STATE OF CALIFORNIA GAVIN NEWSOM, *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

October 13, 2022

Advice Letter 6486-E

Sidney Bob Dietz II
Director, Regulatory Relations
Pacific Gas and Electric Company
77 Beale Street, Mail Code B10C
San Francisco, CA 94177

SUBJECT: Disposition approving advice letter that documents reservation of no temporary generation for use at substations in 2022

Dear Mr. Dietz,

The Energy Division (ED) has determined that Pacific Gas and Electric Company (PG&E) Advice Letter (AL) 6486-E, filed pursuant to Decision (D.) 21-01-018, is approved.

The PG&E AL informs ED of PG&E's plan not to reserve temporary generation for use at substations for the 2022 fire season and thus not to track any costs of this reservation in PG&E's Microgrid Memorandum Account as allowed by D.21-01-018, Appendix A, Section I. This section of the AL requests no additional relief, and is approved effective October 13, 2022.

In addition, AL 6486-E also responds to Commission direction in D.21-12-004 Ordering Paragraphs (OPs) 1 and 2, where the Commission directed PG&E to study the potential use of temporary generation that is reserved for Public Safety Power Shutoff (PSPS) mitigation to also address any system capacity shortfall event in the summer of 2022. PG&E proposed no upgrades or new investments based on this study, in part because PG&E reserved no substation-level temporary generation for PSPS mitigation in 2022. This section of the AL also requests no relief, and is approved effective October 13, 2022. ED finds that AL 6486-E meets the requirements established in OPs 1 and 2 of D.21-12-004 and that PG&E does not need to submit the Tier 1 AL required by OP 3 of D.21-12-004.

PG&E filed AL 6486-E on January 31, 2022. A timely protest was filed on February 22, 2022 by the Public Advocates Office. On March 1, 2022, PG&E filed a reply to the protest.

Attachment 1 contains a detailed discussion of the protest, reply and ED's determination that AL 6486-E is compliant with D.21-01-018, OP 14 and D.21-12-004 OPs 1 and 2. PG&E AL 6486-E, filed pursuant to D.21-01-018 and D.21-12-004, is approved.

Please contact Daniel Tutt of the Energy Division staff at 415-660-8403 (daniel.tutt@cpuc.ca.gov) if you have any questions.

Sincerely,

FOR

Leuwam Tesfai
Deputy Executive Director for Energy and Climate Policy/
Director, Energy Division

cc: Matt Coldwell, Energy Division
Phong Ly, Public Advocates Office
Chloe Lukins, Public Advocates Office

Attachment 1

Review and Analysis

I. Background

On January 31, 2022, PG&E submitted Advice Letter (AL) 6486-E to inform ED of PG&E's plan not to reserve temporary generation for use at substations for the 2022 fire season and thus not to track any costs of this reservation in PG&E's Microgrid Memorandum Account as allowed under Decision (D.) 21-01-018, Appendix A, Section I. Additionally, AL 6486-E responds to Commission direction in D.21-12-004 to study the potential to use temporary generation reserved for Public Safety Power Shutoff (PSPS) mitigation to also address any system capacity shortfall events in the summer of 2022. PG&E proposed no upgrades or new investments based on this study, in part because PG&E reserved no substation-level temporary generation for PSPS mitigation in 2022. PG&E will deploy some non-substation-level temporary generation for distribution microgrids and backup power support in 2022. However, PG&E states this non-substation-level temporary generation would not be available for supporting system capacity shortfall events in the summer of 2022 because of the lengthy process to complete the necessary interconnection studies for enabling this non-substation-level temporary generation to operate in parallel with the grid during a reliability event.

D.21-01-018 allows PG&E to record costs to its Microgrid Memorandum Account for temporary generation programs for safe-to-energize substations affected by transmission-level PSPS provided that:

> (1) the utility has filed an application in accordance with a clean generation transition pursuant to Appendix A, Section II of this decision; and (2) the investor-owned utility has a Tier 2 advice letter demonstrating need and consideration of cleaner alternatives pursuant to Appendix A, Section I of this decision; and (3) the Commission authorized the investor-owned utility's request.[1]

Because PG&E has chosen not to reserve any temporary generation for use at substations in 2022, and thus not to record any costs for that temporary generation to its Microgrid Memorandum Account, the requirements of OP 14 are not triggered. In its AL, PG&E provides its analysis indicating no need for substation-level temporary generation in 2022. As such, AL 6486-E seeks no authorization to reserve substation-level temporary generation for 2022.

D.21-12-004 directs PG&E to:

> …file a Tier 2 Advice Letter, within 60 days upon the effective date of this decision, requesting authorization, if any, for reservation of 2022 temporary generation and associated make-ready improvements for the purposes of mitigating system capacity shortfalls.[2]

Because PG&E chose to reserve no substation-level temporary generation for PSPS mitigation in 2022, it also studied no substation-level sites for the deployment of temporary generation to mitigate system capacity shortfalls. PG&E did complete a preliminary study of 14 distribution microgrid sites but determined that it would not be able interconnect non-substation-level temporary generation at these

[1] Decision 21-01-018, Ordering Paragraph (OP) 14. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M361/K442/361442167.PDF
[2] Decision 21-12-004, OP 1. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M428/K827/428827925.PDF

microgrids in parallel with the larger grid in time for supporting system capacity shortfall events in the summer of 2022. When making this determination, PG&E considered the time it would take to complete interconnection studies for operating temporary generation in parallel with the larger grid, to assess for cost effectiveness, and to physically upgrade sites. As such, AL 6486-E seeks no authorization to reserve temporary generation, or to undertake associated make-ready improvements, for the purposes of mitigating system capacity shortfalls for the summer of 2022.

II. Public Advocates Office Protest and PG&E Reply

Public Advocates Office (PAO) timely filed a protest on February 22, 2022. On March 1, 2022, PG&E timely filed a reply to the protest.

In its protest, PAO argues that AL 6486-E should be dismissed on the grounds that the relief requested is not authorized by D.21-01-018. Specifically, PAO argues that (1) PG&E failed to identify candidate substations for clean microgrids or propose plans to establish a clean substation microgrid project, and (2) that PG&E's related Application (A.) 21-06-022 does not comply with the requirements in D.21-01-018.

In its reply, PG&E asks that PAO's protest be dismissed, and AL 6486-E be made effective.

In response to PAO, PG&E argues that because AL 6486-E requests no substantial relief and merely notifies the Commission of its decision not to reserve substation-level temporary generation, PAO lacks grounds for its protest. In addition, PG&E argues (1) that PG&E has proposed and is pursuing a clean substation microgrid project, contrary to PAO's argument; and (2) that PAO's protest improperly attempts to litigate issues within the scope of A.21-06-022 under the heading of this AL.

No protests or comments were received on the analysis indicating that there is no need for substation-level temporary generation in 2022. Similarly, no protests or comments were received on potential make-ready improvements for the purposes of mitigating system capacity shortfall events.

III. Discussion

In AL 6486-E, PG&E notifies the Commission of its intent *not* to reserve any substation-level temporary generation in 2022 and does not request any substantial relief. PG&E need not rely on any statute or Commission order when simply notifying the Commission of its intent not to take an action. Because PG&E is requesting no substantial relief in this Advice Letter, PAO has no basis to argue that the requested relief is not authorized by Commission order. As such, PAO fails to provide proper grounds for its protest.

Given that AL 6486-E requests no substantial relief and PAO lacks grounds for protest, other issues raised by both PAO and PG&E related to D.21-01-018 are not relevant to the disposition of this Advice Letter.

Given that PG&E does not request authorization to reserve temporary generation for use at substations to mitigate PSPS outages during the 2022 fire season, there is "no substation temporary generation available to study for use in summer capacity shortfall events" as directed in D.21-12-004 OPs 1 and 2.[3] PG&E also does not "propose any make-ready infrastructure upgrade investments to allow the temporary generation at its distribution microgrids to operate in parallel with the grid during system capacity shortfall events" because "PG&E would not be able to parallel its first distribution microgrid in a timely manner."[4] As noted above, no protests or comments were received on these issues.

Because PG&E is not proposing any make-ready infrastructure upgrade investments pursuant to D.21-12-004 OPs 1 and 2, PG&E forgoes the microgrid summer 2022 reliability subaccounts required in D.21-12-004 OP 3 and therefore does not need to submit a Tier 1 advice letter.

[3] PG&E AL 6486-E at 7.
[4] Id. at 7-8.

Pacific Gas and Electric Company

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January 31, 2022

Advice 6486-E
(Pacific Gas and Electric Company ID U 39 E)

Public Utilities Commission of the State of California

Subject: **Reservation of 2022 temporary generation and associated make-ready improvements for the purposes of mitigating Public Safety Power Shutoff events and system capacity shortfalls**

I. Purpose

Pursuant to California Public Utilities Commission (Commission) Decision (D.) 21-01-018 and D. 21-12-004, Pacific Gas and Electric Company (PG&E) submits this Advice Letter to inform the Commission it is not seeking authority at this time to reserve temporary generation for the purpose of energizing safe-to-energize (STE) substation load subject to Public Safety Power Shutoff (PSPS) outages in 2022. This Advice Letter also addresses the requirement in D.21-12-004 that PG&E study the potential to use any generation it reserves for purposes of PSPS mitigation in substation or distribution microgrids in 2022 to also mitigate the potential for system capacity shortfall events in 2022.

II. Background and Summary of Request

A. The Interim Approach Adopted in D.21-01-018

On January 14, 2021, the Commission adopted D.21-01-018 in Track 2 of the Microgrids and Resiliency Strategies rulemaking. That Decision established, among other items, an "Interim Approach" to mitigating the impacts of PSPS outages by establishing a pathway for utilities to propose and receive upfront approval for the reservation of temporary generation to be used at substation-level microgrid sites.[1] This Interim Approach is intended to remain in place until the Commission has approved an alternative long-term framework for procuring substation microgrid solutions.[2] As required by D.21-01-018,

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[1] D.21-01-018, App. A, pp. A-1 to A-6.
[2] *Id.*, App. A, p A-1 ("This framework is an interim step that may apply beyond 2021 if and only if 1) the utility has filed an application pursuant to the process for transitioning to clean generation described below under section II and; 2) the CPUC has not yet issued a decision on that application.").

PG&E filed Application (A.) 21-06-022 in June 2021 proposing a Long-Term Procurement Framework for Substation Microgrid Solutions. That Application remains pending. As a result, and as directed by D.21-01-018, PG&E is continuing to follow the Interim Approach adopted by the Commission to evaluate temporary generation reservation needs for the purpose of providing power to the load of safe-to-energize substations during a PSPS outage.

Under the Interim Approach, PG&E may be authorized to reserve temporary generation for PSPS mitigation at substations under the following conditions:

1. Either:
   a. The utility reserves temporary generation capacity equivalent to 120% or less of the coincident peak deployment of temporary generation in the immediately previous year; or
   b. The utility justifies the scope and scale of the need for providing temporary generation by providing the basis and justification why it is reasonable to prepare for specific substations to be de-energized, including but not limited to:
      i. Historical meteorological data showing probability of public safety power shutoff.
      ii. Historical outage data.
      iii. Fire spread modelling and incorporation of consequences to customers. Transmission asset condition information; and
      iv. Transmission operability assessment information.

2. The utility's previous temporary generation program, if any, has proven effective at serving loads of safe-to-energize substations that would have otherwise been without power during PSPS or other outage events, if and when it was activated to do so.

3. The utility provides evidence that there is resource scarcity that makes it prudent to pay a nonrefundable reservation fee which guarantees generator availability for the duration of fire season in advance of need, or that advance reservation is necessary for logistical reasons to safely mobilize and stage equipment.

4. The utility demonstrates that it has undertaken an analysis of the all-inclusive costs associated with reserving and deploying the temporary generation and that the costs are reasonably close to that associated with deploying similar equipment under normal conditions, such as for a planned maintenance outage.

5. The utility demonstrates ongoing consultation with local air quality agencies, aimed at ensuring the deployment of temporary generation at substations complies with applicable regulations.[3]

Additionally, a utility seeking to reserve temporary generation under the Interim Approach was required to document its plans to establish clean substation microgrid projects located at, or able to serve, at least one substation.[4]

B. The Summer Capacity Shortfall Event Mitigation Study Adopted in D.21-12-004

D.21-12-004 directed PG&E to submit a Tier 2 Advice Letter, within 60 days of the effective date of the decision, requesting authorization, if any, for the reservation of 2022 temporary generation and associated make-ready improvements for the purposes of mitigating system capacity shortfalls.[5] PG&E was further instructed to take a close and sensitive look at how any such temporary generation use could potentially impact a disadvantaged community (DAC).[6] More specifically, the Commission ordered PG&E's Advice Letter to address the following requirements:

1. Identify the number of sites studied for potential parallel connection of temporary generation;
    - Identify sites, and megawatts per site, where temporary generation could be safely interconnected to address a system capacity shortfall;
    - Identify sites, if any, for which additional temporary generation is requested specifically for addressing a system capacity shortfall rather than Public Safety Power Shutoff (PSPS) mitigation purposes;
    - Identify sites where temporary generation reserved for PSPS purposes could also be used to address a system capacity shortfall;
    - Identify, for each site requiring modification to safely and reliably accommodate temporary generation for addressing a system capacity shortfall, the following:
        - The costs necessary to upgrade the site;
        - Timeframe necessary to complete the make-ready upgrades;
        - Estimated incremental operating and maintenance costs for temporary generation for utilization during a system capacity shortfall; (make ready upgrades complete and temporary generation available);
        - Detail any necessary air permit requirements, and how they will be met by September 2022, to permit temporary generation to operate for utilization during a 2022 system capacity shortfall or

[3] *Id.*, App. A, pp. A-1 to A-2.
[4] *Id.*, App. A, p. A-4.
[5] D.21-12-004, p. 54 (Ordering Paragraph (OP) 1).
[6] *Id.*

- if temporary generation would only be able to operate if air permitting requirements were temporarily suspended; and
  - Detail and assess any impact in a DAC should a temporary generation need arise, and discuss why.
- Identify temporary generation, and the temporary generation's total megawatts, that could be feasibly transported to an appropriate site to address a system capacity shortfall.

2. Ensure redundancy of resources so that the physical location of mobile generation and an adequate fuel supply is available for both a simultaneous PSPS event and a system capacity shortfall;

3. Discuss expected availability of renewable diesel and/or hydrotreated vegetable oil for 2022; and

4. How PG&E will utilize renewable diesel and hydrotreated vegetable oil to the maximum extent possible if temporary generation is made available to maintain reliability during a system capacity shortfall.[7]

D.21-12-004 allows PG&E to combine its response to that Decision's requirements with PG&E's Advice Letter to request authority to reserve temporary generation to mitigation PSPS impacts at substations.[8] Accordingly, PG&E addresses each of D.21-12-004's requirements applicable to it in the following sections of this Advice Letter.

Based on the demonstration set forth below, PG&E does not request authority to reserve temporary generation for use at substations in order to mitigate PSPS outages during the 2022 fire season. Furthermore, since PG&E is not requesting authority to reserve substation temporary generation for 2022, and because the interconnection study timeline to enable the temporary generators at distribution microgrids to operate in parallel to the grid is a lengthy process, PG&E is not requesting authority to undertake associated make-ready improvements for the purposes of mitigating system capacity shortfalls.

III. 2022 Substation Temporary Generation Reservation for PSPS Mitigation

In D.21-01-018, the Commission determined that PG&E may demonstrate the reasonableness of its request to reserve temporary generation for mitigation of PSPS events at substations either by: (1) showing that the capacity is at or less 120% of the coincident peak deployment of temporary generation in immediately previous year; or (2) otherwise justifying the scope and scale of the need for providing temporary generation by providing the basis and justification why it is reasonable to prepare for specific substations to be de-energized.[9] As shown in Table 1, below, the coincident peak use of

[7] *Id.*, pp. 54-55 (OP 1).
[8] *Id.*, p. 55 (OP 2).
[9] D.21-01-018, App. A., pp. A-1 to A-2.

temporary generation at substations during 2021 PSPS events was 0 MWs of nameplate capacity. As a result, no capacity reservation is deemed reasonable under the "prior coincident peak deployment" prong of the Interim Approach. Additionally, PG&E does not propose to reserve temporary generation in excess of that amount. The following sections justify the scope and scale review.

Table 1. Coincident Peak Deployment of Substation Temporary Generation in 2021

Substation	MW Energized (nameplate)	2021 PSPS Event	Safe-to-Energize Customer Accounts Served
None	0 MW	N/A	N/A

A. Substation Site Selection

To determine the appropriate locations, if any, for substation temporary generation for 2022 PSPS mitigation, PG&E assessed the relative frequency of historical PSPS impacts through a four-step analysis consisting of: (1) a 10-year historical look-back analysis; (2) frequency and impact magnitude filtering; (3) safe-to-energize customer count filter; and (4) assessment of ongoing work to harden and assess the condition of grid assets in order to reduce future PSPS impacts.

On December 17, 2021, PG&E submitted supplemental testimony in the A.21-06-022 proceeding regarding its revised, 2021-vintage 10-Year Historic Lookback Dataset (the Supplemental Testimony). The Supplemental Testimony is included as Attachment 1 to this Advice Letter for ease of reference. The Supplemental Testimony describes the updates that PG&E made to the 10-Year Historic Lookback methodology since the last 2020 vintage of the model. It also provides a description of the inputs to the analysis and the results. In Table 1 of the Supplemental Testimony, PG&E provided a list of all substations with modeled de-energization events during the 10-year lookback period, including the number of such de-energization events.

The 10-year lookback analysis simulates weather and environmental conditions against PSPS event scoping criteria to identify direct and indirect impacts to the transmission lines, as those terms are more specifically defined in the Supplemental Testimony. This data is then analyzed to determine the frequency and impact magnitude for each substation. Substations with 10 or more events over the lookback period are identified. This is then layered with a count of the number of customers in each event that would have been safe to energize using a substation microgrid during the PSPS event. Consistent with its 2021 methodology and the proposed Long-Term Procurement Framework presented in A.21-06-022, PG&E filtered the number of impacts in order to remove any event at a substation in which there were less than 100 safe-to-energize customer accounts. As shown in the Supplemental Testimony, the combination of filtering for 10 or more events with 100 or more safe-to-energize customers in each event reduced the list to 1 substation, Bangor, as summarized in Table 2 below.

Table 2. List of Candidate Substations

Substation	Event Count	Impacts w/ 100+ STE Customers
Bangor	12	12

As a next step, PG&E studied the Bangor substation to see if other grid solutions could reduce the number of modeled PSPS impacts. PG&E determined there are SCADA enabled switches available on the line that could potentially isolate Bangor from the structures that have historically exceeded the transmission scoping guidelines during several lookback events. Operational and power flow studies were performed on these scenarios to determine the feasibility of utilizing the switches. It was determined to be effective for 7 of the 12 events, dropping the impact down to 5 instances. As a result, Bangor no longer meets PG&E's criteria for requiring mitigation of PSPS events through a substation temporary generation solution. Because PG&E will proceed with the switching solution it identified and is not seeking to reserve temporary generation for use at Bangor substation, and because Bangor was the only priority candidate substation identified in the revised 10-Year Lookback study, PG&E has not identified a need to procure substation temporary generation for 2022.

Concurrent with the submission of this Advice Letter, PG&E is serving supplemental testimony in A.21-06-022 providing additional technical details concerning its alternatives analysis of the Bangor substation. PG&E is incorporating that analysis by reference into this Advice Letter and attaching the testimony for ease of reference as Attachment 2 to this Advice Letter.

PG&E's findings that updated PSPS Scoping Criteria, informed by a growing amount of historical data, and a focus on operational solutions brings all of its substations under the 10+ event threshold in modeling is an important indication that we are succeeding at reducing the impacts of PSPS over time. However, it is important to note that while PG&E's analysis did not identify any substations meeting its established criteria to reserve temporary generation for mitigation of PSPS impacts, the 10-Year Historic Lookback continues to show, and PG&E expects to see, continued PSPS events and the associated de-energization of substations. While PG&E expects that the work it is doing will continue to reduce the scope and frequency of PSPS events generally, it is also possible that PSPS events in any given year will occur with greater frequency than modeled. It is also possible that PSPS events will generally become more common as utilities continue to confront the challenges of climate change. PG&E will continue in future years to assess the need for substation microgrids for PSPS mitigation based on its evolving understanding of the risk of de-energization.

Because PG&E has not identified a need to reserve temporary generation for use at substations to mitigate PSPS events in 2022, it is not addressing the further requirements in D.21-01-018, summarized above, to justify any such request.

IV. Make-Ready Improvements for the Purposes of Mitigating System Capacity Shortfall Events

In D.21-12-004, the Commission adopted PG&E's proposal to study the potential to use temporary generation that it reserved for PSPS mitigation purposes at substation or distribution microgrids to also address any system capacity shortfall event in the summer of 2022. The Commission also directed PG&E to present the results of its study in an Advice Letter, as further described above. This Section addresses that requirement.

PG&E's original proposal presumed that it would seek to reserve temporary generation for use at substations to mitigate PSPS impacts in 2022. As detailed above, the result of PG&E's revised 10-Year Historical Lookback is that PG&E is not seeking to reserve any such temporary generation. Because PG&E proposed to study the use of temporary generation that was already being reserved for PSPS mitigation for the additional summer capacity event use case,[10] and because PG&E is not proposing to reserve temporary generation for use at substations for PSPS mitigation in 2022, there was no substation temporary generation available to study for use in summer capacity shortfall events.

As part of its summer capacity event study, PG&E also considered the distribution microgrids, also called "main street microgrids" in the past. The construction of pre-installed interconnection hubs (PIH) for these distribution microgrids was authorized through PG&E's General Rate Case, and PG&E anticipates reserving temporary generation for use at distribution microgrids in 2022.[11] Specifically, PG&E considered whether the temporary generation located at these fourteen distribution microgrids could

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[10] D.21-12-004, p. 13 ("PG&E proposes to [study] the potential to use additional temporary generation **that will already be procured for PSPS events** at either or both substation and distribution microgrid
sites, if necessary, in a 2022 system capacity shortfall event.") (emphasis added).

[11] This Advice Letter does not request authorization to reserve temporary generation for the distribution microgrids, Community Resource Centers, or critical customer backup power support because the Interim Approach described in D.21-01-018 was explicitly limited to the reservation of temporary generation for use at substations. *See* D.21-01-018, App. A, p. A-1 ("This authorization does not limit or affect in any way the ability of a utility to reserve temporary generation **for other purposes**, such as providing power to community resource centers or critical facilities during events or serving load during routine grid maintenance, **which fall outside the scope of this framework**. Throughout the following document, 'temporary generation' refers to this specific use case above, where temporary generation is reserved for energizing safe-to-energize **substation** load subject to PSPS transmission outages.") (emphasis added).

be operated in parallel with the grid during summer capacity shortfall events in order to export their capacity and mitigate the shortfall on the system.[12]

PG&E's distribution microgrids currently operate in island mode only. In the existing configurations, customers served by the distribution microgrids must first be de-energized so that they can be disconnected with the larger grid and then re-energized using the distribution microgrid. The same process occurs when the customers are returned to normal service from the grid. Therefore, the distribution microgrids, are unable to export power to support the grid during system capacity events, and any use of them in islanded mode to reduce demand on the grid would paradoxically result in the "preemptive" de-energization of customers, which is clearly not the desired outcome.

PG&E next explored whether any of the distribution microgrids could be configured in the future to operate in parallel to the grid, such that they could export to the grid when needed without first de-energizing customers. In order to operate the generation in parallel to the grid, interconnection studies would need to be performed and potential distribution and substation upgrades could be necessary in order for the electrical infrastructure to be able to safely and reliably handle the full export of new generation into the system.

PG&E ultimately found that the upgrades necessary to enable such parallel operation should not be undertaken due to the timeframe required to parallel distribution microgrids. In order for the planned distribution microgrids for 2022 to parallel to the grid, multiple rounds of analyses and studies are needed, which would roughly take up to 90 business days per site. Each site would need to undergo an initial review, supplemental review, and a detailed study requiring 10 business days, 20 business days, and 60 business days respectively. Consequently, each site would require at least four months to analyze, notwithstanding the time needed to deploy and stage the temporary generation, which is roughly 10 business days. Furthermore, before these studies can be initiated, PG&E first needs the exact asset details (i.e., the size of the generators, type of generator, asset characteristics, etc.). This information is not typically known until the generators are procured in May. Additionally, any physical asset upgrades required for paralleling could not be determined until the studies are concluded, and it would not be known until that time if the required upgrades would be cost-efficient. Therefore, as paralleling was meant to mitigate summer capacity events and there is a long lead time to conduct a study, PG&E would not be able to parallel its first distribution microgrid in a timely manner.[13]

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[12] D. 21-12-004, p. 54 (OP 1) (requiring PG&E's study to "[i]dentify the number of sites studied for **potential parallel connection** of temporary generation") (emphasis added).

[13] Another timing issue is that PG&E, as part of a continual improvement effort to reduce costs related to its PSPS mitigation programs, is only currently planning to reserve temporary generation for the distribution microgrids and for critical customer backup support during PSPS events beginning in August 2022. Thus, much of the summer will have already passed by the time the generators are onsite and connected, making additional work that would be required to parallel these generators even less cost-effective. Reserving the temporary generation earlier in the year solely for the system capacity use case would contravene the express intent of D.21-12-

Based on the foregoing, PG&E determined that it would not propose any make-ready infrastructure upgrade investments to allow the temporary generation at its distribution microgrids[14] to operate in parallel with the grid during system capacity shortfall events. Because it does not propose any such upgrades, it is not proposing a cost forecast for approval and is not analyzing the air permitting requirements that would accompany the use of those temporary generators for the system capacity use case.[15]

This submittal would not increase any current rate or charge, cause the withdrawal of service, or conflict with any rate schedule or rule.

<u>Protests</u>

Anyone wishing to protest this submittal may do so by letter sent electronically via E-mail, no later than February 22, 2022, which is 22 days[16] after the date of this submittal. Protests must be submitted to:

CPUC Energy Division
ED Tariff Unit
E-mail: EDTariffUnit@cpuc.ca.gov

The protest shall also be electronically sent to PG&E via E-mail at the address shown below on the same date it is electronically delivered to the Commission:

Sidney Bob Dietz II
Director, Regulatory Relations
c/o Megan Lawson
E-mail: PGETariffs@pge.com

Any person (including individuals, groups, or organizations) may protest or respond to an advice letter (General Order 96-B, Section 7.4). The protest shall contain the following

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004, which focuses only on determining if generation already reserved for PSPS mitigation might also be used for system capacity events.

[14] Although PG&E had only proposed to study temporary generation at substation and distribution microgrids for use during system capacity events, the same considerations that led PG&E to conclude it should not pursue upgrades in its distribution microgrids for this purpose apply to the use of ad-hoc use of temporary generators at single-customer sites for critical backup support during PSPS events. Specifically, the parallel operation of these relatively small amounts of generation would have to be studied after the generators were reserved, leaving insufficient time prior to the fire season. Additionally, as with distribution microgrids, the critical customer load would have to be disconnected from the grid prior to islanding the single-customer microgrids, which defeats the purpose of trying to avoid de-energizations during capacity shortfalls.

[15] *See* D.21-12-004, pp. 54-55 (OP 1).

[16] The 20-day protest period concludes on a weekend and holiday, therefore, PG&E is moving this date to the following business day.

information: specification of the advice letter protested; grounds for the protest; supporting factual information or legal argument; name and e-mail address of the protestant; and statement that the protest was sent to the utility no later than the day on which the protest was submitted to the reviewing Industry Division (General Order 96-B, Section 3.11).

Effective Date

Pursuant to General Order (GO) 96-B, Rule 5.2, Appendix A of D.21-01-018, and OP 1 of D.21-12-004, this advice letter is submitted with a Tier 2 designation. PG&E requests that this Tier 2 advice submittal become effective on regular notice, March 2, 2022**,** which is 30 calendar days after the date of submittal.

Notice

In accordance with General Order 96-B, Section IV, a copy of this advice letter is being sent electronically and via U.S. mail to parties shown on the attached list and the parties on the service list for R.19-09-009 and A.21-06-022. Address changes to the General Order 96-B service list should be directed to PG&E at email address PGETariffs@pge.com. For changes to any other service list, please contact the Commission's Process Office at (415) 703-2021 or at Process_Office@cpuc.ca.gov. Send all electronic approvals to PGETariffs@pge.com. Advice letter submittals can also be accessed electronically at: http://www.pge.com/tariffs/.

/S/
Sidney Bob Dietz II
Director, Regulatory Relations

Attachments
Attachment 1 – December 17, 2021 Supplemental Testimony in A.21-06-022 – 10-Year Historic Lookback Update
Attachment 2 – January 31, 2022 Supplemental Testimony in A.21-06-022 – Substation Safety Information

cc: Service List for R.19-09-009, A.21-06-022

ADVICE LETTER SUMMARY

ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No.: Pacific Gas and Electric Company (ID U39 E)

Utility type:

- [x] ELC
- [ ] GAS
- [ ] WATER
- [ ] PLC
- [ ] HEAT

Contact Person: Annie Ho
Phone #: (415) 973-8794
E-mail: PGETariffs@pge.com
E-mail Disposition Notice to: AMHP@pge.com

EXPLANATION OF UTILITY TYPE

ELC = Electric
GAS = Gas
PLC = Pipeline
HEAT = Heat
WATER = Water

(Date Submitted / Received Stamp by CPUC)

Advice Letter (AL) #: 6486-E

Tier Designation: 2

Subject of AL: Reservation of 2022 temporary generation and associated make-ready improvements for the purposes of mitigating Public Safety Power Shutoff events and system capacity shortfalls

Keywords (choose from CPUC listing): Compilance

AL Type: [ ] Monthly [ ] Quarterly [ ] Annual [x] One-Time [ ] Other:

If AL submitted in compliance with a Commission order, indicate relevant Decision/Resolution #:
D.21-01-018, D.21-12-004

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL:

Summarize differences between the AL and the prior withdrawn or rejected AL:

Confidential treatment requested? [ ] Yes [x] No

If yes, specification of confidential information:
Confidential information will be made available to appropriate parties who execute a nondisclosure agreement. Name and contact information to request nondisclosure agreement/access to confidential information:

Resolution required? [ ] Yes [x] No

Requested effective date: 3/2/22

No. of tariff sheets: N/A

Estimated system annual revenue effect (%): N/A

Estimated system average rate effect (%): N/A

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: N/A

Service affected and changes proposed[1]: N/A

Pending advice letters that revise the same tariff sheets: N/A

[1]Discuss in AL if more space is needed.

Clear Form

Protests and correspondence regarding this AL are to be sent via email and are due no later than 20 days after the date of this submittal, unless otherwise authorized by the Commission, and shall be sent to:

California Public Utilities Commission
Energy Division Tariff Unit Email:
EDTariffUnit@cpuc.ca.gov

Contact Name: Sidney Bob Dietz II, c/o Megan Lawson
Title: Director, Regulatory Relations
Utility/Entity Name: Pacific Gas and Electric Company

Telephone (xxx) xxx-xxxx: (415)973-2093
Facsimile (xxx) xxx-xxxx: (415)973-3582
Email: PGETariffs@pge.com

Contact Name:
Title:
Utility/Entity Name:

Telephone (xxx) xxx-xxxx:
Facsimile (xxx) xxx-xxxx:
Email:

CPUC
Energy Division Tariff Unit
505 Van Ness Avenue
San Francisco, CA 94102

Clear Form

Advice 6486-E
January 31, 2022

Attachment 1

December 17, 2021 Supplemental Testimony in A.21-06-022 – 10-Year Historic Lookback Update

Application: 21-06-022
(U 39 E)
Exhibit No.: _____________________
Date: December 17, 2021
Witness(es): Mark Esguerra

PACIFIC GAS AND ELECTRIC COMPANY

10-YEAR HISTORIC LOOKBACK 2021 UPDATE

SUPPLEMENTAL TESTIMONY

PACIFIC GAS AND ELECTRIC COMPANY
10-YEAR HISTORIC LOOKBACK 2021 UPDATE
SUPPLEMENTAL TESTIMONY

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PACIFIC GAS AND ELECTRIC COMPANY
10-YEAR HISTORIC LOOKBACK 2021 UPDATE
SUPPLEMENTAL TESTIMONY

A. Introduction

This testimony responds to the *Assigned Commissioner's Scoping Memo and Ruling* (Scoping Memo), issued in Application 21-06-022 on September 24, 2021, which directs Pacific Gas and Electric Company (PG&E) to serve supplemental testimony regarding PG&E's 2021-vintage 10-year Historical Lookback analysis and relevant data by December 17, 2021.[1]

This exhibit describes changes made in PG&E's 10-Year Historic Lookback Methodology between the 2020 vintage originally presented in PG&E's Application and the 2021 vintage recently produced. The testimony also summarizes the reasons for those changes. It then presents as relevant data a list of impacted substations based upon the updated 10-year lookback analysis in the same format as provided in the prepared testimony served on June 30, 2021, which had relied on 2020-vintage data and modeling assumptions.[2]

B. Description of Changes in 10-Year Historic Lookback Methodology From 2020 to 2021

The overall technical framework applied to create the 2021-vintage 10-year historic lookback dataset closely resembles the 2020 10-Year Historic Lookback Methodology detailed in PG&E's Advice Letter (AL) 6105-E (the "2021 Temporary Generation AL").[3] As described in the "Description of Current PSPS Scoping Framework and Criteria" section of Chapter 2 of PG&E's prepared testimony, PG&E applied the key steps of projecting weather and environmental conditions against a set of Public Safety Power Shutoff (PSPS) scoping criteria to identify "directly impacted" transmission lines and substations, and

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1 Scoping Memo, p. 4.

2 *See* PG&E Prepared Testimony, Chapter 2, Attachment A, pp. 2-AtchA-8 to 2-AtchA-11 (providing the original list of 2020-vintage impacted substations).

3 *See* PG&E AL 6105-E, submitted March 5, 2021, pp. 6-8.

subsequently to identify any “indirectly impacted” transmission lines and substations.[4]

Compared to 2020, the 2021 lookback data development process utilized a slightly different set of weather and environmental conditions (i.e., covering a period from 2011 to 2020 instead of the previous 2010 to 2019 rolling window). More importantly in terms of impact on lookback data results, the 2021 process applied PG&E’s latest PSPS scoping protocol and criteria approved for operational use during the 2021-2022 wildfire season. The changes in scoping protocol and criteria had a material effect on results, especially the changes in vegetation risk modeling, which reduced the overall frequency of transmission lines identified as being within scope of modeled PSPS events. The changes to the PSPS scoping criteria and protocol are described in more detail in Section B.1, below.

Additionally, as PG&E continues to refine its 10-year historic lookback data development process, it has provided more granularly in mapping of “indirectly impacted” transmission line(s) to substations to better reflect the nature of an interconnected grid. This improvement to the modeling is further described in Section B.2, below.

1. Changes in 2021 Transmission-Level PSPS Scoping Criteria, Protocol, Operational Models, and Asset Data

As under the 2020 PSPS scoping process, transmission lines are potentially scoped into PSPS to mitigate against three types of risks: vegetation, asset, and wildfire consequence and behavior. Within each category, PG&E has further refined scoping protocol and criteria in 2021. These refinements are detailed in PG&E’s September 30, 2021 filing in the Wildfire Mitigation Planning proceeding, the relevant excerpt of which is included as Attachment A to this Exhibit and incorporated here by reference.[5]

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4 Direct and indirect impacts are described further in the 2021 Temporary Generation AL at footnotes 19 and 20.

5 Response of PG&E to Energy Safety Remedy PG&E-21-29 and Change Order Report, September 30, 2021, Sec. 1 “2021 PSPS Process and Protocols Description” (available at: https://efiling.energysafety.ca.gov/Search.aspx?docket=2021-WMPs) (last visited December 9, 2021).

Below, PG&E provides a summary description and a brief discussion on changes that materially impacted the 2021 lookback data results.

a. Vegetation Management

Overall, change in the methodology related to vegetation management is the largest driver in the difference between the 2020 and 2021 lookback dataset, with an impact of reducing frequency of lines being scoped in for PSPS due to projected vegetation risks.

In 2021, PG&E developed a transmission-specific vegetation risk model, which uses aerial Light Detection and Ranging data to map the location and attributes of trees near transmission lines. The model enabled the calculation of risk scores at individual tree level and thus allowed the development of a more granular vegetation PSPS scoping criteria set at each transmission structure level (i.e., a transmission structure is only flagged for PSPS risk when the combined risk score of nearby trees exceed a threshold value of 200 AND the transmission structure is within the footprint of the projected weather event). In contrast, the 2020 transmission vegetation scoping criteria is set at the transmission lines level. The ability to assess risk at a more granular asset level—structure vs. line—provided more precise predictive capabilities.

b. Asset Conditions

In 2021, PG&E continued to refine its Operability Assessment model, which is used to assess the probability of failure of transmission line assets. This included updating the model with the latest available asset failure and inspection data, more granular modeling of individual transmission structural components, and more detailed modeling of environmental conditions such as soil in order to continue to pinpoint asset risks.

Overall, this deepened PG&E's understanding of asset risks, which is reflected in the 2021 lookback results.

c. Wildfire Consequence and Behavior Modeling

In 2021, PG&E incorporated the Technosylva fire simulation model into its PSPS scoping protocol. For transmission-level PSPS scoping, this allowed PG&E to transition its extreme weather risk assessment from a set of triggers based on weather and environmental conditions (i.e., Black Swan conditions) to a set of triggers based on extremely granular – in space and time – modeling of simulated fire consequence and behavior using Technosylva. PG&E believes this further refines understanding of fire behavior, and this is also reflected in the 2021 lookback results.

2. Changes to the Representation of Indirect Impacts in the 2021-Vintage 10-Year Historic Lookback Data Development

As described in its 2021 Temporary Generation AL, for each transmission PSPS event (i.e., a day in the 10-year lookback horizon with at least one "directly impacted" transmission line identified), PG&E performs a power flow analysis to identify any potential "indirectly impacted" lines and substations that would require load drop to alleviate a projected violation of operational transmission reliability criteria.

In 2020, the lookback process mapped such "indirectly impacted" load drop to specific substations in the corresponding transmission sub-area that would help alleviate the projected reliability violations based on simple heuristics (e.g., size of load at the substation; incidences of historic, actual PSPS de-energization to mitigate "indirect impact" at a specific substation). As a result, certain substations were selected repeatedly for de-energization in the lookback data in order to address the potential for sub-area-wide indirect impacts. While this is a reasonable approximation for planning purposes, PG&E believes it can be further refined to reflect the operational reality that a broader set of substations within each transmission sub-area can also be selected to alleviate the needed load drop during a PSPS event.

Towards this end, in the 2021 lookback development process, PG&E has reflected "indirectly impacted" load drop to all effective substations within the subject transmission sub-area.[6] To provide a concrete example, the result of this change is that in a situation where 100 megawatts (MW) of load relief is needed in one transmission sub-area, and where that alleviation on the transmission system can be met by a combination of substations that in aggregate can provide 300 MW of load reduction through de-energization, the 2021 approach assigns an indirect impact for that PSPS event to each of those substations. While PG&E recognizes that this approach, without further analysis, can appear to "overstate" the impact of a given PSPS event, it is a material improvement, for planning purposes, over the 2020 method. Specifically, the 2021 approach reflects the operational reality that during a PSPS event, operators have the ability to choose from a broader set of substations, and that all effective substations (even those that were not "mapped" in the 2020 process), are subjected to this potential PSPS risk.

This approach also aligns well with the proposed framework set forth in Chapter 3 of PG&E's prepared testimony in this proceeding, in which the initial lookback data identifies projected PSPS risk, but mitigations (through, e.g., substation-level microgrids) are only deployed after further assessing whether existing and planned solutions – including, for purposes of these indirect impacts, operational flexibility that is available to the system operators – can further reduce the projected PSPS risk presented in the initial lookback data.[7] To carry forward the example above, PG&E may

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6 In this analysis, an effective substation is defined as one that has an Effectiveness Factor (EF) greater than 1 percent. In simple terms, EF is a measure of the impact of an injection (or withdrawal) of electrical energy at a specific point on the grid towards a given transmission line. This impact is measured as a percentage between the amount of injection (or withdrawal) and its impact on the studied transmission line. In the case of PG&E's lookback development process, EF answers the question "For a 1 MW of load drop at point A, how many MW of relief – reduction in energy flow – would it bring to a transmission line B?" If the relief is 0.01 MW, then the EF of a load drop at point A would be 1 percent. The value of EF can range from 100 percent to -100 percent (where a negative value represents an injection or withdrawal that exacerbates the transmission violation). For a technical discussion on EF, please see CAISO publication "Background Paper on Methodology for Calculating Locational Effectiveness Factors" available at https://www.caiso.com/Documents/AppendixFBoardApproved2014-2015TransmissionPlan.pdf.

7 *See* PG&E Prepared Testimony, Chapter 3, pp. 3-7 to 3-8.

therefore initially determine that several of the substations in the sub-area needing 100 MW of load alleviation have an initial impact count above the threshold for considering mitigation. Then, in Step 1 of the methodology set forth in Chapter 3 of PG&E's prepared testimony, PG&E would refine this assessment by considering which of the candidate substations is best suited for mitigation through a microgrid, and, after identifying the best candidate, it would determine that the remaining substations in the sub-area do not need further mitigation through microgrid installations because the indirect impact on the sub-area would be adequately addressed and would alleviate all of the modeled indirect impacts in that sub-area.

C. Updated Lookback Dataset

With the revisions to its 10-year historic lookback methodology summarized above, PG&E ran its model using 2021-vintage data. Table 1, below, presents the revised list of impacted substations in the same format as provided in the prepared testimony, which relied on 2020-vintage data and criteria.[8]

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8 *See* PG&E Prepared Testimony, Chapter 2, Attach. A, pp. 2-AtchA-8 to 2-AtchA-11 (providing the original list of 2020-vintage impacted substations).

TABLE 1
PSPS-IMPACTED SUBSTATIONS BASED UPON 2021-VINTAGE MODELING DATA AND ASSUMPTIONS

Line No.	Item Number	Substation Name	Event Count	Direct Impact	Indirect Impact	Impacts w/ 100+ STE Customers
1	1	BANGOR	12	12	0	12
2	2	DESCHUTES	10	2	8	9
3	3	VOLTA	10	2	8	9
4	4	ANNAPOLIS	9	2	7	9
5	5	BELLEVUE	9	0	9	9
6	6	CALPELLA	9	0	9	9
7	7	CLEAR LAKE	9	0	9	9
8	8	COTATI	9	0	9	9
9	9	FITCH MOUNTAIN	9	0	9	9
10	10	FULTON	9	0	9	9
11	11	GEYSERVILLE	9	0	9	9
12	12	GUALALA	9	2	7	9
13	13	HARTLEY	9	0	9	9
14	14	MENDOCINO	9	0	9	9
15	15	MIRABEL	9	0	9	9
16	16	MOLINO	9	0	9	9
17	17	MONROE	9	0	9	9
18	18	MONTE RIO	9	0	9	9
19	19	MONTICELLO	9	9	0	9
20	20	PENNGROVE	9	0	9	9
21	21	POTTER VALLEY P H	9	0	9	9
22	22	PUEBLO	9	1	8	9
23	23	RINCON	9	1	8	9
24	24	SANTA ROSA A	9	0	9	9
25	25	SILVERADO	9	1	8	9
26	26	SONOMA	9	0	9	9
27	27	UPPER LAKE	9	0	9	9
28	28	WILLITS	9	0	9	9
29	29	WINDSOR	9	0	9	9
30	30	WEIMAR	9	9	0	8
31	31	ANDERSON	8	1	7	8
32	32	BASALT	8	0	8	8
33	33	CALISTOGA	8	8	0	8
34	34	CARQUINEZ	8	0	8	8
35	35	CORONA	8	0	8	8
36	36	COVELO	8	1	7	8
37	37	DUNBAR	8	1	7	8
38	38	GIRVAN	8	1	7	8
39	39	HIGHWAY	8	0	8	8
40	40	IGNACIO	8	0	8	8
41	41	LAKEVILLE	8	0	8	8
42	42	LAS GALLINAS A	8	0	8	8
43	43	NAPA	8	0	8	8
44	44	PETALUMA A	8	0	8	8
45	45	PETALUMA C	8	0	8	8
46	46	SALMON CREEK	8	1	7	8

TABLE 1
PSPS-IMPACTED SUBSTATIONS BASED UPON 2021-VINTAGE MODELING DATA AND ASSUMPTIONS
(CONTINUED)

Line No.	Item Number	Substation Name	Event Count	Direct Impact	Indirect Impact	Impacts w/ 100+ STE Customers
47	47	SAN RAFAEL	8	0	8	8
48	48	TULUCAY	8	0	8	8
49	49	OREGON TRAIL	13	5	8	7
50	50	FORT ROSS	9	2	7	7
51	51	SHADY GLEN	9	9	0	7
52	52	ALTO	7	0	7	7
53	53	BOLINAS	7	0	7	7
54	54	CORDELIA	7	0	7	7
55	55	GREENBRAE	7	0	7	7
56	56	HOOPA	7	1	6	7
57	57	LAYTONVILLE	7	0	7	7
58	58	NOVATO	7	0	7	7
59	59	OLEMA	7	0	7	7
60	60	SAUSALITO	7	0	7	7
61	61	STAFFORD	7	0	7	7
62	62	WILLOW CREEK	7	1	6	7
63	63	WOODACRE	7	1	6	7
64	64	BIG RIVER	5	0	5	5
65	65	ELK	5	0	5	5
66	66	FORT BRAGG A	5	0	5	5
67	67	HOPLAND	5	0	5	5
68	68	KONOCTI	5	1	4	5
69	69	LUCERNE	5	3	2	5
70	70	MIDDLETOWN	5	1	4	5
71	71	PHILO	5	0	5	5
72	72	POINT ARENA	5	0	5	5
73	73	UKIAH	5	0	5	5
74	74	WEST POINT	5	5	0	5
75	75	BONNIE NOOK	4	4	0	4
76	76	BRUNSWICK	4	4	0	4
77	77	LAURELES	4	4	0	4
78	78	OTTER	4	4	0	4
79	79	POINT MORETTI	4	4	0	4
80	80	RESERVATION ROAD	4	4	0	4
81	81	KESWICK	10	8	2	3
82	82	ANTLER	4	0	4	3
83	83	FRENCH GULCH	3	1	2	3
84	84	TAMARACK	3	3	0	3
85	85	ALLEGHANY	10	10	0	2
86	86	FORESTHILL	9	9	0	2
87	87	BIG BASIN	2	2	0	2
88	88	BURNEY	2	2	0	2
89	89	CLOVERDALE	2	2	0	2

TABLE 1
PSPS-IMPACTED SUBSTATIONS BASED UPON 2021-VINTAGE MODELING DATA AND ASSUMPTIONS
(CONTINUED)

Line No.	Item Number	Substation Name	Event Count	Direct Impact	Indirect Impact	Impacts w/ 100+ STE Customers
90	90	MC ARTHUR	2	2	0	2
91	91	PIT NO 1	2	2	0	2
92	92	PIT NO 3	2	2	0	2
93	93	WHITMORE	2	2	0	2
94	94	STILLWATER	10	8	2	1
95	95	CHALLENGE	9	9	0	1
96	96	RISING RIVER	2	2	0	1
97	97	APPLE HILL	1	1	0	1
98	98	ARCATA	1	1	0	1
99	99	AUBERRY	1	1	0	1
100	100	BIG MEADOWS	1	1	0	1
101	101	BLUE LAKE	1	1	0	1
102	102	BRIDGEVILLE	1	1	0	1
103	103	CARLOTTA	1	1	0	1
104	104	CHESTER	1	1	0	1
105	105	DAIRYVILLE	1	0	1	1
106	106	EEL RIVER	1	1	0	1
107	107	EUREKA A	1	1	0	1
108	108	EUREKA E	1	1	0	1
109	109	FAIRHAVEN	1	1	0	1
110	110	FRUITLAND	1	1	0	1
111	111	GARBERVILLE	1	1	0	1
112	112	GERBER	1	0	1	1
113	113	HARRIS	1	1	0	1
114	114	HUMBOLDT BAY	1	1	0	1
115	115	JANES CREEK	1	1	0	1
116	116	LOS MOLINOS	1	0	1	1
117	117	LOW GAP	1	1	0	1
118	118	MAPLE CREEK	1	1	0	1
119	119	MIWUK	1	1	0	1
120	120	NEWBURG	1	1	0	1
121	121	ORICK	1	1	0	1
122	122	PARADISE	1	1	0	1
123	123	PINE GROVE	1	1	0	1
124	124	PLACERVILLE	1	1	0	1
125	125	RAWSON	1	0	1	1
126	126	RED BLUFF	1	0	1	1
127	127	REDBUD	1	1	0	1
128	128	RIO DELL	1	1	0	1
129	129	SPRING GAP	1	1	0	1
130	130	TRINIDAD	1	1	0	1
131	131	TYLER	1	0	1	1
132	132	VINA	1	0	1	1

D. Implications of 2021-Vintage Data for the Long-Term Procurement Framework for Substation Microgrid Solutions

The significant change in list of impacted substations between 2020 and 2021 demonstrate the sensitivity of this list to assumptions, refinements, and improvements in both PG&E's modeling capability and to the physical state of its assets. PG&E recognizes that its PSPS modeling capabilities and asset conditions will continue to improve over time and that the modeling it did for 2020 was only a first step in that development.

Overall, the change in this list of impacted substations counsels caution in developing long-term substation-level mitigation solutions for PSPS events. To the extent future improvements in scoping criteria and/or grid infrastructure or vegetation management practices obviate the need for de-energization of a substation at which a long-term solution was built, the solution may not be needed to the same extent as when it was proposed, approved, and constructed. Accordingly, PG&E, the California Public Utilities Commission, and parties to this proceeding will need to address the role of future uncertainty in weighing the extent to which longer-term substation-level microgrid solutions should be deployed. PG&E's proposed long-term framework therefore appropriately puts into place steps to assess not just the list of impacted substations, as presented in Table 1 above for 2021, but also then examines plans to make grid improvements, or unplanned opportunities to otherwise address the PSPS risk, before deploying a long-term microgrid solution.

PACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT A

RESPONSE OF PACIFIC GAS AND ELECTRIC COMPANY TO

ENERGY SAFETY REMEDY PG&E-21-29 AND

CHANGE ORDER REPORT

SEPTEMBER 30, 2021

PACIFIC GAS AND ELECTRIC COMPANY

RESPONSE OF PACIFIC GAS AND ELECTRIC COMPANY TO ENERGY SAFETY REMEDY PG&E-21-29 AND CHANGE ORDER REPORT

SEPTEMBER 30, 2021

Response to Remedy PG&E-21-29 Per Office of Energy Infrastructure Safety (OEIS) Action Statement on 2021 Wildfire Mitigation Plan (WMP)

Utility #: PG&E-21-29

Issue Title:

PSPS targets and projections set to expire

Issue Description:

Pacific Gas and Electric Company (PG&E or the Company) states that its Public Safety Power Shutoff (PSPS) approach will likely change in August 2021. When PG&E updates its approach, the PSPS targets and projections presented in its WMP Update and Revision Notice response will become obsolete.

Remedies Required and Alternative Timeline if Applicable:

As soon as practicable, and no later than September 30, 2021, PG&E must submit a Change Order Report:

1) *Describing in full and complete detail its updated PSPS protocols.*
2) *Showing how its updated PSPS protocols affect PSPS projections (Table 11).*
3) *Showing how its updated PSPS protocols affect all quantitative and qualitative target for reducing the scale, scope, and frequency of PSPS.*
4) *Meeting all requirements for a Change Order Report set out in Section 7 of this Action Statement.*

Introduction to PG&E-21-29 Response:

In Sections 8.2.2 and 8.2.6 of our Revised 2021 WMP submitted on June 3, 2021, we outlined our tactical and decision-making protocols for initiating PSPS de-energization events.[1] In the Revised 2021 WMP, we explained that, at that time, we were continuing to evaluate and improve the models and protocols that we use to inform PSPS decisions and described the 2020 PSPS Protocols Plus Tree Overstrike Criteria Potential and Priority Tags, which were the Distribution protocols deployed at the time.[2]

1 See Revised 2021 WMP, p. 950 (Section 8.2.2) and p. 978 (Section 8.2.6).

2 Revised 2021 WMP, pp. 979-982.

In August 2021, we completed the development of our 2021 PSPS Protocols and discontinued using the 2020 PSPS Protocols Plus Tree Overstrike Criteria Potential and Priority Tags. Therefore, as of August 2021, we are using the updated 2021 PSPS Protocols to assess PSPS events.

In the Revised 2021 WMP, we were describing our PSPS Distribution Protocols, which were referred to as “PSPS Protocols.” However, in September 2021, we also completed the development of our 2021 PSPS Transmission Protocols. In our response to Remedy PG&E-21-29, we will address both the 2021 PSPS Distribution and Transmission Protocols and refer to them jointly as the “2021 PSPS Protocols.” Whenever we address just a subset of the protocols (i.e., Distribution or Transmission) we will specify this subset as either the 2021 PSPS Protocols (Distribution) or the 2021 PSPS Protocols (Transmission).

For clarity, we are also providing in Table PG&E-Remedy-21-29-1 below the naming convention that we will use for each of these protocols and the time periods that protocols were or that we expect the protocols to be in effect.

TABLE PG&E-REMEDY-21-29-1:
PSPS PROTOCOLS AND TIME PERIOD IN EFFECT

PSPS Protocol Name	Time Period in Effect
2020 PSPS Protocols	June 2020 – May 2021
2020 PSPS Protocols Plus Tree Overstrike Potential and Priority Tags[(a)]	May 2021 – August 2021
2021 PSPS Protocols	
• 2021 PSPS Protocols (Distribution)	August 2021 – Fall 2022
• 2021 PSPS Protocols (Transmission)	September 2021 – Fall 2022

(a) The update on the 2020 PSPS Protocols Plus Tree Overstrike Potential and Priority Tags was associated with the 2020 PSPS Distribution protocols.

As part of our PSPS continuous improvement process, PG&E plans to develop 2022 PSPS Protocols in early 2022 and operationalize them in advance of the 2022 PSPS season.

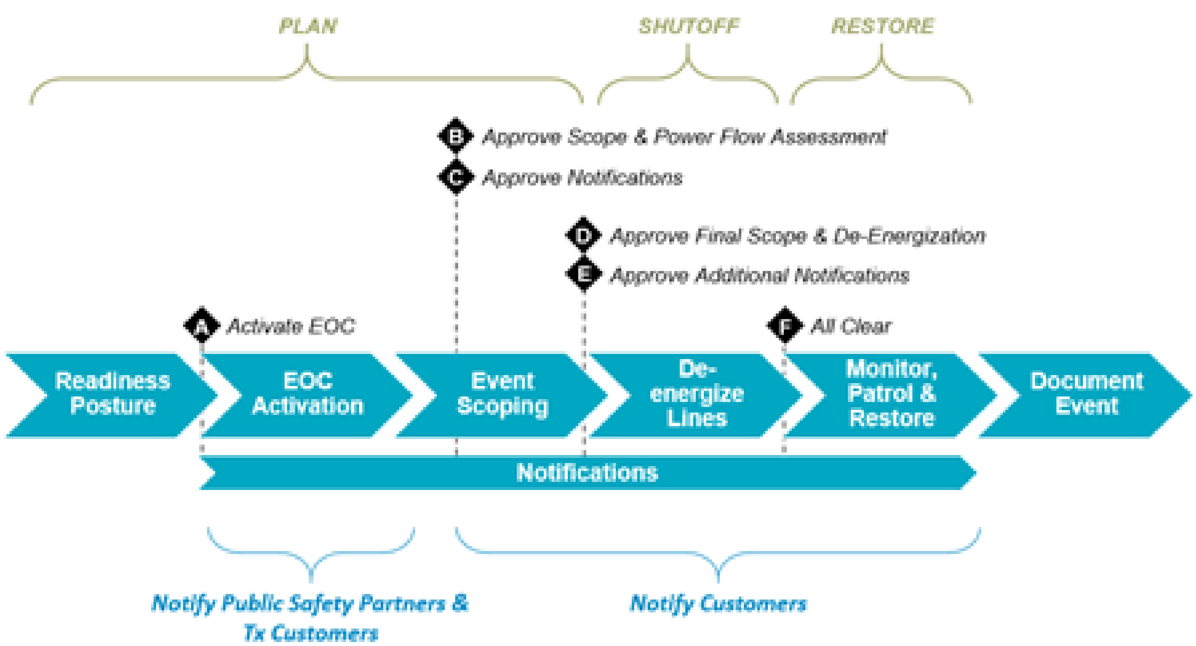
In the remainder of this response to Remedy PG&E-21-29, we will focus on describing the 2021 PSPS Protocols and providing the requested information, including information for a Change Order.

1. 2021 PSPS Process and Protocols Description

1.1. 2021 PSPS Preparation and Scoping Process

This section provides an overview of the process for determining when to initiate a PSPS event under the 2021 PSPS Protocols. Figure PG&E-Remedy-21-29-1 provides a high-level overview of the process to prepare for and conduct a PSPS event.

FIGURE PG&E-REMEDY-21-29-1:
PG&E'S HIGH LEVEL PSPS PROCESS STEPS



PG&E considers implementing a PSPS event when the combination of strong, gusty winds and critically low humidity and fuel moisture levels lies over areas with dry vegetative fuel loads, creating a high risk that vegetation blown into a power line or a spark from a power line could cause an ignition that could lead to a catastrophic wildfire.

Assessments begin several days before the weather event is forecasted to take place. PG&E identifies the weather conditions that could create severe fire risk using high-resolution internal and external weather forecasting models, as well as data from federal agencies. As part of this process, we use external forecasting services and sources, including the European Center for Medium-Range Weather Forecasts (ECMWF), the Global Forecast System (GFS), the Northern and Southern Operations Predictive Services, and the National Weather Service (NWS). Our thresholds and guidance for identifying critical fire risk are determined by analyzing three decades of historical weather data in and around California combined with key external partnerships and extensive academic research.

No single factor drives the determination that a PSPS is necessary, as each situation is dynamic and unique. The main drivers considered for PSPS events under the 2021 PSPS Protocols are described below. External forecast information from the NWS (e.g., Red Flag Warnings (RFW)) and other forecast agencies is examined carefully; furthermore, PG&E coordinates with these agencies during high-risk periods to ultimately decide to de-energize portions of the grid for public safety.

1.2. Overview of 2021 PSPS Protocols

The 2021 PSPS Protocols include enhancements to our Outage Producing Wind (OPW) Model, our Fire Potential Index (FPI) Model, and the integration of Technosylva Fire modeling into our PSPS Protocols. In addition to the model enhancements described above, the 2021 PSPS Protocols also incorporate tree overstrike and high-risk vegetation and asset tags.

FPI Model Enhancements:

To understand the potential for large and catastrophic fires to occur across the PG&E service territory, we first developed the FPI in 2015 and have enhanced the model several times. From 2015 to 2021, we evaluated new features, new datasets and new model configurations with the goal of improving FPI predictions. The 2021 FPI Model combines fire weather parameters (wind speed, temperature, and vapor pressure deficit); dead and live fuel moisture data; and topography and fuel type data to predict the probability of large and/or catastrophic fires. The 2021 FPI Model was trained on an enhanced fire occurrence dataset that combines agency fire information with sub-daily growth from satellite fire detections. We partnered with Sonoma Technology, Inc. to build this enhanced dataset. This was an important development as we can correlate fire growth in sub-daily timeframes to environmental data. Data scientists, meteorologists, and fire scientists tested dozens of new model features for the 2021 FPI Model and various model configurations and types. Among the model-types tested were logistic regression and multiple machine-learning models. Model results were tested using a train-test split ratio of 70 percent-30 percent. This involved training the model with 70 percent of the input data and testing predictions with the remaining 30 percent of fires. We ultimately chose a Balanced Random Forest Classification Machine Learning model for the 2021 FPI Model based on model performance. The

2021 FPI Model has been significantly enhanced with Machine Learning capabilities, environmental and fire occurrence datasets through 2020, new model features, and an enhanced fire occurrence dataset.

OPW Model Enhancements:

The OPW Model forecasts the probability of a wind-driven outage on our system based on forecast windspeeds for each grid cell associated with our distribution lines for every hour of a forecast. As we explained in the Revised 2021 WMP,[3] we recalibrated our OPW Model using the 2km climatology extended to capture outage events in 2020. In the 2021 PSPS Protocols, the OPW output is also enhanced to produce an Ignition Probability using historical outages and ignitions in our service area. This new ignition model is called the Ignition Probability Weather (IPW) Model. Utilizing the IPW Model further helps PG&E pinpoint the areas where the probability of ignition is greatest. When modeled with the 2021 FPI Model, we can more accurately pinpoint the areas of greatest fire risk. In addition, we incorporated tree overstrike risk directly into the IPW Model to further inform vegetation-based outage risk and increase the model's efficacy.

Integration of Technosylva Fire Spread Modeling:

After testing fire spread simulations across historical and forecast time-horizons, we added Technosylva fire spread outputs into the 2021 PSPS Protocols. Utilizing Technosylva Fire Spread Modeling allows us to review millions of simulated ignitions to identify the areas where the risk of an ignition growing into a catastrophic wildfire is greatest. In addition, bringing in a third-party vendor to help produce PG&E's PSPS scope allows us to highlight areas where the models do and do not overlap for forecast corroboration and additional insights.

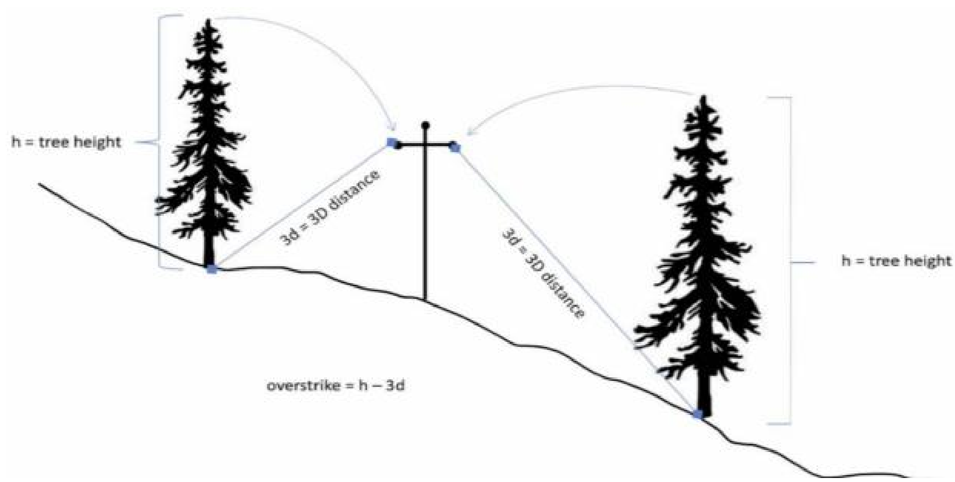
Incorporation of Tree Overstrike:

Overstrike is defined by the amount of timber in which one tree could strike our lines. For example, a taller tree next to our lines would have a higher amount of overstrike than a shorter tree in the same location. This is a function of the Tree Height minus the 3D distance (shortest path from tree to conductor) as illustrated in Figure PG&E-Remedy-21-29-2 below. As discussed in Sections 8.2.2 and 8.2.6 of the Revised 2021 WMP, PG&E worked to further integrate Tree Overstrike as a part of our

3 Revised 2021 WMP, p. 983.

2021 PSPS Protocols (Distribution). Instead of incorporating areas that surpass 70 percent of tree overstrike risk, our 2021 PSPS Protocols (Distribution) now utilize a machine learning model to integrate overstrike directly into our IPW Model. Using a machine learning model helps us more accurately incorporate the risk by analyzing risk posed by the approximately 150 million feet of overstrike in PG&E's service territory at 2x2 km area.

FIGURE PG&E-REMEDY-21-29-2:
DIAGRAM SHOWING TREE OVERSTRIKE POTENTIAL
AS A FUNCTION OF TREE HEIGHT MINUS 3D DISTANCE

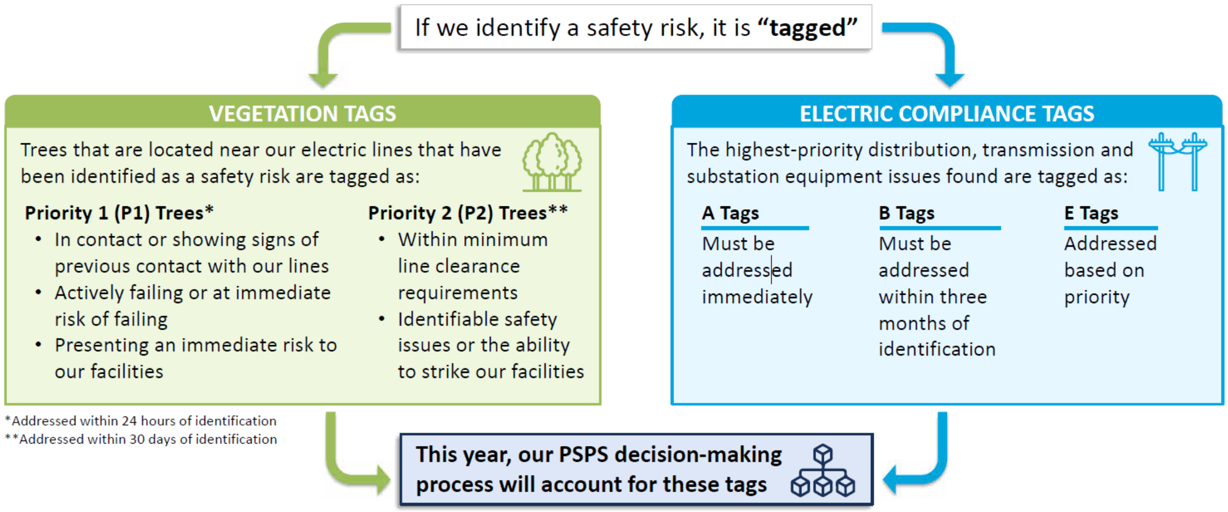


Incorporation of High-Risk Vegetation and Asset Tags:

Similar to our 2020 PSPS Protocols plus Tree Overstrike Potential and Priority Tags, our 2021 PSPS Protocols (Distribution) have continued to incorporate any Priority 1 or Priority 2 tree tags[4] that meet our Minimum Fire Potential Conditions (mFPC). In addition to Priority Tags, we are also including any circuits with high-risk compliance tags that meet our mFPCs as part of our PSPS. Figure PG&E-Remedy-21-29-3 below shows a schematic of our current Vegetation and Asset Hazard Considerations.

4 "Priority 1" and "Priority 2" vegetation tags are created when trained vegetation inspectors identify trees or limbs that currently present elevated risk and must be worked on an expedited basis. Inspectors use Priority 1 tags for vegetation: (1) in contact or showing signs of previous contact with a primary conductor; (2) actively failing or at immediate risk of failing and which could strike PG&E's facilities; or (3) presenting an immediate risk to PG&E's facilities. Inspectors use Priority 2 tags for vegetation that does not rise to the level of Priority 1 but has encroached within the PG&E minimum clearance requirements or has an identifiable potential safety issue requiring expedited work.

FIGURE PG&E-REMEDY-21-29-3:
VEGETATION AND ASSET HAZARD CONSIDERATIONS



In the following part of this section, we describe the 2021 PSPS Protocols (Distribution) and 2021 PSPS Protocols (Transmission) followed by our PSPS process once the Distribution and Transmission event scope has been defined.

1.3. 2021 PSPS Protocols (Distribution)

This section describes the 2021 PSPS Protocols for the distribution system. There are three key inputs of meteorological and fuels analysis to determine minimum PSPS criteria for the distribution system:

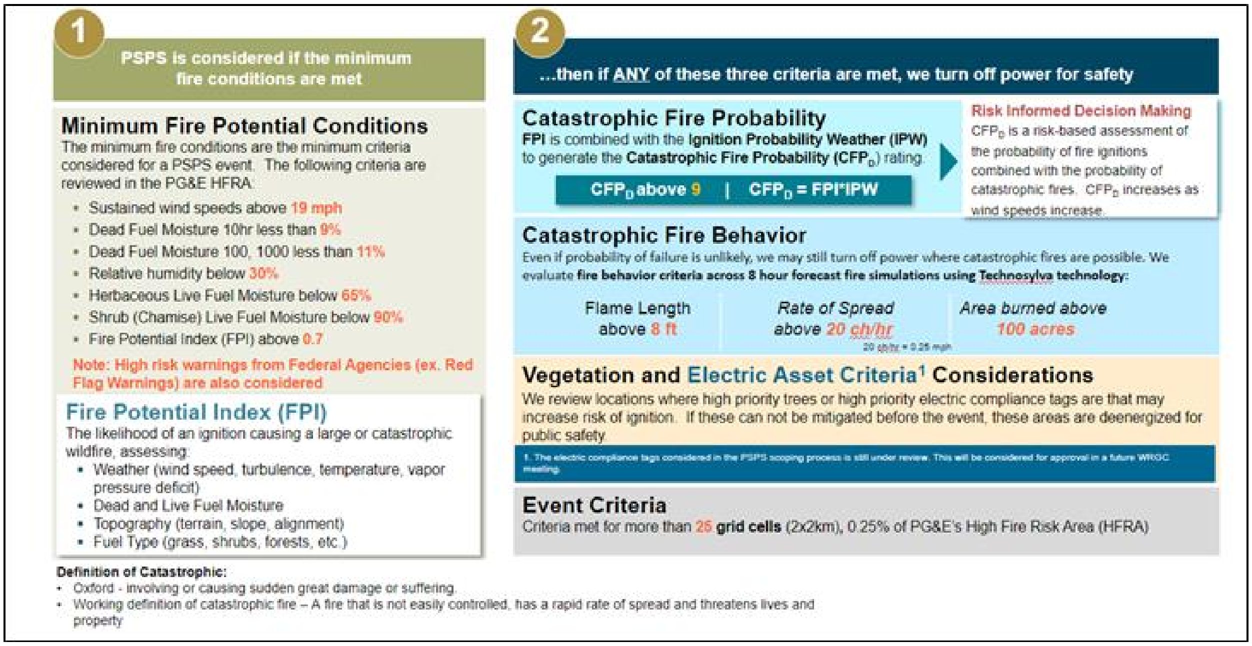
<u>Minimum Fire Potential Conditions</u>:

- Catastrophic Fire Probability (CFP_D) comprised of the following:
  - Ignition Probability Weather;
  - Utility FPI;
- Catastrophic Fire Behavior (CFB) (via fire spread simulations from Technosylva); and
- Consideration of known high-risk vegetation and electric compliance tags.

In addition to the meteorological models, we also evaluate the impacts of de-energization against the risk of wildfire should de-energization not occur. This information is reviewed at key decision points in the PSPS process and informs the ultimate decision to de-energize our customers and our communities. Figure

PG&E-Remedy-21-29-4 below provides a quantitative summary of our 2021 PSPS Protocols (Distribution).

FIGURE PG&E-REMEDY-21-29-4:
2021 PSPS PROTOCOLS (DISTRIBUTION)



The mFPCs are the minimum weather and fuels filter based on relative humidity values, wind speed, and fuel moisture values that must be exceeded for a PSPS event to be considered.

The machine learning IPW and FPI Models are combined in both space and time to form CFP_D output at a 2 x 2 km resolution. CFP_D provides hourly outputs and highlights locations that have concurrence of an increased probability for large fires and increased probability of wind-related ignitions on the distribution system. Additionally, the CFB criteria are used to identify locations that may have a lower probability of ignition but could result in fires that are not easily suppressed and have potentially high consequences.

Below, we describe the steps in the 2021 PSPS Protocols (Distribution).

<u>Step 1</u> – mFPCs/FPI

The first step of determining the scope of a PSPS event for distribution is evaluating the mFPCs. These conditions serve as a first review of weather conditions for a PSPS event to be considered. A PSPS event will only be evaluated if ALL of the following mFPCs are true in a High Fire Risk Area (HFRA):[5]

- Sustained wind speeds above 19 miles per hour;
- Dead fuel moisture 10-hr less than 9 percent;[6]
- Dead fuel moisture 100-hr., 1000-hr. less than 11 percent;[7]
- Relative Humidity below 30 percent;
- Herbaceous live fuel moisture below 65 percent;
- Shrub (Chamise) Live Fuel Moisture below 90 percent; and
- FPI (the probability of large or catastrophic fires given an ignition) above 0.7.

These values were established from an examination of historical fire occurrences in our service area, PSPS sensitivity studies using historical data viewed through the lens of both customer impacts and wildfire risk mitigated, and information published by federal agencies regarding fire behavior and criteria used to issue warnings to the public.

Step 2 – In-depth Review of Fire Risk

If all the mFPCs in Step 1 are met, we conduct an in-depth review of fire risk using three separate measures. If the criteria for any of the measures are met, then PG&E may need to turn off power to preserve safety:

1) Catastrophic Fire Probability – PG&E uses machine learning to assess the likelihood of equipment failing during a given weather event, and the subsequent risk of catastrophic wildfires if a failure occurs. This model uses a combination of the IPW and FPI Models. It is a risk-based assessment that evaluates the probability of an ignition against the probability of catastrophic fires. The CFP model accounts for changes over time based on actual performance data. Thus, the model will address positive and negative trends in grid performance and reliability year-over-year, incorporating grid improvements such as system

5 Revised 2021 WMP, pp. 85-89.

6 10-hr. Dead fuel moisture represents the modeled moisture content in dead fuels in the .25 to 1-inch diameter class and the layer of the forest floor about one inch below the surface.

7 100-hr. Dead fuel moisture represents the modeled moisture content of dead fuels in the 1-to-3-inch diameter class. It can also be used as a very rough estimate of the average moisture content of the forest floor from three-fourths inch to 4 inches below the surface.

hardening and enhanced vegetation management based on their performance mitigating outages over time.

2) Catastrophic Fire Behavior – PG&E may de-energize customers where the consequence of a potential wildfire starting would be extreme, even if the probability of a power line or equipment failure is low.

3) Vegetation and Electric Asset Criteria Considerations – PG&E reviews locations from recent inspections where high-priority trees or electric compliance issues are present that may increase the risk of ignition.

Step 3 – Determining the Outage Area

If weather forecasts indicate a high likelihood of severe fire risk (Step 2), PG&E first identifies the meteorological footprint of severe fire weather and then identifies the distribution lines and other assets within that footprint. Power is turned off if any of the criteria listed on Step 2 above are met over a certain geographic area. This happens if the criteria also meet an area coverage criterion of more than 25 2x2 km grid cells, or 0.25 percent of PG&E's HFRAs.

For distribution lines, the PG&E team determines which circuits are impacted and evaluates the ability to sectionalize circuits to limit the de-energization scope and resulting customer impact.

1.4. 2021 PSPS Protocols (Transmission)

This section describes the 2021 PSPS Protocols for the transmission system. In addition to analyzing distribution circuits that may need to be de-energized for safety, we also review transmission lines and individual structures for risk of igniting a catastrophic wildfire. Like the 2021 PSPS Protocols (Distribution), there is no single factor or threshold that will require shutting off power to a transmission circuit.

The Transmission PSPS decision-making process follows a similar framework as the distribution process, but utilizes transmission-specific models. There are four key inputs of the meteorological and fuels analysis to determine minimum PSPS criteria for the transmission system:

Minimum Fire Potential Conditions:

- CFP_D from Asset Failures (CFP_T – Asset) comprised of the following:
  - Transmission Operability Assessment (OA);

– Utility FPI;

- CFP_D from Vegetation (CFP_T – Veg) comprised of the following:

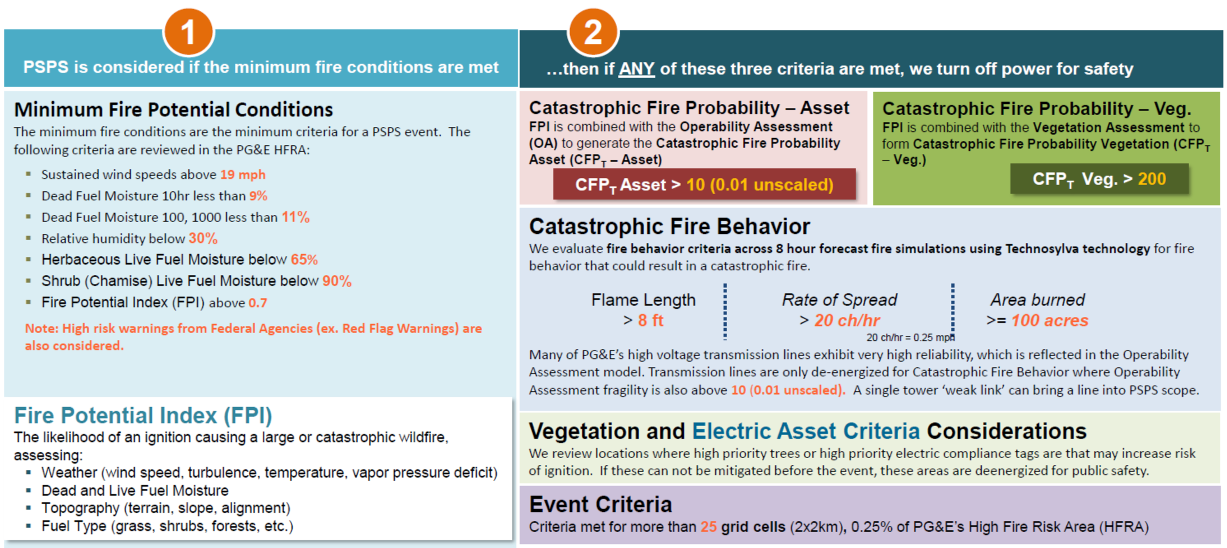
  – Transmission Vegetation Risk Model;

  – Utility FPI;

- CFB (via Fire Spread Simulations from Technosylva); and
- Consideration of known high-risk vegetation and electric compliance tags.

Figure PG&E-Remedy-21-29-5 below provides a quantitative summary of our 2021 PSPS Protocols (Transmission).

FIGURE PG&E-REMEDY-21-29-5:
2021 PSPS – PROTOCOLS (TRANSMISSION)



Step 1 – Minimum Fire Conditions

The first step of determining the scope of a PSPS event on the transmission system is evaluating the mFPCs at the transmission structure level. The same criteria used for the distribution system also apply to the transmission system. These conditions serve as a first review of the weather conditions necessary for a PSPS event to be considered. Once the mFPCs are met, an in-depth review of risk models and other factors is performed.

Step 2 – In-Depth Review of Fire Risk

If all the mFPCs in Step 1 are met, we conduct an in-depth review of fire risk using four separate measures. If the criteria for any of the measures are met, then PG&E may need to turn off power to preserve safety:

1) Catastrophic Fire Probability: Asset – PG&E uses machine learning to assess the likelihood of equipment failing during a given weather event, and the subsequent risk of catastrophic wildfires if a failure occurs. This model uses a combination of the OA and FPI Models, both in time and space, at every transmission structure to form the Transmission CFP_D model for asset failures. (CFP_T - Asset). The OA Model combines historical wind speeds for each structure, historical outage activity, Bayesian updating, and the condition of assets based on inspection programs to help understand the wind-related failure probability of each structure. The OA Model can be driven with forecast wind speeds to output the probability of failure at the structure level.
2) Catastrophic Fire Probability: Vegetation – The transmission-specific vegetation risk model was derived by a collaborative effort between PG&E vegetation management and external contractors such as NV5 and Formation Environmental. This model leverages aerial LiDAR data to map the location and attributes of trees near transmission lines. The transmission vegetation risk model is based on several factors such as overstrike, the amount of unobstructed fall paths to a wire, the slope between tree and conductor, and tree exposure. The transmission vegetation risk model is combined with the FPI Model in space and time to form CFP_T – Veg.
3) Catastrophic Fire Behavior – PG&E may de-energize customers where the consequence of a potential wildfire ignition would be extreme, even if the probability of a power line or equipment failure is low.
4) Vegetation and Electric Asset Criteria Considerations – PG&E reviews locations from recent inspections where high-priority trees or electric compliance issues are present that may increase the risk of ignition.

Step 3 – Determining the Outage Area

Based on the criteria above, transmission lines meeting the criteria pass to the next stage of review for PSPS. PG&E conducts a Power Flow Analysis on the in-scope transmission lines (if applicable) to analyze any potential downstream impacts of load shedding, coordinates this with the California Independent System Operator, and confirms solution feasibility with Transmission System Protection. The de-energization of transmission lines may result in some downstream impacts on substations, transmission lines and distribution lines that may also lose their source.

1.5. After Determining Outage Area (Distribution and Transmission)

After determining the outage area both for Distribution and Transmission, we review the forecasted customer impacts of each circuit against the forecasted wildfire risk of each circuit should an ignition occur on that circuit during the forecasted period of risk for both the distribution and transmission circuits brought into scope from the meteorology models. PG&E then shares this analysis internally during key decision-making points to inform PSPS decision making and further risk modeling.

Starting at 12 hours before an event, PG&E switches from forecasting to observing the weather in real time. Based on real time observations and analysis, we continually evaluate all the outage areas identified in the previous steps to determine whether to call a PSPS event. We also use external tools and analysis to provide input to the decision to call a PSPS event, as described below.

1.6. External Tools and Analysis

During high-risk periods, PG&E meteorologists participate in daily interagency conference calls that commonly include multiple NWS local offices, the NWS western region headquarters, and representatives from the Geographic Area Coordination Center (GACC). This call is hosted by the Northern California or Southern California GACC offices. Agreements with California Department of Forestry and Fire Protection and United States Forest Service leadership allow participation on these calls (although PG&E participation does not influence any forecasts issued by these independent agencies). During these calls, the agencies present their expert assessment on the upcoming periods and locations of risk, wind speeds and fuel moisture levels, and any other relevant factors to consider. PG&E greatly appreciates these conference calls and the opportunity to coordinate with external and independent forecast agencies on upcoming risk periods. During PSPS events, the lead meteorologist for the event, called the Meteorologist in Charge, summarizes these forecasts and discussions for the Officer in Charge (OIC), who ultimately makes the decision to execute a PSPS event. If external agencies are not in agreement with PG&E analysis and do not see an upcoming event as high risk for large fires, the OIC may use this intelligence to decide if a PSPS event is warranted.

In addition to this information, PG&E carefully reviews and considers the location of existing fires and where new fires are detected using the Satellite Fire Detection and Alerting System (FDAS), which uses data from six National Oceanic and Atmospheric Administration (NOAA)/National Aeronautics and Space Administration satellites to detect fires, and other information compiled by PG&E's Hazard and Awareness Warning Center, such as intel from field observers. If an active fire may require imminent community evacuations, we would consider how best to support those efforts in relation to PSPS decisions. In addition, the following sources and tools are considered before initiating a PSPS event:

- Fire Weather Watches and RFW (NWS – Federal);
- Significant fire potential for wind (GACC – Federal);
- Storm Prediction Center (Federal, part of NOAA);
- Daily interagency conference call with agencies during high-risk periods;
- Field observer information;
- Live weather data from weather stations;
- Location of existing fires;
- New fires detected – Satellite Fire Detection and FDAS;
- ECMWF model;
- North American Mesoscale model;
- High-Resolution-Rapid Refresh model;
- GFS American global model; and
- Other weather models.

Based on the above analyses, we can determine how many customers may be subject to de-energization, and further investigate mitigation options—such as advanced switching solutions, sectionalization, the use of islanding, alternative grid solutions, and temporary generation—to support customers who could lose transmission power sources but are in areas that may be safe to keep energized.

PG&E monitors and forecasts weather over a multi-day horizon, so the Company can anticipate when a PSPS event may be needed and activate its Emergency Operations Center ahead of any PSPS event whenever possible. The PG&E Meteorology team updates weather forecasts approximately four times a day to monitor for changes in weather event timing, strength, and potential locations impacted. Weather shifts may force changes to PSPS scope and impacts at any point in time during PSPS planning and execution; this may allow the Company to avoid de-energization in some areas if fire-critical conditions lessen, but can also cause some areas and customers to move into de-energization scope late in the process if forecasted fire-critical weather footprints change or increase. This is driven by the inherent uncertainty in weather forecast models.

1.7. Risk Tools and Risk Assessment

In addition to the 2021 PSPS Protocols, we also use risk assessment tools in evaluating PSPS events. These are not part of the 2021 PSPS Protocols but are considered in addition to the Protocols when evaluating the need to call a PSPS event.

The PSPS Risk-Benefit tool addresses the regulatory requirements presented in California Public Utilities Commission (CPUC or Commission) Decision 21-06-014, which requires California investor-owned utilities to quantify the risk/benefits associated with initiating or not initiating a PSPS event for our customers. We incorporate this risk-benefit analysis to help inform the PSPS decision-making process. The output of the tool is a ratio that compares the PSPS potential benefit from initiating an event (i.e., mitigation of catastrophic wildfire risk) to the induced risks associated with an event (i.e., impact to customers resulting from a PSPS outage). To produce this analysis PG&E inputs the results of Technosylva wildfire simulations on the circuits in scope for de-energization and the forecasted number of customers de-energized and customer hours forecasted per circuit.

The PSPS Risk-Benefit tool utilizes the Multi-Attribute Value Function (MAVF) framework, as defined through the Safety Model Assessment Proceeding. The tool's calculations for risk use an industry-wide standard, non-linear scaling MAVF, reflecting our focus on low-frequency/high-consequence risk events without neglecting high-probability/low-consequence risk events. The MAVF, a unitless number that captures the safety, reliability, and financial impact of these risk events, is used to calculate the risk scores for the risk events in PG&E's Enterprise Risk Register.[8] MAVF

[8] Full details of the MAVF methodology are provided through the Risk Assessment and Modeling Phase (RAMP) Report RAMP Report, pp. 3-3 to 3-15 and General Rate Case (GRC) workpapers in response to Energy Division GRC-2023-PhI_DR_ED_001_Q01Supp01.

scores outputted by the PSPS Risk-Benefit tool are used to compare the risk from a PSPS event to the risk of wildfires on the potentially impacted circuits being considered for PSPS de-energization.

To estimate the potential in-event PSPS and Wildfire Risk Scores, the following information is required and is used in calculations to build MAVF risk scores for PSPS events and wildfires, which are ultimately weighed against one another:

- Forecasted Circuits and Customers Impacted – Identification of the final list of the distribution and transmission circuits in-scope for PSPS, the number of customers impacted, and the estimated outage duration the customers will face.
- Technosylva Wildfire Simulation Data – Fire spread simulation forecasts on the consequence of a potential wildfire's impacts on population and buildings on each circuit for every three hours for the next approximately five days. These values are based on Technosylva's sophisticated wildfire modeling, using real-time weather models, state-of-the-art live fuel moisture models, and 8-hour fire spread modeling.

  Once the above data is made available, the modeling considerations described below are used to estimate the consequence of the: (1) potential wildfire risk; and (2) PSPS risk, at the circuit level. The consequence considerations are included in Table PG&E-Remedy-21-29-2 below and summarized in a visual on Figure PG&E-Remedy-21-29-6.

TABLE PG&E-REMEDY-21-29-2:
2021 PSPS RISK BENEFIT MODEL CONSIDERATIONS

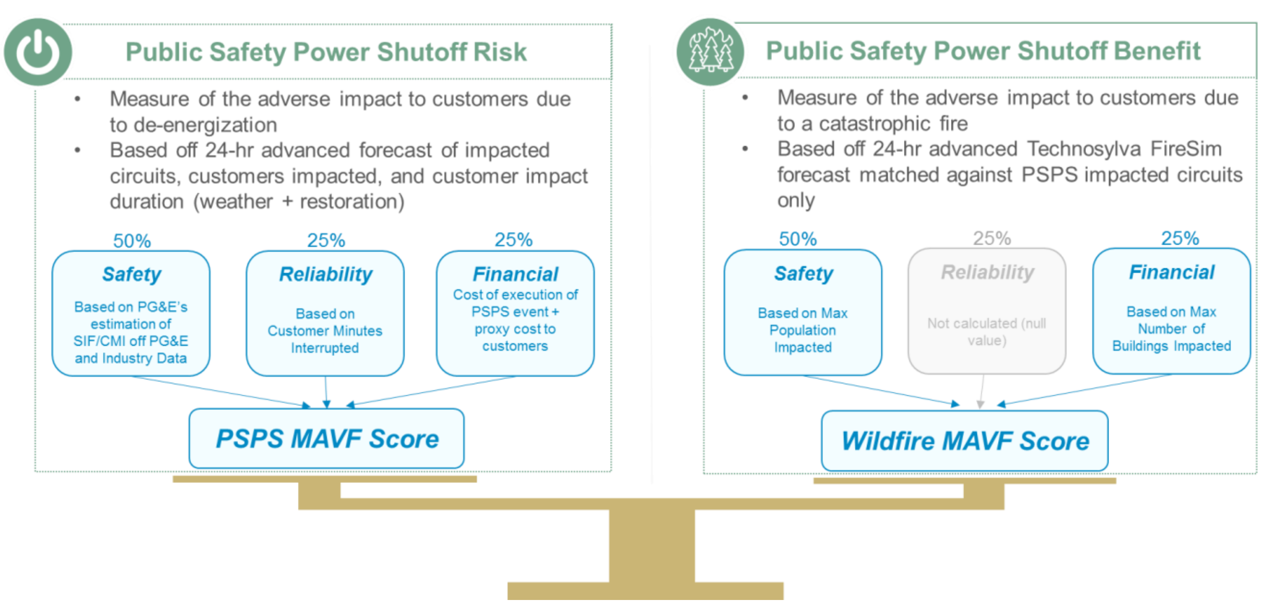
Consequence Type	Wildfire Consequence Considerations	PSPS Consequence Considerations
Safety	Calculated based on maximum population impacts derived from Technosylva wildfire simulation models and a fatality ratio based on National Fire Protection Association data.	Calculated from an estimate of Equivalent Fatalities (EF) per million Customer Minutes Interrupted (MMCI). EF/MMCI ratio is estimated from previous PG&E PSPS and other large external outage events.(a)
Reliability	N/A	Calculated directly from the potential number of customers impacted and outage duration based on customer minutes interrupted.
Financial	Calculated based on maximum building impacts derived from Technosylva wildfire simulation models and a cost per structure burned previously evaluated in 2020 RAMP Report.(b)	Calculated based on two financial estimates: (1) distribution of a lump sum cost of execution across all relevant circuits, and (2) an estimated proxy cost per customer per PSPS event.(c)

(a) Previous PG&E PSPS events include 2019-2020 events, and other large external outage events include 2003 Northeast Blackout in New York City, 2011 Southwest Blackout in San Diego, 2012 Derecho Windstorms, 2012 Superstorm Sandy, and 2017 Hurricane Irma.

(b) See Application 20-06-012.

(c) The assumptions used in these calculations, including the proxy cost per customer per PSPS event, are subject to be updated and are not intended to prejudge or create precedent with regard to the development of more precise values of resiliency or cost of PSPS metrics being considered in other ongoing proceedings at the CPUC, such as the Risk-Based Decision-Making Rulemaking [R.20.07.013] and the Microgrid and Resiliency Strategies.

FIGURE PG&E-REMEDY-21-29-6:
VISUAL REPRESENTATION OF PSPS RISK BENEFIT TOOL



This assessment provides the ability to compare the associated risks between the two scenarios. Once the risk-benefit model calculates the impacts between the PSPS event and a wildfire, it is summarized by indicating if the adverse impact from a PSPS event outweighs the risk of a wildfire.

1.8. Validation of 2021 PSPS Protocols and Thresholds

This section addresses PG&E's examination of the adequacy of the 2021 PSPS Protocols and the determination of the guidance thresholds for the 2021 PSPS Protocols. At the end of this section, we describe how we used many different resources and tools to verify and test our 2021 PSPS Protocols and its guidance thresholds.

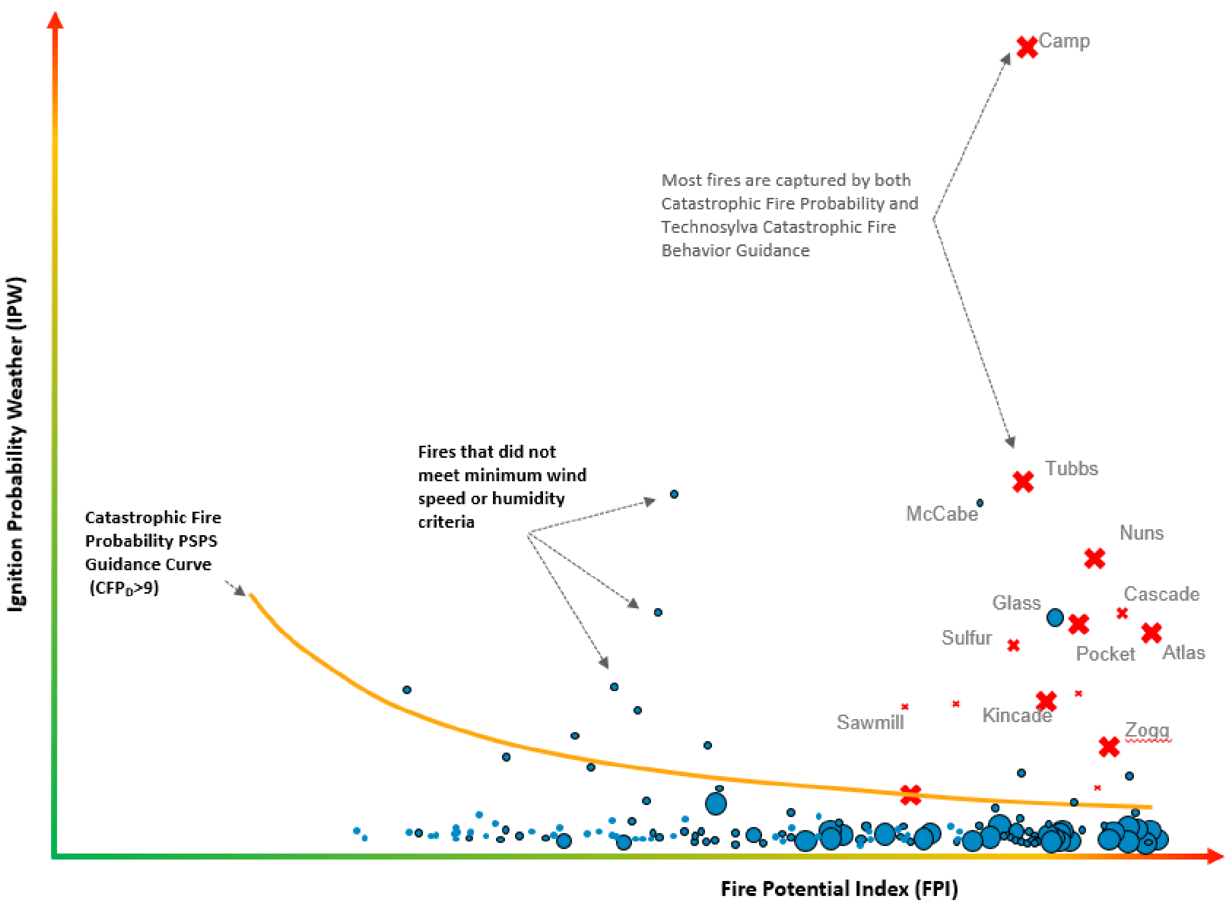
To evaluate if the 2021 PSPS Protocols captures large, catastrophic wind-driven fires, PG&E built a verification dataset by extracting the PSPS guidance for recent fires that have occurred in PG&E's service territory from 2012 to 2020. Based on the historical review of incidents, verification of event dates, and the guidance sensitivity and calibration analysis, a CFP_D value of nine was chosen as the quantitative threshold guidance value to consider for PSPS on the distribution system. The mFPCs and CFP_D guidance that is determined from Technosylva was also evaluated in this fashion.

To establish the PSPS threshold of nine, we performed numerous sensitivity studies in backcast mode for calibration and validation. In 2021, this involved running 68 different versions of the combined distribution PSPS guidance through hourly historical data from 2008 to 2020 to calibrate PSPS guidance. This included simulating and learning from more than 2,500 simulated PSPS events. Through this "lookback" analysis, we can evaluate the potential size, scope, and frequency of PSPS events (including potential customer impacts), the days PSPS events would have occurred, as well as whether utility infrastructure would have qualified for de-energization during the time period of prior fires.

The CFP_D guidance value of nine is shown in Figure PG&E-Remedy-21-29-7 below with respect to recent large fires since 2012. Any fires above the nine line that met the basic mFPCs indicate PSPS would have been executed had these models and guidance been in use during these historic events. The historical results show that had this model been deployed and implemented since 2012, the new PSPS protocols would have prevented wildfires such as the Camp, Tubbs, Nuns, Atlas, Kincade, and Zogg fires. Please note that the inclusion of a fire in this analysis does not indicate that PG&E is directly responsible for and/or caused a fire. Instead, the fires are included for the purposes of analyzing the impact of the 2021 PSPS Protocols.

The red “x” symbols in Figure PG&E-REMEDY-21-29-7 below represent fires that were captured by the both the CFP_D and Technosylva CFB. The blue dots under the line represent fires below the CFP_D Guidance. Blue dots above the line represent events that did not meet the mFPC.

FIGURE PG&E-REMEDY-21-29-7:
CFP_D GUIDANCE



The analysis was a critical step to ensure the most catastrophic incidents of the past are being identified by PSPS guidance while considering the significant impacts to customers from PSPS events across multiple dimensions (e.g., duration and frequency). Furthermore, this step helps ensure that future PSPS events will capture conditions similarly present during the most catastrophic fires of the past while also balancing impacts to customers. To execute the analysis, we utilize cloud computing resources to run PSPS model guidance for every hour at every 2 x 2 km grid cell across the historical data set to determine the number of times and locations PSPS guidance is exceeded. Each location exceeding guidance is then grouped into events to determine the location and size of each PSPS event given the weather and fuels present at that time under the parameters of the study version. This allows us to determine if synoptic-driven events (e.g., Diablo wind events) are being identified, and if historical fires attributable to PG&E equipment may have been mitigated.

In addition to the sensitivity studies presented above, PG&E also performed extensive verification of the 2021 PSPS Protocols using several internal and external datasets. The goal of these analyses was to first determine if certain weather events are being captured (e.g., Diablo and offshore wind events), and second, to determine if lines that have been implicated in historic catastrophic fires would have been identified by the guidance. The following datasets were used in the analysis:

- National Center for Environmental Prediction North American Regional Reanalysis Archive (NARR) synoptic weather maps [external];
- Climatology of Diablo wind events [internal];
- Historical fire occurrence data compiled by federal agencies [external];
- Hourly high-resolution wind maps from the climatology data set [internal];
- Distribution and transmission outage history [internal];
- RFWs from the NWS [external];
- High risk of potential large fires due to wind from the GACC [external];
- The weather signal database [internal]; and
- Exploratory and dynamic dashboards created with internal and external data [internal].

The paragraphs below explain how we leveraged external and internal data to verify its 2021 PSPS Protocols guidance thresholds.

<u>NARR Archive</u>:

PG&E has acquired the NARR archive data dating back to 1995 and produced over 2 million maps that can be utilized to study past events. These maps are also useful to study the antecedent conditions leading up to the event such as the extent (or lack thereof) of precipitation events and heat waves. When the PSPS models are run through the climatology, each event identified is compared against the NARR archive by a meteorologist to determine the large-scale atmospheric features present for each event.

Climatology of Diablo Wind Events:

PG&E also leverages the latest academic research on Diablo Wind events that use surface-based observations to create a climatology of Diablo wind events. We adapted the criteria and processed it hour-by-hour through the 31-year weather climatology to determine the frequency, magnitude, and timing of Diablo winds. The output of this analysis was a 31-year calendar of Diablo wind events experienced in the PG&E territory. As it relates to PSPS directly, the strongest Diablo wind events were evaluated to verify if PSPS guidance also selects these days for potential PSPS events. Using the days identified by PSPS guidance and the Diablo event list, a high-level comparison was completed to evaluate overlap of the events. Any events that did not meet PSPS guidance were evaluated further using additional data sources described in this section. For example, the NARR archive proved useful, as antecedent conditions such as rainfall before an event and the magnitude of the event could be evaluated.

PG&E's Weather Signal Database:

PG&E's Meteorology team built, and continues to maintain, a 'weather signal' database that flags each day from January 1, 1995 to present that experienced any weather-related outages on the distribution system and the main weather driver (e.g., heat, low-elevation snow, northeast wind, winter storm, etc.) for these outages. If distribution outage activity is not driven by weather, the day is classified as a "Blue Sky"[9] day, meaning that weather was not a main driver of outage activity. This dataset combines weather and distribution outage activity that allows rapid filtering of events based on the main weather drivers. To validate PSPS guidance, we used a combination of "Northeast"[10] wind days and "Blue-Sky" days.

The PSPS guidance was validated against all Northeast wind days in the database. This is similar, but complimentary to the Diablo event analysis as it also accounts for outage activity observed on those days. Events were also compared against Blue Sky

9 The definition of a Blue Sky day is as follows: "Blue Sky Day is defined the same as a non-weather impact day (no or very limited impacts due to weather)".

10 Our definition of a Northeast wind day is as follows: "Weather type used when strong offshore (northerly or northeast winds) result in elevated outage activity. This includes Diablo and Santa Ana wind events. An example are the classic offshore winds events where surface high pressure develops in the Upper Great Basin."

days to ensure that PSPS would not be recommended for a high percentage of non-weather-impact days where little to no outage activity was observed.

Red Flag Warnings from the NWS:

PG&E also validated PSPS guidance against RFWs from the NWS. A RFW means warm temperatures, very low humidity, and stronger winds are expected to combine to produce an increased risk of fire danger. These RFWs were collected for the past six years (2015-2020) in shapefile format and used to evaluate the timing and spatial extent of historical RFWs against PSPS guidance. It should be noted that each NWS office in the PG&E territory has different RFW criteria, making direct and quantifiable comparison challenging. However, this dataset is used to evaluate whether RFWs were issued when PSPS guidance was met. Based on historical PSPS analysis, RFWs are expected to occur more frequently and cover a broader area than the area covered by PSPS events.

High Risk of Potential Large Fires Due to Wind From the GACC:

PG&E also validated PSPS guidance against historical "High Risk" days from the GACCs, also known as Predictive Services. The GACCs issue High Risk Day alerts when fuel and weather conditions are predicted that historically have resulted in a significantly higher than normal chance for a new large fire or for significant growth on existing fires. Examples of critical weather conditions are high winds, low humidity, an unstable atmosphere, and very hot weather. Similar to the RFW analysis, this dataset was used to evaluate if High Risk days were issued when PSPS guidance was high. Similar to RFWs, based on historical PSPS analysis, High Risk Days are expected to occur more frequently and cover a broader area than PSPS.

Hourly High-Resolution Wind Maps From PG&E Climatology Data Set:

PG&E created hourly maps from high-resolution climatology and a web-based application to display any hour across 30 years. For each event that meets PSPS guidance in the climatology, these maps were evaluated by a meteorologist to better understand the nature of the event, wind speeds, antecedent conditions, and the spatial extent of strong winds. Importantly, forecast wind speeds are available in the same exact format, allowing operational meteorologists to put forecast events in perspective with historical events using the same model.

Detailed Event Dashboards:

Meteorologists and data scientists utilized the data sources described above to evaluate historical PSPS events hour-by-hour to verify the locations and times that are being flagged as meeting PSPS guidance. These dashboards are very useful to determine if historical fire events would have been flagged by PSPS guidance. Meteorologists evaluated these data sources hourly to verify model performance of the IPW model and suitability for operations. The PSPS guidance can be evaluated spatially using the dashboard map integration, while the size and timing of the event can be evaluated using the timeseries integration.

2. 2021 PSPS Protocols Effect on Scope, Duration, and Frequency

Below, we describe our estimated, quantitative targets regarding the scope, frequency, and duration of forecasted PSPS events in 2021 considering both the 2020 PSPS Protocols and the current 2021 PSPS Protocols. The information included in this analysis is based on the best available data that PG&E has and is subject to further updates in accordance with further analysis.

This section directly compares the 2020 and 2021 PSPS Protocols with the objective to show the expected impacts of updating our PSPS Protocols without including the mitigation initiatives proposed in our Revised 2021 WMP. The cumulative impacts of both the updated 2021 PSPS Protocols and 2021 WMP mitigations relative to 2020 PSPS are presented in Section 3 of the response to Remedy PG&E-21-29.

Quantitative Targets Assuming No Additional Decision Criteria – 2020 PSPS Protocols:

To determine the impacts of our 2021 PSPS Criteria on scope, duration, and frequency, we performed a look-back analysis to identify where and when PSPS events would have occurred in the past four years. The 4-year look-back study was developed using the years 2017-2020 to simulate events using the 2021 PSPS Protocols (Distribution). The estimated quantitative targets for scope, frequency, and duration are the 4-year average of the simulated events. Due to the timing of the look-back analysis, the impacts of the 2021 PSPS Protocols (Transmission) and the priority tags are not included in the analysis. To account for transmission protocols and priority tags, multipliers were applied to the 4-year average of the quantitative targets for the 2021 PSPS Protocols (Distribution).

We also utilized the estimated potential impacts to our PSPS scope, duration, and frequency as a result from the 2021 planned mitigations and process improvements outlined in our Revised 2021 WMP. To review the methodology for calculating these estimated reductions, please see the 2021 WMP Supplemental Filing filed on February 26, 2021 in PGE-11 (Class B). It is important to note that these forecasted reductions are estimates and not WMP commitments. As discussed throughout the Revised 2021 WMP, PSPS impacts in any given year are ultimately dependent on weather patterns and events experienced.

We had previously used a 10-year look-back study to compare the forecasted PSPS events impacts from the different PSPS Protocols. We are currently using the 4-year lookback because we consider the 4-year timeframe more representative of expected near-term future PSPS impacts for the purpose of establishing PSPS Protocols. In Tables PG&E-Remedy-21-29-4 and PG&E-Remedy-21-29-5 below, we provide a comparison of the quantitative targets due to the different PSPS Protocols and the mitigation initiatives adopted in the Revised 2021 WMP. We show both the 10-year and the 4-year lookbacks separately to show the variability caused by the weather can have among the scenarios and to tie the numbers back to those submitted in previous WMP submissions.

Quantitative Targets Assuming Decision Criteria Based on 2021 PSPS Protocols:

- Scope – Based on the lookback analysis, the average scope of each PSPS event decreased as a result 2021 PSP Protocols. When comparing the 2020 PSPS Protocols events to the 2021 PSPS Protocol, the average event size of the PSPS events was 34 percent smaller. The average event size was reduced due to the inclusion of machine learning for the FPI and IPW Models and HFRA[11] updates which resulted in scopes that further covered rural/less populated areas when compared to the 2020 PSPS Protocols. Incorporating Revised 2021 WMP mitigations will further decrease scope relative to 2020 PSPS Protocols, as shown in Table PG&E-Remedy-21-29-3.
- Duration – The average duration per event decreased as a result of the 2021 PSPS Protocols. When comparing the 2020 PSPS Protocols events to the 2021 PSPS Protocols the average duration of the PSPS events incorporating the 2021 PSPS

11 For more information about HFRAs, please see Revised 2021 WMP, pp. 85-89.

Protocols was 6 percent shorter. The average event duration decreased partly due to the different factors in the 2021 PSPS Protocols.

- Frequency – This 4-year look-back analysis resulted in the 2020 PSPS Protocols producing 18 total PSPS events from 2017 to 2020. Under the same lookback analysis, the 2021 PSPS criteria lookback analysis produced 19 events. Thus, the 2021 PSPS criteria increased the amount of PSPS events by 1, which represents a 6 percent increase in PSPS frequency over the 4-year look-back.

TABLE PG&E-REMEDY-21-29-3:
EVENT-LEVEL COMPARISON OF PSPS PROTOCOLS BASED ON A 4-YEAR LOOKBACK

	Event Frequency	Average Event Duration[(a)]	Average Event Customer Count	Largest Event Customer Count
2020 PSPS Protocols	4.5 events per year	39.6 hours	160 thousand customers	553 thousand customers
2021 PSPS Protocols	4.75 events per year	37.1 hours	105 thousand customers	530 thousand customers

Note: This analysis contains both PSPS transmission and distribution effects, which is different than the information shared with the Commission on August 31, 2021 which only included PSPS distribution impacts.

(a) Includes 10.7 hours of total of restoration and switching time.

In Table PG&E-Remedy-21-29-4 and Table PG&E-Remedy-21-29-5 below, we provide a systemwide comparison of the 2020 PSPS Protocols, 2020 PSPS Protocols with 2021 WMP mitigations and Tree Overstrike and Priority Tags, 2021 PSPS Protocols, and 2021 PSPS Protocols with 2021 WMP mitigations. The comparison is of the quantitative targets due to the different PSPS Protocols and the mitigation initiatives adopted in the Revised 2021 WMP. We show both the 10-year and the 4-year lookbacks separately to lay out a fair and logical comparison among the scenarios.

TABLE PG&E-REMEDY-21-29-4:
SYSTEMWIDE COMPARISON OF PSPS PROTOCOLS AND HOW THEY AFFECT PSPS SCOPE, DURATION, AND FREQUENCY BASED ON 4-YEAR LOOKBACK AND AVERAGE (2017-2020)

	Frequency (Events Per Year)	Scope (Thousands of Customers Impacted Per Year)	Duration (Millions of Customer Hours Per Year)
2020 PSPS Protocols[a]	4.50	1,147	54.9
2020 PSPS Protocols with 2021 Planned WMP Mitigations and with Tree Overstrike Inclusion and Priority Tags[b]	7.88	1,522	69.2
2021 PSPS Protocols	4.75	497	18.8
2021 PSPS Protocols with 2021 Planned WMP Mitigations	4.75	457	17.0

(a) 2021 Wildfire Mitigation Plan Report, February 5, 2021, Attachment 1 – All Data Tables Required by 2021 WMP Guidelines.
(b) 2021 Wildfire Mitigation Plan Report – Revised, June 3, 2021, Attachment 1 – All Data Tables Required by 2021 WMP Guidelines.

TABLE PG&E-REMEDY-21-29-5:
COMPARISON OF PSPS PROTOCOLS AND HOW THEY AFFECT PSPS SCOPE, DURATION, AND FREQUENCY BASED ON 10-YEAR LOOKBACK AND AVERAGE (2011-2020)

	Frequency (Events Per Year)[a]	Scope (Thousands of Customers Impacted Per Year)	Duration (Millions of Customer Hours Per Year)
2020 PSPS Protocols	2.94	566	25.9
2020 PSPS Protocols with 2021 Planned WMP Mitigations and with Tree Overstrike Inclusion and Priority Tags	5.11	844	36.9
2021 PSPS Protocols	2.91	204	7.4
2021 PSPS Protocols with 2021 Planned WMP Mitigations	2.91	187	6.7

(a) When using the 10-year lookback data set the average event count for the 2020 PSPS Protocols is higher than the 2021 PSPS protocols. The inverse is observed when comparing the 4-year lookback data sets, even with close results. The variance occurs because the 10-year lookback contains additional springtime PSPS events that meet the 2020 PSPS Protocols thresholds but do not meet the 2021 PSPS Protocols thresholds. We attribute the variance to the inclusion of a minimum requirement for Herbaceous live fuels in the 2021 PSPS Protocols model.

In order to describe the impacts of the Revised 2021 WMP mitigations and changes to 2021 PSPS protocols, we are providing as Attachment "2021WMP_OEISRemedy_PGE-21-29_Atch01" an update to Table 11 that compares PSPS forecasts based on the 2021 PSPS Protocols, and the 2021 PSPS Protocols with the 2021 WMP Planned mitigations. Please see 2021WMP_OEISRemedy_PGE-21-29_Atch01.

3. Effects of 2021 PSPS Protocols and Revised 2021 WMP Mitigations Relative to 2020 PSPS Protocols

Section 2 directly compared the 2020 and 2021 PSPS Protocols with the objective to show the expected impacts of updating our PSPS Protocols. As described in our Revised 2021 WMP, PG&E has also committed to expanding the reach of our PSPS mitigations, which is expected to further reduce the impacts of PSPS on our customers. This section illustrates the potential cumulative impacts of both the updated 2021 PSPS Protocols and 2021 WMP mitigations relative to 2020 PSPS Protocols with the goal to provide a more holistic view of the total change in PSPS impacts. Therefore, the reductions in PSPS scope and duration shown in Table PG&E-Remedy-21-29-6 are slightly larger in magnitude than those shown in the protocols-only comparison in Section 2 above.

With the updated 2021 PSPS Protocols, PG&E now estimates the following changes over the 2020 PSPS Protocols. To calculate the effects of the Revised 2021 WMP mitigations combined with 2021 PSPS Protocols we analyzed two years of PSPS events and identified which customers and circuits could have remained energized had the mitigations been in place. The Revised 2021 WMP mitigations would have resulted in the 2021 PSPS scope being reduced by 8 percent and duration by 2 percent when compared to the 2021 PSPS scope without WMP Mitigations. This analysis also indicated that the effects of the Revised 2021 WMP mitigations combined with 2021 PSPS Protocols would have reduced PSPS scope by 40 percent, duration by 8 percent, and increased frequency by 6 percent when compared to 2020 PSPS protocols without the Revised 2021 WMP mitigations. To illustrate the effect of our Revised 2021 WMP mitigations and the updated 2021 PSPS Protocols we have developed the following four scenarios:

- <u>Scenario 1</u> – Scenario 1 is based off the 2020 PSPS Protocols and our planned Revised 2021 WMP mitigations and is compared to our 2021 PSPS Protocols without the Revised 2021 WMP mitigations. The reductions were calculated based on 2020 PSPS Protocols and illustrate the effect of the planned mitigation, infrastructure and process work as outlined in Remedy 3.b, Remedy 4 and the workpapers attached as 2021 WMP_Revision_PGE_01_Atch01 in the Revised 2021 WMP.

- Scenario 2 – Scenario 2 illustrates the difference between our 2020 PSPS Protocols and our 2020 PSPS Protocols Plus Tree Overstrike Potential and Priority Tags. This scenario is also compared to our 2020 PSPS Protocols without Revised 2021 WMP mitigations. Note that the average event size and scope shrink as there are more comparatively small events with the added overstrike and priority tree criteria which brings the overall averages down while frequency of events increases.
- Scenario 3 – Scenario 3 illustrates the effects of the Revised 2021 WMP mitigations with our current 2020 PSPS Protocols Plus Tree Overstrike Potential and Priority Tags in comparison to the 2020 PSPS Protocols only and is compared to our 2021 PSPS Protocols without the Revised 2021 WMP mitigations. This forecast best estimates the expected scope of PSPS impacts as a result of our current PSPS protocols assuming all Revised 2021 WMP mitigations were completed.
- Scenario 4 – Scenario 4 illustrates the effects of the Revised 2021 WMP mitigations with our current 2021 PSPS Protocols and is compared to our 2021 PSPS Protocols without the Revised 2021 WMP mitigations. This forecast best estimates the expected scope of PSPS impacts as a result of our current PSPS protocols assuming all Revised 2021 WMP mitigations were completed.

TABLE PG&E-REMEDY-21-29-6:
SCENARIO ANALYSIS FOR REDUCTION IN PSPS SCOPE, DURATION, AND FREQUENCY AS A RESULT OF PLANNED 2021 PSPS MITIGATIONS WHEN COMPARED TO 2020 PSPS PROTOCOLS WITHOUT 2021 WMP MITIGATIONS AS A BASELINE

	Scenario 1:	Scenario 2	Scenario 3:	Scenario 4:
	2020 PSPS Protocols with 2021 WMP Mitigations	2020 PSPS Protocols Plus Overstrike Potential and Priority Tags in Comparison to 2020 PSPS Protocols[(a)]	2020 PSPS Protocols Plus Tree Overstrike Potential and Priority Tags and2021 WMP Mitigations in Comparison to our 2020 PSPS Protocols	2021 PSPS Protocols and 2021 WMP Mitigations
Average PSPS Scope per Event	8 percent Reduction	7 percent Reduction	14 percent Reduction	40 percent Reduction
Per-Customer Duration Per Event	2 percent Reduction	2 percent Reduction	4 percent Reduction	8 percent Reduction
Event Frequency	No Impact Relative to 2019 and 2020	74 percent Increase	74 percent Increase	6 percent Increase

(a) When compared to the 2020 PSPS Protocols, the scope and duration of the 2020 PSPS Protocols Plus Tree Overstrike and Priority Tags decrease, on average, as a result smaller size and shorter duration of the additional events.

The results displayed in Table PG&E-Remedy-21-29-6 show the Per-Customer Event duration decreasing by 8 percent as the PSPS events are forecasted to decrease duration.

In order provide the effects of the 2021 PSPS Protocols on mitigation initiatives we are providing as Attachment “2021WMP_OEISRemedy_PGE-21-29_Atch02” an updated version of the 2021 Revised WMP TABLE PG&E-REVISION NOTICE-8.3-1 to 8.3-3[12] with the estimated quantitative reductions to frequency, scope, and duration based on the current 2021 PSPS Protocols. Please see 2021WMP_OEISRemedy_PGE-21-29_Atch02.

4. 2021 PSPS Protocols Whitepaper

To provide additional information about our current 2021 PSPS Protocols, we are attached to this response to Remedy PG&E-21-29 a whitepaper we developed to

[12] Revised 2021 WMP, pp. 1003-1018.

explain the primary steps in our 2021 PSPS Protocols. Please see 2021WMP_OEISRemedy_PGE-21-29_Atch03.

5. Attachment List

- Attachment 1 – 2021WMP_OEISRemedy_PGE-21-29_Atch01
- Attachment 2 – 2021WMP_OEISRemedy_PGE-21-29_Atch02
- Attachment 3 – 2021WMP_OEISRemedy_PGE-21-29_Atch03

6. Change Order Report

In this section, we provide a Change Order Report consistent with the direction provided in Remedy PG&E-21-29 and using the Change Order Report outline provided in Office of Energy Infrastructure Safety's Final Action Statement issued September 22, 2021.

i. The proposed change

a. The initiative being altered with reference to where in the WMP the initiative is discussed

PG&E is proposing a Change Order to update its 2021 PSPS Protocols. The 2020 PSPS Protocols Plus Tree Overstrike Potential and Priority Tags were described on pages 979-982 of the Revised 2021 WMP. The 2021 PSPS protocols replace the 2020 PSPS Protocols Plus Tree Overstrike Potential and Priority Tags described in the Revised 2021 WMP. The 2021 PSPS Protocols are described in detail above in Sections 1-4 of this response to Remedy PG&E-21-29. This Change Order modifies and updates the following sections of the Revised 2021 WMP:

(1) Sections 8.2.2, 8.2.6, 8.2.7, and 8.2.9
(2) Table 11 - PSPS Projections
(3) Tables 8.3-1, 8.3-2, and 8.3-3 – PSPS Impact Mitigation Commitments

b. The planned budget of that initiative

PG&E does not expect the change of our PSPS Protocols to alter the planned financial budget projections for any of the mitigation initiatives included in the Revised WMP 2021. In addition, we are not proposing to update the planned budget for any initiative.

c. The type of change being proposed, reported as one of the following:

i. Increase in scale
ii. Decrease in scale

iii. Change in prioritization
iv. Change in deployment timing
v. Change in work being done
vi. Other change (described)

The expected impact from the 2021 PSPS Protocols on the PSPS scale (scope, duration, and frequency) can be seen in Table PG&E-Remedy-21-29-3 to Table PG&E-Remedy-21-29-5 above. PG&E deployed the 2021 PSPS Protocols (Distribution) in August 2021 and the 2021 PSPS Protocols (Transmission) in September 2021. The 2021 PSPS Protocols (Distribution and Transmission) were approved by the Wildfire Risk Governance Steering Committee in July 2021, and September 2021, respectively. We do not expect any changes in prioritization and work being done due to the update of the 2021 PSPS Protocols.

d. Detailed Description of The Proposed Change

Please refer to Section 1 above which describes in detail PG&E's 2021 PSPS Protocols.

ii. Justification for the Proposed Change

We are proposing to change the PSPS Protocols to more accurately forecast catastrophic wildfire risk based on the most up to date resources we have developed. PG&E's PSPS decision-making models and protocols have evolved since the PSPS program inception in 2018. After each PSPS season, we evaluate the lessons learned from the previous season and worked to improve the input data sets and weather prediction, as well as to test new models to inform better when PSPS should be applied.

a. In what way, if any, does the change address or improve:

i. Completeness
ii. Technical feasibility of the initiative
iii. Effectiveness of the initiative
iv. Resource use efficiency over portfolio of WMP initiatives

We do not expect the update to our 2021 PSPS Protocols to modify the completeness, technical feasibility, or resource use efficiency over the portfolio of WMP initiatives. In terms of effectiveness, our 2021 PSPS Protocols are more granular, and we expect them to be more accurate at capturing wildfire risk. Please see Sections 1-3 above for more details concerning the potential impact on PSPS events as a result of using the 2021 PSPS Protocols.

iii. Change in expected outcomes from the proposed change

a. What outcomes, including quantitative ignition probability and PSPS risk reduction, was the changed initiative expected to achieve in the 2021 WMP Update?

The update to the 2021 PSPS Protocols is expected to improve our effectiveness in capturing wildfire risk and reduce customer impacts. Please see Section 3 above for more details.

b. What outcomes, including quantitative ignition probability and PSPS risk reduction, will the initiative deliver with the proposed adjustment?

We expect the updated 2021 PSPS Protocols to be more accurate at capturing wildfire risk. For the impact of the 2021 PSPS Protocols on frequency, scope and duration of events please see Sections 2 and 3 above.

Advice 6486-E
January 31, 2022

Attachment 2

January 31, 2022 Supplemental Testimony in A.21-06-022 – Substation Safety Information

Application: 21-06-022
(U 39 E)
Exhibit No.: ____________________
Date: January 31, 2022
Witness(es): Mark Esguerra

PACIFIC GAS AND ELECTRIC COMPANY

LONG-TERM PROCUREMENT FRAMEWORK FOR GENERATION TO MITIGATE PUBLIC SAFETY POWER SHUTOFFS – SUBSTATION SAFETY INFORMATION

SUPPLEMENTAL TESTIMONY

PACIFIC GAS AND ELECTRIC COMPANY
LONG-TERM PROCUREMENT FRAMEWORK FOR GENERATION TO MITIGATE PUBLIC SAFETY POWER SHUTOFFS –
SUBSTATION SAFETY INFORMATION
SUPPLEMENTAL TESTIMONY

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PACIFIC GAS AND ELECTRIC COMPANY
LONG-TERM PROCUREMENT FRAMEWORK FOR GENERATION TO MITIGATE PUBLIC SAFETY POWER SHUTOFFS – SUBSTATION SAFETY INFORMATION SUPPLEMENTAL TESTIMONY

A. Introduction

The purpose of this testimony is to provide supplemental "Substation Safety Information" (SSI) for the record of this proceeding, as more specifically described below.

1. Procedural Background and Context

Administrative Law Judge (ALJ) Colin Rizzo's December 14, 2021 E-Mail Ruling Directing PG&E, Public Advocates Office at the California Public Utilities Commission (Cal Advocates), and Parties of Record, to Meet And Confer Regarding Submittal of Pacific Gas and Electric Company (PG&E) SSI (the "ALJ Ruling") in this Proceeding directed parties to meet and confer regarding the following matters:

- How and when PG&E will provide SSI, including a list of substations where Public Safety Power Shutoff (PSPS) outages are expected to remain unmitigated;
- How, when, and to what extent PG&E will provide additional SSI beyond what is discussed in PG&E's December 17, 2021, supplemental testimony; and
- How and when intervenors will have an opportunity to use PG&E's SSI to submit initial and reply testimony.

The ALJ Ruling was in response to the motion filed on October 20, 2021, by Cal Advocates seeking clarification of the Assigned Commissioner's Scoping Memo and Ruling (Scoping Memo). Cal Advocates had asserted that the Scoping Memo was not sufficiently clear about production of "SSI" and intervenors' opportunity to review and use it. PG&E disputed Cal Advocates' assertion in a response filed on November 2, 2021, and Cal Advocates disputed PG&E's response in a reply filed on November 17, 2021.

Following the parties' meet-and-confer on these issues, several parties filed a Joint Case Management Statement on January 13, 2022 describing the proposed scope and timing of additional PG&E SSI Testimony. That Joint Case Management Statement described the scope of the proposed SSI Testimony as follows:[1]

> [PG&E will] present a hypothetical alternatives analysis (PG&E's Proposed Analysis), using the methodology presented in Chapter 3 of PG&E's Opening Testimony, in order to further illustrate how its proposed Long-Term Procurement (LTP) Framework for substation microgrids would be implemented. Specifically, PG&E proposes to focus on the Bangor Substation, the only substation which meets the criteria in Chapter 2 of PG&E's Opening Testimony for substation microgrid eligibility, and to conduct and present in testimony the following additional information:
>
> Step 1: PG&E will identify any committed and planned grid investment projects that are already identified in other distribution- and transmission-planning proceedings (e.g., PG&E's Wildfire Mitigation Plan, PG&E's General Rate Case, California Independent System Operator's Transmission Planning Process) that have a reasonable degree of certainty that they will be carried out (e.g., included in PG&E's five-year investment plan) and are likely to have a material impact on PSPS risk at the Bangor Substation. In addition to investment projects, PG&E may also consider future operational improvements that can utilize existing assets to meaningfully reduce PSPS risk at the Bangor Substation. This will result in a set of planning scenarios across the 3-year, 5-year, and 10-year periods.[2]
>
> Step 2: For each of the planning scenarios identified in Step 1, PG&E proposes to create a new 10-Year Lookback dataset (using the 10-Year Lookback process described in Chapter 2 of PG&E's Opening Testimony) for Bangor, and then to identify whether Bangor Substation remains a candidate for a substation microgrid in any time period using the prioritization criteria discussed in Chapter 2.[3]
>
> Step 3: To the extent Bangor Substation is identified in Step 2 as continuing to have a residual unmitigated PSPS risk (i.e., continues to show 10+ impacts each involving 100+ safe-to-energize customers in the modeling despite planned work and operational improvements) in any time period studied, PG&E will identify whether there are PSPS mitigation alternatives in that time period, whether grid-based or generation-based, that are not currently included in PG&E's investment

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[1] Joint Case Management Statement filed January 13, 2022, pp. 5-7.

[2] PG&E Opening Testimony, Ch. 3, p. 3-7, lines 4-11; *id.*, p. 3-8, lines 7-16.

[3] *Id.*, p. 3-8, lines 17-28.

plan that would be feasible and could more cost-effectively address PSPS risk than a substation-level microgrid.[4]

The scope and schedule presented in the Joint Case Management Statement was adopted by ALJ Rizzo in an E-Mail Ruling issued on January 18, 2022. Accordingly, this SSI Supplemental Testimony provides the additional SSI based on the scope described in the Joint Case Management Statement.

2. Summary of Supplemental SSI Testimony

This exhibit provides a hypothetical example, for illustrative purposes, showing the result of PG&E's proposed LTP Framework for substation microgrid solutions if implemented as of January 2022, based upon the most recent[5] vintage of the 10-Year Historic Lookback Data.[6] Specifically, the purpose of this testimony is to identify any candidate substations at which a substation-level microgrid solution is the preferred alternative to mitigate PSPS risk. For each such substation, PG&E's analysis also identifies the duration of the mitigation need at the substation through the examination of 3-, 5-, and 10-year scenarios.[7] The results of this analysis are the following:

- Bangor Substation is the only current candidate substation for PSPS mitigation based upon the eligibility criteria set forth in PG&E's Opening Testimony;
- Step 1: PG&E identified planned work in the 3-, 5-, and 10-year timeframes, including operational improvements, that are likely to be implemented and would significantly impact the likelihood of de-energization of Bangor Substation in future PSPS events;
- Step 2: PG&E analyzed the likelihood of de-energization at Bangor Substation under each of the 3-, 5-, and 10-year planning scenarios after implementation of the planned work and determined that Bangor

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4 *Id.*, pp. 3-8 to 3-9.

5 The most recent vintage of the 10-Year Historic Lookback is the 2021 update presented in PG&E's December 17, 2021 Supplemental Testimony.

6 The 10-Year Historic Lookback methodology is more fully described in Chapter 2 of PG&E's Opening Testimony and in PG&E's December 17, 2021 Supplemental Testimony.

7 PG&E Opening Testimony, Ch. 3, p. 3-9, lines 17-21.

Substation no longer meets the criteria for needing additional PSPS mitigation after that planned work has been done; and

- Step 3: Step 3 was unnecessary in this alternatives analysis because planned work addressed the only candidate substation for a substation microgrid.

Based on this analysis, PG&E finds that its proposed LTP Framework would not result in the need for a substation microgrid solution at this time. In other words, since there are no substation locations with residual unmitigated PSPS risk for the purpose of Substation Microgrid investment planning, PG&E's plan is to not pursue any Substation Microgrid investments at this time and to re-assess the need for such investment when an updated lookback dataset becomes available, assuming PG&E's proposed LTP Framework is approved.

B. Candidate Substation(s) Identified Using the 2021-Vintage 10-Year Historic Lookback Dataset

As summarized in the introduction, using the most recent, 2021 vintage of the 10-Year Historic Lookback Data, PG&E found that the Bangor Substation is the only substation location that exceeded the screening threshold of 10+ impacts each involving 100+ safe-to-energize customers.[8] Thus, PG&E would apply the proposed alternatives analysis at the Bangor substation to further assess and quantify its unmitigated PSPS risks, if any.

1. Characteristics of Bangor Substation

Bangor substation locates in Butte County and serves approximately 2,000 distribution customers. It is electrically connected to the Palermo-Colgate 60 kilovolt (kV) line, which traverses between the Palermo and the Colgate Substations (located at the northwest and southeast ends of the line, respectively). Geographically, Bangor lies between the Palermo and Colgate substations.

Bangor substation can be energized by electricity flow from either the Colgate/Bangor or Palermo/Bangor section of the Palermo-Colgate 60 kV

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8 As detailed further below, the 10-year lookback dataset identified 12 potential PSPS events, each impacting more than 100 safe-to-energize customers at the Bangor Substation.

line. This ability to utilize alternate energy source is gained from the existing installation of two transmission line switches, located on each end of the Bangor Substation. In simple terms, these switches can be utilized to split the Palermo-Colgate line into two sections: one connecting Bangor to Palermo, another connecting Bangor to Colgate.[9]

Due to operational and reliability considerations, the Bangor Substation is normally energized by the Colgate/Bangor section of the line. This normal operational configuration of the Bangor substation is achieved by closing the transmission line switch on the Colgate side of the line and opening the transmission line switch on the Palermo side of the line. These normal configurations (at Bangor and at other substations on the PG&E grid) are captured in PG&E's transmission planning study base case, upon which PG&E's transmission PSPS lookback study is performed.[10]

As summarized in its December 17, 2021 supplemental filing, PG&E's 2021 lookback study identified 12 potential PSPS events—all due to directly impacted line section(s)—at the Bangor Substation. Table 1-1 below details the specific line section(s) that are de-energized for each simulated PSPS event.

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9 Transmission lines switches thus installed provide various operational and reliability benefits. For example, in the context of PSPS mitigation, switches can be utilized to isolate specific sections of the line that may require de-energization due to exceeding the transmission PSPS scoping criteria, while allowing the opportunity to keep other sections of the line, that may not exceed the criteria, energized in order to minimize impact to customers.

10 Base case refers to the default set of grid data and input assumptions used in a power flow analysis. As part of the transmission PSPS lookback development process, PG&E performs transmission power flow analysis that identifies the Substations to be de-energized due to either Direct or Indirect impact (see Chapter 2 of PG&E's opening testimony for additional details of the PSPS lookback development process).

TABLE 1-1
LIST OF MODELED PSPS EVENTS (PRIOR TO APPLYING THE ALTERNATIVES ANALYSIS)

Event ID	PSPS Event Name	Reason for PSPS De-energization
1	10/1/2017	Direct impact on Colgate/Bangor section of line
2	10/8/2017	Direct impact on Colgate/Bangor and Palermo/Bangor sections of line
3	10/13/2018	Direct impact on Colgate/Bangor section of line
4	11/7/2018	Direct impact on Colgate/Bangor section of line
5	11/10/2018	Direct impact on Colgate/Bangor section of line
6	10/9/2019	Direct impact on Colgate/Bangor section of line
7	10/23/2019	Direct impact on Colgate/Bangor section of line
8	10/26/2019	Direct impact on Colgate/Bangor and Palermo/Bangor sections of line
9	10/29/2019	Direct impact on Colgate/Bangor and Palermo/Bangor sections of line
10	9/7/2020	Direct impact on Colgate/Bangor and Palermo/Bangor sections of line
11	9/27/2020	Direct impact on Colgate/Bangor section of line
12	10/25/2020	Direct impact on Colgate/Bangor and Palermo/Bangor sections of line

As further discussed in the subsequent section, as part of the alternative analysis, PG&E studied the ability to alter Bangor substation's normal configuration—to use instead the Palermo/Bangor section to energize the substation—as a potential mitigation solution.

C. Alternatives Analysis

In this section, PG&E describes how it applied the proposed alternative analysis framework as described in Chapter 3 of PG&E's testimony for the Bangor substation.

Step 1: Incorporate Planned Grid Investments Into Planning Scenarios

In this step, PG&E examined whether planned work or operational changes could reduce the projected PSPS impact at Bangor over the 3-, 5-, and 10-year planning horizons.

In terms of planned investments, PG&E surveyed planned projects in the areas of vegetation management, reliability enhancements, and capacity expansion and found that other than routine maintenance and repair work, there are no planned grid investment projects at this time for the Palermo-Colgate 60 kV transmission line.

In terms of operational improvements or operational flexibility, however, PG&E identified a potential, operational mitigation solution. Specifically, given the availability of an alternate energy source at Bangor discussed in the prior section, PG&E identified the possibility of energizing the Bangor Substation by switching to the normally opened Palermo/Bangor section of the transmission line during a projected PSPS event.

PG&E's assessment of the feasibility and impact of this potential mitigation solution is discussed in Step 2 below.

Step 2: Develop Lookback Dataset and Identify Remaining Candidate Substations for Generation-Based Solutions Over Various Time Horizons

In this step, PG&E assessed the feasibility and impact of the identified solution over the 3-, 5-, and 10-year planning horizon. In the case of Bangor, given that the identified solution—implementing an operational change—is available across each of the 3-, 5-, and 10-year planning horizons, PG&E only had to develop one planning scenario to quantify the mitigation impact. PG&E performed this assessment in two steps.

First, PG&E examined the 12 transmission PSPS events captured in the original 2021 lookback dataset to determine the number of events, if any, where switching Bangor to the alternate energy source from the Palermo/Bangor section of the line could keep Bangor energized. PG&E determined this option is conceptually possible in 7 out of the 12 events.[11]

Next, PG&E conducted transmission power flow sensitivity analysis for each of the 7 potential PSPS events to assess the grid reliability impact of switching Bangor to the alternate source.[12] Specifically, PG&E wanted to ensure that this alternate configuration does not introduce reliability impact elsewhere on the electric system. The results of these power flow analysis—summarized in Table 1-2 below—showed that in all 7 instances, switching Bangor to the Palermo/Bangor section of the line poses no additional reliability risk.[13]

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11 See Table 1-1 which shows that in 7 out of the 12 events, only the Colgate/Bangor section of the line is in PSPS scope, whereas in the other 5 events, both sections of the line are in scope.

12 This is performed by modifying the power flow base case with the proposed mitigation solution (i.e., switching to the normally opened Palermo/Bangor section of the transmission line during each identified PSPS event).

13 In other words, these power flow simulations prove the feasibility of this operational approach.

TABLE 1-2
ASSESSMENT OF PROPOSED MITIGATION SOLUTION BY MODELED PSPS EVENT

Event ID	PSPS Event Name	Proposed mitigation solution effective and feasible?
1	10/1/2017	YES
2	10/8/2017	NO
3	10/13/2018	YES
4	11/7/2018	YES
5	11/10/2018	YES
6	10/9/2019	YES
7	10/23/2019	YES
8	10/26/2019	NO
9	10/29/2019	NO
10	9/7/2020	NO
11	9/27/2020	YES
12	10/25/2020	NO

Thus, PG&E concludes that the operational mitigation solution identified in Step 1 would reduce the projected transmission PSPS impact at the Bangor Substation from 12 to 5 events over the 10-year lookback period.

Given this result, PG&E found that there are no longer any substations that would meet PG&E's substation microgrid PSPS mitigation prioritization criteria, and determined that Step 3 of its alternatives analysis framework—in which PG&E would identify any unplanned wires-related work that might further mitigate the impact of PSPS events at Bangor Substation and compare the cost and effectiveness of that additional work, if any, against the use of a substation microgrid solution—is unnecessary for this planning cycle.

D. Additional Information

This section addresses certain points included in the Joint Case Management Statement filed on January 13, 2022.

1. Explanation of PG&E Criteria and Selection of Bangor Substation

This section explains how PG&E's proposed criteria to identify candidate substations for substation microgrid solutions and its initial selection of Bangor Substation as a candidate for further study satisfy the requirements of Decision (D.) 21-01-018.

Although I am not a legal expert, I have been advised and believe it to be true that the Microgrid Order Instituting Rulemaking Track 2 Decision, D.21-01-018, requires that PG&E's Long-Term Framework for Substation Microgrid Solutions generally identify and provide information about substation locations that will remain unmitigated (and thus subject to potential public safety power shutoffs) due to lack of cost-effective and feasible wires solutions. PG&E has proposed criteria in its Opening Testimony to establish the universe of substations that would be considered "unmitigated" if, following the consideration of any planned work, the application of any available operational flexibility, and the consideration of any other cost-effective but unplanned mitigation options, the substation is modeled in PG&E's 10-Year Lookback as remaining subject to the specified number of de-energization events. PG&E has followed that methodology in this SSI Testimony and has determined that, based on its current 10-Year Lookback Dataset and its proposed criteria, none of its substations remains unmitigated. Accordingly, I believe PG&E's testimony addresses the requirements of D.21-01-018.

Similarly, the sections described above and PG&E's December 17, 2021 Supplemental Testimony describe how the revised 10-Year Lookback in combination with the criteria set forth in PG&E's Opening Testimony resulted in the selection of Bangor Substation as the only current candidate for further consideration of a substation microgrid solution.

2. Identification of Substation Selected

This testimony identifies Bangor Substation as the only candidate substation for a substation microgrid solution to mitigate PSPS outages pursuant to a "snapshot in time" application of PG&E's proposed LTP Framework. No other substation currently falls within the scope of its Application with regard to eligibility for a substation microgrid for PSPS mitigation.

PG&E Gas and Electric
Advice Submittal List
General Order 96-B, Section IV

AT&T
Albion Power Company

Alta Power Group, LLC
Anderson & Poole

Atlas ReFuel
BART

Barkovich & Yap, Inc.
California Cotton Ginners & Growers Assn
California Energy Commission

California Hub for Energy Efficiency Financing

California Alternative Energy and Advanced Transportation Financing Authority
California Public Utilities Commission
Calpine

Cameron-Daniel, P.C.
Casner, Steve
Center for Biological Diversity

Chevron Pipeline and Power
City of Palo Alto

City of San Jose
Clean Power Research
Coast Economic Consulting
Commercial Energy
Crossborder Energy
Crown Road Energy, LLC
Davis Wright Tremaine LLP
Day Carter Murphy

Dept of General Services
Don Pickett & Associates, Inc.
Douglass & Liddell

East Bay Community Energy Ellison Schneider & Harris LLP Energy Management Service
Engineers and Scientists of California

GenOn Energy, Inc.
Goodin, MacBride, Squeri, Schlotz & Ritchie
Green Power Institute
Hanna & Morton
ICF
International Power Technology

Intertie

Intestate Gas Services, Inc.
Kelly Group
Ken Bohn Consulting
Keyes & Fox LLP
Leviton Manufacturing Co., Inc.

Los Angeles County Integrated Waste Management Task Force
MRW & Associates
Manatt Phelps Phillips
Marin Energy Authority
McKenzie & Associates

Modesto Irrigation District
NLine Energy, Inc.
NRG Solar

OnGrid Solar
Pacific Gas and Electric Company
Peninsula Clean Energy

Pioneer Community Energy

Public Advocates Office

Redwood Coast Energy Authority
Regulatory & Cogeneration Service, Inc.
SCD Energy Solutions
San Diego Gas & Electric Company

SPURR
San Francisco Water Power and Sewer
Sempra Utilities

Sierra Telephone Company, Inc.
Southern California Edison Company
Southern California Gas Company
Spark Energy
Sun Light & Power
Sunshine Design
Tecogen, Inc.
TerraVerde Renewable Partners
Tiger Natural Gas, Inc.

TransCanada
Utility Cost Management
Utility Power Solutions
Water and Energy Consulting Wellhead Electric Company
Western Manufactured Housing Communities Association (WMA)
Yep Energy