STATE OF CALIFORNIA GAVIN NEWSOM

PUBLIC UTILITIES COMMISSION

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FILED
11/13/26
02:35 PM
A2511001

November 13, 2026

Agenda ID #24645
Catastrophic Wildfire

TO PARTIES OF RECORD IN APPLICATION 25-11-001:

This is the proposed decision of Commissioner Matthew Baker. Until and unless the Commission hears the item and votes to approve it, the proposed decision has no legal effect. This item may be heard, at the earliest, at the Commission's **December 17, 2026** Business Meeting. To confirm when the item will be heard, please see the Business Meeting agenda, which is posted on the Commission's website 10 days before each Business Meeting.

Parties of record may file comments on the proposed decision as provided in Rule 14.3 of the Commission's Rules of Practice and Procedure.

/s/ MICHELLE COOKE
Michelle Cooke
Chief Administrative Law Judge

MLC: smt

Attachment

COM/MBK/smt

Agenda ID #24645
Catastrophic Wildfire

Decision **PROPOSED DECISION OF COMMISSIONER MATTHEW BAKER**
(Mailed 11/13/2026)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Review and Recovery of Costs Associated with the 2019 Kincade Fire and 2021 Dixie Fire under AB 1054.	Application 25-11-001 (Filed November 14, 2025)

DECISION AUTHORIZING PACIFIC GAS AND ELECTRIC COMPANY TO RECOVER COSTS ASSOCIATED WITH THE 2019 KINCADE FIRE AND 2021 DIXIE FIRE RECORDED IN PACIFIC GAS AND ELECTRIC COMPANY'S WILDFIRE EXPENSE MEMORANDUM ACCOUNT AND CATASTROPHIC EVENT MEMORANDUM ACCOUNT

TABLE OF CONTENTS

Title **Page**

DECISION AUTHORIZING PACIFIC GAS AND ELECTRIC COMPANY TO RECOVER COSTS ASSOCIATED WITH THE 2019 KINCADE FIRE AND 2021 DIXIE FIRE RECORDED IN PACIFIC GAS AND ELECTRIC COMPANY'S WILDFIRE EXPENSE MEMORANDUM ACCOUNT AND CATASTROPHIC EVENT MEMORANDUM ACCOUNT……1
Summary……2
1. Table of Acronyms……5
2. Factual Background……6
2.1. PG&E's Service Area and Operation……6
2.2. The Kincade Fire……9
2.3. The Dixie Fire……10
2.4. Cost Recovery and the Wildfire Fund……12
3. Procedural Background……13
3.1. Submission Date……16
4. Scoped Issues Before the Commission……16
5. The New Reasonableness Legal Standard and the Rules of Statutory Interpretation……17
5.1. Valid Safety Certification……20
5.2. Serious Doubt……21
6. The Parties Have Failed to Raise a Serious Doubt as to the Reasonableness of PG&E's Conduct Regarding the Dixie Fire (Scoping Memo Issue 2)……25
6.1. De-energization of the Entire Circuit Earlier in the Day……25
6.1.1. Cal Advocates……25
6.1.2. Discussion……29
6.2. Non-Differentiated High Fire Threat District Outage Response……34
6.2.1. Cal Advocates……34
6.2.2. Discussion……36
7. The Parties Have Failed to Raise a Serious Doubt as to the Reasonableness of PG&E's Conduct Regarding the Kincade Fire (Scoping Memo Issue 1)……38
7.1. Design and Maintenance of the Geysers #9 Line Jumper……38
7.1.1. Cal Advocates……38
7.1.2. Discussion……39
7.1.2.1. Maintenance of the Jumper in a Non-Standard Configuration……39
7.1.2.2. Design Versus Engineering Criteria for Evaluating the Jumper……44
7.1.2.3. Jumper Inspections……49

TABLE OF CONTENTS

Title **Page**

7.1.2.4. PG&E's Determination Not to De-Energize the Last Three Spans of the Geysers #9 Line 51
7.2. PG&E's Idle Facilities Management Process 55
7.2.1. Cal Advocates 55
7.2.2. Discussion 58
7.3. PG&E's Public Safety Power Shutoff Program 63
7.3.1. Cal Advocates 63
7.3.2. Discussion 66
8. Factors Beyond PG&E's Control Exacerbating the Costs and Expenses Attributable to Both the Dixie and Kincade Fires (Scoping Memo Issues 3, 4, 12, and 13) 68
9. PG&E's Recorded WEMA Costs for the Kincade and Dixie Fires (Scoping Memo Issues 5, 6, 7, and 8) 68
9.1. Settlement Costs 69
9.2. Litigation Costs 70
10. PG&E's Recorded CEMA Costs for the Kincade and Dixie Fires (Scoping Issues 9, 10, and 11) 72
11. PG&E's Cost Recovery Proposals (Scoping Memo Issue 14) 74
11.1. Cost Recovery Proposals 74
11.2. Trailing Costs 76
12. Summary of Public Comment 77
13. Procedural Matters 78
14. Comments on Proposed Decision 78
15. Assignment of Proceeding 79
Findings of Fact 79
Conclusions of Law 85
O R D E R 87

DECISION AUTHORIZING PACIFIC GAS AND ELECTRIC COMPANY TO RECOVER COSTS ASSOCIATED WITH THE 2019 KINCADE FIRE AND 2021 DIXIE FIRE RECORDED IN PACIFIC GAS AND ELECTRIC COMPANY'S WILDFIRE EXPENSE MEMORANDUM ACCOUNT AND CATASTROPHIC EVENT MEMORANDUM ACCOUNT

Summary

This decision grants Pacific Gas and Electric Company's (PG&E) request to recover costs associated with the 2019 Kincade Fire and 2021 Dixie Fire that were recorded in PG&E's Wildfire Expense Memorandum Account (WEMA) and Catastrophic Event Memorandum Account (CEMA). This decision reaches its conclusion on the grounds that at the time of the two subject fires, PG&E had a valid safety certification that was issued in accordance with Public Utilities (Pub. Util.) Code Section 8389. As such, pursuant to Pub. Util. Code Section 451.1(c), PG&E's conduct related to the ignition of the Kincade and Dixie Fires is presumed to have been reasonable (or prudent), and no party to the proceeding has created a serious doubt as to the reasonableness of PG&E's conduct leading up to the fires. Instead, intervening parties have presented differences of opinion as to the reasonableness of PG&E's conduct, without any showing that (1) PG&E violated any law, Commission standards regarding reasonableness, or applicable industry standards; or (2) another electrical corporation would have acted any differently under similar circumstances.

We summarize the reasons for this outcome below.

The Dixie Fire

First, the record demonstrates that the available evidence known to PG&E on the day of the fire indicated that the outage on the Bucks Creek 1101 circuit was routine, looked normal and, therefore, did not justify de-energizing the line until after the PG&E troubleshooter arrived on the scene later in the day and

conducted an assessment. Second, PG&E's procedures for the treatment of outages applied across its service areas, including in High-Fire Threat Districts (HFTD), determined PG&E's outage response based on the type and circumstances of the outage. As there was no indication of an emergency or safety hazard prior to the troubleshooter's arrival, PG&E's procedures did not require the circuit's de-energization. The evidence intervenors presented does not raise a serious doubt regarding PG&E's conduct and therefore the presumption of reasonableness applies.

The specific breakdown of the amounts for the Dixie Fire that PG&E is authorized to recover is as follows:

Approximately $511 million in PG&E's WEMA as of July 31, 2026, net of insurance and Wildfire Fund payments, to resolve third-party claims including claims filed by individual plaintiffs subrogated insurers, and public entities.

Approximately $155 million in costs recorded in PG&E's WEMA as of July 31, 2026, to defend and resolve claims including costs for outside counsel, mediations, experts and consultants, e-discovery, and other litigation costs.

Kincade Fire

First, the record demonstrates that PG&E constructed, inspected, and maintained the subject tower consistent with industry standards and PG&E's policies. Second, PG&E's execution of its idle facilities standard with respect to the last three spans of the Geysers #9 Line does not create a serious doubt based on the evidentiary standards set forth below. Third, PG&E's expanded Public Safety Power Shutoff program included all transmission lines traversing Tier 2 and Tier 3 HFTD to address transmission-line wildfire ignition risks through de-energization. The evidence intervenors presented does not raise a serious doubt

regarding PG&E's conduct and therefore the presumption of reasonableness applies.

The specific breakdown of the amounts for the Kincade Fire that PG&E is authorized to recover is as follows:

Approximately $713 million in costs recorded in PG&E's WEMA as of July 31, 2026, net of insurance and Wildfire Fund payments, to resolve third-party claims including claims filed by individual plaintiffs, subrogated insurers, and public entities.

Approximately $70 million in costs recorded in PG&E's WEMA as of July 31, 2026, to defend and resolve claims including costs for outside counsel, mediations, experts and consultants, e-discovery, and other litigation costs.

Costs Related to Both the Kincade and Dixie Fires

PG&E is authorized to recover the following costs:

Capital costs: approximately $83 million recorded in PG&E's CEMA as of June 30, 2026, that PG&E incurred to restore service to customers and to repair or replace damaged facilities.

Operation and maintenance costs: $245 million recorded in PG&E's CEMA as of June 30, 2026, that PG&E incurred to restore service to customers and to repair or replace damaged facilities.

Revenue requirements: capital revenue requirement of approximately $73 million and operation and maintenance (O&M) revenue requirement of approximately $300 million.

Additional Relief

This decision also grants PG&E's request that it need not reimburse the Wildfire Fund for claims costs paid or eligible to be paid by the Wildfire Fund related to the Kincade and Dixie Fires, with approximately $1.1 billion in

payments received from the Wildfire Fund as of July 31, 2026 (including $127,725,000 million for the Kincade Fire and $1.035 billion for the Dixie Fire).

PG&E is authorized to implement its cost recovery proposals for approved costs recorded in its CEMA and WEMA-Gas, with approved costs recorded in PG&E's WEMA-Electric to be the subject of a future securitization application.

Finally, this decision approves PG&E's proposals for updating and recovering its WMEA and CEMA costs related to the Kincade and Dixie Fires that were not included in PGE-06, PG&E's August 13, 2026, update of WEMA and CEMA costs.

This proceeding is closed.

1. Table of Acronyms

ACO (Administrative Consent Order)

ATS (Applied Technology Services)

CAISO (California Independent System Operator)

CEMA (Catastrophic Event Memorandum Account)

DCC (Distribution Control Centers)

ETGIS (Electric Transmission Geographic Information System)

EVM (Enhanced Vegetation Management)

GCC (Transmission Grid Control Centers)

HFTD (High-Fire Threat Districts)

O&M (Operation and Maintenance)

PSPS (Public Safety Power Shutoff)

SCADA (Supervisory Control and Data Acquisition)

SED (Safety Enforcement Division)

TLAS (Transmission Line Asset Strategy)

WEMA (Wildfire Expense Memorandum Account)

WMP (Wildfire Mitigation Plan)

WSIP (Wildfire Safety Inspection Program)

2. Factual Background

2.1. PG&E's Service Area and Operation

PG&E is the largest combined natural gas and electric utility in the United States and in California.[1] PG&E's service area covers more than 70,000 square miles across 47 of California's 58 counties.[2] PG&E operates approximately 81,000 circuit miles of overhead electric distribution lines and 18,000 circuit miles of overhead electric transmission lines across a diverse service area, from coastal areas to the Sierra Nevada to large cities.[3]

PG&E states that the wildfire risk profile of PG&E's service area has increased over the last decade.[4] The interim fire-threat map adopted by the Commission in 2012 designated less than 15% of PG&E's service area in the highest categories of wildfire risk (Threat Levels 3 and 4).[5] Yet the Commission's final fire-threat map adopted in 2018 designated more than half of PG&E's service area as high fire risk (Tier 2 and 3 HFTD), representing a 300% increase. Nearly one-third of PG&E's electrical system—over 25,000 miles of overhead distribution lines and 5,500 miles of overhead transmission lines—are in HFTDs.[6]

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[1] PGE-01, at 2-3:8–9 (opening testimony of A. Abranches).

[2] *Id.* at 2-3:9–10.

[3] *Id.* at 2-3:11–17.

[4] *Id.* at 2-1:17–20.

[5] *Id.* at 2-1:14–17; *see also id.* at 2-3:22 to 2-4:1 (discussing the Commission's adoption of interim and final fire-threat maps).

[6] *Id.* at 2-5:1–4 (opening testimony of A. Abranches); and pp.2-3:22 to 2-4:1 (discussing the Commission's adoption of interim and final fire-threat maps).

In PG&E's view, the destructive wildfire seasons of 2017 and 2018 illustrated this evolving wildfire-risk landscape and highlighted the role of climate change in intensifying wildfire risk.[7] PG&E expanded and strengthened its wildfire mitigation measures in response.[8] Beginning in 2019 and thereafter, PG&E submitted a Wildfire Mitigation Plan (WMP) update for each approval year describing the policies and programs it was implementing to mitigate the risk of ignitions in its service area.[9] The Office of Energy Infrastructure Safety (Energy Safety) reviewed and approved these plans,[10] and the Commission ratified them by resolution.[11] The approval of PG&E's WMP was a prerequisite to receiving the safety certification described in Section 451.1(c).[12]

Prior to the Kincade and Dixie Fires, PG&E claims that it was executing on the following design and construction, and system operation policies and programs to mitigate the increased wildfire risk in its service area:[13]

Design and Construction. PG&E states that it designed and constructed its electric distribution and transmission facilities in accordance with the Commission's regulatory requirements for overhead powerlines under General

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[7] *Id.* at 2-6:6–14.

[8] *Id.* at 2-6:6–32.

[9] *Id.* at 2-2:10–28; *id.* at p. 1-3:13–22 (opening testimony of S. Singh).

[10] *Id.* at1-24:5–15 (opening testimony of S. Singh). In 2019 (via AB 1054), the Legislature created the Wildfire Safety Division (WSD) within the Commission and gave the WSD authority to review and approve WMPs. *Id.* at 1-3 n.13. In July 2021, Energy Safety was established as a new state department to review and audit compliance with WMPs. *Id.* PG&E uses "Energy Safety" to refer to WSD and/or Energy Safety, depending on the relevant time frame. *See* Gov. Code § 15475; Pub. Util. Code § 8389.

[11] PGE-01, at 1-28:9–11 (opening testimony of S. Singh).

[12] *Id.* at 2-1:25–28 (opening testimony of A. Abranches).

[13] *Id.* at 1-27:4–7 (opening testimony of S. Singh).

Order 95.[14] PG&E states it also used risk modeling to prioritize system-hardening efforts for distribution facilities in HFTDs,[15] and utilized protection devices to detect and isolate faults or other abnormal conditions on the system and de-energize the affected portions of the line.[16]

Inspection and Maintenance. PG&E states it implemented asset inspection programs, including the Wildfire Safety Inspection Program (WSIP), ground inspections, climbing inspections, drone inspections, patrol inspections, and pole inspections. PG&E says it also maintained a vegetation management program through regular patrols, pruning, and removal of vegetation in proximity to electrical infrastructure across its service area.[17] PG&E periodically reviewed and audited its performance under these inspection and maintenance programs.[18]

System Operation. PG&E states it implemented several operational policies, procedures, and programs designed to address safety hazards on its electrical system. PG&E says it used its transmission grid control centers (GCC) and distribution control centers (DCC) to monitor and respond to events on the system.[19] In 2018, PG&E implemented a Public Safety Power Shutoff (PSPS) program to de-energize portions of its system as a measure of last resort to reduce the risk of ignition during extreme weather conditions, and PG&E

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[14] PGE-01, p. 1-28:18–21.

[15] *Id.* at 1-28:22–25.

[16] *Id.* At 2-2:13–15 (opening testimony of A. Abranches).

[17] *Id.* at 2-24:11–15.

[18] *Id*. at 2-2:27–28.

[19] *Id*. at 2-2:29 to 2-3:4.

expanded that program in 2019 to include all transmission and distribution lines traversing Tier 2 or Tier 3 HFTD.[20] PG&E also followed emergency response protocols to facilitate dynamic responses and coordinate with external stakeholders.[21]

As described in its annual WMPs, PG&E states it has continued to update and improve these policies and programs over time based on input from the Commission, Energy Safety, peer utilities, and the broader community.[22] According to PG&E, these efforts include system-hardening investments, changes to PG&E's inspection and maintenance programs, and new and expanded operational mitigations, such as programs to disable reclosers and proactively de-energize lines when warranted.[23]

2.2. The Kincade Fire

The Kincade Fire ignited on the evening of October 23, 2019, in a geothermal field in Sonoma County known as the Geysers.[24] The area was designated as Tier 3 HFTD under the Commission's final Fire Threat Map, although it had not previously been identified as an area of high fire risk under the Commission's interim fire threat map prior to 2018.[25] At the time of the ignition, the area was under a Red Flag Warning, meaning that conditions included warm temperatures, very low humidity, and strong winds, which

[20] *Id*. at 2-7:19–26.

[21] *Id.* at 1-29:29–31 (opening testimony of S. Singh).

[22] *Id.* at 1-28:1–11.

[23] *Id.* at 1-27:22–26.

[24] PGE-01, at 1-8:2–4 (opening testimony of S. Singh).

[25] *Id*. at 3A-2:31 to 3A-3:3 (opening testimony of C. Gill).

combined to increase the risk of wildfires.[26] Those conditions caused the Kincade Fire to spread rapidly. The fire was active for 14 days and burned 77,758 acres before being fully contained on November 6, 2019.[27]

The California Department of Forestry and Fire Protection (Cal Fire) conducted an investigation into the origin and cause of the Kincade Fire and concluded that the ignition resulted from a broken jumper cable associated with the Geysers #9-Lakeville 230 kilovolt (kV) transmission line (Geysers #9 Line) at PG&E transmission Tower 001/006.[28] The jumper cable separated and came into contact with the transmission tower, causing a phase-to ground fault that resulted in arcing between the jumper and the steel tower.[29] The separation point was located within the enclosure of a solid metal shoe, and post-incident metallurgical analysis showed that the jumper cable separated due to fatigue.[30]

2.3. The Dixie Fire

The Dixie Fire ignited in the afternoon of July 13, 2021, in a remote area in the Feather River Canyon in Plumas County, California.[31] The area was designated as Tier 2 HFTD.[32] The Dixie Fire was active for over three months before it was fully contained on October 25, 2021, and ultimately became the

[26] *Id*. at 1-8:4–6 (opening testimony of S. Singh).

[27] *Id*. at 3A-3:3–4 (opening testimony of C. Gill).

[28] *Id.* at 3A-6:22 to 3A-7:2.

[29] *Id.* at 3A-3:6–7; *id.* at 3A-6:25 to 3A-7:1 (opening testimony of E. Christiansen).

[30] *Id.* at 3A-8:3–8 (opening testimony of L. Eiselstein).

[31] PGE-01, at 3B-1:7–9 to 3B-3:4–5 (opening testimony of A. Abranches).

[32] *Id.* at 3B-3:15–16.

largest single-origin wildfire in California history, burning approximately 963,309 acres across five counties.[33]

Cal Fire conducted an investigation into the origin and cause of the Dixie Fire and concluded that the ignition resulted from a Douglas fir tree (referred to in PG&E's prepared testimony as the Subject Tree) falling onto a PG&E 12 kV distribution line called the Bucks Creek 1101 Circuit.[34] The span where this occurred (referred to in PG&E's prepared testimony as the Subject Span) was located on a steep slope that ran down from a single-lane dirt road to the Cresta Dam,[35] a PG&E hydroelectric generation facility.[36] The impact of the falling Subject Tree pushed two of the three conductors together, resulting in a phase-to-phase fault.[37] The fuses upstream of the fault operated as intended to de-energize those two conductors.[38] Because the third conductor was not involved in the fault, the fuse on that phase did not operate and it remained energized.[39] The contact between the third conductor and the Subject Tree resulted in a high-impedance fault—a fault caused by a small amount of electricity flowing through the tree to the ground.[40] The low-current ground fault appeared consistent with normal load and was not detected, and ultimately caused the ignition.[41]

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[33] *Id.* at 3B-3:4–9 (opening testimony of C. Gill); *id.* at 3B-5:4 to 3B-6:2 (opening testimony of E. Christiansen).

[34] *Id.* at 3B-6:3–5 (opening testimony of E. Christiansen); *see also id.* at 3B-1:12–15.

[35] *Id*. at 3B-3:13–15 (opening testimony of C. Gill).

[36] *Id*. at 3B-5:4–6 (opening testimony of E. Christiansen).

[37] *Id*. at 3B-6:19–20.

[38] *Id.* at 3B-16:7 to 3B-18:13 (opening testimony of D. Erwin).

[39] *Id*. at 3B-6:24–25 (opening testimony of E. Christiansen).

[40] *Id.* at 3B-7:4–6.

[41] *Id*. at 3B-2:30–32 (opening testimony of A. Abranches).

2.4. Cost Recovery and the Wildfire Fund

As part of this Application, PG&E has requested that the Commission review, in addition to incremental WEMA costs requested for rate recovery, amounts paid or eligible to be paid by the Wildfire Fund related to the Kincade and Dixie Fires. In Assembly Bill (AB) 1054 (Holden, 2019), the State created the Wildfire Fund, with ratepayers and investors of PG&E, Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) each contributing $10.5 billion to create a $22+ billion liability pool that reimburses those utilities from third-party damages for wildfires.[42]

Under Section 1701.8, a "covered wildfire" means any wildfire ignited on or after July 12, 2019, caused by an electrical corporation, as determined by the governmental agency responsible for determining causation. The Wildfire Fund pays "eligible claims" arising from a covered wildfire, meaning claims for third-party damages from covered wildfires less annual utility retention (larger of $1.0 billion or required insurance layer per fund administrator). If an electrical corporation has received payments from the Wildfire Fund for a third-party damage claim for a covered wildfire, then it files an application at the Commission to recover the costs.[43] If the Commission finds the utility's costs and expenses for the covered wildfire are just and reasonable pursuant to Section 451 or 451.1, as applicable, then the utility does not have to reimburse the Wildfire Fund for claims paid by the fund. If the Commission does not find the

[42] Cal. Pub. Util. Code sections 3281-3297. AB 1054 is codified in various provisions of the Pub. Util. Code, including sections 451.1, 1701.1, 1701.8, 3280, 3284, 3293, 8386, 8386.3, 8386.4, 8389. In Senate Bill 254 (Becker, 2025) the Legislature added the Continuation Fund, in which ratepayers and investors each contributed another $9 billion to create an additional $18+ billion liability pool. Cal. Pub. Util. Code sections 3298-3298.6.

[43] Cal. Pub. Util. Code Section 1701.8(b)(1)(B).

costs and expenses just and reasonable, then the utility shareholders are obligated to reimburse the Wildfire Fund for the portion of the claims covered by the fund to the extent of the utility's imprudence, up to a liability cap.[44]

As of July 31, 2026, payments received from the Wildfire Fund totaled approximately $1.2 billion across both fires. For the reasons set forth herein, PG&E claims it should not be required to reimburse the Wildfire Fund for any amounts it has received or will receive from the Fund.[45]

PG&E states that the *Assigned Commissioner's Scoping Memo and Ruling* in this proceeding recognized that resolution of this Application requires the Commission to decide whether PG&E must repay the Wildfire Fund for the amounts the Fund has paid.[46]

3. Procedural Background

PG&E filed this Application on November 14, 2025, seeking Commission review and approval to recover the costs recorded in its WEMA and CEMA for the Kincade and Dixie Fires. Concurrently with its Application, PG&E served two volumes of prepared testimony supporting the Application and the reasonableness of the WEMA and CEMA costs. The Public Advocates Office at the Commission (Cal Advocates) and The Utility Reform Network (TURN) filed protests to the Application.

On December 5, 2025, a prehearing conference was held. On December 12, 2025, the Assigned Commissioner issued a *Scoping Memo and Ruling* (*Scoping Memo*), setting the procedural schedule and identifying the issues in scope for the proceeding. The Small Business Utility Advocates (SBUA) filed a motion for

[44] Cal. Pub. Util. Code Section 3292.

[45] PGE-03, at 1-13:16–21 (rebuttal testimony of S. Singh).

[46] Assigned Commissioner's Scoping Memo and Ruling (Dec. 12, 2025), at 1 n.1.

party status, which was granted by the assigned Administrative Law Judge on January 6, 2026. San Diego Gas & Electric Company (SDG&E) and Southern California Edison Company (SCE) filed motions for party status, which the Administrative Law Judge granted in part, ruling that their participation would be limited to filing comments on any Commission decision or ruling interpreting AB 1054 and Section 451.1.

On February 24, 2026, Cal Advocates filed a *Motion to Amend the Procedural Schedule*. PG&E filed a response in opposition to the motion on March 2, 2026. On March 4, 2026, the assigned Administrative Law Judge granted that motion in part and extended the deadlines for Cal Advocates' testimony and PG&E's rebuttal testimony.

On May 4, 2026, Cal Advocates served prepared testimony. No other intervenor served prepared testimony.

On June 19, 2026, PG&E served its prepared rebuttal testimony. Concurrent with its rebuttal testimony, PG&E served a Cost Update, updating the WEMA costs through May 31, 2026, and the CEMA costs through March 31, 2026. PG&E later filed an unopposed *Motion to Extend the Due Date for PG&E's Further Cost Update*, which the assigned Administrative Law Judge granted, extending the deadline for PG&E's further cost update from July 14, 2026, to August 13, 2026.

On July 31, 2026, a status conference was held in advance of the evidentiary hearings scheduled for August 17–20, 2026. On August 12, 2026, PG&E served a set of factual stipulations between PG&E and Cal Advocates supporting a mutual waiver of evidentiary hearings with respect to the Dixie Fire. On August 13, 2026, PG&E served its further Cost Update, updating the WEMA costs through July 31, 2026, and the CEMA costs through June 30, 2026.

On August 14, 2026, PG&E served a set of factual stipulations by PG&E and Cal Advocates supporting a mutual waiver of evidentiary hearings with respect to the Kincade Fire. That same day, the assigned Administrative Law Judge held an informal conference with the parties and issued an *Email Ruling Taking Evidentiary Hearings Off Calendar and Setting Procedural Requirements and Modifications*. The *email ruling* set deadlines for the parties to file motions (or joint motions) regarding the admission of final exhibits and factual stipulations, and for simultaneous opening and reply briefs.

On August 21, 2026, PG&E and Cal Advocates filed *Joint Motions to Admit the Final Exhibits and Factual Stipulations for the Kincade and Dixie Fires into Evidence and to Seal the Confidential Exhibits in the Record*. On September 4, 2026, the assigned Administrative Law Judge granted the *Joint Motions*. As set forth in the Scoping Memo, the deadline for issuance of a proposed decision in this proceeding is November 13, 2026.

On September 11, 2026, PG&E, Cal Advocates, and SBUA filed their opening briefs. PG&E also filed a *Motion for Oral Argument*.

On August 21, 2026, the parties filed their *Joint Motion to Admit Exhibits into the Record*. This motion was granted on September 4, 2026, via email ruling. The list of exhibits is appended to this decision as **Attachment A.**

On August 21, 2026, the parties filed their *Joint Motion to Seal a Portion of the Evidentiary Record*. This motion was granted on September 8, 2026, via email ruling.

On October 2, 2026, PG&E, Cal Advocates, and SBUA filed their reply briefs.

On October 26, 2026, the Commission held the oral argument.

3.1. Submission Date

This matter was submitted on October 26, 2026, upon the conclusion of oral argument.

4. Scoped Issues Before the Commission

The Scoping Memo sets forth the following issues to be considered in this proceeding:

1. Was PG&E's conduct related to the ignition of the Kincade Fire prudent and reasonable under Pub. Util. Code Section 451.1?
2. Was PG&E's conduct related to the ignition of the Dixie Fire prudent and reasonable under Pub. Util. Code Section 451.1?
3. Were there any factors beyond PG&E's control that exacerbated the costs and expenses attributable to the Kincade Fire, and what were the costs attributable to those factors?
4. Were there any factors beyond PG&E's control that exacerbated the costs and expenses attributable to the Dixie Fire, and what were the costs attributable to those factors?
5. Are the costs recorded in PG&E's WEMA, net of insurance, to resolve third-party claims arising from the Kincade Fire, including claims filed by individual plaintiffs, subrogated insurers, and public entities, just and reasonable?
6. Are the costs recorded in PG&E's WEMA, net of insurance, to resolve third-party claims arising from the Dixie Fire, including claims filed by individual plaintiffs, subrogated insurers, and public entities, just and reasonable?
7. Are the costs recorded in PG&E's WEMA to defend and resolve claims arising from the Kincade Fire, including costs for outside counsel, mediations, experts and consultants, e-discovery, and other litigation costs, just and reasonable?
8. Are the costs recorded in PG&E's WEMA to defend and

resolve claims arising from the Dixie Fire, including costs for outside counsel, mediations, experts and consultants, e discovery, and other litigation costs, just and reasonable?

9. Are the approximately $71.6 million in capital costs recorded in PG&E's CEMA as of February 28, 2025, and incurred by PG&E to restore service to customers and to repair or replace facilities damaged by the Kincade and Dixie Fires, incremental, just, and reasonable?

10. Are the approximately $242 million in O&M costs recorded in PG&E's CEMA as of February 28, 2025, and incurred by PG&E to restore service to customers and to repair or replace facilities damaged by the Kincade and Dixie Fires, incremental, just, and reasonable?

11. Are the associated capital revenue requirement of approximately $64.5 million and O&M revenue requirement of approximately $296.9 million, incremental, just, and reasonable?

12. Were there any factors beyond PG&E's control that exacerbated the costs and expenses attributable to the Kincade Fire, and what are the costs attributable to such factors?

13. Were there any factors beyond PG&E's control that exacerbated the costs and expenses attributable to the Dixie Fire, and what are the costs attributable to such factors?

14. Should PG&E's cost recovery proposal set forth in chapter 7 of its prepared testimony be adopted?

5. The New Reasonableness Legal Standard and the Rules of Statutory Interpretation

In this matter of first impression, the Commission must interpret and apply the newly created legal standard governing the recovery of catastrophic wildfire related expenses. The Legislature enacted this new standard through AB 1054, which is codified in Section 451.1. As our decision will explain, the

Commission must apply the presumption of prudence (or reasonableness) found in Section 451.1(c), which states as follows:

> An electrical corporation bears the burden to demonstrate, based on a preponderance of the evidence, that its conduct was reasonable pursuant to subdivision (b) unless it has a valid safety certification pursuant to Section 8389 for the time period in which the covered wildfire that is the subject of the application ignited. If the electrical corporation has received a valid safety certification for the time period in which the covered wildfire ignited, an electrical corporation's conduct shall be deemed to have been reasonable pursuant to subdivision (b) unless a party to the proceeding creates a serious doubt as to the reasonableness of the electrical corporation's conduct. Once serious doubt has been raised, the electrical corporation has the burden of dispelling that doubt and proving the conduct to have been reasonable.

Section 451.1(c) has several key components that drive our consideration of PG&E's Application and the protests filed herein: if the electrical corporation has received a valid safety certification for the time period in which the covered wildfire that is the subject of the application ignited, then the electrical corporation's conduct related to the ignition shall be deemed to have been reasonable unless a party to the proceeding creates a serious doubt as to the reasonableness of the electrical corporation's conduct related to the ignition. Then the Commission must determine the amount the electrical corporation is entitled to recover.

But, if a party to the proceeding creates a serious doubt as to the reasonableness of the electrical corporation's conduct related to the ignition, then the burden shifts to the electrical corporation to dispel that doubt and prove by a preponderance of the evidence that its conduct was reasonable. To determine if an electrical corporation's conduct was reasonable, we are guided by Section 451.1(b) which provides, in part, that when "determining an application by an

electrical corporation to recover costs and expenses arising from a covered wildfire, the commission shall allow cost recovery if the costs and expenses are *just and reasonable*." (Italics added.) Costs are just and reasonable "if the conduct of the electrical corporation related to the ignition was consistent with the actions that a reasonable utility would have undertaken in good faith under similar circumstances, at the relevant point in time, and based on the information available to the electrical corporation at the relevant point in time." (*Id*.)

Importantly, Section 451.1(b) provides that the determination of reasonableness can be based on a variety of factors and not an absolute ideal:

> Reasonable conduct is not limited to the optimum practice, method, or act to the exclusion of others, but rather encompasses a spectrum of possible practices, methods, or acts consistent with utility system needs, the interest of the ratepayers, and the requirements of governmental agencies of competent jurisdiction. Costs and expenses in the application may be allocated for cost recovery in full or in part taking into account factors both within and beyond the utility's control that may have exacerbated the costs and expenses, including humidity, temperature, and winds.

To interpret and apply this new statute, the Commission follows the rules of statutory interpretation that have been established in California and recently summarized by the California Supreme Court in *North American Title Company v. Superior Court* (2024) 17 Cal. 5th 155, at 169:

> We first examine the statutory language, giving it a plain and common sense meaning. We do not examine that language in isolation, but in the context of the statutory framework as a whole in order to determine its scope and purpose and to harmonize the various parts of the enactment[.]…Furthermore, we consider portions of a statute in the context of the entire statute and the statutory scheme of which it is a part, giving significance to every work, phrase, sentence, and part of an act in pursuance of the legislative purpose. (Citing to *Los Angeles Unified School District v. Superior Court* (2023) 14 Cal.5th 758, 767-768.)

Second, to the extent the statutory language is uncertain (*i.e.*, capable of being susceptible to more than one reasonable interpretation), the tribunal tasked with interpreting the statute may review extrinsic sources such as the purpose and goals of the statute, the concerns to be remedied, public policy goals, and the accompanying legislative history to confirm the statute's meaning.[47] After reviewing these extrinsic aids, we must then choose the meaning which will best attain the purposes of the statute.[48]

As a starting point, we discuss our interpretation of two statutory terms that inform our resolution of PG&E's Application: "valid safety certification" and "serious doubt".

5.1. Valid Safety Certification

Section 451.1(c) refers to a "valid safety certification" as provided by Section 8389 as a condition precedent to receiving a presumption of reasonableness (or prudence). Section 8389(a) provides that the Director of the Office of Energy Infrastructure Safety shall issue a certificate to an electrical corporation after that electrical corporations provides documentation of the following: (1) the electrical corporation has an approved WMP; (2) the electrical corporation has agreed to implement the recommendations of its most recent safety culture assessments performed; (3) the electrical corporations has established a safety committee of its board of directors composed of members with relevant safety experience; (4) the electrical corporation has established an

[47] *North American,* 17 Cal. 5th at 180, citing to *Larkin v. Workers' Comp. Appeals Bd*. (2015) 62 Cal.4th 152, 164 [consulting legislative history "[t]o the extent any uncertainty nonetheless persists' after examining the statutory text and structure]; and *People v. Cornett* (2012) 53 Cal.4th 1261, 1265.)

[48] *People ex rel. S.F. Bay etc. Com. v. Town of Emeryville* (1968) 69 Cal.2d 533, 543-544.

executive incentive compensation structure approved by the office and structured to promote safety as a priority and to ensure public safety and utility financial stability with performance metrics; (5) the electrical corporation has established board-of-director-level reporting to the commission and office on safety issues; (6) the electrical corporation has established a compensation structure for any new or amended contracts, plans or arrangements that meet certain parameters; and (7) the electrical corporation is implementing the mitigation strategies in its approved WMP.[49]

There is no dispute that PG&E held a valid safety certification in 2019 at the time of the Kincade Fire and in 2021 at the time of the Dixie Fire.[50] As such, PG&E is entitled to a presumption of reasonableness (or prudence) as to its conduct related to the ignition of the fires unless a party raises a serious doubt to rebut the presumption.

5.2. Serious Doubt

Section 451.1(c) does not define "serious doubt," and no other provisions in the Public Utilities Code define this term or provide a benchmark for determining how it is satisfied. But, the legislative history of AB 1054 specifically notes that the rebuttable presumption it established is similar to the cost-recovery standard applied by the Federal Energy Regulatory Commission (FERC),[51] so we can look to FERC precedent and reviewing court decisions as a guide.

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[49] During the time period in question, it was the Commission that issued the safety certificate, as the Office of Energy Infrastructure was not created until July 1, 2021.

[50] PGE-01, at 1-21:9-14 (opening testimony of S. Singh).

[51] PGE-03, at 1-5:6–8 (rebuttal testimony of S. Singh) (citing AB 1054, Senate Committee on Energy, Utilities and Communications (July 8, 2019), at 13); *see also* AB 1054, Senate Committee on Energy, Utilities and Communications (July 8, 2019), at 13 ("AB 1054 proposes new language

Footnote continued on next page.

Under long-standing FERC practice, a utility's expenditures are initially presumed to be prudent, and FERC uses the "serious doubt" standard as the threshold for determining when the burden shifts to the utility to prove that its conduct was prudent. (*Indiana Municipal Power Agency v. FERC* (D.C. Cir. 1995) 56 F.3d 247, 253.) Hence, in FERC practice a utility does not need to proactively prove the reasonableness of every cost in a rate case if it is entitled to the presumption of prudence. However, if an intervening party or participant presents evidence that raises a "serious doubt" regarding the prudence of a specific cost, this presumption is rebutted. The burden of proof then shifts back to the utility to dispel those doubts and demonstrate, under the preponderance of the evidence standard, that the expenditure was just, reasonable, and prudent.[52]

As an initial matter, the "serious doubt" framework applied in FERC matters is a multi-stage process. In *Indiana Municipal Power Agency v. FERC* (D.C. Cir. 1995) 56 F.3d 247, the D.C. Circuit explained that a challenger must present evidence sufficient to raise serious doubt that "a reasonable utility manager, under the same circumstances and acting in good faith," would not have made the same decision and incurred the same costs.[53] If the challenger clears that "initial hurdle," the utility then has the burden of presenting evidence sufficient to dispel the doubt.[54] "Serious doubt" is a threshold question, not a finding that

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to provide the electrical utility the presumption that they acted reasonabl[y] . . . . In this respect, the burden of proof would switch to other parties in the proceeding to raise 'serious doubt' as to the electric IOU's reasonableness. The Governor's Office notes this is a presumption with similarity to what is afforded in the Federal Energy Regulatory Commission (FERC) process.").

[52] *Minnesota Power & Light Co*., 11 FERC ¶ 61645 (1980) (citations omitted).

[53] *Id.* at 253.

[54] *Ibid*.

the utility acted unreasonably. If the challenger raises serious doubt, the burden shifts to the utility to dispel it.[55]

Under FERC precedents, to effectively raise a "serious doubt," an intervening party must provide concrete evidence that "constitutes more than a bare allegation of imprudence."[56] General complaints or vague or unbacked assertions are insufficient to shift the burden of proof back to the utility. "Direct evidence" is necessary.[57] Further establishing a serious doubt regarding prudence requires "reliable, probative, and substantial evidence."[58] Mere concerns about a utility's conduct do not necessarily provide a sufficient basis for shifting the burden.[59]

Once serious doubt has been raised, the utility has "the burden of dispelling these doubts and proving the questioned expenditure to have been prudent"[60] The utility's showing of prudence must meet the ordinary evidentiary standard of a preponderance of the evidence on the record.[61]

To summarize, the utility applicant enjoys a "presumption of reasonableness (or prudence)" in FERC cost recovery proceedings, meaning that the utility "need not justify in its case-in-chief the prudence of all its costs."[62]

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[55] *Id.* at 253.

[56] *Minnesota Power & Light Co*., 11 FERC ¶ 61,312 (1980).

[57] *Mid-America Pipeline Co., LLC*, 124 FERC 63,016, at P 976 (2008) (*Mid-America*), *aff'd* 130 FERC 61,123 (2010); *Evergy Kansas Central, Inc.*, 183 FERC ¶ 61,226 (2023).

[58] *Wis. Elec. Power Co.*, 73 FERC P 63,019, at 65,225 (1995), *aff'd in relevant part*, 98 FERC P 61,233 (2002) (citing Section 7(c), Administrative Procedure Act, 5 U.S.C. § 556(d) (2012).

[59] *Iroquois Gas Transmission System, L.P. v. FERC* (D.C. Cir. 1998) 145 F.3d 398.

[60] *Anaheim, Riverside, Banning, Colton & Azusa v. Federal Energy Regulatory Com.* 669 F.2d 799, 809 (D.C. Cir. 1981).

[61] *Potomac-Appalachian Transmission Highline, LLC*, 158 F.E.R.C. P61,050, 61313, 61315.

[62] *Potomac-Appalachian Transmission Highline, LLC* (2017) 158 FERC ¶ 61,050, P 100.

Rather, a participating party must "create a 'serious doubt'" and then "the burden shifts to the applicant to demonstrate that the expenditure in question was prudent."[63] Creating "serious doubt" in FERC's view is an endeavor that "is highly fact-specific and based upon the record and circumstances presented by a particular record."[64] Under FERC's standard, an intervenor must do more than, in hindsight, second-guess utility management decisions."[65] It also "does not suffice to make general, sweeping allegations of imprudence."[66] Mistakes or even regulatory violations do not necessarily establish serious doubt;[67] and "[f]lawed or even wrong decision-making does not equate to imprudence."[68] Finally, these cases demonstrate that establishing serious doubt regarding

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[63] *Entergy Services* (2010) 130 FERC ¶ 61,023, P 52.

[64] *BP Pipelines* (2015) 153 FERC ¶ 61,233, P 88.

[65] FERC Practice & Proc. Manual ¶ 206, 2006 WL 1984110 (quoting *J. William Foley Inc. v United Illuminating Co.* (2013) 142 FERC ¶ 61,125, P 19); *see* PGE-01, at 1-25:14–15 (opening testimony of S. Singh); *see also, e.g.*, *Re New England Power Co.* (1985) 31 FERC ¶ 61,047; *Midwestern Gas Transmission Co*. (1985) 31 FERC ¶ 61,082, *aff'd sub nom. Violet v. FERC* (1st Cir. 1986) 800 F.2d 280, 283 ("[M]anagers of a utility have broad discretion . . . . We note that while in hindsight it may be clear that a management decision [was] wrong, our task is to review [] prudence . . . based on the particular circumstances existing either at the time the challenged costs were actually incurred, or the time the utility became committed to incur those expenses."); *Midwest Indep. Transmission Sys. Operator, Inc. & Am. Transmission Sys., Inc* (2006) 117 FERC ¶ 61,108, PP 4, 7–8.

[66] PGE-01, at 1-25:11–14 & n.88 (opening testimony of S. Singh) (citing *Pac. Gas & Elec. Co.* (2020) 173 FERC ¶ 61,045, P 181 (Initial Decision)).

[67] PGE-01, at 1-26:9–10 & nn.92, 95 (citing *Pac. Gas & Elec. Co.*, 173 FERC ¶ 61,045, P 180 (Initial Decision) ("[A]ny mistakes made by PG&E in developing this significant transmission project 'do not constitute the kind of mismanagement that should raise serious doubts about the prudency of their expenditures.'")); *see also San Diego Gas & Elec. Co.* (2014) 146 FERC ¶ 63,017, PP 55–56 (concluding that one regulatory violation was "insufficient to cast serious doubt" and noting that "utilities are not expected to be infallible").

[68] PGE-01, pat 1-25:21 to 1-26:1 & n.92 (opening testimony of S. Singh) (citing *TransCanada Keystone Pipeline* (2024) 188 FERC ¶ 61,077, P 112).

prudence "requires reliable, probative, and substantial evidence."[69] Since the legislative history indicates that California's Legislature patterned Section 451.1(c) language after FERC's language, these principles under FERC's standard provide an instructive legal template for the Commission to follow in deciding if the serious doubt standard has been met. While we refer to "the parties," our analysis will focus on the Cal Advocates' arguments and evidence as SBUA's arguments mirror those of Cal Advocates.

6. The Parties Have Failed to Raise a Serious Doubt as to the Reasonableness of PG&E's Conduct Regarding the Dixie Fire (Scoping Memo Issue 2)

Cal Advocates argues that PG&E's functioning protective devices, compliance with its own procedures, and the Commission's approval of PG&E's vegetation management plans do not prove PG&E's decision to leave the line energized was reasonable, because a reasonable utility should have de-energized the circuit earlier in the day based on information PG&E had available to it at the time. Cal Advocates' allegations rest on generalized complaints about PG&E's procedures and arguments based on hindsight, which are insufficient to raise a serious doubt that PG&E acted reasonably by following its de-energization procedures.

6.1. De-energization of the Entire Circuit Earlier in the Day

6.1.1. Cal Advocates

Cal Advocates argues that detection and response depended on PG&E personnel exercising judgment based on the information available to them and their inferred knowledge.[70] Cal Advocates argues that a reasonable utility would

[69] 158 FERC ¶ 61,050, P 90.

[70] Cal Advocates Br., 22-23.

weigh minimal customer impacts of de-energization against ignition risk on a high fire risk circuit in mid-July differently to take proactive measures.

Cal Advocates states that switch 941 is located downstream of the Bucks Creek 1101/2 recloser and upstream of Fuse 17733, and the switch "could be manually operated in the field."[71] Cal Advocates suggests that the recloser itself could be operated remotely or manually to de-energize a line, so PG&E could have de-energized the entire circuit from its control center at any moment.[72] In Cal Advocates' view, PG&E had several occasions to take action:[73]

- At 8:52 a.m., when PG&E knew two downstream customers were out, and could infer that at least two fuses had operated with one phase potentially still energized;
- At 12:30 p.m., when the troubleshooter observed at least one open phase at Fuse 17733 through binoculars from across the canyon;
- At approximately 1:30 p.m., when the troubleshooter was stopped at a closed bridge and told he could not pass for at least two hours, so PG&E's only responder could not reach the fuse for hours while the circuit remained energized;[74] and
- At approximately 4:50 p.m., when PG&E's troubleshooter reached Pole 908 and confirmed the third fuse was closed.

Cal Advocates claims that the economic cost of de-energizing was minimal, noting that there were only four customers on the circuit; Customer 4 and Cresta Dam were already out; PG&E itself did not consider Customer 3 a

[71] CA-06-E at 2, fn. 4; PGE-08 at 3.

[72] CA-06-E at 5.

[73] Occasions 1, 2, and 3, *see* CA-05-E at 7; CA-06-E at 9.

[74] *See* CA-05-E at 7; CA-06-E at 10-11 (PG&E could de-energize at 1:30 p.m. because it "knew its troubleshooter was unable to physically access the site to inspect the blown fuses and would likely remain unable to access the site for several hours.")

critical customer; and operating Switch 941 would have affected at most one non-critical customer outage since the last customer, a Powerhouse, would still be getting power upstream of Switch 941.[75]

Cal Advocates further argues that PG&E's evidence does not dispel the doubt. PG&E states the status of Fuse 17733 could not be verified from an accessible vantage point before about 4:30 p.m.[76] Cal Advocates argues that this does not explain why the circuit remained energized. De-energizing, in Cal Advocates' view, required no confirmation, only reaching a different inference from outage reports and load data PG&E already had.[77]

The 1:30 p.m. bridge closure makes the point more convincing in Cal Advocates' view: even if the situation appeared unclear in the morning, by 1:30 p.m. a reasonable utility would de-energize rather than wait longer for its personnel to complete an investigation. According to Cal Advocates, that the troubleshooter acted immediately upon seeing the Subject Tree and the fire speaks to his diligence, not to the reasonableness of it taking eight hours before he was able to take action. Cal Advocates claims the fact that the events "presented as a routine outage"[78] strengthens the point. Cal Advocates asserts a reasonable utility would not need certainty to act, only the information PG&E concedes it already had. Instead, according to Cal Advocates, PG&E prioritized

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[75] CA-06-E at 10 and fn. 32; PG&E's response to data request SED-005, question 8, Exh. CA-06-SA at 013 (PG&E stated that it was not aware that Customer 3 had backup power at the time of the Dixie Fire. However, PG&E also stated that this customer was not a "critical customer.")

[76] PGE-08 at 2.

[77] *See* CA-06-E at 8-9. By 8:52 a.m., PG&E knew that Customer 4 and Cresta Dam had lost power, while its load data still showed calculated ground current of 0 to 1.6 amps on the circuit. Cal Advocates asserts the normal ground current on a circuit with confirmed downstream outages was itself an anomaly signaling a possible high-impedance fault.

[78] PGE-03 at 1-3.

the reliability of the Powerhouse, and a noncritical Customer,[79] and that PG&E did not take basic steps to contact Customer 3 or Customer 4 to confirm whether they had lost power to assess whether protective de-energization would impact them. Cal Advocates states that while PG&E now states that it did not know that at the time Customer 3 had backup power,[80] that information was just a phone call away. Cal Advocates asserts that, had PG&E made the call, it would have learned that the only customer downstream of Switch 941 that still had power also had battery backup.

Cal Advocates concludes that PG&E cannot prove that leaving the circuit energized was what a reasonable utility would have done because, from Cal Advocates' perspective, the unexplainable downstream outages, minimal customer impact, remote and inaccessible terrain, "historically dry and hot summer," and "extreme drought conditions"[81] should have pointed PG&E to a different conclusion.

Furthermore, Cal Advocates maintains that the parties stipulated that SDG&E first implemented its Sensitive Relay Profile program in 2011, Southern California Edison Company (SCE) implemented its Fast Curve program in 2018, while PG&E first implemented its Enhanced Powerline Safety Settings (EPSS) in July 2021, in response to the Dixie Fire.[82] By July 2021, SCE had enabled fast curve settings across its entire HFTD.[83] Cal Advocates does not contend that a

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[79] *See* CA-05-E at 10; PGE-08 at 2.

[80] CA-06-E at 10 and fn. 32; CA-06-SA at 013.

[81] PGE-01 at 1-37 ("The Dixie Fire also ignited during a historically dry and hot summer. Extreme drought conditions helped propel the fire's progression, . . .")

[82] PGE-08 at 3.

[83] Cal Advocate Testimony, PG&E's Implementation of EPSS Program, 2021 Dixie Fire (Errata), Exh. CA-07-E, Jul. 29, 2026, at 5.

fast-trip program would necessarily have prevented this ignition; the point bears on the reasonableness of PG&E's operating decisions: since PG&E did not deploy the automated protection its peers had utilized for years, its remote high fire risk circuits depended even more heavily on personnel judgment. Cal Advocates concludes that PG&E should have been aware of the heightened risk of not utilizing fast-trip and thus should have emphasized more heavily the human judgment of personnel, rather than following its procedures.

6.1.2. Discussion

After reviewing the arguments and the evidentiary record, we conclude Cal Advocates has failed to demonstrate serious doubt as to the reasonableness of PG&E's decision not to de-energize the line earlier in the day. We base this conclusion on the following Commission finding. Cal Advocates adopted PG&E's showing of the steps PG&E personnel undertook to investigate and respond to the outage that occurred at approximately 6:48 a.m. that day.[84] The parties stipulated that PG&E's response was consistent with its procedures, and Cal Advocates presented no testimony challenging the reasonableness of those procedures. While Cal Advocates' prepared testimony posits a hypothetical alternative response wherein PG&E could have de-energized other customers on the Bucks Creek 1101 Circuit, the information available to PG&E at the time did not warrant such a response. The possibility of a hypothetical alternative response does not create serious doubt regarding the reasonableness of the response PG&E undertook, which we find was consistent with PG&E's de-energization procedures and the information available at the time.

[84] CA-05-E, at 5–10. Cal Advocates has affirmed that it "does not dispute the accuracy or confirmation of the facts represented in the timeline." PGE-08, at 2 (Dixie Factual Stipulations).

There is also no dispute that PG&E's distribution operator and the troubleshooter dispatched to investigate the outage gathered and evaluated the available information.[85] All available information indicated a routine outage resulting from protective devices operating as designed (*i.e.*, to isolate and mitigate fault conditions).[86] The distribution operator analyzed the available electrical data for any sign of a continuing hazard and saw none: The electrical load was stable and balanced across all three phases, and there was no excessive ground current.[87]

At around 12:30 p.m., PG&E's troubleshooter was able to visually inspect the line through binoculars from Cresta Dam, and everything appeared normal.[88] From the dam, the troubleshooter was able to see what appeared to be at least one open fuse at Fuse 17733 hanging down, indicating the fuse had operated.[89] The troubleshooter saw no indications of a line down, vegetation on the line, or a fire.[90]

Although the troubleshooter was unable to access Fuse 17733 earlier in the day the record shows that PG&E followed its procedures providing for a same-day response to what appeared to be a routine outage. PG&E personnel were authorized to de-energize distribution lines if determined to be appropriate

[85] PGE-03, at 3B-10:9–11 (rebuttal testimony of R. Robinson).

[86] The stipulated facts affirm that "[t]he fuses at Fuse 17733 operated as intended in response to a transient fault that occurred at approximately 6:48 a.m. on July 13, 2021," and that fuses "operate on a per-phase basis to de-energize the phase downstream of the fuse." PGE-08, at 3 (Dixie Factual Stipulations).

[87] PGE-01, at 3B-19:26 to 3B-20:1 (opening testimony of R. Robinson); CA-05-E, at 5.

[88] PGE-01, at 3B-21:3–7 (opening testimony of R. Robinson); CA-05-E, at 7.

[89] PGE-01, at 3B-21:5–10 (opening testimony of R. Robinson); CA-05-E, at 7.

[90] PGE-01, at 3B-21:10–11 (opening testimony of R. Robinson); CA-05-E, at 7.

based on known safety hazards or emergencies,[91] but there was no indication of any such hazard or emergency until the troubleshooter arrived on site at approximately 4:50 p.m., at which time he took immediate steps in response.

The Commission disagrees that these facts demonstrate an "alarming pattern of facts" raise a serious doubt whether PG&E acted reasonably by not de-energizing the Bucks Creek 1101 Circuit.[92] The information available to PG&E at the time all indicated a routine outage with no continuing safety hazard until the troubleshooter arrived at Fuse 17733 in the late afternoon.[93]

We disagree with Cal Advocates' suggestion that PG&E should have inferred a continuing high-impedance fault on the line before the troubleshooter arrived at Fuse 17733[94] as hindsight that is not supported by the record. The parties stipulated that "[t]he high-impedance fault on July 13, 2021, evaded automated detection because its low current was below the threshold for detection by PG&E's protective devices at the time of the ignition."[95] While Cal Advocates previously asserted the available ground current data indicated a

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[91] PGE-01, at 3B-23 n.25 (opening testimony of R. Robinson) (noting that "[i]f the NDCC supervisor or distribution operator had known of an emergency or safety hazard that required de-energizing the circuit before the troubleshooter arrived at Fuse 17733, the operator could have de-energized the circuit.

[92] PGE-01, at 3B-23:15–21 (opening testimony of R. Robinson); CA-05-E, at 8. Cal Advocates acknowledges that the distribution operator and troubleshooter determined that the troubleshooter would continue with the outage investigation and "wait for the bridge to reopen" after his initial attempt to access the site was blocked. CA-05-E, at 7; PGE-03, at 3B-13 n.48 (rebuttal testimony of R. Robinson).

[93] PGE-01, at 3B-23:21–22 (opening testimony of R. Robinson); CA-05-E, at 8.

[94] PGE-01, at 3B-23:21 to 3B-24:17 (opening testimony of R. Robinson); CA-05-E, at 8.

[95] PGE-08, at 2 (Dixie Factual Stipulations). The parties' factual stipulations further recognize that "[h]igh-impedance faults are low current and can appear similar to normal customer load." *Id.*

high-impedance fault,[96] this claim is refuted by PG&E's rebuttal testimony.[97] The undisputed record demonstrates that 0 to 1.6 amps of ground current was normal and typical for the Bucks Creek 1101 Circuit.[98] The figure from Exhibit PGE-03 illustrates that "[t]his range remained the same both before and after the 6:48 a.m. fault on July 13, 2021, and aligned with the longer-term range of ground current for this line."[99] Thus, the available ground current data did not indicate a high impedance fault or any hazard on the line.

We also reject Cal Advocates' assertion that a serious doubt has been raised because PG&E could have de-energized other customers. This ignores the fact that de-energizing customers can have significant safety and economic impacts.[100] In the absence of a hazard to safety or property, PG&E's procedures did not direct personnel to de-energize customers with no warning, especially when the available information indicated that PG&E's protection system had

[96] CA-06-E, at 8:12–21.

[97] PGE-03, at 3B-16:3–12 & Figure 3B-3 (rebuttal testimony of D. Erwin).

[98] *Id.* at 3B-16:4–10.

[99] *Id.* at 3B-16:5–7. PG&E's testimony further explained that ground current calculations for the Bucks Creek 1101 Circuit were not tied to load on the line and thus increases and decreases in load did not impact the normal and typical range of recorded ground current for the line. *Id.* at at 3B-17:4–10. The factual stipulations confirm that "[t]he recorded ground current values . . . were calculations by the line recloser controller algorithm." PGE-08, at 3 (Dixie Factual Stipulations).

[100] *Id.* at 3B-13:11 to 3B-14:1. Cal Advocates has recognized these significant impacts. *Id.* at 3B13 to 3B-14:1 & n.50; *see also id.* (citing Comments of the Public Advocates Office on PG&E's June 19 to 22, 2025 PSPS Post-Event Report (Aug. 5, 2025), at 6 (acknowledging the impacts of de-energization); Comments of the Public Advocates Office on the 2021 Wildfire Mitigation Plan Updates of the Large Investor-Owned Utilities (Mar. 29, 2021), at 36 (similar; fast-trip settings); and D.19-05-042, at 4, 68 (acknowledging "far reaching and significant impacts" of PSPS de-energization)). The Bucks Creek 1101 Circuit served a railroad at multiple meters. PGE-03, at 3B-14:4–5 (rebuttal testimony of R. Robinson).

already responded to and isolated the fault conditions.[101] Moreover, Cal Advocates' testimony did not identify another utility that would have de-energized other customers in response to a routine outage in an area designated HFTD. In fact, the procedures produced by SDG&E and SCE indicate that they similarly investigated outages and would not have de-energized additional customers in these circumstances.[102]

Finally, we reject Cal Advocates' assertion that PG&E did not sufficiently emphasize the human judgment of its personnel.[103] [Cal Adv. Br. at 13] PG&E personnel had the discretion to decide whether to de-energize based on the conditions that were known at the time. In *New England Power Co.*, 31 FERC ¶ 61,047, at 61,084 (1985), FERC has made it clear that the exercise of that discretion, even if it is later shown to be incorrect, is insufficient to overcome the presumption of reasonableness:

> Managers of a utility have broad discretion in conducting their business affairs and in incurring costs necessary to provide services to their customers. In performing our duty to determine the prudence of specific costs, the appropriate test to be used is whether they are costs which a reasonable utility management (or that of another jurisdictional entity) would have made, in good faith, under the same circumstances, and at the relevant point in time. We not that while in hindsight it may be clear that a management decision is wrong, our task is to review the prudence of the utility's actions and the costs resulting therefrom based on the particular circumstances

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[101] *Id.* at 3B-14:5–7.

[102] *Id.* at 3B-15:3–11. Specifically, the SDG&E and SCE procedures addressed response requirements specific to known safety hazards and extreme FPI or Red Flag Warning conditions giving rise to PSPS protocols. *Id.* at 3B-15:6–11. It is undisputed there was no Red Flag Warning or PSPS event impacting the Bucks Creek 1101 Circuit on the day of the Dixie Fire. PGE-08, at 1, 3 (Dixie Factual Stipulations).

[103] Cal Advocates Opening Brief at 13

> existing at the time the challenged costs were actually incurred, or the time the utility became committed to incur those expenditures.

In *Violet v. FERC*, 800 F.2d 280, 283 (5th Cir. 1986), the Court of Appeal affirmed FERC's decision allowing New England Power Company to pass on costs on to consumers that were incurred in the construction of a nuclear power plant, reasoning that petitioners had failed to show that similarly situated utilities would have conducted themselves differently:

> The ALJ and Rhode Island have pointed to no evidence in the record of industry practice, or from industry experts, tending to show that a reasonably prudent utility, before taking a minority position in such a joint venture, could or would have insisted upon greater rights of indemnification. …Consequently, we reject petitioners' claim that the Commission erred in failing to find NEP imprudent for not positioning itself to sue BEC successfully for its post-1980 Pilgrim II costs.

We conclude that Cal Advocates has failed to establish that PG&E's decision not to de-energize the line earlier in the day creates a serious doubt as to PG&E's reasonableness.

6.2. Non-Differentiated High Fire Threat District Outage Response

6.2.1. Cal Advocates

Cal Advocates' asserts a reasonable utility would tailor its response to processing an outage rather than follow its established procedures, because the outage occurred in a Tier 2 HFTD during the peak fire season.[104] Cal Advocates states PG&E stipulated that, at the time of the Dixie Fire ignition, PG&E's outage response procedures applied across its service area, including in HFTD areas, and that it did not maintain separate outage response procedures for HFTD

[104] Cal Advocates Reply Brief at 13.

areas.[105] In Cal Advocates' view, the consequences were severe. The 6:48 a.m. Supervisory Control and Data Acquisition (SCADA) alarm was assigned a P04 (Priority 4) level requiring analysis but "without any other specific action required in response."[106] Nearly three hours passed before a tag was issued at 9:36 a.m., and it was a non-emergency Priority 1 tag; the troubleshooter did not report en route until 10:53 a.m., more than four hours after the fault.[107] A fault on a remote circuit in a Tier 2 HFTD in hot and dry mid-July was processed exactly as a fault in any other region in any other month. Cal Advocates asserts this shows a serious doubt about the reasonableness of PG&E's outage response.

Cal Advocates states that PG&E explained its outage response "was consistent with its same-day response procedures at the time," and that Cal Advocates does not assert those procedures themselves were unreasonable.[108] Cal Advocates argues that does not dispel the doubt but restates its source. Per Cal Advocates, the statutory benchmark for reasonableness is the reasonable utility, not the utility's own manual, and the information available to PG&E in real time included everything a reasonable utility would weigh in calibrating urgency. According to Cal Advocates, this information includes: a Tier 2 HFTD, the middle of a fire season, a remote canyon corridor with seven major wildfires in the preceding two decades – including the Camp Fire, ignited within 10 miles less than three years earlier, and, by 8:52 a.m., two of four customers were without power.[109] Per Cal Advocates, PG&E should know, and apparently

[105] PGE-08 at 2.

[106] CA-05-E at 5.

[107] CA-05-E at 5-6.

[108] PGE-08 at 2; PGE-01 at 3B-31.

[109] CA-07-E at 2; CA-05-E at 6.

knew, how to adapt a program to the fire-threat tier. In 2018, PG&E replaced its CEMA second patrol with Accelerated Wildfire Risk Reduction patrols directed specifically at Tier 3 HFTD areas, and the subject span in Tier 2 was excluded.[110] PG&E made that tier-based judgment when allocating inspection resources but made no comparable judgment when deciding how urgently to respond to a fault in the high fire area. Cal Advocates claims that a utility that treats every outage identically, everywhere, in every season, cannot prove that it acted as a reasonable utility would have in these circumstances, because, by design, its program did not consider these differentiating factors.

6.2.2. Discussion

After reviewing the arguments and the evidentiary record, we conclude that Cal Advocates has failed to demonstrate serious doubt about the reasonableness of PG&E's HFTD outage procedures. PG&E's procedures applied across its service area, including HFTDs, and circumstances determined the degree of PG&E's response. PG&E Utility Procedure TD-2700P-09 set forth required responses to specified SCADA alarms with assigned priority levels ranging from Priority 1 (lowest) to Priority 10 (highest). The alarm on July 13, 2021 indicated a transient fault on the bucks Creek 1101 Circuit followed immediately by confirmation that the circuit had returned to normal, which PG&E classifies as a low-priority alarm. If PG&E received a higher priority alarm, including an outage from a circuit breaker operation, its policies required immediate action. In contrast, lower priority alarms required operators to analyze the situation and take appropriate action. Thus, PG&E's dispatch procedures did differentiate response procedures, and distinguished immediate

[110] CA-05-E at 3, fn. 14; PGE-01, Table 3B-1 at 3B-9. CEMA patrols of the circuit resumed in 2020 and 2021.

safety issues like downed wires which required an immediate response, from non-emergency electric outages that called for a same-day response. PG&E's procedures also differentiated outages by requiring distribution operators to gather and evaluate information and develop an appropriate response. PG&E's distribution operators are authorized to de-energize lines if they determine that to be the appropriate response needed based on the known facts and circumstances to ensure safe operation, and troubleshooters can de-energize distribution lines to protect life or property during emergencies. But, as there was no indication of an emergency or safety hazard, there was no reason to de-energize the circuit until the troubleshooter's arrival on site on July 13, 2021.

FERC decisions instruct us that utilities are entitled to exercise considerable discretion in how they manage their operations. As such, in *Midwestern Gas Transmission Co*., 36 FPC 61, 70 (1966), *reh. denied*, 36 FPC 599, *aff'd, Midwestern Gas Transmission Co. v. PFC*, 388 F.2d 444 (7th Cir. 1968), *cert. denied*, 392 U.S. 928 (1968), the Court cautioned against the practice of a reviewing court substituting its judgment for how a utility should be managed in order to find serious doubt:

> It is neither our purpose nor our desire to dictate every phase of the operating practices of the natural gas companies coming within our jurisdiction. The Commission has no authority either to conduct or supervise the day-to-day operations involved in the production and transportation of natural gas in interstate commerce. Those functions are left to management for decision and the managers exercise a broad area of discretion in the conduct of their business affairs.

We conclude that Cal Advocates has failed to establish that PG&E's actions with respect to how its procedures applied across its service area, including in HFTDs, create a serious doubt as to PG&E's reasonableness.

We find Cal Advocates' position that a reasonable utility would have taken a different action rather than follow its procedures, because the outage occurred in a HFTD during the peak fire season, to be general allegations of imprudence insufficient to raise a serious doubt.

7. The Parties Have Failed to Raise a Serious Doubt as to the Reasonableness of PG&E's Conduct Regarding the Kincade Fire (Scoping Memo Issue 1)

7.1. Design and Maintenance of the Geysers #9 Line Jumper

7.1.1. Cal Advocates

Cal Advocates contends that PG&E's maintenance of the Geysers #9 Line jumper in an "open" configuration was imprudent because PG&E knowingly kept an energized transmission line in an unconventional mechanical configuration for more than thirteen years without conducting an engineering evaluation to determine if the configuration could safely withstand long-term wind loading, even though the line served no customer load. Cal Advocates further states that PG&E's rebuttal rests largely on what it says it did not know: it claims that no standard prohibited the jumper configuration,[111] no prior information indicated that the jumper would fail in the manner it did,[112] and its numerous inspections did not identify fatigue.[113] In Cal Advocates' opinion, the Kincade Fire was not caused by an unforeseeable failure of a properly designed and evaluated transmission asset. Rather, Cal Advocates claims that the fire resulted from the foreseeable consequences of leaving an unusually configured

[111] *See* PGE-03 at 3A-8 to 3A-9.

[112] *See* PGE-03 at 3A-9 to 3A-13.

[113] *See* PGE-03 at 3A-14 to 3A-16.

energized conductor exposed to repeated wind-driven movement without adequately evaluating or mitigating the specific fatigue risk.

7.1.2. Discussion

After reviewing the arguments and the evidentiary record, we conclude that Cal Advocates has failed to raise a serious doubt based on PG&E's decision to maintain the Geyser's #9 Line energized in a non-standard configuration up through the ignition date. Cal Advocates allegations rest on generalized complaints and hindsight based on information that became known after-the-fact, which is insufficient to raise a serious doubt that PG&E acted reasonably by in light of the information known or available to it at the time of the ignition.

7.1.2.1. Maintenance of the Jumper in a Non-Standard Configuration

Cal Advocates allegations of serious doubt begin with PG&E's decision to configure and subsequently maintain the jumper in a non-standard configuration for over a decade, up through the ignition date.

The Tower 001/006 jumper was configured "to allow the plant to be more easily and safely reconnected in the future."[114] As originally constructed, the Geysers #9 Line at Tower 001/006 provided interconnection service to the Geysers Units 9/10 geothermal generating facility.[115] The generating plant was initially owned and operated by PG&E until 1999, when PG&E sold the facility to Calpine together with other generation facilities in the area in accordance with Commission policy.[116]

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[114] *Id.* at 2.

[115] PGE-01, at 3A-7:18–20 (opening testimony of L. Eiselstein); *id.* At 3A-22:11–14 (opening testimony of C. Gill).

[116] PGE-03, at 3A-6:11–15 (rebuttal testimony of C. Gill). In 1996, the CPUC issued D.95-12-063, as modified by D.96-01-008, to facilitate a restructuring of California's electric industry. As a

Footnote continued on next page.

Calpine has owned the facility in the time since, including at the time of the Kincade Fire, and maintained an active interconnection agreement with PG&E.[117] In late 2005, a Calpine employee sent an email to PG&E field personnel requesting that PG&E remove the generation tie line—the single span of conductors between the Calpine-owned switchyard at Geysers Units 9/10 and Tower 001/006.[118] In the email, the Calpine employee described Geysers Units 9/10 as "mothballed," a term of art in the industry meaning that the plant was out-of-service but being preserved for future use.[119] The Calpine employee also requested that the insulators on the Geysers #9 side of Tower 001/006 be cleaned to avoid the risk of flashover.[120]

The parties stipulated that in response to that request, PG&E field personnel "disconnected the Geysers Units 9/10 generation interconnection line in approximately May 2006," and "placed the jumpers [on Tower 001/006] in an 'open' configuration."[121] As part of the disconnection work, the May 2006 work crew maintained the jumpers' connection to the vertical support insulator strings and bolted the ends of the jumpers for each phase together.[122,123]

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part of that restructuring, load serving entities like PG&E retained their transmission and distribution networks to deliver electricity to customers but sold much of their utility-owned generation capacity to enable the development of a competitive wholesale market for electricity facilitated by CAISO.

[117] PGE-03, at 3A-22:10–17; PGE-09, at 2 (Kincade Factual Stipulations).

[118] CA-03-SA, at 148–49 (Calpine October 2005 Email).

[119] *Id.*

[120] *Id*.

[121] PGE-09, at 2 (Kincade Factual Stipulations); *see also* PGE-03, at 3A-4:18 to 3A-5:10 (rebuttal testimony of C. Gill).

[122] PGE-03, at 3A-5:2–7.

[123] Reproduction of PGE-01, at 3A-4, Figure 3A-1.

The undisputed factual stipulations establish that the purpose of the jumper configuration was "to allow the [Geysers Units 9/10] plant to be more easily and safely reconnected in the future."[124] Because the May 2006 work preserved the jumper cables that would be used for reconnection, reconnecting the Geysers Units 9/10 to the Geysers #9 Line would involve simply adding a connector to each jumper and running new conductors from the jumpers on Tower 001/006 to the Units 9/10 switchyard.[125] This configuration helped to avoid a far more hazardous, complex, and difficult reconnection project had the jumpers instead been cut near the dead-end shoe, which would have required adding splices and replacing portions of the conductors on the Geysers #9 Line in the high-tension span between Towers 001/006 and 001/007.[126] Splices placed within a span under tension increase the risk of failure by adding a potential failure point—which the PG&E work crew avoided, thereby promoting worker safety and reducing the risk of failure at the connection point.[127]

The record demonstrates that configuring the line to support future reconnection was consistent with the information available to PG&E at the time regarding the future use of Units 9/10, as well as PG&E's contractual tariff obligation to provide service. Pursuant to the 2004 Generator Special Facilities Agreement (GSFA), Calpine paid PG&E $2.8 million annually to maintain special facilities connecting Calpine's geothermal plants with PG&E's transmission

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[124] PGE-09, at 2 (Kincade Factual Stipulations); *see also* PGE-03, at 3A-5:11–13 (rebuttal testimony of C. Gill).

[125] PGE-03, at 3A-5:11–16 (rebuttal testimony of C. Gill).

[126] *Id.* at 3A-5:16–23.

[127] *Id*. at 3A-5:23–29.

system.[128] The GSFA required PG&E to provide the final three spans of the Geysers #9 Line to interconnect the Geysers Units 9/10.[175] Though the GSFA allowed Calpine to provide a termination notice that would release PG&E from this obligation,[129] the stipulated facts establish that "Calpine never provided formal notice of termination under the GSFA related to Units 9/10 and continued to pay for interconnection service" for Units 9/10 at the time of the Kincade Fire.[130] It is therefore undisputed that at the time of the May 2006 work and continuing through the time of the Kincade Fire, PG&E had an ongoing contractual obligation under tariff to provide interconnection service for Geysers Units 9/10 via the last three spans of the Geysers #9 Line, and Calpine continued to pay PG&E for that service.

Calpine's communications with PG&E also confirm that Calpine was continuing to explore future uses for Geysers Units 9/10.[131] The October 2005 email Calpine sent to PG&E described the Geysers Units 9/10 as

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[128] CA-02-SA, at 300 (GSFA) ("Applicant shall pay PG&E any applicable monthly rates and charges for service under PG&E's tariff schedules plus an ownership charge, either (a) or (b) below as specified in Appendix A, namely: (a) COST-OF-OWNERSHIP CHARGE representing PG&E's continuing monthly cost of financing (if applicable), owning and maintaining Special Facilities . . . ."); *id.* at 306–10 (Appendices A and B; identifying the Special Facilities PG&E was obligated to provide under the agreement, including the final three spans of the Geysers #9 Line, as Special Facility 26N).

[129] The GSFA provides that Calpine may provide notice of termination as to any of the special facilities, which "may also decrease the amount of the" fees Calpine paid under the contract each year. However, absent such notice, the GSFA expressly provides that Calpine's "cessation of operations of one or more of the geothermal generating facilities . . . shall not, by itself, . . . relieve PG&E of its obligations to provide interconnection services in accordance with this Agreement." *Id.* at 302.

[130] PGE-09, at 2 (Kincade Factual Stipulations).

[131] *See* PGE-03, at 3A-6:7–9 & n.20, 3A-7:18 to 3A-8:7 (rebuttal testimony of C. Gill).

"mothballed,"[132] indicating that the units were out-of-service but were being maintained in such a condition that Calpine could bring the plant back into service.[133] The simultaneous request to clean the insulators on the Geysers #9 Line to prevent flashovers that "will cause a line outage" further indicated that Calpine expected the facilities to remain in place and electrified to support reconnection.[134] In the years after, Calpine continued to maintain Units 9/10 for future use, including replacing or extensively repairing the roof of the main structure of Units 9/10 in 2016, just a few years before the fire.[135] And, in 2015, Calpine submitted a proposal to house an energy storage project at Units 9/10, leveraging the existing switchyard and interconnection facilities since such a project would require reconnecting Geysers Units 9/10 to the Geysers #9 Line.[136]

We conclude that Cal Advocates' arguments that a reasonable utility would not leave the Geyer's #9 Line energized for over a decade are based on generalized complaints, which are insufficient to raise a serious doubt as to PG&E's conduct. Cal Advocates assertions do not account for record evidence that is consistent with and supported PG&E's decision to configure and maintain

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[132] CA-03-SA, at 149 (Calpine October 2005 email). Cal Advocates has never contested FERC's definition of "mothballed" or provided an alternative definition.

[133] PGE-01, at 3A-23 n.30 (opening testimony of C. Gill). There was precedent for facilities in the Geysers returning to service. Shortly after the May 2006 work, another facility in the Geysers area—the Bottle Rock plant—returned to service after being offline for approximately 16 years. PGE-03, at 3A-8 n.26 (rebuttal testimony of C. Gill).

[134] CA-03-SA, at 149.

[135] PGE-03, at 3A-7 n.25 (rebuttal testimony of C. Gill). At the time of the Kincade Fire, Units 9/10 had much of the equipment necessary to bring the facilities back online, including the step-up transformer, transmission line circuit breaker, steam wells, and a building to house electrical generating equipment. *Id*.

[136] PGE-03C, at 3A-7:21 to 3A-8:7; *see also* CA-02-SA-C, at 234 (Calpine Email, "LAKOMA ENERGY STORAGE PROJECT").

the jumper so as "to allow the plant to be more easily and safely reconnected in the future."[137]

7.1.2.2. Design Versus Engineering Criteria for Evaluating the Jumper

Next, the Commission must consider Cal Advocates' allegations that serious doubt is raised because known conditions would have required PG&E as a prudent manager to take additional measures to protect against a potential wildfire ignition resulting from maintaining an energized jumper in an open configuration. We commence our analysis by setting forth what the parties stipulated to about the open jumper configuration:

> PG&E did not have an engineering standard, design drawing, or guidance document that specifically addressed the "open" jumper configuration used at Tower 001/006 at the time of the Kincade Fire ignition. The jumper met all PG&E design criteria requirements, including with respect to wind mitigation. (PGE-09 at 2.)

Based on the stipulation, while PG&E did not have an engineering standard for the "open" jumper configuration, the Tower 001/006 jumper configuration nonetheless met all PG&E design criteria requirements, including with respect to wind mitigation and the configuration did not violate any specific PG&E standard. Thus, we look at whether Cal Advocates has raised a serious doubt based on the totality of PG&E's conduct in designing and maintaining the jumper in an open configuration, based on information known or available at the time.

Without a requirement for an engineering standard, we must look at whether Cal Advocates has raised a serious doubt based on the totality of PG&E's conduct in designing and maintaining the jumper in an open

[137] PGE-09, at 2 (Kincade Factual Stipulations).

configuration, based on information known or available at the time. We find that PG&E did undertake measures to help the jumper withstand movement from wind. For example, PG&E's internal design standards noted the risks created by wind and incorporated industry-standard mitigations. PG&E's standards required the use of dampers, which were recognized as the most effective method of controlling aeolian vibration; spacers to maintain distance between conductors and mitigate oscillation; and offset arms on towers to increase clearance between phases and minimize the potential for conductor contact. These measures were intended to mitigate wind-induced forces, reducing the risk of mechanical fatigue and supporting reliable performance under varying conditions.[138]

In deciding to undertake these measures, PG&E was guided by the industry literature on wind preventative measures. For example, The Electric Power Research Institute (EPRI) and International Council on Large Electric Systems (CIGRE) manuals published in 2017 also described the principal causes of wind-induced fatigue and explained that they apply primarily to main spans rather than jumpers. The manuals identified three primary types of overhead conductor motion caused by wind: aeolian vibrations, wake-induced oscillations, and conductor galloping. Aeolian vibration and wake-induced oscillation require conductor cables to be under substantial tension and therefore are not an issue for jumper cables, which are not highly tensioned. Conductor galloping occurs mostly in flat terrain under sustained icy conditions, which were not present in

[138] PGE-01, at 3A-18.

the area of the Kincade Fire.[139] PG&E's internal design standards noted the risks created by wind and incorporated industry-standard mitigations.

Further, Cal Advocates propounded data requests on SCE and SDG&E but did not ask if the utilities used jumper configurations like the subject jumper. Cal Advocates did ask SDG&E if it performed "failure risk studies," and SDG&E responded that it uses "inspections and patrols" to evaluate the condition of the infrastructure.[140] Cal Advocates also failed to demonstrate that other utilities in the industry would have refrained from using configurations similar to the subject jumper or would have conducted a specific pre-incident analysis that Cal Advocates suggests. Cal Advocates thus fails to establish that PG&E's actions fell short of the peer utility standard, industry standard, or established industry practice by using the open jumper configuration without conducting an engineering evaluation.

Rule 31.1 also requires that the Commission analyze whether "local conditions known at the time" would have mandated that PG&E perform an engineering evaluation. Cal Advocates' claim that the conditions and the presence of the previous Sawmill Fire would have put a reasonable electrical corporation on notice that maintaining an open jumper configuration was imprudent. Cal Advocates points to the Cal Fire report that noted the Kincade Fire shared some characteristics with the 2016 Sawmill Fire, which was also caused by PG&E-owned equipment in Sonoma County: both fires originated on southwestern-facing, mid-slope spur ridges, and involved mechanical failures

[139] PGE-01, at 3A-18, fn 23.

[140] CA-02-SA, Atch. 18, at 117.

attributed to low-cycle fatigue.[141] Cal Fire's report concluded that these conditions exposed PG&E equipment to above-average winds, increasing the risk of mechanical failure.[142] Cal Fire's investigator further noted that the Sawmill investigation had previously identified the area's high winds as a contributing factor and that those findings were communicated to PG&E in March 2018 with the expectation that PG&E would implement appropriate preventive measures for equipment exposed to similar conditions.[143]

In Cal Advocates' view, the 2018 Camp Fire provided an even more consequential warning of the potential for catastrophic wildfires. According to Cal Advocates, PG&E's energized 115kV transmission facilities caused the deadliest wildfire in state history when a "C hook" which held the energized jumper cable failed.[144] While PG&E was aware of the extreme fire-weather conditions at the time of the Camp Fire, Cal Advocates concludes that PG&E's responsive measures were not those that a reasonable electrical corporation would have implemented.

Cal Advocates alleges facts that PG&E's transmission equipment was responsible for igniting other, prior fires and demonstrated a heightened risk of fires in the Geyser's area, that raise a serious doubt whether PG&E should have taken additional preventative and responsive measures as to Geyser's #9 Line. But PG&E pointed out in its testimony that there were material differences between Sawmill, Camp, and Kincade Fires. The Sawmill Fire involved the

[141] PGE-01 at 3A-Atch01-41.

[142] PGE-01 at 3A-Atch01-42.

[143] PGE-01 at 3A-Atch01-42; CA-04 at 9 (PG&E states it first received the CAL FIRE Sawmill Fire report on March 6, 2018).

[144] CA-04 at 12.

failure of a thin, single stranded, de-energized bond wire after the staples securing it to a wooden pole came loose. The Camp Fire was caused by wear on a C-hook attachment. PG&E further argues that neither of those failure mechanisms is relevant to the Kincade Fire, which involved a 61-strand jumper cable installed on a steel transmission tower, as described herein. (PGE-01, p. 3A-33.)

We find Cal Advocates' general allegations fail to point out specific facts relevant with respect to the cause of the Kincade fire sufficient to raise a serious doubt. Fires can have different main and contributing causes. The fact that there may be some geographical or circumstantial similarities does not mean that an electrical corporation is imprudent in failing to implement all possible measures to prevent a future fire. Instead, we must examine all of the circumstances Cal Advocates alleges were or should have been known to PG&E regarding the prior fires in the area and the circumstances leading to the Kincade Fire to determine if Cal Advocates has demonstrated serious doubt as to PG&E's conduct. We conclude that Cal Advocates has not. The jumper "met all PG&E design criteria requirements, including with respect to wind mitigation,"[145] and did not "violate[] any specific PG&E standard, peer utility standard, industry standard, or established industry practice."[146] What we are left with are differing opinions regarding the appropriate preparedness and mitigation measures that should have been undertaken prior to the Kincade Fire. The fact that opinions among experts differ in the field of fire prevention measures does not create a serious

[145] 151 *Id.*

[146] PGE-04, at Atch1-5 (Cal Advocates' Response to KincadeDixieAB1054_DR_PGE_Cal Advocates_004, Question 8).

doubt, even if, in hindsight, the opinions of the electrical corporation's experts later proves to be wrong.

7.1.2.3. Jumper Inspections

Cal Advocates has not provided evidence that would establish serious doubt as to the reasonableness of PG&E's jumper inspections. The record reveals and the Commission finds that the jumper was examined for signs of wear in the years preceding the fire, including through separate ground, drone, and climbing inspections in 2019 alone.[147] In the years prior to the Kincade Fire, PG&E had a program for inspecting and maintaining its transmission facilities.[148] Following the 2018 Camp Fire, PG&E overhauled its transmission line inspections processes, introducing new inspection methods.[149] In all, PG&E used climbing, drone, infrared, and ground inspections, in addition to a variety of patrols.[150] Just in the last few months before the Kincade Fire, Tower 001/006 and the Geysers #9 Line were inspected multiple times: a ground inspection, a climbing inspection, and a drone inspection.[151] It is likewise undisputed by the parties that none of these inspections "identified any issues on the incident jumper."[152] The only open notification related to Tower 001/006 in PG&E's system at the time of the Kincade Fire addressed repainting of the structure and was not overdue.[153]

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[147] PGE-09, at 3 (Kincade Factual Stipulations).

[148] PGE-01, at 2-16:18 to 2-21:32 (opening testimony of C. Gill).

[149] *Id*. at 2-17:9–27.

[150] *Id*. at 2-18:20 to 2-21:32.

[151] *Id*. at 3A-26:17 to 3A-28:17.

[152] PGE-09, at 3 (Kincade Factual Stipulations).

[153] PGE-01, at 3A-15:25–27 (opening testimony of C. Gill).

None of those inspections "identified any issues on the incident jumper."[154] While this is understandable since "[t]he separation point was located within the solid metal shoe, which obscured the failure location prior to separation,"[155] The inspections do not raise any other information available to PG&E at the time that indicated the jumper would fail in the manner it did. The undisputed evidence regarding PG&E's pre-fire inspections in the months and years preceding the fire establishes that none identified any sign of fatigue. Nor has Cal Advocates identified any pre-fire study, literature, or other information that would have put PG&E on notice of any issue with the open jumper configuration.[156]

The Commission acknowledges, however, that inspections are not perfect and some conditions can be missed. In this case, SED documented that an incorrect template was used for the May 11, 2019, drone inspection which produced "N/A" for jumper condition and found pre-fire photographic indications of bowing.[157] But on June 18, 2019, PG&E re-reviewed the photographs from the May 11th inspection as part of a routine review of forms on which no conditions were reported. PG&E determined in its June 18, 2019, re-review that the Incident Tower was missing a danger sign.[158] When we review the collective record, we do not find that Cal Advocates has established serious doubt as to the reasonableness of PG&E's jumper inspections.

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[154] *Id.*

[155] *Id.*

[156] PGE-03, at 3A-9:7 to 3A-13:12 (rebuttal testimony of L. Eiselstein).

[157] SED Incident Report (October 27, 2021), at 23.

[158] SED Incident Report (October 27, 2021), at 23.

7.1.2.4. PG&E's Determination Not to De-Energize the Last Three Spans of the Geysers #9 Line

Finally, we reject Cal Advocates' argument that PG&E's determination to keep the last three spans of the Geysers #9 Line (which included the incident jumper) energized creates serious doubt as to PG&E's reasonableness. As discussed further below, we do not find Cal Advocates raised a serious doubt regarding PG&E's adoption and implementation of its written standard for identifying and managing idle transmission facilities. But, even absent the question of whether PG&E acted imprudently in developing or implementing that standard, we find no serious doubt raised by PG&E's maintaining the last three spans of the Geysers #9 Line.

PG&E pointed out unique facts and circumstances presented by the last three spans of the Geysers #9 Line.[159] The spans at issue were the last three spans (totaling less than one mile) of the active 43-mile-long Geysers #9 Line, which continued to serve other PG&E customers, including five other Calpine-owned geothermal power plants in the Geysers area.[160] Although Calpine had requested that PG&E remove the generation tie line connecting Geysers Units 9/10 to the Geysers #9 Line at Tower 001/006, at no point did Calpine provide PG&E a notice to terminate interconnection service at Units 9/10—as it was required to do under the parties' GSFA in order to terminate interconnection service to Units 9/10.[161] Indeed, the parties' factual stipulations now establish

[159] *See id.* at 3A-21:26 to 3A-23:2.

[160] *Id.* at 3A-22:3–17.

[161] *Id.* Indeed, in the same communication, Calpine described Units 9/10 as "mothballed"—a term used in the electric utility industry to indicate that a facility is "temporarily out of service and may be brought back online by [its] operator"—and requested that the insulators on the

Footnote continued on next page.

that "Calpine never provided formal notice of termination under the GSFA related to Units 9/10 and continued to pay for interconnection service" to Units 9/10 through the time of the Kincade Fire.[162] Thus, PG&E asserts that it had an ongoing contractual obligation under tariff to provide interconnection service for Geysers Units 9/10.[163]

We conclude that Cal Advocates failed to establish a reasonable doubt that any other utility would have addressed this unique situation differently than PG&E did. While Cal Advocates cites data request responses provided by SCE and SDG&E discussing their practice of de-energizing and removing unneeded facilities in response to a generation customer terminating an interconnection agreement,[164] PG&E claims its practices in such circumstances were the same,[165]

Geysers #9 Line be cleaned, suggesting a plan for future use. PGE-01, at 3A-22:14 to 3A-23:4 (opening testimony of C. Gill).

[162] PGE-09, at 2 (Kincade Factual Stipulations).

[163] PGE-03, at 3A-8:8–11, 3A-24:6–12 (rebuttal testimony of C. Gill).

[164] *See* CA-02, at 6:4–8:14. PG&E argues that SCE's response confirmed that "*upon termination* of a FERC jurisdictional Interconnection Facilities Agreement ('IFA'), its practice was to operationally disconnect the generating facility and remove the associated SCE-owned interconnection equipment" such that the equipment "would be de-energized." CA-02-SA, at 108–10 (SCE Response to Cal Advocates- SCE-A2511001-005, Question 1(a)) (emphasis added); *see* PGE-04, at Atch7-15 (Interconnection Facilities Agreement Between Inland Empire Energy Center, LLC, and SCE, § 12.1) ("Following termination of this Agreement, SCE will remove the Interconnection Facilities from service to [the generating facility]."). PG&E further contends that SDG&E's response similarly stated that "when a generating facility . . . notified SDG&E of the generator's permanent termination of commercial operations and *termination of its generator interconnection agreement*, the transmission line remained energized and in normal service until the generator requested the line [be] de-energized for decommissioning activities"; thereafter, the SDG&E owned transmission facilities "would be physically removed." CA-02-SA, at 114 (SDG&E Response to CALPA-SDGE-A2511001-005, Question 1(a)) (emphasis added).

[165] PGE-03, at 3A-25:11–21 (rebuttal testimony of C. Gill). PG&E claims that the GSFA between PG&E and Calpine demonstrates this. Under that agreement, upon "issuance of a Notice to

Footnote continued on next page.

and that is also consistent with PG&E's formal written standard for managing idle transmission facilities, which neither other utility had.[166] However, in PG&E's assessment, none of those data request responses or any other evidence provided by Cal Advocates indicates what SCE or SDG&E would have done in the unique factual circumstances presented by the last three spans of the Geysers #9 Line—*i.e.*, where an interconnection agreement remains in force and the customer continues to pay for interconnection services but requests that the switchyard be disconnected.[167] Thus, PG&E concludes there is no record evidence suggesting that any other utility would have addressed these circumstances differently than PG&E.

Even if PG&E's inaction constitutes a mistake, the question, then, is whether a single mistake or failure can establish serious doubt about PG&E's prudence to shift the burden of proof. Precedent from FERC suggests not

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Cease Operating Geothermal Facility" and payment of a "facility termination charge," PG&E would remove the Special Facilities subject to the notice, unless they were "being used to provide service to" other customers. *Id.* at 3A25:13–21 (quoting CA-02-SA, at 297–98 (GSFA)). The terms of the standard CAISO-approved interconnection agreement that was current at the time of the Kincade Fire similarly required PG&E to "take all appropriate steps to disconnect the [generator] from [its] Transmission System" upon "termination" of the agreement. *Id.* (second alteration in original).

[166] *Id.* at 3A-24 n.95; PGE-04, at Atch9-1 (SCE Response to CalAdvocates-SCE-A2511001-0005, Question 02(b)) ("SCE did not have a written procedure for disconnecting generating facilities."); *id.* at p. Atch3-1 (SCE Response to CalAdvocates-SCE-A2511001-005, Question 06.A ("From 2001 to 2019, SCE did not have separate policies for unused but energized conductors, redundant spans, or nonessential transmission facilities.").

[167] PGE-03, at 3A-25:22 to 3A-26:11 (rebuttal testimony of C. Gill). To the extent SCE's and SDG&E's responses addressed the Kincade situation at all, they suggest that those utilities did not have a clear policy for a situation, like this one, in which a generator customer had gone offline but had not terminated the relevant interconnection agreement. Both utilities confirmed that they "did not have a standardized checklist requiring evaluation of upstream [transmission line] segments" when "a generating facility disconnected from the grid." *See* PGE-04, at Atch8-1 (SCE's Response to CalAdvocates-SCEA2511001-005, Question 2(a)); CA-02-SA, at 116 (CALPA-SDGE-A2511001-005, Question 2(a)).

necessarily. In FERC's assessment, a mistake without more does "not constitute the kind of mismanagement that should raise serious doubts about the prudency of the [utility's] expenditures."[168]

A similar result was reached in San *Diego Gas & Electric Co.* (2014) 146 FERC ¶ 63,017, in which the Commission intervened in a proceeding before FERC and protested SDG&E's expenditures as being imprudent as SDG&E had allegedly violated General Order (GO) 95. In rejecting the argument that a single act could rebut the presumption of prudence, FERC explained:

> In fact, one violation by a utility does not necessarily constitute imprudence, as utilities are not expected to be infallible. Instead, the Commission looks to things like standard utility practice to determine whether the utility's conduct was that of a reasonable, prudent utility.[169]

Cal Advocates has failed to show that any other utility would have addressed the Geysers #9 spans differently than PG&E, or that PG&E's conduct fell outside utility industry norms. Cal Advocates' data requests to SCE and SDG&E did not ask whether either utility would have de-energized or removed spans facing the same circumstances present by the Geysers #9 spans. Thus, there is no evidence in the record that SCE and SDG&E would have conducted themselves differently with a span that was still subject to an interconnection agreement that had not been terminated.

We conclude that Cal Advocates has failed to create a serious doubt.

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[168] Pacific Gas and Electric Co. (2020) 173 FERC ¶ 61,045, P 180 (Initial Decision).

[169] 146 FERC PP 55-56.

7.2. PG&E's Idle Facilities Management Process

7.2.1. Cal Advocates

Cal Advocates asserts the record establishes that the Incident Spans served no operational function for more than thirteen years, yet PG&E never classified them as idle or even potentially idle. Cal Advocates states that after Geysers Units 9/10 were disconnected in 2006, the Incident Spans carried no load and served no system reliability, contingency, or generation function.[170] Cal Advocates claims that PG&E has no record of any review to determine whether the Geysers #9 Line might have been needed for future capacity or reliability reasons prior to the Kincade Fire, thus the Incident Spans had neither immediate nor near-term load-serving requirement.[171] Nonetheless, Cal Advocates faults PG&E's decision to continue to energize the spans at 230 kV for over thirteen years after, in Cal Advocates' view, their useful purpose ended, until it ignited the Kincade Fire in 2019.

Cal Advocates maintains the continued energization is significant because PG&E had an established process for identifying and managing idle transmission facilities. Under that process, PG&E's Transmission Line Asset Strategy (TLAS) group was responsible for initiating investigations, periodically reviewing facilities for potentially idle status, and coordinating with other departments to determine whether facilities had a foreseeable future use.[172] Starting in 2015, the TLAS group kept a spreadsheet of potentially idle facilities.[173] At the time of the Kincade Fire, that spreadsheet contained seventy-

[170] CA-02, at 3.

[171] *Ibid.*

[172] CA-02 at 13.

[173] *Id.*

two potentially idle transmission facilities, approximately sixteen of which involved spans of active transmission lines.[174] Cal Advocates claims that PG&E imprudently failed to include the unused Incident Spans on its list of idle facilities.

In Cal Advocates' view, PG&E's reliance on its "detailed standard" governing the management of idle transmission facilities does not establish prudence.[175] Cal Advocates argues that a utility cannot demonstrate prudent conduct merely by pointing to a written procedure when the procedure failed to identify an energized facility that had served no operational purpose for more than a decade. Cal Advocates asserts that the relevant question is not whether PG&E had a standard, but whether PG&E's process actually worked to identify and address unnecessary energized facilities. Here, Cal Advocates claims that it did not. Cal Advocates maintains the record establishes that, after Geysers Units 9/10 ceased operating, the Incident Spans no longer served an operational function. Cal Advocates states the generation facility had been taken offline by 2001, and in 2006 PG&E removed the generation tie connecting the facility to the transmission system after Calpine advised that the plant had been "mothballed" for several years.[176] Yet, PG&E continued to energize the last three spans of the Geysers #9 Line and did not identify it as idle or potentially idle. Cal Advocates argues the failure to identify these unnecessary spans as idle and disconnect them was highly imprudent, especially in light of the fact that the plant they served was "mothballed" since around 2001.

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[174] *Id.*, citing PG&E Response to Data Request CalAdvocates-PGE-A2511001-K06, Question 3(c).

[175] PGE-03 at 3A-20.

[176] CA-02 at 14-15.

Cal Advocates claims that PG&E's idle facilities management process appears to have been applied in an inconsistent manner. It notes that PG&E identified the Incident Spans as one of only two spans "that carried no load and were part of active transmission lines for more than ten years."[177] However, unlike the Incident Spans, the TLAS group classified Penn Zier Tap (the other of the two facilities PG&E identified) as "Line Partially Idle" in its spreadsheet.[178] Yet the Incident Spans were never listed as idle, potentially idle, or partially idle. In Cal Advocates view, had PG&E applied an effective and consistent process, the Incident Spans would have been identified for idle-facilities review, and PG&E's review likely would have resulted in the removal or de-energization of the Incident Spans before the Kincade Fire.

Cal Advocates also faults PG&E's explanation for its conduct. According to Cal Advocates, PG&E argues that, "at worst," its failure to identify the Incident Spans as potentially idle "amounts to a single 'breakdown in execution' implementing PG&E's standard for managing idle transmission facilities."[179] However, Cal Advocates argues that PG&E cannot minimize a thirteen-year failure as a "single" error. Per Cal Advocates, the Incident Spans were not merely overlooked once; they remained energized and outside of PG&E's idle facilities process for over a decade despite serving no operational function. From Cal Advocates' perspective, this was not a momentary slip in oversight, it was a

[177] CA-02 at 13, citing PG&E Response to Data Request CalAdvocates-PGE-A2511001-K06, Question 3(c) (CA-02-SA, Attachment 7): "Based on information currently available to PG&E and its review of its idle transmission facilities at the time of the Kincade Fire, PG&E is currently aware of two spans that carried no load and were part of active transmission lines for more than ten years: Geysers #9 Line (001/006 to 001/009) and Penn Zier Tap (004/000 to 003/007)."

[178] CA-02 at 14.

[179] PGE-03 at 3A-19.

persistent failure of PG&E's process to perform its intended function each and every day for nearly 5,000 days. Cal Advocates asserts the failure of PG&E's idle facilities management process is further evidenced by the fact that, in its ACO with SED, PG&E agreed to remove around seventy permanently abandoned transmission lines or portions of lines.[180] Cal Advocates believes this agreement underscores PG&E's inability to achieve its stated idle facilities management objectives and demonstrates the extent of its failure.

Cal Advocates concludes that PG&E was imprudent because its idle facilities management process failed to identify the Incident Spans that served no operational function for more than thirteen years for a plant that had been mothballed since around 2001 yet were left energized. In Cal Advocates' view, had PG&E's process operated as a prudent utility's process should, the Incident Spans would have been identified as idle or potentially idle, evaluated for continued need, and removed or otherwise de-energized. Instead, PG&E continued to energize unnecessary facilities until the failure on the jumper on those spans ignited the Kincade Fire.

7.2.2. Discussion

After reviewing the arguments and the evidentiary record, we conclude Cal Advocates has failed to demonstrate serious doubt as to the reasonableness of PG&E Idle Facilities Management Process. We reach this conclusion based on the following Commission findings. The parties stipulated that at the time of the Kincade Fire "PG&E had a formal standard for identifying and managing idle transmission facilities."[181] PG&E and Cal Advocates also agreed on what the

[180] CA-03-SA, Attachment 3 at Bates 0012.

[181] PGE-09, at 1 (Kincade Factual Stipulations).

standard provided.[182] PG&E's standard defined "idle transmission facilities" as "[f]acilities that are not currently being used to serve transmission load or generation facilities but may have a potential future use by" PG&E.[183] Facilities identified as potentially idle were to be investigated under the standard to determine whether they had potential future use and then classified as either temporarily out of service (if they had potential future use) or permanently abandoned (if they did not).[184] "[F]acilities determined to be temporarily out of service (TOS) would be de-energized or energized at distribution level voltages, and facilities determined to be permanently abandoned (PA) would be removed."[185]

PG&E's standard was adopted in accordance with applicable regulatory requirements and industry practices.[186] By calling for the removal of permanently abandoned facilities, PG&E's standard implemented Rule 31.6 of General Order 95, which requires removal of lines or line segments "that are determined by their owner to have no foreseeable future use."[187] PG&E's standard also "[set] forth procedures for managing idle facilities being

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[182] *Id.* at 1–2.

[183] PGE-01, at 2-13:30 to 2-14:2 (opening testimony of C. Gill).

[184] *Id.* at 2-14:2–7; *see* PGE-09, at 1–2 (Kincade Factual Stipulations).

[185] PGE-09, at 1–2 (Kincade Factual Stipulations).

[186] PGE-01 at 2-13:9–12 (opening testimony of C. Gill); *see also* PGE-09, at 1–2 (Kincade Factual Stipulations) ("PG&E had a formal standard for identifying and managing idle transmission facilities (TD-1003S).").

[187] PGE-01, at 2-13:27–30 (opening testimony of C. Gill); *see also* PGE-09, at 1–2 (Kincade Factual Stipulations) (PG&E's idle facilities standard provided that "facilities determined to be permanently abandoned (PA) would be removed").

maintained for future use" —that is, are not permanently abandoned—a topic not covered in Rule 31.6.[188]

The record also shows that PG&E was implementing its idle facilities standard at the time of the fire.[189] A team within PG&E's asset strategy group was responsible for overseeing implementation of the standard. This included maintaining a list of potentially idle transmission facilities identified for investigation under the standard and updating that list periodically by using maintenance notifications from PG&E's SAP system, reviewing the facilities designated as idle in PG&E's Electric Transmission Geographic Information System (ETGIS), and reaching out to field personnel to identify additional potentially idle facilities.[190] PG&E's team investigated all transmission facilities that had been flagged as potentially idle, coordinating with various groups within PG&E to determine whether the facilities were in fact idle and whether they had future use.[191] At the time of the fire, the team's list included 72 potentially idle transmission facilities being investigated.[192]

In light of this context, Cal Advocates cannot create serious doubt regarding PG&E's prudence by pointing to a single instance in which a potentially idle facility—the spans at issue here—was not identified and investigated pursuant to PG&E's standard. Cal Advocates attempts to separately criticize PG&E at each successive step of the idle facilities

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[188] PGE-03, at 3A-21:12–16 (rebuttal testimony of C. Gill).

[189] *Id.* at 3A-20:10–27.

[190] *Id.*

[191] *Id.* at 3A-21:1–11.

[192] PGE-01, at 3A-25:14–15 (opening testimony of C. Gill).

investigation process with respect to the last three spans of the Geysers #9 Line.[193] Yet it appears that Cal Advocates' criticisms stem from the fact that the spans were never identified as potentially idle.[194] In addition, Cal Advocates identifies no other instances in which PG&E did not identify an idle facility as potentially idle and then did not investigate the facility pursuant to its idle transmission facilities policy.

Moreover, in making this argument, Cal Advocates ignores the unique facts and circumstances presented by the last three spans of the Geysers #9 Line.[195] The spans at issue were the last three spans (totaling less than one mile) of the active 43-mile-long Geysers #9 Line, which continued to serve other PG&E customers, including five other Calpine-owned geothermal power plants in the Geysers area.[196] Although Calpine had requested that PG&E remove the generation tie line connecting Geysers Units 9/10 to the Geysers #9 Line at Tower 001/006, at no point did Calpine provide PG&E a notice to terminate interconnection service at Units 9/10—as it was required to do under the parties' GSFA in order to terminate interconnection service to Units 9/10.[197] Indeed, the

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[193] *See* CA-02 (criticizing PG&E because it (i) "never initiated idle facilities evaluation of incident spans" (*id.* at 12:8–9 (capitalization omitted)), (ii) "did not engage Calpine and properly review idle facilities despite indications of no foreseeable use" (*id.* at p. 14:14–15 (capitalization omitted)), (iii) "did not classify energized incident spans as idle despite spans serving no operational function" (*id.* at 3:3–4 (capitalization omitted)), and (iv) "could have reduced wildfire risk consequences by determining proper idle status of incident spans" (*id.* at 9:8–9 (capitalization omitted))).

[194] *See* PGE-03, at 3A-19:1 to 3A-20:7 (rebuttal testimony of C. Gill).

[195] *See id.* at 3A-21:26 to 3A-23:2.

[196] *Id.* at 3A-22:3–17.

[197] *Id.* Indeed, in the same communication, Calpine described Units 9/10 as "mothballed"—a term used in the electric utility industry to indicate that a facility is "temporarily out of service and may be brought back online by [its] operator"—and requested that the insulators on the

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parties' factual stipulations now establish that "Calpine never provided formal notice of termination under the GSFA related to Units 9/10 and continued to pay for interconnection service" to Units 9/10 through the time of the Kincade Fire.[198] Thus, PG&E had an ongoing contractual obligation under tariff to provide interconnection service for Geysers Units 9/10.[199]

Cal Advocates has also failed to establish that any other utility would have addressed this unique situation differently than PG&E. While Cal Advocates cites data request responses provided by SCE and SDG&E discussing their practice of de-energizing and removing unneeded facilities in response to a generation customer terminating an interconnection agreement,[200] PG&E's practices in such circumstances appear to be the same,[201] and that is also

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Geysers #9 Line be cleaned, suggesting a plan for future use. PGE-01, at 3A-22:14 to 3A-23:4 (opening testimony of C. Gill).

[198] PGE-09, at 2 (Kincade Factual Stipulations).

[199] PGE-03, at 3A-8:8–11, 3A-24:6–12 (rebuttal testimony of C. Gill).

[200] *See* CA-02, at 6:4–8:14. PG&E argues that SCE's response confirmed that "*upon termination* of a FERC jurisdictional Interconnection Facilities Agreement ('IFA'), its practice was to operationally disconnect the generating facility and remove the associated SCE-owned interconnection equipment" such that the equipment "would be de-energized." CA-02-SA, at 108–10 (SCE Response to Cal Advocates- SCE-A2511001-005, Question 1(a)) (emphasis added); *see* PGE-04, at Atch7-15 (Interconnection Facilities Agreement Between Inland Empire Energy Center, LLC, and SCE, § 12.1) ("Following termination of this Agreement, SCE will remove the Interconnection Facilities from service to [the generating facility]."). PG&E further contends that SDG&E's response similarly stated that "when a generating facility . . . notified SDG&E of the generator's permanent termination of commercial operations and *termination of its generator interconnection agreement*, the transmission line remained energized and in normal service until the generator requested the line [be] de-energized for decommissioning activities"; thereafter, the SDG&E owned transmission facilities "would be physically removed." CA-02-SA, at 114 (SDG&E Response to CALPA-SDGE-A2511001-005, Question 1(a)) (emphasis added).

[201] PGE-03, at 3A-25:11–21 (rebuttal testimony of C. Gill). PG&E claims that the GSFA between PG&E and Calpine demonstrates this. Under that agreement, upon "issuance of a Notice to Cease Operating Geothermal Facility" and payment of a "facility termination charge," PG&E would remove the Special Facilities subject to the notice, unless they were "being used to

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consistent with PG&E's formal written standard for managing idle transmission facilities, which apparently neither other utility had.[202] However, none of those data request responses or any other evidence provided by Cal Advocates indicates what SCE or SDG&E would have done in the unique factual circumstances presented by the last three spans of the Geysers #9 Line—*i.e.*, where an interconnection agreement remains in force and the customer continues to pay for interconnection services but requests that the switchyard be disconnected.[203] Thus, there is no record evidence suggesting that any other utility would have addressed these circumstances differently than PG&E.

7.3. PG&E's Public Safety Power Shutoff Program

7.3.1. Cal Advocates

In Cal Advocates' view, a utility cannot establish that its conduct was prudent simply by demonstrating that it followed its own internally developed

provide service to" other customers. *Id.* at 3A25:13–21 (quoting CA-02-SA, at 297–98 (GSFA)). The terms of the standard CAISO-approved interconnection agreement that was current at the time of the Kincade Fire similarly required PG&E to "take all appropriate steps to disconnect the [generator] from [its] Transmission System" upon "termination" of the agreement. *Id.* (second alteration in original).

[202] *Id.* at 3A-24 n.95; PGE-04, at Atch9-1 (SCE Response to CalAdvocates-SCE-A2511001-0005, Question 02(b)) ("SCE did not have a written procedure for disconnecting generating facilities."); *id.* at p. Atch3-1 (SCE Response to CalAdvocates-SCE-A2511001-005, Question 06.A ("From 2001 to 2019, SCE did not have separate policies for unused but energized conductors, redundant spans, or nonessential transmission facilities.").

[203] PGE-03, at 3A-25:22 to 3A-26:11 (rebuttal testimony of C. Gill). To the extent SCE's and SDG&E's responses addressed the Kincade situation at all, they suggest that those utilities did not have a clear policy for a situation, like this one, in which a generator customer had gone offline but had not terminated the relevant interconnection agreement. Both utilities confirmed that they "did not have a standardized checklist requiring evaluation of upstream [transmission line] segments" when "a generating facility disconnected from the grid." *See* PGE-04, at Atch8-1 (SCE's Response to CalAdvocates-SCEA2511001-005, Question 2(a)); CA-02-SA, at 116 (CALPA-SDGE-A2511001-005, Question 2(a)).

criteria. Instead, Cal Advocates suggests the relevant question is whether those criteria reasonably captured the wildfire risks that PG&E knew or reasonably should have known existed.

Cal Advocates argues that PG&E's protocol is not an independent safety standard, it is PG&E's own risk-screening methodology. Cal Advocates claims that by October 2019, PG&E knew energized transmission facilities could become ignition sources for catastrophic wildfires during fire-weather conditions, even when the utility had not identified any pre-existing equipment issues. Cal Advocates points out, for example, the 2016 Sawmill Fire demonstrated that transmission equipment could fail where PG&E did not identify any abnormalities on the circuit nor were any bond wire issues identified in pre-fire inspections.[204] Cal Advocates asserts that Cal Fire noted in its Kincade Fire investigation report that it had communicated its Sawmill Fire findings to PG&E and expected the utility to make appropriate changes and preventive measures to avoid similar failures.[205] Cal Advocates concludes that PG&E imprudently failed to recognize that its inspections were insufficient and failed to make the necessary changes and take preventive measures prior to the Kincade Fire.

In Cal Advocates' view, the 2018 Camp Fire provided an even more consequential warning. PG&E's energized 115 kV transmission facilities caused the deadliest wildfire in state history when a "C hook" which held the energized jumper cable failed.[206] Cal Advocates claims that while PG&E was aware of the extreme fire-weather conditions at the time of the Camp Fire, PG&E's 2018 PSPS

[204] CA-04 at 10.

[205] PGE-01 at 3A-Atch01-42.

[206] CA-04 at 12.

program did not even consider the 115 kV transmission line for de-energization during the relevant PSPS event because its PSPS program at that time was limited to distribution and lower-voltage (70 kV or below) transmission lines.[207] In light of these two fires in the years leading up to the 2019 Kincade Fire, Cal Advocates concludes that a reasonable utility would have designed expansive and nuanced PSPS criteria to adequately address transmission line wildfire ignition risk through de-energization.

In addition, Cal Advocates argues that the fact that Geysers #9 fell outside of PG&E's selected PSPS criteria does not resolve whether the criteria were reasonably designed. Cal Advocates states the record shows that PG&E had already identified the Geysers #9 Line as within the geographic footprint of the anticipated extreme-weather event.[208] Nevertheless, PG&E excluded the line because it did not meet its five criteria. As such, Cal Advocates argues the question is not whether PG&E correctly applied its protocol; instead, the question is whether a prudent utility, armed with PG&E's experience with the Sawmill and Camp Fires, would have regarded an energized transmission line within the forecasted fire-weather footprint as presenting a risk that warranted de-energization, or identify such a line as having a near zero risk, as PG&E did.

Accordingly, in Cal Advocates' view, PG&E cannot convert its compliance with its PSPS protocol into a presumption of prudence. The prudence inquiry must examine the adequacy of the protocol itself, including whether it incorporated the lessons of prior transmission-caused fires and reasonably accounted for the possibility that energized transmission equipment in the area

[207] *Id.*, at 12-13.

[208] *Id.*, at 15.

of the Geysers could fail during extreme weather conditions, as it had just a few years prior. Cal Advocates concludes a prudent PSPS protocol should have incorporated these facts into its decision-making process, but that PG&E's did not.

7.3.2. Discussion

After reviewing the arguments and the evidentiary record, we conclude that Cal Advocates has failed to demonstrate serious doubt as to the reasonableness of PG&E's PSPS protocols. We reach this conclusion based on the following Commission findings. "At the time of the Kincade Fire, PG&E had a multi-factor PSPS protocol for de-energizing transmission lines, which it applied in connection with the October 23, 2019 PSPS event associated with the Kincade Fire."[209] Under that protocol, PG&E would first determine if a transmission line "was in the 'geographic footprint of the PSPS event.'"[210] A transmission line in the geographic footprint would be considered for PSPS if "it met any of" a set of five criteria.[211] PG&E would then coordinate with CAISO to conduct power flow assessments to understand the reliability impacts of de-energizing the transmission lines that met at least one of the criteria, and PG&E's Officer in Charge would make the final de-energization determination.[212]

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[209] PGE-09, at 4 (Kincade Factual Stipulations).

[210] CA-04, at 2:8–9.

[211] *Id.* at 2:9–10. The five criteria were: (1) "a maximum potential consequence score greater than 1,000 units"; (2) "an expected wildfire risk score greater than 10 units"; (3) "any open tags assigned Priority Code A"; (4) "classification as an idle line"; and (5) "for 60 kV and 70 kV lines, more than a low risk of vegetation coming into contact with the line during the weather event." *Id.* at 2:11–16.

[212] PGE-03, at 3A-30:9–19 (rebuttal testimony of S. Holder).

Historically, PSPS had applied only to lower-voltage lines. For example, the PSPS program PG&E introduced in 2018 applied only to distribution and lower-voltage (70 kV or below) transmission lines traversing Tier 3 HFTDs.[236] Following the Camp Fire in November 2018, PG&E expanded its PSPS program to include all transmission lines crossing Tier 2 or Tier 3 HFTD.[237] Pursuant to this new, expanded PSPS program, "PG&E de-energized more high voltage transmission lines than its peer utilities."[238] PG&E also temporarily de-energized 292 transmission lines in 2019;[239] this included 26 lines in the October 23, 2019 PSPS event alone, more than SCE and SDG&E collectively de-energized in all of 2019.[213]

With respect to the October 23, 2019 PSPS event, the Geysers #9 Line "did not meet the criteria for de-energization under PG&E's transmission PSPS protocol" and therefore was not de-energized.[214] Consistent with its PSPS protocol, PG&E claims activated its Emergency Operations Center in advance of the event, and PG&E's meteorology department determined the geographical footprint of the weather event.[215] PG&E then determined which Tier 2 or Tier 3 HFTD lines intersected the geographical footprint of the weather event,[216] and

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[213] *Id.* at 3A-31 n.129, 3A-32:8–10; PGE-04, at Atch10-1 (SCE's Response to CalAdvocates-SCE12511001-002, Question 3), Atch11-1 (SDG&E's Response to CALPA-SDGE-A2511001-003, Question 3).

[214] PGE-09, at 4 (Kincade Factual Stipulations).

[215] PGE-03, at 3A-32:1–4 (rebuttal testimony of S. Holder) ("PG&E's Meteorology Department generated polygons encompassing the geographic areas that met the forecast criteria of having Fire Potential Index (FPI) multiplied by Outage Producing Winds (OPW) of 0.08 or higher, creating an initial footprint for the October 23 PSPS event."); *see also* PGE-01, at 3A-13:22–29 (opening testimony of A. Gibson and S. Holder).

[216] Forecasts showed wind gusts of up to 45 miles per hour and a Fire Potential Index score of 0.35 for the area around the Geysers #9 Line. PGE-01, at 3A-14:3–4 (opening testimony of A. Gibson and S. Holder). Observed wind gusts in the area of the Geysers #9 Line varied by

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evaluated whether those lines met its criteria to be in scope for potential de-energization. As the Geysers #9 Line did not meet PG&E's criteria, it was appropriately excluded.[217]

We conclude that Cal Advocates has failed to raise serious doubt based on allegations that PG&E's transmission PSPS program failed to incorporate other facts known prior to the date of the Kincade Fire.

8. Factors Beyond PG&E's Control Exacerbating the Costs and Expenses Attributable to Both the Dixie and Kincade Fires (Scoping Memo Issues 3, 4, 12, and 13)

As we have determined that the parties have failed to meet their burden of raising serious doubt as to the reasonableness of PG&E's conduct related to the ignition of either the Dixie Fire or the Kincade Fire, PG&E maintains its presumption of reasonableness, and we need not address whether there were factors beyond PG&E's control that exacerbates the costs and expenses attributable to the fires.

9. PG&E's Recorded WEMA Costs for the Kincade and Dixie Fires (Scoping Memo Issues 5, 6, 7, and 8)

We examine PG&E's claim that its settlement and litigation costs related to the Kincade and Dixie Fires were reasonable, which is uncontroverted in the record.[218]

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location but were generally consistent with the forecasts. Two of the three weather stations in the Geysers area closest to

[217] PGE-09, at 4 (Kincade Factual Stipulations); *see also* PGE-03, at 3A-32 n.131 (rebuttal testimony of S. Holder) ("The Geysers #9 Line had a REAX of less than 1,000; an Expected Wildfire risk of less than 10; there were no open A tags; all but three spans of the line was actively serving customer load; and the line was not a 60 or 70 kV line."); CA-04, at 7, Table 1.

[218] *See generally* PGE-02, Chapter 5 (opening testimony of W. Manheim); PGE-06, at 1–6 (PG&E's Further Cost Update Dated August 13, 2026).

9.1. Settlement Costs

As set forth in Exhibit PGE-05, PG&E claims it settled the claims of three main categories of plaintiffs in the litigation arising from the Kincade and Dixie Fires: (1) public entities (Public Entity Plaintiffs), (2) insurance companies that paid claims related to the fires (Subrogation Plaintiffs), and (3) individuals and businesses impacted by the fires (Individual Plaintiffs). PG&E maintains that pursuing settlement was prudent in light of California's inverse condemnation doctrine and the risks of litigating hundreds of cases with thousands of plaintiffs through trial. PG&E points out that the Fund Administrator determined that the settlement costs associated with both the Kincade and Dixie Fires were reasonable when PG&E submitted eligible claims for payment by the Fund.[219] PG&E also notes that the Fund Administrator reviewed the entirety of PG&E's claims and determined that the amounts paid to resolve the claims were consistent with the exercise of reasonable business judgment.[220]

Accordingly, PG&E concludes that these costs are not subject to further reasonableness review by the Commission.[221]

Moreover, PG&E further claims that its testimony details the process PG&E undertook to settle the plaintiffs' claims and demonstrates that the settlement process and settlement amounts are reasonable.[222] PG&E says it pursued settlement with thousands of plaintiffs to avoid facing potentially hundreds of trials, and it did so relatively early in the course of the litigation in

[219] PGE-02, at 5-7:11 to 5-8:18 (opening testimony of W. Manheim).

[220] *Id.* & Attachment 2 (Letters from Fund Administrator); *see also* Pub. Util. Code § 3292(f).

[221] Pub. Util. Code § 3292(f)(1) states, in part, that "To the extent approved by the administrator, a settlement shall not be subject to further review by the commission."

[222] *See* PGE-02, at 5-9:1 to 5-14:26 (opening testimony of W. Manheim).

light of California's inverse condemnation doctrine.[223] By pursuing settlement, PG&E states it avoided the risk of outsized jury awards and expeditiously resolved the plaintiffs' claims.[224] PG&E claims it mediated the Public Entity Plaintiffs' claims to reach favorable settlements;[225] negotiated resolutions with the Subrogation Plaintiffs;[226] and mediated the majority of the Individual Plaintiffs' claims.[227]

Based on our review of the record, the Commission concludes that PG&E's settlement costs are reasonable.

9.2. Litigation Costs

PG&E claims that its prepared testimony also demonstrates the reasonableness of its litigation costs related to the Kincade and Dixie Fires, and that Cal Advocates did not challenge that showing. PG&E states it retained outside counsel with experience handling wildfire litigation to defend against the claims[228] and selected California-based trial counsel to reduce overall travel costs.[229] PG&E says it retained the same lead counsel to coordinate the civil litigation, discovery, and trial strategy for both the Kincade Fire and the Dixie Fire, supporting what it sees as efficiency and cost savings.[230] PG&E claims that

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[223] By law, attorneys' fees and prejudgment interest are recoverable for inverse condemnation claims, which significantly increases the magnitude of recoverable damages. *See id.* at 5-5:22–25.

[224] *Id.* at 5-6:5–13.

[225] *Id.* at 5-9:1 to 5-10:5.

[226] *Id.* at 5-10:6 to 5-11:12.

[227] *Id.* at 5-11:13 to 5-14:4.

[228] PGE-02, at 5-20:21 to 5-23:16 (opening testimony of W. Manheim).

[229] *Id.* at 5-20:11–14.

[230] *Id.* at 5-19:21–27.

outside counsel worked a substantial number of hours over more than five years to defend PG&E against claims filed by nearly 12,000 parties across both fires.[231] PG&E says it retained outside counsel at prudent rates, given the complexity and volume of the work performed, and hired a third-party vendor to vet the cost of the work performed.[232]

PG&E claims that its other litigation-related costs also were reasonable and appropriate given the size and complexity of the litigation arising from the Kincade and Dixie Fires. For instance, PG&E states it retained and paid the experts and consultants necessary to defend the litigation at standard hourly rates consistent with industry norms.[233] PG&E also states that it engaged mediators to negotiate favorable settlements and equally split mediation costs with the plaintiffs.[234] Further, PG&E claims it saved significant costs in both litigations by leveraging discovery undertaken in connection with prior proceedings.[235] PG&E notes it engaged its e-discovery provider to identify, collect, produce, and electronically store the materials required to respond to the voluminous discovery requests propounded by thousands of plaintiffs across both fires.[236] PG&E claims it periodically renegotiated that contract to secure cost savings; reviewed data-storage costs and reduced monthly hosting fees as needed; engaged document reviewers at a discount compared to standard law-

[231] *Id.* at 5-16:11–14.

[232] *Id.* at 5-23:17 to 5-24:12, 5-30:28–34.

[233] *Id.* at 5-24:13 to 5-25:19.

[234] *Id.* at 5-17:3–7, 5-25:20 to 5-27:11. PG&E also batched individual plaintiffs' claims in joint mediation sessions to save on mediator costs and outside counsel fees. *Id.* at 5-26:17–23.

[235] *Id.* at 5-28:4–23.

[236] *Id.* at 5-17:8–11.

firm associate rates; and engaged separate vendors for certain tasks to save additional costs.[237] As a result, PG&E claims that the costs PG&E incurred to defend against the claims were reasonable and appropriate for litigation of this scale.[238]

Based on our review of the record, the Commission concludes that PG&E's litigation costs are reasonable.

10. PG&E's Recorded CEMA Costs for the Kincade and Dixie Fires (Scoping Issues 9, 10, and 11)

PG&E claims the uncontroverted record shows the reasonableness of PG&E's recorded incremental CEMA costs for repair and restoration work related to the Kincade and Dixie Fires.[239] PG&E claims its recorded CEMA costs for the Kincade and Dixie Fires include the costs of repairing damaged electric facilities and restoring electric service to customers following the fire;[240] repairing and restoring gas service to customers;[241] rebuilding and restoring service to damaged power generation facilities;[242] and supporting customers during the restoration and repair of facilities impacted by the Kincade and Dixie Fires.[243] PG&E contends that all of these measures were necessary to restore utility service to the customers affected by the Kincade and Dixie Fires while

[237] *Id.* at 5-28:24 to 5-29:27.

[238] PG&E's Application excludes legal costs associated with (1) probation proceedings, (2) criminal proceedings, and (3) CPUC investigations. *Id.* at 5-31:2–4.

[239] *See generally* PGE-02, Chapter 6 (opening testimony of M. Wendler, T. Latipow, T. Smith, A. Cortes & J. Munoz); PGE-06, at 1, 7–8 (PG&E's Further Cost Update Dated August 13, 2026).

[240] PGE-02, at 6-4:17–26, 6-7:1 to 6-9:26 (opening testimony of M. Wendler).

[241] *Id*. at 5:1 to 6-6:12 (opening testimony of T. Latipow).

[242] *Id*. at 6-9:27 to 6-11:9 (opening testimony of A. Cortes).

[243] *Id*. at 6-6:13 to 6-7:13, 6-11:10 to 6-12:7 (opening testimony of T. Smith).

providing long-term safety, system reliability, and resiliency benefits to the affected communities.[244]

PG&E also claims its prepared testimony establishes that its CEMA repair and restoration costs are incremental, distinct from amounts previously authorized in rates or other cost-recovery proceedings.[245] As shown in PG&E's prepared testimony, PG&E states it uses activity-based forecasting, which estimates incremental costs based on the volume and complexity of the work rather than based on particular staffing levels and other resources.[246] PG&E claims that activity-based forecasting is more efficient and cost-effective for customers because it allows PG&E to deploy resources to work across multiple rate cases and regulatory accounts,[247] rather than hiring two different sets of employees for CEMA and non-CEMA work.[248]

PG&E cites its prepared testimony to establish that the CEMA costs sought are incremental because (1) they are for activities not requested in PG&E's General Rate Case (GRC); (2) contracts, external labor, overtime, and double-time costs comprise most of the total labor costs for PG&E's CEMA event responses; and (3) all of the CEMA costs requested in this Application have been audited by Ernst & Young, which reviewed these costs and confirmed that they are incremental.[249] PG&E states it tracked these costs in work orders that were tagged with identifiers distinct from those included in other cost-recovery

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[244] *Id.* at 6-4:17 to 6-12:7 (opening testimony of M. Wendler, T. Latipow, T. Smith & A. Cortes).

[245] *Id.* at 6-12:9–31 (opening testimony of J. Munoz).

[246] *Id.* at 6-13:9 to 6-14:16.

[247] *Id.* at 6-14:18–26.

[248] *Id.* at 6-15:4–20.

[249] *Id*. at 6-15:28 to 6-16:3.

mechanisms.[250] PG&E claims it used specific fields in its accounting software to track these order costs and direct them to the appropriate accounts for recovery.[251]

Based on our review of the record, the Commission concludes that PG&E's litigation costs are reasonable.

11. PG&E's Cost Recovery Proposals (Scoping Memo Issue 14)

11.1. Cost Recovery Proposals

The cost recovery proposals set forth in PG&E's prepared testimony are reasonable and should be adopted. Cal Advocates presented no testimony challenging PG&E's cost recovery proposals.

WEMA Costs. PG&E seeks authorization to recover WEMA costs totaling approximately $1.449 billion as of July 31, 2026, comprising approximately $782 million related to the Kincade Fire and $667 million related to the Dixie Fire and including financing costs accrued on the balance in PG&E's WEMA at the authorized interest rate for this account.[252] WEMA electric costs represent the vast majority of PG&E's cost recovery request.[253] PG&E claims these costs are eligible for securitization under Section 850 *et seq.*[254] Thus, PG&E proposes to

[250] *Id*. at 6-18:10–14.

[251] *Id*. at 6-18:12 to 6-19:17.

[252] PGE-06, at 1:14–23 and at 1-3 Table 3 (PG&E's Further Cost Update Dated August 13, 2026). As noted in Table 3, approximately $20 million of claims payments recorded in the WEMA as of July 31, 2026, remain subject to payment by the Wildfire Fund. PG&E anticipates truing up the WEMA balance in connection with its proposed securitization application for WEMA electric costs.

[253] *See id.* at 2, Table 1 (showing that approximately $1.37 billion of the approximately $1.449 billion in WEMA costs are WEMA electric costs).

[254] PGE-02, at 7-6:18 to 7-7:24 (opening testimony of M. Cruz).

submit an application following a decision resolving this Application, requesting authorization to issue recovery bonds to finance the WEMA electric costs authorized for rate recovery in this proceeding.[255] In PG&E's view, securitization of these costs supports affordability because low-income customers are exempt from paying recovery bond charges under existing law, and financing through recovery bonds minimizes the bill impact for customers.[256] Under the recovery bond proposal described in Exhibit PGE-02,[257] as updated in Exhibit PGE-06, PG&E estimates that the average cost to customers of the approximately $1.37 billion in WEMA electric costs as of July 31, 2026, would be about $0.71 per month for 25 years.[258] For the relatively smaller amount of WEMA gas costs (approximately $77.8 million as of July 31, 2026), PG&E proposes normal course recovery in rates.[259]

With respect to the approximately $1.2 billion of claims costs paid by the Wildfire Fund as of July 31, 2026, related to the Kincade and Dixie Fires, PG&E requests confirmation that it need not reimburse the Wildfire Fund for these amounts. PG&E asserts that this request has no incremental customer impact because the Fund was capitalized by significant monetary contributions from PG&E customers and shareholders. In PG&E's view, the claims costs paid by the Fund are recorded as credits in the WEMA when payments are received from the Fund and thereby offset incremental WEMA costs requested for rate recovery.

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[255] *Id*. at 7-6:11–16, 7-8:1–11.

[256] *Id*. at 7-8:13 to 7-12:15.

[257] *Id*. at 7-11:15 to 7-12:7.

[258] PGE-06, at 6, Table 10.

[259] *Id*. at 2, Table 1; PGE-02, at 7-12:17 to 7-13:15 (opening testimony of M. Cruz).

CEMA Costs. PG&E proposes normal course recovery in rates for the CEMA O&M revenue requirement of approximately $300 million and CEMA capital revenue requirement of approximately $73 million for the period 2019 through 2030.[260] PG&E proposes to accrue the interest associated with the authorized revenue requirement based on the latest available interest rates, and the final costs recovered will include the interest expense based on those rates, the timing of the decision, and the approved cost recovery.[261]

No party challenged the reasonableness of the WEMA and CEMA cost recovery proposals, and we find PG&E's cost recovery proposals to be reasonable.

11.2. Trailing Costs

The Commission will adopt PG&E's proposal for review and approval of additional WEMA and CEMA costs not included in Exhibit PGE-06.[262] As described in PG&E's prepared testimony, there remain a small number of unresolved claims and potential claims related to the Kincade and Dixie Fires.[263]

PG&E proposes a Tier 2 advice letter process (following the Commission's decision in this proceeding) for the Commission's review and approval of such costs. Cal Advocates did not contest this proposal, and it is consistent with the Commission's approval of a Tier 2 advice letter process for trailing claims in

[260] PGE-02, at 7-15:2 to 7-17:11 (opening testimony of M. Cruz); PGE-06, at 8, Table 15.

[261] PGE-02, at 7-22:30 to 7-23:6 (opening testimony of M. Cruz).

[262] Exhibit PGE-06 reflected PG&E's WEMA balances related to the Kincade and Dixie Fires as of July 31, 2026, and CEMA balances as of June 30, 2026.

[263] PGE-02, at 5-14:28 to 5-15:23 (opening testimony of W. Manheim).

prior wildfire cost recovery proceedings.[264] Such advice letter(s) would include the proposed mechanism by which PG&E seeks to recover the additional costs. For WEMA costs recorded after July 31, 2026, including additional claims and litigation costs, further payments received from the Wildfire Fund, and interest accrued, PG&E anticipates truing up the WEMA balance in connection with its proposed securitization application for WEMA electric costs.

With respect to the claims costs paid by the Wildfire Fund, which PG&E asserts have no incremental customer impact, PG&E asks that the Commission confirm in its decision that PG&E need not reimburse the Fund for any such payments.

The Commission agrees with PG&E's request. Claims costs paid by the Fund will continue to be recorded as credits in the WEMA when payments are received from the Fund and thereby offset incremental WEMA costs requested for rate recovery, as described above. Through the proposed advice letter process, PG&E will also include updates regarding the additional claims costs paid by the Fund and confirm that such amounts have been recorded as credits in the WEMA.

12. Summary of Public Comment

The Commission received 41 public comments, all of which are opposed to PG&E's recovery request. The opposition can be broken down into three categories. First, some oppose the rate increase because of the anticipated negative financial impact on PG&E ratepayers. These comments note that ratepayers are suffering in these difficult economic times and are already paying

[264] D.25-01-042, at 34–35 (decision adopting amended settlement of A.23-08-013, SCE's application to recover costs related to the 2017 Thomas Fire and 2018 Montecito Debris Flow events); D.25-12-023, at 25 (decision adopting settlement of A.24-10-002, SCE's application to recover costs related to the 2018 Woolsey Fire).

some of the highest utility rates in the country. Second, others suggest that the recoveries requested should be borne by PG&E shareholders, board members, and other high-level officers. These comments claim that any financial impact that PG&E is currently facing is the result of a combination of bad upper management decisions and unreasonably deferred maintenance of PG&E's equipment. They argue that ratepayers should not be responsible for bailing PG&E out when its mistakes lead to catastrophic wildfires that lead to exorbitant financial costs and expenses. Third, some suggest that officer compensation be cut and PG&E be transformed into a non-profit entity. They reason that PG&E's structure as a for-profit corporation only encourages wasteful and unproductive spending that the ratepayers remain on the hook for. Commentators suggest that PG&E be transformed into a non-profit entity so that there is greater control over upper-level compensation.

13. Procedural Matters

This decision affirms all rulings made by the Administrative Law Judge and assigned Commissioner in this proceeding. All motions not ruled on are deemed denied.

14. Comments on Proposed Decision

The proposed decision of Commissioner Matthew Baker, the presiding officer, in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on _____, and reply comments were filed on _____ by _____.

15. Assignment of Proceeding

Matthew Baker is the assigned Commissioner and presiding officer, and Robert M. Mason III is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. In D.12-01-032, the Commission adopted the Reax map as the interim fire-threat map for Northern California and that remained the operative map until the Commission's final fire-threat map was adopted in January 2018 pursuant to D.17-12-024.

2. At the time of the Kincade Fire, PG&E possessed a valid safety certificate.

3. PG&E had a formal standard for identifying and managing idle transmission facilities (TD-1003S). Under the standard, facilities determined to be temporarily out of service (TOS) would be de-energized or energized at distribution level voltages, and facilities determined to be permanently abandoned (PA) would be removed. The subject spans were the last three spans of the active 43-mile Geysers #9 Line serving PG&E customers, including five other Calpine-owned geothermal power plants in the Geysers area.

4. Following the disconnection work performed in May 2006 at Calpine's request, the three spans of the Geysers #9 Line between Tower 001/009 and Tower 001/006 (the subject spans) no longer served load and remained energized as part of the Geysers #9 Line.

5. The subject spans were not identified as potentially idle prior to the Kincade Fire and, as a result, PG&E did not conduct an idle facilities investigation of those spans under its standard for identifying and managing idle transmission facilities.

6. Calpine never provided formal notice of termination under the GSFA related to Units 9/10 and continued to pay for interconnection service.

7. When PG&E disconnected the Geysers Units 9/10 generation interconnection line in approximately May 2006, PG&E field personnel placed the jumpers in an "open" configuration to allow the plant to be more easily and safely reconnected in the future.

8. PG&E did not have an engineering standard, design drawing, or guidance document that specifically addressed the "open" jumper configuration used at Tower 001/006 at the time of the Kincade Fire ignition. The jumper met all PG&E design criteria requirements, including with respect to wind mitigation.

9. There is no evidence that other electrical corporations would have refrained from using an open jumper configuration like PG&E's.

10. PG&E's decision to use an open jumper configuration was based on the opinions and experience of PG&E's linemen.

11. The analysis of the photographs taken after the drone and climbing inspections showed no visible sign that the jumper would fail.

12. After the Camp Fire and other wildfire incidents, PG&E developed its WSIP inspection program that was informed by a Failure Modes and Effects Analysis study that PG&E conducted in 2018.

13. The "open" jumper configuration remained in place from 2006 to 2019.

14. PG&E's post-fire laboratory examination and testing by its Applied Technology Services (ATS) department following disassembly studied the jumper separation, concluding that it occurred due to a fatigue fracture from the gradual weakening of the conductor, induced by gusting winds over time.

15. PG&E did not perform an engineering evaluation of the Tower 001/006 "open" jumper configuration between its creation in approximately May 2006 and the Kincade Fire in October 2019, and PG&E's pre-fire ATS reports related to fatigue failures at other facilities did not involve "open" jumper configurations. An engineering evaluation includes evaluations of mechanical performance, fatigue, or component performance under sustained wind-loading conditions.

16. The jumper separation resulted in the jumper contacting and arcing with Tower 001/006 and the ignition of the Kincade Fire.

17. The separation point was located within the solid metal shoe, which obscured the failure location prior to separation.

18. Tower 001/006 was subject to regular equipment inspections, including a drone inspection in May 2019 and a climbing inspection in February 2019, and none identified any issues on the incident jumper.

19. Based on PG&E's search of multiple databases, Cal Advocates has identified ten PG&E event reports that relate to incidents involving transmission jumpers or related hardware prior to the Kincade Fire: two event reports demonstrate past instances of wind-induced jumper failures on its transmission lines; five event reports demonstrate instances of intact jumpers contacting transmission facilities due to wind; two event reports demonstrate instances of hardware failure due to fatigue; and one event report demonstrates an instance of hardware failure due to high winds. None of the reports involves the failure of a jumper with a configuration like the incident jumper at Tower 001/006 at the time of the Kincade Fire.

20. The 2016 Sawmill Fire was associated with the failure of a bond wire on a PG&E 115 kV transmission line. The fire burned 1,547 acres and resulted in two minor injuries during the suppression effort.

21. The 2018 Camp Fire was associated with the failure of a C-hook attachment on a PG&E 115 kV transmission line. The fire burned 153,336 acres, destroyed over 18,000 structures, and caused 84 fatalities.

22. In 2016 PG&E did not have a Public Safety Power Shutoff (PSPS) program to proactively de-energize its facilities. PG&E's PSPS program in 2018 applied only to facilities at voltages of 70 kV and lower and excluded high-voltage transmission lines. Following the Camp Fire, PG&E expanded its PSPS program to include all circuits (transmission and distribution) traversing Tier 2 and Tier 3 HFTDs.

23. PSPS data available on the CPUC's website show that PG&E de-energized more high voltage transmission lines than its peer utilities.

24. At the time of the Kincade Fire, PG&E had a multi-factor PSPS protocol for de-energizing transmission lines, which it applied in connection with the October 23, 2019 PSPS event associated with the Kincade Fire.

25. For the potential October 23, 2019 PSPS event, the Expected Wildfire Risk for the Geysers #9 Line was calculated as near 0 (zero) due to the low value from the Operability Assessment model.

26. While the Geysers #9 Line was in the initial geographic footprint for the potential October 23, 2019 PSPS event, it was excluded from the scope of the October 23, 2019 PSPS event. PG&E excluded it because it did not meet the criteria for de-energization under PG&E's transmission PSPS protocol.

27. CA-04, Figures 4-11 (pp. 20-27) show data from weather stations in the area of the Geysers #9 Line. PG&E has no basis to dispute the weather station data therein, including wind gust speeds, relative humidity, and wind speeds.

28. Exhibit PGE-10 shows data from weather stations PGE281 and PGE125, each identified in CA-04, Figure 3 & Table 2, as located in the area of the Geysers #9 Line.

29. The National Weather Service (NWS) issued a Red Flag Warning for the North Bay area, which includes the ignition location of the Kincade Fire, from 12:00pm on October 23, 2019, until 4:00pm on October 24, 2019.

30. Cal Advocates does not opine that EVM work would have been performed on the Bucks Creek 1101 Circuit before July 13, 2021, under PG&E's prioritization schedule.

31. At the time of the Dixie Fire, PG&E possessed a valid safety certificate.

32. PG&E followed its procedures for a same-day response to an outage.

33. PG&E personnel were authorized to de-energize distribution lines if needed based on the known safety hazards or emergencies.

34. The information available to PG&E personnel indicated that the outage was routine.

35. There is no evidence that either SCE or SDG&E would have acted any differently under the circumstances that PG&E faced.

36. The information available to PG&E personnel gave no indication of an emergency or safety hazard, and there was no reason for PG&E to de-energize the circuit prior to the troubleshooter’s arriveal on site.

37. The ignition area and location of the Subject Span were in HFTD Tier 2.

38. July 13, 2021 was not a red-flag warning day.

39. Cal Advocates compiled the timeline in Exhibit CA-05, Table 1, from PG&E's own responses to Cal Advocates' DR (Exhibit CA-05-SA, pp. 006-010 (response to Cal Advocates DR D02, Q1)) and from the Cal Fire report.

40. Cal Advocates does not dispute the accuracy or confirmation of the facts represented in the timeline.

41. PG&E's response to the outage at Cresta Dam on July 13, 2021 was consistent with its same-day response procedures at the time.

42. At the time of the Dixie Fire ignition, PG&E's outage response procedures applied across its service area, including in HFTD areas. PG&E did not maintain separate outage response procedures for HFTD areas.

43. On July 13, 2021, before PG&E's troubleshooter crossed the bridge at around 4:30 pm, the status of Fuse 17733 could not be verified from an accessible vantage point.

44. On July 13, 2021, Switch 941 could be manually operated in the field and PG&E opened the switch at Cal Fire's request at 8:30 pm.

45. High-impedance faults are low current and can appear similar to normal customer load.

46. The high-impedance fault on July 13, 2021, evaded automated detection because its low current was below the threshold for detection by PG&E's protective devices at the time of the ignition.

47. The recorded ground current values for the Bucks Creek 1101 Circuit were calculations by the line recloser controller algorithm. The calculations were not direct measurements of ground current at the fault location.

48. The fuses at Fuse 17733 operated as intended in response to a transient fault that occurred at approximately 6:48 a.m. on July 13, 2021.

49. Fuses are mechanical system protection devices that cannot be remotely controlled and operate on a per-phase basis to de-energize the phase downstream of the fuse.

50. Energy Safety approved the 2021 WMP, which did not require PG&E to implement a fast trip program.

51. The Commission ratified PG&E's 2021 WMP via Resolution WSD-021.

52. There was no RFW or PSPS event on the Bucks Creek 1101 circuit on July 13, 2021.

53. PG&E first implemented EPSS in July 2021, in response to the Dixie Fire. The information on ignition reduction results initially referenced in CA-07 was not available to PG&E at the time of the ignition.

54. SDG&E first implemented Sensitive Relay Profile (SRP)/Fast Trip program in 2011.

55. SCE first implemented its Fast Curve/Fast trip program in 2018.

Conclusions of Law

1. Because PG&E possessed a valid safety certificate at the time of the Kincade Fire, PG&E is entitled to a presumption of reasonableness.

2. Because PG&E possessed a valid safety certificate at the time of the Dixie Fire, PG&E is entitled to a presumption of reasonableness.

3. Intervenors failed to meet their burden of creating a serious doubt as to PG&E's conduct related to the Dixie Fire.

4. Intervenors failed to meet their burden of creating a serious doubt as to PG&E's conduct related to the Kincade Fire.

5. PG&E's failure to identify the last three spans of the Geysers #9 Line as idle does not create serious doubt as to the reasonableness of PG&E's conduct.

6. The Commission should authorize PG&E to recover the approximately $713 million in the Commission's jurisdictional costs recorded in PG&E's Wildfire Expense Memorandum Account as of July 31, 2026, net of insurance and Wildfire Fund payments, to resolve third-party claims arising from the Kincade Fire, including claims filed by individual plaintiffs, subrogated insurers, and public entities.

7. The Commission should authorize PG&E to recover the approximately $511 million in the Commission's jurisdictional costs recorded in PG&E's Wildfire Expense Memorandum Account as of July 31, 2026, net of insurance and Wildfire Fund payments, to resolve third-party claims arising from the Dixie Fire, including claims filed by individual plaintiffs, subrogated insurers, and public entities.

8. The Commission should confirm that PG&E need not reimburse the Wildfire Fund for claims costs paid or eligible to be paid by the Wildfire Fund related to the Kincade and Dixie Fires, with approximately $1.1 billion in payments received from the Fund as of July 31, 2026 (including $127 million for Kincade and $1.035 billion for Dixie).

9. The Commission should authorize PG&E to recover the approximately $70 million in the Commission's jurisdictional costs recorded in PG&E's Wildfire Expense Memorandum Account as of July 31, 2026, to defend and resolve claims arising from the Kincade Fire, including costs for outside counsel, mediations, experts and consultants, e-discovery, and other litigation costs.

10. The Commission should authorize PG&E to recover the approximately $155 million in the Commission's jurisdictional costs recorded in PG&E's Wildfire Expense Memorandum Account as of July 31, 2026, to defend and resolve claims arising from the Dixie Fire, including costs for outside counsel, mediations, experts and consultants, e-discovery, and other litigation costs.

11. The Commission should authorize PG&E to recover the approximately $83 million in capital costs and $245 million in O&M costs recorded in PG&E's Catastrophic Event Memorandum Account as of June 30, 2026, incurred by PG&E to restore service to customers and to repair or replace facilities damaged by the Kincade and Dixie Fires, and authorize the associated capital revenue requirement of approximately $73 million and O&M revenue requirement of approximately $300 million.

12. The Commission should authorize PG&E to implement its cost recovery proposals for approved costs recorded in PG&E's WEMA-Gas, with approved costs recorded in PG&E's WEMA-Electric to be the subject of a future securitization application.

13. The Commission should approve as reasonable PG&E's proposals for updating and recovering its WEMA and CEMA costs related to the Kincade and Dixie Fires that were not included in PGE-06, PG&E's August 13, 2026, update of WEMA and CEMA costs.

O R D E R

IT IS ORDERED that:

1. Pacific Gas and Electric Company (PG&E) is authorized to recover the approximately $713 million in the Commission's jurisdictional costs recorded in PG&E's Wildfire Expense Memorandum Account as of July 31, 2026, net of insurance and Wildfire Fund payments, to resolve third-party claims arising

from the Kincade Fire, including claims filed by individual plaintiffs, subrogated insurers, and public entities.

2. Pacific Gas and Electric Company (PG&E) is authorized to recover the approximately $511 million in the Commission's jurisdictional costs recorded in PG&E's Wildfire Expense Memorandum Account as of July 31, 2026, net of insurance and Wildfire Fund payments, to resolve third-party claims arising from the Dixie Fire, including claims filed by individual plaintiffs, subrogated insurers, and public entities.

3. Pacific Gas and Electric Company need not reimburse the Wildfire Fund for claims costs paid or eligible to be paid by the Wildfire Fund related to the Kincade and Dixie Fires, with approximately $1.1 billion in payments received from the Fund as of July 31, 2026 (including $127,725 million for Kincade and $1.035 billion for Dixie).

4. Pacific Gas and Electric Company (PG&E) is authorized to recover the approximately $70 million in the Commission's jurisdictional costs recorded in PG&E's Wildfire Expense Memorandum Account as of July 31, 2026, to defend and resolve claims arising from the Kincade Fire, including costs for outside counsel, mediations, experts and consultants, e-discovery, and other litigation costs.

5. Pacific Gas and Electric Company (PG&E) is authorized to recover the approximately $155 million in the Commission's jurisdictional costs recorded in PG&E's Wildfire Expense Memorandum Account as of July 31, 2026, to defend and resolve claims arising from the Dixie Fire, including costs for outside counsel, mediations, experts and consultants, e-discovery, and other litigation costs.

6. Pacific Gas and Electric Company (PG&E) is authorized to recover the approximately $83 million in capital costs and $245 million in Operation & Management (O&M) costs recorded in PG&E's Catastrophic Event Memorandum Account as of June 30, 2026, incurred by PG&E to restore service to customers and to repair or replace facilities damaged by the Kincade and Dixie Fires, and authorize the associated capital revenue requirement of approximately $73 million and O&M revenue requirement of approximately $300 million.

7. Pacific Gas and Electric Company (PG&E) is authorized to implement its cost recovery proposals for approved costs recorded in PG&E's Catastrophic Event Memorandum Account and Wildfire Expense Memorandum Account (WEMA)-Gas (WEMA-G), with approved costs recorded in PG&E's WEMA-Electric (WEMA-E) to be the subject of a future securitization application.

8. Pacific Gas and Electric Company's (PG&E) proposals for updating and recovering its Wildfire Expense Memorandum Account (WEMA) and Catastrophic Event Memorandum Account (CEMA) costs related to the Kincade and Dixie Fires that were not included in PGE-06, PG&E's August 13, 2026 update of WEMA and CEMA costs, are approved as reasonable.

9. Application 25-11-001 is closed.

This order is effective today.

Dated _____, at San Francisco, California.

ATTACHMENT A

Joint Exhibit List