NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

San Fernando Disturbance

Southern California Event: July 7, 2020
Joint NERC and WECC Staff Report

November 2020

RELIABILITY | RESILIENCE | SECURITY




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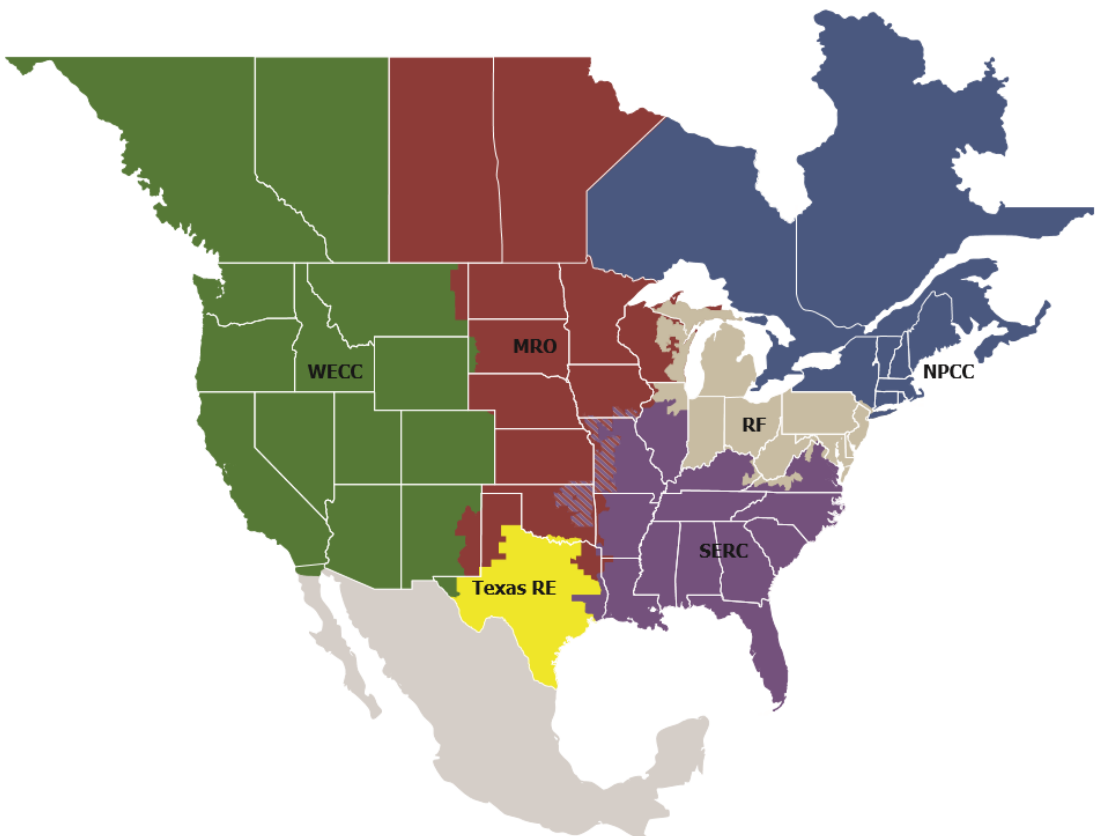
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one RE while associated Transmission Owners (TOs)/Operators (TOPs) participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

Executive Summary

This report contains the ERO analysis of the BPS disturbance that occurred in Southern California on July 7, 2020, referred to herein as the "San Fernando Disturbance." This event involved a widespread reduction of active power output from solar photovoltaic (PV) facilities across a relatively large geographic area, initiating a more detailed ERO review. California Independent System Operator (CAISO) provided WECC and NERC with a brief report as the disturbance was categorized as a Category 1i event.[1] Working with CAISO, it was determined that additional information beyond what was provided in the brief report was needed to determine the root cause of solar PV power reductions. Data requests were sent to the affected Generator Owners (GOs) whose facilities were identified as experiencing a notable reduction in power during the event. In addition, NERC and WECC worked collaboratively with the impacted transmission service providers to gather additional information and corroborate incoming data with other sources. The purpose of the report is to document the analysis of this disturbance and provide key findings and recommendations for the industry.

Description of Disturbance

At 11:38 a.m. Pacific Daylight Time (PDT) on July 7, 2020, the static wire on a 230 kV double circuit tower failed, causing a single-line-to-ground (SLG) fault on both the #1 and #2 parallel circuits on the tower. The fault was cleared normally in about three cycles. In addition, a nearby 230 kV line relay incorrectly operated for an external fault. For this first fault event, approximately 205 MW of power reduction was observed at BPS-connected solar PV facilities in the Southern California region. At 11:41 PDT, the #1 circuit was re-energized and held; however, at 11:41:31, the #2 line was re-energized and relayed back out. The cause of relaying back out was a low-impedance three-phase fault that was cleared normally in 2.3 cycles. This second fault event experienced a larger 1,000 MW reduction in solar PV output primarily due to the fact that it was a three-phase fault.

Table ES.1: Primary Causes of Reduced Solar PV Output

Cause	Amount
Momentary Cessation	434
Inverter Tripping	69
Other Reductions	145

Table ES.1 shows the primary causes of BPS-connected solar PV reduction for the second fault event at the facilities that NERC and WECC analyzed (a subset of the total solar PV loss). These causes include:

- **Momentary Cessation:** Many inverters entered momentary cessation, ceasing current injection with the BPS during the fault and then recovering active and reactive current after the fault cleared. Some resources returned in a reasonable time period (i.e., around one second) while the majority of resources required substantially more time to return to predisturbance power output levels. This is not a recommended dynamic response of BPS-connected inverter-based resources per the NERC reliability guideline[2] and NERC alerts.

- **Inverter Tripping:** Multiple plants experienced partial tripping of inverters during the fault events for various reasons. The primary cause of inverter tripping was active current (ac) overcurrent protection that was attributed to one inverter manufacturer. Other forms of tripping included direct current (dc) low voltage tripping and ac low voltage tripping. No resources were tripped as a consequence of the faulted element being removed from service for this normally-cleared fault; therefore, all inverter tripping is considered abnormal and has an adverse impact on post-fault BPS performance.

- **Other Inverter Active Power Reductions:** One plant reduced its active power output due to anomalous behavior of the plant-level controller restricting power output and ramping it back over a period of minutes. Other plants appeared to have inverters that provided current injection during the fault (did not reduce both active and reactive power to zero) yet their active power dropped and remained at a level lower than the

[1] NERC Event Analysis Program: https://www.nerc.com/pa/rrm/ea/Pages/EA-Program.aspx

[2] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_IBR_Interconnection_Requirements_Improvements.pdf

predisturbance output for many seconds or minutes. This may be due to inverter control settings or abnormal interactions between the inverter and plant-level controls.

Each Balancing Authority (BA) reviewed their total solar PV output during both fault events, and from this information the team was able to determine the aggregate amount of solar PV reduction for this disturbance. **Table ES.2** shows the BAs that reported solar PV reduction. The majority of solar PV tripping occurred in the Southern California Edison (SCE) footprint where a significant amount of BPS-connected solar PV is interconnected to nearby BPS buses close to the fault location. San Diego Gas and Electric (SDG&E), Salt River Project (SRP), and Arizona Public Service (APS) all reported no affected solar PV in their footprint.

Both SCE and Los Angeles Department of Water and Power (LADWP) also reviewed their area net load quantities during the fault events to identify whether any amount of distributed energy resources (DERs) may have tripped due to the faults. SCE reported a net load increase of 5 MW for the first fault and 80 MW for the second fault that is attributed to solar PV DER tripping. LADWP experienced a net load reduction indicative of end-use load tripping and did not experience any net load increase that would be attributed to loss of DERs.

Table ES.2 provides an overview of the resources involved in the two fault events, including BPS-connected solar PV facilities and an estimation of possible DERs that may have tripped. While the reported values from the TOPs within CAISO should add up to the total CAISO-reported amount, it is not uncommon for these numbers to not match due to different supervisory control and data acquisition (SCADA) scan rates, monitoring equipment, reporting practices, and other factors.

Table ES.2: Overview of Resource Performance

Area	Fault Event #1 [MW]	Fault Event #2 [MW]
BPS-Connected Solar PV Reduction		
CAISO	122	901
SCE	100	535
PG&E	6	79
LADWP	83	62
IID	0	37
Total*	**205**	**1,000**
Net Load Increases (Possible DER Tripping)		
SCE	5	80
Total*	**5**	**80**

* Summation of CAISO, LADWP, and IID BA footprints.

Chapter 1 provides details regarding the initiating events, the performance of the BPS-connected solar PV fleet during the disturbance, and additional details around the event. **Chapter 2** provide detailed findings and recommendations from the analysis.

Key Findings and Recommendations

This report provides a number of key findings and recommendations based on the analysis of performance of the solar PV fleet during this disturbance. **Chapter 2** provides details around these findings and recommendations. The analysis team tracked high-level takeaways from the review of fleet performance, discussions with involved stakeholders, and comparisons with past information collected. The high-level takeaways that should be considered by all stakeholders and acted upon accordingly include the following:

- **Poor Solar PV Data Resolution:** Almost all solar PV facilities involved in this disturbance were not able to provide adequate information to the analysis team to fully understand the causes of tripping and develop recommended mitigating actions. In many cases, the archived data had resolutions of one-minute or even five-minutes; this serves no useful purpose for post-mortem disturbance analysis. Data resolutions should be on the order of one-second, and other forms of high-speed data recording should be available from the individual inverters within the facility as well as at the plant-level controller. Point-on-wave digital fault recorder data is the most useful data for this type of analysis along with inverter fault codes and inverter oscillography data.
  - **Recommendation (GO, Generator Operator (GOP)):** All GOs and GOPs should ensure adequate data monitoring within their facilities for inverter-based resources to determine root causes of abnormal performance to BPS disturbances. This includes having access to inverter and plant-level settings, fault codes, oscillography records, digital fault recorder data, and archived plant data (i.e., SCADA data) with a resolution of one sample per second or faster. NERC Standards should be enhanced to ensure this data is available from all BPS generating facilities, as this continues to be a major issue limiting the ability to perform event analysis.
  - **Recommendation (TO, FERC):** All TOs should establish or improve data recording requirements for all BPS-connected generating resources, including both synchronous and inverter-based resources, to ensure appropriate data is available for event analysis. FERC may consider adding this capability to the pro forma *Large Generator Interconnection Agreement*.[3] Detailed recommendations are documented in NERC *Reliability Guideline: Improvements to Interconnection Requirements for BPS-Connected Inverter-Based Resources*.[4]
- **Continued and Improved Analyses Needed:** This event, as with past events, involved a significant number of solar PV resources reducing power output (either due to momentary cessation or inverter tripping) as a result of normally-cleared BPS faults. The widespread nature of power reduction across many facilities poses risks to BPS performance and reliability. Many of the issues identified in this disturbance appear systemic and are not being widely addressed by the solar PV fleet.
  - **Recommendation (Reliability Coordinator (RC), GO, GOP):** Analysis of inverter-based resource performance for system faults should be conducted on a regular basis to identify possible abnormal performance. Root cause analysis should be conducted for identified abnormal performance events to develop mitigating measures to improve fleet performance. RCs should be analyzing fleet performance after significant grid disturbances, identifying any abnormal performance, and ensuring affected entities are determining whether improvements to their facilities can be made to eliminate abnormal performance. It does not appear these activities are regularly taking place, and improvements to processes should be developed so that these activities occur more frequently by RCs and affected entities rather than primarily by the ERO Enterprise. Entities are strongly encouraged to share their lessons learned with NERC and its Inverter-Based Resource Performance Working Group (IRPWG) to help industry advance its capabilities moving forward.

[3] https://www.ferc.gov/industries-data/electric/electric-transmission/generator-interconnection/standard-interconnection
[4] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_IBR_Interconnection_Requirements_Improvements.pdf

- Recommendation (NERC IRPWG, Industry): NERC and its technical stakeholder groups (i.e., NERC IRPWG) should continue outreach and the development of recommended practices and reliability guidelines to help industry ensure BPS reliability as the penetration of BPS-connected inverter-based resources continues to increase. However, while outreach has been effective in supporting industry in these efforts, it is clear that outreach alone is not an effective means of minimizing possible abnormal behavior from these resources and developing mitigating measures to eliminate these issues. Additional actions (e.g., standards enhancements, updates to interconnection requirements, engagement in IEEE P2800 activities) are needed by industry to ensure entities are taking appropriate steps to support reliable operation of the BPS.

- **Improvements to Identification of Disturbances and Event Reporting:** These events impact many resources across multiple BAs and RC footprints. EOP-004-4[5] does not include events of this nature due to the large generation loss criteria contained within EOP-004-4. Therefore, no reporting on these types of events is required and has led to the identification of these events being on an ad hoc basis. CAISO provided a brief report for this event under the voluntary NERC Event Analysis (EA) Process; however, NERC and WECC needed to perform a more comprehensive analysis to determine any root causes since the brief report did not provide this level of detail or recommend any mitigating actions.
  - **Recommendation (Industry, NERC, FERC):** Ad hoc reporting of events involving multiple generating resources and possible systemic performance issues should not be considered an acceptable level of reporting. NERC EOP-004-4 should be reviewed in terms of the thresholds used for generator tripping events and should also consider the extent of resources involved in the disturbance. A reasonable threshold for reporting would be around 500 MW of reduction in output (partial or full tripping across all affected resources). Updates to reporting these types of events (not necessarily with quick turnaround times) will help industry improve their situational awareness of abnormal inverter-based resource performance and possible issues needing mitigating action by facility owners to improve their performance.

- **Inverter Tripping:** There were three causes of BPS-connected solar PV tripping during this disturbance—ac overcurrent protection, dc low voltage protection, and ac low voltage protection. The vast majority of inverters that tripped were from a single manufacturer that tripped on either ac overcurrent or dc low voltage protection. All inverter tripping was considered abnormal since the BPS fault events were normally-cleared and no resources were disconnected as a consequence of the faulted elements being removed. The primary form of tripping, ac overcurrent protection, is not considered in PRC-024 since it is not related to voltage or frequency protection within the facility. Similar to past disturbances involving tripping due to dc reverse current protection, phase jump protection, and phase lock loop loss of synchronism protection, none of these common trip mechanisms are captured in the latest version of PRC-024.
  - **Recommendation (GO, GOP, TO, NERC, FERC):** Partial tripping of inverters within a facility is still considered tripping and has an adverse impact on BPS performance. Partial tripping of inverters during normally-cleared faults should not be considered an acceptable level of performance from inverter-based resources. Facility performance should be more closely reviewed for compliance with NERC Reliability Standards and other applicable interconnection requirements. GOs and GOPs should analyze partial tripping events and work with their inverter manufacturers to mitigate inverter tripping to the extent possible.
  - **Recommendation (GO, GOP, TO, FERC):** Inverters are commonly tripped for reasons other than voltage- or frequency-related tripping, and the PRC-024 curves are often set directly in the inverter solely for compliance with PRC-024 rather than to protect the inverter from physical damage. These other forms of tripping (e.g., ac overcurrent, phase lock loop loss of synchronism) lead to partial tripping of many different solar PV facilities and have an adverse impact on BPS performance. These types of tripping

[5] https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=EOP-004-4&title=Event%20Reporting

should not be considered acceptable for normally-cleared BPS fault events and enhancements to PRC-024 (or a possibly a new standard focused on ride-through capability) should be made to account for these other forms of tripping.

- **Recommendation (TO, Transmission Planner (TP), Planning Coordinator (PC), TOP, RC):** Interconnection requirements should ensure that the models provided during the interconnection study process are able to account for all forms of tripping by inverter-based resources so that sufficiently accurate studies can be conducted by the TP and PC. In most cases, this will require the collection of accurate, plant-specific electromagnetic transient (EMT) models. TPs and PCs should be conducting studies during the interconnection process to ensure adequate fault ride-through while considering all possible forms of inverter tripping. Phase lock loop issues, dc reverse current tripping, ac overcurrent tripping, and any other form of tripping beyond simply PRC-024 protection requirements should be accurately modeled and tested by the TP and PC during their interconnection studies. Any unexpected or abnormal performance identified during interconnection studies should be addressed prior to allowing that facility to interconnect to the BPS (per the NERC FAC standards). Furthermore, all models should be updated after plant commissioning and checked to ensure that the model matches the as-built, plant-specific settings, controls, and behavior. Any modeling issues or performance issues identified by the TP and PC should be addressed as quickly as possible, reported to the TOP and RC, and corrective actions put in place in a timely manner.

- **Dynamic Behavior of Solar PV during Faults:** Many facilities had a dynamic response to the fault events in this disturbance; however, multiple facilities exhibited dynamic behavior that does not meet the recommended performance specified in previously published NERC reliability guidelines.[6] Some solar PV facilities use legacy inverters that cannot make improvements to performance. Other facilities have relatively newer inverters where changes could be made but were not made prior to the faults, signifying a lack of action being taken by industry to incorporate the recommendations set forth. Some facilities with newer inverter technology were able to use current injection during the fault (eliminating momentary cessation) but required tens of seconds to return to predisturbance output; this is not a preferred behavior. Concerted focus should be made by NERC Compliance Monitoring and Enforcement Program (CMEP) to ensure all BES facilities are meeting the requirements set forth in NERC Reliability Standards including the latest version of PRC-024.
  - **Recommendation (GO, GOP):** All existing solar PV facilities should review the recommendations in the NERC reliability guidelines and ensure that their equipment is configured to meet the recommendations set forth. Solar PV resources should eliminate the use of momentary cessation to the extent possible. If elimination is not possible, the momentary cessation settings should be configured (if possible) to minimize its use (lower voltage threshold) and return to predisturbance output within one second. If elimination is possible, other forms of current injection during fault ride-through (e.g., reactive current injection or some form of active and reactive current injection) should be used.
  - **Recommendation (GO, GOP):** All existing solar PV facilities should review the recommendations in the NERC reliability guidelines and ensure that their equipment is configured to meet the recommendations set forth. Solar PV resources that use current injection should ensure that the inverter controls and plant-level controls are configured to allow the resource to return to predisturbance output (assuming no current limits are reached) within one second. Resources should not have a prolonged recovery of active power following a dynamic response to a fault event on the BPS. Plant-level ramp rates or other BA-imposed balancing ramp rates should not interfere with the resource returning to predisturbance output levels in a quick and stable manner after a BPS fault event.

[6] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Inverter-Based_Resource_Performance_Guideline.pdf
https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_IBR_Interconnection_Requirements_Improvements.pdf

- **Recommendation (TO):** TOs should ensure their interconnection requirements are clear regarding the dynamic performance requirements and settings for inverter-based resources. TOs are strongly encouraged to ensure resources are complying with these requirements and developing mitigation plans for any requirements that are not being met. In particular, these requirements should ensure clarity and consistency for post-fault recovery of active power following fault events. Furthermore, rise times and settling times should also be specified as well as any reactive current injection (e.g., “K-factor”) settings for large disturbance voltage support.

- **Settings Changes:** After coordinating with NERC and WECC on this disturbance analysis, a couple of solar PV facilities stated that they had made changes to equipment settings and performance to improve the dynamic response to fault events. This includes eliminating momentary cessation in favor of reactive current injection and some improvements to momentary cessation or active power recovery rates to be more aligned with the recommendations in the NERC reliability guidelines.
  - **Recommendation (TO):** All GOs of solar PV facilities, and other BPS-connected inverter-based resources, should review these key findings and recommendations as well as those listed in **Chapter 2** and ensure their resources are configured to provide the best dynamic response to support BPS reliability. GOs should consult the NERC reliability guidelines as well as their BA, RC, TP, and PC if they have any questions regarding recommended performance.

- **Dynamic Model Accuracy:** NERC and WECC have previously identified[7] modeling issues in the interconnection-wide planning base cases, and modeling challenges continue to be an issue with industry. Discussions with GOs of solar PV facilities during this analysis have highlighted that changes to equipment may take place, but there is little to no emphasis put on getting TP or PC approval of these changes (as a material modification to the facility) prior to making them, nor on ensuring that the TP and PC receive updated dynamic models following those changes. NERC IRPWG has submitted a standard authorization request to modify FAC-002-2 to clarify the use of “material modification” in that standard.
  - **Recommendation (GO, GOP):** GOs and GOPs should ensure that any changes to plant-level settings, inverter settings, or facility topologies or ratings should be articulated to the TP, PC, BA, and RC. Any applicable interconnection requirements, per FAC-001-3 and FAC-002-2, must be met prior to these changes being made to the facility, including restudy of these changes by the TP and PC. GOs and GOPs should coordinate with their TP and PC to determine if any changes within the facility are considered “material” and require any additional restudy.
  - **Recommendation (TO, TP, PC, Industry):** TOs should ensure that their interconnection requirements are clear and any modifications to the facility that can or will change the electrical behavior of the facility (including any settings changes to inverters that affect its electrical output during steady-state or dynamic conditions) should be considered material and should be studied prior to those changes being made. TOs, TPs, and PCs should ensure that their processes for making these changes are timely and effective such that GOs are not discouraged from making these changes to support overall reliability of the BPS.

[7] https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/NERC-WECC_2020_IBR_Modeling_Report.pdf

Introduction

Background

The ERO has previously published three disturbance reports related to the reduction of solar PV power output following BPS fault events:

- Blue Cut Fire disturbance[8] (August 16, 2016)
- Canyon 2 Fire disturbance[9] (October 9, 2017)
- Palmdale Roost and Angeles Forest disturbances[10] (April 20, 2018, and May 11, 2018, respectively)

Following the Blue Cut Fire and Canyon 2 Fire disturbances, NERC issued alerts[11, 12] to the industry to gather additional information from BPS-connected solar PV resources and to provide recommendations for all BPS-connected solar PV facilities based on the key findings from the disturbance reports. The NERC IRPWG has also published two foundational reliability guidelines:

- *Reliability Guideline: BPS-Connected Inverter-Based Resource Performance* (September 2018)[13]
- *Reliability Guideline: Improvements to Interconnection Requirements for BPS-Connected Inverter-Based Resources* (September 2019)[14]

Lastly, the Institute of Electrical and Electronics Engineers (IEEE) Standards Association has initiated Project 2800 (IEEE P2800)[15] to "establish recommended interconnection capability and performance criteria for inverter-based resources interconnected with transmission and networked sub-transmission systems." IEEE P2800 is expected to ensure that future interconnections of BPS-connected inverter-based resources are designed and installed with the equipment and functional performance capabilities to mitigate some or all of the issues identified in past ERO disturbance analyses.

Description of Analysis Process

The WECC EA and Situational Awareness (SA) team identified a grid disturbance by using their situational awareness tools, particularly an oscillation monitoring system that identified a possible grid event. The timing of the oscillation notification aligned with transmission line faults in the Southern California area. WECC analyzes the CAISO solar output charts any time a line fault occurs in the proximity of solar PV resources and noted a reduction of solar PV for this disturbance. WECC then reached out to CAISO, which was already analyzing this grid disturbance. Initial correspondence identified that this event may meet the NERC EA Program Category 1i criteria. CAISO was very responsive throughout, confirmed observations made by WECC, and started working on a brief report for this event.

[8] Blue Cut Fire Disturbance report, June 2017:
https://www.nerc.com/pa/rrm/ea/Pages/1200-MW-Fault-Induced-Solar-Photovoltaic-Resource-Interruption-Disturbance-Report.aspx.
[9] Canyon 2 Fire Disturbance report, February 2018:
https://www.nerc.com/pa/rrm/ea/Pages/October-9-2017-Canyon-2-Fire-Disturbance-Report.aspx.
[10] Palmdale Roost and Angeles Forest Disturbance report, January 2019:
https://www.nerc.com/pa/rrm/ea/Pages/April-May-2018-Fault-Induced-Solar-PV-Resource-Interruption-Disturbances-Report.aspx
[11] Blue Cut Fire Disturbance NERC Alert, June 2017:
https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/NERC%20Alert%20Loss%20of%20Solar%20Resources%20during%20Transmission%20Disturbance.pdf.
[12] Canyon 2 Fire Disturbance NERC Alert, May 2018:
https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/NERC_Alert_Loss_of_Solar_Resources_during_Transmission_Disturbance-II_2018.pdf.
[13] *Reliability Guideline: BPS-Connected Inverter-Based Resource Performance*:
https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Inverter-Based_Resource_Performance_Guideline.pdf
[14] *Reliability Guideline: Improvements to Interconnection Requirements for BPS-Connected Inverter-Based Resources*:
https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_IBR_Interconnection_Requirements_Improvements.pdf
[15] IEEE P2800: https://standards.ieee.org/project/2800.html

They also presented the disturbance to the WECC Event and Performance Analysis Subcommittee at their monthly closed-door meeting. An interim CAISO brief report was provided about three weeks following the disturbance, and the final CAISO brief report was provided three weeks thereafter.

The CAISO brief report identified 51 individual solar PV facilities that experienced a change in active power output for the second fault event with many of those facilities experiencing only a relatively small change in power output. The report identified which facilities involved tripping and momentary cessation; however, it did not explore the root causes of these actions, whether settings can be modified to eliminate these unwanted behaviors, or whether any follow-up activities were planned. Therefore, after reviewing the final CAISO brief report, NERC and WECC determined that more detailed data requests and follow-up analysis were needed to more clearly understand the extent of possible solar PV power reduction and any causes for abnormal solar PV response to the BPS fault events.

NERC and WECC formed a small team to issue data requests to all GOs owning an affected solar PV facility that reduced power output by more than 10 MW and to develop key findings and recommendations from the analysis of this disturbance. Coordination calls were held with all impacted GOs to discuss the data request, and follow-up activities were completed with the GOs and all possibly impacted TOPs and BAs. All of these activities led to the development of this disturbance report.

Overall Location of Disturbance and Affected Areas

The two fault events occurred in the Northern Los Angeles area and affected solar PV resources in the LADWP, CAISO (SCE and Pacific Gas & Electric (PG&E)), and Imperial Irrigation District (IID) footprints. No noticeable impact to BPS-connected solar PV was observed in the SDG&E, SRP, or APS footprints. **Figure I.1** shows the geographic location of the fault as well as the solar PV facilities affected by the fault. The fault events were in North Los Angeles within the LADWP footprint; however, the abnormal response of solar PV was observed across a much wider geographic area within the CAISO footprint. The color variations show the bus voltage magnitude during the *on-fault* conditions for a simulated three-phase bolted fault by using a simulation scenario of similar operating conditions to those experienced on July 7, 2020.[16] Resources within the dark blue areas may have experienced a point of interconnection (POI) bus voltage of less than 0.8 pu; resources within the light blue areas may have experienced a POI bus voltage less than 0.9 pu; the remaining resources experienced bus voltages greater than 0.92–0.95 pu.

[16] Note that these simulation results are not intended to match the actual fault event; rather, they are intended to illustrate the extent to which low voltage may be observed for these types of faults and to illustrate the possible voltages observed at point of interconnection for the various plants involved.

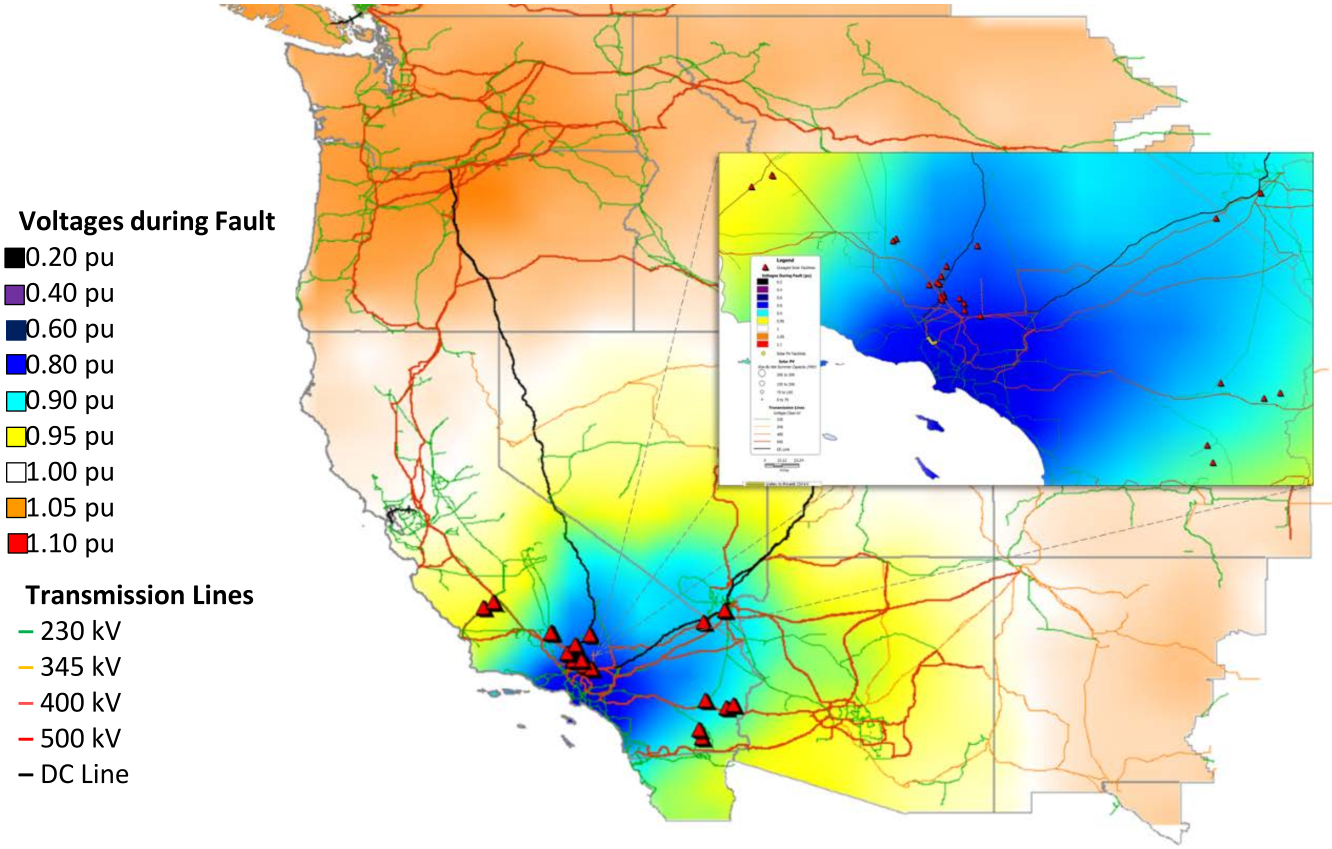


Figure I.1: Map of the Fault Location and Affected Facilities

Figure I.2 shows the CAISO solar PV power output profile for July 7, 2020. The disturbance occurred very close to the time of maximum solar PV output for that day. The disturbance is clearly visible in the total solar PV power output; however, the magnitude of the reduction is not the primary concern. Figure I.3 and Figure I.4 show the solar PV reduction observed by CAISO broken down by its areas within California. The SCE Inland and Imperial Valley areas experienced the majority of solar PV reduction during this event.

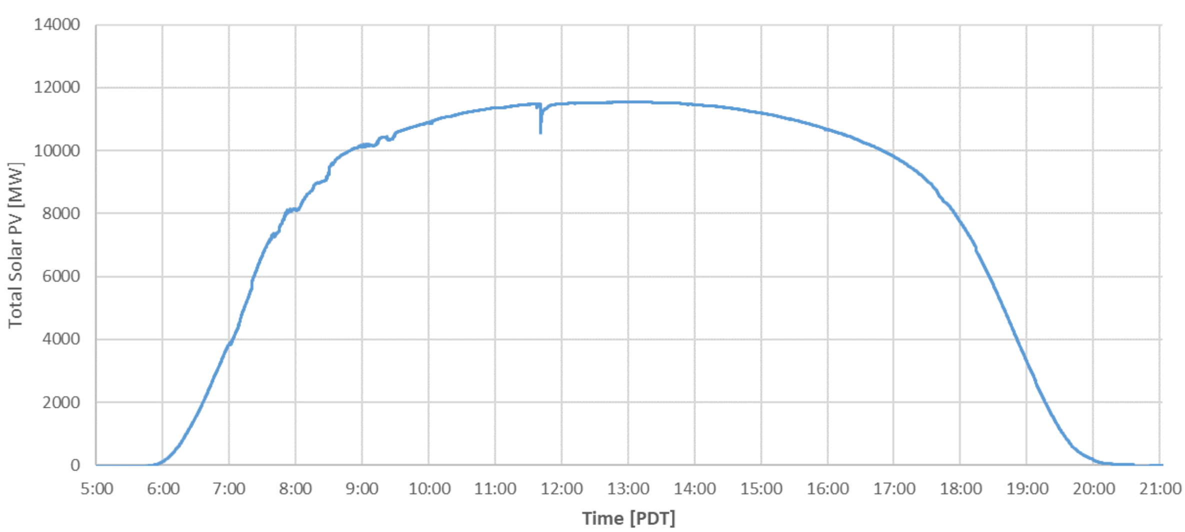


Figure I.2: CAISO Solar PV Profile for July 7, 2020 [Source: CAISO]

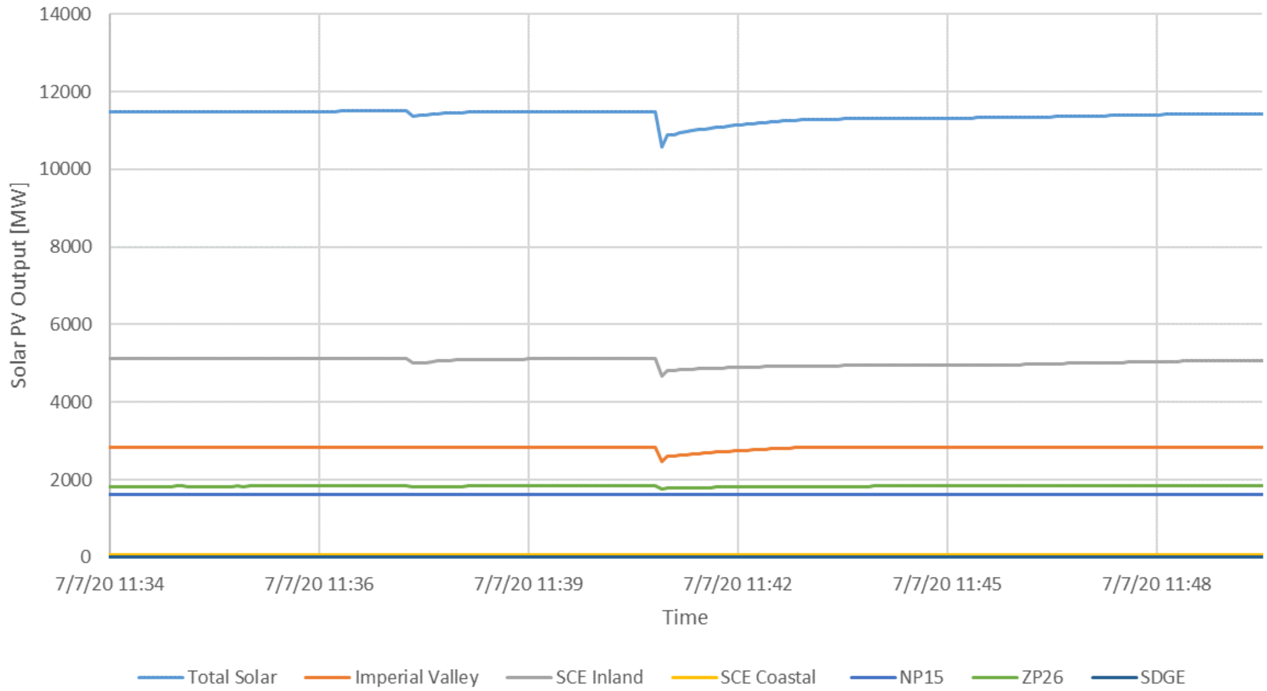


Figure I.3: CAISO Total Solar PV by Region 1 [Source: CAISO]

Figure I.4: CAISO Total Solar PV by Region 2 [Source: CAISO]

Table I.1 shows the internal net[17] demand, BPS-connected solar power output, and BPS-connected wind power output within the CAISO, LADWP, and IID footprints prior to the first fault event. CAISO had about 43% of its internal net demand served by BPS-connected solar PV and another 7% served from wind. LADWP had 29% of demand served by BPS-connected solar PV and another 8% from wind. These predisturbance operating conditions illustrate the increasing penetration of BPS-connected inverter-based resources and help highlight the importance of ensuring that all BPS-connected inverter-based resources are operating in a manner that helps ensure reliable operation of the BPS.

Table I.1: Predisturbance Generation Mix

BA Area	Internal Net Demand	BPS-Connected Solar Output		BPS-Connected Wind Output	
	MW	MW	%	MW	%
CAISO	26,992[18]	11,596	43%	1,787	7%
LADWP	3,916	1,150	29%	295	8%
IID	692	461	41%	0	0%

[17] Net demand in this case refers to the internal demand being served by the BA including any offsets by behind-the-meter DERs.
[18] CAISO reported a "net demand" of 13,609 MW that they calculate as total gross demand less wind and solar. For uniform reporting, these numbers were summed to determine the internal net demand (not accounting for DERs) within the CAISO footprint.

Chapter 1: Disturbance Analysis

On July 7, 2020, at 11:38:07 a.m. PDT, an overhead static wire failed and fell across three phases on one of two 230 kV parallel circuits on a common tower structure. This initially caused a B-phase-to-ground fault on both circuits that cleared in three cycles (see **Figure 1.1**). At the same time, a nearby 230 kV circuit incorrectly[19] operated for an external fault due to incorrect settings. At 11:41 PDT, one of the 230 kV lines tested and held; however, at 11:41:31 PDT the second 230 kV parallel line with the permanent static wire fault tested and relayed out. This caused a bolted three-phase fault that cleared in approximately two cycles (see **Figure 1.2** and **Figure 1.3**). The three-phase fault significantly depressed BPS voltages across the Southern California area.

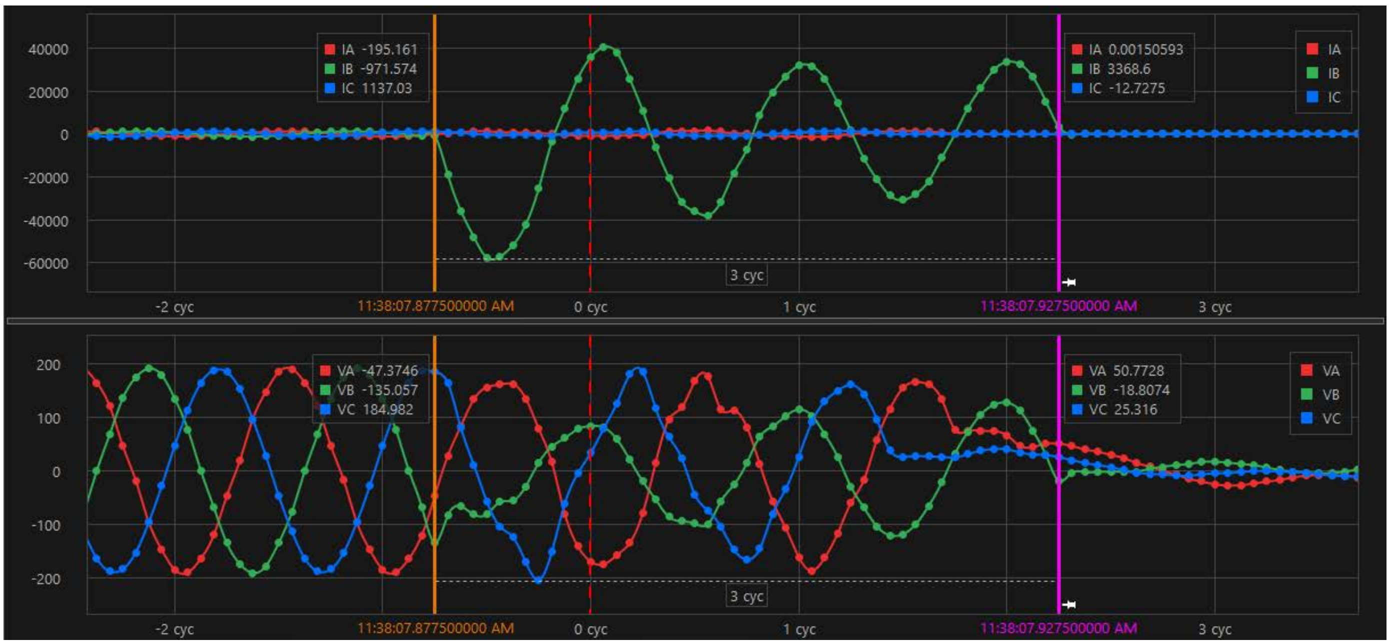


Figure 1.1: Event #1—B-Phase-to-Ground Fault on 230 kV Line [Source: LADWP]

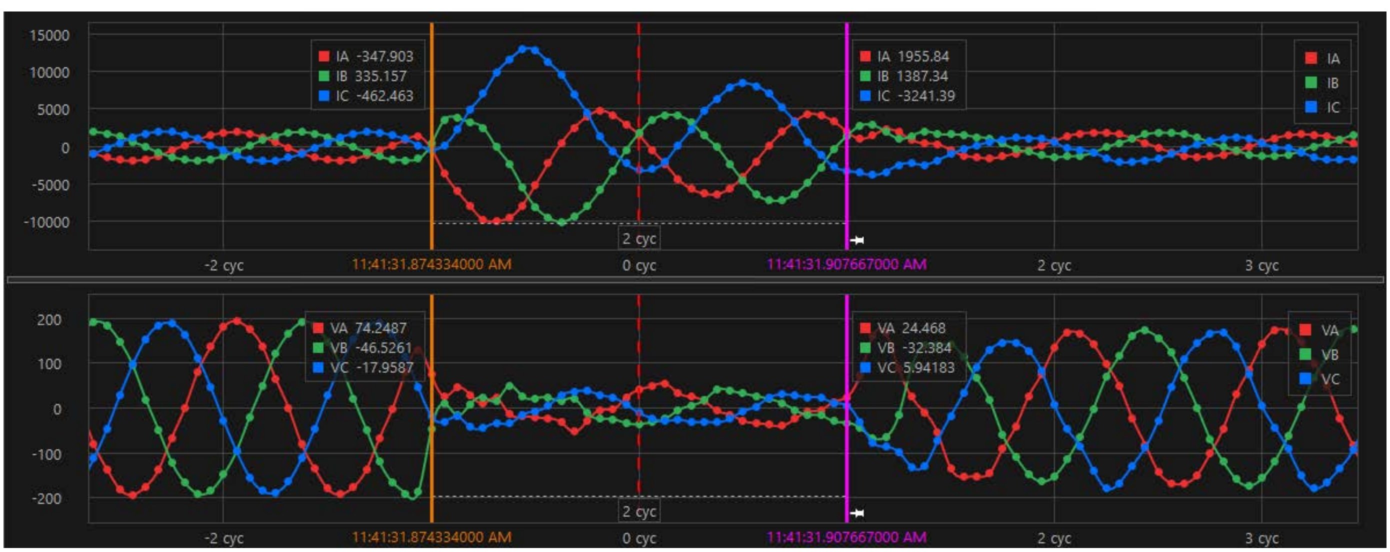


Figure 1.2: Event #2—Three-Phase Fault Observed on Parallel #1 230 kV Circuit Already Returned To Service [Source: LADWP]

19 The TO has a capital project underway to replace these relays by the end of 2020.

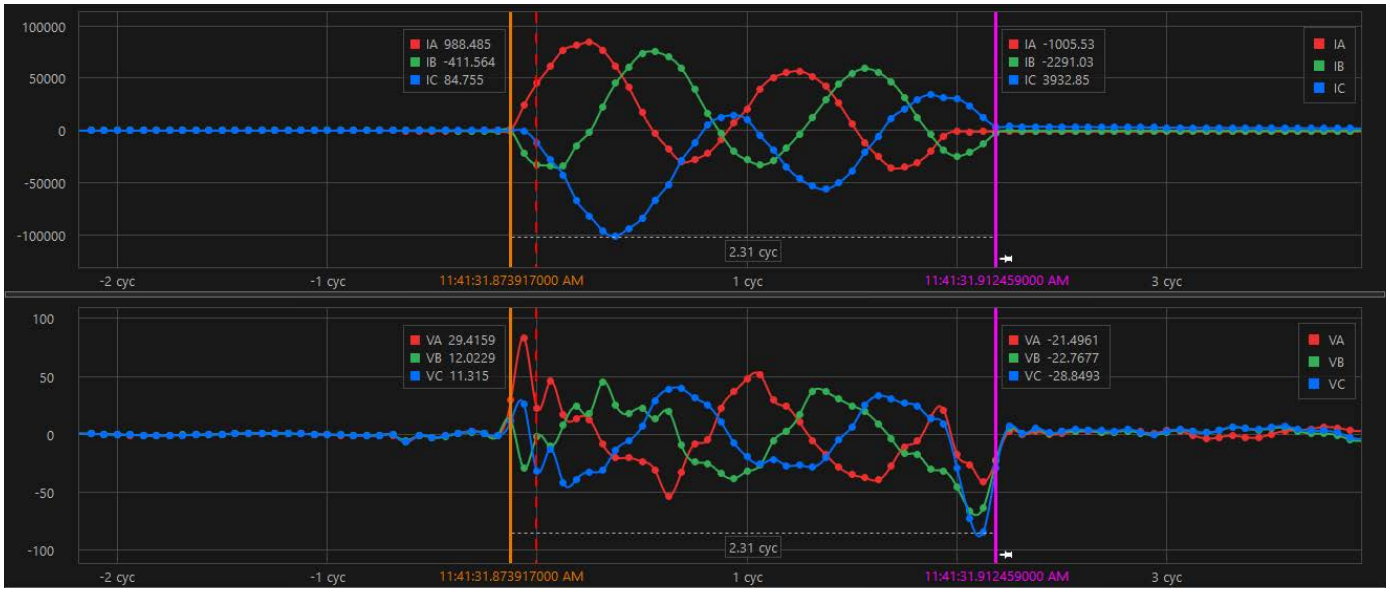


Figure 1.3: Event #2—Three-Phase Fault for Test on #2 230 kV Circuit [Source: LADWP]

No solar PV resources were de-energized as a direct consequence of protective relaying removing the faulted transmission elements from service. Rather, solar PV inverter controls and protection caused the reduction in output from all affected plants. This response of BPS-connected solar PV resources was observed across multiple BA footprints as described above. Figure 1.4 – Figure 1.8 show the response of solar PV resources in the CAISO, SCE, PG&E, LADWP, and IID footprints.[20] Again, no noticeable impact to BPS-connected solar PV was observed in the SDG&E, SRP, or APS footprints. Appendix B provides more details regarding the performance of individual plants involved in the disturbance. Table 1.1 shows the reduction of BPS-connected solar PV facilities in each area.

Table 1.1: BPS-Connected Solar PV Reductions by Area

Area	Fault Event #1 [MW]	Fault Event #2 [MW]
CAISO	122	901
SCE	100	535
PG&E	6	79
SDG&E	0	0
LADWP	83	62
IID	0	37
SRP	0	0
APS	0	0
Total*	**205**	**1,000**

* Summation of CAISO, LADWP, IID, SRP, and APS BA footprints

[20] Note that SCE and PG&E are within the CAISO BA. Plots for each specific entity are shown for reference. Past experience shows that these plots are not likely to match identically due to different SCADA scan rates and data collection practices.

As with the past disturbance reports involving fault-induced solar PV reductions, the size of the disturbance (in MW) is determined by using the summation of BA SCADA data from all affected BAs, typically with a scan rate of two to four seconds. Due to SCADA scan rate differences, different metering points, different accounting practices, and other factors, it is not expected that the CAISO SCADA data numbers would match the summation of its TOP SCADA data numbers. As with past disturbances, it is difficult to determine the actual reduction in solar PV output due to these discrepancies; however, the aforementioned reductions in solar PV output provide a relative indicator of the impact of these reductions compared to past disturbances.

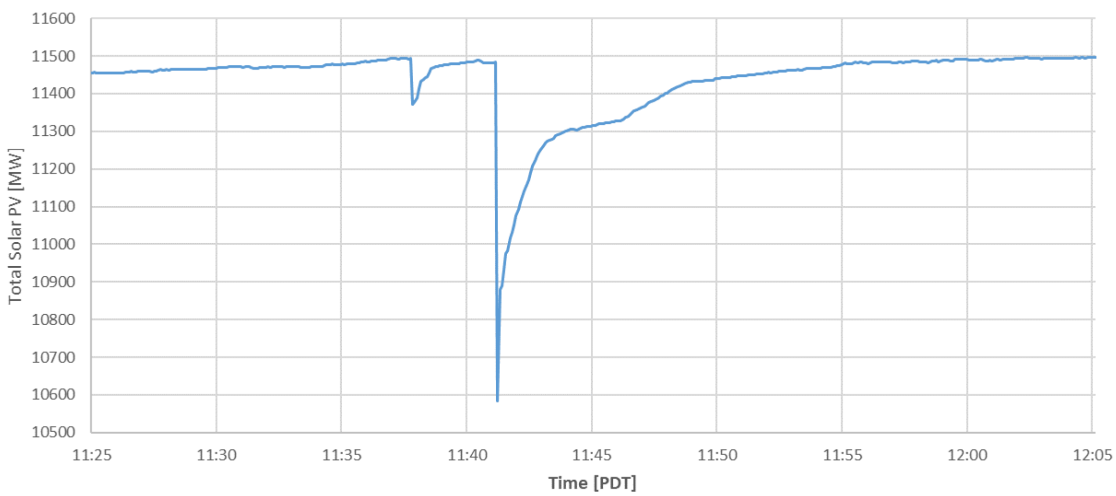


Figure 1.4: CAISO BPS-Connected Solar PV during Disturbance [Source: CAISO]

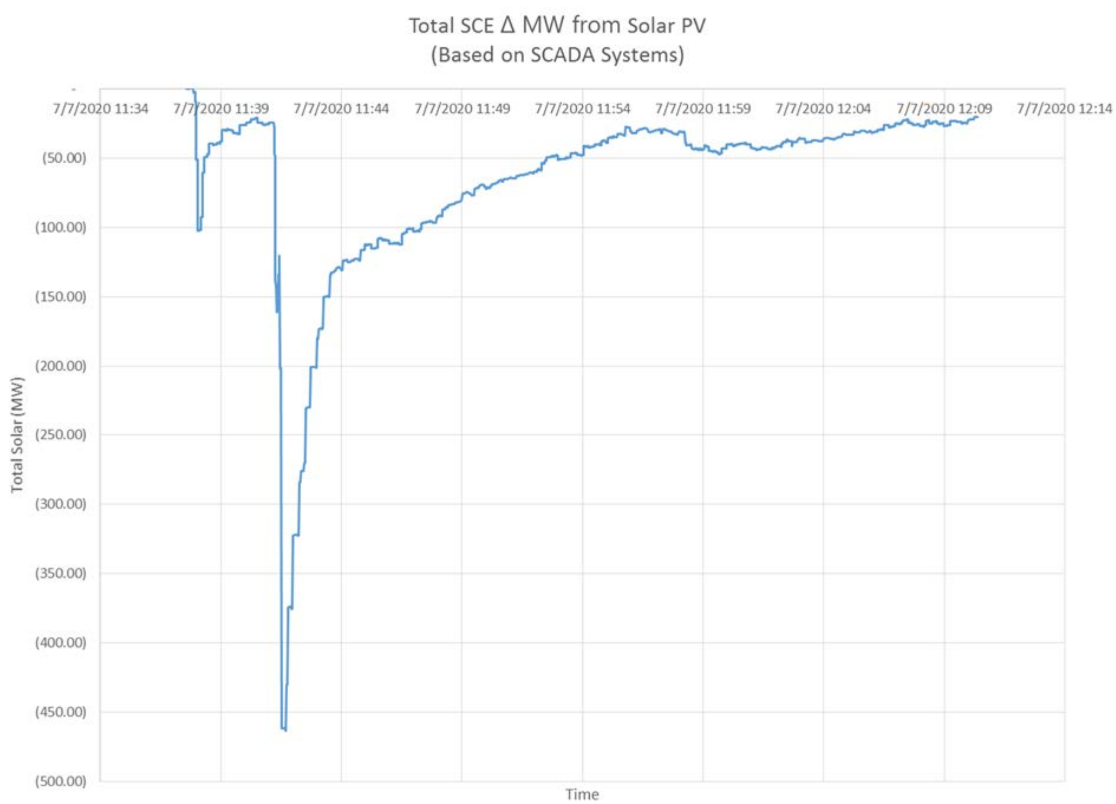


Figure 1.5: SCE BPS-Connected Solar PV during Disturbance [Source: SCE]

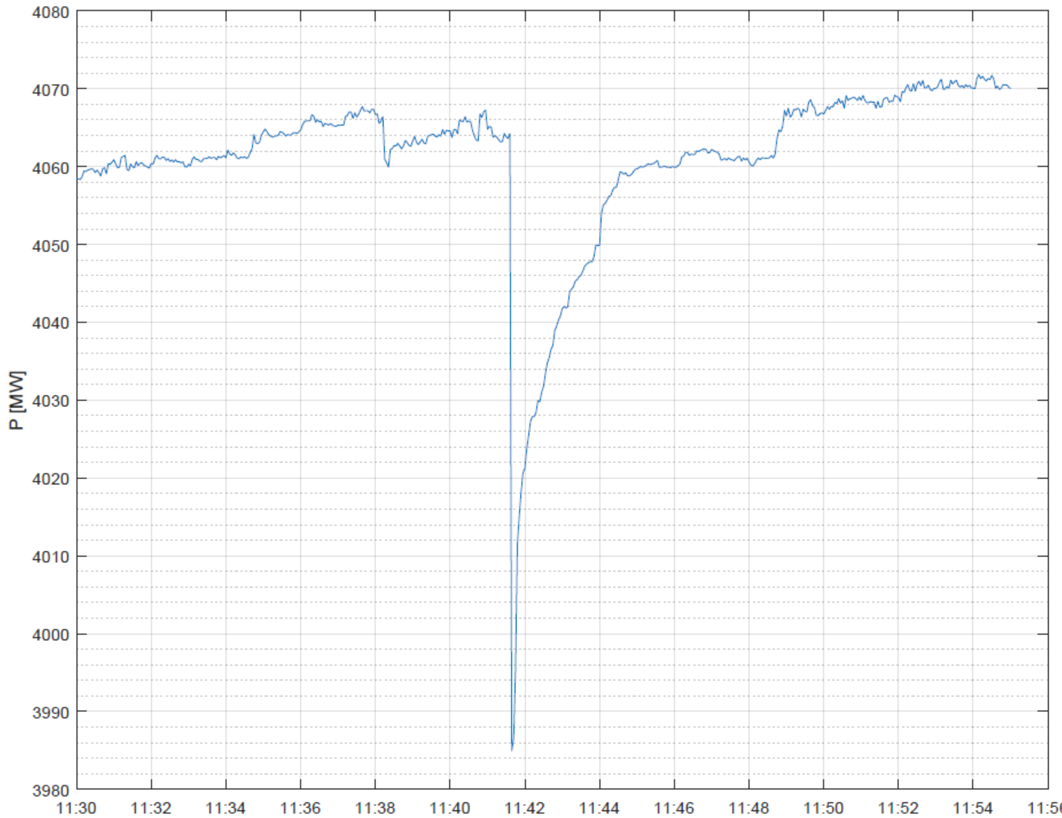


Figure 1.6: PG&E BPS-Connected Solar PV during Disturbance [Source: PG&E]

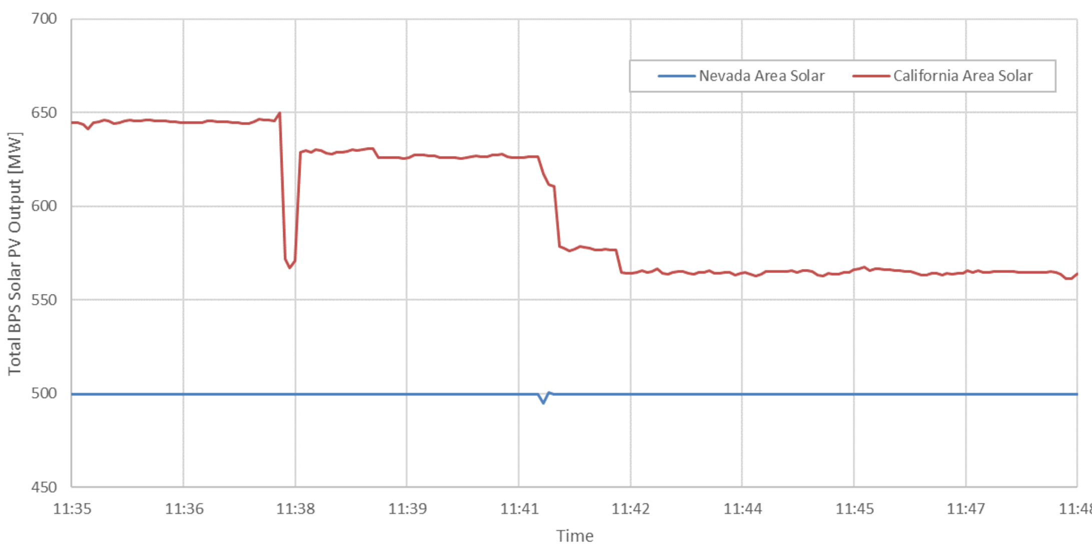


Figure 1.7: LADWP BPS-Connected Solar PV during Disturbance [Source: LADWP]

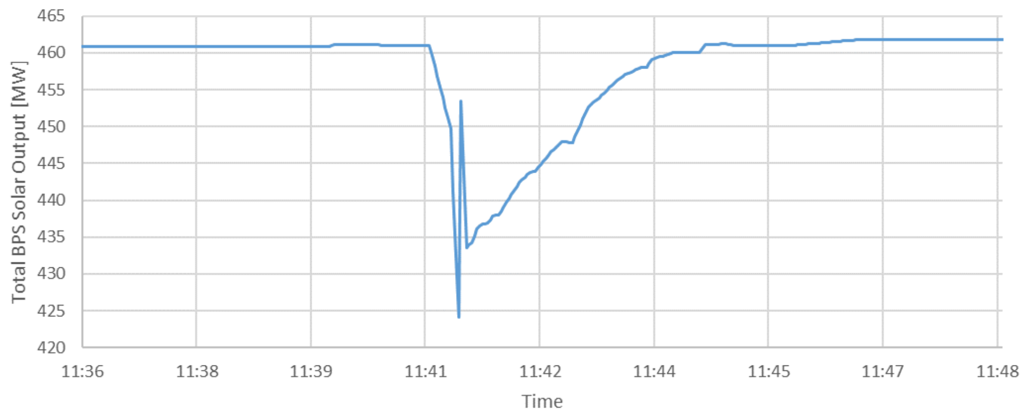


Figure 1.8: IID BPS-Connected Solar PV during Disturbance [Source: IID]

The Angeles Forest disturbance was the first fault event for which NERC identified a discernible change in net demand that was attributed to the tripping of DERs.[21] The same techniques to determine possible DER tripping were employed in this analysis, and SCE identified some possible DER tripping as observed in **Figure 1.9**. Each time-series plot in **Figure 1.9** represents a subtransmission interface near the fault location. The net load increases persist for about five to seven minutes, indicative of legacy DER settings that include a restart time delay of around this time. Net load values return to predisturbance levels soon thereafter as the predominantly solar PV DERs ramp back up to their maximum available power output.

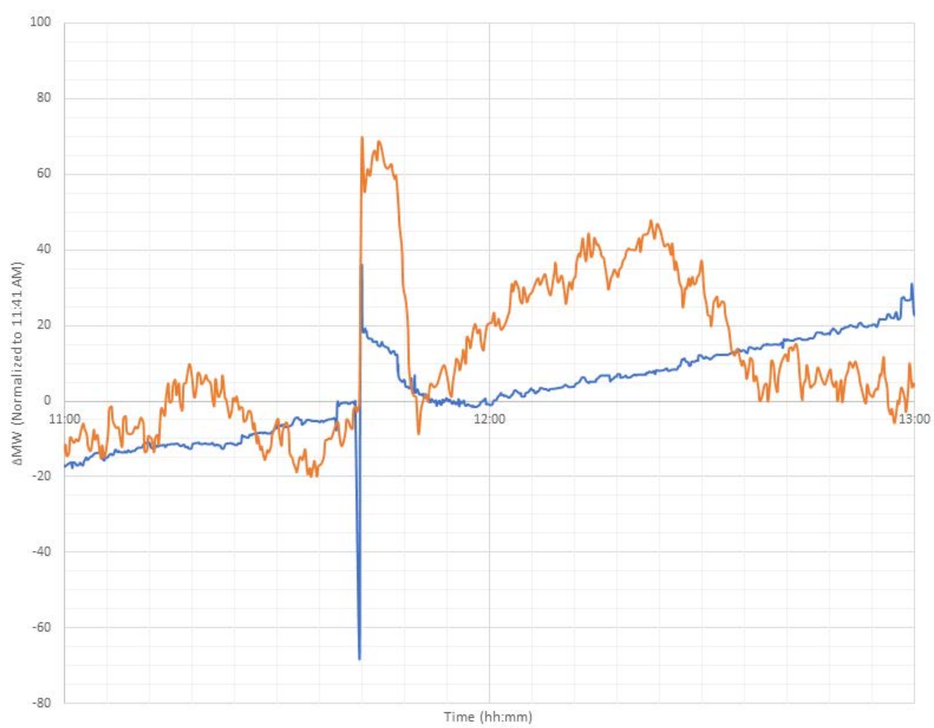


Figure 1.9: Net Load Increase Observed by SCE [Source: SCE]

[21] *Palmdale Roost and Angeles Forest Disturbance* report, January 2019: https://www.nerc.com/pa/rrm/ea/Pages/April-May-2018-Fault-Induced-Solar-PV-Resource-Interruption-Disturbances-Report.aspx

Figure 1.10 shows system frequency measurements for Event #2 exhibiting an initial spike at the time of the fault followed by a drop in system frequency to a mean value of about 59.9 Hz[22] caused by the loss of solar PV resources. **Figure 1.11** also shows the relative phase angles from the frequency recording devices with post-fault angle differences reaching about 37 degrees across the system.[23]

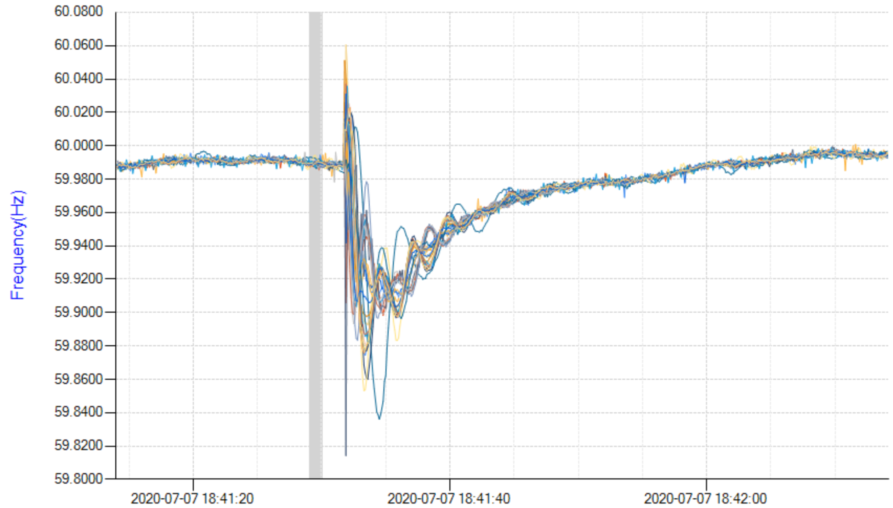


Figure 1.10: FNET Frequency Measurements for Event #2 [Source: UTK/ORNL]

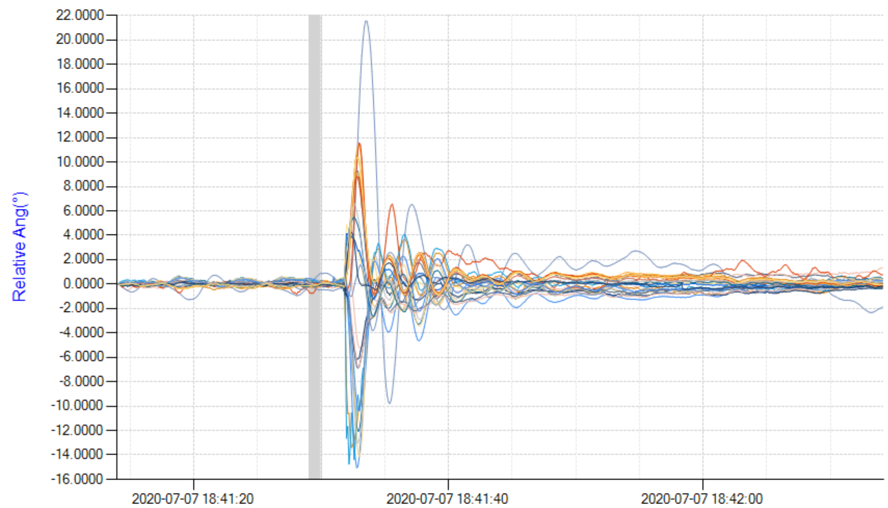


Figure 1.11: FNET Relative Phase Angle Measurements for Event #2 [Source: UTK/ORNL]

[22] Some local frequency measurements dropped to around 59.84 Hz.

[23] It is likely that these recording devices filtered out instantaneous phase jumps at the fault inception; hence, the plot does not show phase jumps at the time of the fault.

Chapter 2: Detailed Findings from Disturbance Analysis

WECC requested data from all affected solar PV generating facilities that experienced a change in active power output of greater than 10 MW. Information was collected regarding the primary causes of reduction in output and the inverter characteristics at each site. NERC and WECC staff, in coordination with the affected entities and TOs, analyzed the information collected; this chapter describes the key findings and recommendations from these analyses.

Poor Data Resolution from Solar PV Facilities

Each affected solar PV facility was requested to "provide plant electrical quantities[24] at the highest resolution available" and was also requested to provide high-resolution "continuous monitoring data" (e.g., data from a phasor measurement unit). The review team tracked the resolution of the data provided from each facility, and this information is provided in **Table B.1** in **Appendix B**. The table clearly shows the following:

- No facilities provided electrical quantity information that captured the on-fault behavior of the facility (i.e., with data resolution high enough to observe the fault).
- Some facilities were able to provide one-second data (and one facility provided higher resolution data) that was able to indicate the post-disturbance behavior of the facility; specifically, this data was used to analyze the active power recovery of the plant.
- Some facilities were only able to provide data with one-minute or even five-minute resolution, proving entirely ineffective for analyzing the performance of the facility. Data had to be collected by the local TOs as well as the BA (if different) to gather sufficient data to be able to perform the analysis.
- No facilities were able to provide any oscillography data from individual inverters. Therefore, it is impossible to fully understand what the individual inverters may have experienced at their terminals for this three-phase BPS fault event.

Key Finding:

Poor data resolution from the affected solar PV fleet significantly deterred a comprehensive analysis of this disturbance. Many facilities have data historians that only record information with a resolution of one-minute (or even five-minute in some cases). Furthermore, no facilities recorded electrical quantities with sufficient resolution to observe their on-fault behavior, limiting the team's ability to perform a more detailed analysis.

Recommendation:

Phasor measurement units (or similar recording within the plant) should continuously capture and store RMS quantities for these events with resolution of around one-cycle. Digital fault recorders, triggered on low voltage events, should capture electrical quantities at the POI and will provide the best information to analyze the facility's response to the event. Lastly, inverter oscillography records provide the most useful information for post-mortem analysis and possible mitigation of inverter tripping or other abnormal behavior.

Existing solar PV (and other inverter-based resources) are strongly encouraged to capture the information described above, and all newly interconnecting solar PV facilities should be required to collect, store, and provide this information to the ERO for event analysis (upon request). The NERC PRC-002 Reliability Standard and/or the FERC Large and Small Generator Interconnection Agreements should be significantly enhanced to ensure all newly interconnecting generating facilities have this type of recording capability to ensure BPS reliability now and into the future as the penetration of these types of resources continues to rise.

[24] Plant RMS three-phase active power, plant RMS three-phase reactive power, plant RMS phase voltages, and plant frequency

Causes of Inverter Tripping

Three types of inverter tripping were identified in this disturbance: ac overcurrent tripping, dc low voltage tripping, and ac low voltage tripping. Multiple inverter models from one inverter manufacturer had ac overcurrent and dc low voltage tripping attributed to them. Multiple solar PV facilities had partial tripping of inverters for both reasons; however, the ac overcurrent tripping was more common. Brief descriptions of the observed tripping are provided below:

- **AC Overcurrent:** The most prominent inverter tripping occurred when inverter ac currents exceeded 150% of rated current or when ac output power exceeded dc input power. This type of tripping was observed at facilities that exhibited momentary cessation (older models of inverter) as well as at facilities that exhibited current injection during the disturbance. Follow up with other inverter manufacturers highlighted that this type of tripping may occur if the electronic switches (i.e., insulated-gate bipolar transistors (IGBTs)) within the inverter are not tightly controlled at the time of a large ac-side system faults such that uncontrolled current is injected into the low ac voltage conditions and can lead to instantaneous overcurrent conditions. GOPs were unable to provide details regarding this type of tripping since it is based on inverter control topology.
- **DC Low Voltage:** During this disturbance, dc low voltage tripping was also observed. Settings were provided for this trip threshold and were set fairly robustly but with a very short time delay since dc voltage must be strictly controlled. However, if the power electronic switches within the inverter are not appropriately controlling current when an ac-side severe low voltage occurs along the same lines as described above, current injection into a short-circuit condition will deplete the dc bus energy supply, and the voltage will drop rapidly. It is believed that these two trip mechanisms are related, especially since inverters of similar make and model exhibited similar behavior at different facilities.
- **AC Low Voltage:** One solar PV resource experienced "Fast AC Low Voltage" tripping that initiates a trip when voltage falls below a defined low voltage threshold for a predetermined period of time. In this case, the GO reported that the plant experienced voltage below an undefined trip threshold for more than 10 cycles. However, the fault only persisted for less than 3 cycles, so it is unlikely that POI voltage for this facility remained low for 10 cycles. However, since high-speed data is not available from the inverters or from the plant POI, further investigation to better understand any discrepancies was not possible.

The predominant form of inverter tripping in this disturbance, ac overcurrent protection, is not addressed in *NERC Reliability Standard PRC-024* since it does not involve voltage or frequency protective relaying. This is similar to past disturbances where inverter tripping included phase lock loop loss of synchronism and dc reverse current.

Key Finding:
Causes of inverter tripping included ac overcurrent, dc low voltage, and ac low voltage. Considering the fault was a normally-cleared BPS fault, no resources should have tripped from this disturbance. This type of behavior from solar PV resources is abnormal and adversely impacts reliability of the BPS.

Recommendation:
GOs of inverter-based resources, particularly solar PV resources, are encouraged to evaluate their ac overcurrent and dc low voltage protection in coordination with their inverter manufacturer. Resources involved in this disturbance should proactively work with their inverter manufacturer to investigate why the inverters tripped for this disturbance as this is considered abnormal behavior. TPs and PCs should ensure that system impact studies performed during the interconnection process have sufficient granularity to identify possible ac overcurrent and dc low voltage tripping; this requires the collection of EMT models and the evaluation of system performance with EMT studies. Lastly, the NERC PRC-024 standard (or a new standard) should be enhanced to ensure that BPS-connected inverter-based resources are able to ride through expected BPS fault events and not trip for causes other than only voltage and frequency protective relaying.

Large Disturbance Behavior of Solar PV Facilities

BPS-connected solar PV resources exhibited a number of different unique dynamic responses to the BPS fault events that occurred. The following describe the primary modes of operation for the solar PV fleet, some observations made regarding each response, and recommendations for industry to address solar PV performance issues:

- **Continued Momentary Cessation at Legacy Solar PV Facilities:** Multiple solar PV resources that exhibited momentary cessation were installed prior to the recommendations put forth in the NERC reliability guideline and have inverters that cannot eliminate or change momentary cessation settings (i.e., hardcoded into the inverter controls). This specific inverter manufacturer does not produce this inverter model anymore; new inverters are able to provide current injection during low voltage ride-through events. NERC continues to review the number of facilities involved in each disturbance that cannot eliminate momentary, and currently NERC does not see this as a significant reliability issue.
- **Unchanged Momentary Cessation at Sites That Have Capability to Modify:** The review team compared momentary cessation data provided by GOs of solar PV facilities for this disturbance with the alert[25] data following the Canyon 2 Fire disturbance. Multiple solar PV facilities that exhibited momentary cessation during this disturbance have inverters that can be updated with relatively straightforward software changes to eliminate its use; however, those changes were not made prior to the disturbance. NERC has published multiple reliability guidelines recommending changes to inverter-based resources, to the extent possible, to eliminate momentary cessation and replace its use with some form of active and reactive current injection. NERC has also engaged with TPs and PCs in the Western Interconnection, encouraging them to review the performance and models of solar PV facilities in their footprint and to work with GOs to ensure the inverters are set based on the recommendations set for in the NERC Guidelines.
    - **Updated Controls Following Disturbance Analysis:** NERC and WECC met with each affected solar PV facility that received a data request to follow up with any questions regarding the information provided. During each discussion, the teams discussed possible causes of any abnormal performance and also discussed recommended updates to settings and controls. The NERC and WECC teams recommended that the GO and GOP coordinate with the equipment manufacturers to determine if any changes can be made to improve performance, mainly focused on momentary cessation settings and trip settings (as applicable). At least one entity was able to confirm that changes were made to eliminate momentary cessation after these follow-up activities.

[25] https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/NERC_Alert_Loss_of_Solar_Resources_during_Transmission_Disturbance-II_2018.pdf

- **Delayed Recovery of Active Power during Momentary Cessation:** A number of solar PV plants entered momentary cessation yet their active power recovery did not meet the recovery time of one second as recommended in the NERC reliability guidelines. **Figure 2.1** shows an example of a solar PV plant with a commercial operation date of late 2017 with momentary cessation low voltage threshold of 0.9 pu and active power recovery ramp rate of 10%/second.[26] Active power drops at the time of the fault and requires about 2.5–3 minutes to recover active power. Active power recovery clearly does not return within 10 seconds (assuming 10%/second recovery); this recovery is hindered in some way, possibly by poorly coordinated controls between the plant controller and the individual inverters.

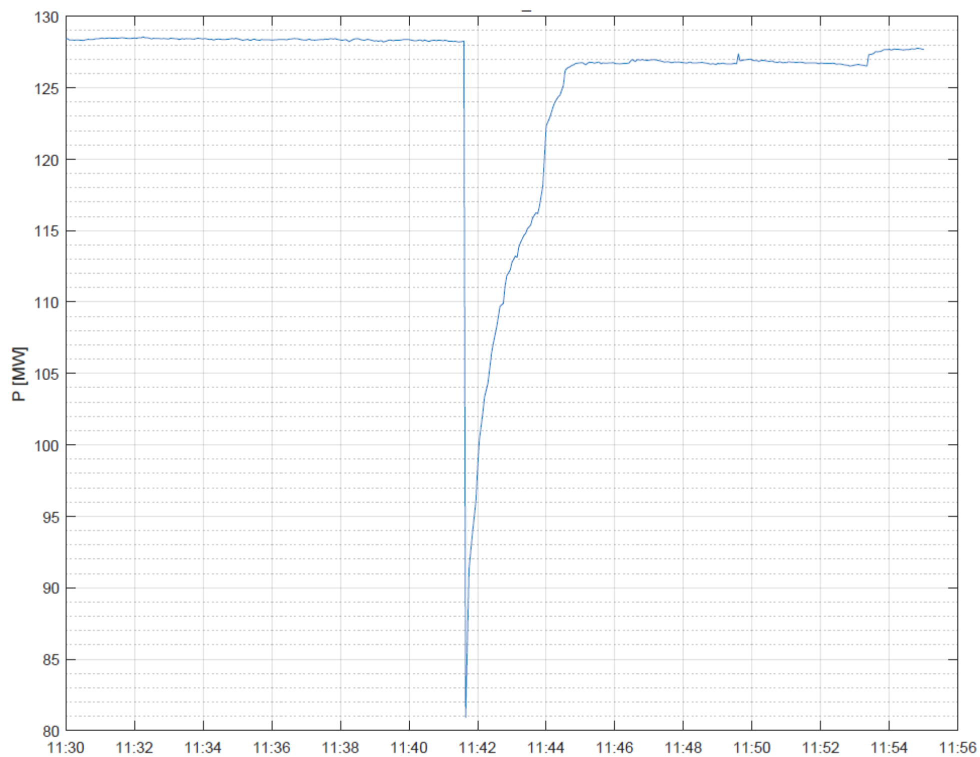


Figure 2.1: Example of Delayed Recovery of Active Power Following Momentary Cessation

- **Current Injection during Fault Events:** Some solar PV facilities with newer inverters provided current injection during the fault events and exhibited a similar response to the one shown in **Figure 2.2**. The reduction in active power and increase of reactive power is expected for a severe voltage depression, such as the one that occurred in this disturbance. This facility provided reactive power for a sustained time period of about 15–20 seconds and returned to predisturbance levels as active power recovers. Two observations were made by the analysis team:
  - A number of newer solar PV facilities had inverters set to current injection for large disturbances. This is the recommended performance of these facilities to provide essential reliability services to the BPS including dynamic voltage support. TOs have been establishing interconnection requirements that generally prohibit or discourage the use of momentary cessation, and it appears that many of these newer facilities are aligned with these requirements or recommendations.
  - On the other hand, it is curious that the active power also requires over 20 seconds to return to predisturbance levels and also exhibits two distinct ramp rates. This leads the review team to believe that controller interactions within the plant are also impacting inverter response here as well. Furthermore,

[26] Some inverters in the facility also tripped, leading to the step response around the time 11:44.

the fault clears within three electrical cycles, and BPS voltages recover quickly to predisturbance levels. Therefore, the sustained increase in reactive power output is slightly unexpected. Studies are needed to ensure that the controls are coordinated.

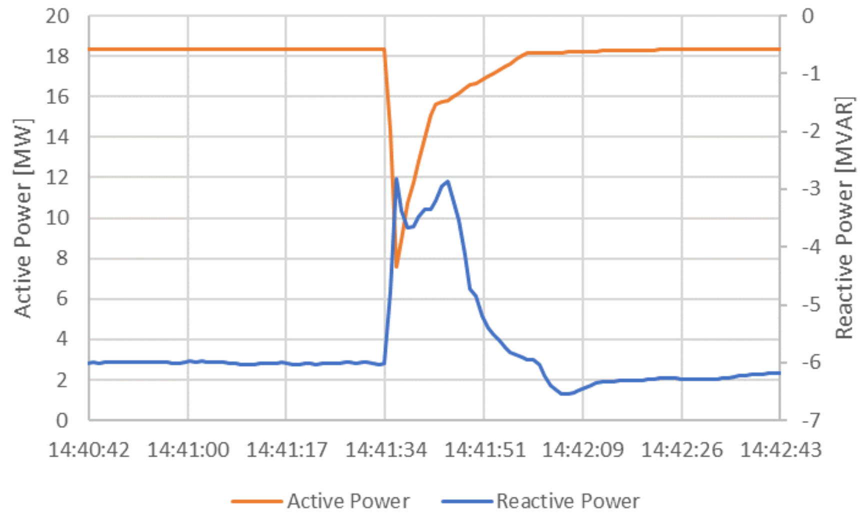


Figure 2.2: Example of Delayed Recovery of Active Power Following Momentary Cessation

Net Load Increase Attributed to DER Tripping

SCE evaluated the performance of all subtransmission load points for this disturbance. Similar to previous events, SCE observed an increase in net load at the time of the fault events, particularly Event #2, in areas with high penetrations of DERs. The net load increases were identified at only two subtransmission systems fed directly from 230 kV BPS buses located relatively close to the fault location. **Figure 2.3** shows the increases observed for these load points (time divisions are six minutes). Net loads at these locations increased by about 60 MW and 20 MW for Event #2. The net load increase persisted for about five to seven minutes, indicative of DER tripping and an automatic reconnection time specified in legacy IEEE 1547 standards.[27] This is also consistent with the performance from previous events in this local area. These areas where net load increases were observed include high penetrations of residential rooftop solar installations, commercial installations, and utility-scale solar PV plants in the 1–10 MW range.

LADWP reviewed their net load quantities (shown in **Figure 2.4**) and determined that they did not experience any net load increase. Rather, LADWP experienced a reduction in net load that is attributed to possible tripping of voltage-sensitive end-use loads.

[27] https://standards.ieee.org/standard/1547-2003.html

Key Finding:
SCE observed a net load increase for their subtransmission networks near the fault location. The behavior of the net load with a five to seven minute increase and then return to predisturbance levels is indicative of legacy IEEE 1547 compliant DERs. This has been observed in past disturbances in this area as well, particularly the Angeles Forest and Palmdale Roost disturbances.

Recommendation:
TOs, BAs, RCs, and other transmission entities are encouraged to review load SCADA points following grid disturbances to identify any impacts that DERs may be having on BPS performance. This is increasingly important as DERs in many areas across North America continue to increase. NERC System Planning Impacts from DERs Working Group (SPIDERWG) should continue providing industry with guidance on how to perform this type of analysis and deduce DER performance with available data.

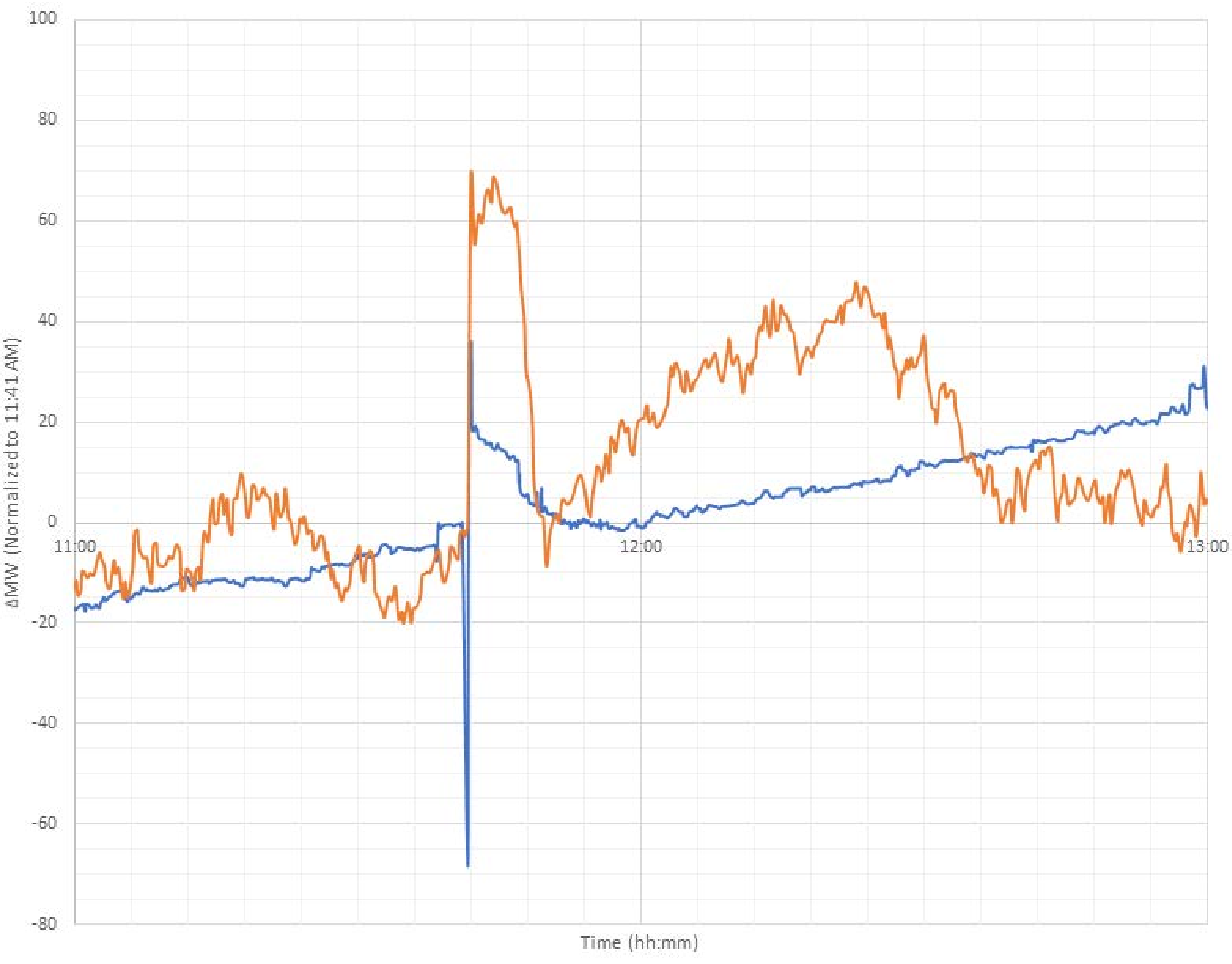


Figure 2.3: Net Load Increase Observed by SCE [Source: SCE]

Figure 2.4: LADWP Net Load during Disturbance [Source: LADWP]

Appendix A: Disturbance Analysis Teams

This disturbance was analyzed by the following individuals. NERC gratefully acknowledges WECC, CAISO, LADWP, SCE, and the affected GOs and GOPs. The coordination between all affected entities was crucial to identifying the key findings and developing recommendations for improved performance. NERC would also like to acknowledge the continued engagement and support of the inverter manufacturers to ensure that the mitigating measures being developed are pragmatic. Lastly, all members of the NERC IRPWG continue to help support NERC in its mission to ensure reliability of the BPS, particularly as the BPS is faced with rapidly changing technology and evolving grid performance characteristics.

Name	Company
Rich Bauer	North American Electric Reliability Corporation
Ryan Quint	North American Electric Reliability Corporation
Jule Tate	North American Electric Reliability Corporation
Enoch Davies	WECC
James Hanson	WECC
Evan Paull	WECC
Tim Reynolds	WECC
Doug Tucker	WECC
Greg Berglund	California Independent System Operator
Lou Fonte	California Independent System Operator
Tricia Johnstone	California Independent System Operator
Rachel Lucas	California Independent System Operator
Songzhe Zhu	California Independent System Operator
Willard Chun	Los Angeles Department of Water and Power
Robert Kerrigan	Los Angeles Department of Water and Power
James Wells	Los Angeles Department of Water and Power
David Piper	Southern California Edison
Matthew Smelser	Imperial Irrigation District

Appendix B: Detailed Review of Solar PV Facilities

This appendix provides a detailed review of most of the solar PV facilities that exhibited a power reduction exceeding the 10 MW threshold established for this review. Table B.1 provides a high-level overview of the involved facilities and each subsection describes the facility in more detail. Note that "Reduction" values in the table are those reported by CAISO. Other information was collected through the data requests sent out to affected facilities and from the analysis performed by NERC and WECC.

Table B.1: Review of Solar PV Facilities						
Facility ID	**MW Capacity**	**Reduction**	**POI Voltage**	**In-Service Date**	**Data Resolution**	**NERC-WECC Review**
Plant A	250	167	230 kV	12/2014	1-second	Inverters of one make entered momentary cessation (0.875 pu threshold) and are not programmable; this performance will persist.
Plant B	300	135	230 kV	12/2014	1-second	Inverters of one make entered momentary cessation (0.875 pu threshold) and are not programmable; this performance will persist.
Plant C	103	73.3	230 kV	7/2019	1-second	Some inverters tripped on ac overcurrent protection set at 150% of rated current. Other inverters are programmed to provide current injection during faults; however, their recovery of active power output upon fault clearing was sustained for more than 15 seconds.
Plant D Plant E	D: 310 E: 276	48 (total)	230 kV	10/2013	3-second	Plants increased output at time of fault, followed by subsequent drops in output with a long ramp rate of recovery matching the plant controller ramp rate; plant unable to determine root cause of abnormal behavior.
Plant F	248	43	230 kV	2013-2014 (by block)	0.33-second	Inverters of one make entered momentary cessation (0.875 pu threshold) and are not programmable; this performance will persist.
Plant G	20	41	230 kV	2015	1-minute	Incorrectly noted as responding to event; plant did not reduce power output.
Plant H	140	34	230 kV	11/2017	1-second	Multiple inverters tripped on ac overcurrent protection. Remaining inverters entered momentary cessation (0.9 pu threshold with 10%/sec recovery ramp rate) and are not programmable; this performance will persist.
Plant I and J[28]	I: 51 J: 25	30	230 kV	I: 7/2017 J: 9/2018	I: 5-minute J: 1-second	I: Reduction of output likely due to momentary cessation J: Change in active and reactive power at the facility during the fault; unclear as to why active power had delayed recovery and why reactive power sustained change for prolonged period of time (relative to fault duration and BPS voltage recovery).
N/A	N/A	29	N/A	N/A	N/A	Wrong facility reported by CAISO; NERC/WECC team determined unnecessary to follow up at this time.
Plant K	50	22	220 kV	12/2016	5-minute	Some inverters tripped on ac overcurrent protection for both faults; other inverters entered momentary cessation (0.9 pu threshold with 10%/sec recovery ramp rate) and are not programmable; this performance will persist.

[28] This was determined to be different facilities than stated by CAISO; however, the review team was able to work with IID to identify the appropriate facilities affected.

Table B.1: Review of Solar PV Facilities						
Facility ID	MW Capacity	Reduction	POI Voltage	In-Service Date	Data Resolution	NERC-WECC Review
Plant L	94	20	220 kV	12/2016	5-minute	Twelve inverters entered momentary cessation in both Event #1 and Event #2, one inverter tripped on ac overcurrent for Event #1, and three additional inverters tripping on ac overcurrent for Event #2; five-minute resolution data provided that was not usable for event analysis.
Plant M	150	19	220 kV	4/2019	10-second	Inverters configured for current injection during fault events; dynamic response of reactive power appears to be abnormal; delayed recovery of active power upon fault clearing.
Plant N	25	17	115 kV	1/2018	1-minute	GO stated momentary cessation not used; however, plant significantly drops in output and recovers in 1.5 minutes; poor data resolution makes analysis difficult.
Plant O	26	15	220 kV	12/2017	5-minute	Most inverters tripped on dc low voltage.
Plant P	20	15	66 kV	1/2019	1-second	Some inverters tripped on ac low voltage, but GO unable to determine trip threshold or timer; other inverters entered momentary cessation, but GO unable to determine if settings can be modified.
Plant Q	172	13	230 kV	6/2012 and 4/2015	1-second	Some inverters entered momentary cessation (0.9 pu threshold with 25%/sec recovery ramp rate); GO modified settings to eliminate momentary cessation after event.
Other		122				

Plants A and B

Plants A and B are 250 MW and 300 MW, respectively, and went into commercial operation in December 2014. These facilities include inverters that cannot change momentary cessation settings and are expected to enter momentary cessation at 0.875 pu voltage with a 1.02 second time delay for recovery and an active power recovery ramp rate of 8.2%/second. This facility is known to have the momentary cessation limitations and has been involved in prior disturbances that NERC and WECC have analyzed. Figure B.1 shows the active power recovery of the facility following the second fault event. CAISO reported a drop of 302 MW[29] at the time of the fault event. The plant returns to predisturbance power two minutes after the fault. The GO in this case reported that only a small handful of inverters entered momentary cessation; however, it is clear from the plant output that this was understated by the GO.

[29] This plot was provided by SCE; hence, the slightly lower data resolution results in values different than those reported by CAISO.

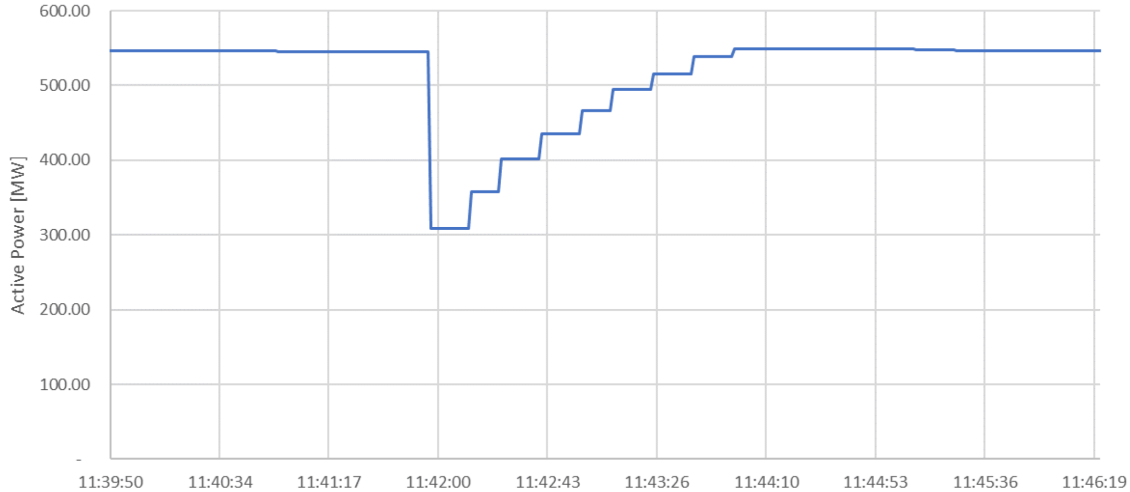


Figure B.1: Plants A and B Combined Active Power Output

Plant C

This plant is a 103 MW facility that went into commercial operation in July 2019. The plant consists of inverters that exhibit current injection for large voltage excursions. Figure B.2 shows active and reactive power from the facility (one-second resolution measured at the point of interconnection) for Event #1.[30] Active power drops during and immediately after the fault, and most inverters at the facility enter "ride-through mode" with reactive current priority. While the fault only lasts for less than three cycles, and BPS voltages return to close to nominal values quickly, the facility remains with decreased active power for about 10 seconds before beginning to ramp back to predisturbance levels over about six seconds. The difference in pre- and post-disturbance output is due to six inverters tripping on ac overcurrent protection set at 150% of rated current.[31] This is a systemic tripping mechanism observed for one specific inverter manufacturer in this event and is believed to be related to the management of power electronic switch controls during severe fault events. During follow-up discussions with the facility to discuss mitigating measures, they were not able to provide details on the root cause of tripping nor provided any mitigating actions; therefore, this cause of tripping may persist.

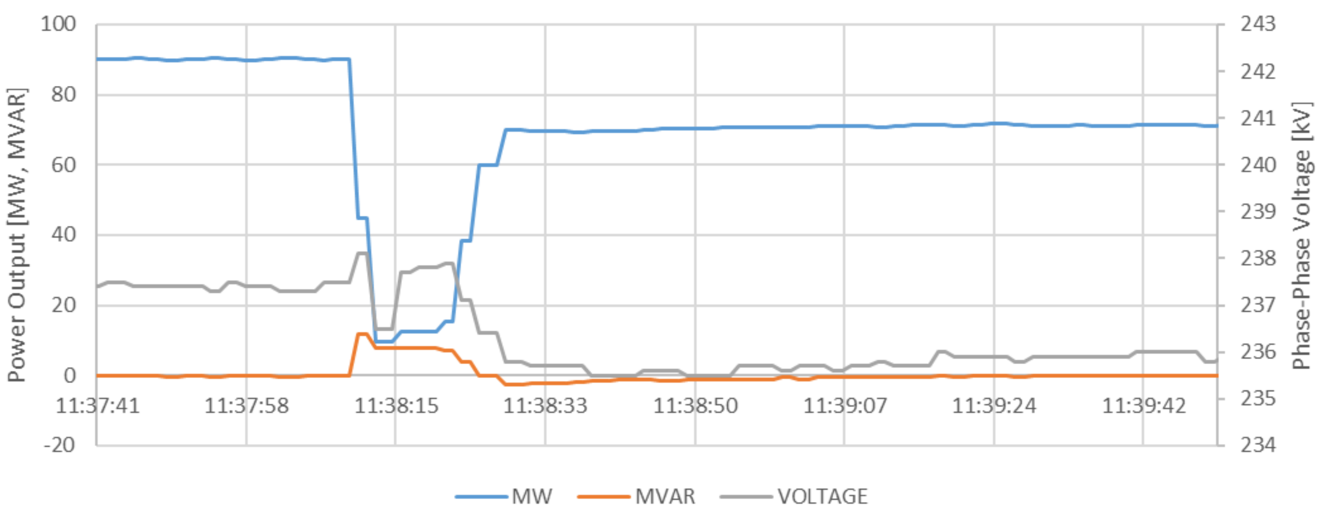


Figure B.2: Plant C Active Power, Reactive Power, and Voltage for Event #1

[30] The review team was not able to deduce why the facility significantly responded to Event #1 but did not respond to Event #2.
[31] This has been observed for this specific manufacturer over multiple events and multiple facilities.

Plants D and E

These two plants were reported as one facility by CAISO; however, WECC and NERC (in coordination with the GOs) identified that both facilities were involved in the disturbance. Plant D and Plant E are 310 MW and 276 MW facilities that entered commercial operation in October 2013 and November 2013, respectively. These plants both exhibited an abnormal behavior to Event #2. No inverters tripped or entered momentary cessation; however, the overall response of the plant highlighted some abnormal behavior between the inverter and plant controls. Figure B.3 shows the active power output of the facilities that exhibited a quick rise in active power followed by a rapid reduction in active power to well below predisturbance levels. The plant controller increased its set point to slowly ramp the pant back to predisturbance output with a predefined ramp rate expressed as Watts/second rather than percent/second. Therefore, the times to recovering to predisturbance levels are different between the facilities. Regardless, following the fault events, the plant controller caused strange behavior that led to an unexpected reduction in active power, and then the plant output required minutes to return to expected output levels. This is not the expected or recommended behavior for solar PV facilities; the plant should not have responded abnormally and should also be able to rapidly recover to predisturbance levels following these types of disturbances with no interaction or hindrance from the plant controller. NERC and WECC encouraged this GO to coordinate with their equipment manufacturers to identify a fix to this undesired behavior of the facility.

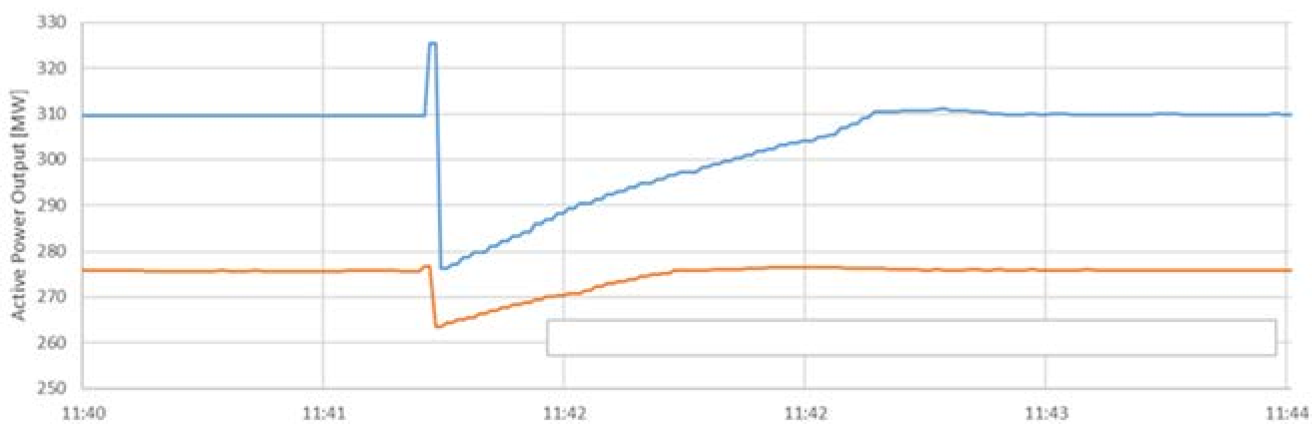


Figure B.3: Plants D and E Active Power Output for Event #2

Plant F

This plant is a 248 MW facility went into commercial operation in 2013–2014 and includes a mix of inverters that enter momentary cessation and provide current injection during voltage excursions. All inverters of the former type entered momentary cessation with settings that cannot be changed. These inverters are set to enter momentary cessation at 0.875 pu voltage, have a 1.02 second delay for recovery of active power after voltage returns to above the threshold value, and also have a 8.2%/second active power recovery ramp rate. One inverter faulted on dc overcurrent. Figure B.4 shows the active power (orange) and reactive power (blue) response from the facility for Event #2. Active power drops from 228 MW to around 184 MW and reactive current support also decreases (due to momentary cessation ceasing current injection). The facility recovers to predisturbance levels in about 1 minute and 40 seconds.

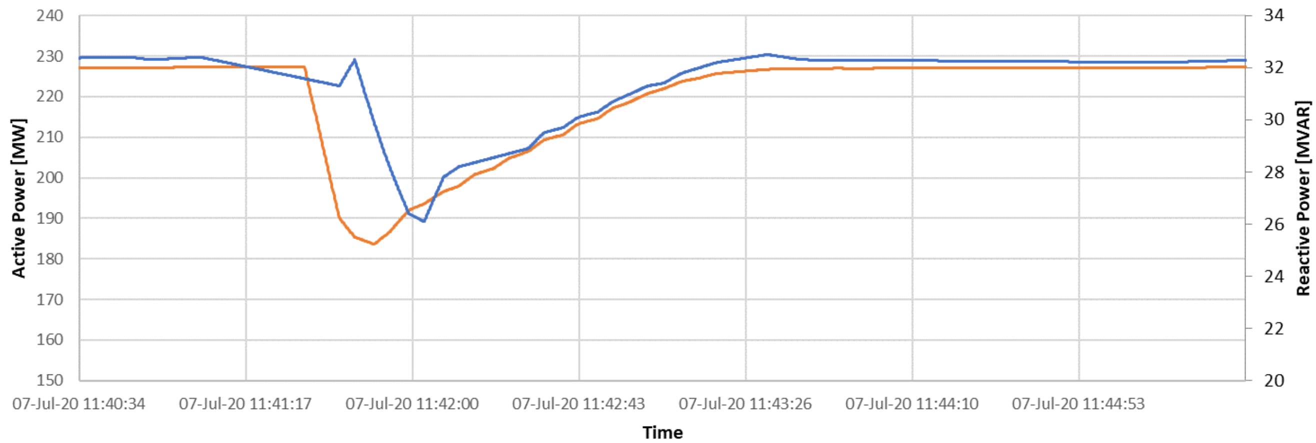


Figure B.4: Plant F Active and Reactive Power Output for Event #2

Plant G

CAISO identified this facility as reducing power output by 43 MW; however, upon NERC and WECC follow-up with the GO, the owners provided metering data with two-second resolution showing that the facility only experienced a minor reduction in active power output during this event that was not attributed to the fault events.

Plant H

This plant is a 140 MW facility with a commercial operation date of November 2017; its inverters are set to enter momentary cessation at 0.9 pu voltage, and the plant has an active power recovery ramp rate of 10%/second. Twelve inverters tripped on ac overcurrent protection and were distributed throughout the solar PV collector system (i.e., not all located at end of the feeder or near the substation). Figure B.5 shows the active power response of the facility for Event #2. Active power drops at the time of the fault and required about 3 minutes to return to near predisturbance output levels. It is assumed that the inverters at this facility have a 2-minute restart time for this type of inverter fault code, hence the jump in active power at 11:44 PDT. However, it is also clear that the recovery of active power by the inverters (at 10%/second) is hindered since the plant does not recover up to about 116 MW within 10 seconds. This is likely due to poorly coordinated controls between the plant controller and the individual inverters with the plant controller overriding the inverter controls (since voltage is back within acceptable levels within 3 cycles).

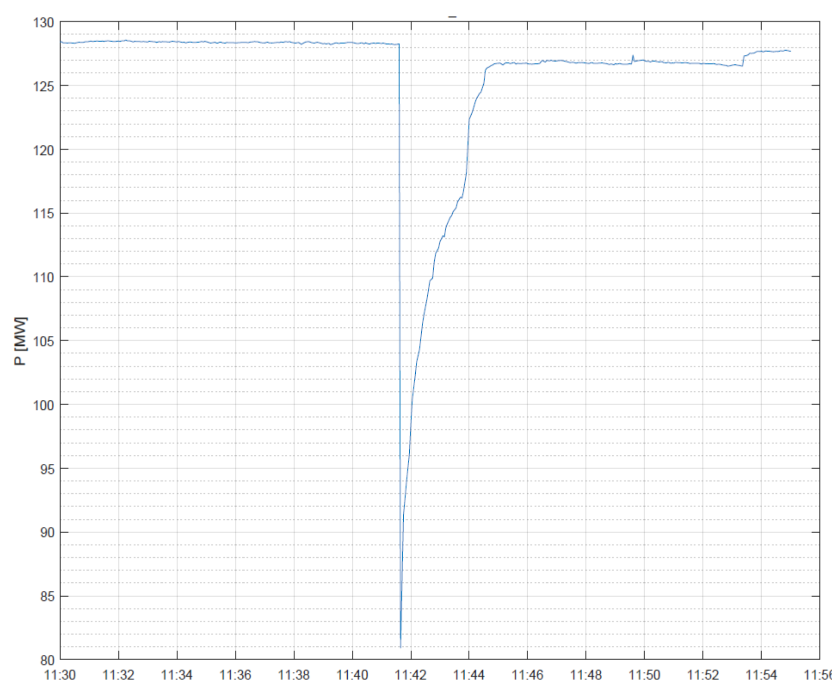


Figure B.5: Plant H Active Power Output for Event #2

Plant I

This plant is a 51 MW facility that went into commercial operation in July 2017. The plant owner stated that no inverters tripped and they cannot determine if momentary cessation occurred since their data is stored with 5-minute resolution. However, CAISO data shows a reduction of power output that is attributed to inverters entering momentary cessation.

Plant J

This plant is a 24.5 MW facility that went into commercial operation in September 2018 comprised of inverters that do not use momentary cessation. During the second fault, plant active power output reduced and reactive power consumption decreased (**Figure B.6**). As reactive power settled to a new settling point, active power also returned to predisturbance levels; however, this occurred over a 15-second time frame that is not the recommended recovery of active power following a fault event. It is unclear if the overall change in plant reactive power consumption was caused by response of the inverter controls or due to inverter active power reducing (causing less consumption of reactive power inside the facility). Without more detailed data, determining a root cause to the delayed recovery of active and reactive power is not possible.

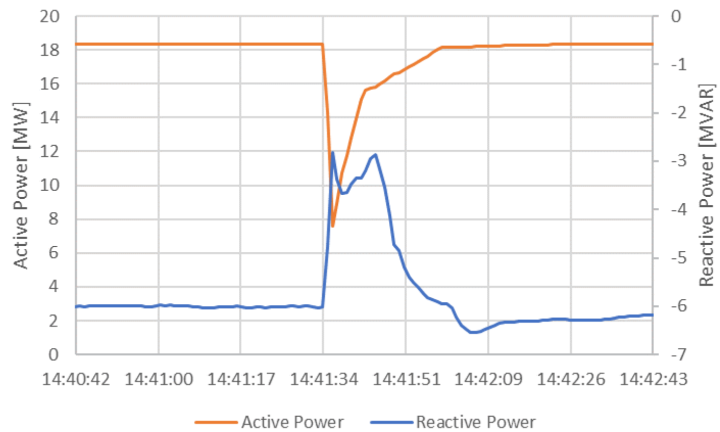


Figure B.6: Plant J Active and Reactive Power Output for Event #2

Plant K

This plant is 50 MW facility that went into commercial operation in December 2016. Multiple inverters tripped on ac overcurrent protection for both fault events, and other inverters entered momentary cessation. Due to poor (5-minute) data resolution, the number of inverters involved cannot be accurately determined. The ac overcurrent protection is set to trip when ac current exceeds 150% of rated current and automatically restores in 5 minutes.

Plant L

This plant is a 94 MW (limited to 85 MW at POI) facility that went into commercial operation in December 2016. Twelve inverters entered momentary cessation in both Event #1 and Event #2, one inverter tripped on ac overcurrent for Event #1, and three additional inverters tripping on ac overcurrent for Event #2. The ac overcurrent protection is set to trip the inverter when ac current exceeds 150% of rated current and automatically restores output after 5 minutes. The GO provided data with 5-minute resolution that was not usable from an event analysis perspective.

Plant M

This plant is a 150 MW facility that went into commercial operation in June 2019 and consists of inverters configured for current injection during fault events. **Figure B.7** shows the active and reactive power output of the plant for both events (note the time synchronization and reactive power unit errors). The dynamic response of reactive power appears to be abnormal with reactive power increasing for one fault and then decreasing for the more severe fault. This anomaly is currently unexplained. The plant does appear to have a delayed recovery of active power after these low voltage conditions, requiring about 15–30 seconds to return to predisturbance output levels after the fault.

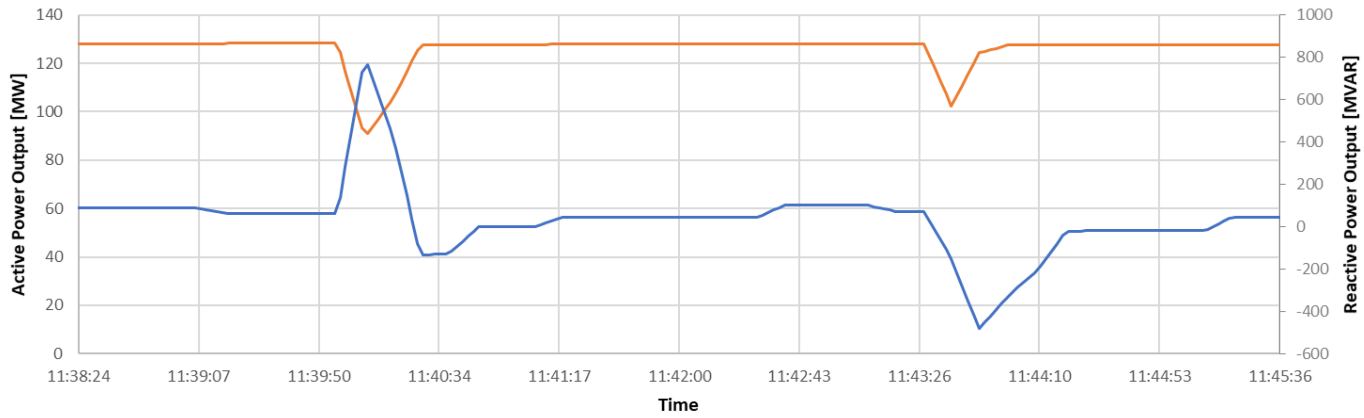


Figure B.7: Plant M Active Power Output

Plant N

This plant is a 20 MW facility with a commercial operation date of January 2018. It consists of inverters that the GO stated "will continue to operate and inject the power factor and active current as issued by the [inverter] control loop," indicating that the facility does not employ momentary cessation. The GO was only able to provide 1-minute resolution data that does not provide any useful information about the dynamic behavior of the plant. Furthermore, data collected from PG&E (**Figure B.8**) shows a significant drop in active power during Event #2 with output returning to predisturbance values after about 1.5 minutes. The discrepancy between information provided by the GO and the plot of active power output do not match; however, no further analysis can be done without additional information from the GO. Regardless, the delayed recovery of active power does not meet the recommendations set forth in the NERC reliability guidelines.

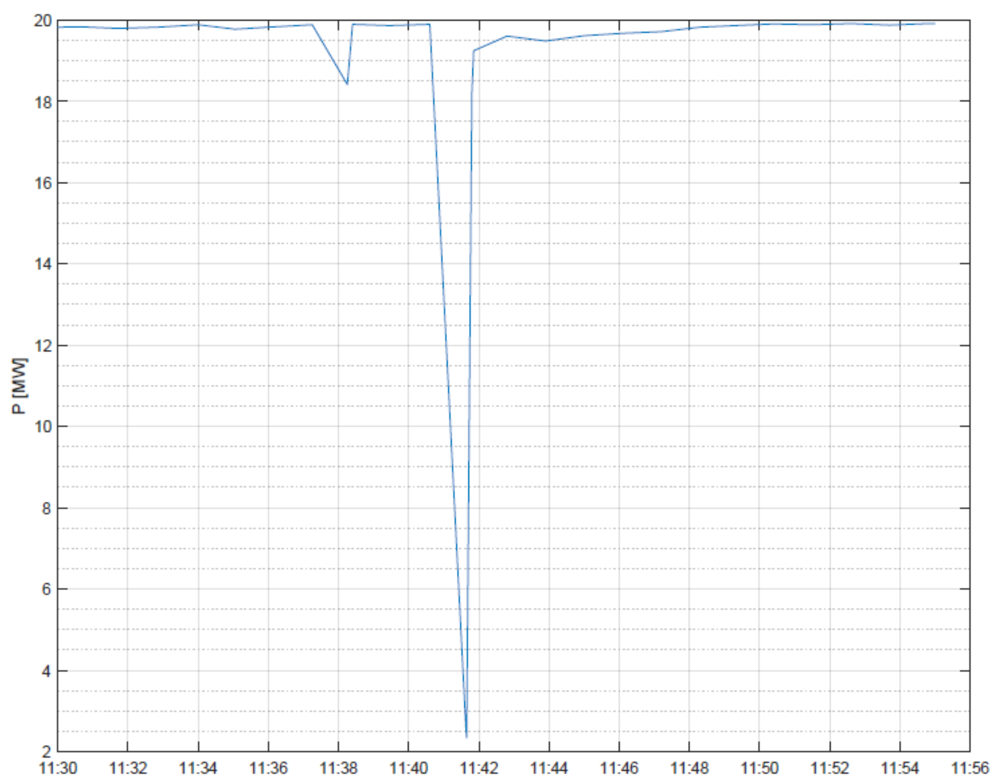


Figure B.8: Plant N Active Power Output

Plant O

This plant is a 26 MW facility (limited to 20 MW at POI) that went into commercial operation in December 2017. The majority of inverters at the facility tripped on dc low voltage during Event #2 and required manual reset to return to service. Figure B.9 shows the reduction of active power near the event and long-term recovery after the inverters had been reset.

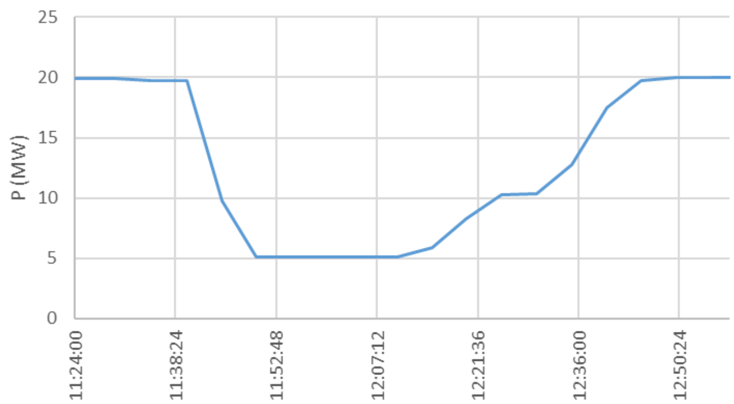


Figure B.9: Plant O Active Power Output

Plant P

This plant is a 20 MW facility that went into commercial operation December 2019 and is comprised of inverters that use momentary cessation. During this disturbance, 32 inverters entered momentary cessation and 4 inverters tripped on ac low voltage (see Figure B.10). Momentary cessation settings include a low voltage threshold of 0.86 pu, a return to service delay of 2 cycles, and an active power ramp rate of 50% per second. However, the data provided by the facility showed that the active power returned to predisturbance levels after roughly 10 seconds. Furthermore, the trip setting indicates low voltage was observed for greater than 10 cycles; however, the entity could not determine the trip threshold and received little response from the inverter manufacturer to support these efforts.

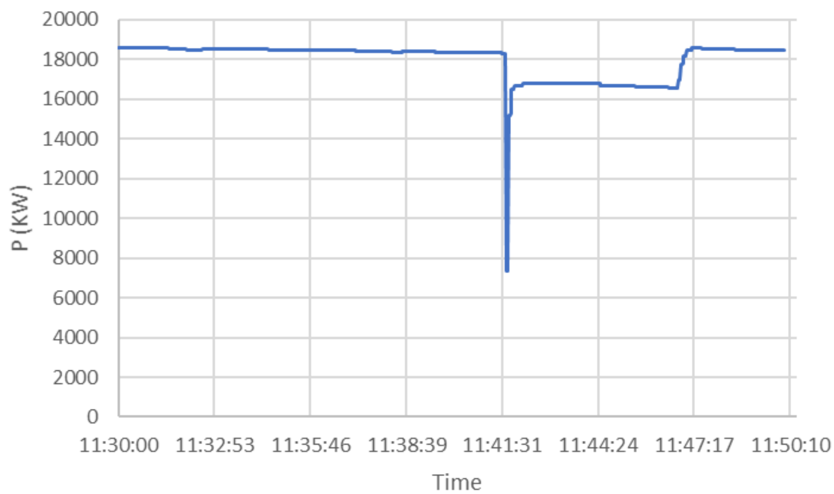


Figure B.10: Plant P Active Power Output

Plant Q

This plant is a 172 MW facility that went into commercial operation in June 2012 (Phase 1) and April 2015 (Phase 2) consisting of some inverters that used momentary cessation and other that did not. During this disturbance, 17 inverters entered momentary cessation. The momentary cessation settings at the time of the event were set to a 0.9 pu low voltage threshold, a 50 ms time delay to start recovery, and a 25%/second active power recovery ramp rate. The settings on these inverters are adjustable and momentary cessation can be eliminated. At the time of this disturbance, the GO or GOP had not made any changes as recommended in the NERC reliability guidelines or NERC alerts, hence the reduction of active power and recovery in about 4 seconds during this event (see **Figure B.11**).[32] However, after NERC and WECC discussions with the facility, the GO and GOP have changed the settings at this facility to use reactive current injection during fault events rather than momentary cessation.

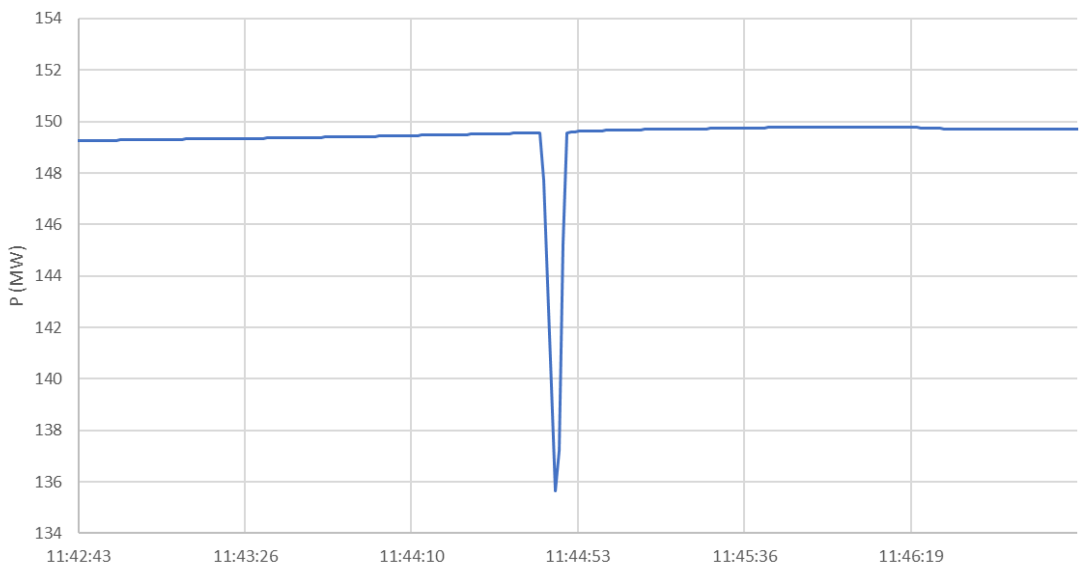


Figure B.11: Plant Q Active Power Output

Small Plants

Many other solar PV facilities responded to the fault events described in this report. Many of these facilities are non-BES solar PV generating resources that had a noticeable effect on BPS performance in aggregate. **Figure B.12** shows two examples of these facilities and the response from them. It is clear that they mirror the responses of the larger solar PV facilities; this is to be expected since the inverter manufacturer, make, and model are likely similar. The most common reduction of solar PV, as shown in **Figure B.12**, is caused by inverters entering momentary cessation and returning to service on the order of multiple minutes. Again, this is not the recommended performance of BPS-connected solar PV per the NERC reliability guidelines.

[32] The time stamp reported by the GO is off.

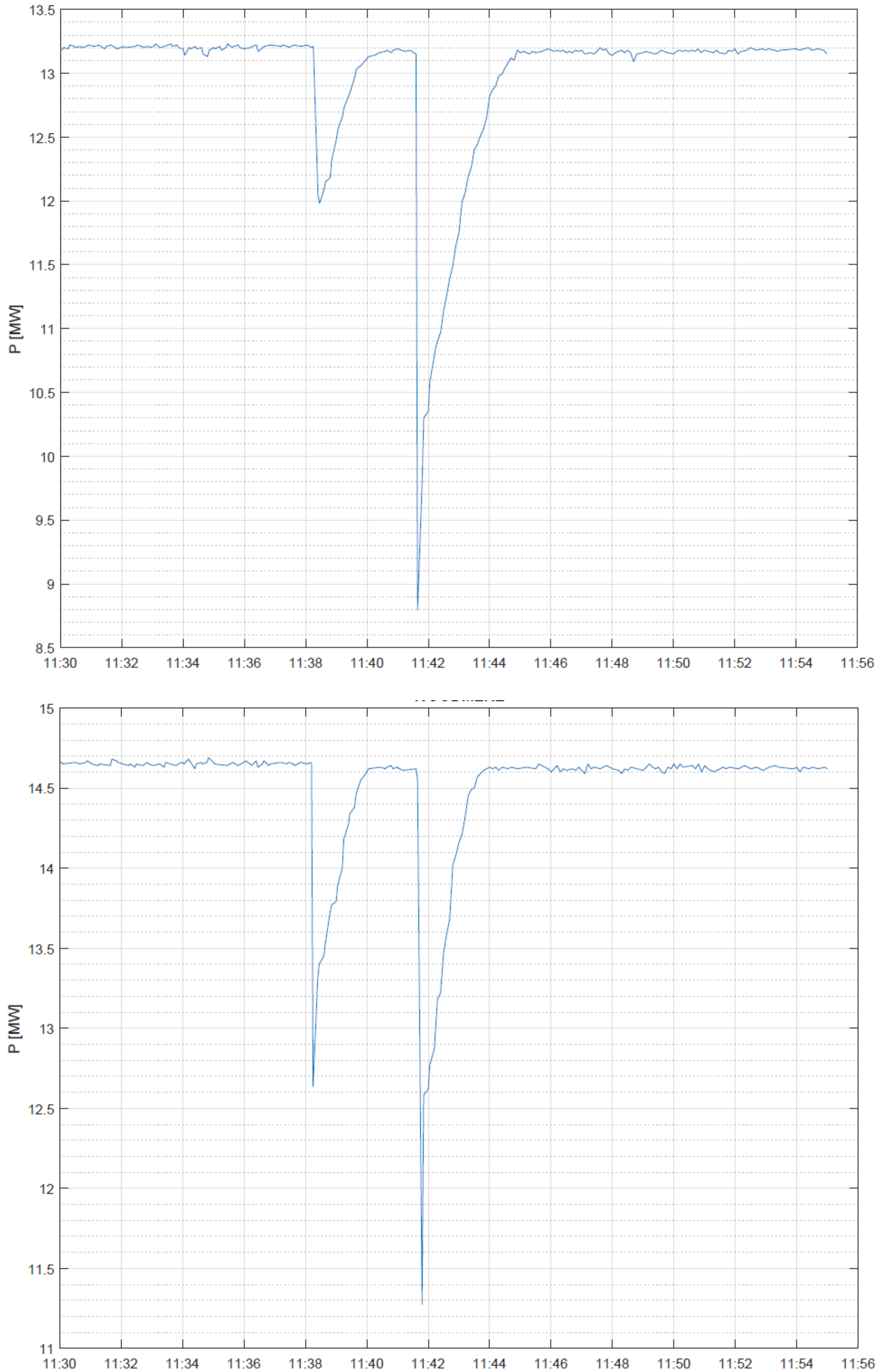


Figure B.12: Active Power Output from Two Smaller Solar PV Facilities during the Disturbance