February 28, 2019

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: California Independent System Operator Corporation
Docket No. ER19-___-000

Tariff Amendment to Mitigate Temporary Losses of Inverter-based Generators

Dear Secretary Bose:

The California Independent System Operator Corporation ("CAISO") submits this tariff amendment to mitigate reliability issues caused when inverter-based generators[1] go offline or cease to inject current into the grid due to the routine clearing of high voltage transmission faults or transient voltage.[2] In addition, these revisions will establish a platform to collect information that will help educate the CAISO, its grid operators, and stakeholders on the operation of inverter-based generators. This information will support additional steps the CAISO and stakeholders may pursue in the future to enhance the reliability and resiliency of the transmission system. These tariff revisions result from the CAISO's most recent Interconnection Process Enhancements ("IPE") stakeholder initiative. The CAISO requests the Commission accept these tariff revisions effective April 30, 2019.

The proposed tariff revisions are a vital component of the CAISO's effort to maintain grid reliability and resilience given the rapidly changing resource mix and operating conditions on its system. In its comments in Docket No. AD18-7, where the Commission is evaluating the resilience of the bulk power system, the CAISO identified problems arising from inverter-based generator operation as a threat to grid resilience

[1] Inverter-based generators included solar photovoltaic ("PV") and wind resources, *inter alia*.

[2] The CAISO submits this filing pursuant to section 205 of the Federal Power Act, 16 U.S.C. § 824d. Capitalized terms not otherwise defined herein have the meanings set forth in the CAISO tariff, and references to specific sections, articles, and appendices are references to sections, articles, and appendices in the current CAISO tariff and revised or proposed in this filing, unless otherwise indicated.

that must be addressed.[3] The proposed requirements for inverter-based generators will ensure more consistent and reliable operation of these resources.

The volume of inverter-based generators interconnecting within the CAISO's balancing authority area has dramatically increased in recent years. Presently the CAISO's resource fleet includes over 18,000 MW of inverter-based generators.[4] If appropriately configured, these resources have capabilities to support reliable operation of the CAISO's transmission system. However, the sudden loss of inverter-based generators' energy has been a significant reliability challenge for the CAISO in recent years. Inverter-based generators are programmed to trip offline to disconnect from the grid or cease injecting current when they detect transmission conditions that might harm them. Problematically, they frequently do so at times where there is no risk of harm, resulting in the avoidable and sudden loss of hundreds of megawatts of generation. These losses can cause immediate reliability issues or exacerbate them. These generators also frequently take more time than necessary to start injecting current into the system again, leaving grid operators scurrying to re-dispatch generation to balance load. These challenges have resulted from a lack of robust rules for programming inverters to ride through normal transmission faults. As the CEO of the North American Electric Reliability Corporation ("NERC") explained at the Commission's 2018 Reliability Technical Conference, "[E]ffectively what has happened is inverters have many smart capabilities built into them but nobody ever told the inverter owners how to program them. . . ."[5]

The CAISO's proposed tariff revisions address these issues. They are consistent with NERC's recommendations,[6] and result from diligent work by NERC, the CAISO, transmission owners, generation developers, inverter manufacturers, and other CAISO stakeholders. The CAISO has designed its requirements specifically so they can be met easily by current available inverters, without causing any undue financial (or other)

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[3] Comments of the California Independent System operator Corporation in Response to the Commission's Request for Comments about System Resiliency and Threats to Resilience, Docket No. AD18-7, Mach 9, 2018.

[4] This figure only includes commercial CAISO resources registered in the CAISO master file. It therefore excludes rooftop solar generation. http://www.caiso.com/informed/Pages/CleanGrid/default.aspx.

[5] 2018 Reliability Technical Conference regarding the Bulk-power System, Transcript at p. 72, Docket No. AD18-11-000 (July 31, 2018), *available at* https://www.ferc.gov/CalendarFiles/20180827102327-Transcript%20-%20073118ReliabilityTechnicalConference%20(002).pdf?csrt=1547081061294544747. Recent wildfires also have exacerbated this challenge because they increase the frequency of the transmission faults and transient voltage conditions that can trigger these losses.

[6] NERC, "Industry Recommendation: Loss of Solar Resources during Transmission Disturbances due to Inverter Settings," Alert ID R-2017-06-20-01 (June 20, 2017), *available at* https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/NERC%20Alert%20Loss%20of%20Solar%20Resources%20during%20Transmission%20Disturbance.pdf.

burden.

As discussed in detail below, the proposed tariff revisions make significant strides in mitigating reliability issues by achieving the following:

(1) Eliminating unnecessary momentary cessation for inverters during the clearing of a transmission line fault;

(2) Eliminating inverter tripping for momentary losses of synchronism; and

(3) Requiring coordination of the central plant controller with the individual inverter control systems to facilitate reconnection of the inverters following a trip.

The CAISO proposes to memorialize these requirements in the inverter-based generators' interconnection agreements ("GIAs"), similar to the Commission's reforms in Order No. 842 to require equipment capable of providing primary frequency response.[7] As such, they will apply to resources that execute an interconnection agreement after the date the revisions take effect,[8] and to existing resources that request GIA modifications to repower or replace inverter equipment for reasons other than individual inverter replacement in kind (*e.g.,* due to individual inverter failure or other routine maintenance issues).[9] For GIA modifications that seek to repower or replace inverter equipment, existing resource owners must contact the CAISO for approval.[10] Replacing an individual inverter due to failure or for purposes of routine maintenance does not require the resource to submit a modification request or notify the CAISO.

Additionally, the CAISO proposes that new inverter-based generators above 20 MW in capacity install specific diagnostic equipment to monitor their resources' output and record transient data during certain events. Installing this equipment is neither costly nor burdensome because it generally is already included in system controls. Having access to these data will ensure that the CAISO and the generator can determine the cause of any unexpected or persistent issue, which has been a challenge to date.

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[7] *Essential Reliability Services and the Evolving Bulk-Power System—Primary Frequency Response*, FERC Order No. 842, 162 FERC ¶ 61,128 (2018).

[8] Or request the filing of an unexecuted agreement.

[9] Proposed Section 25.4.2 of the CAISO tariff.

[10] *See generally* CAISO tariff section 25.5; Article 5.19 of Appendix EE to the CAISO tariff.

I. Background

A. Inverters

Virtually all modular, asynchronous, renewable generators (*e.g.*, solar PV, wind turbines) produce electricity in the form of direct current ("DC") or variable frequency alternating current ("AC"), while the electric grid generally is designed to transmit this electricity in the form of AC at a frequency equal to 60 Hz.[11] The most basic function of inverters is to change DC or variable frequency AC to 60 Hz AC for the transmission and delivery of the electricity the generators produce.[12] But inverters also monitor grid conditions and provide controls to ensure electricity from the generating unit is deliverable. Specifically, inverters monitor the voltage and frequency of the grid and synchronize the generator's production to inject more or less current as needed. If the inverters detect grid conditions that could harm the generator, the inverters are programmed to trip: a circuit breaker between the inverter and the grid opens so that electricity does not flow between them. These grid conditions are called "faults," and can refer to any abnormal current, including short circuits, low or high voltages, or frequency deviations. Most faults on the transmission grid are "transient," meaning that they occur momentarily and often can be remedied in less than one second by "clearing" the fault by disconnecting and restoring power on the impacted line. For example, transient faults can occur when animals or smoke from wild fires contact electrical lines.[13]

Modern inverters are sophisticated in detecting and responding to faults. In general they are designed to "ride-through" most fault conditions so that the generators do *not* disconnect from the grid. This function is critical because grid operators must balance generation and load equally at all times to maintain frequency and ensure reliability. As such, the Commission, NERC, and the Institute of Electrical and Electronics Engineers ("IEEE") also have instituted a number of rules, recommendations, and guidelines regarding when and how inverters should ride-through or respond to faults. As demonstrated below, however, these rules have resulted in regulatory gaps. The CAISO's recent reliability issues have occurred despite inverter-based generators' general compliance with these rules.

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11 *See, e.g.,* Jill Jones, EMPIRES OF LIGHT, Random House (2004).

12 *See* Sun Run, "Solar Inverter – Definition," ***available at*** https://www.sunrun.com/go-solar-center/solar-terms/definition/solar-inverter.

13 Non-transient faults are known as persistent faults.

B. Current Regulatory Requirements

The Commission has required large generators[14] to ride-through certain fault conditions since Order No. 2003, and small generators since Order No. 828.[15] Consistent with these requirements, the CAISO's *pro forma* large generator interconnection agreement ("LGIA") and small generator interconnection agreement ("SGIA") contain detailed provisions specifying that generators must comply with the ride-through requirements of applicable reliability standards. Asynchronous generators also must comply with the specific requirements set forth in Appendix H to the LGIA and Attachment Seven to the SGIA. These requirements include, *inter alia*:

- Remaining online for the voltage disturbance caused by any fault less than the normal three-phase fault clearing time (4-9 cycles) or one-hundred fifty (150) milliseconds;
- Remaining online for any voltage disturbance caused by a single-phase fault on the transmission grid;
- Providing SCADA[16] capability to transmit data and receive instructions from the transmission owner and the CAISO to protect system reliability.[17]

These requirements apply where the voltage at the generators' point of interconnection has remained within the range of 0.9 and 1.10 per-unit of nominal voltage for the preceding two seconds. For faults lasting longer than or farther outside of the nominal voltage ranges described above, these generators are allowed to trip.[18] When they do so, there is *no* requirement that they return online within any specified period, or that they return online within a prescribed ramping rate.

Generators subject to NERC requirements also must abide by reliability standard PRC-024-2, "Generator Frequency and Voltage Protective Relay Settings." NERC states that the purpose of this requirement is to "ensure Generator Owners set their generator protective relays such that generating units remain connected during defined

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14 Large generators are those generators subject to Large Generator Interconnection Agreements.

15 *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at P 562 (2003) ("Order No. 2003"); *Requirements for Frequency and Voltage Ride Through Capability of Small Generating Facilities*, Order No. 828, 156 FERC ¶ 61,062 (2016) ("Order No. 828").

16 SCADA is supervisory control and data acquisition.

17 *See* Appendix H to Appendix EE to the CAISO tariff.

18 *Id*.

frequency and voltage excursions."[19] PRC-024-2 requires a generator with protective relays to "set its protective relaying such that the generator frequency protective relaying does not trip the applicable generating unit(s) within the 'no trip zone.'"[20] The following table (Figure A) reflects the no-trip zones in the Western Interconnection for both high and low frequency disturbances,

Figure A: Western Interconnection No-trip Zones

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

The parameters in this table mean, for example, that a generator may trip instantaneously if the frequency rose above 61.7 Hz, or if the frequency remained at 60.6 Hz for 180 seconds.[21] PRC-024-2 also provides that generators may trip "due to an impending or actual loss of synchronism," "if clearing a system fault necessitates disconnecting," or "for documented and communicated regulatory or equipment limitations."[22]

To be sure, generators are not *required* to trip in any circumstance. The purpose of PRC-024-2 is merely to ensure that generators subject to NERC requirements do *not* trip within the no-trip zone. However, a significant and growing portion of the CAISO's inverter-based generation fleet is not subject to NERC requirements because these generators are not connected to the bulk electric system, are smaller than 75 MVA, or both.[23] As such, the CAISO's LGIA and SGIA provisions provide enhanced regulatory

19 PRC-024-2 at A.3.

20 *Id*. at B.R1.

21 *Id*. at Attachment 1.

22 *Id*. at B.R1.

23 *See* NERC, Glossary of Terms, "Bulk Electric System," *available at* https://www.nerc.com/files/glossary_of_terms.pdf.

certainty and ensure that all transmission interconnected generators are subject to similar rates, terms, and conditions of service, regardless of whether they are subject to NERC standards. As Order No. 828 described, NERC "has found that a lack of coordination between small generating facilities and Reliability Standards can lead to events where system load imbalance may increase during frequency excursions or voltage deviations due to the disconnection of distributed energy resources, which may exacerbate a disturbance on the Bulk-Power System."[24]

Additionally, the Energy Policy Act of 2005 requires electric utilities to offer interconnection service on their distribution systems "based upon the standards developed by the Institute of Electrical and Electronics Engineers: IEEE Standard 1547[a] for Interconnecting Distributed Resources with Electric Power Systems."[25] IEEE Standard 1547a contains "must trip" requirements, but does not contain "must ride through requirements" like PRC-024-2.[26] As the Commission has stated, IEEE 1547a thus "allows generators to ride through disturbances, but they are not required to do so."[27] Based upon this standard, the Commission held that it had become appropriate to impose ride-through requirements on small generating facilities "to remedy undue discrimination by ensuring that small generating facilities have ride through requirements comparable to large generating facilities."[28] The Commission noted that "[t]he absence of ride through requirements for small generating facilities increases the risk that an initial voltage or frequency disturbance may cause a significant number of small generating facilities to trip across a particular area or Interconnection, further exacerbating the initial disturbance."[29]

The gaps between PRC-024-2 and IEEE 1547 are manifold. The former applies based on a generator's size and level of interconnection and imposes a no-trip zone, the latter applies solely to the level of interconnection and does not impose a no-trip zone. The losses described below have occurred despite inverter-based generators' general compliance with current applicable standards. For these reasons, the CAISO is proposing standard performance requirements in its GIAs, irrespective of resource size or interconnection voltage, for all resources that interconnect to the transmission system under the CAISOs control.

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24 Order No. 828 at P 8.

25 16 U.S.C. § 2621(d)(15) (2018).

26 Order No. 828 at P 7 n. 13.

27 *Id*.

28 *Id*. at P 11.

29 *Id*.

C. Recent Losses due to Inverter Settings

Despite the standards discussed above, the CAISO has experienced numerous reliability events when inverter-based generators either tripped or ceased injecting current even though the faults that triggered those trips were cleared almost instantaneously. Each event resulted in the loss of a substantial amount of generation. The following table (Figure B) lists some of these events, including the approximate amount of generation lost as a result of inverters' tripping offline or entering into momentary cessation:[30]

Figure B: Recent Generation Losses due to Inverter Settings

Date	Daily Total Generation Lost	Time	Generation Lost	Transmission Line
August 16, 2016	1,753 MW	11:45 AM	1178 MW	Lugo – Mira Loma No.3 (500 kV)
		2:04 PM	234 MW	Lugo – Mira Loma No.3 (500 kV)
		3:13 PM	311 MW	Lugo – Mira Loma No.2 (500 kV)
		3:19 PM	30 MW	Lugo – Mira Loma No.2 (500 kV)
September 6, 2016	755 MW	1:17 PM	755 MW	Kingbird – Whirlwind (220 kV)
November 12, 2016	231 MW	10:00 AM	231 MW	Victorville Sub (LADWP) (220 kV)
February 6, 2017	740 MW	12:13 PM	740 MW	Antelope – Vincent No.2 (500 kV)
May 10, 2017	543 MW	12:00 PM	543 MW	Hassayampa – Hoodoo Wash (500 kV)
June 15, 2017	813 MW	1:00 PM	813 MW	Victorville – McCullough (500 kV)
October 9, 2017	1,619 MW	12:12 PM	682 MW	Serrano – Chino (220 kV)
		12:14 PM	937 MW	Serrano – Valley (500 kV)
April 20, 2018	694 MW	5:11 PM	694 MW	Mira Loma – Vincent (500 kV)
May 11, 2018	618 MW	3:20 PM	618 MW	Antelope – Vincent No.2 (500 kV)

These losses were significant. Four of the events represented instant losses of approximately four percent of the CAISO's total generation.[31] The October 9, 2017 event represented the loss of 8.1 percent of CAISO generation in just three minutes. These events require CAISO operators to take immediate and significant actions, frequently out of the market, to maintain or restore system stability, frequency, and

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[30] As discussed below, the amount of generation lost is an approximation because of the difficulty in gathering data on inverter tripping after events occur. Nevertheless, the CAISO believes these approximations are very close to the actual figures based on the CAISO's analysis of generation and load at the time.

[31] August 16, 2016 (11:45 AM), February 6, 2017, June 15, 2017, and April 20, 2018. The CAISO's load and generation data are available on the CAISO's public OASIS: http://oasis.caiso.com/mrioasis/logon.do.

voltage.

After the August 16, 2016 event, the NERC Operating Committee established a task force including staff from the Commission, NERC, the Western Electricity Coordinating Council ("WECC"), the CAISO, Southern California Edison Company ("SCE"), the Electric Reliability Council of Texas, generator owners, and inverter manufacturers. The task force helped develop a NERC Report on the August 16, 2016 event, and a separate industry recommendation issued through a NERC Alert on June 20, 2017.[32] The task force's initial "Key Finding" was that "inverters that trip instantaneously based on near instantaneous frequency measurements are susceptible to erroneous tripping during transients generated by faults on the power system."[33] The loss of inverter-based generation on August 16, 2016 is fairly typical of all of the loss events listed above, and illustrate the need for the CAISO's proposed tariff revisions in addition to the current regulatory requirements. The CAISO discusses it here as an example; however, all of the listed above have been significant reliability events that warrant reform.

According to the NERC Report, on August 16, 2016, the Blue Cut forest fire encroached upon "an important transmission corridor" consisting of three 500 kV lines owned by SCE and two 287 kV lines owned by the Los Angeles Department of Water and Power ("LADWP").[34] 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.[35] The NERC Report noted that "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."[36]

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[32] NERC, "Industry Recommendation: Loss of Solar Resources during Transmission Disturbances due to Inverter Settings," Alert ID R-2017-06-20-01 (June 20, 2017), *available at* https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/NERC%20Alert%20Loss%20of%20Solar%20Resources%20during%20Transmission%20Disturbance.pdf. NERC clarified and expanded on this recommendation in two subsequent publications. On February 27, 2018 NERC issued a Modeling Notification titled "Recommended Practices for Modeling Momentary Cessation." On May 1, 2018, NERC revised its June 20, 2017 Alert based upon the task force's findings.

[33] NERC, "1,200 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report: Southern California 8/16/2016 Event," p. v, published June 2017 ("NERC Report"), *available at* https://www.nerc.com/pa/rrm/ea/1200_MW_Fault_Induced_Solar_Photovoltaic_Resource_/1200_MW_Fault_Induced_Solar_Photovoltaic_Resource_Interruption_Final.pdf.

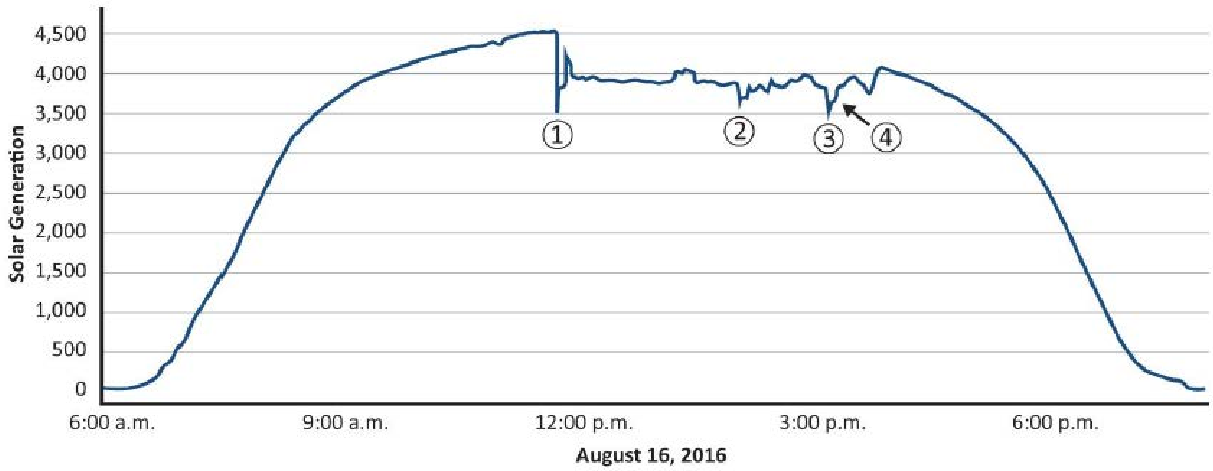
[34] NERC Report at p. 1.

[35] *Id*. Importantly, the faults should not be mistaken for outages, as the transmission lines in question remained in service.

[36] *Id*.

All of the faults resulted in a drop in frequency, with the lowest frequency occurring at 59.867 Hz.[37] Moreover, all of the faults were cleared by SCE between 3.45 and 2.49 cycles, or approximately between 0.04 and 0.06 seconds.[38] The following graph (Figure C) illustrates the utility-scale solar PV output in SCE on August 16, 2016:[39]

Figure C: August 16, 2016 Solar PV in SCE - Day



Based on information provided by the inverter manufacturers, solar development owners and operators, SCE, and the CAISO, the NERC Report determined that the largest percentage of the resource loss (~700 MW) was due to "a perceived, though incorrect, low system frequency condition that the inverters responded to by tripping."[40] The NERC Report stated:

> 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-024-24 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.[41]

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37 *Id*. at pp. 1-2.

38 *Id*. at p. 2.

39 *Id*. at p. 3.

40 *Id*. at p. 4. NERC defines tripping as ceasing to energize and not returning to service for five minutes or more.

41 *Id*.

NERC noted that among the largest contributors to losses, tripping was the "most impactful," because "it removes the resource from the interconnection" for at least five minutes.[42]

The second largest significant contributor (~450 MW lost) was due to "inverter momentary cessation due to system voltage reaching the low voltage ride-through setting of the inverters."[43] The NERC Report stated:

> 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) and at a defined ramp rate. 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).[44]

The following graph (Figure D) illustrates utility-scale solar PV generation in SCE on August 16.[45]

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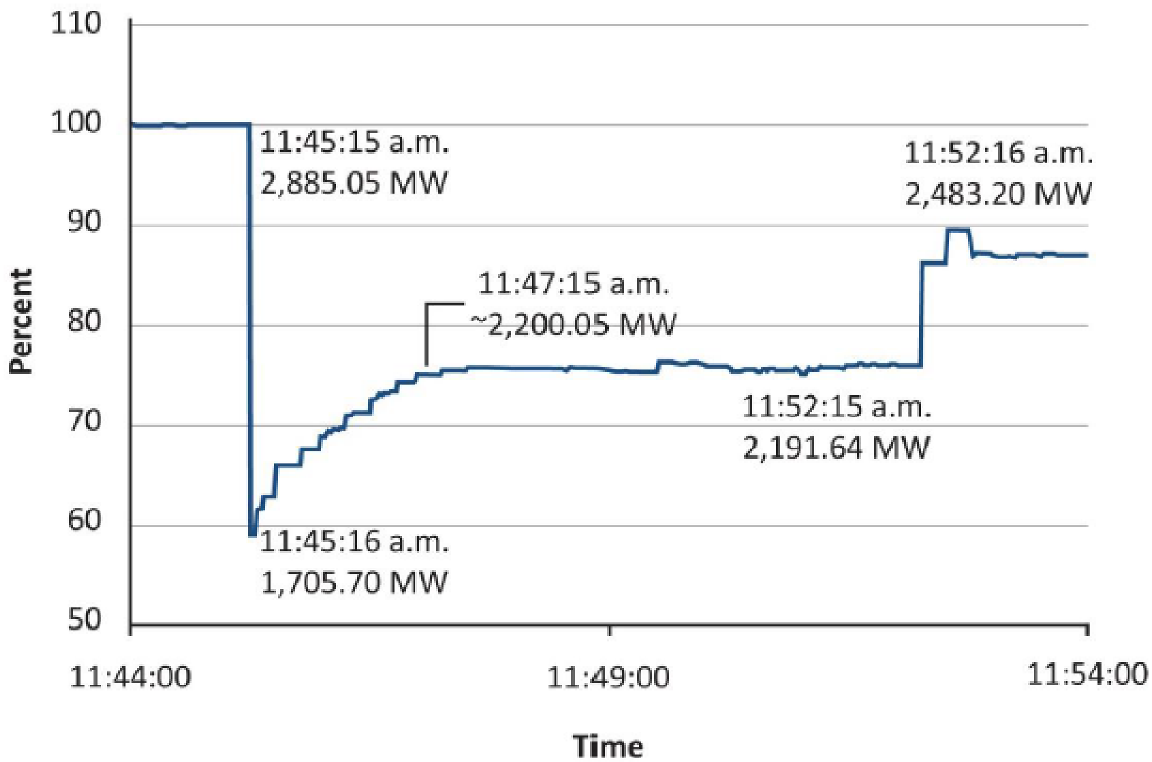
42 *Id*. at p 5.

43 *Id*.

44 *Id*.

45 *Id*.

Figure D: August 16, 2016 Solar PV in SCE - Morning



NERC noted that "[s]ome inverter manufacturers and Generator Owners have interpreted the no-trip area of the PRC-024-2 curves to allow momentary cessation," and because some GIAs allow momentary cessation during voltages less than 0.9 per unit or above 1.1 per unit, some generators believe that momentary cessation is allowed in the PRC-024-2 no-trip area.[46] NERC's CEO explained the concerns with this interpretation at the Commission's 2018 Reliability Technical Conference:

> One of the issues we've always been concerned about and manifested itself in August of [2016] was that in the course of an event that inverters would start to act in tandem and that they would actually elect to protect the equipment more than protect the grid because there was never any guidance as to what they needed to do to protect the grid.
>
> They all calculated it differently . . . so they all started to behave inappropriately, and again, a loss of 1200 megawatts is a substantial event, particularly on a hot day in the summer in California.[47]

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[46] *Id*.

[47] *See* 2018 Reliability Technical Conference regarding the Bulk-power System, Transcript at pp. 72 *et seq.*, Docket No. AD18-11-000 (July 31, 2018), *available at* https://www.ferc.gov/CalendarFiles/20180827102327-Transcript%20-%20073118ReliabilityTechnicalConference%20(002).pdf?csrt=1547081061294544747.

During losses such as these, the CAISO must arrest the frequency decline due to the sudden load/generation imbalance. The CAISO's—and most balancing authorities'—primary tool to do so is generation reserves with primary frequency response capabilities.[48] If the reserves are insufficient to cover the losses, the balancing authority is forced to rely on load shedding.[49]

At the time of the August 16, 2016 event, the CAISO had 9,800 MW of utility-scale solar PV generation installed,[50] not including "rooftop solar."[51] During light load days, almost half of CAISO load has been served by utility-scale solar.[52] The NERC Report noted that "this widespread disconnection of inverter connected resources is a significant concern for CAISO. Additionally, with the proliferation of solar in many balancing areas across North America, this issue needs to be resolved to ensure interconnection reliability."[53]

In response to the August 16, 2016 event and the similar loss events listed above, many generator owners reconfigured their inverters and protective relays to avoid the unnecessary trips and momentary cessation that caused these events. Although such actions have helped abate the magnitude and frequency of these events, the risk of future events will remain until all inverter-based generators are required to program their inverter internal protection and protective relays consistently.

D. NERC Recommendations

To provide guidance for addressing these issues in the future, NERC also published a separate industry recommendation through a NERC Alert on June 20, 2017.[54] This alert made four recommendations:

1. Inverter-based generators should ensure that inverter controls will not trip due to an erroneous instantaneous frequency measurement during

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48 *Id* at pp. 5-6.

49 *Id*.

50 *Id*. at p 6.

51 Rooftop solar PV is installed behind the retail customer meter and generally does not have telemetry.

52 *Id*.

53 *Id*.

54 NERC, "Industry Recommendation: Loss of Solar Resources during Transmission Disturbances due to Inverter Settings," Alert ID R-2017-06-20-01 (June 20, 2017), *available at* https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/NERC%20Alert%20Loss%20of%20Solar%20Resources%20during%20Transmission%20Disturbance.pdf.

transients on the power system;[55]

2. If inverters momentarily cease to inject current for voltages above 1.1 per unit or below 0.9 per unit during abnormal voltage conditions, generators should ensure the time to restore output of the inverter to the state prior to the abnormal voltage conditions is as soon as practical, but no greater than five seconds;[56]

3. If the equipment identified in recommendations 1 and 2 are left unmitigated, Reliability Coordinators and Balancing Authorities should identify which inverter-based plants are unmitigated, and consider in their daily resource plan the potential for the loss of these resources during transmission faults on the power system. Reliability Coordinators and Balancing Authorities should take appropriate mitigating measures;[57] and

4. Generators should provide data regarding these recommendations for each plant in service to NERC and to their Reliability Coordinator, Balancing Authority, and Transmission Operator.[58]

As shown on Figure B above, even after the issuance of this NERC Alert, generation losses have occurred on the CAISO system as the result of problematic inverter settings.

NERC clarified and expanded on these recommendations in two subsequent publications. On February 27, 2018, NERC issued a Modeling Notification titled "Recommended Practices for Modeling Momentary Cessation"[59] that recommended generators obtain and understand a prescribed list of modeling data from their inverter manufacturers regarding momentary cessation. The Modeling Notification also recommended that generators provide updated models to their transmission providers as soon as available.

On May 1, 2018, NERC revised its June 20, 2017 Alert based upon the task force's findings.[60] NERC's revised recommendations included the following:

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55 *Id*. at p. 2.

56 *Id*. (The second alert on this topic, described below, revised this requirement to one second).

57 *Id*. at p. 3.

58 *Id*. at pp. 3-5 (describing the data to be provided).

59 NERC, "Modeling Notification: Recommended Practices for Modeling Momentary Cessation," February 27, 2018, *available at* https://www.nerc.com/comm/PC/NERCModelingNotifications/Modeling_Notification_-_Modeling_Momentary_Cessation_-_2018-02-27.pdf.

60 NERC, "Industry Recommendation: Loss of Solar Resources during Transmission Disturbances due to Inverter Settings – II," Alert ID R-2018-05-01-01, May 1, 2018, *available at* https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/NERC_Alert_Loss_of_Solar_Resources_during_Transmission_Disturbance-II_2018.pdf.

1. (a) Generators should ensure that their dynamic models are accurate consistent with the Modeling Notification;[61]

1. (b)[62] Generators should work with inverter manufacturers to eliminate momentary cessation to the greatest extent possible. For inverters where momentary cessation cannot be eliminated entirely (*i.e*., by using another form of ride-through mode), generators should identify the changes that can be made to momentary cessation settings that result in:

   a) Reducing the momentary cessation low voltage threshold to the lowest value possible;

   b) Increasing the momentary cessation high voltage threshold to the highest value possible, at least higher than the NERC Reliability Standard PRC-024-2 voltage ride-through curve levels;

   c) Reducing the recovery delay (time between voltage recovery and start of current injection) to the smallest value possible (i.e., on the order of 1-3 electrical cycles);

   d) Increasing the active power ramp rate upon return from momentary cessation to at least 100% per second,[63] unless specific reliability studies have demonstrated otherwise;[64]

2. Generators should ensure that inverter restoration from momentary cessation is not impeded by plant-level control ramp rates. This could involve adding a short delay before the plant-level controller resumes sending power commands to the individual inverters after voltage recovers and the inverters re-enter continuous operation range;

3. Generators should coordinate with their inverter manufacturers to ensure that they do not interpret the PRC-024-2 "may trip" zone as a "must trip" zone. To the contrary, "[i]t is preferable to avoid instantaneous tripping coupled with an unfiltered voltage measurement that could cause inverters to trip for transient (sub-cycle) overvoltages the inverter could withstand

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[61] *Id*. at p. 2.

[62] The CAISO has included NERC's 1a/1b numbering for consistency between this paper and the alert.

[63] Meaning that the generator should ramp from no output to full output in one second or less.

[64] *Id*. at pp. 2-3.

without tripping;"[65] and

4. Generators should consult with their inverter and solar panel manufacturers to implement inverter DC reverse current protection settings based on equipment limitations, such that the resource will not trip unnecessarily during high voltage transient conditions.[66]

Again, many generator owners have reconfigured their inverters and protective relays consistent with these recommendations, but the risk of future events will remain until all inverter-based generators are required to program their inverter internal protection and protective relays consistently. The CAISO and its stakeholders participated as key members of NERC's task force to analyze these issues. NERC's recommendations formed the foundation for the CAISO's stakeholder initiative, which focused on implementing NERC's recommendations and guidance in a manner tailored to the CAISO's specific needs on a timely basis. The CAISO also conducted its own studies and simulations on momentary cessation and inverter tripping, as discussed in detail below. NERC's task force incorporated the CAISO's study data in its February 2018 white paper, which concluded:

> Momentary cessation during transient low voltage conditions should be eliminated for future solar PV resources connecting to the [Bulk Power System (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.[67]

The CAISO's proposed tariff revisions are consistent with these recommendations, as discussed below.

II. Proposed Tariff Revisions

A. Mitigating Momentary Cessation

The CAISO and its stakeholders developed GIA revisions consistent with existing regulatory standards, NERC's recommendations, and current inverter designs to mitigate the issues discussed above. Consistent with the Commission's similar directive in Order No. 842, these revisions will apply to generators executing GIAs going forward.

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65 *Id*. at p. 3.

66 *Id*.

67 NERC, "Resource Loss Protection Criteria Assessment, February 2018, pg. 2, *available at* https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/IRPTF_RLPC_Assessment.pdf.

Generators that are online or have already executed GIAs would be subject to these requirements only if they request to make modifications that replace their generating units or their inverters (excepting replacements part of routine maintenance or repairs due to malfunction or failure).[68] Based on feedback received from stakeholders, including various inverter manufacturers, the CAISO developed the proposed requirements so that they can be met easily by modern inverters. Generators subject to these requirements should not face any challenge in obtaining and programming inverters to follow them. Based on input from generation developers and inverter manufactures that participated in the NERC task force and the CAISO's stakeholder initiative, the CAISO believes that the cost of meeting these requirements will be *de minimis*.

Pursuant to Order Nos. 2003 and 828, the CAISO's GIAs already specify that asynchronous generating facilities must remain online for transmission faults or voltage disturbances lasting four to nine cycles or 150 milliseconds, and for single-phase faults. Moreover, the GIAs already specify that clearing time must be based on the maximum normal clearing time associated with any three-phase fault location that reduces the voltage to 0.2 per-unit of nominal voltage or less, independent of any fault current contribution from the generator.[69] As such, the CAISO's proposed revisions essentially clarify the extent to which tripping and momentary cessation are allowed or prohibited within these established rules.

First, the CAISO proposes to clarify that momentary cessation violates the existing requirement to "remain online" under certain specified conditions.[70] The CAISO proposes to remove any existing ambiguity in the tariff by specifying that momentary cessation—ceasing to inject current during a fault—is prohibited unless transient high voltage conditions rise to 1.20 per unit or more, consistent with the Commission's current ride-through requirement. This proposal is just and reasonable because it will greatly help to mitigate the reliability issues discussed above without imposing any burden on the generators that will be subject to this requirement. The CAISO's proposal also is consistent with NERC's recommendation "to eliminate momentary cessation to the greatest extent possible."[71] For transient low voltage conditions, the

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[68] Proposed Section 25.4.2 of the CAISO tariff.

[69] *See* Section A(i)(1) and (2) of Appendix H to Appendix EE; Sections A(i)(1) and (2) of Attachment 7 to Appendix FF.

[70] Proposed Section A(i)(3) of Appendix H to Appendix EE; proposed Section A(i)(3) of Attachment 7 to Appendix FF.

[71] NERC, "Industry Recommendation: Loss of Solar Resources during Transmission Disturbances due to Inverter Settings – II," Alert ID R-2018-05-01-01, at pp. 2-3, May 1, 2018, *available at* https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/NERC_Alert_Loss_of_Solar_Resources_during_Transmission_Disturbance-II_2018.pdf. The CAISO notes that "transient high voltage conditions" and "transient low voltage conditions" refer to the fact that the voltage is high or low relative to nominal levels, whatever they are; not the voltage *capacity* of the lines relative to each other, as in "low voltage lines or high voltage lines." In

generator will inject reactive current directionally proportional to the decrease in voltage. The inverter must produce full rating reactive current when the AC voltage at the inverter terminals drops to a level of 0.50 per unit, and must continue to operate and attempt to maintain voltage for transient voltage conditions between 1.10 and 1.20 per unit.[72] The requirements are different between transient high voltage conditions and transient low voltage conditions because during low voltage conditions (but not high), prioritizing the injection of reactive power provides voltage support to the system and helps to mitigate transient low voltage conditions. Synchronicity would neither hurt nor help, and momentary cessation exacerbates the problem. That said, the CAISO recognizes that generators should not be required to mitigate the voltage delta at risk to their equipment, so the CAISO proposes to require the generators to remain online and provide reactive current only within the existing "no trip" zone.

The CAISO's proposal is the result of its own technical analyses and the IPE stakeholder process. CAISO transmission engineers ran a number of simulations under different conditions to determine the extent to which inverter-based generators will engage in momentary cessation, the impact of doing so, and the CAISO's optimal mitigation.[73] The CAISO's transient stability simulations of the Western Interconnection demonstrate that for faults at critical locations, a three-phase bolted fault[74] could cause more than 9,000 MW of solar PV resources to enter momentary cessation.[75]

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other words, transient low/high voltage conditions can occur on both low voltage transmission lines and high voltage transmission lines.

72 The CAISO emphasizes that the proposed requirements to provide reactive support within this range apply to transient conditions only. The CAISO anticipates that inverter based resources will read voltage at their generator terminals, but will often be under the control of a central plant controller that will maintain voltage at the high side the generator substation consistent with the requirements of CAISO tariff section 25.4.1.

73 One of the simulations was for a light spring system condition reflecting realistic but worst case demand levels and renewable dispatch, as well as reasonable power transfer levels among different balancing authority areas. In the simulation, the Western Interconnection is assumed to experience a minimum daylight demand level. The solar resources are dispatched close to their maximum capacity. The unloaded online capacity of the synchronous generators is minimized to a level matching the minimum spinning requirement. The simulation studied contingencies that are 4-cycle, three phase bolted temporary bus faults, *i.e.*, no transmission elements tripped post fault-clearance. The faulted buses that could result in widespread monetary cessation are selected across the Western Interconnection. All inverter based solar PV generation are assumed to enter momentary cessation. Typical settings and sensitivity settings associated with momentary cessation are applied to all the inverter based solar PV generation in various simulation runs.

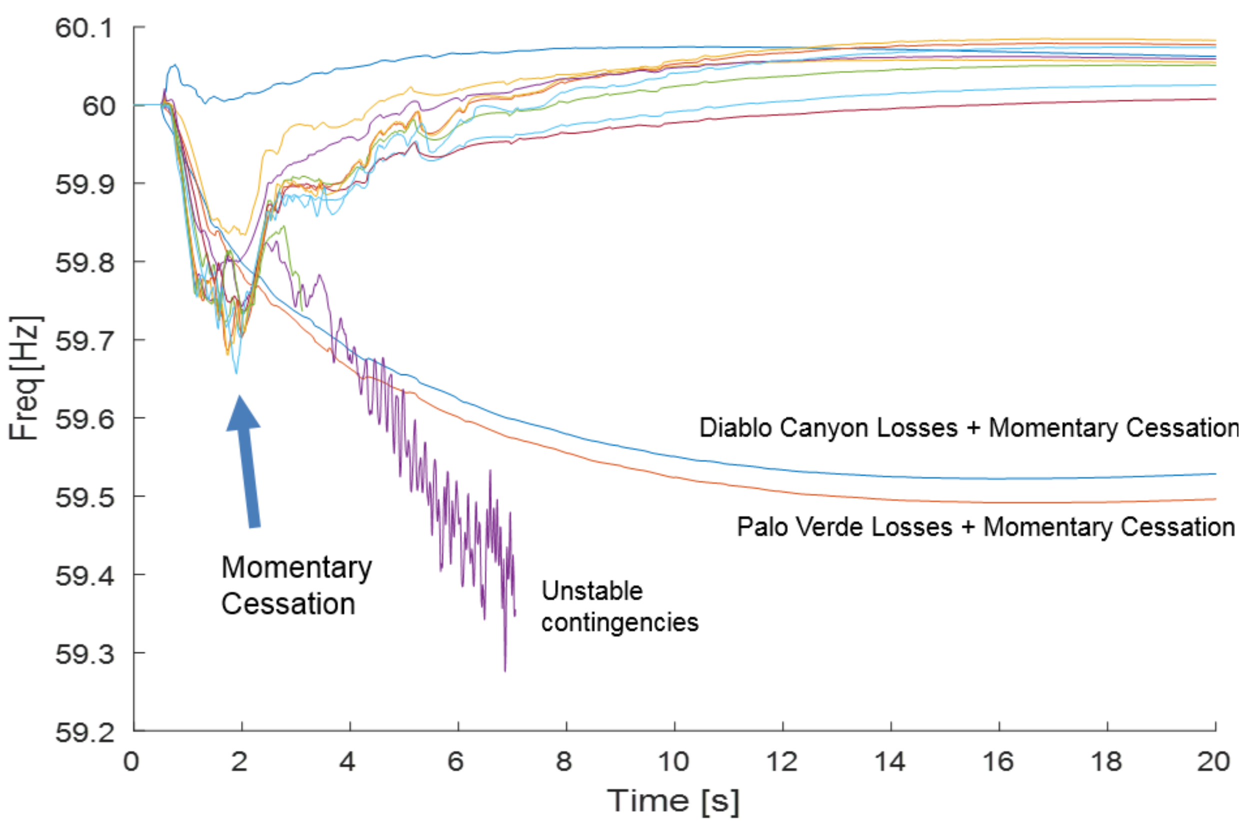
74 A bolted fault is a fault with no resistance. Bolted faults deliver the highest possible fault current for a given location and system configuration, and are used in selecting equipment to withstand and interrupting ratings and in the setting of protective relays.

75 NERC IRPFT Resource Loss Protection Criteria Assessment https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/IRPTF_RLPC_Assessment.pdf.

Depending on each generator's momentary cessation settings and without any mitigation, the CAISO and Western Interconnection could experience stability issues, particularly under daytime summer conditions where electric demand is higher, major interties are more heavily loaded, and reactive reserves are lower.

The following figure (Figure E) depicts system median frequency response (y axis) over time (x axis) for credible faults at different locations, including the frequency response for loss of two Palo Verde generating units[76] and two Diablo Canyon generating units.[77] The CAISO studied these potential fault locations because they represent the most critical, credible contingencies in WECC and are therefore used for NERC compliance purposes to model balancing authorities' ability to maintain frequency and stability. The modeled contingencies assume that inverter-based solar PV generation will continue to enter into momentary cessation.

Figure E: System Median Frequency in Response to Faults at Different Locations



[76] Palo Verde nuclear generation station is located near Tonopah, Arizona. It consists of three generating units, each with 1.31 GW of capacity.

[77] Diablo Canyon power plant is a nuclear generation plant located in San Luis Obispo County, California. It consists of two generating units, each with 1.1 GW of capacity.

The large drop in frequency between zero and two seconds results from inverter-based generation entering into momentary cessation. Specifically, the CAISO's simulations showed transient instability if inverter-based generators in the Western Interconnection enter momentary cessation at an inverter terminal voltage of 0.9 per unit and with a 0.5 second delay before recovering from momentary cessation to normal output over one second. This means that without the CAISO's prohibition on momentary cessation within the "no trip" zone, inverter-based generation would severely exacerbate grid conditions during a contingency (as the past has demonstrated).[78] The CAISO performed similar simulations under different system conditions, which produced similar results.

Additionally, the CAISO ran a number of simulations to determine the optimal solution to this problem. These simulations demonstrated that injecting reactive current—as the CAISO has proposed here—provides the greatest mitigation.[79] Injecting reactive current essentially is the only way to increase voltage to nominal levels to enable the injection of active power. Without the initial injection of reactive current, the injection of active power does little to restore system conditions to nominal levels.

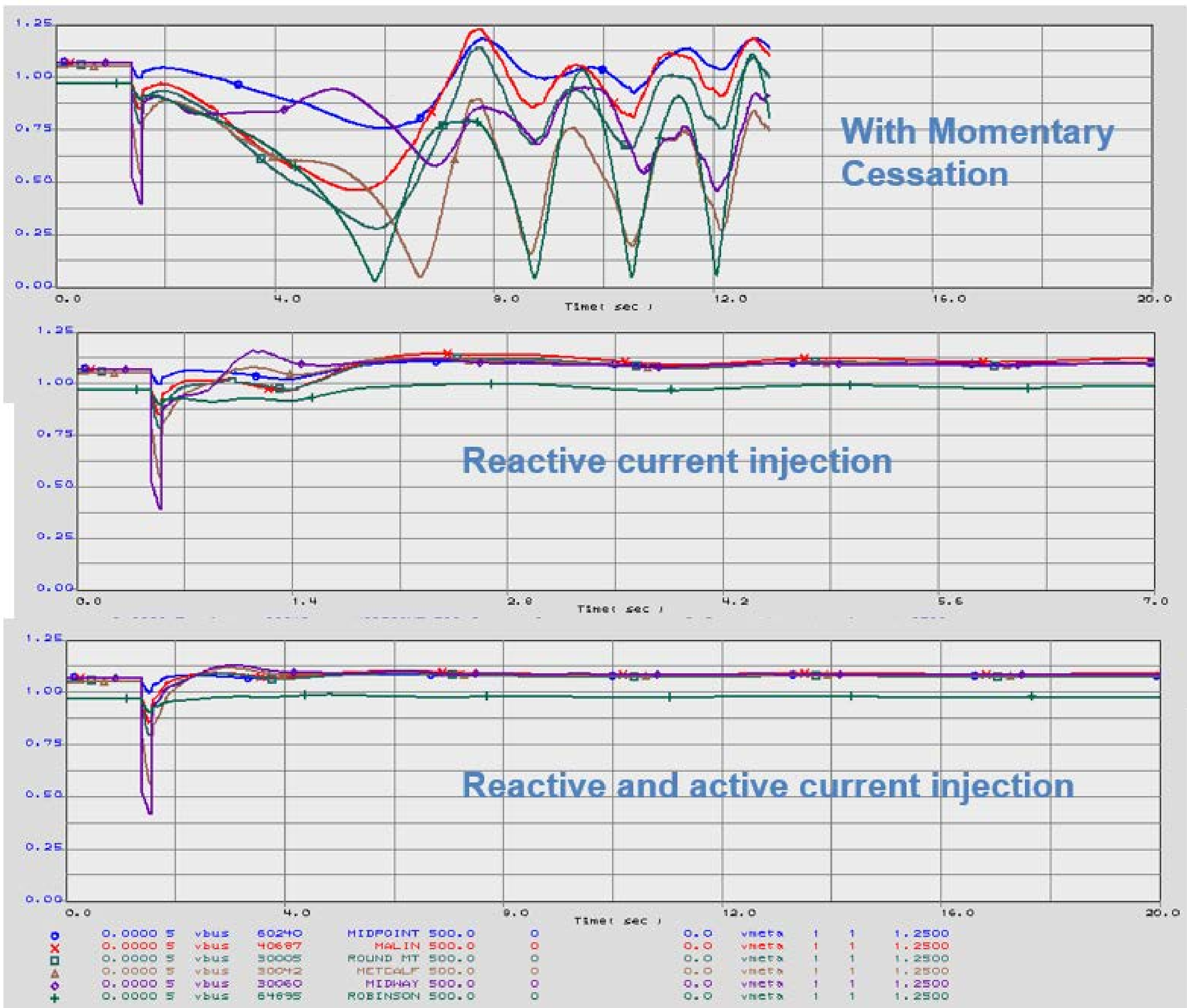
The following three graphs (collectively, Figure F) represent the voltage (y axis, with 1.00 representing nominal voltage) at different 500 kV buses over time (x axis) in response to the contingencies the CAISO uses to plan for grid stability consistent with NERC standards. Each color line represents a different bus. The first graph assumes current typical momentary cessation settings. The second and third graphs both assume that inverter-based generators have adopted the CAISO's proposal and set their controllers to prioritize the injection of reactive current under low voltage conditions. The second graph assumes that the inverters do not have the capability to produce active current, and therefore only produce reactive current. The third graph assumes the inverters could produce active current along with the reactive current. The CAISO notes that the first graph, based on current inverter settings, produces instability

[78] The simulations with sensitivity momentary cessation settings showed that the instability also could be mitigated by reducing the momentary cessation low voltage threshold, shortening the recovery delay, or increasing the transient active power ramp rate limit. However, because many of the existing inverter-based generators will continue momentary cessation with their current equipment, prohibiting future generators from momentary cessation within the "no trip" zone will provide the optimal solution to ensure reliability.

[79] The CAISO performed these simulations for a summer mid-day to reflect realistic peak demand levels and renewable dispatch and reasonably high power transfer levels between Northwest and California. In the simulation, the Western Interconnection is assumed to experience a minimum summer noon time demand level. The solar resources are dispatched close to their maximum capacity. The unloaded online capacity of the synchronous generators is set to lower than the level from saved snapshots of real-time system operation. The simulation studied contingencies that are 4-cycle, three-phase-to-ground faults on 500kV or 230kV transmission lines. All inverter-based solar PV generators are assumed to enter momentary cessation. Typical settings associated with momentary cessation are applied to all the inverter-based solar PV generation in various simulation runs.

outside NERC and WECC planning standards. The second and third graphs, however, meet applicable standards.

Figure F: Comparison of Bus Voltages among Momentary Cessation and Current Injection Options



These graphs demonstrate two clear conclusions. First, comparing the first and second graphs shows that the CAISO's proposal to prioritize the injection of reactive current mitigates the voltage issues resulting from momentary cessation. Second, comparing the second and third graphs clearly shows that adding active current under low voltage condition does little to stabilize the system beyond what the reactive current alone achieves. This is because inverters act as a constant current source during a fault. However, the total current from the inverter is limited when it is programmed to try to achieve both active power control and reactive power control. When the voltage drop is deep, a high reactive current is needed to boost the voltage. Injecting active current does nothing until reactive current has restored the voltage to a level where active power can flow. The CAISO's proposal emphasizes reactive current injection under low voltage condition because it is an effective control strategy to restore voltage and inverter active power output. The CAISO's proposal also reduces the risk of inverters tripping when faced with sustained low voltage because injecting reactive current will boost voltage on the system and help restore the ability of inverter-based generators to inject active power.

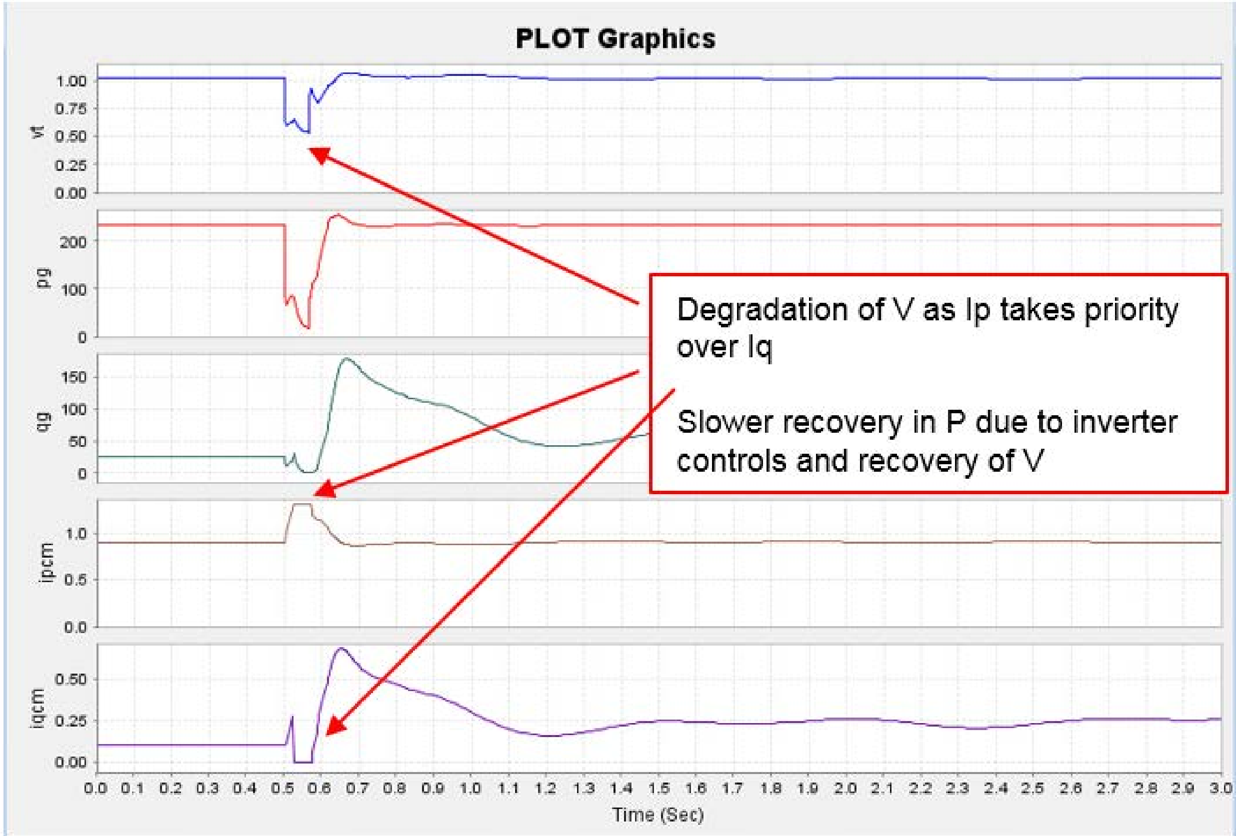
Importantly, the CAISO's proposal does not *preclude* active current injection during a fault. After first meeting the voltage control need, current can be used to produce active output at the same time. Further, the requirement of producing full rating reactive current when the voltage drops to 0.5 per unit balances out the active and reactive current injections and reduces risk of overshooting the voltage control upon clearance of the fault.

The CAISO also examined individual generator performance to test its proposal against alternative options. The CAISO modeled a 250 MW solar PV plant, which is representative of inverter-based generators in the CAISO. The CAISO then modeled different active and reactive current injection strategies. Ultimately these simulations (1) reaffirmed the CAISO's proposal to prioritize the injection of reactive current after a fault, and (2) demonstrated the effectiveness of producing full rating reactive current when the voltage drops to 0.5 per unit.

To effect this simulation, the CAISO modeled a fault on a 500 kV transmission line that caused less than 0.5 per unit voltage drop at the nearby inverter terminal. The following figures contain five graphs showing the generator's terminal voltage (top, "vt"); active current output (second, "pg"); reactive current output (third, "qg"); the generator's active current control command (fourth, "ipcm"); and the generator's reactive current control command (bottom, "iqcm"). The generator's current control commands represent what the generator effectively is trying to achieve, and can be compared to its active and reactive power outputs to gauge success. All graphs are shown over time in seconds on the x-axis.

The following figure (Figure G) shows plant performance when the generator's inverters are programmed to prioritize the injection of active current in response to a fault—a proposal the CAISO ultimately abandoned due to poor results.

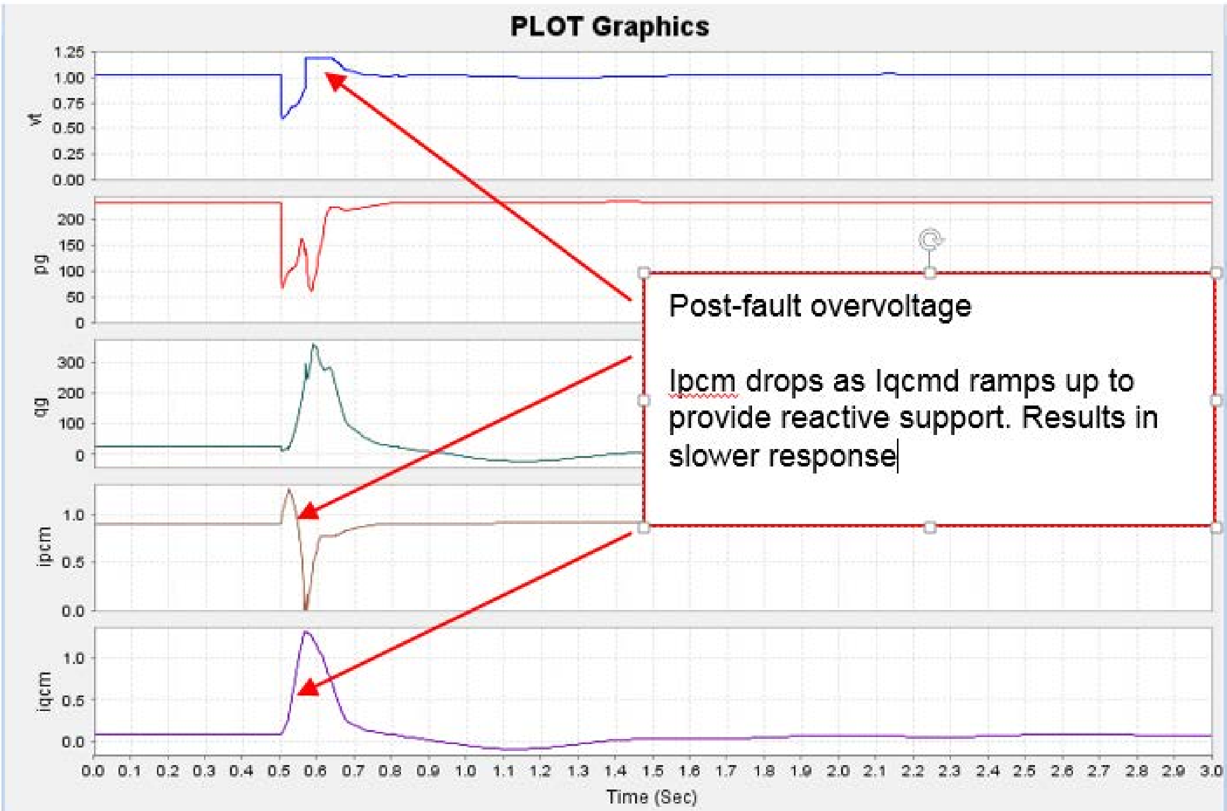
Figure G: Plant Performance with Active Current Priority



The key takeaway from these graphs comes from comparing the generator's control commands to its actual outputs. Prioritizing active current results in the voltage degrading further during a fault due to the lack of the reactive current. Active output also continues to drop. For these reasons the CAISO and stakeholders did not adopt this approach.

The next figure (Figure H) demonstrates a generator response when it has prioritized reactive current injection, but without being required to produce full current when the voltage drops to 0.5 per unit (often referred to as "open loop K-factor control"). In other words, the generator inverters have been programmed to prioritize the injection of reactive current to raise the voltage, but have not been told how much the reactive current should be.

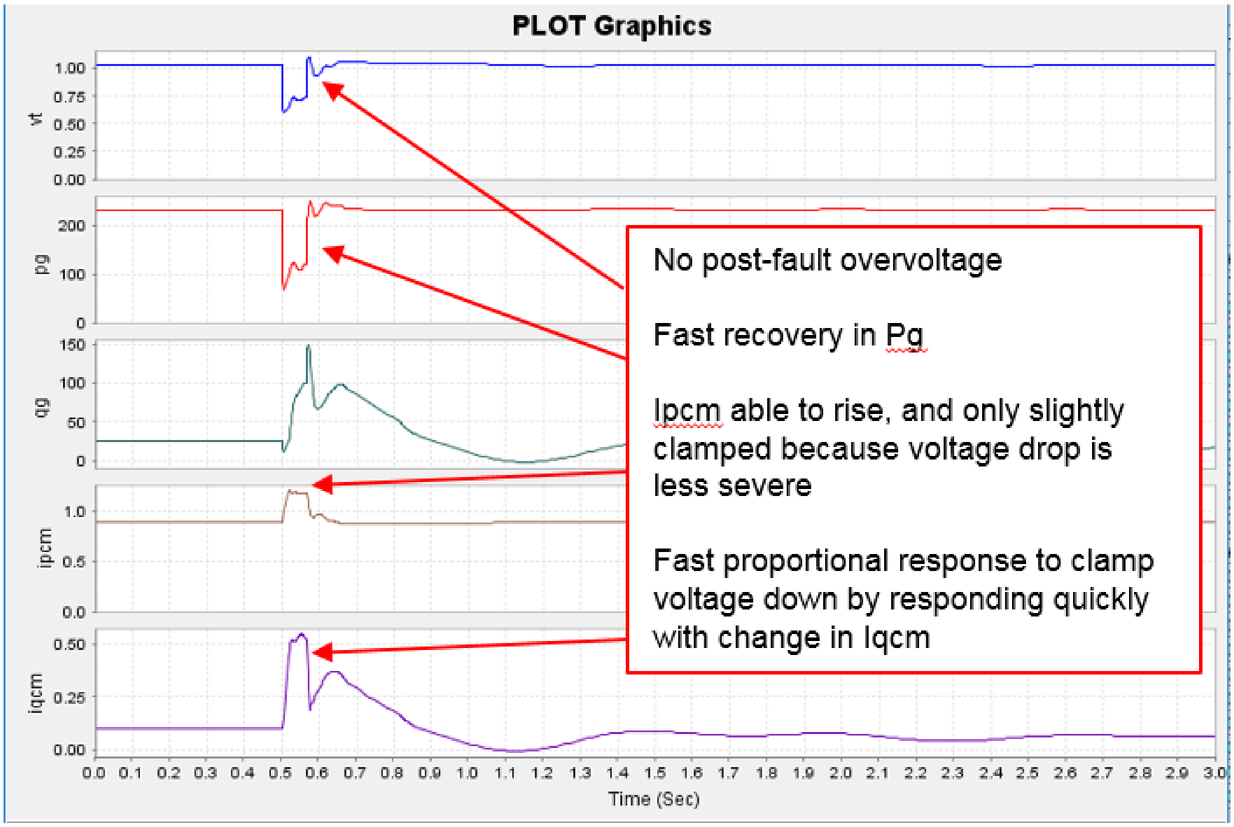
Figure H: Plant Performance with Reactive Current Priority but without Specified Reactive Current Open-Loop Control Target



Although the reactive current raises voltage to enable the generator's desired active power output during the fault, the top graph (terminal voltage) shows that the inverters actually overshoot their target and raise the voltage above nominal levels upon fault clearance, effectively turning a low voltage problem into a high voltage problem. The reactive current command continues to rise for a few cycles under the high voltage by the nature of the closed-loop control. This, in turn, requires the generator to reduce its active power output—represented by the drop in ipcm—before voltage is restored to nominal. As such, the CAISO and stakeholders did not adopt this approach.

The next figure (Figure I) represents the CAISO's proposal: reactive current injection priority with the reactive current open-loop control target.

Figure I: CAISO Proposal



To simulate harsher conditions, the CAISO also examined control performance with the fault at the point of the interconnection of the plant and causing a 0.75 per unit drop in voltage. These simulations produced similar results.[80] They demonstrated that injecting reactive current directionally proportional to the decrease in per unit voltage mitigates the instability issues discussed above, but without "overshooting" the target. The CAISO's proposal also enables the generator to resume producing real power as soon as possible. For these reasons, the CAISO proposes to require generators to inject reactive current during transient low voltage conditions directionally proportional to the decrease in per unit voltage.[81] Additionally, generators will be required to produce full reactive current capability when the voltage drops to a level of 0.50 per unit or below nominal.

The CAISO's proposal will help ensure reliability by stabilizing voltage during fault conditions. Instead of exacerbating reliability issues through momentary cessation, inverter-based generation will provide reactive support during faults, which in turn will allow generators to inject real power more quickly. The CAISO's approach is balanced and can be implemented at little to no cost according to stakeholders. The CAISO's proposal is consistent with NERC's recommendations and results from meticulous study and modeling. For these reasons, the CAISO's proposal to address losses caused by momentary cessation is just and reasonable.

B. Mitigating Additional Issues

To mitigate additional concerns identified by the CAISO studies and NERC's recommendations, the CAISO proposes several additional measures. First, the CAISO proposes to clarify that asynchronous generating facility inverters may not trip or cease to inject current for momentary loss of synchronism within the no-trip zone.[82] This prohibition is just and reasonable because it will ensure that generators remain online for faults that will be cleared almost instantaneously. It will not present a compliance burden to generators, and will work to avoid events similar to the August 16, 2016

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[80] The CAISO provided the NERC task force and Commission staff with these results. The CAISO has not included them here for concision and because they support the same conclusions as the faults simulated above.

[81] Proposed Section A(i)(3) of Appendix H to Appendix EE; proposed Section A(i)(3) of Attachment 7 to Appendix FF.

[82] Proposed Section A(i)(10) of Appendix H to Appendix EE; proposed Section A(i)(9) of Attachment 7 to Appendix FF. The tariff language used here refers to inverter controls locking the phase lock loop to the last synchronized point, and continuing to inject current into the grid at that last calculated phase prior to the loss of synchronism. This language matches how inverter controls are programmed, and was developed based on comments provided by inverter manufactures in the stakeholder process. *See* http://www.caiso.com/Documents/DraftFinalProposal-2018InterconnectionProcessEnhancements.pdf, and attached here as Attachment C.

event. With the proliferation of inverter-based generation in the CAISO, reliability events likely will increase without this prohibition.[83] Consistent with PRC-024, the CAISO also proposes to clarify that inverters may trip or cease to inject power to protect their facilities for persistent faults, namely, faults that prevent the inverter from regaining synchronism for more than 150 milliseconds.[84] Likewise, the CAISO proposes to clarify that current injection may be limited (but not ceased) to protect the inverters within the no-trip zone.[85]

Second, the CAISO proposes to clarify that its existing power factor design criteria should be measured at the high-voltage side of the generating facility transformer.[86] Currently these provisions merely state "at the point of interconnection," without specifying which side of that point. This clarification is consistent with existing practices and the Commission's existing *pro forma* provisions regarding where to measure voltage.[87] Providing this specificity in the tariff increases transparency and removes any ambiguity.

Third, the CAISO proposes to require that when generators trip or cease to inject current, they attempt to resynchronize promptly and consistently.[88] The May 1, 2018 NERC Alert noted that generator owners and inverter manufacturers found that individual inverters often have tripped, ceased to inject current, been unable to resynchronize, or have resynchronized too slowly after a trip due to "plant-level controllers," *i.e.*, electrical controls over the entire generating facility that may take precedence over individual component programming. Consistent with NERC's

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[83] The CAISO currently has over 18,000 MW installed in solar and wind capacity. *See* http://www.caiso.com/informed/Pages/CleanGrid/default.aspx. The California Public Utilities Commission reported that in 2017, California's three investor-owned utilities served 36% of their retail electricity sales with renewable power (the vast majority coming from inverter-based generators, namely, solar PV and wind). To comply with California's renewable portfolio standards, California load serving entities will need to serve 50% of load with renewable power by 2030, and 100% by 2045. *See* http://www.cpuc.ca.gov/RPS_Homepage/. The CAISO's generator interconnection queue currently has 280 active interconnection requests. Of these 270 consist of solar, wind, or storage.

[84] *Id*. (150 milliseconds is the default time set by the Commission's existing *pro forma* language elsewhere in the GIAs: *See, e.g.*, Sections A(i)(1) and (10) of Appendix H to Appendix EE; Sections A(i)(1) and (9) of Attachment 7 to Appendix FF).

[85] *Id*.

[86] Proposed Section A(iii) of Appendix H to Appendix EE; proposed Section A(iii) of Attachment 7 to Appendix FF.

[87] *See, e.g.*, Section A(i)(1) and (2) of Appendix H to Appendix EE; Sections A(i)(1) and (2) of Attachment 7 to Appendix FF (specifying faults on the transmission grid or between the point of interconnection and the high voltage terminals).

[88] Proposed Section A(i)(4) of Appendix H to Appendix EE; Section (A)(i)(3) of Attachment 7 to Appendix FF. Generators will *not* be required to resynchronize if their inverters tripped due to a fatal fault code, as determined by the original equipment manufacturer. *Id*.

recommendation, the CAISO proposes to include GIA language stating that such controllers may not impede inverter restoration, and that if an asynchronous generating facility uses a plant level controller, the controller must be programmed to allow its inverters to re-synchronize rapidly without delayed ramping before resuming control of the inverters.[89] Likewise, and as discussed above, where a generator engages in momentary cessation, the CAISO proposes to require the generators' inverters to return to full output at a minimum 100 percent per second ramping rate upon the end of transient voltage conditions.[90] In other words, the CAISO will require the generator's inverters to inject active current (real power) from no output to full output in one second or less. This requirement is consistent with NERC's recommendation (1b)(d) in its May 1, 2018 Alert. Additionally, the generation developers and inverter manufactures represented during the CAISO stakeholder process that this requirement can be met by available inverter technology without additional expense, burden, or problem. It will ensure that generator losses are recouped immediately and at a consistent ramp rate in the event of faults that trigger momentary cessation.

Fourth, the CAISO proposes to update an anachronistic reference in the GIAs. Currently the GIAs state that "an Asynchronous Generating Facility shall comply with the off nominal frequency requirements set forth in the WECC Under Frequency Load Shedding Relay Application Guide or successor requirements as they may be amended from time to time."[91] WECC no longer publishes this document, which in any case does not carry the regulatory certainty of a reliability standard or regional variation. The CAISO proposes to update this reference to require asynchronous generating facilities to comply with the "NERC Reliability Standard for Generator Frequency and Voltage Protective Relay Settings, or successor requirements as they may be amended from time to time."[92] Currently this is PRC-024-2. Updating this anachronistic reference will provide generating facilities further clarity in programming their protective relays.[93] The CAISO also proposes to remove an anachronistic provision pertaining to interconnection customers that were exempt from the first iteration of asynchronous technical requirements if they had purchased at least 30 percent of their inverters before July 3, 2010.[94] There are no longer any interconnection customers eligible for this exemption.

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89 Proposed Section A(i)(11) of Appendix H to Appendix EE; proposed Section A(i)(10) of Attachment 7 to Appendix FF.

90 Proposed Section A(i)(3) of Appendix H to Appendix EE; proposed Section A(i)(3) of Attachment 7 to Appendix FF.

91 Section A(ii) of Appendix H to Appendix EE; Section A(ii) of Attachment 7 to Appendix FF.

92 Proposed Section A(ii) of Appendix H to Appendix EE; proposed Section A(ii) of Attachment 7 to Appendix FF.

93 In any case, the CAISO believes that the requirements in both documents were similar such that there will be no substantive change in requirements.

94 Proposed Section A(i) of Appendix H to Appendix EE.

C. Recording Data for Generators above 20 MW

The CAISO also proposes to require asynchronous generating facilities above 20 MW in capacity to "monitor and record data for all frequency or voltage ride-through events, momentary cessation for transient high voltage events, and inverter trips."[95] Generators may record this data in central plan control systems, if available. Generators must record the following data for the plant as a whole:

1) Plant three phase voltage, current, and phase angle measuring units;
2) Status of ancillary reactive devices;
3) Status of all plant circuit breakers;
4) Status of plant controller;
5) Plant control set points;
6) Position of main plant transformer no-load taps;
7) Position of main plant transformer tap changer (if extant); and
8) Protective relay trips or relay target data.[96]

Additionally, generators must record the following data at the individual inverter level:

1) Frequency, current, and voltage during ride-through events;
2) Voltage and current during momentary cessation for transient high voltage events;
3) Voltage and current during reactive current injection for transient low voltage events;
4) Inverter alarm and fault codes;
5) DC current; and
6) DC voltage.[97]

The CAISO proposes to require that data be GPS-synchronized and sampled every 10 milliseconds. If a voltage or frequency ride-through event, momentary cessation, or trip occurs, the generator also must record a minimum of 150 milliseconds of data prior to the event, and 1 second of data after the event.[98] The generator also must install and maintain a phase angle measuring unit or functional equivalent equipment at its entrance or main substation transformer to measure voltage. The phase angle measuring unit must have a resolution of at least 30 samples per second. Based on the CAISO's work with the NERC task force and the IPE stakeholder process, the CAISO believes that many protective relays in asynchronous generating facilities already have

95 Proposed Section A(vi) of Appendix H to Appendix EE.

96 *Id*.

97 *Id*.

98 *Id*.

these capabilities installed, and simply require a change in relay settings to activate them. In any case, the computer storage required to record and maintain these data is equivalent to, if not far less, than that of a personal computer.

The asynchronous generator must store these data for a minimum of 30 days, and provide all data within 10 days of request from the CAISO or the participating transmission owner.[99] The CAISO developed these data requirements in the stakeholder process based upon the data necessary to investigate the reliability events discussed herein. In investigating the events, many generators learned that they could gather these data, but that their systems were deleting the data too quickly after an event. As such, the effort required by NERC, the CAISO, transmission owners, and generator operators to gather and analyze data to date often has been extensive. The CAISO believes that these requirements are just, reasonable, and prudent because they will help to ensure that the CAISO and its stakeholders can analyze any future events to make further reliability enhancements, as necessary. Further, they will ensure that all large generators collect and maintain the same data without the burden of needing to store the data beyond 30 days. This period will help ensure that the CAISO and investigating transmission owners can obtain data promptly after an event.

Applying these data requirements to large generators is a prudent and non-burdensome initial step at this time. Based on the CAISO's stakeholder process, large generators generally already have the plant controllers and analytics to comply with these requirements. The CAISO and its stakeholders elected to use a 20 MW capacity demarcation based on the Commission's historic differentiation between large and small generators.[100] Applying theses requirement to larger resources is reasonable because of the magnitude of the potential loss of their generating capacity to the CAISO transmission system. These resources generally interconnect at higher voltages and can have a greater individual impact on the system than the loss of small resources interconnected to lower voltage facilities.

III. Summary

Grid operators' priority is maintaining reliability. The CAISO's proposed tariff revisions will address the inverter-based generation issues that have consistently threatened CAISO reliability the last few years. These tariff revisions resulted from years of careful study, research, and analysis by the CAISO, Commission staff, NERC, utilities, generator owners, and inverter manufacturers. They represent cost-effective solutions that can be put in place today to help secure grid reliability. To the extent these revisions diverge from the *pro forma* GIA provisions Order Nos. 2003 and 828, they are essential to address issues that occur despite all parties' compliance with those

[99] *Id*.

[100] *See* Order No. 2003 at PP 1; 11 n. 10. The CAISO included the 20 MW figure expressly because smaller generators can elect to use LGIAs in lieu of SGIAs, and should not be discouraged to do so because they would have come under this requirement.

pro forma provisions.

The CAISO recognizes that these issues may require further mitigation in the future. The CAISO believes that these tariff revisions represent the prudent and critical first step, and are just and reasonable in and of themselves. The CAISO will continue to work with its stakeholders and regulators in identifying further steps that may be warranted based on future grid topology and technology advancement in the field of inverter design, control, and operation. On February 12 and 13 the CAISO hosted the NERC task force for a technical workshop on inverter-based generator performance and analysis on the Blue Cut Fire and Canyon 2 Fire disturbances.[101] The workshop featured discussions led by generation developers, inverter manufactures, power systems software developers, the Electric Power Research Institute, NERC, WECC, SCE, and the CAISO.[102] The CAISO's proposal is consistent with these discussions and NERC's published key takeaways.[103]

IV. Stakeholder Process

The CAISO continuously reviews and enhances its generator interconnection procedures.[104] After implementing significant generator interconnection reforms in 2008,[105] 2010,[106] and 2012,[107] the CAISO launched its first IPE initiative in 2013.[108] The 2013 IPE initiative resulted in interconnection enhancements to the CAISO tariff,

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101 NERC, "Inverter-based Resource Performance and Analysis Technical Workshop," February 12-13, 2019, https://www.nerc.com/pa/RAPA/Lists/RAPA/DispForm.aspx?ID=322.

102 All presentations are available on NERC's website at https://www.nerc.com/comm/PC/IRPTF%20Workshops/IRPTF_Workshop_Presentations.pdf.

103 NERC, "Key Takeaways: February 2019 Workshop," *available at* https://www.nerc.com/comm/PC/IRPTF%20Workshops/2019_IRPTF_Workshop_Key_Takeaways.pdf.

104 The generator interconnection process and related provisions are set forth primarily in section 25 of the CAISO tariff. The interconnection procedures and *pro forma* generator interconnection agreements ("GIAs") are generally contained in appendices S through FF to the CAISO tariff.

105 *California Independent System Operator Corp.*, 124 FERC ¶ 61,292 (2008) (approving revisions to move from a serial to a cluster process, and to establish project viability and developer commitment as soon as interconnection customers have an estimate of the costs of their projects).

106 *California Independent System Operator Corp.*, 133 FERC ¶ 61,223 (2010) (approving revisions to harmonize the CAISO's Large Generator Interconnection Procedures ("LGIP") with its Small Generator Interconnection Procedures ("SGIP") by establishing integrated cluster study processes for small and large generators, and to expedite study processes for independent or otherwise adroit generators by implementing new independent study and fast track processes).

107 *California Independent System Operator Corp.*, 140 FERC ¶ 61,070 (2012) (approving revisions to integrate the transmission planning and generator interconnection processes).

108 Further background information on the IPE initiative is provided in the CAISO's September 30, 2013 tariff amendment filing in Docket No. ER13-2484 to implement the first set of tariff revisions to enhance the generation interconnection process for interconnection customers.

business practice manuals, and procedures in 2013 and 2014.[109] The CAISO conducted another IPE initiative in 2015 that resulted in two more sets of enhancements.[110] In 2017 the CAISO conducted an expedited IPE initiative to implement two minor but critical sets of enhancements.[111]

After the success of the previous IPE initiatives, in 2018 the CAISO re-launched the IPE initiative. In doing so, the CAISO and stakeholders identified many enhancements that will improve the interconnection process for interconnection customers, ratepayers, transmission owners, and the CAISO. The vast majority of these enhancements resulted in the CAISO's September 27, 2018 filing in Docket No. ER18-2498, which was approved by the Commission on February 19, 2019.[112] This filing represents further enhancements developed in the 2018 IPE initiative.

The stakeholder process that resulted in this filing included:

- The CAISO's soliciting stakeholder suggestions on items to be included in this iteration of the IPE initiative;
- Four issue papers issued by the CAISO;
- Developing draft tariff provisions;
- Four stakeholder meetings and conference calls to discuss the CAISO papers, including an in-person workshop to develop tariff revisions; and
- Five opportunities to submit written comments on the CAISO papers and the draft tariff provisions.[113]

The proposals were presented to the CAISO Governing Board during its public meetings on November 7, 2018. The Board voted unanimously to authorize this

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[109] *See, e.g., California Independent System Operator Corp.*, 149 FERC ¶ 61,231 (2014); *California Independent System Operator Corp.,* 148 FERC ¶ 61,077 (2014); *California Independent System Operator Corp.,* 145 FERC ¶ 61,172 (2013).

[110] *California Independent System Operator Corp*., 153 FERC ¶ 61,242 (2015); 154 FERC ¶ 61,169 (2016).

[111] *California Independent System Operator Corp.*, 162 FERC ¶ 61,207 (2018) (extending the deliverability parking period and reconfiguring the interconnection request window to allow more time for corrections).

[112] *California Independent System Operator Corp.*, 166 FERC ¶ 61,113 (2019).

[113] Materials regarding the IPE stakeholder process are available on the CAISO website at http://www.caiso.com/informed/Pages/StakeholderProcesses/InterconnectionProcessEnhancements.aspx. A list of key dates in the stakeholder process that are relevant to this tariff amendment is provided in attachment E to this filing.

filing.[114]

The CAISO worked closely with its stakeholders to develop the tariff revisions proposed herein to ensure that they could mitigate reliability risks without undue burden on generators. To this end the CAISO included its draft tariff revisions throughout the policy process to allow stakeholders to develop the GIA language. Based on stakeholder requests, the CAISO also held an in-person stakeholder workshop dedicated to the GIA revisions and resolving all lingering issues. Generation developers, transmission owners, and inverter manufactures all provided a number of edits and clarifications to the CAISO's proposal, resulting in the GIA revisions proposed herein.[115] No stakeholder opposed the CAISO's final proposal.

V. Effective Date

The CAISO requests an effective date of April 30, 2019, 61 days from this filing.

VI. Communications

In accordance to Rule 203(b)(3) to the Commission's Rules of Practice and Procedure,[116] the CAISO respectfully requests that correspondence and other communications regarding this filing should be directed to the following:

Roger E. Collanton
General Counsel
Sidney L. Mannheim
Assistant General Counsel
Andrew Ulmer
Director of Federal Regulatory Affairs
William H. Weaver
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114 Materials related to the Board's authorization to prepare and submit this filing are available on the CAISO website at http://www.caiso.com/informed/Pages/BoardCommittees/BoardGovernorsMeetings.aspx. The Memoranda provided to the Board is provided in attachment D to this filing.

115 *See, e.g.*, the IPE Draft Final Proposal, adopting final edits provided by First Solar on momentary cessation, NextEra on data recording, PG&E on applicability, SDG&E on reactive power, and TMEIC on inverter tripping for phase lock loop, *available at* http://www.caiso.com/Documents/DraftFinalProposal-2018InterconnectionProcessEnhancements.pdf, and attached here as Attachment C.

116 18 C.F.R. § 385.203(b)(3).

VII. Service

The CAISO has served copies of this filing on the California Public Utilities Commission, the California Energy Commission, and all parties with scheduling coordinator agreements under the CAISO tariff. In addition, the CAISO has posted a copy of this filing on the CAISO website.

VIII. Contents of Filing

In addition to this transmittal letter, this filing includes the following attachments:

Attachment A	Clean CAISO tariff sheets incorporating this tariff amendment;
Attachment B	Red-lined document showing the revisions in this tariff amendment;
Attachment C	Draft final proposal on this tariff amendment;
Attachment D	Board memoranda; and
Attachment E	List of key dates in the stakeholder process.

IX. Conclusion

The CAISO requests that the Commission accept the tariff revision in this filing to mitigate reliability issues caused when inverter-based generators go offline or cease to inject current into the grid due to the routine clearing of high-voltage transmission faults or transient voltage. The CAISO's revisions also will establish a platform to collect information that will the CAISO, its transmission operators, and stakeholders model and study the operation of inverter-based resources in the future. For the reasons set forth in this filing, the CAISO respectfully requests that the Commission accept the tariff revisions proposed in the filing effective April 30, 2019.

Respectfully submitted,

/s/ William H. Weaver
Roger E. Collanton
General Counsel
Sidney L. Mannheim
Assistant General Counsel
Andrew Ulmer
Director of Federal Regulatory Affairs
William H. Weaver
Senior Counsel

Counsel for the California Independent System Operator Corporation

Attachment A – Clean Tariff

Temporary Losses of Inverter-Based Generators Mitigation

California Independent System Operator Corporation

25.4.2 Asynchronous Generating Facilities – GIA Technical Criteria

The technical requirements for Asynchronous Generating Facilities set forth in Appendix H to Appendix EE to the CAISO tariff and Attachment 7 to Appendix FF to the CAISO tariff, or applicable successor requirements, apply to existing individual Generating Units to the extent the Generating Facility makes modifications that replace its Generating Unit(s) or any inverter(s), even where a new Interconnection Request is not required or the Interconnection Customer is subject to an earlier SGIA or LGIA. The same technical requirements will not apply where the Generating Facility replaces an inverter as part of routine maintenance or repairs due to malfunction or failure.

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Appendix EE

Large Generator Interconnection Agreement

for Interconnection Requests Processed under the Generator Interconnection and Deliverability Allocation Procedures (Appendix to the CAISO Tariff)

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Appendix H

INTERCONNECTION REQUIREMENTS FOR AN ASYNCHRONOUS GENERATING FACILITY

Appendix H sets forth interconnection requirements specific to all Asynchronous Generating Facilities. Except as provided in Section 25.4.2 of the CAISO tariff, existing individual generating units of an Asynchronous Generating Facility that are, or have been, interconnected to the CAISO Controlled Grid at the same location are exempt from the requirements of this Appendix H for the remaining life of the existing generating unit.

A. Technical Requirements Applicable to Asynchronous Generating Facilities

i. Voltage Ride-Through Capability

An Asynchronous Generating Facility shall be able to remain online during voltage disturbances up to the time periods and associated voltage levels set forth in the requirements below.

1. An Asynchronous Generating Facility shall remain online for the voltage disturbance caused by any fault on the transmission grid, or within the Asynchronous Generating Facility between the Point of Interconnection and the high voltage terminals of the Asynchronous Generating Facility's step up transformer, having a duration equal to the lesser of the normal three-phase fault clearing time (4-9 cycles) or one-hundred fifty (150) milliseconds, plus any subsequent post-fault voltage recovery to the final steady-state post-fault voltage unless clearing the fault effectively disconnects the generator from the system. Clearing time shall be based on the maximum

normal clearing time associated with any three-phase fault location that reduces the voltage at the Asynchronous Generating Facility's Point of Interconnection to 0.2 per-unit of nominal voltage or less, independent of any fault current contribution from the Asynchronous Generating Facility.

2. An Asynchronous Generating Facility shall remain online for any voltage disturbance caused by a single-phase fault on the transmission grid, or within the Asynchronous Generating Facility between the Point of Interconnection and the high voltage terminals of the Asynchronous Generating Facility's step up transformer, with delayed clearing, plus any subsequent post-fault voltage recovery to the final steady-state post-fault voltage unless clearing the fault effectively disconnects the generator from the system. Clearing time shall be based on the maximum backup clearing time associated with a single point of failure (protection or breaker failure) for any single-phase fault location that reduces any phase-to-ground or phase-to-phase voltage at the Asynchronous Generating Facility's Point of Interconnection to 0.2 per-unit of nominal voltage or less, independent of any fault current contribution from the Asynchronous Generating Facility.

3. 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. Momentary cessation (namely, ceasing to inject current during a fault without mechanical isolation) is prohibited unless transient high voltage conditions rise to 1.20 per unit or more. For transient low voltage conditions, the Asynchronous Generating Facility's inverters will inject reactive current. The level of this reactive current must be directionally proportional to the decrease in per unit voltage at the inverter AC terminals. The inverter must produce full reactive current capability when the AC voltage at the inverter terminals drops to a level of 0.50 per unit or below. The Asynchronous Generating Facility must continue to operate and absorb reactive current for transient voltage conditions between 1.10 and 1.20 per unit

   Upon the cessation of transient voltage conditions and the return of the grid to normal operating voltage ($0.90 < V < 1.10$ per unit), the Asynchronous Generating Facility's inverters automatically must transition to normal active (real power) current injection. The Asynchronous Generating Facility's inverters must ramp up to inject active (real power) current with a minimum ramping rate of at least 100% per second (from no output to full available output). The total time to complete the transition from reactive current injection or absorption to normal active (real power) current injection must be one second or less. The total time to return from momentary cessation, if used, during transient high voltage conditions over 1.20 per unit or more must be one second or less.

4. The Asynchronous Generating Facility's inverter will be considered to have tripped where its AC circuit breaker is open or otherwise has electrically isolated the inverter from the grid. Following an inverter trip, the inverter must make at least one attempt to resynchronize and connect back to the grid unless the trip resulted from a fatal fault code, as defined by the inverter manufacturer. This attempt must take place within 2.5 minutes from the inverter trip. An attempt to resynchronize and connect back to the grid is not required if the trip was initiated due to a fatal fault code, as determined by the original equipment manufacturer.

5. The Asynchronous Generating Facility is not required to remain on line during multi-phased faults exceeding the duration described in Section A.i.1 of this Appendix H or single-phase faults exceeding the duration described in Section A.i.2 of this Appendix H.

6 The requirements of this Section A.i. of this Appendix H do not apply to faults that occur between the Asynchronous Generating Facility's terminals and the high side of the step-up transformer to the high-voltage transmission system.

7. Asynchronous Generating Facilities may be tripped after the fault period if this action is intended as part of a special protection system.

8. Asynchronous Generating Facilities may meet the requirements of this Section A.i of this Appendix H through the performance of the generating units or by installing additional equipment within the Asynchronous Generating Facility, or by a combination of generating unit performance and additional equipment.

9. The provisions of this Section A.i of this Appendix H apply only if the voltage at the Point of Interconnection has remained within the range of 0.9 and 1.10 per-unit of nominal voltage for the preceding two seconds, excluding any sub-cycle transient deviations.

10. Asynchronous Generating Facility inverters may not trip or cease to inject current for momentary loss of synchronism. As a minimum, the Asynchronous Generating Facility's inverter controls may lock the phase lock loop to the last synchronized point and continue to inject current into the grid at that last calculated phase prior to the loss of synchronism until the phase lock loop can regain synchronism. The current injection may be limited to protect the inverter. Any inverter may trip if the phase lock loop is unable to regain synchronism 150 milliseconds after loss of synchronism.

11. Inverter restoration following transient voltage conditions must not be impeded by plant level controllers. If the Asynchronous Generating Facility uses a plant level controller, it must be programmed to allow the inverters to automatically re-synchronize rapidly and ramp up to active current injection (without delayed ramping) following transient voltage recovery, before resuming overall control of the individual plant inverters.

ii. Frequency Disturbance Ride-Through Capability

An Asynchronous Generating Facility shall comply with the off nominal frequency requirements set forth in the NERC Reliability Standard for Generator Frequency and Voltage Protective Relay Settings, or successor requirements as they may be amended from time to time.

iii. Power Factor Design Criteria (Reactive Power)

An Asynchronous Generating Facility not studied under the Independent Study Process, as set forth in Section 4 of Appendix DD, shall operate within a power factor within the range of 0.95 leading to 0.95 lagging, measured at the high voltage side of the substation transformer, as defined in this LGIA in order to maintain a specified voltage schedule, if the Phase II Interconnection Study shows that such a requirement is necessary to ensure safety or reliability. An Asynchronous Generating Facility studied under the Independent Study Process, as set forth in Section 4 of Appendix DD, shall operate within a power factor within the range of 0.95 leading to 0.95 lagging, measured at the high voltage side of the substation transformer, as defined in this LGIA in order to maintain a specified voltage schedule. The power factor range standards set forth in this section can be met by using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors, or a combination of the two, if agreed to by the Participating TO and CAISO. The Interconnection Customer shall not disable power factor equipment while the Asynchronous Generating Facility is in operation. Asynchronous Generating Facilities shall also be able to provide sufficient dynamic voltage support in lieu of the power system stabilizer and automatic voltage regulation at the generator excitation system if the Phase II Interconnection Study shows this to be required for system safety or reliability.

iv. Supervisory Control and Data Acquisition (SCADA) Capability

An Asynchronous Generating Facility shall provide SCADA capability to transmit data and receive instructions from the Participating TO and CAISO to protect system reliability. The Participating TO and CAISO and the Asynchronous Generating Facility Interconnection Customer shall determine what SCADA information is essential for the proposed Asynchronous Generating Facility, taking into account the size of the plant and its characteristics, location, and importance in maintaining generation resource adequacy and transmission system reliability.

v. Power System Stabilizers (PSS)

Power system stabilizers are not required for Asynchronous Generating Facilities.

vi. Transient Data Recording Equipment for Facilities above 20 MW

Asynchronous Generating Facilities with generating capacities of more than 20 MW must monitor and record data for all frequency ride-through events, transient low voltage disturbances that initiated reactive current injection, reactive current injection or momentary cessation for transient high voltage disturbances, and inverter trips. The data may be recorded and stored in a central plant control system. The following data must be recorded:

Plant Level:

(1) Plant three phase voltage and current
(2) Status of ancillary reactive devices
(3) Status of all plant circuit breakers
(4) Status of plan controller
(5) Plant control set points
(6) Position of main plant transformer no-load taps
(7) Position of main plant transformer tap changer (if extant)
(8) Protective relay trips or relay target data

Inverter Level:

(1) Frequency, current, and voltage during frequency ride-through events
(2) Voltage and current during momentary cessation for transient high voltage events (when used)
(3) Voltage and current during reactive current injection for transient low or high voltage events
(4) Inverter alarm and fault codes
(5) DC current
(6) DC voltage

The data must be time synchronized, using a GPS clock or similar device, to a one millisecond level of resolution. All data except phase angle measuring unit data must be sampled at least every 10 milliseconds. Data recording must be triggered upon detecting a frequency ride-through event, a transient low voltage disturbance that initiated reactive current injection, momentary cessation or reactive current injection for a transient high voltage disturbance, or an inverter trip. Each recording will include as a minimum 150 milliseconds of data prior to the triggering event, and 1000 milliseconds of data after the event trigger. The Asynchronous Generating Facility must store this data for a minimum of 30 days. The Asynchronous Generating Facility will provide all data within 10 calendar days of a request from the CAISO or the Participating TO.

The Asynchronous Generating Facility must install and maintain a phase angle measuring unit or functional equivalent at the entrance to the facility or at the Generating Facility’s main substation transformer. The phase angle measuring unit must have a resolution of at least 30 samples per second. The Asynchronous Generating Facility will store this data for a minimum of 30 days. The Asynchronous Generating Facility will provide all phase angle measuring unit data within 10 calendar days of a request from the CAISO or the Participating TO.

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Appendix FF

Small Generator Interconnection Agreement

for Interconnection Requests Processed under the Generator Interconnection and Deliverability

Allocation Procedures (Appendix to the CAISO Tariff)

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Attachment 7

Interconnection Requirements for an Asynchronous Small Generating Facility

Attachment 7 sets forth requirements and provisions specific to all Asynchronous Generating Facilities. All other requirements of this Agreement continue to apply to all Asynchronous Generating Facility interconnections consistent with Section 25.4.2 of the CAISO tariff.

A. Technical Standards Applicable to Asynchronous Generating Facilities

i. Low Voltage Ride-Through (LVRT) Capability

An Asynchronous Generating Facility shall be able to remain online during voltage disturbances up to the time periods and associated voltage levels set forth in the requirements below.

1. An Asynchronous Generating Facility shall remain online for the voltage disturbance caused by any fault on the transmission grid, or within the Asynchronous Generating Facility between the Point of Interconnection and the high voltage terminals of the Asynchronous Generating Facility's step up transformer, having a duration equal to the lesser of the normal three-phase fault clearing time (4-9 cycles) or one-hundred fifty (150) milliseconds, plus any subsequent post-fault voltage recovery to the final steady-state post-fault voltage. Clearing time shall be based on the maximum normal clearing time associated with any three-phase fault location that reduces the voltage at the Asynchronous Generating Facility's Point of Interconnection to 0.2 per-unit of nominal voltage or less, independent of any fault current contribution from the Asynchronous Generating Facility.

2. An Asynchronous Generating Facility shall remain online for any voltage disturbance caused by a single-phase fault on the transmission grid, or within the Asynchronous Generating Facility between the Point of Interconnection and the high voltage terminals of the Asynchronous Generating Facility's step up transformer, with delayed clearing, plus any subsequent post-fault voltage recovery to the final steady-state post-fault voltage. Clearing time shall be based on the maximum backup clearing time associated with a single point of failure (protection or breaker failure) for any single-phase fault location that reduces any phase-to-ground or phase-to-phase voltage at the Asynchronous Generating Facility's Point of Interconnection to 0.2 per-unit of nominal voltage or less, independent of any fault current contribution from the Asynchronous Generating Facility.

3. 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. Momentary cessation (namely, ceasing to inject current during a fault without mechanical isolation) is prohibited unless transient high voltage conditions rise to 1.20 per unit or more. For transient low voltage conditions, the Asynchronous Generating Facility's inverters will inject reactive current. The level of this reactive current must be directionally proportional to the decrease in per unit voltage at the inverter AC terminals. The inverter must produce full reactive current capability when the AC voltage at the inverter terminals drops to a level of 0.50 per unit or below. The Asynchronous Generating Facility must continue to operate and absorb reactive

current for transient voltage conditions between 1.10 and 1.20 per unit.

Upon the cessation of transient voltage conditions and the return of the grid to normal operating voltage (0.90 < V < 1.10 per unit), the Asynchronous Generating Facility's inverters automatically must transition to normal active (real power) current injection. The Asynchronous Generating Facility's inverters must ramp up to inject active (real power) current with a minimum ramping rate of at least 100% per second (from no output to full available output). The total time to complete the transition from reactive current injection or absorption to normal active (real power) current injection must be one second or less. The total time to return from momentary cessation, if used, during transient high voltage conditions over 1.20 per unit or more must be one second or less.

The Asynchronous Generating Facility's inverter will be considered to have tripped where its AC circuit breaker is open or otherwise has electrically isolated the inverter from the grid. Following an inverter trip, the inverter must make at least one attempt to resynchronize and connect back to the grid unless the trip resulted from a fatal fault code, as defined by the inverter manufacturer. This attempt must take place within 2.5 minutes from the inverter trip. An attempt to resynchronize and connect back to the grid is not required if the trip was initiated due to a fatal fault code, as determined by the original equipment manufacturer.

4. The Asynchronous Generating Facility is not required to remain on line during multi-phased faults exceeding the duration described in Section A.i.1 of this Attachment 7 or single-phase faults exceeding the duration described in Section A.i.2 of this Attachment 7.

5. The requirements of this Section A.i of this Attachment 7 do not apply to faults that occur between the Asynchronous Generating Facility's terminals and the high side of the step-up transformer to the high-voltage transmission system.

6. Asynchronous Generating Facilities may be tripped after the fault period if this action is intended as part of a special protection system.

7. Asynchronous Generating Facilities may meet the requirements of this Section A of this Attachment 7 through the performance of the generating units or by installing additional equipment within the Asynchronous Generating Facility or by a combination of generating unit performance and additional equipment.

8. The provisions of this Section A.i of this Attachment 7 apply only if the voltage at the Point of Interconnection has remained within the range of 0.9 and 1.10 per-unit of nominal voltage for the preceding two seconds, excluding any sub-cycle transient deviations.

9. Asynchronous Generating Facility inverters may not trip or cease to inject current for momentary loss of synchronism. As a minimum, the Asynchronous Generating Facility's inverter controls may lock the phase lock loop to the last synchronized point and continue to inject current into the grid at that last calculated phase prior to the loss of synchronism until the phase lock loop can regain synchronism. The current injection may be limited to protect the inverter. Any inverter may trip if the phase lock loop is unable to regain synchronism 150 milliseconds after loss of synchronism.

10. Inverter restoration following transient voltage conditions must not be impeded by plant level controllers. If the Asynchronous Generating Facility uses a plant level controller, it must be programmed to allow the inverters to automatically re-synchronize rapidly and ramp up to active current injection (without delayed ramping) following transient voltage recovery, before resuming overall control of the individual plant inverters.

ii. Frequency Disturbance Ride-Through Capacity

An Asynchronous Generating Facility shall comply with the off nominal frequency requirements set forth in the NERC Reliability Standard for Generator Frequency and Voltage Protective Relay Settings as they may be amended from time to time.

iii. Power Factor Design Criteria (Reactive Power)

An Asynchronous Generating Facility not studied under the Independent Study Process, as set forth in Section 4 of Appendix DD, shall operate within a power factor within the range of 0.95 leading to 0.95 lagging, measured at the high voltage side of the substation transformer, as defined in this SGIA in order to maintain a specified voltage schedule, if the Phase II Interconnection Study shows that such a requirement is necessary to ensure safety or reliability. An Asynchronous Generating Facility studied under the Independent Study Process, as set forth in Section 4 of Appendix DD, shall operate within a power factor within the range of 0.95 leading to 0.95 lagging, measured at the high voltage side of the substation transformer, as defined in this SGIA in order to maintain a specified voltage schedule. The power factor range standards set forth in this section can be met by using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors, or a combination of the two, if agreed to by the Participating TO and CAISO. The Interconnection Customer shall not disable power factor equipment while the Asynchronous Generating Facility is in operation. Asynchronous Generating Facilities shall also be able to provide sufficient dynamic voltage support in lieu of the power system stabilizer and automatic voltage regulation at the generator excitation system if the Phase II Interconnection Study shows this to be required for system safety or reliability.

iv. Supervisory Control and Data Acquisition (SCADA) Capability

An Asynchronous Generating Facility shall provide SCADA capability to transmit data and receive instructions from the Participating TO and CAISO to protect system reliability. The Participating TO and CAISO and the Asynchronous Generating Facility Interconnection Customer shall determine what SCADA information is essential for the proposed Asynchronous Generating Facility, taking into account the size of the plant and its characteristics, location, and importance in maintaining generation resource adequacy and transmission system reliability.

v. Power System Stabilizers (PSS)

Power system stabilizers are not required for Asynchronous Generating Facilities.

Attachment B – Marked Tariff

Temporary Losses of Inverter-Based Generators Mitigation

California Independent System Operator Corporation

25.4.2 Asynchronous Generating Facilities – GIA Technical Criteria

The technical requirements for Asynchronous Generating Facilities set forth in Appendix H to Appendix EE to the CAISO tariff and Attachment 7 to Appendix FF to the CAISO tariff, or applicable successor requirements, apply to existing individual Generating Units to the extent the Generating Facility makes modifications that replace its Generating Unit(s) or any inverter(s), even where a new Interconnection Request is not required or the Interconnection Customer is subject to an earlier SGIA or LGIA. The same technical requirements will not apply where the Generating Facility replaces an inverter as part of routine maintenance or repairs due to malfunction or failure.

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Appendix EE

Large Generator Interconnection Agreement

for Interconnection Requests Processed under the Generator Interconnection and Deliverability Allocation Procedures (Appendix to the CAISO Tariff)

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Appendix H

INTERCONNECTION REQUIREMENTS FOR AN ASYNCHRONOUS GENERATING FACILITY

Appendix H sets forth interconnection requirements specific to all Asynchronous Generating Facilities. Except as provided in Section 25.4.2 of the CAISO tariff, ~~E~~existing individual generating units of an Asynchronous Generating Facility that are, or have been, interconnected to the CAISO Controlled Grid at the same location are exempt from the requirements of this Appendix H for the remaining life of the existing generating unit. ~~Generating units that are replaced, however, shall meet the requirements of this Appendix H.~~

A. Technical Requirements Applicable to Asynchronous Generating Facilities

i. ~~Low~~ Voltage Ride-Through ~~(LVRT)~~ Capability

An Asynchronous Generating Facility shall be able to remain online during voltage disturbances up to the time periods and associated voltage levels set forth in the requirements below.

1. An Asynchronous Generating Facility shall remain online for the voltage disturbance caused by any fault on the transmission grid, or within the Asynchronous Generating Facility between the Point of Interconnection and the high voltage terminals of the Asynchronous Generating Facility's step up transformer, having a duration equal to the lesser of the normal three-phase fault clearing time (4-9 cycles) or one-hundred fifty (150) milliseconds, plus any subsequent post-fault voltage recovery to the final steady-state post-fault voltage unless clearing the fault effectively

disconnects the generator from the system. Clearing time shall be based on the maximum normal clearing time associated with any three-phase fault location that reduces the voltage at the Asynchronous Generating Facility's Point of Interconnection to 0.2 per-unit of nominal voltage or less, independent of any fault current contribution from the Asynchronous Generating Facility.

2. An Asynchronous Generating Facility shall remain online for any voltage disturbance caused by a single-phase fault on the transmission grid, or within the Asynchronous Generating Facility between the Point of Interconnection and the high voltage terminals of the Asynchronous Generating Facility's step up transformer, with delayed clearing, plus any subsequent post-fault voltage recovery to the final steady-state post-fault voltage unless clearing the fault effectively disconnects the generator from the system. Clearing time shall be based on the maximum backup clearing time associated with a single point of failure (protection or breaker failure) for any single-phase fault location that reduces any phase-to-ground or phase-to-phase voltage at the Asynchronous Generating Facility's Point of Interconnection to 0.2 per-unit of nominal voltage or less, independent of any fault current contribution from the Asynchronous Generating Facility.

3. 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~~ Momentary cessation (namely, ceasing to inject current ~~into the transmission grid~~ during a fault without mechanical isolation) is prohibited unless transient high voltage conditions rise to 1.20 per unit or more. For transient low voltage conditions, the Asynchronous Generating Facility's inverters will inject reactive current. The level of this reactive current must be directionally proportional to the decrease in per unit voltage at the inverter AC terminals. The inverter must produce full reactive current capability when the AC voltage at the inverter terminals drops to a level of 0.50 per unit or below. The Asynchronous Generating Facility must continue to operate and absorb reactive current for transient voltage conditions between 1.10 and 1.20 per unit

Upon the cessation of transient voltage conditions and the return of the grid to normal operating voltage (0.90 < V < 1.10 per unit), the Asynchronous Generating Facility's inverters automatically must transition to normal active (real power) current injection. The Asynchronous Generating Facility's inverters must ramp up to inject active (real power) current with a minimum ramping rate of at least 100% per second (from no output to full available output). The total time to complete the transition from reactive current injection or absorption to normal active (real power) current injection must be one second or less. The total time to return from momentary cessation, if used, during transient high voltage conditions over 1.20 per unit or more must be one second or less.

4. The Asynchronous Generating Facility's inverter will be considered to have tripped where its AC circuit breaker is open or otherwise has electrically isolated the inverter from the grid. Following an inverter trip, the inverter must make at least one attempt to resynchronize and connect back to the grid unless the trip resulted from a fatal fault code, as defined by the inverter manufacturer. This attempt must take place within 2.5 minutes from the inverter trip. An attempt to resynchronize and connect back to the grid is not required if the trip was initiated due to a fatal fault code, as determined by the original equipment manufacturer.

5. The Asynchronous Generating Facility is not required to remain on line during multi-phased faults exceeding the duration described in Section A.i.1 of this Appendix H or single-phase faults exceeding the duration described in Section A.i.2 of this Appendix H.

~~5~~6 The requirements of this Section A.i. of this Appendix H do not apply to faults that occur between the Asynchronous Generating Facility's terminals and the high side of the step-up transformer to the high-voltage transmission system.

~~6~~7. Asynchronous Generating Facilities may be tripped after the fault period if this action is intended as part of a special protection system.

~~7~~8. Asynchronous Generating Facilities may meet the requirements of this Section A.i of this Appendix H through the performance of the generating units or by installing additional equipment within the Asynchronous Generating Facility, or by a combination of generating unit performance and additional equipment.

~~8~~9. The provisions of this Section A.i of this Appendix H apply only if the voltage at the Point of Interconnection has remained within the range of 0.9 and 1.10 per-unit of nominal voltage for the preceding two seconds, excluding any sub-cycle transient deviations.

10. Asynchronous Generating Facility inverters may not trip or cease to inject current for momentary loss of synchronism. As a minimum, the Asynchronous Generating Facility's inverter controls may lock the phase lock loop to the last synchronized point and continue to inject current into the grid at that last calculated phase prior to the loss of synchronism until the phase lock loop can regain synchronism. The current injection may be limited to protect the inverter. Any inverter may trip if the phase lock loop is unable to regain synchronism 150 milliseconds after loss of synchronism.

11. Inverter restoration following transient voltage conditions must not be impeded by plant level controllers. If the Asynchronous Generating Facility uses a plant level controller, it must be programmed to allow the inverters to automatically re-synchronize rapidly and ramp up to active current injection (without delayed ramping) following transient voltage recovery, before resuming overall control of the individual plant inverters.

~~The requirements of this Section A.i in this Appendix H shall not apply to any Asynchronous Generating Facility that can demonstrate to the CAISO a binding commitment, as of July 3, 2010, to purchase inverters for thirty (30) percent or more of the Generating Facility's maximum Generating Facility Capacity that are incapable of complying with the requirements of this Section A.i in this Appendix H. The Interconnection Customer must include a statement from the inverter manufacturer confirming the inability to comply with this requirement in addition to any information requested by the CAISO to determine the applicability of this exemption.~~

ii. Frequency Disturbance Ride-Through Capability

An Asynchronous Generating Facility shall comply with the off nominal frequency requirements set forth in the ~~WECC Under~~ NERC Reliability Standard for Generator Frequency ~~Load Shedding~~ and Voltage Protective Relay ~~Application Guide~~ Settings, or successor requirements as they may be amended from time to time.

iii. Power Factor Design Criteria (Reactive Power)

An Asynchronous Generating Facility not studied under the Independent Study Process, as set forth in Section 4 of Appendix DD, shall operate within a power factor within the range of 0.95 leading to 0.95 lagging, measured at the ~~Point of Interconnection~~ high voltage side of the substation transformer, as defined in this LGIA in order to maintain a specified voltage schedule, if the Phase II Interconnection Study shows that such a requirement is necessary to ensure safety or reliability. An Asynchronous Generating Facility studied under the Independent Study Process, as set forth in Section 4 of Appendix DD, shall operate within a power factor within the range of 0.95 leading to 0.95 lagging, measured at the ~~Point of Interconnection~~ high voltage side of the substation transformer, as defined in this LGIA in order to maintain a specified voltage schedule. The power factor range standards set forth in this section can be met by using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors, or a combination of the two, if agreed to by the Participating TO and CAISO. The Interconnection Customer shall not disable power factor equipment while the Asynchronous Generating Facility is in operation. Asynchronous Generating Facilities shall also be able to provide sufficient dynamic voltage support in lieu of the power system stabilizer and automatic voltage regulation at the generator excitation system if the Phase II Interconnection Study shows this to be required for system safety or reliability.

iv. Supervisory Control and Data Acquisition (SCADA) Capability

An Asynchronous Generating Facility shall provide SCADA capability to transmit data and receive instructions from the Participating TO and CAISO to protect system reliability. The Participating TO and CAISO and the Asynchronous Generating Facility Interconnection Customer shall determine what SCADA information is essential for the proposed Asynchronous Generating Facility, taking into account the size of the plant and its characteristics, location, and importance in maintaining generation resource adequacy and transmission system reliability.

v. Power System Stabilizers (PSS)

Power system stabilizers are not required for Asynchronous Generating Facilities.

vi. Transient Data Recording Equipment for Facilities above 20 MW

Asynchronous Generating Facilities with generating capacities of more than 20 MW must monitor and record data for all frequency ride-through events, transient low voltage disturbances that initiated reactive current injection, reactive current injection or momentary cessation for transient high voltage disturbances, and inverter trips. The data may be recorded and stored in a central plant control system. The following data must be recorded:

Plant Level:

(1) Plant three phase voltage and current
(2) Status of ancillary reactive devices
(3) Status of all plant circuit breakers
(4) Status of plan controller
(5) Plant control set points
(6) Position of main plant transformer no-load taps
(7) Position of main plant transformer tap changer (if extant)
(8) Protective relay trips or relay target data

Inverter Level:

(1) Frequency, current, and voltage during frequency ride-through events
(2) Voltage and current during momentary cessation for transient high voltage events (when used)
(3) Voltage and current during reactive current injection for transient low or high voltage events
(4) Inverter alarm and fault codes
(5) DC current
(6) DC voltage

The data must be time synchronized, using a GPS clock or similar device, to a one millisecond level of resolution. All data except phase angle measuring unit data must be sampled at least every 10 milliseconds. Data recording must be triggered upon detecting a frequency ride-through event, a transient low voltage disturbance that initiated reactive current injection, momentary cessation or reactive current injection for a transient high voltage disturbance, or an inverter trip. Each recording will include as a minimum 150 milliseconds of data prior to the triggering event, and 1000 milliseconds of data after the event trigger. The Asynchronous Generating Facility must store this data for a minimum of 30 days. The Asynchronous Generating Facility will provide all data within 10 calendar days of a request from the CAISO or the Participating TO.

The Asynchronous Generating Facility must install and maintain a phase angle measuring unit or functional equivalent at the entrance to the facility or at the Generating Facility's main substation transformer. The phase angle measuring unit must have a resolution of at least 30 samples per second. The Asynchronous Generating Facility will store this data for a minimum of 30 days. The Asynchronous Generating Facility will provide all phase angle measuring unit data within 10 calendar days of a request from the CAISO or the Participating TO.

* * * * * *

Appendix FF

Small Generator Interconnection Agreement

for Interconnection Requests Processed under the Generator Interconnection and Deliverability

Allocation Procedures (Appendix to the CAISO Tariff)

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Attachment 7

Interconnection Requirements for an Asynchronous Small Generating Facility

Attachment 7 sets forth requirements and provisions specific to all Asynchronous Generating Facilities. All other requirements of this Agreement continue to apply to all Asynchronous Generating Facility interconnections consistent with Section 25.4.2 of the CAISO tariff.

A. Technical Standards Applicable to Asynchronous Generating Facilities

i. Low Voltage Ride-Through (LVRT) Capability

An Asynchronous Generating Facility shall be able to remain online during voltage disturbances up to the time periods and associated voltage levels set forth in the requirements below.

1. An Asynchronous Generating Facility shall remain online for the voltage disturbance caused by any fault on the transmission grid, or within the Asynchronous Generating Facility between the Point of Interconnection and the high voltage terminals of the Asynchronous Generating Facility's step up transformer, having a duration equal to the lesser of the normal three-phase fault clearing time (4-9 cycles) or one-hundred fifty (150) milliseconds, plus any subsequent post-fault voltage recovery to the final steady-state post-fault voltage. Clearing time shall be based on the maximum normal clearing time associated with any three-phase fault location that reduces the voltage at the Asynchronous Generating Facility's Point of Interconnection to 0.2 per-unit of nominal voltage or less, independent of any fault current contribution from the Asynchronous Generating Facility.

2. An Asynchronous Generating Facility shall remain online for any voltage disturbance caused by a single-phase fault on the transmission grid, or within the Asynchronous Generating Facility between the Point of Interconnection and the high voltage terminals of the Asynchronous Generating Facility's step up transformer, with delayed clearing, plus any subsequent post-fault voltage recovery to the final steady-state post-fault voltage. Clearing time shall be based on the maximum backup clearing time associated with a single point of failure (protection or breaker failure) for any single-phase fault location that reduces any phase-to-ground or phase-to-phase voltage at the Asynchronous Generating Facility's Point of Interconnection to 0.2 per-unit of nominal voltage or less, independent of any fault current contribution from the Asynchronous Generating Facility.

3. 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~~ Momentary cessation (namely, ceasing to inject current ~~into the transmission grid~~ during a fault without mechanical isolation) is prohibited unless transient high voltage conditions rise to 1.20 per unit or more. For transient low voltage conditions, the Asynchronous Generating Facility's inverters will inject reactive current. The level of this reactive current must be directionally proportional to the decrease in per unit voltage at the inverter AC terminals. The inverter must produce full reactive current capability when the AC voltage at the inverter terminals drops to a level of 0.50 per unit or below. The Asynchronous Generating Facility must continue to operate and absorb reactive current for transient voltage conditions between 1.10 and 1.20 per unit.

   Upon the cessation of transient voltage conditions and the return of the grid to normal operating voltage ($0.90 < V < 1.10$ per unit), the Asynchronous Generating Facility's inverters automatically must transition to normal active (real power) current injection. The Asynchronous Generating Facility's inverters must ramp up to inject active (real power) current with a minimum ramping rate of at least 100% per second (from no output to full available output). The total time to complete the transition from reactive current injection or absorption to normal active (real power) current injection must be one second or less. The total time to return from momentary cessation, if used, during transient high voltage conditions over 1.20 per unit or more must be one second or less.

   The Asynchronous Generating Facility's inverter will be considered to have tripped where its AC circuit breaker is open or otherwise has electrically isolated the inverter from the grid. Following an inverter trip, the inverter must make at least one attempt to resynchronize and connect back to the grid unless the trip resulted from a fatal fault code, as defined by the inverter manufacturer. This attempt must take place within 2.5 minutes from the inverter trip. An attempt to resynchronize and connect back to the grid is not required if the trip was initiated due to a fatal fault code, as determined by the original equipment manufacturer.

4. The Asynchronous Generating Facility is not required to remain on line during multi-phased faults exceeding the duration described in Section A.i.1 of this Attachment 7 or single-phase faults exceeding the duration described in Section A.i.2 of this Attachment 7.

5. The requirements of this Section A.i of this Attachment 7 do not apply to faults that occur between the Asynchronous Generating Facility's terminals and the high side of the step-up transformer to the high-voltage transmission system.

6. Asynchronous Generating Facilities may be tripped after the fault period if this action is intended as part of a special protection system.

7. Asynchronous Generating Facilities may meet the requirements of this Section A of this Attachment 7 through the performance of the generating units or by installing additional equipment within the Asynchronous Generating Facility or by a combination of generating unit performance and additional equipment.

8. The provisions of this Section A.i of this Attachment 7 apply only if the voltage at the Point of Interconnection has remained within the range of 0.9 and 1.10 per-unit of nominal voltage for the preceding two seconds, excluding any sub-cycle transient deviations.

9. Asynchronous Generating Facility inverters may not trip or cease to inject current for momentary loss of synchronism. As a minimum, the Asynchronous Generating Facility's inverter controls may lock the phase lock loop to the last synchronized point and continue to inject current into the grid at that last calculated phase prior to the loss of synchronism until the phase lock loop can regain synchronism. The current injection may be limited to protect the inverter. Any inverter may trip if the phase lock loop is unable to regain synchronism 150 milliseconds after loss of synchronism.

10. Inverter restoration following transient voltage conditions must not be impeded by plant level controllers. If the Asynchronous Generating Facility uses a plant level controller, it must be programmed to allow the inverters to automatically re-synchronize rapidly and ramp up to active current injection (without delayed ramping) following transient voltage recovery, before resuming overall control of the individual plant inverters.

ii. Frequency Disturbance Ride-Through Capacity

An Asynchronous Generating Facility shall comply with the off nominal frequency requirements set forth in the ~~WECC Under Frequency Load Shedding Relay Application Guide or successor requirements~~ NERC Reliability Standard for Generator Frequency and Voltage Protective Relay Settings as they may be amended from time to time.

iii. Power Factor Design Criteria (Reactive Power)

An Asynchronous Generating Facility not studied under the Independent Study Process, as set forth in Section 4 of Appendix DD, shall operate within a power factor within the range of 0.95 leading to 0.95 lagging, measured at the ~~Point of Interconnection~~ high voltage side of the substation transformer, as defined in this SGIA in order to maintain a specified voltage schedule, if the Phase II Interconnection Study shows that such a requirement is necessary to ensure safety or reliability. An Asynchronous Generating Facility studied under the Independent Study Process, as set forth in Section 4 of Appendix DD, shall operate within a power factor within the range of 0.95 leading to 0.95 lagging, measured at the ~~Point of Interconnection~~ high voltage side of the substation transformer, as defined in this SGIA in order to maintain a specified voltage schedule. The power factor range standards set forth in this section can be met by using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors, or a combination of the two, if agreed to by the Participating TO and CAISO. The Interconnection Customer shall not disable power factor equipment while the Asynchronous Generating Facility is in operation. Asynchronous Generating Facilities shall also be able to provide sufficient dynamic voltage support in lieu of the power system stabilizer and automatic voltage regulation at the generator excitation system if the Phase II Interconnection Study shows this to be required for system safety or reliability.

iv. Supervisory Control and Data Acquisition (SCADA) Capability

An Asynchronous Generating Facility shall provide SCADA capability to transmit data and receive instructions from the Participating TO and CAISO to protect system reliability. The Participating TO and CAISO and the Asynchronous Generating Facility Interconnection Customer shall determine what SCADA information is essential for the proposed Asynchronous Generating Facility, taking into account the size of the plant and its characteristics, location, and importance in maintaining generation resource adequacy and transmission system reliability.

v. Power System Stabilizers (PSS)

Power system stabilizers are not required for Asynchronous Generating Facilities.

Attachment C – Draft Final Proposal

Temporary Losses of Inverter-Based Generators Mitigation

California Independent System Operator Corporation

2018 Interconnection Process Enhancements

Draft Final Proposal

September 4, 2018

Table of Contents

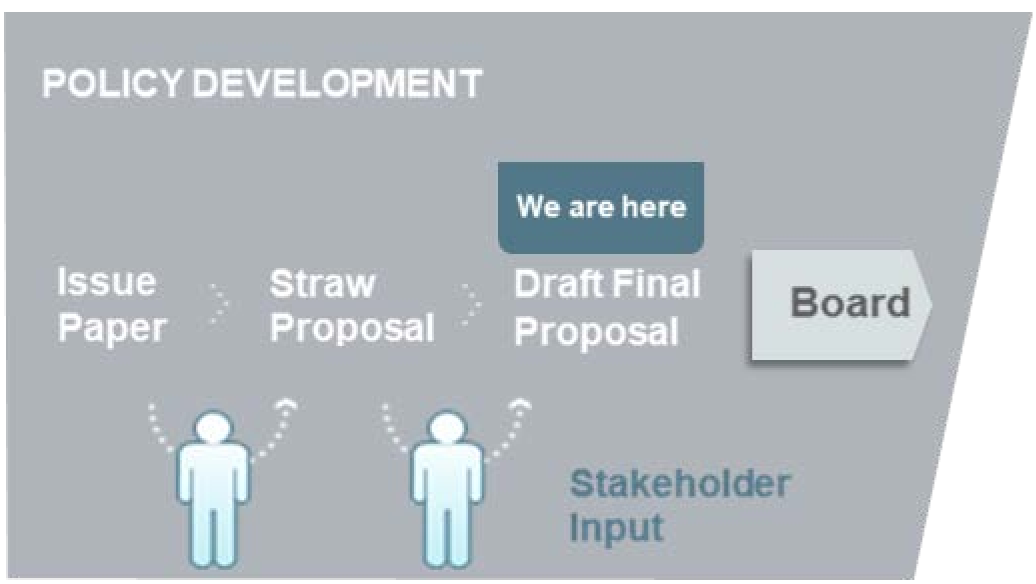
1. Introduction

Previous iterations of the California Independent System Operator Corporation's (CAISO) Interconnection Process Enhancement (IPE) initiative focused on several enhancements to the CAISO's interconnection and deliverability allocation procedures. The 2018 IPE will address some substantial concepts, but also a myriad of minor concepts that have not been addressed in some time, along with issues that have surfaced since the 2015 IPE that need to be resolved. This draft final proposal reviews topics still under development. Topics included in the 2018 IPE initiative fall into six broad categories; deliverability, energy storage, generator interconnection agreements, interconnection cost responsibility and financial security, interconnection requests, and modifications.

2. Stakeholder Process

The 2018 IPE stakeholder process is now at the Draft Final Proposal stage. Figure 1, below, shows the current status within the overall 2018 IPE stakeholder process. The draft final proposal is intended to present the scope and proposed solutions to topics that are in track 3 related to generator interconnection agreements and interconnection cost responsibility and financial security. Track 1 includes the issues that were approved at the July Board meeting. Track 2 includes the issues that will be presented for approval at the September Board meeting. Track 3 includes issues that are still being discussed and are anticipated to be presented at the November Board meeting. The CAISO has reviewed and considered stakeholder feedback provided through comments submitted on the revised straw proposal and have incorporated and addressed these comments in this draft final proposal.

Figure 1: Stakeholder Process for 2018 IPE Stakeholder Initiative



3. Scope

As described above, topics included in track 1 were finalized in the straw proposal and were approved at the July 2018 Board of Governors meeting, topics in track 2 were finalized in the revised straw proposal will be presented for approval at the September 2018 Board of Governors meeting, and topics in track 3 are targeted for the November Board of Governors meeting. The table below reflects the scope for this initiative and includes the identification of the Board of Governors meetings that each topic included in this initiative will be presented for approval.

Table 1: Overall Topic Status

Category	Section	Topic	Targeted Board of Governors Meeting
Deliverability	4.1	Transmission Plan Deliverability Allocation	September 2018
	4.2	Balance Sheet Financing	September 2018
	4.3	Participating in the Annual Deliverability Allocation	September 2018
	4.4	Change in Deliverability Status to Energy Only	September 2018
	4.5	Energy Only Projects' Ability to Re-enter the Queue for Full Capacity	September 2018
	4.6	Options to Transfer Deliverability	September 2018
Energy Storage	5.2	Replacing Entire Existing Generator Facilities with Storage	September 2018
Generator Interconnection Agreements	6.1	Suspension Notice	BPM Change
	6.2	Affected Participating Transmission Owner	November 2018
	6.3	Clarify New Resource Interconnection Requirements	July 2018
	6.4	Ride-through Requirements for Inverter-based Generation	November 2018
Interconnection Financial Security and Cost Responsibility	7.1	Maximum Cost Responsibility for NUs and potential NUs	November 2018
	7.3	Eliminate Conditions for Partial IFS Recovery upon Withdrawal	September 2018
	7.5	Shared SANU and SANU Posting Criteria Issues	BPM Change
	7.6	Clarification on Posting Requirements for PTOs	July 2018
	7.7	Reliability Network Upgrade Reimbursement Cap	November 2018
	7.9	Impact of Modifications on Initial Financial Security Posting	July 2018
Interconnection Requests	8.1	Study Agreements	July 2018
	8.4	Project Name Publication	September 2018
Modifications	9.1	Timing of Fuel Type Changes	September 2018
	9.2	Commercial Viability – PPA Path Clarification	September 2018
	9.3	PPA Transparency	July 2018
	9.4	Increase Repowering Deposit	July 2018
	9.5	Clarify Measure for Modifications After COD	July 2018
	9.6	Short Circuit Duty Contribution Criteria for Repower Projects	BPM Change

Note: The topics in yellow were combined into one topic.

6 Generator Interconnection Agreements

6.2 Affected Participating Transmission Owner

Background/Issue

Generating facilities interconnecting to the CAISO controlled grid may affect the transmission system of a PTO that is not the PTO at the Point of Interconnection (POI). In these instances, the PTO being impacted is referred to as an affected PTO. The current GIDAP does not address how the interconnection customer's financial security postings, cost responsibility, and affected PTO repayment will be disbursed among the interconnecting and affected PTOs.

The CAISO currently documents the contractual rights and obligations of the CAISO, interconnection customer, interconnection PTO and affected PTO in two separate agreements.

The CAISO enters into a *pro forma* small or large generator interconnection agreement with the interconnection customer and interconnecting PTO under which interconnection service is provided to the interconnection customer. The non *pro forma* affected participating transmission owner upgrade facilities agreement (UFA) among the CAISO, interconnection customer and affected PTO establishes the mitigation measures required on the affected PTO's electric system due to the interconnection of the interconnection customer's generating facility to the CAISO controlled grid.

Stakeholder Input

SCE supports the revised straw proposal to have separate cost estimates for the interconnecting PTO and any affected PTOs documented in the interconnection studies and the GIA or affected PTO's facilities agreement as appropriate, and the ISO's revised proposal that such separate cost estimates sum to set a single maximum cost responsibility for the interconnections customer's entire project. SCE continues to believe the interconnection customers should make all financial security postings to each PTO separately.

While not precisely the ISO's proposal, PG&E comments stated that they support the ISO's proposal to separate maximum cost responsibility (ISO proposes separate cost estimates) for each PTO in the event that another PTO is affected by the interconnection of a generator project.

While stakeholders generally support the express and memorialized separation of the interconnection customer's financial security postings, cost responsibility, and affected PTO repayment, regarding how that separation is memorialized, there is little consensus. NextEra, EDF and LSA strongly support a single GIA that incorporates the affected PTOs upgrade facilities. First Solar believes the issue is still under development and suggests adding it to the list of topics taken up after another round of comments. SDG&E and PG&E support the current structure of the GIA and a separate upgrade facilities agreement. SCE agrees and opposes the potential adoption of a single four-party agreement.

CAISO Response

The CAISO proposal from the revised straw proposal regarding maximum cost responsibility and repayment remains the same. The PTO cost estimates will sum to set a single maximum cost responsibility for the interconnections customer's entire project.

The CAISO carefully considered the input of stakeholders regarding the contractual relationship among the CAISO, interconnection customer, interconnecting PTO and affected PTOs. Because the stakeholders cannot reach a consensus on this issue and CAISO does not have projects that currently require this functionality, CAISO will defer this issue to the next IPE process.

6.4 Ride-through Requirements for Inverter-based Generation

Background/Issue

The CAISO proposed modifications to the technical requirements for the interconnection of inverter based generation to the CAISO controlled grid. The CAISO proposed these new requirements to address incorrect and undesired tripping or cessation of inverter based generation which occurred during the routine high speed clearing of bulk electric transmission lines.

Stakeholder Input

CESA, Intersect Power, LSA, Six Cities, and Wellhead had no comments at this time.

First Solar appreciated the CAISO providing the redlined draft language for Appendix H. First Solar believes that the language is a good start but would benefit from a discussion with stakeholders to ensure that it captures what the CAISO is intending and that the operators of facilities with these technologies agree that the language accomplishes what the CAISO intends. We suggest this would be best done in a workshop environment. First Solar asserts that the CAISO is not clearly expressing its intent in paragraph A(i)(3) – it seems that the facility should be required to return to its pre-event condition after the event, and the language should capture that, and then describe the ramping capability that is desired for facility's rate of return in the timeline desired. In another example, in section (iii) the point of interconnection is changed out for the "high voltage side of the substation transformer" but later in that paragraph the term "point of interconnection" is used again – Fist Solar also expresses that it is unclear what is intended with this change and whether it should be consistent.

Nextera generally supports the proposed new requirements, assuming (as stated in the last stakeholder meeting) that they would be applicable only to new generation projects and those seeking to change out inverters. However, Nextera has concerns in the two areas described below.

- Diagnostic Equipment: Continuous recording of inverter-level data on a 1 msec resolution, with 30-day storage, would be a significant data-storage requirement. The CAISO should verify with equipment manufacturers that the cost of such capability would not be significant as inverters currently do not have this capability. If the cost would be significant, the CAISO should instead consider requiring equipment (similar to fault recorders) that would only be triggered for low- and high-voltage events.
- Requirement for a PMU at every site: Nextera requests further information on the need for this requirement. Individual solar sites generally aren't large enough to have significant impacts, and the PMU sampling is too slow to capture momentary cessation and therefore may not be that useful for model verification.

PG&E is generally supportive of the CAISO's proposal to ensure that inverters don't cause momentary cessation during voltage excursions smaller than 1.2 p.u. PG&E would like the proposal to apply to not only new projects, but also to any projects going through the repower or post-COD modification.

SCE reiterated its support for the CAISO to address voltage and frequency ride-through requirements, including the requirement to continue to inject current during system fault conditions that are cleared within a prescribed time period (i.e., cycles needed for system protection to clear faulted facilities). SCE agrees with the CAISO that tripping should be based on physical equipment limitations to protect the inverter itself. Minimum technical standards for return times following transient voltage deviations and post inverter trip return time are also appropriate to stabilize the grid following a disturbance and to not jeopardize the reliability of the network.

SDG&E noted that the written proposal doesn't specify the duration required for a generation facility to inject reactive current into the grid. This may be inconsistent with NERC inverter-based resource performance task force (IRPTC) guidelines.

TMEIC comments that the elimination of the trip due to PLL or loss of synchronism should instead be retained. TMEIC argues that removing the PLL trip will dramatically limit the control the inverter has and believes that having control and getting offline when there is no 3phase system anymore is important. TMEIC proposes a ride through either with or without reduced current injection or momentary cessation with current resumption within 500ms (assuming no loss of synch). If the ride through is long enough that inverters lose synch, then re-synch and resumption of current injection may take up to 1.5s – ramp rates should be discussed as this is most likely an unstable system and different than a LVRT event. TMEIC proposes a 15 degree phase shift and a 150ms ride through prior to tripping offline as a discussion point.

CAISO Response

First Solar made a request for a technical workshop. The CAISO has scheduled a stakeholder meeting to discuss the various technical aspects of the proposed new requirements on September 17, 2018. The CAISO agrees with First Solar that paragraph A(i)3 would benefit from clarifying verbiage. The intent of the revision is to no longer allow momentary cessation for transient voltage conditions that extend beyond the nominal 0.9 to 1.1 PU magnitude, with the possible exception of transient high voltages greater than 1.20 Per Unit. Further, the intent is to allow reactive current injection that is proportional to the voltage deviation as an acceptable replacement for the use of momentary cessation. The CAISO also agrees with First Solar that the inverter should return to its pre-event condition upon the clearing of the voltage transient. The CAISO offers additional revisions to paragraph A(i)3 of Appendix H as shown in redline below.

Nextera expressed concern in the area of cost to require the inverter to record 30 days of inverter level data. The CAISO agrees that this is beyond the normal capability of inverters available today. The intent here is for the Generator Owner and /or Operator to record and store this data, but not necessarily in the inverters themselves. The use of a central data recording system for all plant event data is acceptable to the CAISO. To add clarity to this requirement, the CAISO proposes to modify paragraph A(vi) of Appendix H as shown in redline below.

Nextera also expressed concern about the requirement to install a PMU (Phase angle Measuring Unit). The CAISO notes that many of the protective relays installed in Asynchronous Generating Facilities already have this capability, and just require a change in the relay settings to activate this capability. It will be necessary to record this data. The CAISO agrees that this requirement can be clarified, and proposes additional revisions to section A(vi) in Appendix H as shown in redline below.

PG&E is generally supportive, but requested that the proposed requirements apply not only to new projects, but also to any projects going through a repower or post COD modification. The CAISO will apply the new requirements to repowers and post COD modifications where new inverters will be installed.

SCE's comments are supportive of the CAISO proposal and do not require any additional clarification.

SDG&E expressed concern that the proposal does not identify how long the units need to express reactive power. The CAISO's proposal focuses on implementing the recent NERC recommendation of eliminating the use of momentary cessation to the greatest extent possible. As such, the CAISO proposal addresses the use of reactive current injection during transient voltage conditions where the magnitude of the voltage transient is beyond the normal operating range of 0.9 Per Unit < V < 1.10 Per Unit. The proposed revision to paragraph A(i)3 of Appendix H, as described above, clarifies this.

TMEIC expressed concern that it is important to retain inverter tripping for loss of the Phase Lock Loop. The CAISO agrees. The intent is to have the inverter remain in service for momentary loss of synchronism, which may be due to the failure of the Phase Lock Loop to remain synchronized. The CAISO proposes to modify paragraph A(i)10 of Appendix H as shown in redline below.

Appendix H

INTERCONNECTION REQUIREMENTS FOR AN ASYNCHRONOUS GENERATING FACILITY

Appendix H sets forth interconnection requirements specific to all Asynchronous Generating Facilities. Existing individual generating units of an Asynchronous Generating Facility that are, or have been, interconnected to the CAISO Controlled Grid at the same location are exempt from the requirements of this Appendix H for the remaining life of the existing generating unit. Generating units that ~~are replaced~~repower or replace inverters during the life of the project, however, shall meet the requirements of this Appendix H.

A. Technical Requirements Applicable to Asynchronous Generating Facilities

i. Low Voltage Ride-Through (LVRT) Capability

An Asynchronous Generating Facility shall be able to remain online during voltage disturbances up to the time periods and associated voltage levels set forth in the requirements below.

1. An Asynchronous Generating Facility shall remain online for the voltage disturbance caused by any fault on the transmission grid, or within the Asynchronous Generating Facility between the Point of Interconnection and the high voltage terminals of the Asynchronous Generating Facility's step up transformer, having a duration equal to the lesser of the normal three-phase fault clearing time (4-9 cycles) or one-hundred fifty (150) milliseconds, plus any subsequent post-fault voltage recovery to the final steady-state post-fault voltage unless clearing the fault effectively disconnects the generator from the system. Clearing time shall be based on the maximum normal clearing time associated with any three-phase fault location that reduces the voltage at the Asynchronous Generating Facility's Point of Interconnection to 0.2 per-unit of nominal voltage or less, independent of any fault current contribution from the Asynchronous Generating Facility.

2. An Asynchronous Generating Facility shall remain online for any voltage disturbance caused by a single-phase fault on the transmission grid, or within the Asynchronous

Generating Facility between the Point of Interconnection and the high voltage terminals of the Asynchronous Generating Facility's step up transformer, with delayed clearing, plus any subsequent post-fault voltage recovery to the final steady-state post-fault voltage unless clearing the fault effectively disconnects the generator from the system. Clearing time shall be based on the maximum backup clearing time associated with a single point of failure (protection or breaker failure) for any single-phase fault location that reduces any phase-to-ground or phase-to-phase voltage at the Asynchronous Generating Facility's Point of Interconnection to 0.2 per-unit of nominal voltage or less, independent of any fault current contribution from the Asynchronous Generating Facility.

3. 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.~~ Momentary cessation (i.e. ceasing to inject current) is no longer an acceptable mode of operation, with one exception as noted below. For transient low voltage conditions, the Asynchronous Generating Facility's units will inject reactive current. The level of this reactive current shall be directly proportional to the decrease in Per Unit voltage at the inverter AC terminals. The inverter shall produce full rating reactive current when the AC voltage at the inverter terminals drops to a level of 0.50 Per Unit. The Asynchronous Generating Facility shall absorb reactive current for transient voltages between 1.10 and 1.20 Per Unit. The Asynchronous Generating Facility's units may momentarily cease to inject current into the transmission grid for transient high voltage conditions above 1.20 PU. ~~The Asynchronous Generating Facility should continue to absorb reactive current for transient voltages between 1.10 and 1.20 PU.~~

Upon cessation of transient voltage conditions and the return of the grid to normal operating voltage (0.90 < V < 1.10 Per Unit), the Asynchronous Generating Facility's units shall automatically ~~connect to the grid within a maximum of 0.10 seconds (if momentary cessation was used for transient high voltage), and~~ transition to normal active (real power) current injection. The Asynchronous Generating Facility's units shall ramp up to inject active (real power) current with a minimum ramp rate – from no output to full output – of at least 100% per second. A ramp rate of 200% per second is preferred. The entire time to complete the transition from reactive current injection or absorption (or momentary cessation if used for voltages above 1.20 Per Unit) shall be one second or less.

Inverter protective functions should use a filtered, fundamental frequency voltage input for overvoltage protection to avoid spurious tripping on transient high voltages.

4. An Asynchronous Generating Facility unit trip is defined as the opening of the unit's AC circuit breaker or otherwise electrical isolation of the unit from the grid. Following the unit trip, the unit will make at least one attempt to resynchronize and connect back to the grid. The time delay to accomplish this will be adjustable to between 2 and 5 minutes. The default time shall be 2 ½ minutes. An attempt to resynchronize and connect back to the grid is not required if the unit trip was initiated due to a fatal fault code, as determined by the original equipment manufacturer.

5. The Asynchronous Generating Facility is not required to remain on line during multi-phased faults exceeding the duration described in Section A.i.1 of this Appendix H or single-phase faults exceeding the duration described in Section A.i.2 of this Appendix H.

6. The requirements of this Section A.i of this Appendix H do not apply to faults that occur between the Asynchronous Generating Facility's terminals and the high side of the step-up transformer to the high-voltage transmission system.

7. Asynchronous Generating Facilities may be tripped after the fault period if this action is intended as part of a special protection system.

8. Asynchronous Generating Facilities may meet the requirements of this Section A.i of this Appendix H through the performance of the generating units or by installing additional equipment within the Asynchronous Generating Facility, or by a combination of generating unit performance and additional equipment.

9. The provisions of this Section A.i of this Appendix H apply only if the voltage at the Point of Interconnection has remained within the range of 0.9 and 1.10 per-unit of nominal voltage for the preceding two seconds, excluding any sub-cycle transient deviations.

10. Asynchronous Generating Facility units shall not trip or cease to inject current for ~~loss of the Phase Lock Loop (PLL)~~ momentary loss of synchronism. As a minimum, the Asynchronous Generating Facility's unit controls may lock the PLL to the last synchronized point and continue to inject current into the grid at that last calculated phase until the PLL can regain synchronism ~~upon voltage recovery (e.g. the transmission system fault clears).~~ The ~~reactive~~ current injection may be limited to protect the inverter. The inverter may trip if the PLL is unable to regain synchronism after 150 mSec.

11. Inverter restoration following transient voltage conditions must not be impeded by plant level controllers. If the Asynchronous Generating Facility uses a plant level controller, it must be coordinated to allow the individual inverters to rapidly respond following transient voltage recovery, before resuming overall control of the individual plant inverters.

~~The requirements of this Section A.i in this Appendix H shall not apply to any Asynchronous Generating Facility that can demonstrate to the CAISO a binding commitment, as of July 3, 2010, to purchase inverters for thirty (30) percent or more of the Generating Facility's maximum Generating Facility Capacity that are incapable of complying with the requirements of this Section A.i in this Appendix H. The Interconnection Customer must include a statement from the inverter manufacturer confirming the inability to comply with this requirement in addition to any information requested by the CAISO to determine the applicability of this exemption.~~[1]

ii. Frequency Disturbance Ride-Through Capability

An Asynchronous Generating Facility shall comply with the off nominal frequency requirements set forth in the ~~WECC Under Frequency Load Shedding Relay Application Guide or successor requirements as they may be amended from time to time.~~ NERC Standard PRC-024, Western Variance.

iii. Power Factor Design Criteria (Reactive Power)

An Asynchronous Generating Facility not studied under the Independent Study Process, as set forth in Section 4 of Appendix DD, shall operate within a power factor within the range of 0.95 leading to 0.95 lagging, measured at the high voltage side of the substation transformer ~~Point of Interconnection~~ as defined in this LGIA in order to maintain a specified voltage schedule, if the Phase II Interconnection Study shows that such a requirement is necessary to ensure safety or reliability. An Asynchronous Generating Facility studied under the Independent Study Process, as set forth in Section 4 of Appendix DD, shall operate within a power factor within the range of

[1] New policy aside, the CAISO may remove this paragraph as anachronistic. The CAISO will move this language into the BPM for those generators for which this applied.

0.95 leading to 0.95 lagging, measured at the ~~Point of Interconnection~~ high voltage side of the substation transformer as defined in this LGIA in order to maintain a specified voltage schedule. The power factor range standards set forth in this section can be met by using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors, or a combination of the two, if agreed to by the Participating TO and CAISO. The Interconnection Customer shall not disable power factor equipment while the Asynchronous Generating Facility is in operation. Asynchronous Generating Facilities shall also be able to provide sufficient dynamic voltage support in lieu of the power system stabilizer and automatic voltage regulation at the generator excitation system if the Phase II Interconnection Study shows this to be required for system safety or reliability.

iv. Supervisory Control and Data Acquisition (SCADA) Capability

An Asynchronous Generating Facility shall provide SCADA capability to transmit data and receive instructions from the Participating TO and CAISO to protect system reliability. The Participating TO and CAISO and the Asynchronous Generating Facility Interconnection Customer shall determine what SCADA information is essential for the proposed Asynchronous Generating Facility, taking into account the size of the plant and its characteristics, location, and importance in maintaining generation resource adequacy and transmission system reliability.

v. Power System Stabilizers (PSS)

Power system stabilizers are not required for Asynchronous Generating Facilities.

vi. Diagnostic Equipment

An asynchronous Generating Facility shall monitor and record ~~the following~~ data in real time. The data may be recorded and stored in a central plant control system. These requirements shall pertain to all Generators with a net export to the CAISO of 20 MW or greater. The following data in real time shall be recorded:

Plant Level

(1) Plant three phase voltage, current and power factor
(2) Status of ancillary reactive devices
(3) Status of all plant circuit breakers
(4) Status of plant controller
(5) Plant control set points
(6) Status of main plant transformer no load taps
(7) Status of main plant transformer tap changer (if applicable)
(8) Protective relay trips (relay target data)

Inverter Level Data

(1) High and low frequency ride through events
(2) High and low voltage ride through events
(3) Momentary cessation for transient high voltage events
(4) Reactive current injection for transient low voltage events
(5) Phase Lock Loop (PLL) status
(6) Inverter status
(7) AC and DC current

(8) AC and DC voltage

The data shall be time synchronized to a one millisecond level of resolution. The Asynchronous Generating Facility shall store this data for a minimum of 30 calendar days. The Asynchronous Generating Facility, upon request from the CAISO or the PTO, shall make this data available within 10 calendar days of the request.

The Asynchronous Generating Facility shall install and maintain a PMU (Phase angle Measuring Unit) or functional equivalent normally provided by protective relays at the service entrance to the facility. The PMU shall have a resolution of at least 30 samples per second. The Asynchronous Generating Facility, upon request from the CAISO or the PTO, shall make this data available within 10 calendar days. The CAISO does not require real time telemetry of the PMU data to the CAISO.

7 Interconnection Financial Security and Cost Responsibility

7.1 Maximum Cost Responsibility for Network Upgrades and Potential Network Upgrades

Background/Issue

Currently, an interconnection customers' maximum cost responsibility is established from its phase I and phase II study reports. The combined costs for all network upgrades in the phase I and phase II study reports are compared, and the lower cost sets the maximum cost responsibility for network upgrades for the project. An interconnection customer's current cost responsibility is then used to calculate its required interconnection financial security (IFS), which can change as the result of, *inter alia*, customers withdrawing from the queue. The CAISO is aware that the reassessment-related cost responsibility changes and the increased appearance of potential (fka contingent) network upgrade costs in project's study reports has created confusion around how the maximum cost responsibility plays out in practice. The CAISO also has observed that there is confusion regarding when and how an upgrade impacts the maximum cost responsibility and/or the current cost responsibility.

Following the straw and revised straw proposal, it became clear that the CAISO was placing too much uncertainty on the cost responsibilities to Interconnection Customers associated with potential network upgrades. The CAISO has adjusted its proposal in this paper such that the addition of new and clarified cost responsibility definitions should clarify how potential network upgrades from prior clusters—where GIAs have and have not been executed—affect cost responsibility.

Please note that due to the FERC definition of contingent upgrades in Order No. 845, the CAISO is converting the use of *contingent* network upgrades to *potential* network upgrades.

Stakeholder Input

EDF-R suggests that the execution of a GIA is a sufficient milestone for defining the shift in cost responsibility for upgrades if that project withdraws. EDF-R notes that PTOs have not demonstrated an undue burden and projects must make their first and second postings prior to signing a GIA.

First Solar suggests additional processes are needed and suggests the CAISO schedule a workshop in an effort to achieve balance between cost and timing certainty.

Intersect Power, LSA, NextEra suggests that placing 100% of each contingent (potential) upgrade in a projects maximum cost exposure is inconsistent with the current GIDAP provisions.

PG&E, SCE, and SDG&E continue to have concerns associated with the protections provided by contingent (potential) network upgrades, and appreciates the additional definitions and clarifications provided in the revised straw proposal. PG&E and SCE suggest that in the place of the execution of the GIA as the trigger for the removal of contingent (potential) network upgrades, the trigger be changed to the execution of the GIA and submission of final security postings.

Six Cities is requesting clarification on maximum cost exposure and how the maximum cost responsibility can change over time.

Wellhead suggests the CAISO remove contingent (potential) network upgrades such that they represent a liability that could cause a project to become non-financeable.

SCE noted that the CAISO did not specifically address their concern and suggests confirmation is needed from the CAISO that plan of service RNUs will be treated differently versus other RNUs as pertaining to the provisions of Section 14.2.2 of the GIDAP and the backstop financing responsibility of PTOs in that Section. SCE believes that a PTO must not be exposed to additional financing risk just because it allowed multiple interconnection customers to share a plan of service RNU that serves no other purpose than to terminate an interconnection customer –owned generation tie line.

CAISO Response and Proposal

Upon review of stakeholder comments, the CAISO is further revising its proposal and looks forward to the upcoming in-person stakeholder discussion on this topic. In this revised proposal, the CAISO attempts to balance the concerns of providing cost certainty and responsibility to interconnection customers and at the same time limit cost risks to a PTO. The CAISO believes the following revised proposal provides the right balance for maintaining consistency with current tariff policy (by allocating potential network upgrade costs in a consistent manner as cost allocations for directly assigned network upgrades), providing interconnection customers more definitive cost certainty, and providing PTOs reasonable and manageable cost risk associated with potential upgrades and maximum cost responsibility.

The CAISO understands and appreciates the PTOs' concerns that PTOs become responsible for the cost of network upgrades upon the execution of a GIA when the upgrade is still needed by future clusters. However, with the proposed implementation of the ranking groups for the allocation of transmission plan deliverability, and proposed changes to cost responsibility herein, the CAISO maintains the transfer of responsibility at the time a GIA is executed is still appropriate. Except for projects that receive a transmission plan deliverability allocation, GIAs are being tendered such that they should be executed near or upon the start of construction of a project's assigned network upgrades. As such, PTOs should be requiring final postings at or near the execution of the GIA. This process helps mitigate the risk to PTOs of GIAs being executed by projects sooner than needed and at a time when the project is less certain. Projects that do receive a transmission plan deliverability allocation must execute a GIA to retain the allocation, but now will have demonstrated they have a power purchase agreement (PPA), are on a shortlist for a PPA, or state the projects will proceed to commercial operation without a PPA. These are the projects with the lowest likelihood of withdrawing of all projects in the queue.

The CAISO's revised proposal is a framework for overall cost responsibility as well as proposed definitions around upgrades and cost responsibilities. They are:

Proposed Definitions:

> Potential Network Upgrade: *Reliability and/or Local Deliverability Network Upgrades where the cost responsibility for which was already assigned to one or more prior clusters, but which may fall to the interconnection customer because none of the prior-cluster Interconnection Customers have executed a Generator Interconnection Agreement pursuant to Section 14.2.2 of Appendix DD.*
>
> Directly Assigned Network Upgrade: *Reliability and/or Local Deliverability Network Upgrades identified in the Interconnection Customer's Interconnection Study or annual reassessment, and for which the Interconnection Customer has a direct financial responsibility, exclusive of Potential Network Upgrades that could become Directly Assigned Network Upgrades.*
>
> Interconnection Service Upgrades: *Reliability Network Upgrades at the Point of Interconnection to accomplish the physical interconnection of the generator project to the CAISO controlled grid. Interconnection Service Upgrades can be Potential Network Upgrades and/or Directly Assigned Network Upgrades.*
>
> Precursor Network Upgrades: *Network Upgrades that are required by a project for its selected level of service, including (1) the cost responsibility for which is assigned to one or more prior cluster that has executed a Generator Interconnection Agreement, and/or (2) upgrades approved in the CAISO Transmission Plan.*
>
> Current Cost Responsibility: *The sum of the Interconnection Customer's current allocated costs for Directly Assigned Network Upgrades. This cost is used to calculate the Interconnection Financial Security requirement, not to exceed the Maximum Cost Responsibility.*
>
> Maximum Cost Responsibility: *The sum of the Interconnection Customer's assigned Direct Network Upgrades plus the Interconnection Customer's assigned Potential Network Upgrades identified in its Interconnection Studies. Where the Interconnection Customer has received a Phase I and a Phase II Interconnection Study Report, the lower sum of the above from the Phase I and the Phase II Interconnection Study Reports will establish the Interconnection Customer's Maximum Cost Responsibility.*

Revised proposal for upgraded assignment and cost responsibility structure:

The CAISO proposes the following modified approach to the assignment and cost allocation of network upgrades:

1. An interconnection customer is assigned upgrades and associated cost responsibility of

the following two components in their Phase I and Phase II study reports:

a. Directly assigned network upgrades

b. Potential network upgrades

2. Cost allocation of directly assigned network upgrades will follow the current provisions in tariff Appendix DD, Section 8.3 for RNUs and 8.4 for LDNUs[2], with the following exception:

   The allocation of cost responsibility for interconnection service upgrades will be:

   a. For maximum cost responsibility – fully allocated (100% cost responsibility) to each generation project that requires the upgrades to interconnect. [3]

   b. For current cost responsibility – the project's current cost allocation associated with the phase I, phase II, or latest reassessment study report, as applicable. Projects within a cluster requiring the same interconnection service upgrade will share the cost for the upgrade(s) equally.

3. Cost allocation of potential network upgrades will follow the current provisions in tariff Appendix DD, Section 8.3 for RNUs and 8.4 for LDNUs and:

   a. The allocation of cost responsibility for interconnection service upgrades will be fully allocated (100% cost responsibility) to the maximum cost responsibility of each generation project that requires the upgrades to interconnect.

4. The interconnection customer's maximum cost responsibility equals the sum of the following two components:

   a. Directly assigned network upgrades (as describe in #2 above); and

   b. Potential network upgrade (as described in #3 above)

   Where the interconnection customer has received a Phase I and a Phase II interconnection study report, the lower sum of (a) and (b) above from the Phase I and the Phase II interconnection study reports will establish the interconnection customer's maximum cost responsibility.

5. The interconnection customer only posts IFS for directly assigned network upgrades (current cost responsibility). Interconnection customers will not post IFS for the cost of potential network upgrades unless and until they become directly assigned network upgrades for those interconnection customers. If the interconnection customer wishes to achieve commercial operation before its potential network upgrades are completed by the

[2] http://www.caiso.com/Documents/AppendixDD_GeneratorInterconnection_DeliverabiltyAllocationProcess_asof_Mar11_2018.pdf

[3] SCE's comments raised a concern with "plan of service" RNUs, stating, confirmation is needed from the CAISO that plan of service RNUs will be treated differently versus other RNUs. The ISO believes that by fully allocating (100% cost responsibility) into each generation project's maximum cost responsibility that requires the "interconnection service" upgrades to interconnect achieves what SCE seeks to accomplish.

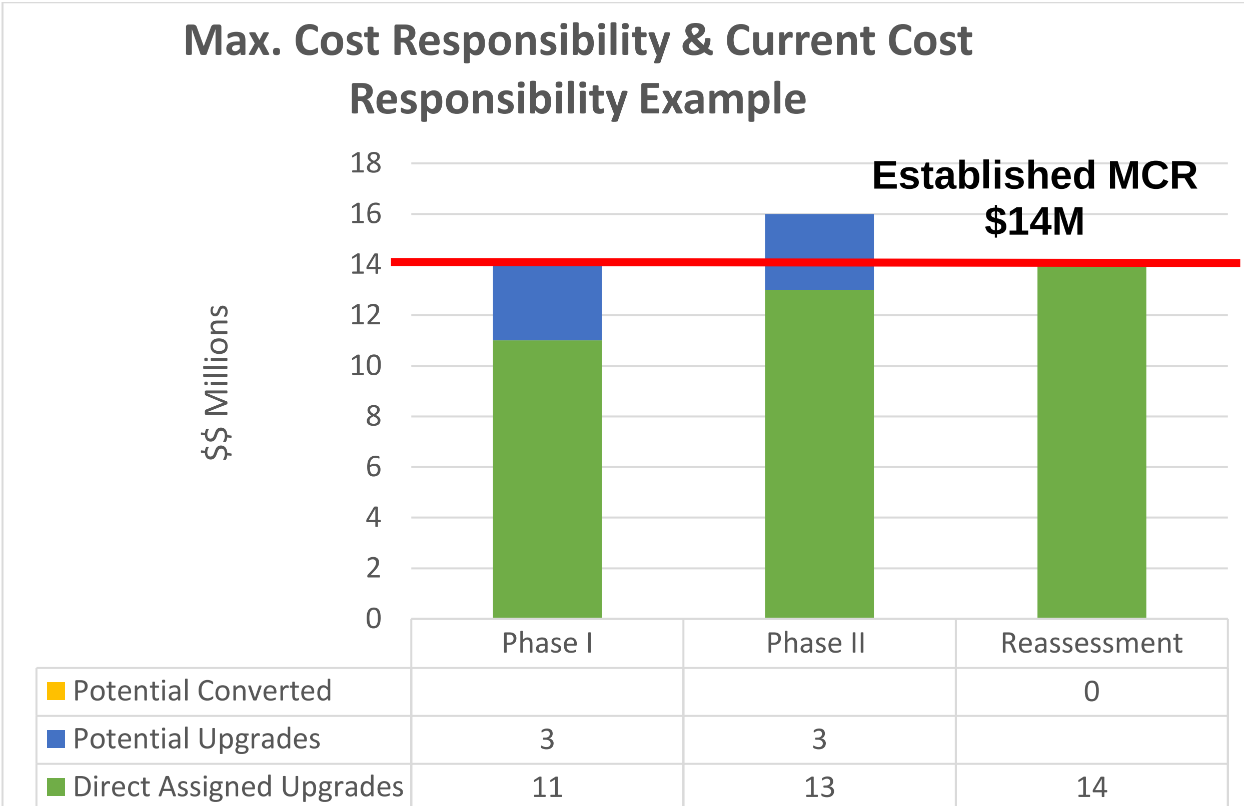
cluster/project that is currently funding such upgrades, that interconnection customer must post and fund the potential reliability network upgrades in lieu of the earlier-queued cluster. If the potential network upgrades are DNUs and the interconnection customer wants to achieve commercial operation before their anticipated completion, the interconnection customer also could elect to (1) post and fund the potential DNUs, or (2) achieve commercial operation but forego its final deliverability status until they are complete. The CAISO notes that interconnection customers have only desired to achieve commercial operation ahead of such precursor or potential upgrades in very few circumstances, and there the CAISO and PTO worked to find case-by-case solutions, including the construction of new and/or temporary network upgrades on a merchant basis. The CAISO anticipates that if this situation arises again, other options may be available, and the CAISO and PTO would work with the interconnection customer to identify potential solutions in addition to those identified above.

A potential network upgrade stops being a potential network upgrade and becomes a directly assigned network upgrade when all prior cluster projects assigned a cost responsibility allocation (direct or potential) for the network upgrade withdraw without having executed a GIA. For example, if cluster 5 triggered an upgrade, it is considered a potential upgrade for cluster 6, cluster 7, and cluster 8 if no projects in cluster 5 requiring the upgrade has executed a GIA. When all applicable cluster 5 projects withdraw, the upgrade becomes direct for cluster 6, but remains potential for cluster 7 and cluster 8. In this example, the cluster 6 projects will become responsible for the costs of the potential network upgrade and such costs will be included in the project's current cost responsibility for network upgrades based on the amount allocated to the project (as described above), up to the project's maximum cost responsibility.

A potential network upgrade stops being a potential network upgrade and becomes a precursor network upgrade (as defined above) when at least one of the prior cluster projects executes a GIA that contains a the network upgrade as a direct upgrade. The later cluster project(s) will no longer have cost responsibility for that network upgrade.

For clarification purposes, at any time a potential network upgrade is removed from a project's maximum cost responsibility, it may provide headroom within the maximum cost responsibility for increasing cost allocations of a project's other directly assigned network upgrades through the reassessment study process. Eligibility for adjustments to the maximum cost responsibility will follow Section 7.4 of Tariff appendix DD.

The following charts depict two scenarios: 1) a potential network upgrade is removed from the project's obligation. The removal of the potential network upgrade provided headroom for the reallocation of the direct assigned network upgrades already assigned to the project, and 2) a potential network upgrade becomes a direct assigned network upgrade and the current cost responsibility of the project. This example shows the interconnection customer's maximum cost responsibility is maintained.


Max. Cost Responsibility & Current Cost Responsibility Example
Established MCR $14M
$$ Millions
18
16
14
12
10
8
6
4
2
0
Phase I
Phase II
Reassessment
Potential Converted 0
Potential Upgrades 3 3
Direct Assigned Upgrades 11 13 14


Max. Cost Responsibility & Current Cost Responsibility Example
Established MCR $14M
$$ Millions
18
16
14
12
10
8
6
4
2
0
Phase I
Phase II
Reassessment
Potential Converted 3
Potential Upgrades 3 3
Direct Assigned Upgrades 11 13 12

7.7 Reliability Network Upgrade Reimbursement Cap

Background/Issue

Section 14.3.2.1 of the GIDAP provides that PTOs will reimburse an interconnection customer's cost responsibility for RNUs only up to $60,000 per MW of the interconnection customer's generating capacity, as specified in its GIA.[4] This policy was designed to ensure that ratepayers only incur costs for RNUs commensurate with the benefits they receive from the new generator. The repayment limit of $60,000 per MW for RNUs assigned to a project was determined to result in full cash repayment for RNUs for the vast majority of projects, and provides an incentive for interconnection customers to avoid siting projects in locations where the costs of RNUs needed to support the interconnections would be inappropriately high.

The CAISO has found that the $60,000 per MW maximum reimbursement amount for an RNU for funds advanced for network upgrades has the potential to be circumvented in instances where earlier-queued projects withdraw from the queue but the upgrades are still needed. To demonstrate this potential issue, consider the following example; Assume a 100 MW project in Cluster 8 with an executed GIA has a required RNU whose cost exceeds the $60,000 per MW limit. Also assume a Cluster 10 project, also 100 MW, requires the same RNU as the Cluster 8 project to interconnect. If the Cluster 8 project that triggered the RNU withdraws, the PTO must fund the construction costs of the RNU for the Cluster 10 project.[5] In this example the PTO is responsible for funding the entire cost of the RNU, including the portion over $60,000 per MW, and will include the entire cost of the RNU into its Transmission Revenue Requirement and ratepayers will ultimately have to pay for the entire cost of the RNU.

Stakeholder Input

EDF-R, LSA, NextEra, oppose all three options suggested by the CAISO and believe that the issue of projects that have upgrades that exceed the RNU reimbursement is rare and those projects with such upgrades rarely execute GIAs. The stakeholders also raise the issue of cost escalation of the $60,000 per MW value, noting that the value was established in 2012 and per-unit costs have increased with an annual escalation, and suggest that the CAISO consider applying escalation factor to the currently established $60,000 per MW value.

First Solar is concerned with this proposal and three suggested solutions and suggests the CAISO reevaluate the reimbursement cap based on more recent cluster studies. Further, First Solar is concerned about the categorization of deliverability and reliability network upgrades and requests clarification of how RNUs and DNUs are categorized.

Intersect Power raises issues with the three suggested solutions and suggest the CAISO delay this topic to ensure stakeholders can adequately address the issue and determine an amenable solution.

PG&E supports the CAISO's proposal for the RNU Reimbursement Cap that closes the loophole

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[4] Reimbursement beyond the cost cap would come in the form of Merchant Transmission Congestion Revenue Rights.

[5] *See* Section 14.2.2 of Appendix DD to the CAISO tariff.

of Interconnection Customers with projects in different clusters that need the same Network Upgrades could ultimately require ratepayers to pay the entire cost of the network upgrades, and not just the $60,000 per MW limit on reimbursement, by withdrawing their project after GIA execution

SCE, SDG&E, and Six Cities support the CAISO continuing to seek a mechanism to require a project that ultimately benefits from the RNU to pay the cost component in excess of the $60,000/MW cap directly related to their project.

Wellhead supports options three provided in the revised straw proposal.

CAISO Response

While the CAISO believes a potential issue remains with this policy as established, based on stakeholder feedback and that the CAISO has not identified an actual instance where the $60K/mw cap has been circumvented to the detriment of ratepayers, the CAISO will not proceed with this topic in this 2018 IPE. The CAISO will, however, continue to monitor its concerns for the foreseeable future to ensure there is no adverse impact to ratepayers, interconnection customers, or the PTOs as a result of misuse of the intent or spirit of the policy.

However, the ISO agrees with stakeholder comments that the $60,000 per MW cap for RNU reimbursement should be escalated by an industry-based escalation factor. The ISO proposes to work with the PTOs to determine an appropriate index to determine the escalation factor. Because this $60,000 cap was established in 2012, the CAISO proposes to revise its tariff to specify that the 2012, $60,000 figure will be used as the baseline and be escalated on an annual basis thereafter. The annual escalation rate and the resulting RNU reimbursement cost cap will be developed in coordination with the PTOs and included in the annual per unit cost update process.[6] Each project's reimbursement cap value will be determined based on the date in which the RNU is placed into service. Forecasts of future year escalation rates will be provided with the historical escalation rates. The table below illustrates the process and serves as an example of the escalated value to date. The final values will be developed through the annual per unit cost update process.

Year	2012	2013	2014	2015	2016	2017	2018
Actual Escalation Rates		1.20%	1.90%	1.80%	2.10%	2.10%	1.80%
Escalation Factors	1.0000	1.0120	1.0312	1.0498	1.0718	1.0943	1.1140
Escalated RNU Cost Cap	**$60,000**	**$60,720**	**$61,874**	**$62,987**	**$64,310**	**$65,661**	**$66,843**

[6] Link to the "Participating transmission owner per unit costs" (at bottom of the page).

http://www.caiso.com/planning/Pages/GeneratorInterconnection/InterconnectionStudy/Default.aspx

Attachment D – Board Memoranda

Temporary Losses of Inverter-Based Generators Mitigation

California Independent System Operator Corporation

Memorandum

To: ISO Board of Governors

From: Keith Casey, Vice President, Market and Infrastructure Development

Date: November 7, 2018

Re: **Decision on Interconnection Process Enhancements – Track 3**

This memorandum requires Board action.

EXECUTIVE SUMMARY

The interconnection process enhancement (IPE) 2018 is the California Independent System Operator Corporation's current stakeholder initiative in its ongoing commitment to a continuous improvement process of the Generator Interconnection and Deliverability Allocation Procedures (GIDAP). As discussed at the July and September Board meetings, IPE 2018 identified twenty-five topics for this year. Some require tariff amendments and some will result in modifications to business practice manuals. A total of fifteen enhancements have been approved by the Board to date and a couple more are still being discussed with stakeholders and are planned to be presented at the February 2019 Board meeting. Management now proposes for Board approval of three topics that require tariff amendments, which are as follows:

1. Revise ride-through requirements for inverter-based generation;
2. Revise the reliability network upgrade reimbursement cap; and
3. Define and memorialize the concept of an *affected* participating transmission owner

Management recommends the following motion:

> ***Moved, that the ISO Board of Governors approves the proposed interconnection process enhancements, as described in the memorandum dated November 7, 2018; and***
>
> ***Moved, that the ISO Board of Governors authorizes Management to make all necessary and appropriate filings with the Federal Energy Regulatory Commission to implement the proposal, including any filings that implement the overarching initiative policy but contain discrete revisions to incorporate Commission guidance in any initial ruling on the proposed tariff amendment.***

DISCUSSION AND ANALYSIS

The ISO currently has 288 active projects in the interconnection queue that have not achieved commercial operation. To accomplish the interconnection and queue management processes effectively in a changing environment, the ISO strives to enhance interconnection processes when needed. To that end, Management seeks Board approval of the following enhancements:

1. Revise ride-through requirements for inverter-based generation

On August 16, 2016, fires burning in the southern California area caused several high voltage transmission lines to relay due to smoke contamination. During this time, the ISO observed over 1,100 MW of solar PV generation capacity that was unexpectedly lost during the routine clearing of the transmission line faults. Since that time, the ISO has observed twelve more instances of unexpected loss of solar PV generation, which occurred during the routine clearing of transmission system faults. The most recent event occurred on May 11, 2018. The ISO brought this issue to the attention of NERC, which formed a task force to investigate. The ISO was an active participant in this task force.

In May 2018, NERC issued a reliability guideline and an advisory notice for inverters. The documents contained recommendations for the reliable operation of inverter-based generation systems. Management proposes to update the technical requirements of the large and small generator interconnection agreements to include the basic recommendations contained in the NERC documents.

The proposed new requirements include (1) the elimination of momentary cessation for transient low voltages that typically occur on inverters during the clearing of a transmission line fault, (2) the elimination of inverter tripping for momentary loss of synchronism, and (3) the coordination of the central plant controller with the individual inverter control systems. In addition to these requirements, Management proposes to require the installation of diagnostic equipment for projects executing a large generator interconnection agreement. The diagnostic equipment functions identified in the proposal include constant monitoring of the inverter-based generation output and recording transient data during generation events defined as inverter ride-through or trip conditions. Management also proposes to require that the generator store data for a minimum of 30 days, and make the data available to the ISO and the interconnecting PTO within ten days upon request. There are no telemetry requirements included in the proposal.

These new technical requirements will apply to all new asynchronous generators in the generation interconnection process that have not yet executed a generation interconnection agreement. They also will apply to all asynchronous generators that have executed a generation interconnection agreement and are in development if the generator is changing its inverter equipment through the modification process. Finally, they will apply to all asynchronous generators that are already in service and repower or replace inverter equipment for reasons other than individual inverter replacement in kind (*e.g.*, due to individual inverter failure or other typical maintenance issues).

2. Revise the reliability network upgrade reimbursement cap

In 2012, the ISO established a $60,000 per MW reimbursement cap for reliability network upgrades to provide an incentive for interconnection customers to make efficient siting decisions that take into account the cost of required transmission. This cap establishes the amount of money the interconnection customer is reimbursed from the participating transmission owner for reliability network upgrades once the project achieves commercial operation, thus protecting ratepayers from undue costs.

In the 2018 IPE, stakeholders representing interconnection customers expressed concern that this $60,000 per MW reimbursement figure has remained static since 2012. Management agrees that updating the $60,000 per MW figure annually to account for inflation and construction cost escalation is appropriate and consistent with the original intent.

Management proposes to escalate annually the $60,000 per MW cap by an industry-based escalation factor for reliability network upgrade reimbursements, starting in year 2013. The ISO will work with stakeholders to identify the most appropriate industry escalation factor, and will incorporate the reliability network upgrade cost cap escalation into the annual PTO per-unit cost guide update process, publishing the annual updated reliability network upgrade cost cap on the ISO web site with the updated PTO per-unit cost guides.

3. Define and memorialize the concept of an *affected* participating transmission owner

The tariff addresses the participating transmission owner as the entity where the interconnection customer's project interconnects. However, depending on the electrical proximity of a project, an interconnection sometimes may impact a nearby participating transmission owner as well. In effect, the ISO and the generator must mitigate an interconnection's impact with the "interconnecting PTO" and the "affected PTO."

This type of interconnection creates two sets of issues: (1) how the reliability network upgrade reimbursement cap, financial security postings, cost responsibilities, and cost repayment for network upgrades are allocated between the interconnecting and affected PTOs; and (2) and whether the contractual arrangements should be a separate agreement with each PTO or one combined four-party agreement with both PTOs executing a single agreement.

<u>Financial Considerations</u>

Management proposes to modify the tariff to describe separate network cost estimates for the interconnecting PTO and any affected PTOs. These PTO cost estimates will sum to establish a single maximum cost responsibility for the interconnection customer's entire project. This framework enables the ISO to consider potential alternative network upgrades that might provide more efficient and lower overall network cost solutions without being constrained by an interconnection customer having multiple maximum costs responsibilities across multiple PTOs.

The interconnection customer will make their first and second interconnection financial security posting to the interconnecting PTO and will make the third interconnection financial security posting to each PTO separately based on each PTO's network upgrade cost estimate. In addition, interconnection customers will be entitled to receive repayment for their contribution to the cost of network upgrades from each PTO separately. Repayment of amounts advanced for reliability network upgrades will be paid by each PTO up to a combined maximum of $60,000 (escalated per item 2, above) per MW of generating capacity as specified in the generator interconnection agreement. Total repayment from each PTO will be applied proportionately based on the amount paid to each PTO for its reliability network upgrades.

Single vs Multiple Generation Interconnection Agreements

The ISO currently documents the contractual rights and obligations of the ISO, interconnection customer, interconnecting PTO and affected PTO in two separate agreements. The ISO enters into a *pro forma* small or large generator interconnection agreement with the interconnection customer and interconnecting PTO under which interconnection service is provided to the interconnection customer. If an interconnection request also requires mitigations to another PTO's facilities, the ISO enters into a non *pro forma* affected participating transmission owner agreement with the interconnection customer and affected PTO that establishes the mitigation measures required on the affected PTO's electric system due to the interconnection of the interconnection customer's generating facility to the ISO controlled grid.

The ISO could not reach sufficient support with stakeholders on a proposal to continue with the existing contracting process or move to a single agreement. Therefore, the ISO is not proposing a change to the tariff at this time. However, the ISO did commit, if all parties agree, to pilot a single four-party generator interconnection agreement, which will seek to ensure that all parties affected by the interconnection customer's interconnection are accountable to each other in a single agreement.

POSITIONS OF THE PARTIES

The ISO conducted stakeholder outreach on these topics consisting of an issue paper on January 24, 2018, a straw proposal on May 21, 2018, a revised straw proposal on July 10, 2018, and a draft final proposal on September 17, 2018. Stakeholders were able to provide comments at each phase with a majority fully or partially supporting the four Track 3 topic proposals with some exceptions. The more notable exceptions are summarized below along with Management's response to them. A comprehensive summary of all stakeholder comments is provided in Attachment A.

1. Modify ride-through requirements for inverter-based generation

Pacific Gas & Electric (PG&E), the Large-scale Solar Association (LSA), and EDF Renewables (EDF-R) all indicated their support for the proposal.

SPower responded that the technical revisions seem reasonable, but that the proposal should apply only to projects submitting new interconnection requests after the new provisions become effective. SPower expressed concern that the new standards should not apply retroactively to projects already operating or in the study process, even if a request is made to modify the inverters. As discussed, the proposed technical revisions recommended by NERC seek to solve critical grid reliability issues, and Management believes that these revisions should apply to as many asynchronous generators as possible going forward. Moreover, FERC has used execution of the GIA (or substantial modifications thereafter) as the point of demarcation for similar new requirements, most recently the capability to provide primary frequency response. This would include all projects that have not executed a generation interconnection agreement, generators who repower, and generators that are changing their inverters through the modification process. Management agrees that the technical requirements should not apply to generators that are not changing their inverters through the modification process simply to replace individual inverters due to inverter failure or other maintenance issues. However, for substantial modifications, the new requirements should apply.

San Diego Gas & Electric (SDG&E) generally supports the proposal, but suggested that the voltage units specified in the technical proposal be specified in per unit values versus root mean square (RMS). Management's proposal uses RMS voltage values to be consistent with existing NERC Standard PRC-024. SDG&E also proposed that the ISO include a requirement that all generators provide data for frequency events below 59.9 Hz. Management does not agree with this proposal because no other generators are required to automatically report data for frequency events.

First Solar provided comments that the proposal should be more specific and identify minimum time parameters of recorded data both pre- and post-event. First Solar also commented that the proposal should provide clear guidance as to what events need to be recorded. Management agrees. The ISO held a technical workshop after the last stakeholder meeting. Various attendees, including First Solar, participated and consensus was reached on the time ranges and the scope of events to be recorded. It was agreed with stakeholders at the technical workshop that this would be reflected in the tariff filing.

California Wind Energy Association (CalWEA) commented that it is aligned with the ISO's objectives to address ride-through requirements, but that there should be no rush to a solution unless the industry is "completely on board" with the proposed requirements. Further, CalWEA stated that the requirements should apply to all inverter-based generation throughout the ISO service territory, including on the distribution system. The ISO notes that the requirements identified in its proposal are based on recent NERC advisories and in the recently issued NERC Reliability Guideline for bulk connected inverter-based generation. Further, the ISO notes that these proposed requirements cannot be applied to inverter-based generation connected to the distribution system. Generation interconnected to the distribution system is subject to the CPUC's Rule 21, which is contained in each PTO's distribution tariff. The ISO's proposed requirements will apply to all new inverter-based generators interconnecting to the transmission system.

2. Modify the reliability network upgrade reimbursement cap

All stakeholders who responded to the ISO's proposal on this issue support escalating the $60,000 per MW cap for reliability network upgrade reimbursement.

CalWEA suggested that the same escalation factor applied by each PTO in estimating the future escalated cost of reliability network upgrades should be applied to the reliability network upgrade reimbursement cap for that PTO. EDF-R, Nextera, SPower, and LSA each commented that the index mechanism that the ISO selects should be shared with stakeholders, open to comment, and monitored when implemented to ensure it is representative of any changes in PTO per-unit costs. As discussed earlier in this memo, the ISO will work with stakeholders to identify the most appropriate escalation factor for this industry.

PG&E requested clarification on whether the ISO intends for changes in the per-MW reliability network upgrade reimbursement cap to be retrospective or prospective. Management proposes that the escalation of the reimbursement cap will apply to all generators that have not yet achieved commercial operation.

Stakeholder discussions on this topic also raised a concern that the $60,000 per-MW maximum reimbursement amount for funds advanced for reliability network upgrades has the potential to be circumvented in instances where earlier-queued projects withdraw from the queue but the upgrades are still needed by later-queued resources. SCE continues to believe that such a situation could play out in a manner that results in the reliability network upgrade reimbursement cap being circumvented. Management believes that a proposal is not justified at this time because no actual gaming has occurred and potential future gaming was determined to be unlikely. The ISO will monitor the situation and address any issue on an *ad-hoc* basis.

3. Define and memorialize the concept of an *affected* participating transmission owner

Stakeholders unanimously support the proposals to address how the interconnection customer's financial security postings, cost responsibility, and affected PTO repayment will be disbursed among the interconnecting and affected PTOs.

CONCLUSION

Management recommends that the Board approve the three proposals in this memorandum. These changes are generally supported by stakeholders and were refined to address many of their comments and concerns throughout the stakeholder process. The proposed modifications improve the effectiveness of the interconnection process and the reliability of the transmission system. The proposed modifications will continue to improve the ISO's generator interconnection procedures to help California and the West to have robust capacity and meet their public policy goals while protecting ratepayers from undue costs.

Attachment E – List of Key Dates

Temporary Losses of Inverter-Based Generators Mitigation

California Independent System Operator Corporation

List of Key Dates in the Stakeholder Process for this Tariff Amendment[1]

Date	Event
August 10, 2017	CAISO solicits stakeholder suggestions for IPE topics
September 18, 2017	Stakeholders submit IPE topic suggestions
January 17, 2018	CAISO publishes issue paper
January 24, 2018	CAISO hosts stakeholder conference call and web conference on issue paper
February 8, 2018	Stakeholders submit comments on issue paper
May 17, 2018	CAISO publishes straw proposal
May 21, 2017	CAISO hosts stakeholder conference call and web conference on straw proposal
June 11, 2018	Stakeholders submit comments on straw proposal
July 10, 2018	CAISO publishes revised straw proposal
July 17, 2018	CAISO hosts stakeholder conference call and web conference on revised straw proposal
August 9, 2018	Stakeholders submit comments on revised straw proposal
September 4, 2018	CAISO publishes draft final proposal
September 13, 2018	CAISO hosts stakeholder workshop and web conference to develop tariff revisions on inverter technical requirements
September 25, 2018	Stakeholders submit comments on draft final proposal
January 15, 2019	CAISO publishes draft tariff revisions
January 25, 2019	Stakeholders submit comments on draft tariff revisions

1 Please note that IPE 2018 split into different tracks. The above table only refers to stakeholder dates pertaining to this topic. *See* http://www.caiso.com/informed/Pages/StakeholderProcesses/InterconnectionProcessEnhancements.aspx for links to all documents.