NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Resource Loss Protection Criteria Assessment

NERC Inverter-Based Resource Performance Task Force (IRPTF)
White Paper – February 2018

Purpose

The NERC Inverter-Based Resource Performance Task Force (IRPTF) was tasked by the NERC Resources Subcommittee (RS) to perform an assessment of whether the impacts of momentary cessation warrant a modification to the Resource Loss Protection Criteria (RLPC) for the Western Interconnection. NERC IRPTF created a modeling and simulations sub-group consisting of modeling experts and Transmission Planners from the Western Interconnection to perform stability simulations to make this determination. This report provides details and key findings from this assessment.

Key Findings and Recommendations

This section describes the key findings and recommendations from the stability studies performed by the NERC IRPTF related to the analysis of the Western Interconnection RLPC.

Key Findings

The following key findings are an outcome of the studies performed by the IRPTF:

- The Western Interconnection Resource Loss Protection Criteria (RLPC) does not require modification to account for impacts of momentary cessation of solar PV resources. Interconnection frequency remains above the benchmark RLPC (loss 2 Palo Verde units) for all momentary cessation simulations.[1]
- Expected momentary cessation settings for the majority of solar PV resources connected to the BPS include:
  - Momentary cessation voltage threshold – 0.9 pu
  - Delay upon voltage recovery – 0-0.5 sec
  - Active power ramp rate – 100%/sec
- The models currently used in the interconnection-wide models used to plan the BPS do not sufficiently capture the effects of momentary cessation that are currently used by existing resources. A user-defined model was add to sufficiently capture all the effects of momentary cessation for the purposes of this study.
- For normally-cleared, three-phase bolted faults at certain locations in the Western Interconnection, upwards of 9,000 MW of solar PV resources could enter momentary cessation. The voltage

[1] While transient stability occurs for certain critical fault locations identified in the simulation, this is not considered a frequency stability issue and should not affect the RLPC.

depression caused by a fault at a 500 kV bus has a widespread impact on grid voltage during on-fault conditions and can be felt by solar PV resources across a large geographic area.

- With momentary cessation settings of Vmc = 0.9 pu, Δtsr = 0 sec, and Δtrr = 100%/sec, interconnection frequency does not reach a frequency nadir lower than the 2 Palo Verde N-2 benchmark contingency for all fault contingencies studied.
- With momentary cessation settings of Vmc = 0.9 pu, Δtsr = 0.5 sec, and Δtrr = 100%/sec, interconnection frequency does not reach a frequency nadir lower than the 2 Palo Verde N-2 benchmark contingency for all stable contingencies studied.
- Of the contingencies studied[2], two bus locations were identified where potential transient instability conditions could occur under the studied operating conditions. The transient instability is caused by excessive transfer of inter-area power flows during and after momentary cessation. The large angular swings resulting from momentary cessation result in system-wide uncontrolled separation.
- For the minimum reserve requirements case developed for the purposes of this study, the benchmark 2PV N-2 contingency has a minimum frequency nadir that falls below the highest stage of UFLS (i.e., 59.5 Hz).

Recommendations

The following recommendations are made based on the key findings and simulation results:

- No change to the Western Interconnection RLPC is recommended, based on the studies performed by IRPTF.
- Modeling improvements should be made by all GOs of solar PV facilities connected to the BPS. A NERC Modeling Notification should be developed to provide guidance on how to accurately model momentary cessation using the generic second generation renewable energy system models.
- Modeling improvements to capture the effects of momentary cessation should be made in both the long-term planning models as well as the operations planning and real-time models. Planning Coordinators, Transmission Planners, Transmission Operators, and Reliability Coordinators should ensure that their models accurately capture the dynamic behavior of solar PV resources. These entities should coordinate with their respective Generator Owners in their footprint to ensure models are accurately capturing momentary cessation.
- Momentary cessation during transient low voltage conditions should be eliminated for future solar PV resources connecting to the BPS, and should be mitigated to the greatest extent possible for existing solar PV resources connected to the BPS. Momentary cessation poses potential risks to grid transient and voltage stability, caused by the large changes in power flow when multiple solar PV resources enter into momentary cessation.
- Potential stability issues may exist in the Western Interconnection under different operating conditions, particularly under daytime summer conditions where electric demand is higher, major

[2] While the contingencies simulated were temporary bus faults, these proved to be equally as severe as a normal N-1 contingency where the faulted element is removed from service when the fault is cleared. This is because the momentary cessation has already occurred by the time the fault is cleared.

interties are more heavily loaded, and reactive reserves are tighter. These conditions should be studied in more detail by the IRPTF.

- The IRPTF should provide guidance as to the recommended performance of solar PV resources during ride-through conditions. In particular, since momentary cessation is not recommended moving forward, the type of current injection (e.g., active vs. reactive current priority) during ride-through should be specified. These recommendations should have supporting simulations to ensure reliability of the BPS.
- The IRPTF should continue exploring potential mitigating measures[3] to ensure reliability of the BPS. However, the initial IRPTF studies have shown that the most impactful mitigating measure is to eliminate the use of momentary cessation for inverter-based resources across the BPS. This eliminates any potential stability risks that could exist today and in the future.

Background

Momentary cessation[4] is defined as an inverter operating mode where the inverter temporarily ceases injection of active and reactive current ("zero current injection") into the point of connection with the grid. The power electronic firing commands are blocked, and therefore the inverter does not exchange any current (real or reactive) with the grid. Other operating modes where active or reactive power are prioritized based on inverter controls are not considered momentary cessation since the power electronic switches are still firing and current is being exchanged with the grid.

Momentary cessation is used by a significant number of inverter-based resources connected to the bulk power system (BPS), as identified in the data collected from the NERC Alert following the Blue Cut Fire. While the dynamic models used for representing inverter-based resources connected to the BPS include some capability to model momentary cessation, these models have traditionally not been configured to represent this operating mode in the past. Hence, the impacts of momentary cessation on wide-area stability, including frequency stability, are not well understood.

Modeling Momentary Cessation

The overall characteristic of momentary cessation is shown in Figure 1. Momentary cessation occurs when inverter terminal voltage falls below a threshold, V_{mc}. Both the real and reactive components of current output fall to zero while voltage remains below V_{mc}. Once the terminal voltage recovers to above V_{mc}, the inverter may delay the beginning of its recovery of current by some amount of time, Δt_{sr}.[5] Once the inverter begins to recover current injection, this typically occurs over a time period, Δt_{rr}.[6] The ramp rate (*rr*) of recovery is the reciprocal of this value (e.g., recovery to full current injection within 5 seconds is equivalent to a ramp rate of 20%/second).

[3] These measures for future study could include, but are not limited to, minimum reserve/inertia requirements, limitations on transfers across major interties, etc.
[4] Momentary cessation is sometimes referred to as "blocking" for this reason.
[5] Δt_{sr}: time between voltage recovery and the inverter start to current injection recovery
[6] Δt_{rr}: time between start of and completion of active current recovery back to pre-momentary cessation output

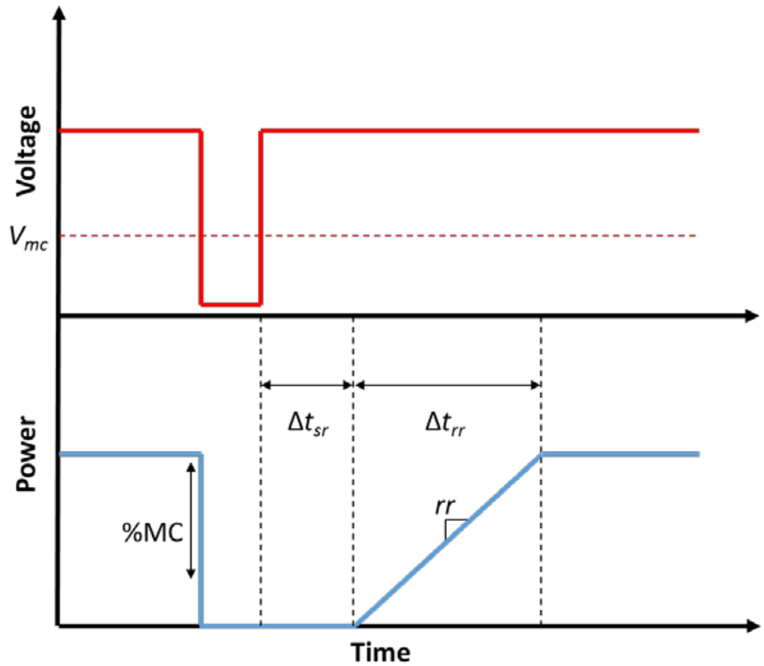

Figure 1: Illustration of Momentary Cessation Characteristics

The IRPTF determined that the best modeling approach for the purposes of this study is to use the models supplied by the equipment owners, and introduce a user-written model that interacts with those models to capture the performance characteristics that may not be capable or accurately modeled with these models. This ensures consistency with the models submitted by the equipment owners while also enables study of these characteristics. The goal is to minimize, to the best extent possible, any changes to the supplied models.

A user-defined model was created to model the impacts of momentary cessation for all inverter-based solar PV resources. It detects the conditions into/out of momentary cessation and imposes additional controls on the active and reactive current output of the resource based on the characteristics described above. Varying settings for momentary cessation, delay, and ramp rate were studied to understand their impacts.

Expected Momentary Cessation Settings for Existing BPS-Connected Resources

The data collected by the NERC Alert following the Blue Cut Fire were analyzed to determine reasonable parameter values for momentary cessation. While the data collected had some variability in the settings, the vast majority of resources are configured for the settings shown in Table 1. These settings are considered a reasonable set of parameters to represent most resources connected to the BPS. Regarding the values selected:

- The momentary cessation voltage threshold is fairly consistent across the BPS. While some resources may use values slightly lower (e.g., 0.86-0.88 pu), 0.9 pu was selected as a conservative value for the studies.

- The time to restart is less consistent across resources on the BPS. However, the majority of data collected and most resources analyzed during the grid disturbances show a time delay to restart ranging from nearly instantaneously (upon voltage recovery) to around 500 ms.
- The ramp rates are also less consistent across resources on the BPS. However, the majority of responses and data collection show a fairly quick ramp rate from the inverters upon recovery from momentary cessation. This does not include the interactions between the inverter and the plant-level controller, which was observed during the Canyon 2 disturbance and is trying to be remediated by the IRPTF in their recommended performance specifications.

Again, these settings were chosen based on data collected for installed resources on the BPS. The dynamic models used in the planning and operations cases currently have a deficiency in that they do not accurately represent the characteristics of momentary cessation. Hence why the IRPTF made a selected of "expected" settings to be used in the studies.

Table 1: Momentary Cessation Settings

Setting	Description	Expected Value
V_{mc}	Voltage below which momentary cessation occurs for low voltage conditions	0.9 pu
Δt_{sr}	Time between voltage recovery and the inverter start to power recovery	0-0.5 sec
rr	Active current ramp rate following momentary cessation[7]	100%/sec

[7] The reciprocal of this ramp rate is the time between the start of and completion of active current recovery back to pre-momentary cessation output (Δt_{rr})

Powerflow Base Case Setup

This section provides details regarding steady-state modeling assumptions used in the studies performed.

Demand Level

Frequency response simulations were performed using a modified 2018 Light Winter base case as the starting case. The powerflow case was modified to reflect realistic, worst case demand levels and renewables dispatch, as well as reasonable transfer levels. Case modificiation included:

- **Demand Level**: Historical 2016 WECC demand levels were reviewed. For the hours where solar resources would be operating near their peak output, WECC experienced a minimum daylight[8] demand level of around 85,000 MW around 12 noon Pacific. The case was modified to an interconnection-wide demand level of around 85,000 MW as a reasonable worst case light load condition. Table 2 shows the case as modified from the starting 18LW case to the new load level, including the percentage of load change and associated area aggregated load power factors.

Table 2: Base Case Demand Levels

AREA	AREA_NAME	PRE-PLOAD	POST-PLOAD	POST-QLOAD	% LOAD	POWER FACTOR
54	ALBERTA	8413.2	6852.6	4201.7	81	0.853
14	ARIZONA	8696	8696	1439.6	100	0.987
50	B.C.HYDRO	7473.4	6389.8	2323.7	86	0.940
11	EL PASO	759.2	759.2	170	100	0.976
60	IDAHO	1476.6	1550.4	225.9	105	0.990
21	IID	364.4	364.4	93.1	100	0.969
26	LADWP	2419.9	2419.9	305	100	0.992
20	MEXICO-CFE	979.3	979.3	44	100	0.999
62	MONTANA	1319.1	1174	390.7	89	0.949
18	NEVADA	2160.6	1879.7	216.3	87	0.993
10	NEW MEXICO	1765.7	1765.7	228.4	100	0.992
40	NORTHWEST	18764.2	17382.1	3558.5	93	0.980
65	PACE	5683.8	4810.1	1928.9	85	0.928
30	PG AND E	14401.5	9928.9	2140.2	69	0.978
70	PSCOLORADO	4311.6	3880.5	877.2	90	0.975
64	SIERRA	1441.4	1254	251.8	87	0.980
24	SOCALIF	9118.2	9182.3	-483	101	0.999
52	FORTISBC	512	437.7	163.6	85	0.937
73	WAPA R.M.	3577	3219.3	801.6	90	0.970
63	WAPA U.W.	-85.7	-85.7	89.4	100	-0.692
19	WAPA L.C.	559.7	559.7	95.8	100	0.986
22	SANDIEGO	2500	1662	66.1	66	0.999

[8] WECC experienced a minimum demand of about 75,000 MW in November in the middle of the night when solar resources are not on-line.

Solar and Wind Output Assumptions

The WECC TEPCC wind/solar hourly profiles were used to identify the hourly wind vs. solar output profiles for hours in March to May when solar output is above 90% of installed capacity. Figure 2 shows the scatter plot for the data gathered. Based on this analysis, the case was dispatched with solar output at 95% and wind output at 60-65% of maximum capability. This is intended to represent a midday hour around 1200 Mountain Time.

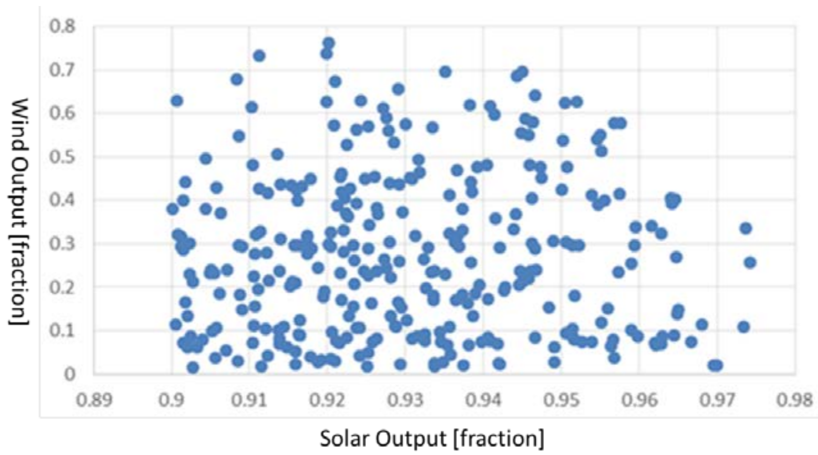

Figure 2: Solar vs. Wind Output – WECC TEPPC Data Sets

Import-Exports

All inter-area transfers are within expected operating limits in the steady-state powerflow case, and set up to represent a reasonable dispatch under the studied operating conditions.

Online Contingency (Spinning) and Frequency Responsive Reserves

The amount of online spinning reserve[9], online frequency responsive reserve[10], and online frequency responsive reserve to UFLS[11] for each area are provided in Table 3. The methods used for calculating these quantities are provided in Appendix A.

[9] For the purposes of these studies, spinning reserve refers to the amount of "unloaded generation that is synchronized and ready to serve additional demand" that is modeled in the steady-state powerflow case. This generation may or may not be frequency responsive.

[10] For the purposes of these studies, online frequency responsive reserve refers to the amount of unloaded generation that is synchronized and to the grid and responsive to changes in frequency. The model uses a baseload flag to disable, or block, governors response for units that are not responsive to frequency.

[11] For the purposes of these studies, online frequency responsive reserve to UFLS refers to the amount of online frequency responsive reserve that would be deployable prior to reaching underfrequency load shedding (UFLS). See Appendix A for more information.

Table 3: Base Case Reserves					
Area No.	Area Name	Online Spinning Reserve		Online Frequency Responsive Reserve	
		MW	%	MW	%
10	NEW MEXICO	138	7.83	90	5.1
11	EL PASO	79	10.38	25	3.29
14	ARIZONA	328	3.82	101	1.17
18	NEVADA	196	10.45	26	1.41
19	WAPA L.C.	128	22.95	34	6.03
20	MEXICO-CFE	28	2.9	8	0.79
21	IID	30	8.19	30	8.19
22	SANDIEGO	25	1.52	25	1.52
24	SOCALIF	219	2.41	167	1.84
26	LADWP	487	20.12	354	14.61
30	PG AND E	337	3.39	97	0.98
40	NORTHWEST	1481	8.52	580	3.34
50	B.C.HYDRO	770	12.05	141	2.21
52	FORTISBC	92	20.96	20	4.54
54	ALBERTA	740	10.8	200	2.92
60	IDAHO	208	13.43	82	5.3
62	MONTANA	241	20.57	79	6.73
63	WAPA U.W.	48	0	15	0
64	SIERRA	350	27.9	81	6.5
65	PACE	205	4.26	39	0.8
70	PSCOLORADO	546	14.08	285	7.35
73	WAPA R.M.	333	10.35	58	1.81

The amount of online spinning reserve and frequency responsive reserve are based on the requirements set forth in BAL-002-WECC-2. The assumption is made that the online spinning reserve should be between 3-6% of online resource capacity. There is no requirement that all this must be frequency responsive, so the assumption is made that some percentage (expected around or greater than 50%) of that amount has frequency response capability. Both are tracked in this study. For example, assume Area XYZ has 1000 MW of load, then it is expected to be dispatched with 30-60 MW of Contingency reserve and 15-20 MW of frequency responsive reserve (available headroom (Pmax-Pgen) and baseload flag set to 0).

Base Case Unit Dispatch

With demand level set for each Area, and the solar and wind output set according to the methods above, the remaining generation is dispatched to meet load based on engineering judgment and reserve requirements.

- Solar PV assigned to Zone 984 and wind was assigned to Zone 980 for tracking these resources.[12]
- Synchronous/thermal resource re-dispatch priority is based on each Area's engineering judgment.

Table 4 shows the breakdown of dispatch for each area for the final light load case.

Table 4: Base Case Unit Dispatch

Area No.	Area Name	Pgen	Pload	Interchange	Wind	Solar	Wind+Solar	Non-Wind+Solar
10	NEW MEXICO	1361	1766	-474	238	140	378	983
11	EL PASO	247	759	-540	0	103	103	144
14	ARIZONA	8445	8586	-317	136	983	1119	7326
18	NEVADA	1250	1880	-663	0	468	468	782
19	WAPA L.C.	2557	560	1943	0	0	0	2557
20	MEXICO-CFE	998	979	-1	18	0	18	980
21	IID	946	364	556	0	550	550	396
22	SANDIEGO	2061	1662	344	403	1149	1551	510
24	SOCALIF	7793	9092	-1522	2730	4511	7241	552
26	LADWP	2987	2420	449	254	1064	1318	1669
30	PG AND E	8847	9913	-1493	1091	3434	4525	4322
40	NORTHWEST	18549	17382	518	4126	0	4126	14423
50	B.C.HYDRO	5632	6390	-937	437	0	437	5195
52	FORTISBC	228	438	-215	0	0	0	228
54	ALBERTA	6964	6852	-146	1108	0	1108	5856
60	IDAHO	1192	1550	-395	372	135	506	686
62	MONTANA	3137	1174	1845	373	0	373	2764
63	WAPA U.W.	68	-86	146	0	0	0	68
64	SIERRA	786	1254	-521	90	87	177	609
65	PACE	5832	4810	836	1165	789	1954	3878
70	PSCOLORADO	3312	3880	-656	1623	264	1887	1425
73	WAPA R.M.	4572	3219	1242	217	0	217	4355

Modeling Distributed Energy Resources

The impacts of distributed energy resources (DER) are not considered in this study. This is a valid assumption since historical disturbances have not shown a significant impact of DER on BPS frequency response performance.

[12] Zone number picked based on an available/empty zone.

Dynamic Modeling Setup

This section provides details regarding dynamic modeling assumptions used in the studies performed.

Dynamic Models

The 2017-2018 Light Winter dynamics model library file (.dyd) was used as-is, as provided by the MOD-032 Designee. Note that the Fast AC Reactive Insertion (FACRI) scheme, which automatically reacts to fast-changing grid conditions near the California-Oregon Intertie (COI), was also modeled in the .dyd file. The FACRI supports system stability for certain contingencies in the Western Interconnection.

Dynamic Load Modeling

The 2017-2018 Light Winter frequency response case assumes a Light Winter hour 1200 (Mountain Time) composite load model representation.

Contingencies

The RLPC for the Western Interconnection is the loss of 2 generating units at Palo Verde Nuclear Generating Station, totaling 2,626 MW[13]. A RAS trips local load to maintain stability along the COI. The other resource loss contingency selected for study, for benchmarking purposes, was the loss of 2 generating units at Diablo Canyon, totaling 2,399 MW.

In addition to these benchmark events, each Transmission Planner selected critical contingencies within their TP footprint that have a greater likelihood of resulting in a widespread area experiencing a significant voltage depression at inverter-based resources. From that initial testing, contingencies that could result in widespread momentary cessation were selected for further study. At a high level, these are located in the areas shown in Table 5. The faults applied were 4-cycle, three-phase bolted temporary bus faults (fault applied but no Elements tripped subsequently).

Table 5: Contingency Definitions

Area	# Contingent Buses
ARIZONA	1
NEVADA	1
SOCALIF	2
LADWP	3
PG&E	4
NORTHWEST	1

N-1 contingency events were also selected at large generating plants where solar generating resources could also enter into momentary cessation. These “Fault + N-1 Resource Loss” contingencies assume a 4-cycle, normally cleared fault at the high side of the generator step up (GSU) transformer, resulting in tripping of the GSU and generating resource upon fault clearing.

[13] The RLPC for each interconnection does not change based on seasonal conditions.

Extreme contingencies were also selected for study purposes only. These included applying a 3-phase fault resulting in tripping two generating resources. These are not "electrically credible" N-2 contingencies, and result in a significant amount of momentary cessation as well as loss of the two largest generating resources. There is no electrical connection in the WECC system that would result in this contingency being "credible" from a design criteria standpoint.

Momentary Cessation Sensitivity Settings

For each of the specified contingencies, the following momentary cessation settings were studied.

- Low Voltage Threshold: 0.25 pu, 0.5 pu, 0.75 pu, 0.9 pu
- Recovery Delay: 0 sec, 0.1 sec, 0.25 sec, 0.5 sec, 1 sec, 5 sec
- Ramp Rate: 0.2 pu/sec, 1 pu/sec, 2 pu/sec, 5 pu/sec, 10 pu/sec

Low and High Frequency Ride Through

Since it is not expected that frequency will fall (or rise) to levels in which low (and high) frequency ride-through is an issue for inverter-based resources (e.g., 57-63 Hz), and because these models are prone to miscalculation of frequency in the simulation during severe fault conditions, it was decided to disable these models for the purpose of this study. This has no impact on the simulation results because any significantly low frequencies will be documented regardless.

Underfrequency Load Shedding Relay Activation – Unacceptable Frequency Performance

Underfrequency load shedding (UFLS) relays were disabled in the simulations. The intent of the simulation is to determine if momentary cessation is more or less impactful to system frequency than the current RLPC for the Western Interconnection. The goal was not to address whether sufficient UFLS relaying can maintain frequency stability, as a safety net, for any of these simulations.

Results

This section highlights some of the key findings and takeaways from the simulations results.

2 Palo Verde Unit Outage - Benchmark

The current Resource Loss Protection Criteria (RLPC) for the Western Interconnection is the loss of 2 Palo Verde generating units less a small amount of load tripped due to RAS action ("2PV" contingency). This 2PV contingency was simulated for different combinations of momentary cessation, including conservative yet reasonable settings assumptions, and the simulation results are shown in Figure 3. All the 2PV simulations resulted in identical results – the loss of the two generating units and local load tripping does not cause any significant voltage swings that cause inverter-based resources to enter momentary cessation. Figure 4 shows the terminal bus voltage and POI bus voltage for a solar PV resource near the Palo Verde generating unit. It can be concluded that accurately modeling momentary cessation in combination with this resource loss event yields the same results as have historically been observed for this contingency.

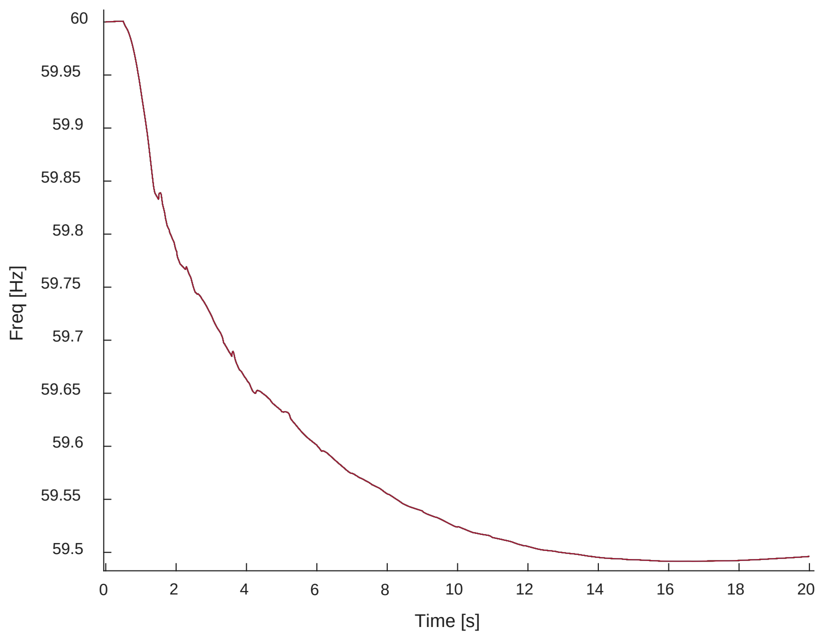

Figure 3: System Frequency for 2 Palo Verde Simulation

The 2PV contingency resulted in a frequency nadir below the highest level of UFLS for the Western Interconnection (i.e., 59.5 Hz). This was due to the base case being set up to represent a minimum spinning reserve level using BAL-002-WECC-2 as a guiding consideration. It is expected that operating conditions with higher reserves that are more reflective of historical operating conditions would not cause frequency to reach UFLS.[14] The NERC RS may consider further investigating the sufficient amount of spinning reserves needed to mitigate triggering UFLS for the RPLC in the Western Interconnection (and other interconnections, if necessary). Based on the studies performed for these operating conditions, additional

[14] Since the base case operating conditions represent the minimum spinning reserve levels, and may not be representative of minimum historical operating conditions, the simulated frequency response will differ from historical trends.

spinning reserves may be needed to to ensure sufficient frequency response to mitigate triggering UFLS for the RLPC.

Regardless, this 2PV simulation is used as the benchmark result for all momentary cessation simulations. Therefore, the minimum frequency nadir from this simulation (59.47 Hz) is used to compare the other simulations against, rather than the first stage of UFLS (59.5 Hz).

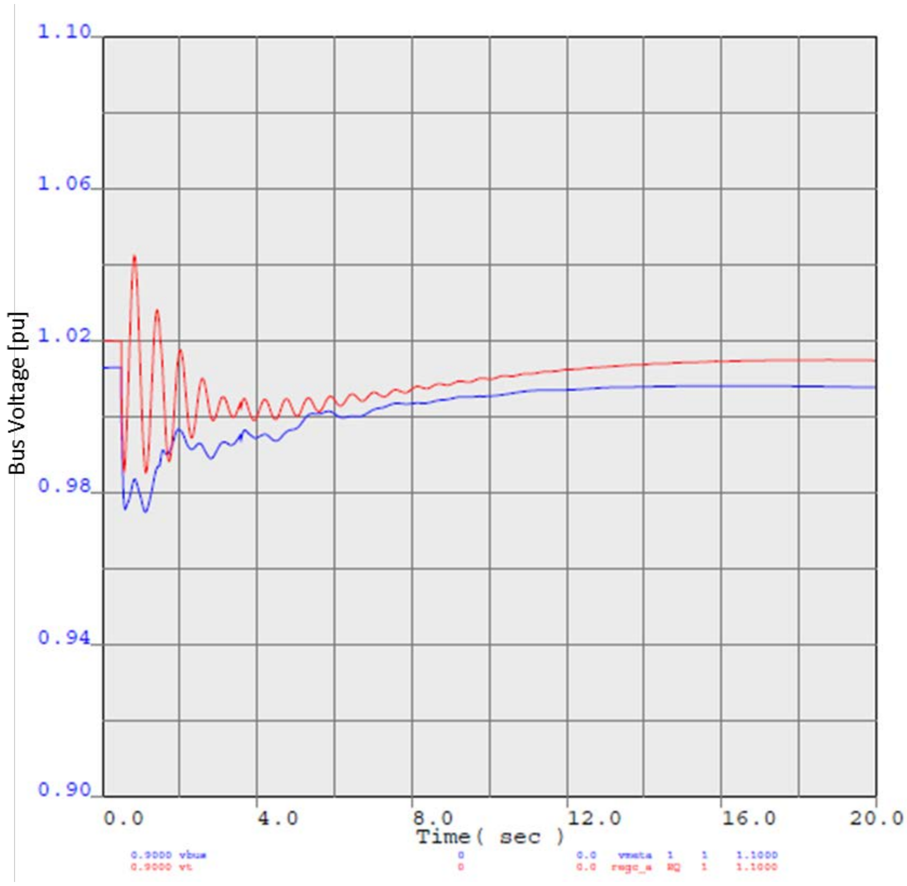

Figure 4: POI and Terminal Bus Voltage for Solar PV Plant Near Palo Verde

2 Diablo Canyon Unit Outage – Comparison to 2 PV

The IRPTF simulated the loss of 2 Diablo Canyon generating units ("2DC" contingency), simply to again confirm that the 2PV contingency is the worst N-2 contingency from a frequency stability standpoint. Results from the two simulations are shown in Figure 5. It was confirmed that the 2PV contingency results in a lower frequency nadir than the 2DC contingency, validating the 2PV as the RLPC for the Western Interconnection (not considering any momentary cessation yet).

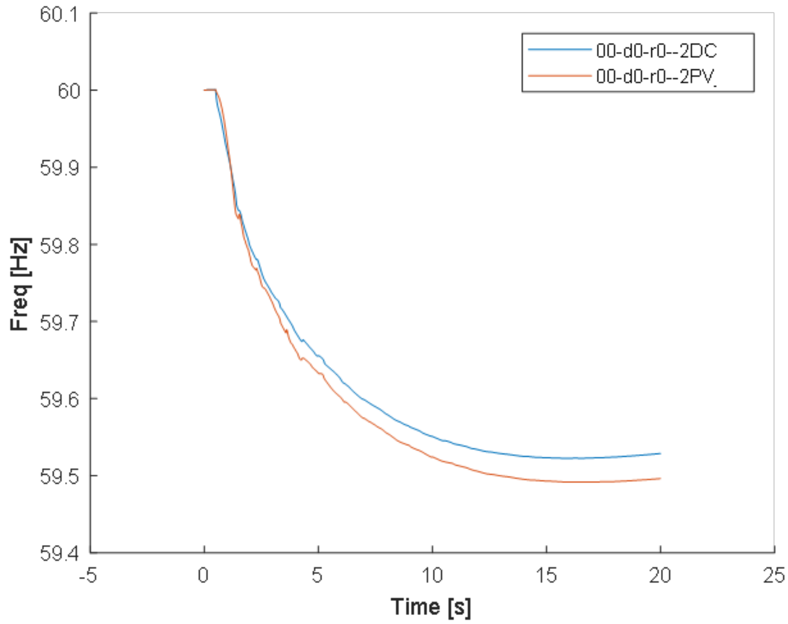

Figure 5: System Frequency for 2 Diablo Canyon Simulation

Expected Momentary Cessation Settings

Momentary cessation is not accurately captured with the generic dynamic models that represent the existing solar PV resoures. The NERC IRPTF is developing guidance to address and correct this issue in the future. For this study, "expected" values of momentary cessation were selected, as described previously. The expected momentary cessation setting scenarios are shown in Table 6.

Table 6: Expected Settings Cases	
Case	**Description**
1	Momentary Cessation Voltage (V_{mc}) = 0.9 pu Recovery Delay (Δt_{sr}) = 0 sec Ramp Rate (Δt_{rr}) = 100%/sec
2	Momentary Cessation Voltage (V_{mc}) = 0.9 pu Recovery Delay (Δt_{sr}) = 0.5 sec Ramp Rate (Δt_{rr}) = 100%/sec

For three-phase bolted fault contingencies, Western Interconnection frequency performance is better than the 2PV benchmark in Case 1. Figure 6 shows that the minimum frequency nadir for the critical momentary cessation simulations is 59.8 Hz while the 2PV frequency nadir if 59.47 Hz. Figure 7 shows the total solar PV power output across the Western Interconnection for each of the simulated contingency events. Initial rate of change of frequency (ROCOF) is steeper for the fault contingencies where momentary cessation occurs (see Figure 8); however, this is expected for the initial larger reduction in active power caused by the fault and momentary cessation as compared with the RLPC. The frequency nadir occurs much earlier than the 2PV simulations; however, this is also expected since the return from momentary cessation will arrest and recover frequency quickly based on the momentary cessation restore output characteristics.

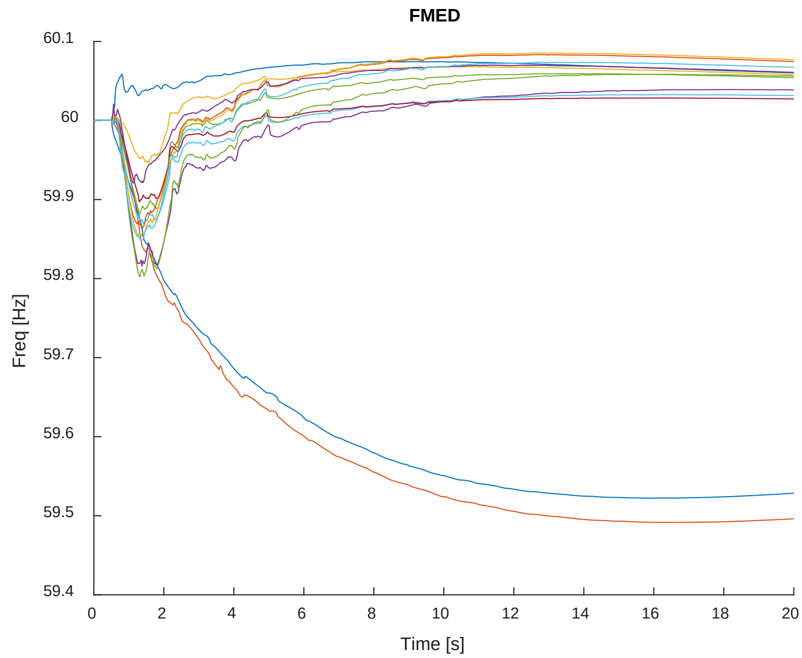

Figure 6: System Frequency for Case 1 Momentary Cessation Settings

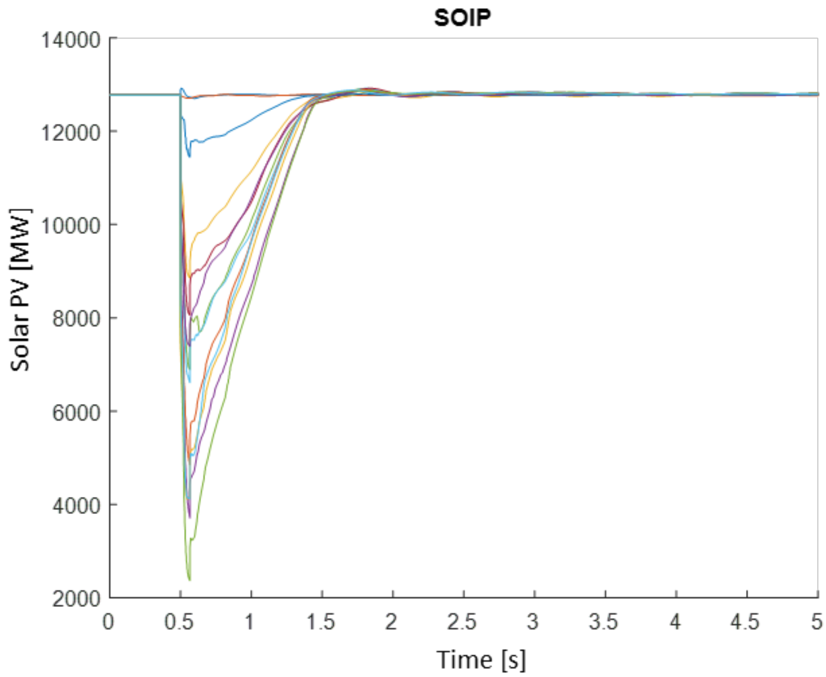

Figure 7: Solar PV Active Power Output for Case 1 Momentary Cessation Settings

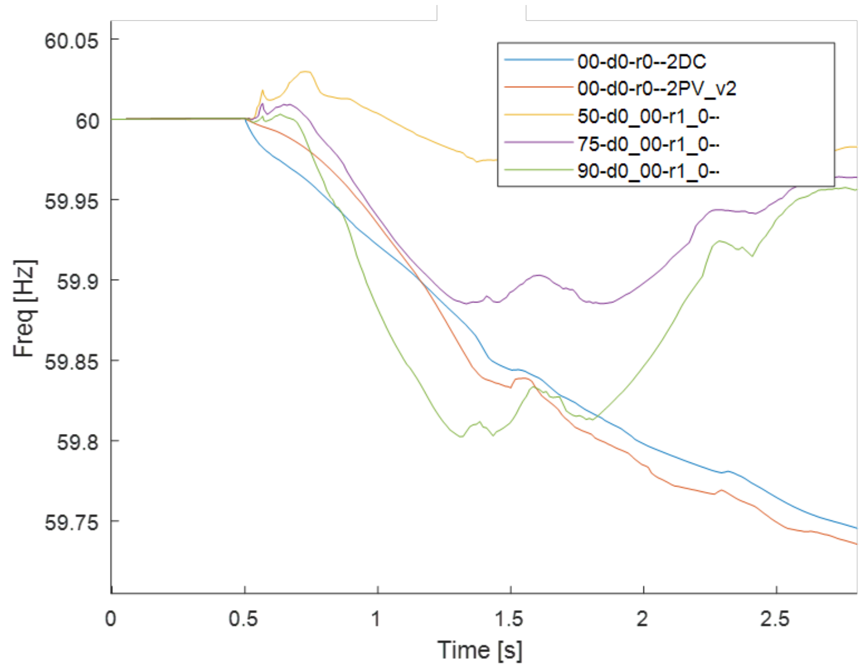

Figure 8: Initial ROCOF for Momentary Cessation and Generation Loss Events

Case 2 results in two unstable cases and the rest of the momentary cessation simulations are stable (see Figure 9). The stable momentary cessation cases result in a minimum frequency nadir of 59.65 Hz, which is higher than the nadir for the 2PV simulation. The minimum nadir from the momentary cessation simulations is lower in this case due to the delay in recovery which causes the recovery to start 0.5 seconds later. The delay in recovery of the large reduction in active power injection to the BPS causes frequency to decline an additional 150 mHz compared with Case 1. However, it still does not pose a risk to frequency stability for the Western Interconnection, and frequency performance is better than the 2PV case. Similar to Case 1, ROCOF is steeper and time to the nadir is faster than the 2PV case; however, these results are expected.

Case 2 poses a challenge in that two of the momentary cessation simulations result in system-wide instability. The IRPTF investigated these unstable cases closely and performed additional sensitivities to ensure actual system stability issues rather than numerical simulation issues (this analysis is discussed in the following subsection). The key takeaway from this analysis is that the instability is not related to frequency stability. Rather, momentary cessation causes system-wide transient instability that results in voltage collapse. (Figures 13 and 14 show that the voltage collapse starts at the oscillation center – along Arizona-New Mexico border, Utah-Colorado border, and mid-Wyoming for this simulation.[15])

[15] The collapse is caused by large changes in power transfer across wide areas of the BPS. The location of the collapse is dependent on the case dispatch and path loading.

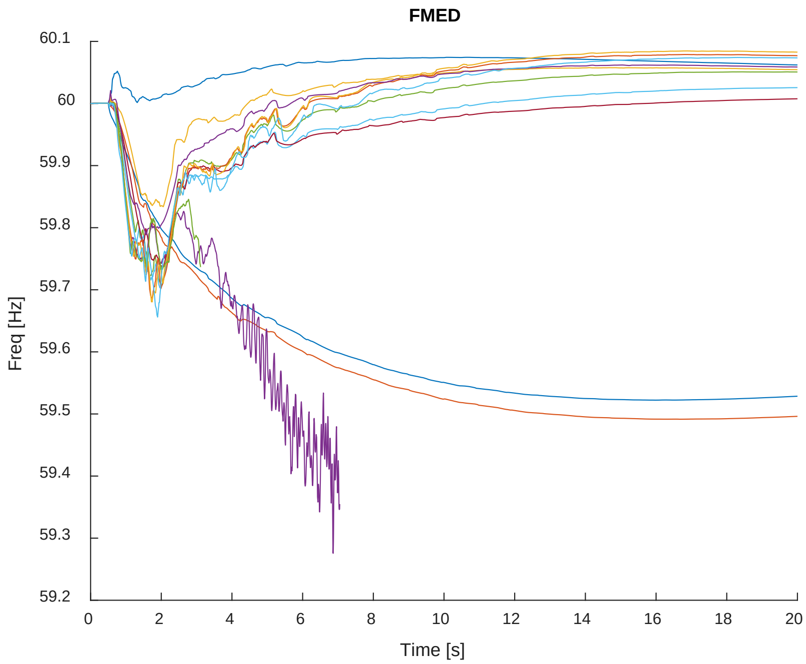

Figure 9: System Frequency for Case 2 Momentary Cessation Settings

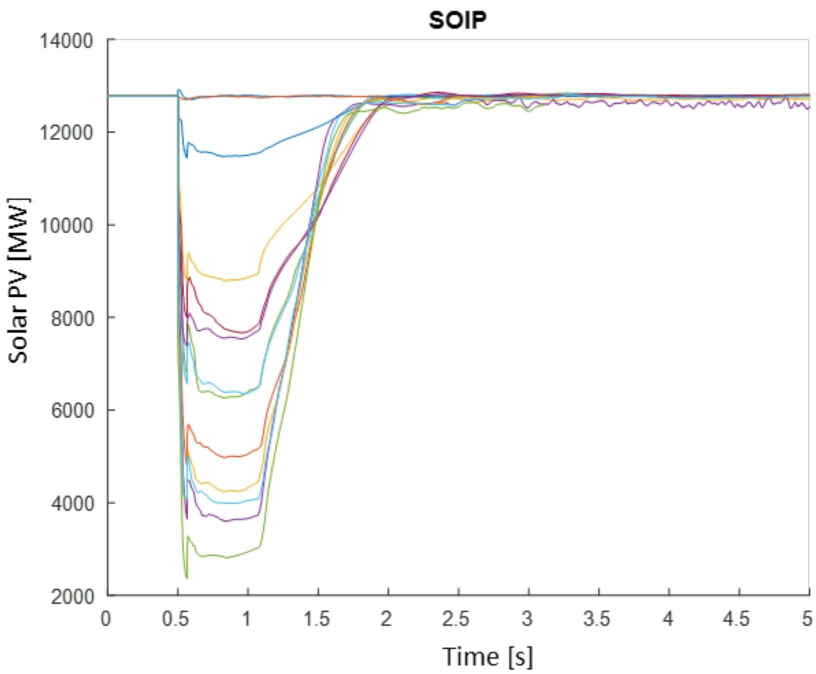

Figure 10: Solar PV Active Power Output for Case 2 Momentary Cessation Settings

Analysis of Unstable Momentary Cessation Simulations

Two momentary cessation simulations resulted in system-wide instability for Case 2 (momentary cessation threshold = 0.9 pu, delay in recovery = 0.5 sec, ramp rate = 100%/sec). Sensitivities were performed for varying momentary cessation settings to understand the extent of instability for these critical locations in the system. Results from those sensitivities are shown in Table 7. Both locations exhibit the same unstable cases based on the momentary cessation settings. Unstable simulation results highlight the following key findings:

- **Momentary Cessation Voltage:** Lowering momentary cessation voltage has a significant impact on improving interconnection stability. A momentary cessation voltage threshold of 0.75 pu resulted in mitigating the instability conditions. Further reduction of the momentary cessation threshold, to the greatest extent possible, will help mitigate any potential stability issues that could be caused by momentary cessation.
- **Long Ramp Rate:** For a momentary cessation setting of 0.9 pu and a delay of 0 seconds, a longer ramp rate of 20%/sec (5 seconds to full recovery) will result in instability.
- **Delay in Recovery:** For a momentary cessation setting of 0.9 pu and delays exceeding 0.5 seconds result in consistent[16] instability.
- **Recovery Performance:** Reducing the delay in recovery to zero and ramping active power to 100 percent of predisturbance output in less than 1 second results in stable operation, even for a high momentary cessation threshold.

[16] The simulation with 0.5 second delay and 1000%/sec ramp rate (0.1 sec return to full output) did result in stable operation; however, this ramp rate is not a reasonable expectation for solar PV to achieve.

Table 7: Expected Settings Cases							
Unstable Location "A"				Unstable Location "B"			
V_{mc}	Δt_{sr}	Δt_{rr}	Unstable?	V_{mc}	Δt_{sr}	Δt_{rr}	Unstable?
0.9	0	20	✓	0.9	0	20	✓
0.9	0	100		0.9	0	100	
0.9	0	200		0.9	0	200	
0.9	0	500		0.9	0	500	
0.9	0	1000		0.9	0	1000	
0.9	0.1	1000		0.9	0.1	1000	
0.9	0.25	1000		0.9	0.25	1000	
0.9	0.5	20	✓	0.9	0.5	20	✓
0.9	0.5	100	✓	0.9	0.5	100	✓
0.9	0.5	1000		0.9	0.5	1000	
0.9	1	20	✓	0.9	1	20	✓
0.9	1	100	✓	0.9	1	100	✓
0.9	1	1000	✓	0.9	1	1000	✓
0.9	5	1000	✓	0.9	5	1000	✓

The momentary cessation voltage threshold has the most significant impact on how many generators enter momentary cessation following a fault. The delay in recovering active power (whether through a pure delay or a long ramp rate) determines how much energy is lost from each generator that enters momentary cessation. Figure 11 shows the total solar PV output across the Western Interconnection for one of the critical contingencies as the momentary cessation threshold is varied. During momentary cessation, solar PV active power reduces by the following:

- ~9,750 MW for Vmc = 0.90 pu
- ~6,275 MW for Vmc = 0.75 pu
- ~2,050 MW for Vmc = 0.50 pu
- ~1,450 MW for Vmc = 0.25 pu

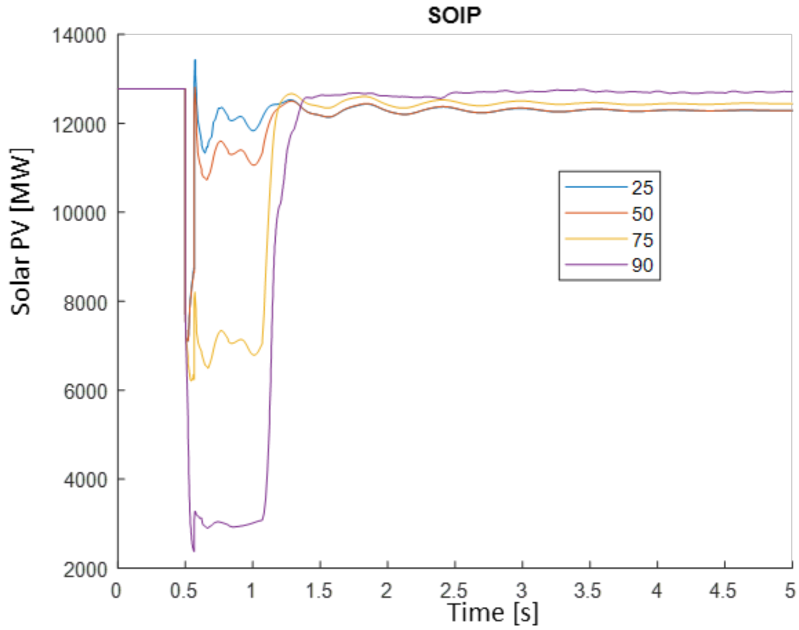

Figure 11: Sensitivity of Active Power Output to Momentary Cessation Threshold Setting

The BPS loses stability for simulations with V_{mc} = 0.9 pu and Δt_{sr} = 0.5 sec (delay), while maintaining stability for lower momentary cessation voltage thresholds. When the momentary cessation threshold is lower (e.g., 0.75 pu or less), the instability cases are resolved. Further reduction in momentary cessation voltage, in conjunction with reduction of the delay in recovery and increase in ramp rate, will help support wide-area stability. Figure 12 illustrates how the instability is a transient stability issue rather than a frequency stability issue. As more resources are instantaneously lost, the system is unable to withstand the sudden change and loses synchronism. On the other hand, if the initial change in power is not significantly large, the system is able to withstand the loss for 15+ seconds. Frequency instability does not occur for these drastic delays in response (used for illustrative purposes only).

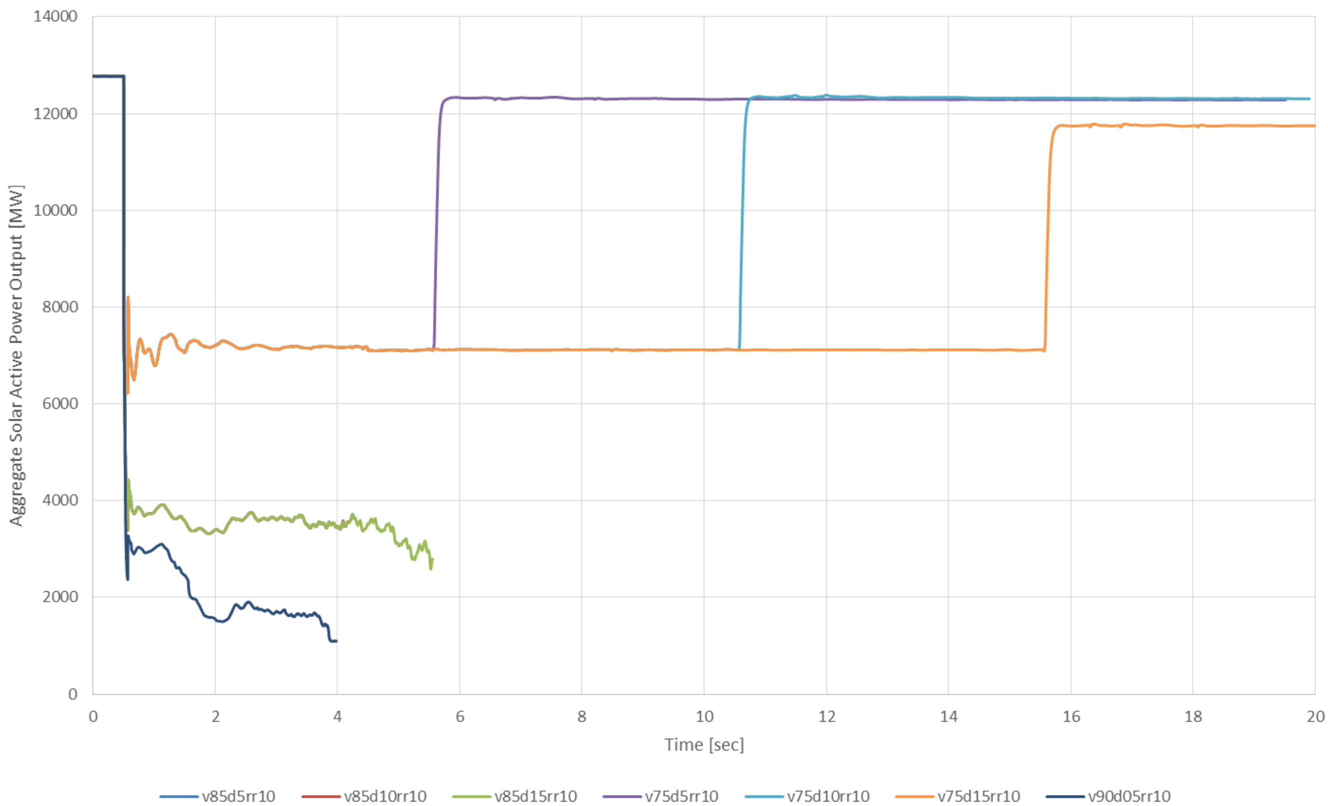

Figure 12: Illustration of Transient Stability Issues for Large Solar PV ΔP

The instantaneous change in active power output from a significant amount of solar PV resources across a wide area of the BPS was determined to be the primary cause of transient instability. The active power loss is concentrated in one general region (CA, NV and AZ). Different response times from the Northwest and Southeast parts of the system result in power swings between the west and east. Instead of frequency simply declining until instability, the eastern part of the system accelerates and the western part decelerates. This leads to rotor angle instability and system separation.

Figure 13 shows a sequence of voltage contour plots across the Western Interconnection. The top left plot shows the on-fault condition when voltages are depressed. Solar resources located in the area shaded light or dark blue are likely to enter into momentary cessation (with V_{mc} = 0.9 pu) for a 3-phase bolted fault at the critical location. Once the fault clears, voltages recover in most areas. However, the transient swings across interties that are caused by momentary cessation cause the system separate. Figure 14 shows the phase angles across the Western Interconnection during the sequence of events. It is clear from the geographic plots that momentary cessation can have a widespread impact to BPS reliability if it occurs for a significant number of inverter-based resources (even if they are located in a similar region of the overall interconnection).

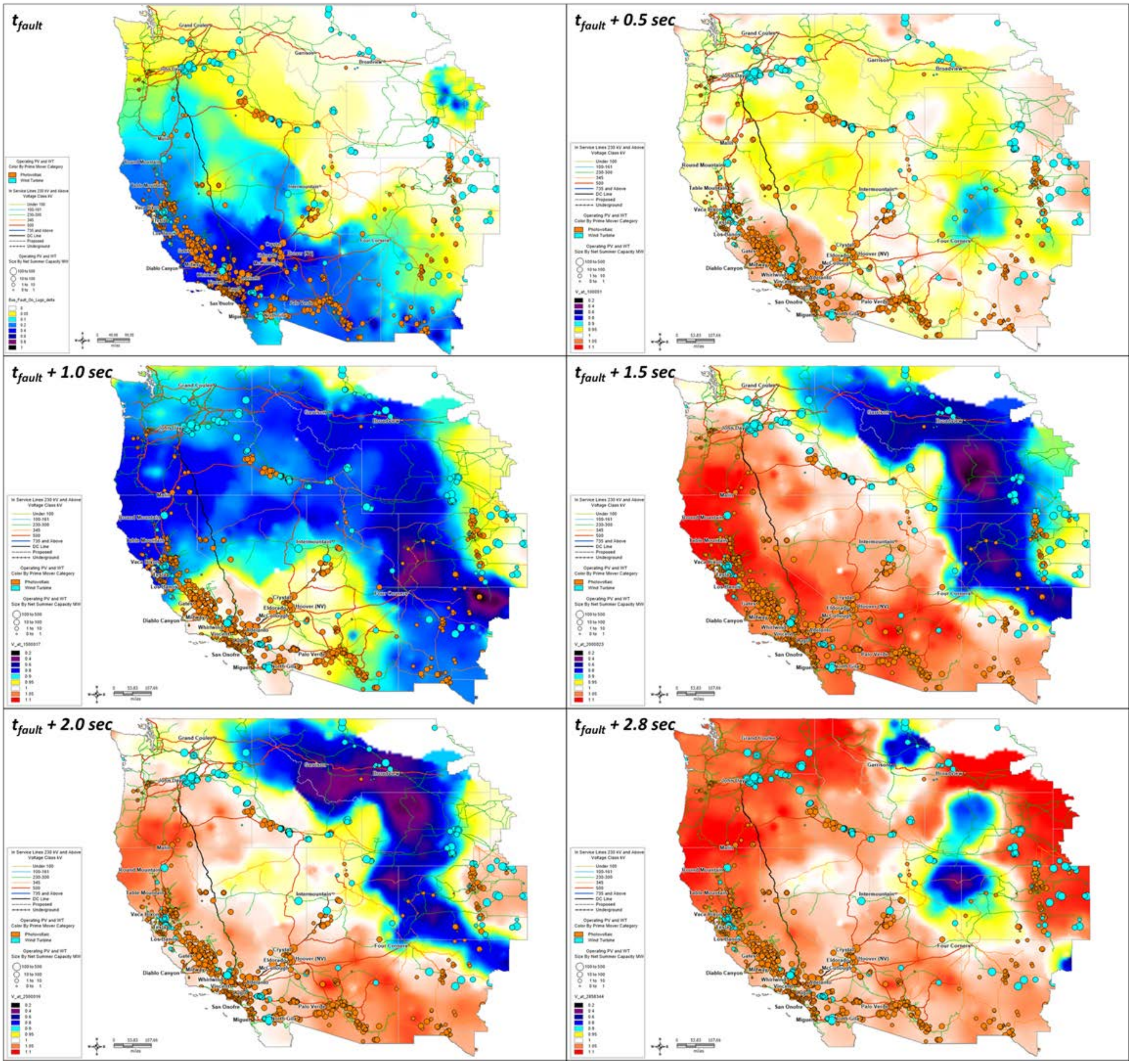

Figure 13: Voltage Contour Plots of Wide-Area Instability

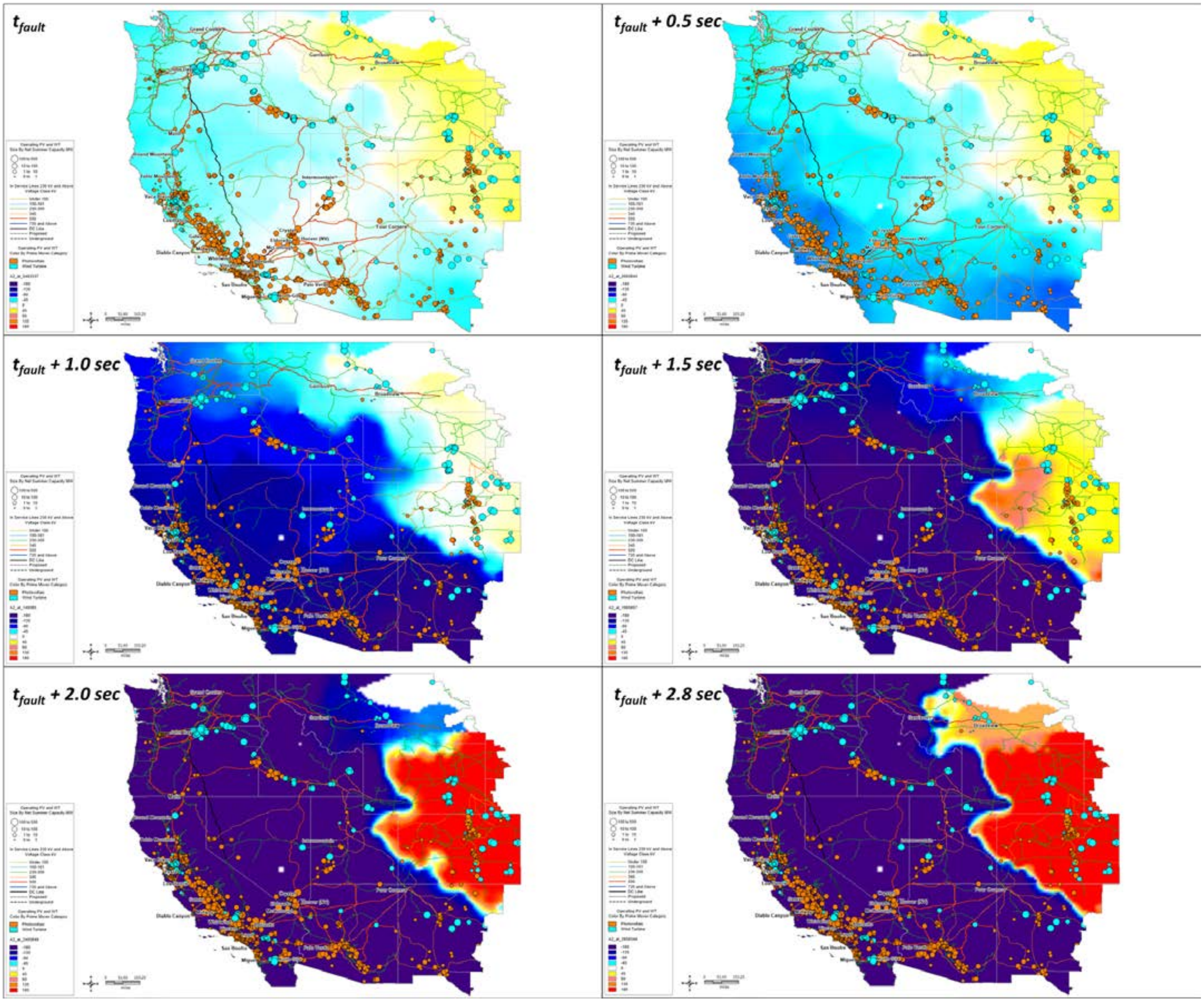

Figure 14: Phase Angle Contour Plots of Wide-Area Instability

The BPS in not designed to withstand an instantaneous loss of 10-12 GW, and studies show that this reduction in active power for more than a very short period (e.g., around 0.5 seconds) will cause system separation. This causes significant pickup of the major interties across the Western Interconnection. Figure 15 shows the change in major intertie power flows for the unstable simulation while Figure 16 shows the change in flows for the 2PV benchmark simulation. Notice how in the unstable case, the path flows pick up over twice as much power flow very quickly. These large magnitude, fast transient swings in power across large portions of the BPS pose significant reliability issues if not planned for ahead of time.

90/0.5/100%/sec Substation “A”

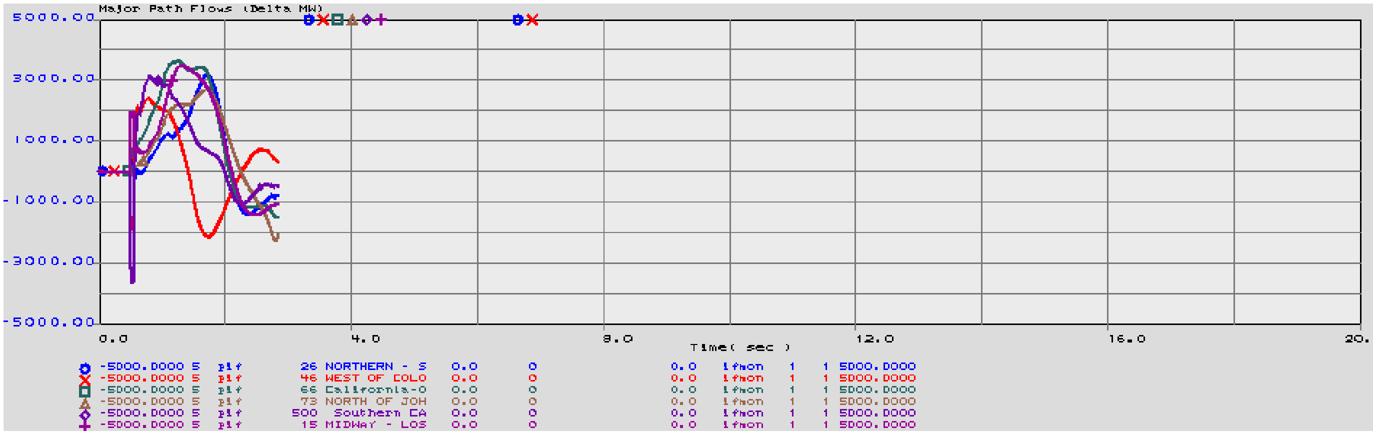

Figure 15: Major Western Interconnection Intertie Power Flows – Unstable Case

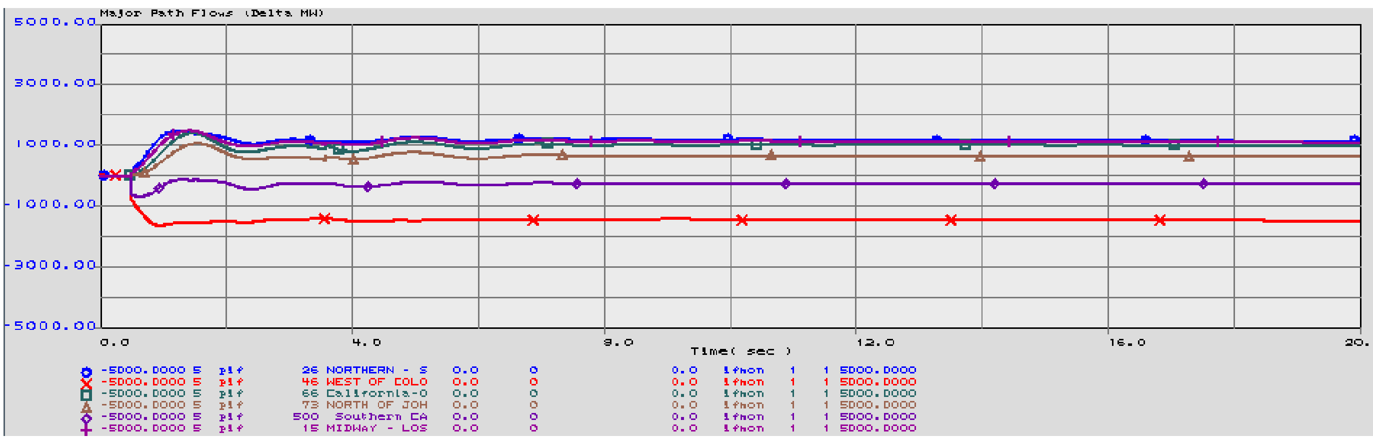

Figure 16: Major Western Interconnection Intertie Power Flows – 2PV Benchmark Case

3-Phase, Normally Cleared Fault with N-1 Gen Trip

The IRPTF studied potential credible fault contingencies near generating resources that could potentially result in an N-1 resource loss caused by clearing the fault on the generator step up (GSU) transformer as well as momentary cessation resulting from depressed system voltages during the fault. Figures 17 and 18 compare simulation results for these “N-1 Resource Loss + Fault” cases with the 2PV benchmark case. Large synchronous generating resources located near significant amounts of solar PV resources were selected for this sensitivity. In particular, Palo Verde, Navajo, Intermountain, and Diablo Canyon were selected and compared against the 2PV benchmark contingency. Conservative expected momentary cessation settings of 0.9 pu voltage, 0.5 second delay, and 100%/sec ramp rate were used for the study.

Results show that the fault contingencies resulting in N-1 loss of a single generating resource, including the effects of momentary cessation, are less severe than the 2PV benchmark case. The minimum nadir for these contingencies is occurs for the “Fault + Diablo Canyon N-1” contingency, where frequency falls to 59.62 Hz.

The frequency nadir is much sooner and the ROCOF is steeper; however, again, this is to be expected for momentary cessation of a large amount of solar PV resources.

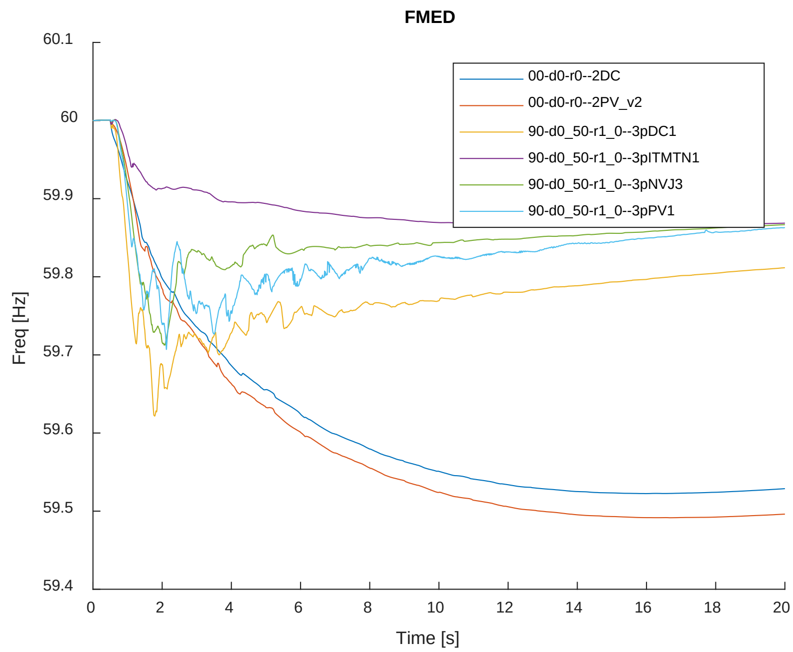

Figure 17: System Frequency for Fault + N-1 Generation Loss Simulations

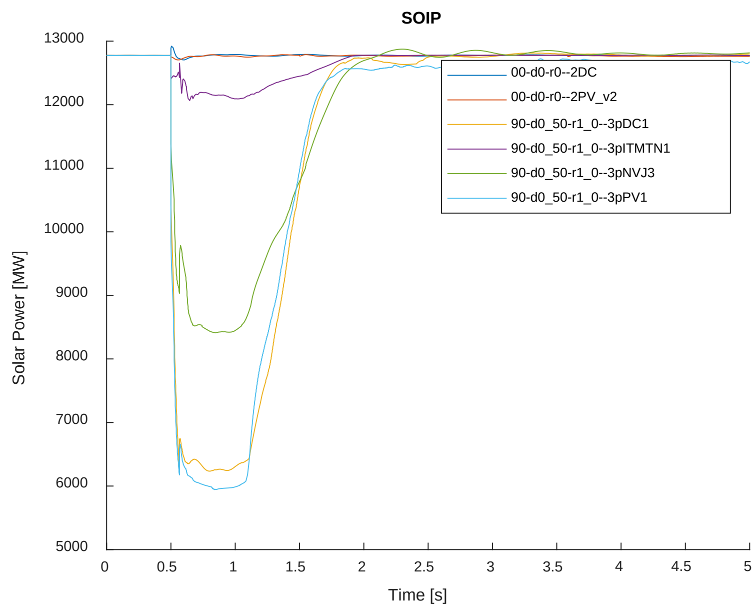

Figure 18: Solar Power Output for Fault + N-1 Generation Loss Simulations

Key Findings and Recommendations

The following key findings are an outcome of the studies performed by the IRPTF:

- The Western Interconnection Resource Loss Protection Criteria (RLPC) does not require modification to account for impacts of momentary cessation of solar PV resources. Interconnection frequency remains above the benchmark RLPC (loss 2 Palo Verde units) for all momentary cessation simulations.[17]
- Expected momentary cessation settings for the majority of solar PV resources connected to the BPS include:
  - Momentary cessation voltage threshold – 0.9 pu
  - Delay upon voltage recovery – 0-0.5 sec
  - Active power ramp rate – 100%/sec
- The models currently used in the interconnection-wide models used to plan the BPS do not sufficiently capture the effects of momentary cessation that are currently used by existing resources. A user-defined model was add to sufficiently capture all the effects of momentary cessation for the purposes of this study.
- For normally-cleared, three-phase bolted faults at certain locations in the Western Interconnection, upwards of 9,000 MW of solar PV resources could enter momentary cessation. The voltage depression caused by a fault at a 500 kV bus has a widespread impact on grid voltage during on-fault conditions and can be felt by solar PV resources across a large geographic area.
- With momentary cessation settings of V_{mc} = 0.9 pu, Δt_{sr} = 0 sec, and Δt_{rr} = 100%/sec, interconnection frequency does not reach a frequency nadir lower than the 2 Palo Verde N-2 benchmark contingency for all fault contingencies studied.
- With momentary cessation settings of V_{mc} = 0.9 pu, Δt_{sr} = 0.5 sec, and Δt_{rr} = 100%/sec, interconnection frequency does not reach a frequency nadir lower than the 2 Palo Verde N-2 benchmark contingency for all stable contingencies studied.
- Of the contingencies studied[18], two bus locations were identified where potential transient instability conditions could occur under the studied operating conditions. The transient instability is caused by excessive transfer of inter-area power flows during and after momentary cessation. The large angular swings resulting from momentary cessation result in system-wide uncontrolled separation.
- For the minimum reserve requirements case developed for the purposes of this study, the benchmark 2PV N-2 contingency has a minimum frequency nadir that falls below the highest stage of UFLS (i.e., 59.5 Hz).

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[17] While transient stability occurs for certain critical fault locations identified in the simulation, this is not considered a frequency stability issue and should not affect the RLPC.

[18] While the contingencies simulated were temporary bus faults, these proved to be equally as severe as a normal N-1 contingency where the faulted element is removed from service when the fault is cleared. This is because the momentary cessation has already occurred by the time the fault is cleared.

The following recommendations are made based on the key findings and simulation results:

- No change to the Western Interconnection RLPC is recommended, based on the studies performed by IRPTF.
- Modeling improvements should be made by all GOs of solar PV facilities connected to the BPS. A NERC Modeling Notification should be developed to provide guidance on how to accurately model momentary cessation using the generic second generation renewable energy system models.
- Modeling improvements to capture the effects of momentary cessation should be made in both the long-term planning models as well as the operations planning and real-time models. Planning Coordinators, Transmission Planners, Transmission Operators, and Reliability Coordinators should ensure that their models accurately capture the dynamic behavior of solar PV resources. These entities should coordinate with their respective Generator Owners in their footprint to ensure models are accurately capturing momentary cessation.
- Momentary cessation during transient low voltage conditions should be eliminated for future solar PV resources connecting to the BPS, and should be mitigated to the greatest extent possible for existing solar PV resources connected to the BPS. Momentary cessation poses potential risks to grid transient and voltage stability, caused by the large changes in power flow when multiple solar PV resources enter into momentary cessation.
- Potential stability issues may exist in the Western Interconnection under different operating conditions, particularly under daytime summer conditions where electric demand is higher, major interties are more heavily loaded, and reactive reserves are tighter. These conditions should be studied in more detail by the IRPTF.
- The IRPTF should provide guidance as to the recommended performance of solar PV resources during ride-through conditions. In particular, since momentary cessation is not recommended moving forward, the type of current injection (e.g., active vs. reactive current priority) during ride-through should be specified. These recommendations should have supporting simulations to ensure reliability of the BPS.
- The IRPTF should continue exploring potential mitigating measures[19] to ensure reliability of the BPS. However, the initial IRPTF studies have shown that the most impactful mitigating measure is to eliminate the use of momentary cessation for inverter-based resources across the BPS. This eliminates any potential stability risks that could exist today and in the future.

[19] These measures for future study could include, but are not limited to, minimum reserve/inertia requirements, limitations on transfers across major interties, etc.

Appendix A: Reserve Calculation Methods

Online *spinning reserve* is defined as

$$Reserve_{Spinning} = \sum_{i=0}^{n} K_i * \left(P_{max,i} - P_{gen,i}\right)$$

where n is the total number of online units in the case, K_I is the status of unit *i* (K_i = 1 for online, K_i = 0 for offline), $P_{max,I}$ is the maximum active power output of unit *i*, and $P_{gen,I}$ is the active power output of unit *i*.

Online *frequency responsive reserves* is defined as:

$$Reserve_{FrequencyResponsive} = \sum_{i=0}^{n} K_i * (1 - B_i) * \left(P_{max,i} - P_{gen,i}\right)$$

where n is the total number of online units in the case, K_I is the status of unit *i* (K_i = 1 for online, K_i = 0 for offline), B_I is the "baseload flag"[20] for unit *i* (B_i = 1 for non-frequency responsive, B_i = 0 for frequency responsive), $P_{max,I}$ is the maximum active power output of unit *i*, and $P_{gen,I}$ is the active power output of unit *i*.

Online *frequency responsive reserves to UFLS* are defined as a fraction of the online *frequency responsive reserves* that would be deployed (assuming a 5% droop) up to hitting the first stage of interconnection UFLS (59.5 Hz in the WI):

$$Reserve_{FrequencyResponsive,UFLS} = \sum_{i=0}^{n} K_i * (1 - B_i) * \min\left(P_{max,i} * \frac{0.5}{3}, P_{max,i} - P_{gen,i}\right)$$

The 0.5/3 comes from the basic proportional droop equation where 5% droop means that the unit will move 100% of its available capacity for a 5% change in speed (3 Hz). Therefore we solve for the change in output for a 0.5 Hz change in speed. This gives:

$$0.5\frac{3\ Hz}{1\ pu} = \frac{0.5\ Hz}{X} \rightarrow X = \frac{0.5\ Hz * 1pu}{3\ Hz} = 16.7\%$$

This is simply used as an additional high-level tracking metric for the amount of expected reserves deployable prior to hitting UFLS.

[20] The baseload flag in powerflow and transient stability programs is used to set specific generating units as non-responsive (either in the upward direction, downward direction, or in both directions) even if not dispatched at P_{max}.