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NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

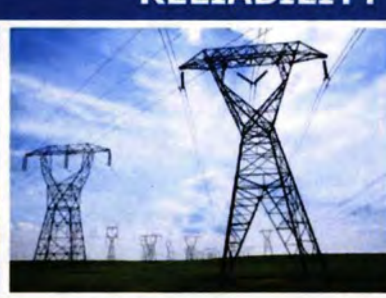
1,200 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report

Southern California 8/16/2016 Event

June 2017

RELIABILITY | ACCOUNTABILITY



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Current draft in bold

Table of Contents

Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to assure the reliability of the bulk power system (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

The North American BPS is divided into the eight Regional Entity (RE) boundaries, as shown in the map and corresponding table below.

The Regional boundaries in this map are approximate. The highlighted area between SPP and SERC denotes overlap as some load-serving entities participate in one Region while associated transmission owners/operators participate in another.

FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	Reliability First
SERC	SERC Reliability Corporation
SPP RE	Southwest Power Pool Regional Entity
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Executive Summary

This report contains the ERO analyses of the Blue Cut Fire, a system disturbance that occurred in the Southern California area on August 16, 2016. This report was prepared by a NERC/WECC joint task force that was assembled by the NERC Operating Committee (OC) to analyze this disturbance, determine the causes, and develop key findings and recommendations to ensure that occurrences such as this one are mitigated throughout the North American BPS.

On August 16, 2016, at 10:36 a.m. Pacific, the Blue Cut fire began in the Cajon Pass, just east of Interstate 15. The fire quickly moved toward an important transmission corridor that is comprised of three 500 kV lines owned by Southern California Edison (SCE) and two 287 kV lines owned by Los Angeles Department of Water and Power (LADWP). By the end of the day, the SCE transmission system experienced thirteen 500 kV line faults, and the LADWP system experienced two 287 kV faults as a result of the fire. Four of these fault events resulted in the loss of a significant amount of solar photovoltaic (PV) generation. The most significant event related to the solar PV generation loss occurred at 11:45 a.m. Pacific and resulted in the loss of nearly 1,200 MW. There were no solar PV facilities de-energized as a direct consequence of the fault event; rather, the facilities ceased output as a response to the fault on the system.

2016 Key Findings and Recommendations:

- **Key Findings:** Inverters that trip instantaneously based on near instantaneous frequency measurements are susceptible to erroneous tripping during transients generated by faults on the power system.

  Recommendations: Inverter manufacturers that experienced this type of tripping during the Blue Cut fire event have recommended changes to their inverter settings to avoid this erroneous tripping; this change will add a time delay to inverter frequency tripping that will allow the inverter to "ride through" the transient/distorted waveform period without tripping. Solar development owners and operators involved in this event are working with their inverter manufacturers, California Independent System Operator (CAISO), and SCE to develop a corrective action plan for implementation of changes to inverter parameters.

- **Key Findings:** The majority of currently installed inverters are configured to momentarily cease current injection for voltages above 1.1 per unit or below 0.9 per unit. During the Blue Cut fire event, some inverters that went into momentary cessation mode returned to pre-disturbance levels at a slow ramp rate.

  Recommendations: Inverters that momentarily cease output for voltages outside their continuous operating range should be configured to restore output with a delay no greater than five seconds. NERC should review PRC-024-2 to determine if it needs to be revised to indicate that momentary cessation of inverter connected resources is not allowed within the no-trip area of the voltage curves.

Additional Recommendations:

- A NERC alert should be issued to the NERC registered Generator Owners (GOs) and Generator Operators (GOPs) to ensure they are aware of the recommended changes to inverter settings and alert them of the risk of unintended loss of resources. This alert should include a recommendation for Balancing Authorities (BAs) and Reliability Coordinators (RCs) to assess the reliability risk of solar PV momentary cessation and take appropriate measures. NERC should review PRC-024-2 to determine if it needs to be revised to add clarity that outside the frequency curves is a "may-trip" area (if needed to protect equipment) and not a must-trip area and to determine if there should be a required delay for the lowest levels of frequency to ensure transient/distorted waveform ride through.

- In-depth analysis of momentary cessation with higher penetrations of inverter connected resources is needed to determine if that should be allowed for voltages less than 0.9 per unit or greater than 1.1 per unit. More detailed benchmarking studies and analysis should be performed by the ERO Enterprise and affected BAs to determine the extent to which these potential resource loss events caused by momentary cessation or tripping could pose a reliability risk. NERC should communicate findings and recommendations in this area to the industry, regulators, and other venues.

- With the proliferation of solar development in all interconnections across North America, the results of this disturbance analysis needs to be widely communicated to the industry highlighting the present potential for widespread solar resource loss during transmission faults on the BPS. The NERC alert, along with further study and outreach, will assist the industry in taking steps to resolve this issue and ensure interconnection reliability.

The task force included members from NERC, WECC, FERC, affected registered entities involved in the event, industry subject matter experts in the area of inverter-based resources, and inverter manufacturer representatives; the task force was formed to capitalize on the technical expertise of all of these organizations. Data and information about the event were gathered from the affected registered entities involved in the disturbance, and this was instrumental to the successful and timely completion of this analysis. This report uses terminology that is aligned with the latest draft of IEEE 1547,[1] which is currently under revision and will also assist in addressing this issue.

[1] IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems
http://grouper.ieee.org/groups/scc21/1547/1547_index.html

Chapter 1: Event Summary

On August 16, 2016, at 10:36 a.m. Pacific, the Blue Cut fire began in the Cajon Pass, just east of Interstate 15. The fire quickly raced toward an important transmission corridor that is comprised of three 500 kV lines owned by Southern California Edison (SCE), and two 287 kV lines owned by Los Angeles Department of Water and Power (LADWP). **Figure 1.1** shows a high-level map of the affected area and location of the Blue Cut fire and transmission fault event.

Figure 1.1: Map of the Affected Area and Blue Cut Fire Location

By the end of the day, the SCE transmission system experienced thirteen 500 kV line faults and the LADWP system experienced two 287 kV faults as a result of the fire. Four of these fault events resulted in the loss of a significant amount of solar PV generation.

The most significant event, which occurred at 11:45 a.m. Pacific, resulted in the loss of nearly 1,200 MW of solar PV generation. This value was determined by SCE's supervisory control and data acquisition (SCADA) system, which has a sampling rate of approximately 1 sample/4 seconds. It is possible that there was a larger loss of resources that was not captured due to the SCADA sampling rate. There were no solar PV facilities de-energized as a direct consequence of the fault event; rather, the facilities ceased output as a response to the fault on the system. SCE analyzed the net load response and determined that no noticeable amount of distributed energy resources (DERs)[2] tripped due to the fault on the BPS; this analysis focused solely on the solar PV generation connected to the BPS.

The Western Interconnection frequency reached its lowest point of 59.867 Hz, shown in **Figure 1.2**. The frequency recovered about seven minutes (420 seconds) later (not shown in **Figure 1.2**). Notice the second frequency graph is of a smaller time frame to accent the primary frequency response characteristics (**Table 1.1**).

[2] DERs, in this statement, are referring to resources connected at the distribution voltage level.

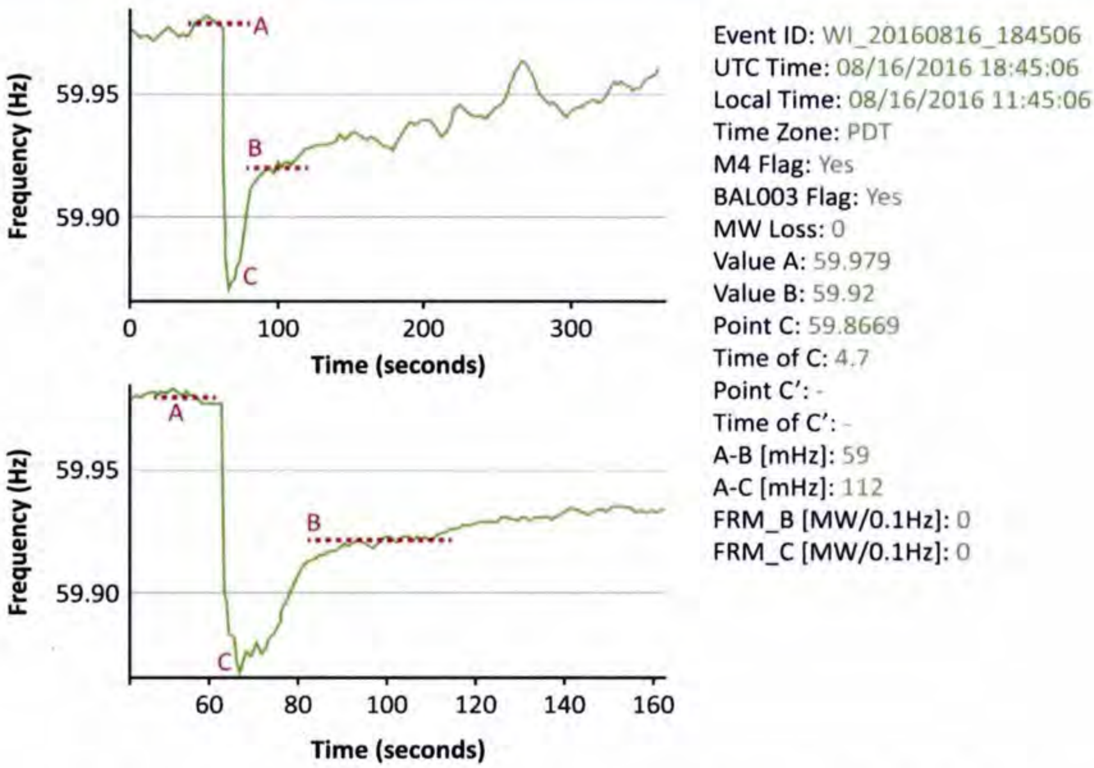

Figure 1.2: Western Interconnection Frequency during Fault

All of the line faults caused by the fire cleared normally with roughly the same fault clearing time and fault magnitude. Of the 15 faults, four caused a loss of PV generation as shown in **Table 1.1**.

Table 1.1: Solar Photovoltaic Generation Loss

Event No.	Date/Time	Fault Location	Fault Type	Clearing Time (cycles)	Lost Generation (MW)	Geographic Impact
1	8/16/2016 11:45	500 kV line	Line to Line (AB)	2.49	1,178	Widespread
2	8/16/2016 14:04	500 kV line	Line to Ground (AG)	2.93	234	Somewhat Localized
3	8/16/2016 15:13	500 kV line	Line to Ground (AG)	3.45	311	Widespread
4	8/16/2016 15:19	500 kV line	Line to Ground (AG)	3.05	30	Localized

Event No. 1 was particularly impactful because of the widespread loss of 1,178 MW of PV generation. Approximately 66 percent of the generation lost in that event recovered within about five minutes. Three PV plants had a sustained loss of 400 MW that did not return until the following day, reportedly due to curtailment orders from the BA.

Figure 1.3 shows the reduction in solar output for the four events on August 16. It is noteworthy to point out that the solar production did not return to its pre-disturbance level after the 11:45 Pacific event; this was largely due to the three PV plants that reported the 400 MW of curtailments issued to them. It is possible that the subsequent three events could have had larger resource losses if those curtailments had not been in place.

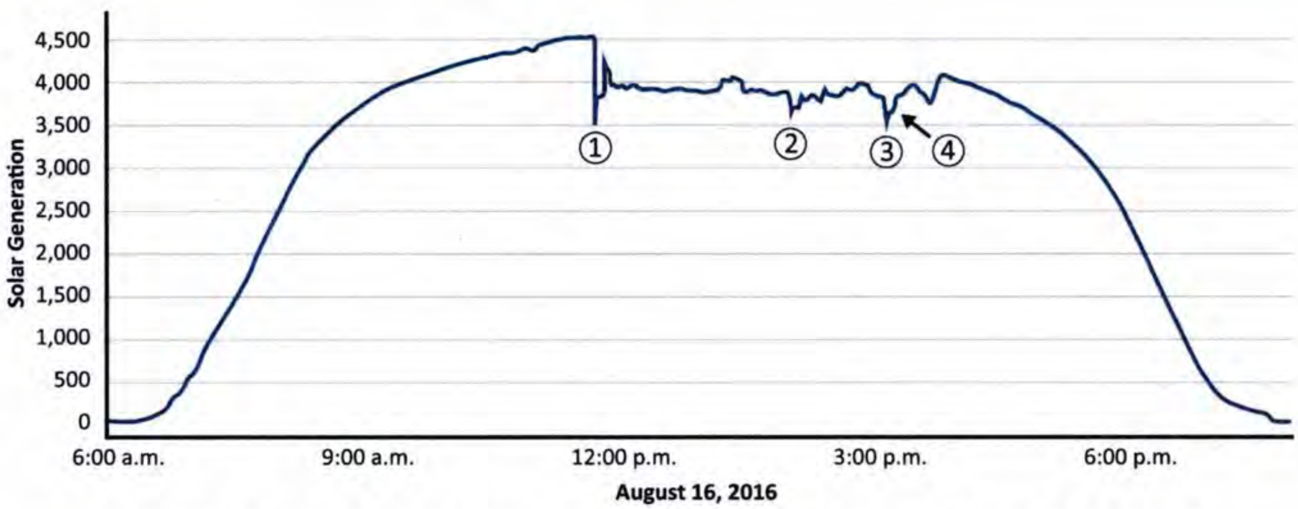

Figure 1.3: Utility-Scale Solar PV Output in SCE Footprint on August 16, 2016

The August 16 event illuminated the issue of inverter disconnects during faults. Now aware of the potential for this action, SCE/CAISO discovered that this was not an isolated incident. Including the August 16 events, SCE/CAISO determined that this type of inverter disconnect has occurred eleven times between August 16, 2016, and February 6, 2017, as shown in **Table 1.2**.

Table 1.2: Fault Event Information

Event No.	Date/Time	Fault Location	Fault Type	Clearing Time (cycles)	Lost Generation (MW)	Geographic Impact
1	08/16/2016 11:45	500 kV line	Line to Line (AB)	2.49	1,178	Widespread
2	08/16/2016 14:04	500 kV line	Line to Ground (AG)	2.93	234	Somewhat Localized
3	08/16/2016 15:13	500 kV line	Line to Ground (AG)	3.45	311	Widespread
4	08/16/2016 15:19	500 kV line	Line to Ground (AG)	3.05	30	Localized
5	09/06/2016 13:17	220 kV line	Line to Ground (AG)	2.5	490	Localized
6	09/12/2016 17:40	500 kV line	Line to Ground (BG)	3.04	62	Localized
7	11/12/2016 10:00	500 kV CB	Line to Ground (CG)	2.05	231	Widespread
8	02/06/2017 12:13	500 kV line	Line to Ground (BG)	2.97	319	Widespread
9	02/06/2017 12:31	500 kV line	Line to Ground (BG)	3.01	38	Localized
10	02/06/2017 13:03	500 kV line	Line to Ground (BG)	3.00	543	Widespread
11	05/10/2017 10:13	500 kV line	unknown	unknown	579	Somewhat Localized

Knowing that this was not an isolated incident and considering the rapid increase in solar installations in the CAISO Balancing Authority area (BAA), it was determined that these types of inverter disconnect events could be a potential reliability risk that need to be analyzed and mitigated.

Causes of the PV Resource Interruption

Based on information provided by the inverter manufacturers, solar development owners and operators, SCE, and the CAISO; it was determined that the largest percentage of the resource loss (~700 MW[3]) was attributed to a perceived, though incorrect, low system frequency condition that the inverters responded to by "tripping" (cease to energize and not return to service for a default duration of five minutes or later). The perceived low frequency was due to a distorted voltage waveform caused by the transients generated by the transmission line fault. The inverters were configured to trip in 10 milliseconds for frequencies less than or equal to 57 Hz. The Curve Data Points section of PRC-024-2[4] indicates an instantaneous trip for frequencies less than or equal to 57 Hz for the Western Interconnection. This has led to many inverter manufacturers believing that they must trip instantaneously for that level of frequency.

The second largest significant contributor (~450 MW) was determined to be inverter momentary cessation due to system voltage reaching the low voltage ride-through setting of the inverters. Momentary cessation is when the inverter control ceases to inject current into the grid while the voltage is outside the continuous operating voltage range of the inverter. The inverter remains connected to the grid but temporarily suspends current injection. When the system voltage returns within the continuous operating range, the inverter will resume current injection after a short delay (typically 50 milliseconds, or msec, to one second)[5] and at a defined ramp rate.[6] Some organizations (inverter manufacturers) refer to this operation as ride through or momentary cessation, which is fundamentally different from the conventional understanding of the term "ride through." In the August 16 ~1,200 MW loss event, many inverters momentarily ceased current injection. The time to return to pre-disturbance values (restoration of output) was a ramp of approximately two minutes. (11:45:15 to 11:47:15). **Figure 1.4** shows this as the percentage increases gradually after the initial event.

[3] All MW loss quantities in this report are based on SCADA measurements. SCADA measurement scan rates are typically greater than two seconds. Due to the quick time in which inverter momentary cessation and restore output can occur coincident with a fault, some of those occurrences could be missed by SCADA measurements. As such, the MW loss values in this report could be lower than what actually occurred during the events. Additionally, there could be events that are overlooked because SCADA does not register any losses for that event.

[4] http://www.nerc.com/pa/Stand/Reliability%20Standards/PRC-024-2.pdf

[5] These are the default settings of the inverter

[6] Some inverters have a settable ramp rate. Others have a fixed ramp rate that is not easily configurable.

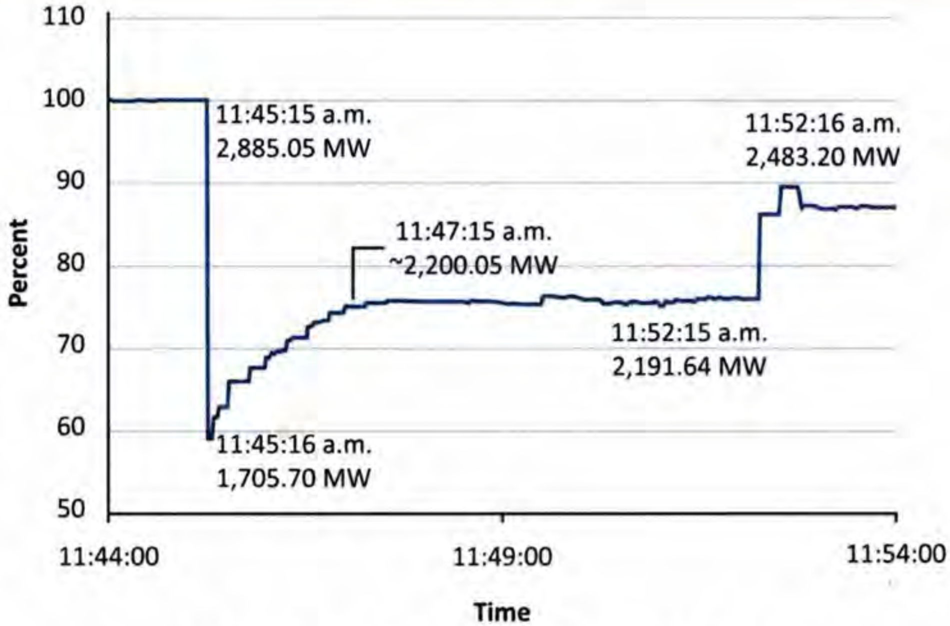

Figure 1.4: SCE Solar Resource Output SCADA Graph

Inverters have three basic modes of operation: Continuous Operation, Momentary Cessation, and Trip.

- **Continuous Operation:** An operating mode where inverters are actively injecting current into the grid.
- **Momentary Cessation:** A mode where inverters have momentarily ceased injecting active current into the grid but remain electrically connected; this mode is triggered by abnormal system voltages (< 0.9 or > 1.1 per unit).
- **Trip (Cease to Energize):** A mode where inverters have ceased injecting current and will delay returning to service (typically a five-minute delay). They may also mechanically disconnect the inverter from the grid.

Some inverter manufacturers and Generator Owners have interpreted the no-trip area of the PRC-024-2 curves to allow momentary cessation. Some transmission service providers include in their generator interconnection agreements language that allows momentary cessation during voltages less than 0.9 per unit or above 1.1 per unit. This contributes to the interpretation that momentary cessation is allowed in the PRC-024-2 no-trip area.

The third largest amount of loss was approximately 100 MW that tripped by inverter dc overcurrent protection after starting the momentary cessation operation. The exact cause of these inverters tripping has not been determined and is still under investigation by the manufacturers.

Of the two types of interruption, tripping and momentary cessation, tripping is the most impactful as it removes the resource from the interconnection for approximately five minutes. If momentary cessation is restored quickly, the frequency decline is less severe than an equivalent MW amount of tripping.

Impacted Area

Losing generating resources impacts the interconnection where the resources reside. A balance between generation and load is needed to maintain interconnection frequency near a nominal value of 60 Hz. An interconnection is comprised of BAs that balance generation and load within their individual BAAs. BAs plan for resource loss contingencies by having enough resources in reserve to cover their most severe single contingency

(MSSC). During a resource loss, an interconnection will arrest the frequency decline (due to load/resource imbalance) by deploying automatic primary frequency responsive reserves. The frequency will settle at a value lower than nominal frequency after this arresting period. The BA that experienced the resource loss then has to deploy their contingency reserves within their BAA to recover the frequency back to nominal. If there is widespread loss of resources during a single transmission fault, that loss may exceed the resource contingency criteria (RCC) of the interconnection and/or MSSC of the BA. Resource losses much greater than the RCC of the interconnection could trigger underfrequency load shedding (UFLS). As such, widespread losses of resources need to be avoided.

This event occurred in the CAISO BA area (See **Figure 1.5**). The CAISO balancing area has experienced a rapid growth of solar photovoltaic (PV) resources in the recent past. CAISO has recorded a peak of 9,800 MW of utility scale solar[7] PV generation. During light load days, they have experienced 47 percent of the area load served by utility scale solar. This widespread disconnection of inverter connected resources is a significant concern for CAISO. Additionally, with the proliferation of solar in many balancing areas across the North America, this issue needs to be resolved to ensure interconnection reliability.

Figure 1.5: California Balancing Authority Area

[7] Utility-scale solar does not include residential rooftop solar.

Chapter 2: Inverter Loss Details

Initiating Fault

During faults on the transmission system, the normally sinusoidal voltage and current waveforms may undergo instantaneous phase shifts, a sag in transmission voltage, and harmonic distortion. **Figure 2.1** shows the three-phase voltage waveform distorted from the four phase shifts in the disturbance.

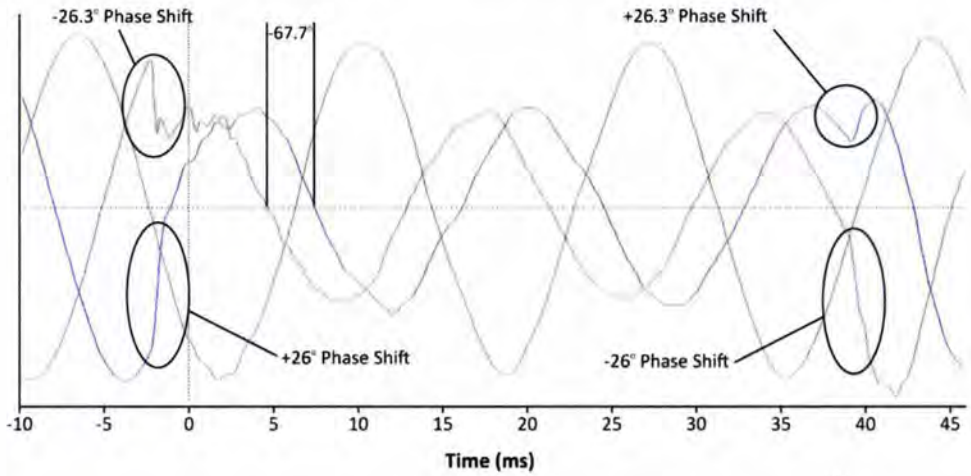

Figure 2.1: Distortion of the Sine Waves

This instantaneous phase shift in the waveform is often referred to as a "phase-jump." This phase-jump and distortion of the sine wave (**Figure 2.1**) can create near instantaneous large deviations in calculated frequency. This phenomenon is amplified during phase-to-phase (LL) faults as the two faulted phases have a phase-jump as they pull toward each other. As electrical distance from the fault increases, the phase-jump will be less pronounced. The analysis of events from August 16 showed that the most significant loss was in response to a LL fault. However, as can be seen in **Table 1.2**, there have been significant losses in response to single-line-to-ground (SLG) faults as well. **Table 1.2** shows that all of the faults were cleared in less than 3.5 cycles (58.3 msec), and for the most significant event, the fault was cleared in 2.5 cycles (41.7 msec). **Figure 2.2** shows the oscillography record of the 500 kV fault, indicating the phase-to-phase fault and the clearing time of 2.5 cycles.

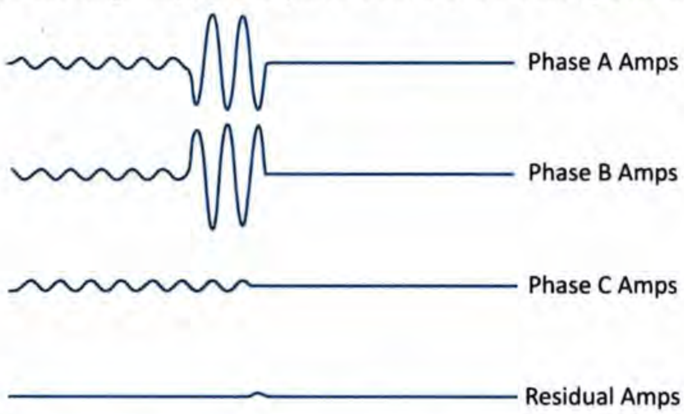

Figure 2.2: Oscillography Record of the 500 kV Fault

Analysis and Findings

The analysis revealed that the largest percentage of inverter loss (~700 MW) was due to the inverter phase lock loop (PLL) control detecting a frequency less than 57 Hz and initiating an instantaneous inverter trip. Frequency measuring network (FNET) data from this disturbance (see **Figure 2.3**) shows that the Western Interconnection frequency did not actually reach 57 Hz; the lowest recorded frequency only dropped to 59.867 Hz before arresting and recovering. Near instantaneous frequency change measurement of localized fault voltage waveforms does not always exactly represent the true system frequency. To ensure that a more accurate representation of the system frequency measurement is used for inverter controls, a minimum delay for frequency detection and/or filtering should be implemented.

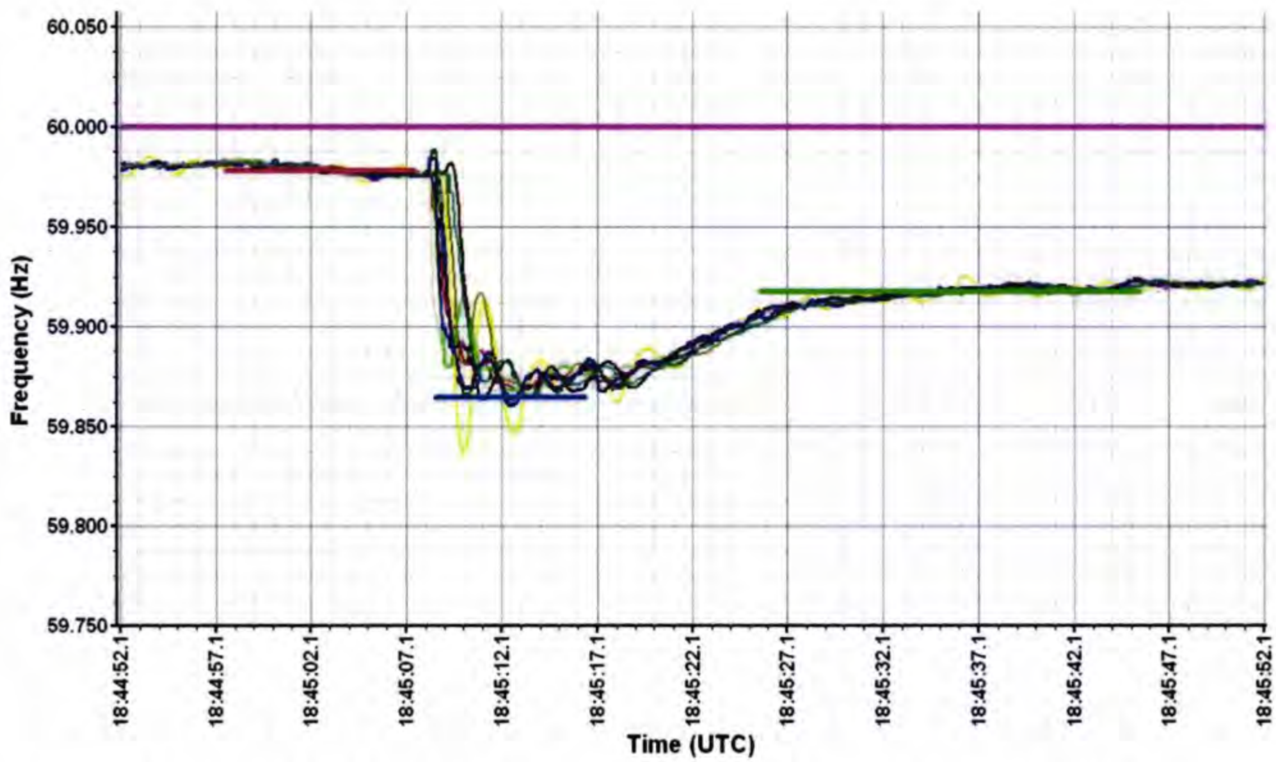

Figure 2.3: FNET Data for Large Resource Loss Event (August 16, 2016)

The inverter manufacturers used digital fault recorder (DFR) records of the point-on-wave data from the disturbance, collected from transmission substations that captured the fault, to play back into their inverters as a simulation. The inverter response from the simulations showed that one particular inverter model indicated the frequency, as measured by the PLL, was much lower than the actual system frequency; the indicated frequency was very close to the configured 57 Hz underfrequency trip setting. It was determined that the PLL detected frequency during the transient and acted instantaneously to trip for frequency below 57 Hz (or above 63 Hz). Once the inverters tripped, they are set to verify that the inverter terminal voltage and frequency are within normal operating limits for about five minutes before automatically returning to service. This is a recommendation of IEEE 1547[8] to which distribution-connected inverters must comply. This inverter manufacturer and CAISO have agreed to implement a five-second delay for underfrequency tripping and a two-second delay for over-frequency tripping to ensure against unintended tripping. Further, they have agreed to a 150-second restarting delay after tripping to mitigate the impact of a future event that may cause tripping. They are working with the solar development owners to develop a corrective action plan for implementation of these changes.

[8] http://grouper.ieee.org/groups/scc21/1547/1547_index.html

The second largest loss of resource (~450 MW) was due to momentary cessation caused by low voltage. Many of the transmission-connected inverters in service are configured to momentarily cease current injection for voltages less than 0.9 per unit or greater than 1.1 per unit. They resume current injection quickly after the system voltage returns to a value between 0.9 and 1.1 per unit. The inverter will then ramp up to their currently available power at a configurable ramp rate. During the disturbance, approximately 450 MW of inverters momentarily ceased to inject current for low voltage. Then, over a period of approximately two minutes, they ramped back to pre-disturbance levels.

Now knowing that most currently installed inverters momentarily cease current injection during low voltage periods, the task force was concerned with the impact that momentary cessation could have on the interconnection with respect to frequency decline during a transmission line fault. A sub-group of the task force undertook simulations to determine the risk and determine minimum times for inverters to restore output to avoid frequency excursions that would approach UFLS. The group performed simulations of inverter momentary cessation and tripping scenarios under high penetrations of solar PV in the California region. Sensitivity analysis was performed to determine the momentary cessation and restore output characteristics that would mitigate any near-term reliability impacts for the BPS in the Western Interconnection. The goal was to provide a rough quantification of the following: 1) the amount of resource loss due to solar PV momentary cessation that could be experienced due to a transient low-voltage condition, 2) the Western Interconnection frequency response characteristic under these scenarios, and 3) the time to triggering the first stage UFLS to understand any potential future performance requirement considerations. The simulations showed that approximately 7,200 MW of inverter busses could see a voltage less than 0.9 per unit for a transmission fault. The group then ran simulations with those inverters restoring output at different ramp rates; it was determined that the maximum delay to restore output to pre-disturbance levels should be five seconds. The sub-group determined that these conservative limits would provide enough margin to ensure UFLS would be avoided for momentary cessation of inverters in response to transmission faults. A full description of the simulations can be found in Appendix A of this report.

Continued analysis needs to be performed with respect to momentary cessation of inverter connected resources in response to voltage excursions. As higher penetrations of inverter connected resources are connected and serving load, the impact of a large amount of utility scale transmission connected resource ceasing to provide power during voltages less than 0.9 per unit or above 1.1 per unit should be fully understood. If it is determined that current injection is required, it needs to be determined when reactive current should be injected.

Going forward, any inverters that are connected to the grid should have the capability to continuously inject active or reactive current during abnormal voltages. Then if it is determined that continuous current injection is required, those inverters will already have the capability.

It has been indicated by at least one manufacturer that a large percentage of their currently installed inverters (40 percent) would need major modification or possibly replacement to not momentarily cease current injection for voltages below 0.9 per unit. Providing current during a voltage dip is a function of software (control algorithms, PLL settings, PLL sensitivity, etc.) and hardware (control power supplies, analog inputs, etc.) Legacy inverters from different manufacturers may have different limitations in providing current during voltage excursions below 0.9 per unit. In some cases, the hardware may not be compatible, in other cases new software will have to be developed and tested. In many cases, new design personnel may have to pick up, analyze, and build on the original designs. Dismantled test labs that were used to certify the inverter five years ago may have to be built again. Additionally, there are some inverters in service whose manufacturer is no longer in business. Due to these obstacles, inverter replacement may be the only option. If the inverter happens to be using a dc voltage that is no longer available, an entire reconfiguration of the PV panels would be required to accommodate the different dc voltage. These limitations should be considered before requiring legacy facilities to continuously inject current during abnormal voltages.

Approximately 100 MW of solar resources tripped on inverter dc overcurrent protection after starting the momentary cessation operation. The exact cause of those inverters tripping has not been determined and is still under investigation by the manufacturers. Once the root cause is found, the manufacturers should take the appropriate steps to ensure there are no reoccurrences in the future.

Discussion of Contributing Factors

There are two predominant industry standards that relate to inverter operation. NERC Reliability Standard PRC-024-2 and IEEE Standard 1547. NERC PRC-024-2 outlines voltage and frequency relay setting requirements for generating resources that are classified as BES (this includes synchronous and asynchronous resources). The PRC-024-2 standard went into effect on June 1, 2016. IEEE 1547 is a standard that applies to inverters connecting to the distribution system; it was created in 2003 and was modified in 2014 to permit ride through. Major revisions have been completed by the IEEE P1547 working group.[9] Balloting of this IEEE working group's proposed revised IEEE 1547 standard was scheduled to begin before the end of May 2017 and will proceed through the summer. This proposed revision to IEEE 1547 includes the 2014 amendment changes to the current IEEE 1547-2003 standard and adds other relevant aspects to this task force's areas of interest, including the following:

- Removal of the existing 10 MW limitation
- Add minimum reactive power capacity—kW to kVA ratings
- Add minimum VAR controls mode capabilities
- Add minimum ride through for defined system voltage, frequency deviation, and frequency deviation duration
- Add frequency responsive attributes, for response to abnormal system frequencies
- Update or add new definitions for many relevant terms, including cease to energize, trip, etc.
- Add requirements for minimum measurement accuracy

The specifics (e.g., minimum VAR/PF values, ride-through limit values) are contingent on the pending balloting and comment resolution process for approval of the proposed revision to IEEE 1547. The information provided by this NERC task force report is timely for the IEEE P1547 working group's consideration in making final comment resolution edits to the pending full revision of IEEE 1547.

Additionally, there are other items that influence the inverter operating capabilities: Underwriter Laboratories (UL) 1741 specifies testing requirements to obtain the UL 1741 certification, and, the state of California has implemented its CA Rule 21 that dictates, within the state of California, requirements for inverters connecting to the distribution system. This CPUC-approved tariff rule used by CA investor-owned utilities, and which is applicable to retail electric customer resources, was updated to add the Phase II recommendations of the CA Smart Inverter Working Group[10] (SWIG Ph. II); the SWIG Ph. II "smart inverter" functions include ride through. UL has added a supplement to UL 1741 (UL-1741 SA)[11] to include these recent updated CA Rule 21 requirements to the UL 1741 test-based certification of key IEEE 1547 requirements.

[9] http://grouper.ieee.org/groups/scc21/1547_revision/1547revision_index.html

[10] http://www.energy.ca.gov/electricity_analysis/rule21/

[11] http://www.ul.com/newsroom/pressreleases/ul-launches-advanced-inverter-testing-and-certification-program/

In addition to these standards, generator interconnection agreements (GIAs) also govern generator operation. GIAs are documents that are executed between the Transmission Service Provider, the GO, and sometimes the BA.[12] These GIAs routinely contain language that provides requirements with respect to generator operation. GIAs are specific to each generator interconnection and can be different for each individual interconnection.

The PRC-024-2 standard that went into effect June 1, 2016, is a protective relay setting standard. It prescribes that protective relays that trip for under/over voltage and that the frequency be set "such that generating units remain connected during defined frequency and voltage excursions." PRC-024-2 uses language that is more common for conventional synchronous rotating ac generators with traditional protective relays. Inverter-based resources do not typically use traditional protective relay, and they operate very differently than conventional synchronous rotating ac machines. At a high level, inverters have the following three operating modes:

- **Continuous Operation**: An operating mode where they are actively injecting current into the grid
- **Momentary Cessation:** A mode where they have momentarily ceased injecting active current into the grid but remain electrically connected. This mode is triggered by abnormal system voltages (< 0.9 or > 1.1 per unit)
- **Trip mode (Cease to Energize):** A mode where the inverters have ceased injecting current and will delay returning to service (typically a five-minute delay). They may also mechanically disconnect the inverter from the grid

PRC-024-2 specifies a no-trip area for voltage and frequency excursions. Solar development owners and inverter manufacturers have articulated that they do not treat the no-trip area as a "no momentary cessation" area and may use momentary cessation within the no-trip area. PRC-024-2 should be reviewed to see if specific language is needed to indicate that the no-trip area refers to mandatory continuous current injection. For grid stability/reliability, especially with increasing penetrations of inverter connected resources, it may be critical that momentary cessation not occur in the no-trip area. In addition, the use of "instantaneous trip" in Table 2.1 in the PRC-024-2 standard have led solar development owners and inverter manufacturers to believe that outside of the no-trip area is a required must-trip area. PRC-024-2 should be reviewed to consider inverter behavior and ensure necessary performance in both no-trip and must-trip areas. See **Figure 2.4** and **Figure 2.5**.

[12] CAISO has recently adopted three party GIAs between the Generator Owner, the Transmission Owner, and CAISO.

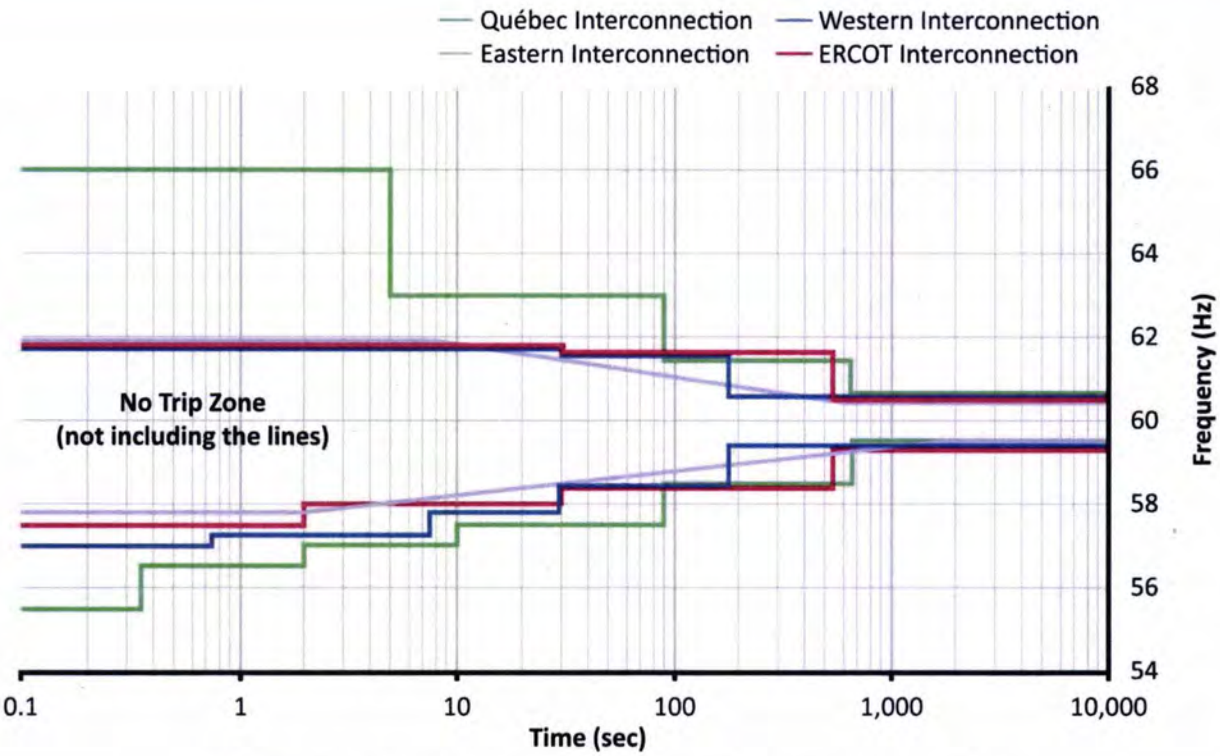

Figure 2.4: PRC-024-2 Frequency Ride-Through Curves

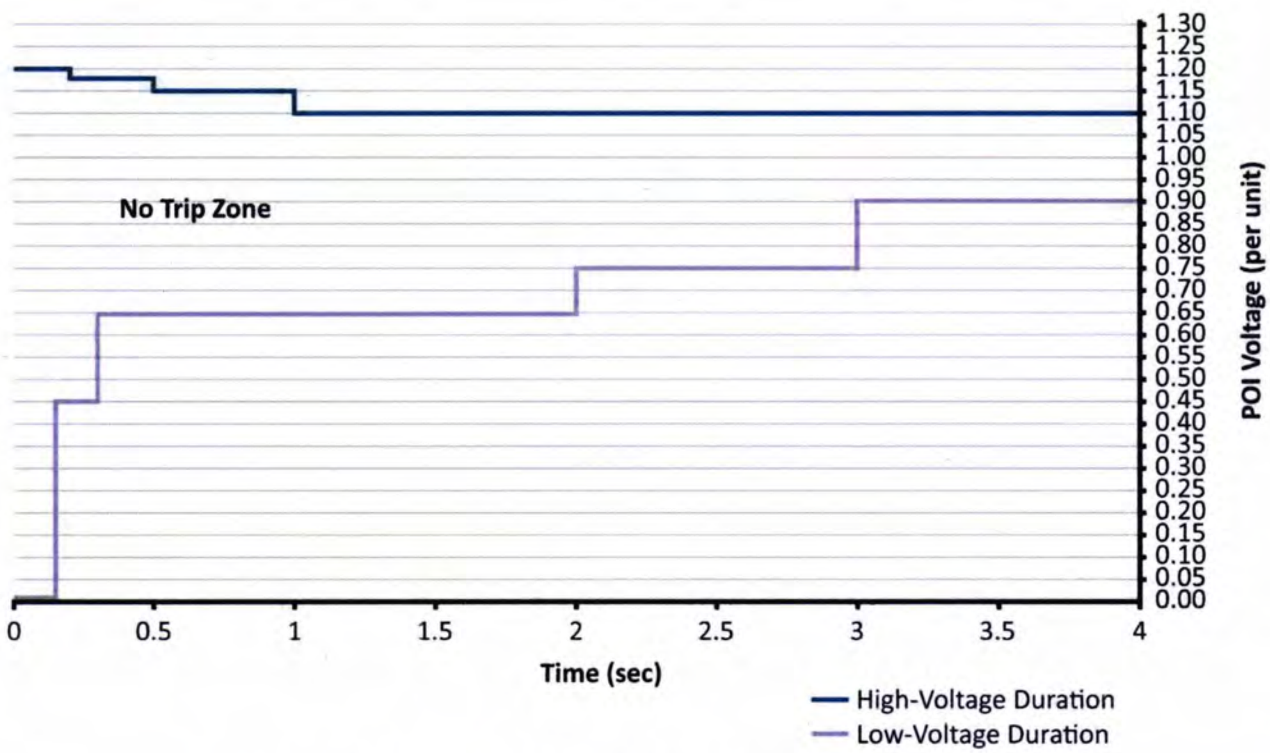

Figure 2.5: PRC-024-2 Voltage Ride-Through Curves

Table 2.1: PRC-024-2 Frequency Trip Tables

Eastern Interconnection			
High Frequency Duration		**Low Frequency Duration**	
Frequency (Hz)	**Time (sec)**	**Frequency (Hz)**	**Time (sec)**
≥ 61.8	Instantaneous Trip	≤ 57.8	Instantaneous Trip
≥ 60.5	$10^{(90.935-1.45713*f)}$	≤ 59.5	$10^{(1.7373*f-100.116)}$
< 60.5	Continuous Operation	> 59.5	Continuous Operation
Western Interconnection			
High Frequency Duration		**Low Frequency Duration**	
Frequency (Hz)	**Time (sec)**	**Frequency (Hz)**	**Time (sec)**
≥ 61.7	Instantaneous Trip	≤ 57.0	Instantaneous Trip
≥ 61.6	30	≤ 57.3	0.75
≥ 60.6	180	≤ 57.8	7.5
< 60.6	Continuous Operation	≤ 58.4	30
		≤ 59.4	180
		> 59.4	Continuous Operation
Quebec Interconnection			
High Frequency Duration		**Low Frequency Duration**	
Frequency (Hz)	**Time (sec)**	**Frequency (Hz)**	**Time (sec)**
≥ 66.0	Instantaneous Trip	≤ 55.5	Instantaneous Trip
≥ 63.0	5	≤ 56.5	0.35
≥ 61.5	90	≤ 57.0	2
≥ 60.6	660	≤ 57.5	10
< 60.6	Continuous Operation	≤ 58.5	90
		≤ 59.4	660
		> 59.4	Continuous Operation
ERCOT Interconnection			
High Frequency Duration		**Low Frequency Duration**	
Frequency (Hz)	**Time (sec)**	**Frequency (Hz)**	**Time (sec)**
≥ 61.8	Instantaneous Trip	≤ 57.5	Instantaneous Trip
≥ 61.6	30	≤ 58.0	2
≥ 60.6	540	≤ 58.4	30
< 60.6	Continuous Operation	≤ 59.4	540
		>59.4	Continuous Operation

Some solar PV plants in the CAISO area have GIAs that specify provisions for asynchronous generators (inverters). The GIA states: "An Asynchronous Generating Facility shall remain online for the voltage disturbance caused by any fault on the transmission grid ..." and "Remaining on-line shall be defined as continuous connection between the Point of Interconnection and the Asynchronous Generating Facility's units, without any mechanical isolation. Asynchronous Generating Facilities may cease to inject current into the transmission grid during a fault."[13] GIAs that are in conflict with NERC Standards create confusion for GOs.

The IEEE 1547 standard recommends certain operating characteristics for distribution connected resources. In the past, one of the main concerns for distribution connected generation was islanding. This emphasis on anti-islanding led to a large amount of the operating criteria in the currently approved 1547[14] to be contrary to the

[13] http://www.caiso.com/Documents/AppendixEE_LargeGeneratorInterconnectionAgreementForGIDAP_Dec19_2014.pdf

[14] IEEE 1547 is undergoing an extensive rewrite at this time

ride-through requirements of the BES. While existing IEEE 1547 and PRC-024-2 cover distinctly different jurisdictions, the requirements are inherently in conflict with each other. The philosophy for distribution connected generation has changed in the recent past to put more emphasis on ride through and smart inverter type technology. These revised philosophies are now in line with the intent of NERC PRC-024-2 with regards to ride-through capability and voltage support. If the revised IEEE 1547 goes into effect without major changes, the ride-through requirements of IEEE 1547 will be in alignment with PRC-024-2.

Many inverter manufacturers are using the IEEE 1547-2003 standard requirements, originally meant for generators less than 10 MW and connected to the distribution system as a default for control settings for inverters connected to the BES. Further, GOs are supporting this as the GOs are being required to obtain a UL listing for their equipment. Underwriter Laboratories UL 1741 testing requirements reference a large number of IEEE 1547 recommendations. In order to achieve UL 1741 certification, the inverter must demonstrate that it meets these recommendations from the existing IEEE 1547. UL 1741 is currently referencing the existing IEEE 1547 standard that is in conflict with NERC PRC-024-2. There is a newer UL 1741 Supplement A (testing and certification) that is based on California's Rule 21. While this is certainly an improvement over the UL 1741 testing and certification, the focus is still on distribution connected resources. Solar development owners are not electric utilities and therefore are subject to the National Electric Code (NEC). The NEC requires that the inverters they install have the UL 1741 certification. This means that inverters are being installed that are in conflict with NERC PRC-024-2; because they have to be UL 1741 certified. This is a challenge for solar development owners. If there were a utility-scale transmission standard that a UL 1741 testing and certification could be based on, that may alleviate this challenge.

Chapter 3: Detailed Findings, Actions, and Recommendations

Finding 1: PV Disconnect Due to Error in Frequency

A significant amount of solar PV resources disconnected due to a perceived system frequency below 57 Hz. This perceived frequency was due to the PLL indicating a near instantaneous frequency during the transient/distorted waveform period as less than 57 Hz. The solar development owner and inverter manufacturer interpreted outside of the PRC-024-2 no-trip curve area as a must-trip area. The frequency table in PRC-024-2 for the Western Interconnection indicates instantaneous trip for frequency equal to or less than 57 Hz. Therefore, the inverters were set to trip instantaneously upon seeing a frequency of 57 Hz.

Action 1

The inverter manufacturer and the affected entities are working collaboratively to develop a corrective action plan to implement a five-second time delay for low frequency tripping and a two second delay for high frequency tripping to alleviate incorrect frequency tripping due to phase-jump and sine wave distortion during transient faults on the system.

Recommendation 1a

NERC should review PRC-024-2 to determine if it needs to be revised to add clarity that outside the frequency curves are a may-trip area (if needed to protect equipment) and not a must-trip area.

Recommendation 1b

NERC should review PRC-024-2 to determine if there should be a required delay for the lowest levels of frequency to ensure transient/distorted waveform ride through.

Finding 2: Momentary Cessation Due to Low Voltage

The majority of currently installed inverters are configured to momentarily cease active current injection for voltages above 1.1 per unit or below 0.9 per unit.

Action 2

Simulations were conducted for the Western Interconnection to determine the frequency decline potential for inverters momentarily ceasing to inject active current at voltages less than 0.9 per unit. 7,200 MW of inverter connected resources were identified as a worst case value that could potentially momentarily cease to inject active current for a transmission fault.

Recommendation 2a

Inverters that momentarily cease active power output for these voltage excursions should be configured to restore output to pre-disturbance levels in no greater than five seconds, provided that the inverter is capable of these changes.

Recommendation 2b

NERC should review PRC-024-2 to determine if it needs to be revised to indicate that momentary cessation of inverter connected resources is not allowed within the no-trip area of the voltage curves.

Recommendation 2b.i

It has been indicated by some manufacturers that a large percentage of their currently installed inverters (40 percent) would need major modification or possibly replacement to not momentarily cease current injection for voltages less than 0.9 per unit or greater than 1.1 per unit.

NERC should clarify what equipment limitations PRC-024-2 Requirement R3 applies to.

Recommendation 2c

NERC should continue to perform further, in-depth analysis of momentary cessation with higher penetrations of inverter connected resources to determine if that should be allowed for voltages less than 0.9 per unit or greater than 1.1 per unit. If current injection is required, the analysis should determine what type of current (active or reactive, positive – negative - zero sequence) should be injected at what voltage levels.

Recommendation 2ci

More detailed benchmarking studies and analysis should be performed by the ERO Enterprise and affected entities to determine the extent to which these potential resource loss events caused by momentary cessation or tripping could pose a reliability risk. WECC should conduct a more detailed benchmarking effort to explore high penetration solar PV conditions and the potential for resource loss caused by momentary cessation and tripping of these resources due to transmission system fault conditions. Once a more detailed quantification of potential impact has been determined, including the amount of momentary cessation and/or tripping as well as the inverter-based resources' return from these conditions, the NERC Resources Subcommittee should consider whether any adjustments to the resource loss protection criteria are needed to protect interconnection frequency stability.

Finding 3: NERC Alert Warranted

This disturbance analysis highlights an unknown potential risk to reliability. With the proliferation of solar development in all interconnections, the results of this disturbance analysis needs to be widely communicated to the industry to alert them of the potential for widespread solar resource loss during transmission faults on the power system.

Action 3

NERC Event Analysis is developing a NERC alert that will be issued to the industry to ensure they are aware of the risks discussed herein and to ensure that they understand the steps that can be taken to mitigate these risks while potential changes to NERC Reliability Standards are being considered.

Recommendation 3a

A NERC alert should be issued to the industry to ensure they are aware of the recommended changes to inverter settings and alert them of the risk of unintended loss of resources. This alert should include a recommendation for BAs and RCs to assess the reliability risk of solar PV momentary cessation and take appropriate measures.

Finding 4: Potential Inconsistencies

GOs installing inverter connected resources, as well as the inverter manufacturers, are often facing potential inconsistencies in requirements with NERC Standards, IEEE 1547, UL 1741, National Electrical Code, GIAs, and other applicable references. Many inverter manufacturers are using the existing IEEE 1547 Standards, originally meant for generators less than 10 MW and connected to the distribution system, as a default for inverter control settings. Further, generator owners are supporting this as they are required to obtain a UL listing for their equipment. If a new standard for inverter-based operation is successfully promulgated, coordinate with UL such that it can now use this standard, written for inverter-based generation interconnected to the transmission system, as the basis for testing to obtain a UL listing.

Recommendation 4

NERC should work with FERC, IEEE, UL, the National Fire Protection Association (NFPA), and state jurisdictions to develop a solution to these conflicting requirements. A potential solution may be to develop a standard that is pertinent to inverters used for generation that will be connected to the transmission system.

Recommendation 4b

NERC should investigate the need for developing a standard that is pertinent to inverters used for generation that will be connected to the transmission system. As a minimum, this new standard could address the following:

- The use of reactive current injection into the grid instead of momentary cessation while in the voltage ride-through mode.
- Identify the method to determine the amount of reactive current injection during the voltage ride-through mode when/if it is determined that this is the preferred method of operation (current magnitude can be identified via voltage "droop," etc.
- The maximum allowed time to return to normal (i.e., real and reactive power injection) operating mode following a momentary cessation or current injection during the voltage ride-through operation.
- Identification of allowable modes for inverter trips.
- The maximum allowed time to return to service (i.e., real and reactive power injection) following a trip operation.
- Whether it is acceptable for inverters to use a counter to lock out the inverter following a predetermined number of trip operations in a predefined operating period (e.g., three trips in a 24-hour period will lock out the inverter).

Appendix A: Transient Stability Simulations

The task force performed simulations of 500 kV faults and inverter momentary cessation to identify potential effects of solar PV momentary cessation on the Western Interconnection. These simulations supported the task force's efforts to identify the extent to which the momentary cessation and tripping could cause a reliability risk to the BPS. This appendix provides a high-level overview of the studies that were performed and observations made from these studies.

Base Case and Modeling Assumptions

Two powerflow and dynamics cases were used in the analysis of the event, including the following:

- WECC used a West-wide System Model (WSM) base case from March 2, 2017, where CAISO set a new solar peak record of 9,066 MW
- SCE obtained an Operating Studies Subcommittee (OSS) heavy winter scenario with 14,000 MW demand level in SCE, adjusted to maximize the penetration of large scale solar in the southwest

SCE and WECC collaborated on study assumptions and modeling techniques throughout to ensure consistency in approaches. The two cases above were used since they both represent reasonable conditions (one from the planning-based model and one from the operations-based model) from which studies of higher penetration solar PV could be conducted. Solar PV and momentary cessation/tripping protection was modeled by using a generic PV model to represent the behavior of known solar PV generation sites in the southwest. All existing models of PV were replaced in the study area with the model shown in **Figure A.1**.[15]

```
pv1e ###### "BUSNAME" ##.#### "PV" : #9 "varflg" 0.0000 "Kqi" 0.1000 "Kvi"
40.000 "Vmax" 1.1000 "Vmin" 0.9000 "Qmax" 0.3120 "Qmin" -0.3120 "Tr" 0.0200
"Tc" 0.1500 "Kpv" 18.0000 "Kiv" 5.0000 "pfaflg" 0.0000 "fn" 1.0000 "Tv"
0.0500 "Tpwr" 0.0500 "Iphl" 1.0000 "Iqhl" 0.31200 "Pqflag" 0.0000 "Xc" 0.0000
"Kqd" 0.0000 "Tlpqd" 0.0000 "Xqd" 0.0000 "Vermn" -0.1000 "Vermx" 0.1000
"Vfrz" 0.7000  "imaxtd" 1.0000 "Viqlim" 1.6

pv1g ###### " BUSNAME " ##.#### "PV" : #9 mva=Pmax*1.1      "Lvplsw" 1.0000
"Rrpwr" 0.1 "Brkpt" 0.## "Zerox" 0.## "Lvpl1" 1.2200 "Volim" 1.2200 "Lvpnt1"
0.8000 "Lvpnt0" 0.4000 "Iolim" -1.0000 "Khv"  0.0000
```

Figure A.1: Solar PV Generic Model

Brkpt and Zerox determine what voltage must be exceeded in order for the solar PV facility to enter momentary cessation mode. Rrpwr controls the ramp rate where the total recovery, back to pre-disturbance output, is reached at 1/Rrpwr seconds.

Other relevant study assumptions include the following:

- Distributed energy resource (DER) solar PV controls were not modeled explicitly. DERs were not affected by the disturbance being considered, and therefore were outside the scope of this study.
- All inverters were modeled using the same control settings shown above in Figure A.1 for each scenario. This is not intended to simulate the actual system performance of generators that are currently connected to the BPS. Rather, it is intended to capture a "bookend" worst case scenario where all affected PV inverters would momentarily cease to inject current at the same voltage.

[15] The pv1e and pv1g models were used for simplicity by the sub-group. The sub-group was familiar with these models and considering the time needed to do the studies, the sub-group decide to use these models.

- The return from momentary cessation is modeled without a time delay. Inverter manufacturers have stated that a small time delay exists between voltage recovery and return from momentary cessation (beginning the ramp back). These times are generally relatively short (i.e., sub-cycle) and not expected to have a significant impact on simulation results.
- Frequency calculation issues discussed above were not modeled (no modeling capability), as they were assumed to be resolved by settings changes made by the affected inverter manufacturer(s).

Line-Line Fault Simulation

The line-line (LL) fault on the Lugo-Rancho Vista 500 kV transmission circuit that occurred 32.4 percent down the line from Lugo substation was simulated[16] to analyze solar PV response (note that this is using the generic PV model with momentary cessation enabled for all solar PV in the study area as a worst case analysis). Fault impedance values for the LL fault were simulated in the positive sequence transient stability program using Rf = 0.000174 pu and Xf = 0.003813 pu (impedances on 500 kV base). The following figures show the results from the simulated fault for the individual PV plants (**Figure A.2**), aggregated PV plant output (**Figure A.3**), and nearby per unit bus voltages (**Figure A.4**). Approximately 4,013 MW of solar PV entered momentary cessation and recovered with the defined ramp rate (shown in **Figure A.3**). The momentary cessation threshold was set to 0.9 pu in this case as a conservative assumption.

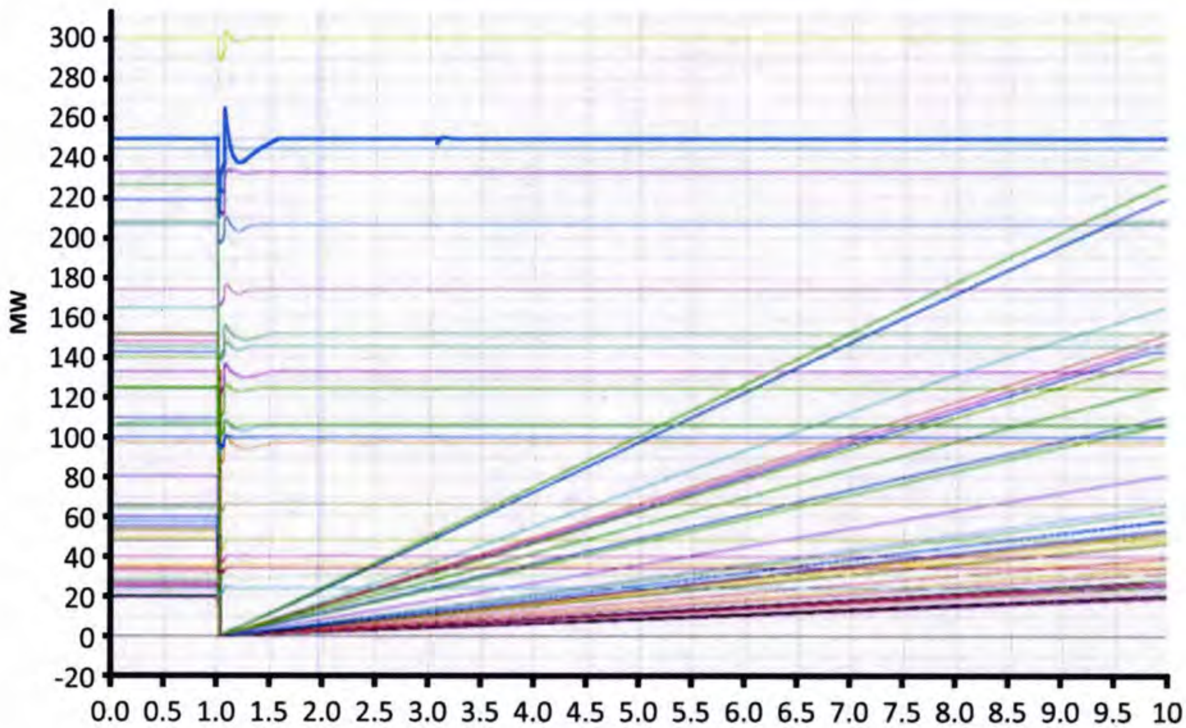

Figure A.2: Individual PV Plant Inverter MW Responses

[16] The Thevenin impedance for the fault is used to represent the LL fault condition in positive sequence. It is understood that this is the positive sequence representation and does not capture any phase-based protection or controls that may be involved in the inverter behavior. This simulation was performed for exploratory analysis.

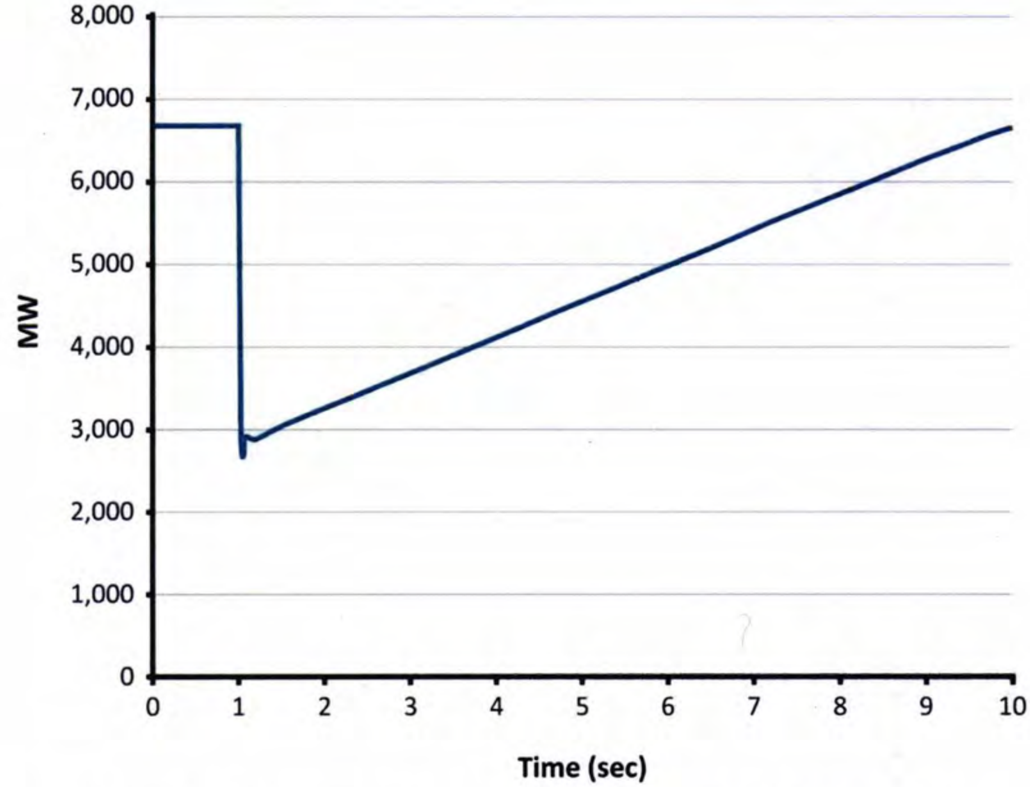

Figure A.3: Aggregated PV Plant MW Response (Ramp Rate)

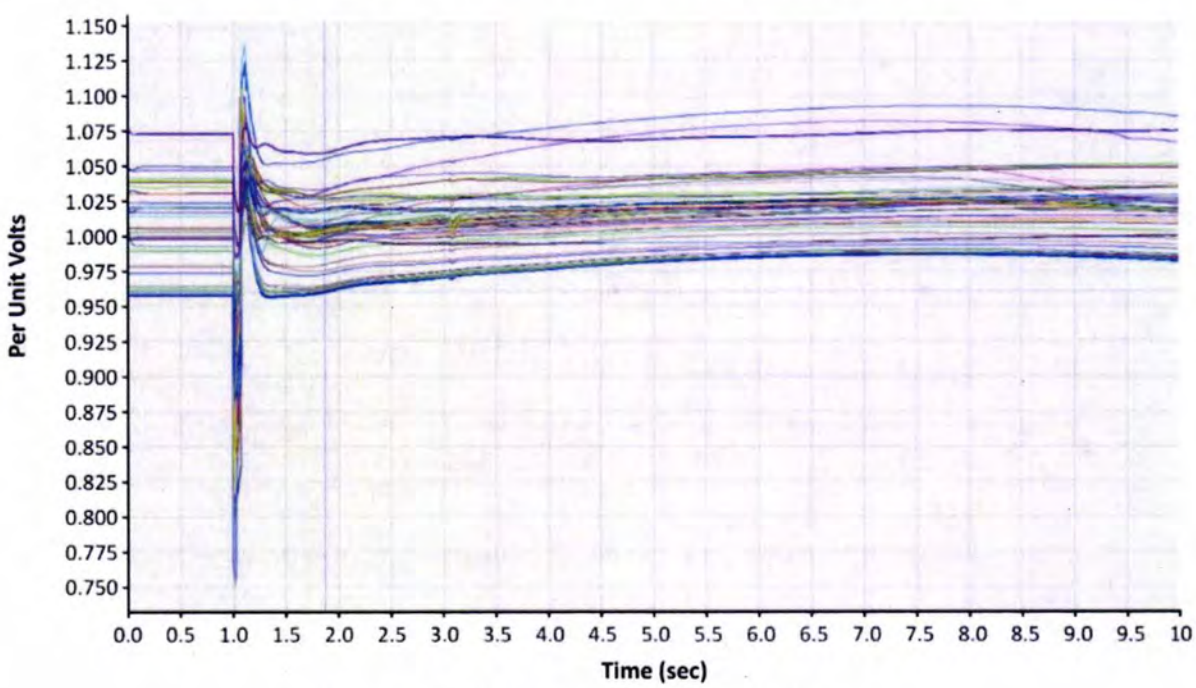

Figure A.4: Nearby Per Unit Bus Voltages

This simulation was the only simulation that used a fault impedance to represent the LL fault that actually occurred in the August event. The remaining discussions use a bolted three-phase fault in the simulations as the commonly used worst case assumption for normally cleared faults during planning and operations stability studies.

WECC Studies using WSM Base Case

The WECC studies under high penetration of solar PV using the WSM model are discussed in this subsection. Three scenarios were initially run to understand the sensitivity between solar PV control settings and BPS performance. These scenarios included the following:

- Scenario 1: Brkpt = 0.75, Rrpwr = 0.1
- Scenario 2: Brkpt = 0.9, Rrpwr = 0.1
- Scenario 3: Brkpt = 0.9, Rrpwr = 0.0001

A four-cycle fault was applied at the Lugo 500 kV bus. The primary concern is frequency stability for a significant loss of solar PV generation following the fault; frequency plots for SCE average frequency (frequencies near the event) and Malin 500 kV bus frequency (representative of system frequency) are shown in **Figure A.5** and **Figure A.6**. The following observations are made:

- Solar PV momentary cessation affects 5,421 MW of solar generation using a threshold of 0.75 pu and 7,198 MW using a threshold of 0.9 pu voltage.
- Under a highly unlikely scenario of all solar PV inverters tripping for voltage less than 0.9 pu, system frequency drops to a minimum of around 59.37 Hz. This would exceed the first stage of UFLS and result in load loss. However, this scenario is simply an absolute worst case and not expected to occur in reality since inverters do not generally trip for voltage below 0.9 pu.
- The Western Interconnection had a mean frequency response measure of 1,344 MW/0.1 Hz and C:B ratio of 1.525[17] between 2012 and 2015.[18] Extrapolating these values to a loss of approximately 7,200 MW would result in a Value B of 59.46 Hz and Point C of 59.18 Hz. The simulations show significantly improved primary frequency response than these estimated numbers that may be attributed to a number of factors, including governor headroom, unit dispatch, and generator frequency responsiveness in the simulation. The study cases also used different load model characteristics.[19] Note that in the tripping simulation (rrpwr=0.0001), the C:B ratio is much lower, which shows that the ramped recovery (and ramp rate) of PV also affects the C:B ratio. In comparing a ramped PV recovery to a traditional fault/generation loss scenario, the recovery of the PV momentary cessation manifests itself similar to a fast primary frequency response (governor response) in system frequency.
- Momentary cessation response with either 0.9 pu or 0.75 pu voltage thresholds do not cause frequency to fall below the UFLS. The no-delay beginning of the ramp rate to return to full output arrests the frequency decline sufficiently fast to mitigate reaching the UFLS. This may be a slightly optimistic result of the simulation and the inability to model the delayed ramp rate.
- The 0.75 pu voltage threshold provides a much less severe voltage dip (nadir of the frequency excursion) and faster frequency recovery compared with the 0.9 pu threshold.

[17] 2016 NERC Frequency Response Annual Analysis Report

[18] 2016 NERC State of Reliability Report

[19] The WSM model does not use a dynamic load model; rather, it uses a ZIP model at this time. WECC performed sensitivity analysis, adding in 20 percent motorw, and results showed nearly identical frequency response between the two cases.

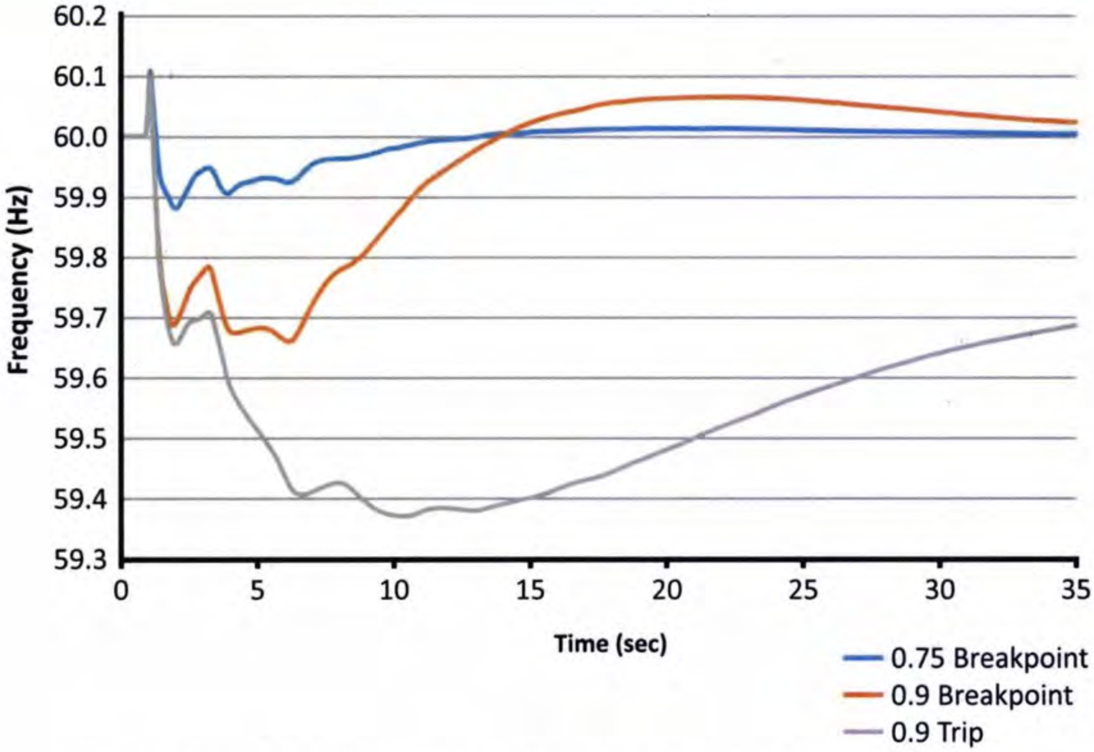

Figure A.5: SCE Average Frequency for Sensitivity Cases

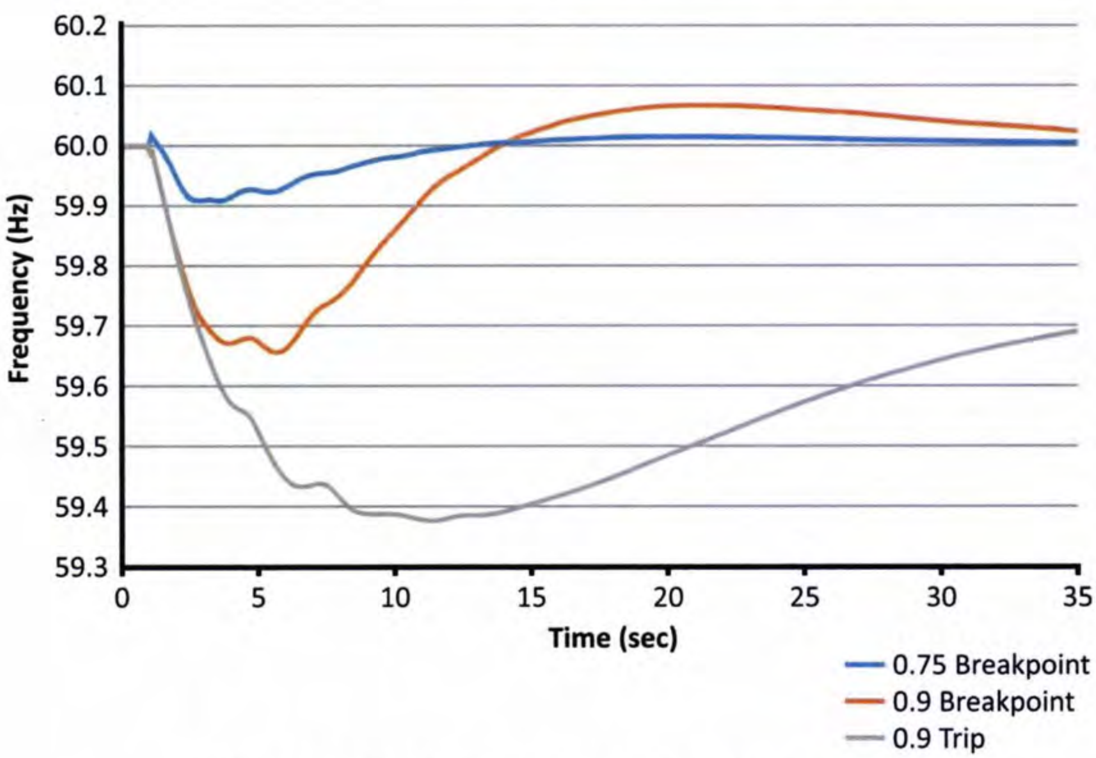

Figure A.6: Malin Frequency for Sensitivity Cases

It was then determined that a ramp rate of 10%/second (Rrpwr = 0.1) is likely a conservative value and that inverters likely ramp active power output following a momentary cessation condition significantly faster. Therefore, WECC performed a sensitivity to determine the frequency response characteristic with a ramp rate of 100%/sec (10%/100 ms) and Rrpwr = 1.

Figure A.7 shows the results from this sensitivity. The yellow and green curves show the 1 second ramp. The BPS does experience an initial drop in frequency due to the instantaneous change in power balance caused by the inverter entering momentary cessation. Frequency falls to about 59.84 Hz (for the 0.9 pu momentary cessation voltage threshold) and then recovers quickly to near nominal frequency. This response is likely more characteristic of equipment that is installed on the BPS today. Solar PV facility GOs have provided data on ramp rate characteristics ranging from as fast as ~100%/100 ms (full recovery in 0.1 seconds) to as slow as 10%/sec (full recovery in 10 seconds). More common ramp rates from momentary cessation are 20%/sec to 50%/sec (2–5 seconds to full recovery).

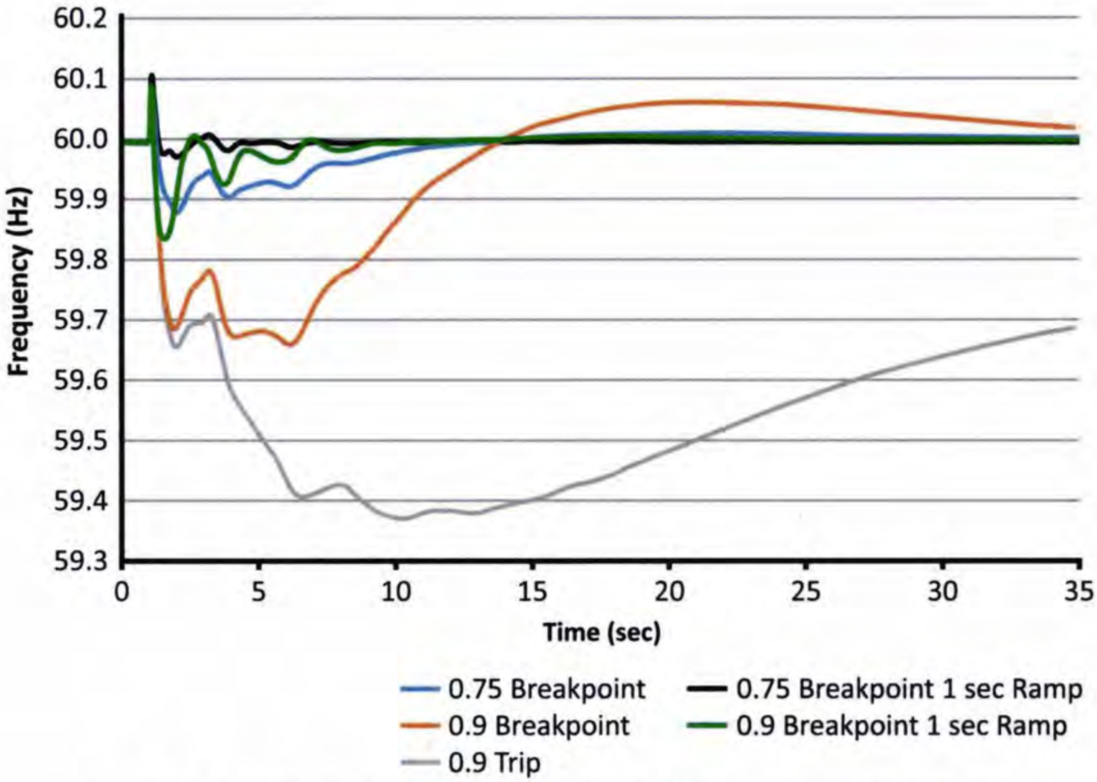

Figure A.7: SCE Average Frequency for Additional Sensitivity Cases

Figure A.8 shows the total current output on A-phase, expressed in percentage, during and after a momentary cessation event. This data was collected at the point of interconnection of the solar PV facility to the BES (i.e., a single-plant response). The ramp from momentary cessation actually has an exponential response rather than a linear response (as the models use). This plant returns to 90 percent output in approximately three seconds.

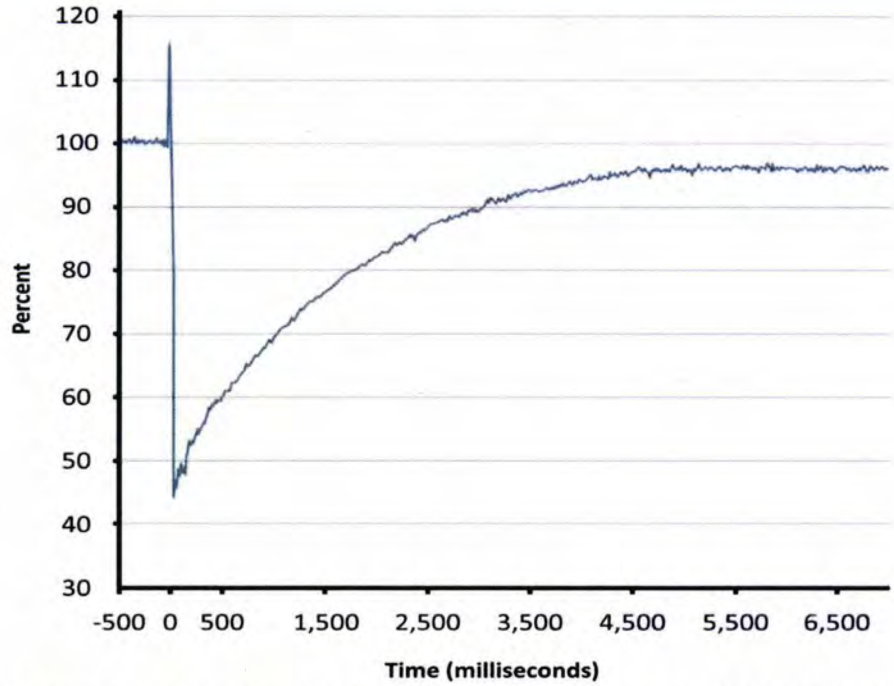

Figure A.8: Example of Solar PV A-Phase Current during and after Momentary Cessation

Figure A.9 shows verification that the current during the ramp is essentially entirely active current (blue is real power, orange is reactive power), and reactive current returns to zero following the fault event.

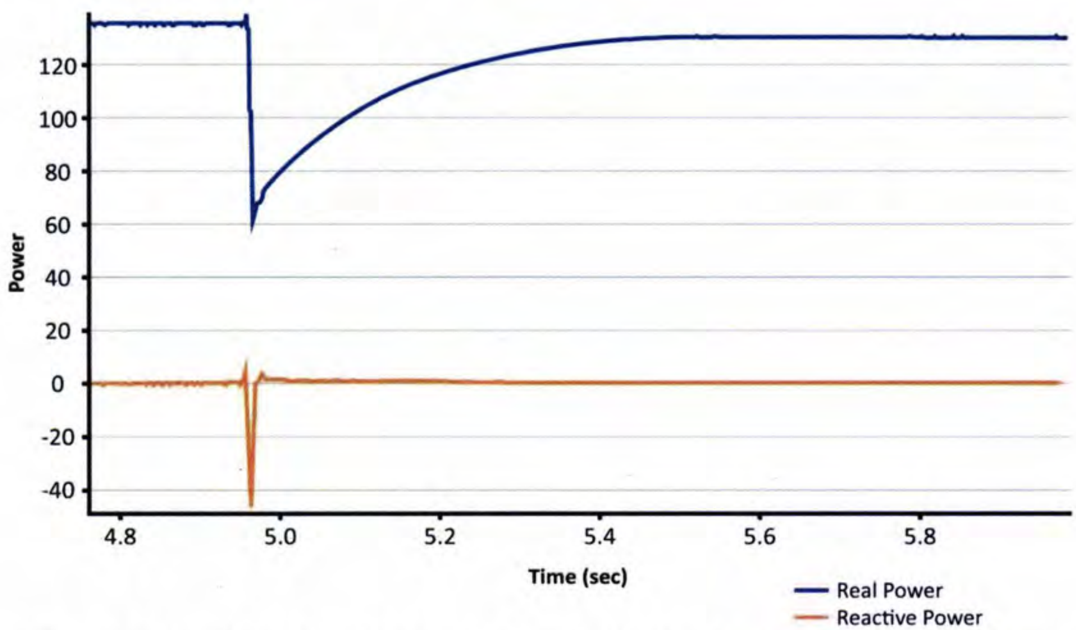

Figure A.9: Real and Reactive Current Output of Solar PV during and after Momentary Cessation

These results were corroborated with simulations performed by SCE that are described in the next sub-section.

SCE Studies using Operating Studies Subcommittee (OSS) Base Case

The SCE studies performed using the OSS base case are discussed in this subsection. SCE performed similar analyses and sensitivities as WECC using the OSS case, including different momentary cessation thresholds (as well as a tripping sensitivity) and ramp rate times.

The tripping case was performed to understand the worst case scenario as described in the previous sub-section. **Figure A.10** shows the SCE bus frequencies for this scenario. Following the fault clearing, frequency reaches a minimum of 59.623 Hz.

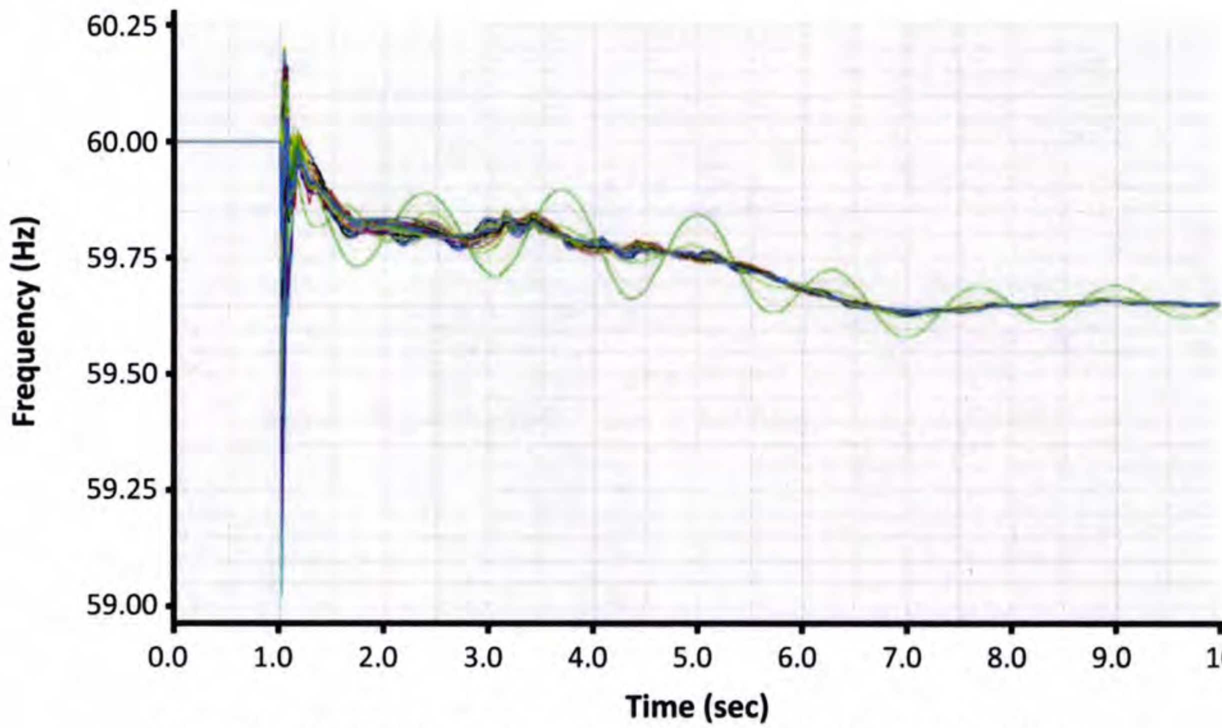

Figure A.10: SCE Bus Frequencies for Solar PV Tripping Sensitivity

Results show that 5,563 MW of solar PV generation are tripped due to the 0.9 pu voltage threshold (again, worst case scenario), as shown in **Figure A.11**. These results show less of a reliability risk of reaching UFLS for loss of solar PV caused by momentary cessation/tripping initiated by a fault event. Observations and considerations for differences between this and the WECC studies include the following:

- Different dispatch of frequency responsive resources
- Different (yet similar) dispatch and status of solar PV resources in study area
- The WSM model uses the ZIP model while the OSS case uses the composite load model. Some amount of load may be tripping due to the low-voltage conditions near the fault.

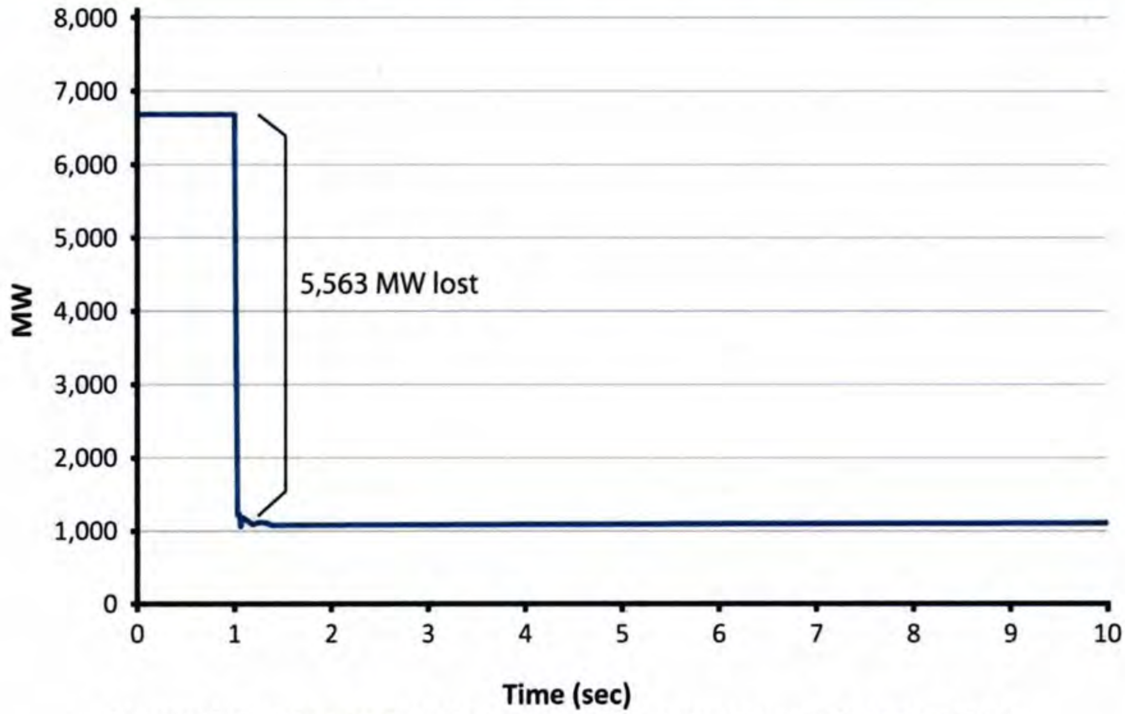

Figure A.11: Aggregate SCE Solar PV Generation Output vs. Time

The SCE also studied varying ramp rates to understand the sensitivity of frequency response to solar PV inverter ramp rates. **Figure A.12** shows the aggregate solar PV output for the scenarios studied, ranging from 10 seconds down to 1 second recovery.

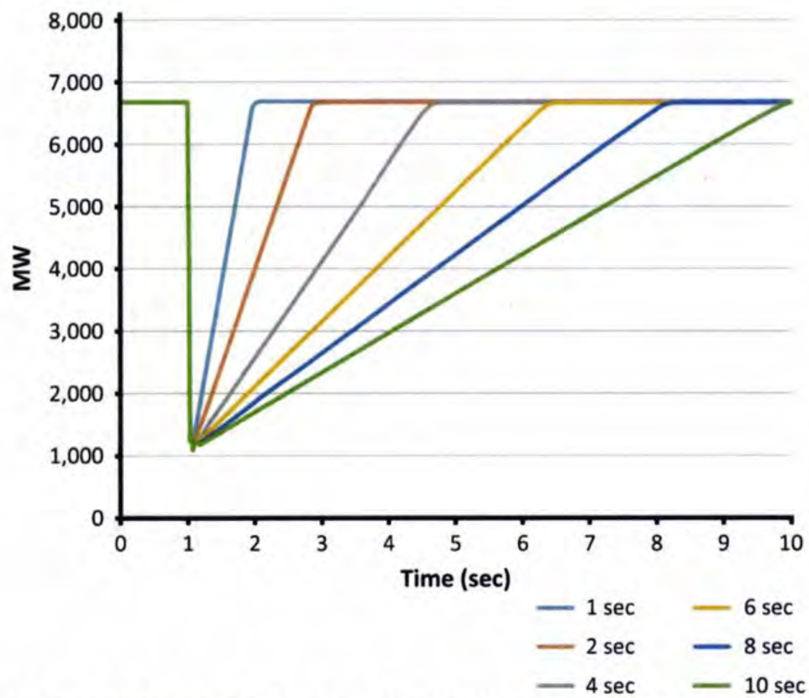

Figure A.12: Aggregate Solar PV Ramp Rate Recoveries

Figure A.13 shows the frequency at Lugo for these simulations. As the ramp rate increases, the frequency nadir following the first frequency swing will decrease (lower nadir). This is due to the extended duration of generation-load imbalance. While these simulations do not result in UFLS action, the extended frequency decline for an event that should not have a significant frequency perturbation is still a concern from a BPS reliability perspective.

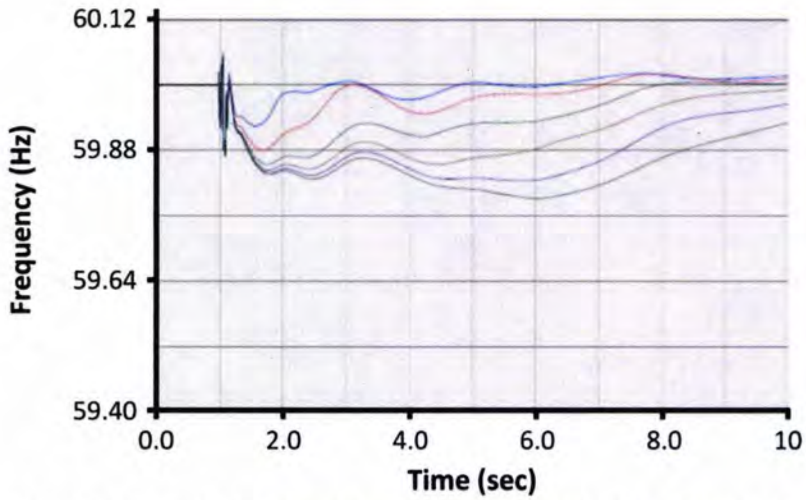

Figure A.13: Lugo Bus Frequency for Ramp Rate Sensitivity Studies

Lastly, the SCE also studied sensitivities around the momentary cessation threshold value to understand the extent of the impact for decreasing momentary cessation voltage levels. **Figure A.14** shows the frequency results and **Figure A.15** shows the individual inverter responses if the momentary cessation threshold is lowered to 0.5 pu. It was determined that the voltage threshold for momentary cessation has an exponential effect on the amount of inverter tripping for a given fault condition. As the voltage momentary cessation threshold increases, the number of inverters that will experience this condition and enter momentary cessation mode increases nonlinearly. Results for the 0.5 pu voltage momentary cessation show that a minimal number of inverters were affected for the studied 500 kV bolted fault contingency.

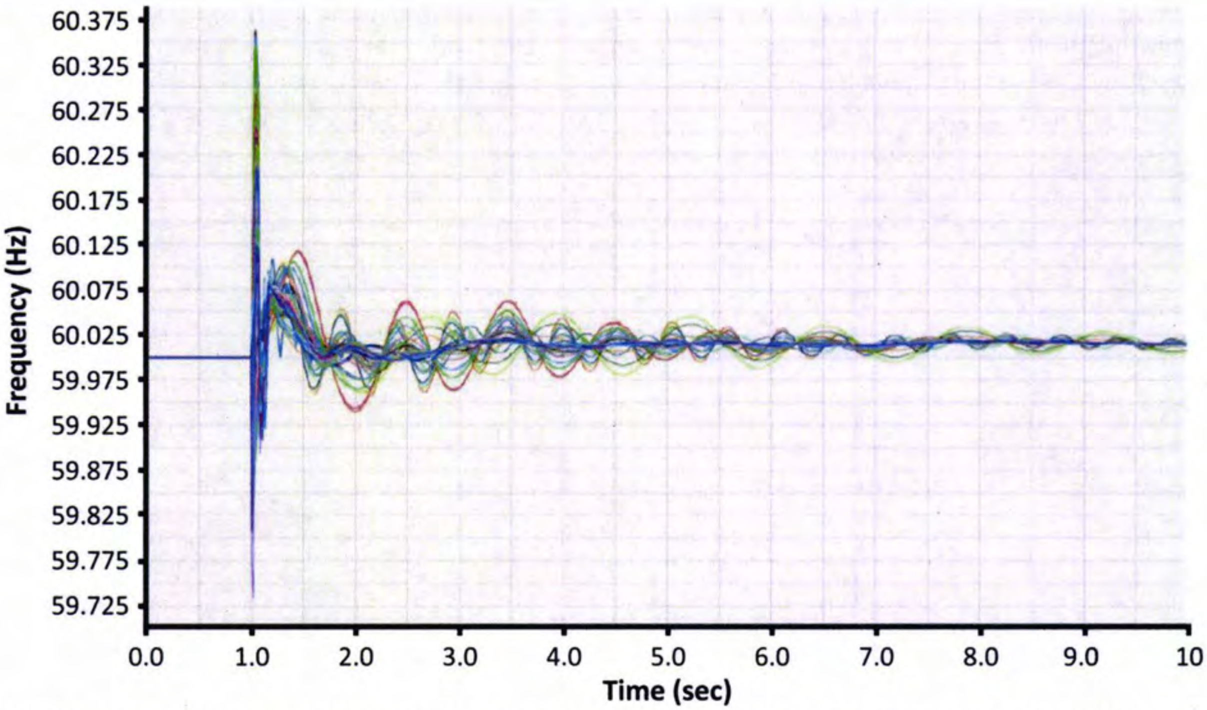

Figure A.14: SCE Bus Frequencies for Inverter Momentary Cessation at 0.5 pu Voltage

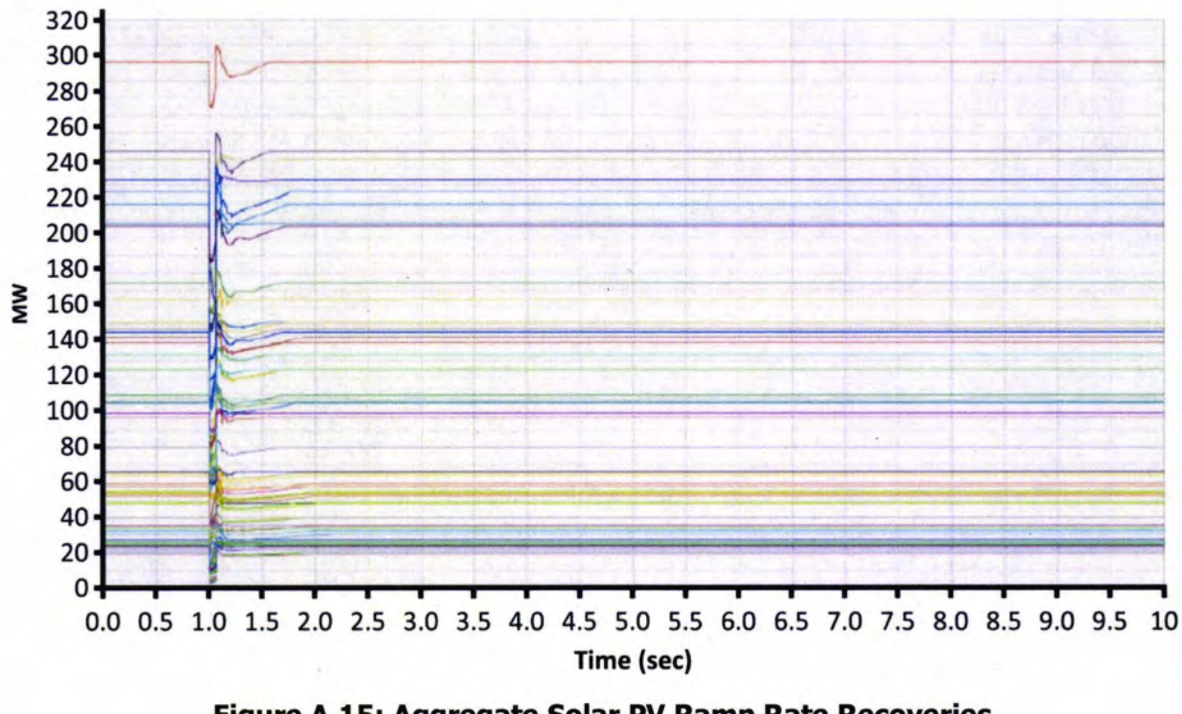

Figure A.15: Aggregate Solar PV Ramp Rate Recoveries

Simulation Observations and Takeaways

The following key observations and takeaways are provided based on the simulations performed by WECC and SCE:

- These simulation studies are intended to show the potential effects of PV momentary cessation in the southwestern portion of the WECC system under high penetrations of solar PV inverters. The simulations used various levels of momentary cessation (and tripping) thresholds to understand how these inverter settings could impact reliability. The goal is not to characterize how the inverters behave as installed today; rather, it is to study potential bookend conditions and any reliability risks associated with those condition.
- Utility-scale solar PV facilities are often located in centralized areas of high solar irradiance. Land availability and access to transmission facilities also tend to cause solar PV plants to develop in large groups. As a result, abnormal voltage conditions caused by faults can impact large amounts of solar PV plants because there is a low electrical distance between plants. As the penetration of solar PV continues to increase, control settings that do not support BPS reliability (e.g., 0.9 pu voltage momentary cessation) could pose a reliability risk. Tripping for voltages above 0.5 pu should be avoided.
- The recovery ramp rate after momentary cessation has a significant impact on the frequency response performance of the BPS. Longer ramp rates should be avoided, and ramp rates should be minimized to the extent possible. Typical maximum values should not exceed 3–5 seconds to fully recover to pre-disturbance output. However, inverter manufacturers have stated that these rates are often much shorter (e.g., return to pre-disturbance output in around 100 ms).
- As the allowed momentary cessation voltage increases, the amount of inverter momentary cessation (due to penetration levels) increases nonlinearly. A momentary cessation voltage of 0.9 pu has an impact over a wide area; whereas a momentary cessation voltage lower than 0.5 pu has significantly smaller impact.
- Related to modeling, the following takeaways are made:
  - Models used for interconnection-wide case creation should use the NERC List of Acceptable Models[20]. Particularly, solar PV facilities should be modeled using the latest generic model with parameters that are representative of the actual installation. These should include representative values for momentary cessation and tripping, accordingly, based on actual installed settings.
  - More detailed (e.g., user-defined, vendor-specific, etc.) positive sequence models should be used by the local TP for generation interconnection studies.
  - In some situations, particularly under weak grid conditions, detailed electromagnetic transient (EMT) models should be used as necessary.

It is recommended that WECC, in conjunction with its members, explore this event and potential vulnerabilities to this momentary cessation/tripping phenomena more closely to determine any reliability risks for high penetration scenarios.

20 http://www.nerc.com/comm/PC/Model%20Validation%20Working%20Group%20MVWG%202013/NERC%20Standardized%20Component%20Model%20Manual.pdf

Appendix B: Glossary of Terms and Acronyms

Acronym/Term	Definition
ACE	Area Control Error
BA	Balancing Authority
BAA	Balancing Authority Area
BES	Bulk Electric System
CAISO	California Independent System Operator
Continuous Operation	Inverter operating mode where the inverter is injecting current into the grid while the grid is within specified parameters
DER	Distributed Energy Resource
DFR	Digital fault recorder
ERO	Electric Reliability Organization
FERC	Federal Energy Regulatory Commission
FNET	Frequency monitoring network
GIA	Generator Interconnection Agreement
GO	Generator Owner
GOP	Generator Operator
IEEE	Institute of Electrical and Electronic Engineers
LADWP	Los Angeles Department of Water and Power
LL	Line to line fault
Momentary Cessation	Operating mode where the inverter temporarily ceases to inject current into the grid in response to a system voltage excursion with the capability of immediate restore output when the system voltage returns to normal
MSSC	most severe single contingency
MW	Megawatt
NERC	North American Electric Reliability Corporation
OC	NERC Operating Committee
PF	Power Factor
PLL	Phase lock loop
p.u.	Per Unit
PV	Photovoltaic
RC	Reliability Coordinator
RE	Regional Entity
Restore Output	Return operation of the DER to the state prior to the abnormal excursion of voltage that resulted in Momentary Cessation
SCADA	Supervisory Control and Data Acquisition
SCE	Southern California Edison
SLG	Single-line-to-ground fault
TO	Transmission Owner
Trip mode	A mode where they have ceased injecting current and will delay returning to service (typically a five-minute delay). They may also mechanically disconnect the inverter from the grid.
TOP	Transmission Operator
VAR	Volt Ampere Reactive
WECC	Western Electric Coordinating Council

Appendix C: NERC/WECC Inverter Task Force Participants

Name	Company
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Siddharth Pant	General Electric
David Piper	SCE
Deepak Ramasubramanian	EPRI
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Miaolei Shao	General Electric
Adam Sparacino	Mitsubishi
Efrem Tagliamonte	Power Electronics
Carl Turner	Florida Municipal Power Agency
Charlie Vartanian	Mitsubishi
Eddie Lim	FERC Observer
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Bob Cummings	NERC
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Errata

20 June 2017

Page 6: first paragraph: Language was corrected to more accurately reflect resource contingency criteria (RCC) rather than MSSC in some instances in that paragraph.