

**PUBLIC UTILITIES COMMISSION**505 VAN NESS AVENUE
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TO PARTIES OF RECORD IN RULEMAKING 08-11-005

This is the proposed decision of Commissioner Timothy Alan Simon. It will not appear on the Commission's agenda sooner than 30 days from the date it is mailed. The Commission may act then, or it may postpone action until later.

When the Commission acts on the proposed decision, it may adopt all or part of it as written, amend or modify it, or set it aside and prepare its own decision. Only when the Commission acts does the decision become binding on the parties.

Parties to the proceeding may file comments on the proposed decision as provided in Article 14 of the Commission's Rules of Practice and Procedure (Rules), accessible on the Commission's website at www.cpuc.ca.gov. Pursuant to Rule 14.3, opening comments shall not exceed 25 pages.

Comments must be filed pursuant to Rule 1.13 either electronically or in hard copy. Comments should be served on parties to this proceeding in accordance with Rules 1.9 and 1.10. Electronic and hard copies of comments should be sent to ALJ Timothy Kenney at tim@cpuc.ca.gov and Commissioner Simon's advisor at esc@cpuc.ca.gov. The current service list for this proceeding is available on the Commission's website at www.cpuc.ca.gov.

/s/ JANET A. ECONOME for
Karen V. Clopton, Chief
Administrative Law Judge

KVC:lil

Attachment

Decision **PROPOSED DECISION OF COMMISSIONER SIMON**
(Mailed 6/10/2011)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Revise and Clarify Commission Regulations Relating to the Safety of Electric Utility and Communications Infrastructure Provider Facilities.

Rulemaking 08-11-005
(Filed November 6, 2008)

**DECISION ADOPTING REGULATIONS TO REDUCE
FIRE HAZARDS ASSOCIATED WITH OVERHEAD POWER LINES AND
COMMUNICATION FACILITIES**

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DECISION ADOPTING REGULATIONS TO REDUCE FIRE HAZARDS ASSOCIATED WITH OVERHEAD POWER LINES AND COMMUNICATION FACILITIES

1. Summary

Today's decision adopts regulations to reduce the fire hazards associated with overhead power lines and aerial communication facilities located in close proximity to power lines. The most significant regulations adopted by today's decision are as follows:

- Rule 18A of General Order (GO) 95 is revised to require electric utilities and communication infrastructure providers (CIPs) to correct within 12 months any Level 2 nonconformance that creates a fire hazard in a high fire-threat area of Southern California.
- Rule 31.2 of GO 95 is revised to require CIPs to inspect their aerial facilities on the following cycles:
 - i. Patrol inspections every year for facilities located in high fire-threat areas of Southern California, and every two years for facilities located in high fire-threat areas of Northern California.
 - ii. Detailed inspections every five years for facilities located in high fire-threat areas of Southern California, and every 10 years for facilities located in high fire-threat areas of Northern California.
 - iii. The inspection requirements in Items (i) – (ii) apply to CIP facilities attached to joint-use poles and to CIP-only poles within three spans of a joint-use pole.
 - iv. Intrusive inspections on the cycles set forth in GO 165 for CIP-only poles that are located within three spans of a joint-use pole in high fire-threat areas of Southern California, and within one span of a joint-use pole in high fire-threat areas of Northern California.
- Rule 35 of GO 95 is revised to (1) apply vegetation management requirements to electric utility facilities and CIP facilities located on lands owned by state and local agencies; (2) require electric

utilities and CIPs to remove vegetation-related strain on conductors energized at 750 volts or less; and (3) allow electric utilities and CIPs to notify land owners who obstruct vegetation management that if a vegetation-related fire occurs, the company may seek to recover its fire-related costs from the land owner.

- Rule 44.2 of GO 95 is revised to require pole-loading calculations whenever a proposed attachment could exceed 10% of the estimated unused carrying capacity of the structure. Rule 44.4 is revised to require entities to share information needed for pole-loading calculations.
- A new Rule 91.5 is added to GO 95 that requires CIPs to attach to their cables and conductors that are affixed to joint-use poles a marker that identifies the owner of the facilities and provides contact information for the owner.
- Appendix E of GO 95 is revised to (1) state that electric utilities and CIPs may exceed the recommended minimum time-of-trim vegetation clearances, and (2) provide a list of factors that electric utilities and CIPs should consider when deciding whether, and to what extent, to exceed the recommended minimum time-of-trim clearances.
- A new Standard 1.E is added to GO 166 that requires electric utilities in Southern California to prepare and submit plans to prevent power-line fires during extreme fire-weather events. Electric utilities in Northern California must make a good faith effort to determine if there is a credible possibility of extreme fire-weather events in their service territories and, if so, to prepare and submit plans to prevent power-line fires from occurring during such events.
- Electric utilities are authorized to revise their tariffs to state that the electric utility may shut off power to a property owner who obstructs access to the utility's overhead power-line facilities located on the owner's property for vegetation management purposes. This authority is limited to one meter serving the property owner's primary residence, or if the property owner is a business entity, the entity's primary place of business. This one meter is in addition to shutting off power

at the location of the vegetation-related fire hazard. Prior to shutting off power, the electric utility must follow the notice requirements that are applicable to the discontinuance of service for non payment, including the notice requirements applicable for sensitive customers, customers who are not proficient in English, and other customer groups.

- A new Phase 3 of this proceeding is established to address two matters. First, Phase 3 will provide a venue for the Consumer Protection and Safety Division to develop and submit a plan to collect data on power-line fires, analyze the data, and use this information to formulate measures to reduce the number of fires ignited by power lines. Second, Phase 3 will develop and adopt fire-threat maps. This will include consideration of fire-threat maps developed by the CIP Coalition (the Reax Map), San Diego Gas & Electric Company (SDG&E), and other parties. The California Department of Forestry and Fire Protection (Cal Fire) and Lawrence Livermore National Laboratory are invited to participate in Phase 3.
- Until permanent fire-threat maps are adopted in Phase 3, the electric utilities and CIPs shall use, on an interim basis, the Reax Map, the SDG&E Map, and Cal Fire's Fire Resource Assessment Program Fire Threat Map to implement the fire-prevention measures adopted in this proceeding.

The investor-owned electric utilities may file applications to recover the costs they incur to implement the regulations adopted in this proceeding until their next general rate case (GRC) proceedings. The electric utilities shall thereafter seek to recover such costs through the GRC process. Similarly, the Small Local Exchange Carriers may use their annual California High Cost Fund-A advice letters to recover the costs they incur to implement the regulations adopted in this proceeding until their next GRC proceedings.

Finally, today's decision denies the request by several parties to open a new rulemaking proceeding to consider if electric Tariff Rule 20 should be

amended to add “fire risk” to the list of reasons to permit the undergrounding of aerial facilities pursuant to Tariff Rule 20.

2. Background

2.1. Procedural Background

In October 2007, strong Santa Ana winds swept across Southern California and caused dozens of wildfires. The resulting conflagration burned more than 780 square miles, killed 17 people, and destroyed thousands of homes and buildings. Hundreds of thousands of people were evacuated at the height of the fire siege. Transportation was disrupted over a large area for several days, including many road closures. Portions of the electric power network, public communication systems, and community water sources were destroyed.¹

Several of the worst wildfires were reportedly ignited by power lines. These included the Grass Valley Fire (1,247 acres); the Malibu Canyon Fire (4,521 acres); the Rice Fire (9,472 acres); the Sedgewick Fire (710 acres); and the Witch Fire (197,990 acres).² The total area burned by these five power-line fires was more than 334 square miles.

In response to the widespread devastation, the Commission issued Order Instituting Rulemaking (OIR) 08-11-005 on November 6, 2008, to consider and adopt regulations to reduce the fire hazards associated with overhead power-line facilities and aerial communication facilities in close proximity to power lines. On January 6, 2009, the Assigned Commissioner issued a ruling and scoping

¹ *California Fire Siege 2007 – an Overview* prepared by the California Department of Forestry and Fire Protection, at page 6. We take official notice of this document on our own motion pursuant to Pub. Util. Code §§ 701 and 1701, and Rule 13.9 of the Commission’s Rules of Practice and Procedure.

² *California Fire Siege 2007 – an Overview*, at pages 20, 27, and Appendix II.

memo (“Scoping Memo”) that split this proceeding into two phases. The focus of Phase 1 was to adopt fire-prevention measures that could be implemented in time for the 2009 autumn fire season in Southern California. Phase 1 concluded with the issuance of Decision (D.) 09-08-029 (“the Phase 1 Decision”).

A prehearing conference for Phase 2 was held on October 9, 2009. On November 5, 2009, the Assigned Commissioner issued the Phase 2 Scoping Memo that identified 25 topics as within the scope of Phase 2, including the issue of whether “fire risk” should be added to the list of reasons to permit undergrounding pursuant to electric Tariff Rule 20.

The Phase 1 Decision directed that Phase 2 be conducted through a workshop process.³ To this end, the Phase 2 Scoping Memo established a framework for conducting the Phase 2 workshops, set a workshop schedule, and appointed Administrative Law Judges (ALJs) Angela Minkin and Jean Vieth to serve as neutral facilitators for the workshops. The Phase 2 Scoping Memo also directed the workshop participants to prepare and submit a workshop report containing proposals for reducing fire hazards.

Parties were given an opportunity to request an evidentiary hearing regarding Phase 2 issues using the procedures in the Phase 2 Scoping Memo. There were no requests for an evidentiary hearing and none was held.

2.2. The Phase 2 Workshops

The first workshop for Phase 2 was held on January 15, 2010. In total, 25 days of workshops were held over a period of six months. The workshop sessions were publicly noticed and open to the public. Thirty nine parties actively participated in the workshops, including Commission’s staff,

³ D.09-08-029 at 45 and Conclusion of Law 19.

investor-owned utilities, municipal utilities, telecommunications companies, a labor union, consumer groups, and independent consultants. The parties represented at the workshops are listed below:

List of Phase 2 Workshop Participants
Bill Adams
AT&T California and New Cingular Wireless PCS, LLC (AT&T)
The Commission's Consumer Protection Division (CPSD)
The Commission's Division of Ratepayer Advocates (DRA)
California Cable & Telecommunications Association (CCTA)
California Department of Forestry and Fire Protection (Cal Fire)
California Farm Bureau Federation (CFBF)
California Independent System Operator Corporation (CAISO)
California Municipal Utilities Association (CMUA)
California Association of Competitive Telecommunications Carriers (Cal Tel)
Frontier Communications of California (Frontier)
CTIA-The Wireless Association (CTIA)
Comcast Phone of California, LLC (Comcast)
County of Los Angeles Fire Department (LA County)
CoxCom Inc. and Cox California Telecom, L.L.C. (Cox)
Davey Tree
Extenet
Facilities Management Specialists, LLC
International Brotherhood of Electrical Workers 1245 (IBEW 1245)
Los Angeles Department of Water and Power (LADWP)
Mussey Grade Road Alliance (MGRA)
NextG Networks of California, Inc. (NextG)
Northern California Power Association
Osmose Utilities Services
Pacific Gas and Electric Company (PG&E)

List of Phase 2 Workshop Participants
PacifiCorp
Sacramento Municipal Utility District (SMUD)
San Diego Gas & Electric Company (SDG&E)
Sierra Pacific Power Company (Sierra Pacific)
The Small Local Exchange Carriers (Small LECs)
Sunesys, LLC (Sunesys)
SureWest Telephone
Southern California Edison Company (SCE)
Sprint Nextel (Sprint)
The Utility Reform Network (TURN)
T-Mobile West Corporation d/b/a/ T-Mobile (T-Mobile)
Time Warner Cable (Time Warner)
tw telecom of California, lp (tw telecom)
Verizon California Inc. (Verizon)

The workshop process resulted in many thoughtful proposals for reducing fire hazards. Much of the credit for the success of the workshops belongs to ALJ Minkin and ALJ Vieth. As a result of their leadership, the 39 parties were able to debate dozens of proposals and reach a consensus in important areas. We also thank the workshop participants for their hard work, dedication, and many thoughtful proposals.

2.3. The Phase 2 Workshop Report and Briefs

On August 13, 2010, Sunesys filed and served the *Phase 2 Joint Parties' Workshop Report for Workshops Held January – June 2010* (“the Phase 2 Workshop Report”) on behalf of itself and the following parties: AT&T, CAISO, CalTel, CCTA, CFBF, CMUA, Comcast, Cox, CPSD, CTIA, Davey Tree, DRA, Frontier, IBEW 1245, LA County, LADWP, MGRA, NextG, Osmose, PG&E, PacifiCorp,

SDG&E, Sierra Pacific, the Small LECs,⁴ SureWest, SCE, Sprint, Time Warner, T-Mobile, TURN, tw telecom, and Verizon. Several parties who attended the Phase 2 workshops did not join the Phase 2 Workshop Report.

The Phase 2 Workshop Report presents 36 proposals that were discussed during the workshops. The workshop participants reached a consensus on six of the proposals, which are contained in Appendix A of the Workshop Report. The remaining proposals were contested by one or more parties. The contested proposals are contained in Appendix B of the Phase 2 Workshop Report.

Opening Briefs regarding the Phase 2 Workshop Report were filed on September 30, 2010, by the following parties: Cal Fire, CFBF, CAISO, CMUA, a coalition of communication infrastructure providers (the CIP Coalition),⁵ CPSD, DRA, IBEW 1245, LA County, LADWP, Multi-Jurisdictional Utilities (MJU),⁶ MGRA, PG&E, SDG&E, SCE, the Small LECs, and TURN. Reply briefs were filed on September 17, 2010, by the following parties: CFBF, CMUA, the CIP Coalition, CPSD, DRA, IBEW 1245, LA County, LADWP, MGRA, PacifiCorp, PG&E, SDG&E, SCE, Small LECs, Sierra Pacific,⁷ and TURN. With

⁴ The Small LECs are the following carriers: Calaveras Telephone Company, Cal-Ore Telephone Co., Ducor Telephone Company, Foresthill Telephone Co., Happy Valley Telephone Company, Hornitos Telephone Company, Kerman Telephone Co., Pinnacles Telephone Co., The Ponderosa Telephone Co., Sierra Telephone Company, Inc., The Siskiyou Telephone Company, Volcano Telephone Company, and Winterhaven Telephone Company.

⁵ The CIP Coalition is comprised of AT&T, CCTA, CTIA, Comcast, Cox, Frontier, the Small LECs, Sunesys, SureWest Telephone, Sprint, T-Mobile, Time Warner Cable, tw telecom of california, lp, and Verizon.

⁶ The MJUs are PacifiCorp and Sierra Pacific.

⁷ In D.10-10-017, the Commission approved the transfer of Sierra Pacific's public utility facilities and operations in California to California Pacific Electric Company,

Footnote continued on next page

the permission of the assigned ALJ, CPSD and MGRA filed a joint sur-reply brief on October 18, 2010, that addressed certain issues raised in PG&E's reply brief. PG&E filed a response to the sur-reply brief on November 11, 2010.

3. Commission Jurisdiction

The purpose of this rulemaking proceeding is to consider and adopt regulations to reduce the fire hazards associated with (1) overhead power-line facilities, and (2) aerial communication facilities located in close proximity to overhead power lines. The California Constitution and the Public Utilities Code provide the Commission with broad jurisdiction to adopt regulations regarding the safety of utility facilities and operations.⁸ Utilities are required by Pub. Util. Code § 702 to "obey and comply" with such requirements.⁹

The Commission has enacted an extensive set of safety regulations governing utility facilities and operations, including General Orders 95 and 165. A major goal of these General Orders is to minimize fire hazards.

In addition to the Commission's broad jurisdiction to regulate investor-owned utilities, Pub. Util. Code §§ 8002, 8037, and 8056 provide the Commission with authority to adopt and enforce rules governing electric transmission and distribution facilities of publicly owned utilities (POUs) for the limited purpose of protecting the safety of employees and the general public. Today's decision does not re-litigate the Commission's determination in the OIR and the Phase 1

LLC (CalPeco). Today's decision uses "Sierra Pacific" to refer to both CalPeco and Sierra Pacific, unless otherwise indicated.

⁸ Cal. Constitution, Article XII, §§ 3 and 6, and Pub. Util. Code §§ 216, 701, 761, 768, 770, 1001, 8037 and 8056. See also *San Diego Gas & Electric Company v. Superior Court*, (1996) 13 Cal.4th 893, 923-924.

⁹ See also Pub. Util. Code §§ 761, 762, 767.5, 768, 770.

Decision that it may adopt and enforce safety-related regulations for POU electric transmission and distribution facilities.¹⁰

Today's decision adopts several safety-related regulations that apply to electric transmission facilities. These rules do not conflict with (1) reliability standards issued by an Electric Reliability Organization that is certified by the Federal Energy Regulatory Commission (FERC), or (2) performance standards issued by CAISO for transmission facilities under its control pursuant to Pub. Util. Code § 348 or FERC-approved Transmission Control Agreements.

The Commission's comprehensive jurisdiction over matters of public safety associated with utility facilities extends to attachments to utility poles by CIPs. Specifically, 47 U.S.C. § 224 provides that the Federal Communications Commission (FCC) does not have "jurisdiction [under 47 U.S.C. § 224] with respect to rates, terms, and conditions, or access to poles, ducts, conduits, and rights-of-way as provided in subsection (f) for pole attachments in any case where such matters are regulated by a State." The Commission has certified to the FCC that the Commission regulates the rates, terms, and conditions of access to poles, conduits, ducts, and rights-of-way in conformance with 47 U.S.C. §§ 224(c)(2) and (3).¹¹ Further, under 47 U.S.C. § 253(b) the Commission may adopt regulations to protect the public safety and welfare.

Likewise, the Cable Communications Policy Act of 1984 specifically grants states jurisdiction over cable service in safety matters. (47 U.S.C. § 556 (a).) The California Legislature asserted such jurisdiction in Pub. Util. Code § 768.5, which

¹⁰ OIR at 6, and D.09-08-029 at 8 – 9 and Conclusion of Law 3. See also the Phase 2 Scoping Memo at 4, Item 8.

¹¹ D.98-10-058, 82 CPUC2d 510, 531, as modified by D.00-04-061, 6 CPUC3d 1, 5.

gave the Commission authority to regulate cable companies with respect to the safe operation, maintenance, and construction of their facilities.

4. Criteria for the Adoption of New Regulations

The main purpose of this proceeding is to consider and adopt regulations to reduce the fire hazards associated with overhead power-lines and aerial communication facilities in close proximity to power lines. Therefore, in deciding whether to adopt the proposals in the Phase 2 Workshop Report, the primary standard we will use is whether the proposals are likely to reduce fire hazards. We must also consider the costs of the proposed regulations. If the cost of a proposed regulation appears to exceed the benefits to be gained from the reduction in fire hazards, the regulation should be rejected.

Because this is a quasi-legislative rulemaking proceeding,¹² today's decision may rely on legislative facts¹³ obtained from written submissions in this proceeding, such as the Phase 2 Workshop Report and briefs. We may also draw on evidence from past proceedings, our experience and expertise in regulating utilities, our current policies, and common sense.¹⁴

We do not need to rely on formal evidence or hold an evidentiary hearing in a quasi-legislative rulemaking proceeding. As set forth in Pub. Util. Code § 1708.5(f), "the commission may conduct any proceeding to adopt, amend, or

¹² Phase 1 Scoping Memo at 16. A quasi-legislative proceeding establishes policies or rules affecting a class of regulated utilities. (Rule 1.3(d) of the Commission's Rules of Practice and Procedure.)

¹³ Legislative facts are general facts that help the Commission to decide questions of law and policy and discretion. (Rule 13.3(c) of the Commission's Rules of Practice and Procedure.)

¹⁴ D.06-06-071 at 26; D.06-12-029 at 13 - 14; D.04-03-041 at 11; and D.99-07-047, 1 CPUC3d 627, 634 - 636.

repeal a regulation using notice and comment rulemaking procedures, without an evidentiary hearing, except with respect to a regulation being amended or repealed that was adopted after an evidentiary hearing, in which case the parties to the original proceeding shall retain any right to an evidentiary hearing accorded by Section 1708.” Notice of OIR 08-11-005 was served on all potential parties, including regulated electric corporations, municipal electric utilities, and CIPs operating in California.¹⁵ Parties were given an opportunity to request an evidentiary hearing using the procedures in the Phase 1 and Phase 2 Scoping Memos. No party requested an evidentiary hearing¹⁶ and none was held.

5. Consensus Proposals

Appendix A of the Phase 2 Workshop Report contains six consensus proposals to revise the Commission’s General Orders. There is no opposition to the consensus proposals. We address each of the consensus proposals below.

5.1. Consensus Proposal 1 re: GO 95, Rule 18A

5.1.1. Summary of Proposal

Rule 18A of General Order (GO) 95 requires CIPs and electric utilities to correct safety hazards and violations of GO 95. Consensus Proposal 1 would replace the word “violation” in Rule 18A with the word “nonconformance.” The proposed revisions to Rule 18A are shown in Appendix A of today’s decision.¹⁷

The parties do not expect Consensus Proposal 1 to have any financial impact on electric utilities or CIPs.

¹⁵ OIR 08-11-005, at Ordering Paragraph 6.

¹⁶ Certain parties initially requested an evidentiary hearing in Phase 1, but later opted for workshops in lieu of evidentiary hearings. (D.09-08-029 at 6.)

¹⁷ The consensus proposal to revise Rule 18A is in addition to two contested proposals to revise Rule 18A that are addressed later in today’s decision.

5.1.2. Position of the Parties

Most parties either did not address Consensus Proposal 1 in their briefs or expressed general support for the proposal.

CPSD does not believe the consensus proposal to replace the word “violation” with “nonconformance” will improve safety. CPSD is neutral on the proposal because, in CPSD’s opinion, it does not matter which word is used, as the Commission has determined that a “nonconformance” is a “violation.”¹⁸

SCE believes there is an important distinction between the words “nonconformance” and “violation.” SCE states that the term nonconformance is broader than violation. By using the term nonconformance, the applicability of Rule 18A will be broadened to encompass conditions that do not rise to a level that is considered to be a violation by Commission decisions.

5.1.3. Discussion

We agree with the Phase 2 Workshop Report that revising Rule 18A to use the word “nonconformance” in place of “violation” will facilitate the timely correction of all conditions that do not adhere to the requirements of GO 95.¹⁹ The timely correction of non-conforming conditions should help achieve our goal of improved fire safety. The consensus revisions to Rule 18A are also consistent with the terminology found in GO 95, Rule 12.6 (Third Party Nonconformance) and Rule 35 (Vegetation Management) – Exception #3.

For the preceding reasons, we find the consensus revisions to Rule 18A are reasonable in light of the record, consistent with the law, and in the public

¹⁸ D.04-04-065, 2004 Cal. PUC LEXIS 207 at *18.

¹⁹ Phase 2 Workshop Report, Appendix A, at A-8.

interest. We therefore adopt the revisions. The text of the revised Rule 18A is contained in Appendix B of today's decision.²⁰

5.2. Consensus Proposal 2 re: GO 95, Rule 18B

5.2.1. Summary of Proposal

Rule 18B of GO 95 requires that if one company discovers a safety hazard with respect to another company's facilities, the first company must notify the second company of the hazard no later than 10 business days after the discovery. Consensus Proposal 2 consists of several proposed revisions to Rule 18B that are intended to clarify the rule. The proposed revisions to Rule 18B are shown in Appendix A of today's decision.

A first consensus revision concerns the applicability of Rule 18B. The rule currently applies when a company is "inspecting its facilities." The consensus revision replaces the phrase "inspecting its facilities" with the "performing inspections." The replacement phrase is intended to clarify that Rule 18B applies to inspections during the normal course of business, and not to emergency situations when companies must inspect their facilities to remedy the emergency.

The second consensus revision adds flexibility to the notification requirement. Rule 18B currently requires that notifications be "in writing." The revision requires that notifications be "documented" to avoid limiting the methods used by a company to notify another company of a safety hazard. For example, the proposed revision would allow the inspecting company to meet the notification requirement by making a phone call and then documenting the call.

²⁰ The revised Rule 18A adopted by today's decision reflects the consensus revisions as well as certain contested revisions that are addressed later in today's decision.

The third consensus revision provides greater flexibility for a pole owner that is informed about a safety hazard with the facilities of one of its pole tenants. Currently, the pole owner must notify the pole tenant of the safety hazard “promptly.” The proposed revision states that the timeframe is “normally” not to exceed five business days. The use of the word “normally” reflects the fact that it is sometimes impossible to provide notice within five business days. This could occur, for example, when the pole owner must visit facilities that are located on land where the property owner refuses to provide access.

The fourth consensus revision to Rule 18B simplifies the term “electric transmission or distribution facility” to “electric facility.”

The fifth revision removes the requirement that the inspecting company must state in its notification whether the safety hazard is in a high fire-threat zone. The workshop participants agreed that this requirement is unnecessary.

The final consensus revision is to the sentence that states: “It is the responsibility of each pole owner to know the identity of each entity using or maintaining equipment on its pole.” Several parties expressed concern about whether Rule 18B requires each joint owner of a utility pole to know the identity of every entity that another joint owner leases its space to. The consensus revision clarifies this requirement by stating that a company must be able to determine the identity of (1) its own pole tenants, and (2) other pole owners.

The authors of the Phase 2 Workshop Report do not expect the consensus revisions to Rule 18B to increase costs significantly.

5.2.2. Position of the Parties

Most parties either did not address Consensus Proposal 2 in their briefs or expressed general support for the proposal.

SCE submits that the consensus revisions to Rule 18B will make it clear that utility inspectors do not need to apply the rule's requirements during emergencies or trouble calls when the focus is on restoring service.

SCE states that the consensus revisions also recognize the difficulties faced by joint owners of utility poles in identifying every pole tenant. While a utility knows the tenants in the space it owns on jointly owned poles, the utility does not always know the tenants in the space of the other pole owners. The revised rule recognizes this reality, and permits the inspecting company to notify the relevant joint owner when it cannot identify the tenant whose facilities are causing a safety hazard. It is then the responsibility of the relevant joint owner to notify its tenant of the hazard.

In its opening brief, SCE proposed – apparently for the first time – to revise Rule 18B to remove all deadlines for providing notice of safety hazards. SCE disfavors placing time frames and other operational requirements in GO 95. Instead, SCE favors a “programmatic approach” to regulation within GO 95. Specifically, GO 95 should contain the standards to be met by regulated utilities. The utilities should be required to develop a program to meet those standards, and Commission staff should audit the utilities to ensure their programs are designed to meet the standards and that each utility is following its program. This approach allows each utility to consider the unique aspects of its service territory and operations when developing compliance programs.

5.2.3. Discussion

We agree with the rationale in the Phase 2 Workshop Report that the consensus revisions to Rule 18B will clarify and streamline the requirements

regarding the notification of safety hazards.²¹ This will facilitate notice of safety hazards to the entities responsible for correcting the hazards which, in turn, should help to reduce safety hazards over time.

For the preceding reasons, we find the proposed consensus revisions to Rule 18B are reasonable in light of the record, consistent with the law, and in the public interest. We therefore adopt the revisions. The text of the revised Rule 18B is contained in Appendix B of today's decision.

We decline to adopt SCE's proposal to eliminate from Rule 18B the deadlines for providing notice of safety hazards. As a preliminary matter, SCE's proposal was apparently not raised during the Phase 2 Workshops. Thus, the issue was not properly raised in this proceeding. More fundamentally, we believe SCE's proposal would be detrimental to public safety, as it would eliminate the requirement for a utility to provide notice of an observed safety hazard to the entity responsible for correcting the hazard within a specified timeframe. It is not in the public interest to adopt a proposal that would allow an observed safety hazard to go unreported (and uncorrected) indefinitely.

5.3. Consensus Proposal 3 re: GO 95, Rule 35

5.3.1. Summary of Proposal

Rule 35 of GO 95 requires electric utilities and CIPs to keep their overhead facilities clear of vegetation. Consensus Proposal 3 consists of revisions to Paragraphs 1 - 3 of Rule 35. The consensus revisions to Rule 35 are shown in Appendix A of today's decision.

²¹ Workshop Report, Appendix A, at A-12 to A-14.

The consensus revisions to Paragraph 1 clarify that Rule 35 applies to all electric utility and CIP facilities located on lands owned by state and local agencies. This is intended to ensure consistent vegetation management practices on all lands throughout the state.²²

The consensus revisions to Paragraph 2 clarify that it is permissible for healthy trees to lean toward or overhang conductors, and that electric utilities and CIPs should trim or remove a tree only when they have actual knowledge that a dead, rotten or diseased tree (including trunks, limbs, or branches) is poised to fall onto a power line or communication line. Also, the term “span” is modified to include the phrase “of supply or communication lines” to avoid interpretive errors.²³

The consensus revisions to Paragraph 3 clarify that low voltage conductors (0 - 750 volts) deflected by trees, but still within allowable tension, are subject to vegetation management in order to avert support structure damage or failure due to excessive transverse loads.

The Phase 2 Workshop Report states that it is unknown at this time whether Consensus Proposal 3 will result in additional costs.

5.3.2. Position of the Parties

Most parties either did not address Consensus Proposal 3 in their briefs or expressed general support for the proposal.

CPSD, PG&E, and SCE aver that the consensus revisions to Rule 35 will clarify that vegetation management requirements apply to facilities located on

²² Nothing in the proposed revisions to Rules 35 is meant to suggest that the minimum clearances currently in Table 1, Cases 13 and 14 apply to communication lines.

²³ Today’s decision uses the terms “power line” and “supply line” interchangeably.

state and local lands, which should help utilities to deal with government entities that refuse to allow utilities to perform vegetation management work. PG&E and SCE add that the consensus revisions will also clarify that (1) it is permissible for healthy trees or limbs to overhang or lean toward conductors; and (2) vegetation-related strain on a conductor needs to be corrected when it compromises the integrity of the supporting structures.

5.3.3. Discussion

We find that the consensus revisions to Rule 35 will enhance public safety by reducing the fire hazards associated with overhead electric utility and CIP facilities. The consensus revisions to Paragraph 1 of Rule 35 will require overhead power lines and communication lines located on lands owned by state and local public agencies to be kept clear of vegetation.

The consensus revisions to Paragraph 2 will help electric utilities and CIPs to determine when a tree that overhangs or leans toward a conductor should be trimmed or removed. This should make vegetation management activities more efficient and effective at reducing fire hazards.

Finally, the consensus revisions to Paragraph 3 will clarify that electric utilities and CIPs are responsible for remedying vegetation-related strain on conductors energized at 750 volts or less. This should reduce the incidence of damaged lines, appurtenances, and support structures, and thereby reduce safety risks to workers and the general public.

Although the Phase 2 Workshop Report does not provide an estimate of the costs, if any, to implement the consensus revisions to Rule 35, we anticipate such costs will be minimal.

For the preceding reasons, we find the proposed consensus revisions to Rule 35 to be reasonable in light of the record, consistent with the law, and in the

public interest. We therefore adopt the revisions. The text of the revised Rule 35 is contained in Appendix B of today's decision. The adopted text includes the correction of the following typo, omission, and inconsistency in the Phase 2 Workshop Report: (1) replacing the period at the end of the first sentence of Rule 35, Paragraph 1, with a comma, so that the first and second sentences are combined into one sentence; (2) adding the word "General" before "Order" in the last sentence of the first paragraph; and (3) replacing the word "violation" with "nonconformance" in the last sentence of the third paragraph, which is consistent with the use of the word "nonconformance" in the Third Exception listed in Rule 35 and in the adopted consensus revisions to Rule 18A.

5.4. Consensus Proposal 4 re: GO 95, Rule 37, Table 1, Case 14 and Footnotes (fff) - (jjj)

5.4.1. Summary of Proposal

The Phase 1 Decision modified Rule 37, Table 1, Case 14, and associated Footnotes (fff) through (jjj). These modifications (1) expanded the minimum vegetation clearances around bare-line conductors in the high fire-threat areas of Southern California, and (2) required the expanded minimum clearances to be maintained on a year-round basis, not just during fire season.²⁴ The Phase 1 Decision also excluded orchards from the expanded clearances, recognizing that actively managed orchards pose less of a fire hazard than other areas. These measures were adopted on an interim basis pending further review in Phase 2. However, there were no proposals to revise the interim measures in Phase 2.

The purpose of Consensus Proposal 4 is to permanently adopt the "interim" revisions to Rule 37 and to correct typographical errors in

²⁴ D.09-08-029 at 31 - 32.

Footnote (fff). The proposed revisions are shown in Appendix A of today's decision. The parties do not anticipate that the conversion of the interim rule into a permanent rule will result in significant additional costs, although the rule itself - whether interim or permanent - does impose costs.

5.4.2. Position of the Parties

Most parties either did not address Consensus Proposal 4 in their briefs or expressed general support for the proposal.

SCE observes that Footnote (hhh) of Rule 37 contains a reference to Cal Fire's Fire and Resource Assessment Program (FRAP) Fire Threat Map. SCE notes that one of the issues before the Commission in Phase 2 of this proceeding is the selection of appropriate fire-threat maps. SCE requests that the Commission affirm that the use of Cal Fire's FRAP Map as referenced in Footnote (hhh) and elsewhere in GO 95 and GO 165 is subject to change.

5.4.3. Discussion

We conclude that the permanent adoption of expanded vegetation clearances around bare-line conductors in the high fire-threat areas of Southern California will promote our goal of reducing fire risks. We also find that it is reasonable to exclude actively managed orchards from the expanded vegetation clearances because, as was noted in the Phase 1 Decision, such orchards pose less of a fire hazard.²⁵ Although there will be costs to comply with the expanded vegetation clearances, no party objects to the costs. We find that such costs are outweighed by the public-safety benefits.

²⁵ D.09-08-029 at 31 - 32. As noted in Footnote (jjj) of Rule 37, the Case 13 clearances apply to orchards that are excluded from the Case 14 clearances.

For the preceding reasons, we find the consensus revisions to Rule 37 are reasonable in light of the record, consistent with the law, and in the public interest. We therefore adopt the revisions. The text of the revised Rule 37, Table 1, Case 14 and Footnotes (fff) – (jjj) is in Appendix B of today’s decision.

In response to SCE’s request that we affirm that the use of the FRAP Map as referenced in Footnote (hhh) of Rule 37 and elsewhere in GO 95 and GO 165 may be changed in the future, we note that later in today’s decision we establish a Phase 3 of this proceeding for the specific purpose of developing and adopting fire-threat maps to replace the FRAP Map.

5.5. Consensus Proposal 5 re: GO 95, Rules 23.0, 44.1, 44.2, and 44.3

5.5.1. Summary of Proposal

Consensus Proposal 5 consists of revisions to Rules 23.0, 44.1, 44.2, and 44.3 of GO 95. The proposed revisions are shown in Appendix A of today’s decision.

The consensus revisions to Rule 23.0 have the effect of applying the safety factors for new construction in Rule 44.1 to a “change to an existing grade of construction or class of circuit.”

The consensus revisions to Rule 44.1 add “mechanical strength” as a design criterion for lines and elements of lines that are installed or reconstructed. This will help ensure that mechanical strength is both considered during design calculations and subject to the safety factors in Rule 44.1. The proposed revisions to Rule 44.1 also replace the word “utility” with “company” to reflect that the entity doing the installation or reconstruction may not be a utility.

There are several consensus revisions to Rule 44.2. The first revision clarifies that Rule 44.2 applies to any “supply or communication company,”

rather than to any “utility.” The second revision changes “utility” to “company” in several spots to clarify that Rule 44.2 applies to companies that may not technically be utilities. The third revision clarifies that a load calculation is required before a company adds facilities that materially increase vertical, transverse, and longitudinal loads. This is intended to promote public safety by ensuring that all loads are considered before facilities are added. The fourth revision changes a general reference to “Section IV” to a specific reference to “Rule 44.3.” This clarifies which design criteria are applicable to additional construction on poles. The fifth revision requires the company doing load calculations to maintain records of its calculations for five years. This is consistent with the five-year document-retention requirement in Rule 19. The sixth revision changes “intrusive pole loading data” to the more accurate “intrusive pole test results.” The final revision eliminates a note added by D.09-08-029 that states, “Nothing contained in this rule shall be construed as allowing the safety factor of a facility to be reduced below the required values specified in Rules 44.1 and 44.3.” The workshop participants agreed that this note is no longer necessary given the consensus revisions to Rule 44.3 addressed below and the specific reference to Rule 44.3 that is being added to Rule 44.2.

Rule 44.3 requires replacement or reinforcement of lines or parts thereof before safety factors fall below specified levels due to deterioration. The consensus revision adds “installation of additional facilities” as another factor that would justify replacement or reinforcement. The new text is a more direct way of stating the concept already embodied in the note to Rule 44.2 and thereby allows for the elimination of the note.

The Phase 2 Workshop Report states that the cost impacts of the proposed revisions are not certain. Companies that currently do not retain pole loading

calculations for five years may incur additional document retention costs. The inclusion of additional design criteria could lead to more pole replacements and/or reinforcements, and thus higher costs.

5.5.2. Position of the Parties

Most parties either did not address Consensus Proposal 5 in their briefs or expressed general support for the proposal.

CPSD, PG&E, and SCE support Consensus Proposal 5 because it will help ensure that (1) companies perform pole-loading calculations, and (2) pole-loading calculations employ the correct safety factors and consider both structural loads and mechanical strength.

5.5.3. Discussion

With one exception, we agree with the Phase 2 Workshop Report that the consensus revisions to Rules 23.0, 44.1, 44.2 and 44.3 will clarify which design criteria are applicable to the installation, reconstruction, addition, and replacement of facilities on utility poles.²⁶ This should promote public safety by helping to ensure that utility poles and attachments do not fail and thereby ignite a fire. The revisions also clarify that the provisions of Rule 44.2 apply to any “company” planning to add facilities to a pole, rather than to any “utility.” This change should promote public safety by helping to ensure that both electric and telecommunications companies are expected to perform and share pole-loading calculations. Although the exact costs of these consensus revisions are unknown, no party objects to these costs. We find that such costs are unlikely to exceed the public-safety benefits of the adopted revisions.

²⁶ Workshop Report, Appendix A, page A-31.

The one exception concerns the proposed five-year record retention period for pole-loading calculations. We believe that a longer record retention period is needed so that we may conduct a thorough forensic analysis in the event there is a major safety-related incident. To this end, we will require CIPs and electric utilities to retain records of pole-loading calculations for ten years.

For the preceding reasons, we find the proposed revisions to GO 95, Rules 23, 44.1, 44.2, and 44.3, as revised by today's decision, are reasonable in light of the record, consistent with the law, and in the public interest. We therefore adopt the revisions. The text of revised rules is contained in Appendix B of today's decision.²⁷

5.6. Consensus Proposal 6 re: GO 165, Sections I - IV

5.6.1. Summary of Proposal

Consensus Proposal 6 consists of several revisions to GO 165. The proposed revisions to GO 165 are shown in Appendix A of today's decision.

The first consensus revision extends the inspection and reporting requirements in GO 165 to all outdoors electric distribution and transmission facilities (except substations)²⁸ that are under the Commission's jurisdiction, including facilities that belong to non-electric utilities such as Southern California Gas Company, which owns an overhead electric distribution system at

²⁷ The revised Rule 44.2 adopted by today's decision reflects the consensus revisions as well as certain contested revisions that are addressed later in today's decision. The revised Rule 44.3 is corrected to add the word "rule" to the last sentence so that it reads: "In no case shall the application of this rule..."

²⁸ The proposed consensus revisions do not apply to substations because the Commission is currently considering a new general order in R.10-09-001 that would contain inspections and reporting requirements for electric substation facilities.

its Aliso Canyon storage field. Consensus Proposal 6 specifically excludes CIP facilities and cathodic protection systems for natural gas facilities from GO 165.

The second consensus revision streamlines the recordkeeping and reporting requirements in GO 165.

The final consensus revision adds a new Section III.E to GO 165 that creates a mechanism to revise GO 165 that is similar to the mechanism in Rule 15.1 of GO 95. The proposed Section III.E would allow entities to request revisions to maintenance and inspection programs based on new technology and practices without a formal Commission proceeding.

The Phase 2 Workshop Report acknowledges that CAISO has oversight responsibilities for the electric transmission facilities under its operational authority. CAISO requires Participating Transmission Owners to inspect and maintain their transmission facilities according to pre-approved plans, and to submit reports to CAISO on their inspection and maintenance activities. The Phase 2 Workshop Report states that the consensus revisions that pertain to the inspection and maintenance of electric transmission facilities do not conflict with CAISO regulations.

The Phase 2 Workshop Report notes that the consensus revisions will not increase costs for electric utilities that are currently covered by GO 165. On the other hand, companies that are newly subject to GO 165, including non-electric utilities such as SoCalGas, will incur additional costs to comply with GO 165.

5.6.2. Position of the Parties

Most parties either did not address Consensus Proposal 6 in their briefs or expressed general support for the proposal.

CAISO agrees that the consensus revisions to GO 165 do not conflict with its jurisdiction and regulations. CPSD avers that Consensus Proposal 6 will

enable CPSD to ensure that transmission facilities in California are adequately inspected and maintained, without duplicating CAISO's regulations. PG&E and SCE submit that the consensus revisions will vastly improve GO 165 by streamlining many of its requirements.

5.6.3. Discussion

With one exception described below, we agree with the assessment in the Phase 2 Workshop Report that the consensus revisions will streamline and clarify GO 165, thereby making it more useful to utilities and CPSD.²⁹ These revisions should improve compliance and reduce costs. Extending GO 165 to additional electric distribution and transmission facilities located outside of buildings should promote public safety and reduce fire hazards by ensuring that these additional facilities are inspected in accordance with GO 165. As noted by CAISO, the proposed revisions to GO 165 do not conflict with CAISO's jurisdiction or regulations.

Our one reservation with the consensus revisions to GO 165 is the following provision that would add a new mechanism for seeking future exemptions from, or modifications to, GO 165:

If, in a particular case, exemption from or modification of any of the requirements herein is desired, the Commission will consider a request for such exemption or modification when accompanied by a full statement of conditions existing and the reasons why such exemption or modification is asked and is believed to be justifiable. It is to be understood that, unless otherwise ordered, any exemption or modification so granted shall be limited to the particular case covered by the request.

²⁹ Phase 2 Workshop Report, Appendix A, page A-50.

The above provision is vague because it does not (1) state who may ask for an exemption or modification, or (2) specify a procedure for seeking an exemption or modification. The provision is also unnecessary because the Commission already has procedures to request an exemption or modification, including applications, petitions for modification of Commission decisions, and petitions for new rulemaking proceedings. We therefore see no value or need for the above provision, and we decline to adopt it.

For the preceding reasons, we find that the proposed consensus revisions to GO 165, as modified by today's decision, are reasonable in light of the record, consistent with the law, and in the public interest. We therefore adopt the revisions. The text of the revised GO 165 is contained in Appendix B of today's decision.³⁰ We recognize that the adopted revisions to GO 165 could increase costs for companies that were not previously subject to GO 165. However, no party suggests that such costs are unreasonable. We find that the increased costs are unlikely to exceed the public-safety benefits of the adopted revisions.

6. Contested Proposals

The Phase 2 Workshop Report contains more than two dozen contested proposals for improving fire safety. These proposals are presented in Appendix B of the Workshop Report. We address the contested proposals below.

³⁰ The adopted text corrects two typos. The first correction is in Section III.B where the word "assure" is replaced with "ensure." The second correction is in Note 1 under the Sample Report Template where "their" is replaced with "its."

6.1. Contested Proposals 1A and 1B re: GO 95, Rule 11

6.1.1. Summary of Proposals

Rule 11 of GO 95 contains a short description of the purpose of GO 95. The Phase 2 Workshop Report presents two competing proposals by CPSD and the CIP Coalition to revise Rule 11. The proposed revisions are shown below with strikeout and underline:

CPSD Contested Proposal 1A

The purpose of these rules is to formulate, for the State of California, ~~uniform~~ requirements for overhead ~~electrical~~ line design, construction, and maintenance, the application of which will ~~ensure~~ adequate service and secure safety to persons engaged in the construction, maintenance, operation or use of overhead ~~electrical~~ lines and to the public in general.

CIP Coalition Contested Proposal 1B

The purpose of these rules is to formulate, for the State of California, ~~uniform~~ requirements for overhead electrical line design, construction, and maintenance, the application of which will ~~ensure~~ adequate service and secure safety to persons engaged in the construction, maintenance, operation or use of overhead electrical lines and to the public in general.

The only difference between the two competing proposals is that CPSD would remove the modifier “electrical” before the word “line,” while the CIP Coalition would retain the modifier “electrical.”

6.1.2. Position of the Parties

CPSD states that its proposed revisions to Rule 11 (Contested Proposal 1A) will clarify that GO 95 applies to communication lines in addition to electrical lines. CPSD notes that when Rule 11 was adopted in 1922, both power lines and communication lines conducted electricity. Thus, historically, the term “electrical lines” as used in Rule 11 included “communication lines.” Removing

the modifier “electrical” should prevent GO 95 from being misinterpreted as applying only to electrical lines.

CPSD states that its proposal will also clarify that GO 95 specifies design and maintenance standards in addition to construction standards. CPSD asserts that this clarification is necessary because some companies have told CPSD that Rule 11 only requires that lines be constructed in accordance with GO 95, and not designed and maintained in accordance with the GO 95.

CPSD’s proposal is supported by DRA, IBEW 1245, PacifiCorp, PG&E, SCE, SDG&E, and Sierra Pacific. Although PG&E and SCE support CPSD’s proposal, they are concerned that both CPSD’s and the CIP Coalition’s proposals would broaden the focus of GO 95 to include design and maintenance. Traditionally, the utilities have had flexibility to tailor their internal operations to fit their individual needs. Adding more detail to GO 95 will reduce flexibility.

SDG&E agrees that CPSD’s proposal to eliminate the modifier “electrical” from Rule 11 should remove confusion over what types of lines GO 95 applies to. Unlike PG&E and SCE, SDG&E is not concerned about the addition of the words “design” and “maintenance” to Rule 11, since certain rules in GO 95 already address the design and maintenance of overhead power lines and communication lines. SDG&E also supports the elimination of the word “uniform” from Rule 11 to acknowledge the fact that the requirements for overhead power lines and communication lines are not uniform.

SDG&E disagrees with the CIP Coalition’s position, summarized below, that CPSD has not justified deletion of “electrical” or explained how this deletion would impact the other 400+ pages of GO 95. SDG&E opines that CPSD’s proposal appropriately preclude the possibility of CIPs arguing that GO 95 does not apply to communications lines because the “purpose” section of Rule 11 only

mentions “electrical” lines. SDG&E further states that the other provisions of GO 95 stand on their own and are not affected by CPSD’s proposed deletion of the word “electrical” from the “purpose” section of GO 95.

The CIP Coalition urges the Commission to adopt the CIP Coalition’s proposal (Contested Proposal 1B) and reject CPSD’s proposal. The CIP Coalition argues that CPSD has not explained how the deletion of the word “electrical” in Rule 11 would impact the 400+ pages of GO 95. Because Rule 11 has not been modified since its adoption in 1922, the removal of the word “electrical,” without reviewing the entirety of GO 95 and making any necessary conforming changes, adds an element of uncertainty to GO 95. The CIP Coalition adds that removing the word “electrical” does not advance the objective of this proceeding of reducing the fire hazards associated with utility facilities.

6.1.3. Discussion

We conclude for the following reasons that CPSD’s proposed revisions to Rule 11 are reasonable, and we adopt them. There is no additional cost for the adopted revisions to Rule 11, as they only clarify existing requirements. The text of the revised Rule 11 is contained in Appendix B of today’s decision.

CPSD’s and the CIP Coalition’s competing proposals to revise Rule 11 are identical in most respects. Both proposals add the words “design” and “maintenance” to the described purpose of GO 95, since GO 95 specifies design and maintenance standards for overhead lines. Both proposals also eliminate the modifier “uniform” before the word “requirements” to reflect the fact that GO 95 has different requirements for overhead power lines versus communication lines in some instances. These technical revisions to Rule 11 are clearly reasonable.

The only difference between the two proposals is that CPSD’s proposal would delete the modifier “electrical” prior to the word “line” in two places, so

that Rule 11 would state the purpose of GO 95 is to formulate requirements for “overhead line design, construction, and maintenance” rather than “overhead electrical line design, construction, and maintenance.” The CIP Coalition would retain the modifier “electrical.”

We find that CPSD’s proposal provides a more accurate description of the purpose of Rule 11. GO 95 applies to both overhead power lines and overhead communication lines. Removing the modifier “electrical,” as CPSD proposes, should eliminate the possibility that Rule 11 could be misinterpreted to mean that GO 95 applies only to electric power lines, and not to communication lines.

The CIP Coalition’s fear that removing the word “electrical” may have unintended impacts on the other 400+ pages of GO 95 is unfounded. The CIP Coalition did not cite one example of unintended consequences; nor did we find any unintended consequences in our own review of GO 95. To the contrary, we find that removing the modifier “electrical” from Rule 11 has the salutary effect of harmonizing the rule with the remainder of GO 95.

We disagree with the CIP Coalition’s position that deleting the modifier “electrical” from Rule 11 does nothing to enhance public safety. As stated previously, deleting the modifier “electrical” removes the possibility that Rule 11 could be misinterpreted to mean that GO 95 does not apply to communication lines. This will help ensure that CIPs comply with the many safety-related rules in GO 95, which should improve the overall fire safety of overhead facilities.

6.2. Contested Proposal 2 re: GO 95, Rule 12 and GO 165

6.2.1. Summary of Proposal

Rule 12 of GO 95 specifies which facilities are subject to GO 95. CPSD proposes to add a provision to Rule 12 that states GO 95 applies to

publicly owned utilities (POUs). CPSD also proposes similar revisions to GO 165. The proposed revisions are shown in Appendix A of today's decision.

6.2.2. Position of the Parties

CPSD represents that it routinely meets resistance from POUs when enforcing the Commission's safety rules that pertain to electric facilities. CPSD asserts that GO 95 and GO 165 should state that POUs are subject to these General Orders in order to facilitate CPSD's ability to conduct safety audits and enforce the Commission's safety rules.

CPSD's proposal is supported by DRA and IBEW 1245. However, IBEW 1245 believes it would be problematic for the Commission to impose fines or directives on POUs that have a material impact on their finances.

CMUA and LADWP oppose CPSD's proposal. They note that CPSD submitted the same proposal in Phase 1, which was rejected by the Phase 1 Decision. CMUA and LADWP argue that CPSD should not be allowed to raise the same issue again.

CMUA contends that CPSD has failed to justify its proposal. As far as CMUA is aware, the POUs in California cooperate with CPSD despite jurisdictional disputes. This is because POUs value the input provided by CPSD and treat GO 95 and GO 165 as industry standards.

6.2.3. Discussion

As in Phase 1, CPSD proposes to revise GO 95 and GO 165 to state that these General Orders apply to POUs. The Phase 1 Decision rejected the proposal for the following reasons:

CPSD also recommended that we adopt language expressly stating that General Order 95 applies to municipal electric utilities. CPSD makes this recommendation in response to CPSD's claim that it encounters resistance from publicly-

owned utilities when seeking to enforce the Commission's rules and regulations concerning the safety of overhead and underground electric transmission and distribution facilities. In response to CPSD's concerns, we urge greater cooperation with CPSD. We agree with SCE that Rule 12 is sufficient to bind all entities that fall within the Commission's jurisdiction and again restate that under Pub. Util. Code §§ 8002, 8037, and 8056, the Commission's jurisdiction extends to publicly-owned utilities for the limited purpose of adopting and enforcing rules governing electric transmission and distribution facilities to protect the safety of employees and the general public. (D.09-08-029 at 16.)

We decline to revisit our decision in Phase 1 where we rejected CPSD's proposed revisions to Rule 12 of GO 95. If parties were allowed to resubmit their rejected Phase 1 proposals in Phase 2, then Phase 1 would have served no purpose. Although we do not adopt CPSD's proposed revisions to Rule 12 of GO 95 (and similar revisions to GO 165), we are troubled that CPSD reports it encounters resistance from POU's when inspecting and auditing POU facilities subject to the Commission's jurisdiction. We remind the POU's of our determination in D.09-08-029 that the Commission has authority under Pub. Util. Code §§ 8002, 8037, and 8056 to adopt and enforce rules governing electric transmission and distribution facilities to protect the safety of employees and the general public. If a POU refuses to cooperate with an inspection or audit of its facilities by CPSD, or refuses to correct a safety-related violation, then CPSD should bring this matter to our attention so that we may take appropriate action.

6.3. Contested Proposals 3A and 3B re: GO 95, Rule 18A

6.3.1. Summary of Proposals

Rule 18A to GO 95 requires all CIPs and electric utilities subject to the Commission's jurisdiction to (1) establish auditable maintenance programs for

their overhead facilities; (2) categorize nonconformances in accordance the three priority levels specified in Rule 18A; (3) correct nonconformances within the time frame specified for each priority level; and (4) maintain auditable records of their maintenance programs and corrective actions. Rule 18A also directs electric utilities that have auditable maintenance programs under GO 165 that are consistent with Rule 18A to continue to follow their GO 165 programs.

The CIP Coalition³¹ and SDG&E present similar proposals to revise Rule 18A.³² Both proposals remove what the CIP Coalition and SDG&E see as conflicting, unnecessary, and redundant provisions. For example, both proposals delete Item 4 of Rule 18A, which requires companies to correct within 30 days the following: (1) certain nonconformances located in Extreme and Very High Fire Threat Zones in Southern California, and (2) a significant safety risk to utility employees. The CIP Coalition and SDG&E agree that Item 4 is redundant with the three priority levels established by Rule 18A for correcting nonconformances.

The only substantive difference between the two proposals is the time period for correcting certain types of priority Level 2 nonconformances. The CIP Coalition's proposal (Contested Proposal 3A) retains the existing requirement to correct Level 2 nonconformances within 59 months. SDG&E's proposal (Contested Proposal 3B) also retains a general requirement to correct Level 2 nonconformances within 59 months. However, if the nonconformance either compromises worker safety or creates a fire risk in an Extreme or Very

³¹ Cox, a member of the CIP Coalition, abstains from taking a position on Contested Proposals 3A and 3B.

³² The CIP Coalition's and SDG&E's proposals to revise Rule 18A include the consensus revisions to Rule 18 adopted previously in today's decision.

High Fire Threat Zone in Southern California, SDG&E's proposal would require the safety hazard to be corrected within 12 months. For ease of reference, the proposed revisions with respect to the time period for correcting Level 2 nonconformances are set forth below:

CIP Coalition Contested Proposal 3A

Time period for correction to be determined at the time of identification by a qualified company representative, but not to exceed 59 months.

SDG&E Contested Proposal 3B

Time period for correction to be determined at the time of identification by a qualified company representative, but not to exceed: (1) 12 months for nonconformances that compromise worker safety, (2) 12 months for nonconformances that create a fire risk and are located in an Extreme or Very High Fire Threat Zone in Southern California, and (3) 59 months for all other Level 2 nonconformances.

The complete text of the proposed revisions to Rule 18A under Contested Proposals 3A and 3B is contained in Appendix A of today's decision.

The CIP Coalition and SDG&E believe their proposals will reduce costs by streamlining Rule 18A requirements. However, SDG&E's proposal could accelerate costs compared to the CIP Coalition's proposal for those companies that would take longer than SDG&E's proposed 12 months to correct Level 2 nonconformances that create a worker-safety risk or fire risk.

6.3.2. Position of the Parties

The CIP Coalition asserts that its proposal (Contested Proposal 3A) will eliminate duplicative, vague, and/or unnecessary obligations in Rule 18A. For example, Rule 18A currently requires that prior to work being performed, companies must document the current status of the nonconformance, including

whether it is in a specified Fire Zone. The CIP Coalition posits that the required documentation provides no safety benefits, delays work, and increases costs.

The CIP Coalition opposes SDG&E's proposal to reduce the deadline from 59 months to 12 months for correcting nonconformances that compromise worker safety or create a fire risk in an Extreme or Very High Fire Threat Zone in Southern California. The CIP Coalition states that SDG&E's proposed 12-month requirement hinges on two vague terms (i.e., "compromise" and "fire risk") which could be interpreted to mean that any nonconformance would require corrective action within 12 months, thus eliminating the entire rationale for having a 59-month range in the first place.

The CIP Coalition submits that SDG&E's proposed 12-month deadline is unnecessary because, under the CIP Coalition's proposal, any nonconformance categorized as a Level 2 priority would have to be corrected within a timeframe commensurate with the risk, not to exceed 59 months. Thus, the fact that the Level 2 priority has a range of 0-59 months does not mean that a company can wait 59 months to repair every Level 2 nonconformance.

The CIP Coalition also argues that SDG&E's proposal unfairly imposes obligations on CIPs but not electric utilities. This is because Rule 18A exempts electric utilities that have maintenance programs that comply with GO 165, such as PG&E, SCE, and SDG&E.

Turning to a separate matter, the CIP Coalition notes that SCE proposes significant edits to GO 95, summarized below, that would move the content of Rule 18A to other parts of GO 95. The CIP Coalition cannot endorse SCE's changes that were submitted for the first time in SCE's opening brief.

The CIP Coalition's proposal is supported by CPSD, LADWP, PacifiCorp, PG&E, SCE, and Sierra Pacific. In general, the supporters of the CIP Coalition's

proposal believe it will streamline Rule 18A, clarify its requirements, and enable companies to prioritize maintenance work based on local conditions and available resources. This should help companies to manage their maintenance programs more efficiently.

PG&E and SCE oppose SDG&E's proposed 12-month timeframe for correcting certain Level 2 safety hazards for the following reasons: (1) Rigid timeframes hinder the ability to prioritize maintenance activities based on local conditions and available resources; (2) timeframes for corrective actions should not be included in a General Order, since maintenance timeframes are based on judgments made in the field and can change depending on local conditions, technological advancements, and process improvements; (3) if changes to corrective maintenance timeframes are desirable, parties would have to seek a modification to GO 95, a process that could take years.

Although SCE supports the CIP Coalition's proposal, SCE recommends moving the contents of Rule 18A, as modified by the CIP Coalition's proposal, to Rules 12.2 and 23.3 and a new Appendix J. SCE's proposed edits were presented for the first time in its opening brief.

SDG&E generally supports the CIP Coalition's proposed revisions to Rule 18A. However, SDG&E opposes the retention of the current deadline of 59 months for correcting all Level 2 nonconformances. By definition, Level 2 nonconformances can have high safety risks.³³ SDG&E believes that a nonconformance which either compromises worker safety or creates a fire risk in an Extreme or Very High Fire Threat Zone in Southern California should be

³³ Under the existing Rule 18A and both 18A proposals, Level 2 priorities are "[v]ariable (non-immediate high to low) safety and/or reliability risk."

corrected within 12 months as required by SDG&E's proposal, not 59 months as allowed by the CIP Coalition's proposal. SDG&E states that 12 months is more than enough time to cure safety hazards.

SDG&E disagrees with the CIP Coalition's claim that SDG&E's proposal could be interpreted to mean any alleged nonconformance would require corrective action within 12 months, thus eliminating the rationale for having a 59 month range. SDG&E responds that for each Level 2 (high to low, but non-immediate) nonconformance, the same two or three questions need to be asked. First, does it compromise worker safety? SDG&E believes that many types of GO 95 nonconformances would not. Second, is it located in an Extreme or Very High Fire Threat Zone in Southern California? If so, does it create a fire risk? SDG&E submits that these questions can be answered by trained personnel in the same way they are called upon to decide if particular safety hazards and GO 95 nonconformances are Level 1, Level 2, or Level 3.

SDG&E disputes the CIP Coalition's assertion that SDG&E seeks to impose a tougher requirement on CIPs than electric utilities. SDG&E states that its Commission-authorized GO 165 maintenance plan requires SDG&E to correct all nonconformances within 12 months. Thus, SDG&E is proposing a less stringent standard for CIPs than what currently applies to SDG&E.

LA County supports SDG&E's proposal to correct within 12 months nonconformances that compromise worker safety and/or create a fire risk in the high fire-threat areas of Southern California. Conversely, LA County opposes the CIP Coalition's proposal to allow up to 59 months to correct these safety hazards. LA County believes that 59 months is too long. There could be several high-wind events over 59 months, and the possibility that poles will fail is

increased the longer that violations linger. Thus, the CIP Coalition's proposal, if adopted, would decrease safety and might cause additional wildfires.

IBEW 1245 supports both proposals. If the Commission agrees to a 59-month deadline, IBEW 1245 recommends that it be made clear that companies which fail to correct GO 95 violations after 59 months will face serious sanctions. IBEW 1245 further recommends that the Commission require expedited correction of any violation of climbing space.

CMUA supports the provision in both proposals that requires communication companies to have robust maintenance programs.

6.3.3. Discussion

The CIP Coalition's and SDG&E's proposed revisions to Rule 18A are the same in all material respects with one exception discussed below. Both proposals retain the following core elements of Rule 18A adopted by the Phase 1 Decision:

- The obligation to maintain overhead facilities in good condition; to take corrective actions; and to keep auditable records of maintenance programs and corrective actions.
- Three priority levels for taking corrective actions, the factors on which priorities must be based, deadlines within each priority level for completing corrective actions, and situations when the deadlines for completing corrective actions may be extended.
- The obligation to correct Level 1 nonconformances immediately. Level 1 consists of "Immediate safety and/or reliability risk with high probability for significant impact."
- The ability of electric utilities with maintenance programs established under GO 165 to rely on these programs, provided these programs are consistent with Rule 18A.

The revisions to Rule 18A that are common to both proposals are intended to streamline record keeping requirements and to remove unnecessary and

redundant provisions. There is no opposition to these proposed revisions. We hereby adopt them. Among other things, the adopted revisions will clarify the requirements of Rule 18A, which should enhance the ability of companies to manage their maintenance programs efficiently and thereby reduce safety hazards and costs.

The only substantive difference between the two proposals is the deadline for correcting Level 2 nonconformances. The CIP Coalition's proposal would retain the current requirement in Rule 18A to correct all Level 2 nonconformances within 59 months. SDG&E's proposal, on the other hand, would establish two deadlines for correcting Level 2 nonconformances:

- 12 months for nonconformances that either compromise worker safety or create a fire hazard in an Extreme or Very High Fire Threat Zone in Southern California.
- 59 months for all other Level 2 nonconformances.

We find that it is reasonable to adopt SDG&E's proposal because it provides a higher level of worker safety and fire safety. We will also incorporate into Rule 18A the fire-threat maps that we adopt later in today's decision to designate high fire-threat areas in Southern California for the purpose of implementing Rule 18A. The adopted text of Rule 18A is contained in Appendix B of today's decision. The adopted text also reflects the consensus revisions to Rule 18A that were adopted previously in today's decision.³⁴

³⁴ The adopted revisions to Rule 18A correct two typos in SDG&E's proposal. One correction replaces the semicolon with a period in the bullet in Section 2a that begins with "Direct or potential..." The second correction replaces a semicolon with a colon in the sentence in Section 2a that begins with "Time period for correction..."

We emphasize that the deadlines for correcting nonconformances adopted by today's decision do not relieve CIPs and electric utilities of their obligation to correct nonconformances sooner if doing so is necessary to protect public safety or maintain reliability. We also affirm our determination in the Phase 1 Decision that Rule 18A (as modified by today's decision) does not preempt any stricter local rules establishing priority systems for correcting safety hazards.³⁵

Today's decision retains the current provision in Rule 18A that electric utilities which have established maintenance programs under GO 165 "that are consistent with the purpose of Rule 18" shall continue to follow their GO 165 programs.³⁶ We interpret this provision to mean that the deadlines for corrective actions under GO 165 maintenance programs cannot exceed the deadlines for corrective actions in Rule 18, as revised by today's decision.

We are not persuaded by the argument made by several parties that it is unnecessary to set deadlines for correcting Level 2 nonconformances other than 59 months. Although we generally agree that companies should have flexibility to prioritize the repair of most Level 2 nonconformances within an overall window of 59 months, we also conclude that conditions which compromise worker safety or increase fire risk in the high fire-threat areas of Southern California should not be allowed to persist for up to 59 months. We concur with SDG&E's assessment that the best way to ensure that threats to worker safety and fire safety are corrected within a reasonable timeframe is to establish an explicit deadline for doing so in Rule 18A.

³⁵ D.09-08-029 at 17.

³⁶ D.09-08-029 at 20.

We decline to adopt SCE's proposal to move the contents of Rule 18A to other parts of GO 95 and a new Appendix J. SCE's proposal was not presented at the Phase 2 workshops and, therefore, falls outside the scope of today's decision.

6.4. Contested Proposal 4 re: GO 95, Rule 18C

6.4.1. Summary of Proposal

MGRA proposes to add a new Rule 18C to GO 95 that would require electric utilities to develop plans to prevent power-line fires when strong winds exceed the structural limits for overhead facilities in areas of high fire risk during periods of high fire danger. The text of the proposed Rule 18C is contained in Appendix A of today's decision. MGRA did not provide a cost estimate for its proposal, but MGRA believes the cost would be far outweighed by the benefits of avoided catastrophic wildfires.

6.4.2. Position of the Parties

MGRA states that the risk of power lines igniting catastrophic wildfires during windstorms can be greatly reduced by contingency planning that includes the following three elements: (1) defining reasonably foreseeable wind hazards, (2) identifying the occurrence of hazardous winds, and (3) planning a response. MGRA submits that statistical analysis of historical weather data can be used to estimate the maximum worst case wind load on power lines. Using this information, appropriate countermeasures can be planned.

MGRA suggests that fire-prevention plans consist of engineering countermeasures, operational countermeasures, or both. Engineering countermeasures could include hardening of power-line facilities in areas where it is foreseeable that strong winds may exceed the structural design standards for overhead facilities set forth in GO 95. Operational countermeasures could be

employed when winds exceed the structural design limits, and might include revised settings for reclosers and shutting off power.

MGRA recognizes that operational countermeasures can cause physical and financial harm to residents. Therefore, such countermeasures should only be used when much greater harm from power-line fires is the likely consequence of inaction. Ideally, this should be determined by a cost-benefit analysis.

MGRA emphasizes that its proposed Rule 18C is focused on solving the potential in Southern California for high winds to cause multiple power-line fires, as observed in October 2007. MGRA is not aware of a similar wind hazard in Northern California, but MGRA recommends that the Commission obtain an expert opinion on this matter.

LA County supports MGRA's proposal. LA County asserts that the need for the proposed rule is demonstrated by the multiple large fires that ignited simultaneously throughout Southern California during Santa Ana wind events in 2003 and 2007. These fires taxed fire-fighting resources, resulted in large scale evacuations, and caused significant loss of life and property. LA County opines that shutting off power should only be used as a last resort, but that utilities need this option when faced with extreme circumstances.

MGRA's proposal is opposed by CMUA, the CIP Coalition, LADWP, PacifiCorp, PG&E, SCE, SDG&E, and Sierra Pacific for the following reasons. First, the opponents state that fire-prevention plans do not belong in GO 95, which is limited to construction and maintenance standards. Second, the proposed rule is unnecessary because electric utilities are already required by GO 166 to plan for major emergencies. Third, electric utilities cannot accurately predict hazardous wind conditions or power-line fires. Consequently, the proposed rule is impossible to implement. Fourth, the only sure way to prevent

strong winds from igniting power-line fires is to shut off power, but this option was rejected by D.09-09-030. Finally, the proposed fire-prevention plans would be costly to develop with no commensurate benefits.

CMUA notes that the Phase 1 Scoping Memo determined that “[t]his rulemaking proceeding will not decide issues that will be resolved in the Commission’s decision on SDG&E’s Application (A.) 08-12-021 filed on December 22, 2008, in which SDG&E asked the Commission to review SDG&E’s plan to shut off power to high fire risk areas during certain extreme weather conditions.”³⁷ Thus, MGRA’s proposal is outside the scope of this proceeding to the extent it calls for electric utilities to develop plans to shut of power in response to high-wind conditions.

PacifiCorp and Sierra Pacific raise additional concerns. They represent that strong winds in their service territories typically occur during the winter as part of snowstorms and rainstorms. Consequently, MGRA’s proposal is unlikely to reduce fire risks in their service territories.

SDG&E is concerned that MGRA’s proposal would conflict with D.09-09-030, which ordered SDG&E to convene a collaborative stakeholder process to develop a fire-prevention plan. Thus, there is no need to require SDG&E to develop a contingency plan to deal with wind and fire dangers because SDG&E is already doing so pursuant to D.09-09-030.

6.4.3. Discussion

We agree with MGRA that electric utilities should develop and implement fire-prevention plans to address situations where it is reasonably foreseeable that strong winds may exceed the structural limits of overhead electric facilities

³⁷ Phase 1 Scoping Memo dated January 6, 2009, at 5.

during periods of high fire danger. The need for fire-prevention plans is demonstrated by the events of October 2007 when strong Santa Ana winds in Southern California caused power lines to ignite wildfires at multiple locations. Together, these power-line fires burned more than 334 square miles and caused immense devastation and disruption, including the largest evacuation in California's history.³⁸ It is virtually certain that Southern California will continue to experience Santa Ana windstorms. Thus, there is a grave and ongoing risk that Santa Ana windstorms will again cause power lines to ignite catastrophic wildfires unless electric utilities plan and prepare for such events.

For the preceding reasons, we will require electric utilities in Southern California to develop plans to reduce the risk of severe windstorms igniting power-line fires during periods of high fire danger. Consistent with the Phase 1 Decision, we define Southern California as consisting of Imperial, Santa Barbara, Ventura, Los Angeles, Orange, San Diego, Riverside, and San Bernardino Counties.³⁹ Each electric utility in Southern California shall complete its initial fire-prevention plan by December 31, 2012, and file and serve a copy of its plan via a Tier 1 compliance advice letter.

Unlike Southern California, the need for electric utilities to develop fire-prevention plans in Northern California is not clear cut.⁴⁰ To our knowledge, there has never been an instance in Northern California where strong winds

³⁸ *California Fire Siege 2007 – an Overview*, at 20, 27, 58, and Appendices II and III.

³⁹ D.09-08-029, Ordering Paragraph 1. Today's decision adds Imperial County to the list of counties that comprise Southern California.

⁴⁰ For the purpose of today's decision, we define Northern California as all counties in California except Imperial, Santa Barbara, Ventura, Los Angeles, Orange, San Diego, Riverside, and San Bernardino Counties.

have caused power lines to ignite large-scale wildfires. This is consistent with PacifiCorp and Sierra Pacific's statement that strong winds in their service territories are confined to winter months when the risk of wildfires is low.⁴¹

Nevertheless, we remain concerned about the risk of wind-caused power-line fires in Northern California. Both the FRAP Map and the Reax Map discussed later in today's decision show millions of acres in Northern California where there is a high fire threat. In order to determine the magnitude of the risk, we will require electric utilities in Northern California to do the following:

- Identify their overhead power-line facilities that are located in high fire-threat areas on the interim fire-threat maps adopted later in today's decision.
- Make a good-faith effort to obtain historical records of Red Flag Warnings issued by the National Weather Service that applied to areas occupied by facilities identified in the first bullet.
- Make a good-faith effort to obtain historical wind records of Remote Automatic Weather Stations located within 25 miles of the facilities identified in the first bullet.
- Use the information from the second and third bullets to estimate how often, if ever, sustained winds occur during a Red Flag Warning that exceed the maximum working stresses specified in GO 95, Section IV, for facilities identified in the first bullet.

Utilities may pool their resources and hire consultants to carry out the above tasks. Utilities may also seek to recover the reasonable costs they incur to carry out the above tasks in accordance with the procedures specified later in today's decision.

⁴¹ Multi-Jurisdictional Electric Utilities' Opening Brief at 9 - 10.

An electric utility that serves Northern California shall develop a fire-prevention plan if the utility determines, after completing the previously identified tasks, that it has overhead power-line facilities in a high fire-threat area where it is reasonably foreseeable that there will be sustained winds with a return interval of 100 years or less that exceed the maximum working stresses for such facilities during a Red Flag Warning. Electric utilities in Northern California shall complete the above tasks and prepare a fire-prevention plan, if necessary, no later than December 31, 2012. Electric utilities in Northern California shall also file a Tier 1 compliance advice letter by December 31, 2012, that either (i) contains a copy of their fire-prevention plan, or (ii) provides notice that a fire-prevention plan is not required by today's decision.

Consistent with MGRA's proposal, the fire-prevention plans shall address situations where all three of the following conditions occur simultaneously: (1) sustained wind speeds exceed the structural or mechanical design standards for the affected overhead power-line facilities, (2) the sustained winds occur during a period of high fire danger, and (3) the affected facilities are located in a high fire-threat area.⁴² We define sustained wind speed as the average observed wind speed over a two-minute period.⁴³ We define "structural or mechanical design standards" as the maximum working stresses set forth in GO 95, Section IV. We define "period of high fire danger" as the period covered by a Red Flag Warning issued by the United States National Weather Service. We

⁴² Electric utilities may develop fire-prevention plans that address a broader array of situations than required by today's decision.

⁴³ The definition of sustained wind speed comes from the National Weather Service. (<http://www.weather.gov/glossary/index.php?letter=s>)

define high fire-threat areas as areas designated as such on the fire-threat maps adopted later in today's decision.

A utility's fire-prevention plan must specify (A) how the utility will identify the occurrence of sustained winds that exceed the structural or mechanical design standards for overhead power-line facilities; and (B) the countermeasures the utility will implement to mitigate the threat of power-line fire ignitions. Today's decision does not require any particular countermeasures. Each utility should implement the countermeasures it deems appropriate for its circumstances. We anticipate that countermeasures will include both operational responses to high winds (e.g., adjusting the settings on automatic re-closers) and physical changes to utility facilities (e.g., strengthening facilities). Some countermeasures can likely be implemented relatively quickly, such as operational countermeasures, while other countermeasures that involve physical alternations to overhead power-line facilities may take years or decades to implement completely.

Any electric utility that intends to shut off power as part of its fire-prevention plan must file an application for authority to do so. The application shall demonstrate with a cost-benefit analysis developed in accordance with the guidance provided by D.09-09-030 that the benefits of shutting of power in terms of a net reduction in wildfire ignitions outweigh the substantial costs, burdens, and risks that shutting off power would impose on customers and communities affected by the shut off.⁴⁴ The application must also include mitigation measures to reduce or eliminate the inevitable adverse impacts caused by shutting off power. Special effort should be placed on

⁴⁴ D.09-09-030 at 58 - 61.

mitigating the adverse impacts on people with disabilities, providers of essential services, and schools. An electric utility may not shut off power as a part of its fire-prevention plan until the Commission has granted authority to do so.

We agree with the position advocated by several parties that the requirement to prepare fire-prevention plans does not belong in GO 95, which sets forth rules for the design, construction, and maintenance of overhead facilities. We conclude that the requirement to prepare fire-prevention plans is better suited to GO 166, which specifies standards for emergency planning and restoration of service following a disaster. Today's decision adds a new Standard 1.E (Fire Prevention) to GO 166, and the existing Standards 1.E (Safety Considerations) through 1.I (Plan Update) are renumbered 1.F through 1.J. The text for the new Standard 1.E is contained in Appendix B of today's decision.

All of the provisions of GO 166 shall apply to fire-prevention plans. For example, electric utilities will have to review and update their fire-prevention plans annually, submit revised plans to the Commission, and conduct an annual exercise using the procedures set forth in the fire-prevention plans.⁴⁵

Several parties argue that it is unnecessary to require electric utilities to prepare fire-prevention plans because electric utilities are already required by GO 166 to prepare for major emergencies. We disagree. GO 166 was adopted more than 20 years ago, yet only SDG&E appears to have a fire-prevention plan in effect or under development. Given the general lack of vigilance, we conclude that GO 166 needs to be revised to ensure that electric utilities prepare for foreseeable extreme fire-weather events.

⁴⁵ GO 166, Standards 1.J (renumbered), 3, and 11.

We also disagree with SDG&E's argument that there is no need to require SDG&E to prepare a fire-prevention plan because SDG&E is already doing so pursuant to D.09-09-030. In D.09-09-030, the Commission authorized, but did not require, SDG&E to submit a fire-prevention plan.⁴⁶ In contrast, today's decision requires SDG&E to prepare a fire-prevention plan.⁴⁷

Several parties mistakenly claim that D.09-09-030 rejected the option of shutting off power to prevent fires. Today's decision directs electric utilities that intend to shut off power during extreme fire-weather events to file applications for authority to do so. This is consistent with the Commission's determination in D.09-09-030 that SDG&E should be allowed to file another application for authority to shut-off power, provided SDG&E's power shut-off plan meets certain criteria specified in D.09-09-030.⁴⁸

CMUA mistakenly claims that MGRA's proposed fire-prevention plan is outside the scope of this proceeding pursuant to the Phase 1 Scoping Memo dated January 6, 2009. There, the Assigned Commissioner determined that "[t]his rulemaking proceeding will not decide issues that will be resolved in the Commission's decision on SDG&E's Application (A.) 08-12-021...in which SDG&E asks the Commission to review SDG&E's plan to shut off power to high risk fire areas during certain extreme weather conditions.⁴⁹" Today's decision does not decide or re-visit any issues that were resolved in D.09-09-030, the

⁴⁶ D.09-09-030, Ordering Paragraphs 2 and 3.

⁴⁷ D.09-09-030 contains specific requirements regarding the development and content of SDG&E's fire-prevention plan. All of the requirements adopted by D.09-09-030 for SDG&E continue to apply.

⁴⁸ D.09-09-030 at 56 - 59 and Ordering Paragraph 3.

⁴⁹ Phase 1 Scoping Memo dated January 6, 2010, at page 5.

Commission's decision regarding A.08-12-021. Rather, today's decision adopts several measures that are consistent with D.09-09-030.

We decline to exempt PacifiCorp and Sierra Pacific from the requirements in today's decision pertaining to fire-prevention plans because strong winds in their service territories purportedly occur only in winter months when the risk of wildfires is low. The events of October 2007 demonstrate that strong winds can cause power lines to ignite catastrophic wildfires. In order to protect public safety, we conclude that it is necessary for all electric utilities, including PacifiCorp and Sierra Pacific, to assess the risk of wind-ignited power-line fires during extreme fire-weather events and to develop fire-prevention plans in areas where it is determined that there is a relatively high risk for such fires.

Several parties express concern that electric utilities cannot predict hazardous wind conditions or power-line fires. Today's decision does not require such predictions. Rather, today's decision requires electric utilities to monitor weather stations to determine when wind conditions are likely to exceed GO 95 design standards during extreme fire-weather conditions and to implement countermeasures to reduce the likelihood of power-line fires during these conditions. SDG&E is already well on its way to achieving these objectives.

As a final matter, we emphasize that today's decision does not affect electric utilities' authority under § 451 and § 399.2(a) to shut off power in emergency situations when necessary to protect public safety. This is consistent with the Commission's determination in D.09-09-030 "that SDG&E may need to shut off power in order to protect public safety if Santa Ana winds exceed the design limits for SDG&E's system and threaten to topple power lines onto tinder

dry brush.⁵⁰ Any decision by utilities to shut off power under their existing statutory authority may be reviewed by the Commission pursuant to its broad jurisdiction over matters regarding the safety of public utility operations and facilities. The Commission may decide at that time whether a utility's decision to shut off power was reasonable and qualifies for an exemption from liability under Tariff Rule 14.⁵¹

6.5. Contested Proposal 5 re: GO 95, Rule 31.1

6.5.1. Summary of Proposal

Rule 31.1 of GO 95 requires electric utilities and CIPs to design, construct, and maintain their systems in accordance with the intended use of the systems and the conditions under which the systems will be operated. Rule 31.1 further requires that for all particulars not specified in GO 95, electric utilities and CIPs must design, construct, and maintain their systems in accordance with accepted good practice for the given local conditions known at the time.

PG&E, SCE, and SDG&E (the "Joint Utilities") propose to revise Rule 31.1 to state that electric utilities and CIPs will be in compliance with Rule 31.1 if they design, construct, and maintain their facilities in accordance with all particulars specified in GO 95 or, if particulars are not specified, in accordance with accepted good practice. They also seek to revise Rule 31.1 to state that "accepted good practice" will be determined on a case-by-case basis "with reference to any of the practices, methods, and acts engaged in or approved by a significant

⁵⁰ D.09-09-030 at 60.

⁵¹ Most electric utilities have a Tariff Rule 14 or similar tariff rule that states the electric utility will not be held liable for an interruption in service caused by inevitable accidents, act of God, fire, strikes, riots, war, or any other cause outside of its control.

portion of the relevant industry, or which may be expected to accomplish the desired result with regard to safety and reliability at a reasonable cost.” The text of the proposed revisions to Rule 31.1 is contained in Appendix A of today’s decision.

6.5.2. Position of the Parties

The Joint Utilities’ proposal is intended to limit CPSD’s ability to allege that utilities have violated Rule 31.1 without having to identify the specific design, construction, or maintenance standard that was violated.

The proposal is supported by the CIP Coalition, CMUA, PacifiCorp, and Sierra Pacific. These parties agree with the Joint Utilities that CPSD has used the existing Rule 31.1, with its vague directive to furnish “safe, adequate, and proper service,” as a catch-all provision to allege violations without citing any particular General Order, specific industry practice, or engineering standard.

The proposed revisions to Rule 31.1 would clarify that CIPs and electric utilities must design, construct and maintain their facilities in accordance with the standards specified GO 95 and, if no standards are specified, in accordance with accepted good practice. The “accepted good practice” standard is currently in Rule 31.1, but is not defined. The proposal defines “accepted good practice” so that CIPs and electric utilities will know what requirements they must meet to comply with GO 95. The proposal reduces the risk that CPSD will find a “violation” of a standard that is not described in GO 95. It will also help ensure that companies follow industry best practices for system reliability and safety.

CPSD is the only party opposed to the proposal. CPSD currently uses Rule 31.1 to cite utilities for unsafe conditions not covered by other rules. CPSD contends that the proposal will diminish public safety by preventing the Commission from citing companies for unsafe conditions. Although utilities

have long complained that Rule 31.1 lacks sufficient specificity to provide proper notice as to what constitutes a violation, the Commission and the courts have rejected these arguments as often as the utilities have made them.⁵²

CPSD submits that the Commission has always relied on general principles to ensure the safe operation of utility systems. For example, Rule 12.2 of GO 128 requires facilities to “be maintained in such condition as to secure safety to workmen and the public in general.” Rule 17.1 of GO 128 requires facilities to be “maintained in a condition which will provide adequate service and secure safety to workmen, property and the general public.” And Pub. Util. Code § 451 requires utilities to furnish “just and reasonable service, instrumentalities, equipment, and facilities as are necessary to promote the safety, health, comfort, and convenience of its patrons, employees, and the public.”

CPSD maintains that defining “accepted good practice” as any practice approved by a significant portion of the relevant industry would allow utilities to collude to develop whatever design, construction, and maintenance practices they see fit. Then, if a utility follows these self-prescribed practices, the utility would be deemed in compliance with GO 95 and avoid any liability. Moreover, the proposed definition of “accepted good practice” is vague as to the meaning of a “significant portion of the relevant industry.” For example, it is unclear whether this refers to California or the entire United States. The way it is written, “accepted good practice” would mean whatever utilities want it to mean.

⁵² See, e.g., D.99-04-029, D.04-09-062, and *Cingular Wireless v. CPUC* (2006) 140 Cal.App.4th 718.

Finally, CPSD believes the proposed revisions to Rule 31.1 fall outside the scope of this proceeding, as the proposal would reduce the utilities' liability, both at the Commission and in civil courts, by narrowing the circumstances in which Rule 31.1 may be used to cite utilities for unsafe conditions.

6.5.3. Discussion

We agree with the Joint Utilities that Rule 31.1 does not provide clear guidance regarding what constitutes compliance with the design, construction, and maintenance standards in GO 95, which hinders the ability of electric utilities and CIPs to comply with the General Order. This is contrary to the Commission's intent that GO 95 should be "capable of definite interpretation sufficient to form the basis of working specifications for overhead electric line construction."⁵³

The Joint Utilities' proposed revisions to Rule 31.1 will clarify the Commission's expectations about what constitutes compliance with GO 95 by adding the following paragraph and note to the Rule 31.1 that state:

For all particulars specified in this General Order, a supply or communications company is **in compliance** with this rule if it designs, constructs and maintains a facility in accordance with such particulars. For particulars not specified in this General Order, a supply or communications company is **in compliance** with this rule if it designs, construct and maintains a facility in accordance with accepted good practice. (Emphasis added.)⁵⁴

Note: The standard of accepted good practice should be applied on a case by case basis. For example, the application

⁵³ GO 95, Preface, at page x.

⁵⁴ Today's decision corrects a possible oversight in the Phase 2 Workshop Report by changing the word "Order" to the term "General Order."

of “accepted good practice” may be aided by reference to any of the practices, methods, and acts engaged in or approved by a significant portion of the relevant industry, or which may be expected to accomplish the desired result with regard to safety and reliability at a reasonable cost.

We believe the proposed revisions to Rule 31.1 will improve public safety by clarifying the compliance obligations of electric utilities and CIPs under GO 95. It is beyond dispute that complying with these standards should minimize the safety hazards – including fire risks – associated with overhead power lines and aerial CIP facilities. For these reasons, we conclude that it is in the public interest to adopt the proposed revisions to Rule 31.1.

We do not share CPSD’s concern that the adopted revisions to Rule 31.1 will limit the Commission’s ability to penalize companies for unsafe conditions. As stated previously, our intent in adopting the revisions to Rule 31.1 is to clarify the compliance obligations of electric utilities and CIPs under GO 95. By clarifying these obligations, we also facilitate enforcement of these obligations.

The revised Rule 31.1 will still be available to CPSD as an enforcement tool whenever a company has failed to comply with GO 95 or accepted good practice. The revised Rule 31.1 does not alter the Commission’s existing authority to determine what constitutes compliance with GO 95 on a case-by-case basis in light of specific facts and circumstances. Nor does the revised rule relieve electric utilities and CIPs of their obligation under Rule 31.1 to design, construct, and maintain their facilities for their intended use. If an intended use requires a more rigorous standard than specified in GO 95 “to enable the furnishing of safe, proper, and adequate service,”⁵⁵ the company must follow the higher standard.

⁵⁵ Rule 31.1, first paragraph.

CPSD asserts that the adopted revisions will weaken safety requirements by allowing CIPs and electric utilities to collude to establish whatever “accepted good practices” they see fit. We disagree. As noted earlier, the Commission may determine what constitutes accepted good practice on a case-by-case basis. Regardless, the notion that CIPs and electric utilities would collude to weaken safety standards seems farfetched.

Finally, CPSD mistakenly contends that the adopted revisions to Rule 31.1 fall outside the scope of this proceeding (fire safety mitigation). The Phase 2 Scoping Memo allows “matters with a direct nexus to this proceeding”⁵⁶ including proposals that “improve the meaning and clarity of those provisions in the General Orders that pertain to fire safety.”⁵⁷ The adopted revisions to Rule 31.1 meet these criteria.

6.6. Contested Proposals 6A – 6D re: GO 95, Rules 31.2 and 80.1A

Rule 31.2 of GO 95 requires power lines and communication lines to be inspected frequently and thoroughly. Electric utilities fulfill their inspection obligation in accordance with the standards in GO 165. There are no similar standards in the General Orders for the inspection of CIP facilities.

The Phase 2 Workshop Report presents five contested proposals to revise Rule 31.2 and other parts of GO 95 to incorporate inspection requirements for CIP facilities. Four of these proposals (Contested Proposals 6A through 6D) are addressed immediately below. The fifth proposal (Contested Proposal 6E) is addressed later in today’s decision.

⁵⁶ Phase 2 Scoping Memo at 8.

⁵⁷ Phase 2 Scoping Memo at 12.

6.6.1. Summary of Proposals 6A and 6B

The members of the CIP Coalition submitted two proposals. Proposal 6A, also known as the CIP-1 proposal, was submitted by CCTA, Comcast, CTIA, NextG, Sprint, Sunesys, Time Warner, T-Mobile, tw telecom, and Verizon (together, “the CIP-1 Proponents”). The CIP-1 proposal would require (1) patrol inspections⁵⁸ every three years for CIP facilities on joint-use poles⁵⁹ or one pole length away in high fire-threat areas⁶⁰ of the state; (2) detailed inspections⁶¹ every nine years for these same facilities; and (3) records of all inspections.

Proposal 6B, also known as the CIP-2 proposal, was submitted by AT&T, Frontier Communications, and the Small LECs (together, “the CIP-2 Proponents”). The CIP-2 proposal would require (1) patrol inspections every five years for CIP facilities on joint-use poles or one pole length away in high fire-threat areas of the state; and (2) records of all inspections. The CIP-2 proposal does not require detailed inspections.

The proposed revisions to Rule 31.2 under the CIP-1 proposal and the CIP-2 proposal are shown in Appendix A of today’s decision. There will be additional costs associated with the CIP-1 and CIP-2 proposals, but the amount is unknown. The CIP Coalition states that because their proposals are limited to

⁵⁸ Patrol inspections are simple visual inspections that are designed to identify obvious structural problems and hazards.

⁵⁹ Today’s decision defines a joint-use pole as a utility pole that has both CIP facilities and power lines attached.

⁶⁰ The fire-threat maps that should be used to designate high fire-threat areas are addressed later in today’s decision as part of Contested Proposal 14.

⁶¹ Detailed inspections are careful visual inspections using binoculars and measuring devices, as appropriate.

areas where the potential fire risk is highest, their proposals strike a proper balance between the costs and benefits of inspections.

6.6.2. Summary of Proposals 6C and 6D

Proposal 6C was submitted by CPSD. This proposal would establish the following statewide standards for the inspection of CIP facilities located on joint-use poles and CIP-only poles within one span of joint-use poles: (1) one-year patrol inspection cycle for urban areas; (2) two-year patrol inspection cycle for rural areas; (3) one-year patrol inspection cycle for rural areas in the high fire-threat areas of Southern California; and (4) ten-year detailed inspection cycle for the CIP facilities identified in (1) through (3). The inspection cycle for all other CIP facilities would be determined by the CIPs based on the following factors: (a) Proximity to electric facilities, (b) terrain, (c) accessibility, and (d) location. CPSD's proposal would also require CIPs to keep records of their inspections.

Proposal 6D was submitted by SDG&E. SDG&E's proposal is the same as CPSD's proposal in all but two respects. First, CPSD's proposal would require inspections of CIP-only poles within one span of a joint-use pole. SDG&E's proposal would apply to CIP-only poles within three spans of a joint-use pole. Second, CPSD's proposal would require detailed inspections every ten years for specified CIP facilities. SDG&E's proposal would require detailed inspections every five years for CIP facilities located in high fire-threat areas of Southern California, and 10 years for other areas.

The text of CPSD's and SDG&E's proposals would be placed in a new Rule 80.1A, with a reference to the new rule added to Rule 31.2. The text of the proposed revisions to Rule 31.2 and the new Rule 80.1A under CPSD's and SDG&E's proposals are shown in Appendix A of today's decision.

CPSD and SDG&E do not believe their proposals will result in significant additional costs for CIPs, as the CIPs are already required by Rule 31.2 to inspect their communication lines frequently and thoroughly.

6.6.3. Position of the Parties

The CIP-1 Proponents support both the CIP-1 proposal and the CIP-2 proposal. In contrast, the CIP-2 Proponents oppose the CIP-1 proposal but support their own CIP-2 proposal. The CIP Coalition as a group is opposed to CPSD's and SDG&E's proposals.⁶²

The CIP Coalition asserts that it was the only party that provided a scientific basis for its proposals. In particular, AT&T retained Exponent Failure Analysis Associates (Exponent) to evaluate the fire risks associated with CIP facilities. Exponent analyzed all publicly available databases regarding fires associated with utility facilities, including databases maintained by Cal Fire.⁶³ Exponent also researched published technical literature and conducted an engineering review of failure modes that could cause fires. Exponent found that the fire risk associated with CIP facilities is negligible. The inspection cycles in the CIP-1 and CIP-2 proposals reflect the very low fire risk of CIP facilities.

The CIP Coalition dismisses CPSD's claim, summarized below, that it found several instances of CIP facilities that had not been properly maintained. The CIP Coalition rebutted CPSD allegation in Phase 1.⁶⁴ Moreover, CPSD has not demonstrated that the alleged maintenance issues led to fires.

⁶² Cox, a member of the CIP Coalition, does not take a position on Contested Proposals 6A through 6D.

⁶³ The Exponent Report is attached in AT&T's Phase 1 Opening Comments filed on March 27, 2009.

⁶⁴ CIP Coalition Phase 1 Opening Comments filed on March 27, 2009, at 10.

The CIP Coalition urges the Commission to reject CPSD's and SDG&E's inspection proposals for the following reasons. First, both proposals require patrol inspections of specified CIP facilities throughout the state, regardless of the fire risk for a particular location. As a result, CPSD's and SDG&E's proposals would waste resources on inspecting CIP facilities in areas where the risk of wildfires is low to nonexistent.

Second, CPSD's and SDG&E's proposals would require patrol inspections every year in urban areas, and every two years in rural areas for most parts of the state. This defies common sense, according to the CIP Coalition. Rural areas are a greater fire risk than urban areas, yet CPSD's and SDG&E's proposals would require more frequent inspections in urban areas.

Third, CPSD's and SDG&E's proposals would require more frequent inspections in the high fire-threat areas of rural Southern California compared to Northern California. The CIP Coalition sees no reason to provide less protection for Northern California.

Fourth, CPSD's and SDG&E's proposals largely mirror the inspection requirements for electric utilities contained in GO 165. The CIP Coalition contends that it is unreasonable to subject CIP facilities to the same inspection requirements as power lines due to the vast difference in fire risks. Moreover, GO 165 is designed to address electric system reliability, not fire safety.

Finally, the CIP Coalition states that SDG&E's proposal is more onerous than CPSD's proposal. SDG&E's proposal would (a) double the number of detailed inspections in the high fire-threat areas of Southern California, and (b) triple the number of CIP-only poles subject to inspections. The CIP Coalition alleges that SDG&E failed to provide any support for its onerous requirements.

AT&T estimates its costs to implement CPSD's and SDG&E's proposals will be \$18 million and \$20 million per year, respectively. This estimate is exclusive of system development costs, equipment and tools to perform the inspections, and administrative costs. This cost estimate is only for AT&T and not other CIPs. The CIP Coalition declares that these costs are unreasonable given the lack of evidence that CPSD's and SDG&E's proposals will decrease the already negligible fire hazards associated with CIP facilities.

CMUA supports the CIP-1 proposal because it constitutes a significant improvement over the status quo and is a reasonable compromise of the various positions articulated by the parties.

CPSD states that the intent of its proposal (Contested Proposal 6C) is to provide clear guidance regarding how frequently and thoroughly the CIPs must inspect all of their aerial facilities, not just facilities in high fire-threat areas. CPSD supports both its own proposal and SDG&E's proposal, but prefers its own proposal over SDG&E's proposal. CPSD opposes both CIP proposals.

CPSD identified several ways that improperly maintained CIP facilities could cause nearby power lines to ignite fires. These are not hypothetical scenarios, according to CPSD, as its safety audits have discovered improperly maintained CIP facilities on many occasions. Moreover, CIP facilities in close proximity to power lines are dangerous regardless of location. Thus, in order to protect public safety, CIP inspection requirements must be statewide as in CPSD's proposal, and not limited to high fire-threat areas as in the CIP-1 and CIP-2 proposals.

CPSD raises two additional concerns with the CIP-2 proposal. First, it would require patrol inspections on a five-year cycle, which would allow violations to exist for several years before being inspected and corrected.

Second, the CIP-2 proposal does not require detailed inspections. CPSD states that patrol inspections are intended to detect obvious safety hazards, while detailed inspections are intended to detect less obvious hazards. The lack of detailed inspections could result in safety hazards going undetected.

DRA states without elaboration that it supports CPSD's proposal.

IBEW 1245 supports CPSD's and SDG&E's proposals. IBEW 1245 believes that statewide inspections are needed due to the proliferation of CIP facilities on joint-use poles in recent years, from ground level to pole top.

IBEW 1245 states that keeping climbing space clear of obstructions is vital for fire protection. This is because obstructions can hinder the ability of electric utility personnel to quickly and safely operate high voltage air switches, fuse assemblies, reclosers, and other protective devices. IBEW 1245 adds that patrol inspections usually do not detect climbing space violations. The only sure way to detect climbing space violations is with detailed inspections.

IBEW 1245 disputes the CIP Coalition's assertion that CIP facilities do not pose a significant fire risk. IBEW 1245 responds that it is not unusual for CIP facilities on joint-use poles to be in violation of the climbing space provisions of GO 95. IBEW 1245 further notes that CIPs have only recently been allowed to install pole-top antennas above high-voltage power lines. It is too soon to know what impact these installations will have on joint-use poles during high winds. IBEW 1245 believes that the continuing installation of antennas and the associated hardware through and above the high-voltage area of joint-use poles justifies an aggressive inspection regimen for CIP facilities.

LA County states that CPSD's and SDG&E's proposals are necessary to mitigate the safety hazard posed by CIP facilities in close proximity to power lines. For example, CIP facilities can (1) add weight to existing poles, which

increases the chance that a pole might break; (2) create additional conductor sag, which increases the risk of contact between power lines and communication lines; and (3) intrude into climbing space. In addition, many pole-top antennas have been installed in recent years, which has increased the potential for CIP facilities falling onto power lines.

LA County opposes the CIP-1 and CIP-2 proposals. LA County states that performing patrol inspections every three years under the CIP-1 proposal, or every five years under the CIP-2 proposal, is not frequent enough in areas where trees can grow rapidly in years with above average rainfall and strong Santa Ana winds blow each year. Another problem with the CIP-2 proposal is that it does not require detailed inspections. LA County notes that patrol inspections may be completed from a passing vehicle. Using this inspection regimen, many CIPs would only learn that a pole needs to be replaced when it fails.

PacifiCorp supports CPSD's and SDG&E's proposals because they include reasonable inspection cycles on a statewide basis. PacifiCorp agrees with SDG&E's position that inspection requirements should apply to CIP facilities within three spans of joint-use poles because of the possibility that damage to CIP facilities could cascade to nearby joint-use poles.

PacifiCorp opposes the CIP-1 and CIP-2 proposals for several reasons. First, the proposals are limited to high fire-threat areas, but CIP facilities pose a fire hazard regardless of location. Second, the CIP-2 proposal does not require detailed inspections, which are needed to ensure that CIP facilities do not become a fire hazard. Finally, the CIP-2 proposal calls for patrol inspections every five years, which is not sufficient to protect against potential fire risks.

PG&E supports the CIP-1 proposal, opposes the CIP-2 proposal, and is neutral with respect to CPSD's and SDG&E's proposals. PG&E sees the CIP-1

proposal as providing reasonable inspection requirements that are focused on fire mitigation. PG&E opposes the CIP-2 proposal because it would only require patrol inspections of CIP facilities every five years, with no requirement for detailed inspections. This will do little to reduce fire risks, according to PG&E.

PG&E urges the Commission to require CIP facilities to be inspected using both routine patrols and detailed inspections. PG&E has seen enough problems with CIP facilities to believe that such an inspection program is warranted. On the other hand, PG&E recognizes that CIP facilities are less risky than electric facilities. Consequently, the intervals for CIP inspections do not need to match the inspection intervals used for electric facilities.

PG&E disagrees with the Exponent Report that CIP facilities pose a negligible fire hazard. PG&E states that there have been more than 50 incidents during the past 3 years where PG&E found vegetation entangled with CIP facilities on joint-use poles. This entanglement affected adjacent power lines and caused both outages (which always have the potential for a fire) and three fires.

PG&E recommends that if either CPSD's proposal or SDG&E's proposal is adopted, it should be limited to Southern California. PG&E also recommends that CIP inspection requirements be placed in a new Rule 80.1A as proposed by CPSD and SDG&E.

SCE supports both CIP proposals and takes a neutral position on CPSD's and SDG&E's proposals. SCE believes it is important to require regular inspections of CIP facilities located near power lines in high fire-threat areas. SCE considers both CIP proposals to be aligned with this goal. In contrast, the CPSD and SDG&E proposals would expand the scope of inspections to locations outside of high fire-threat areas without adequate justification.

SDG&E supports both its own proposal (Contested Proposal 6D) and CPSD's proposal (Contested Proposal 6C), but SDG&E prefers its own proposal over CPSD's proposal. SDG&E opposes both CIP proposals.

SDG&E's proposal differs from CPSD's proposal in two respects. First, SDG&E's proposal would require inspection of CIP facilities within three spans of joint-use poles, versus one span under CPSD's proposal. SDG&E submits that a three-span requirement is necessary because of the possibility that damage to CIP facilities could cascade to joint-use poles several spans away. Second, SDG&E's proposal would require detailed inspections every five years in the high fire-threat areas of Southern California, versus every 10 years under CPSD's proposal. SDG&E argues that 10 years is too long of an interval for detailed inspections in high fire-threat areas. The Commission has already established a five-year cycle for detailed inspections of electric facilities. SDG&E submits that it is reasonable for CIPs to have the same inspection cycle as electric utilities in high fire-threat areas.

SDG&E disagrees with the CIP Coalition's claim that SDG&E has not provided support for its proposal. During the workshop process, SDG&E presented photographs of broken and damaged CIP lashing wires that SDG&E had found during inspections of its facilities in 2010.

SDG&E opposes the CIP-1 and CIP-2 proposals because their inspection cycles are too long. The CIP-1 proposal and CIP-2 proposal would require patrol inspections every three years and five years, respectively. SDG&E believes this is not frequent enough in high fire-threat areas where strong Santa Ana winds occur regularly. A five-year patrol inspection cycle is especially inappropriate, as it could allow hazards to exist for several years before being discovered. Detailed inspections should also occur more frequently than every nine years

under the CIP-1 proposal, and not at all under the CIP-2 proposal. SDG&E conducts patrol inspections annually in high fire-threat areas and detailed inspections every five years. CIPs should do the same.

Another flaw with the CIP proposals, according to SDG&E, is their lack of required inspection cycles for CIP facilities located outside of high fire-threat areas. SDG&E states that because strong Santa Ana winds occur throughout its service territory, public safety requires regular inspections of CIP facilities that are located near power lines, regardless of location.

SDG&E questions the finding in the Exponent Report that the fire risk associated with CIP facilities is negligible. Exponent based its finding, in part, on a review of historical fires in databases maintained by the National Fire Incident Reporting System and Cal Fire. It is SDG&E's understanding that these databases do not track power-line fires that were caused, at least in part, by CIP facilities. For example, SDG&E does not believe the Cal Fire database shows that CIP facilities contributed to the ignition of the Guejito Fire in October 2007, even though Cal Fire determined that CIP facilities were involved.

6.6.4. Discussion

The issue before us is the scope of the CIP inspection requirement and associated record keeping. In deciding this issue, our principle concern is the prevention of catastrophic wildfires caused by improperly installed or maintained CIP facilities in close proximity to overhead power lines. We are also mindful that any adopted inspection requirement should achieve our goal of fire prevention in a cost-effective manner.

The record of this proceeding establishes that CIP facilities located in close proximity to power lines are a latent fire hazard. CIP facilities include bare metal components such as messenger wires, lashing wires, and pole-top antennas. If

not installed and maintained properly, CIP facilities could contact power lines and ignite a fire. CIP-only poles can also fail, causing a cascade that topples nearby joint-use poles with power lines attached, resulting in wildfires.

The record of this proceeding also indicates that the occurrence of improperly installed and maintained CIP facilities is not a rare phenomenon. Several parties who are in regular contact with CIP facilities – including CPSD, IBEW 1245, PacifiCorp, PG&E and SDG&E – represent that they have found instances of improperly installed and maintained CIP facilities.⁶⁵

The far-reaching extent of the fire hazard posed by CIP facilities is illustrated by the 2007 Guejito Fire in San Diego County. Cal Fire determined that the Guejito Fire started when a CIP lashing wire made contact with a 12 kilovolt (kV) overhead conductor during strong Santa Ana winds.⁶⁶ Cal Fire did not attempt to determine the size of the Guejito Fire because it eventually merged with the larger Witch Fire that had started the day before. The Guejito Fire was unquestionable large, however. Within 30 minutes of being reported, the Guejito Fire reached I-15, closing the highway and disrupting the evacuation

⁶⁵ Phase 2 Workshop Report, Appendix B, at B-73; CPSD Phase 2 Opening Brief at 16; CPSD Reply Brief at 8, Footnote 1; IBEW 1245 Opening Brief at 9 – 10; IBEW 1245 Reply Brief at 2; PacifiCorp Reply Brief at 4; PG&E Reply Brief at 8; SDG&E Opening Brief at 16; and SDG&E Reply Brief at 14 – 15.

⁶⁶ Cal Fire's report on the Guejito Fire can be viewed at http://www.fire.ca.gov/fire_protection/downloads/redsheets/CA-MVU-010484_Complete.pdf. We take official notice of this document on our own motion pursuant to Pub. Util. Code §§ 701 and 1701, and Rule 13.9 of the Commission's Rules of Practice and Procedure. Today's decision does not (i) decide any issues that were litigated in the Commission's investigation of the Guejito Fire, which is now closed (D.10-04-047, Ordering Paragraph 9); (ii) determine the root cause of the Guejito Fire; or (iii) find that the Guejito Fire was caused by improperly installed or maintained facilities. Rather, today's decision cites Cal Fire's finding that the Guejito Fire was started when a CIP lashing wire touched a 12 kV power line.

of communities threatened by the Witch Fire. The Guejito Fire then crossed I-15 and spread several miles to the west.⁶⁷

In light of the inherent fire risk of CIP facilities located in close proximity to power lines, it is essential that CIP facilities be installed and maintained properly to protect public safety. To achieve this goal, we conclude that CIPs should be required to perform patrol and detailed inspections on the following cycles:

- Patrol inspections every year for CIP facilities located in high fire-threat areas of Southern California.
- Patrol inspections every two years for CIP facilities located in high fire-threat areas of Northern California.
- Detailed inspections every five years for CIP facilities located in high fire-threat areas of Southern California.
- Detailed inspections every 10 years for CIP facilities located in high fire-threat areas of Northern California.

These inspection requirements shall apply to CIP facilities attached to joint-use poles and to CIP-only poles within three spans of a joint-use pole. Today's decision defines Southern California as Imperial, Los Angeles, Orange, Riverside, Santa Barbara, San Bernardino, San Diego, and Ventura Counties. Northern California is defined as all other counties. High fire-threat areas are shown on the fire-threat maps adopted later in today's decision.

To ensure consistent implementation of the adopted inspection intervals, we define the term "year" as 12 consecutive calendar months starting the first full calendar month after an inspection is performed. For example, if an inspection is performed in January of 2012 and the required inspection interval is

⁶⁷ *California Fire Siege 2007 – an Overview*, at 84.

one year, the next inspection must be completed by the end of January 2013.⁶⁸ We will also add this definition of “year” to GO 165 to ensure consistent interpretation of inspection intervals for both CIPs and electric utilities.

CIPs shall keep records that provide the following information for each facility: The location of the facility, the date(s) the facility was inspected, the results of each inspection, the personnel who performed each inspection, the date and description of each corrective action, and the personnel who performed each corrective action.

Consistent with CPSD’s and SDG&E’s proposals, the adopted inspection and record-keeping requirements shall be placed in a new Rule 80.1A of GO 95, with a reference to the new rule added to Rule 31.2. The adopted text is contained in Appendix B of today’s decision.

We conclude that the protection of public safety requires patrol inspections every year, and detailed inspections every five years, for CIP facilities located in the high fire-threat areas of Southern California. The catastrophic wildfires of October 2007 convince us that extra precautions are warranted in these areas. In addition, the strong Santa Ana winds that occur regularly in these areas substantially increase the risk that improperly installed or maintained facilities will ignite a fire. Frequent inspections will help to mitigate this risk.

We also conclude that patrol inspections every two years, and detailed inspections every ten years, is sufficient for CIP facilities located in the high fire-threat areas of Northern California. There is no history of catastrophic power-line fires in Northern California, and Northern California does not

⁶⁸ Likewise, if an inspection interval is two or five years, the next inspection must be completed within 24 or 60 calendar months, respectively.

experience Santa Ana winds that contribute significantly to the risk of catastrophic power-line fires in Southern California. Therefore, because the overall risk of power-line fires is lower in Northern California, we can safely reduce the frequency (and associated cost) of inspections.

We agree with SDG&E that the adopted inspection requirements should apply to CIP-only poles located within three spans of a joint-use pole. It is widely recognized in the utility industry that the failure of one pole, or the facilities attached to a pole, can cascade to nearby poles. Limiting CIP inspections to one-span from joint-use poles would not provide an adequate buffer to protect against cascading failures.

The CIP inspection requirements adopted by today's decision are minimum requirements. CIPs should inspect their facilities more often than required by today's decision if doing so is necessary to protect public safety.

We decline to adopt CPSD's and SDG&E's proposals to set inspection cycles for CIP facilities located outside high fire-threat areas. The central focus of this proceeding is the reduction of fire hazards posed by overhead electric utility and CIP facilities. CPSD and SDG&E have not demonstrated that mandatory inspection cycles for CIP facilities in lower risk areas will provide a meaningful or cost-effective reduction in the fire hazard posed by CIP facilities. We emphasize that although today's decision does not adopt mandatory inspection cycles for CIP facilities in lower risk areas, this does not affect the CIPs' obligation under Rule 31.2 to inspect their facilities in these areas frequently and thoroughly. Nor does today's decision relieve CIPs of their obligation under Pub. Util. Code § 451 to maintain their facilities in a safe condition at all times.

We decline to adopt the CIP-1 and CIP-2 proposals for patrol inspection cycles of three years and five years, respectively. As LA County points out,

vegetation can grow rapidly in years when rainfall is above average. A three-year or five-year inspection cycle could allow vegetation-related fire hazards to exist for several years before being discovered and remedied.

We also decline to adopt the CIP-2 proposal to rely exclusively on patrol inspections, with no requirement for detailed inspections. While patrol inspections can detect obvious fire hazards, some hazards can only be detected by detailed inspections that require an inspector to examine each utility pole carefully. Consequently, relying exclusively on patrol inspections could allow dangerous fire hazards to go undetected until disaster strikes. This is an unacceptable risk in the wake of the catastrophic wildfires of October 2007.

The CIPs argue that the adopted inspection requirements for CIPs are improperly modeled on the GO 165 inspection rules for electric utilities. The CIPs assert that GO 165 is intended to promote reliable service, not reduce fire risk. This description of GO 165 is incorrect. A primary purpose of GO 165 is to ensure safe electrical service.⁶⁹ The prevention of fires is an integral part of this safety mandate.

We are not persuaded by the CIP Coalition that the Exponent Report demonstrates that CIP facilities pose little fire risk and, therefore, the inspection cycles adopted by today's decision are excessive. The Exponent Report relied on databases of historical fires that do not track power-line fires that were caused, at least in part, by CIP facilities. For instance, the Cal Fire database used by Exponent apparently does not show CIP facilities as contributing to the ignition

⁶⁹ GO 165, Sections I, II, III.F, and IV.

of the Guejito Fire, even though Cal Fire's report on the Guejito Fire states the fire was started when a CIP lashing wire touched a power line.⁷⁰

Finally, the CIP Coalition argues that CPSD's and SDG&E's proposals would be unduly costly to implement. For example, AT&T estimates that it would cost \$18 million to implement CPSD's proposal and \$20 million to implement SDG&E's proposal. As a preliminary matter, the CIP inspection requirements adopted by today's decision should cost considerably less than estimated by AT&T because the geographic scope of the adopted requirements is significantly less than proposed by CPSD and SDG&E.⁷¹ Moreover, because CIPs are already required by Rule 31.2 to inspect their facilities frequently and thoroughly, there should not be significant additional costs to implement the inspection requirements adopted by today's decision. In our judgment, the costs incurred by CIPs will be more than offset by the public-safety benefits from the reduced risk of catastrophic wildfires.

6.7. Contested Proposal 6E re: GO 95, Rule 80.1B

6.7.1. Summary of Proposal

GO 165 requires intrusive inspections of wood poles that support power lines. GO 165 defines intrusive inspections as "the movement of soil, taking samples for analysis, and/or using more sophisticated diagnostic tools beyond visual inspections or instrument reading." The first intrusive inspection of a pole

⁷⁰ SDG&E Reply Brief at 10 - 11. See also Cal Fire's report on the Guejito Fire at http://www.fire.ca.gov/fire_protection/downloads/redsheat/CA-MVU-010484_Complete.pdf.

⁷¹ CPSD's and SDG&E's proposals would apply to the entire state. The adopted inspection cycles apply only to high fire-threat areas.

must occur during years 15 through 24 of a pole's service life. Poles that have passed an intrusive inspection do not need to be inspected for another 20 years.

There is currently no requirement for intrusive inspections of wood poles that support only CIP facilities ("CIP-only poles"). CPSD proposes to add a new Rule 80.1B to GO 95 that would apply the GO 165 intrusive inspection requirements to CIP-only poles that are physically connected to joint-use poles. CPSD's proposal would be limited to CIP-only poles that are (1) interseted or within three spans of a joint-use pole in the high fire-threat areas of Southern California, and (2) within one span of a joint-use pole in all other areas.

CPSD estimates that the cost for intrusive inspections of CIP-only poles would be approximately \$30 - 50 per pole. The text of CPSD's proposed new Rule 80.1B is contained in Appendix A of today's decision.

6.7.2. Position of the Parties

CPSD states that the failure of a CIP-only pole that is physically connected to joint-use poles could damage power-line facilities and thereby ignite a fire. The failure of CIP-only poles could also cause other public-safety issues such as the loss of 911 service. CPSD's proposal to require intrusive inspections is intended to ensure that CIP-only poles are repaired or replaced prior to failure.

CPSD believes that intrusive inspections are warranted by the fact that GO 95 allows CIP-only poles to have a lower safety factor than poles that support power lines, and thus can break more easily in high winds. The fact that CIP-only poles are not as sturdy also means that it is easier for the failure of one CIP-only pole to cascade down a line of CIP-only poles during high winds.

CPSD observes that high-wind conditions which can cause CIP-only poles to break are the same conditions that can lead to catastrophic fires. Because the risk of wind-related fires is much higher in Southern California, CPSD's proposal

would require intrusive inspections of CIP-only poles within three spans of joint-use poles in the high fire-threat areas of Southern California, versus one span in all other areas of California.

CPSD's estimated cost of intrusive inspections of \$30 - \$50 per pole is based on information provided at the workshops from several parties. Osmose Utility (which performs intrusive inspections) stated that the cost for intrusive inspections, including full excavation and pole treatment, is \$30 to \$50 per pole. PG&E estimated its costs at \$45 per pole. PacifiCorp estimated its costs at \$39 per pole. CPSD also believes that its proposal could save money over the long run. According to Osmose Utility, wood poles will last approximately 45 years with no inspection or treatment, but will last 80 years with 2 to 3 treatments.

CPSD's proposal is supported by DRA, IBEW 1245, LA County, PacifiCorp, PG&E, SCE, SDG&E, Sierra Pacific, and TURN. They agree that the failure of a CIP-only pole could damage nearby joint-use poles and ignite a fire. Therefore, as a matter of public safety, CIP-only poles need to be inspected. LA County adds that CIP-only poles that fail during high-wind events can not only ignite fires, but also block egress and ingress of both evacuees and first responders, turning a hazardous situation into a life-threatening one.

While PG&E supports intrusive inspections for CIP-only poles, PG&E states that CIP-only poles are less of a fire risk than joint-use poles. Consequently, the intervals for a CIP inspection program do not need to match the inspection intervals for electric facilities.

SCE does not take a position on whether every element of CPSD's proposal is necessary or cost effective. In general, SCE would prefer to limit intrusive inspections for CIP-only wood poles to high fire-threat areas.

SDG&E asserts there is a clear need for intrusive inspections of CIP-only poles. SDG&E has encountered problems with the failure of CIP-only poles, including a March 2010 failure of a CIP-only pole that cascaded into SDG&E's power-line facilities and ignited a small fire.

CPSD's proposal is opposed by the CIP Coalition.⁷² The CIP Coalition argues that CPSD's proposal is outside the scope of this proceeding as set forth in the Phase 2 Scoping Ruling:

The purpose of this rulemaking proceeding is to consider measures to reduce fire hazards associated with: (1) electric transmission and distribution facilities and (2) communication infrastructure provider (CIP) facilities in close proximity to overhead electric power lines. (Phase 2 Scoping Ruling at 1.)

The CIP Coalition contends that CPSD's proposal does not focus on fire hazards associated with CIP facilities in close proximity to power lines because (1) the proposal is not limited to high fire-threat areas, and (2) there are no power lines attached to CIP-only poles, and hence no power lines in close proximity.

The CIP Coalition asserts there is no evidence that CIP-only poles have caused fires or that intrusive testing of CIP-only poles will reduce fires. While several parties speculate that intrusive testing could identify poles that are likely to fail and cause a fire, speculation should not be the basis for a new regulation.

The CIP Coalition dismisses LA County's concern that CIP-only poles can fall and block egress and ingress during emergencies, since LA County failed to cite one incident where a CIP pole has blocked access. The CIP Coalition also dismisses SDG&E allegation that a CIP-only pole broke in March 2010 and fell onto SDG&E's power-lines, causing a small fire. SDG&E did not provide

⁷² Cox, a member of the CIP Coalition, does not take a position on CPSD's proposal.

evidence that the incident actually occurred or that intrusive inspections could have prevented the incident. Regardless, one incident is not a sufficient basis for adopting a new statewide regulation.

The CIP Coalition asserts that the costs of intrusive inspections will be significant. For AT&T alone, the estimated costs to test all of its CIP-only poles would be approximately \$11 million.⁷³ Given that there would be no reduction in fire risks, these costs should not be imposed on the CIPs and their customers.

If the Commission decides to adopt an intrusive inspection requirement for CIP-only poles, the CIP Coalition submits that the inspection cycles in GO 165 for electric facilities are excessive for CIP facilities given the difference in fire risks.

6.7.3. Discussion

The issue before us is the whether to adopt CPSD's proposal to require intrusive inspections of CIP-only poles. In deciding this issue, our main concern is the prevention of wildfires caused by poorly maintained CIP-only poles in close proximity to power lines. Any adopted inspection requirement should achieve our goal of fire prevention in a cost-effective manner.

All wood poles will fail at some point. If not maintained properly and replaced when necessary, CIP-only poles can break and damage nearby joint-use poles and the attached power lines, resulting in a fire. Intrusive inspections can determine the remaining strength of wood poles so that poles can be treated or replaced before they fail.

⁷³ AT&T's estimate is for all of its CIP-only poles, not just those poles that would be affected by CPSD's proposal. AT&T does not know at this time how many of its CIP-only poles would be subject to CPSD's proposal.

In order to protect public safety, we conclude that it is reasonable to set intrusive inspection cycles for CIP-only poles connected to nearby power lines. Accordingly, we will adopt CPSD's proposal with one significant modification. While CPSD's proposal would apply statewide, we agree with the CIP Coalition and SCE that mandatory intrusive inspection cycles for CIP-only poles should be limited to high fire-threat areas. Consistent with CPSD's proposal, we will require intrusive inspections of CIP-only poles located within one span of joint-use poles in the high fire-threat areas of Northern California, and within three spans of joint-use poles in the high fire-threat areas of Southern California. The adopted intrusive inspection cycles shall be placed in a new Rule 80.1B of GO 95 as proposed by CPSD. The text of the new Rule 80.1B is contained in Appendix B of today's decision.⁷⁴

The intrusive inspection requirements adopted by today's decision are minimum requirements. CIPs should inspect their poles as often as necessary to protect public safety.

CPSD did not propose a record keeping requirement for intrusive inspections. We believe that such a requirement is necessary to monitor compliance. Therefore, we will require CIPs to keep records that provide the following information for each CIP-only pole: The location of the pole, the date(s) the pole was inspected, the results of each intrusive inspection, the personnel who performed each inspection, the date and description of any corrective actions, and the personnel who performed the correction actions.

⁷⁴ The adopted text for Rule 80.1B differs non-substantively from the text proposed by CPSD. The adopted text also references the fire-threat maps that are adopted later in today's decision.

We find no merit to the CIP Coalition's argument that the issue of intrusive inspections for CIP-only poles is outside the scope of this proceeding because these poles do not pose any fire risk. GO 95 allows wood poles that support CIP facilities to have a lower safety factor than poles that support power lines. Therefore, CIP-only poles can break more easily when subjected to high winds, falling vegetation, or other stresses. The failure of a CIP-only pole that is physically connected to a nearby joint-use pole by a messenger wire, guy wire, or other means can pull down the connected joint-use pole and attached power lines, resulting in a fire. High wind conditions that can cause CIP-only poles to break are the same conditions that can lead to a catastrophic wildfire, especially in Southern California which experiences Santa Ana winds regularly.

We are not persuaded by the CIP Coalition that there is no evidence that CIP-only poles pose a fire hazard. It is indisputable that wood poles can fail if they are not maintained properly and replaced when necessary. By requiring intrusive inspections of CIP-only poles, today's decision will help ensure that poles in need of repair or replacement are detected so they do not damage nearby electric facilities and thereby cause a fire.

Finally, we disagree with the CIP Coalition that the cost of required intrusive inspections exceeds the benefits. The cost of intrusive inspections should be far less than AT&T's estimate of \$11 million to test all of its CIP-only poles. Today's decision sets intrusive inspection cycles for only a fraction of AT&T's poles and allows CIPs to spread the cost of intrusive inspections over many years. Once a wood pole has passed an intrusive inspection, it would only be required to be intrusively inspected on a 20-year cycle thereafter. As result, the annual costs incurred by AT&T and other CIPs to implement the intrusive inspection requirements adopted by today's decision should be relatively small,

and in the case of AT&T, far less than \$11 million. We believe the costs will be more than offset by the public-safety benefits from the reduced risk of catastrophic wildfires.

6.8. Contested Proposal 7A re: GO 95, Rule 35, Paragraph 4

6.8.1. Summary of Proposal

In the Phase 1 Decision, the Commission indicated that it would consider proposals in Phase 2 for dealing with landowners who obstruct vegetation management.⁷⁵ In response, PG&E, SCE, and SDG&E (together, “the Joint Utilities”) propose to add a new Paragraph 4 to Rule 35 of GO 95 that would allow electric utilities to shut off power to customers who obstruct vegetation management on their property. The proposal would apply to all of a customer’s service locations, not just the location where the customer obstructs vegetation management. For example, if a farmer refuses to allow access to a transmission line in a cultivated field, the electric utility could shut off power to the farmer’s residence, vacation home, and any other properties owned by the farmer in the utility’s service territory. Electric utilities would provide written notice at least five days before shutting off service, unless the vegetation condition poses an imminent safety hazard. Importantly, this proposal does not contemplate shutting off service to state or city customers. The text of the proposed addition to Rule 35 is contained in Appendix A of today’s decision.

The Joint Utilities will incur little or no net costs to implement the proposal. The cost to reconnect service will be at the customer’s expense.

⁷⁵ D.09-08-029 at 29-30.

6.8.2. Position of the Parties

The Joint Utilities' proposal is supported by CMUA, IBEW 1245, PacifiCorp, Sierra Pacific, and TURN. The proponents state the proposal is aimed at the small number of property owners who refuse to allow electric utilities to access their property to keep power lines clear of vegetation. These property owners place their communities in jeopardy of potential fires, power outages, and injury to power-line workers and the public.

The Joint Utilities, together with PacifiCorp and Sierra Pacific (collectively, "the electric investor-owned utilities" or "electric IOUs") already have authority under their tariffs to terminate service if a customer does not permit vegetation management activities. They see the proposed rule as a logical extension of their existing authority. The electric IOUs also represent that they will (1) shut off power only as a last resort, and (2) attempt to contact the customer multiple times to resolve a vegetation-management dispute before shutting off power. The electric IOUs expect the threat of shutting off power will convince customers to allow vegetation management.

Although TURN supports the Joint Utilities' proposal, TURN also recommends that the electric IOUs make the following modifications to their tariffs. First, tariff Electric Rule 11 (Discontinuance of Service) should be revised to state that the utility may terminate service at any location where the customer receives service whenever a customer obstructs access to overhead facilities, such that the electric utility cannot inspect its facilities or there is an imminent threat that required vegetation clearances will not be maintained.

Second, the tariffs should describe the notice requirements for vegetation-related shut-offs. TURN recommends that the Commission direct utilities to provide written notice 30 days prior to a vegetation-related

disconnection. TURN states that 30 days' notice will give the customer an opportunity to work with the utility to have trees cut in a manner agreeable to both parties, but still give electric utilities the leverage they assert is needed to complete vegetation management activities.

Third, TURN recommends that electric utilities attempt to contact, by telephone or in person, an adult person residing at the property where service will be terminated and at the billing address of the customer of record. TURN also recommends that the utilities attempt such contact at least 25 days prior to the termination of service; a second attempt at least five days prior to termination of service if no prior contact has been achieved with an adult person; and a final attempt at least 24 hours prior to termination of service.

Fourth, because the Joint Utilities' proposal may impact persons living in multi-residential buildings, TURN recommends that the electric IOU be required to post a notice on each tenant's door and in common areas that informs the tenants that service will be discontinued for obstruction of vegetation management activities at least 30 days prior to discontinuance of service.

Fifth, TURN recommends that utility tariffs be modified to clarify that disconnections for vegetation management noncompliance will be subject to the same heightened notice requirements for sensitive customers as utilities apply to disconnections for non-payment. TURN also recommends that the Commission require the final attempt to contact a sensitive customer be an in-person visit.

Finally, TURN recommends that any requirements regarding disconnection-related communications with customers who are not English-proficient, or who have vision or hearing impairments, also apply to vegetation management disconnections.

The electric IOUs take different positions with respect to TURN's tariff recommendations. PacifiCorp and Sierra Pacific support TURN's recommendations. PG&E, SCE, and SDG&E do not object to modifying their tariffs to reflect their proposed revisions to Rule 35. However, they oppose TURN's other tariff recommendations because they would undermine the disconnection process by making it too unwieldy.

The Joint Utilities' proposal is opposed by CFBF, CPSD, LA County, and MGRA. In general, the opponents acknowledge that electric IOUs have authority under their tariffs to shut off power where there is an imminent safety hazard. The Joint Utilities' proposal would go much further by allowing electric IOUs to shut off power at locations where no safety hazard exists. It would also create collateral harm by shutting off power to persons other than the customer who is obstructing vegetation management (e.g., residents of sub-metered apartments).

CFBF argues that the Joint Utilities' proposal is outside the scope of this proceeding because it is not focused on reducing fire hazards. Rather, the proposal would allow electric IOUs to shut off power anywhere, not just in high fire-threat areas.

CFBF states there may be valid reasons for customers to balk at the timing or extent of vegetation management activities. The proposed rule unfairly provides the utility with carte blanche to shut off power when there is a legitimate dispute. Agricultural customers would be hardest hit by this proposal, as their properties are crossed by thousands of miles of power lines.

CFBF further argues that the Commission has no authority to authorize utilities to shut off power as a device to force property owners to provide access to their properties. CFBF states that the terms and conditions of access are

governed by easement agreements between property owners and utilities. The Commission has acknowledged it does not have jurisdiction to adjudicate easement disputes and must defer to the courts.⁷⁶

MGRA asserts the electric IOUs are seeking police powers to force entry onto property. MGRA believes the Commission's efforts would be better focused on finding ways to enhance law enforcement cooperation with utilities rather than placing the right of enforcement in the hands of utilities.

If the Commission adopts the Joint Utilities' proposal, CPSD recommends that the authority to shut off power should not be added to GO 95, which governs design, maintenance, and construction standards for overhead lines. Instead, it should be addressed in utilities' tariffs as a "condition of service."

6.8.3. Discussion

The issue before us is whether to adopt the Joint Utilities' proposal to authorize electric utilities to shut off power to customers who obstruct vegetation management on their property. The proposal would allow electric utilities to terminate service at any location where a customer receives service, not just the location where the customer obstructs vegetation management. In deciding this issue, our main concern is the prevention of wildfires caused by the failure of property owners to allow access to power-line facilities to perform necessary vegetation management activities. We must also weigh the negative impacts of shutting off power to all service locations of a non-cooperative customer.

The failure to keep power lines clear of vegetation poses a serious threat to public safety. It is well known that vegetation contact with high-voltage power lines can ignite fires and/or cause power outages that deprive communities of

⁷⁶ See, for example, D.98-04-070, 80 CPUC 2d 199, 200.

vital electric service. In addition, the task of maintaining clearances is much more dangerous when vegetation is allowed to grow close to power lines.

We agree with the Joint Utilities that in order to protect public safety, electric utilities need appropriate tools to deal with customers who obstruct access to their property for vegetation-management activities. We conclude that the Joint Utilities' proposal rule is a reasonable solution to address a known public-safety hazard, and we adopt the proposal with the following conditions. First, as proposed by the Joint Utilities, an electric utility may shut off power to a property owner who obstructs access to the utility's overhead power-line facilities located on the owner's property, such that the utility cannot inspect its facilities or maintain required vegetation clearances around power lines.

Second, as proposed by the Joint Utilities, the authority to shut off power to customers who obstruct vegetation management does not extend to state and local government customers.

Third, we decline to adopt the Joint Utilities' request for broad authority to terminate service at all locations where a customer receives service. This could cause harmful disruption to third parties who have no responsibility whatsoever for a customer's obstruction of vegetation management. In order to keep the remedy of shutting off power focused on the customer responsible for obstructing vegetation management, we will limit the electric utilities' authority to shut off power to one meter serving the property owner's primary residence, or if the property owner is a business entity, the entity's primary place of business. This one meter is in addition to shutting off power, if necessary for public safety, at the location of the vegetation hazard.

Fourth, prior to shutting of power, electric utilities shall follow the procedures and notice requirements applicable to discontinuance of service for

non-payment, including the requirements applicable for sensitive customers, customers who are not proficient in English, and other customer groups.

Finally, for vegetation hazards that pose an immediate threat to public safety (such as vegetation contacting a power line during windy conditions), electric utilities may shut off power to the obstructing property owner's residence or primary place of business at any time. Under these circumstances, the electric utility shall attempt to contact the property owner by daily visits to the property owner's residence or primary place of business, in addition to sending written notice, until contact is achieved and the property owner is notified why power has been shut off and what steps need to be taken to restore power.

We agree with CPSD and TURN that the authority to shut off power to a customer who obstructs vegetation management should be added to the utilities' tariffs as a "condition of service." To this end, each electric IOU shall file and serve a Tier 3 advice letter to make the necessary revisions to its tariffs no later than 60 days from the issuance date of today's decision.

We further agree with CPSD that the electric utilities' authority to shut off power should not be added to GO 95, which governs design, maintenance, and construction standards for overhead lines. This is consistent with the treatment of electric utilities' existing authority contained in their tariffs, but not in GO 95, to shut off power at locations where there is a safety hazard.

CFBF argues that the Commission lacks jurisdiction to determine the rights of parties in real property disputes. Today's decision does not attempt to resolve property disputes. Rather, today's decision addresses the terms and conditions under which electric utilities may terminate service to a defined group of customers, which is matter that is clearly within the Commission's

jurisdiction. If an electric utility conducts vegetation management activities in a way that violates its easement agreement with a property owner, the property owner may pursue legal remedies through the courts.

6.9. Contested Proposal 7B re: GO 95, Rule 35, Third Exception

6.9.1. Summary of Proposal

Rule 35 of GO 95 requires electric utilities and CIPs to maintain prescribed vegetation clearances around their overhead facilities. Rule 35 also lists four exceptions to the prescribed clearances. PG&E, SCE, and SDG&E (together, “the Joint Utilities”) propose a new Third Exception, with the current Third and Fourth Exceptions renumbered. Under the new Third Exception, electric utilities and CIPs would not be held responsible for the consequences of failing to trim or remove vegetation when a property owner obstructs vegetation-management activities and the company can document (1) at least one attempt at personal contact with the owner, (2) at least one written communication to the owner, and (3) notification to Commission Staff.

The Joint Utilities also propose to amend the Second Exception to replace the word “utilities” with “supply or communication company.” This technical revision is consistent with the same revision in certain consensus proposals adopted by today’s decision.

The proposed revisions to Rule 35 are contained in Appendix A of today’s decision. The Joint Utilities do not anticipate that their proposal would create any additional costs for electric utilities, CIPs, or their customers.

6.9.2. Position of the Parties

The main purpose of the Joint Utilities’ proposal is to shift responsibility for the failure to perform vegetation management from the electric utilities and

CIPs to the property owners who obstruct vegetation management. The proposal is supported by many CIPs,⁷⁷ PacifiCorp, and Sierra Pacific. The proponents of the proposal agree that shifting responsibility to the obstructing property owners is not only fair, it will reduce obstructions when property owners realize they will be responsible for the consequences. The end result should be improved compliance with vegetation-management requirements and a parallel reduction in fire hazards.

There is no opposition to the Joint Utilities' proposed technical revisions to the Second Exception to Rule 35. The Joint Utilities' proposal to add a new Third Exception is opposed by CPSD, CFBF, MGRA, and TURN.

The opponents note that the Phase 2 Scoping Memo determined that the scope of this proceeding excludes proposals to limit the liability of electric utilities and CIPs.⁷⁸ The opponents assert that the Joint Utilities' proposal is clearly an attempt to limit the electric utilities' liability.

The opponents submit there is no guarantee that vegetation management will occur if electric utilities and CIPs are allowed to shift responsibility for performing vegetation management to the property owners who obstruct vegetation management. The only sure outcome, according to the opponents, is that electric utilities and CIPs will have no incentive to aggressively conduct vegetation management if they can shift liability to the obstructing property owners. The end result is likely to be an exacerbation of fire risks.

⁷⁷ The CIPs that support this proposal are AT&T, CTIA, the Small LECS, Sprint, Sunesys, SureWest Telephone, T-Mobile, and Verizon.

⁷⁸ Phase 2 Scoping Memo at 8.

CFBF is concerned that the proposal requires only minimal attempts to contact property owners, with no requirement that contact actually occur. CFBF states that it is unfair to shift legal liabilities to property owners without any assurance the affected party has been contacted.

6.9.3. Discussion

The primary issue before us is whether to adopt the Joint Utilities' proposal to relieve electric utilities and CIPs of responsibility for the consequences of failing to perform vegetation management when a property owner obstructs access to overhead facilities. We decline to adopt the proposal because it is outside the scope of this proceeding as set forth in the Phase 2 Scoping Memo:

[The] scope of Phase 2 excludes matters that are focused on reducing utilities' legal liability. The overarching objective of Phase 2 is to consider measures to reduce the fire hazards associated with utility facilities. Considering ways to reduce liability would divert attention from the main focus of Phase 2. (Phase 2 Scoping Memo at 8.)

Even if the proposal were within the scope of this proceeding, we would still reject it. In our opinion, the proposal would likely exacerbate fire hazards by removing the incentive for electric utilities and CIPs to aggressively pursue vegetation management on the properties of recalcitrant landowners.

We recognize that property owners who obstruct vegetation management activities can create a fire hazard that threatens public safety. We believe it is reasonable for electric utilities and CIPs to hold the obstructing property owners responsible. Therefore, if a property owner obstructs vegetation management, and there is a vegetation-related fire or other harm, we encourage the electric utilities and CIPs to seek compensation for any costs and liabilities they incur

from the property owner. The written notices sent to property owners under the current Second Exception may include a statement that the electric utility or CIP may seek to recover fire-related costs and liabilities from the property owner.⁷⁹ We believe that such notices will provide a strong incentive for property owners to allow access to their properties, thus achieving the stated goal of this proceeding. Likewise, the electrical utilities and CIPs would continue to have a strong motivation to aggressively address safety issues.⁸⁰

We adopt the Joint Utilities' unopposed proposal to revise the Second Exception to Rule 35 to replace the generic term "utilities" with the more descriptive "supply or communication company." The adopted revisions to Rule 35 are contained in Appendix B of today's decision.

6.10. Contested Proposal 8A re: GO 95, Appendix E

6.10.1. Summary of Proposal

Electric utilities and CIPs are required by Rule 35 of GO 95 to maintain minimum radial clearances between energized bare-line conductors and vegetation. The minimum radial clearances are set forth in Table 1 of GO 95. In general, the higher the voltage, the greater the required clearance.

Electric utilities and CIPs periodically trim vegetation around their bare-line conductors to maintain the required minimum clearances. By necessity, the clearances achieved at the time-of-trim are greater than the

⁷⁹ The Second Exception states, in relevant part, that "Rule 35 requirements do not apply where the utility has made a 'good faith' effort to obtain permission to trim...but permission was refused or unobtainable. A 'good faith' effort shall consist of...a written communication, including documentation of mailing or delivery."

⁸⁰ Today's decision does not reduce electric utilities and CIPs' legal liability. Rather, it facilitates the ability of electric utilities and CIPs to recover their monetary losses from the property owners who bear at least some responsibility for such losses.

required minimum clearances so that vegetation growth between trims does not intrude on the required minimum clearances.

Appendix E of GO 95 contains guidelines for the minimum radial clearances that should be achieved at time-of-trim, where practical. In the Phase 1 Decision, the Commission revised Appendix E to increase the guidelines for time-of-trim clearances in the high fire-threat areas of Southern California. The Commission also stated that it would consider proposals in Phase 2 to further increase the guidelines for minimum time-of-trim clearances.⁸¹

PG&E, SCE, and SDG&E (“the Joint Utilities”) propose to revise Appendix E to increase the guidelines for minimum time-of-trim clearances in the high fire-threat areas of Southern California from 6.5 feet to 10 feet for conductors operating in the range of 2,400 volts to 69,999 volts, and from 10 feet to 15 feet for conductors operating in the range of 72,000 volts to 109,999 volts. The proposal would also replace the word “volts” in Appendix E with the commonly used abbreviation “V”. The proposed revisions to Appendix E are shown in Appendix A of today’s decision.

This proposal would affect both electric utilities and CIPs. The Joint Utilities anticipate that their proposal could create a one-time cost for companies that do not currently trim to the proposed minimum guidelines.

6.10.2. Position of the Parties

The Joint Utilities’ proposal is supported by PacifiCorp and Sierra Pacific. The electric IOUs agree that the proposal is a limited and reasonable approach to enhancing fire safety in areas of the state where the fire threat is the highest.

⁸¹ D.09-08-029 at 29 – 30.

The Joint Utilities' proposal is opposed by LA County, LADWP, and MGRA. They contend that because the minimum time-of-trim clearances were increased recently by the Phase 1 Decision, there is no need for an additional increase. They further contend that because companies have authority under Appendix E to exceed the minimum time-of-trim clearances, increasing the minimum clearances will not enhance fire safety.

The opponents of the proposal are concerned that another increase in the minimum time-of-term clearances will negatively affect aesthetics, vegetation, and efforts to combat global warming. For example, to combat global warming, LADWP has distributed more than 100,000 trees. LADWP is concerned that these efforts would be adversely affected by the Joint Utilities' proposal to increase the minimum time-of-trim clearances.

MGRA represents that SDG&E already trims 10 to 15 feet around its power lines in the Mussey Grade Road area, which exceeds to the current minimum time-of-trim clearances of 6.5 to 10 feet that were adopted by the Phase 1 Decision. MGRA is concerned that if greater time-of-trim clearances are adopted in Phase 2, SDG&E would feel free to regularly trim beyond the 10 to 15 feet (depending on voltage) in the Joint Utilities' proposal, just as SDG&E presently feels free to trim beyond the current time-of-trim clearances of 6.5 to 10 feet (depending on voltage) adopted by the Phase 1 Decision.

6.10.3. Discussion

The issue before us is whether to adopt the Joint Utilities' proposal to increase the guidelines for minimum time-of-trim clearances between energized bare-line conductors and vegetation in the high fire-threat areas of Southern California. In deciding this issue, we note that no party attempted to show that the current guidelines for minimum time-of-trim clearances are unsafe.

Moreover, Appendix E of GO 95 establishes only minimum time-of-trim clearances. Electric utilities have wide latitude under Appendix E to exceed the minimum time-of-trim clearances whenever “[r]easonable vegetation management practices may make it advantageous to obtain greater clearances.” We interpret “reasonable vegetation management practices” as including fire safety. For the preceding reasons, we conclude there is no safety-related need to increase the guidelines for minimum time-of-trim clearances, and we decline to adopt the Joint Utilities’ proposal.

There is no opposition to the Joint Utilities’ proposal to replace the word “volts” in Appendix E with the abbreviation “V”. We find the proposed technical revision to be reasonable, and we adopt it. The adopted revisions to Appendix E of GO 95 are contained in Appendix B of today’s decision.

6.11. Contested Proposals 8B and 8C re: GO 95, Rule 35, Appendix E, Guidelines Only

6.11.1. Summary of Proposals

Appendix E of GO 95 provides guidelines for minimum time-of-trim clearances between energized bare-line conductors and surrounding vegetation. Appendix E also states that “[r]easonable vegetation management practices may make it advantageous to obtain greater clearances” than in the guidelines for minimum time-of-trim clearances.

The Phase 2 Workshop Report presents two competing proposals to revise Appendix E to provide additional guidance about when it is reasonable to obtain greater time-of-trim clearances. One proposal (Contested Proposal 8B) was offered by PG&E, SCE, and SDG&E (“the Joint Utilities”). The second proposal (Contested Proposal 8C) was offered by CFBF and MGRA. The proposed revisions to Appendix E are shown below with ~~strikeout~~ and underline:

Joint Utilities Proposal

The radial clearances shown below are recommended minimum clearances that should be established, at time of trimming, between the vegetation and the energized conductors and associated live parts where practicable. Reasonable vegetation management practices may make it advantageous to obtain greater clearances than those listed below: to ensure compliance until the next scheduled maintenance. Each utility may determine and apply additional appropriate clearances beyond clearances listed below, which take into consideration various factors, including: line operating voltage, length of span, line sag, planned maintenance cycles, location of vegetation within the span, species type, experience with particular species, vegetation growth rate and characteristics, vegetation management standards and best practices, local climate, elevation, and fire risk.

CFBF/MGRA Proposal

The radial clearances shown below are recommended minimum clearances that should be established, at time of trimming, between the vegetation and the energized conductors and associated live parts where practicable. Reasonable vegetation management practices may make it advantageous **for the purposes of public safety, reliability or tree health** to obtain greater clearances than those listed below: to ensure compliance until the next scheduled maintenance. Each utility may determine and apply additional appropriate clearances beyond clearances listed below, which take into consideration various factors, including: line operating voltage, length of span, line sag, planned maintenance cycles, location of vegetation within the span, species type, experience with particular species, vegetation growth rate and characteristics, vegetation management standards and best practices (including when feasible appropriate tree crop production manuals), local climate, elevation, and fire risk. (Bold font added for emphasis.)

CFBF/MGRA's proposal is identical to the Joint Utilities' proposal except for the additional text that is shown in the CFBF/MGRA's proposal in bold font

above. Both proposals would affect electric utilities and CIPs. Neither proposal is expected to create additional costs for electric utilities, CIPs, or other parties.

6.11.2. Position of the Parties

The Joint Utilities' proposal (Contested Proposal 8B) is supported by CMUA, PacifiCorp, Sierra Pacific, and TURN.⁸² The Joint Utilities state that their proposal will not change utility trimming practices. Utilities already consider all of the factors listed in the proposal to determine appropriate additional clearances at time-of-trim. Rather, the purpose of the Joint Utilities' proposal is to help electric utilities and CIPs deal with property owners who want to limit trimming to the minimums set forth in Appendix E. By clarifying that utilities may obtain greater clearances, and by identifying the factors that will be considered when determining the appropriate additional clearances, the Joint Utilities' proposal will encourage property owners to allow the necessary vegetation management work to proceed.

The CFBF/MGRA proposal (Contested Proposal 8C) is supported by LA County, PacifiCorp, Sierra Pacific, and TURN.⁸³ The CFBF/MGRA proposal adds two phrases to the Joint Utilities proposal. The first phrase - "for the purposes of public safety, reliability, or tree health" - explains why trimming beyond the specified minimum clearances may be necessary. The second phrase - "(including when feasible appropriate tree crop production manuals)" - captures the importance of using best practices with respect to orchard trees that sustain the livelihoods of thousands of farmers.

⁸² PacifiCorp, Sierra Pacific, and TURN support both the Joint Utilities' proposal and the CFBF/MGRA's proposal.

⁸³ Ditto.

The proponents of the CFBF/MGRA proposal contend that because any revisions to the time-of-trim guidelines will affect the entire state, not just high fire-threat areas, a broad range of factors should be considered when determining minimum time-of-trim clearances. The Joint Utilities' proposal is limited to factors that are important to utilities. In contrast, the CFBF/MGRA proposal ensures that the concerns of both utilities and property owners will be considered when determining time-of-trim clearances.

The CFBF/MGRA proposal is opposed by CMUA, LADWP, PG&E, SCE, and SDG&E. In general, the opponents are concerned that the CFBF/MGRA proposal will provide problem landowners with more reasons to obstruct reasonable tree-trimming practices.

6.11.3. Discussion

The issue before us is whether to adopt either of the two competing proposals to revise Appendix E of GO 95 to explain when it is reasonable to exceed the minimum time-of-trim clearances around bare-line conductors set forth in Appendix E. In deciding this matter, our principle concern is the prevention of wildfires and other safety hazards caused by contact between vegetation and bare-line conductors operating at high voltages.

The Joint Utilities' proposal would revise Appendix E to (1) state that the minimum time-of-trim clearances specified in Appendix E are "recommended"; (2) state that electric utilities and CIPs may exceed the recommended time-of-trim clearances; and (3) provide a list of factors that electric utilities and CIPs should consider when determining whether, and to what extent, it is appropriate to exceed the recommended time-of-trim clearances. The proposed factors include line sag, vegetation trimming cycles, vegetation growth rates, and fire risk. All of the factors are directly related to our public-safety goal of

keeping high-voltage conductors clear of vegetation. Accordingly, we find the Joint Utilities' proposal to be reasonable, and we hereby adopt it. The text of the adopted revisions to Appendix E of GO 95 is contained in Appendix B of today's decision.

We adopt in part and reject in part the CFBF/MGRA proposal to add to Appendix E the phrase "for the purposes of public safety, reliability or tree health." The purpose of the phrase is to summarize when it is appropriate to exceed the minimum time-of-trim guidelines. We agree that Appendix E should be revised to state that companies may exceed the minimum time-of-trim guidelines when necessary for "public safety" and "reliability," as these reasons are directly related to the safety and reliability purposes of GO 95.⁸⁴ Adding these reasons to Appendix E should help electric utilities and CIPs explain to property owners why vegetation needs to be trimmed.

We decline to add "tree health" as a reason for exceeding the minimum time-of-trim guidelines, as tree health is not directly related to the overarching safety and reliability purposes of GO 95. This does not mean that tree health is irrelevant in determining time-of-trim clearances. In fact, the adopted revisions to the Appendix E state that electric utilities and CIPs should consider "vegetation management standards and best practices" when determining time-of-trim clearances. We interpret this provision as incorporating tree health.

We decline to adopt CFBF/MGRA's proposal to add the parenthetical "(including when feasible appropriate tree crop production manuals)" as one of

⁸⁴ To ensure that the revised text of Appendix E is clear, we have added the modifier "service" before the word "reliability," so that the revised text states "service reliability."

the factors that may be considered when determining whether to exceed the minimum time-of-trim guidelines. The parenthetical is vague and will likely cause disagreements between utilities and orchard owners about what constitutes an “appropriate” manual.

6.12. Contested Proposal 9 re: GO 95, Rule 38, Table 2, Footnote (aaa)

6.12.1. Summary of Proposal

Rule 38 of GO 95 specifies minimum clearances between power lines and cables, wires, communication lines, and other conductors. The required minimum clearances are set forth in Table 2 of Rule 38. Once installed, the required minimum clearances between power lines and other conductors can be reduced by 10% during the course of a day due to thermal loading.

PG&E, SCE, and SDG&E (“the Joint Utilities”) propose to add to Table 2 a new Footnote (aaa) that states as follows:

(aaa) The vertical separation requirement between conductors in the adjoining mid-span may or may not require increased vertical separation at the pole based on the sag characteristics of the conductors.

The proposed footnote would apply to the minimum required clearances set forth in Table 2, Cases 1 through 13. It would not apply to the minimum clearance requirements in Cases 14 through 20.

The proposed Footnote (aaa) would affect electric utilities and CIPs. The Joint Utilities do not anticipate their proposal will create additional costs for electric utilities, CIPs, or their customers.

6.12.2. Position of the Parties

The Joint Utilities state that maintaining the required minimum clearances between power lines and other conductors is vital in areas with combustible

vegetation, strong winds, and hot weather. Sag can increase significantly with high thermal loads. It is important for entities with facilities affixed to the same pole and/or crossing under power lines to account for the sag of power lines in order to maintain required clearances. The proposed footnote will promote safety by reminding responsible personnel that the minimum clearances specified in Table 2 of Rule 38 must be met under all expected sag scenarios.

The Joint Utilities' proposal is supported by IBEW 1245, LA County, and PacifiCorp. IBEW 1245 supports the proposal because it will help to ensure the safety of linemen working midspan between power lines and other conductors. PacifiCorp supports the proposal because it is consistent with the National Electric Safety Code that has been adopted by many of the other states where PacifiCorp operates. This will help to reduce the burden on PacifiCorp of complying with different requirements in different jurisdictions.

The Joint Utilities' proposed footnote is opposed by CPSD and the CIP Coalition. CPSD states that the proposed footnote is unnecessary because the required clearances between conductors must be met at all times.

The CIP Coalition asserts that the proposed footnote is redundant with the following provisions in GO 95 regarding conductor clearances and sags:

- Table 2 of Rule 38 prescribes minimum vertical, horizontal, and radial clearances between conductors.
- Rule 43 prescribes temperature and loading conditions that must be considered in determining conductor clearances, including certain conditions pertaining to conductor sags.
- Rule 43.1 requires facilities installed at elevations above 3,000 feet to be designed for wind pressure of 6 pounds per square foot on conductors and ½ inch of ice.

- Rule 43.2 requires facilities installed at elevations below 3,000 feet to be designed for wind pressure of 8 pounds per square foot on conductors and no ice.
- Rule 43.1 and Rule 43.2 require that conductor sag be considered at the “normal temperature” of 60°F and at a “maximum temperature” of 130°F.
- Additional sag requirements are set forth in Rule 49.4 C(5), Rule 84.5, and Appendix C. Appendix C contains sag curves and formulas for determining the minimum sag necessary to comply with applicable requirements for different conductor types and span lengths at different temperatures.
- Appendix C specifically states that the sag values contained in Appendix C, Table 25 are greater than required to meet minimum requirements, but are “considered to be in accordance with good practice.”
- Appendix F contains examples of “typical problems” in line construction and explains how conductor sag and tension should be determined in hypothetical conditions.
- Rule 31.1 requires for all particulars not specified in GO 95, “design, construction and maintenance should be done in accordance with accepted good practice for the given local conditions known at the time.”

The CIP Coalition contends that the Joint Utilities did not show that the Commission’s existing conductor clearances and sag requirements are unsafe. To the contrary, the Commission’s existing requirements are conservative and in certain respects exceed the minimum conductor clearance requirements in the National Electric Safety Code applicable in most other states.

6.12.3. Discussion

The issue before us is whether to adopt the Joint Utilities’ proposal to add a new Footnote (aaa) to Table 2 of Rule 38. The purpose of the footnote is to remind electric utilities and CIPs to take sag characteristics into account when

installing new conductors so that required clearances between conductors is maintained at all times.

We agree with CPSD that the proposed footnote is unnecessary, and we decline to adopt it. The electric utilities and CIPs are well aware of the sag characteristics of conductors and the required minimum clearances between conductors. The proposed footnote is purely advisory and adds nothing new. It provides no substantive information regarding what types of conductors may require extra separation, under what conditions extra separation may be required, or how much additional separation may be required. Instead, the proposed footnote offers only the vague advice that conductors “may or may not require increased vertical separation at the pole based on sag characteristics of the conductors.”

Although we decline to adopt the Joint Utilities’ proposed footnote, we remind the electric utilities and CIPs that they are required by GO 95 to take sag characteristics into account when installing new conductors to ensure that the minimum clearance requirements between conductors that in Table 2 of Rule 38 are maintained at all times. We view any failure to maintain minimum conductor-to-conductor clearances as a serious fire hazard. Any failure to maintain the required minimum clearances shall be deemed either a Level 1 or Level 2 nonconformance, depending on circumstances, and must be corrected within the timeframes specified in Rule 18 (as revised by today’s decision).

6.13. Contested Proposals 10A and 10B re: GO 95, Rule 44.2, Rule 44.4, and Appendix I

6.13.1. Summary of Proposals

The Phase 1 Decision added Rule 44.2 to GO 95. This rule requires an entity that seeks to attach facilities to a structure (e.g., a utility pole) that

materially increase the load on the structure to perform a loading calculation. The purpose of this requirement is to ensure that the attachment of new facilities does not reduce the safety factors for the structure below those required by Section IV of GO 95. Rule 44.2 also requires entities that own the structure and/or have facilities already attached to the structure to provide information needed by the entity performing the loading calculations.⁸⁵

The Commission stated in the Phase 1 Decision that it would revisit in Phase 2 the issues of (1) the time period for exchanging data needed for pole-loading calculations, and (2) the definition of what constitutes a “material increase” in the load on a structure.⁸⁶

The Phase 2 Workshop Report contains two competing proposals to revise GO 95 to incorporate timelines and procedures for sharing information needed for pole-loading calculations. One proposal was offered by the CIP Coalition (Contested Proposal 10A), and the other was offered by the Joint Utilities (Contested Proposal 10B). The text of both proposals is contained in Appendix A of today’s decision.

Both proposals would require all entities that own or occupy a joint-use pole to provide, upon request, information needed for pole-loading calculations to an entity that seeks to attach facilities to the joint-use pole. Both proposals would also require the information to be provided as soon as practical, but, absent exigent circumstances or mutual agreement, no more than 15 business days from the date of request.

⁸⁵ D.09-08-029 at 37-40 and Ordering Paragraphs 3 and 4.

⁸⁶ D.09-08-029 at 39-40.

The text of each proposal is nearly identical. The most visible difference between the two proposals is that the CIP Coalition's proposal would place the text in a new Rule 44.4. of GO 95, while the Joint Utilities' proposal would place the bulk of the text, including specific requirements, in a new Appendix I of GO 95, with a reference to the new Appendix I in a new Rule 44.4.

There are several other differences between the two proposals. First, the Joint Utilities' proposal would make two technical revisions to the first paragraph of Rule 44.2 and delete the second paragraph of Rule 44.2. The CIP Coalition agrees with both these proposed revisions, even though these revisions are not part of the CIP Coalition's proposal.

Second, the CIP Coalition's proposal directs entities to cooperate by "promptly providing or making reasonably available" the information needed for pole-loading calculations. The Joint Utilities' proposal does not include the phrase "making reasonably available" provision.

Finally, if the entity responsible for a joint-use pole rejects an application to attach new facilities to the pole, the CIP Coalition's proposal would require the rejecting entity to explain in the returned application the reasons for the rejection. The Joint Utilities' proposal does not include this requirement.

Both proposals would apply to all entities that own joint-use poles and/or attach facilities to joint-use poles. Neither proposal is expected to result in significant costs for electric utilities, CIPs, or their customers.

6.13.2. Position of the Parties

The CIP Coalition's proposal (Contested Proposal 10A) is supported by LA County. These same parties oppose the Joint Utilities' proposal.⁸⁷

The CIP Coalition states that the most significant difference between the two proposals is that the CIPs believe that cooperation is a fundamental necessity that needs to be codified in a new Rule 44.4 of GO 95, whereas the Joint Utilities' proposal would relegate cooperation to the status of "guidelines" in an appendix to GO 95. The CIP Coalition is concerned that entities could interpret the guidelines as mere recommendations that can be disregarded at will. The CIP Coalitions asserts minimum requirements are necessary because the exchange of information has been problematic in the past.

The CIP Coalition disagrees with the Joint Utilities' position, summarized below, that the details for sharing information are best left to contracts. The problem, according to the CIP Coalition, is that there are no contracts to share information. This only highlights the need for a Commission requirement to share information.

The Joint Utilities' proposal (Contested Proposal 10B) is supported by LADWP, PacifiCorp, and Sierra Pacific. The same parties oppose the CIP Coalition's proposal.

The proponents of the Joint Utilities' proposal contend that GO 95 should be limited to high-level standards for the design, construction, and maintenance of overhead facilities. It should be up to the parties to work out the operational details in contracts. GO 95 should not be rewritten to mandate preordained

⁸⁷ Sunesys, a member of the CIP Coalition, takes no position on Contested Proposals 10A and 10B.

requirements for sharing information. The Joint Utilities' proposal to incorporate "guidelines" into GO 95 for sharing information strikes the appropriate balance between articulating a requirement for cooperation among pole occupants, and allowing flexibility to adapt to varied and changing circumstances.

SCE is convinced that the true purpose of the CIP Coalition's proposal is to undermine the current contractual agreements between SCE and its joint-pole partners by inserting into GO 95 the new and unrelated requirement to provide reasons for rejecting pole-attachment applications. SCE states that operational details among joint-pole users are currently negotiated and memorialized in pole-attachment agreements. Putting such details into GO 95 would short-circuit the contractual process and throw the current agreements into disarray.

CPSD supports both proposals, but prefers the CIP Coalition's proposal over the Joint Utilities' proposal because the CIP Coalition's proposal codifies the provisions for cooperation in GO 95 itself, rather than in guidelines.

6.13.3. Discussion

Cooperation among the electric utilities and CIPs is necessary to ensure that attachments to joint-use poles comply with the safety factors set forth in Rule 44. Such cooperation reduces the chance of pole failures and the associated fire risks. Specific cooperation rules will help ensure that all entities have sufficient information to timely evaluate the safety implications of potential additions to poles as well as the timely replacement of poles when necessary.

There is no dispute about the need for pole owners and pole occupants to cooperate with an entity that seeks to add additional load to a pole. Nor is there any dispute about what information needs to be shared for pole-loading calculations or how long it should take to provide the information. The only dispute is whether the requirement to share information should take the form of

a new Rule 44.4 in GO 95 (the CIP Coalition's proposal) or the form of guidelines in an appendix to GO 95 (the Joint Utilities' proposal).

We conclude that the CIP Coalition's proposal is superior, and we hereby adopt it with certain modifications described below. In our judgment, the public interest is better served by a formal rule that requires entities to share information needed for pole-loading calculations. As mentioned previously, it is important to share information needed for pole-loading calculations to ensure that joint-use poles do not become overloaded and fail, which could ignite a fire, injure and kill people, and destroy property. The adopted rule is not unduly prescriptive, as it reflects the parties' agreement regarding the timeframe for sharing information and the specific information that needs to be shared. The adopted rule has the added benefit of ensuring that an entity which submits a pole-attachment application is notified why the application has been rejected so that appropriate adjustments to the application can be made.

There is no opposition to the Joint Utilities' proposal to the extent the proposal seeks minor technical revisions to the first paragraph of Rule 44.2 (i.e., replacing the word "utility" with the word "entity" in two places) and to delete the second paragraph of Rule 44.2 because it duplicates the new Rule 44.4 adopted by today's decision. We find these proposed revisions to be reasonable, and we hereby adopt them. The adopted revisions to Rule 44.2 and the text of the new Rule 44.4 are contained in Appendix B of today's decision.⁸⁸

⁸⁸ One minor grammatical error is corrected in new Rule 44.4. The words "All entities" in the first sentence of Rule 44.4 are changed to "Each entity" to match the pronoun "its" in Item b.

We find no merit to SCE's unsupported assertion that the CIPs will use the adopted Rule 44.4 to undermine existing pole-attachment agreements. Today's decision requires entities to share information that is needed for pole-loading calculations. Both SCE and the CIP Coalition agree that such information needs to be shared. We fail to see how a formal requirement to share such information could undermine existing pole-attachment agreements.

As a final matter, we note that the Phase 1 Decision indicated the Commission would revisit in Phase 2 the following provision in Ordering Paragraph 4 of D.09-08-029 regarding what constitutes a "material increase" in load on a structure:

Ordering Paragraph 4: For purposes of pole loading and Rule 44.2 of General Order 95, additional facilities that **"materially increase the load on a structure" refers to an addition which increases the load on a pole by more than five percent per installation, or 10 percent over a 12 month span of the utility's or Communication Infrastructure Provider's current load.** (D.09-08-029 at 38. Emphasis added)

Surprisingly, neither the CIP Coalition's proposal nor the Joint Utilities' proposal addresses the issue of what constitutes a material increase in the load on a structure, which triggers the need for a pole-loading calculation. We conclude that in order to protect public safety, a pole-loading calculation should be required whenever a proposed attachment would exceed 10% of the estimated remaining unused load, or carrying capacity, of a structure (computed using the minimum end-of-service-life safety factors for the structure required by Rule 44). Our determination of what constitutes a material increase in the load on a structure is included in the adopted text of Rule 44.2 that is contained in Appendix B of today's decision.

6.14. Contested Proposals 11A and 11B re: GO 95, Rule 48

6.14.1. Summary of Proposals

Rule 48 of GO 95 specifies the strength of materials and structures for overhead facilities. The first two paragraphs of Rule 48 state as follows:

Structural members and their connection shall be designed and constructed so that the structures and parts thereof **will not fail or be seriously distorted** at any load less than their maximum working loads (developed under the current construction arrangements with loadings as specified in Rule 43) multiplied by the safety factor specified in Rule 44.

Values used for the ultimate strength of material shall comply with the safety factors specified in Rule 44. (Emphasis added.)

The Phase 2 Workshop Report presents two competing proposals related to Rule 48. One proposal was offered by the Joint Utilities (Contested Proposal 11A). The second was offered by CPSD (Contested Proposal 11B). The text of both proposals is contained in Appendix A of today's decision.

The Joint Utilities propose to revise Rule 48 to remove the "will not fail" provision that is highlighted above. CPSD does not propose any changes to Rule 48 at this time. Instead, CPSD proposes an ordering paragraph that directs CPSD to form a technical working group to identify and recommend potential changes to Section IV of GO 95 (which consists of Rules 40 through 49) to remove antiquated requirements and incorporate modern technologies and practices.

The Joint Utilities' proposal is not expected to result in any additional costs for electric utilities and CIPs. CPSD's proposal could result in cost savings and/or cost increases, depending on the revisions to Section IV of GO 95 that are ultimately adopted.

6.14.2. Position of the Parties

The Joint Utilities' proposal (Contested Proposal 11A) is supported by the CIP Coalition, PacifiCorp, and Sierra Pacific. These parties assert that the "will not fail" provision in Rule 48 sets an impossible standard because it is not feasible to build overhead facilities that will never fail. They also note that a similar view was expressed in a letter dated December 14, 2009 from the Deputy Director the Energy Division (Ken Lewis) sent a letter to the GO 95 Rules Committee asking the Rules Committee to delete the first two paragraphs of Rule 48, stating: "These paragraphs impose a design standard that we believe violates standard practice and, if literally interpreted, would result in unnecessarily expensive transmission and distribution lines."

The proponents of the Joint Utilities' proposal represent that it will not affect safety because the proposal does not alter the existing requirement to design and construct facilities in accordance with the loading requirements, safety factors, and material strengths specified in Rules 43, 44, and 48, respectively. Rather, the Joint Utilities' proposal is a response to CPSD's interpreting the "will not fail" provision in Rule 48 as a mandatory performance standard. If a structure fails, CPSD may find that a company has violated the "will not fail" provision in Rule 48 and seek to impose fines, even though the structure was designed and constructed in accordance with Rules 43, 44, and 48.

The Joint Utilities' proposal is opposed by CPSD, IBEW 1245, and LA County. They contend that the Joint Utilities' proposal will do nothing to enhance fire safety. CPSD and LA County believe the real motive for the Joint Utilities' proposal is to remove the legal liability that electric utilities and CIPs incur when a structure fails. Under the Joint Utilities proposal, as long as companies design and construct their facilities in accordance with the revised

Rule 48, there would be no legal consequences when facilities fail. For example, CPSD asserts that the proposal would allow a utility pole to fail when no wind is present without violating GO 95 if the pole had been designed and constructed in accordance with Rules 43, 44, and 48.

CPSD argues that the Joint Utilities' proposal is an ill-advised approach to revising Section IV of GO 95. The various rules in Section IV work synergistically to provide appropriate strength requirements. Change to one rule necessitates considering change to other rules. This is one reason why CPSD urges the Commission to reject the Joint Utilities' proposal and adopt CPSD's recommendation to conduct a comprehensive review of Section IV.

IBEW 1245 is concerned that the Joint Utilities' proposal would hinder the ability of journeymen to build safe facilities. IBEW 1245 represents that it is not unusual for experienced journeymen building structures to demand modifications to make the structures stronger and safer. IBEW 1245 believes the proposed rule would militate against in-the-field modifications.

CPSD recommends that its proposal (Contested Proposal 11B) be adopted in lieu of the Joint Utilities' proposed revisions to Rule 48. CPSD's proposal consists of an ordering paragraph that directs CPSD to form a technical workgroup for the purpose of revising Section IV to remove antiquated requirements and incorporate modern technologies and practices, with the overall goal of enhancing safety and reliability. CPSD observes that Section IV of GO 95 has remained largely unchanged since it was adopted in 1941.

With certain caveats summarized below, CPSD's proposal is supported by CIPs (CCTA and the CIP Coalition), the electric IOUs (PacifiCorp, PG&E, SCE, SDG&E, and Sierra Pacific), DRA, IBEW 1245, and LA County. The CIPs and electric IOUs support CPSD's proposal as an addition to, but not a substitute for,

the Joint Utilities' proposed revisions to Rule 48. They recommend that the Commission adopt both proposals.

6.14.3. Discussion

The issue before us is whether to adopt the Joint Utilities' proposal and/or CPSD's proposal. We first consider the Joint Utilities' proposal, followed by CPSD's proposal.

The Joint Utilities seek to delete the provision in Rule 48 that states utility structures must be designed and constructed so they "will not fail" at any load less than their maximum working loads specified in Rule 43 multiplied by the safety factors specified in Rule 44. The primary reason the Joint Utilities seek to delete the "will not fail" provision from Rule 48 is that it purportedly establishes an impossible performance standard for the design and construction of facilities. This exposes the Joint Utilities to liability if a structure fails, even though the structure was designed and constructed to meet the maximum working stresses, safety factors, and material strengths specified in Rules 43, 44, and 48.

We find that the Joint Utilities have not presented a reasonable justification for revising Rule 48. The primary purpose of this proceeding is to consider and adopt measures to reduce the fire hazards associated with overhead facilities. The Joint Utilities' proposal is unrelated to this purpose. Furthermore, the scope of this proceeding specifically excludes matters that are focused on reducing utilities' legal liability,⁸⁹ which is apparently what the Joint Utilities' proposal seeks to do. Therefore, we decline to adopt the Joint Utilities' proposal.

On the other hand, the Joint Utilities' proposal does implicate an issue that is within the scope of this proceeding, namely, the proper interpretation of the

⁸⁹ Phase 2 Scoping Ruling at 8.

“will not fail” provision in Rule 48.⁹⁰ We conclude that the purpose of Rule 48 is to ensure that structures “will not fail” when subjected to “maximum working loads.”⁹¹ The requirement to build structures to bear maximum working loads is a core safety requirement. Structures should never fail at loads equal to, or less than, maximum working loads. Rule 48 accomplishes this objective by requiring companies to build structures that are designed to bear the anticipated maximum working loads multiplied by the safety factors in Rule 44. The intended result is structures that are typically much stronger than needed for the maximum working loads.

We further conclude that Rule 48 should not be interpreted as establishing an absolute requirement that structures “will not fail” when subjected to loads that exceed the maximum working loads but less than the applicable safety factors. Our conclusion is based largely on the fact that Rule 48 requires electric utilities and CIPs to design structures based on the presumed strengths of the materials listed in Rules 48.1 through 48.7. However, building materials have natural variability, particularly wood products. As a result, the actual strengths of the materials used to build a structure are likely to deviate to some extent from the presumed strengths of materials listed in Rule 48. The natural variability of materials is one reason why Rule 48 requires structures to be designed with the safety factors listed in Rule 44. As a result, the failure of a structure that is subjected to loads that exceed the maximum working loads for the structure must be evaluated in light of the conditions at the time of the failure

⁹⁰ Phase 2 Scoping Ruling at 6, Item 20.b.

⁹¹ Rule 48 does not define “maximum working loads.” We interpret “maximum working loads” as synonymous with the phrase “maximum working stresses” that is defined in Rule 44.

and the innate variability in the strengths of the materials that were used to build the structure, particularly wood products.

We next consider CPSD's proposal for an ordering paragraph that directs CPSD to form a technical workgroup for the purpose of updating Section IV of GO 95 to reflect modern materials and practices, with the goal of improving safety and reliability. We strongly support the goals of CPSD's proposal, but we do not see a need for CPSD's proposed workgroup, as it would duplicate the existing GO 95/128 Rules Committee. The GO 95/128 Rules Committee is comprised of representatives from electric utilities, CIPs, unions, and other professionals knowledgeable in the application of GO 95 and GO 128.⁹² The Rules Committee meets regularly to review GO 95 and GO 128 and will occasionally submit proposed revisions to the Commission for adoption. Therefore, we decline to adopt CPSD's proposal.

We encourage CPSD to work with the GO 95/128 Rules Committee for the purpose of updating Section IV of GO 95. The Rules Committee and CPSD may jointly submit proposed revisions to GO 95 for Commission approval by filing a petition for rulemaking pursuant to Rule 6.3 of the Commission's Rules of Practice and Procedure. The petition should include a detailed description and justification for each proposed revision to GO 95 as set forth in the Phase 2 Scoping Ruling at page 11. The petition may also include alternative proposals for revising GO 95 if no consensus can be reached.

⁹² GO 95 applies to overhead power lines and communication lines. GO 128 applies to underground power lines and communication lines.

6.15. Contested Proposal 12 re: GO 95, Rule 91.5

6.15.1. Summary of Proposal

SDG&E proposes to add a new Rule 91.5 to GO 95 that would require CIPs to mark their cables and conductors attached to joint-use poles with information that identifies the owner of CIP facilities. The text of the proposed Rule 91.5 is contained in Appendix A of today's decision.

SDG&E's proposed rule would affect all CIPs subject to the Commission's jurisdiction. The proposed rule would create additional costs for CIPs, but SDG&E believes the costs are likely to be minimal.

6.15.2. Position of the Parties

SDG&E's proposal is supported by IBEW 1245, LA County, and PacifiCorp. The proponents of the proposal believe that marking CIP facilities with ownership information will help to quickly identify the owners of CIP facilities so that timely notification and correction of safety hazards can occur.

The proponents state that it is often difficult to identify which CIP is responsible for safety hazards on joint-use poles. As a result, repairs are delayed, and utility workers and the general public are placed at risk. This identification problem is even greater in emergency situations when field crews need to reach the owners of particular CIP facilities immediately. Moreover, the problem of identifying the owners of CIP facilities is becoming worse due to the tremendous growth of the telecommunications industry in recent years. It is now common to have four or more CIPs with facilities attached to a single joint-use pole. Simple marking of CIP facilities will solve the identification problem.

PacifiCorp and SDG&E note that the proposed requirement to mark CIP facilities attached to joint-use poles is consistent with marking requirements in

both the Northern and Southern Joint Pole Agreements, and with Rule 94.5 of GO 95, which requires wireless CIPs to mark their facilities on joint-use poles.

SDG&E submits that physically marking CIP facilities should not be expensive. A simple plastic tag is all that is needed. The proposed rule would only apply to new construction and reconstruction, so no additional labor or site visits would be needed. The only additional cost would be plastic tags.

SDG&E's proposal is deliberately non-specific so that CIPs can mark their facilities in a way that makes sense for them. The method of marking does not matter so long as the end result is achieved -- pole owners and pole tenants being able to readily identify the owner of particular communication facilities.

SDG&E disputes the CIP Coalition's claim, summarized below, that there is no evidence that the marking of CIP facilities is needed. During the Phase 2 workshops, SDG&E informed the participants that it is often difficult for SDG&E personnel to identify the CIPs that are responsible for safety hazards on joint-use poles. SDG&E sends out notices of hazards as required by Rule 18A, only to hear "not us" from the CIPs. As a result, repairs are delayed and SDG&E workers and the general public are placed at risk. Physical marking of facilities would help to put an end to this sort of run around.

PacifiCorp and SDG&E dispute the CIP Coalition's argument, summarized below, that electric utilities have all the information they need to track the ownership of CIP facilities. While it is true that electric utilities keep records of pole occupants for billing and other purposes, these records are not available to field personnel and are not designed for the rapid identification of the owner of each CIP facility on each pole.

SDG&E's proposal is opposed by the CIP Coalition, CMUA, PG&E, and SCE. The CIP Coalition declares there is no evidence that marking CIP facilities

would speed hazard notifications or restoration times. The CIPs do not rely on electric utilities to tell them if CIP facilities are disabled – they already know.

The CIP Coalition asserts that SDG&E already has all the information it needs to identify the owners of CIP facilities. SDG&E is the sole owner of its poles, and CIPs must lease space from SDG&E pursuant to written agreements. As a result, SDG&E has records of exactly what facilities are attached to its poles and who owns those facilities. If SDG&E cannot quickly identify the owners of CIP facilities attached to its poles, SDG&E should improve its internal record keeping rather than impose a new rule and associated costs on the CIPs.

The opponents of SDG&E's proposal agree that it would be costly to implement. Not only would CIPs have to install identification tags, they would incur ongoing costs to replace tags that fall off, fade over time, or incur other damage that renders them useless. In addition, the ownership of CIP facilities changes relatively often, so keeping ownership labels current would be expensive. The changing ownership also means that those working around CIP facilities might not be able to rely on the accuracy of labels.

Finally, PG&E and SCE state that SDG&E's proposal lacks specificity. The proposal does not indicate how, where, or when CIP facilities will be marked. In contrast, Rule 51.6 of GO 95 provides detailed rules for marking conductors over 750 volts. Among other things, Rule 51.6 specifies the minimum size of markers, the color, and the location on the pole. SDG&E's proposal has none of this detail.

6.15.3. Discussion

The issue before us is whether to adopt SDG&E's proposal to require CIPs to mark their cables and conductors on joint-use poles with ownership information. Our primary standard for deciding this issue is whether SDG&E's

proposal will enhance fire safety. Any adopted marking requirement should achieve our goal of fire safety in a cost-effective manner.

SDG&E's proposal is consistent with existing requirements. Rule 94.5 of GO 95 requires CIPs to mark their wireless facilities on joint-use poles with ownership information. Similarly, Rule 44.1(d) of GO 128 requires that:

All communications equipment in a manhole, or other underground splicing chamber with supply cables or conductors, shall be marked if different ownership than the supply cables or conductors.

The Commission has already determined that CIP facilities located in underground chambers next to power lines should be physically marked. There is no reason to limit this requirement to underground CIP facilities. Indeed, a marking requirement for overhead facilities is arguably even more crucial given that aerial facilities are more prone to damage from environmental conditions (e.g., strong winds and encroaching vegetation) than underground facilities, and damaged aerial facilities typically pose a much greater threat to public safety than damaged underground facilities. The ability to quickly identify the owner of damaged aerial CIP facilities will likely speed the repair of safety hazards.

We conclude for the previous reasons that SDG&E's proposal is reasonable, and we adopt it with certain modifications described below. We recognize that CIPs will incur costs to mark their facilities and maintain the markers. We believe the costs will be relatively modest, as the CIPs can use inexpensive and durable plastic tags. The adopted rule may be implemented over time as CIPs install new facilities and conduct maintenance on existing facilities. Therefore, the rule will not entail significant additional costs for labor or site visits. We believe the benefits that will accrue from the rapid

identification of CIP facilities in terms of worker safety, fire safety, and general public safety outweigh the additional cost associated with marking CIP facilities.

We are not persuaded by the CIP Coalition that the new rule is unnecessary because SDG&E already knows the owners of the CIP facilities attached to its poles. Field workers need to rapidly identify the owners of damaged facilities in emergency situations; they should not have to contact office staff to comb through pole-attachment agreements to determine the owner of damaged CIP facilities. Moreover, SDG&E will not always be the first responder to an urgent situation; the first responder might be another CIP or other entities. In such instances, facility markings would provide the information necessary for the first responder to contact the appropriate party to remedy the situation.

The one shortcoming in SDG&E's proposal is that it requires CIPs to mark their facilities, but does not specify a deadline for doing so. This could result in confusion in future years about whether an unmarked CIP facility is in compliance with the new Rule 91.5 adopted by today's decision. Nor does SDG&E's proposal specify what particular information should be on the markers or where they should be placed. To provide clarity, we will require all CIP facilities attached to a joint-use pole to be marked by no later than January 1, 2015. Consistent with Rule 94.5, each marker shall (1) identify the facility owner or operator; (2) provide a 24 hour contact telephone number for emergencies or information; (3) be made of weather and corrosion resistant material; and (4) be clearly visible to workers who climb the pole or ascend by mechanical means.

6.16. Contested Proposals 13A and 13B re: GO 165, Section V and Proposed Ordering Paragraph

6.16.1. Summary of Proposals

The Phase 2 Workshop Report presents two competing proposals regarding the reporting of fire-related data by electric IOUs. One proposal was offered jointly by CPSD and MGRA (Contested Proposal 13A). The second proposal was submitted by PG&E. The text of both proposals is contained in Appendix A of today's decision.

CPSD and MGRA propose to add a new Section V to GO 165 that would require each electric IOU to collect information on all fire incidents which are attributable to its overhead power lines. The data collected for each incident would include the date, time, location, equipment, voltage, fire agencies involved, weather conditions, vegetation conditions, and apparent cause. The data would be reported annually to CPSD and could be submitted confidentially under GO 66-C and Pub. Util. Code § 583. CPSD and MGRA acknowledge that their proposal would impose costs on IOUs to collect and report fire-related data, but they believe the costs will be insignificant.

PG&E proposes an ordering paragraph that would require electric utilities and CPSD to meet and discuss whether CPSD is receiving the fire-related data it needs from the electric utilities, whether electric utilities should collect different and/or additional data, and whether the data should be provided to CPSD and fire agencies such as Cal Fire. State fire agencies would be invited to participate in the discussions, but not the CIPs. The electric utilities and CPSD would be required to submit a report to the Commission's Executive Director within nine months regarding the results of the discussions. PG&E anticipates that the costs of its proposal would be negligible.

6.16.2. Position of the Parties

The purpose of the CPSD/MGRA proposal (Contested Proposal 13A) is to help prevent catastrophic power-line fires by providing information about the causes of power-line fires so that strategies for preventing fires can be devised. The proposal would also provide data to evaluate the effectiveness of fire-prevention measures adopted in this proceeding and in the future.

The CPSD/MGRA proposal is supported by DRA and LA County. The proponents of the CPSD/MGRA proposal represent that there are no publically available databases maintained by federal, state, or local fire agencies that provide the detailed information sought by CPSD and MGRA for all IOU power-line fires. Although Cal Fire plans to upgrade its database to include more information about fires in California, CPSD and MGRA cite information from Cal Fire which indicates that Cal Fire does not intend to collect data that can be used to formulate fire-prevention strategies for power-line facilities.

CPSD, LA County, and MGRA oppose PG&E's proposed ordering paragraph. They see no need to discuss what data CPSD is currently receiving and what additional data is needed. CPSD says that it is currently receiving no data, and the CPSD/MGRA proposal spells out what data should be provided and how it will be used. PG&E's proposed ordering paragraph would simply delay, or prevent altogether, the collection of this important data.

PG&E's proposal (Contested Proposal 13B) is supported by the CIP Coalition, CMUA, PacifiCorp, SCE, SDG&E, Sierra Pacific, and TURN. In general, the proponents of PG&E's proposal believe it is premature to require electric IOUs to report data to CPSD about the causes of power-line fires. PG&E's proposal for CPSD to meet with the electric IOUs and Cal Fire to discuss what data is available to satisfy CPSD's needs would put the Commission in a

better position to determine what fire-incident data should be reported. If it is determined that electric IOUs should report additional fire-incident data, then the Commission may adopt a reporting requirement through the resolution process as was done with emergency incident reporting in Resolution E-4184.

The proponents of the PG&E proposal note that electric IOUs were required for several years to report all power-line fires that involved vegetation. However, in D.06-04-055 the Commission found that the burden of the reporting requirement outweighed whatever use was made of the reported information, and the Commission curtailed the requirement. The proponents of the PG&E proposal state that there have been no developments since D.06-04-055 that justify an expanded fire-reporting requirement.

The proponents of the PG&E's proposal identify several publicly available collections of fire data that can be mined by CPSD. For instance, Cal Fire maintains two databases. One contains information about wildfires, and the second contains information about all ignitions in California. Additional information is available from the Federal Emergency Management Agency's National Fire Incident Reporting System. PG&E adds that Cal Fire is planning to upgrade its databases to provide detailed information regarding the root causes for all fires, including power-line fires. PG&E states that if Cal Fire is working on a new database capability, there is no need for CPSD to start from scratch.

Most of the proponents of PG&E's proposal are opposed to the CPSD/MGRA proposal. One major concern is that the CPSD/MGRA proposal will impose significant costs on electric IOUs. For example, PG&E estimates that it will incur \$2 million to implement the CPSD/MGRA proposal. Another concern is that information about the causes of power-line fires reported to CPSD may be used by plaintiffs' attorneys to troll for clients, resulting in frivolous

litigation. The proponents of the PG&E proposal further assert that the Commission cannot compel electric IOUs to disclose privileged attorney work-product information on the “apparent cause” of a power-line fire, yet that is exactly what the CPSD/MGRA proposal requires.

Sierra Pacific and TURN suggest that experts at state and local fire agencies should collect information on fire incidents rather than electric IOUs, and that these same fire experts should analyze the data instead of CPSD.

6.16.3. Discussion

The issue before us is whether to adopt either of the two competing proposals regarding the reporting of data on power-line fires by electric IOUs. In deciding this matter, our principle concern is the reduction in the number of power-line fires over time. We must also consider if the benefits of reporting data on power-line fires outweigh the attendant costs.

We agree with CPSD and MGRA that requiring electric IOUs to report information on power-line fires would be very useful in formulating fire-prevention measures and gauging the effectiveness of the adopted measures. The collection and reporting of data is a prerequisite for any serious program of sustained and cost-effective fire-safety improvement.

The problem with the CPSD/MGRA proposal is that it only requires electric IOUs to report data on power-line fires. CPSD does not have a firm plan for using the data. The proposal does not require CPSD to analyze the data it receives or formulate strategies to reduce the number of power-line fires. Nor does the proposal identify a procedure for CPSD to submit fire-safety recommendations to the Commission, for the interested parties and the Commission to evaluate the proposals, and for the Commission to approve or reject the proposals.

We are mindful of the Commission's previous experience with reporting of data on power-line fires. In D.98-07-097, the Commission required electric utilities to report all power-line fires involving vegetation, no matter how small. Subsequently, in D.06-04-055 the Commission narrowed the scope of reportable power-line fires to those that (1) result in a fatality or injury requiring hospitalization; (2) receive significant public attention or media coverage; or (3) cause property damage of \$20,000 or more. One of the reasons cited for curtailing the scope of reported power-line fires was "limited staff resources."⁹³

We are not convinced that the CPSD/MGRA proposal to require IOUs to report detailed data on all power-line fires will be any more successful than our previous effort in this regard, particularly given the lack of a concrete plan to use the reported information. Therefore, we decline to adopt the CPSD/MGRA proposal at this time.

Although we decline to adopt the proposal, we agree with the intent of the proposal. There are many power-line fires every year. PG&E alone experiences approximately 75 vegetation-related fires each year.⁹⁴ The threat to public safety posed by a power-line fire depends largely on the wind, humidity, and vegetation conditions at the time and place of the fire. The fact that there are scores of power-line fires annually for a single IOU indicates there is a credible risk that power-line fires will eventually occur under hazardous conditions.

We will establish a Phase 3 of this proceeding to provide a venue where CPSD can develop and submit a comprehensive plan for collecting data on power-line fires, analyzing the data, and using this information to formulate

⁹³ D.06-04-055 at 7.

⁹⁴ PG&E Reply Brief at 14, fn. 32.

measures to reduce the number of fires ignited by power lines. During Phase 3, CPSD shall confer regularly with the electric IOUs, CIPs, MGRA, Cal Fire, and other interested parties to develop the plan. Other state and local fire-safety agencies should be consulted as well. CPSD shall file and serve its proposed plan no later than six months from the issuance date of today's decision. Parties may file and serve opening and reply comments regarding CPSD's proposed plan two weeks and four weeks, respectively, after CPSD files its plan. We anticipate that we will issue a decision regarding CPSD proposed plan based on the plan submitted by CPSD and the comments on the plan.

The plan submitted by CPSD should provide clear guidance to electric IOUs regarding the specific information that they should report about the causes of power-line fires.⁹⁵ CPSD should make sure that it receives enough detail about the causes of fires so that effective prevention measures can be developed. On the other hand, CPSD should avoid the collection of data from the IOUs that is either privileged or readily available from publicly accessible databases.⁹⁶

We decline to adopt PG&E's proposed ordering paragraph to require CPSD to meet and confer with electric IOUs to discuss what data, if any, should be provided to CPSD. PG&E's proposal does not go far enough. Today's decision finds that electric IOUs should provide data on power-line fires to CPSD once CPSD has developed, and we have approved, a concrete plan for using such data. We expect the IOUs to cooperate with CPSD in developing the plan.

⁹⁵ The CPSD/MGRA proposal requires IOUs to report the "apparent cause" of a power line fire, but provides no guidance about the level of detail that should be reported on the apparent cause.

⁹⁶ Today's decision does not prevent or prejudge any requests by CPSD to compel the disclosure of information that an electric IOU has labeled as privileged.

It is premature to address the other issues raised by the opponents of the CPSD/MGRA proposal, such as the cost of the proposal, duplication with databases maintained by fire-safety agencies, the ability of plaintiffs' attorneys to access the data reported to CPSD, and other issues. These issues are better addressed after CPSD submits its plan for the collection and use of fire-incident data. We may reject CPSD's forthcoming plan if we find that the public-safety benefits of the plan are outweighed by its costs and other disadvantages.

**6.17. Contested Proposals 14A, 14B, and 14C re:
Fire-Threat Maps**

6.17.1. Summary of Proposals

The Phase 1 Decision ordered the CIPs to conduct patrol inspections of specified overhead facilities in those areas of Southern California that are designated as Extreme and Very High Fire Zones on Cal Fire's Fire and Resource Assessment Program Fire Threat Map (FRAP Map). The Phase 1 Decision also determined that the Commission would consider in Phase 2 whether the FRAP Map should be used to designate areas for CIP inspections in Northern California.⁹⁷ The Phase 2 Scoping Memo established the scope of Phase 2 as including (1) whether the FRAP Map or other fire-threat maps should be used to designate areas for CIP inspections in Northern California, and (2) whether better maps could be developed.⁹⁸

The Phase 2 Workshop Report presents two competing proposals regarding fire-threat maps. The first proposal was submitted jointly by CPSD and MGRA (Contested Proposal 14A). The second proposal was submitted by

⁹⁷ D.09-08-029 at 23 and Ordering Paragraph 1.

⁹⁸ Phase 2 Scoping Memo at 5 - 6, Items 11, 12, and 15.

the CIP Coalition (Contested Proposals 14B and 14C). The difference between Contested Proposals 14B and 14C is not meaningful for the purpose of today's decision, and the two proposals will be treated as a single proposal. The text of the competing proposals is contained in Appendix A of today's decision.

6.17.1.1 Summary of Contested Proposal 14A

The CPSD/MGRA proposal consists of an ordering paragraph that would require electric IOUs and CIPs to prepare a work plan, in consultation with CPSD and Cal Fire, for the development of statewide, high-resolution maps that combine wind and vegetation data to identify areas where there is a high risk of catastrophic power-line fires occurring. The fire-threat maps would be used to determine inspection and maintenance cycles in all cases where geographic locations and maps are mentioned in GO 95 and GO 165.

The proposed work plan would include (1) a process for developing fire-threat maps; (2) an estimate of the time and costs to develop and maintain fire-threat maps; (3) a process for updating fire-threat maps to incorporate changes to the underlying data and new analytical techniques; and (4) a list of actions the Commission would need to take to enable the creation, adoption, and implementation of utility-specific maps. The electric IOUs and CIPs would be required to submit a report to the Commission on the status of the work plan within six months. Upon completion of the work plan, the Commission would decide whether to order the electric IOUs and CIPs to fund the development and maintenance of fire-threat maps. The fire-threat maps adopted in Phase 1 and/or Phase 2 would remain in effect until further order by the Commission.

The electric IOUs and CIPs would be required to fund the creation of the work plan. CPSD and MGRA believe the costs to create the work plan would be

small. CPSD and MGRA did not provide an estimate of the costs to develop, implement, and maintain fire-threat maps.

6.17.1.2 Summary of Contested Proposals 14B and 14C

The CIP Coalition's proposal would add a new provision to Rule 31.2 of GO 95 that specifies the areas in Northern California where aerial CIP facilities would be subject to the inspection cycles set forth in Rule 31.2. The centerpiece of the CIP Coalition's proposal is a fire-threat map that was developed jointly by the University of California at Berkeley and Reax Engineering Inc., a consulting company (the "Reax Map").

The CIP Coalition's proposal would apply only to aerial CIP facilities in Northern California that are designated as Threat Class 3 and Class 4 on the Reax Map, the two highest fire-threat categories. The FRAP Map would continue to be used to designate the high fire-threat areas in Southern California where overhead CIP facilities would be subject the inspection cycles set forth in Rule 31.2. The CIP Coalition's proposal would not apply to electric utilities.

The costs to develop the Reax Map have already been incurred and will not be recovered directly from customers. Future costs to implement the map may be recovered, to the extent possible, in market-based prices for CIP services.

6.17.2. Position of the Parties

The intent of the CPSD/MGRA proposal (Contested Proposal 14A) is to establish a scientifically sound process for the development of high-resolution maps to identify areas where catastrophic power-line fires are most likely to occur. The maps would be developed in consultation with Cal Fire and peer reviewed by fire-safety experts. Once developed, the maps would be used by electric IOUs and CIPs to implement the augmented inspection, maintenance,

and vegetation management requirements of GO 95 and GO 165 for high fire-threat areas. The maps could also be used for the following purposes:

- Identify areas where it would be beneficial to employ additional fire-prevention measures such as burying power lines, strengthening facilities to withstand stronger winds, adding insulation to conductors, or rerouting.
- Plan new power-line facilities and routes in a manner that minimizes fire risk.
- Maximize fire-prevention benefits from limited funds.

The CPSD/MGRA proposal is supported by DRA and LA County. The proponents of the proposal believe it is vital to replace the FRAP Map that was adopted by the Phase 1 Decision for CIP inspection purposes in Southern California, as Cal Fire has warned that the FRAP Map is not suited for this purpose.

The CPSD/MGRA proposal is opposed by the CIP Coalition, LADWP, PacifiCorp, PG&E, SCE, SDG&E, Sierra Pacific, and TURN. Most of the opponents see no need to develop new fire-threat maps because adequate maps are either in place or waiting for Commission approval. These include (1) the FRAP Map that was adopted by the Phase 1 Decision, (2) the Reax Map that is before the Commission in Phase 2, and (3) a fire-threat map that SDG&E has developed and implemented for its own use.

Several of the opponents are concerned that the CPSD/MGRA proposal will be costly to implement. For example, the CIP Coalition recently implemented the FRAP Map in Southern California. Switching to the new fire-threat maps contemplated by the CPSD/MGRA proposal would require the CIPs to reconfigure their inspection efforts around the new maps.

PacifiCorp and Sierra Pacific argue that they should not have to bear any costs for the fire-threat maps proposed by CPSD and MGRA because the proposed maps would not reduce fire risks in their service territories. This is because the fire-threat maps envisioned by CPSD and MGRA would rely primarily on wind data to designate high fire-threat areas. The strongest winds in PacifiCorp's and Sierra Pacific's service territories occur during the winter months when the fire danger is low.

TURN is concerned that the high-resolution maps envisioned by CPSD and MGRA would reduce fire safety. Presumably, the high-resolution maps would pinpoint the areas where fire risk-mitigation activities should take place. Absent high-resolution maps, fire-prevention measures would need to be deployed over a larger area, which has the salutary effect of providing a better margin of safety.

SDG&E represents that it has already developed and implemented a fire-threat map for its service territory. Consequently, SDG&E has no need for the new fire-threat maps proposed by CPSD and MGRA. SDG&E also believes that its fire-threat map is better than the one contemplated by the CPSD/MGRA proposal. Compared to the CPSD/MGRA proposal, SDG&E used a more comprehensive risk assessment that included wind, vegetation, topography, historical fires, downwind impacts, and practical considerations for operations and maintenance of facilities.

If the Commission decides to develop a new fire-threat map, PacifiCorp and PG&E submit that it is reasonable to allow CPSD to review the Reax Map and then have the Commission consider the adoption of the Reax Map for use by the CIPs. This effort may be appropriate for a Phase 3 of this proceeding.

The CIP Coalition urges the Commission to adopt the Reax Map, which provides a scientifically-based geographic delineation of high fire-threat areas in Northern California.⁹⁹ The methodology used to create the Reax Map, while based on the FRAP Map, applied several enhancements to assess the factors leading to fires associated with joint-use poles, such as local terrain and weather, wind-induced pole/line failure, ignition sources, and fire-spread behavior. The end result is a fire-threat map that incorporates more extensive and more recent data than the FRAP Map, and more accurately delineates the geographic areas in Northern California where there is a high fire threat.¹⁰⁰

The CIP Coalition asserts that the Commission does not require peer review of expert reports submitted to the Commission. To the contrary, it is the Commission's practice to conduct its own review of expert reports and to issue decisions addressing the merits of such reports. That is not to say that the Commission's adoption of the Reax Map should forestall additional evaluation of the map. Interested parties such as CPSD, MGRA, and Cal Fire can continue to assess the Reax Map. If they find something that might warrant a change to the Reax Map, they can bring such changes to the Commission attention with a petition to modify the Phase 2 decision.

⁹⁹ Cox, a member of the CIP Coalition, abstains from taking a position on Contested Proposals 14A, 14B, and 14C.

¹⁰⁰ The Reax Map and a report describing the methodology that was used to develop the Reax Map are attached to the Phase 2 Workshop Report as Appendix E. On September 15, 2010, David Rich, principal engineer at Reax Engineering Inc., filed a verification with the Commission verifying the contents of the Reax Map and report.

The CIP Coalition's proposal (Contested Proposals 14A and 14B) is supported by PacifiCorp. No other parties expressed support for the CIP Coalition's proposal in their briefs.

CPSD and MGRA do not oppose the Reax Map at this time, but they are concerned that the map has not been reviewed by experts. TURN agrees with CPSD and MGRA that any fire-threat map should be evaluated by experts prior to adoption by the Commission.¹⁰¹ Nonetheless, CPSD and MGRA are optimistic that the Reax Map could be the foundation for a statewide fire-threat map. They note that the Reax Engineering Inc., has the capability of extending the Reax Map for Northern California to Southern California.

MGRA recommends using the Reax Map on an interim basis in Northern California for CIP inspections purposes until a formal peer review of the Reax Map is complete. MGRA also supports using the SDG&E Map on an interim basis for SDG&E's service territory pending a review of the SDG&E Map.

6.17.3. Position of Cal Fire

Cal Fire opposed the Commission's decision in Phase 1 to use Cal Fire's FRAP Map to identify areas where the threat of power-line fires is most acute in Southern California. The issues raised by Cal Fire related to the deficiencies of map resolution and accuracy, model formulation, underlying data, and the overall inappropriate application of the FRAP Map. Cal Fire warns that the FRAP Map remains ill-suited for the uses adopted by the Phase 1 Decision and the uses contemplated by various parties in Phase 2.

¹⁰¹ TURN opposes both the CPSD/MGRA proposal and the CIP Coalition proposal.

Cal Fire supports the CPSD/MGRA proposal to develop fire-threat maps that meet the needs of the Commission, utilities, and other stakeholders. Subject to staff availability and the recovery of significant costs, Cal Fire is willing to:

- Participate with Commission staff, utilities, and other stakeholders in preparing a work plan for the development and maintenance of appropriate fire-threat maps.
- Participate in a review of any fire-threat maps that may be developed as a result of the work plan.

Cal Fire states that the Reax Map could be an appropriate starting point for developing a work plan, but Cal Fire has not reviewed the Reax Map and has no opinion on the map. Cal Fire is willing to participate in a peer review of the Reax Map to the extent that staff and other resources are available.

Cal Fire notes that it has inspection and law enforcement responsibilities regarding utilities, power lines, and fires. Given these mandated responsibilities, Cal Fire states that it cannot approve any utility-related fire-threat maps. Rather, the Commission should have the responsibility to approve maps that are developed as part of its regulatory jurisdiction.

6.17.4. Discussion

The issue before us is whether to adopt the CPSD/MGRA proposal or the CIP Coalition proposal regarding fire-threat maps. CPSD and MGRA seek to establish a process for the development and adoption of fire-threat maps for various uses by the CIPs and electric IOUs. The CIP Coalition seeks the immediate adoption of the Reax Map for the narrow purpose of delineating the geographic area of CIP inspections in Northern California under Rule 31.2 of GO 95. In deciding this issue, it is helpful to review the intended use of fire-threat maps.

The function of fire-threat maps is to accurately designate geographic areas where power-line fires are more likely to be ignited and spread rapidly, thereby posing an increased risk of catastrophic wildfires. To reduce the risk of power-line fires occurring in high fire-threat areas, the Phase 1 Decision and today's decision together adopt the following measures that rely on fire-threat maps:

- GO 95, Rule 18A, requires electric utilities and CIPs to place a high priority on the correction of significant fire-safety hazards in areas of Southern California that are designated as Extreme and Very High Fire Threat Zones on the FRAP Map.¹⁰²
- GO 95, Rules 31.2, 80.1A, and 90.1B establish the minimum frequency for patrol inspections, detailed inspections, and intrusive inspections of aerial communication facilities located in close proximity to power lines in any area of the state that is designated as a high fire-threat on the relevant fire-threat map adopted by the Commission.
- GO 95, Rule 35 and Appendix E, specifies increased time-of-trim clearances between vegetation and energized conductors in areas of Southern California that are designated as Extreme and Very High Fire Threat Zones on the FRAP Map.
- GO 95, Rule 37, Table 1, Case 14, requires increased radial clearances between bare-line conductors and vegetation in areas of Southern California that are designated as Extreme and Very High Fire Threat Zones on the FRAP Map.
- GO 165, Appendix A, Table 1, requires more frequent patrol inspections of overhead power-line facilities in rural areas of Southern California that are designated as Extreme and Very High Fire Threat Zones on the FRAP Map.

¹⁰² Today's decision defines Southern California as Imperial, Los Angeles, Orange, Riverside, Santa Barbara, San Bernardino, San Diego, and Ventura Counties. Northern California is defined as all other counties in California.

- GO 166, Standard 1.E., requires electric utilities in Southern California to develop and submit a plan to reduce the risk of fire ignitions by overhead power-line facilities located in high fire-threat areas during extreme fire-weather events. Electric utilities in Northern California must also develop and submit a plan if the utility has overhead power-line facilities that are located in an area that is (1) designated as a high fire-threat area on a fire-threat map adopted by the Commission, and (2) subject to extreme fire-weather events.

The success of the previously identified measures at reducing the risk of catastrophic power-line fires depends on maps that accurately identify areas where power line fires are most likely to occur and spread rapidly. Stated differently, we cannot effectively mitigate the risk of power-line fires unless we know where the risks are located.

The Phase 1 Decision adopted the FRAP Map to establish inspection cycles, prioritize repairs, and determine vegetation clearances in the high fire-threat areas of Southern California.¹⁰³ However, the FRAP Map was adopted against Cal Fire's advice that the map is ill-suited for identifying high-risk areas for power-line fires.¹⁰⁴ The Phase 1 Decision nevertheless adopted the FRAP Map because there was no better fire-threat map available at the time.

Unlike the FRAP Map, the Reax Map and the SDG&E Map are specifically designed to identify areas where there is a heightened risk of power-line fires. Both maps take into account the major factors that contribute to the ignition and spread of power-line fires, including wind, vegetation, and topography. However, while both the Reax Map and SDG&E Map show promise, neither has

¹⁰³ D.09-08-029 at pp. 15, 21, and 34.

¹⁰⁴ Cal Fire Phase 1 Comments filed on March 27, 2009, at pp. 2 - 5.

been reviewed by the parties to this proceeding¹⁰⁵ or by neutral fire-safety experts such as Cal Fire. Given the vital public safety issues involved, we conclude that the Reax Map and the SDG&E Map must be reviewed by neutral experts before they are adopted on a permanent basis.

The Reax Map and the SDG&E Map are also limited in the geographic areas they cover. The Reax Map covers only Northern California, and the SDG&E Map is confined to SDG&E's service territory. It is imperative that accurate fire-threat maps be developed for all of Southern California, as this is the area of the state with the greatest risk of catastrophic power-line fires.

For the preceding reasons, we conclude that it is reasonable to adopt the major elements of the CPSD/MGRA proposal. We will order the CIPs and electric IOUs to participate in a workshop with CPSD and Cal Fire for the purpose of preparing a detailed work plan to develop and adopt statewide, high-resolution maps that accurately designate areas where there is a high threat of power-line fires occurring and spreading rapidly. We also invite Lawrence Livermore National Laboratory to participate in the workshops. The fire-threat maps must be specifically designed for use in conjunction with the previously identified fire-prevention measures adopted by the Phase 1 Decision and today's decision. Although we would prefer a single statewide fire-threat map, this is not necessary. The workshop should not exclude any fire-threat maps from consideration.

¹⁰⁵ The Reax Map was not provided to the Phase 2 Workshop participants until the final day of the workshops. This left no time for the parties to review the Reax Map. SDG&E informed the parties that it had created a fire-threat map, but SDG&E did not submit its fire-threat map for review by the parties.

We will initiate a Phase 3 of this proceeding for the purpose of developing and adopting fire-threat maps.¹⁰⁶ We will also appoint a Commission staff member to serve as a neutral facilitator for the Phase 3 workshops or, alternatively, the workshop participants may select and pay for an external neutral facilitator. The Phase 3 workshops should follow the format that is outlined in the Phase 2 Scoping Memo.

Today's decision constitutes a preliminary scoping memo for Phase 3 and, as such, sets a preliminary deadline of 18 months from the issuance date of today's decision for resolving Phase 3 issues pursuant to Pub. Util. Code § 1701.5(b). The final deadline will be set by the scoping memo for Phase 3.

The workshop participants shall file and serve a workshop report within six months from the issuance date of today's decision that contains the following:

- A proposed work plan for the development of accurate, high resolution fire-threat maps that cover the entire state. The purpose of the fire-threat maps is to identify the specific geographic areas where power-line fires are more likely to occur and spread rapidly. The detailed proposal shall address the option of reviewing and adopting the Reax Map and/or the SDG&E Map for regional or statewide use.
- Recommendations for obtaining assistance from Cal Fire, Lawrence Livermore National Laboratory, and other neutral experts in the development and review of fire-threat maps, including the Reax Map and the SDG&E Map.
- Estimated costs and proposed funding sources for the development, expert review, implementation, and maintenance of fire-threat maps.

¹⁰⁶ As set forth previously in today's decision, Phase 3 will also provide a venue for CPSD to develop and submit a comprehensive plan for collecting data on power-line fires, analyzing the data, and using this information to formulate measures to reduce the number of fires ignited by power lines.

- A proposed schedule and a list of milestones for the development, review, adoption, implementation, and periodic updates of fire-threat maps.

The workshop report may include alternative work plans and recommendations if the workshop participants cannot reach a consensus.

Parties may file and serve opening and reply comments regarding the workshop report described. The opening and comments shall be due two weeks and four weeks, respectively, after the workshop report is filed. We anticipate that we will issue a decision regarding the development and adoption of fire-threat maps based on the workshop report and comments on the report.

Until permanent fire-threat maps are adopted in Phase 3, the CIPs and electric utilities shall use the FRAP Map, Reax Map, and SDG&E Map on an interim basis to implement the fire-prevention measures adopted by the Phase 1 Decision and today's decision. The CIPs shall use Reax Map in Northern California and the FRAP Map in Southern California. The electric utilities other than SDG&E shall use the Reax Map in Northern California and the FRAP Map in Southern California. SDG&E may use its own fire-threat map. Copies of the FRAP Map and Reax Map are contained in Appendix C of today's decision. SDG&E shall provide a copy of its fire-threat map to any party that requests it.

The adopted fire-prevention measures shall be implemented on an interim basis in areas that are designated as Extreme and Very High Fire Threat Zones on the FRAP Map and SDG&E Map,¹⁰⁷ and in areas that are designated as Threat Class 3 and Threat Class 4 on the Reax Map. The boundaries should be broadly construed. The CIPs and electric utilities should use their own expertise and

¹⁰⁷ SDG&E did not provide a copy of its fire-threat map. We assume the SDG&E Map uses the same labels for fire-threat zones as the FRAP Map.

judgment to determine if local conditions require them to adjust the boundaries of the relevant map.

We recognize that the interim maps may be flawed. However, we conclude that the threat of catastrophic power-line fires is so great that the public interest is better served by requiring the CIPs and electric utilities to implement the adopted fire-prevention measures using the available maps rather than waiting for the development and adoption of permanent maps in Phase 3. While there is some risk in using the un-reviewed Reax Map and SDG&E Map on an interim basis, we believe the risk is low, as both maps are designed to identify areas where there is a high risk of catastrophic power-line fires.

We are not persuaded by the assertion from several parties that the FRAP Map is sufficient for the purposes intended by the Phase 1 Decision and today's decision. We believe it would be imprudent to adopt the FRAP Map on a permanent basis for the purpose of designating areas where the adopted fire-prevention measures should be deployed when the state agency that created the FRAP Map warns against its use for this very purpose.

PacifiCorp and Sierra Pacific argue unpersuasively that they should not have to pay any costs for the development of new fire-threat maps because there is no threat of catastrophic power-line fires in their service territories. A comparison of maps showing PacifiCorp's and Sierra Pacific's service territories¹⁰⁸ with the Reax Map in Appendix C of today's decision reveals that

¹⁰⁸ A map that shows PacifiCorp's and Sierra Pacific's service territories is available at http://www.energy.ca.gov/2007_energypolicy/documents/2007-05-15_workshop/presentations/Electric%20Utility%20Service%20Areas%205-10-07.pdf. We take official notice of this document pursuant to Rule 13.9 of the Commission's Rules of Practice and Procedure.

there are large swaths of their service territories that are designated as Fire Threat Class 3 on the Reax Map, and several pockets of their service territories that are designated as Fire Threat Class 4.

We are not persuaded by TURN that the adoption of high-resolution maps which accurately pinpoint the areas of elevated fire risk will reduce safety by decreasing the size of the areas where CIPs and electric utilities are required to implement fire-prevention measures. The high-resolution maps required by today's decision are essential for the effective deployment of many of the fire-prevention measures adopted in this proceeding. The FRAP Map is ill-suited for this purpose, as Cal Fire readily acknowledges. In our judgment, the ability to accurately target high fire-threat areas will enhance public safety by reducing the number of power-line fires.

Finally, several parties contend that it will be too costly to develop and implement new fire-threat maps. As stated previously, the fire-threat maps required by today's decision are an essential tool for the successful deployment of the fire-prevention measures adopted in this proceeding. We find that the public-safety benefits from the reduced risk of catastrophic power-line fires more than offset the cost of developing and implementing high-resolution maps that accurately designate the areas where there is an elevated threat of catastrophic power-line fires occurring.

6.18. Record Retention

All of the inspection and repair rules proposed by the parties retain the existing record retention requirements. In general, the existing rules require CIPs and electric utilities to retain records of their inspections and repairs for a five-year period. We believe that longer record retention period is needed in order to ensure there is sufficient information to conduct a thorough forensic

analysis in the event there is a serious safety-related incident with overhead power lines and/or CIP facilities. Therefore, we will adopt a general requirement to create and maintain for ten (10) years records of all inspections and repairs of overhead facilities. In the case of intrusive inspections of wood poles, we will require records of such inspections, and any repairs that result from such inspections, to be maintained for the life of the pole.

6.19. Commission Jurisdiction and Publicly Owned Utilities

CMUA and LADWP ask the Commission to clarify the extent of its jurisdiction and enforcement powers over publicly owned utilities (POUs) with respect to several of the rules and regulations adopted by the Phase 1 Decision and today's decision. We interpret CMUA and LADWP's request as seeking an advisory opinion. Like the courts, we have a long-standing policy against issuing advisory opinions,¹⁰⁹ and we decline to do so here.¹¹⁰

6.20. Cost Recovery

The Phase 1 Decision provided the following guidance regarding the recovery of costs incurred electric utilities, CIPs, and other entities to implement the regulations adopted in this proceeding:

We find that **each cost-of-service regulated utility is entitled to recover reasonable costs prudently incurred to comply with the changes to the Commission's rules adopted today.** To be clear, we do not find today that all costs incurred to comply with the revised rules will be automatically assumed to be reasonable but that, **after the Commission verifies the reasonableness of costs, recovery will be permitted.** We

¹⁰⁹ D.00-01-052, 4 CPUC 3d 160, 166 – 168.

¹¹⁰ The Commission's general position on its jurisdiction with respect to POUs is summarized in Section 3 of today's decision.

direct each cost-of-service regulated utility to record its costs in a memorandum account to avoid retroactive ratemaking.

We will address costs more fully in [Phase 2] and expect cost-of-service regulated utilities to provide cost data. We will decide the appropriate forum for seeking recovery of these costs in [Phase 2]. **In [Phase 2], we will also develop an appropriate tracking mechanism for these additional costs and decide how to incorporate these costs into each utility's general rate case.**

* * * *

Regarding those utilities with deregulated rates, including incumbent local exchange carriers (ILECs), we decline to adopt any mechanisms for recovery of costs associated with today's rule changes, as telecommunications companies with rate flexibility may charge different rates to recover costs without our approval. To the extent that a telecommunications company with rate flexibility seeks to place a line-item on its bill to recover such costs, however, it must not falsely imply that such charge is CPUC-mandated or approved.

* * * *

Small local exchange carriers which are on cost-of-service regulation will operate under the same framework set forth above as electric companies. (D.09-08-029 at pp. 43 - 44. Emphasis added.)

We affirm our determination in the Phase 1 Decision that cost-of-service utilities are entitled to recover the reasonable costs they incur to comply with the regulations that are adopted in this proceeding after the reasonableness of such costs has been verified by the Commission. We also affirm that such costs should be verified and recovered in general rate case (GRC) proceedings.

As contemplated by the Phase 1 Decision, we establish interim mechanisms, described below, for cost-of-service utilities to recover their reasonably incurred and verified costs until such costs can be incorporated into each company's GRC. The interim cost-recovery mechanisms will ensure that

funding is available in a timely manner to implement the fire-prevention measures adopted in this proceeding.

Consistent with the Phase 1 Decision, we find there is no need to establish a cost-recovery mechanism for utilities with deregulated rates. Any utility with deregulated rates or rate flexibility that places a line-item charge on its customer bills to recover costs that are incurred as a result of this proceeding must not state or imply that such charge is mandated or approved by the Commission.

6.20.1. Cost Recovery for Electric IOUs

With certain exceptions described below, the electric IOUs¹¹¹ shall track and record their costs to implement the regulations adopted in this proceeding in the Fire Hazard Prevention Memorandum Accounts (FHPMAs) they have established pursuant to the Phase 1 Decision. Each electric IOU may file one or more applications to recover the costs recorded in its FHPMA. The number and timing of applications will be at the discretion of each electric IOU. We will verify and assess the reasonableness of recorded costs in application proceedings.

The electric IOUs shall record in their FHPMAs only those costs that are not being recovered elsewhere. For example, PacifiCorp and Sierra Pacific already recover their costs to implement the Phase 1 Decision in their respective GRCs.¹¹² Consequently, PacifiCorp and Sierra Pacific may not record any Phase 1 costs in their FHPMAs. Similarly, SCE, SDG&E, and SoCalGas have

¹¹¹ For the purpose of today's decision, the term "electric IOUs" includes Southern California Gas Company to the extent it operates overhead power-line facilities that are subject to the Commission's jurisdiction.

¹¹² PacifiCorp and Sierra Pacific Joint Phase 2 Opening Brief at 28.

included forecasted costs from the Phase 1 Decision in their 2012 GRCs.¹¹³ Thus, the only Phase 1 costs these companies may record in their FHPMAs are their actual costs to implement the Phase 1 Decision that are incurred prior to 2012.

Each electric IOU may continue to record authorized costs in its FHPMA until the first GRC that occurs after the close of this proceeding, at which time the FHPMA shall be closed. The electric IOU may then use the GRC mechanism to request recovery of the costs it incurs from that point forward to comply with the regulations adopted in this rulemaking proceeding. The electric IOU may seek to recover the ending balance in its FHPMA, if any, by filing an application.

6.20.2. Cost Recovery for the Small LECs

The Small LECs may use their annual California High Cost Fund-A (CHCF-A) Tier 3 advice letters¹¹⁴ to request recovery of the costs recorded in their FHPMAs. This procedure is consistent with D.91-09-042, which allows Small LECs to obtain financial support from CHCF-A based on recorded financial data.¹¹⁵ We will verify and assess the reasonableness of the costs recorded in each Small LEC's FHPMA as part of our review the Small LEC's annual CHCF-A advice letters.

Each Small LEC may continue to use this procedure until the first GRC that occurs after the close of this proceeding. At that time, the Small LEC shall close its FHPMA and thereafter use the GRC mechanism to request recovery of the costs it incurs to comply with the regulations adopted in this rulemaking

¹¹³ Phase 2 Workshop Report, Appendix B, at B-256, Fn. 66.

¹¹⁴ The Tier 3 advice letter process allows for protest periods and Commission review of the advice letter prior to a final decision or resolution.

¹¹⁵ D.91-09-042, 41 CPUC 2d 326, 330 - 331.

proceeding. The Small LEC may seek to recover the ending balance of its FHPMA, if any, in its annual CHCF-A advice letter filing.

We note that there is no requirement for Small LECs to file GRCs. However, if a Small LEC does not file a GRC, it will eventually lose all of its financial support from the CHCF-A through the so-called waterfall process.¹¹⁶ Under the waterfall process, a Small LEC will receive 100% of its authorized financial support from the CHCF-A for three years following the GRC. Financial support then falls to 80% of the authorized amount in the fourth year after the GRC, 60% in the fifth year, and zero percent in the sixth year.¹¹⁷ Thus, the ability of a Small LEC to recover the costs recorded in its FHPMA through annual CHCF-A advice letters will decline and eventually end if it does not file a GRC.

We will require each Small LEC to close its FHPMA when its authority to seek financial support from the CHCF-A reaches zero percent. The company's authority to seek recovery of the costs recorded in its FHPMA shall expire upon the closure of its FHPMA.

We note that several Small LECs have opted out of the CHCF-A, and there is no requirement for these companies to file a GRC.¹¹⁸ These companies may seek to recover the costs recorded in their FHPMA as part of their next GRC filing, if any. Their authority to seek recovery of such costs will end on January 1, 2015, at which time their FHPMAs shall be closed.

¹¹⁶ D.91-09-042, 41 CPUC 2d 326, 332.

¹¹⁷ Ibid.

¹¹⁸ These companies are Happy Valley Telephone Company, Hornitos Telephone Company, Winterhaven Telephone Company, and Verizon West Coast (which is now owned by Frontier).

6.21. Implementation

All entities subject to the rules, regulations, and ordering paragraphs adopted by today's decision shall implement these directives as soon as possible. We do not adopt any deadlines except those specifically established in the rules, regulations, or ordering paragraphs themselves.

CPSD shall revise GOs 95, 165, and 166 to incorporate the revisions adopted by today's decision and publish the amended GOs on the Commission's website within 60 days from the issuance date of today's decision. The adopted revisions include replacing the placeholder "Decision 11-XX-YYY" in several locations with the decision number for today's decision.

7. California Environmental Quality Act

The California Environmental Quality Act (CEQA)¹¹⁹ applies to any project that has a potential for resulting in a direct physical change in the environment or a reasonably foreseeable indirect physical change in the environment unless the project is exempt from CEQA by statute or regulation.¹²⁰ The Phase 2 Workshop Report states that each proposal addressed by today's decision is exempt from CEQA pursuant to Section 15378 of the CEQA Guidelines¹²¹ because it is not a "project" under CEQA and will not have any significant impacts on the environment. No party disagrees with this assessment.

The Commission is the lead agency under CEQA with respect to the regulations adopted by today's decision. We find that all of the adopted

¹¹⁹ CEQA is contained in Cal. Pub. Res. Code § 21000 et seq.

¹²⁰ 14 Cal. Code Regs., Section 15378.

¹²¹ The CEQA guidelines are set forth in 14 Cal. Code Regs., Section 15000 et seq.

regulations are exempt from CEQA pursuant to one or more the following statutory exemptions or categorical exemptions in the CEQA guidelines:

- The adopted regulation allows for the operation, repair, or maintenance of existing electric utility and CIP facilities, and involves negligible or no expansion of an existing authorized use. (14 Cal. Code Regs., Section 15301(b).)
- The adopted regulation allows for the restoration or rehabilitation of deteriorated or damaged structures, facilities, or mechanical equipment to meet current standards of public health and safety, and involves negligible or no expansion of an existing authorized use. (14 Cal. Code Regs., Section 15301(d).)
- The adopted regulation allows for the maintenance of existing landscaping and native growth, and involves negligible or no expansion of an existing authorized use. (14 Cal. Code Regs., Section 15301(h).)
- The adopted regulation allows for minor alterations of land that provide for fuel management activities within 30 feet of structures to reduce the volume of flammable vegetation, and will not result in the taking of endangered, rare, or threatened plant or animal species or significant erosion and sedimentation of surface waters. (14 Cal. Code Regs., Section 15304(i).)
- The adopted regulation involves the creation of government funding mechanisms or other government fiscal activities, which do not involve any commitment to a specific project which may result in a potentially significant physical impact on the environment. (14 Cal. Code Regs., Section 15378(b)(4).)
- The adopted regulation involves the establishment, modification, structuring, restructuring, or approval of rates or other charges for the purpose of (A) meeting operating expenses, including employee wage rates and fringe benefits, (B) purchasing or leasing supplies, equipment, or materials, (C) meeting financial reserve needs and requirements, (D) obtaining funds for capital projects necessary to maintain service within existing service areas. (Pub. Res. Code § 21080(b)(8).)

- The adopted regulation will not have a potentially significant impact on the environment and is therefore not a “project” as defined by CEQA in Pub. Res. Code § 21065 and 14 Cal. Code Regs., Section 15378(a).
- The regulation continues provisions which were adopted in D.09-08-029, or which are very similar to those adopted in D.09-08-029, wherein it was determined that CEQA did not apply to the adopted measures. (D.09-08-029 at 7.)

8. Proposed Rulemaking Proceeding re: Electric Tariff Rule 20

8.1. Background

Electric Tariff Rule 20 provides a process for placing overhead power-line facilities underground for aesthetic reasons. The Commission authorizes funding and cost recovery for Tariff Rule 20 projects in GRC proceedings.¹²²

Tariff Rule 20 contains a formula for allocating the available funds for undergrounding projects among cities and counties. Each jurisdiction saves its allocation, and can “borrow” ahead for 5 years’ worth of allocations in order to fund a project. Because projects are expensive, it may take many years for a smaller jurisdiction to afford even a small project.

Tariff Rule 20 prescribes a multi-stage process for local jurisdictions to obtain and use the available funds for undergrounding projects. The governing body of the city or county must consult with the electric utility, hold public hearings, makes a determination that undergrounding is in the public interest, and create an undergrounding district. The project is then designed, scheduled, and executed by the IOUs. Projects usually take several years at a minimum.

¹²² D.01-12-009 at 5, Fn. 5. Individual customers may be required to pay a portion of the cost to underground electric facilities from the street to the customer’s meter. (D.01-12-009 at 5 - 6.)

The CIPs must place their aerial communication lines underground at the same time as the electric utilities. Unlike the electric IOUs, the CIPs do not have a regulatory mechanism to fund their share of undergrounding projects. The CIPs must pay for undergrounding projects from general revenues.

The Phase 2 Scoping Memo determined that Phase 2 “may consider adding fire risk to the list of reasons to permit undergrounding under Tariff Rule 20.¹²³” On February 9, 2010, the CIP Coalition filed a motion to exclude from this proceeding any proposed changes to the existing tariff rules governing the conversion of aerial facilities to underground facilities. The CIP Coalition argued that the proposed changes were subject to Pub. Util. Code § 1708, which requires notice before a Commission decision is changed. The CIP Coalition observed that no notice had been provided to the parties in prior proceedings where the Commission had rejected proposals to revise Tariff Rule 20 to allow aerial electric facilities to be placed underground for the purpose of reducing fire risk.

On April 6, 2010, the assigned ALJ, in consultation with the Assigned Commissioner, issued a ruling that granted the CIP Coalition’s motion to exclude Tariff Rule 20 issues from this proceeding. However, the ruling also authorized parties to file comments on whether the Commission should open a new rulemaking proceeding to consider if fire risk should be added to the list of reasons to permit undergrounding under Tariff Rule 20 and how to provide notice of this new proceeding in conformance with Pub. Util. Code § 1708.

Opening comments were filed on May 7, 2010, by Facilities Management Specialists LLC (FMS), SDG&E, TURN, and collectively by the CCTA, Comcast,

¹²³ Phase 2 Scoping Memo at 8.

Time Warner, tw telecom of california, llc, and the Verizon companies.¹²⁴ Reply comments were filed on May 21, 2010, by CPSD, FMS, LADWP, PG&E, SDG&E, and collectively by AT&T, CCTA, Comcast, CoxCom, Inc., Cox, Time Warner, tw telecom of california, lp, and the Verizon companies (collectively, “the Commenting CIPs”).

8.2. Position of the Parties

CPSD, FMS, LADWP, and SDG&E support a new rulemaking proceeding to consider if fire risk should be added to the list of reasons to permit undergrounding under Tariff Rule 20. They believe the Commission should consider all options for preventing power-line fires.

SDG&E states that regardless of whether the Commission decides to open a new rulemaking proceeding, SDG&E intends to file an application that would establish a new Tariff Rule 20D for allocating funds among cities and counties to place overhead power-line facilities underground for fire-prevention purposes. The proposed Tariff Rule 20D would apply only to SDG&E, and not to other electric IOUs or CIPs.

The proposed rulemaking proceeding is opposed by the Commenting CIPs and TURN. The Commenting CIPs assert that the Commission must first address the issue of CIP cost recovery for undergrounding projects. The Commenting CIPs are concerned that a new rulemaking proceeding would result in the expansion of undergrounding projects under Tariff Rule 20,

¹²⁴ The Verizon companies include MCI Communications Services, Inc., d/b/a Verizon Business Services (U-5378-C), MCI Metro Access Transmission Services, d/b/a Verizon Access Transmission Services (U-5253-C), TTI National, Inc., d/b/a Verizon Business Services (U-5403-C), Verizon California Inc. (U-1002-C), and Verizon West Coast (U-1020-C).

resulting in greater costs for the CIPs. However, unlike the electric IOUs, the CIPs do not have captive ratepayers to pay for undergrounding projects. The Commenting CIPs argue that the failure to address the issue of CIP cost recovery would raise an equal protection challenge, as there is allegedly no rational basis for making the electric IOUs whole but not the CIPs.

TURN states there are several reasons why Tariff Rule 20 is a poor vehicle for addressing fire risks. First, Tariff Rule 20 is not designed to address fire risks in an urgent manner, as projects usually take several years from conception to completion. While this leisurely pace is suitable for beautification projects, it may be too slow to address known fire risks.

Second, the fire risk associated with overhead power-line facilities is generally much lower in Northern California. Thus, there is not a statewide need to amend Tariff Rule 20 to address fire risk.

Third, the allocation of funds under Tariff Rule 20 is not appropriate for fire-prevention purposes. The majority of funding currently goes to cities. This is the opposite of the allocation that would be needed to address fire risk.

Finally, the Commission currently requires that aerial communication lines be placed underground at the same time that power lines are placed underground pursuant to Tariff Rule 20. TURN states there is usually no need to place communication lines underground to mitigate fire risks.

TURN opines that GRCs are a better venue for considering the merits of undergrounding projects for fire-prevention purposes. There, the Commission can consider the costs and benefits of different measures for mitigating fire risk and allocate limited ratepayer funds to the most cost-effective fire-prevention measures and the highest priority fire-prevention projects.

SDG&E agrees with TURN that funding for fire-prevention measures, including undergrounding projects, should be decided in GRC proceedings. But SDG&E also believes that a new Tariff Rule 20D for fire-safety undergrounding could help SDG&E implement Commission-authorized fire safety undergrounding activities by making the affected cities and counties an integral part of the undergrounding process. This is because the new Tariff Rule 20D would (1) provide for greater municipal and public input on selection, prioritization, schedules, and cost; (2) allow for better coordination with municipalities on issues such as land rights acquisition and public improvements; (3) provide an equitable distribution of projects among municipalities; and (4) establish rules that do not need to be litigated each GRC.

PG&E neither supports nor opposes a new rulemaking proceeding to consider if fire risk should be added to the list of reasons to permit undergrounding under Tariff Rule 20. If the Commission decides to open a new proceeding, PG&E urges the Commission to ensure that the entire panoply of costs, risks and benefits is fully explored and that all stakeholders are invited.

8.3. Discussion

The overarching purpose of Tariff Rule 20 is to place overhead power lines underground for aesthetic reasons. To this end, the tariff rule contains a formula for allocating the available funds among cities and counties, and prescribes a process that cities and counties must use to obtain funds.

The purpose of Tariff Rule 20 is unrelated to fire prevention. We see no reason to clutter the rule with new and unrelated provisions regarding fire prevention. We agree with TURN that GRCs, and not Tariff Rule 20, should be used to allocate ratepayer funds for fire-prevention projects.

The GRC process has several advantages over Tariff Rule 20 in terms of allocating funds for fire-prevention purposes. First, a GRC enables the utility, the Commission, and interested parties to identify the highest priority fire-prevention projects and to allocate ratepayer funds to those projects. In contrast, Tariff Rule 20 contains no procedures for identifying high priority fire-prevention projects and no mechanism for ensuring that such projects are funded. Each city and county would have discretion to use its allotted funds for lower priority fire-prevention projects in its own jurisdiction ahead of higher priority projects in other jurisdictions.

Second, the only fire-prevention measure available under Tariff Rule 20 is placing overhead power-line facilities underground. This is perhaps the most expensive fire-prevention tool available. There are many other fire-prevention options, such as line spacers, wire insulation, and vegetation management. A GRC proceeding would allow the Commission to consider a range of fire-prevention options and select the most cost-effective solutions.

Third, fire risk should be assessed from the standpoint of the utility's entire service territory, and not from the piecemeal and narrow geographical perspectives of individual jurisdictions. The utility can assess wind conditions, vegetation type, population density, and other factors to identify the portions of its service territory where the risk of power-line fires is greatest. While this can be done in a GRC proceeding, it is not possible with Tariff Rule 20.

Finally, ratepayers have limited resources. The use of limited resources for fire-prevention purposes must be balanced with other priorities such as system reliability and reasonable rates. This is best done in a GRC.

We conclude for the preceding reasons that there is no need to open a new rulemaking proceeding to consider adding fire risk to the list of reasons to

permit undergrounding under Tariff Rule 20. Our decision to forego a new rulemaking proceeding does not signal any reduction in our concern about fire prevention. To the contrary, we believe that GRCs are a superior regulatory mechanism for selecting and funding fire-prevention measures compared to the ad hoc allocation of ratepayer funds for fire-prevention projects under Tariff Rule 20.¹²⁵

9. Need for Hearing

In OIR 08-11-005, the Commission preliminarily determined that hearings are not needed in this proceeding. Parties were provided an opportunity by the Phase 1 Scoping Memo and the Phase 2 Scoping Memo to request evidentiary hearings, but no such requests were submitted. Today's decision affirms that there is no need for evidentiary hearings in Phase 2 of this proceeding.

10. Comments on the Proposed Decision

The proposed decision for Phase 2 of this proceeding was mailed to the parties in accordance with Pub. Util. Code § 311, and comments were allowed in accordance with Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on _____ by _____. Reply comments were filed on _____ by _____.

11. Assignment of the Proceeding

Timothy A. Simon is the assigned Commissioner and Timothy Kenney is the assigned Administrative Law Judge in this proceeding.

¹²⁵ Today's decision does not prejudge any application that SDG&E may file for authority to establish a new Tariff Rule 20D to allocate funds for undergrounding power lines for fire-prevention purposes, much like Tariff Rule 20 allocates funds for beautification projects.

Findings of Fact

1. The regulatory requirements adopted by today's decision will improve the fire safety of overhead electric utility facilities and aerial CIP facilities in close proximity to overhead power lines. Any additional costs that the new regulatory requirements impose on electric utilities, CIPs, and other entities are more than offset by the public-safety benefits.

2. In addition to enhancing fire safety, many of the revisions to GO 95 and GO 165 that are adopted by today's decision will (i) improve the clarity of these General Orders, (ii) streamline existing requirements, and/or (iii) remove obsolete, unnecessary, or redundant provisions in these General Orders. These revisions will improve the ability of CIPs and electric utilities to manage their operations efficiently and thereby reduce safety hazards and costs.

3. There is a grave and ongoing risk that Santa Ana windstorms will cause catastrophic power-line fires unless electric utilities in Southern California plan and prepare for such events.

4. The FRAP Map and Reax Map show there are millions of acres in Northern California where there is a high fire threat. However, the magnitude of the risk of catastrophic wind-caused power-line fires occurring in Northern California is unknown at this time.

5. Aerial CIP facilities located in close proximity to power lines are a latent fire hazard. If not installed and maintained properly, aerial CIP facilities could contact power lines and ignite a fire. CIP-only poles can also fail, causing a cascade that topples nearby joint-use poles, resulting in wildfires.

6. The protection of public safety requires that CIPs carry out patrol inspections, detailed inspections, and intrusive inspections of their aerial

facilities and poles located in close proximity to overhead power-line facilities in the high fire-threat areas of the state.

7. There is no history of catastrophic power-line fires in Northern California, and Northern California does not experience Santa Ana windstorms that contribute significantly to the risk of catastrophic power-line fires in Southern California. Because the risk of power-line fires is lower in Northern California compared to Southern California, it is reasonable to have a lower frequency of patrol inspections, detailed inspections, and intrusive inspections of CIP facilities in Northern California compared to Southern California.

8. The failure to keep power lines clear of vegetation poses a serious fire risk and threat to public safety. In order to protect public safety, electric utilities need appropriate tools to deal with customers who prevent access to their property for vegetation management.

9. The minimum time-of-trim guidelines in Appendix E of GO 95 provide an adequate margin for fire safety in most circumstances. Electric utilities and CIPs are authorized by Appendix E to exceed the minimum time-of-trim guidelines when it is advantageous to do so for fire-safety purpose.

10. Appendix E of GO 95 does not provide guidance about what factors should be considered by electric utilities and CIPs for determining whether, and to what extent, they should exceed the minimum time-of-trim guidelines specified in Appendix E.

11. It is of utmost importance to perform pole-loading calculations and to share information needed for pole-loading calculations in order to ensure that utility poles do not become overloaded and fail, which could ignite a fire, injure and kill people, and destroy property.

12. Rule 48 of GO 95 requires electric utilities and CIPs to design their structures based on the presumed strengths of the materials listed in Rules 48.1 through 48.7, including the strengths for wood poles listed in Rule 48.2.

13. Building materials have natural variability, particularly wood products. As a result, the actual strength of materials used by electric utilities and CIPs to build structures will likely deviate to some degree from the presumed strength of materials listed in Rules 48.1 through 48.7 of GO 95. The natural variability of materials is one reason why Rule 48 requires structures to be designed with the safety factors listed in Rule 44.

14. The marking of each CIP aerial cable and conductor attached to a joint-use pole with ownership information will enhance fire safety by enabling electric utilities, CIPs, and others to identify the owner of CIP facilities that pose a fire hazard so that the owner can be notified and repairs made.

15. There are many power-line fires every year. Requiring electric IOUs to report information on power-line fires would be useful in formulating fire-prevention measures and gauging the effectiveness of the adopted measures.

16. The availability of high-resolution maps that can accurately identify areas where power-line fires are more likely to occur and spread rapidly is essential to the successful and cost-effective deployment of many of the fire-prevention measures adopted in this proceeding.

17. The FRAP Map is not suited for use on a permanent basis to designate areas where the fire-preventions measures adopted in this proceeding should be deployed.

18. The Reax Map and the SDG&E Map are designed to identify areas where fire-prevention measures should be deployed, but neither map has been reviewed by neutral experts.

19. With the possible exception of SDG&E's service territory, there are currently no maps that accurately identify areas of Southern California where power-line fires are more likely to occur and spread rapidly.

20. There were no requests for evidentiary hearings in Phase 1 or Phase 2 of this proceeding.

Conclusions of Law

1. This is a quasi-legislative rulemaking proceeding in which no party requested evidentiary hearings and none were held. Accordingly, today's decision may rely on legislative facts obtained from written submissions in this proceeding, such as the Phase 2 Workshop Report and briefs. Today's decision may also draw on evidence from past proceedings, the Commission's experience and expertise in regulating utilities, Commission policies, and common sense.

2. It is in the public interest to adopt the revisions to GOs 95, 165, and 166 that are contained in Appendix B of today's decision for the reasons set forth in the body of today's decision and the Findings of Fact.

3. CPSD should amend GOs 95, 165, and 166 to incorporate the revisions to these GOs adopted by today's decision and publish the amended GOs on the Commission's website within 60 days from today's decision. The adopted revisions include replacing the placeholder "Decision 11-XX-YYY" in several locations with the decision number for today's decision.

4. Rule 18A of GO 95, as modified by today's decision, does not preempt any stricter local rules establishing priority systems for correcting safety hazards.

5. The deadlines for completing corrective actions under the inspection and maintenance programs established by electric utilities pursuant to GO 165 may not exceed the deadlines for completing corrective actions specified in Rule 18A of GO 95, as modified by today's decision.

6. Each electric utility in Southern California should prepare and submit a fire-prevention plan by December 31, 2012.

7. Each electric utility in Northern California should determine if there is a credible risk of catastrophic power-line fires in its service territory and, if so, prepare and submit a fire-prevention plan by December 31, 2012.

8. Each electric utility's fire-prevention plan should address situations where all three of the following conditions occur simultaneously: (i) sustained winds exceed the structural and mechanical design standards for overhead power-line facilities; (ii) the sustained winds occur during a period of high fire danger; and (iii) the affected facilities are located in high fire-threat areas. The fire-prevention plans should also specify (a) how the utility will identify the occurrence of sustained winds that exceed the design standards for overhead power-line facilities; and (b) the countermeasures the utility will implement to mitigate the threat of power-line fire ignitions.

9. Any electric IOU that intends to shut off power as part of its fire-prevention plan should file an application for authority to do so. The application should demonstrate with a cost-benefit analysis developed in accordance with the guidance provided by D.09-09-030 that the benefits of shutting off power in terms of a net reduction in fires outweigh the substantial costs, burdens, and risks that shutting off power would impose on customers and communities affected by the shut off.

10. The new Standard 1.E of GO 166 that is adopted by today's decision is subject to the other provisions in GO 166, including the requirement to update a fire-prevention plan annually and to conduct an annual exercise of the fire-prevention plan.

11. The Commission has authority to determine what constitutes compliance with GO 95 on a case-by-case basis in light of specific facts and circumstances.

12. For the purpose of implementing the inspection intervals for CIP facilities in GO 95, Rule 80.1, and for electric utility facilities in GO 165, the term “year” should be defined as 12 consecutive calendar months starting the first full calendar month after an inspection is performed.

13. Electric IOUs should revise their tariffs to state that the electric utility may shut off power to customers who do not allow access to their property for vegetation-management activities.

14. Electric utilities have wide latitude under Appendix E of GO 95 to exceed the minimum time-of-trim guidelines for fire-safety purposes.

15. The failure to maintain the required minimum clearance between an energized conductor and another conductor is either a Level 1 or Level 2 nonconformance, depending on circumstances, and must be corrected within the timeframes specified in Rule 18 of GO 95.

16. Rule 48 of GO 95 requires CIPs and electric utilities to build structures that will not fail when subjected to loads that are equal to, or less than, the “maximum working stresses” defined by Rule 44.

17. The failure of a structure that is subjected to loads that exceed the maximum working stresses as defined by Rule 44 of GO 95 should be evaluated in light of the conditions at the time of the failure and the inherent variability of the materials that comprise the structure.

18. There should be a Phase 3 of this proceeding to provide a venue for CPSD to develop and submit a comprehensive plan for collecting data on power-line fires, analyzing the data, and using this information to formulate measures to reduce the number of fires ignited by power lines. To this end, CPSD should

confer regularly with the electric IOUs, CIPs, MGRA, Cal Fire, and other interested parties to discuss the elements of the plan. CPSD should file and serve its plan no later than six months from the issuance date of today's decision, and parties should be authorized to file comments on CPSD's plan.

19. There should be a Phase 3 of this proceeding to develop and adopt accurate, high-resolution fire-threat maps. The Reax Map and the SDG&E Map should be evaluated by neutral experts in Phase 3 for the purpose of determining if these fire-threat maps should be adopted on a permanent basis.

20. The threat of catastrophic power-line fires is so great that the public interest is better served by requiring CIPs and electric utilities to implement the fire-prevention measures adopted in this proceeding using the available fire-threat maps rather than waiting for the development and adoption of permanent fire-threat maps in Phase 3.

21. Until permanent fire-threat maps are adopted in Phase 3, the CIPs and electric utilities should use the FRAP Map, Reax Map, and SDG&E Map on an interim basis to implement the fire-prevention measures adopted in this proceeding. The CIPs should use Reax Map in Northern California and the FRAP Map in Southern California. The electric utilities other than SDG&E should use the Reax Map in Northern California and the FRAP Map in Southern California. SDG&E should use its own fire-threat map.

22. Today's decision constitutes a preliminary scoping memo for Phase 3 and, as such, sets a preliminary deadline of 18 months from the issuance date of today's decision for resolving Phase 3 issues pursuant to Pub. Util. Code § 1701.5(b). The final deadline should be set by the scoping memo for Phase 3.

23. Electric utilities and CIPs should create and retain records of pole-loading calculations, patrol inspections, detailed inspections, and repairs for at least ten

years in order to provide information needed for forensic analysis in the event there is a major safety-related incident associated with overhead facilities. For the same reason, electric utilities and CIPs should create and retain records of all intrusive inspections of a wood utility pole, and any associated repairs that result from such inspections, for the life of the pole.

24. Cost-of-service utilities are entitled to recover the reasonable costs they incur to implement the regulations that are adopted in this proceeding after the reasonableness of such costs has been verified by the Commission. The cost-of-service utilities should be authorized to seek recovery of such costs on an interim basis until such costs can be incorporated into each utility's GRC.

25. There is no need to establish a cost-recovery mechanism for utilities and CIPs whose rates are not regulated by the Commission.

26. All entities subject to the rules, regulations, and ordering paragraphs adopted by today's decision should implement these directives as soon as possible. There should be no deadlines, except for those specifically established in the rules, regulations, or ordering paragraphs themselves.

27. CEQA applies to any project that has a potential for resulting in either a direct physical change in the environment or a reasonably foreseeable indirect physical change in the environment unless the project is exempt from CEQA by statute or regulation.

28. The Commission is the lead agency under CEQA with respect to the regulations adopted by today's decision.

29. All of the regulations adopted by today's decision are exempt from CEQA pursuant to one or more the statutory exemptions or categorical exemptions identified in the body of today's decision.

30. GRCs are a superior regulatory mechanism for selecting and funding fire-prevention measures compared to the ad hoc allocation of ratepayer funds for fire-prevention projects under Electric Tariff Rule 20.

31. There is no need for evidentiary hearings in Phase 2 of this proceeding.

32. The following order should be effective immediately.

O R D E R

IT IS ORDERED that:

1. General Orders (GOs) 95, 165, and 166 are revised to include the new and amended rules set forth in Appendix B of today's decision. The Commission's Consumer Protection and Safety Division shall revise GOs 95, 165, and 166 to incorporate the new and amended rules and publish the revised GOs on the Commission's website within 60 days from the issuance date of today's decision.

2. Each electric utility in Southern California shall (i) prepare a fire-prevention plan, and (ii) file and serve a copy of its fire-prevention plan by December 31, 2012, via a Tier 1 compliance advice letter.

3. Each electric utility in Northern California shall take the following steps to determine the risk of catastrophic power-line fires in its service territory and prepare a fire-prevention plan, if necessary:

- i. Identify its overhead power-line facilities that are located in high fire-threat areas on the fire-threat maps adopted by today's decision.
- ii. Make a good-faith effort to obtain historical records of Red Flag Warnings issued by the National Weather Service that applied to areas occupied by facilities identified in the previous Item (i).
- iii. Make a good-faith effort to obtain historical wind records of Remote Automatic Weather Stations located within 25 miles of the facilities identified in Item (i).

- iv. Use the information from Items (ii) and (iii) to estimate how often, if ever, sustained winds occur during a Red Flag Warning that exceed the maximum working stress specified in General Order 95, Section IV, for facilities identified in Item (i).
- v. Develop a fire-prevention plan if the utility determines, after completing the previously identified tasks, that it has overhead power-line facilities in a high fire-threat area where it is reasonably foreseeable that there will be sustained winds with a return interval of 100 years or less that exceed the maximum working stress for such facilities during a Red Flag Warning.
- vi. File a Tier 1 compliance advice letter by December 31, 2012 that either (a) contains a copy of the fire-prevention plan, or (b) provides notice that a fire-prevention plan is not required by today's decision.

4. The fire-prevention plans required by today's decision shall address situations where all three of the following conditions occur simultaneously: (i) sustained wind speeds exceed the structural or mechanical design standards for the affected overhead power-line facilities, (ii) the sustained winds occur during a period of high fire danger, and (iii) the affected facilities are located in a high fire-threat area. For the purpose of this Ordering Paragraph, the following definitions apply: (a) sustained winds are the average of observed wind speeds over a two-minute period; (b) structural and mechanical design standards are the maximum working stresses set forth in Section IV of General Order 95; (c) period of high fire danger is the period covered by a Red Flag Warning issued by the United States National Weather Service; and (d) high fire-threat areas are areas designated as such on the fire-threat maps adopted by today's decision.

5. The fire-prevention plans required by today's decision shall specify (i) how the electric utility will identify the occurrence of sustained winds that exceed the structural or mechanical design standards for overhead power-line facilities; and (ii) the countermeasures the utility will implement to mitigate the threat of power-line fire ignitions.

6. Any electric investor-owned utility that intends to shut off power as part of its fire-prevention plan must file an application for authority to do so. The application shall demonstrate with a cost-benefit analysis developed in accordance with the guidance provided by Decision 09-09-030 that the benefits of shutting of power in terms of a net reduction in fires outweigh the substantial costs, burdens, and risks that shutting off power would impose on customers and communities affected by the shut off. The application must also identify proposed mitigation measures to reduce or eliminate the inevitable adverse impacts caused by shutting off power, particularly the adverse impacts on people with disabilities, providers of essential services, and schools.

7. Investor-owed electric utilities shall file and serve a Tier 3 advice letter to revise their tariffs to state that the electric utility may shut off power to customers who do not allow access to their property for vegetation management activities, subject to the following conditions:

- i. The authority to shut off power is limited to situations where the electric utility cannot inspect its facilities or maintain required vegetation clearances around its power lines.
- ii. The authority to shut off power to customers who obstruct vegetation management activities does not extend to customers that are state and local governments and agencies.
- iii. The authority to shut off power is limited to one meter serving the property owner's primary residence, or if the property owner is a business entity, the entity's primary place of business. This one meter is in addition to shutting off power, if necessary for public safety, at the location of the vegetation-related fire hazard.
- iv. Prior to shutting off power, the electric utility shall follow the procedures and notice requirements applicable to discontinuance of service for non-payment, including the requirements applicable for sensitive customers, customers who are not proficient in English, and other customer groups, except as set forth in Item (v) below.

- v. For vegetation hazards that pose an immediate threat to public safety, the electric utility may shut off power to the obstructing property owner's residence or primary place of business at any time. Under these circumstances, the electric utility shall attempt to contact the property owner by daily visits to the property owner's residence or primary place of business, in addition to sending written notice, until contact is achieved and the property owner is notified why their power has been shut off and how they can restore power.

8. Phase 3 of this proceeding is established to address the matters set forth in the following three ordering paragraphs.

9. In Phase 3, the Consumer Protection and Safety Division (CPSD) shall develop and file a comprehensive plan for collecting data on power-line fires from investor-owned electric utilities (IOUs), analyzing the data, and using this information to formulate measures to reduce the number of fires ignited by power lines. To develop its plan, CPSD shall confer regularly with IOUs, communications infrastructure providers, the Mussey Grade Road Alliance, the California Department of Forestry and Fire Protection, and other interested parties that participated in this proceeding. CPSD shall file and serve its plan no later than six months after the issuance date of today's decision. The plan submitted by CPSD shall not seek to collect data from IOUs that is privileged or available from publicly accessible databases. Parties may file and serve opening and reply comments regarding CPSD's plan. The opening and reply comments shall be due two weeks and four weeks, respectively, after CPSD files its plan.

10. Phase 3 of this proceeding shall develop and adopt fire-threat maps that accurately identify areas where there is an elevated risk of catastrophic power-line fires occurring. Once adopted, these maps shall be used in conjunction with the fire-prevention measures adopted by Decision 09-08-029 and today's decision that rely on fire-threat maps for their implementation.

11. Phase 3 shall include workshops to prepare a detailed work plan for the development, adoption, implementation, and funding of fire-threat maps. The investor-owned electric utilities and communication infrastructure providers shall cooperate with the Consumer Protection and Safety Division and the California Department of Forestry and Fire Protection (Cal Fire) in the preparation of the work plan. Lawrence Livermore National Laboratory is invited to participate, too. Within six months from the issuance date of today's decision, the workshop participants shall file and serve a work plan that contains the following:

- i. A detailed proposal for the development of high resolution fire-threat maps that cover the entire state. The detailed proposal shall address the option of reviewing and adopting for regional or statewide use the Reax Map and/or the fire-threat map developed by San Diego Gas & Electric Company (SDG&E).
- ii. Recommendations for obtaining assistance from Cal Fire, Lawrence Livermore National Laboratory, and other neutral experts in the development and review of fire-threat maps, including the Reax Map and the SDG&E Map.
- iii. Estimated costs for the development, expert review, implementation, and maintenance of fire-threat maps.
- iv. Recommendations for funding the development, expert review, implementation, and maintenance of fire-threat maps.
- v. A proposed schedule and milestones for the development, adoption and implementation of fire-threat maps.
- vi. The workshop report may include alternative work plans and recommendations if the workshop participants cannot reach a consensus.

12. Parties may file and serve opening and reply comments regarding the workshop report described in the previous ordering paragraph. The opening

and reply comments shall be due two weeks and four weeks, respectively, after the workshop report is filed.

13. The Assigned Commissioner and/or the assigned Administrative Law Judge may appoint a neutral facilitator for the Phase 3 workshops.

14. Until permanent fire-threat maps are adopted in Phase 3, the electric utilities and communication infrastructure providers (CIPs) shall use the following fire-threat maps to implement the fire-prevention measures adopted by Decision (D.) 09-08-029 and today's decision that rely on a fire-threat map for their implementation:

- i. The CIPs and electric utilities other than San Diego Gas & Electric Company (SDG&E) shall use the Reax Map for Northern California and Cal Fire's Fire Resource Assessment Program Fire Threat Map (FRAP Map) in Southern California. SDG&E may use its own fire-threat map. Copies of the Reax Map and FRAP Map are contained in Appendix C of today's decision.
- ii. The fire-prevention measures adopted by D.09-08-029 and today's decision shall be implemented on an interim basis in areas that are designated as Extreme and Very High Fire Threat Zones on the FRAP Map and the SDG&E Map, and in areas that are designated as Threat Class 3 and Threat Class 4 on the Reax Map. The FRAP Map, SDG&E Map, and Reax Map shall be used to establish the approximate boundaries for the implementation of the fire-prevention measures adopted by D.09-08-029 and today's decision. The boundaries are to be broadly construed. The CIPs and electric utilities shall use their own expertise and judgment to determine if local conditions require them to adjust the boundaries of the relevant map.

15. The statutory deadline under Pub. Util. Code § 1701.5(b) for completing Phase 3 of this proceeding shall be set forth in the Assigned Commissioner's scoping memo for Phase 3.

16. Any utility with deregulated rates or rate flexibility that seeks to place a line-item charge on its customer bills to recover costs that are incurred as a result of this proceeding must not state or imply that the line-item charge is mandated or approved by the Commission.

17. The electric investor-owned utilities (IOUs) and Small Local Exchange Carriers (LECs) shall use the following procedures to request the recovery of the costs they incur to implement the regulations adopted in this proceeding:

- i. The electric IOUs and Small LECs may only seek to recover costs that are recorded in the Fire Hazard Prevention Memorandum Accounts (FHPMAs) they have established pursuant to Decision 09-08-029. Companies shall record in their FHPMAs only those costs that are not being recovered elsewhere.
- ii. Each electric IOU may file one or more applications to recover the costs recorded in its FHPMA. The number and timing of applications will be at the discretion of the electric IOU. Each electric IOU may continue to use this procedure until the first general rate case (GRC) that occurs after the close of this proceeding. At that time, the electric IOU shall close its FHPMA and thereafter use the GRC mechanism to request recovery of the costs it incurs to comply with the regulations adopted in this proceeding. The electric IOU may seek to recover the ending balance in its FHPMA, if any, by filing an application.
- iii. Each Small LEC may use its annual California High Cost Fund-A (CHCF-A) Tier 3 advice letter to request the recovery of costs recorded in its FHPMA. Each Small LEC may continue to use this procedure until the first GRC that occurs after the close of this proceeding. At that time, the Small LEC shall close its FHPMA and thereafter use the GRC mechanism to request recovery of the costs it incurs to comply with the regulations adopted in this proceeding. The Small LEC may seek to recover the ending balance in its FHPMA, if any, in its annual CHCF-A advice letter filing.
- iv. A Small LEC shall close its FHPMA when its authority to seek financial support from the CHCF-A reaches 0%. The company's authority to seek recovery of any costs remaining in its FHPMA will expire upon the closure of its FHPMA.

- v. The Small LECs that have opted out of the CHCF-A may seek to recover the costs recorded in their FHPMAs as part of their next GRC filing, if any. Their authority to seek recovery of such costs will end on January 1, 2015, at which time their FHPMAs shall be closed.

18. All entities subject to the rules, regulations, and ordering paragraphs adopted by today's decision shall implement these directives as soon as possible. Today's decision does not adopt any deadlines, except those specifically established in the rules, regulations, or ordering paragraphs themselves.

19. For the purpose of the previous ordering paragraphs, Southern California is defined as Imperial, Los Angeles, Orange, Riverside, Santa Barbara, San Bernardino, San Diego, and Ventura Counties. Northern California is defined as all other counties in California.

20. This proceeding remains open for Phase 3.

This order is effective today.

Appendix A: Proposed Regulations

Appendix A shows the proposed revisions and additions to General Orders 95, 165, and 166 with strikeout and underline.

Consensus Proposal 1 re: GO 95, Rule 18A**Proposed Revisions to Current Rule 18A Shown with Strikeout and Underline****18 Reporting and Resolution of Safety Hazards Discovered by Utilities****A. Resolution of Safety Hazards And General Order 95 Nonconformances
~~Violations~~**

Each company (including utilities and CIPs) is responsible for taking appropriate corrective action to remedy safety hazards and GO 95 nonconformances ~~violations~~ posed by their facility. Upon completion of the corrective action, the company records shall show the nature of the work, the date and identity of persons performing the work. Prior to the work being completed, the company shall document the current status of the safety hazard, including whether the safety hazard is located in an Extreme and Very High Fire Threat Zone in Southern California, and shall include a scheduled date of corrective action. These records shall be preserved by the company for at least five years, and shall be of sufficient detail to allow Commission staff during an audit, if any, to determine that the safety hazard has been remedied. The records shall be made available to Commission staff immediately upon request. Additionally, for any work completed after the initial scheduled date of corrective action, the company shall document the reason or reasons that the work was not completed by the original scheduled date of corrective action.

For purposes of this rule, “safety hazard” means a condition that poses a significant threat to life or property, including, but not limited to, the ignition of a wildland or structure fire. “Extreme and Very High Fire Threat Zones” are defined in the Commission decision issued in Phase I of R.08-11-005. “Southern California” is defined as the following: Santa Barbara, Ventura, San Bernardino, Riverside, Los Angeles, Orange, and San Diego Counties.

Companies that have existing General Order 165 auditable inspection and maintenance programs that are consistent with the purpose of Rule 18 shall continue to follow their General Order 165 programs. All companies shall establish an auditable maintenance program for their facilities and lines. Further, all companies must include a timeline for corrective actions to be taken following the identification of a safety hazard or nonconformance ~~violation~~ of General Orders 95 or 128 on the companies’ facilities.

The auditable maintenance program should be developed and implemented based on the following principles.

(1) Priorities shall be assigned based on the specifics of the safety hazard or nonconformance violation as related to direct impact and the probability for impact on safety or reliability using the following factors:

- Type of facility or equipment;
- Location;
- Accessibility;
- Climate;
- Direct or potential impact on operations, customers, electrical company workers, communications workers, and the general public;
- Whether the safety hazard or nonconformance violation is located in an Extreme or Very High Fire Threat zone.

(2) There will be three priority levels, as follows:

(a) Level 1:

- Immediate safety and/or reliability risk with high probability for significant impact.
- Take action immediately, either by fully repairing the condition, or by temporarily repairing and reclassifying the condition to a lower priority.

(b) Level 2:

- Variable (non-immediate high to low) safety and/or reliability risk.
- Take action to correct within specified time period (fully repair, or by temporarily repairing and reclassifying the condition to a lower priority).
- Time period for correction to be determined at the point of identification by a qualified company representative:
Overhead: 0-59 months
- Where communications company actions result in electric utility GO nonconformances violations, the electric utility's remedial action will be to transmit a single documented notice of identified nonconformances violations to the communications company for compliance.

(c) Level 3:

- Acceptable safety and/or reliability risk.
- Take action (re-inspect, re-evaluate, or repair) at or before the next detailed inspection.

(d) Exceptions (Levels 2 and 3 only) – Correction times may be extended under reasonable circumstances, such as:

- Third party refusal
- Customer issue
- No access
- Permits required
- System emergencies (e.g. fires, severe weather conditions)

(3) Upon completion of the corrective action, the company's records shall show the nature of the work, the date, and the identity of persons performing the work. These records should be preserved by the company for at least five years.

(4) The company shall prioritize implementing this maintenance plan within the Extreme and Very High Fire Threat Zones of Southern California. With the exception of a safety hazard or nonconformance violation requiring immediate correction, a company must correct a nonconformance violation or safety hazard within 30 days of discovering or being notified of a nonconformance violation or safety hazard, if the nonconformance violation or safety hazard fails to fully comply with ~~violates~~ a clearance requirement listed in columns E, F, or G of Table 1 in this General Order, or ~~violates~~ a pole overloading requirement in Rule 44.3 of this General Order, and is located in an Extreme and Very High Fire Threat Zone in Southern California. The company must correct a nonconformance violation or safety hazard within 30 days if the utility is notified that the nonconformance violation must be corrected to alleviate a significant safety risk to any utility's employees.

Consensus Proposal 2 re: GO 95, Rule 18B**Proposed Revisions to Current Rule 18B Shown with Strikeout and Underline****B. Notification of Safety Hazards**

If a company, while performing inspections of ~~inspecting~~ its facilities, discovers a safety hazard(s) on or near a communications facility, or ~~transmission or distribution electric~~ facility involving another company, the inspecting company shall notify the other company and/or facility owner of such safety hazard(s) no later than 10 business days after the discovery. ~~The inspecting company shall also provide a copy of the notice to the pole owner(s). The inspecting company shall include in such notice whether the safety hazard which requires corrective action is located in a designated Extreme and Very High Fire Threat Zone in Southern California.~~ To the extent the inspecting company cannot determine the facility owner/operator ~~of other company~~, it shall contact the pole owner(s), who shall be responsible for promptly notifying the company owning/operating the facility with the safety hazard(s), normally not to exceed five business days after being notified of the safety hazard. The notification shall be ~~in writing~~ documented and such documentation must be preserved by all parties for at least five years. ~~It is the responsibility of each pole owner to know the identity of each entity using or maintaining equipment on its pole.~~

Note: Each pole owner must be able to determine all other pole owners on poles it owns. Each pole owner must be able to determine all authorized entities that attach equipment on its portion of a pole.

Consensus Proposal 3 re: GO 95, Rule 35**Proposed Revisions to Current Rule 35 Shown with Strikeout and Underline**

Where overhead conductors traverse trees and vegetation, safety and reliability of service demand that certain vegetation management activities be performed in order to establish necessary and reasonable clearances. The minimum clearances set forth in Table 1, Cases 13 and 14, measured between line conductors and vegetation under normal conditions shall be maintained. (Also see Appendix E for tree trimming guidelines.) These requirements apply to all overhead electrical supply and communication facilities that are covered by this Order, including facilities on lands owned and maintained by California state and local agencies.

When a ~~utility supply or communication company~~ has actual knowledge, obtained either through normal operating practices or notification to the ~~utility company~~, ~~of that~~ dead, rotten ~~or and~~ diseased trees or ~~dead, rotten or and diseased~~ portions ~~there of~~ otherwise healthy trees that overhang or lean toward and may fall into a span ~~of nearby supply or communication lines~~, said trees or portions thereof should be removed.

Communication and electric supply circuits, energized at 750 volts or less, including their service drops, should be kept clear of vegetation in new construction and when circuits are reconstructed or repaired, whenever practicable. When a ~~utility supply or communication company~~ has actual knowledge, obtained either through normal operating practices or notification to the ~~utility company~~, that ~~any its~~ circuit energized at 750 volts or less shows strain or evidences abrasion from vegetation contact, the condition shall be corrected by reducing conductor tension, rearranging or replacing the conductor, pruning the vegetation, or placing mechanical protection on the conductor(s). For the purpose of this rule, abrasion is defined as damage to the insulation resulting from the friction between the vegetation and conductor. Scuffing or polishing of the insulation ~~or~~ covering is not considered abrasion. Strain is present when ~~deflection causes additional tension beyond the allowable tension of the span~~ vegetation contact significantly compromises the structural integrity of supply or communication facilities. Contact between vegetation and conductors, in and of itself, does not constitute a violation of the rule.

Consensus Proposal 4 re: GO 95, Rule 37, Table 1, Case 14 and Footnotes (fff) – (jjj)

Proposed Revisions to Current Rule Shown with Strikeout and Underline

Table 1: Basic Minimum Allowable Vertical Clearance of Wires above Railroads, Thoroughfares, Ground or Water Surfaces; Also Clearances from Poles, Buildings, Structures or Other Objects (nn) (Letter References Denote Modifications of Minimum Clearances as Referred to in Notes Following This Table)

		Wire of Conductor Concerned						
Case No.	Nature of Clearance	A Span Wires (Other than Trolley Span Wires) Overhead Guys and Messengers	B Communications Conductors (including Open Wire, Cables and Service Drops) Supply Service Drops of 0-750 Volts	C Trolley Contact Feeder and Span Wires, 0-5,000 Volts	D Supply Conductors of 0-750 Volts and Supply Cable Treated as in Rule 57.8	E Supply Conductors and Supply Cables, 750-22,500 Volts	F Supply Conductors And Supply Cables, 22.5-300 kV	G Supply Conductors and Supply Cables, 300-550 kV(mm)
14	Radial clearance of bare line conductors from vegetation in Extreme and Very High Fire Threat Zones in Southern California (aaa) (ddd) (hhh)(jjj)			18 inches (bbb)		48 inches (bbb) (iii)	48 inches (fff)	120 inches (ggg)

(fff) Clearances in this case shall be increased for conductors operating above ~~88~~ 72 kV, to the following:
 1. Conductors operating between ~~88~~ 72 kV and a 110 kV shall maintain a ~~60~~ 72 inch clearance.
 2. Conductors operating above 110 kV shall maintain a 120 inch clearance.

(ggg) Shall be increased by 0.40 inch per kV in excess of 500 kV.

(hhh) Extreme and Very High Fire Threat Zones are defined by California Department of Forestry and Fire Protection’s Fire and Resource Assessment Program (FRAP) Fire Threat Map. The FRAP Fire Threat Map is to be used to establish approximate boundaries for purposes of this rule. The boundaries of the map are to be broadly construed, and utilities should use their own expertise and judgment to determine if local conditions require them to adjust the boundaries of the map. Southern California shall be defined as the following: Santa Barbara, Ventura, San Bernardino, Riverside, Los Angeles, Orange, and San Diego Counties.

(iii) May be reduced to 18 inches for conductors operating less than 2.4 kV.

(jjj) Clearances in this case shall not apply to orchards of fruit, nut or citrus trees that are plowed or cultivated. In those

areas Case 13 clearances shall apply.

Consensus Proposal 5 re: GO 95, Rules 23, 44.1, 44.2, and 44.3

Proposed Revisions to Current Rules Shown with Strikeout and Underline

Rule 23.0

Reconstruction means that work which in any way changes the identity of the pole, tower or structure on which it is performed. A change in grade of construction or class of circuit is considered reconstruction. For exceptions see Rule 12.1.

44.1 Installation and Reconstruction

Lines and elements of lines upon installation or reconstruction, shall provide as a minimum the safety factors specified in Table 4 for vertical loads and loads transverse to lines and for loads longitudinal to lines except where longitudinal loads are balanced or where there are changes in grade of construction (see Rules 47.3, 47.4 and 47.5). The design shall consider the structural loading and mechanical strength requirements of all supply and communication facilities planned to occupy the structure. For purposes of this rule, the term “planned” applies to the facilities intended to occupy the structure that are actually known to the constructing utility company at the time of design.

44.2 Additional Construction

Any utility supply or communication company planning the addition of facilities that materially increase the vertical, transverse or longitudinal loading on a structure shall perform a loading calculation to ensure that the addition of the facilities will not reduce the safety factors below the values specified by Rule 44.3 Section IV. Such utility company shall maintain these pole loading calculations for five years and shall provide such information to authorized joint use pole occupants and the Commission upon request.

All other utilities or companies on the subject pole shall cooperate with the utility company performing the load calculations described above including, but not limited to, providing intrusive pole loading test data results and other data necessary to perform those such calculations.

~~Note: Nothing contained in this rule shall be construed as allowing the safety factor of a facility to be reduced below the required values specified in Rules 44.1 and 44.3.~~

44.3 - Replacement

Lines or parts thereof shall be replaced or reinforced before safety factors have

been reduced (due to deterioration and/or installation of additional facilities) in Grades "A" and "B" construction to less than two-thirds of the construction safety factors specified in Rule 44.1 and in Grades "C" and "F" construction to less than one-half of the construction safety factors specified in Rule 44.1. Poles in Grade "F" construction shall also conform to the requirements of Rule 81.3-A. In no case shall the application of this be held to permit the use of structures or any member of any structure with a safety factor less than one.

Consensus Proposal 6 re: GO 165, Sections I – IV

Proposed Revisions to GO 165 Shown with Strikeout and Underline

Appendix A

Public Utilities Commission of the State of California Inspection ~~Cycles~~ Requirements for Electric Distribution and Transmission Facilities

Adopted March 31, 1997

Effective March 1, 1997

(D.97-03-070 in I.95-02-015 and R.96-11-004)

Amended August 20, 2009

(D.09-08-029 in R.08-11-005)

I. Purpose

The purpose of this General Order is to establish ~~minimum~~ requirements for electric distribution and transmission facilities (~~excluding those facilities contained in a substation~~) regarding inspections (~~including maximum allowable inspection cycle lengths~~), ~~condition rating, scheduling and performance of corrective action, record keeping, and reporting~~, in order to ensure safe and high-quality electrical service, ~~and to implement the provisions of Section 364 of Assembly Bill 1890, Chapter 854, Statutes of 1996.~~

II. Applicability

~~As of March 31, 1997, t~~This General Order applies to ~~Pacific Gas and Electric Company, Pacificorp, San Diego Gas and Electric Company, Sierra Pacific Power Company, and Southern California Edison Company~~ all electric distribution and transmission facilities (~~excluding those facilities contained in a substation~~) that come within the jurisdiction of this Commission, located outside of buildings, including electric distribution and transmission facilities that belong to non-electric utilities.

The requirements of this order are in addition to the requirements imposed upon utilities under General Orders 95 and 128 to maintain a safe and reliable electric system. Nothing in this General Order relieves any utility from any requirements or obligations that it has under General Orders 95 and 128.

This General Order does not apply to facilities of communication infrastructure providers.

III. Definitions Distribution Facilities

A Definitions

For the purpose of this General Order,

A1 "Urban" shall be defined as those areas with a population of more than 1,000 persons per square mile as determined by the United States Bureau of the Census.

B2 "Rural" shall be defined as those areas with a population of less than 1,000 persons per square mile as determined by the United States Bureau of the Census.

C3 "Patrol" shall be defined as a simple visual inspection, of applicable utility equipment and structures, that is designed to identify obvious structural problems and hazards. Patrols may be carried out in the course of other company business.

D4 "Detailed" inspection shall be defined as one where individual pieces of equipment and structures are carefully examined, visually and through use of routine diagnostic test, as appropriate, and (if practical and if useful information can be so gathered) opened, and the condition of each rated and recorded.

E5 "Intrusive" inspection is defined as one involving movement of soil, taking samples for analysis, and/or using more sophisticated diagnostic tools beyond visual inspections or instrument reading.

F6 "Corrective Action" shall be defined as maintenance, repair, or replacement of utility equipment and structures so that they function properly and safely.

IV. B Standards for Inspection, ~~Record-keeping, and Reporting~~

Each utility subject to this General Order shall conduct inspections of its distribution facilities, as necessary, to assure reliable, high-quality, and safe operation, but in no case may the period between inspections (measured in years) exceed the time specified in ~~the attached~~ Table 1.

~~Each utility subject to this General Order shall submit to the Commission by no later than July 1, 1997, compliance plans for the inspections and record-keeping required by this order. These compliance plans will include the proposed forms and formats for annual reports and source records, as well as the utility's plans for the types of inspections and equipment to be inspected during the coming year. For detailed and intrusive inspections, schedules should be detailed enough (in terms of the months of inspection and the circuit, area, or equipment to be inspected) to allow staff to confirm that schedule inspections are proceeding as planned. For patrol inspections, companies should explain how all required facilities will be covered during the year. Energy Division or any successor staff divisions may prescribe changes relating to data, definitions, reporting and record-keeping formats and forms when and as necessary.~~

~~Each utility subject to this General Order shall submit an annual report detailing its compliance with this General Order under penalty of perjury. The first report required under this section shall be filed with the Commission by no later than July 1, 1998. Each utility shall file subsequent annual reports for every following year by no later than July 1. The report shall identify the number of facilities, by type which have been inspected during the previous period. It shall identify those facilities which were scheduled for inspection but which were not inspected according to schedule and shall explain why the inspections were not conducted, and a date certain by which the required inspection will occur. The report shall also present the total and percentage breakdown of equipment rated at each condition rating level, including that equipment determined to be in need of corrective action. Where corrective action was scheduled during the reporting period, the report will present the total and percentage of equipment which was and was not corrected during the reporting period. For the latter, an explanation will be provided, including a date certain by which required corrective action will occur. The report will also present totals and the percentage of equipment in need of corrective action, but with a scheduled date beyond the reporting period, classified by the amount of time remaining before the scheduled action. All of the above information shall be presented for each type of facility identified in the attached table and shall be aggregated by district.~~

C Record Keeping

The ~~company~~utility shall maintain records of inspection activities which shall be made available to parties or pursuant to Commission rules upon 30 days notice. Commission staff shall be permitted to inspect such records consistent with Public Utilities Code Section 314 (a).

For all inspections, ~~within a reasonable period, company~~ records shall specify the circuit, area, facility or equipment inspected, ~~the name of~~ the inspector, the date of the inspection, and any problems (or items requiring corrective action) identified during each inspection, as well as the scheduled date of corrective action. ~~For detailed and intrusive inspections, companies shall also rate the condition of inspected equipment. Upon completion of corrective action, company records will show the nature of the work, the date, and the identity of persons performing the work.~~

D Reporting

By July 1st each utility subject to this General Order shall submit an annual report for the previous year under penalty of perjury.

The report shall list four categorical types of inspections: Patrols, Overhead Detailed, Underground Detailed and Wood Pole Intrusive. The report shall denote the total units of work by inspection type for the reporting period and the number of outstanding (not completed) inspections within the same reporting period for each of the four categories.

Sample Report Template:

<u>Type of Inspections</u> <u>(1)</u>	<u>Due (2)</u>	<u>Outstanding (3)</u>
<u>Patrols</u>	<u>xxx</u>	<u>xxx</u>
<u>OH Detailed</u>	<u>xxx</u>	<u>xxx</u>
<u>UG Detailed</u>	<u>xxx</u>	<u>xxx</u>
<u>Wood Pole Intrusive</u>	<u>xxx</u>	<u>xxx</u>

Notes:

- 1) Each utility will define their reporting unit basis (e.g., circuit, grid, facility / equipment).
- 2) Total inspections due in the reporting period. (Does not include outstanding inspections from prior years.)
- 3) Total inspections required that were not completed in the reporting period. (Does not include outstanding inspections from prior years.)

E Changes to Requirements Herein

If, in a particular case, exemption from or modification of any of the requirements herein is desired, the Commission will consider a request for such exemption or modification when accompanied by a full statement of conditions existing and the reasons why such exemption or modification is asked and is believed to be justifiable. It is to be understood that, unless otherwise ordered, any exemption or modification so granted shall be limited to the particular case covered by the request.

IV. Transmission Facilities

Each utility shall prepare and follow procedures for conducting inspections and maintenance activities for transmission lines.

Each utility shall maintain records of inspection and maintenance activities.

Commission staff shall be permitted to inspect records and procedures consistent with Public Utilities Code Section 314 (a).

/s/ Wesley M. Franklin

Paul Clanon

~~Wesley M. Franklin~~

Paul Clanon

Executive Director

Appendix A

Table 1

~~Electric Company System~~ Distribution Inspection Cycles (Maximum Intervals in Years)

	Patrol		Detailed		Intrusive	
	Urban	Rural	Urban	Rural	Urban	Rural
Transformers						
Overhead	1	2 ¹	5	5	---	---
Underground	1	2	3	3	---	---
Padmounted	1	2	5	5	---	---
Switching/Protective Devices						
Overhead	1	2 ¹	5	5	---	---
Underground	1	2	3	3	---	---
Padmounted	1	2	5	5	---	---
Regulators/Capacitors						
Overhead	1	2 ¹	5	5	---	---

Underground	1	2	3	3	---	---
Padmounted	1	2	5	5	---	---
Overhead Conductor and Cables	1	2 ¹	5	5	---	---
Streetlighting	1	2	x	x	---	---
Wood Poles under 15 years	1	2	x	x	---	---
Wood Poles over 15 years which have not been subject to intrusive inspection	1	2	x	x	10	10
Wood poles which passed intrusive inspection	---	---	---	---	20	20

(1) Patrol inspections in rural areas shall be increased to once per year in Extreme and Very High Fire Threat Zones in the following counties: Santa Barbara, Ventura, Los Angeles, San Bernardino, Orange, Riverside, and San Diego. Extreme and Very High Fire Threat Zones are defined by California Department of Forestry and Fire Protection’s Fire and Resource Assessment Program (FRAP) Fire Threat Map. The FRAP Fire Threat Map is to be used to establish approximate boundaries and Utilities should use their own expertise and judgment to determine if local conditions require them to adjust the boundaries of the map.

Note: This General Order does not apply to cathodic protection systems associated with natural gas facilities.

Contested Proposal 1A re: GO 95, Rule 11 (CPSD)**CPSD's Proposed Revisions to Rule 11 Shown with Strikeout and Underline****11 Purpose of Rules**

The purpose of these rules is to formulate, for the State of California, ~~uniform~~ requirements for overhead ~~electrical~~ line design, construction, and maintenance, the application of which will ~~e~~insure adequate service and secure safety to persons engaged in the construction, maintenance, operation or use of overhead ~~electrical~~ lines and to the public in general.

Contested Proposal 1B re: GO 95, Rule 11 (CIP Coalition)**CIP Coalitions' Proposed Revisions to Rule 11 Shown with Strikeout and Underline****11 Purpose of Rules**

The purpose of these rules is to formulate, for the State of California, ~~uniform~~ requirements for overhead electrical line design, construction, and maintenance, the application of which will ~~e~~insure adequate service and secure safety to persons engaged in the construction, maintenance, operation or use of overhead electrical lines and to the public in general.

Contested Proposal 2 re: GO 95, Rule 12 (CPSD)**CPSD's Proposed Revisions to Rule 12 Shown with Strikeout and Underline****12 Applicability of Rules**

These rules apply to all overhead electrical supply and communication facilities that come within the jurisdiction of this Commission, located outside of buildings, including facilities that belong to non-electric utilities and publicly-owned utility electric supply facilities, as follows:

- 12.1 Construction and Reconstruction of Lines
- 12.2 Maintenance of Lines
- 12.3 Lines Constructed Prior to This Order
- 12.4 Reconstruction or Alteration
- 12.5 Emergency Installation

12.6 Third Party Nonconformance

Contested Proposal 3A re: GO 95, Rule 18 (CIP Coalition)

CIP Coalition's Proposed Revisions to Rule 18 Shown with Strikeout and Underline

The CIP Coalition's proposed revisions to Rule 18 incorporate the consensus revisions to Rule 18 that replace the term "violation" with the term "nonconformance."

18 Reporting and Resolution of Safety Hazards Discovered by Utilities

For purposes of this rule, "Safety Hazard" means a condition that poses a significant threat to human life or property.

"Extreme and Very High Fire Threat Zones" are defined in the Commission Decision 09-08-029. "Southern California" is defined as the following: Santa Barbara, Ventura, San Bernardino, Riverside, Los Angeles, Orange, and San Diego.

Part A: Resolution of Safety Hazards And General Order 95
Violations/Nonconformances

(1)(a) Each company (including utilities and CIPs) is responsible for taking appropriate corrective action to remedy Safety Hazards and GO 95 violations/nonconformances posed by ~~their~~ its facilities.

(b) Upon completion of the corrective action, the company's records shall show, with sufficient detail, the nature of the work, the date, and the identity of persons performing the work. ~~Prior to the work being completed, the company shall document the current status of the safety hazard, including whether the safety hazard is located in an Extreme and Very High Fire Threat Zone in Southern California, and shall include a scheduled date of corrective action.~~ These records shall be preserved by the company for at least five years and shall be ~~of sufficient detail to allow Commission staff during an audit, if any, to determine that the safety hazard has been remedied.~~ The records made available to Commission staff upon 30 days notice ~~immediately upon request.~~ ~~Additionally, for any work completed after the initial scheduled date of corrective action, the company shall document the reason or reasons that the work was not completed by the original scheduled date of corrective action.~~

For purposes of this rule, "safety hazard" means a condition that poses a significant threat to life or property, including, but not limited to, the ignition of a wildland or structure fire. "Extreme and Very High Fire

~~Threat Zones” are defined in the Commission decision issued in Phase I of R.08-11-005. “Southern California” is defined as the following: Santa Barbara, Ventura, San Bernardino, Riverside, Los Angeles, Orange, and San Diego Counties.~~

~~Companies that have existing General Order 165 auditable inspection and maintenance programs that are consistent with the purpose of Rule 18 shall continue to follow their General Order 165 programs. All companies shall establish an auditable maintenance program for their facilities and lines. Further, all companies must include a timeline for corrective actions to be taken following the identification of a safety hazard or violation of General Orders 95 or 128 on the companies’ facilities.~~

~~The auditable maintenance program should be developed and implemented based on the following principles:~~

~~(2)(a) All companies shall establish an auditable maintenance program for their facilities and lines. All companies must include a timeline for corrective actions to be taken following the identification of a Safety Hazard or violations/nonconformances with General Order 95 on the company’s facilities. The auditable maintenance program shall prioritize corrective actions consistent with the priority levels set forth below and based on (1) Priorities shall be assigned based on the specifics of the safety hazard or violation as related to direct impact and the probability for impact on safety or reliability using the following factors, as appropriate:~~

- ~~• Safety and reliability as specified in the priority levels below;~~
- ~~• Type of facility or equipment;~~
- ~~• Location, including whether the Safety Hazard or violation/nonconformance is located in an Extreme or Very High Fire Threat zone in Southern California;~~
- ~~• Accessibility;~~
- ~~• Climate;~~
- ~~• Direct or potential impact on operations, customers, electrical company workers, communications workers, and the general public;~~
- ~~• Whether the safety hazard or violation is located in an Extreme or Very High Fire Threat Zone~~

~~(2) There willshall be ~~three~~ 3 priority levels, as follows.~~

~~(a)–(i) Level 1:~~

- Immediate safety and/or reliability risk with high probability for significant impact.
- Take action immediately, either by fully repairing the condition, or by temporarily repairing and reclassifying the condition to a lower priority.

~~(b)~~ (ii) Level 2:

- Variable (non-immediate high to low) safety and/or reliability risk.
- Take action to correct within specified time period (fully repair, or by temporarily repairing and reclassifying the condition to a lower priority).
- Time period for correction to be determined at the ~~point~~time of identification by a qualified company representative, but not to exceed 59 months.

- ~~Overhead: 0-59 months~~

~~Where communications company actions result in electric utility GO violations, the electric utility's remedial action will be to transmit a single documented notice of identified violations to the communications company for compliance.~~

~~(c)~~ (iii) Level 3:

- Acceptable safety and/or reliability risk.
- Take action (re-inspect, re-evaluate, or repair) ~~at or before the next~~ detailed inspection as appropriate.

~~(b)~~ ~~(d) Exceptions (Levels 2 and 3 only)~~—Correction times may be extended under reasonable circumstances, such as:

- Third party refusal
- Customer issue
- No access
- Permits required
- System emergencies (e.g. fires, severe weather conditions)

(3) Companies that have existing General Order 165 auditable inspection and maintenance programs that are consistent with the purpose of Rule 18A shall continue to follow their General Order 165 programs.

- ~~(3) — Upon completion of the corrective action, the company’s records shall show the nature of the work, the date, and the identity of persons performing the work. These records should be preserved by the company for at least five years.~~
- ~~(4) — The company shall prioritize implementing this maintenance plan within the Extreme and Very High Fire Threat Zones of Southern California. With the exception of a safety hazard or violation requiring immediate correction, a company must correct a violation or safety hazard within 30 days of discovering or being notified of a violation or safety hazard, if the violation or safety hazard violates a clearance requirement listed in columns E, F, or G of Table 1 in this General Order, or violates a pole overloading requirement in Rule 44.3 of this General Order, and is located in an Extreme and Very High Fire Threat Zone in Southern California. The company must correct a violation or safety hazard within 30 days if the utility is notified that the violation must be corrected to alleviate a significant safety risk to any utility’s employees.~~

Contested Proposal 3B re: GO 95, Rule 18 (SDG&E)
SDG&E's Proposed Revisions to Rule 18A Shown with
Strikeout and Underline

SDG&E's proposed revisions to Rule 18 incorporate the consensus revisions to Rule 18 that replace the term "violation" with the term "nonconformance."

18 Reporting and Resolution of Safety Hazards Discovered by Utilities

For purposes of this rule, "Safety Hazard" means a condition that poses a significant threat to human life or property.

"Extreme and Very High Fire Threat Zones" are defined in the Commission Decision 09-08-029. "Southern California" is defined as the following: Santa Barbara, Ventura, San Bernardino, Riverside, Los Angeles, Orange, and San Diego Counties.

Part A: Resolution of Safety Hazards And General Order 95 ~~Violations/~~ Nonconformances

(1)(a) Each company (including utilities and CIPs) is responsible for taking appropriate corrective action to remedy Safety Hazards and GO 95 ~~violations/nonconformances~~ posed by ~~their~~ its facilities.

(b) Upon completion of the corrective action, the company's records shall show ~~the date and with sufficient detail,~~ the nature of the work, the date, and ~~the identity of persons performing the work. Prior to the work being completed, the company shall document the current status of the safety hazard, including whether the safety hazard is located in an Extreme and Very High Fire Threat Zone in Southern California, and shall include a scheduled date of corrective action.~~ These records shall be preserved by the company for at least five years, ~~and shall be of sufficient detail to allow Commission staff during an audit, in any, to determine that the safety hazard has been remedied made available to Commission staff upon 30 days notice. The records shall be made available to Commission staff immediately upon request. Additinally, for any work completed after initial scheduled date of corrective action, the company shall document the reason or reasons that the work was not completed by the original scheduled date of correction action.~~

For purposes of this rule, "safety hazard" means a condition that poses a significant threat to life or property, including, but not limited to, the

~~ignition of a wildland or structure fire. "Extreme and Very High Fire Threat Zones" are defined in the Commission decision issued in Phase I of R.08-11-005. "Southern California" is defined as the following: Santa Barbara, Ventura, San Bernardino, Riverside, Los Angeles, Orange, and San Diego Counties.~~

~~Companies that have existing General Order 165 auditable inspection and maintenance programs that are consistent with the purpose of Rule 18 shall continue to follow their General Order 165 programs.~~

(2)(a) All companies shall establish an auditable maintenance program for their facilities and lines. ~~Further,~~ All companies must include a timeline for corrective actions to be taken following the identification of a Safety Hazard or violations/nonconformances of with General Orders 95 or 128 on the ~~companies'~~ company's facilities. The auditable maintenance program ~~should be developed and implemented~~ shall prioritize corrective actions consistent with the priority levels set forth below and based on the following ~~principles~~ factors, as appropriate:

~~(1) — Priorities shall be assigned based on the specifics of the safety hazard or violation as related to direct impact and the probability for impact on safety or reliability using the following factors:~~

- Safety and reliability as specified in the priority levels below;
- Type of facility or equipment;
- Location; including whether the Safety Hazard or nonconformance is located in an Extreme or Very High Fire Threat Zone in Southern California;
- Accessibility;
- Climate;
- Direct or potential impact on operations, customers, electrical company workers, communications workers, and the general public;
- ~~Whether the safety hazard or violation is located in an Extreme or Very High Fire Threat zone.~~

~~(2) — There will~~ shall be ~~three~~ 3 priority levels, ~~as follows:~~

(ai) Level 1:

- Immediate safety and/or reliability risk with high probability for significant impact.
- Take action immediately, either by fully repairing the condition, or by

temporarily repairing and reclassifying the condition to a lower priority.

(bii) Level 2:

- Variable (non-immediate high to low) safety and/or reliability risk.
- Take action to correct within specified time period (fully repair, or by temporarily repairing and reclassifying the condition to a lower priority).

• ~~Time period for correction to be determined at the pointtime of identification by a qualified company representative; but not to exceed;~~
~~(1) 12 months for violations/nonconformances that compromise worker safety,~~
~~(2) 12 months for violations/nonconformances that create a fire risk and are located in an Extreme or Very High Fire Threat Zone in Southern California, and~~
~~(3) 59 months for all other Level 2 violations/nonconformances.~~

~~• Overhead: 0-59 months~~

- ~~• Where communications company actions result in electric utility GO violations, the electric utility's remedial action will be to transmit a single documented notice of identified violations to the communications company for compliance.;~~

(eiii) Level 3:

- Acceptable safety and/or reliability risk.
- Take action (re-inspect, re-evaluate, or repair) ~~at or before the next detailed inspection as appropriate.~~

~~(d) Exceptions (Levels 2 and 3 only) - b~~ Correction times may be extended under reasonable circumstances, such as:

- Third party refusal
- Customer issue
- No access
- Permits required
- System emergencies (e.g. fires, severe weather conditions)

~~(3) Upon completion of the corrective action, the company's records shall show the nature of the work, the date, and the identity of persons performing the work. These records should be preserved by the company for at least five years.~~

~~(3) Companies that have existing General Order 165 auditable inspection and~~

maintenance programs that are consistent with the purpose of Rule 18A shall continue to follow their General Order 165 programs.

~~(4) — The company shall prioritize implementing this maintenance plan within the Extreme and Very High Fire Threat Zones of Southern California. With the exception of a safety hazard or violation requiring immediate correction, a company must correct a violation or safety hazard within 30 days of discovering or being notified of a violation or safety hazard, if the violation or safety hazard violates a clearance requirement listed in columns E, F, or G of Table 1 in this General Order, or violates a pole overloading requirement in Rule 44.3 of this General Order, and is located in an Extreme and Very High Fire Threat Zone in Southern California. The company must correct a violation or safety hazard within 30 days if the utility is notified that the violation must be corrected to alleviate a significant safety risk to any utility's employees.~~

Contested Proposal 4 re: GO 95, Rule 18C (MGRA)**MGRA's Proposed New Rule 18C Shown with Underline****18C - Contingency Planning**

Electric utilities shall have in place contingency plans for predicting and identifying hazard conditions that exceed wind loadings of Rule 43 in areas designated as having high fire risk during periods of high fire danger. These plans shall include measures to prevent ignitions of wildland fires by equipment that meets GO 95 wind loading and vegetation management requirements.

Contested Proposal 5 re: GO 95, Rule 31.1 (Joint Utilities)**Joint Utilities' Proposed Revisions to Rule 31.1 Shown with Underline****31.1 Design, Construction and Maintenance**

Electrical supply and communication systems shall be designed, constructed, and maintained for their intended use, regard being given to the conditions under which they are to be operated, to enable the furnishing of safe, proper, and adequate service.

For all particulars not specified in these rules, design, construction, and maintenance should be done in accordance with accepted good practice for the given local conditions known at the time by those responsible for the design, construction, or maintenance of [the] communication or supply lines and equipment.

For all particulars specified in this Order, a supply or communications company is in compliance with this rule if it designs, constructs and maintains a facility in accordance with such particulars. For all particulars not specified in this Order, a supply or communications company is in compliance with this rule if it designs, constructs and maintains a facility in accordance with accepted good practice.

All work performed on public streets and highways shall be done in such a manner that the operations of other utilities and the convenience of the public will be interfered with as little as possible and no conditions unusually dangerous to workmen, pedestrians or others shall be established at any time.

Note: The standard of accepted good practice should be applied on a case by case basis. For example, the application of "accepted good practice" may be aided by reference to any of the practices, methods, and acts engaged in or approved by a significant portion of the relevant industry, or which may be expected to accomplish the desired result with regard to safety and reliability at a reasonable cost.

Contested Proposal 6A re: GO 95, Rule 31.2 (CIP-1)
Proposed Revisions to Rule 31.2 Shown with Underline

31.2 Inspection of Lines

Lines shall be inspected frequently and thoroughly for the purpose of insuring that they are in good condition so as to conform with these rules. Lines temporarily out of service shall be inspected and maintained in such condition as not to create a hazard.

A. Communications Lines In Specified Fire Areas:

Communication lines shall be inspected in Specified Fire Areas, as follows:

(1) Patrols shall be performed not less often than once every three (3) years on overhead communications lines installed on joint use poles with electric distribution or transmission facilities, as well as on communication lines one span away.

Patrol means a simple visual inspection of communications equipment and structures that is designed to identify obvious structural problems and hazards. Patrols may be carried out in the course of other company business.

(2) Detail Inspections shall be performed not less often than once every nine (9) years on overhead communications lines installed on joint use poles with electric distribution or transmission facilities, as well as on communication lines one span away.

Detail Inspection means a careful visual inspection of communications equipment and structures using inspection tools such as binoculars and measuring devices, as appropriate. Detail Inspections may be carried out in the course of other company business.

For all patrols and details, records shall specify the facility or equipment inspected; the name of the inspector; the date of the inspection; and any problems (or items requiring corrective action) identified during each inspection, as well as the scheduled date of corrective action. Records of Patrols and Details shall be made available to Commission staff upon 30 days notice.

Note: Specified Fire Areas shall be defined as [in Southern California - FRAP Maps; in Central and Northern California - to be worked out in workshops].

Electric Lines: shall be inspected in compliance with the minimum

intervals set forth in General Order 165.

Contested Proposal 6B re: GO 95, Rule 31.2 (CIP-2)**Proposed Revisions to Rule 31.2 Shown with Strikeout and Underline****31.2 Inspection of Lines**

A. Lines shall be inspected frequently and thoroughly for the purpose of ~~e~~nsuring that they are in good condition so as to conform with these rules. Lines temporarily out of service shall be inspected and maintained in such condition as not to create a hazard.

For the purpose of the remaining subsections of this Rule:

“Patrol” means a simple visual inspection designed to identify obvious structural problems and hazards. Patrols may be carried out in the course of other company business.

“Specified Fire Areas” shall be defined as: for Southern California, the Extreme and Very High Threat Zones on the California Department of Forestry and Fire Protection’s Fire and Resource Assessment Program’s map in Santa Barbara, Ventura, Los Angeles, Orange, San Diego, Riverside, and San Bernardino; for Central and Northern California, [to be determined in the workshops.]

B. Patrols shall encompass overhead communication lines installed on joint use poles with electric distribution facilities, as well as those facilities that are one span away in the Specified Fire Areas. Each Specified Fire Area shall be inspected not less than once every five (5) years.

C. Records demonstrating compliance with subsection (B) of this Rule shall be maintained. Company records shall specify the plant, area or equipment inspected, the name of the inspector and the date of the inspection. Such documentation shall be retained for five (5) years.

Contested Proposal 6C re: GO 95, Rule 31.2 and Rule 80.1 (CPSD)

Proposed Revisions to Rule 31.2 Shown with Strikeout and Underline

31.2 Inspection of Lines

Lines shall be inspected frequently and thoroughly for the purpose of einsuring that they are in good condition so as to conform with these rules. Lines temporarily out of service shall be inspected and maintained in such condition as not to create a hazard.

A. Communication Lines (See Rule 80.1)

B. Supply Lines shall be inspected in compliance with the requirements of General Order 165.

80.1 Inspection Requirements for Communication Lines:

A. Each company shall prepare, follow and modify as necessary procedures for conducting inspections for all Communication Lines. The procedures at a minimum shall contain the following:

- Maximum allowable intervals between inspections. The intervals between inspections shall be based upon the following factors:
 - Proximity to electric facilities
 - Terrain
 - Accessibility
 - Location

In no case may the period between inspections (measured in calendar years) for Communication Lines located on Joint Use Poles (See Rule 21.8) that support Supply Lines, as well as those Communication Lines attached to a pole that are one span away from Joint Use Poles that support Supply Lines, exceed the time specified in the below Table.

<u>Patrol</u>		
<u>Urban</u>	<u>Rural</u>	<u>Detailed</u>
<u>1</u>	<u>2¹</u>	<u>10</u>

(1) Patrol inspections in rural areas shall be increased to once per year in Extreme and Very High Fire Threat Zones in the following counties: Santa Barbara, Ventura, Los Angeles, San Bernardino, Orange, Riverside, and San Diego. Extreme and Very High Fire Threat Zones

are defined by California Department of Forestry and Fire Protection's Fire and Resource Assessment Program (FRAP) Fire Threat Map. The FRAP Fire Threat Map is to be used to establish approximate boundaries and Utilities should use their own expertise and judgment to determine if local conditions require them to adjust the boundaries of the map.

- Methodology to ensure that all lines are subjected to:

- Detailed Inspections

Note: For the purpose of this rule Detailed Inspection shall be defined as a careful visual inspection of Communication facilities and structures using inspection tools such as binoculars and measuring devices, as appropriate.

- Patrol Inspections

Note: For the purpose of this rule Patrol Inspection shall be defined as a simple visual inspection, of applicable communications facilities equipment and structures that is designed to identify obvious structural problems and hazards. Patrol inspections may be carried out in the course of other company business.

- Procedures specifying what problems shall be identified.

Each company shall maintain records of inspections. Commission staff shall be permitted to inspect records and procedures consistent with Public Utilities Code Section 314 (a).

Contested Proposal 6D re: GO 95, Rule 31.2 and Rule 80.1 (SDG&E)

Proposed Revisions Shown in with Strikeout and Underline

31.2 Inspection of Lines

Lines shall be inspected frequently and thoroughly for the purpose of einsuring that they are in good condition so as to conform with these rules. Lines temporarily out of service shall be inspected and maintained in such condition as not to create a hazard.

A. Communication Lines (See Rule 80.1)

B. Supply Lines shall be inspected in compliance with the requirements of General Order 165.

80.1 Inspection Requirements for Communication Lines:

Each company shall prepare, follow and modify as necessary procedures for conducting inspections for all Communication Lines. The procedures at a minimum shall contain the following:

- Maximum allowable intervals between inspections. The intervals between inspections shall be based upon the following factors:
 - Proximity to electric facilities
 - Terrain
 - Accessibility
 - Location

In no case may the period between inspections (measured in years) for Communication Lines located on Joint Use Poles (See Rule 21.8) that contain Supply Circuits (See Rule 20.6-D), as well as those Communication Lines attached to a pole that are within three spans of Joint Use Poles that contain Supply Circuits, exceed the time specified in the below Table.

<u>Patrol</u>		<u>Detail</u>
<u>Urban</u>	<u>Rural</u>	<u>d</u>
<u>1</u>	<u>2¹</u>	<u>10¹</u>

(1) Patrol inspections in rural areas shall be increased to once per year, and detailed inspections shall be increased to once every five years, in Extreme and Very High Fire Threat Zones in the following counties: Santa Barbara, Ventura, Los Angeles, San Bernardino,

Orange, Riverside, and San Diego. Extreme and Very High Fire Threat Zones are defined by California Department of Forestry and Fire Protection's Fire and Resource Assessment Program (FRAP) Fire Threat Map. The FRAP Fire Threat Map is to be used to establish approximate boundaries and Utilities should use their own expertise and judgment to determine if local conditions require them to adjust the boundaries of the map.

- Methodology to ensure that all lines are subjected to:

- Detailed Inspections

Note: For the purpose of this rule Detailed Inspection shall be defined as a careful visual inspection of Communication facilities and structures using inspection tools such as binoculars and measuring devices, as appropriate.

- Patrol Inspections

Note: For the purpose of this rule Patrol Inspection shall be defined as a simple visual inspection, of applicable communications facilities equipment and structures that is designed to identify obvious structural problems and hazards. Patrol inspections may be carried out in the course of other company business.

- Procedures specifying what problems shall be identified.

Each company shall maintain records of inspections. Commission staff shall be permitted to inspect records and procedures consistent with Public Utilities Code Section 314 (a).

Contested Proposal 6E re: GO 95, Rule 31.2 and Rule 80.1B (CPSD)**Proposed New Rule 80.1B Shown with Underline****80.1 Inspection Requirements for Communication Lines:****B. Intrusive Inspections**

Wood poles supporting only Communication Lines or equipment, that are:
Located in Extreme or Very High Fire Threat Zones in Southern California
and inter-set between joint use poles supporting Supply Lines,

Or,

Located in Extreme or Very High Fire Threat Zones in Southern California
and extend up to three spans from a joint use pole supporting Supply
Lines,

Or,

Located in areas outside Extreme or Very High Fire Threat Zones in
Southern California and extend one span from a joint use pole supporting
Supply Lines, shall be intrusively inspected accordance with the schedule
established in General Order 165 for wood poles that support Supply
Lines.

Note: For the purpose of this rule Intrusive Inspections shall be defined as
an inspection involving movement of soil, and/or using more
sophisticated diagnostic tools beyond visual inspections or instrument
reading.

Contested Proposal 7A re: GO 95, Rule 35, Paragraph 4 (Joint Utilities)

Proposed New Paragraph Shown with Underline

35 Vegetation Management

Insert new fourth Paragraph as follows:

Whenever a property owner obstructs access to, or fails to make accessible, overhead facilities for vegetation management activities, such that the supply company cannot inspect its facilities or there is an imminent threat of violation of required regulatory or statutory clearances, the supply company, at its discretion and with proper notice, may discontinue electric service the property owner is receiving at any location where the owner may receive the supply company's electric service. "Proper notice" shall, at a minimum, consist of five days written notice, unless the condition poses an imminent safety hazard to the public.

Contested Proposal 7B re: GO 95, Rule 35, Exception 3 (Joint Utilities)**Proposed New Exception Shown with Strikeout and Underline****35 Vegetation Management**

Where overhead conductors traverse trees and vegetation, safety and reliability of service demand that certain vegetation management activities be performed in order to establish necessary and reasonable clearances. The minimum clearances established in Table 1, Cases 13 and 14, measured between line conductors and vegetation under normal conditions, shall be maintained. (Also see Appendix E for tree trimming guidelines).

When a utility has actual knowledge, obtained either through normal operating practices or notification to the utility, dead, rotten and diseased trees or portions thereof, that overhang or lean toward and may fall into a span, should be removed.

Communication and electric supply circuits, energized at 750 volts or less, including their service drops, should be kept clear of vegetation in new construction and when circuits are reconstructed or repaired, whenever practicable. When a utility has actual knowledge, obtained either through normal operating practices or notification to the utility, that any circuit energized at 750 volts or less shows strain or evidences abrasion from vegetation contact, the condition shall be corrected by reducing conductor tension rearranging or replacing the conductor, pruning the vegetation or placing mechanical protection on the conductor(s). For the purpose of this rule, abrasion is defined as damage to the insulation resulting from the friction between the tree and conductor. Scuffing or polishing of the insulating covering is not considered abrasion. Strain on a conductor is present when there is additional tension causing a deflection of the conductor beyond the slack of the span. Contact between vegetation and conductors, in and of itself, does not constitute a violation of the rule.

EXCEPTIONS:

1. Rule 35 requirements do not apply to conductors, or aerial cable that complies with Rule 57.4-C, energized at less than 60,000 volts, where trimming or removal is not practicable and the conductor is separated from the tree with suitable materials or devices to avoid conductor damage by abrasion and grounding of the circuit through the tree.
2. Rule 35 requirements do not apply where the ~~utility~~ supply or communication

company has made a “good faith” effort to obtain permission to trim or remove vegetation but permission was refused or unobtainable. A “good faith” effort shall consist of current documentation of a minimum of an attempted personal contact and a written communication, including documentation of mailing or delivery. However, this does not preclude other action or actions from demonstrating “good faith”. If permission to trim or remove vegetation is unobtainable and requirements of exception 2 are met, the utility company is not compelled to comply with the requirements of exception 1.

3. Whenever a property owner obstructs access to, or fails to make accessible, overhead facilities for vegetation management activities, the supply or communication company shall not be responsible for the consequences of failing to trim or remove such vegetation so long as the supply or communication company can document (1) at least one attempted personal contact with the owner, (2) at least one written communication to the owner, including documentation of mailing or delivery, and (3) notification to Commission Staff.

~~3.~~4. The Commission recognizes that unusual circumstances beyond the control of the utility may result in nonconformance with the rules. In such cases, the utility may be directed by the Commission to take prompt remedial action to come into conformance, whether or not the nonconformance gives rise to penalties or is alleged to fall within permitted exceptions or phase-in requirements.

Contested Proposal 8A re: GO 95, Rule 35, Appendix E, Table (Joint Utilities)

Proposed Revisions Shown with Strikeout and Underline

<u>Voltage of Lines</u>	<u>Case 13 of Table 1</u>	<u>Case 14 of Table 1</u>
Radial clearances for any conductor of a line operating at 2,400 <u>V</u> or more volts , but less than 72,000 volts <u>V</u>	4 feet	6.5 10 feet
Radial clearances for any conductor of a line operating at 72,000 <u>V</u> or more volts , but less than 110,000 volts <u>V</u>	6 feet	10 15 feet
Radial clearances for any conductor of a line operating at 110,000 <u>V</u> or more volts , but less than 300,000 volts <u>V</u>	10 feet	20 feet
Radial clearances for any conductor of a line operating at 300,000 or more volts <u>V</u>	15 feet	20 feet

Contested Proposal 8B re: GO 95, Rule 35, Guidelines (Joint Utilities)

Proposed Revisions Shown with Strikeout and Underline

The following are guidelines to Rule 35.

The radial clearances shown below are recommended minimum clearances that should be established, at time of trimming, between the vegetation and the energized conductors and associated live parts where practicable. Reasonable vegetation management practices may make it advantageous to obtain greater clearances than those listed below: ~~to ensure compliance until the next scheduled maintenance. Each utility may determine and apply additional appropriate clearances beyond clearances listed below, which take into consideration various factors, including: line operating voltage, length of span, line sag, planned maintenance cycles, location of vegetation within the span, species type, experience with particular species, vegetation growth rate and characteristics, vegetation management standards and best practices, local climate, elevation, and fire risk.~~

Contested Proposal 8C re: GO 95, Rule 35, Guidelines (CFBF and MGRA)**Proposed Revisions Shown with Strikeout and Underline**

The following are guidelines to Rule 35.

The radial clearances shown below are recommended minimum clearances that should be established, at time of trimming, between the vegetation and the energized conductors and associated live parts where practicable. Reasonable vegetation management practices may make it advantageous for the purposes of public safety, reliability or tree health to obtain greater clearances than those listed below: to ensure compliance until the next scheduled maintenance. Each utility may determine and apply additional appropriate clearances beyond clearances listed below, which take into consideration various factors, including: line operating voltage, length of span, line sag, planned maintenance cycles, location of vegetation within the span, species type, experience with particular species, vegetation growth rate and characteristics, vegetation management standards and best practices (including when feasible appropriate tree crop production manuals), local climate, elevation, and fire risk.

**Contested Proposal 9 re: GO 95, Rule 38, Table 2, Footnote (aaa)
(Joint Utilities)****Proposed New Footnote Shown with Underline**

New Footnote "aaa" to clearances specified in Rule 38, Table 2, Cases 1-13:

(aaa) The vertical separation requirement between conductors in the adjoining mid-span may or may not require increased vertical separation at the pole based on the sag characteristics of the conductors.

Contested Proposal 10A re: GO 95, Rule 44.4 (CIP Coalition)**Proposed New Rule 44.4 Shown with Underline****44.4 Cooperation**

All entities with facilities on the subject pole shall cooperate with the company performing the load calculations necessitated by the provisions of Rule 44.1, 44.2 or 44.3, including, but not limited to, promptly providing or making reasonably available, upon request and to the extent it exists, the following:

- (a) The most recent intrusive pole test data;
- (b) Any information regarding its facilities necessary to perform a pole loading calculation that is not readily available to the company performing the pole loading calculations through a field visit; and
- (c) A table of standard input values used by the Responding Company in pole loading calculations (e.g., standard conductor or cable sizes, tension values, and equipment sizes and weights).

In the event a pole attachment application or a joint pole application submitted to a pole owner is rejected, the pole owner shall provide the applicant with the reason(s) for the rejection with the returned application. In the event a pole attachment application or a joint pole application is rejected by a pole owner because it has failed to meet the pole loading limitations established by the pole owner (consistent with General Order 95 or any subsequent regulation), the pole owner should also provide the applicant with sufficient information to determine how the pole loading limitations were exceeded with the returned application.

Note: "Promptly" means as soon as practicable but, absent exigent circumstances or mutual agreement, no more than fifteen (15) business days from the date of the request. (Exigent circumstances include requests for intrusive data or other necessary information on transmission poles, or requests for information on a large number of poles in a limited time period.)

**Contested Proposal 10B re: GO 95, Rule 44.2, Rule 44.4, and Appendix I
(Joint Utilities)**

**Proposed Revisions to Rules 44.2 and 44.4 Shown with Strikeout and
Underline.**

Proposed Revisions to Rule 44.2 and Addition of New Rule 44.4

44.2 Additional Construction

Any ~~utility entity~~ planning the addition of facilities that materially increase the load on a structure shall perform a loading calculation to ensure that the addition of the facilities will not reduce the safety factors below the values specified by Section IV. Such ~~utility entity~~ shall maintain these pole loading calculations and shall provide such information to authorized joint use pole occupants and the Commission upon request.

~~All other utilities or on the subject pole shall cooperate with the utility performing the load calculations described above including, but not limited to, providing intrusive pole loading data and other data necessary to perform those calculations.~~

Note: Nothing contained in this rule shall be construed as allowing the safety factor of a facility to be reduced below the required values specified in Rules 44.1 and 44.3.

44.4 Cooperation

~~Entities with facilities on a pole shall cooperate with entities performing pole load calculations necessitated by Rules 44.1, 44.2 and 44.3 including, but not limited to, providing upon request intrusive pole test results and other data necessary to perform those calculations. (See Appendix I)~~

General Order 95 Appendix I
Guidelines to Rule 44.4

~~The following are guidelines to Rule 44.4~~

~~Entities with facilities on a pole should cooperate with the entity performing the load calculations necessitated by the provisions of Rule 44.1, 44.2 or 44.3, including, but not limited to, promptly providing, upon request and if available, the following:~~

- (a) The most recent intrusive pole test data;
- (b) Any information regarding its facilities necessary to perform a pole loading calculation that is not readily available to the company performing the pole loading calculations through a field visit; and
- (c) A table of standard input values used by the responding entity in pole loading calculations (e.g., standard conductor or cable sizes, tension values, and equipment sizes and weights).

“Promptly providing” means as soon as practicable but, absent exigent circumstances or mutual agreement, no more than fifteen (15) business days from the date of the request. (Exigent circumstances include requests for intrusive data or other necessary information on transmission poles, or requests for information on a large number of poles in a limited time period.)

In the event a pole attachment application or a joint pole application submitted to a pole owner is rejected, the pole owner should provide the applicant with an explanation of the reason(s) for the rejection with the returned application. In the event a pole attachment application or a joint pole application is rejected by a pole owner because it has failed to meet the pole loading limitations established by the pole owner (consistent with General Order 95 or any subsequent regulation), the pole owner should also provide the applicant with, sufficient information to determine how the pole loading limitations were exceeded.

Contested Proposals 11A re: GO 95, Rule 48 (Joint Utilities)**Proposed Revisions to Rule 48 Shown with Strikeout and Underline.****48 Ultimate Strength of Materials**

Structural members, ~~and their~~ connections, and other elements of overhead lines shall be designed and constructed in accordance with the loading criteria specified in Rule 43 so that the structures and parts thereof will not fail or be seriously distorted at any load less than their maximum working loads (developed under the current construction arrangements with loadings as specified in Rule 43) and the safety factors specified in Rule 44.

~~Values used for the ultimate strength of material shall comply with the safety factors specified in Rule 44.~~

**Contested Proposal 11B re: GO 95, Section IV,
Proposed Ordering Paragraph (CPSD)****Proposed Ordering Paragraph Shown with Underline.****Proposed Ordering Paragraph:**

The Consumer Protection and Safety Division shall establish a technical working group to address possible changes to Section IV of General Order 95. The technical working group shall consider appropriate revisions, if any, to Section IV of General Order 95 to update the section to incorporate modern materials and practices. CPSD shall report back to the Commission within 12 months.

Contested Proposal 12 re: GO 95, Proposed Rule 91.5 (SDG&E)**Proposed Rule 91.5 Shown with Underline.****91.5 Marking**

Communication cables and conductors shall be marked as to ownership to facilitate identification.

Contested Proposal 13A re: GO 165, Section V (CPSD and MGRA)**Proposed New Section V of GO 165 Shown with Underline.****V. Fire Incident Reporting and Data Collection Requirements**

California investor-owned electric utilities shall collect information on all fire incidents which are attributable or allegedly attributable to their overhead electric distribution lines or transmission lines. Data to be collected per incident shall include date, time, general location, specific geographical coordinates, equipment, voltage, fire agencies involved, weather conditions, vegetation conditions, and apparent cause. Collected data shall be provided electronically under General Order 66-C and Section 583 of the Public Utilities Code annually to the Director of CPSD or its successor. Summaries of collected data shall be provided electronically annually to the Director of CPSD or its successor, which may be made available to the public and state or local fire agencies.

Contested Proposal 13B re: Proposed Ordering Paragraph on Data Collection (PG&E)**Proposed Ordering Paragraph Shown with Underline.****Proposed Ordering Paragraph:**

Within 6 months of the effective date of this decision, the electric utilities and CPSD shall meet and confer regarding electric utility collection and utilization of fire-related data. Such discussions shall consider whether CPSD is receiving the fire-related data it needs from the electric utilities, and whether it would be useful for the electric utilities to collect different and/or additional data that would be provided to CPSD and/or fire agencies such as Cal Fire. Within 9 months of the effective date of this decision, the electric utilities and CPSD shall submit a report to the Executive Director of the Commission regarding the results of such discussions. State fire agencies shall be invited to participate in the discussions and report. These discussions shall be conducted in such a manner as to protect the confidentiality of the utilities' data.

Contested Proposal 14A re: Proposed Ordering Paragraph Regarding Fire Maps (CPSD and MGRA)**Proposed Ordering Paragraph Shown with Underline.****Proposed Ordering Paragraph**

Investor-owned electric utilities (IOUs) and communication infrastructure providers (CIPs) shall provide funding to support the development of a working plan to determine how to create utility-specific high-resolution maps combining wind and vegetation data that identify areas at the greatest risk of catastrophic power line wildland fire ignitions. Within 60 days of the issuance of this decision, or at a time mutually agreed to by the participating parties, investor-owned electric utilities (IOUs) and communication infrastructure providers (CIPs) shall meet and confer with CAL FIRE and CPSD staff in order to discuss how to create utility-specific high-resolution maps combining wind and vegetation data that identify areas at the greatest risk of catastrophic power line wildland fire ignitions. The purpose of the maps will be for determining inspection and maintenance cycles in all cases where geographic locations and maps are referred to in General Orders 95 and 165, and the maps may be used in the future to determine geography-specific construction, maintenance, and operational standards. The IOUs and CIPs shall cooperate with CAL FIRE and CPSD staff to develop a working plan to determine the process by which the maps would be produced, estimate the time and costs required to produce and maintain maps, devise a proposed revision cycle under which subsequent updates to the maps would be undertaken to incorporate changes to the underlying data or improvements or changes to analysis techniques, and any other actions that the Commission would need to take to enable the creation of utility-specific maps, including the use of funding provided by IOUs and CIPs. IOUs and CIPs shall further meet and confer with CAL FIRE to determine what funding may be required to produce such a working plan. Within six months after the issuance of this decision, IOUs and CIPs shall report back to the Commission and CPSD staff on the status of the working plan. Upon completion of the working plan, the Commission will decide whether to order the investor-owned electric utilities and communication infrastructure providers to fund the creation and maintenance of utility-specific high-resolution maps. Maps adopted in Phase 1 or Phase 2 of this OIR shall remain applicable until further order by the Commission.

**Contested Proposals 14A and 14B re: GO 95, Rule 31.2,
Fire Maps for CIP Inspections**

Proposed Additions to GO 95, Rule 31.2, Shown with Underline.

31.2 Inspection of Lines

Note: For the following Southern California counties: Santa Barbara, Ventura, Los Angeles, Orange, San Diego, Riverside, and San Bernardino, Specified Fire Areas shall be defined as the Extreme and Very High Fire Threat Zones as identified in Cal Fire's Fire and Resource Assessment Program Fire Threat Map. For the remaining counties in the State of California, Specified Fire Areas are defined as the areas designated as Threat Class 3 and 4 identified on Threat Class 3 and 4 Map attached as Appendix G, Figure 90. Communication Infrastructure Providers shall have the discretion to use their own expertise and judgment to determine if local conditions require them to adjust the boundaries of the maps.

APPENDIX G

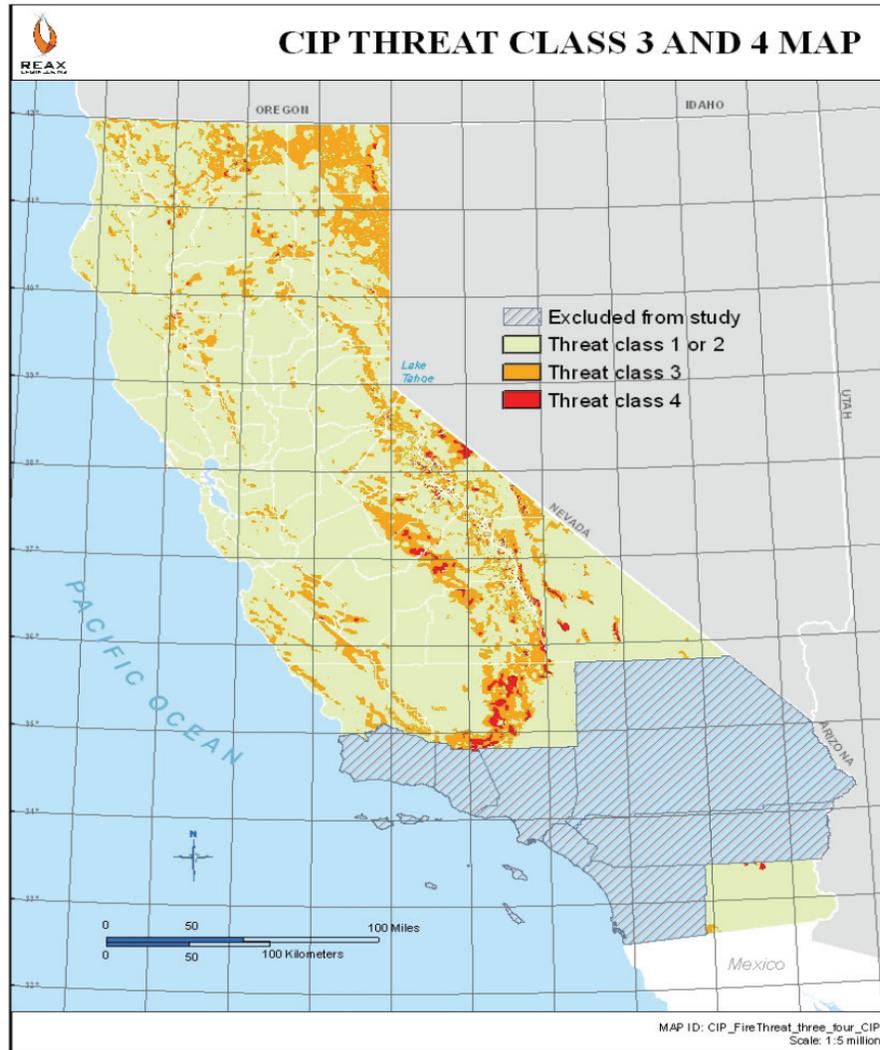


Figure 24. CIP fire threat class three and four map. (three_4_cip.jpg)

Figure 90

(END OF APPENDIX A)

Appendix B: Adopted Revisions to General Orders 95, 165, and 166

Appendix B shows the text of General Orders 95, 165, and 166
as revised by today's decision.

General Order 95, Rule 11
Adopted Rule in Final Form

18 Purpose of Rules

The purpose of these rules is to formulate, for the State of California, requirements for overhead line design, construction, and maintenance, the application of which will ensure adequate service and secure safety to persons engaged in the construction, maintenance, operation or use of overhead lines and to the public in general.

General Order 95, Rule 18A**Adopted Rule in Final Form**

This adopted revisions to Rule 18A include the consensus revisions to Rule 18A that replace the term “violation” with the term “nonconformance.”

18 Reporting and Resolution of Safety Hazards Discovered by Utilities

For purposes of this rule, “Safety Hazard” means a condition that poses a significant threat to human life or property.

“Southern California” is defined as the following: Imperial, Los Angeles, Orange, Riverside, Santa Barbara, San Bernardino, San Diego, and Ventura Counties.

“Extreme and Very High Fire Threat Zones” are defined on the Fire and Resource Assessment Program (FRAP) Map prepared by the California Department of Forestry and Fire Protection or the modified FRAP Map prepared by San Diego Gas & Electric Company (SDG&E) and adopted by Decision 11-XX – YYY in Phase 2 of Rulemaking 08-11-005. All entities subject to Rule 18 shall use the FRAP Map to implement Rule 18, except that SDG&E may use its modified FRAP Map to implement Rule 18.

Part A: Resolution of Safety Hazards and General Order 95 Nonconformances

- (1)(a) Each company (including utilities and CIPs) is responsible for taking appropriate corrective action to remedy Safety Hazards and GO 95 nonconformances posed by its facilities.
 - (b) Upon completion of the corrective action, the company’s records shall show, with sufficient detail, the nature of the work, the date, and the identity of persons performing the work. These records shall be preserved by the company for at least ten (10) years and shall be made available to Commission staff upon 30 days notice.
- (2)(a) All companies shall establish an auditable maintenance program for their facilities and lines. All companies must include a timeline for corrective actions to be taken following the identification of a Safety Hazard or nonconformances with General Order 95 on the company’s facilities. The auditable maintenance program shall prioritize corrective actions consistent with the priority levels set forth below and based on the following factors, as appropriate:
 - Safety and reliability as specified in the priority levels below;

- Type of facility or equipment;
- Location, including whether the Safety Hazard or nonconformance is located in an Extreme or Very High Fire Threat Zone in Southern California;
- Accessibility;
- Climate;
- Direct or potential impact on operations, customers, electrical company workers, communications workers, and the general public.

There shall be 3 priority levels.

(i) Level 1:

- Immediate safety and/or reliability risk with high probability for significant impact.
- Take action immediately, either by fully repairing the condition, or by temporarily repairing and reclassifying the condition to a lower priority.

(ii) Level 2:

- Variable (non-immediate high to low) safety and/or reliability risk.
- Take action to correct within specified time period (fully repair, or by temporarily repairing and reclassifying the condition to a lower priority).

Time period for correction to be determined at the time of identification by a qualified company representative, but not to exceed:

- (1) 12 months for nonconformances that compromise worker safety, (2) 12 months for nonconformances that create a fire risk and are located in an Extreme or Very High Fire Threat Zone in Southern California, and (3) 59 months for all other Level 2 nonconformances.

(iii) Level 3:

- Acceptable safety and/or reliability risk.
- Take action (re-inspect, re-evaluate, or repair) as appropriate.

(b) Correction times may be extended under reasonable circumstances, such as:

- Third party refusal
- Customer issue

- No access
 - Permits required
 - System emergencies (e.g. fires, severe weather conditions)
- (3) Companies that have existing General Order 165 auditable inspection and maintenance programs that are consistent with the purpose of Rule 18A shall continue to follow their General Order 165 programs.

General Order 95, Rule 18B**Adopted Rule in Final Form****B. Notification of Safety Hazards**

If a company, while performing inspections of its facilities, discovers a safety hazard(s) on or near a communications facility or electric facility involving another company, the inspecting company shall notify the other company and/or facility owner of such safety hazard(s) no later than 10 business days after the discovery. To the extent the inspecting company cannot determine the facility owner/operator, it shall contact the pole owner(s), who shall be responsible for promptly notifying the company owning/operating the facility with the safety hazard(s), normally not to exceed five business days after being notified of the safety hazard. The notification shall be documented and such documentation must be preserved by all parties for at least ten years.

Note: Each pole owner must be able to determine all other pole owners on poles it owns. Each pole owner must be able to determine all authorized entities that attach equipment on its portion of a pole.

General Order 95, Rule 23.0**Adopted Rule in Final Form**

Rule 23.0 Reconstruction means that work which in any way changes the identity of the pole, tower or structure on which it is performed. A change in grade of construction or class of circuit is considered reconstruction. For exceptions see Rule 12.1.

General Order 95, Rule 31.1
Adopted Rule in Final Form

31.1 Design, Construction and Maintenance

Electrical supply and communication systems shall be designed, constructed, and maintained for their intended use, regard being given to the conditions under which they are to be operated, to enable the furnishing of safe, proper, and adequate service.

For all particulars not specified in these rules, design, construction, and maintenance should be done in accordance with accepted good practice for the given local conditions known at the time by those responsible for the design, construction, or maintenance of communication or supply lines and equipment.

For all particulars specified in this General Order, a supply or communications company is in compliance with this rule if it designs, constructs and maintains a facility in accordance with such particulars. For all particulars not specified in this General Order, a supply or communications company is in compliance with this rule if it designs, constructs and maintains a facility in accordance with accepted good practice.

All work performed on public streets and highways shall be done in such a manner that the operations of other utilities and the convenience of the public will be interfered with as little as possible and no conditions unusually dangerous to workmen, pedestrians or others shall be established at any time.

Note: The standard of accepted good practice should be applied on a case by case basis. For example, the application of "accepted good practice" may be aided by reference to any of the practices, methods, and acts engaged in or approved by a significant portion of the relevant industry, or which may be expected to accomplish the desired result with regard to safety and reliability at a reasonable cost.

General Order 95, Rule 31.2
Adopted Rule in Final Form

31.2 Inspection of Lines

Lines shall be inspected frequently and thoroughly for the purpose of ensuring that they are in good condition so as to conform with these rules. Lines temporarily out of service shall be inspected and maintained in such condition as not to create a hazard.

- A. Communication Lines** (See Rule 80.1)
- B. Supply Lines** shall be inspected in compliance with the requirements of General Order 165.

General Order 95, Rule 35
Adopted Rule in Final Form

35 Vegetation Management

Where overhead conductors traverse trees and vegetation, safety and reliability of service demand that certain vegetation management activities be performed in order to establish necessary and reasonable clearances, the minimum clearances set forth in Table 1, Cases 13 and 14, measured between line conductors and vegetation under normal conditions shall be maintained. (Also see Appendix E for tree trimming guidelines.) These requirements apply to all overhead electrical supply and communication facilities that are covered by this General Order, including facilities on lands owned and maintained by California state and local agencies.

When a supply or communication company has actual knowledge, obtained either through normal operating practices or notification to the company, that dead, rotten or diseased trees or dead, rotten or diseased portions of otherwise healthy trees overhang or lean toward and may fall into a span of supply or communication lines, said trees or portions thereof should be removed.

Communication and electric supply circuits, energized at 750 volts or less, including their service drops, should be kept clear of vegetation in new construction and when circuits are reconstructed or repaired, whenever practicable. When a supply or communication company has actual knowledge, obtained either through normal operating practices or notification to the company, that its circuit energized at 750 volts or less shows strain or evidences abrasion from vegetation contact, the condition shall be corrected by reducing conductor tension, rearranging or replacing the conductor, pruning the vegetation, or placing mechanical protection on the conductor(s). For the purpose of this rule, abrasion is defined as damage to the insulation resulting from the friction between the vegetation and conductor. Scuffing or polishing of the insulation or covering is not considered abrasion. Strain on a conductor is present when vegetation contact significantly compromises the structural integrity of supply or communication facilities. Contact between vegetation and conductors, in and of itself, does not constitute a nonconformance with the rule.

EXCEPTIONS:

1. Rule 35 requirements do not apply to conductors, or aerial cable that complies with Rule 57.4-C, energized at less than 60,000 volts, where trimming or removal is not practicable and the conductor is separated from the tree with

suitable materials or devices to avoid conductor damage by abrasion and grounding of the circuit through the tree.

2. Rule 35 requirements do not apply where the supply or communication company has made a “good faith” effort to obtain permission to trim or remove vegetation but permission was refused or unobtainable. A “good faith” effort shall consist of current documentation of a minimum of an attempted personal contact and a written communication, including documentation of mailing or delivery. The written communication may include a statement that the company may seek to recover any costs and liabilities incurred by the company due to its inability to trim or remove vegetation. However, this does not preclude other action or actions from demonstrating “good faith”. If permission to trim or remove vegetation is unobtainable and requirements of exception 2 are met, the company is not compelled to comply with the requirements of exception 1.
3. The Commission recognizes that unusual circumstances beyond the control of the utility may result in nonconformance with the rules. In such cases, the utility may be directed by the Commission to take prompt remedial action to come into conformance, whether or not the nonconformance gives rise to penalties or is alleged to fall within permitted exceptions or phase-in requirements.
4. Mature trees whose trunks and major limbs are located more than six inches, but less than the clearance required by Table 1, Cases 13E and 14E, from primary distribution conductors are exempt from the minimum clearance requirement under this rule. The trunks and limbs to which this exemption applies shall only be those of sufficient strength and rigidity to prevent the trunk or limb from encroaching upon the six-inch minimum clearance under reasonably foreseeable local wind and weather conditions. The utility shall bear the risk of determining whether this exemption applies, and the Commission shall have final authority to determine whether the exemption applies in any specific instance, and to order that corrective action be taken in accordance with this rule, if it determines that the exemption does not apply.

**General Order 95, Rule 35, Appendix E, Guidelines
Adopted Revisions to GO 95, Appendix E in Final Form**

The following are guidelines to Rule 35.

The radial clearances shown below are recommended minimum clearances that should be established, at time of trimming, between the vegetation and the energized conductors and associated live parts where practicable. Reasonable vegetation management practices may make it advantageous for the purposes of public safety or service reliability to obtain greater clearances than those listed below to ensure compliance until the next scheduled maintenance. Each utility may determine and apply additional appropriate clearances beyond clearances listed below, which take into consideration various factors, including: line operating voltage, length of span, line sag, planned maintenance cycles, location of vegetation within the span, species type, experience with particular species, vegetation growth rate and characteristics, vegetation management standards and best practices, local climate, elevation, and fire risk.

**General Order 95, Rule 35, Appendix E, Table
Adopted Rule in Final Form**

<u>Voltage of Lines</u>	<u>Case 13 of Table 1</u>	<u>Case 14 of Table 1</u>
Radial clearances for any conductor of a line operating at 2,400 V or more, but less than 72,000 V	4 feet	6.5 feet
Radial clearances for any conductor of a line operating at 72,000 V or more, but less than 110,000 V	6 feet	10 feet
Radial clearances for any conductor of a line operating at 110,000 V or more, but less than 300,000 V	10 feet	20 feet
Radial clearances for any conductor of a line operating at 300,000 V	15 feet	20 feet

**General Order 95, Rule 37, Table 1, Case 14 and Footnotes (fff) -(jjj)
Adopted Rule in Final Form**

Table 1: Basic Minimum Allowable Vertical Clearance of Wires above Railroads, Thoroughfares, Ground or Water Surfaces; Also Clearances from Poles, Buildings, Structures or Other Objects (nn) (Letter References Denote Modifications of Minimum Clearances as Referred to in Notes Following This Table)

Case No.	Nature of Clearance	Wire of Conductor Concerned						
		A	B	C	D	E	F	G
		Span Wires (Other than Trolley Span Wires) Overhead Guys and Messengers	Communication s Conductors (including Open Wire, Cables and Service Drops) Supply Service Drops of 0-750 Volts	Trolley Contact Feeder and Span Wires, 0-5,000 Volts	Supply Conductors of 0-750 Volts and Supply Cable Treated as in Rule 57.8	Supply Conductors and Supply Cables, 750-22,500 Volts	Supply Conductors And Supply Cables, 22.5-300 kV	Supply Conductors and Supply Cables, 300-550 kV(mm)
14	Radial clearance of bare line conductors from vegetation in Extreme and Very High Fire Threat Zones in Southern California (aaa) (ddd) (hhh)(jjj)			18 inches (bbb)		48 inches (bbb) (iii)	48 inches (fff)	120 inches (ggg)

(fff) Clearances in this case shall be increased for conductors operating above 72 kV, to the following:

1. Conductors operating between 72 kV and a 110 kV shall maintain a 72 inch clearance.
2. Conductors operating above 110 kV shall maintain a 120 inch clearance.

(ggg) Shall be increased by 0.40 inch per kV in excess of 500 kV.

(hhh) Extreme and Very High Fire Threat Zones are defined by California Department of Forestry and Fire Protection’s Fire and Resource Assessment Program (FRAP) Fire Threat Map. The FRAP Fire Threat Map is to be used to establish approximate boundaries for purposes of this rule. The boundaries of the map are to be broadly construed, and utilities should use their own expertise and judgment to determine if local conditions require them to adjust the boundaries of the map. Southern California shall be defined as the following: Imperial, Los Angeles, Orange, Riverside, Santa Barbara, San Bernardino, San Diego, and Ventura Counties.

(iii) May be reduced to 18 inches for conductors operating less than 2.4 kV.

(jjj) Clearances in this case shall not apply to orchards of fruit, nut or citrus trees that are plowed or cultivated. In those areas Case 13 clearances shall apply.

General Order 95, Rules 44.1, 44.2, 44.3**Adopted Rules in Final Form****44.1 Installation and Reconstruction**

Lines and elements of lines upon installation or reconstruction, shall provide as a minimum the safety factors specified in Table 4 for vertical loads and loads transverse to lines and for loads longitudinal to lines except where longitudinal loads are balanced or where there are changes in grade of construction (see Rules 47.3, 47.4 and 47.5). The design shall consider the structural loading and mechanical strength requirements of all supply and communication facilities planned to occupy the structure. For purposes of this rule, the term "planned" applies to the facilities intended to occupy the structure that are actually known to the constructing company at the time of design.

44.2 Additional Construction

Any entity planning the addition of facilities that materially increase vertical, transverse or longitudinal loading on a structure shall perform a loading calculation to ensure that the addition of the facilities will not reduce the safety factors below the values specified by Rule 44.3. Such entity shall maintain these pole loading calculations for ten years and shall provide such information to authorized joint use pole occupants and the Commission upon request.

Note: For the purpose of Rule 44.2, a material increase in load is when a proposed addition to a structure could exceed 10 percent of the estimated remaining unused load, or carrying capacity, of the structure (with the remaining unused load, or carrying capacity, computed using the minimum end-of-service-life safety factors for the structure required by Rule 44).

44.3 Replacement

Lines or parts thereof shall be replaced or reinforced before safety factors have been reduced (due to deterioration and/or installation of additional facilities) in Grades "A" and "B" construction to less than two-thirds of the construction safety factors specified in Rule 44.1 and in Grades "C" and "F" construction to less than one-half of the construction safety factors specified in Rule 44.1. Poles in Grade "F" construction shall also conform to the requirements of Rule 81.3-A. In no case shall the application of this rule be held to permit the use of structures or any member of any structure with a safety factor less than one.

General Order 95, Rule 44.4
Adopted Rule in Final Form

44.4 Cooperation

All entities with facilities on the subject pole shall cooperate with the company performing the load calculations necessitated by the provisions of Rule 44.1, 44.2 or 44.3, including, but not limited to, promptly providing or making reasonably available, upon request and to the extent it exists, the following:

- a. The most recent intrusive pole test data;
- b. Any information regarding its facilities necessary to perform a pole loading calculation that is not readily available to the company performing the pole loading calculations through a field visit; and
- c. A table of standard input values used by the Responding Company in pole loading calculations (e.g., standard conductor or cable sizes, tension values, and equipment sizes and weights).

In the event a pole attachment application or a joint pole application submitted to a pole owner is rejected, the pole owner shall provide the applicant with the reason(s) for the rejection with the returned application. In the event a pole attachment application or a joint pole application is rejected by a pole owner because it has failed to meet the pole loading limitations established by the pole owner (consistent with General Order 95 or any subsequent regulation), the pole owner should also provide the applicant with sufficient information to determine how the pole loading limitations were exceeded with the returned application.

Note: "Promptly" means as soon as practicable but, absent exigent circumstances or mutual agreement, no more than fifteen (15) business days from the date of the request. (Exigent circumstances include requests for intrusive data or other necessary information on transmission poles, or requests for information on a large number of poles in a limited time period.)

General Order 95, Rule 80.1A
Adopted Rule in Final Form

80.1 Inspection Requirements for Communication Lines:

A. Patrol and Detailed Inspections

Each company shall prepare, follow, and modify as necessary procedures for conducting patrol and detailed inspections for all Communication Lines. The procedures at a minimum shall contain the following:

- Maximum allowable intervals between inspections. The intervals between inspections shall be based upon the following factors:
 - Proximity to electric facilities
 - Terrain
 - Accessibility
 - Location

In no case may the period between inspections (measured in years) for Communication Lines located on Joint-Use Poles (See Rule 21.8) that contain Supply Circuits (See Rule 20.6-D), as well as those Communication Lines attached to a pole that is within three spans of a Joint-Use Pole with Supply Circuits, exceed the time specified in the following Table for high fire-threat areas.

Inspection	Northern California	Southern California
Patrol	2 Years	1 Year
Detailed	10 Years	5 Years

For the purpose of the above Table, the high fire-threat areas in Southern California are Extreme and Very High Fire Threat Zones in the following counties: Imperial, Los Angeles, Orange, Riverside, Santa Barbara, San Bernardino, San Diego, and Ventura. Extreme and Very High Fire Threat Zones are defined by California Department of Forestry and Fire Protection's Fire and Resource Assessment Program (FRAP) Fire Threat Map.

For the purpose of the above Table, the high fire-threat areas in Northern California are areas designated as Threat Classes 3 and 4 on the Reax Map adopted in Decision 11-XX-YYY issued in Phase 2 of

Rulemaking 08-11-005.

For the purpose of the above Table, the term “year” is defined as 12 consecutive calendar months starting the first full calendar month after an inspection is performed.

The FRAP Map and Reax Map are to be used to establish approximate boundaries. Communications Infrastructure Providers should use their own expertise and judgment to determine if local conditions require them to adjust the boundaries of the map.

- Methodology to ensure that all communications lines are subjected to:
 - Detailed Inspections
Note: For the purpose of this rule Detailed Inspection shall be defined as a careful visual inspection of Communication facilities and structures using inspection tools such as binoculars and measuring devices, as appropriate.
 - Patrol Inspections
Note: For the purpose of this rule Patrol Inspection shall be defined as a simple visual inspection, of applicable communications facilities equipment and structures that is designed to identify obvious structural problems and hazards. Patrol inspections may be carried out in the course of other company business.
- Procedures specifying what problems shall be identified.

Each company shall maintain records for at least ten (10) years that provide the following information for each facility subject to this rule: The location of the facility, the date of each inspection of the facility, the results of each inspection, the personnel who performed each inspection, the date and description of each corrective action, and the personnel who performed each correction action. Commission staff shall be permitted to inspect records consistent with Public Utilities Code Section 314 (a).

General Order 95, Rule 80.1B
Adopted Rule in Final Form

80.1 Inspection Requirements for Communication Lines:

B. Intrusive Inspections

Wood poles supporting only Communication Lines or equipment shall be intrusively inspected in accordance with the schedule established in General Order 165 if they are:

- Interset between joint-use poles supporting supply lines in the high fire-threat areas of Southern California.
- Within three spans of a joint-use pole supporting supply lines in the high fire-threat areas of Southern California.
- Within one span of a joint-use pole supporting supply lines in the high fire-threat areas of Northern California.

For the purpose of this rule, the high fire-threat areas in Southern California are Extreme and Very High Fire Threat Zones in the following counties: Imperial, Los Angeles, Orange, Riverside, Santa Barbara, San Bernardino, San Diego, and Ventura. Extreme and Very High Fire Threat Zones are defined by California Department of Forestry and Fire Protection's Fire and Resource Assessment Program (FRAP) Fire Threat Map. The high fire-threat areas in Northern California are areas designated as Threat Classes 3 and 4 on the Reax Map adopted in Decision 11-XX-YYY issued in Phase 2 of Rulemaking 08-11-005.

The FRAP Fire Threat Map and Reax Map are to be used to establish approximate boundaries. Communications Infrastructure Providers (CIPs) should use their own expertise and judgment to determine if local conditions require them to adjust the boundaries of the map.

Note: For the purpose of this rule, Intrusive Inspections are defined as an inspection involving movement of soil, and/or using more sophisticated diagnostic tools beyond visual inspections or instrument reading.

CIPs shall maintain records for the life of the pole that provide the following information for each wood pole subject to this rule: The location of the pole, the date of each intrusive inspection, the results of

each inspection, the personnel who performed each intrusive inspections, the date and description of each corrective action, and the personnel who performed each correction action. Commission staff may inspect records consistent with Public Utilities Code Section 314(a).

General Order 95, Rule 91.5
Adopted Rule 91.5 in Final Form

91.5 Marking

Each communication cable and conductor attached to a joint-use pole shall be marked as to ownership by no later than January 1, 2015. The marker shall (1) identify the owner of the cable and/or conductor; (2) provide a 24 hour contact number for emergencies or information; (3) be made of weather and corrosion resistant material; and (4) be clearly visible to workers who climb the pole or ascend by mechanical means.

General Order 165, Sections I - IV
Adopted Rule in Final Form

Appendix A
Public Utilities Commission of the State of California
Inspection Requirements for Electric Distribution and Transmission
Facilities

Adopted March 31, 1997

Effective March 1, 1997

(D.97-03-070 in I.95-02-015 and R.96-11-004)

Amended August 20, 2009

(D.09-08-029 in R.08-11-005)

I. Purpose

The purpose of this General Order is to establish requirements for electric distribution and transmission facilities (excluding those facilities contained in a substation) regarding inspections in order to ensure safe and high-quality electrical service.

II. Applicability

This General Order applies to all electric distribution and transmission facilities (excluding those facilities contained in a substation) that come within the jurisdiction of this Commission, located outside of buildings, including electric distribution and transmission facilities that belong to non-electric utilities.

The requirements of this order are in addition to the requirements imposed upon utilities under General Orders 95 and 128 to maintain a safe and reliable electric system. Nothing in this General Order relieves any utility from any requirements or obligations that it has under General Orders 95 and 128.

This General Order does not apply to facilities of communication infrastructure providers.

III. Distribution Facilities

A Definitions

For the purpose of this General Order,

1 "Urban" shall be defined as those areas with a population of more than 1,000 persons per square mile as determined by the United States Bureau of the Census.

2 "Rural" shall be defined as those areas with a population of less than 1,000 persons per square mile as determined by the United States Bureau of the Census.

3 "Patrol" shall be defined as a simple visual inspection, of applicable utility equipment and structures, that is designed to identify obvious structural problems and hazards. Patrols may be carried out in the course of other company business.

4 "Detailed" inspection shall be defined as one where individual pieces of equipment and structures are carefully examined, visually and through use of routine diagnostic test, as appropriate, and (if practical and if useful information can be so gathered) opened, and the condition of each rated and recorded.

5. "Intrusive" inspection is defined as one involving movement of soil, taking samples for analysis, and/or using more sophisticated diagnostic tools beyond visual inspections or instrument reading.

6 "Corrective Action" shall be defined as maintenance, repair, or replacement of utility equipment and structures so that they function properly and safely.

B Standards for Inspection

Each utility subject to this General Order shall conduct inspections of its distribution facilities, as necessary, to ensure reliable, high-quality, and safe operation, but in no case may the period between inspections (measured in years) exceed the time specified in Table 1.

C Record Keeping

The utility shall maintain records for (1) at least ten (10) years of patrol and detailed inspection activities, and (2) the life of the pole for intrusive inspection activities. Such records shall be made available to parties or pursuant to Commission rules upon 30 days notice. Commission staff shall be permitted to inspect such records consistent with Public Utilities Code Section 314 (a).

For all inspections records shall specify the circuit, area, facility or equipment inspected, the inspector, the date of the inspection, and any problems (or items requiring corrective action) identified during each inspection, as well as the scheduled date of corrective action.

D Reporting

By July 1st each utility subject to this General Order shall submit an annual

report for the previous year under penalty of perjury.

The report shall list four categorical types of inspections: Patrols, Overhead Detailed, Underground Detailed and Wood Pole Intrusive. The report shall denote the total units of work by inspection type for the reporting period and the number of outstanding (not completed) inspections within the same reporting period for each of the four categories.

Sample Report Template:

Type of Inspections (1)	Due (2)	Outstanding (3)
Patrols	xxx	xxx
OH Detailed	xxx	xxx
UG Detailed	xxx	xxx
Wood Pole Intrusive	xxx	xxx

Notes:

- 1) Each utility will define its reporting unit basis (e.g., circuit, grid, facility / equipment).
- 2) Total inspections due in the reporting period. (Does not include outstanding inspections from prior years.)
- 3) Total inspections required that were not completed in the reporting period. (Does not include outstanding inspections from prior years.)

IV. Transmission Facilities

Each utility shall prepare and follow procedures for conducting inspections and maintenance activities for transmission lines.

Each utility shall maintain records of inspection and maintenance activities.

Commission staff shall be permitted to inspect records and procedures consistent with Public Utilities Code Section 314 (a).

/s/ Paul Clanon
Paul Clanon
Executive Director

Appendix A

**Table 1
Distribution Inspection Cycles (Maximum Intervals in Years)**

	Patrol		Detailed		Intrusive	
	Urban	Rural	Urban	Rural	Urban	Rural
Transformers						
Overhead	1	2 ¹	5	5	---	---
Underground	1	2	3	3	---	---
Padmounted	1	2	5	5	---	---
Switching/Protective Devices						
Overhead	1	2 ¹	5	5	---	---
Underground	1	2	3	3	---	---
Padmounted	1	2	5	5	---	---
Regulators/Capacitors						
Overhead	1	2 ¹	5	5	---	---
Underground	1	2	3	3	---	---
Padmounted	1	2	5	5	---	---

Overhead Conductor and Cables	1	2 ¹	5	5	---	---
Streetlighting	1	2	X	x	---	---
Wood Poles under 15 years	1	2	X	x	---	---
Wood Poles over 15 years which have not been subject to intrusive inspection	1	2	X	x	10	10
Wood poles which passed intrusive inspection	---	---	---	---	20	20

(1) Patrol inspections in rural areas shall be increased to once per year in Extreme and Very High Fire Threat Zones in the following counties Imperial, Los Angeles, Orange, Riverside, Santa Barbara, San Bernardino, San Diego, and Ventura. Extreme and Very High Fire Threat Zones are defined by California Department of Forestry and Fire Protection’s Fire and Resource Assessment Program (FRAP) Fire Threat Map. The FRAP Fire Threat Map is to be used to establish approximate boundaries and Utilities should use their own expertise and judgment to determine if local conditions require them to adjust the boundaries of the map.

Note: This General Order does not apply to cathodic protection systems associated with natural gas facilities.

Note: For the purpose of implementing the inspection intervals in Table 1 above, the term “year” is defined as 12 consecutive calendar months starting the first full calendar month after an inspection is performed.

General Order 166, Standard 1.E
Adopted Rule in Final Form

E. Fire Prevention

For those electric utilities identified below, the plan shall describe the measures the electric utility intends to implement, both in the short run and in the long run, to mitigate the threat of power-line fire ignitions in situations that meet all of the following criteria: (i) The force of sustained winds exceeds the maximum working stress specified in General Order 95, Section IV, for installed overhead electric facilities; (ii) the installed overhead electric facilities affected by the sustained winds are located in geographic areas designated as the first or second highest fire threat area on a fire-threat map adopted by the Commission in Rulemaking (R.) 08-11-005; and (iii) the sustained winds occur at the time and place of a Red Flag Warning issued by United States National Weather Service. The requirement to prepare a fire-prevention plan applies to: (1) Electric utilities in Imperial, Los Angeles, Orange, Riverside, Santa Barbara, San Bernardino, San Diego, and Ventura counties; and (2) electric utilities in all other counties with overhead electric facilities located in areas of high fire risk as determined by such utilities in accordance with Decision 11-XX-YYY issued in Phase 2 of R.08-11-005.

Note: The existing GO 166 Standards 1.E (Safety Considerations) through 1.I (Plan Update) are renumbered Standards 1.F through 1.J.

(END OF APPENDIX B)

Appendix C: Adopted Interim Fire-Threat Maps

Reax Map

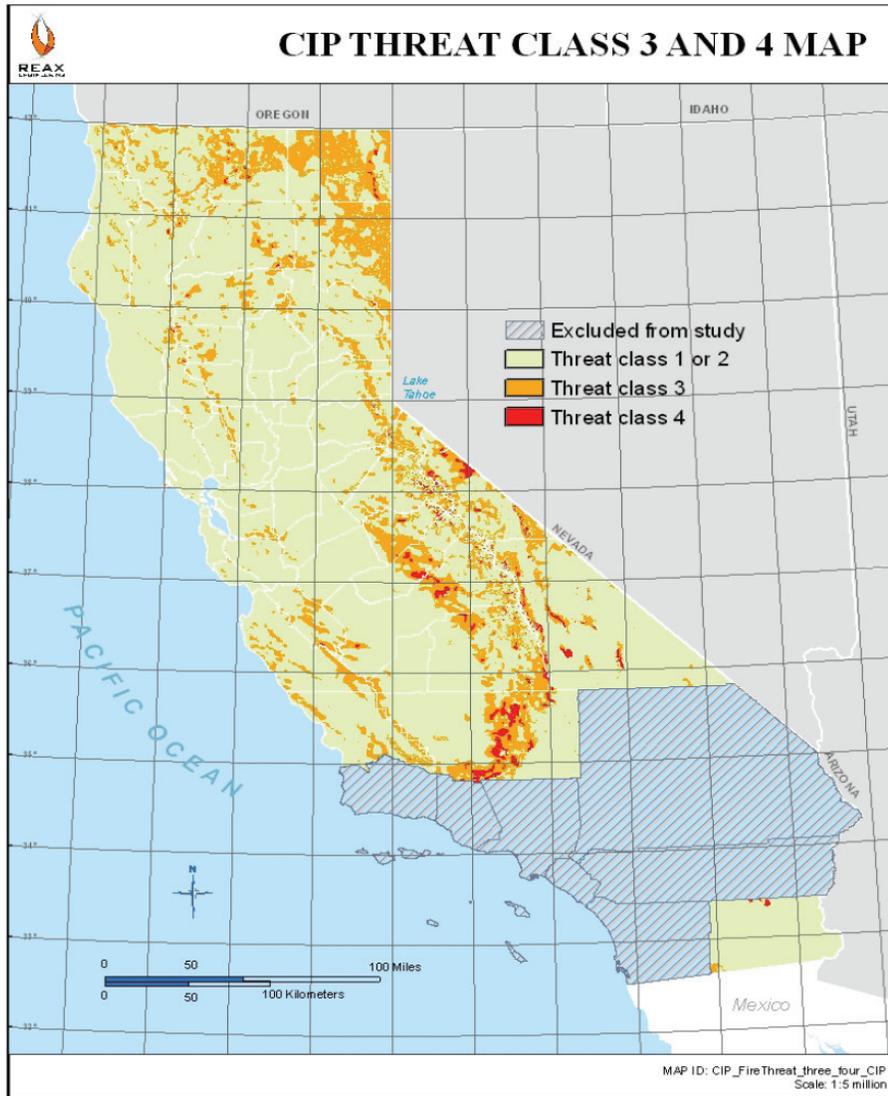


Figure 24. CIP fire threat class three and four map. (three_4_cip.jpg)



(END OF APPENDIX C)