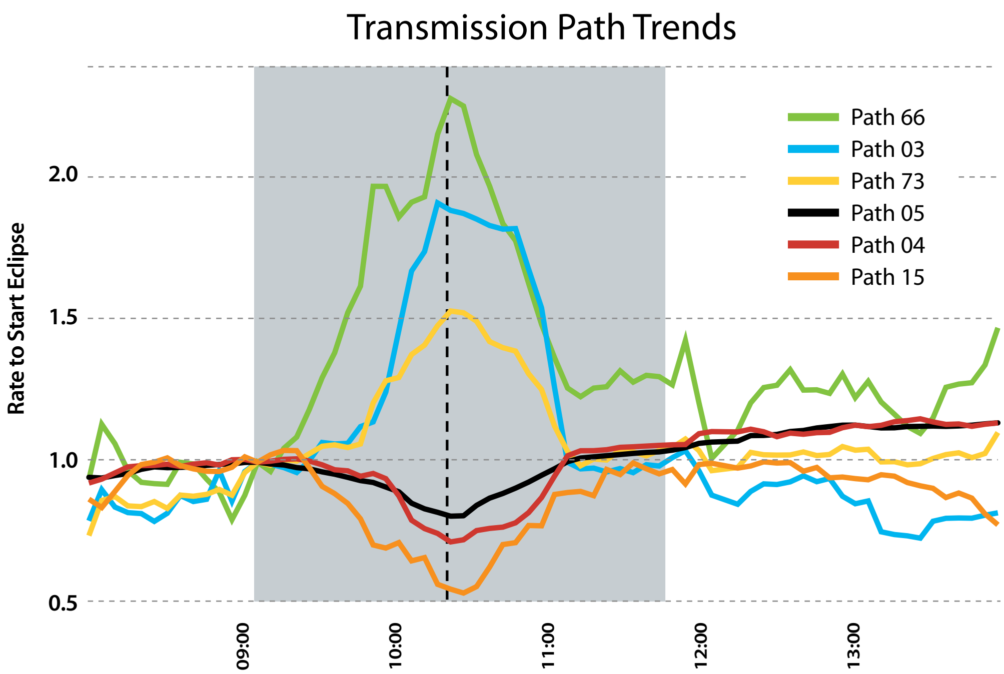


Figure 31. Transmission flow trends along affected paths

Path 3 and Path 66 picked up more than twice their flow relative to the start of the eclipse. As the eclipse left the footprint, the flows returned to the pre-eclipse values. The actual power flows for the impacted paths are shown in Figure 32.

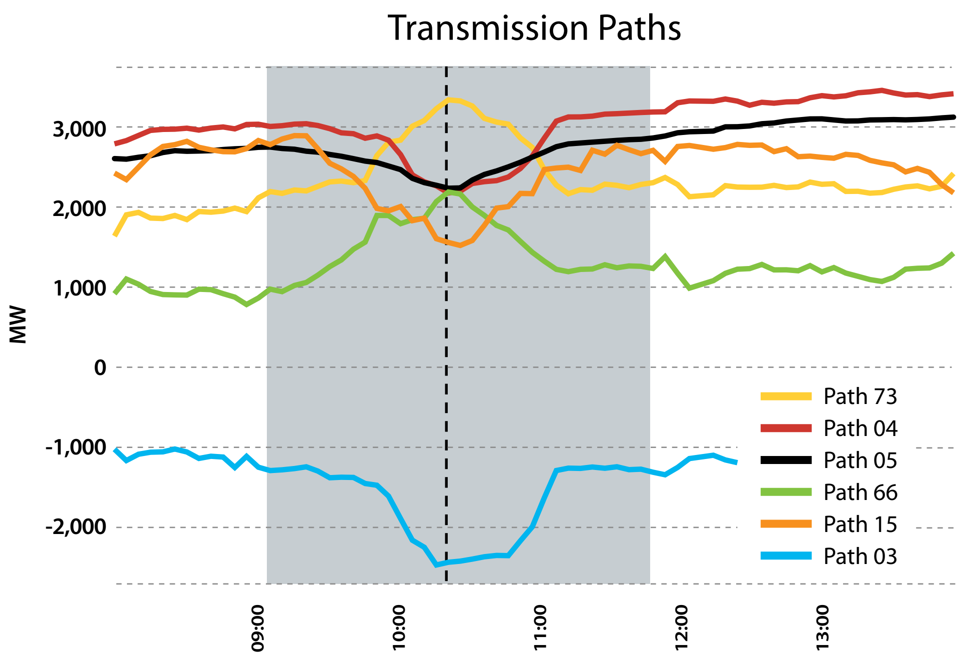


Figure 32. Transmission flows along affected paths

4.2.6 Impact on Generation Dispatch

The change in transfer flows was caused by the change in generation dispatch among the different BA areas. Change in flows by BA for the affected areas is presented in Figure 33.

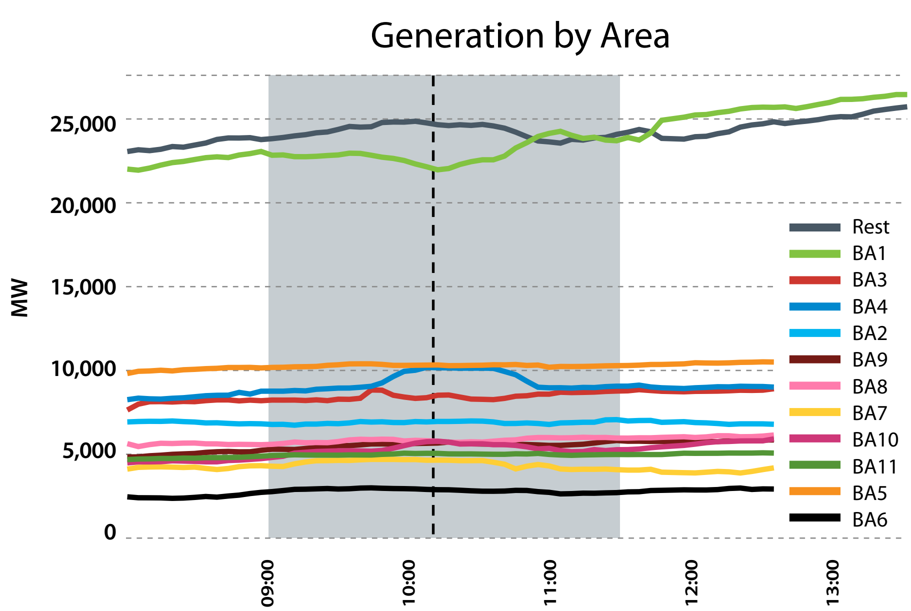


Figure 33. Total generation by affected utility areas

The change in generation profiles by area is more obvious after normalization in relation to the start of the eclipse. Generation trends are presented in Figure 34. Note that BA4 and BA10 picked up 20% more generation relative to the start of the eclipse. BA1 shows a modest 5% drop at the peak of the eclipse. The other affected areas show increased levels of generation during the eclipse duration.

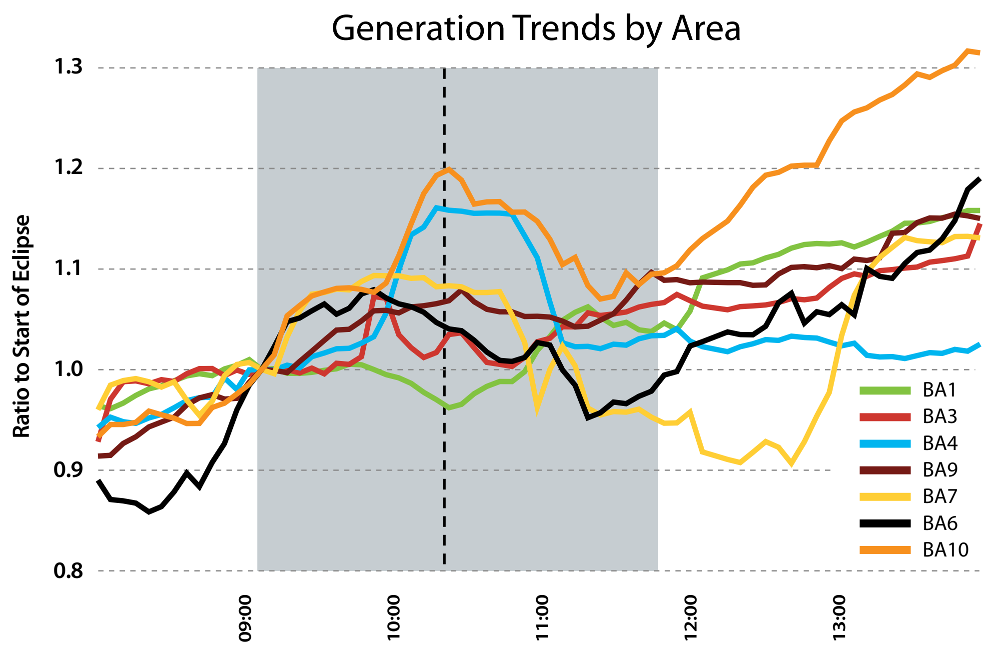


Figure 34. Generation trends in affected utility areas

Impact of generation can also be studied based on fuel type, as shown in Figure 35.

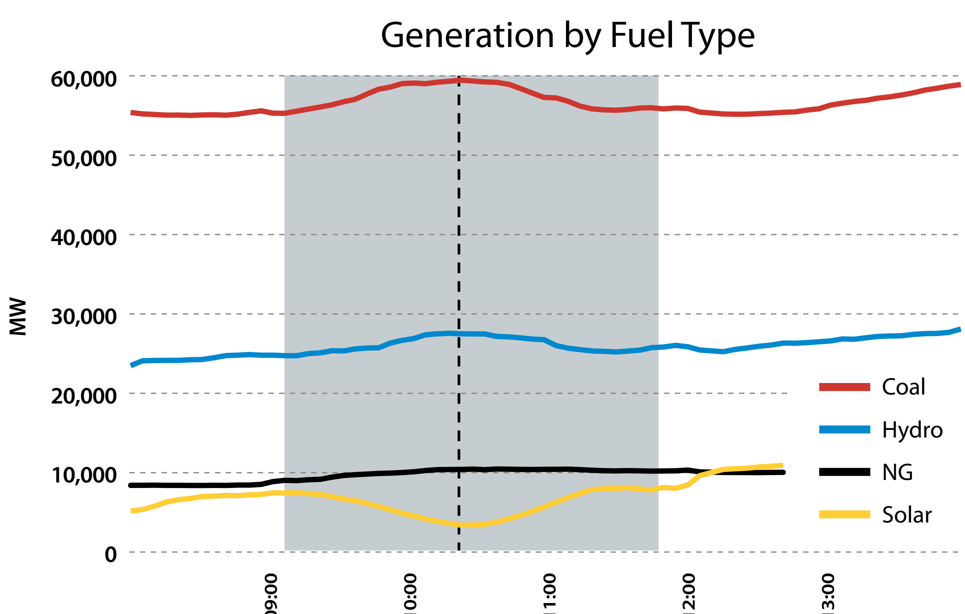


Figure 35. Total WECC generation by fuel types

The impact of an eclipse is clearer after normalization relative to the start of the eclipse. Figure 36 represents generation trends by fuel type. As shown, the loss of PV was made up by an increase in hydropower plants, natural gas, and coal-powered plants.

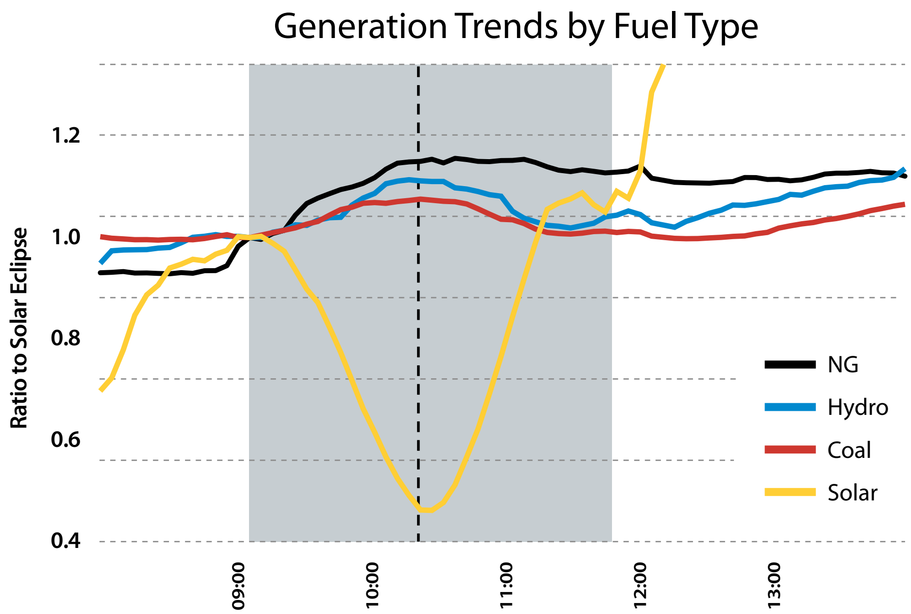


Figure 36. Generation trends by fuel type

4.2.7 Impact on Generation by Fuel Type and Area

Appendix B shows how generation by fuel type was impacted as a result of the eclipse in selected utility areas.

4.2.8 Peak Reliability Operations

A week prior to the eclipse, Peak Reliability hosted a solar eclipse readiness webinar with all of its BAs and TOPs to ensure the entities were prepared for the solar eclipse. During the webinar, Peak Reliability disseminated its study results from the worst-case scenario studies while discussing portions of the footprint-wide operating memo. Peak Reliability also had a few larger solar-producing BAs discuss their plans with the other BAs and TOPs in their RC area. The night before the eclipse, Peak Reliability followed up with all the BAs and TOPs to verify the information in their respective operating plans.

Peak Reliability developed displays to monitor the grid during the eclipse event in real time, shown in Figure 37.

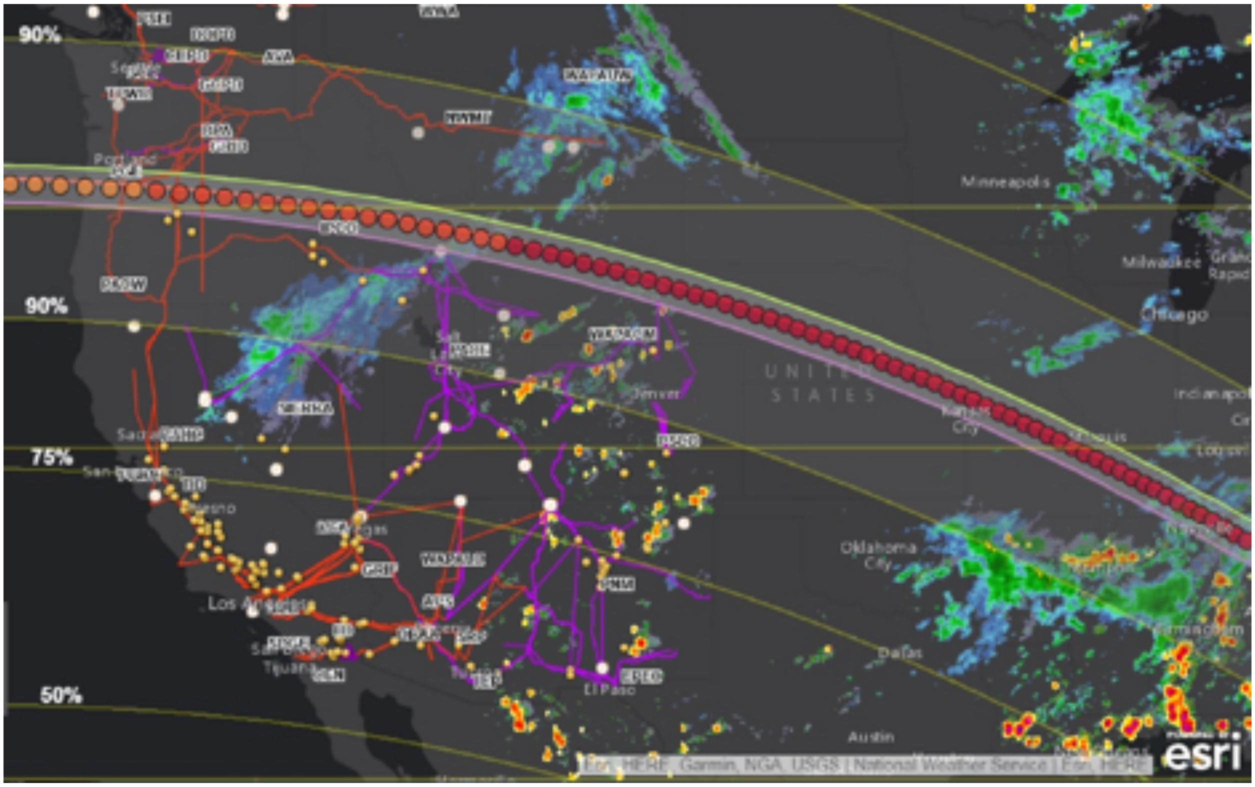


Figure 37. Solar eclipse display for real-time monitoring (internal)

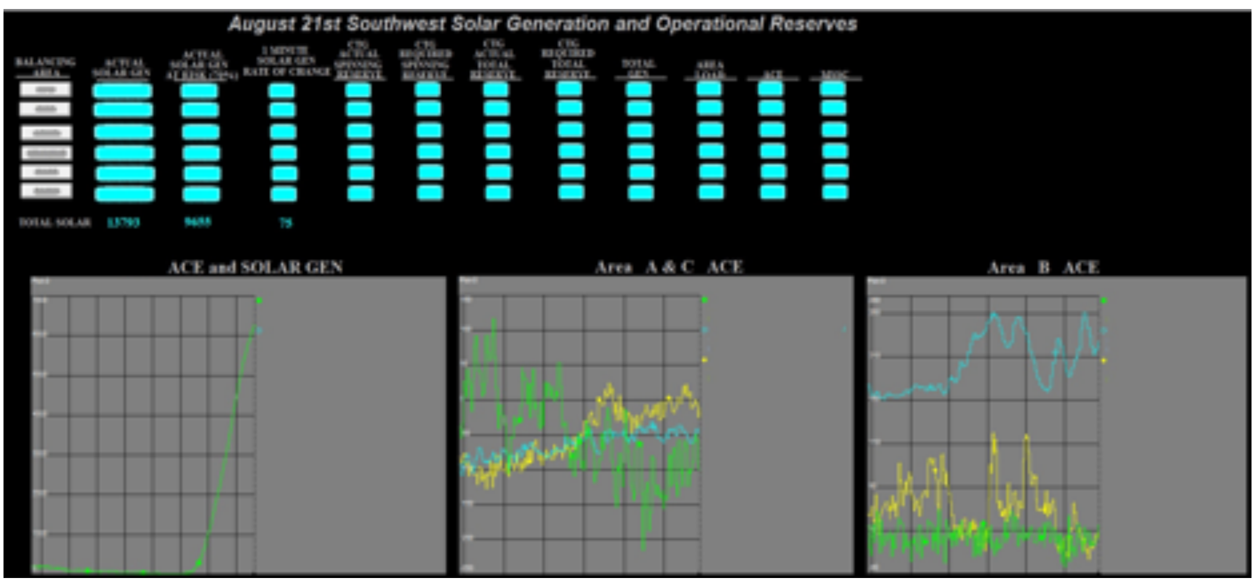


Figure 38. Solar eclipse display (external)

4.2.8.1 Photovoltaic Curtailment

CAISO curtailed UPV within its footprint as PV was ramping up after the eclipse peak [15]. The curtailment was because of the inability to back off conventional generators, leading to overgeneration. CAISO indicated that it had curtailed 1.7 GW of PV between 11 a.m. and 12 p.m. MDT, losing 0.8 GWh of energy. Considering the data shown in Figure 22, the research team estimated that the curtailment happened between 11:16:41 a.m. and 11:56:36 a.m. MDT, for a duration of 40 minutes.

5. Summary

This NREL-conducted study played an important role in helping Peak Reliability and the BAs in the western United States prepare for the eclipse event. Although Peak Reliability focused on a worst-case "clear-day" scenario, the NREL team worked on a typical day scenario. This approach allowed for greater certainty as Peak Reliability prepared and reviewed mitigation measures as well as transmission operating plans for the eclipse day.

The study uncovered important insights for bulk grid operators, utility industry, and researchers using previously-developed tools and databases to study the penetration of DPV in the WECC footprint. This information will enable Peak Reliability to disaggregate the load into DPV and actual load in its study and operational models.

NREL capitalized on the opportunity to not only study the impact of the August 2017 solar eclipse on grid operations, but also develop a framework for studying a large, geophysical phenomenon, such as a significant weather event or a future eclipse. A subsequent report with more details on the framework will be published in 2018. Such a framework will be critical because entities like NERC and transmission utilities are increasingly considering the impact of DPV on the reliability of the bulk grid and defining their role for grid operations.

6. References

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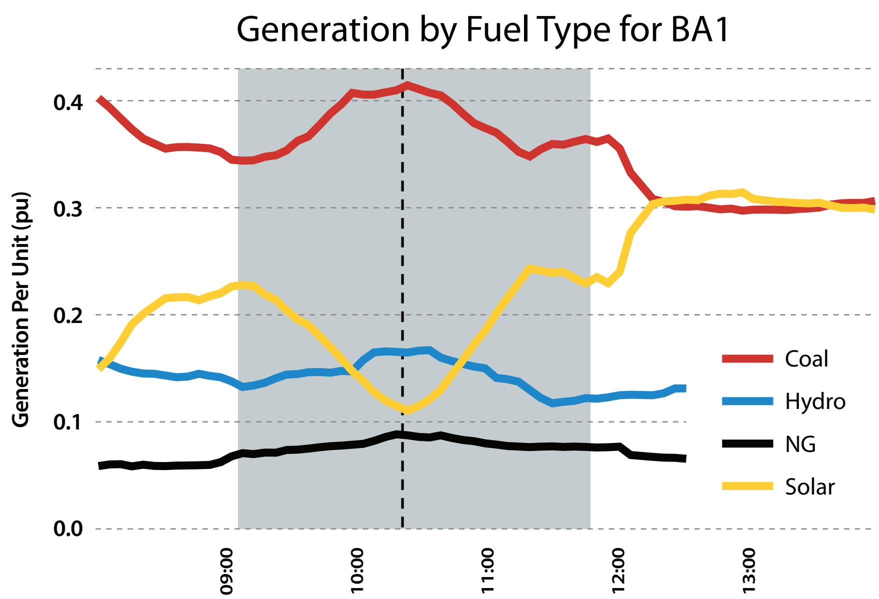
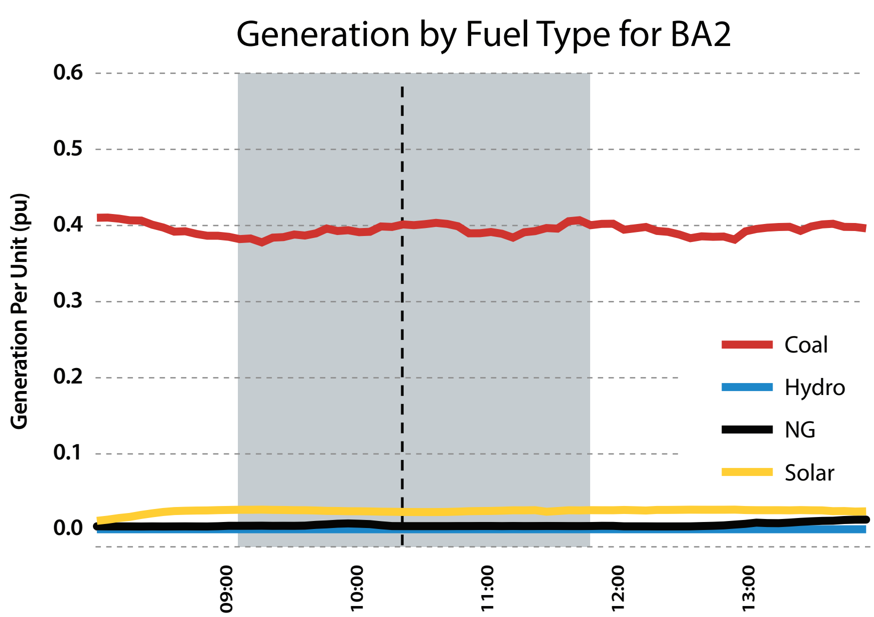
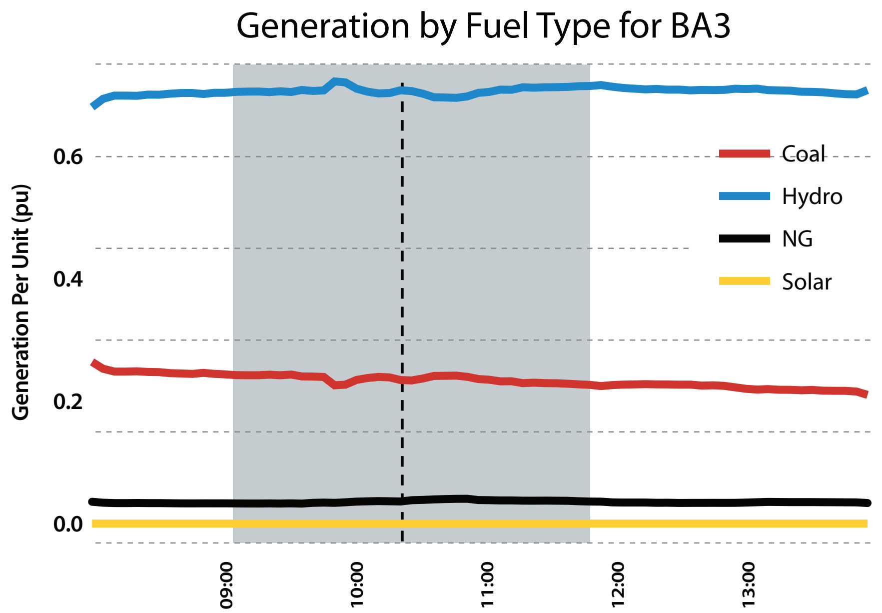
Appendix A: WECC Path Definition and Ratings

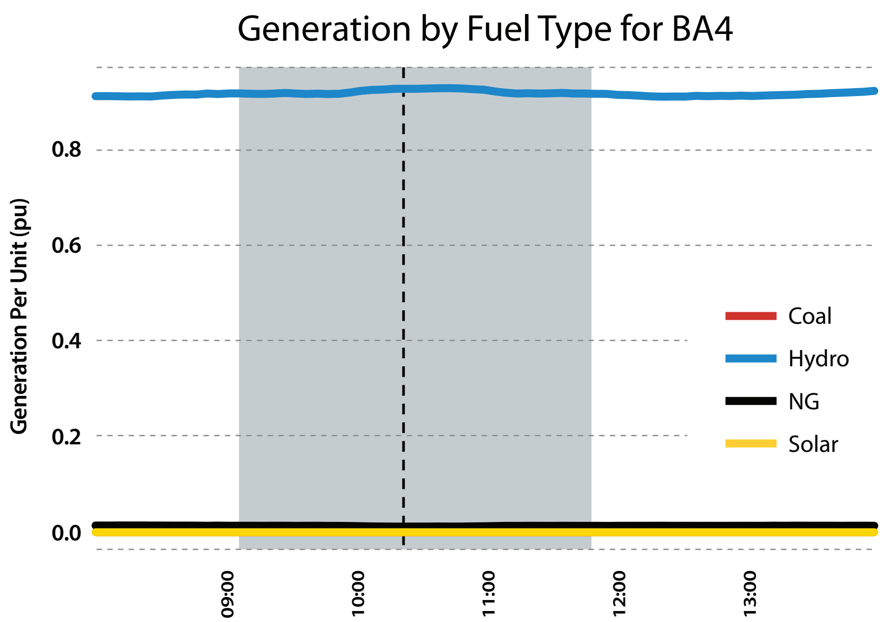
Path #	Name	Path Rating Transfer Limit (MW)		Defined Positive Flow Direction (Primary Direction)
		E to W (N to S)	W to E (S to N)	
Path 1	Alberta to BC	1,000	1,200	E to W
Path 3	Northwest to Canada	3,150	2,000	S to N
Path 8	Montana to NW	2,200	1,350	E to W
Path 14	Idaho to NW	2,400	1,200	E to W
Path 17	Borah W	2,557	Not defined	E to W
Path 18	Montana to Idaho	337	256	N to S
Path 19	Bridger West	2,200	Not defined	E to W
Path 20	Oath C	1,000	1,000	S to N
Path 22	Southwest of 4-Corners	2,325	Not defined	E to W
Path 23	4-Corners Transformer	N/A	N/A	N/A
Path 27	IPP DC Line	1,920	1,400	N to S
Path 30	TOT 1A	650	Not defined	E to W
Path 31	TOT 2A	690	Not defined	N to S
Path 34	TOT 2B	795	900	N to S
Path 35	TOT 2C	300	300	NE to SW
Path 36	TOT 3	1,605	Not defined	N to S
Path 45	CISO - CFE	408	800	S to N
Path 46	West of Colorado River	10,623	Not defined	E to W
Path 47	Southern New Mexico	1,048	Not defined	N to S
Path 48	Northern New Mexico	1,970	Not defined	NW to SE
Path 49	East of Colorado River	9,300	Not defined	E to W
Path 50	Cholla Pinnacle Peak	1,200	Not defined	NE to SW
Path 51	Southern Navajo	2,800	Not defined	N to S
Path 65	Pacific DC Intertie	3,100	3,100	N to S
Path 66	California-Oregon Intertie	4,800	3,675	N to S

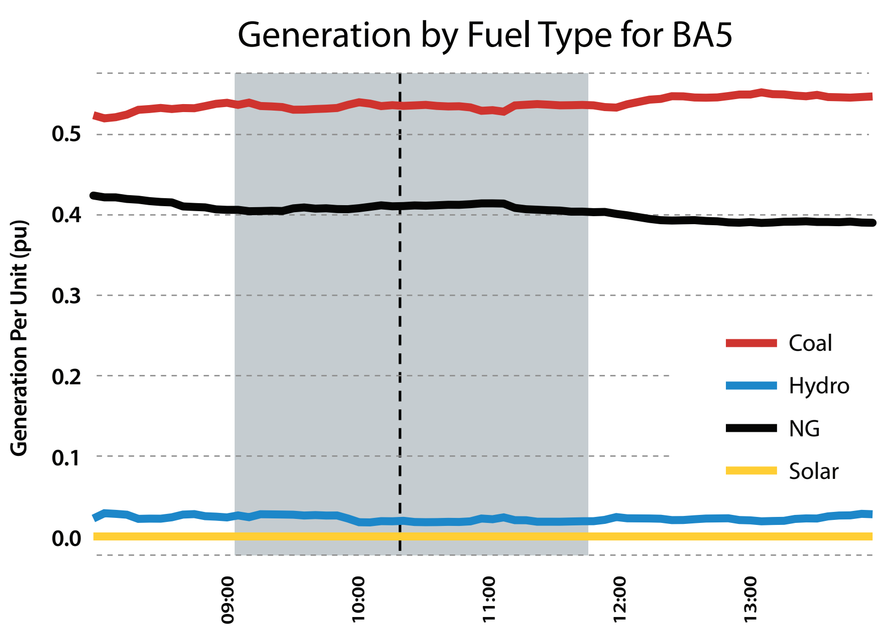
Appendix B: Generation by Fuel Type for Each Utility Area

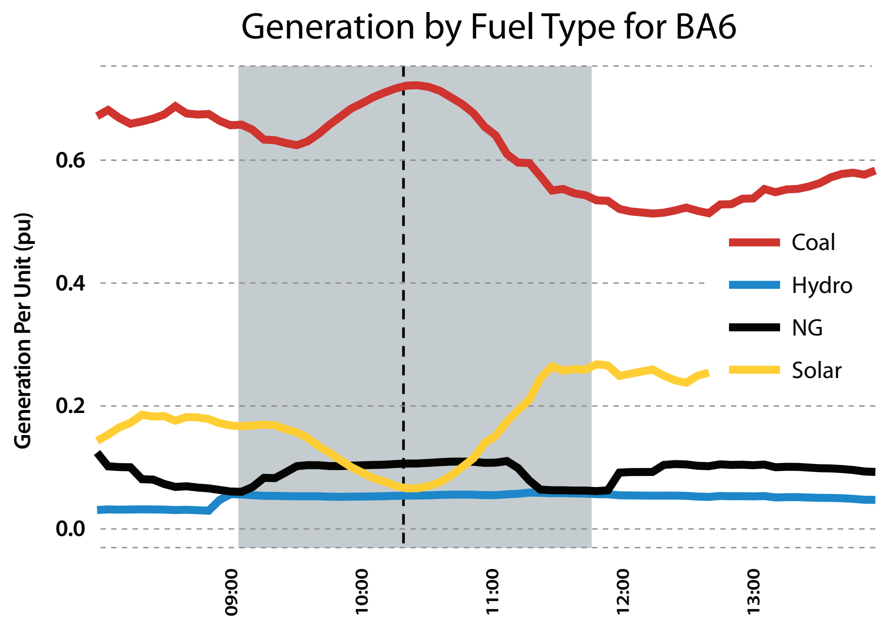




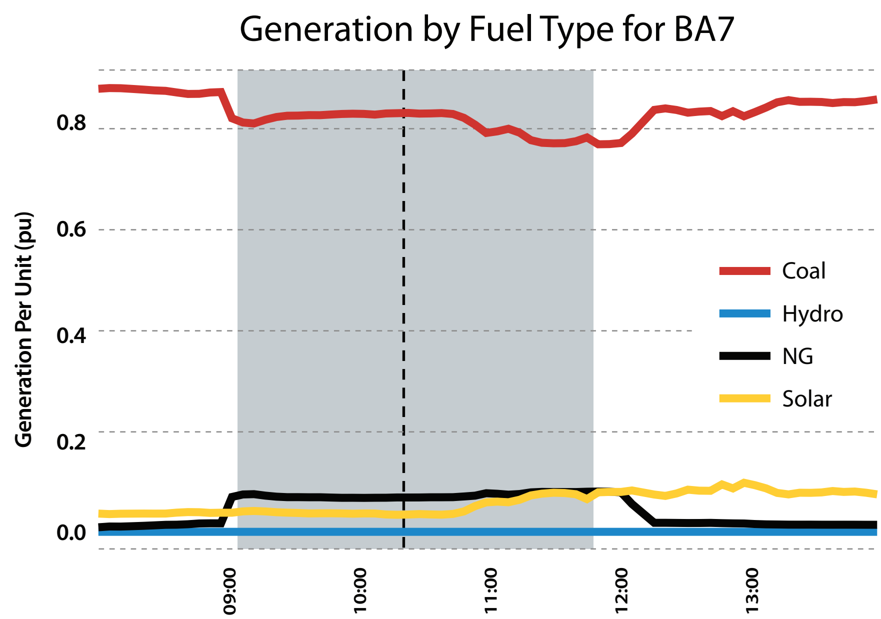

Generation by Fuel Type for BA3
Generation Per Unit (pu)
0.6
0.4
0.2
0.0
09:00
10:00
11:00
12:00
13:00
Coal
Hydro
NG
Solar


Generation by Fuel Type for BA4
Generation Per Unit (pu)
0.8
0.6
0.4
0.2
0.0
09:00
10:00
11:00
12:00
13:00
Coal
Hydro
NG
Solar

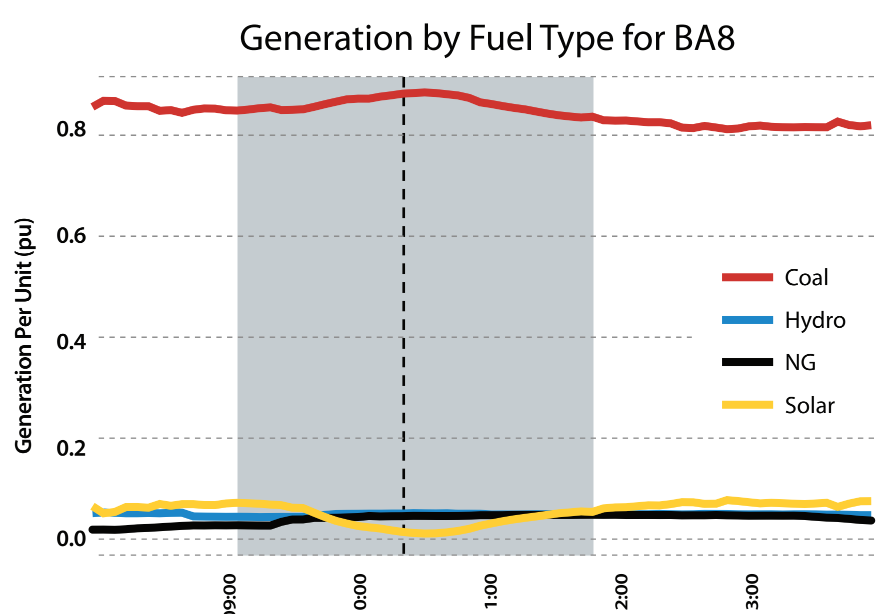

Generation by Fuel Type for BA5
Generation Per Unit (pu)
0.5
0.4
0.3
0.2
0.1
0.0
09:00
10:00
11:00
12:00
13:00
Coal
Hydro
NG
Solar



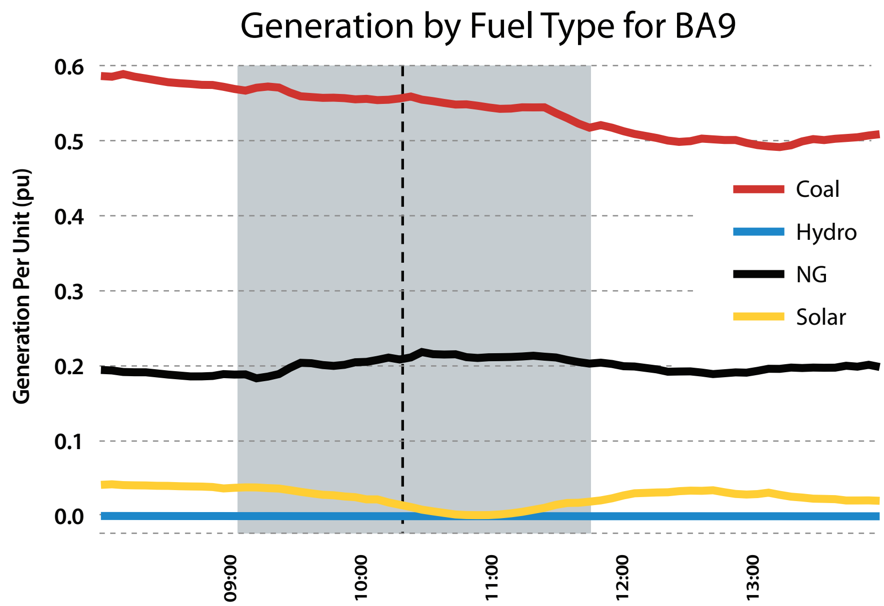
Generation by Fuel Type for BA6
Generation Per Unit (pu)
0.0
0.2
0.4
0.6
Coal
Hydro
NG
Solar
09:00
10:00
11:00
12:00
13:00

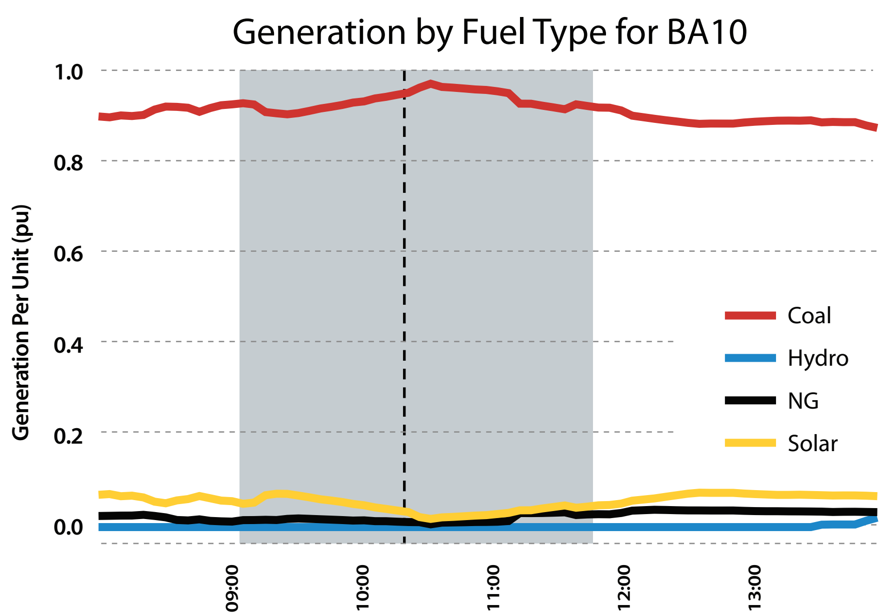


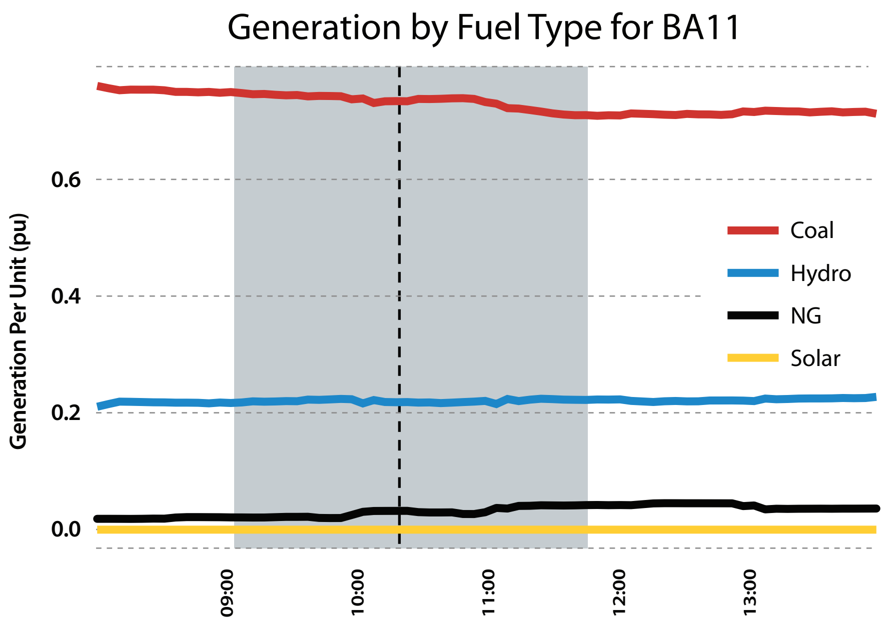
Generation by Fuel Type for BA7
Generation Per Unit (pu)
0.0
0.2
0.4
0.6
0.8
Coal
Hydro
NG
Solar
09:00
10:00
11:00
12:00
13:00

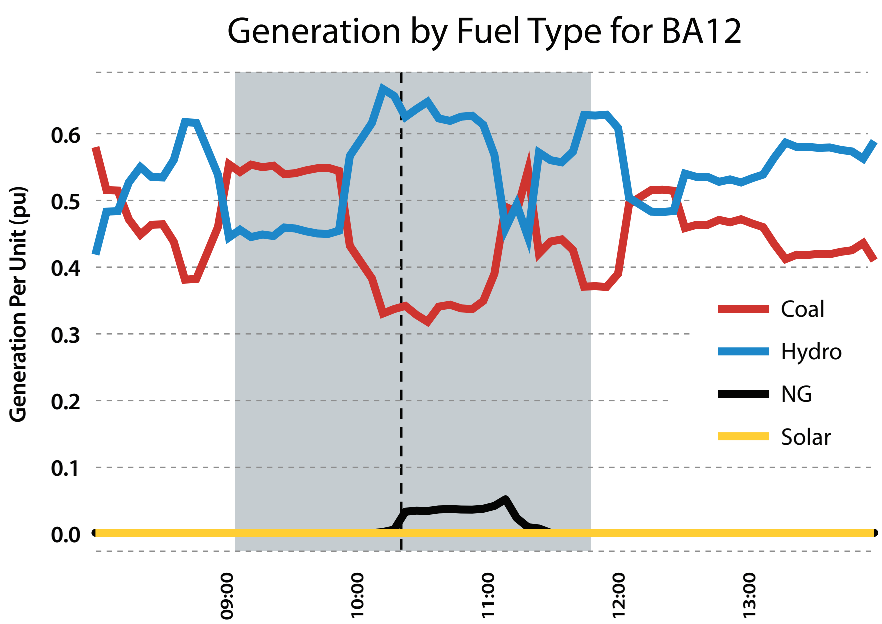


Generation by Fuel Type for BA8
Generation Per Unit (pu)
0.0
0.2
0.4
0.6
0.8
Coal
Hydro
NG
Solar
09:00
10:00
11:00
12:00
13:00


Generation by Fuel Type for BA9
Generation Per Unit (pu)
0.6
0.5
0.4
0.3
0.2
0.1
0.0
09:00
10:00
11:00
12:00
13:00
Coal
Hydro
NG
Solar


Generation by Fuel Type for BA10
Generation Per Unit (pu)
1.0
0.8
0.6
0.4
0.2
0.0
09:00
10:00
11:00
12:00
13:00
Coal
Hydro
NG
Solar


Generation by Fuel Type for BA11
Generation Per Unit (pu)
0.6
0.4
0.2
0.0
09:00
10:00
11:00
12:00
13:00
Coal
Hydro
NG
Solar


Generation by Fuel Type for BA12
Generation Per Unit (pu)
0.6
0.5
0.4
0.3
0.2
0.1
0.0
09:00
10:00
11:00
12:00
13:00
Coal
Hydro
NG
Solar

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