Pacific Gas and Electric Company™

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July 28, 2023

BY ENERGY SAFETY E-FILING

Caroline Thomas Jacobs
Director, Office of Energy Infrastructure Safety
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Re: **<u>Pacific Gas and Electric Company's Comments on the Public Workshop on Safety Requirements to Address Increasing Wildfire Risk from Climate Change and Aging Infrastructure</u>**
Docket: Electrical: Wildfire Safety Requirements Recommendations / 2023-WSRR

Dear Director Thomas Jacobs:

Pacific Gas and Electric Company (PG&E) respectfully submits the following comments on the Public Workshop on Safety Requirements to Address Increasing Wildfire Risk from Climate Change and Aging Infrastructure held by the Office of Energy Infrastructure Safety (Energy Safety) on July 13 and 14, 2023.

I. PROPOSED REGULATORY CHANGES FOR CONSIDERATION

PG&E greatly appreciates the efforts of Energy Safety to bring together regulatory agencies, stakeholders, and the public to participate in a dialogue on how regulation could best address the increasing wildfire risk in California. We strongly believe that regulatory requirements must prioritize risk, flexibility, and efficiency. Below we offer some specific examples of where applying a risk-focused, flexible, and efficient approach to regulatory requirements could offer considerable public benefit. As can be seen, these examples demonstrate that these goals are often interconnected, and that one will naturally follow the other.

A. Removal of the Requirement for Placing High Voltage Signs on Distribution Poles Will Allow Resources to Be Better Used to Eliminate Asset-Based Risk.

A relatively small regulatory change that could provide an outsized impact on electrical utilities would be to remove the requirement for marking distribution poles with high voltage signs. GO 95, Rule 51.6 requires that poles supporting line conductors of over 750 volts be marked with high voltage signs no more than 40 inches below the lowest conductor on the pole. This is an archaic rule that is no longer required in any state other than California, and which no longer serves a useful purpose. While at one time it was difficult to distinguish electrical lines from telephone or telegraph lines on a pole, such is no longer the case, and the lines are visually distinct. Inspecting for, and installing, high voltage signs is a substantial burden on the electrical utilities that is of negligible benefit to the general public or to the trained workers who climb the poles. Thus, we recommend that this vestigial requirement be eliminated to bring California in line with the rest of the country and to allow these significant resources to be directed to inspecting and performing repairs on asset conditions that represent substantial risk to the public and the electrical workers.

B. Targeted Regulation on Pole Loading Could Improve Public Safety.

Other modest regulatory changes that could yield significant safety impact relate to pole loading on joint poles. First, there could be a positive safety impact from a requirement that any joint owner of a distribution pole transfer its assets and remove a topped, old pole (also called a "buddy pole") within 180 days after the completion of the construction on the new pole. There are currently tens of thousands of these buddy poles that are in need of removal because they no longer meet the safety factors required to pole loading and for which many municipalities have expressed concern. Clarification from the regulators on this issue—potentially by revising GO 95, Rule 31.6 to include dual/buddy poles—could help alleviate this growing safety issue.

Second, we recommend revisions to GO 95, Rule 44.1, concerning installation and reconstruction. Rule 44.1 currently states that the entity responsible for performing the loading calculations for an installation or reconstruction shall maintain records of these calculations for the service life of the pole or other structure for which a loading calculation was made and shall provide such information to the Commission upon request. This requirement is not sufficient to prevent tenants from adding lines to in-service poles without notifying the owner and causing the pole to overload. Thus, Rule 44.1 should be revised to further state that: "Any changes to the facility without notifying the base owner of the facility will be considered an unauthorized attachment and subject to all applicable penalties. Unauthorized attachments must be removed until attachments are approved by the base owner. Any attacher that has overloaded a pole is required to immediately remove the unauthorized facilities." We also recommend that this same language be added to GO 95, Rule 44.2, which concerns additional construction, and where there is a similar problem of unauthorized attachments causing poles to overload.

C. The Scheduling of Overhead and Underground Inspections Should Focus on a Risk-Based Approach and Maximizing Efficiency.

Changes to the regulations around the overhead and underground inspection process could allow for this work to be performed more efficiently and reduce the impact on customers. Specifically, aligning inspection cycles for overhead and underground assets would allow the inspections to be completed at the same time, with the same crew. This would positively impact customers who would be subject to less visits and suffer from less interruptions, as well as the inspectors who would have a safer working environment due to having to drive less miles. Finally, this would also benefit the utilities and their customers since less time and money would be spent on performing inspections in different years and this effort could be redirected to other risk-based inspection/maintenance efforts. In Table 1 to the appendix of this filing, we include the current inspection cycle for distribution assets, highlighting the specific areas where change would be beneficial.

Additionally, updating the due dates for inspections to allow for more flexibility through a risk-based approach could provide significant efficiencies and increase safety. The current regulations, under GO 95, Rule 80.1(A)(1), set due dates based on a rigid 15-month timeframe for inspections be performed. However, performance of inspections can be significantly impacted by weather, as we saw with the unprecedented winter storms earlier this year. An inflexible due date can pose challenges for safely performing these inspections in a timely manner. Furthermore, allowing inspection due dates to be set based on risk (for example, to align with fire season) could make this process both safer and more efficient (since it could eliminate the need for voluntary, supplemental inspections during specific high-risk periods). This increased efficiency could then be used to re-invest in future technologies, such as drone, LiDAR, and artificial intelligence, all of which are currently being explored.

D. Regulatory Efforts in Vegetation Management Would Benefit from Coordination with Other Regulatory Agencies.

While numerous potential changes to vegetation management regulations were explored at the workshop, PG&E urges Energy Safety to work in concert with the California Board of Forestry who is currently seeking to revise 14 California Code of Regulations (CCR) Section 1250 to 1258, as opposed to pushing for the creation of new General Orders. The Board of Forestry has undertaken this effort in partnership with Cal Fire and the California utilities, and as this process is still ongoing, Energy Safety's contributions would be valuable. This coordination would ensure consistency and allow for the codification of flexible vegetation management requirements and standards that reflect modern practices and future technological advancements. Working with the other regulatory agencies (including Cal Fire, the Commission, and the Board of Forestry Administrative Staff) would help align expectations, prevent unnecessary site visits and re-work, and increase safety by allowing resources to be used in the most risk-efficient manner.

E. Flexibility Should Be Prioritized in Regulation Related to System Hardening, Undergrounding and Grid Operations.

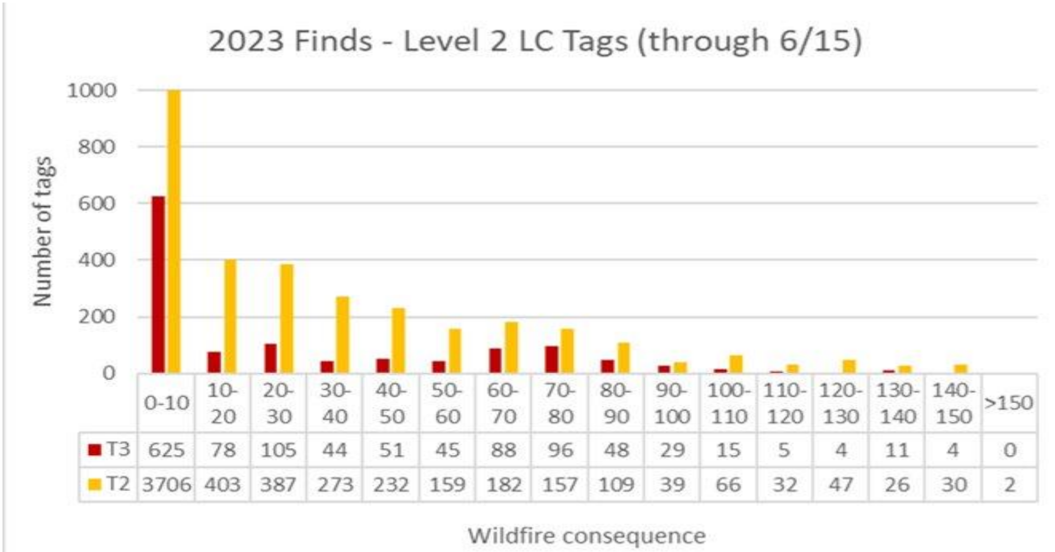
Given the rapid pace of technological change in these areas, PG&E specifically wishes to emphasize that regulatory efforts in relation to system hardening, undergrounding and grid operations focus on flexibility. This includes both the flexibility to use the right tool (different construction methods, design approach, etc.) for the right location in order to reduce wildfire risk and the flexibility to evaluate, pilot and use new technologies in the future. In the next several years, utilities will learn a lot about how to cost effectively reduce wildfire risk leveraging the latest tools and technologies. To this end, the regulatory framework would ideally be set up to allow utilities to deploy those lessons learned. An example of this may be the "level grounding" electric line installation tool set that PG&E is currently testing out and which may efficiently provide significant safety benefits for communities in high fire risk areas. Thus, regulations should be sufficiently flexible to allow for different combinations of mitigations depending on a particular situation. Overly regulating certain mitigations may result in sub-optimization, less risk reduction, and higher costs.

Similarly, flexibility should be prioritized in regulations related to electric utility and communications lines, since this can have a substantial impact on the cost of undergrounding work. With the latest available technologies, and as technology continues to evolve, communications lines often do not require the same level of separation as is currently defined by GO 128. Providing clear support for electric utility and communications companies to align on the appropriate separation of underground assets, as opposed to continuing to have rigid requirements, could substantially reduce the cost and complexity of future undergrounding projects.

While potentially beyond the scope of these workshops, an important, related issue is the alignment of requirements across different regulatory agencies. If requirements and regulations can be aligned, it can result in significant improvements to the cost efficiency of key risk reduction programs like undergrounding. An example of this would be the minimum cover requirements for underground electric conduits. Specifically, GO 128 establishes a minimum cover requirement of 24 inches which allows flexibility to perform undergrounding cost effectively in some locations, particularly where hard rock makes digging deeper increasingly costly. However, policies or requirements of other agencies, for example the California Department of Transportation, may be misaligned with this regulation and require substantially more depth of cover (e.g., 42 inches) even when underground lines are not being placed in the actual roadway. Another example of this would be the designation of some roads as 'highways' by the State and supported by local governments, which subjects them to increased regulation and makes wildfire risk reduction work adjacent to those roads meaningfully more costly. Therefore, it is worth considering that increasing the flexibility of General Orders may not have a significant effect on improving the cost effectiveness of wildfire risk reduction activities if similar policies or regulations of other agencies remain more onerous.

F. Asset Replacement and Repair Should be Risk Informed Rather Than Based on the Static High Fire Threat Maps.

GO 95, Rule 18 asset repair times are based on the High Fire Threat District (HFTD) tier map. While this was an important first step in prioritizing tags based on risk, the utilities and regulators are now able to perform much more sophisticated analyses to calculate asset-based risk than they were five years ago, as is demonstrated in Energy Safety's ongoing Risk Modeling Working Group. As a result, it is now apparent that asset tags in Tier 3 may have a lower ignition consequence than some tags in Tier 2, which can be seen in the chart below, but which is not reflected in the rigid timelines set out in Rule 18.



The chart depicts the ignition consequence (based on our modeling) for Level 2 tags found in 2023 (through mid-June) in both HFTD Tier 2 and Tier 3 areas. The chart demonstrates that there are a substantial number of tags located in Tier 2 with a higher wildfire consequence than some of the tags found in Tier 3. Despite this, under the Rule 18 timelines, work in Tier 3 must be prioritized despite its lower safety impact. Given this discrepancy, we recommend that GO 95, Rule 18 asset repair times be revised to reflect a more advanced risk-based approach. This will allow the greatest reduction in wildfire risk and benefit to the public.

G. Reporting Requirements Should Similarly Be Risk Based and Not Overly Prescriptive.

As with the other recommendations included in these comments, we strongly believe that reporting requirements should be risk-focused and not overly rigid. An excellent example where this approach could be beneficial is for reporting requirements related to ignitions. Given that catastrophic wildfires are more likely to occur in concentrated high-risk periods, it is substantially more valuable to implement reporting requirements that capture this risk, rather than those that do not. Thus, Energy Safety's current reporting requirements, codified under 14 CCR Section 29300, require utilities to report an extremely broad scope of ignitions regardless of size or risk. We recommend a more sophisticated approach to these requirements that considers the risk conditions (for example, Red Flag Warnings or high wind events) when implementing reporting requirements.

II. CONCLUSION

We appreciate the opportunity to provide these comments and look forward to further discussion and engagement on this important topic.

Should you have any questions or concerns, please do not hesitate to contact the undersigned at vincent.tanguay@pge.com.

Very sincerely yours,

/s/ Vincent Tanguay

Vincent Tanguay

APPENDIX

Table 1 below depicts the current inspection cycles for distribution assets, with the discrepancy in the timing for underground and overhead assets in red. PG&E recommends aligning the inspection frequency for distribution and overhead to reduce the impact on customers, decrease the amount of travel time/driving for inspectors (a positive safety impact), and increase the efficiency of the inspection process, allowing utilities to reallocate resources to other risk-based mitigation work.

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